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Executive Summary

The European Union consumes annually about 400 to 450 bcm natural gas, if completely burned corresponding with an annual CO_2 emission ranging between some 710 and 800 MtCO_2e. The EU reference scenario assumes that by 2030 the overall gas consumption will not be much different, albeit that by then the current (2016) import share of natural gas of 72% will have increased to about 79%. The target of the EU is to reduce its greenhouse gas (GHG) emissions by 80 – 95% below 1990 levels by 2050. This means that natural gas can no longer be used by that date, unless the CO_2 linked with the burning of natural gas can be stored underground or otherwise compensated by additional mitigation.

So far, the greening of the gas system has typically focused on the introduction of biogas and biomethane, almost exclusively produced with the help of anaerobic digestion technology. Subsidy schemes have promoted the production of biogas, although with varying success across the EU Member States. Most of the biogas throughout Europe is produced in the North-western part of it, with Germany being a clear champion (about half of the EU production volume). Due to technical and cost issues, only a limited share of the biogas is upgraded such that it can enter the grid as biomethane: so far some 11% only. The rest of the biogas is used for the production of heat and power.

So far, the greening of the gas system, based on biogas and biomethane, has proceeded to a share of about 4%. Estimates as to how this share may increase towards 2030 differ, because this progress will obviously depend on incentives, public acceptance, and technology learning curves. The scenarios that can be considered optimistic in this regard suggest that the current 4% share could grow towards 12%, at least if biomass gasification technologies – currently still in their infancy – would also add somewhat to the volume.

Although methane is currently the most important gaseous energy carrier in our economy, hydrogen could fulfil a similar role. A gradual shift from our current natural gas-based world to a hydrogen economy could take place in the foreseeable future. Hydrogen from renewable sources is therefore also considered in this report.

So, a relatively new development in ‘greening’ gas is the power-to-gas technology in which renewable power from wind and solar energy is turned into green hydrogen. The green hydrogen can be used directly but also be further converted in either green methane via methanation, or into green liquids through various conversion technologies. Although power-to-gas technologies are just only in their pilot stage, this technology is considered a promising new way to turn renewable energy surpluses into an energy form that is easy and cheap to store, to transport, and to apply. The technology, however, still has to go through a considerable part of the learning curve, which explains why most scenarios assume that by 2030 it is unlikely that considerable volumes of green gases (hydrogen or methane) will be put on the market based on power-to-gas technologies. Still, it seems not unlikely, obviously depending on the incentives towards this technology, that by 2030 green gases based on power-to-gas will represent a few percent of the EU-wide gas volume. After that year, it is well conceivable that power-to-gas technology and the green gases based on it will exponentially grow in use throughout Europe, especially if mobility would turn massively towards green hydrogen/green gas cars, and if the chemical industry would (need to) replace hydrogen feedstock from natural gas by green hydrogen from renewables.

How much of the gas will be green by 2030 also strongly depends on the acceptance of certificates. On the one hand, guarantees of origin (GoOs) are certificates based on the physical production of green gases. On the other hand, CO_2 certificates are based on other ways of reducing GHG emissions of all kinds globally. All certificates can be linked to natural gas to ‘green’ the gas, assuming that these certificates are not abused for double-counting. The certificate market, buoyant under the Kyoto Protocol regime, has currently been less prominent in volume worldwide, but could easily grow again in volume if the demand or certificates in order to ‘green’ e.g. natural gas would grow. It is difficult to make any projections for 2030 on the degree to which certificates could grow in importance to ‘green’ the about 400 bcm of gas to be consumed across the EU in 2030 (according to the EU reference scenario), but this share could become substantial indeed. Scattered information suggests the increase in popularity of this way of ‘greening’ gas.

In this report, the various factors determining the greening of gas across the EU by 2030 have been inventoried, and summarised in four scenarios, that differ in the degree to which markets on the one hand and policies and measures on the other hand create incentives to get to green gases. In the two extreme scenarios, either (in the optimistic scenario) the share of green gas would grow towards 13 to 14% even if the ‘greening’ through CO_2 certificates would not be included, or (in the pessimistic scenario) the current share of about 4% would hardly grow (some 4.5%), again excluding the greening through CO_2 certificates. Obviously, if the ‘greening’ through CO_2 certificates is included in the scenarios, the differences mentioned could grow towards much wider proportions.

1 Introduction

Natural gas is currently fulfilling a large part of the energy requirements in Europe: about 25% of the primary energy demand in the EU is delivered by natural gas (European Commission, 2016). Natural gas is a gas mixture that consists primarily of methane and it has many different applications: it can be used to generate electricity, for heating, as a fuel for cars, and also as a feedstock for industry.

Figure 1 shows the natural gas consumption and production in the European Union between 2002 and 2016. The consumption of natural gas has been declining between 2010 and 2014 but is increasing again in recent years. In 2016, there was a sharp increase in gas consumption of 30 billion cubic meters (bcm), which was the fastest growth since 2010. This was caused by both the increasing competitiveness of gas relative to coal, and weakness in production of nuclear and renewable energy in Europe (BP, 2017a). The production of natural gas in the EU has been steadily decreasing in this period. The percentages displayed in the figure indicate the share of total consumed natural gas in the EU that was produced within its own borders. The figure shows that this share has also been decreasing: in 2002 the EU was producing half of its own natural gas consumption while this was reduced to only 28% in 2016, thereby increasing the EU's dependency on gas imports.

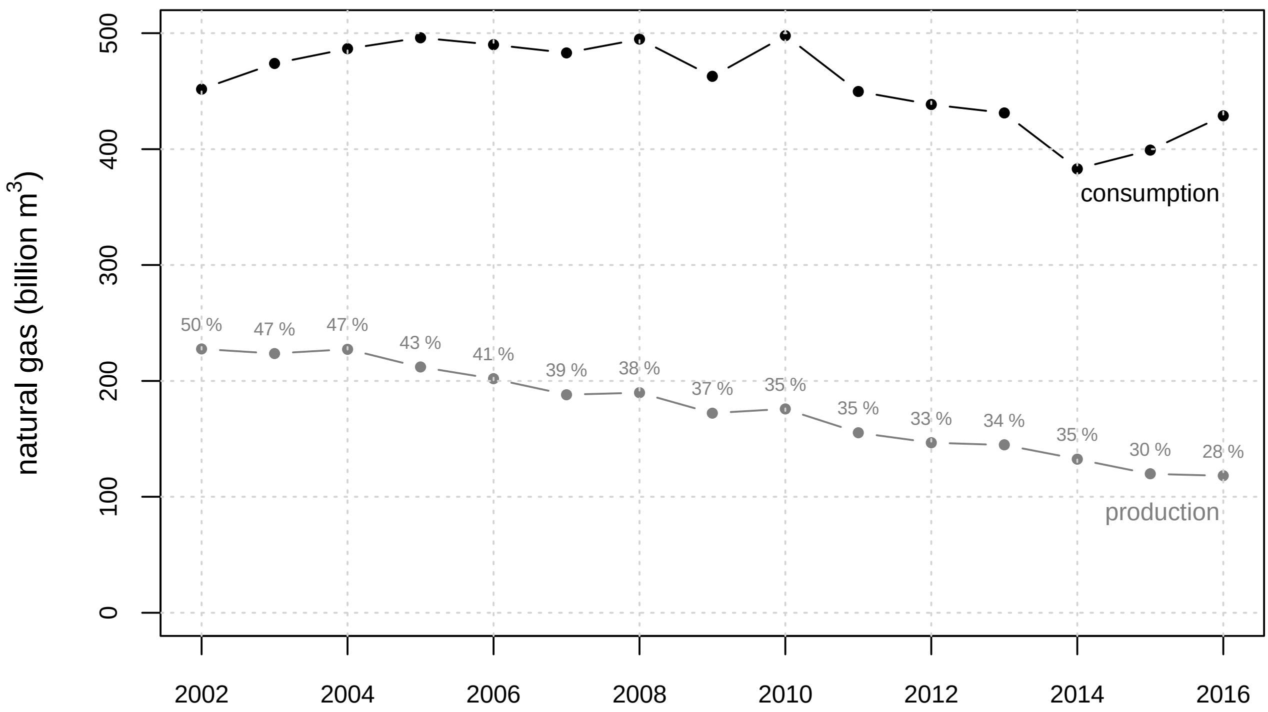

Figure 1: Natural gas consumption and production in the EU between 2002 and 2016. The share of production in the total consumption is added to the graph. Data are retrieved from BP (2017a; 2013).

The vast majority of natural gas in the EU is produced in the Netherlands and the UK, each country taking up a share of roughly 30 – 40% of total EU production. In both countries, natural gas production has been decreasing. Other EU countries with some natural gas production are Denmark, Germany, Italy, Poland, and Romania. Also in these countries production has decreased in recent years. The largest producer of natural gas in Europe is Norway: in 2015 and 2016 this country produced roughly the same amount of natural gas as the whole EU combined (BP, 2017a).

According to the EU Reference scenario (European Commission, 2016), natural gas consumption in the EU is expected to remain relatively stable in the coming decades – varying somewhere between 400 and 450 bcm per annum up to 2050, if completely burned corresponding with an annual CO_2 emission ranging between some 710 and 800 $MtCO_2e$.

The gas production in the EU is expected to continue to decrease reaching volumes of only 87 and 59 bcm in 2030 and 2050 respectively, which would correspond to 21% and 14% of the expected natural gas consumption in those years only. The dependency of the EU on natural gas imports will therefore continue to increase.

Besides the wish to keep its gas import dependency limited, the EU has set targets to significantly reduce GHG emissions. Producing biomethane – a green substitute for natural gas – is serving both goals. Biomethane is essentially the same as methane – and therefore also has the same applications – but it is made from renewable biomass such as energy crops, organic waste and sewage. To produce biomethane, biomass is first converted into biogas, which is a pre-stage of biomethane consisting not only of methane but also of large amounts of carbon dioxide (CO_2) and some other trace gases. The biogas can be used directly to produce electricity or heat, but can also be upgraded to increase the methane content and obtain biomethane, which can be injected in the natural gas grid or used directly in for example the transport sector.

Due to successful policies in various Member States of the EU, biogas production has increased rapidly in recent years (CE Delft et al., 2017), with the number of biogas installations amounting to 17,376 by late-2015 (EBA, 2016). Figure 2 shows the biogas production in the EU between 2004 and 2015 in million tonnes of oil equivalent (Mtoe)[1].

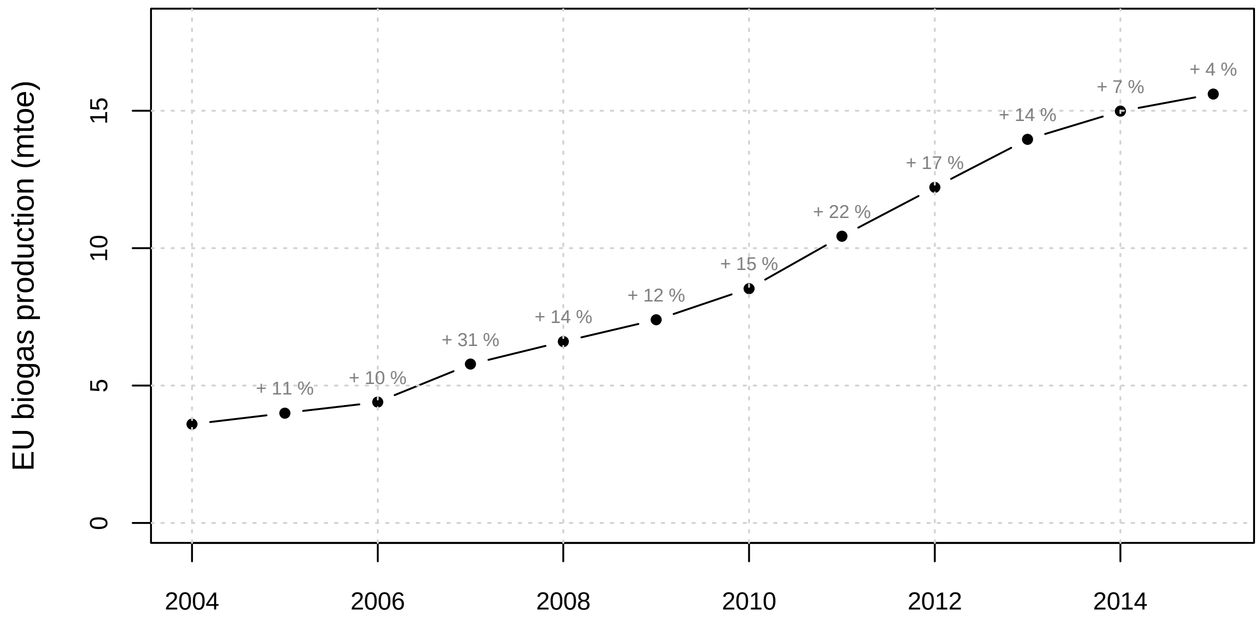

Figure 2: Biogas production in the EU between 2004 and 2015 according to Eurostat (2016a) including yearly growth rates.

In 2015, EU biogas production was equal to 15.6 Mtoe, of which roughly 50% (7.8 Mtoe) was produced in Germany. Other large biogas producers in the EU are the UK (2.3 Mtoe in 2015) and Italy (1.9 Mtoe in 2015)[2] (Eurostat, 2016a). Biogas is produced at wastewater treatment plants, at landfills, and from other biomass by anaerobic digestion (AD). These three methods roughly covered 10%,

[1] The energy amount of biogas in Mtoe can be converted into bcm (billion cubic meters in natural gas equivalent) with a factor 0.9, with 1 bcm = 0.9 Mtoe (BP, 2017b). This means that in 2015 15.6 Mtoe or 17.3 bcm natural gas equivalent of biogas was produced.

[2] Biogas production in other EU Member States is limited, with the Czech Republic, France, and the Netherlands being the 4th, 5th and 6th EU biogas producers with production levels of 0.6, 0.5 and 0.3 Mtoe respectively.

21% and 69%, respectively, of the total biogas production in recent years in the EU (CE Delft et al., 2017; EurObserv'ER, 2014). The green share in total methane production is equal to roughly 4%.[3] Although volumes of biogas production in the EU are still increasing, Figure 2 shows that the growth rate has slowed down in recent years.

Most of the biogas is used directly to produce green electricity or heat. Upgrading of the biogas to biomethane only covers a substantial percentage of biogas use in Sweden, the Netherlands and Germany. In Germany and the Netherlands, most of the biomethane is injected into the natural gas grid, whereas in Sweden it is mostly transported to its final destination by trucks[4] (CE Delft et al., 2017). Biomethane production is also becoming increasingly interesting for countries in the EU because it enables them to reduce their dependency on natural gas imports (EurObserv'ER, 2014). It is especially interesting for those countries that perceive themselves as being highly and increasingly vulnerable for foreign imports of gas.

Data on volumes of biogas upgraded to biomethane are not widely available. According to CE Delft et al. (2017), about 11% of the generated energy from biogas was used for biomethane production in 2014. The rest was used for electricity (62%) and heat (27%) production. This would imply a EU-wide production of 1.6 Mtoe biomethane (1.8 bcm) in 2014. EBA (2016) gives an overview of biomethane production in the EU, specified per country. They state that biomethane was produced in 15 countries in 459 biogas-upgrading plants in 2015 and estimate total biomethane production at 1.23 bcm. As no volumes were known, however, for 5 out of the 15 countries (representing 29 of the 459 plants), this figure probably underestimates the true biomethane production.

The volumes of biogas and biomethane have remained modest so far, at least as percentage of natural gas consumption, but the upward trend is clear. The key question is therefore if, and to what extent this trend will continue in the coming one or two decades. This question includes both the further increase of AD and biogas upgrading plants, as well as possible developments in the fields of alternative biomethane production methods.

Although currently virtually all biomethane is produced from landfills, sewage, or with AD, it can also be produced by two alternative methods called biomass gasification and methanation of renewable hydrogen. In gasification, solid biomass such as woody biomass is converted into a mixture of mainly carbon monoxide (CO), hydrogen (H_2) and carbon dioxide (CO_2), called syngas. This is done at high temperatures under influence of oxygen. Syngas is a fuel that can be used directly but it can also be converted into hydrogen, methanol, or methane. Renewable produced hydrogen can be converted into biomethane via methanation. For this, an external source of CO_2 is required. The most evident method to produce renewable hydrogen is power-to-gas. With power-to-gas, (renewable) electricity is used to split water into hydrogen (H_2) and oxygen (O_2). The two alternative biomethane production methods are currently still in their pilot phase but have the potential to significantly increase the volumes of biomethane production in the near future (CE Delft et al., 2017).

Although biomethane is usually considered as *the* green gas and often also simply called green gas, carbon-neutral produced hydrogen can also be called a green gas. Just as methane, hydrogen is a gaseous energy carrier that could be used in many different applications such as power generation and transportation. A gradual shift from our current natural gas-based world to a so-called “hydrogen economy” in which hydrogen becomes the main energy carrier (taking over the role of methane) is

[3] In 2015, natural gas consumption was equal to 399.1 bcm and biogas production was 17.3 bcm natural gas equivalent, which is 4% of the total methane consumption.

[4] In Sweden biomethane transport by truck is common practice due to a limited gas infrastructure. Biomethane is used mostly as a fuel in the transportation sector, which is stimulated by tax exemptions (CE Delft et al., 2017).

foreseen in many different studies, articles, and reports (e.g. (Mazloomi and Gomes, 2012; Ogden, 1999)).

Hydrogen is currently primarily used in refineries (for hydrocracking of crude oil) and in the chemical industry as a feedstock for primarily ammonia and methanol production. Ammonia is used to produce fertilizers and its production consumes over half of all produced hydrogen in the EU (Certifhy, 2015; Stolten and Emonts, 2016). Hydrogen generation and consumption generally takes place at the same site to limit safety hazard issues arising from transport and storage. Due to this on-site production of hydrogen, it is difficult to estimate total volumes of global hydrogen production and reported numbers are uncertain (Stolten and Emonts, 2016). Certifhy (2015) estimates the EU consumption of hydrogen at roughly 8 million tonnes, with the industry sector consuming 90% of the total, equal to roughly 7 million tonnes. Within the industry sector, the chemical sector consumes about 4.3 million tonnes (63% market share) and the refinery sector 2.1 million tonnes (30% market share). It is assumed that consumption of hydrogen in the industry sector will grow with a constant rate in the coming years up to 2030 (Certifhy, 2015). When the hydrogen economy will come off the ground, the use of hydrogen will not be limited anymore to the industrial sector but will also be widely used in other sectors such as mobility and power generation.

Around 96% of the hydrogen is currently produced from fossil fuels. Refineries produce the majority of the required hydrogen through internal refinery processes and the remaining amounts by gasification of heavy residues. The vast majority of hydrogen in the chemical industry is produced through steam reforming of natural gas. Gasification of coal is another important technique for hydrogen production in the chemical industry. Steam reforming and gasification can also be applied to other feedstock (Stolten and Emonts, 2016).

Alternative to production from fossil fuels, hydrogen can be generated with power-to-gas, as was already explained above. Electrolysis is currently responsible for roughly 4% of the global hydrogen production and is mainly applied in processes where relatively small amounts of extremely pure hydrogen are required (Stolten and Emonts, 2016). The source of electricity is important for determining whether the produced hydrogen is green or not.

1.1 Scope of the study

This study aims to make projections for the 2030 EU-wide demand for green gases as part of overall EU demand for gases. Green gases are defined as *gaseous energy carriers offered to the market without a serious GHG footprint*. The latter means that green gases not only comprise biogas/biomethane, but also green hydrogen, green syngas, and possibly even also natural gas ‘greened’ with the help of reliable green certificates guaranteeing additional GHG emission reduction. The definition of what is and what is not a green gas will be extensively discussed in the next chapter (section 2.1).

In order to make projections, information on supply and general market conditions is obviously crucial, because demand can only be exercised if supply is able to match such demand. That is why a fairly extensive overview of production and supply of green gases is provided in section 2.2. Transport and storage and certificates of green gases are also discussed in chapter 2.

Chapter 3 describes the demand for green gases for the four different energy consumption sectors mobility, industry, power generation and built environment. Much of the demand for green gases is driven by policies and measures. For example, EU regulation demanding a certain percentage of gas consumption to be green or demanding fertiliser production to be only based on green hydrogen input would strongly increase the demand for green gases. Demand can also be driven by autonomous demand shifts fuelled by a generic awareness of climate and other environmental concerns, or by other factors such as general development in welfare. In this report, it has not been tried to provide a comprehensive econometric analysis of factors driving the demand for green gases because it is assumed that such analysis would be blurred too much by the impact on demand of possible policy scenarios. One particular issue at the demand side, that will be given somewhat more attention, is the ‘willingness to pay’ for ‘green’. Section 3.5 gives some insight into the degree to which end-users would be prepared to pay a premium for a green fuel. With regard to the rest of the report, we have chosen to focus on the conceivable interplay between market and policy developments that together give shape to a number of scenarios.

In chapter 4, four scenarios will be distinguished that vary in terms of the market-driven factors affecting the relative price of green gases versus that of fossil fuel based gases on the one hand, and on the degree to which policies and measures will support production and use of green gases on the other hand. The two extreme scenarios are those in which both policies and measures and the market (i.e. including technological and autonomous market uptake developments) develop favourably, or either slow or even stagnant. In the four scenarios, the EU-wide use of green gases in the overall gas demand up to 2030 will be sketched and assessed. The report ends with a discussion and conclusions.

2 Green gases

This chapter describes the key aspects of green gases. Section 2.1 discusses the important issue of defining of what is and what is not a green gas. Section 2.2 discusses the production technologies for biomethane (section 2.2.1) and green hydrogen (section 2.2.2) and the developments, costs and potential production volumes of these technologies. Transport and storage of green gases are shortly discussed in section 2.3 whereas policies and measures relevant for the production of green gases in the EU are discusses in section 2.4.

2.1 Definition of green gases

What is a green gas? The term green gas is often used to indicate biomethane, typically referring to methane produced from renewable biomass that is upgraded to obtain a gas quality similar to that of natural gas. Besides production from landfills, sewage and biomass by anaerobic digestion (AD), biomethane can also be produced from woody biomass via gasification or from renewable produced hydrogen combined with carbon dioxide. Although biomethane might be considered as *the* green gas, other gaseous energy carriers could also be called green gases: the main examples of this are raw biogas (containing roughly 60 Vol.-% methane and 40 Vol.-% CO_2) and renewable produced hydrogen.

In this study, a green gas is defined as *a gaseous energy carrier offered to the market without a serious GHG footprint*. Both methane and hydrogen are taken into account as gaseous energy carriers. Although the definition seems to be quite straightforward, it implicitly contains a number of issues that deserve to be discussed, most importantly the acceptable system boundaries, the acceptable sources for production of the gases and the use of certificates. In the following three subsections, these issues will be shortly discussed.

2.1.1 System boundaries

To produce a green gas without a serious GHG footprint is quite a challenge. For example, consider the production of biomethane from biomass that is produced by agriculture. Several questions arise with determining whether or not there is a serious GHG footprint associated with the biomethane production. Does the complete agricultural footprint need to be taken into account, including the use of heavy machinery and fertilizers? Should one also take into account the footprint of transport and storage of both the biomass and the final produced biomethane? If these things need to be taken into account, when is the footprint labelled as “serious”? To answer these questions it is important to define the system boundaries. In the extreme, one could implement a complete life cycle assessment, but this would still leave open at what level the footprint would be serious enough to prevent the gas from being labelled green.

2.1.2 Source of the gas

The feedstock used to produce methane or hydrogen determines whether or not the gases could be labelled green. There are several techniques for the production of green methane and green hydrogen, which all require different feedstock.[5]

Currently, over two-thirds of the green methane produced throughout the EU is generated from biomass by AD. Biomass is also widely used to produce biofuels for the transportation sector. This has

[5] The production technologies will be discussed extensively in section 2.2. This section only shortly discusses the possible influence of different feedstock on the green label.

led to a policy discussion on the sustainability of the biomass production process in terms of: competition of biomass use for food, local environmental issues, biodiversity and indirect land use changes (ILUC). Biomass materials used for biofuel or biomethane production are classified in three categories: food crops, waste and residue streams, and advanced materials, also often referred to as 1st, 2nd and 3rd generation biofuels. Biofuels produced from food crops were limited to 7% of the final consumption of energy in transport in the EU Member States under the amendment of the legislation on biofuels (European Commission, 2015). For biogas production, the feedstock is usually composed of different raw materials that fall under different categories of biofuels. Countries have to implement the EU Directive in national legislation. The UK government proposed to limit the input of energy crops for biogas production to 50% (CE Delft et al., 2017). The amount of energy crops is unlimited from a technical perspective but its utilisation is expected to be limited by future sustainability policies (CE Delft et al., 2017).

Except for production from biomass, renewable methane can also be produced from hydrogen (H_2) and carbon dioxide (CO_2) via methanation. To determine if the produced methane is green or not, the source of both the H_2 and the CO_2 are important.

Hydrogen, which is also a green gas itself, can be produced from natural gas or other fossil fuels such as coal. Production from fossil fuels is clearly not green, except possibly in case the produced CO_2 is not emitted to the atmosphere but stored underground in a geological formation with carbon capture and storage (CCS) or used in another process with carbon capture and utilisation (CCU). In the latter process, the CO_2 emission is only postponed, which is why it is debatable if this is really green. Using the same technique for hydrogen production from natural gas, biomethane can also be used for producing green hydrogen. Another option is to produce the hydrogen from electricity in a process called electrolysis, in which water is split into hydrogen and oxygen. The source of electricity determines whether or not the produced hydrogen can be considered green. Renewable electricity clearly produces green hydrogen, whereas fossil electricity does not. The use of nuclear electricity might also be acceptable for green hydrogen production as there are hardly any GHG emissions arising from nuclear power generation (Certifhy, 2016a).

There are many different sources of CO_2 that could be used for the methanation of renewable hydrogen. Options are ranging from coal-fired power plants, industry, biomass digesters, wastewater treatment plants, and ambient air. There are on-going discussions on what CO_2 sources are considered acceptable as an input for green methane production. In the case, for example, of a coal-fired power plant, it is argued that using its CO_2 for green gas production would in fact legitimise the continuation of the plant. CO_2 sources from industry might be more acceptable, depending on the circumstances. For some industrial processes (e.g. cement production), little or no green alternatives are available, thus making their CO_2 emissions unavoidable. Valorisation of these unavoidable CO_2 sources can help decreasing industrial GHG emissions (Meylan et al., 2017). Other options are the extraction of CO_2 from ambient air and using CO_2 originating from biomass conversion. These sources are usually considered as “green” and are thus accepted inputs for green methane production.[6]

2.1.3 Certificates

Green gas can be delivered by trucks or through dedicated pipelines. In this way, consumers directly receive the actual physical green gas. Alternatively, green gases can be transported through the natural gas grid, hereby often strongly reducing transportation costs. Both biomethane and green

[6] An extensive discussion about the influence of both the electricity and CO_2 source on the carbon balance of green methane produced with power-to-gas and subsequent methanation is given in Meylan et al. (2017).

hydrogen can be injected into the natural gas grid, although there are strict limits for hydrogen admixture in the grid. Once injected into the grid, no distinction can be made anymore between green and fossil gases. The only way to sell green gas that is transported through the natural gas grid is therefore by the use of certificates.

With the production of biomethane, a guarantee of origin (GoO) certificate is generated. The GoO is an expression of the sustainability of the source of the produced gas and can be traded separately from the gas itself. For renewable produced hydrogen, a certification system is not implemented yet. The EU project CertifHy developed a framework and roadmap for implementation of a certificate system for green hydrogen, which should be operational by 2020 (Certifhy, 2016a).

Because the biomethane production in the EU has been limited so far, green methane cannot be delivered to households in large quantities at the moment. Energy suppliers that offer green products to their customers therefore deliver natural gas combined with compensation projects throughout the world. Examples in the Netherlands are the green energy suppliers Greenchoice and vandebron. Both companies compensate all GHG emissions that are associated with the natural gas consumption of their customers with projects such as the additional protection and planting of forests. Greenchoice partially also delivers real upgraded biogas (Greenchoice, 2017; vandebron, 2017). Energy suppliers not focussing specifically on green energy also sometimes offer their customers the possibility to compensate their GHG emissions from natural gas use against an additional charge (e.g. Eneco (Eneco, 2017)). In Germany, energy suppliers offer similar options. The German company naturstrom offers physical biomethane to their customers, who can choose 10%, 20% or 100% biomethane in their gas mixture. The price for the gas depends on the share of biogas in the gas mixture (naturstrom, 2017).

Figure 3 summarises the discussed principles of green gas production, delivery and consumption with the use of certificates. The *gas certificates* in the figure are generated with actual green gas production and the total amount of green gas consumption is therefore the same as what was actually produced. The *CO_2 certificates* are generated from other GHG mitigation actions such as afforestation projects in the tropics. With this system, additional volumes of "green" gases are put on the market without actually being produced.

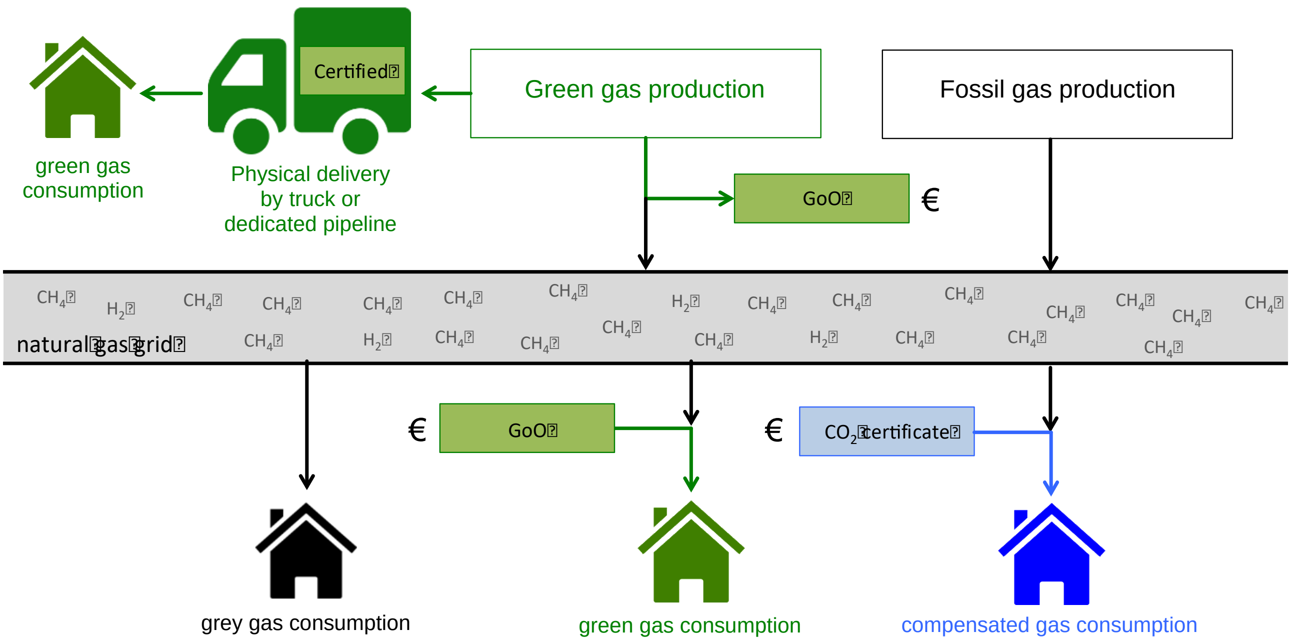

Figure 3: Illustration of the use of certificates with the production, delivery and consumption of green and grey gases, valid for both methane and hydrogen. Green gases can be transported by trucks or through dedicated pipelines to be delivered physically. Alternatively, they can be transported through the natural gas grid, but here,

no physical distinction can be made anymore between green and fossil gases. Certificates therefore have to determine which consumers consume green gas. Besides GoOs generated with the production of actual green gas, alternative CO_2 certificates from e.g. afforestation projects can be used to compensate the CO_2 emissions that arise from natural gas consumption.

2.2 Producing green gases and their potential supply

Several different techniques exist for producing biomethane and green hydrogen. The different technologies will be discussed in this section, including some estimates on the potential supply of green gases from these techniques.

2.2.1 Biomethane

Table 1 shows the five main technologies for producing biomethane.

Table 1: The five production technologies for producing biomethane.

#	Technology	Description
1	Waste water treatment plants	Biogas production followed by upgrading to biomethane
2	Landfills	Biogas production followed by upgrading to biomethane[7]
3	Anaerobic digestion of biomass	Biogas production followed by upgrading to biomethane
4	Gasification of woody biomass	Production of syngas from woody biomass followed by methanation
5	Methanation of green hydrogen	Renewable produced hydrogen combined with CO_2 in methanation

At the moment, virtually all biomethane is produced from landfills, sewage, and AD. All three technologies are well developed. They first produce raw biogas, consisting of roughly 60% methane (CH_4), 40% carbon dioxide (CO_2) and some trace gases. To reach natural gas grid quality, the biogas needs to be upgraded to biomethane by removing the CO_2, which can be done by several different techniques such as water scrubbing, chemical absorption, amine scrubbing, pressure-swing adsorption (PSA), membrane separation and physical absorption (Bauer et al., 2013; EBA, 2016). Technologies for upgrading biogas to biomethane are in general mature, efficient and safe (GreenGasGrids, 2013).

Gasification of woody biomass is currently only performed at several pilot plants. It has, however, great potential to increase the amount of biogas production in the near future. The first large-scale biomass gasification demonstration project for producing biomethane is located in Göteborg, Sweden. Woody biomass is first gasified to produce syngas: a gas mixture consisting of mainly CO, CO_2, H_2, CH_4 and H_2O. To produce biomethane, the syngas is converted in a subsequent methanation process consisting of four steps: a water gas shift reactor, a CO_2 scrubber, a methanation reactor and a dehydration system. After these steps, the produced methane can be injected into the natural gas grid (Li et al., 2017). Syngas produced from gasification can also be used directly or converted into methanol or hydrogen. Gasification of woody biomass is therefore not only a method to produce biomethane but is also suitable for production of green hydrogen (see section 2.2.2).

[7] Upgrading of biogas from landfills and subsequent injection into the natural gas grid is prohibited in some countries (e.g. Germany, Switzerland and Austria) (Bailón Allegue and Hinge, 2012) due to harmful trace components (siloxanes) in the landfill gas (Garcilasso et al., 2017).

The four production methods (waste water treatment, landfills, AD and gasification) use biomass as an input for biomethane production. A key variable for the future potential supply of biomethane from these techniques is therefore the potential volumes of available biomass for conversion.

Whether or not the technical biomass potential is converted into biogas or syngas and subsequently converted into biomethane depends on the costs of doing this. Costs for biogas production from biomass depend strongly on the feedstock used. Energy crops, for example, are easy to digest and therefore have a fast production of biogas with relatively small – and thus less expensive – reactors. Other feedstock (e.g. manure) are more difficult to digest and require higher investment costs, but the feedstock themselves are cheap, sometimes even with a negative price. Wet substrates produce large amounts of digestates that need to be disposed of. Depending on the country and local nitrogen and phosphate surpluses / shortages, distributing the digestate over agricultural land costs or brings in money (CE Delft et al., 2017).

Biogas upgrading becomes less expensive with increasing scale (CE Delft et al., 2017; Eurostat, 2016a). Upgrading biogas in small facilities is very expensive due to high investment costs of the upgrading equipment. No matter the scale of the plant, the same number of valves, analysis equipment and pipes are needed, making economies of scale very important (Bauer et al., 2013).

Several studies investigated the potential for biogas and biomethane production from biomass in the EU. The estimates are summarized in Table 3 and shortly discussed here.

CE Delft et al. (2017) extensively investigated the potential for biogas and biomethane production in the EU from sewage, landfills and anaerobic digesters. Gasification was not taken into account. Two feedstock scenarios were developed, leading to estimates of EU biogas production from the current (2014) level of 15.0 Mtoe (16.7 bcm) to 28.8 Mtoe (32.0 bcm) or even 40.2 Mtoe (44.7 bcm) in 2030[8]. To arrive at these numbers, the feedstock potentials of all EU Member States were taken into account. The feedstock potential depends not only on the size of the country but also on the structure of the agricultural sector, especially with regard to the amount of available manure, which is considered as an important feedstock for future biogas production. Not much growth in biogas production is expected anymore from energy crops and sludge. Landfill gas is expected to increase only moderately. According to the study, the largest biogas producers in the EU in 2030 will be Germany, Spain, France, Italy, the Netherlands, Romania and the UK. The study compares two different output options for the produced biogas: direct use in CHP plants and conversion into biomethane and subsequent use as a fuel in transportation.

Thrän and Müller-Langer (2013) also estimate the potential for biogas production based on European biomass potential. Both anaerobic digestion and gasification are taken into account. The agricultural land available for the production of energy crops is expected to increase, due to stagnant demand for food and feed produced in Europe combined with technical and breeding progress. For 2020, it was estimated that around 2482, 3661 and 2598 – 7730 PJ per year would be available from forest wood, residual materials (including wood, straw, manure, harvest residues and sewage) and energy crops respectively. In total, the biomethane production from gasification is estimated at 2587 PJ (61.8 Mtoe or 68.7 bcm) per year. This includes forest wood, wood residuals and half of the stalk-like biomass as resources. Biomethane production rom anaerobic digestion is estimated at 2836 – 6243 PJ (67.7 - 149.1 Mtoe or 75.3 – 165.7 bcm) per year, originating from stalk-like biomass, moisture biomass (excluding municipal waste) and energy crops, the latter being the original from the uncertainty in the estimated potential.

[8] Bcm is billion cubic meters, here expressed in natural gas equivalent.

GreenGasGrids (2013) state that about 28 bcm of biogas (natural gas equivalent) will be produced in the EU in 2020 according the National Renewable Energy Action plans. The technical biomethane potentials from Thrän and Müller-Langer (2013) are used to determine the potential of biomethane in 2030. The lower estimate from energy crops is taken to arrive at a technical potential of roughly 150 bcm biomethane. The authors further assume that consequent political commitment and efficient support systems would lead to 32 – 33% of this technical potential to be realised within the EU by 2030, which would equal to 48 – 50 bcm biomethane. To reach this, it is assumed that gasification technology is mature and widely available by 2030, but the share of gasification in the total production is not further specified. The authors furthermore assume that out of the 48 – 50 bcm biogas, about 40% will be upgraded to biomethane, which would be roughly 18 – 20 bcm of biomethane in 2030.

In the fifth method in Table 1, renewable produced hydrogen is converted into biomethane by combining it with an external source of CO_2 (different from methanation of syngas, which already contains both H_2 and CO_2)[9]. The reaction, known as the Sabatier reaction, is shown in equation 1.

$$4H_2 + CO_2 \rightarrow CH_4 + 2H_2O \qquad \textbf{Equation 1}$$

The production of renewable hydrogen, which is also a green gas itself, is discussed in the next subsection (2.2.2). As was pointed out already in subsection 2.1.2, the source of the CO_2 used for methanation of the green hydrogen is very important and the availability of CO_2 appears to be crucial in determining the possible future potential biomethane supply from this technology. This availability does not only relate to the discussion about whether or not a CO_2 source is accepted to produce green methane, but also takes into account the efforts needed to obtain it, which should preferably be with high purity, low costs and sufficient flow rates.

Most CO_2 sources from industry require a CO_2 capture and upgrading of the captured gas to remove poisoning trace gases before it can be used. This upgrading is expensive and decreases the energy efficiency. Power plants and industrial sources with low CO_2 contents are therefore not preferred. Some industrial sources have relatively high-purity CO_2 streams, which would be more suitable for conversion of green hydrogen into biomethane (Götz et al., 2016). Still, industrial sources might not be accepted as an input for green methane production.

Extracting the required CO_2 from ambient air can be done at any location and therefore reduces spatial restrictions for power-to-gas plants and the need for transporting the CO_2. The concentration of CO_2 in the atmosphere is, however, only roughly 400 ppm and it needs to be concentrated to an almost pure form, which is a very energy intensive and expensive process (Schiebahn et al., 2015).

It is possible that biomass sources will become the most important CO_2 sources for hydrogen methanation plants, especially because these sources of CO_2 are accepted as a green input for biomethane production. Pure CO_2 could be taken from biogas upgrading plants and used in a methanation reactor. Alternatively, the raw biogas could be used directly as a source of CO_2. In this case, methanation takes place in situ in the biomass digester by just injecting additional (green) hydrogen. Methanogenic bacteria already present in the biogas plant convert the CO_2 and injected H_2 into methane. In this way, it is possible to remove virtually all the CO_2 from the biogas by converting it into methane and a conventional upgrading system is not required anymore (Bensmann et al., 2014; DGC, 2013; Götz et al., 2016).

[9] Some additional hydrogen could, however, still be necessary for complete conversion of the CO_2 in the syngas. In this way, the syngas from biomass gasification can be used as a small external source of CO_2.

To give an estimate on the technical potential of biomethane production from renewable hydrogen using different CO_2 sources, volumes of available CO_2 are required. Table 2 shows the Sabatier reaction with the stoichiometric ratios converted into weight and volume ratios, based on the molar masses and densities of the four substances.

Table 2: The Sabatier reaction in stoichiometric equation converted into the ratio in weight and the ratio in volume, using the molar masses and densities of the four substances in the equation. Note that this relates to 100% efficiency and the density of water given here is for liquid water.

Sabatier reaction	$4H_2$ +	CO_2 →	CH_4 +	$2H_2O$
Molar mass (g/mol)	2.02	44.01	16.04	18.02
Ratio in weight (g)	8	44	16	36
Density (kg/Nm^3)	0.0899	1.98	0.668	1000
Ratio in volume (Nm^3)	90	22	24	0.04

At an efficiency of 100%, 8 kg of hydrogen and 44 kg of carbon dioxide can be converted into 16 kg of methane and 36 kg of water. The (energy) efficiency of the methanation reaction is most often reported to be around 80%[10] (e.g. Budny et al., 2015; Hofstetter et al., 2014; Lehner et al., 2014; Schiebahn et al., 2015)). From the table, it is possible to calculate the maximum potential amount of biomethane production when the amount of available CO_2 is known.

To give an order of magnitude for possible volumes of biomethane production from methanation of green hydrogen with biogas as the source of CO_2 it is assumed that biogas on average consists of 60 Vol.-% methane and 40 Vol.-% carbon dioxide. Using the 2014 EU biogas and biomethane production volumes (as reported in Table 3) we find that the theoretical maximal biomethane production equals to 12.0 bcm and 1.3 bcm respectively in case all biogas plants or only biogas upgrading plants are used as a source of CO_2 for methanation.[11] So, original biomethane production from biomass by AD can be increased by roughly 72% when all available CO_2 is converted into biomethane by methanation with green hydrogen.[12]

In actual practice, it will not be possible to convert all CO_2 from (current or future) biogas plants into biomethane. A very important reason for this is the scale of biogas plants. As was stated before, upgrading biogas in small facilities is very expensive due to high investment costs of the upgrading equipment. The same is true for equipping small-scale biogas plants with a methanation reactor, connection to the natural gas grid and green hydrogen production plant. Using 2015 data from (EBA, 2016), it was estimated that the average EU biogas plant roughly produced 800,000 m^3 biogas (natural gas equivalent)[13]. Assuming an average composition of 60 Vol.-% methane and 40 Vol.-% CO_2,

[10] Because this number reports the energy efficiency, it relates to the conversion of hydrogen into methane, and does not relate to the CO_2 in this reaction.

[11] The EU biogas production in 2014 was equal to 16.7 bcm natural gas equivalent, which would be (assuming 60 Vol.-% CH_4 and 40 Vol.-% CO_2) 27.8 bcm biogas, containing 11.1 bcm CO_2. Calculated similarly, the 1.8 bcm biomethane in 2014 originally contained 1.2 bcm CO_2 when it was still biogas and this amount will thus become available (theoretical maximum) from the biogas upgrading plants.

[12] To illustrate this with easy numbers: 60 bcm biogas in natural gas equivalent would be equal to 100 bcm biogas, containing thus 60 bcm biomethane and 40 bcm CO_2. The 40 bcm CO_2 could be converted into 43.2 bcm biomethane (assuming 100% conversion), which is 72% of the original amount of biomethane (60 bcm).

[13] According to EBA (2016), the amount of biogas plants in 2015 was equal to 17,376 and they produced about 498,024 TJ of biogas, which is equal to 11.9 Mtoe and 13.2 bcm. This would imply an average production of 0.8

roughly 500,000 m^3 CO_2 would be available at an average-sized biogas plant per year. Although this is an average and there are also larger biogas plants available, the size remains limited. Biogas plants that are already equipped with an upgrading facility most often have several advantages compared to other biogas plants: they are relatively large, have an already existing connection to the natural gas grid and have the availability of a relatively pure stream of CO_2.[14] These plants are therefore the most probable CO_2 sources for methanation of renewable hydrogen. Using the estimate of GreenGasGrids (2013) for the technical potential of upgraded biomethane from biomasses, which is 19.3 bcm in 2030, an additional 13.9 bcm biomethane can be generated by methanation of green hydrogen with CO_2 from biogas upgrading plants.

Although methanation of green hydrogen using CO_2 from biomass would be a very suitable option to produce additional volumes of biomethane, the biomethane production volumes remain limited compared to total EU natural gas consumption. For the production of large volumes of biomethane at large-scale methanation plants, other sources of CO_2 should be used. To reach very high production volumes of biomethane, the use of industrial CO_2 sources is inevitable.

Table 3 summarises the estimates for biogas and biomethane production from the different techniques mentioned in Table 1. The estimates given for biomethane production based on methanation are only representing biomass sources of CO_2 and do not take into account other potential CO_2 sources. Possible volumes of green hydrogen production needed as an input for methanation are also not considered here, as they will be discussed in the following section.

Table 3: Overview of the technical potential and 2030 potential for biomethane production from biogas (wastewater treatment, landfills and anaerobic digestion), gasification and methanation from different references and calculations.

Method	What	Biogas (bcm)	Biomethane (bcm)	Reference
AD	Production 2014	16.7	1.8	Eurostat, 2016a
	Potential 2030 (growth)	32.0	32.0	CE Delft et al., 2017
	Potential 2030 (acc.)	44.7	44.7	CE Delft et al., 2017
	Technical potential low	-	75.3	Thrän and Müller-Langer, 2013
	Technical potential high	-	165.7	Thrän and Müller-Langer, 2013
Gasification	Technical potential	-	68.7	Thrän and Müller-Langer, 2013
All biomass-based	Potential 2030	48.3	19.3	GreenGasGrids, 2013
Methanation	Theoretical max 2014	-	12.0	Calculated from 2014 biogas
	Theoretical max 2014	-	1.3	Calculated from 2014 biomethane

million m^3 biogas (natural gas equivalent) per plant. Note that the total amount of biogas production reported here is different from what is reported by Eurostat (2016a).

[14] It is important to note that not all upgrading techniques are equally suitable for producing a CO_2 stream for methanation. The CO_2 must preferably be obtained without the use of air, since this would dilute the CO_2 with nitrogen and oxygen, which must be removed before it can be used, thereby increasing the costs. For this reason, biogas upgrading plants based on pressure swing adsorption (PSA) are not very suitable for combining with a power-to-gas plant (Hofstetter et al., 2014).

Estimate 2030	13.9	Based on biomethane potential 2030

2.2.2 Green hydrogen

Table 4 shows the four main technologies for producing green hydrogen. They were identified as hydrogen production technologies that emit less than 60% GHGs compared to the most conventional fossil hydrogen production method, being steam methane reforming (SMR) of natural gas (Certifhy, 2016a).

Table 4: The four production technologies for producing green hydrogen

#	Technology	Description
1	Gasification of woody biomass	Production of syngas from woody biomass upgraded to hydrogen
2	SMR of biomethane	Steam methane reforming of biomethane
3	SMR combined with CCS	Conventional steam methane reforming combined with CCS
4	Power-to-gas	Electrolysis with renewable (or nuclear) electricity

The first two production methods in Table 4 are based on biomass. SMR of biomethane is identical to conventional SMR, except for the source of the methane, which can be any of the production methods listed in the previous section in Table 1. Gasification of woody biomass is the same technology as was listed in Table 1 but the resulted syngas is upgraded to green hydrogen instead of converted into biomethane. Potentials for green hydrogen production with these two methods are strongly related to the potentials estimated in the previous section and listed in Table 3.

In the third method, the conventional hydrogen production from methane using SMR is combined with carbon capture and storage (CCS) to prevent emissions of CO_2 to the atmosphere. Similarly, other conventional production methods could be combined with CCS to reduce GHG emissions. The CertifHy project did, however, estimate GHG emissions from coal gasification combined with CCS higher than the 60% threshold value and therefore did not include this option to the list of green hydrogen production methods. Large emissions arise from the supply of coal, which is included in the calculations based on complete life cycle analysis (Certifhy, 2016a).

As was written already in the introduction, the vast majority of the hydrogen used in the chemical industry is made on site by SMR. With large volumes of natural gas available, even more hydrogen can probably be easily made with SMR. The possibility, costs and acceptability of CCS are determining for the potential of green hydrogen production from SMR+CCS. With regard to possibility, a suitable geological formation must be available for storage of CO_2 in relatively close proximity of the CO_2 source. Using geological formations at a large distance from the source is possible but requires transportation of the CO_2, thereby increasing costs. Costs for CCS are generally very high, with most of the costs attributed to the capture process and a clear business case for CCS is so far absent. Costs must be substantially reduced before CCS can be deployed on a large scale (e.g. (Leung et al., 2014; Rubin et al., 2015). Last but not least, the acceptability for CCS is an important issue. Many people regard CCS as an end-of-pipe solution that might replace investments in renewable energy technologies. People are also afraid of leakages and elevated pressures in the geological formations. Local protests against CCS projects can lead to cancelling of these projects (L'Orange Seigo et al., 2014). This happened, for example, with onshore CCS projects in the Netherlands in 2011 when it was decided to only support CCS projects under the North Sea (Verhagen, 2011). Due to the very insecure future of CCS, it is not possible to give a conclusive estimate on the potential volumes of green hydrogen production using SMR+CCS. If costs drop and CCS becomes widely accepted, however, volumes of green hydrogen production from SMR+CCS can become very large, in principle able to replace all current grey hydrogen production.

The last technique mentioned in Table 4 is power-to-gas. In a power-to-gas plant, an electrolyser is used to split water (H_2O) into hydrogen (H_2) and oxygen (O_2) according to equation 2.

$$2H_2O \rightarrow 2H_2 + O_2 \qquad \textbf{Equation 2}$$

To produce the hydrogen without GHG emissions, the source of the electricity is important. According to life cycle analyses made by Certifhy (2016a), both renewable electricity and electricity from nuclear power plants produce hydrogen with a CO_2 emission footprint below the threshold of 60% less GHG emissions compared to conventional hydrogen production with SMR. One could argue, however, if nuclear power should be accepted as a source of electricity for green hydrogen production. Renewable electricity from sources such as wind and sun will be accepted in all cases.

The electrolyser is the core of the power-to-gas plant. Two main electrolyser techniques are currently available for the market: alkaline electrolysis and proton exchange membrane (PEM) electrolysis. Alkaline electrolysis is the most highly developed and cheapest technique and therefore most commonly used (Gahleitner, 2013; Holladay et al., 2009). PEM electrolysers can reach higher efficiencies and can deal with fast load changes, which is very beneficial in Power-to-Gas applications. The technique is, however, not very highly developed yet and suffers from problems with limited lifetime, small available capacities and high costs (Gahleitner, 2013). Nevertheless, the technique is already used in several Power-to-Gas pilot plants (Gahleitner, 2013) and should be considered as a serious alternative for alkaline electrolysers.

Electrolysers are currently highly expensive and cost around 1000 – 1500 €/kW capacity (e.g. Bertuccioli et al., 2014; Greiner et al., 2007; Grond et al., 2013; Schiebahn et al., 2015)). Also, most of the electrolysers currently in use are relatively small, typically about 1 MW, so that substantial capacity can only be achieved by coupling of various units, so that economies of scale are difficult to reach (Bertuccioli et al., 2014). It is expected that prices will significantly drop during the next few years, to reach levels in the order of half the current prices (500 – 600 €/kW) or even lower (Bertuccioli et al., 2014; Schiebahn et al., 2015). These cost reductions will determine to an important extent the potential for the future production of hydrogen from power-to-gas.

Power prices and their variations are also of great importance for the power-to-gas business case as it is the main input to production. In Europe, wholesale power prices have on average shown a declining trend in the last decade, although volatility does not seem to have increased. Besides the wholesale electricity price, also taxes and the prices of GoOs for renewable electricity determine the final electricity price that has to be paid by the power-to-gas plant.

To determine potential volumes of hydrogen production from power-to-gas, the availability of renewable, and potentially nuclear, electricity is important, just as the efficiency of the average electrolyser. The efficiency of an electrolyser is often defined in terms of electricity consumed per normal cubic meter (Nm^3) of produced hydrogen. To express the efficiency in terms of percentage, the higher heating value (HHV) of hydrogen is required, which is equal to 3.54 kWh/Nm^3 and expresses the amount of heat that would be released with complete combustion of the hydrogen. In a perfect situation, 3.54 kWh of electricity would be needed to create 1 Nm^3 H_2. In reality, however, there is always a loss of energy, and the electricity need for the generation of 1 Nm^3 H_2 is therefore always higher. Larger units work more efficiency and so the energy consumption decreases with volume (Smolinka et al., 2011). Several sources report power consumption or efficiencies of both alkaline and PEM electrolysers. Smolinka et al. (2011) reports efficiencies to be between 47% and 79% (4.5 – 7.5 kWh/Nm^3) and expect the efficiency to drop to values of 62-82% for Alkaline and 74-86% for PEM electrolysers in the future. Gahleitner (2013) investigated power-to-gas pilot plants and found efficiencies to range between 54-85% for alkaline electrolysers and between 52-79% for PEM electrolysers. The author remarks that the efficiencies of the pilot plants are hard to compare due to insufficient documentation about the efficiency calculation. The efficiencies strongly depend on the system configuration, operating conditions and the system boundaries.

Assuming an electrolyser system efficiency (including not only the electrolyser itself but also surrounding equipment) of 75%, 4.72 kWh is needed to produce 1 Nm^3 of hydrogen. To give a feeling of the orders of magnitude of hydrogen production from renewable electricity in the EU, these numbers can be linked to the EU wind power production.

According to Wind Europe (2017), 153.7 GW of wind power was installed in the EU in 2016, including both onshore and offshore windmills. These windmills together produced 296 TWh of electricity in this year, which was equal to 10.4% of the EU total electricity demand. When all electricity from wind power in 2016 would have been used for the generation of hydrogen in power-to-gas plants with a system efficiency of 75%, 63 billion Nm^3 of hydrogen would have been produced, which is equal to 5.6 million tonnes of H_2. This is not even enough to completely replace the estimated current EU hydrogen consumption of roughly 8 million tonnes per year (Certifhy, 2015).

Installed wind power capacity in the EU is increasing every year (Wind Europe, 2017). It is expected that installed wind capacity will continue to increase. The EWEA (2015) studied wind power scenarios for the EU for the year 2030. In the central scenario, 320 GW of installed wind power capacity is expected in the EU in 2030, generating 778 TWh of electricity. Although this would be more than sufficient to generate the 8 million tonnes of hydrogen per year (14.8 million tonnes to be precise), it is no likely that such a large part of the wind power production would be available for hydrogen production.

It is suggested to use power-to-gas to absorb excess renewable energy that must be curtailed otherwise (see for example Caumon et al., 2015; Guandalini et al., 2015; Qadrdan et al., 2015; Schiebahn et al., 2015; Vandewalle et al., 2015)). Curtailment of electricity is necessary when production exceeds demand and it is influenced by the transmission capacity (for spreading power fluctuations over a larger area), consumer demand and installed generation units such as nuclear that cannot easily be switched off (Qadrdan et al., 2015). Electrolysers can be switched on during times of excess electricity in certain areas and produce hydrogen, thereby storing the excess renewable electricity. Curtailment of renewable electricity is expected to increase with increased renewable power capacity installed. Not all excess power can be economically converted into hydrogen as peak excess only occurs a few times per year (Guandalini et al., 2015; Schiebahn et al., 2015; Vandewalle et al., 2015). An estimate for EU wide hydrogen production from excess renewable electricity in 2030 is hard to give. Vandewalle et al. (2015) assume that about 55% of the excess renewable electricity can be used in power-to-gas; the remaining 45% still need to be curtailed. In a study of Fraunhofer IWES (2015), the flexibility needs in the power system in EU by 2030 were investigated. With an expected share of 50% renewables in the power system that year (being mainly wind and solar power), integration of power markets is expected to be crucial for enabling sufficient flexibility. Depending on the development of the cross-border electricity interconnections within Europe, curtailment can vary between 5.9 and 46.6 TWh per year. To give an order of magnitude for hydrogen production from excess renewable energy in 2030, we can assume 50% of renewable power excess equal to 26 TWh (an average between 5.9 and 46.6 TWh) can be used in power-to-gas plants. The 13 TWh could be converted into 2.8 billion Nm^3 or 0.2 million tonnes of hydrogen.

In case nuclear power can also be used for renewable hydrogen production, additional volumes can be produced, although still large amounts of electricity are required, and the availability of nuclear power strongly depends on the specific EU Member States. In France, nuclear power generated over 76% of all electricity in 2015 (RTE, 2016). Other countries with significant shares of nuclear power in electricity generation are Germany, the UK, Spain, Sweden and Finland (REE, 2016; Statistics Finland, 2017; Swedish Energy Agency, 2016; Umwelt Bundesamt, 2017; United Kingdom

Statistics Authority, 2016). In Germany, however, the share of nuclear power is decreasing and the German government planned to phase-out nuclear power completely by 2022.

2.2.3 Summary

The potential volumes of biomethane and green hydrogen in 2030 are difficult to estimate. They depend on the availability of biomass and renewable (and nuclear) electricity in the EU for green gas production, on technology and cost breakthroughs in techniques such as woody biomass gasification, power-to-gas, CCS, methanation and biogas upgrading and on acceptability issues regarding CCS, different sources of CO_2 for biomethane production and nuclear energy.

Even under favourable conditions, it will be very hard to replace all conventional fossil methane and hydrogen production with green alternatives. It is also important to note that for some techniques, green hydrogen and biomethane are rivals: the syngas produced from biomass gasification can be used for both hydrogen and methane production and renewable produced hydrogen can be used directly or converted into biomethane via methanation.

Besides physical production of green gas, energy suppliers can offer *compensated gas* to their customers based on compensation projects elsewhere in the world. Volumes of this type of green gas are even harder to predict, as they do not rely on technical potential but more on demand for green / compensated gas and possibilities and costs for generating these CO_2 certificates. The demand for methane, hydrogen and their green substitutes will be discussed in chapter 3.

2.3 Transport of green gases

Green gases can be transported through dedicated pipelines or by trucks. In this way, the green products are directly delivered to the customers. Alternatively, the extensive EU-wide natural gas grid can be used for transportation of both green methane and green hydrogen.

Hydrogen can be injected into the natural gas grid but there are technical and legislative restrictions on the quantities that can be injected. It is unclear to what extent hydrogen could be fed in and information about this is contradictory (Gahleitner, 2013; Qadrdan et al., 2015). The adding of hydrogen to natural gas influences the combustion behaviour and has an effect on materials integrity. The allowable limit would be location-specific and depends not only on the gas grid infrastructure but also on the specific end-users (Grond et al., 2013; Müller-Syring et al., 2013). Every country has set its own, often conservative, limitations. An overview is given in Table 5.

Table 5: Hydrogen admixture limits in the natural gas grid for different countries

Country	Limit (Vol.%)	Source
United Kingdom	0.1%	Clegg and Mancarella, 2015; Qadrdan et al., 2015
Netherlands (current)	0.02%	De Joode, 2014; Grond et al., 2013
Netherlands (near future)	0.5%	Verhagen, 2012
Switzerland	2.0%	Hofstetter et al., 2014
Germany	5.0%	Schiebahn et al., 2015
Germany (near future)	10%[15]	Grond et al., 2013

[15] Unless there are technical limitations or safety issues for transportation and end-use applications

Another important effect of hydrogen admixture in the natural gas grid is the changing of the energy density of the gas in the grid. The volumetric energy density of hydrogen is one third of that of natural gas (13 vs. 39 MJ/m^3) and thus a higher flow rate is required to meet the demand (Qadrdan et al., 2015).

Not only the hydrogen admixture limit determines the possible volumes that can be injected, the specific pipeline is also important. The higher the flow and pressure in the pipeline, the more hydrogen can be injected at a specific point. Because distribution grids usually have a low throughput compared to transmission grids, the latter are usually more suitable for hydrogen admixture, assuming the same admixture limit in both grids.

It is expected that in the near future, the hydrogen admixture limits will be set higher. In case higher tolerances are allowed for hydrogen admixture in the natural gas grid, the need for hydrogen upgrading into methane from power-to-gas plants reduces.

Biomethane is chemically identical to natural gas and can therefore easily injected into the natural gas grid, once quality checks have been performed. Although the natural gas grid is very suitable for transportation of biomethane, injecting large volumes is not without any restrictions. The limited gas demand during off-peak hours is the main bottleneck. The maximum amount of biomethane that can be continuously injected throughout the year is equal to the minimum demand during the year, which is usually during summer nights. The location is very important and the more injection points already exist, the more difficult (and expensive) it becomes to inject more green gas in the natural gas grid (PwC, 2012).

The type of transport is dependent on the costs: in countries with a dense natural gas network, distribution costs will be lower than in countries with a less developed grid. Dedicated pipelines are needed for connecting biomethane production sites to the natural gas grid. Sweden has a limited gas infrastructure, which is why trucks typically transport the produced biomethane (CE Delft et al., 2017). Once the biomethane has access to the natural gas grid, it has also access to the widely available storage options for natural gas (e.g. in salt caverns).

2.4 Policies and measures towards green gas

Policies and measures to promote supply of green gases relate to all elements of the gas value chain: production, transport, storage and application, and are either generic aiming for mitigation of GHG emissions or specifically directed towards green gases. Examples of generic policies and measures affecting the introduction of green gases into the energy system are generic CO_2 penalties or CO_2 reduction subsidies that effectively may provide a price advantage for green gases as compared to fossil gases. Such generic policies and measures will not be discussed here any further. Policies and measures with the specific aim to enhance the role of green gases typically focus on biomass conversion via anaerobic digesters (AD). To that end, in a considerable number of EU Member States feed-in tariffs or other supportive measures have been introduced covering the differences between the market and production cost price of green gases while accepting a usually modest profit margin. The Netherlands, for example, introduced a support scheme (MEP) to promote the production of renewable electricity (including electricity based on biogas) by 2003. Similarly in Germany a comparable scheme was introduced by 2000 (EEG). Policies and measures to support biogas and biomethane vary widely between EU Member States. (CE Delft et al., 2017) gives an extensive overview of all biogas and biomethane polices in the EU.

The various existing subsidy schemes supporting biogas production – primarily based on anaerobic digestion – have clearly stimulated the introduction of biogas on the market, a small part of which is treated and upgraded such that its quality is sufficient for feeding into the natural gas grid. Biogas upgrading and subsequent injection into the gas grid is, however, not supported in most of the EU Member States. Only in Sweden, Germany and the Netherlands, a substantial part of the biogas is upgraded to biomethane, thanks to explicit measures within the feed-in support schemes to support feeding in green gas into the grid. In Germany, for instance, the EEG included a destination clause implying that support could only be obtained if the biogas was converted into electricity. From 2009 onwards, however, the EEG included specific support for upgrading of biogas into biomethane via an upgrading bonus (which, however, currently no longer exists). A similar measure was taken in the Netherlands, with the introduction of the SDE scheme in 2008.

One of the reasons why a relatively small share of biogas production is upgraded and fed into the gas grid relates to the fact that policies mainly support biogas use for direct electricity and heat production rather than turning it into biomethane. Moreover, the EU Biofuels Directive (2003/30/EC) launched in 2003 to increase the share of biofuels supplied to the transport sector in actual practice mainly promoted the use of liquid fuels that could be easily blended with conventional gasoline and diesel fuels, and not the use of green gases, even if these gases were eligible for the fuel quota obligations in most countries (European Parliament & Council of the European Union, 2003).

A typical issue for cases in which biogas is upgraded and injected into the gas grid relates to how the green gas enters the market. Exactly because the green gas is usually admixed to the fossil gases transported via the same grid, physical delivery of green gas is not possible. This means that the green gas can only be sold as "normal" fossil gas and that the premium of being green will need to be captured by selling the GoO testifying of the gas being produced "green". It seems likely that in the future and under the pressure of EU regulation (see the text of the legislative proposal on Clean Energy for all Europeans, the 'Winter Package', on this), the guarantee of origin returns to the green gas producer may need to be evened out with the feed in subsidy. This would mean, to give a hypothetical example, that if the production price (plus acceptable margin) of 1 m^3 green gas is € 0.40, the fossil gas price is € 0.25 and the GoO market price € 0.10, the feed-in subsidy will be 0.40 – 0.25 – 0.10 = € 0.05/m^3.

The generic issue of the risk of double subsidies has consistently drawn the attention of EU policy makers, and therefore also relates to biogas and biomethane. For instance, both the 2003 Biofuels Directive (2003/30/EC) and the Renewable Energy Directive (2009/28/EC) provided support for biomethane production and use, and both contain national targets per Member State (European Parliament, 2009; European Parliament & Council of the European Union, 2003). This creates the risk that one single performance could obtain double support. For this reason, within the Netherlands, for instance, a 2011 decision explicitly blocked this risk.

Specific policies and measures for the production and market uptake of green gases from gasification and power-to-gas have so far remained very little. Occasionally, subsidies have been provided for R&D and some pilots, but much more than that does not exist. Demonstration projects in this area have so far not yet come off the ground; so current production of green gases from these technologies is virtually zero.

Not all policies and measures are predictable and stable due to changing political considerations. The resulting uncertainty has hampered the development and application of conversion technologies to generate biogas. For the further development of the application of anaerobic digestion, more policy coordination between EU Member States and more stable and predictable policy regimes seem to be important (CE Delft et al., 2017). The same applies for the future development of green gases from gasification and power-to-gas.

2.4.1 Future support structures for renewable gases

Up until 2020 the support structures for renewable gases are expected to largely remain focussed on promoting the production. After 2020 renewable energy is expected to be able to deal better with conventional market forces, such as balancing issues, and therefore require lower levels of production support. In fact the EC Guidelines on State aid for environmental protection and energy 2014-2020 (European Commission, 2014) state that:

"These Guidelines apply to the period up to 2020. However, they should prepare the ground for achieving the objectives set in the 2030 Framework. Notably, it is expected that in the period between 2020 and 2030 established renewable energy sources will become grid-competitive, implying that subsidies and exemptions from balancing responsibilities should be phased out in a degressive way."

The speed at which subsidies for renewable energy can / will be phased-out will likely depend on whether or not subsidies for fossil fuels will be phased out as well. However, particularly in some examples (offshore) wind electricity projects in the North Sea area has seen its first bids where no government subsidy is requested (Andresen, 2017). Also solar PV is anticipated to become grid-competitive in the 2020-30 period raising questions in several EU countries about the right level of support for renewable electricity. For example, the Netherlands government recently (July 2017) decided to keep the 'net-metering' incentive for solar PV for households in place up to 2023 (Kamp, 2017). However, after 2023 the net-metering support will be revised and support levels are expected to become more modest. Whether also the production of biogas / biomethane / green gas will become grid-competitive before 2030 is questionable; if not, feed-in subsidies or comparable support schemes will probably need to remain in place.

With grid-competitiveness within reach for wind and solar, a few EU countries therefore have already started policy experiments that focus on balancing issues related to renewable energies.

On this, Spijker et al. (2015) note that in 2012 in the German EEG system a 'direct marketing approach' has been established: "The new approach of direct marketing allows the producer to market the energy on his own. At the same time, a market premium has been established. It is designed to guarantee an economic incentive to invest in renewable electricity. Similar to the tariff, this premium is paid by the DSOs on a monthly basis and socialised through the EEG-Umlage (§33g EEG 2012). Following §33d of EEG 2012, renewable electricity producers are allowed to switch between the fixed tariff and the different forms of direct marketing on a monthly basis. In addition, if renewable electricity is produced by using biogas or biomethane, the producer is able to gain the flexibility premium (§33i EEG 2012). This premium is an incentive to invest in additional production capacities that allow for a more independent production of gas and electricity, in compliance with time-wise fluctuating demand patterns."

This flexibility premium allows biogas plant operators to generate sufficient income for that share of their installed capacity that can be dispatched flexibly (i.e. when electricity production from wind and solar is too low). The fact that renewable gases are subject to a world first policy experiment related to balancing intermittent renewables, like solar and wind, is not surprising. Power-to-gas projects are built on the principle that gaseous energy carriers have good properties for providing (relatively) low-cost balancing services to electricity grids (as well as gas, and heat grids).

However, it is uncertain if excess renewable electricity that is produced with some form of subsidy will also be eligible for receiving additional support when converted into a renewable gas. The existing feed-in support schemes would then first promote the production of renewable electricity, and secondly promote the production of renewable gases based upon that renewable electricity. However, when considering a combination of two different kinds of support this problem can be avoided. By combining direct production subsidies for renewable electricity with grid balancing support, there are two different support instruments being used for two different objectives in the power-to-gas value chain.

So far, the EU policy seems to assume that beneficiaries of support schemes are subject to standard balancing responsibilities. State aid guidelines for renewable electricity explicitly indicate that any beneficiary of a support scheme for renewable electricity launched after 1 January 2016 should be subject to such "standard" responsibilities (Article 3.3.2.1 of the EU state aid guidelines (European Commission, 2014)). However, it can be questioned whether in actual practice all renewable electricity options can operate grid-competitive (and cost-competitive) when it comes to providing flexibility and balancing. Given that, for example, also for conventional gas-fired power plants direct subsidies for balancing are considered, it seems conceivable that also grid injection based on power-to-gas activity would be eligible to similar subsidies in the 2016 – 2030 period.

3 Natural gas and green gas demand

Natural gas is currently used in many different applications. (Eurostat, 2017a) provides detailed information on the consumption of natural gas in the EU, part of which is given for the year 2015 in Table 6.

Table 6: Natural gas consumption in the EU in 2015 in billion cubic meters (bcm). The last column shows the share of total consumption. Source: Eurostat (2017a).

Natural gas consumption in the EU	bcm	%
Gross inland consumption	397.7	100%
Transformation input	110.2	28%
Distribution losses	2.1	1%
Consumption in the energy sector	17.8	4%
Energy available for final consumption	267.5	67%
Final energy consumption	254.0	64%
Industry	87.8	22%
Transport	3.6	1%
Road	1.9	0%
Consumption in pipeline transport	1.6	0%
Non-specified	0.1	0%
Other sectors	162.6	41%
Residential	108.3	27%
Agriculture / forestry / fishing	3.6	1%
Services	49.5	12%
Non-specified	1.3	0%
Final non-energy consumption (industry)	14.7	4%
Statistical difference	-1.2	0%

The gross inland consumption of natural gas amounted to almost 400 bcm in 2015 (see also Figure 1). About 28% of the natural gas is used for transformation into another form of energy. This category includes quantities of natural gas used for primary or secondary conversion of energy (e.g. conversion of natural gas into electricity) or transformation into derived energy products (e.g. natural gas to methanol) (European Parliament, 2008). The energy available for final consumption is further subdivided into energy and non-energy use. The non-energy use virtually completely takes place in the industry sector, where natural gas is used as a feedstock. The industry sector also uses natural gas as an energy source. Together, the industry sector consumes little over a quarter of the natural gas in the EU. The residential sector is using 27% of the gross inland gas consumption. The transport sector has consumed only 3.6 bcm natural gas in 2015.

Although biomethane could substitute natural gas in every sector and application, the demand profile will not be the same everywhere. In this chapter, the demand for natural gas and biomethane as a green substitute is discussed for the four different sectors mobility, industry, power generation and built environment. Developments in the overall gas, and green gas demand specifically, are discussed, and possible drivers for green gas demand identified.

Besides natural gas and biomethane, also the demand for hydrogen and green hydrogen will be discussed in this chapter. Currently, hydrogen is almost exclusively used in the industry sector, but this could change in the (near) future when hydrogen could have a more important role as an alternative gaseous energy carrier.

3.1 Mobility

The mobility sector is the least diversified energy demand sector: oil products deliver 93% of the final energy consumption (Eurostat, 2016b). So far, the transport sector has not fundamentally changed in terms of fuel input, and improved efficiency of traditional cars has been the main driver for emission reductions. Total emissions from the transportation sector have increased in the past two decades (European Commission, 2011). Traditional cars are still expected to further improve their energy efficiency[16], but to substantially further reduce GHG emissions in the transport sector, oil products need to be replaced by alternative fuels (European Commission, 2013).

There are several alternatives for oil products in the transportation sector. European Commission (2013) states there is no single fuel solution for the future of mobility and all main alternative fuel strategies should be developed, without a preference to a particular fuel. Table 7 shows the five alternative fuels that will be stimulated by the EU and their application in the different mobility modes and ranges, as given in the document "Clean power for Transport: a European alternative fuels strategy" (European Commission, 2013). The EU will stimulate the introduction and use of alternative fuels by regulating and enabling availability and by setting common technical specifications.

Table 7: Coverage of transport modes and travel range by alternative fuels (European Commission, 2013)

Fuel	Mode	Road-passenger			Road-freight			Air	Rail	Water		
	Range	Short	Medium	Long	Short	Medium	Long			Inland	Sea	Maritime
LPG		■	■	■	■	■	■			■	■	
Methane	LNG	■	■	■	■	■	■		■	■	■	■
	CNG	■	■	■	■	■						
Electricity		■			■				■			
Biofuels		■	■	■	■	■	■	■	■	■	■	■
Hydrogen		■	■	■	■	■			■	■		

As can be seen in Table 7, only biofuels can substitute conventional fuels in all applications. Methane, however, is also very widely applicable: air transport is the only mode in which it cannot be

[16] Traditional ICE is expected to improve by another 30% (McKinsey & Company, 2010) or by 17% in 2020 and 29% by 2030 relative to 2010 (European Commission, 2016).

used. Hydrogen is considered suitable for most transport modes, except for long-range road freight, air and sea transport.

The EU is aiming to stimulate methane in the transport sector not only as biomethane but also as natural gas. Although natural gas is a fossil fuel just like conventional fuels such as gasoline and diesel, it offers advantages in terms of diversification of transport fuels and both GHG emissions and pollutants are lower than those from oil products (European Commission, 2013). The well-to-wheel GHG emissions of a passenger car running on natural gas (CNG) was found to be 23% lower than those determined for petrol passenger cars and 7% lower than those for Diesel passenger cars (thinkstep, 2017). Using biomethane instead of natural gas would even further lower GHG emissions.

Methane can be used in two forms in the transportation sector: compressed as compressed natural gas (CNG) or liquefied as liquefied natural gas (LNG). LNG can be a very important alternative for diesel in long-distance road freight, where not much other alternatives exist. CNG is already widely used in the EU, with close to 1 million vehicles and around 3000 filling stations. Since the natural gas grid can deliver methane, additional refuelling stations are easily supplied. Market development is expected since CNG cars are competitive with conventional vehicles in price and performance (European Commission, 2013).

According to the European Commission (2013), the technology for hydrogen fuel cell electric vehicles (FCEVs) is maturing and is demonstrated in passenger cars, city buses, light vans and inland ships. They have performance, driving ranges, and refuelling times comparable to gasoline and diesel cars. Presently there are about 500 vehicles in operation[17], and around 120 hydrogen-refuelling stations[18] in place. Industry has announced the roll out of vehicles and several member states plan hydrogen-refuelling networks.[19] Main issues are the high cost of fuel cells and the absence of a refuelling infrastructure network. Industry studies indicate that costs can be reduced to the levels of conventional petrol and diesel vehicles by 2025 (European Commission, 2013).

Two specific renewable energy targets are set for the transportation sector. In 2020, the EU wants to achieve a 10% share of renewables in the transport sector. In 2050, the EU needs to reduce its GHG emissions by 80 – 95% below 1990 levels and whereas deeper cuts need and can be achieved in other sectors, a reduction of at least 60% of GHG emissions is required from the transport sector (European Commission, 2011).

The Member States of the EU have to report their progress towards the use of renewable energy under the Directive 2009/28/EC every two years (European Parliament, 2009). In the progress reports, the member states specify their renewable energy in transport in five categories: bioethanol/bio-ETBE, biodiesel, hydrogen (from renewable sources), renewable electricity and others (biomethane, vegetable oils, etc.). In the progress reports of 2015, none of the Member States reported hydrogen use in transport up to 2014. For the other four categories, the combined amounts of energy were 10.7 Mtoe for biodiesel (71%), 2.6 Mtoe for bioethanol (17%), 1.4 Mtoe for electricity (9%) and 0.3 Mtoe for other fuels (2%) (EU member states, 2016). Since biomethane falls under the category others, it is not possible to further specify it from these reports.

Several studies are available predicting the development of the mobility sector in specific countries, Europe, or the world. The EU reference scenario (European Commission, 2016) predicts the future

[17] According to IEA (2015), there are around 550 FCEVs (passenger cars and buses) running in several demonstration projects across the world – with 192 in Europe, 102 in Japan, 100 in Korea and 146 in the United States.

[18] According to IEA (2015), the existing hydrogen refuelling stations are 36 in Europe, 21 in Japan, 13 in Korea and 9 in the United States (adding up to 79).

[19] Germany is currently building 400 hydrogen refuelling stations across the country

final energy demand in the transportation sector up to 2050. Figure 4 shows the final energy demand in transport per fuel type throughout time.

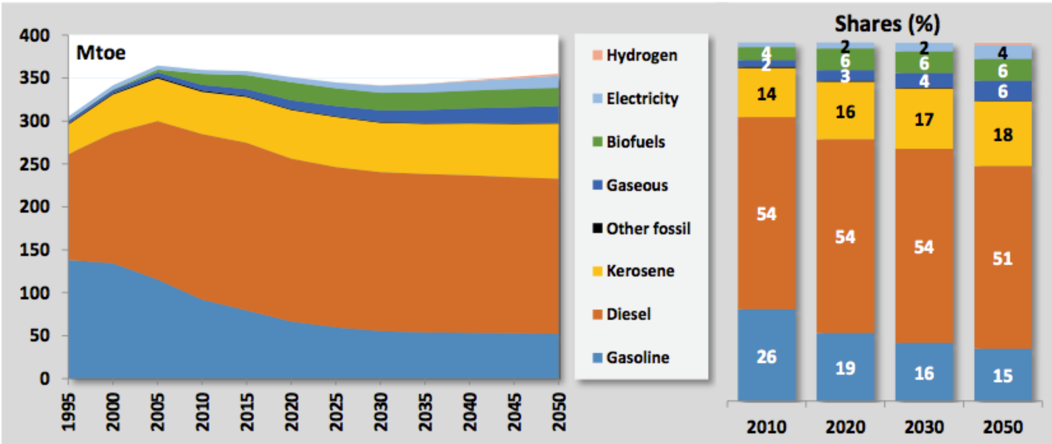

Figure 4: Final energy demand in transport by fuel type according to the EU reference scenario (European Commission, 2016).

The document states that the penetration of biofuels is mainly driven by the legally binding target of 10% renewable energy in transport (RES-T target). Beyond 2020, with no further tightening of the RES-T target, biofuel quantities in the EU remain relatively stable, with a share of 6% from 2020 onwards. LNG enters the market for road freight and inland navigation transportation. This is driven by the implementation of the directive on the deployment of alternative fuels infrastructure. In total the share of fuels in 2030 is estimated at 16% gasoline, 54% diesel, 17% kerosene, 4% gaseous, 6% biofuels and 2% electricity. The use of hydrogen in the transportation sector is not visible in the scale of this figure, but is expected to represent roughly 0.1% by 2030, increasing up to 0.7% by 2050.

For light duty vehicles, the reference scenario takes a closer look as visible in Figure 5.

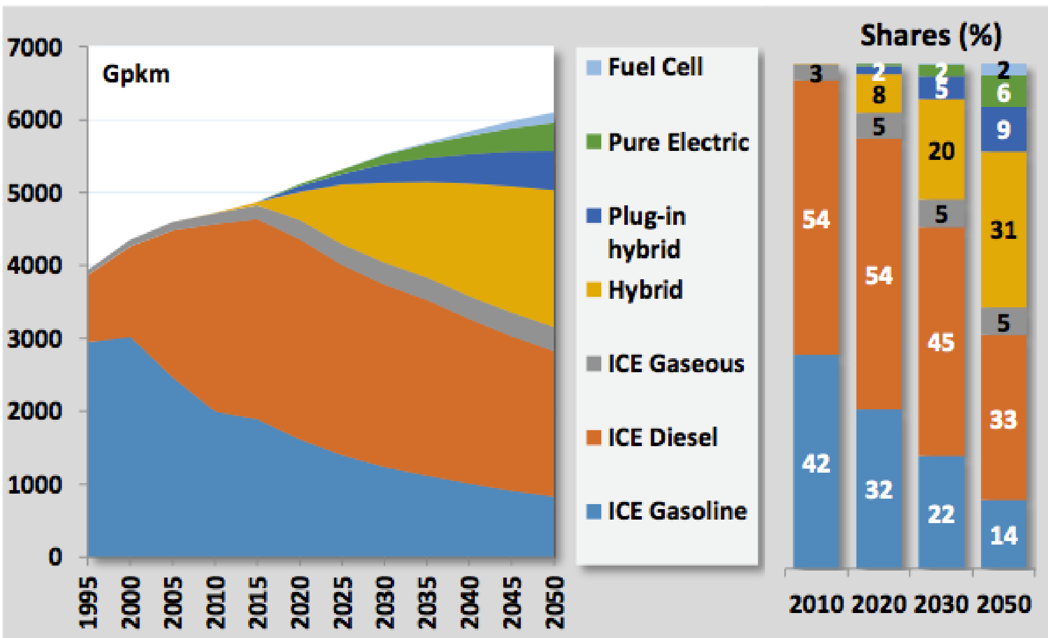

Figure 5: Evolution of activity of passenger cars and vans by type and fuel (in Giga passenger kilometre) according to the EU reference scenario (European Commission, 2016).

According to the figure, fuel cell cars (FCEVs) running on hydrogen would still represent a niche market by 2050, due their relatively higher, albeit decreasing costs. For 2030, its use is not even visible in the scale of the figure. Gas-fuelled vehicles represent roughly 5% of the market in 2030.

To arrive at the results in this reference scenario, national plans already in place for supporting the penetration of alternative vehicles were taken (European Commission, 2016). Additional support for the use of green gases in the mobility sector could therefore lead to an increased market share.

The *technology roadmap hydrogen and fuel cells* from the IEA (2015) assumes a high hydrogen penetration in the transport sector, mainly in three regions in the world, which are the Unites States, EU4 (France, Germany, Italy, and the UK), and Japan. In the scenario, FCEVs become competitive with conventional cars by 2030 and even more by 2050. For hydrogen production, the report states that initially, most of the hydrogen will be supplied using steam methane reforming (SMR) of natural gas without carbon capture and storage (CCS). Only after 2030 SMR with CCS is expected to become cost competitive due to increased CO_2 prices. Hydrogen from renewable electricity is assumed to be only cost effective if low-cost, surplus electricity is used. The supply will depend on the region and for EU4 it is estimated that electrolysis could deliver 30% of the hydrogen used in transport by 2050. Hydrogen production from biomass is assumed to play a minor role in all three regions. To cost effectively meet future hydrogen demand, an important share of generation is based on fossil fuels in combination with CCS. Alternative scenarios envisaging higher shares of hydrogen from renewable electricity are feasible, especially if the use of CCS is constrained by political choices or a lack of available CO_2 storage resources, although these alternatives are more costly. As hydrogen produced from grid electricity is significantly more expensive than hydrogen from SMR or from low-cost surplus electricity, this will affect the cost of hydrogen at the station. Significantly increasing the share of hydrogen from renewable electricity in the generation mix would require substantial additions to renewable power capacity (IEA, 2015).

In another analysis, the IEA studies the mobility sector in the Nordic countries up to 2050 (IEA, 2013). The Nordic countries are characterised by ambitious long-term targets to reduce GHG emissions across all sectors, including transport. The Swedish government aims to have a vehicle stock completely independent of fossil fuels by 2030. Denmark, Norway and Sweden have the target to reduce emissions across all sectors by 100% in 2050. Iceland and Finland have slightly lower ambitions. The document assesses how Nordic policy action can lead the way to a cleaner energy system and how the countries can serve as an example for other countries and regions. The main building blocks in a low-carbon Nordic transport system are a reduced growth in travel demand, electrification of passenger transport, a move to biofuels for long-haul and freight transport and a higher share of rail transport for freight. The share of biofuels is very high in the future Nordic transport sector: depending on the scenario it can go up to 70%. Electric cars play a key role in reducing CO_2 emissions and dependency on oil within individual passenger transport in the longer term. Beyond 2040, however, FCEVs might offer some of the same advantages and even better options within long-haul transport. Compressed natural gas (CNG) and biogas can reduce emissions in long-distance transport. Biogas and CNG cover up to 7% of total fuels used for transport in two of the scenarios. In one of the scenarios, hydrogen fuel cell vehicles do not enter the market at all because of availability of cheaper biofuels. In the other three scenarios, FCEVs do not show a significant market penetration before 2030, but reach a share of about 2 million vehicles in 2050 (which is roughly 14%).

To summarise the above studies, a significant market share for hydrogen in the mobility sector is not expected before 2030 and even in 2050 the share is often still low. A major problem for hydrogen use in the transportation sector is the current lack of refuelling infrastructure. A study performed by Van der Zwaan et al., 2013 states that the picture for hydrogen in the mobility sector looks very different when projecting further towards 2100. In that year, hydrogen becomes the dominant energy carrier in the transport sector according to their model. (Green) methane is already used widely throughout the EU and its use can easily be further expanded. Refuelling stations can be easily supplied from the natural gas grid, which is an extensive infrastructure in most EU Member States.

Nevertheless, conventional fossil fuels are still expected to make up a substantial share of fuels in the transport sector by 2030, in most scenarios.

It is important to note that an increased use of methane and hydrogen in the mobility sector does not necessarily mean that these gases are green. Most use of hydrogen and methane in the mobility sector is even expected to be produced from fossils. Although most studies do not predict major changes in the transportation sector up to 2030, policies and measures and technological breakthroughs in both green gas production and FCEVs could stimulate the use of (green) gases in the mobility sector.

3.2 Industry

In industry, natural gas is used both as a feedstock and as an energy source. As was shown in Table 6, in the industry sector about 88 bcm of natural gas was consumed in 2015 as an energy source and another 15 bcm as feedstock. Volumes of biomethane consumption in the industry are not known, but it seems fair to assume that this relates to a very limited amount, possibly due to the little availability and relatively high price of biomethane so far. It is also not known to what extent industry is inclined to 'green' the natural gas used with the help of certificates. However, it seems fair to assume that in the absence of clear incentives, this does not relate to substantial amounts. Given the EU targets for reduction of GHG emissions in industry (such as the 2030 target to reduce GHG emissions by 43% compared to 2005 in the EU ETS-covered sectors), it seems logical that the use of green gases in the industry replacing fossils will significantly increase.

Figure 6 shows the final energy consumption in the industrial sector by energy form as predicted by the European Commission (2016). As can be seen in the figure, overall energy consumption in the industrial sector is expected to decrease in the coming decades. A decline is expected for solid and petroleum fuels and increase in the share of electricity and renewables. The share of gas is expected to decrease only very slightly: from around 33% in 2015 to 28% in 2030 and the years thereafter. As the total energy consumption is decreasing, so is the total gas consumption: from 94 Mtoe (104 bcm) in 2015 to 75 Mtoe (83 bcm) in 2030.

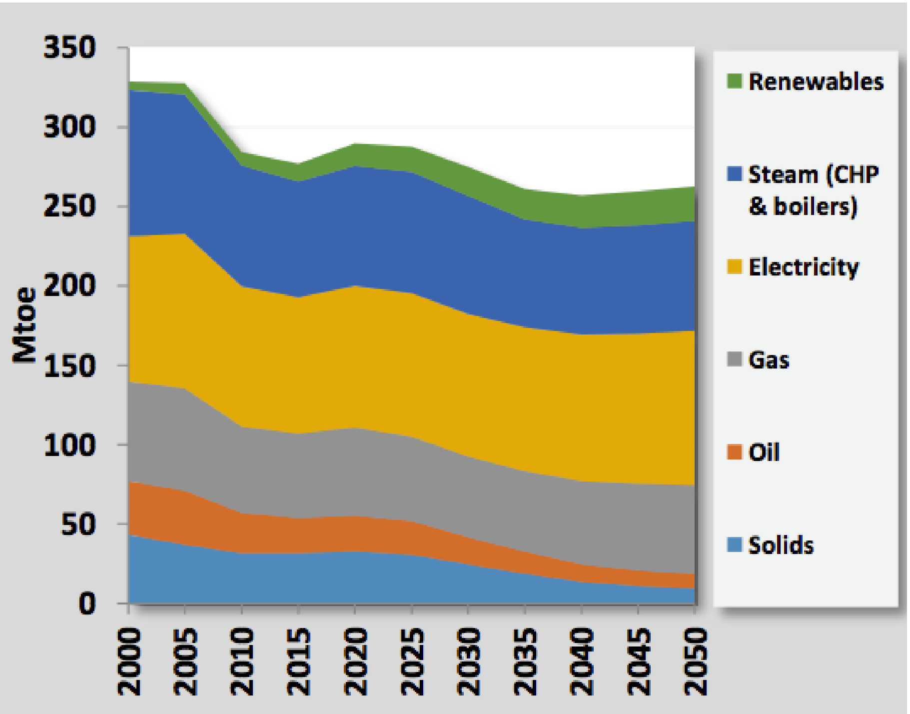

Figure 6: Final energy consumption in industry by energy form according to the EU reference scenario (European Commission, 2016).

Next to natural gas, industry also uses fairly substantial volumes of hydrogen. In a recent study by Certifhy (2016a) it was indicated that in 2010 the EU consumed about 8 million tonnes of hydrogen of the about 43 million tonnes consumed worldwide. The industrial sector is the largest consumer of hydrogen, within Europe a share of 90%, i.e. some 7 million tonnes. The demand for hydrogen is expected to grow, both globally and in the EU specifically, with the EU industrial sector expecting to consume roughly 8.5 million tonnes of hydrogen by 2030.

If, and to what extent, the current use of hydrogen, which is almost exclusively 'grey' because produced from natural gas or coal without capture or even reuse of the CO_2 component, will be replaced by green hydrogen, strongly depends on clear, focused, and consistent policies and measures to 'green' not only the natural gas but also the hydrogen consumption. Some recent initiatives such as by the Norwegian Ministry of Petroleum and Energy with Gassnova and Gassco, but also by some chemical industries, suggest that first steps to 'green' the hydrogen may be taken by combining 'grey' hydrogen production with CCS activity. The concept is to use natural gas for hydrogen production, but to store the CO_2 released underground, so that the net impact is to create carbon-neutral hydrogen. This 'green' hydrogen can obviously be compared with 'green' hydrogen from renewables based on electrolysis; so far production costs of the latter seem to surpass those of the hydrogen which is greened with the help of CCS, but learning effects, renewable power prices, policies and measures, and public acceptance may change this merit order in the future.

3.3 Power generation

A significant share of electricity is generated using natural gas as primary input in the EU. Figure 7 reports the share of fuels in the electricity generation in the EU according to World Bank (2017).

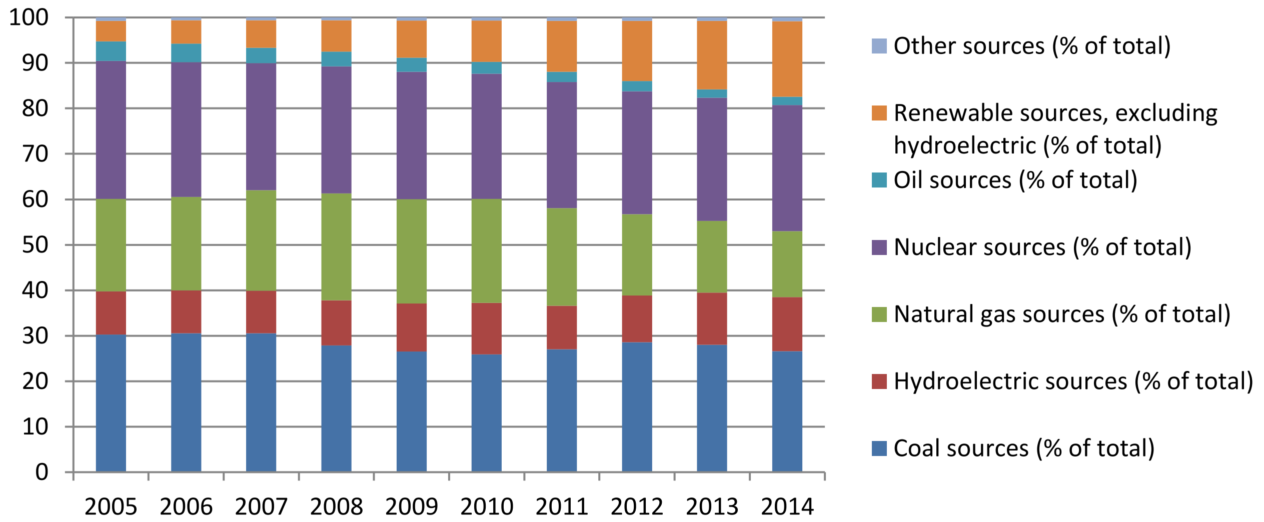

Figure 7: Share (%) of fuels in electricity generation in the EU. Source: World Bank (2017).

In 2014 the share of gas in power generation was 14.5%, coming down from 20.3% in 2005. The reduction in gas demand from the power sector reflects a changing landscape in this sector. Due to environmental concerns, several European governments have been extensively supporting renewable electricity generation, in particular wind and photovoltaic power. Figure 8 shows the additional installed capacity per year between 2000 and 2016, from which it becomes clear that investments in renewable capacity have rapidly increased since the early 2000s and dominated new investments from 2011 onwards. In addition to renewables, especially before 2009, investments in gas-fired power plants have been important in the past 15 years. The significant growth in investment in renewable capacity has resulted in a rapidly growing share of renewables in both the production of electricity (Figure 7) and the installed capacity (Figure 9). In contrast to the reduction in the share of gas in electricity production, its share in installed capacity has remained fairly stable at just over 20% in the past 10 years, as can be seen from Figure 9.

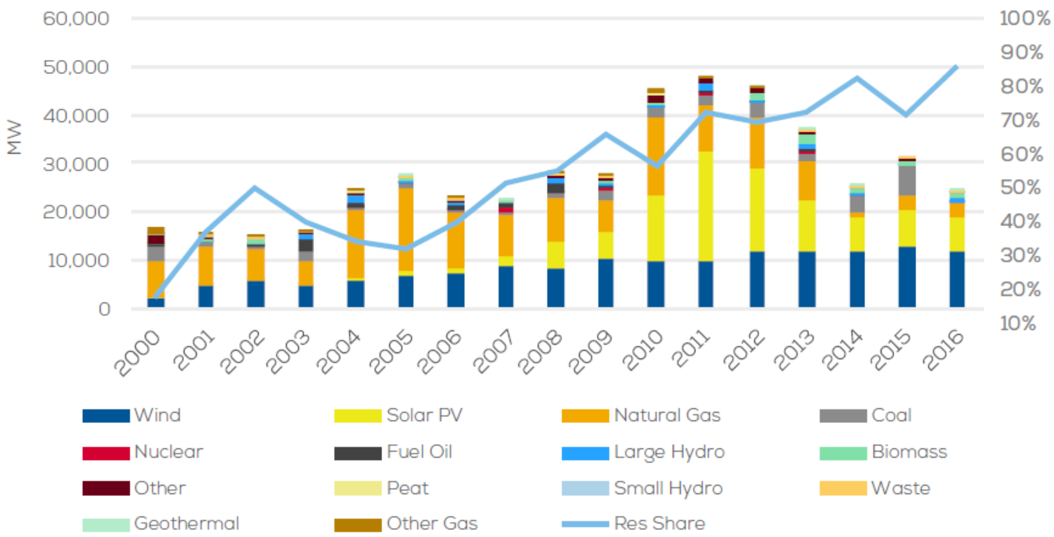

Figure 8: Additional installed capacity per year. Source: Wind Europe (2017).

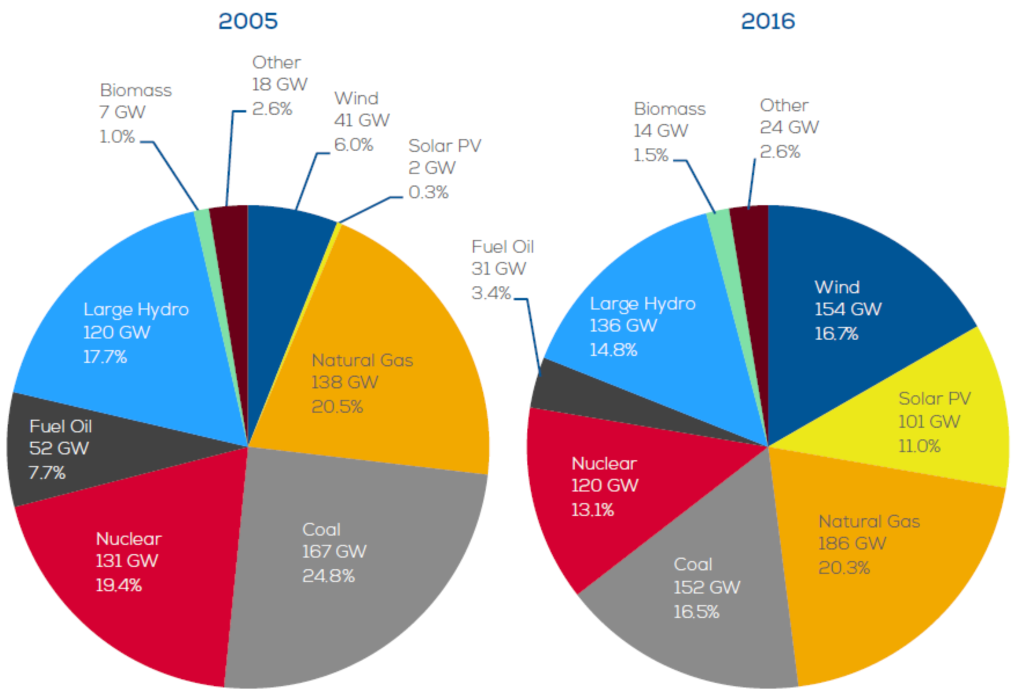

Figure 9: Installed power capacity in the EU. Source: Wind Europe (2017).

The growing share of renewables combined with a reduction in power demand following the economic crisis has put the profitability of gas-fired power plants under pressure since 2009 (Honoré, 2014). The additional renewable capacity typically has negligible marginal costs, putting them at the low end of the electricity generation merit order: the ordering of power plants by their marginal costs of generation. Typically, generators located lower in the merit order are dispatched before generators higher up the merit order. Since also hydropower and nuclear power plants are typically located below gas in the merit order, gas fired power plants were primarily competing with coal fired power plants for a residual demand that was reducing in size since 2009. From the perspective of owners of gas plants, unfavourable combinations of gas, coal and CO_2 prices have led to gas plants being 'out of the money' in most important European power markets (Stern, 2017).

The role of gas in the power sector in the future is somewhat uncertain. On the one hand, environmental policies favours fuel switching from burning gas instead of coal, but on the other hand, these policies promote renewable generation capacity and energy efficiency, reducing the size of residual demand that gas-fired generators are competing for. At current and projected future commodity prices, investing in new gas fired powered plants is projected to be more profitable than investing in new coal fired power plants in Europe, despite that existing gas plants are currently unable to compete with coal plants (IEA, 2016). Consequently, the phasing out of old coal plants is expected to increase the importance of gas in the power sector in the coming decades. The share of gas in the power sector will then importantly depend on the total demand for electricity and the share of renewables, which in turn are dependent on governments' environmental policies. Both the European Commission (2016) and the IEA (2016) project an increasing share of gas in the power sector, while the latter expects the rise in the share of gas to be lower for increasingly tight environmental policies.

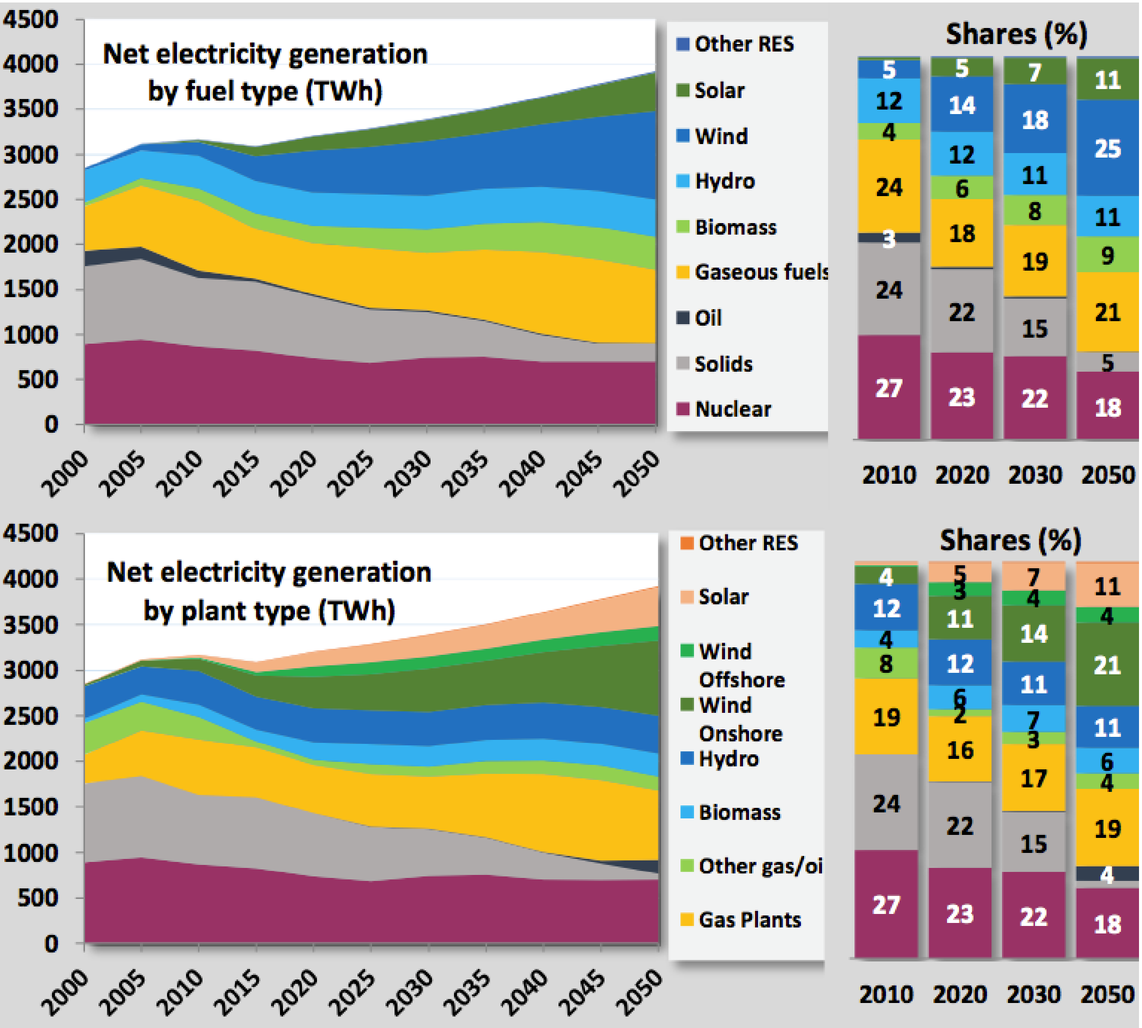

Figure 10: Electricity generation by fuel and by plant type according to the EU reference scenario (European Commission, 2016).

Figure 10 shows the electricity generation by fuel and by plant type between 2000 and 2050 according to the EU Reference scenario (European Commission, 2016). As can be seen in the figure, electricity demand is expected to increase in the EU in the coming decades. The share of gaseous fuels in power generation is initially expected to decrease to 18% in 2020 but afterwards expected to increase again up to 19% and 21% in 2030 and 2050 respectively. Gas is expected to play a key role as a back-up technology for variable renewable electricity generation. Power generation from gas emits less GHG emissions than power generation from other fossil fuels and gas power plants can be operated in a very flexible manner, hereby serving as balancing power for the electricity grid (European Commission, 2016).

Green gas currently plays virtually no role in the power sector for several reasons. Firstly, there is apparently no profitable business case for gas fired power plants to generate electricity with green gas. Green gas is more expensive than conventional gas, which makes it unattractive to power plant owners, although there is an additional benefit of burning green gas over conventional gas. The benefit of burning green gas is that the produced power is green which may be sold at a premium[20]. Assuming a generation efficiency of 50%, burning green gas is viable when the value of a 1MWh electricity guarantee of origin (which captures the additional value of sustainably produced electricity) equals at least the price of two 1MWh gas guarantees of origin (which captures the additional cost of burning green rather than grey gas). The value of an electricity guarantee of origin itself depends on the method of electricity generation and since generation on the basis of green gas is virtually non-existent, this value is unknown. However, in general the prices for green electricity guarantees of origin tend to be low (Mulder and Zomer, 2016) and it does not seem likely that the price ratio between electricity and gas guarantees of origin would currently support a business case for green electricity generation on the basis of green gas.

Secondly, the still very limited amount of green gas that is currently produced seems to form a barrier for energy retailers to offer energy products on the basis of physical green gas. A number of energy retailers offer green gas to their customers where the label green in this case typically stems from either CO_2-compensation projects or from physical green gas forming only a limited share of the delivered gas (see section 2.1.3). Greenchoice explicitly mentions the lack of available green gas volumes as a reason for them to offer green gas on the basis of CO_2-compensation projects rather than physical green gas (Greenchoice, 2017). While these are gas products, it can be expected that the same argument holds for green electricity products based on green gas as well.

The role of green gas in the power sector in the future depends importantly on the premiums for green gas and green electricity (produced from green gas). The electricity sector is a highly competitive sector and it is therefore unlikely for power plant owners to spend resources on a costly input such as green gas without appropriate returns. As long as the ratio between the premiums for green gas and electricity are unsupportive to a business case, wide penetration of green gas in the power sector is not to be expected. In addition, if consumers value green gas they may prefer consuming it in more direct applications (e.g. for heating or mobility) rather than green electricity which is derived from green gas.

3.4 Built environment

In the built environment, natural gas is mainly used for heating purposes (including cooking) predominantly in the residential and services sectors. The use of hydrogen in the built environment is virtually non-existent. Figure 11 depicts the annual natural gas consumption between 2005 and 2015 in the residential and services sectors according to Eurostat (2017a). The combined consumption of natural gas in these two sectors was approximately 158 bcm in 2015 in the EU, coming down from approximately 181 bcm in 2005. The decline in gas consumption in the built environment has not been constant throughout time and gas consumption reached a peak of 190 bcm in 2010.

[20] This does not hold for several European countries (e.g. Germany and France) if the power plant owner received a subsidy to produce sustainable electricity.

The key determinants of natural gas use in the built environment are the number of households, household characteristics (e.g. the number of inhabitants per household), the size of commercial floor space, the efficiency of the building stock (e.g. quality of the building shell), the efficiency of the heating equipment, income, prices of competing heating techniques and their inputs (e.g. electric heaters and electricity), and weather conditions. For gas consumption in the built environment, it is important to make a distinction between the short-run and the long-run, as many of the determinants of consumption cannot be altered in the short-run.

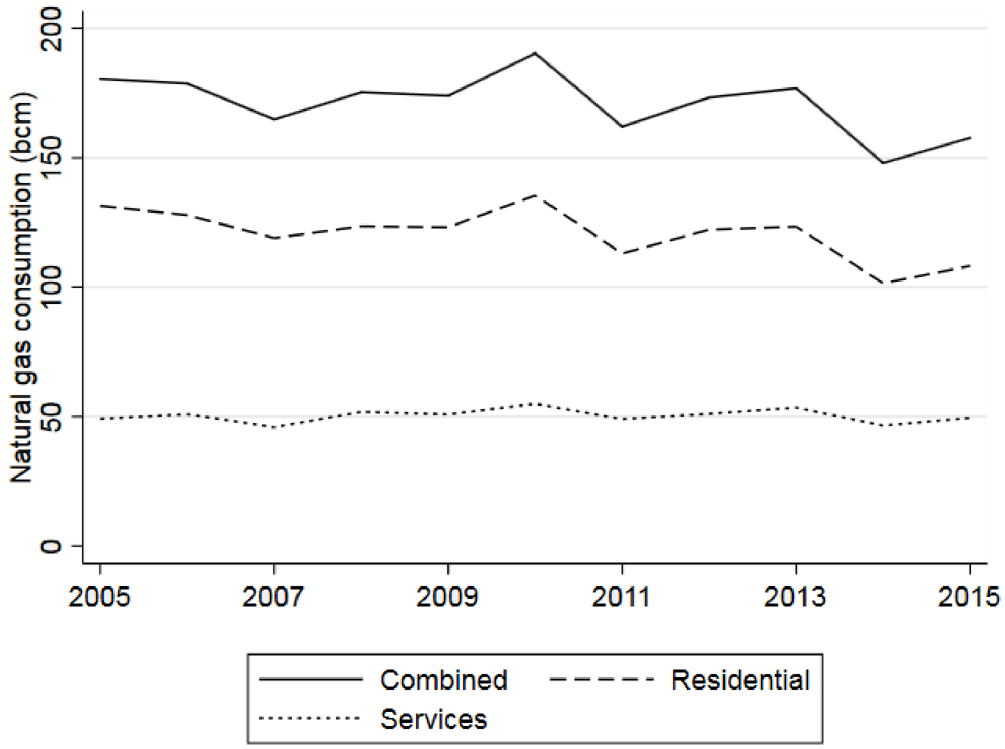

Figure 11: Annual natural gas consumption in the residential and services sectors. Source: Eurostat (2017a).

In the short-run, the heating equipment and related building facets (e.g. insulation materials, window types) are generally fixed, and switching to another heating source is typically not possible. As a result, the demand for gas from buildings in the short-run is mainly determined by weather conditions and, to a limited degree, on the price of natural gas. Regarding the latter, individuals tend to have a strong preference for the comfort of heating services and are relatively unresponsive to changes in the price of natural gas (Asche et al., 2008; Dilaver et al., 2014). Moreover, many residential and commercial gas consumers have shielded themselves from short-run price changes through fixed-price contracts.

In the long-run, however, heating equipment and related building facets may be altered and the building stock itself can be replaced. The prices of competing heating systems, their inputs, and efficiency measures become relevant for the demand for gas for heating purposes and individuals become somewhat more responsive to changes in the price of gas (Asche et al., 2008; Dilaver et al., 2014).

In 2010, the EU implemented the Energy Performance of Buildings Directive (EPBD) (European Parliament & Council of the European Union, 2010) including specific requirements on energy efficiency for new buildings and existing buildings (including replacement of heating systems) aimed at improving the energy efficiency of the building stock. The impact of these new standards has, however, not yet fully materialised as the replacement rate of the building stock has been steadily declining between 2006 and 2014, as can be seen in Table 8.

Table 8: Replacement rate of the building stock per year in the EU. Source: European Commission (2017).

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
1.22%	1.26%	1.22%	0.98%	0.78%	0.73%	0.66%	0.63%	0.50%	0.51%

Figure 12 shows the share of buildings that were constructed in several different time periods in the years 2011 and 2014. The share of buildings that was built before 1969 has been decreasing between 2011 and 2014, but these older buildings still represented almost half (49%) of the total building stock.

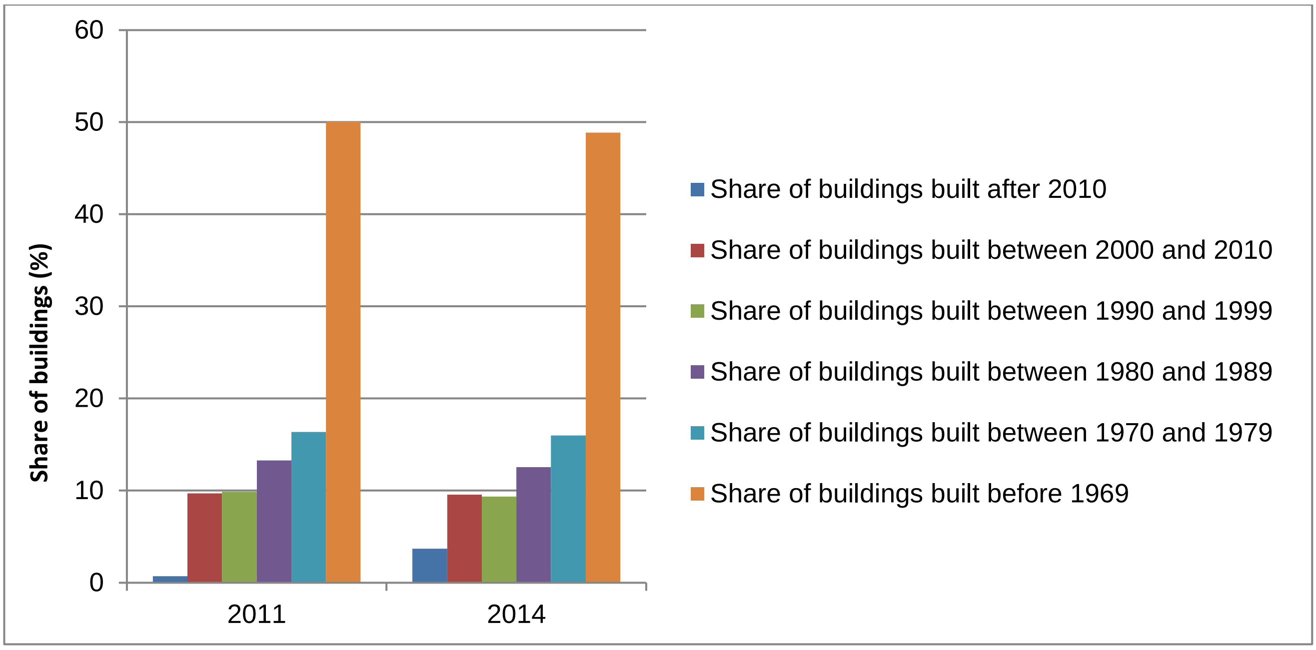

Figure 12: Shares of buildings in the building stock by time period in the EU. Source: European Commission (2017).

The EU Buildings Database provides (limited) data with respect to what type of energy is used in buildings (European Commission, 2017). Table 9 provides an overview of the number of buildings with space heating by fuel type.

Table 9: Number of buildings (in millions) with space heating in the residential sector by fuel type. Source: European Commission (2017).

	2005	2006	2007	2008	2009	2010
Natural gas	92.66	94.34	97.46	97.07	98.51	97.21
Fuel oil	36.34	35.25	30.76	33.90	32.13	31.75
Kerosene	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*
LPG	3.09	2.73	2.69	2.56	2.23	2.22
Solar thermal energy	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*
Coal	7.83	8.35	8.37	8.71	8.80	9.20
Biomass	29.09	29.58	32.23	33.23	35.08	37.37
Electricity	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*
Total	**169.01**	**170.25**	**171.51**	**175.46**	**176.74**	**177.75**
Share (%) of natural gas	54.82	55.41	56.82	55.32	55.73	54.69

Unfortunately, data is only available for the residential sector until 2010 and data for several fuel types is missing (including electricity). Data for other types of heating is also unavailable. According to the data, the total number of residential buildings with space heating increased with 8.7 million between 2005 and 2010, of which 52% are heated using natural gas. This resulted in a slight drop in the total share of gas-fired space heating from 54.8% in 2005 to 54.7% in 2010.

In a scenario study, Entranze (2014) reports that for space heating the main driver of carbon emission reductions in the coming decades is a reduction in energy demand. Entranze (2014) finds that the role of gas in heating remains prominent until 2030 although improvements in energy efficiency of buildings could reduce the demand for gas for heating in 2030 by 21-31% compared to 2008. In contrast, the European Commission (2016) expects the use of natural gas and energy demand in general in the residential and services sectors to remain relatively stable in the coming decades, as is illustrated in Figure 13. Efficiency improvements cancel out energy demand increase from income growth in the residential sector and activity growth in the residential sector (European Commission, 2016). In 2030, volumes of natural gas use in the residential and tertiary sector are expected to be roughly 124 and 52 bcm respectively.

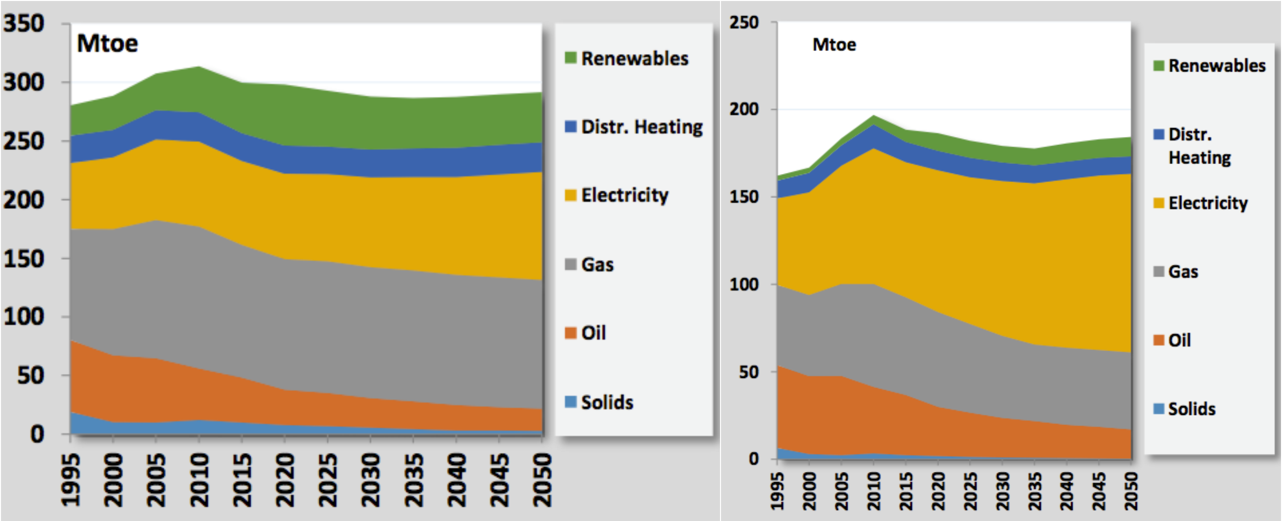

Figure 13: Energy demand in the residential (left) and tertiary (right) sector in the EU according to the EU Reference scenario (European Commission, 2016).

With respect to green methane, households in many European countries can already choose to consume a green variety of methane through contracts with utility companies, although the choice is often restricted to green gas for which the related CO_2 emissions are compensated by certificates of CO_2 compensation projects, or by a contract promising that a limited share of the gas was physically-produced green methane (see section 2.1.3). Unfortunately there is no data available regarding the number of households and firms choosing these types of contracts or their consumption profiles. Comparing the retail prices of green and conventional methane is not straightforward since the contracts differ in many aspects next to the types of methane and their prices, such as variable versus fixed prices, contract duration, and standing charges. Table 10 provides a simple assessment of the largest German and Dutch energy retail companies.

Several of the companies listed in Table 10 offer contracts that differ only in the type of methane (green versus conventional) and corresponding prices, while all other contract aspects are held constant. The prices are taken from the company websites and are based on the same location and consumption indication. It should be noted that Table 10 merely provides a very incomplete overview of the premiums charged by utilities for green methane. Nevertheless, it is interesting to note the differences in the premiums between companies within countries but also between countries. Premiums vary between approximately €0.60 per MWh to €4.80 per MWh and appear to be higher in Austria and Germany than in the Netherlands. For an annual gas consumption of 17000 kWh that translates to an additional yearly cost of between €10.20 and €81.60.

Table 10: Premiums for green methane in retail contracts of the largest German and Dutch energy utilities. Prices are retrieved from the websites of the respective energy companies on the 11th of August, 2017. Premiums are calculated by comparing the prices per kWh (using a conversion factor of 1 m^3 = 9,769 kWh for Dutch contracts) of contracts of the same supplier that are identical in every respect except for the type of methane (green versus conventional).

Country	Company	Green methane premium (€ per MWh)	Type of green methane offered
Austria	EVN	€4.80	5% of consumption physically delivered green methane
	VERBUND	Only offers green	
Germany	EnBW	€2.50	10% of consumption physically delivered green methane
	EON	€3.60	CO_2 emissions compensated with certificates from climate protection projects
	Innogy	Green not offered	
	Vattenfall	Green not offered	
Netherlands	Eneco	€0.879	CO_2 emissions compensated with certificates from climate protection projects
	Essent	€1.795	CO_2 emissions compensated with certificates from climate protection projects
	Nuon	€0.594	CO_2 emissions compensated with certificates from climate protection projects

The role of green gas in the residential and services sectors may become more prominent. Green methane may become a more widely option to consumers wishing to reduce their own CO_2 emissions. Hydrogen is not expected to become important as a direct input for heating in the residential and services sectors (European commission, 2016), although it may play an indirect role in providing electricity for electrical heating systems (Fraunhofer ISE, 2016). The future importance of green methane in the residential and services sectors is largely dependent on the extent to which end-users, consumers and firms, are willing to pay premiums for green gas heating purposes. Between these two groups of end-users there may exist differences in the degree to which they are willing to pay extra for green since consumers and firms pursue different interests. While consumers aim to maximize their utility, firms aim to maximize their profits and these different objectives may lead to differences in preferences for green gas. The next section elaborates on the topic of willingness to pay for green gas, which is relevant for all applications of green gases.

3.5 The willingness to pay for green gas

Green and grey energy of the same type (e.g. methane, hydrogen or electricity) can be priced differently. While the grey and green alternatives are identical in usage, many consumers do not perceive them as perfect substitutes. For those consumers, the origin of the energy they consume matters, for example because of environmental concerns. As a result of these differences in preferences, many consumers value green and grey energy differently. In particular, those consumers with a preference for green energy are willing to pay a premium for green relative to grey, allowing the producer to charge a higher price for the green alternative. Therefore, for the future price and potential of green gases it is relevant to what extent consumers are willing to pay a premium for the green character of the gas and how this willingness to pay is distributed amongst consumers.

The instrument for producers to capture a premium for a green gas is the GoO. Current prices of GoOs are informative regarding the premium that producers can expect to capture. However, there are several issues with analysing the prices of existing GoOs for green gas.

Firstly, the prices of GoOs are not publicly available. Since trade occurs mostly on the basis of bilateral agreements, transaction prices and volumes are not automatically announced and, in addition, many producers of green gas are reluctant with disclosing information. As a result, very little information about transaction prices and volumes reaches the public domain. We have consulted some experts in the field who estimate the price of Dutch Vertogas green methane GoOs to be in the range of €0.03 to €0.11 (1 GoO equals 1MWh).

Secondly, the production volumes of green gases are currently very low. Current prices of GoOs do not necessarily reflect the premium that can be captured by producers if larger volumes are delivered to the market. Like other goods, the willingness to pay for green gases is distributed unequally amongst consumers where some people are willing to pay considerable premiums while others are not. This distribution is an important determinant of the future price for GoOs. For example, if only few individuals have a positive willingness to pay for green gases then a relatively large supply will result in very low prices for GoOs, i.e. low premiums.

A third concern relates to the design of GoOs and the degree to which it reduces information asymmetry. Information asymmetry between producers and consumers of green gases arises due to the inability of consumers to distinguish between green and grey types (e.g. green versus grey methane) since they are identical in usage. Without regulation, a seller's claims that its gas is green is difficult to verify for consumers. GoOs can help overcome this information asymmetry problem by creating a system of issuing, cancelling and monitoring GoOs for production and consumption of green gas. However, it can be questioned whether the European GoO system is successful in fully reducing information asymmetry. Some consumers question the credibility of the claim derived from European GoO (Veum et al., 2015). If information asymmetry remains present in the market, some consumers may choose not to buy green gas in spite of a positive willingness to pay due to a lack of trust that green gas will be delivered to them. If this occurs, premiums paid for green gases are lower compared to a situation where the system of GoOs successfully reduces information asymmetry.

In addition to analysing realised prices of GoOs for green gases it would be interesting to analyse consumers' willingness to pay. Unfortunately, for green gases in particular this information is largely unavailable. Much more information is available for the green electricity market, which has been studied extensively. In a meta-analysis of this academic literature, Sundt and Rehdanz (2015) estimate the average willingness to pay of European consumers to be €0.03993[21] per kWh. This would translate to approximately 19% on top of the average electricity price (including taxes and levies) of €0.20965 in 2015 in the EU (Eurostat, 2017c). This willingness to pay is not equal amongst consumers and has been linked to income, education, age and gender (e.g. Zorić and Hrovatin (2012)), although the findings with respect to the directions of these relationships are not consistent across studies. Regarding the distribution of willingness to pay for green electricity, Bollino (2009) finds that 61% of the Italian consumers is willing to pay €5 per month on their electricity bill to support an increase in the share of renewable electricity. In contrast, Löschel et al. (2013) find that the majority of German consumers is not willing to pay anything for reducing CO_2 emissions by buying EU ETS permits, although the authors note that a significant share of the participants mistrusted the EU ETS system. The willingness to pay for green gases is an interesting field for further study.

Gas can also be 'greened' based on 'non-physical' CO_2 certificates: i.e. CO_2 certificates based on a variety of climate change mitigation activities (see also section 2.1.3). In a recent study by Hamrick and Goldstein (2016), the total global volume of the voluntary certificate trade in $MtCO_2e$ was estimated at 84 in 2015, and cumulative during 2005-2015 in the order of 920 $MtCO_2e$. In addition, there has been the carbon credit trading under the Kyoto Protocol, based on among others Clean Development Mechanism (CDM) projects, where at its height in 2006 more than 500 $MtCO_2e$ per year was traded. On the whole, the voluntary market is to be considered a buyers' market so far, with on

[21] Using the 2015 annual average EUR/USD exchange rate of 1.1095 according to (Eurostat, 2017b).

average rather low and decreasing (since 2011) prices, averaging less than $ 3 per tonne in 2015. Prices seem to vary quite widely; most prices (52% of the surveyed volume of some 45 $MtCO_2e$) varied between $ 0.10 and $ 3 per tonne, but occasionally significantly higher prices were paid, with 12% of surveyed volume sold for over $ 6 per tonne (possibly because such projects had co-benefits such as social, environmental, and economic sustainability). To illustrate, assuming an average household using about 1,500 m^3 of natural gas per year, and related emissions of about 2.7 tCO_2e per year, this gas can be ‘greened’ based on CO_2 certificates of $ 3 per tonne for about $ 8.10 or € 7 per year.

4 Scenarios for the future demand of green gases

In this chapter four scenarios will be described together roughly reflecting the different possible future outcomes regarding demand for green gases across the EU until 2030. In these scenarios, the focus will be on the share of green gases in the overall gas demand as projected in the official EU reference scenario (European Commission, 2016). In doing so, we assume that new and additional sources of green gas supply will not create additional demand for gas beyond the reference scenario levels but rather replace volumes of (not CO_2-certificate-compensated) conventionally produced gas. The key outcome variable defining the different scenarios therefore is the share of green gases in the overall gas volume.

To develop the four scenarios two key developments affecting the demand for green gas are identified. Figure 14 depicts the two key developments and four resulting scenarios.

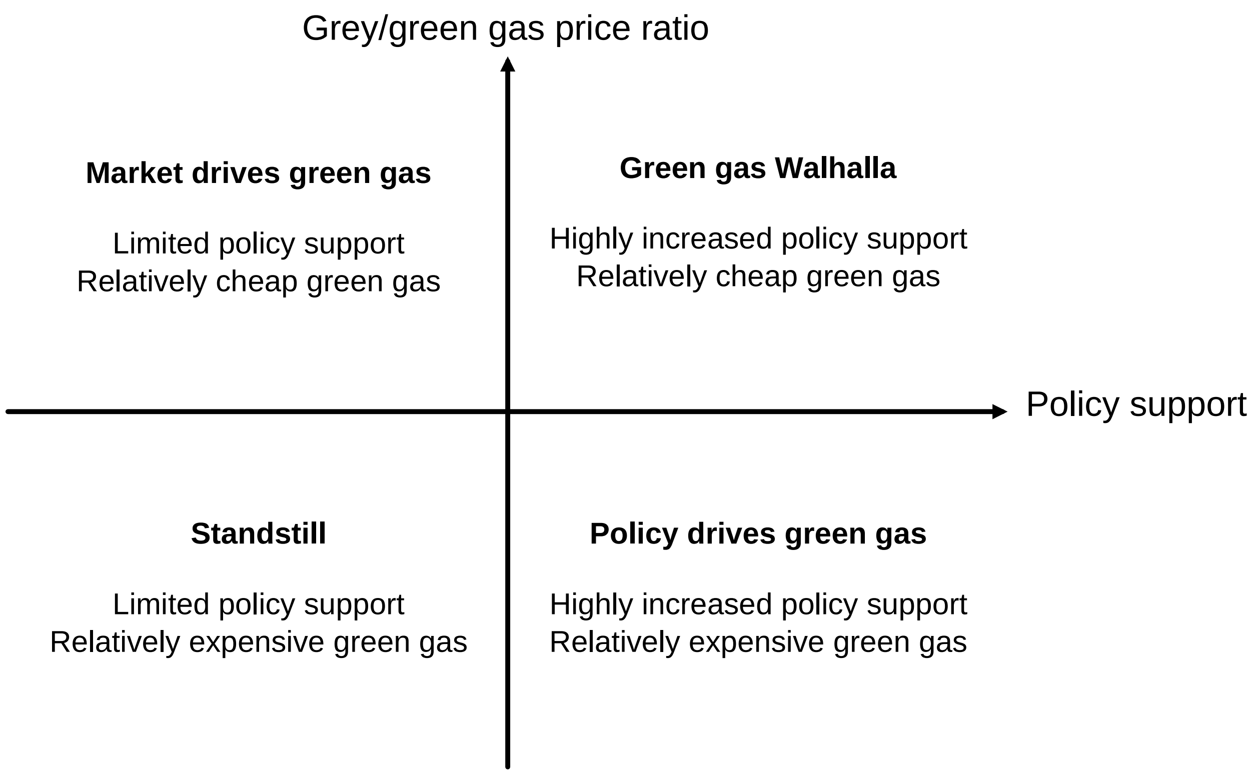

Figure 14: Four scenarios describing the future EU demand for green gas.

Firstly, the policy regime, in particular specific support for green gas, is a key uncertainty affecting the role of green gas in the total supply of gas, which is depicted on the horizontal axis. For our scenarios we consider outcomes for policy support for green gas ranging from the *limited policy support* situation on the left hand side to *highly increased policy support* on the right hand side. By shifting from left to the right, we assume that policies and measures are increasingly supportive for green gases. The left hand side is characterized by a situation of no specific policy support for green gases while on the right hand side policies are specifically targeted towards the adoption of green gas technologies. For example:

- Generic policies (either subsidies, tax schemes, or other generic policies and measures) favouring carbon neutral technologies become increasingly supportive from left to right.
- While absent on the left hand side, the right hand side represents outcomes with specific support for green gas technologies, for instance in the form of innovation and production subsidies or specific measures to support grid access of green gases including green hydrogen admixture in the natural gas grid.

- In addition, the definitions for green gas chosen by policy makers increasingly favour green gas from left to right, that is to say as we move to the right along the axis, policies increasingly recognise CO_2 certificates as a legitimate means to 'green' natural gas.

On the vertical axis, the market development is central, that is to say the "spontaneous" or autonomous technological development and the public acceptance and active support for green gases including their various definitions. Together, these factors determine the relative price between green and conventional ('grey') gas, which is therefore driven by a combination of consumer preferences (including what is generally perceived as an acceptable definition of green gases) and market developments including technological and autonomous market uptake aspects, determining the scope for extension of the share of green gas in the overall gas demand portfolio. So, by shifting upward:

- The technological development is increasingly favourable towards green gas production (e.g. gasification and power-to-gas see breakthroughs and enter maturity, while digestion is gaining considerable strength).
- Market uptake conditions are improving considerably,
  - primarily because society is very favourable towards using green gases including hydrogen (e.g. in mobility, in industry, and in the built environment),
  - but also because the public at large responds favourably towards the option to use CO_2 certificates as a way of 'greening' natural gas and hydrogen, and towards the use of hydrogen in various applications.

So, this shift upwards leads to a *higher grey/green gas price ratio* (representing a situation where green gas is relatively cheap).

Combining these two uncertainties yields four possible outcomes, our scenarios, which we titled **Market drives green gas**, **Green gas Walhalla**, **Standstill** and **Policy drives green gas**. The top left scenario titled **Market drives green gas** is characterized by a continuation of existing European climate policy and relatively cheap green gas. The top right scenario titled **Green gas Walhalla** combines a more stringent European climate policy with relatively cheap green gas. The bottom left scenario, **Standstill**, represents an outcome of continuing existing (moderate) European climate policies and relatively expensive green gas. The bottom right scenario, **Policy drives green gas**, represents the combination of more stringent European climate policies with relatively expensive green gas.

If the assumptions are lumped together with the other scattered information on the future profiles of green gas, what could then be the share of green gas in the overall EU gas demand by 2030 in the various scenarios? To answer this question, a disclaimer is in order, i.e. given the various projections, extrapolations, and other data from the literature, in fact one can only make some crude guesstimates as to how future demand for green gases across Europe could develop between now and 2030. The figures linked with the four subsequent scenarios and specified below are therefore assessed in the perspective of this disclaimer. In the assessment, the several 'layers' of green gases as illustrated in Figure 3 in section 2.1.3, that together cover the definition of green gases used in this study, need to be distinguished: physically-produced and delivered green gases, green gases based delivered using guarantees of origin (GoOs), and green gases based on other CO_2 certificates.

The four scenarios will be described and discussed in more detail in the following subsections.

4.1 Green gas Walhalla

In this scenario, green gas makes a considerable jump forward driven by both developments in the private domain and public support. Policies and measures extend their scope such that not only digestion technology is supported but also gasification, upgrading of biogas to biomethane and power-to-gas. Policies that benefit green gas technologies include both innovation subsidies as well as production subsidies. In addition, major breakthroughs in gasification and power-to-gas technology are achieved, further reducing the production costs of green gases. As a result, considerable volumes of green gases are produced throughout the EU. As a result of the policy support and breakthroughs production of green gases becomes competitive with conventional gas production and it becomes quite normal that green gases, including hydrogen, enter the grid, are implemented in mobility, replace natural gas and hydrogen produced from fossils, and are traded with GoOs in a mature market.

4.1.1 Green gas production costs/technology development

The supply conditions for green gas develop relatively favourably and also policies and measures towards the production and use of green gases get increasingly favourable. This applies not only to digestion technologies, which are strongly inspired by targets to try to get less reliant on non-EU gas, but also to power-to-gas and gasification technologies. The EU clearly wants to push those technologies towards maturity levels well before the 2030s.

4.1.2 EU climate/green gas policy focus

The result of the favourable market and policy conditions is that power-to-gas gets off the ground much more quickly than many had anticipated. A considerable part of the intermittent renewable power production, including the offshore part, is converted into green gases, because one increasingly recognises EU-wide that even after the energy transition a substantial part of energy will be consumed as green molecules, but also that without conversion intermittent energy sources create insurmountable transport challenges: it is simply impossible to transport the large volumes of intermittent power towards their final destination, because grid extension cannot be achieved in time or within any acceptable societal cost margins, let alone public acceptance conditions. This notion forces the EU to introduce, next to green policies, aggressive policies towards energy conversion and storage, all benefitting the case of green gases. The technological breakthroughs in power-to-gas and gasification technologies are benefitting from considerable subsidies to get through the valley-of-death as quickly as possible. The result is that power-to-gas and gasification technologies get to maturity by the mid-2020s and volumes of green gases from these technologies rise rapidly towards 2030.

The EU reactivates in this scenario the former CCS strategies that lost much of their appeal in the mid-2000s. The reason why public acceptance issues are no longer a serious obstacle is that CO_2 underground storage is now almost completely limited to offshore situations. It becomes normal for the remaining offshore gas production to split the CO_2 from the methane, to store the CO_2 offshore, and to transport the remaining green hydrogen to shore for direct application (or possibly methanation if application conditions so require). In addition, substantial CO_2 flows are channelled towards the sea, and the North Sea in particular, to be stored underground. The traditional natural gas grid is typically used for such transport. CO_2 penalties raise to such levels that CCS – the cost of which keeps declining towards on average levels below € 50 per tonne due to technological progress and economies of scale – gets close to a business case, but subsidies are implemented to reach that stage.

4.1.3 Demand profile development

Demand for green gases develops very quickly, to start with in mobility. The famous chicken-egg-issue – no demand for cars without sufficient fuelling capacity and vice versa – is resolved because traditional energy companies rapidly recognise that policies and measures will phase out diesel and petrol-driven cars throughout the EU within a few decades. In order to survive, they will therefore rapidly have to focus on electric cars (both battery electric vehicles (BEVs) and fuel cell electric vehicles (FCEVs)) and servicing them, which means that hydrogen-driven cars with fuel cells are very aggressively promoted, not only by the car industry but also the further infrastructure by the energy majors, both supported by active policies and measures throughout the EU. This development is supported by the increasing issues that are encountered with regard to battery technology, that turns out to be not only relatively costly, but also more demanding than power grid can service, and less environmentally benign, than anticipated. Batteries therefore will only play a limited role in mobility, except for niches related to local transport.

Some support for optimism towards the role of hydrogen in mobility in the future is provided by the scenarios generated by Certifhy (2015) and McKinsey & Company (2010). Certifhy (2015) develops four scenarios with regard to the role of hydrogen in mobility, and concludes that in their scenario with 'high policy support, but modest learning' (comparable to the 'policy drives green gas' scenario in this study), hydrogen for fuel cell vehicles could reach a 3% penetration rate by 2025. For the 'high policy support with fast learning' scenario (comparable to the 'green gas Walhalla' scenario in this study) they project a 7% penetration rate by 2025 and even a 9-13% penetration rate by 2030. If the latter result would materialise, by 2030 some 12 to 25 million fuel cell vehicles would be used throughout the EU, fuelled by hydrogen. McKinsey & Company (2010) suggest a 25% penetration rate by 2050, which would imply that by then over 18,000 hydrogen retail stations would be available in the EU (some 2,300 by 2025, to more than double to 5,100 by 2030).

In the chemical industry, it is increasingly recognised that the green chemical production profile offers a rapidly increasing positive business case. As an example, hydrogen is used in refineries for hydrocracking and in the chemical industry where it serves as a feedstock for mainly ammonia and methanol production (Stolten and Emonts, 2016). The refineries and chemical industry could reduce their GHG emissions by replacing fossil based hydrogen with renewable hydrogen from electrolysis. This could significantly reduce natural gas consumption in the EU. Several refineries from e.g. BP are already considering placing electrolysers on their plants to produce (part of) the required hydrogen (Port of Rotterdam, 2017).

So, in this scenario, fertiliser production based on 'grey' hydrogen (i.e. hydrogen produced from natural gas releasing the CO_2 into the air) is rapidly facing serious disincentives, and therefore gets replaced by fertiliser/ammonia production from green hydrogen. In the beginning, most of the green hydrogen is produced from (offshore) natural gas combined with CCS and from 'grey' hydrogen with CO_2 certificates, but increasingly demand will develop towards chemicals based on 'real' green hydrogen, i.e. green hydrogen from renewables based on power-to-gas technology.

Green gas also benefits from the fact that the public at large is quite relaxed on the issue how the carbon footprint of the gases consumed is achieved, as long as certificates are considered reliable and sufficiently controlled. In other words, green CO_2 certificates are on average considered to be a completely acceptable means of greening the gas, because in the end for the climate issue it is immaterial where, when, and how the additional mitigation performance has been made. This flexibility allows for a rapid extension of the volume of green gas, even if natural gas is still – albeit increasingly less – delivered to the market throughout the 2020s.

The former assessment has indicated that the current penetration rate of physical biogas/biomethane of some 4% may evolve, under favourable circumstances, towards some 12% (48-50 bcm). This figure would include some biogas/biomethane production from gasification. In addition, green gas could be produced by power-to-gas technologies.

Certifhy (2016b) expects that by 2030, about 17% of all hydrogen could be generated by power-to-gas, which would be 1.7 million tonnes of green hydrogen made from 83 TWh electricity. Together, physically produced green gases could replace more than 13% of gas by 2030. In addition, gas could be 'greened' non-physically by combining natural gas with CO_2 certificates. Currently, the worldwide CO_2 certificate trade volume amounts to some 84 $MtCO_2e$, which would theoretically cover about 12% of the EU CO_2 emissions related to the consumption of about 400 bcm of natural gas (some 710 $MtCO_2e$). It is very difficult to make a guesstimate of the potential growth of the certificate market related to the EU gas sector, but if CCS projects and other international mitigation projects (including forestry) would generate considerable green CO_2 certificates picked up by the gas sector, this part could become considerable and potentially even lead to a situation in which overall the gas uptake would become to a substantial extent or even completely 'green'.

4.2 Market drives green gas

In this scenario, policy makers increasingly take the position that green gas development and uptake should be left to the market: the market conditions therefore will determine which role green gases will play in the energy system.. The policy makers in EU Member States choose to abolish existing policy support for green gas and only generic mitigation policies and measures remain to some extent. At the same time, technological improvement reduces the production costs of green gases, irrespective if they are produced by digestion, gasification or via power-to-gas. Green gas technologies therefore enter full competition with other green technologies such as electrification (wind and sun), energy efficiency measures and carbon capture and storage (CCS). Assuming a favourable push and pull development (not only technological improvement mentioned but also a supportive demand side development in which market uptake of green gases speeds up, and green gases including green hydrogen and active certificate trading and acceptance show a strong increase), the market itself is strong enough to provide support to the role of green gases without major supporting policies.

More explicitly, in this scenario the following components can be distinguished:

4.2.1 Green gas production costs/technology development

In this scenario, the production subsidies for power and gases based on renewable production will disappear, also for biogas/green gas production, and be replaced from the producer perspective by the returns on selling increasingly valuable GoOs on the one hand and the increasing benefits from the grid balancing contribution on the other hand. Both returns are market-driven, so that these developments are in line with the EU targets to try to get rid of production subsidies for renewables and replace these incentives by market-driven ones. In addition, CO_2 penalties increase due to higher CO_2 credit levels.

Because the digestion capacities increase strongly throughout the EU, economies of scale and technological breakthroughs substantially reduce the cost of producing green gas via digestion, such that biogas/green gas enters the market against competitive prices, while providing an acceptable margin to producers. Large-scale conversion capacities to turn biogas into green gas develops gradually, also gains from economies of scale and further technological progress, and becomes a standard process to convert biomass. Serious issues for the green gas to enter the grid are resolved, so that grid access is no longer a problem, the more so as gas quality norms are relaxed throughout the EU.

In the course of the 2020s the rapidly increasing demand for hydrogen in both mobility and chemical industry raises green hydrogen prices considerably, and therefore strongly supports the further development of power-to-gas technology. Serious breakthroughs in these technologies therefore develop much more quickly than anticipated, among others because electrolyser costs come down with more than 50% very quickly, so that this technology becomes relatively cheap and standard by the end of the 2020s. By then, part of the hydrogen is turned into methane via large-scale methanation units, especially in those parts of Europe where appliances require methane rather than hydrogen. As a result, the price of green hydrogen including returns from the GoO becomes lower than that of conventionally produced hydrogen. In fact, green gases become a major component to resolving power grid balancing issues, because green gas storage turns out to be relatively cheap, not only for cases of large-scale storage in depleted gas fields and salt caverns but also for cases in which the green gas is stored in a decentralised relatively small-scale manner, especially near-farm. As a result, the grid balancing 'bonus' of green gases to power is such that it becomes economically feasible to convert part of the green gases into power.

Finally, gasification technology comes off the ground due to, among others, the ample availability of woody biomass from various parts of Europe, but also from other parts of the world (Canada, Russia). Prices of such biomass remain quite low due to heavy competition, so that gasification gradually gets a business case towards 2030 and capacity expands, especially near harbour facilities.

4.2.2 EU climate/green gas policy focus

The EU strongly aims for the abolishment of subsidies, both CAPEX and OPEX, on renewable energy production, to be replaced by incentives provided by the market itself. The latter are primarily GoOs, the prices of which are determined by market forces. In addition, flexibility services in the power market are expected to be increasingly rewarded based on market conditions. These sets of incentives – together with the on-going CO_2 penalties – are the main policy drivers of the energy transition during the 2020s, and benefit the role of green gases, because of their grid balancing capabilities and their low transport costs.

Because specific policies and measures to support the production and use of green gases are abolished, the valley-of-death issue from which power-to-gas and gasification technologies may suffer, will remain to a certain extent. This explains why these technologies come off the ground relatively slowly, so that green gas produced via these technologies only seriously enters the market in the second half of the 2020s.

4.2.3 Demand profile development

The prices of the GoOs rise strongly, because demand for green gas in general increases strongly, especially demand from mobility and from the chemical industry, but also outside the gas market demand for GoOs becomes buoyant. The GoOs are also increasingly popular in other parts of the industry and mobility. The willingness to pay for green gas versus fossil gas is increasing rapidly, because fossil gas is perceived by the public at large as an ‘old-school’ product that they increasingly no longer want to consume. The use of CO_2 certificates to ‘green’ gases is considered a normal, accepted and standard way of satisfying demand for green gases, irrespective what the source of the certificates is as long as certificates are considered reliable. This explains why green gas GoOs increasingly gain economic value because they cannot only be used to green the gas, but also to green liquids and other sources of energy.

Moreover, it is increasingly recognised that even after the energy transition, a substantial part of the energy demand will need to be satisfied by green molecules rather than green electrons, especially demand from the industry and mobility. This also contributes to favourable market conditions for green gases.

4.2.4 Some illustrative figures

Just as in the Walhalla scenario, the physical production of biogas and biomethane through digestion benefits from favourable market conditions, although it does not receive the extra boost from dedicated policies and measures, and therefore may develop somewhat slower than under the Walhalla conditions. Moreover, gasification as well as power-to-gas technology suffer more strongly from the valley-of-death conditions, and therefore also come off the ground slower than under Walhalla conditions. Because policy does not substantially interfere any longer with green gases uptake, markets may be quite relaxed on the scope of green gases considered acceptable, so that interest in green gases may focus more strongly on certificate-based greening whereby the public is fairly indifferent whether certificates are GoOs from physical green gas production or other CO_2 certificates. We therefore assume as a ballpark figure that the physical production of green gas will increase not more than to about double the current level, so from about 4% to about 8%, while physical delivery from gasification and power-to-gas will remain limited to no more than about 0.5%. Together the green gas share based on physical production can grow to about 8.5%. CO_2 certificate-based green gas uptake, instead, flourishes, such that overall the penetration of green gases can get very substantial indeed.

4.3 Policy drives green gas

In this scenario, government policies promote the adoption of green gas while no major breakthroughs occur in the production technologies. Governments support green gas mainly via production subsidies, favouring the cheapest sources of green gas. Since gasification and power-to-gas remain expensive production technologies, they do not play a serious role in the energy mix in this scenario. Green gas from digestion on the other hand, will experience an increase in produced volumes mainly by increasing the use of manure and organic waste, where still large potentials are expected (CE Delft et al., 2017).

4.3.1 Green gas production costs/technology development

In this scenario, EU policies increasingly support the production and use of green gases, but the market fails to strongly respond to the incentives provided. One reason could be that the learning curves for gasification, power-to-gas, and upgrading turn out to be much less steep than anticipated, because of the complexities due to the interaction between technology, public acceptance, grid conditions, and safety issues. Digesters increasingly face protests from local communities because of the bad smell and adverse impact on the landscape. Moreover, hydrogen production and the production of syngas equally suffer from public distrust, because of the perceived risk of leakage and explosion. This slows down gasification and power-to-gas technology up to the point of very little progress towards 2030, despite serious policies and measures to promote the advancement of such technologies.

Green gas production therefore remains limited to digesters, especially in agricultural areas. Despite policies to expand green gas production from this source, market uptake remains limited such that the GoOs receive limited prices. The current level of maturity prevents considerable technological progress to develop towards digestion technology, so that production costs cannot benefit from substantial reduction. Digestion therefore keeps suffering from an insufficient business case, and therefore remains strongly dependent on the on-going subsidy support.

4.3.2 EU climate/green gas policy focus

The policy towards the promotion of green gas production from biogas as has been initiated in some of the EU Member States by the late 2000s is extended to cover most of the EU. Also coordination of these policies is improved as well as the conditions for GoO trading between Member States. Through this policy, the EU tries to aggressively support biomass conversion, especially biomass from waste. This way, it is hoped to add to solving the increasing power-grid balancing issues. More far going green gas production technologies are however not supported, because these technologies are considered to become only feasible post-2030. Although some renewable sources, notably wind and solar, can do without production subsidies to enter the market, it is recognised that this does not yet apply to biomass conversion, at least not before 2030. This, however, is not considered a problem because biogas production support schemes contribute to the reduction of gas dependence from non-EU sources, and because this support favours a stable and clean agricultural supply base throughout Europe.

4.3.3 Demand profile development

The demand for green gases comes not really off the ground in this scenario, despite EU-wide continuous efforts to support green gas from biomass digestion. The mobility sector chooses for an all-electric scenario with batteries on the one hand, and a continued fossil scenario (with some CO_2 certificate greening) on the other hand. The chemical sector remains convinced that using green gas as a feedstock is too detrimental for the business case to be acceptable for a sector exposed to fierce international competition.

The public at large increasingly sees green gas from digestion as a product that is linked with badly smelling farming towers spoiling the landscape. It is also questioned if turning biomass into green gases is the best way to use that biomass; biomass production specifically for energy purposes is increasingly less considered acceptable. The use of GoOs derived from this therefore remains limited, because such GoOs are considered low-grade and have a low price. The willingness to pay for green gas as compared to fossil gas remains therefore very low; in fact most people are not prepared to pay anything extra for green gas if fossil gas is equally available.

4.3.4 Some illustrative figures

In this scenario, the government puts substantial pressure on the further extension of digestion, such that biogas and biomethane production based on this technology steadily grows further, although public resistance against digesters is growing and slows the development. We therefore assume as a best guess that the physical production of biogas/biomethane will only grow from the current 4% towards about 6-7%. Additional production of green gases from gasification and power-to-gas will remain very modest because subsidies will be limited to innovation subsidies as long as these technologies have not yet reached maturity levels. Given that, governments will consider production subsidies for these technologies as non-feasible. We therefore assume only very limited, about 0.1%, additional supply of green gases from these technologies. Note in this regard, that the CertifHy project assumes in its 'high policy support, but modest learning' scenario (comparable to our 'policy drives green gas' scenario) that hydrogen for fuel cell vehicles could reach a 3% penetration rate by 2025, corresponding with some 4 to 6 million vehicles (Certifhy, 2015). We assume, however, that due to a lack of spontaneous market uptake, the corresponding numbers will be much smaller.

The market develops no substantial interest in CO_2 certificate-based green gases in this scenario, so that the overall penetration rate of green gases probably will remain modest, i.e. below 15 or even below 10% (unless government policies will be introduced forcing a substantially larger share of green gases on the market, based on CO_2 certificates).

4.4 Standstill

In this scenario, there are no major technological breakthroughs nor are policies supportive of green gas production, technology or implementation. Moreover, the general public is no longer eager to consume green gases. A high green/grey gas price ratio favours conventional gas for the supply of gas and green gas does not play an important role in reducing CO_2 emissions in the EU. A substantial EU CO_2 certificate market does not come off the ground, nor is green gas based on gasification and power-to-gas competitive enough to gain importance. The current emphasis on biogas production from digestion therefore remains, but volumes will remain fairly small. Both the mobility and the chemical industry are not taking serious initiatives to introduce green gases. As a result, the share of green gas in the total gas consumption increases only to a very limited degree.

4.4.1 Green gas production costs/technology development

Because digestion is an already quite mature technology, substantial production cost reductions will not take place in this scenario. Most of the extension of green gas production therefore comes from the increasing use of manure and organic waste as a source of biogas. The same lack of substantial technological progress applies to the alternative technologies, power-to-gas, gasification, and biogas upgrading. By lack of serious dedicated policies and measures to support green gas production and of clear market incentives via the prices of GoOs and flexibility services, the green gas production activity can best be characterised as 'muddling through'. Production volumes increase, but slowly and only to a limited degree.

4.4.2 EU climate/green gas policy focus

Feed-in support schemes for biogas production are phased out, to be replaced by market-driven incentives in conformity with the EU philosophy that the energy transition ultimately needs to be primarily driven by market forces. Due to this phase out, biogas production stagnates so that substantially increasing volumes are not achieved. To the extent that biogas is still produced, most of it is used for the production of heat and power; little is converted into green gas for grid injection.

Because gasification and power-to-gas technologies are also left to the market to develop, in fact relatively little progress is made by lack of a solid business case, or at least solid business case expectations. Although there are scattered initiatives via some pilots and demos, maturity of these technologies is not achieved before 2030, let alone significant green gas production via these technologies coming to the market.

4.4.3 Demand profile development

In mobility, green gas does not really come off the ground, because of the chicken-egg issue that will not be resolved by lack of any clear policy guidance or significant market initiative. As a result, developments in mobility towards greening the system remain slow, and mobility therefore remains fairly strongly dependent on fossil fuels.

In the chemical industry the picture is comparable. Although in some niche markets green gases are introduced, on the whole the volumes remain modest by lack of clear incentives.

The public at large is reluctant to accept green gases based on GoOs, because of suspicion against the certificates' origin and because of the preference to get 'physical' green gas rather than only a GoO. The willingness to pay extra for the green gas is by far insufficient to cover the extra production costs of it, as compared to that of traditional fossil gas, so that green gas demand remains limited to small consumer groups with atypical preferences. Greening gas with the help of CCS is not accepted either, so that this option also doesn't work.

4.4.4 Some illustrative figures

In this scenario, the use of physically produced green gases will mainly be based on biogas and biomethane from digestion. The volumes of these gases will, however, show little growth. At the same time, neither power-to-gas nor gasification technologies get much further than the pilot or possibly demonstration phase, but anyhow do not get to commercial maturity yet. The lack of acceptance of especially CO_2 certificates as a "too easy way out" implies that the gas will be to a large extent based on physical deliveries with all the complexities to it. We therefore assume as a best guess that the current about 4% market share will only marginally increase with some 10% towards 4.4%. The other supplies of green gases remain very modest, and are therefore assumed to grow to levels just in the order of 0.1%. Together, physical green gases will therefore see a penetration rate of about 4.5%. Green gas based on CO_2 certificates will also play a modest role, so that overall the penetration rate of green gases will remain less than 10%.

5 Final remarks

This report has tried to provide a perspective on the greening of the EU-wide gas consumption by 2030, via a scenario analysis. The main conclusion is that of the projected gas use by 2030, in the order of 400 to 450 bcm per year, still a relatively limited share will be ‘greened’ by then. So far, the dominant source of green gas, i.e. green gas based on digestion of biomass, has succeeded in greening gas use to a level of about 4%. Most of the expected increase in ‘greening’ of gases will still be based on the same source. In an optimistic scenario, such green gas could comprise in the order of 10% of 2030 gas use. New technologies to generate green gases are currently under development, biomass gasification and renewable power-to-gas, but given their position in the technology cycle, green gas volumes based on those technologies, will grow but according to most current scenario studies are unlikely to represent more than a few percent of the 2030 gas use.

The speed of ‘greening’ the gas system will therefore also depend to a large extent on the market uptake of gas that has been ‘greened’ with the help of CO_2 certificates. In the absence of a clear perspective on policies and measures to generally promote the ‘greening’ of gases as energy carriers, either physically or via CO_2 certificates, it is hard to make any clear projections on the share of the gas that can be called ‘green’ by 2030.

There is a number of further research issues following from this study, that will be examined during the course of the STORE&GO project in order to be able to predict better the future development of a European green gas market.

First: what part of the future market uptake of energy carriers will be in the form of (green) electrons, and what part in the form of (green) molecules? Is the energy system gradually moving towards a dominance of green electrons, or is it more likely that, even on the longer term, demand for (green) molecules will remain substantial, if not dominant in terms of energy content? Obviously, the answer to this question will define the future demand for energy conversion, storage, transport needs, and energy application, and therefore overall demand for (green) gaseous energy carriers.

Second, how rapidly can gasification and power-to-gas technologies be ramped up, if demand profiles, learning effects, and supportive policies and measures, all would develop favourably? Can the new green gases be handled without much complexity and to a considerable extent by the existing transport and storage modalities, and can the various appliances cope with the emerging gas quality issues?

Third, what can the impact be of shifts in end-user preferences towards green energy carriers, wat determines such shifts, and what is the role new policies and measures can play in this regard? In other words, can the greening of the gas uptake be primarily left to the market and consumer preferences, or will continuous and clear policy initiatives be required to make sure that gaseous energy carriers will lose their CO_2 footprint in time?

Fourth, how will the demand-side deal with the choice between grey and green gases, and how will one look upon the role of CO_2 certificates to ‘green’ gases? Similarly, will, for instance, CCS technology be accepted so that natural gas can still be used in the foreseeable future as a gas without a CO_2 footprint?

Finally, the issue is how the public at large and the industry will take up the introduction of green hydrogen on the market. In other words, how quickly can the current methane-based gas system be turned into a system dominated by the influx of green hydrogen on the one hand and possibly the outflux of CO_2 on the other hand, and to what extent may such a conversion within the gas system be affected by demand factors?

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