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Green gas contribution for energy systems decarbonisation

Gabin Mantulet

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THÈSE

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Présentée par

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dans l'École Doctorale I-MEP2

La contribution des gaz renouvelables à la décarbonation des systèmes énergétiques

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Introduction

Climate, energy and institutional context

The transformation of the energy system is a major challenge of the XXIst century. World population and Gross Domestic Product (GDP) growths increase demand for water, food and energy while the Earth resources are limited and are depleting. Until now, GDP growth entails energy consumption growth that leads to an increase in energy extraction and production. Historically, this trend is due to Northern countries development. Nevertheless, the recent development of Southern countries accelerates this tendency. This increase of energy consumption affects and changes the environment. According the Intergovernmental Panel on Climate Change (IPCC¹) work, global warming is due to the increase in Greenhouse Gases (GHG) concentration in the air that reinforces the natural greenhouse effect of the atmosphere (IPCC 2018). Besides, IPCC also concludes that human activities negatively affect the environment. It drives to a degradation of ecosystems that is more and more alarming. Threats are looming for Earth biodiversity sustainability. Thanks to this work, it is now clear that anthropogenic GHG emissions, mainly from coal, oil and gas energy combustion, are causing an acceleration of global climate change that is a major challenge to be urgently tackled.

Such growing recognition of the threat of climate change and energy security has motivated many countries to try to decrease their GHG emissions and diminish their reliance on fossil fuels. To address this problem, international climate energy policies have been initiated and objectives have been set, in particular at the COP21 in Paris (ONU 2015). Indeed, proceeding with the current policies would lead to a sharp rise in global CO₂ emissions, with disastrous climate consequences (IEA 2019). For example, the European Union (EU) purpose is carbon neutrality by 2050 (European Comission, Green new deal 2019).

The 3 decarbonisation pillars

All the measures that can be implemented to fight climate change and GHG emissions rely on three pillars of decarbonization: energy efficiency and sobriety, switches to decarbonised vectors, decarbonisation of end uses (DDPP 2015).

The first pillar of the decarbonisation is the energy sobriety and the increase of energy efficiency. The energy consumption has to be reduced and lowered by technically improving products and processes as well as behavioural or structural changes from people and society. A reduction of the energy consumption for a given service or production is searched. The hunt for losses in energy chains is also key to reach this pillar's objectives.

¹ The IPCC is an international organization composed of scientists and experts. Its mandate is to evaluate the scientific, technical and socio-economic information available from the scientific community concerning the climate in a neutral and objective way. IPCC aims at accounting for different perspectives and uncertainties, while clearly identifying elements that are within the consensus of the scientific literature. Its mission is to "regularly establish a collective scientific expertise on climate change".

The second pillar is the decarbonisation of electricity and fuels. The aim is to reduce the carbon content of all energy vectors. For example, it is better to have renewable power plants rather than fossil power plants for electricity generation from a GHG emission viewpoint. Likewise, liquid and gas fuels for mobility can be produced from low carbon processes, for example by using biomass-based biofuels. Overall, the secondary energies (electricity, heat, liquids and gases fuels) should move closer to carbon neutrality.

The third and last pillar is the decarbonisation of the end uses. As the energy sector represents almost 80% of GHG releases, sustainable and decarbonized energy vectors have to develop massively to replace fossil fuels and their related GHG emissions. In a first step, coal can be replaced by gas that is twice less carbon intense. Using no primary carbon energies such as coal, oil and natural gas for energy uses and replacing them by carbon free energies has to be the ultimate purpose for moving, lighting, heating, etc.

Clearly, these three pillars are connected and the work done in one pillar can facilitate the others. For example, a reduction of the consumption for one need may imply lower carbon free energy production deployment to reach a full decarbonisation. Besides, these three pillars are common to all countries and regions through the world, but their contribution in the decarbonization trajectories are variables because of contrasting national conditions and specificities (DDPP 2015).

Low carbon electricity, a key option to decarbonise energy systems, but not the silver bullet

Solar, wind, hydro are renewables that transform a natural source of energy (sun lighting, wind or water) into appropriate energy for our energy systems, electricity or heat. These low carbon energies represents a real feedstock for GHG emissions cuts (IPCC 2014). The electricity energy carrier allows the conversion of all these renewable sources to meet many uses applications such as heating, cooling, lighting and transport. The high potential and the projected development of all these renewables makes them a key option to decarbonise the whole energy system. Hence, the power system will play a greater role in the total energy consumed (DDPP 2015).

However, even if electricity is a powerful decarbonisation option, it is not applicable to all sectors. For example, air transportation would not be decarbonised with electric motors because of technological bottlenecks. Indeed, batteries would be too heavy, too costly, too energy intensive to provide the autonomy required. Likewise, some industrial processes cannot be decarbonised with electricity such as cement plants. Finally, yet importantly, electricity systems do not have a lot of long-term storage in order to store electricity and consume it when needed over a long timescale, e.g. several months. It limits the possibility to install many must run production plants, whose production will not necessarily be used. Therefore, other alternatives may be needed to reach a complete decarbonisation for the entire energy system because there is no silver bullet, so that a portfolio of different technologies should be implemented (Energy Systems Catapult 2019).

Bioenergy: another alternative to decarbonise almost all energy systems?

Bioenergy represents currently the highest renewable energy consumption in the world with 70% of all renewables energy production and consumption (IEA 2017). It is a major option for meeting international targets for renewable share and for energy system decarbonisation; in particular bioenergy consumption is expected to increase by 60% from 2015 to 2030 with current climate policies implementation and application (IRENA 2014). Furthermore, bioenergy would play a central role in two of the three pillars in all deep decarbonisation scenarios where bioenergy will reduce the carbon content of all transformed energies and will switch energy end-uses to lower-carbon energy carriers (DDPP 2015). While the renewables presented above are only relevant to produce green electricity or heat, bioenergy can be an energy source in many energy sectors: for sure for electricity production, but also for liquid fuels, biogas, and hydrogen production. This flexibility and this versatility make biomass and bioenergy technologies a noticeable and credible option for the decarbonisation of energy uses (IPCC 2014).

Renewable gas: the missing piece of the decarbonisation puzzle?

The gas obtained from a biomass treatment or with green electricity conversion, called green gas or renewable gas, has the same properties as natural gas. It is just not extracted from underground as natural gas. Therefore, green gas represents another decarbonisation option because of its lower carbon content assessed according to the analysis of a complete life cycle. Upgraded and injected in gas networks, green gas uses the actual widespread and efficient gas network through the world to transport green gas from production to consumption sites. Moreover, these networks allow a long-time storage, several months, so that it is useful to fight against seasonal variation of Variable Renewable Energy (VRE: wind and solar) production with giving a long term and high energy storage capacity. Green gas is therefore a credible option to reduce gas' applications carbon content and decarbonise uses (OIES 2017).

Objectives of the thesis

The development of green gas decarbonisation option is needed to complete the whole energy system description. In particular, the long-term technical and economic perspectives of the technologies at stake, correlated with the resource potential and the final uses have not been studied widely. Therefore, we will try to answer the following question:

What role would green gas play in energy systems decarbonisation?

A first scientific challenge is related to the modelling of green gas energy sources and their integration into the current modelling. Indeed, the difference of sources, actors, markets have some consequences in the planning of power systems, which are not well represented in the current long-term foresight energy models (E3MLab 2018) (Desprès, Criqui, et al. 2014) (IAEA 2017). Our first objective is thus to

take into account the system effects of gas and green gas injected in the gas network in long-term technical and economic scenarios in model POLES (European Commission 2018).

With this objective in mind, we will study scenarios with political measures to fight against climate change or not as well as scenarios with normal or high incitation to develop green gas production.

The aim is to quantify the possible production of green gas and its impact on different sectors of consumption for different political and decarbonisation objectives took into account in this study in order to delimit a whole potential of green gas development. Besides, we will highlight some thresholds in term of performances and costs for the technologies and fields in order to meet decarbonisation policies objectives.

Outline of the thesis

This thesis is organized in five chapters.

In a first chapter, we explain why we have chosen green gas as the main topic of the thesis. A presentation about decarbonisation stakes and decarbonisation options results in the emergence of greening the gas in the energy system.

The second chapter describes the scope of our subject. A general presentation about gas, green gas and green gas technologies is given. Then, past productions, potentials, costs and estimates for the future of green gas are presented.

In a third chapter, an overview of green gas modelling in partial equilibrium energy models is done. A description of the methodology of our work and POLES modelling approach used as a tool to tackle the problematic then follow.

The fourth chapter deals with the decarbonisation of final uses thanks to green gas. The amount of green gas in the gas network is first estimated thanks to an application of the POLES model to assess the green gas production and the competitions for resources that produce renewable gas. Then, we study the evolution of green gas consumption in different sectors. First, the mobility needs and the role of gas mobility for transportation decarbonisation. Next, buildings, industrial and agricultural sectors decarbonisation are considered.

The last chapter underlines the interactions between gas and electricity energy carriers. These two carriers are thus connected thanks to power to gas and gas to power technologies. An analysis is carried out on the competition and complementarities of both energy carriers. The assessment of power to gas business model and optimal operational conditions is modelled.

A general conclusion and a summary in French conclude this work.

Keywords

Green gas, methanisation, gasification, power-to-gas, modelling, POLES model, long term energy modelling, energy transition, decarbonisation

Chapter 1: The emergence of greening the gas in energy sector

1. The energy and climate context

1.1. A recent strong growth in world energy consumption

For nearly 200 years, our societies have experienced unprecedented development thanks to energy abundance. This expansion began in the middle of the XIXth century during the first industrial revolution with the use of coal as an energy source. The physical characteristics (heat capacity and energy concentration), the accessibility and, therefore, the relative low price of fossil energy sources largely explain their widespread distribution in all sectors of the economy. Primary energy consumption has been increasing worldwide and more significantly since the 1950s with the exploitation of oil and natural gas (*figure 1*).

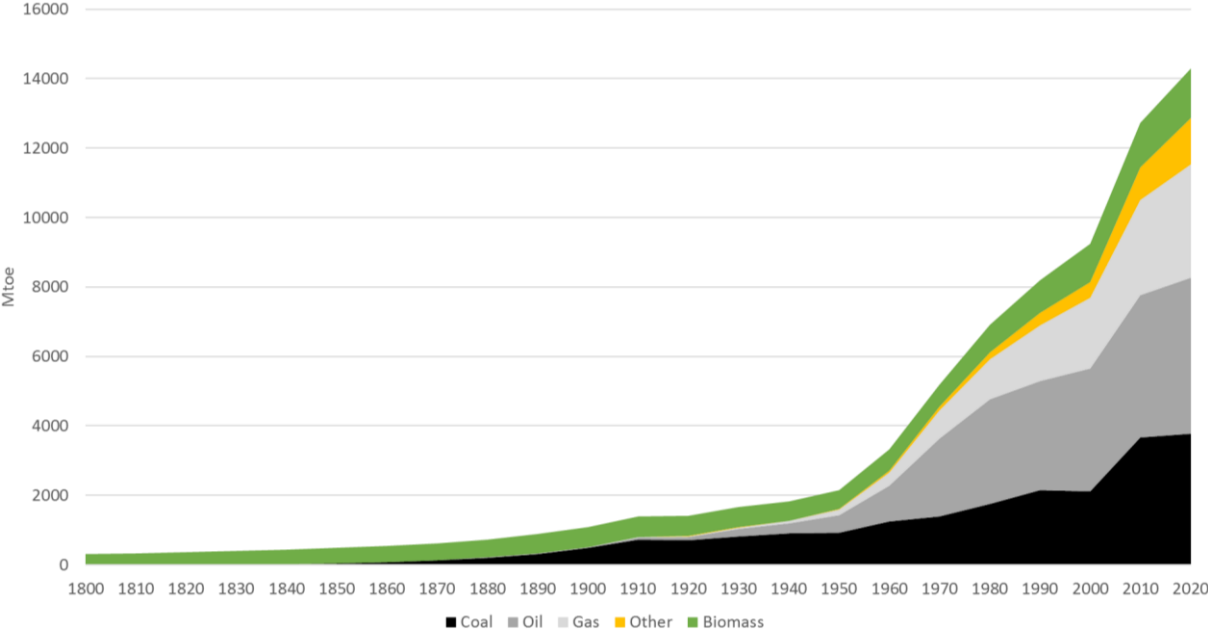


Figure 1: World primary energy consumption
Data from (IEA 2018) (BP 2019)

In 2015, around 14 Gtoe of primary energy were consumed worldwide. 32% came from the combustion of oil, 23% from gas and 30% from coal so that fossil fuels provide 80% of global energy (Delaurens 2020). One of the factors catalyzing this growth is the increase in the world's population, which has accelerated in the second half of the XXth century. It rises from 2.5 billion inhabitants in 1950, to 4.4 billion in 1980, 6.1 billion in 2000, and 7.6 billion in early 2019 and this trend continues with 9 to 10 billion inhabitants expected in 2050 (UNO 2015). Similarly, maintaining a slight growth in the economies of developed countries combined with the efforts of developing countries to bridge their economic gap (current economic growth of 6 to 10% in China and India among others compared to GDP growth between 0 and 3% in developed countries) are accelerating global energy demand before COVID19. The real income of the world has risen 87% over the past 20 years. Therefore, more people

with more income mean that energy consumption and production will still increase to fulfil those needs.

1.2. Relative threats for Earth sustainability

Threats are existing around this endless economic and energy consumption growth. What about the scarcity of resources? We live in a finite world with a finite amount of resource so that it is impossible to extract, produce and consume more and more resources, products and goods in the future (Barnett et Morse 2013).

Sharp and rapid oscillation in the price of oil have effects on companies, economies, and geopolitics. Indeed, oil price spikes could go against economic activity because people can have a reduction in their purchasing power due to higher budget dedicated to mobility or heating. For many countries, the oil price is a parameter they cannot really determine but that can change totally the government budgets possibilities and, then, the reforms they can or cannot implement. This is the case for Russia or Venezuela for instance where the national incomes are in majority due to fossils fuels exportations. It is also a main parameter at play in geopolitical relations. Oil price uncertainty is also a threat as it drives many other markets such as gas, fuels or food markets, etc. (Greenberg 2019).

Last but not least, global warming. The atmosphere of Earth is warming. In the 2010, the temperature was about 1°C higher than in the pre-industrial area (**figure 2**). It may seem to be very low but it is worth noticing that there is a difference of only 5°C in average between the last ice age (20000 years ago) and today. Europe was partly under a huge glacier and the ocean was 120 meters below its current level (Ehlers, Gibbard et Hughes 2011). This warming trend is accelerating as 2019 ended with a global average temperature of 1.1 °C above estimated pre-industrial levels, which is only surpassed by the record set in 2016, due to a very strong El Niño episode. Moreover, the 2015-2019 period represents the five years and, 2010-2019, the hottest decade on record. Since the 1980s, each successive decade has been warmer than all previous decades since 1850 (World Meteorological Organization 2020).

It hides also local disparities where some regions are the subjects of higher warming such as mountains or islands and more severe sides effects for its ecosystems.

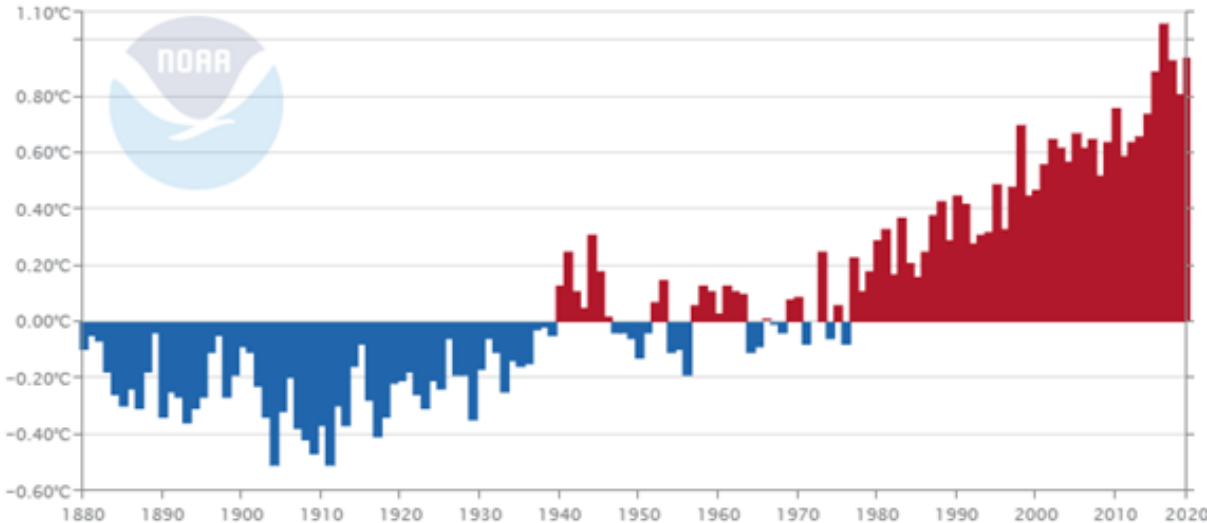


Figure 2 : World global temperature relative evolution compared to 1850 level
Taken from (N. NOAA 2019)

Nowadays, emissions of carbon dioxide (CO₂) are twice the level that the natural environment can store through the carbon sinks of forests or oceans. CO₂ in excess, about 3.5 billion tons a year (3GtCO₂/year), is accumulating in the atmosphere, increasing its CO₂ concentration (**figure 3**), and contributing to global warming reinforcement. The most alarming is the recent rise in continuous temperature increases since 1980. This is due to the CO₂ concentration growth that is accelerating for several years, so that the warming is accelerating too.

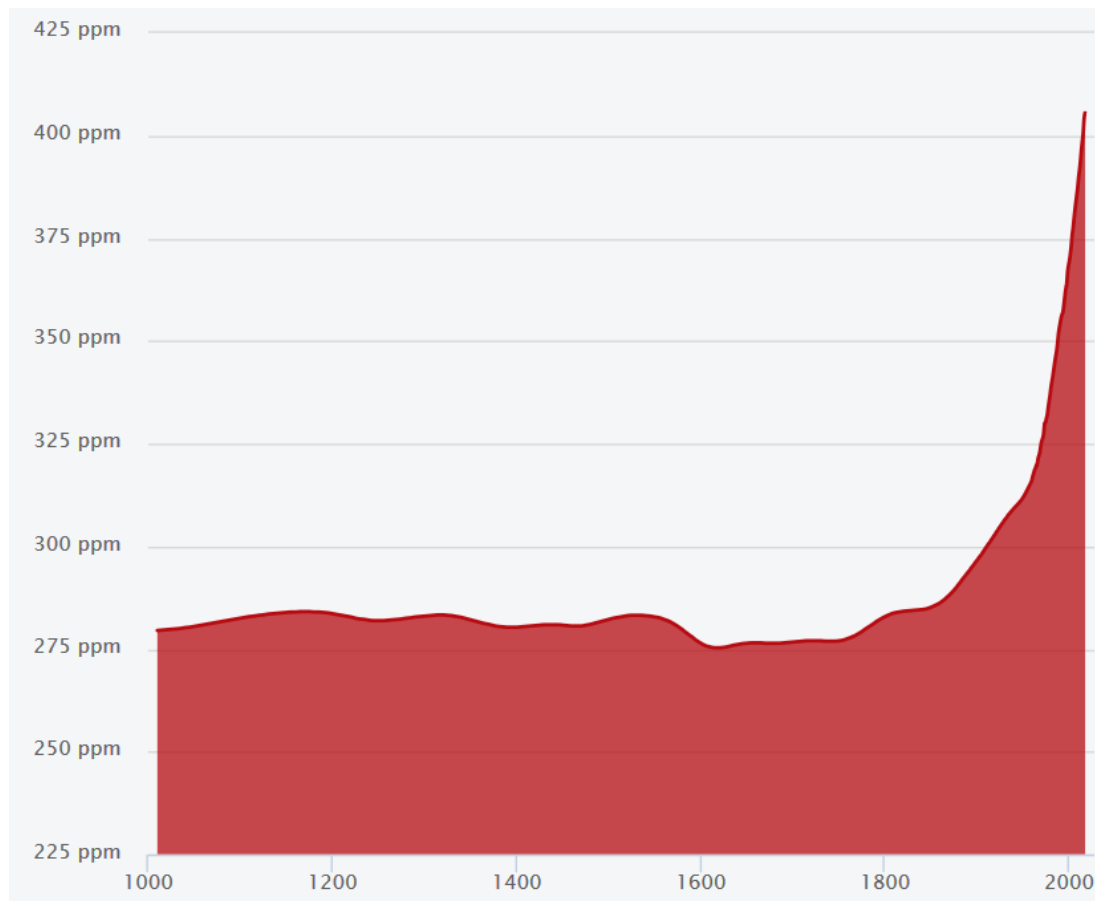


Figure 3 : Evolution of CO₂ concentration in the Earth atmosphere since year 1000
Adapted from (NOAA 2019) (CDIAC 2019)

Hence, environment is changing and deteriorating. The IPCC confirms the threats concerning global warming that causes a gradual deterioration of the environment whether it is air, water or soils. There is growing evidence on the probability of species extinction due to climate change (Kolbert 2015). The effects of climate change on species range from rising sea levels to habitat destruction to variations in the availability of food resources. Anthropogenic climate change is already affecting species in most latitudes and in most types of natural habitats, including coral reefs, forests, tundra, deserts, grasslands and wetlands. Climate change is a threat to nearly one-fifth of the species living in the world (Wheatley, et al. 2017). There is also threats about the acidification of oceans and the circulation of diseases, which is greatly increased by humans mobility. All that has an impact on human life and for the Earth sustainability.

This ascertainment implies strictly reduce the total amount of carbon emissions by the end of the century, requiring "unprecedented" efforts, a "change of growth paradigm" and "an ecological big bang, for policymakers and for humanity as a whole" (WWF 2018). The idea of an enforcement of a determined "carbon budget" linking a quantity of future warming to a total amount of CO₂ emissions

is based on the strong relationship between cumulative emissions and temperatures in reality and in climate models.

2. Decarbonisation, the most important challenge of XXIst century?

2.1. Causes, consequences and impacts of climate change

There are already observed changes in the climate system. The atmosphere and oceans are warming, sea is rising and acidifying and there is a diminution of amounts of snow and ice. Recent climate changes have had widespread impacts on human and natural systems. Besides, there are also more extreme weather and climate events since 1950: increases in warm temperature extremes in all continents, in extreme high sea levels and in the number of heavy precipitation events. Droughts, floods, storms, hurricanes, fires are more frequent or more intense all around the world. Furthermore, many aspects of global warming and associated climate impacts will continue for years and centuries, even if anthropogenic emissions of greenhouse gases are reduced because it is a slow and a long-term process. Species extinctions are also huge consequences of climate change. The risks of abrupt or irreversible changes in the long term increase as the magnitude of the warming increases (IPCC 2014).

Global warming acceleration is mainly due to human activities and fossil fuels consumption. This consumption releases GHG that reinforce greenhouse effect and warm the climate. CO₂ is the largest source of GHG emissions. Energy-related CO₂ emissions account for 59% of the world's equivalent CO₂ emissions. Total CO₂ emissions, which also include industrial processes and emissions related to the land sector, represent 76% of global GHG emissions (IEA 2020). Huge efforts have to be made to release less GHG and important threats for human life and the Earth are coming if we do not change our fossil fuels consumption habits. Coal consumption starts to increase in 1850 to supply the first steam engines. Then oil in the XXth century during the second industrial revolution and then gas. It is worth noticing that these different consumptions do not substitute but add up to each other, which leads to more and more emissions as seen the evolution of CO₂ concentration in **figure 3** (IEA 2019).

Global CO₂ emissions increased by 64% between 1990 and 2017. They account for three-quarters of GHG emissions, which reached 53.5 GtCO_{2eq} in 2017 (I4CE et Ministère de la transition écologique et solidaire 2019). The IPCC has just launched a new warning signal: in its last report of October 2018, it implies that the increase of 1.5°C in the global temperature will probably be reached between 2030 and 2050 (IPCC 2018).

As well, the atmospheric methane content has risen steadily since the pre-industrial era, from 720 parts per billion (ppb) in 1750 to 1850 ppb in 2017. However, it seems to undergo through a very strong growth since 2014 at an unprecedented rate. It is therefore a growing problem as methane has a 100 years Global Warming Power (GWP) between 25 to 30 times higher than carbon dioxide that means that one molecule of CH₄ has the same effect on Earth warming than 25-30 molecules of CO₂ during one century (Reisinger, Meinshausen et Manning 2011). Researchers believe that if this increase continues at this rate, it would have unexpected effects on the climate. In the RCP2.6 IPCC scenario, limiting the global warming less than 2°C, the atmospheric methane content should decrease by 6 ppb between 2010 and 2050, then by 4 ppb between 2050 and 2100, when it would reach 1250 ppb. Nevertheless, the current trend is completely the opposite: at the current rate, the methane content could reach 2400 ppb in 2100 that is the double of the objective. This trend could jeopardize

compliance with the Paris Agreement, even with massive CO₂ emissions reduction. Methane's increase since 2007 was not expected in future greenhouse gas scenarios compliant with the targets of the Paris Agreement, and if the increase continues at the same rates, it may become very difficult to meet the Paris goals (Nisbet, et al. 2019). Besides, there may have been a chronic underestimation (-25% to -40%) of methane emissions from the combustion of fossil fuels, so that balance sheets may be misjudged raising another problem for GHG accountings (Schwietzke, et al. 2016).

This increase of human energy consumption presented above drives to increased GHG concentration in the air since the pre-industrial era. Average concentration remained stable around 280ppm before 1850. Then, concentration began to increase after 1850 because of the start of coal consumption. The growth becomes stronger after 1950 with the acceleration of fossils fuels consumption and the large development of oil and gas (WEO 2018). Cumulative emissions of CO₂ largely determine global mean surface warming by the late XXIst century and beyond (IPCC 2014).

2.2. The three decarbonisation pillars

Some strategies have to be set in order to fight climate change and limit as much as possible this warming. No matter what each country did in the past, three groups of decarbonisation strategies can be gathered: improve energy sobriety and energy efficiency (pillar 1), lower the carbon content of energy carriers (pillar 2) and switch fuel to decarbonise energy uses (pillar 3) (DDPP 2015). These three pillars of energy system transformation has been highlighted to decarbonise energy systems. A decomposition of CO₂ emissions based on KAYA equation (**equation 1**) allows us to structure the factors of CO₂ emissions.

$$CO_2 = POP * \frac{GDP}{POP} * \frac{Energy}{GDP} * \frac{CO_2}{Energy}$$

Equation 1 : KAYA equation

POP reflects the population effect (POP) on the total CO₂ emissions. The term GDP/POP is called "production per person", that translates the wealth of the inhabitants and the effect of GDP growth. Energy/GDP is named "energy intensity of the economy": it is the amount of energy used to produce a dollar or a euro of goods or services. Last, CO₂/Energy means that CO₂ emissions will depend a lot on the distribution of the various sources we decide to use for a given energy consumption.

Population growth without any changes for the other parameters implies directly emissions growth. The trend is the same for the production per person factor. Actions levers are existing concerning these two first parameters to reduce the emissions but it implicates a large political will and a deep social acceptance that are not obvious currently. A bit outside of our scope, we will not open this discussion in this thesis.

The three pillars mentioned for decarbonisation would tackle the two others terms in the equation that play directly on the energy.

- Energy efficiency and sobriety play on *Energy/GDP* in **equation 1**. For reaching CO₂ emissions reduction, the goal is to lower the energy consumed per unit of GDP. The possibilities are coming from technical improvements of products and processes. There is also a work to be done to reduce wastes in processes. For example, it concerns the improvement in processes or devices efficiencies. Energy efficiency improvement represents the absolute urgency to reduce global energy demand and relative emissions. The increase of 1,2% in energy efficiency

was far too low in 2018, compared to the 3% annual increase required to achieve an essential energy transition (IEA 2019).

- Decarbonizing energy carriers and decarbonising the end-uses play on $CO_2/$ Energy. While pillar two aims at reducing the carbon content of all transformed energies (electricity, H_2 , heat, liquids and gases), pillar three deals with the switch for decarbonised energy to fulfil demand. We could separate the fraction into two terms, one (CO_2 (Well --> Tank)) / Energy that would deal with the vector decarbonisation and the fuel switch, for example shifting from coal to natural gas and even renewables in the power sector. Another term (CO_2 (Tank--> Wheel)) / Energy would focus on the uses decarbonisation, for instance shifting from conventional to electric vehicles or gas to electric heating systems.

Sobriety is a concept in which consumption sectors reduce their needs. They have to think about another paradigm of consumption in order to reduce their needs without degrading their quality of service. The entry is through the energy services, that is to say the analysis of services rendered by energy consumption: heating, movement, operation of equipment, industrial processes, etc. In order to bring the need for energy services closer to their utility, sobriety acts on parameters as diverse as the dimensioning of equipment, their duration of use and their degree of pooling resources, the filling rate or the maximal speed of vehicles. It can be translated concretely by switching off night lighting, unplugging household appliances when not used, reducing packaging, reducing our mobility needs, reducing the power of vehicle engines, developing shared mobility, etc.

Efficiency represents the reduction of the energy quantity needed to meet one demand. It consists in seeking to minimize the losses associated with the energy chain supplying these services through different vectors such as gas, electricity or heat, themselves derived from primary energy resources. Therefore, efficiency is a way to reduce the energy consumption for an equal service. It can be achieved by isolating buildings to reduce heating power, by changing lighting appliances with lower consumption ones, by increasing efficiency in vehicles or in industrial processes, etc. This involves also taking into account the reduction of the energy consumption required for their manufacturing, called gray energy that represents a not negligible energy content and associated relative carbon footprint (Fourcroy, Gallouj et Decellas 2015).

Renewables are energy sources whose natural renewal is fast enough so that they can be considered as inexhaustible at the scale of human time. Renewables is the short and common word of the terms "renewable energy sources" or "renewable energies" that are more precise from a physics point of view. They come from cyclical or constant natural phenomena: solar power for the heat and the light, wind power created by atmosphere waves, geothermal energy, hydropower and bioenergies. Their renewable nature depends partly on the speed at which the source is consumed and on the other hand on the rate at which it is renewed. The priority choice of renewable energies to replace fuels releasing GHG to cover residual needs is justified by their inexhaustible nature (they are flux energies, in contrast to the stock energies based on finite reserves of coal, oil, fossil gas and uranium) and their much lesser impact on the environment, either locally or globally. Nevertheless, these resources must be exploited in a sustainable manner so as not to cause environmental damage such as droughts with misuse of water or deforestation. Most of the new renewables are integrated in the electricity production, an energy carrier relatively easy to transport thanks to the grids built since decades in developed countries, with lots of end uses applications.

2.3. Energy transition and decarbonisation options

IPCC scenarios compatible with the Paris Agreements define the temporality of a transition where CO₂ emissions would be reduced by 75% or almost carbon neutrality by 2050 to reach zero or even become negative by 2100. An “energy transition” from a toxic reliance on fossil fuels to low-CO₂ production methods is needed. The term "energy transition" is used to describe a major change in our energy infrastructure. Several definitions exist in the literature. They represent a shift in energy sources and fuels used in a society and an economic system. In our case, it represents the shift from a fossil fuel based economy to a low carbon and efficient based economy (Fouquet et Pearson 2012) (Hirsh et Jones 2014) (Miller, Richter et O’Leary 2015) (Smil 2016).

80% of the energy consumed in 2015 in the world came from fossil fuels. Electricity generation represents around 40% of world GHG emissions because more than 60% of world electricity is produced from coal, oil or gas combustion. Industries and transportation sectors account for 21% emissions each. The last 18% are due to buildings and other sectors like agriculture or energy sector self-consumption (IEA, World energy balances 2018 2018) (Munteam, et al. 2018).

Therefore, low carbon electricity is expected to expand to cut off emissions for this largest emitting sector, but also by being an option in the decarbonisation of other sectors. An increase of electrical use is expected in the transport sector with the development of plug-in-hybrid or full-electric vehicles (IEA 2018) and the heating sector for buildings or industries thanks to heat pumps. The power sector will undertake tremendous transformations, related to the increase of the share of renewable energy sources, as discussed above. Literature is expanding concerning electric mix as in some countries where studies focus on the technological, economic and political conditions to reach 100% renewable electricity (Friedrich 2012) (ADEME 2016) (Bogdanov et Breyer 2016) (Ram 2017) (Blakers, Lu et Stocks 2017) (Lu, Blakers et Stocks 2017) (Zappa, Junginger et Van der Broek 2018) (Brown, et al. 2018).

Nevertheless, low carbon electricity does not represent a silver bullet to decarbonise the entire energy system. Some uses are not “electricity compatible” and have to rely on other energy vectors. Mobility can be switched partially to electric motor but it is still not possible for long road transportation or aviation because of the size, the weight and the cost of batteries needed. Likewise, some industrial processes do not use electricity so they have to use other decarbonisation options as cement factories, chemicals processes. Besides, some electric devices can be used but are a non-sense from the efficiency point of view such as convectors heating. Therefore, other energy carriers like heat, gas, fuels, mandatory for some use applications, have to be decarbonised too. Hence, production of these carriers have to switch from fossil fuels that emits lots of GHG and pollutants to renewables sources, which cannot be produced with renewable electricity. For example, heat can be produced thanks to solar energy with thermic panels or also thanks to a heat network supplied by renewable sources such as wood or wastes. Biofuels produced by biomass helps also to use less fossil fuels.

Next section will develop the multiple possible use of biomass, a renewable energy sources, for different energetic purposes.

3. Bioenergy role in decarbonisation

3.1. Biomass feedstocks overview

Biomass feedstock can be separated in three main categories. First generation biomass gathers food production relative cultures: sugarcane, beetroot, corns, colza, maize, sunflower, palm or even soya.

These resources aim at feeding the planet but are also convertible in biofuels as biodiesel for oil seeds and bioethanol for sugar seeds. It is their only possibility of energetic valorization. Second generation biomass is referring to lignocellulosic resource: forests, plants for energetic purpose such as Miscanthus and agricultural wastes. Several energetic conversions are possible: direct use in heat, biofuels (Diesel Fisher-Tropsch and Ethanol) and electricity or gas conversion. This generation of biomass will be the center of this thesis because of its high potential and advanced end-uses possibilities. Third generation is composed of algae and microalgae. For the moment, this energetic conversion process are only at an early step of R&D for all valorization possibilities: electricity, fuels, gas and heat. Their maturity is still limited compared to other generations, so that we will not discuss this resource in this work as mentioned in the last section. In the end, if it will develop in the future, this resource will boost the green gas production field (Solagro, Afterres2050 2016). Bioenergy is the only source of renewable energy able to provide electricity, but also heat, fuels for transport and gas.

In theory, this resource represents a way to store carbon thanks to photosynthesis. Indeed, all the carbon released during energetic valorization has been stored during the growth of the biomass, so that the carbon footprint in the entire life cycle is neutral or negative. However, concerns about biomass sustainability and biomass breeding plans have to be paid attention, in order to be a sustainable carbon sink. For decarbonisation purpose, the release of other GHG, such as nitrogen oxides due to biomass exploitation and the changes that could occur through land use, land-use change and forestry (LULUCF) have to be considered and their negatives side effects for emissions minimized (United Nations 2020).

In addition, it is worth creating technological revolutions as reorienting crops to pull even more carbon dioxide out of the atmosphere and store that carbon underground. For example, crop engineering aims at breeding plants to store more carbon in their roots and then growing them with no-till methods that leave carbon undisturbed (IRENA 2014).

3.2. Biomass, a renewable and polyvalent source of energy conversion

Bioenergy means energy content in solid, liquid and gaseous products derived from biomass feedstocks as animal by products, vegetable by products, household or industrial wastes, energy crops or woody biomass. All types of biomass use the CO₂ in the air, in the soils or in the water in order to grow through photosynthesis process (Solagro, Afterres2050 2016).

As well as renewable energies like solar, wind or hydro, bioenergy represents an important feedstock for GHG emissions reductions. Bioenergy would play a major role in two of the three pillars in all deep decarbonization project scenarios where bioenergy will reduce the carbon content of all transformed energies and will switch energy end-uses to low or zero-carbon energy carriers (DDPP 2015). Because this resource represents a way to store carbon, the main strength of biomass is its carbon neutrality as carbon released during combustion had been captured during biomass growth. While other renewables are only used to make green electricity, bioenergy can be used in lots of other energy sectors.

This flexibility makes bioenergy and bioenergy technologies valuable for the decarbonisation of energy use and for reaching political objectives. In Europe, bioenergy represents almost 10% of total EU energy consumption, and 60% of its renewable energy. Used for heat at 74%, electricity at 14% and fuels at 13%, it is a key source of renewable energy to reach the European political objectives known

as 3x20 with 20% of renewable energy in the energy mix in 2020, whose checking will be done at the end of the year (European Environment Agency 2017).

World bioenergy consumption has almost doubled since 2000 from 55 Mtoe to 112 Mtoe in 2015 with an annual growth rate of 5%. However, trends are different: while bioheat and bioelectricity grow by 6-7% per year, biofuels stagnate, due to European changes of regulations for biofuels in the early 2010s (REN21 2019). Indeed, biomass is one of renewable and low carbon feedstocks that represents many sources of energy that are storable and compatible with many valorization processes.

Biogas produced by biomass upgraded to biomethane has emerged as a good alternative to the use of food-based crops biofuels to replace fossil fuels for transport, due to its reduced environmental impact, reduced indirect effects and lower GHG emissions. Beyond this, biomethane is an energy carrier with a strong benefit because it is flexible in use as a gas and offers a large and seasonal storage capacity. Biomethane could even reach negative GHG emissions when it is produced from feedstocks which otherwise would emit methane during decomposition, such as manure or when the CO₂ emissions associated with its use are captured and stored. Various biomethane support schemes in European countries have led to significant improvements in biogas upgrading technology. Markets have been recently developing, in Sweden for example or in France where the biomethane injected almost doubled each year since 2015 (Scarlat, Dallemand et Fahl 2018) (GRDF, GRTgaz, et al. 2019).

This biomass valorization in green gas will be at the center of our work in this thesis and next section will introduce the features of green gas in the decarbonisation context.

4. Green gas seen as a decarbonisation option

4.1. Gas can be a key energy for the energy transition

Gas has attracted a growing interest in decarbonizing the energy sector. Gas, as an energy carrier, has two key strong points in order to reach global emissions reductions that are required to keep the rise in global average temperatures below 2°C and to improve the world's air quality. First, versatility: gas can play multiple roles across the energy system in a way that no other fuel or technology can match. Gas can generate electric power, can heat residential and tertiary buildings, can be used in industrial boilers and as raw material for chemistry, and be used for long distance transportation (IEA 2018). Second, the environmental dimension: combustion of gas does produce some nitrogen oxides (NOX), but emissions of the other GHG or major sources of poor air quality, particulate matter and sulfur dioxide (SOX), are negligible compared to coal or oil releases. Gas, as an energy source, releases also approximately 20-30% less CO₂ than oil, 40-50% less than coal for the same energy produced. Indeed, efficient combined gas cycle power plants emit on average 440gCO_{2eq}/kWh while oil power plants emit around 780gCO_{2eq}/kWh and coal power plants emit almost 1000gCO_{2eq}/kWh. Even if these rough estimates depend of the type and quality of the gas, oil and coal used, gas anyway produces less GHG releases compared to other fossils (ADEME 2010).

Gas contributes to a reliable electricity supply and can facilitate the insertion of variable renewables (VRE) in the electric network by playing a “back-up” role. As wind and solar powers are intermittent, electricity has still to be produced in the case of limited VRE production. Gas power plants, whose production variations and rampings performance are good, provide this service efficiently. Gas has also a well-developed network in many countries, for example in Europe, so that gas power plants are sure to be supplied with the resource (IRENA 2013). Gas can also be used in the transportation sector and

reduce emissions from this sector by replacing petroleum products as well as fighting against local air pollution thanks to the absence of fine particles releases. It can also be used for heating in buildings or industrial processes because, although it is still a carbon energy carrier, it can reduce emissions related to heating compared to oil based fuel or high carbon electricity (Cornot-Gandolphe 2018).

For several political strategies, gas is said to be a relevant transition energy option to switch from fossils consumption to an almost 100% renewable world (European Commission 2011). At the same time, the associated underground storage infrastructures of gas are a relevant solution to the inter-seasonal storage requirements inherent to a highly renewable electricity system. This network is currently well developed with a large storage capacity, around 2.8 million kilometers of pipelines worldwide, so that gas supply is relatively reliable in many countries. For example, there are 130 TWh of gas storage capacity in France representing 3 to 4 months of national gas consumption, and 1580 TWh on a European scale. Decisions on the future of gas networks need to consider their potential to deliver different types of gas in a low emissions future, as well as their role in ensuring energy security. As gas infrastructures and networks are well developed worldwide, this energy carrier would play a major role in energetic transition thanks to its storage capacity.

Gas infrastructure will continue to play an important role under the effect of several factors: the growth of gaseous mobility uses, and a contribution of gas for electricity production that remains important for the passage of the winter peak in addition to the decarbonised electricity. However, the use of gas should deeply decarbonize itself if gas wants to play a role in achieving ambitious goals such as carbon neutrality or zero emissions that would be needed to reach the 2°C or 1,5°C Paris agreement objectives (The United Nations 2015).

4.2. Biomass and green gas: a linkage to decarbonise the gas and the energy system

In the medium term, the issue of the decarbonisation of energy systems favors the substitution of coal and fuel oil for other less carbon-based primary sources, including natural gas. However, in the longer term, the need in deep decarbonisation and almost carbon neutrality is a lot more ambitious. The fossil carbon from natural gas would be an obstacle to achieving these objectives. That is why we deal with “green gas”.

In order to consider the gas produced as “green”, these fields take in input a low carbon source of energy. Produced from renewable sources as biomass or green electricity, biomethane or green gas can complete the gas production side in order to produce low carbon gas. Although its use releases as much CO₂ as any gas combustion, green gas represents a substitute for natural gas consumption limitation. It would reduce the insertion into the atmosphere of fossil carbon, based on a short carbon cycle.

Therefore, greening the gas production aims at reducing the carbon content of gas during the life cycle of this energy carrier. It allows a deep decarbonisation of the energy system thanks to the decarbonisation of its fossil source and use as an energy carrier only. Indeed, the benefits of green gas production are that it requires no change to existing equipment for natural gas boilers and gas power plants, limited adaptation for cars and that it is compatible with the current natural gas network after purification. Another benefit is also to use the value of existing assets already built through the world.

Nowadays, some installations are already producing green gas thanks to the methanisation process. This process uses biomass in input, which undergo an anaerobic digestion natural process, and has a

large potential for development. However, there are arbitrations and prioritization needed for land use and management because of the competition for the resource with food needs attention. Land management should be done with care in order to avoid the overexploitation of lands to produce bioenergy. Other processes exist and are developing to produce green gas: biomass gasification and power to gas. Gasification uses a thermal process to convert lignocellulosic resource into gas, with another considerable resource potential to decarbonise the gas supply. Power to gas should also develop thanks to VRE development. Electricity that would be produced when there is low demand could go into this process to convert electricity in gas. That is also a promising technology to decarbonise gas supply (OIES 2017) (GRDF 2013).

Many uncertainties are existing concerning the development of green gas. First is the role of fossil or green gas in the future. As it is a source of energy that releases CO₂, gas would not be an option in the long-term in high constraint scenarios for GHG emissions. Some scenarios shows that gas consumption should not increase a lot in 2050 and 2100 milestones to reach 2°C objectives (IEA 2019). In this way, short-term decisions on whether to invest in gas grids will have major long-term implications, in particular the need in gas infrastructures adaptations to incorporate local green gas sources. Green gas production costs are still more expensive than natural prices even with quite high CO₂ prices (it would be discussed further in chapter 5), so that policy incentives have to be set to launch these fields with development uncertainties in the future and with a lot of work in R&D needed to improve processes. Besides, questions about the relative importance and roles of electricity and gas networks are central to the design of energy transitions to a low emissions future in the political and economic efforts prioritization.

Questions about the quantities and the maximum capacities for green gas production and injection are tackled as well as a focus on the already existing potential. This work tries also to define some threshold costs and possible subsidies for which technologies would develop or not in different CO₂ taxations contexts for decarbonisation purpose. Then, as the energy system is complex with many interactions between productions, conversions and consumptions, we will deal with several technologies and energy carriers. They are as good competitors in some cases but they act in synergies in other cases. That is why it is worth studying the development of these green gas fields, its incorporation in gas markets and the linkages existing with other vectors, carriers and networks in the future of energy.

Chapter 2: State of the art of greening the gas production

Gas can represent an important option in the energy transition and in supporting the development of renewable energies. The gas sector has recently been experiencing a wave of innovations with the development of new sources of renewable gas, also called “green” gas. After a summary about natural gas aspects, we will present in this chapter green gas pathways and their techno economic features.

1. Technical and economic aspects of natural gas

The existing gas network is historically supplied by fossil gas. It has achieved GHG emissions reductions in the energy sector because gas is less polluting than other fossil fuels, oil and coal. Historically, natural gas is extracted from multiple wells all around the world, and then gathered and piped to gas processing facilities. After being purified, it is then injected into the gas transmission network, or delivered to liquefied natural gas (LNG) terminals. It is then routed to consumption sites.

1.1. Gas physical properties

Natural gas is a primary energy source. As the name suggests, it is naturally occurring gas in the subsoil and almost does not undergo transformation after its extraction.

Like all hydrocarbons, natural gas is composed of carbon (C) and hydrogen (H) atoms, but at normal temperature and pressure, the compounds of these atoms are in gaseous form. Colorless, odorless, natural gas is lighter than air and composed mainly of methane (CH_4 as chemical formula) but also propane (C_3H_8), butane (C_4H_{10}), ethane (C_2H_6) and pentane (C_5H_{12}). The proportions of these different types of gas vary from one field to another, but methane is still dominant, from 70 to 98% of the molecular weight. Because of these differences, not all gases have the same calorific value. In France, for example, the gas consumed in the North, from the Netherlands, called B gas, has a high nitrogen content and a low calorific value, resulting in an equivalent of less than $10 \text{ kWh} / \text{m}^3$, while that from Norway, Russia or Algeria, known as A gas, is closer to $12 \text{ kWh} / \text{m}^3$ (Mantulet 2020).

Like all fossil fuels, natural gas comes from a natural process that takes thousands of years to transform organic matter into gas. The natural gas comes from underground reservoirs, where it is extracted and transported by pipelines or methane terminals. Networks are well developed in the world, especially in Europe and in the United States (GRDF 2015).

LNG is a clear, colorless, and non-toxic liquid, which results from cooling natural gas around -162°C . The cooling process shrinks the volume of the gas by 600 times. In its liquid phase, LNG does not ignite. This allows it to be transported safely and efficiently on specially designed LNG ships. After arriving at its destination, LNG goes to LNG regasification terminals and returns to its gaseous phase. It is then delivered to natural gas customers through local pipelines. LNG can also be used directly as a liquid in certain applications, avoiding the need to re-gasify. Small-scale LNG applications, like fueling truck fleets and supplying remote communities, are also beginning to raise. LNG field is growing in the gas world structure since its first shipping in 1964 coming from Algeria to the United Kingdom: LNG represents 42% of international gas trade in the world in 2020 (IEA 2019) (IGU 2019).

1.2. Natural gas value chain

Gas was long regarded as a dangerous co-product in oil wells and difficult to collect and transport, so that it was flared up directly on site. Then, gas was gradually exploited. Coal mining gas is first used in the XVIIIth century for street lighting. Then, in the XIXth century, the first gas deposits are drilled, but the uses are limited and it is after the construction of several thousands of kilometers of pipelines after the Second World War that gas uses developed for domestic and industrial purposes.

Conventional gas trapped in the basement is an easily accessible deposit. It is concentrated in rocks and naturally trapped under pressure under an impermeable cover to isolate the deposit. The so-called associated gas is present in solution in the oil and must be separated during the extraction of the latter. Once considered a waste, it is now reinjected into oil fields to maintain pressure or is valued. On the contrary, the unassociated gas is present in the oil deposits but it is not mixed with it.

Unconventional gases, shale gas, coal gas, compact gas or methane hydrates are difficult to extract compared to conventional gases. Gas producers have historically favored the exploitation of conventional gas, which guarantees a resource recovery rate of 80% compared to an average of 20% for unconventional gas. The share of the latter, however, has increased sharply in recent years, particularly in the United States.

Exploration is the search for gas deposits with mapping and seismography techniques to identify potential reserves of technically and economically exploitable gas. Special sensors are mobilized to record data relating to the propagation of artificial shock waves, making it possible to obtain information on the geological structures present. Subsoil mapping is then established from these data to assess the presence of natural gas. Then, drilling confirms the presence of a deposit and determines its economic potential.

After the exploration phase, gas extraction requires complex infrastructures. However, once the deposit is drilled, the conventional gas that is naturally under pressure easily rises to the surface to be collected. It is then treated and purified with the removal of sulfur compounds and carbon dioxide to be marketed. Last but not least, the gas collected is transported to consumption sites. The older and the more developed way to transport gas is through pipelines. They are the most used means of transporting gas because they are reliable and profitable. Steel tubes are welded to form a pipeline up to thousands kilometres long. The diameter of these tubes varies between 50 centimetres and one meter. However, the transport infrastructure is expensive and takes several years to build. The average cost of building a gas pipeline over 1,000 km is several billion euros. Indeed, added to tubes, compressor stations are installed at regular intervals along the pipeline (every 100 to 200 km), to guarantee optimum speed for gas circulation and avoid energy losses and gas leaks. With the same energy potential, transporting gas costs 5 times more than transporting oil because the gas energy density is lower than oil liquid energy density (Connaissance des énergies 2015).

Liquefied Natural Gas is becoming more and more important in the gas structure. It has important advantages both in importing and in exporting countries. It is often the only possibility to transport gas to consumers who are geographically isolated from production areas or transport networks such as Japan. It is a means of diversifying the supply of a region such as Europe. An LNG carrier carrying 100,000 tonnes of LNG costs an average of 200 million euros. However, as the cost of the LNG chain remains high compared to the pipeline option, LNG exports are therefore often only considered when the construction of a pipeline is not feasible (Bret Rouzaut et Favennec 2010) (Mantulet 2020).

1.3. Gas consumption

1.3.1. World mapping

Gas has been used more recently than coal or oil in the world: its consumption really takes off in the 1970s. Its share in the global energy mix is currently growing. While it accounted for only 7% of world primary energy consumption in 1950 for 153 Mtoe, gas accounted for 16% of total primary consumption in 1980 for 1158 Mtoe and 21% in 2000 for 2026 Mtoe. Gas now accounts for 23% of all primary energy consumption in the world, raising at 3260 Mtoe.

This energy had the particularity of being used for a long time only in the United States: until 1965, more than 60% of the world's gas consumption was made by this unique country. Markets were underdeveloped at the time, and gas production was related to oil production, with black gold mining also producing gaseous releases of methane. The difficulty and high initial cost of capturing, storing and transporting the gas meant that it was released into the atmosphere or burned on the spot without being upgraded. It is only after gas energy utility was identified that the infrastructure of extraction, storage, transport and use of gas has developed.

The United States and Russia are the world's largest producers of natural gas in 2018, with nearly 40% of the volumes extracted worldwide, respectively 20% and 17,3% (IEA 2019). The share of the United States tends to increase with the strong development of unconventional gas extraction. Next are Gulf countries (Iran, Qatar, Saudi Arabia in particular), and historical producers like Canada, Norway, Australia or Algeria.

Nowadays, gas consumption has grown all around the world: Asia, Europe and North America represent in 2015 about 30% each of the world's gas consumption, the remaining 10% being the result of South America and Oceania. There are also significant differences in the importance of gas in the different continental energy mixes. Indeed, while gas accounts for only 10% of primary energy consumption in West Asia, it accounts for about 30% of consumption in the other continents. In Middle East, it accounts for half the primary energy consumption of the area. It can be explained by the abundance of this resource on the territory and by the difficulties linked with gas transportation in long distances, so that it may favor local consumption. Markets and imports-exports (detailed in section 1.5) now play a major role in the global use of gas (BP 2019).

1.3.2. Gas uses

Natural gas, in the form of methane, is a fuel with many different possible uses. It is used to produce electricity and heat, to power industrial processes and as a fuel for mobility.

Figure 4 sums up the uses of gas. It shows that the major part of the natural gas is used for electricity supply. The other main consumption sectors are buildings, mainly for heat production and industry for heat generation and as an input in industrial processes.

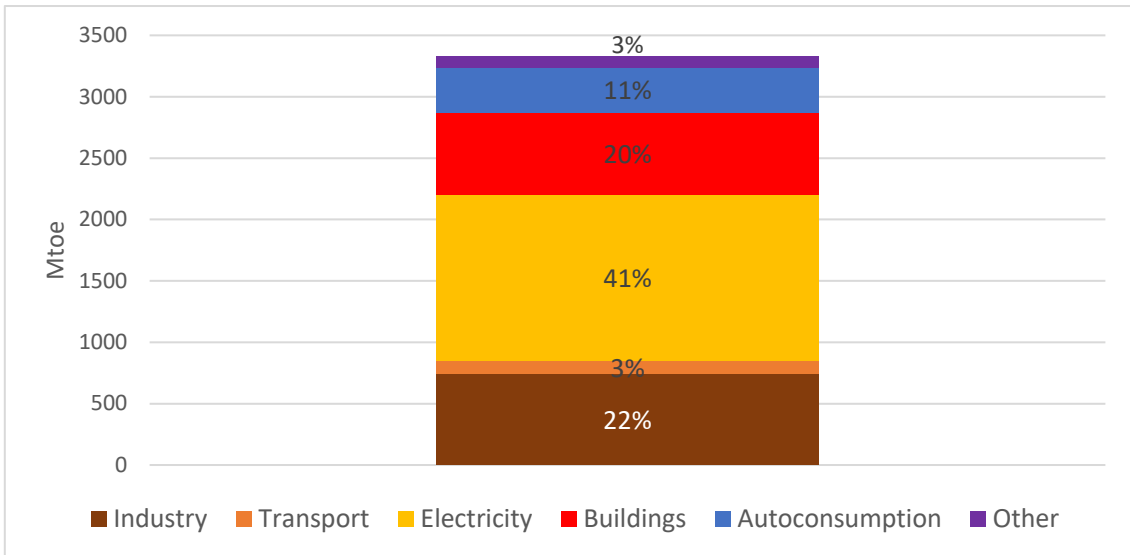


Figure 4 : World sectoral energy demand for gas in 2017
Data from (IEA 2019)

Each country has different specificities in terms of gas consumption sector. Some countries have developed a lot of gas, even if gas mobility remain in the minority, others have privileged the production of electricity and others the gas consumption in industrial sector.

For instance, the distribution of gas consumption in the United States, in Europe and in China in 2017 shown in **figure 5** is quite different.

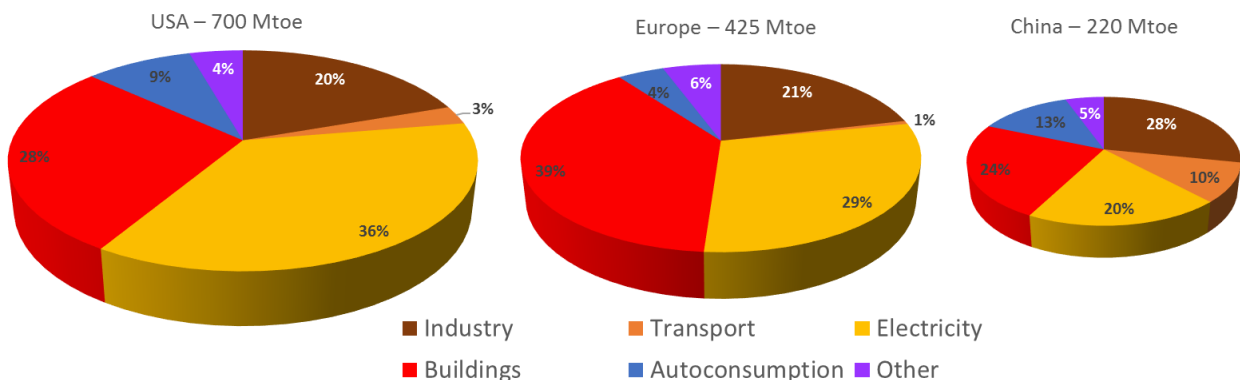


Figure 5 : Natural gas consumption repartition in the United States, Europe and China by sector in 2017
Data from (IEA, Data and statistics 2019)

For the USA, more than a third of the gas consumed is in electricity production. Then, more than a quarter is devoted to residential or tertiary buildings consumption. About one fifth is dedicated to industry and the remaining is dedicated to the energy sector and a minority to gas mobility. For Europe, there is a lower ratio of gas consumed in electricity production and more in building. In China, the ratio increases for industry and transport and drops for buildings and electricity production.

Gas knows a rapid development in all these uses. This trend can be explained by "physical" advantages compared to other fossils. For its industrial and heating uses, gas has the strong point of generating less local pollution than its oil and coal competitors (detailed below in section 1.4). In addition, it removes energy storage concerns for the user without the need to fill the tank periodically thanks to gas network. Finally, it costs roughly the same, per unit of energy, as petroleum products. Because of

these characteristics, the factories have gradually turned to this fuel for their heat needs, to the detriment of coal and fuels oil-based.

Gas supplies about a quarter of the world's electricity and this share is increasing to replace coal plants (GRTgaz 2020). It also helps to play a back-up role in the production of electricity with the development of renewable but intermittent and unpredictable electricity sources to secure the electricity supply. Another element plays even more for gas power plants spread: the low capital requirement for a given installed power. Indeed, to install a megawatt of power, it is necessary to pay 3-4 million euros in nuclear, 1-2 million euros with a coal-fired power plant, but only 0.5-1 million euros for a gas-fired power plant (Direction générale de l'énergie et du climat 2014). Since gas use has the lowest "barrier to entry", it is currently favored by western economies for new power plant constructions. Besides, gas may become a storage possibility with converting electricity in gas through electrolyzers and injecting the gas produced in the gas network (IEA 2017).

1.4. Gas relative emissions

As a fossil fuel, gas also contributes to CO₂ emissions that disrupt the climate system. With a similar amount of energy, it emits 30% less CO₂ than oil and about 50% less than coal, but that is not zero: 20% of global CO₂ emissions come from use of gas (IEA 2018). Besides, the presence of leaks throughout the gas supply value chain may cause the release of CH₄. This is more harmful for the planet because of the global warming power (GWP²) of CH₄, which is around 25 times higher than that of CO₂ for a 100 years duration and around 80 times higher for a 20 years horizon (Reisinger, Meinshausen et Manning 2011) (Myhre, et al. 2013).

As for any hydrocarbon whose combustion takes place in the air, gas combustion generates nitrogen oxides (NO_x), which are pollutants and which, combined with unburned hydrocarbons and the sun, lead to the appearance of ozone. However, by nature, it does not contain sulfur (soluble in oil and present in coal, but not gaseous), which avoids SO₂ emissions that is responsible for pulmonary irritation and acidification of rainwater. It does not generate either fine particles, dust, ash. Actually, gas' complete combustion releases only CO₂ and water, which are two gases without any particular toxicity for an exhaust to the air, even if CO₂ generates delayed climate change, but it is a physical effect, not a direct toxic effect.

1.5. Gas trade and prices

1.5.1. International exchanges

In terms of proven reserves, Russia (18.1% of world reserves), Iran (17.2%) and Qatar (12.9%) are the three best gas-endowed countries, accounting for more than half of the world's proven natural gas reserves. Nevertheless, proved reserves are evolving rapidly following new analyzes, discoveries and technical progress. The United States has thus advanced Saudi Arabia in proven reserves of natural gas following the intense development of shale gas extraction and subsequent soil analyzes. The main players in shale gas are oil majors such as BP, Chevron, Exxon, Shell, Total and of course those in the gas sector such as Gazprom or Engie, who devote a significant portion of their investments to this exploration phase (IGU 2019).

² The GWP is a comparison index associated with a greenhouse gas (GHG), which quantifies its marginal contribution to global warming compared to that of CO₂, over a certain period.

The constraint of transport justifies the organization of the gas industry around three large regional market segments: America, Europe and Asia. Each of these markets is supplied by specific producers.

The share of natural gas produced giving rise to international trade is around 20%. It has been much lower than that of oil in the order of 70% since the late 1990s, but it is increasing rapidly. The LNG share represents more than 40% of this world trade against 23% at the end of the 1990s but the supply by pipelines remains predominant (Locatelli et Boussena 2020).

1.5.2. Prices settlement

Despite the development of liquefied natural gas (LNG), and given the very diverse level of development and gas market structures, there is not yet a fully globalized natural gas market. The price formation mechanisms are differentiated according to the regions considered. The competitive logic dominates in the United States. The European gas market is characterized by a price system that can be described as hybrid, spot price and price based on the logic of long-term contracts (LT). Asian trade, mainly in the form of LNG, remains dominated by long-term contracts and the logic of price indexation on petroleum products / crude oil. Natural gas therefore still remains a “regional commodity” but gradually prices on the three regional markets tend to come closer (Locatelli et Boussena 2020).

These prices have remained almost steady through the different markets around 5 to 15€/MWh over the last 30 years despite some increases in the 2000s as seen in **figure 6** for the gas price for the USA Henry Hub. In 2018, given the abundance in the markets thanks to LNG, the US shale gas boom and the occidental lower consumption, gas prices have remained below 10€/MWh for all markets until now (EDF 2019).

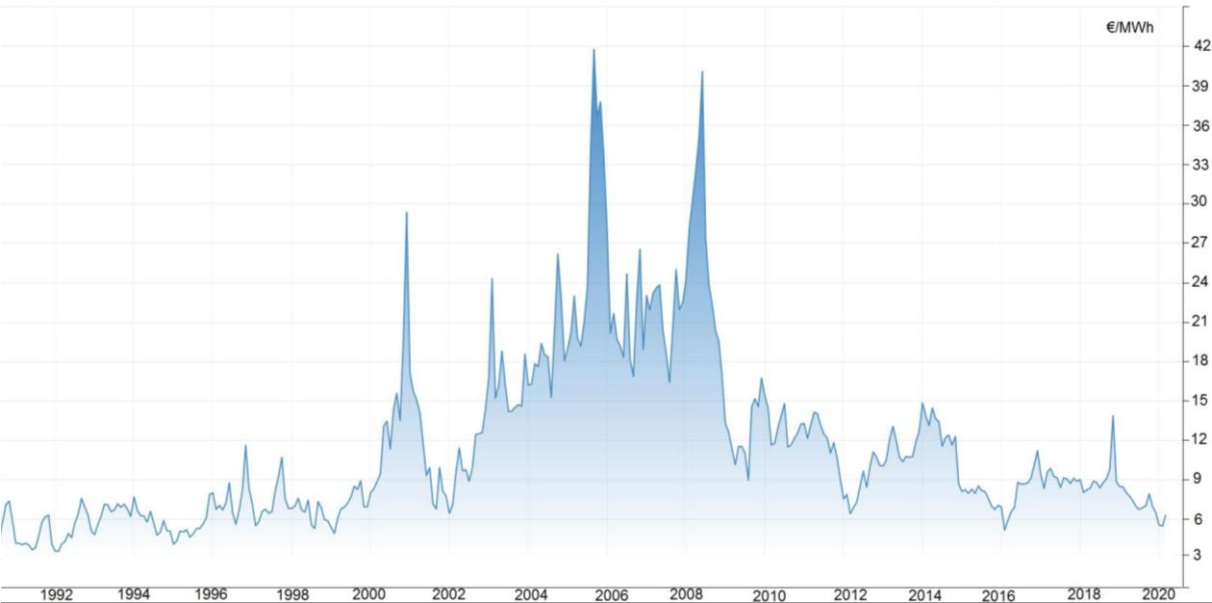


Figure 6 : NYMEX gas price in Henry Hub
Adapted from (U.S. Energy Information Administration 2020)

LNG producers can export to all markets and arbitrate based on prices in the different markets. For the latter, it opens up possibilities for arbitration between the three regional markets based on price differentials. Therefore, LNG can offer flexibility both in an importing and in an exporting country by being independent from pipelines routes. Hence, the growing importance of LNG in world exchanges

as well as the gas markets liberalization tend to reduce the spread between the three markets. Furthermore, the recent introduction of carbon tax and its expected increase will play a big role in prices settlement. It is worth noticing that the future prices are very difficult to estimate because, based on oil prices in many countries, many factors, on which we can have little control, affect the evolution of prices. For instance, there are geopolitical relations that can create tensions on the markets, there are not concerted changes in production for gas and oil by the Organization of Petroleum Exporting Countries (OPEC), middle eastern countries, the US, etc. that can change the market balance (European Commission 2019).

1.6. Projections of the future of gas

Feedstocks are evolving rapidly due to the prospecting of new territories (in Arctic for example) and the progress of techniques making the unconventional resource competitive. According to the World Energy Outlook 2019 of the International Energy Agency, price trends should continue over the long term to remain quite stable and low, even if unexpected events could change all these forecasts. World gas demand would grow by 1.6% per year, much higher than oil growth (less than 1% per year) and should mainly be driven by China and India. On the demand side, by 2040, China should assert itself as the world's leading importer of natural gas before the EU. On the supply side, the United States thanks to the production of shale gas, Russia, but also the Middle East would balance the international markets. The international gas trade should be dominated by LNG, the share of which in 2040 should be close to 57% compared to 40% currently (IEA 2019).

2. Presentation of renewable gas

Even if gas is historically provided by fossil natural gas resources, extracted from the soils and routed to the consumption site by pipelines and liquefied natural gas, other sources of gas exist and can be produced from low carbon energies: biomass and low carbon electricity. Biomethane injected into a natural gas grid may provide considerable increase of renewable energy share within the natural gas-fired systems. This meets political objectives: for example, in its long-term strategy unveiled in November 2018, the European Commission plans to reduce the consumption of natural gas in the European Union in favor of renewable gas thanks to the huge potential to transition to decarbonised gases (European Commission 2018).

It is worth to define some terms before presenting renewable gas systems. Biogas is the output of anaerobic digestion (methanisation). Typically, this is a mixture of 50-65% of CH_4 , 30-50% of CO_2 and small quantities of other gases and impurities, depending on feedstock. Biomethane is the output after biogas upgrading to remove most of the CO_2 and impurities. It results in a product over 90% of CH_4 that meets the quality requirements for injection into the gas grid. Syngas is the gas mixture that is the product of gasification process made of H_2 , CO , H_2O , CO_2 and CH_4 .

2.1. History of biogas and technological introduction

Biogas formation is a natural phenomenon that occurs in swamps, manure piles and in the gut of animals and humans. For centuries, humans have been observing the bacteriological power of digestion of organic waste. In Asia, hundreds of thousands of rustic family digesters allow families to cook on biogas stoves and are still using it, in particular in China. In Europe, whole villages were supplied with electricity and heat through centralized biogas systems. During the Second World War, German army vehicles ran on biogas recovered from farm manure in gas engines. Over the last fifty

years, noticeable technological advances in the development of anaerobic digestion systems have enabled to concentrate and increase methane productivity from organic waste. Today, from simple dairy farms to wastewater treatment plants, thousands of projects around the world demonstrate that biogas collection for energy purposes has a positive impact on the environment (Biogas world 2019).

Gas can also be produced by burning wood, which releases fumes and a mixture of gases through a gasification reaction. In these processes, these fumes can be collected, cleaned and stored to be used later in other processes using this gas as an input. It is still a developing path as it is still difficult and expensive to purify and store useful gas efficiently and affordably so that it is not in operation yet.

Another operation, the Sabatier chemical reaction or methanation, allows the conversion of H_2 and CO in CH_4 and H_2O , with a high exothermic reaction. Besides, thanks to water electrolysis, hydrogen can be produced from electricity and water. Therefore, gas can then be produced from electricity, which produce H_2 after electrolysis and CH_4 after methanation. Hence, a complete value chain for a renewable gas exists with a renewable electricity producing “renewable” hydrogen and then a “renewable” gas. However, reactions stability, in particular temperature control and high costs have slowed down the technology development.

The green gas production technologies are presented in detail below.

2.2. Green gas technologies portfolio presentation

Three different generation technologies for green gas production are existing. The first is called methanisation, which aim is to put fermentable inputs in a digester in order to produce biogas thanks to biomass digestion. Besides, there is a growing interest for microalgae to feed digesters through the same methanisation process (Connaissance des Energies 2011). The second technology category consists of pyrogasification: it is a pyrolysis of lignocellulosic biomass followed by oxidative gasification stage to reach biomethane after purification. The last way, called Power-To-Gas (P2G), is to electrolyze water from low carbon electricity energy to produce renewable hydrogen that can be either partly injected into the network or combined with CO or CO_2 to make CH_4 (Carbone 4 2019).

2.2.1. Methanisation

2.2.1.1. Process description

Methanisation is a degradation process by microorganisms of animal or vegetable organic matter. It is also called anaerobic digestion. It produces a gaseous mixture saturated with water and consisting of 50 to 65% methane. Once collected and transported to the anaerobic digestion site, organic matter is sorted, brewed and heated for a few weeks in a digester, an enclosure deprived of oxygen. This process of anaerobic digestion of organic matter produces biogas that can be recovered by combustion in the form of heat, electricity or even in cogeneration. This biogas can also be purified in order to achieve the quality of natural gas, a gas called "biomethane", and be injected in the gas network. The energetic yield for this bioenergy conversion from biomass to biogas is between 55% and 75% depending of the input used (Dupont 2014).

Figure 7 represents the value chain of this process

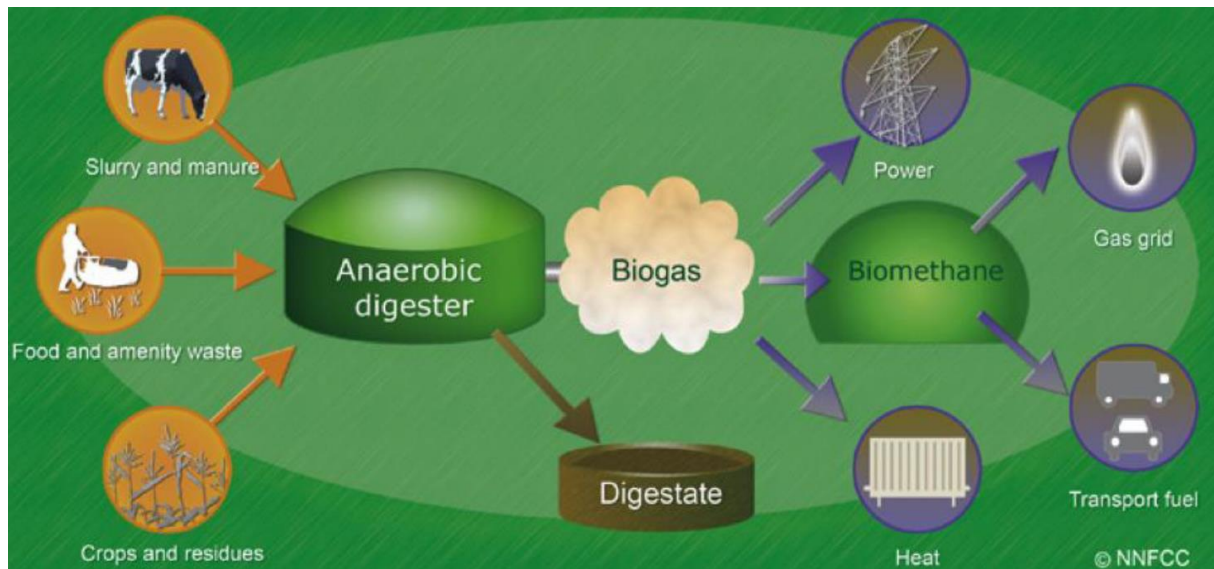


Figure 7 : Overview of methanisation process
Taken from (OIES 2017)

In order to transfer biogas into biomethane, two major steps are performed for the purification step that is essential to rid the biogas of its impurities and undesirable components such as carbon dioxide, sulfur compounds and water. First, there is a cleaning process to remove the trace components. Second, there is an upgrading process to adjust the calorific value of the output. Upgrading is generally performed in order to meet the standards for use as vehicle fuel or for injection in the natural gas grid. Different methods for biogas cleaning and upgrading can be used. They differ in regard of the gas eliminated. Condensation or drying methods can be used to remove water. Absorption in liquids or addition of iron oxide are two ways to remove sulfurs or NO_x, and methane can be separated from CO₂ using adsorptions methods or membrane separation. Once purified and odorized, biomethane can be injected into natural gas networks or be used in vehicles or boilers (Ryckebosch, Drouillon et Vervaeren 2011).

2.2.1.2. Type of inputs

There are several typology of biomethane injection sites and classes of inputs used to supply them.

First, there are autonomous or territorial agriculture methanisors. It is worn by one or more farmers and it methanizes principally agricultural materials from the farms. These materials are farming effluents: slurry (composed of liquid and solid excrement from animals) and manure (mixing manure with animal litter: straw, hay ...). There are also agricultural waste from crops (example: cane corn). There are also intermediate energy-based crops that are cultures planted and harvested between two main crops in a rotation crop and can be harvested for use in an agricultural methanisation unit. As well, energy cultures that are crops grown primarily for food and feed production purposes can be used as inputs in anaerobic digestion units. Historically, especially in Germany, methanisation boomed thanks to this last feedstock, but Europe set limits for food crops quantities in methanisation to avoid concern about food supply security. Farms based methanisors represent the main potential for methanisation development in Europe and already the main plants in operation (EurObserv'ER 2018).

Second, there are sewage treatment sludges in water treatment plants. It gathers urban and industrial sludges in wastewater treatment plants coming from human activity. Their valuation for the biomethane production has been authorized since 2014 in France. This energetic feedstock is almost fully used as it has been cost competitive thanks to advantageous feed in tariff given by using waste based energy.

Last, methanisation facilities use sludge and co-products from the food industry, animal by-products, household waste, green waste and waste from not dangerous storage facilities.

Table 1 sums up the different methanisor design and the resource taken in input

Table 1 : Overview of methanisation installations

Actors	Inputs
Farms	Vegetal, animal and sewage wastes Food crops (limited) Wood residues (minor)
Water treatment plant	Plant sludge
Wastes	All wastes excepted electronics in landfills
	Industrial wastes
	Domestic wastes
	Municipal wastes such as grass

Adapted from (ATEE 2017)

2.2.2. Gasification

2.2.2.1. Process description

Biomass gasification is a thermal process for transforming biomass into a gas mixture called synthetic gas (SNG) or syngas. The steps in the process are biomass pre-treatment, gasification at high temperatures (700-1500°C) and gas cleaning and conditioning. Pyrogasification uses dry biomass residues or solid recovered fuels. It allows the conversion of lignocellulosic biomass into gas. The gasification reaction is a complex thermochemical reaction that occurs in the presence of an oxidizing agent introduced in default. This reaction can be seen as an incomplete combustion since the oxidizing agent is insufficient to produce the combustion of the woody feedstock. The pyrolysis reaction being endothermic, it is necessary to bring heat to the process. For example, it is possible to burn in a separate reactor a part of the synthesis gas produced in order to release the heat necessary for the process (this is the co-combustion step). The gas obtained after gasification is called syngas and contains mainly H₂ and CO with smaller quantities of H₂O, CO₂ and CH₄. After a purification step to eliminate solid and gaseous wastes from the syngas, the methanation step upgrades the syngas into some gas rich in methane but still containing H₂O, CO₂ and H₂. Another purification step allows the collection and use of pure methane in one hand and CO₂ in another hand that can be stored and used in other processes (GRDF 2013) (Dupont 2014).

Figure 8 represents the value chain of this process.

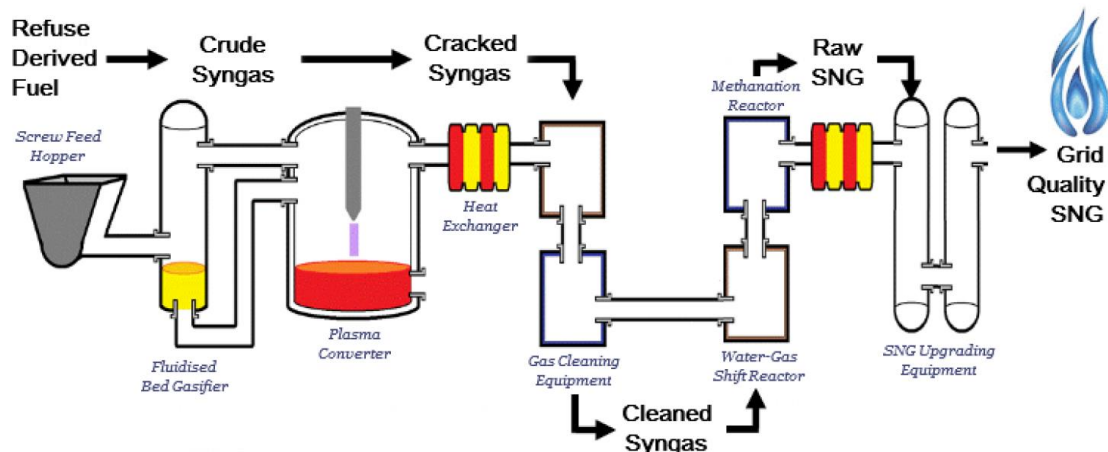


Figure 8: Overview of gasification process
Taken from (OIES 2017)

2.2.2.2. Type of gasifiers

There are different gasification technologies: fixed, fluidized and driven bed. **Table 2** presents the different types of gasifiers with their features and their energetic application.

Table 2 : Overview of gasification installations

Type of gasifier	Target size and applications	Drawbacks	Advantages
Downdraft – fixed bed reactor (75% of gasifiers installed)	Small scales up to 1,5MW Application : electricity	Poor control of temperature, mass and heat transfer Inefficient char removal	Simple and robust Biomass flexibility in input Low tars
Updraft – fixed bed reactor (2,5% of gasifiers installed)	Upper scales up to 2,5MW Application : heat	Poor control of temperature, mass and heat transfer Production of lots of tars	Simple and robust Biomass flexibility in input
Fluid bed reactor (20% of gasifiers installed)	Medium scales up to 25MW Application : electricity	Biomass moisture requirements Ash management	Efficient control of temperature, mass and heat transfer Easy to scale up
Entrained Flows Reactors : (2,5% of gasifiers installed)	Large scales up to 100MW Application : liquid fuels	Complex Expensive	Compact No tars and char Ash management

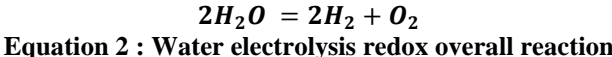
Adapted from (Dupont 2014)

Even if the energetic conversion yields are important, from 60% to 90% according to the gasifier used, (Sansaniwal, et al. 2017) some progress has to be done on the costs in order to be competitive for gas production (see section 3).

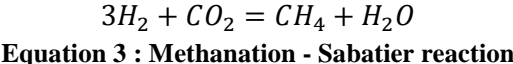
If the core of the hydrothermal gasification process is already mastered, a number of technical challenges are yet to be addressed to enable industrialization and marketing of facilities. In particular, work is yet to be done to improve the regeneration of the catalyst, to improve the proportion of methane in the synthesis gas produced, perfect the separation of the solid phase according to the type of input, and find the best technical-economic compromise for heat recycling process. Other development efforts are focused on achieving the scaling up the process, reducing operating and maintenance costs and simplifying the operation of installations (GRTgaz 2019).

2.2.3. Electricity electrolysis

The process called power to gas (P2G) transforms electrical energy to a gas that can be hydrogen or methane. The first step of the process is the water electrolysis that converts an electrical power and water in dihydrogen and dioxygen by a redox reaction (equation 2).



Another step of the process is possible with the Sabatier reaction. This is the reaction of dihydrogen with carbon dioxide to produce methane and water (equation 3). It is catalyzed by nickel and is very exothermic, so that temperature control is key for this process (AFHYPAC 2018).



In the following paragraphs, when we will mention power to gas, it will gather these two reactions and represent the whole process from electricity to methane production as represented figure 9. Electrolysis is around 60% efficiency round-trip from electricity to hydrogen production, then falls to 40% for electricity to methane conversion and reaches only 20% efficiency at the end of the conversion chain for electricity-to-electricity (ENEA Consulting 2016) (Sapy 2019).

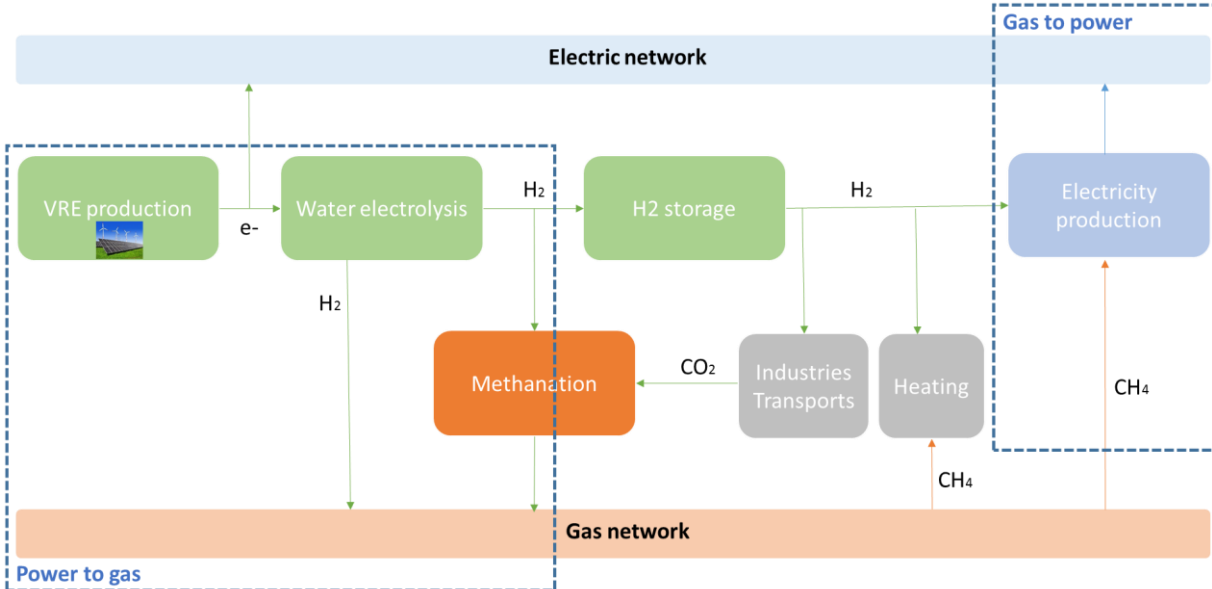


Figure 9 : Power to gas process overview
Based on (ENEA Consulting 2016) (AFHYPAC 2018)

As well as biomass gasification, power to gas facilities are still in a demonstration stage and further R&D work is needed to make this field cost-effective with higher efficiencies (Belderbos 2019) such as

Jupiter 1000 in the south of France (GRTgaz 2018). Despite the absence of industrial demonstration nowadays, this technology is essential in all scenarios of massive GHG reduction and high penetration of renewable energies (ADEME, GRTgaz, et al. 2014). It is also needed in studies attempting to demonstrate the feasibility of 100% renewable electricity grids (ADEME 2016) (Brown, et al. 2018) (German Federal Environmental Foundation (DBU) et Stiftung Mercator 2018) (Krajačić, Duić et Carvalho 2011) (Connolly, et al. 2011).

The power-to-gas constitutes a relevant tool to decarbonize gas uses, to maximize the integration of electric renewable energies in the energy system and to offer an inter-seasonal storage solution for energy. The advantages are a theoretical capacity to store energy on a very large scale for a long time, and to use existing gas network infrastructures. A particular focus on linkages existing between gas and electricity and on power to gas technology will be done in chapter 5.

A benefit of P2G is, beyond having CH₄ (the gas needed) and H₂O (a non-dangerous co product) in output, using CO₂ in input. Hence, it turns CO₂, the gas largely responsible for global warming, into a kind of valuable feedstock in a process. This represents a non-negligible amount of resource available for energetic purpose (Hepburn, et al. 2019). Nevertheless, to reach cost effectiveness, it also requires having a reliable CO₂ production site nearby. For instance, the CO₂ produced from a methanisation site can be injected as an input in a methanation process for power to gas. It may create a synergy between these two green gas fields (ADEME 2016).

2.2.4. Summary

2.2.4.1. Technological development

Figure 10 summarizes the perimeter of green gas, the resources in stake as well as the Technology Readiness Level (TRL) development state for each technology and the time horizon for the technology expected development.

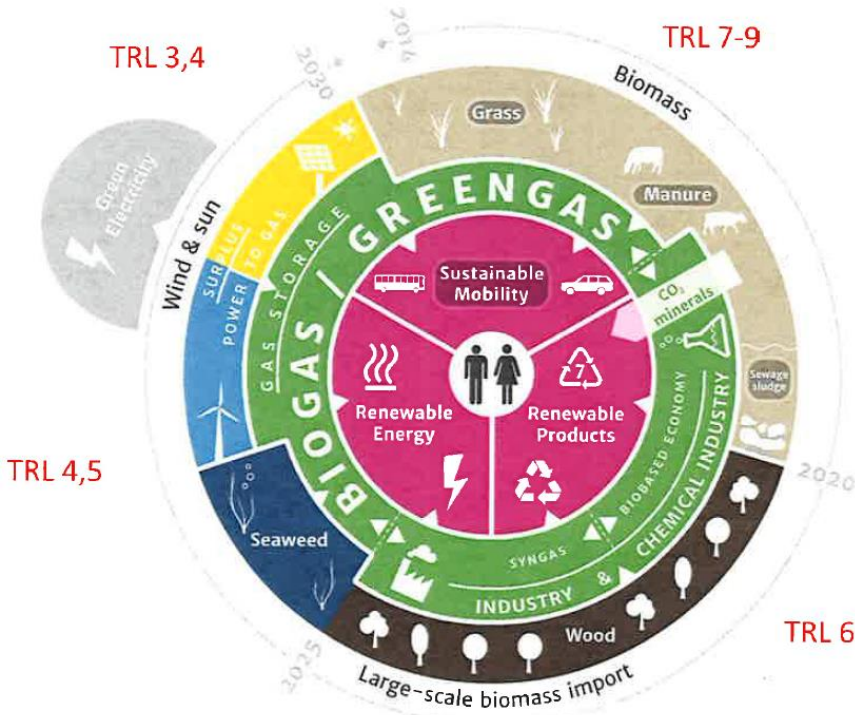


Figure 10: Green gas production routes structure and development
Taken from (ERI 2019)

Methanisation technology (TRL 7-9) is already in operation, is spreading and is still developing to improve the process (see chapter 2 section 3.1). It is currently the only source of green gas in our networks. It starts to decarbonise heat, electricity, mobility or industry by using the biogas produced in the process. Pyrogasification is in a demonstration stage (TRL 6) where projects and demonstrators are being built to set the business model for these installations (Gobigas s.d.) (Fulcrum s.d.) (Sundrop fuels s.d.) (Gaya s.d.). Algae gasification is in an early R&D step (TRL 4), this field will not be developed in our study because many researches for potential determination and technologies possibilities are yet to be undertaken (Raslavičius, Striūgas et Felneris 2018) (Milledge et Harvey 2018). Last, power to gas is also at an early R&D step in order to make the electricity to methane process competitive on the energy markets for being another source of green gas. There are also more than 120 demonstrators' projects over the last ten years in Europe (Wulf, Linssen et Zapp 2018) in particular in Germany with the Energiepark Mainz project, the largest demonstrator in the world with its power of 6MW or the Wind/Gas Falkenhagen project and its power of 2MW active since 2013 (Le Roy 2020). Others power to methane European demonstrators are in construction and operation like Jupiter 1000 or GRHYD in France, Synfuel in Denmark. In the rest of the world, some smaller projects exist in North America and Japan but no country has reached an industrial level of Power-to-gas production.

As a summary, **figure 11** presents the different routes for green gas production from the production to the consumptions, with a description of intermediate conversion technologies.

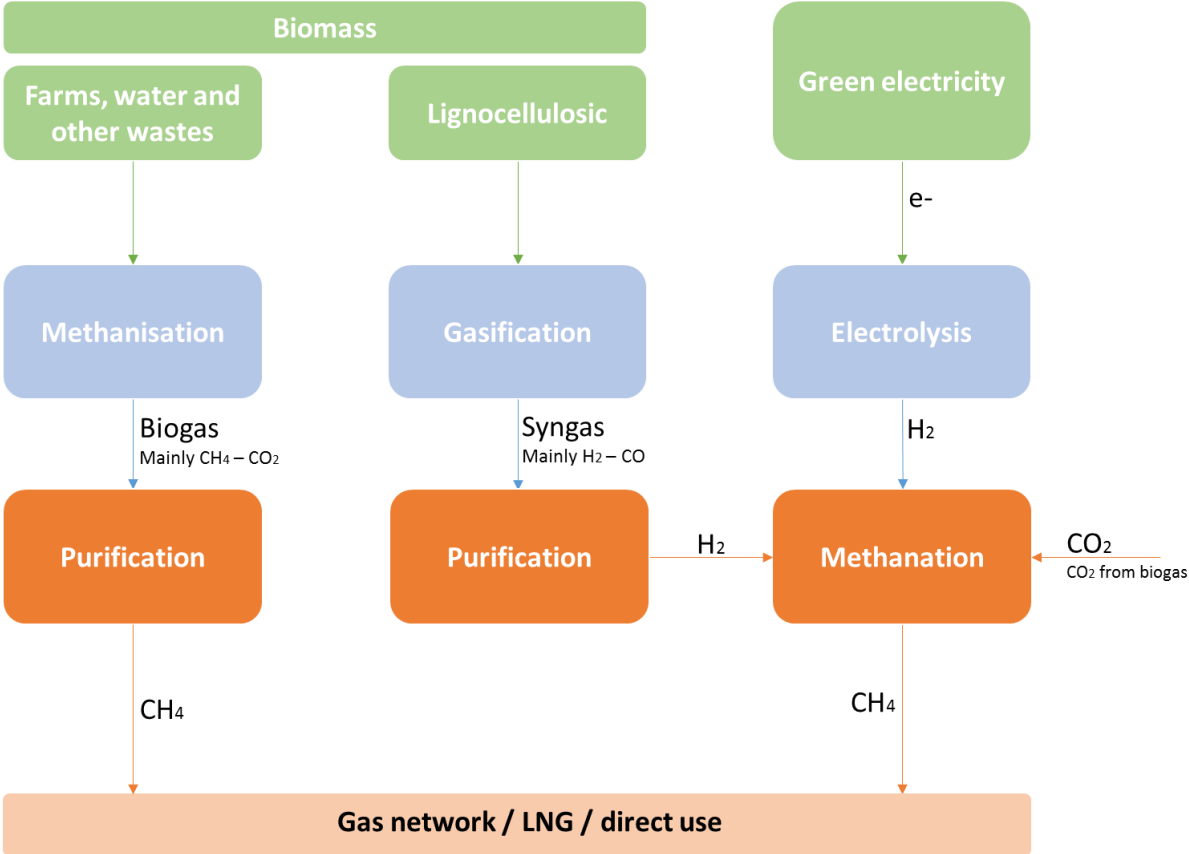
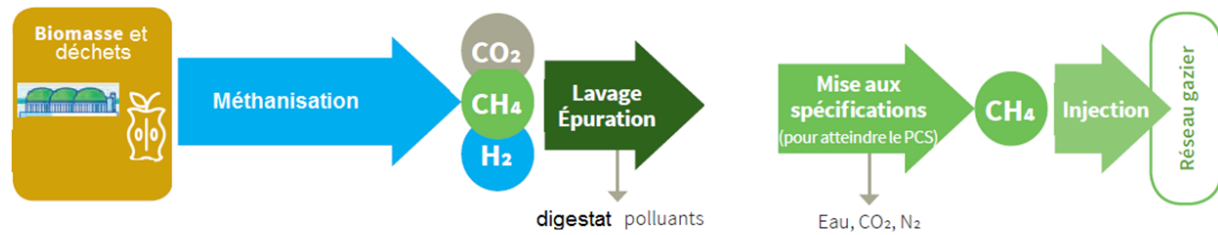


Figure 11: Biomethane production routes
Adapted from (IFP Energies Nouvelles 2018)

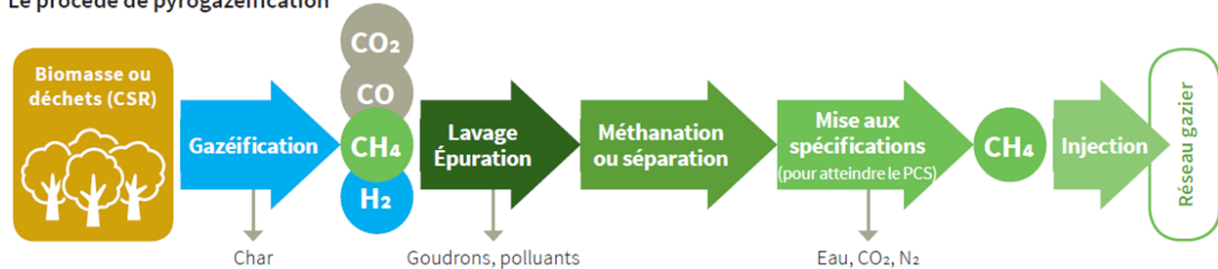
This green gas production can be injected in gas network, can be stored under LNG or be used directly as a gas fuel for several end uses such as a fuel for GNV vehicles. In our work, we will focus on the

injection in gas network. **Figure 12** sets the paths for each technology between the resource and the gas injection.

Le procédé méthanisation



Le procédé de pyrogazéification



Le procédé power-to-gas

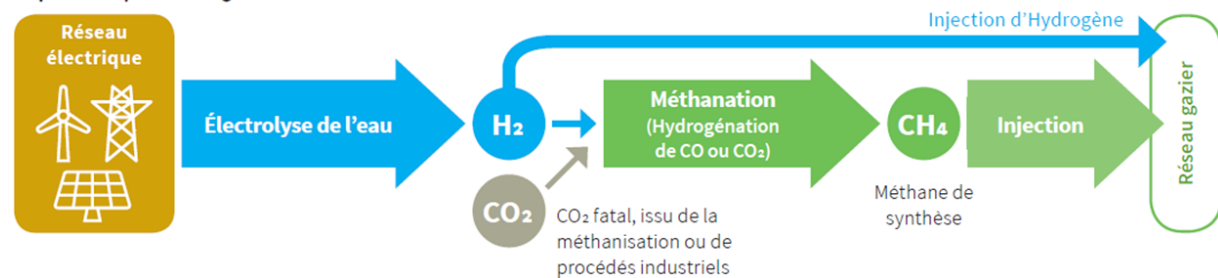


Figure 12 : Paths from resource to gas injection
Adapted from (GRDF, GRTgaz, et al. 2019)

2.2.4.2. Green gas technologies benefits

Green gas relies on several key advantages. The gas energy carrier is directly applicable in numerous sectors such as in heating and cooling, in electricity production, in transport or even in the chemical industry. Green gas can provide renewable energy all year long with no intermittency compared to other renewables as solar or wind. Biogas is a silver bullet in agriculture for mitigating methane emissions, the second most contributor in GHG releases after CO₂. It allows the upgrade of several types of wastes to renewable energy and valuable fertilizer.

Methanisation has the specificity of being a production chain for energy, but also an alternative treatment of organic waste. The production of biogas by anaerobic digestion also makes it possible to treat organic discharges and thus reduce the polluting load of industrial waste (GRDF, GRTgaz, et al. 2019). Anaerobic digestion is also a catalyst of the circular economy. The production of biogas also generates a co-product called digestate. This natural organic fertilizing material can be spread on agricultural land and substitutes for mineral fertilizers of fossil origin. It produces an improved fertilizer more easily assimilated by plants. It allows a reduction of energy expenses for farms and agro-food industries for electricity or heat. It represents also a diversification of farmers' incomes by selling the biogas/electricity/heat produced that supports local and rural employment. Last, it allows also a

reduction of farms fertilizers expenses by using the digestate. Gasification and power to gas are also fields that use local resources and may develop local competences.

Unlike the combustion of petroleum products, the biogas recovered from organic digestion can be considered almost neutral. Biogenic production and combustion biomethane may induce a direct 40% reduction compared to fossil gas. It can also avoid agricultural emissions by around 50% by avoiding the natural GHG releases from methanisation inputs that were usually stored outdoors (Carbone 4 2019). Besides, the CO₂ produced from methanisation can be an input for methanation process in power to gas. This business model of this supply chain is yet to be determined and is studied in demonstrators, for instance in the Energiepark Mainz project in Germany with the question of quantifying the carbon content of the process and the associated CO₂ costs (Le Roy 2020).

The renewable gas participates also to the energy independence of the country with the production of a sustainable renewable energy stored in networks and produced near areas of consumption. For example, the industry of biomethane can create on average three to four jobs with one MW farm installation (ADEME 2017). It will also develop on the national territory the equipment for the production of renewable gases, and thus limit the import of this kind of equipment (Müller-Lohse 2019).

Moreover, there is a noticeable potential concerning the sector coupling and integration, where a hybrid energy infrastructure built on both the gas and electricity networks, will form the solid backbone to decarbonise energy systems. Together or separately, the combined virtues of electricity and renewable gases are essential to achieving long-term climate ambitions effectively and on time. This will be discussed in chapter 4 and 5.

Finally, yet importantly, the security of energy supply would be improved thanks to the inherent resilience and flexibility of the gas network coupled with this new local production so that it avoids calling high gas importations for non-producing countries. Indeed, gas grids can manage high demand fluctuation and can be associated with variable renewable electricity for storage purpose. Green gas is also produced locally, so that it reduces tensions concerning the gas trade and makes the country more energy independent. Nevertheless, biogas upgrading to biomethane and gas network injection allows a gas consumption in a different place from the gas production site, thanks to gas transit through the network, which is not possible for cogeneration onsite just after methanisation. This adds a flexibility in uses and an added-value for biomethane compared to biogas (European Biogas association 2018) (IFP Energies Nouvelles 2018).

2.2.4.3. Green gas technologies concerns

As it is a way to decarbonise the energy systems, these green gas technologies should be prioritized and developed in the future. Then, a sustainable exploitation of the resource is required. Developing massively methanisation should not trigger massive dedicated food crops production for energy purpose. As well, large development of gasification should not rhyme with deforestation. Therefore, a smart technological development based on the sustainable potential available has to be searched.

The quantification of GHG emissions from industrial plants is becoming more and more important. In order to assess the environmental compatibility of a plant, it is important to consider the emissions during all the process, especially the methane leaks, as methane is a GHG with a very high greenhouse effect. It is therefore essential to recover this methane and transform it into electricity or heat to avoid negative side effects and increase the GHG content of these processes and not helping to the energy

transition. If not, the positive GHG balance of a biogas plant can vanish or become negative. The mitigation of methane emissions from biogas plants is not only essential for climate protection, but is also very important because of safety issues, possible odor problems and because of economic reasons for the biogas plant owners (Paolini, et al. 2018).

Other concerns are existing and are related to the projects development such as the local acceptance for methanisation or gasification installation. This is due to concerns about safety of the process, the noise produced, the odors produced and the need for local transport for the inputs of the process. Sensitization about these measures concerning a plant to people is key to make acceptance of these installations, which look like another industrial plant.

To answer these concerns, biogas plant operators are forced to implement standard precautionary measures in order to identify potential hazards and minimize the risks associated with the plant production. Plants operators take also measures to do an appropriate layout of the 'noise sources' and strict noise standards are applied. Odors come from the transport and storage of the inputs and outputs. Different solutions are used for different feedstock to minimize the spread of odors such as closed storage tanks or silos, manure cellars and bunkers with air scrubbing. Besides, the biological process used in biogas plants has the positive side effect to reduce unpleasant odors, while having a sanitation effect on feedstock. Last but not least, the biomass transport to the biogas plant will indeed cause more locally concentrated transport, but there are strict routes to transporters and transport is only allowed during working days (EBA 2019).

3. Green gas system details

Even though natural gas is a CO₂ emitting fossil fuel, gas infrastructure will continue to play an important role because of several factors presented above, among them a substitution for "green" gas to decrease the carbon content of gas. This section would quantify the importance of greening the gas in gas supply nowadays. The figures are integrated in POLES scenarios as initializations and databases for the prospective studies that will be shown in chapter 4.

3.1. Historical production

In 2019, in the world, green gas production is done thanks to methanisation. Methanisation is the only technology that is a mature and almost cost effective conversion process. As mentioned in the previous part, gasification and power to gas are still at a demonstration or early R&D step and need further development to reach process stability and industrialization. Moreover, economics are the key determining factors affecting the development of biogas production so that a decrease in cost is needed as well as cost effectiveness for the technology scaled up at an industrial process. Political willingness is also required to provide means for R&D and develop the technologies (Scarlat, Dallemand et Fahl 2018). For instance, even if methanisation process is quite mastered, its development still needs policies incentives to be cost competitive with natural gas prices.

3.1.1. Biogas production

3.1.1.1. World

World biogas production raised around 30 Mtoe in 2017. By comparison, overall gas consumption reached 3,55 Gtoe in 2018, actual biogas production represents just less than 1% of gas world needs (IEA 2019). There are currently about 50 million micro-digesters corresponding to home installations and 132,000 small- scale digesters. Many of them are situated in China because China was a precursor

for biogas with many rural installations producing biogas from home and local agriculture wastes. The number of biogas sites is more than dozen of millions reaching a 5,9 Mtoe biogas production in 2005 (Science in Society 2019). Nevertheless, it is very difficult to estimate the installed power and the quantities produced more recently because of a lack of data (World biogas association 2019).

Centralized and listed biogas production has strongly developed since 2008 as seen in **figure 13**.

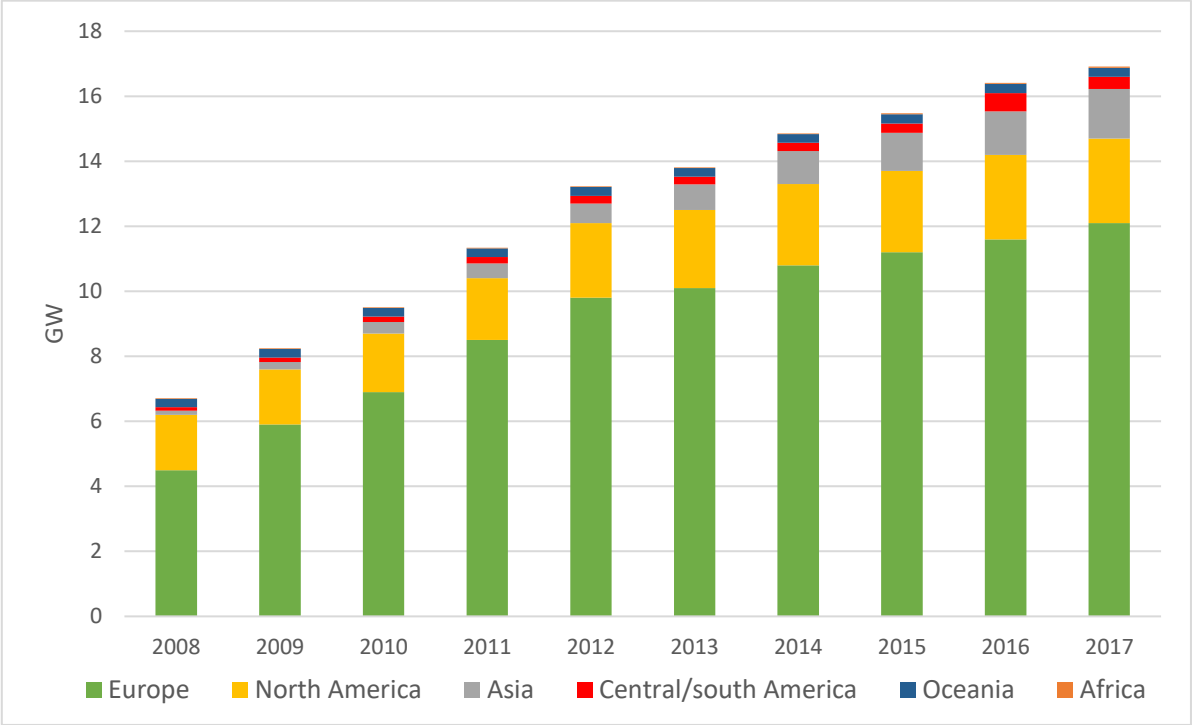


Figure 13 : World biogas installed capacity
Adapted from (IEA 2019) (World biogas association 2019)

A majority of biogas production is currently valorized directly in electricity, heat or cogeneration (around 60%). The installed capacity reach 17GW worldwide, with more than 12,5GW in Europe, 2,7GW in America and 1,7GW in Asia. **Table 3** shows the electricity production by continent and country.

Table 3 : Electricity production from biogas in 2017 by main producers

	Production (TWh / Mtoe)
World	88 / 7,57
Asia	4,2 / 0,36
China	2,4 / 0,21
Europe	64 / 5,50
Germany	34 / 2,92
Italy	8,3 / 0,71
UK	7,7 / 0,66
France	2,2 / 0,19
America	14,9 / 1,28

Adapted from (IRENA 2019)

Around 30% of global biogas production is consumed directly in buildings, mainly in the residential sector. Less than 8% of biogas produced globally today is upgraded in biomethane. This percentage varies widely between regions: around 15% for North and South America of biogas production is upgraded; around 10% in Europe, the region that produces the most biogas and biomethane, and in Asia only 2% (IEA 2019).

A further 20% of plants deliver biomethane for use in road vehicles through dedicated distribution networks, so that the biomethane is not injected in the gas network. This is the business model for biomethane valorization in some countries such as in Italy or Sweden (European Biogas association 2018).

Figure 14 sums up the biogas production by continent and by feedstock.

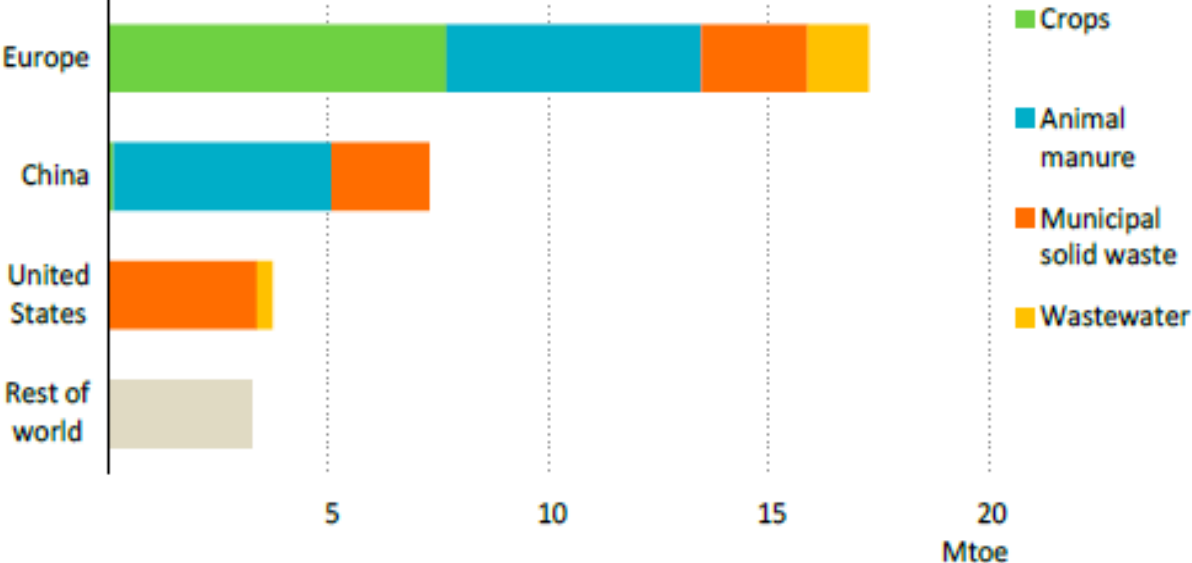


Figure 14 : Biogas production by continent and by feedstock in 2017
Taken from (IEA 2019)

Agricultural feedstock is the main source of biogas production in Europe as animal manure. This feedstock is the most used in China. In the same time, municipal solid wastes is the main feedstock used in the United States

In China, policies in place incentivize the development of more biogas installations such as a national biogas construction plan. The goal for the country's annual biogas output is set at over 10 Gm³ (9 Mtoe) by 2025 and 20 Gm³ (18 Mtoe) by 2030 according to the guideline jointly released by the National Energy Administration and nine other central departments (Xinhuanet 2019).

In the USA, there were 2116 operational biogas systems in the United States in 2014, mainly from wastes and a few from water treatment plants. Even if the country has a huge agricultural potential, this feedstock is not used for biogas production (US DOE, US DOA et US EPA 2014).

Concerning Brazil, it reaches more than 400 biogas plants in operation at the end of 2019, an increase of 40% compared to the previous year. The National Biofuel Policy called RenovaBio introduced sale of decarbonisation certificates in January 2020, so that it aims to boost the biogas industry for the future (Biogas channel 2020).

3.1.1.2. Europe

Restricted to the European scope, biogas represents a primary energy production that went from 8 TWh (0,7Mtoe) in 1990 to 23 TWh (2 Mtoe) in 2000 to more than 200 TWh (17,2 Mtoe) in 2017 (**figure 15**). Biogas represents 1% of final energy consumption in the EU in 2017. By comparison, in 2018, the share of energy from renewable sources in final energy consumption increased and reached 18% in the EU (up from 17.5% in 2017 and more than double its 2004 level (8.5%)). Among it, biogas represents 5,5% of renewable energy consumption. Gas represents 20% of EU’s primary energy consumption that amounts to 5000 TWh (430 Mtoe), biogas represents 4% of total current gas consumption in Europe (Navigant 2019).

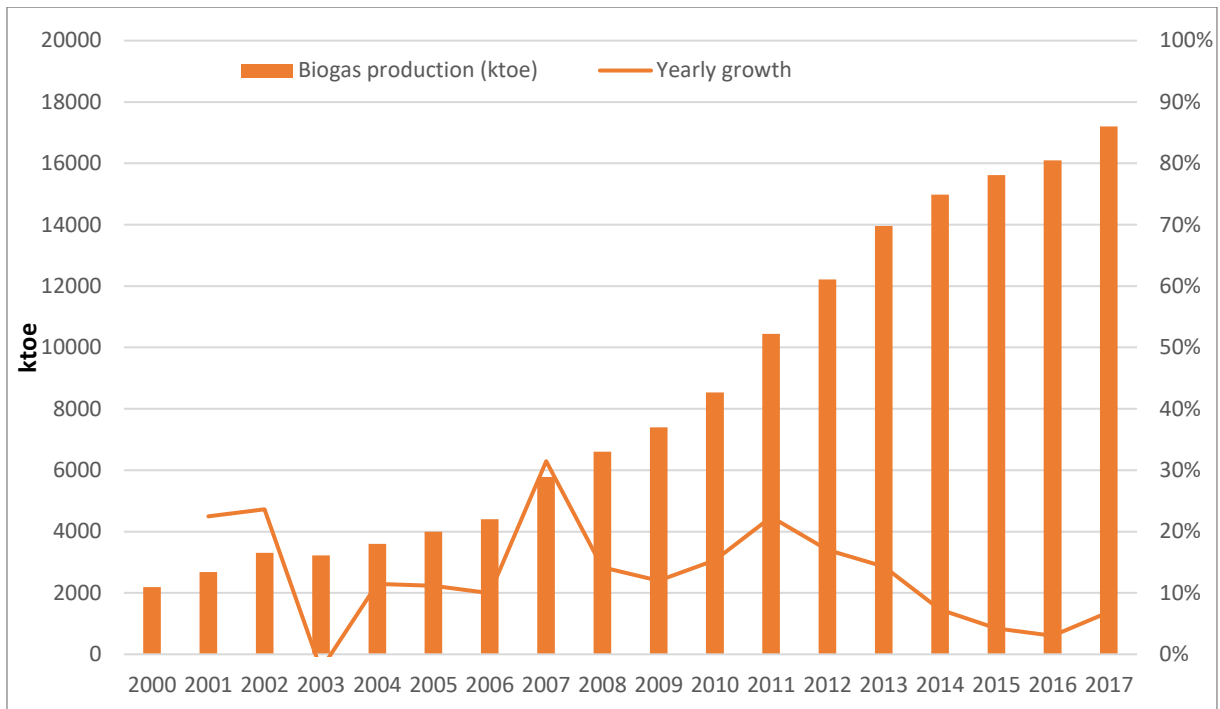


Figure 15 : European biogas production
Adapted from (European Biogas association 2018)

By the end of 2017, which is the last year with consolidated figures, there were 17,783 biogas plants and 540 biomethane plants in operation Europe-wide. **Figure 16** represents the evolution of biogas plants in Europe since 2010.

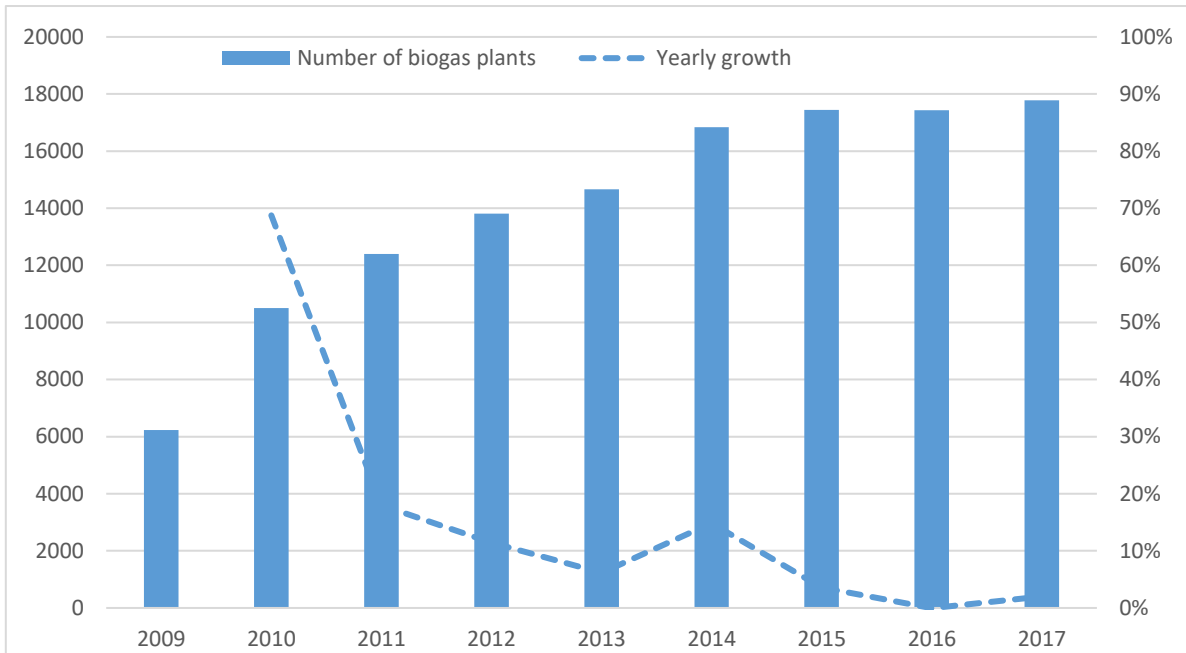


Figure 16 : European number of biogas plants
Adapted from (European Biogas association 2018)

Having become a mature sector and helped with political incitation such as feed in tariffs, methanisation has developed widely in Germany, Italy, Denmark, the United Kingdom or France. The number of biogas production plants knows a noticeable growth: the number of biogas plants has grown from around 6000 in 2009 to almost 18000 in 2017, and mainly in Germany (about 10900). This country, the European leader in the production of renewable gas, already produces very significant volumes of biogas, including nearly 80 TWh of biogas for the production of electricity and heat cogeneration, and about 10 TWh of biomethane injected into the networks. The level of development of the German industry shows that it is already possible to reach significant production levels, that is for the moment solely based on the anaerobic digestion system (Ecube et CRE 2018).

Differences exist for methanisation process valorization in European countries. Germany privilege mainly biogas for electricity production while France aims at favoring the gas injection in gas network. Italy or Sweden privilege off grid consumption in gaseous transportation fleets. Political incentives are key in this choice because France, and not Germany, has an injection support regime and interesting feed-in-tariffs (Müller-Lohse 2019).

In Denmark, for example, biogas plants developed at the local level in the 1980s and 1990s by groups of farms, frequently supplying heat networks. The injection of biogas comes later after some trouble concerning biomass dedication for energy in competition with food and after some changes in feed in tariffs, which did not encourage electricity production anymore. With the introduction of a dedicated purchase price or feed in tariff under the 2012 Energy Agreement, the injection of biomethane into the Danish gas networks has experienced a strong growth: biomethane now accounts for more than 10% of volumes of gas transported in the country's gas networks. (European Biogas association 2018). Biomethane production in Europe today is 2 Gm³ per year (around 21 TWh or 1,85 Mtoe).

64 TWh of electricity were produced by biogas plants across Europe in 2017 (see **table 3**), which amounts to roughly 6% of the renewable electricity generation in Europe (EBA 2019). Units of biogas specially designed for energy recovery, such as on-farm biogas, digestion biogas and industrial biogas,

account for almost three quarters of total biogas, the rest is produced by landfill biogas and biogas from treatment sewage sludge (EurObserv'ER 2018). Represented **figure 17**, this electricity production from biogas is due to three reasons. First is the process chain that does not need a drastic and costly purification step as the biogas burnt to produce electricity does not have to be as pure as a gas injectable in the gas network. Besides, it does not need an extension of the gas grid to connect the production site to the network. Last, the feed in tariff has been principally set on the electricity side, so that producers are paid with their electricity production and not for being paid for the biogas produced (Torrijos 2016).

However, there are new policies frames that limit the controversial use of food cereals as substrates as it was the case for the German development in the 2000s, limiting the thresholds for the supply of anaerobic digestion facilities by food crops at 60%, so that this development slowed in the last 3 years (Müller-Lohse 2019). In Austria, this limit is 30% and in France, the decree No. 2016-929 of July 7, 2016 fixed this threshold at a maximum proportion of 15% of the tonnage total gross input per calendar year (EurObserv'ER 2018) (GRDF, GRTgaz, et al. 2019).

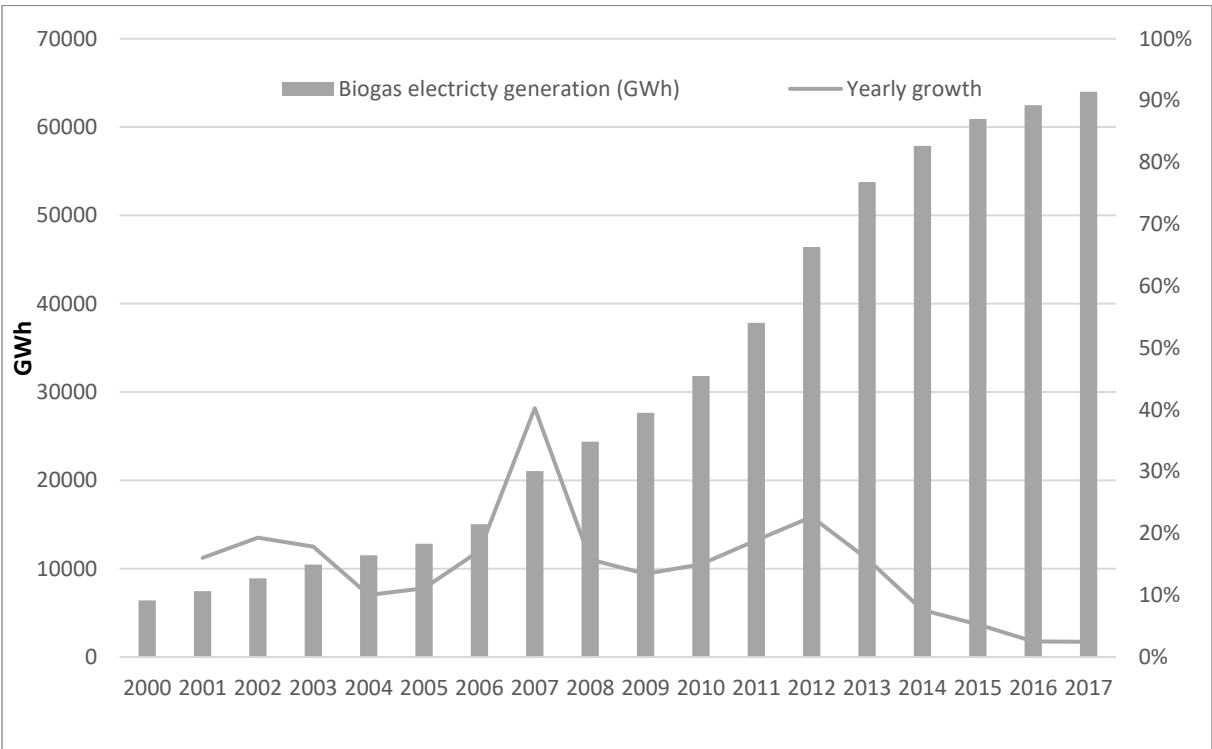


Figure 17 : European electricity production from biogas plants
Adapted from (European Biogas association 2018)

3.1.2. Biomethane production

Data on this sector are comparatively scarce and sources of information – national, regional or sectoral – are highly dispersed, so that it is difficult to have consolidated figures for lots of countries, in particular for countries outside Europe (Cedigaz, 2019).

3.1.2.1. World trends

There were over 720 biomethane plants in operation producing around 29 TWh - 2.5 Mtoe of biomethane globally in 2017 (**figure 18**). Most of these plants are in Europe (540) and America (130), but the growth of biomethane plants occur also slightly in other regions. Only few biomethane plants (less than twenty) are in operation in China, in South Korea or in Brazil (Sapp 2017) (Cedigaz, 2019).

Some changes are eager to come soon because of changes in regulatory measures concerning biogas upgrading in China, India or Brazil, so that biomethane injection should develop in these countries in the next years (Cedigaz, 2019). However, while three quarters of countries inject biomethane into existing gas networks, some countries privileged off grid uses such as vehicle charging stations, for example in Italy or Sweden.

There is a six-fold increase in global biomethane production since 2010 and there will be 1,000 biomethane production plants in the world soon through 34 different countries (Cedigaz, 2019). The main countries that have developed biomethane plants are located in Europe.

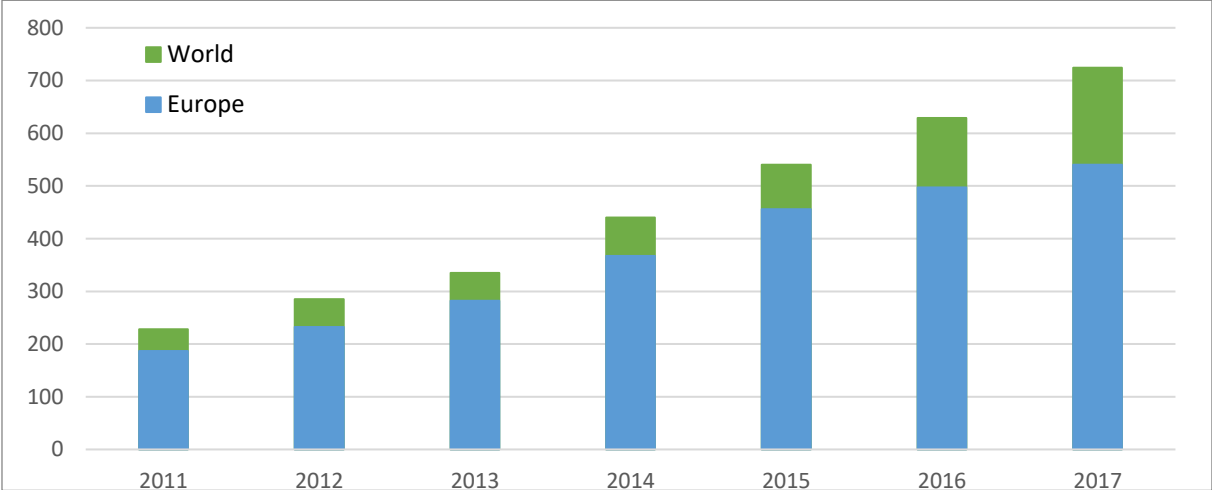


Figure 18 : World number of biomethane plants
Adapted from (Cedigaz, 2019)

3.1.2.2. Europe

The number of biomethane plants has risen in recent years, from 187 plants in 2011 up to 540 plants in 2017 (figure 19). The production reaches 19,5 TWh – 1,7 Mtoe (figure 20). The growth was huge because of technology was in its infancy and receive support schemes.

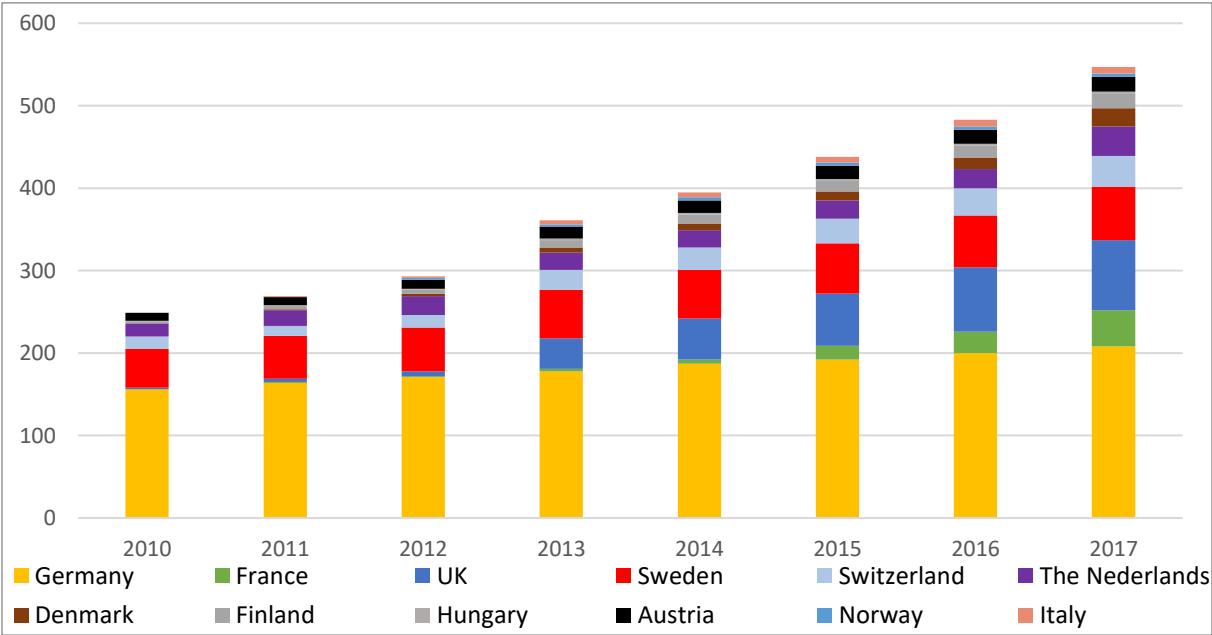


Figure 19: European number of biomethane injection plants
Adapted from (OIES 2017) (European Biogas association 2018)

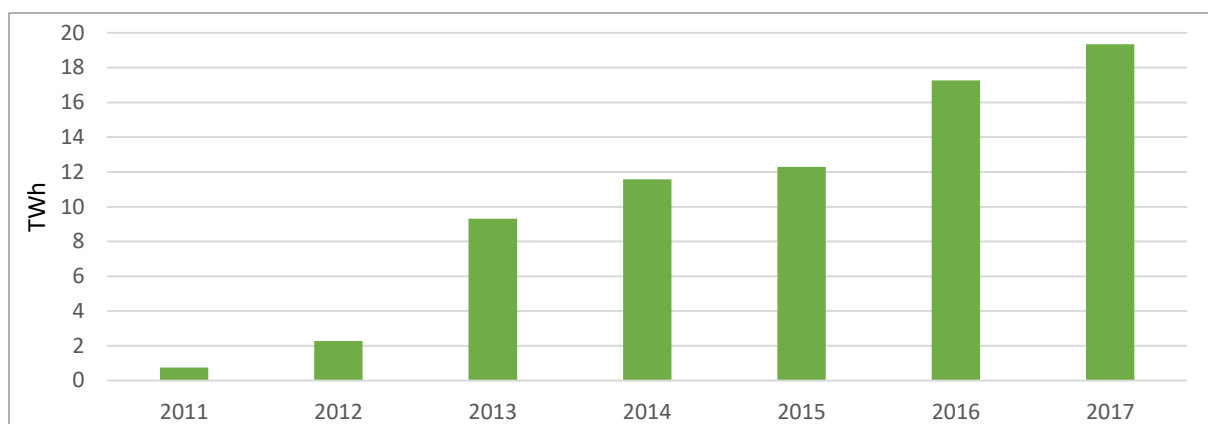


Figure 20: European biomethane injection quantities

Adapted from (European Biogas association 2018)

France is the European country with the highest annual growth in 2018 (+17 plants). France is followed by the Netherlands (+13 plants), Denmark (+8 plants) and the United Kingdom (+7 plants).

In Italy, adjustments made to the subsidy scheme for biomethane have had an impact on national biomethane strategy. Historically, there was no incentives for biomethane injection in the network so that it did not happen. Biomethane had developed off grid for gas vehicle charging stations. However, five demonstration-scale biomethane plants were closed in 2017 while 2018 saw the installation of four new plants connected to the gas network. These demonstrators may foster the green gas injection even if the gas and biogas are mainly use as a vehicle fuel in this country (NGV Global 2019)

Table 4 sums up the last census for local green gas injection plants and injected quantities for European countries in 2017.

Table 4 : Inventory of European biogas production site and gas injection in 2017

Country	Number of sites for biogas production	Yearly quantities of biogas produced (GWh) (2016)	Number of sites for green gas injection and % of biogas sites		Yearly quantities injected in gas networks (GWh) and % of biogas	
			Number of sites	% of biogas sites	Yearly quantities (GWh)	% of biogas
France	742	6745	44	6%	406	6%
Germany	10941	92528	208	2%	9800	11%
Italy	1655	23586	6	0%	100	0%
Switzerland	632	-	37	6%	340	-
Great Britain	613	27993	85	14%	3600	13%
Ireland	-	651	13	-	400	61%
The Netherlands	268	3768	36	13%	900	24%
Finland	96	1244	18	19%	100	8%
Sweden	179	2012	65	36%	470	23%
Norway	-	-	4	-	120	-
Denmark	144	1430	22	15%	1800	126%
Austria	423	3594	18	4%	250	7%
Spain	204	2687	1	0%	23	1%
Luxemburg	30	233	3	10%	62	27%

Adapted from (European Biogas association 2018) (Eyl Mazzega et Mathieu 2019) (GRDF, GRTgaz, et al. 2019)

3.1.2.3. France

At the end of 2018, France had more than 785 production units of biogas. Following the world trend, direct cogeneration remains the main valuation of biomethane: around 75% of installations in France in 2018. Only 10%, 76 facilities in 2018, upgrade the biogas in biomethane and inject it on the gas network with a predominance for farm type and station facilities treatment (Carbone 4, Biométhane et climat, font-ils bon ménage? 2019). The number of biomethane plants in France increased a lot recently: 17 more in 2017 and 32 in 2018.

The government is seeking to redirect the flow of subsidies to the injection because it is the only main lever to date for decarbonizing the gas network. In addition, electricity is already decarbonized in France and the networks of heat decarbonizes at full speed thanks to wastes or woody resource (GRDF, GRTgaz, et al. 2019). The state has set up a specific purchase price for gas injected into the network as well as associated guarantees of origin. Strong growth observed in 2017 has further increased in 2018: there was an increase of 76% for gas volumes injected (reaching 716 GWh) and an increase of 77% for capacity reservation injection compared to the previous year.

3.1.3. Gasification and power to gas development

Concerning gasification, some demonstrators are expected to give off a business model for the process in Europe. (Project Lahti Energy's Kymijärvi II s.d.) (Gobigas s.d.) (Project bioSNG in Güssing s.d.) (Sundrop fuels s.d.) (Fulcrum s.d.) (Held et Olofsson 2018). Demonstrators' projects also exist in France. GAYA experimental platform develops a process chain innovative biomethane production by pyrogasification of dry biomass. Others, like bioTfuel, aim at studying the conversion of lignocellulosic biomass into biofuels (GRDF, GRTgaz, et al. 2019). GRHYD and Jupiter 1000 are the only two projects concerning power to gas studying respectively the process of hydrogen injection into the gas grid and the whole value chain of power to gas (Engie 2017) (GRTgaz 2018). Other projects are in the pipelines in France, Methycentre, the first power-to-gas project coupled with anaerobic digestion, commissioning is scheduled for 2021, and Hyaunais, a power-to-gas project coupled with a non-hazardous waste storage facility producing biogas and testing the biological pathway of methanation. (GRDF, GRTgaz, et al. 2019).

3.2. Biogas and biomethane potentials

3.2.1. World

Actual potential to generate energy from currently available and sustainably grown/recovered major feedstocks in the world is estimated 10100 - 14000 TWh (0,9-1,2Gtoe). This energy can meet close to 6-9% of the world's primary energy consumption. This potential can evaluate and double to triple by 2030 (IRENA 2014). The repartition of this world potential can be assessed thanks to (Paolini, et al. 2018) and is represented on **figure 21**.

Many report and analysis assess the biogas potential (so the biomethane potential if upgrading possibilities) for several countries. Substrates vary amongst countries and regions. For instance, the potential for China is estimated at 117 Mtoe in (Science in Society 2019). **Table 5** shows an estimation of biogas potential and use for the USA.

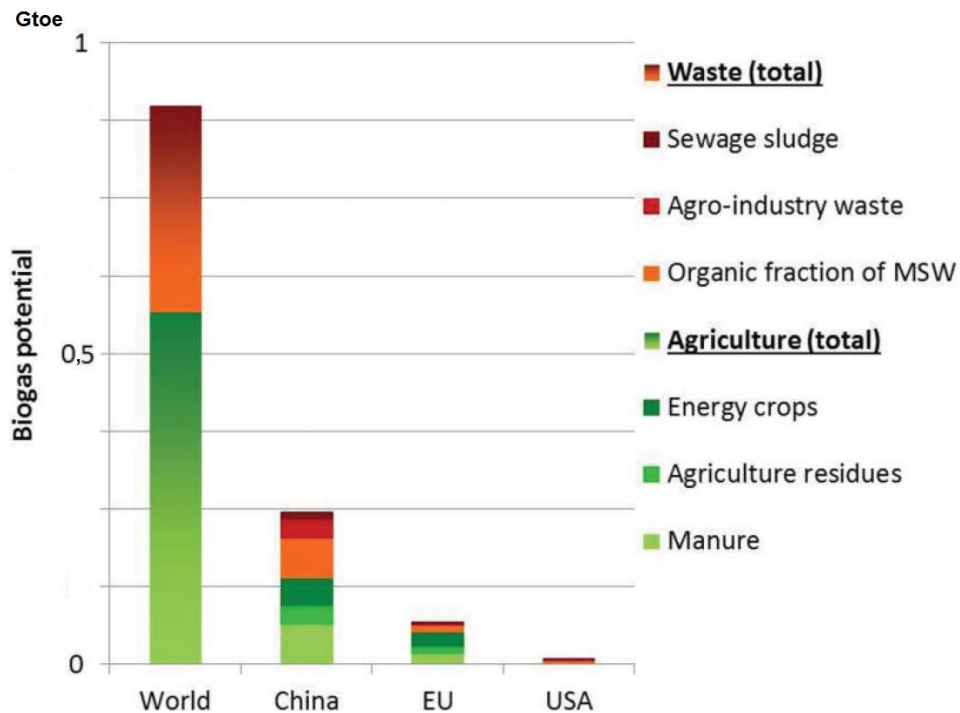


Figure 21 : World biogas potential
Taken from (Paolini, et al. 2018)

Table 5 : Biogas potential for the USA

Biogas current potential	16,11 Mtoe/year with 13000 plants
Annual resource production potential (Gtoe/year)	0,14
Electricity production from biogas (TWh)	41.2

Based on (US DOE, US DOA et US EPA 2014)

Other huge potentials are situated in Brazil, in Canada, Russia or Australia where biomass resource is well spread. A precise quantification of the potential is hard to implement (IRENA 2014).

3.2.2. Europe

Renewable gas may reach 10% of EU's current natural gas consumption by 2030 (roughly 500 TWh – 43 Mtoe). Likewise, there are 1,072 TWh – 92 Mtoe of sustainable biomethane that can be produced by 2050, representing roughly one fifth of current natural gas consumption (EBA 2019).

If we add the production of hydrogen by renewable electricity electrolysis to that of biomethane and synthetic methane from the pyrogasification process made from resources such as wood residues, the potential of renewable gas at European level could reach 2830 TWh - 243 Mtoe per year (Navigant 2019). This quantity represents more than a half of total European consumption in 2018, which gas consumption is a quarter of total European energy consumption. The potential of green gas in Europe can represent an eighth of total European energy consumption so that it is a relevant large-scale decarbonisation option (OIES 2017).

3.2.3. France

The pool of primary resource of biomass and recovery energy that could be used for green gas production can rise between 400 and 550 TWh (Solagro, Afterres2050 2016). This potential is to be compared to the 400 TWh of natural gas consumed in 2011 on French territory. France has a bioenergy

potential above European average thanks to the size of the country, its agricultural potential and its forests resources. It confirms the interest of the sector with regard to the objectives of the Grenelle Environment Forum and the energy transition law for decarbonisation (Ministère de la transition écologique et solidaire 2017).

Methanisation

Nevertheless, potential estimation varies a lot depending of the assessment and the methodology taken into account. For instance, some studies evaluate the methanisation potential for France up to 132 million tons of resource representing 56TWh – 4,8 Mtoe. Among it, there is 51TWh coming from agricultural resources (Solagro, Inddigo et ADEME, Estimation des gisements potentiels de substrats utilisables en methanisation 2013). Other estimations assess a potential for methanisation of 200 TWh relying on all degradable resources with dedicated valorization paths support, in particular for wastes treatment (GRDF 2013).

Gasification

For France, the technical potential for producing second generation of biomethane varies from 100 to a maximum of 250TWh / year depending on scenarios envisaged with or without the culture of dedicated energy crops. These scenarios are also different with the biomass culture pattern, for example if intermediary energy crops are cultivated between two classical cultures (GRDF 2013).

Power to Gas

This is another 15-40TWh green gas production potential with power to gas and 10-20TWh with micro algae gasification (GRDF 2013) (ADEME 2018). These figures are a good order of magnitude for the total potential available but it would be more precise in the future with other studies and demonstrators return of experience concerning the process (G. I. GRDF 2017).

3.3. Biogas and biomethane costs

- CAPEX costs

CAPEX for methanisation are really dependent on the size of the installations and range between 100 to 500€/kW (IRENA 2017) as seen in **appendix 1**). Other studies highlight a range between 100 to 2500€/kW (Cedibat 2018).

In case of methanisation, it is also worth noticing that the cost of the upgrading system to biomethane is not negligible and can reach half of the CAPEX cost (**table 5** and **appendix 1**). This ratio varies in function of the size of the installation (the bigger the installation is, the lower proportion of CAPEX) and the type of inputs (they are higher CAPEX with higher proportion of wastes). In particular, that was why biomethane has not been developed in priority in the past because of costs associated with purification and strong control for output gas purity.

There are also the connection costs that reach on average 190 €/meter to connect the plant and the gas grid. Some analysis shows that this connection cost can be estimated on average to 4% of the total cost of the plant (Cedibat 2018), that will be the figure we will take into account in the modelling.

Biomass gasification plants are still in a demonstration point, so that it is difficult to set a typical cost for these installations. Nowadays, costs raise approximately to 1000€ to 3500€ per kW installed

(Holmgren 2015). This is at least two to ten times more than current methanisor costs. Besides, the implementation of CCS would increase the CAPEX by 50% on average (Brack et King 2020).

- OPEX costs

OPEX are really dependent of the cost of the resource taken. For example, in methanisation, if there is a higher proportion of cereals that can be dedicated for food or feed production, costs increase a lot because of this feedstock cost: the feedstock can represent 80% of the OPEX costs and 50% of the total cost (as detailed in *annex*). Likewise, for gasification, a higher ratio of wood costs more than a higher ratio of lignocellulosic wastes. In power to gas, the price of electricity variation is also important for OPEX costs.

- Global production costs

Figure 22 summarizes a range cost stacking for current methanisation installations, for a best case on the right and a worse case in the left.

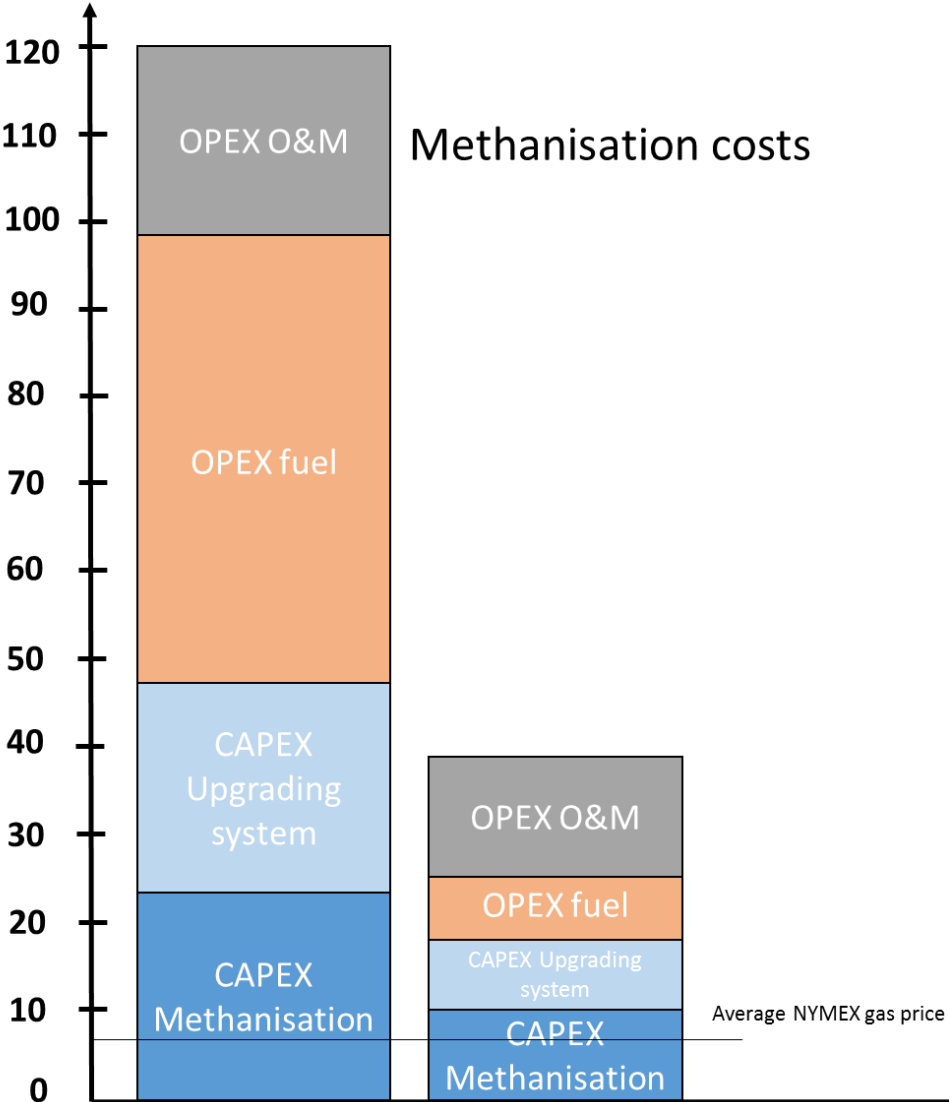


Figure 22 : Methanisation cost stacking
Based on (IRENA 2017) (ADEME, GRTgaz, et al. 2014)

Table 6 details an example of an installation cost repartition

Table 6 : CAPEX and OPEX for a methanisation plant

Size of installation	1 MW	5 MW
Inputs tonnage per year	15000 t	40-50000 t
Total CAPEX	2,1-2,4 M €	5,5-6 M €
Methanisor	1,4 M €	3 M €
Epurator	0,7-1 M €	2,5-3 M €
Total OPEX	320 k€/an	830 k€/an
Methanisation	100 k€/year	280k€/year
Epurator	90-120 k€/year	290-450 k€/year
Control and injection	100 k€/year	100 k€/year

Based on (Cedibat 2018)

In methanisation, biogas production costs vary widely depending on the feedstock cost, the size of the installation, the output and the support scheme set in place in the country of production. Estimations for biomethane production set costs from 40-110€/MWh (IEA, World Energy Outlook 2019 2019). Other estimations for biomethane production are ranged from 40-120€/MWh (IRENA 2012) or a levelized cost of energy (LCOE) for biomethane production can range from 40-90€/MWh depending on the resource used and the localization of the methanisor (ADEME 2018).

Likewise, we represent in **figure 23** the cost stacking for gasification and power to gas for 2020 for the best estimations. Costs are really more expensive than methanisation, so that is why these technologies are not still spread at high scale and are still in development to reduce systems costs (ENEA Consulting 2016). Nowadays, gasification has higher costs in the range 120-250€/MWh because of higher CAPEX needed especially for the syngas upgrading system (Holmgren 2015).

Currently, the hydrogen sector has a production cost of around 100 €/MWh by electrolysis in the best cases (Becker 2014) (ENEA Consulting 2016). The methanation sector has also costs a bit lower than 100 €/MWh but depends a lot of the resource needed, for example from where the CO₂ needed for methanation process comes (ADEME, GRTgaz, et al. 2014). Besides, we consider a mean value for electricity cost in this representation even if electricity price changes every hour and even if a projected business model considers that the electricity in input should have been curtailed if not used in power to gas so that it can be considered as free. These hypotheses will be discussed as well as the power to gas business model in chapter 5.

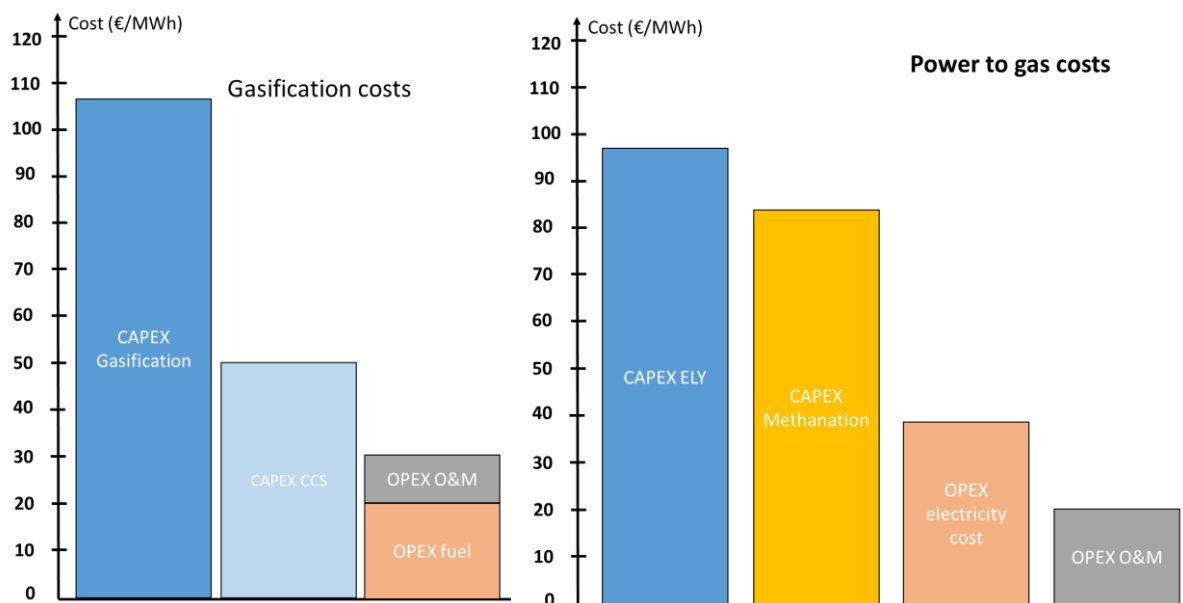


Figure 23 : Gasification and power to gas stacking costs

Based on (Becker 2014) (ENEA Consulting 2016) (Holmgren 2015) (ADEME, GRTgaz, et al. 2014)

In comparison, natural gas price reaches only 5 to 10€/MWh (see chapter 2 section 1), so that biomethane fields are not cost competitive to replace natural fossil gas nowadays. Subsidies, feed in tariffs or other incitations are thus needed nowadays to develop the biomethane production fields. However, gas prices should increase a bit in the future, especially if negative environmental externalities are taken into account through a carbon tax. In the same time, production costs for biomethane should decrease so that biomethane costs and gas prices should close in (IEA 2019). The synthetic methane sector would be in a cost range between 1.5 and 3.5 times higher than the price of fossil natural gas. Under these conditions, for green gas being developed following markets rules, a carbon tax between 200 to 300€/tCO₂ is needed because it would increase the natural gas price by 30-45€/MWh.

Ranges and projections used in (ADEME, GRTgaz, et al. 2014) used for our database can be found in **appendix**.

- CO₂

The assessment of greenhouse gas emissions is an extremely tricky topic, and is dependent on a variety of factors: the choice of feedstock used to produce green gas, its transportation and handling, the specific production processes used, the amount of any methane leakage along the supply chain, and the end use of the product, as well as the calculation methodology. Indeed, when green gas is used, carbon dioxide and water are formed.

First, it is worth considering the feedstock biomass. Some studies consider that the carbon content of bioenergy is by definition zero because there is carbon neutrality considering the biomass reference: the amount of CO₂ released during combustion has been captured during plant growth (Dupont 2014). It is a natural cycle in which, over time, trees or plants growth balances the carbon emitted on combustion as long as the trees or crops are regrown after harvesting: the CO₂ released comes from

the air absorbed by plants in the process of photosynthesis during the growth of the plant. The CO₂ released was indeed already in circulation in the atmosphere as opposed to fossil energy, where it is stored below ground. It was also the hypothesis taken for models working on IPCC 5th Assessment Report (IPCC 2014). Another example is the carbon content taken by RTE in France to assess electric production carbon content. The CO₂ emission factors used for household waste is zero for the renewable part of these wastes (RTE 2020). That gives biogas a climatic advantage compared to natural gas from a GHG emission viewpoint (Biogas world 2019). Other studies assess even more that the biomethane use can be carbon negative in reference of a case where the biomass feedstock is not used but is releasing naturally CO₂, for example wastes in landfills (JRC 2014). The implementation of CCS will also reduce the GHG releases of the process in particular the gasification releases.

Nevertheless, recent studies, with some reviewed in IPCC 1,5°C report (IPCC 2018) have recognized that this central assumption for CO₂ emissions calculations can be invalid, so that it can have some limitation for bioenergy development and use. A large life cycle analysis has to be implemented to assess the correct balance between carbon in biomass and in the air. For example, an increase in bioenergy production affects soil degradation and relative soil carbon capture. There are also concerns about the rate of carbon absorption in trees where young trees absorb less carbon than mature trees. So carbon flux are not compensated when young species planted after harvestings from old plants grow compared to the releases for old plants energetic valorization (Brack et King 2020) (Stephenson et al. 2014).

Hence, by studying the whole life cycle of biomethane, some studies estimate CO₂ emissions reduced by around 200 kgCO₂/MWh by using biomethane from methanisation compared to natural gas, it is around half of the natural gas emissions (G. I. GRDF 2017). Other studies estimate the carbon content of biomethane from methanisation 10 to 12 times less than natural gas, around 30-40kgCO₂/MWh (GRDF, GRTgaz, et al. 2019). Other estimations exist comparing the emission of biomethane and the emissions of gasoline in transportation sector, where there are a GHG emission reduction between 60 and 80% by using biomethane in transportation (OIES 2017).

Concerning power to gas, regarding GHG, there are no direct emissions from a tank to wheel approach considering green electricity use. Assessed with a life cycle analysis, there are 25kgCO₂/MWh for hydrogen production considering the energy used for the investment and for the process. Another estimation amounts to 37kgCO₂/MWh for synthetic methane (ADEME, GRTgaz, et al. 2014), but this last figure may change noticeably according to the source of CO₂ used. For example, the carbon content would decrease if the source of CO₂ comes from methanisation outputs (ADEME, GRTgaz, et al. 2014). This quantification and the methodology associated are still to be precised in R&D programs.

3.4. Political instruments to incentivize green gas production

It is clear from the discussion by comparing biogas production costs and fossil fuels prices that in the absence of a dramatic rise in the price of fossil-derived natural gas, the further development of biogas investments will continue to be driven only by government support and incentives. Several support schemes are existing and are required to stimulate technical progress and help renewable energy in becoming market competitive with existing technologies based on fossil sources. The approaches used to promote biogas include Feed-in tariffs (FiT), Feed-in Premiums (FiP), Green Certificates (GC) and various tax incentives/exemptions, depending on each European country. FiT are currently fostered for biogas promotion, but this is rapidly shifting to more flexible support schemes such as FiP.

The rationale for this high incentive and supporting policy is based on the requirement to initiate a new infrastructure that would not otherwise happen without intervention of a government incentivising decarbonised transport and clean air. Biomethane as a transport fuel requires a very significant change in infrastructure, including the provision of compressed natural gas service stations and natural gas vehicles. Initially (as for other successful renewable energy systems) larger incentives would be required to allow initiation of the industry, but these subsidies can be reduced over time. Biomethane as a transport fuel offers similar rewards as for electric vehicles, decarbonised transport and clean air along with energy security, renewable energy, indigenous jobs and supporting greening of agriculture.

Germany has been the leading proponent of biogas in Europe: its development of biogas plants started in the 1990s and grew rapidly between 2006 and 2013 supported by a feed-in tariff system. Italy has followed a similar model, while the US has supported biogas production via Production Tax Credits and Investment Tax Credits. Sweden has also strongly supported biogas, but with a particular focus on upgrading to biomethane for use in the transport sector (EurObserv'ER 2018). A new renewable energy law in Germany effective from 1 August 2014 aimed to reduce the use of energy crops and refocus the industry on waste-derived feedstocks. This has markedly slowed the rate of growth for biogas plants: around 1000 new plants per year were added in Germany between 2009 and 2011 and this had dropped to only 150 in 2014. Likewise, in Italy, the second highest number of biogas plants in Europe, changed its incentive scheme in 2013, similarly aiming to reduce incentives for the use of energy crops and promoting smaller scale plants using that drove to a slow of biogas plants development.

The UK provides also a good example of how government policy can stimulate rapid growth in biomethane upgrading. In 2011, there was just one biomethane plant in the country. The introduction of a carbon price support from 2013, as well as a Feed-In Tariff per kWh of biomethane injected into the grid under the Renewable Heat Incentive, resulted in the installation of 20-30 new plants per year between 2014 and 2016. In 2018, there were around 100 biomethane injection sites in operation in the UK (OIES 2017).

In France, producers can sell biomethane from methanisation between 45 and 125 €/MWh (ADEME 2015). The range depends on the size of the installation: the more the capacity of the plant is, the less is the feeding tariff. Besides, there are waste premiums that promote the recovery of waste from agriculture, from wastewater and from urban wastes. These premiums are 5 €/MWh for urban wastes, between 20-30 €/MWh for agricultural residues and between 10-40 €/MWh for wastewater (GRDF, GRTgaz, et al. 2019). (See **appendix 3** for the detail of the FiT). Through the 2015 Energy Transition Law for the Green Growth (LTECV), France has set itself an integration objective 10% of renewable gas in its consumption total gas by 2030 (Ministère de la transition écologique et solidaire, Loi de transition énergétique pour la croissance verte 2017). Nevertheless, it called into question because the last PPE project marks a clear decline in ambitions for the next period until 2029. It now predicts that biogas will reach 6-8% of gas consumption in 2030 even if France declares accelerating towards carbon neutrality. This joins the problem for long-term coherence of policies to develop the fields in the long term. Beyond these objectives for energy production, other political objectives in sub sectors would incentivize the green gas production. For instance, the LTECV aims at having 65% of wastes valorized in 2025, that implies an energetic valorization and, among other options, a biogas development.

Chapter 3: Energy system modelling and thesis methodology

Energy system models provide a comprehensive approach of energy sectors and interactions between sectors during a fixed time that can be short term (few seconds, minutes, hours), middle term (few days, weeks, months) or long term (few years or decades). It is nothing else than a very complex software, whose goal is to reproduce as closely as possible the climate, the energy system and their impacts. It is a representation of a behavior of a system, with inputs, parameters and outputs. It is a big program for computers, built in the following way: some data are fixed and others are variable and endogenously calculated through time, which are considered sufficient to characterize the system. Physical laws express relations between one compartment with another. The computer modeling properly intervenes, that is to say that one represents, by lines of computer code, the cause-effect relationships and the laws of physics mentioned above.

Energy models give us some information about energy quantities produced and their sources, the quantities used with each application and the quantities traded. All is linked with economic aspects and secondary effects such as greenhouse gases emissions. Some models are optimizing systems by minimizing energy consumption, energy costs, GHG emissions or maximizing one's revenues. Others are giving future maps for systems in order to plan the transitions needed to go from today's characteristics to assessed future (Desprès, Criqui, et al. 2014).

Concerning long term energy modelling tools, some are called top-down as DICE (Matarasso 2003) and others bottom-up as PRIMES or TIAM (IEA, IEA-ETSAP Energy Systems Analysis Tools s.d.) (E3MLab 2018). Top-down means that models start their simulation with macro-economic considerations and implicate local behavior. In contrast, bottom-up models consider each sectorial demand and the related technological characteristics and ascend the simulation to macro-economic considerations. Most of the time, models are composed with a core that represents the dynamic of the model and are complemented by a set of sub-modules focusing on one sector, for instance transport or industry.

In this work, we will use POLES model, a bottom up model that will be described in the following section to assess the use of bioenergy, the development of green gas technologies and the amount of green gas production and the sectors of uses. The modelling structure, the database and the scenarios considered for simulations are presented here.

1. POLES Model presentation

1.1. General aspects

The Prospective Outlook for Long term Energy Scenarios modeling (POLES) has been developed by the CNRS-EDDEN team (GAEL 2020), the European Commission IPTS-Seville Joint Research Center (European Commission 2018) and the private company Enerdata³ (Enerdata 2020) since the early 1990s. It is today one of the reference models used to analyze the structure of the energy demand and supply as well as the development of the energy technologies through the assessment of climate energy policies. POLES is a simulation model of the global energy system up to 2100. There are

³ Website : www.enerdata.fr

exogenous assumptions for demographic and economic developments as for GDP growth and the world population evolution, for each of the major countries or regions representing the entire world (66 regions are defined in the used version⁴). Other variables like energy and commodity prices, energy consumption, transformation and production are taken from databases for the past years and are calculated endogenously in the model for the future years.

The model allows sectorial equilibrium by recursive simulation, starting from the initial year then year to year, by the scaled adjustments of the variables of the supply and demand on the one hand and of prices on the other hand. This partial equilibrium model aims at maintaining a description of detailed "generic" technologies, about fifty key energy technologies. With the introduction of endogenous technological change, this modelling helps to consider the inertia of energy systems. It is worth noticing that POLES is a market-oriented model where market equilibrium influences future demand and supply and is not an optimization model.

The model is built according to a hierarchical structure of interconnected modules at the national, regional and global levels and representing price dynamics and energy flows in physical units. The national level integrates the modules of consumption, new energies, conversion into electricity or hydrogen and production of fossil energies for each region. Regional or global levels integrate energy trade flows and international price modules, for the three major energies with wide international trade: petroleum, natural gas and coal. **Figure 24** represents the global structure of POLES.

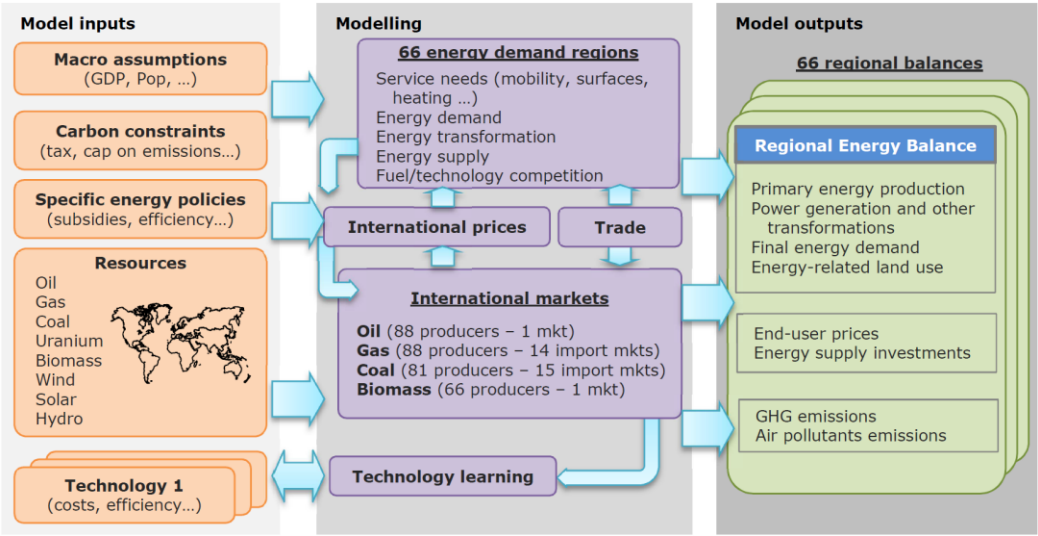


Figure 24 : Schematic representation of the POLES-JRC model architecture
 Taken from (Desprès, Keramidas, et al. 2018)

The evolution of trade results from the linking of consumption and primary energy production by country or region. For oil, only one world market is considered and oil price changes are dependent on those of the Reserves / Production ratio at the global level and a short-term, the utilization rate of production capacity in the Gulf countries. For natural gas, the world market is structured in three large regional groups (Americas, Eurafrica, Asia), for each of which is calculated a price of natural gas, according to an indexing term on oil prices. For coal, international prices, also for three regional groups, depend on the rate of expansion of coal production in the major producing countries (USA, South Africa, Australia, China, etc.).

⁴ We use the 2018 version of the model to develop the GREEN GAS PRODUCTION MODULE.

It takes into account the resource constraints that weight on the long-term development of oil and gas, in a logic that allows to accounting fully for issues like "Hubbert peak", but also the impact of the progress of technical recovery techniques that can expand the resource base. In addition to a comprehensive modeling of energy demand by sector, the development of new and renewable energy technologies, the electricity generation sector, and hydrogen-energy, the model offers a detailed description of the energy production process.

Five technological portfolios allow an explicit description of the main options for the development of the energy system and the fight against greenhouse gas emissions: the "Very Low Emissions" demand technologies for transport and building, renewable energies, centralized power generation including nuclear power, hydrogen production and CO₂ capture and storage (CCS) options. The whole model thus gives a complete picture of the national and international energy systems, with a description - probably not exhaustive but nevertheless detailed - of the technologies used and taking into account the fundamental mechanisms of dynamic adjustments of supply and demand.

For further details about the model POLES structure, please refer to POLES JRC model documentation (Desprès, Keramidas, et al. 2018).

Next section will present the biomass module and the gas module as those energy carriers are our thesis scope.

1.2. Biomass energy modelling

We find two types of biomass, the first generation gathering food crops and the second generation gathering woody biomass, biomass energy crops and wastes.

For energy valorization in POLES, first generation can be allocated for biofuel production only. This allocation comes after providing the food needs so that there is no competition between these uses and there is not threats about food security.

Second generation of biomass can be allocated for several energetic purpose. There is direct biomass use for heat and electricity production. There is also a gasification process producing biofuels, electricity or heat. Likewise, hydrogen routes from biomass are already represented in the model.

Figure 25 represents the current modeling for biomass uses in POLES at it was before this thesis.

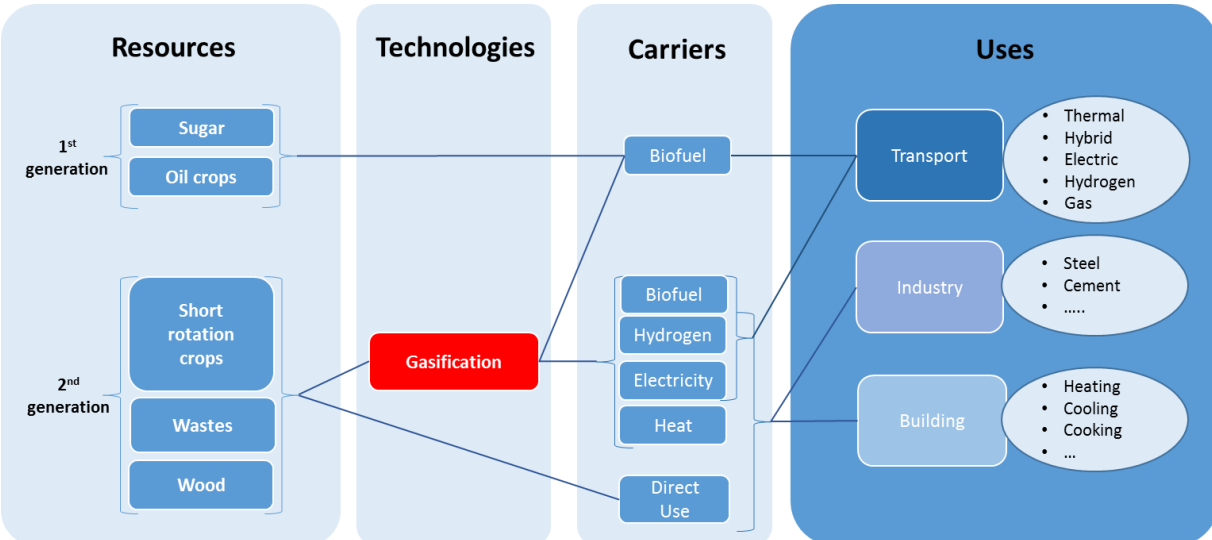


Figure 25 : POLES bioenergy conversion representation in POLES model before green gas module

1.2.1. Biomass potential

First, it is worth noticing that the POLES biomass potentials are exogenous inputs and are given by the Global Biosphere Management Model (GLOBIOM) developed by IIASA (IIASA 2019). GLOBIOM is a database used by several models such as for IEA or E3Mlab energy prospection studies, in order to provide the land use and change, the biomass potential for food or energy, etc. The model distinguishes three primary biomass resource types for energy uses. Each type is associated with an energy potential and a supply cost curve. There are forest residues, short rotation energy crops, and dedicated agriculture energy crops (non-cellulosic) for first-generation liquid biofuels.

Besides, for agriculture crops (used in first-generation liquid biofuels), the energy potential is derived from available area (assumed decreasing share of agricultural areas) and yield. The domestic production of agriculture crops for energy purposes is determined by local needs for first-generation liquid biofuels production. The domestic consumption of cellulosic biomass is determined by needs for all second-generation valorizations possibilities: biofuels, heat, electricity, hydrogen. A competition takes place between this feedstock use cost and the other feedstocks available to fulfil this demand (for example gas, coal, VRE production for electricity) As well, there is some competition between domestic production and imports, comparing the local production cost and the international market price. An international price of cellulosic biomass is derived from the aggregation of regional cost curves. This is also an estimation of urban wastes that build a potential used to produce gas from wastes (Desprès, Keramidas, et al. 2018).

1.2.2. Bioenergy routes

First, the model takes the food requirement to allocate the land use. It takes into account the agricultural, bioenergy and forestry sectors to other land use allocation. There is a detailed modelling with about 20 globally important crops (maize, wheat, cane, beet, etc.), a range of livestock production activities and forestry commodities. It includes also the projection of emissions from land use, land use change and forestry (LULUCF). Data treatment is done to have in input the potential for aggregate types of biomass and the evolution of land allocation in model POLES.

Figure 26 sums up the biomass feedstock feature and its allocation for energy purpose.

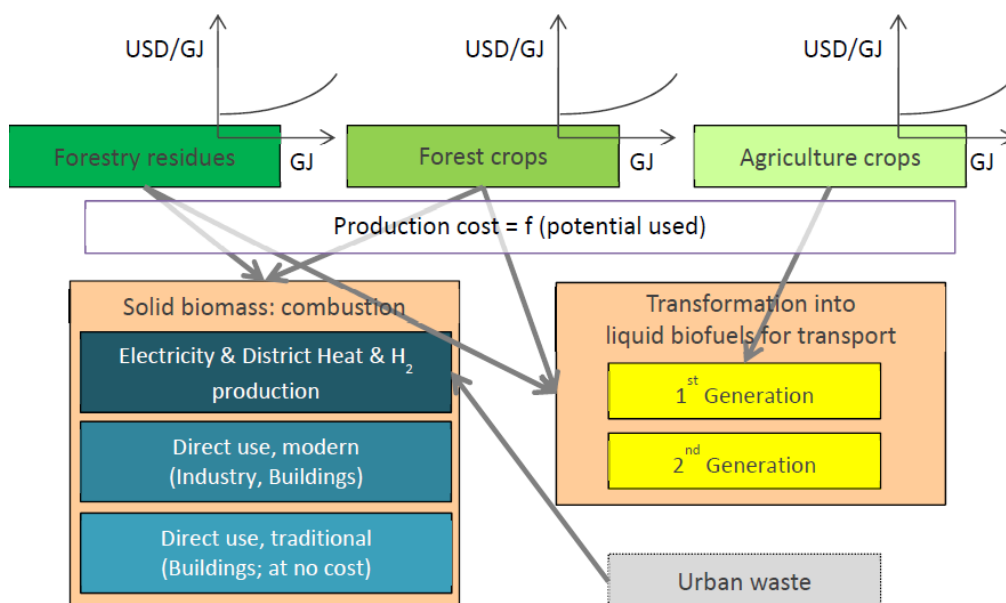


Figure 26 : POLES biomass resource consideration
Taken from (Desprès, Keramidas, et al. 2018)

Bioenergy appears as the adjustment variable in many climate models. It presents other benefits for humans and ecosystems: health of the soil, agricultural productivity, protection of water resources, etc. However, threats are existing. The use of dedicated crops, exclusively intended to be used for energy purpose, would generate conflicts of use by coming to compete with agriculture and food production, so bioenergy agricultural and forestry waste should be privileged rather than dedicated cultures to avoid food security concerns. These same caveats apply to bioenergy with capture and storage CO₂ (BECCS). Yet this technique, which burns biomass to produce energy and then to capture and store the CO₂ emitted by this combustion, raises many hopes because it generates what the experts call "negative emissions". Other said, at the end of the operation, the quantity of CO₂ in the atmosphere is lower to what it was before, because account for the absorbed CO₂ along the growth of the plant before to be burned (IPCC 2014).

2. Overview of the gas system modelling approach

In this section, we will present some energy modelling for gas system. We will compare POLES with other well-known bottom up model: the World Energy Model of IEA and PRIMES used for example by the European Commission to set their prospective scenarios (European Commission).

World Energy Model (WEM)

In the model WEM, gas is provided thanks to fossil resources and the trade market is represented between each region of the world.

Considering the biomass resource, the model uses an external database for the biomass potential for energy purpose that are separated in four feedstock (forestry products, forestry residues, agricultural residues, energy crops). They will meet demand concerning direct use of bioenergy, biofuel production and electricity production in bioenergy power plants, considering also the biomass markets to allocate the resource where it is needed.

The model WEM in 2018 does not consider a particular supply of green gas as a whole. In all these two sections of the model, green gas production and use is not considered as a specific part of gas production (IEA 2018).

PRIMES

The PRIMES model is an energy system model, which simulates energy consumption and the energy supply in Europe. **Figure 27** shows the sources of gas in PRIMES in the left and the uses in the right. In this partial equilibrium model, green gas is considered in the gas production structure. In fact, in the biomass model and for gaseous bio-energy commodities, the model PRIMES differentiates between bio-methane and raw biogas. (Blanco, et al. 2018).

The perimeter concerned in this model is only Europe; that is why the sources on the left are the European gas sources. It shows the different gas sources: the gas coming from the soil and routed by pipelines, LNG gas and synthetic gas. Besides, it adds the self-production and consumption for production countries and storage systems. Concerning the consumption sites, gas can be routed to end use sectors using gas: electricity production, agriculture, commercial, industrial, residential, transport. For transport, it can be used under a LNG form. Gas can also be transformed in hydrogen or liquid fuel. At the end, gas can possibly be stored to be used later.

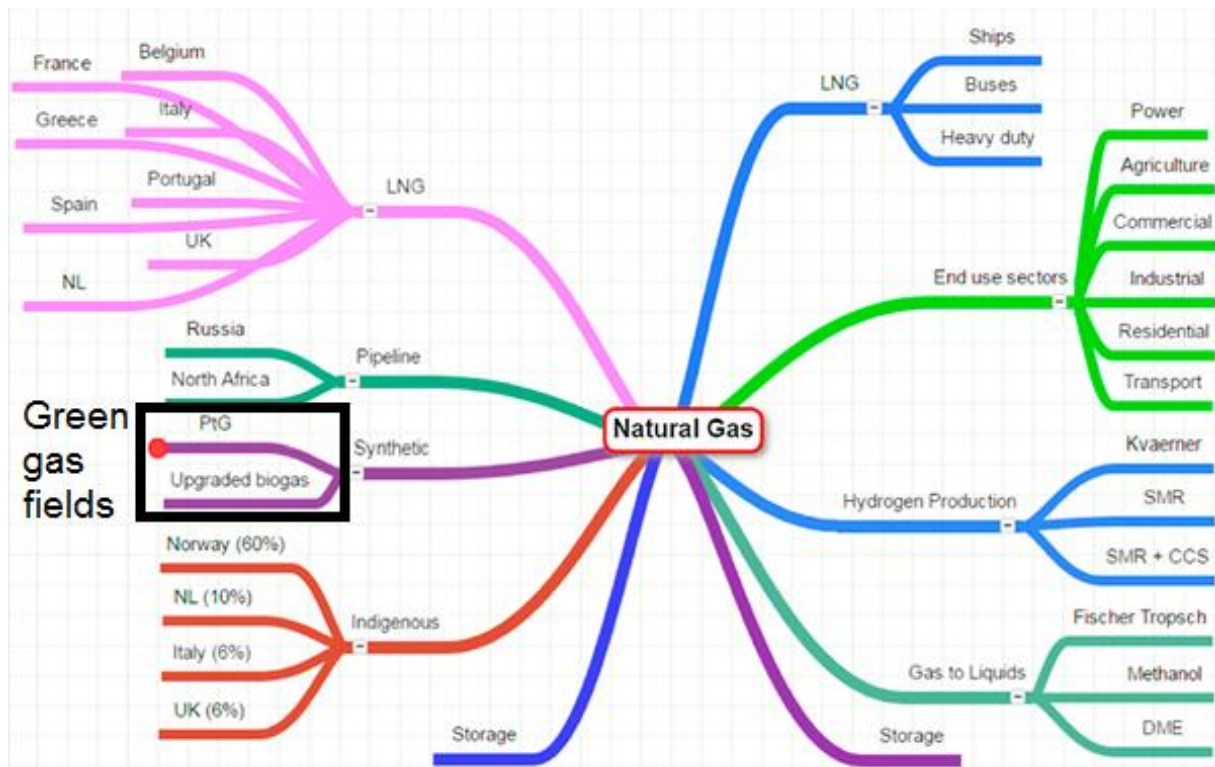


Figure 27 : Gas sources and uses in PRIMES
Adapted from (Blanco, et al. 2018)

Therefore, PRIMES is modelling renewable gas produced by biomass or wastes under the “synthetic” gas form as seen in **table 7**. Then, this gas produced is injected in a common gas network that gather all the gas produced and routed. This network aggregate the different type of gas and melt them. Gas is used in consumption sites without discerning which gas produced is used in each consumption site.

Table 7 : Biomethane production in PRIMES: feedstock and technology

Type of gas	Feedstock	Technology
Gas from wastes	Organic wastes	Methanisation
	Landfill and sewage sludge	
Syngas/biomethane	Woody biomass	Gasification
		Enzymatic hydrolysis

Adapted from (Blanco, et al. 2018)

POLES

The gas modelling is done with a representation of natural gas system with gas trade. A mapping of the reserve is done and countries are qualified as exporters or importers. It includes a representation of the costs in primary energy supply, for both conventional and unconventional resources. Then routes are represented to create flux between production and consumption areas. Then markets are used to have a monetary balance of this gas framework. At the same time, the demand for gas is assessed and matched through price adjustments, region-by-region. The projected demand uses also the level of the price to reach an equilibrium (Desprès, Keramidis, et al. 2018).

Until now, gas supply is not done by renewable sources in model POLES. It will be our contribution to incorporate this in POLES modelling to complete the technological portfolio for energy transition.

3. Green gas energy module in POLES

Several routes are existing using renewable resources (biomass and green electricity) and new technologies (methanisation, gasification and power to gas) to produce methane. This green gas resource has the same properties than natural gas so that they can be melted in pipelines and has to be considered in the modelling.

3.1. General structure

One work of the thesis is to develop a module to take into account the green gas production, injection and use in the modeling that was not the case yet. The aim is to study the contribution of the green gas injected in the gas networks. In this new module, we consider the green gas as an injected gas in the gas network. Whereas previous existing technology such as heat, electricity or cogeneration by biomass combustion or even electricity to electrolysis, this module connects biomass and electricity to the gas vector and network. This module creation is useful because rather than creating a decarbonised end use as biomass cogeneration, it allows to decarbonise gas carrier and the entire gas system by adding renewable sources to feed the gas system.

Hence, we add three green gas production technologies: methanisation, gasification and power to gas to connect directly the resource (biomass or electricity) to the gas carrier supply and the gas network (*figure 28*).

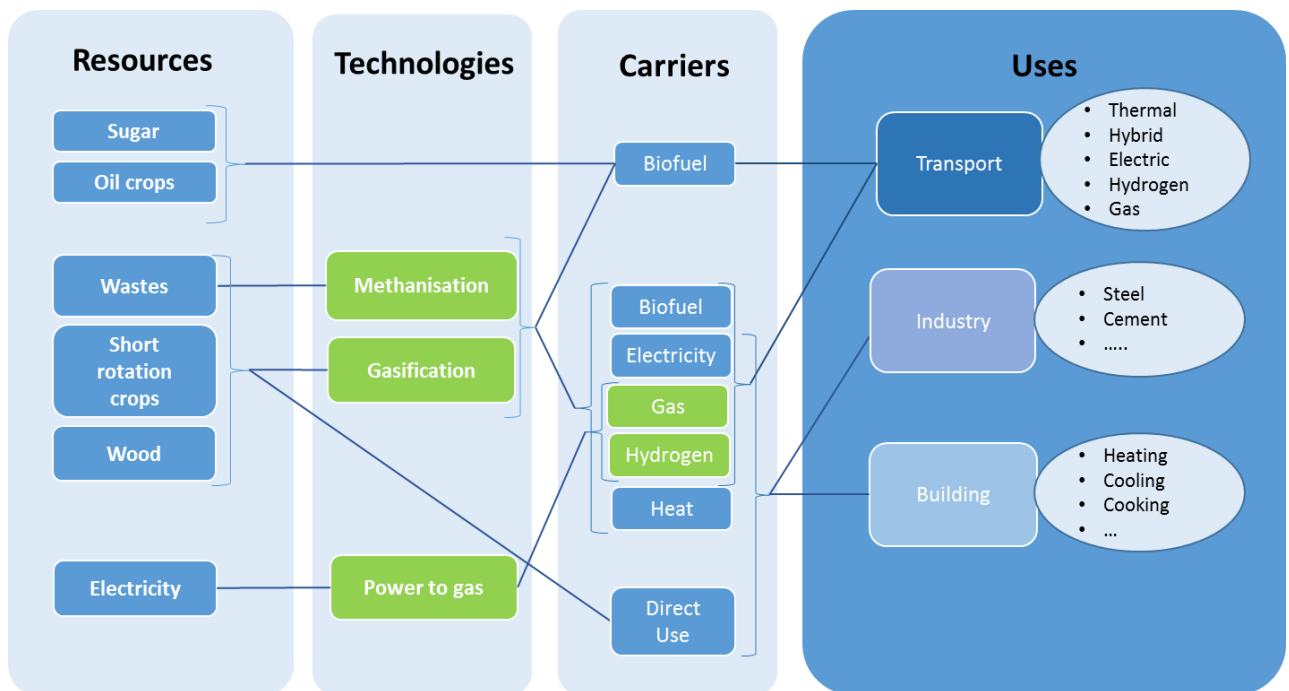


Figure 28: POLES bioenergy model representation with green gas production module

Some assumptions have been made for green gas production module's development, in relation with the literature review done for green gas trends. First, green gas is not traded separately from natural gas. It is assumed that the green gas produced in one country or POLES region is injected in the gas network in the same region (for example renewable gas produced in Germany is injected in German gas network). This modeling represents a business model highlighted for green gas production as a local production, injection and utilization (ADEME 2018). Besides, we consider green gas as priority for gas network injection by the regulation as VRE for electricity (Méthanisation PACA 2020).

Second, following the previous assumption, we do not model new routes for gas network. The green gas produced goes into current network. In order to take the linking cost that exist in reality to connect green gas production factory to the gas network, 3% of additional costs are taken in the technological CAPEX cost to represent injection, connection and grid reinforcement costs, based on (ADEME 2018).

Third, because we wanted to model the injection of green gas in the network, we do not create dedicated green gas sources for off grid consumption. For instance, we do not develop dedicated gas vehicle charging station directly fueled with a dedicated green gas production plant as it is the case in reality for instance in Italy (Maggioni 2017). It would be an improvement to be made in the modeling considering grid and off grid arbitration for green gas when the green gas production business model will be more defined, precised and robust after having feedbacks and return of experience from first green gas projects and demonstrators.

The framework of the module is represented **figure 29**. We mention here the key parameters for green gas consideration in the modeling.

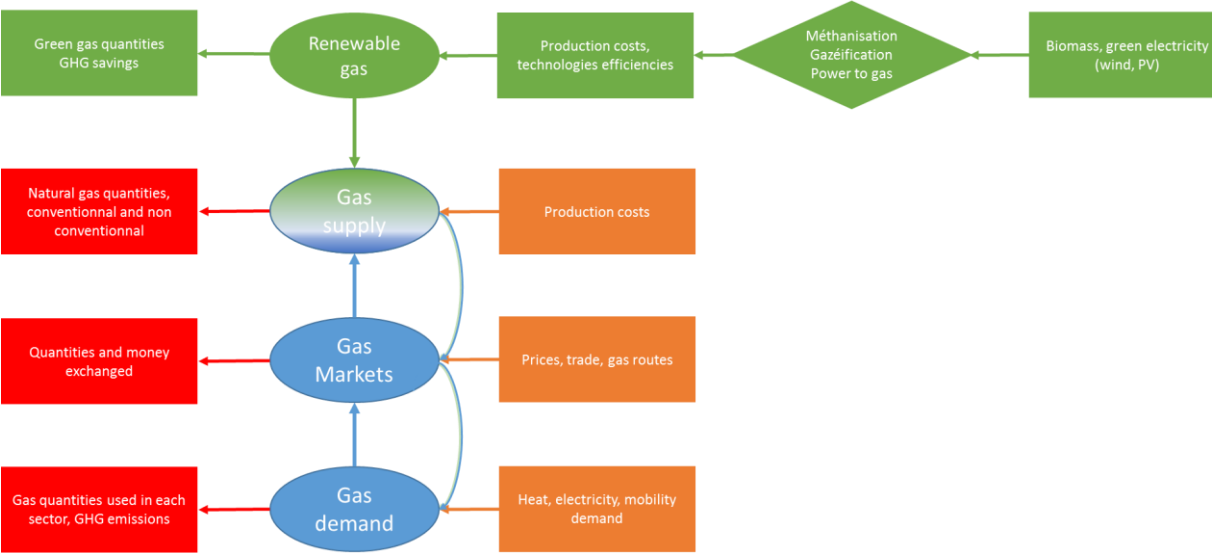


Figure 29 : Gas framework and green gas module incorporation in POLES model

Green gas technologies are defined by the feedstock used (biomass or green electricity in our case), the output of the process (the gas produced and injected in gas networks) and where it is taken into account in the modelling (the total gas production of each country). There are also the technologies' performance standards and load factors and all the costs associated to the construction of the production capacities, the maintenance and fuel costs.

The carbon content of the gas stored in networks will change after green gas production. We take into account that green gas has a lower carbon footprint than fossil gas (see chapter 2), so that the carbon value is decreased in proportion to the amount of green gas in the networks. The higher the ratio of green gas in the networks, the lower the CO₂ footprint of gas consumption would be.

3.2. Detailed code mechanisms

In this section, we will just present the main mechanisms governing the deployment of renewable gas technologies.

3.2.1. Methanisation

Methanisation is a transformation process that transform wastes and biomass in a gas mixture called biogas in digesters through enzymatic reactions (more details in chapter 2). The biogas can be directly burned to produce electricity and heat or can be upgraded in biofuels and biomethane. Biomethane is the valorization pathway we consider in our work.

Until now, there is just an existing technology called **BW**, which transform directly wastes and biomass in electricity. So, a technology transforming agricultural, urban and industrial wastes in biomethane is lacking. We introduce a new one called **BGM** that will transform this feedstock into biomethane.

3.2.2. Gasification

Gasification is a thermal conversion process to transform biomass in a gas mixture called syngas. The syngas can also be directly burned to produce electricity and heat or can be upgraded in biofuels and biomethane.

There are already two technologies representing gasification, **BGA and BGS**. These technologies convert lignocellulosic biomass in electricity. The difference is that the second technology adds a carbon capture and storage device in the gasification process in order to capture and reduce the carbon dioxide emitted in the process. There are also three technologies, BGA, BGS and BPY (biomass pyrolysis) that convert biomass into hydrogen. Then, the hydrogen produced is injected in the hydrogen network. There were no technologies that transform a biomass resource into methane that is comparable with natural gas.

That is why we introduce two technologies called **BGG and BGGs** that represent biomass gasification for gas production and injection. The second, BGGs, means a CCS device added to the gasification technology in order to capture and store the CO₂ produced in the gasification transformation.

3.2.3. Power to gas

Fourteen technologies that produce hydrogen are existing in model POLES. There are especially electrolyzers that produce hydrogen from electricity. There is also a separation between them, where each type of electricity production (solar, wind, nuclear, etc.) is connected with a dedicated electrolyzer. Until now, there is no existing conversion processes that combine this hydrogen produced with carbon dioxide to produce methane in the current modelling. Hence, we orientate a percentage of the hydrogen produced by renewable electricity electrolysis in the methanation process for gas production and injection.

Therefore, we consider only the solar and wind hydrogen production technologies to be dedicated for green gas production in chapter 4. Indeed, an expected business model of power to gas is to valorize electricity surplus produced by variable renewable electricity production systems and store it in gas through the gas network (ADEME 2017). It is subject to debate and we will discuss more in detail the business model of power to gas and the electricity the process takes in input in chapter 5.

3.2.4. Technology modelling

Each technology is defined with several parameters. The following parameters are the key parameters defining these technologies and would be different for each country and each technology. We detail below the variable parameters taken into account in **table 8**.

Table 8 : Parameters taken into account for green gas modelling

Parameters	Variable name	Unit
Investment cost	ACINBG	\$/toe
Technical lifetime	ACLTBG	Years
Installed capacities	ACIPBG	GW
Fixed costs	ACFOBG	\$/toe
Variable O&M costs	ACVOBG	\$/toe
Efficiency	ACEFBG	%

Table 9 sums up the source and origins of the parameters taken into account

Table 9 : Sources for parameters taken into account for green gas modelling

	Potential (energy)	Performances (efficiencies, costs)	Capacities (power)	Production (energy)
Methanisation	Linked to agricultural and industrial wastes	Experts current and projected data Based on demonstrators and return on experience	Determined after comparison between price of gas and green gas production cost and remaining potential	Linked to installed capacities
Gasification	Globiom database for biomass			
Power to methane	Electrolysis installed power			

3.2.5. Technology development

The development of each technology is determined thanks to two main arbitrations.

The first condition is the respect of the maximum potential available for the resource: the technology cannot develop at higher level than the potential useable for this technology. The second condition for green gas technologies development is linked with their production costs compared with the natural gas price. Indeed, there is an incentive to produce green gas only when its production cost is below the price of gas with a carbon tax.

The expected power of installed capacities for green gas production year after year is determined endogeneously and is driven by these two conditions. Therefore, the development rate for green gas technologies is calculated in function of the natural gas price/green gas production cost ratio and the ratio between the potential used and the total potential. The expected power for each year takes the installed power the year before, which is multiplied by a coefficient mixing remaining potential and cost comparison.

Hence, if one of the two conditions is not respected, green gas technology will not develop. In the favorable case, there is still the growth rate to set. This speed is driven by two drivers: the bigger the

spread between gas price and green gas production cost, the faster the development of green gas is. As well, the more potential is remaining, the faster the development of these technologies is.

4. Database structure

The new green gas module need a detailed database covering the exogenous variables like the potential of biomass for gasification and methanisation, the costs and the performances of each technology. Exogenous parameters have to be assessed for the future too, like the green gas potential in the future and the evolution of costs and performances according to experts' estimations.

Endogenous database concerns the past and current green gas production, capacities installed, costs and performances.

4.1. Green gas production

We collected data for the past and actual biomethane production to calibrate the model. We succeed in collecting the data for Europe (see chapter 2). We set also the current costs found in the literature for the technologies. The detailed remaining data are lacking so we extrapolate the global data found for the rest of the world and split this quantity for the countries contributing to green gas production.

4.2. Resource potentials and marginal costs

For the potential of biomethane from gasification, we consider the potential as the lignocellulosic biomass and the biomass planted for energetic purpose. This is already modelled in POLES and named second generation. Therefore, we consider this potential as the potential for biomethane production (see **figure 28** for the structure of bioenergy modelling). The cost for this resource in function of quantity used is also modelled (see **figure 26**), so that the evolution of cost according to the quantity of resource used is considered.

For the potential of biomethane from methanisation, we cannot take the same methodology to build the potential: the resource used in methanisation is not considered in the biomass modelling in POLES because this modelling do not gather the agricultural, urban and industrial wastes. Agricultural crops are modelled but these are those dedicated for food and biofuel production only: wastes are not taken into account. As the resource used for methanisation is agricultural and industrial wastes, we built a potential following the agricultural, industrial economic activity. To set the starting point, we consider the past and current raw biogas production as the all biomethane production potential for the main countries in Europe for which data are available and reliable. This is relevant because biomethane is a possible output after a biogas production, so that biomethane production is limited by the entire biogas production. For the other countries, we take as the biomethane potential a percentage of second generation biomass that correspond to the average percentage (15%) between methanisation potential and second generation biomass potential in calibrated countries in Europe. This percentage corresponds to the average ratio between biomethane potential and second generation biomass potential for the calibrated countries with biogas production. After setting the past and current potential, there is the potential to set for the future. The potential for the following year takes the potential of the previous year multiplied by the economic growth for these sectors. Hence, the potential grows and follow the sectoral growth for each region of the model. The marginal cost for the call of the methanisation resource is linked with the marginal cost for second generation biomass, so that we assume that marginal cost for methanisation potential follow this one's.

For the potential of biomethane from power to gas, the potential is represented by the hydrogen produced from green electricity electrolysis. We have already this production represented in POLES so that we have just to connect the biomethane production as a following process of VRE electrolysis. Therefore, the cost of potential is the marginal cost of the hydrogen produced by electrolysis and is already modelled.

4.3. Technological costs and performances

One hypothesis we take for the database construction is that the performance and costs parameters are uniform for all countries. That means that we take the same evolution and development for the technologies for all the regions in the world. In reality, this is not completely true because technologies progress are spreading between and among countries with a certain delay. Indeed, some things are slowing the progress diffusion as the accessibility to the technologies in some areas, the presence of political regulatory restrictions or some lack of funding that do not allow the technology spread everywhere in the same schedule. As well, there are noticeable differences in work cost in the world, so that O&M costs would vary between world regions (World Bank 2008).

The performances evolution follows the trends already mentioned in the presentation in chapter 2. One hypothesis we make is that the variable O&M cost do not vary through time, as there is still the same operational needs. As the OPEX cost for the resource is the cost considered in last section, there is just the CAPEX variation remaining.

Because it is still well developed, methanisation will not know large costs improvements. We assumed that around another third of the current cost could still be won in methanisation installations until 2050. Concerning gasification, a decrease of two third can be reached until 2060. Moreover, considering power to gas, a decrease of three quarter can be reached until 2060. This variation is estimated linear between 2020 and 2050 or 2060 for all of these technologies to spread the costs gains for each year. After these milestones, the costs are considered constant, as progress should be limited after this time. Projections are very difficult to foresee for this distant timescale concerning the future of actual technologies and even other technological innovations and breakthrough.

All the figures of green gas production, feedstock potentials and technological characteristics are detailed in chapter 2. **Appendix 3** represents this database for historical green gas production.

5. Scenarios considered

In order to analyze the role of the green gas in the decarbonisation of the energy system, the dynamics of the green gas production and the corresponding uses, as well as the linkages between gas and electricity energy carriers, we build and study different scenarios.

5.1. Climate policies scenarios

We carry out some energy scenarios that span across the XXIst century where long-term effects are depicted. These scenarios are defined according to different political energy strategies that lead to different energy uses and energy mixes and their relative carbon emissions. The scenarios study the sensitivity to several parameters. We propose two main scenarios dealing with the implementation of climate policies.

The first one is the “baseline” one. This scenario is built for comparison used as the starting point for a comparison and projection exercise. It would explain how the current situation would evolve without

additional public intervention. It is the 'no policy change' scenario driving to a +4/5°C warming. The other is a climate constraint scenario introducing a carbon value. The carbon value is a proxy of the cost of all efforts needed to be done by the energy sector. We have chosen a 2°C scenario that translates the application of climate policies aiming at limiting global warming under 2°C in 2100, which is more stringent for CO₂ releases. The goal is to respect the associated carbon budget of 810GtCO_{2eq} releases between 2017 and 2100 while the carbon budget reaches 3000 GtCO_{2eq} in the baseline scenario (I4CE et Ministère de la transition écologique et solidaire 2019). In 2°C scenario, a carbon tax is introduced so that prices are higher for energies that release GHG such as coal, oil or gas and their derivatives: gasoline, fuels, coke, etc. Hence, unlike fossil fuels, cleaner technologies that do not release GHG are becoming competitive against fossil derivatives products and are fostered and their development speeded up.

It is worth noticing that we do not consider a 1,5°C scenario although it is the objective in Paris climate accord (The United Nations 2015). Indeed, already studied by integrated assessment models, 1,5°C cannot be reached but with strong and very ambitious hypothesis. Among the few successful scenarios reaching a 1,5°C limitation at the end century, knowing that we are already at 0,9°C warming in 2019 (see **figure 2** in chapter 1), it would require a rapid shift from fossils fuels, a quick and huge reduction of energy consumption and a large spread of CCS technologies that are still currently in development and still not price affordable. A carbon tax should be also very high with a strong growth in the coming year, higher than the law written evolution in France⁵. It deals also with the problem of social acceptance of such a sharp and quick change of paradigm for energy consumption. The place of social science is required to study this kind of scenario, something that is not modelled and studied in POLES. Besides, some experts declares that because of global warming inertia and the long-time global warming effect of GHG, a +1,5°C world is unavoidable in the coming years (B&L évolution 2018). Moreover, the tendencies and sensitivity analysis we want to analyse would be biased considering the 1,5°C scenario because of the large energy consumption reduction need, so that energy mix are not very comparable because of huge difference in energy mixes (Rogelj et al. 2018).

They are some limitations using this methodology. First, world population, growth domestic products, coal, oil and gas reserves and biomass potential come from others databases, so are taken into account exogenously in our scenarios. Besides, they will not vary for all scenarios. This is a strong hypothesis and a limitation in our study because, in reality, the GDP (and to a lesser extend the world population) should vary in the presence or not of climates policies because they change the economic and social paradigm. Furthermore, the world characteristics in a +1,5°C, +2°C, +3°C, +5°C or +8°C warming should be very different and drives to unpredictable side effects with unexpected or unforeseeable feedback loops on these parameters and are very tricky to incorporate in a global energy model.

5.2. Technological scenarios

A strength of the POLES modelling is the separation of the biomass valorisation technologies, so that we are able to determine the penetration rate of methanisation and biomass gasification through the XXIst century. Hence, we will implement some sensitivities about the technological progress of green gas technologies.

⁵ The carbon value should be 30,5 € in 2017, 44,6 € in 2018, 55 € in 2019, 65,4 € in 2020 and 100 € in 2030. Besides, following the yellow vest social movement in the fall of 2018, the French Government decided to preserve the purchasing power of households by freezing, in 2019 and 2020, the tax rates for 2018 (IDDRI 2019).

5.2.1. Technical and costs progress

Even if we can find raw figures from experts that determine the expected progress, many uncertainties are remaining about the development and the industrialisation of these technologies. Therefore, it is worth considering different patterns for technologies development in particular for gasification and power to gas, which are still in early step of TRL (see chapter 2) and whose current implementation is only in the stage of demonstration. Experimentations and return of experience are still awaited to recognize and set possible costs and performances for the future.

Anyway, in our study, we will take the range of the experts forecast and we will do an analysis with the more ambitious and the less ambitious performances and costs in the future for these technologies. Hence, we consider the actual costs assessment for each of the technologies for our reference case as already presented chapter 2 **figure 16**. After setting these initials values, progress are expected and would follow the figures set in section 4.3. Then, these costs are considered unchanged between 2060 and 2100 where visibility is lacking about energy landscape. Future development and/or other technological push is almost impossible to foresee. We consider a pessimistic scenario where actual costs are projected unchanged through all the century. We consider also an optimistic scenario where costs evolution and reduction is 2 times more ambitious than projected today.

5.2.2. Political incentives

In this section, we will deal with the political measures taken to help the development of green gas technologies. Indeed, there are current frameworks that help the technologies development. The two main measures are, first, subsidies allocated to biomethane projects owners in order to decrease the investment cost of the installation for the operator and, second, feed in tariffs to guarantee a price for the energy production that allow the operator to meet its costs without any market trouble.

In our study, we will implement different subsidies and feed in tariff to see the influence of those parameters on the green gas technologies spread. The reference case is the absence of any subsidy and feed in tariff so that there is only a market arbitration between green gas and fossil gas based on production costs and market prices. The second political incentive scenario is the setting up of subsidies and feed in tariffs that makes current projects competitive against natural gas (with considering the carbon tax), as it is the case for current projects development (see chapter 2). These subsidies and feed in tariffs are progressively phased out when green gas technologies costs decrease and are stopped when these costs become lower than natural gas price. This is the objective of this kind of measures: putting subsidies to launch the field, expecting development and progress and then be competitive without any help (Ministère de la transition écologique et solidaire 2020).

5.3. The importance of CCS

Last, the “classic” 2°C scenario is divided in two declinations, one with CCS technology and the other without. CCS can be put on coal, gas and biomass power plants. The future of CCS deployment is the key parameter developing widely or not bioenergy or gas plants for decarbonisation: “All pathways that limit global warming to 1.5C with limited or no overshoot project the use of Carbon Dioxide Removal (CDR) on the order of 100-1,000GtCO₂ over the XXIst century” (IPCC 2018). In particular, biomass and gas based electricity can manage the power system and be a source of negative emissions (Cloete et Hirth 2019) (Johansson, Lehtveer et Göransson 2018). However, doubts remain about the economical profitability of CCS deployment and because of concerns about CO₂ storage sites feasibility,

technologies costs and real potential and scale of implementation. Negative emissions technologies face other challenges as the acceptability concerns from populations. Moreover, low fossil fuels prices, the relative failure of CO₂ quota markets in the 2010s, local legislation, etc. do not send incentives for CCS development (Fuss, et al. 2016). Currently, CCS costs need to be lowered substantially or carbon prices have to increase by at least ten times, in order to bridge the economical gap to ramp up CCS deployment.

5.4. Summary

Table 10 summarizes the scenarios considered in our work, with the scenarios characteristics and the parameters in stake

Table 10 : POLES scenarios for green gas production analysis

Scenario	Characteristics	Parameters modified
Baseline	2015 situation of climate policies without expected change used as the starting point in our projection and comparison exercise.	
2°C	Application of climate policies aiming at limiting global warming under 2°C in 2100 Experts projection for green gas technologies development	Carbon taxation
2°C scenario + ambitious technological progress = 2°C ambitious	More ambitious costs reduction for green gas production energy	Green gas technologies costs and performances
2°C scenario + unambitious technological progress = 2°C unambitious	No costs reduction for green gas production energy compared for today	Green gas technologies costs and performances
2°C scenario + political subsidies = 2°C subsidies	Subsidies and feed-in-tariffs are allocated to green gas production technologies to make them currently competitive with natural gas prices	Green gas technologies costs
2°C + no possibility to use CCS technologies = 2°C no CCS	Expected failure in CCS technology development and spread	CCS technologies progress

Our analysis will focus mainly for the European scope. Even if we will present some generic graphs to have an idea about the world trends for green gas development and mechanism involved, many precise data are lacking outside Europe, so that a deep analysis about green gas production and consumption, country by country is not very relevant.

Chapter 4: Green gas in sectoral decarbonisation

Energy uses can be gathered in few categories as they answer different needs: to move, to heat, to light, etc. These uses occur in different perimeters: the residential and tertiary sectors, the transportation sector, the industrial sector, the agricultural sector and other consumptions like energy sector auto consumption where energy is consumed in processes in order to extract or produce energy.

It is worth here reminding the differences between primary and secondary energy sources. Primary energy resources are those found in nature, including the fossil fuels (petroleum, natural gas, and coal), uranium, wind, water, sun and biomass. Secondary energy resources are those forms that must be produced by conversion of primary resources, and includes gasoline and liquid fuels, refined biofuels, electricity, hydrogen, and heat. We call it also energy vectors or energy carriers because they are produced from several primary resources and allow to satisfy all the final uses of energy for social and economic development. Final energy might also be different as it is the energy consumed in uses. For instance, electricity is an intermediate energy carrier because it cannot be found like this on Earth (except from storms and thunderbolts but is very difficult to collect and reuse after). Therefore, electricity is seen as a secondary energy, which can be consumed in many sectors (IEA 2017). Among this energetic landscape, gas is special as it is both a primary source of energy extracted from the Earth (conventional and unconventional fossil gas), a secondary energy that can be produced by chemical, thermic or enzymatic transformations and then transported and used elsewhere.

Figure 30 shows world final energy consumption by sector and by fuel in 2017. Transportation, buildings and industry represents each around 30% of total energy consumption and other sectors the 10% remaining. In parallel, we notice that this energy is still mainly due to fossil for about 70%, and electricity, which is mainly produced by fossils fuels too, around 65% (see chapter 5). Therefore, decarbonisation of energy final consumption represents a big challenge.

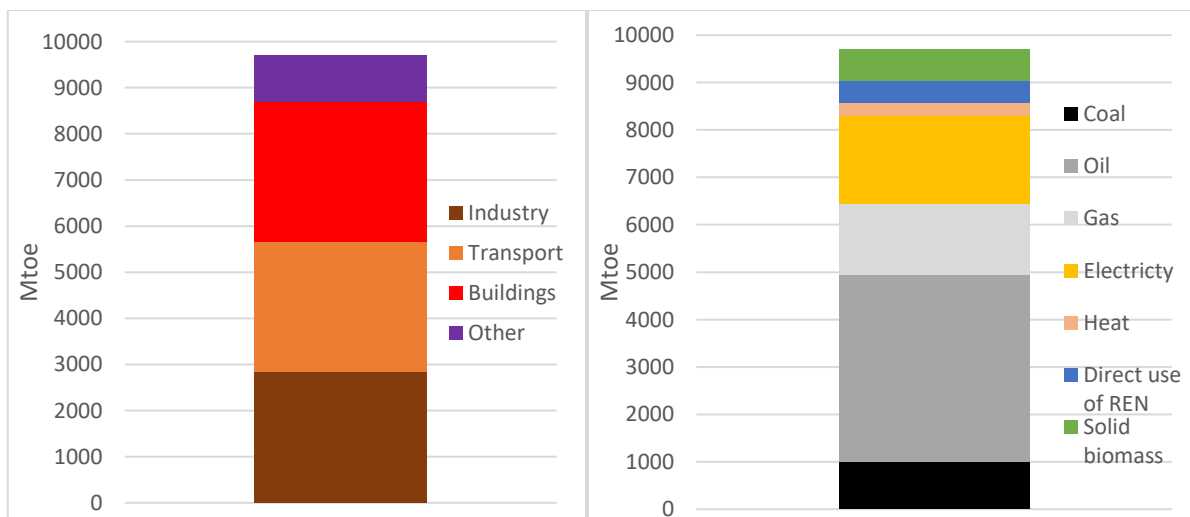


Figure 30 : World final energy consumption represented according to POLES sectors and fuels in 2017
Data from (IEA 2019)

Figure 31 presents the evolutions of the relative CO₂ emissions by sector over XXIst century as simulated with POLES. Emissions grow for the world and stagnate for Europe in a baseline scenario

because energy consumption is expected to grow in parallel of GDP growth, but this tendency is more limited in Europe. In climate policies scenarios, emissions peaked in 2020 and decrease to reach almost carbon neutrality in Europe in the second part of the century. All sectors goes toward a more or less complete decarbonisation compared to a reference case. These trajectories can be reach by following several decarbonisation paths, among it the gas consumption and its greening.

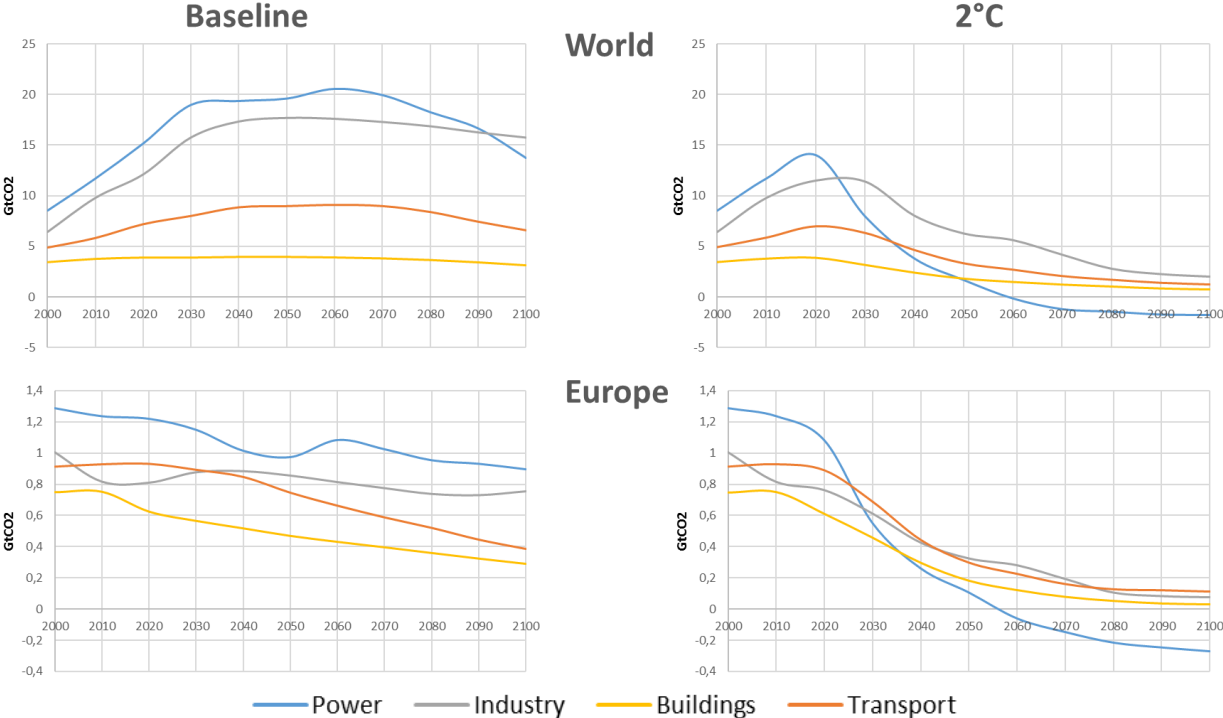


Figure 31 : World and European CO₂ emissions Scenarios baseline and 2°C POLES-GAEL

As seen in chapter 2 section 1, gas can be used to fulfil many energetic needs. It is possible to heat residential and tertiary buildings, as industrial furnaces or boilers. It is also a raw material for chemistry, for example to produce hydrogen and ammonia. Gas represents about a quarter of residential energy consumption, principally as a heat provider. Likewise, it represents a quarter of industrial energy consumption. Gas supplies about a quarter of the world's electricity. Finally, it is marginally used in transport as in Natural Gas Vehicle (NGV).

Gas consumption could know an increase in several sectors and green gas would help decarbonizing these fields. We will see in this chapter how the renewable gas field change the gas consumption pattern and how it plays a role in uses' decarbonisation in the future by implementing the methodology and the scenarios presented in the chapter 3. The advantage of using POLES model with green gas production module is that the regional differences can be highlighted. We divide the analysis as follow.

First, the decarbonisation of gas production will be presented. We will compare the climate and non-climate constrained scenarios (scenarios 2°C and baseline) for world and Europe macro tendencies, whose trends are quite different. Then, we will detail the green gas production pattern for four main countries in Europe for which data and calibration are robust: France, Germany, Italy and Great Britain to highlight regional specificities and differences in green gas production. Last, we will deal with the sensitivities implemented about technological progress, political incentives and CCS development for Europe to see the influence of these parameters on green gas development.

Second, a focus for each final consumption sectors, transportation, buildings, industry and agriculture is done for European scope. The quantification of gas and green gas in the decarbonisation of these sectors would be assessed.

1. Increasing green gas in the gas supply

1.1. Main features of the gas supply

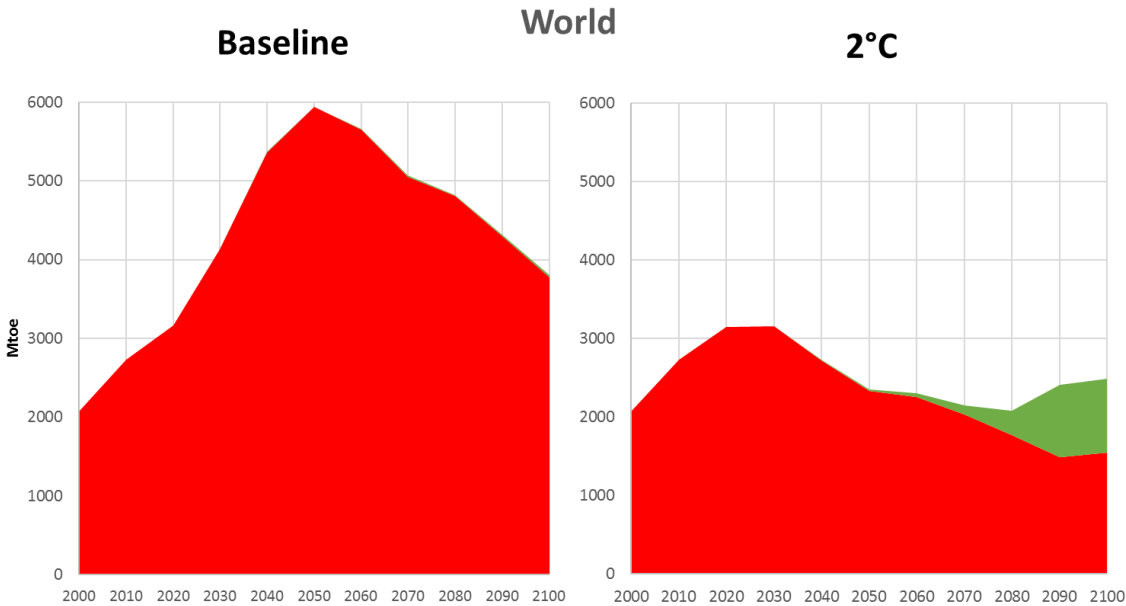
First, we will study the gas and green gas production scope between baseline and 2°C scenarios in order to compare the impact of climate policies implementation.

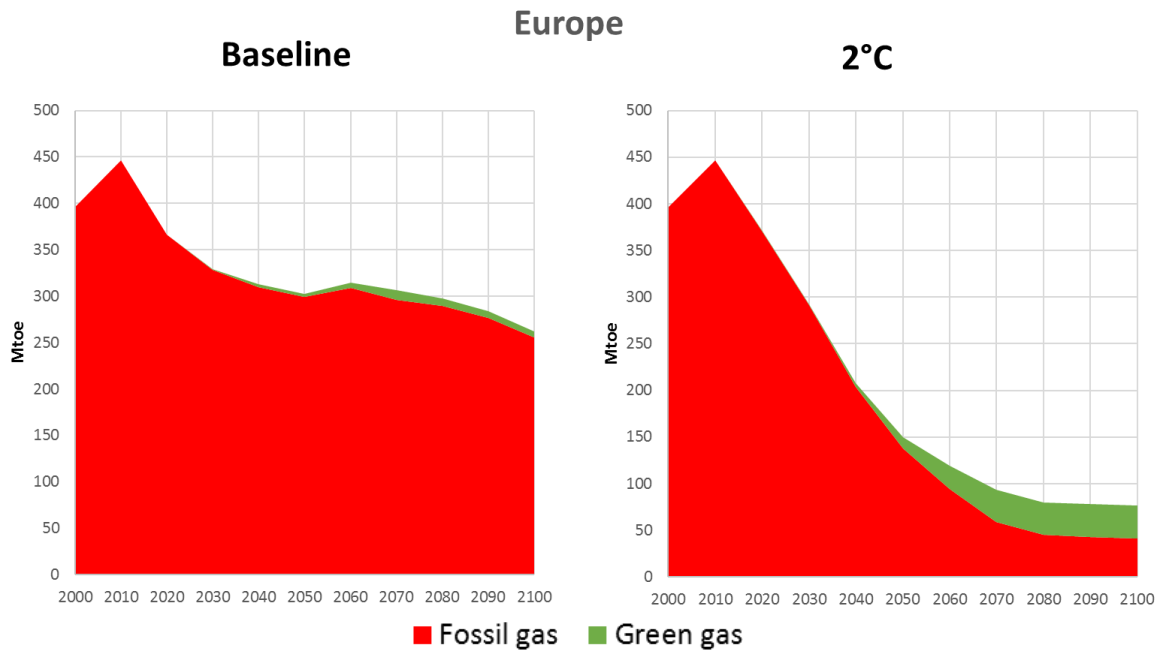
1.1.1. Gas supply decarbonisation

Figure 32 shows the gas consumption and green gas production for world and Europe for scenario baseline and 2°C simulated with POLES model with green gas production module.

In the baseline scenario, world gas consumption raises until 2040, and decreases in the second part of the century by 30%. Green gas production is almost inexistent because of the availability of conventional resources and because the cost of natural gas remains cheaper than the one of green gas production so that green gas fields will not develop without subsidies. In climate policies scenarios, unlike in baseline, the total use of gas will not grow and decreases after 2025. The total use of gas increases a bit at the end of the century thanks to a growing green gas production that will reach around 40% of total gas consumption in 2100 according to the modelling done.

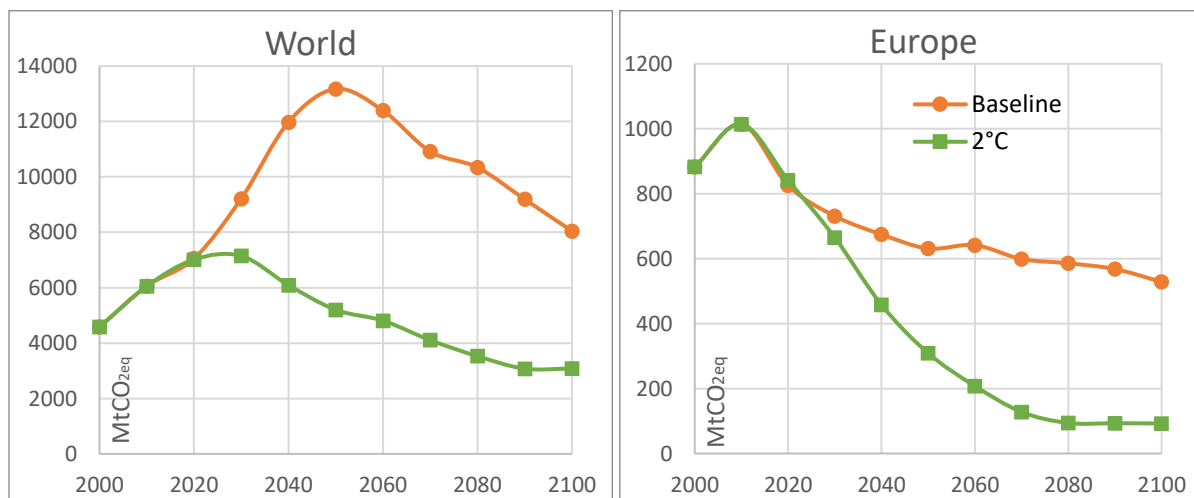
Consumption trends are different for Europe, where gas consumption should decrease for both scenarios by 30% between 2020 and 2100 in baseline, but much more strongly in the 2°C scenario with a 80% decrease between 2020 and 2100. This macro tendency can be partly explained thanks to the population and GDP growths that are more limited compared to other continents. There are also huge efforts made for energy sobriety and efficiency meeting the first decarbonisation pillar objectives. Hence, the energy needs, growth are lower than world’s evolution. Besides, as at the world scale, green gas production share develops noticeably only in the 2°C scenario as at the world scale, and represent around half of the gas consumption at the end of the century.





**Figure 32 : World and Europe gas and green gas production
Scenarios baseline and 2°C POLES-GAEL**

Figure 33 shows the GHG emissions from gas use. Between those two scenarios, there are around two third emissions reduction in 2050 at the world scale from gas combustion that represent 8 GtCO₂. For Europe, the difference raises 60% and a reduction of 300 MtCO_{2eq} in 2°C scenario compared to baseline. This difference may be mainly due to the effects of first decarbonisation pillar with sobriety and efficiencies measures as overall gas consumption decrease noticeably in 2°C scenario compared to baseline with a reduction of 3500 Mtoe in the world consumption and 150 Mtoe in Europe (**figure 32**). In 2100, although there is approximately the same gas consumption in world than in 2050 in 2°C scenario, the emissions are decreased for almost 2 GtCO_{2eq} thanks to the development of green gas to replace natural gas, making echo to pillar 2 of decarbonisation that is the decarbonisation of the energy carrier. For Europe, emissions are decreased by 400 MtCO_{2eq} in 2100 that are 20% of European emissions nowadays.



**Figure 33 : World and Europe GHG emissions by gas
Scenarios baseline and 2°C POLES-GAEL**

Green gas contribution can be also seen for the world perimeter where total gas consumption is more or less the same in 2100 compared to 2100, but emissions from gas are 30% lower. In the last two decades of the century, green gas production allows an increase of total gas consumption even with carbon taxations that penalize traditional natural gas uses. These estimations concerning CO₂ emissions by gas consumption are coherent with (Koorneef, et al. 2013), who estimates that the use of biomethane with a 2°C warming objective could avoid around 8GtCO₂ emissions in 2050 worldwide.

1.1.2. Technology competition for green gas production

In a second time, we compare the green gas production by technology: methanisation, gasification, gasification with CCS and power to gas. We will present here only the graphs for scenario 2°C as green gas penetration is almost absent in baseline one.

Figure 34 shows the green gas production mix by technology for world and Europe.

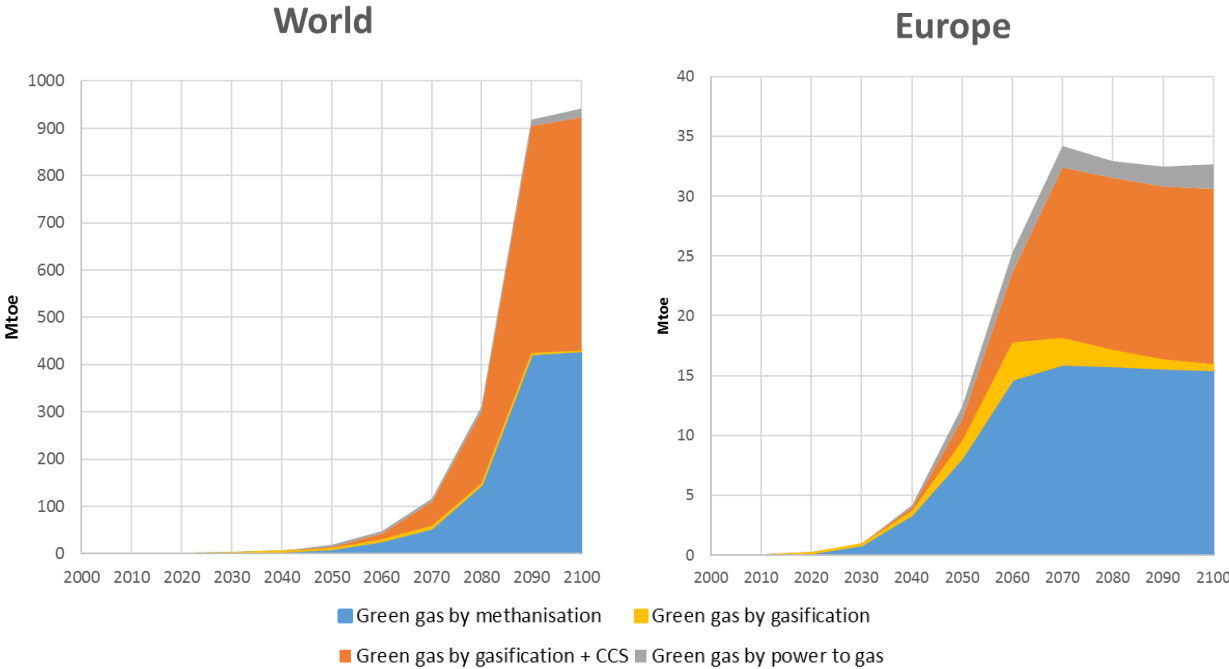


Figure 34 : World and Europe green gas production by technology Scenario 2°C POLES-GAEL

World biomethane penetration depends on local resource potential and on global technology maturities and cost effectiveness. Therefore, methanisation develops earlier than gasification because the process is already industrialized since the early 2010s and quite developed nowadays. Nevertheless, gasification catches up methanisation thanks to a high resource potential and process progress expected in R&D. It is also scalable to higher level, so that gasification makes use of economies of scale. Hence, it will be used at the same order of magnitude in the second part of the century and even more in the presence of competitive CCS, which are in development stages today, to reach higher emissions cuts. Last but not least, power to gas would know a very slight development because costs and performances remain too high. This technology is not competitive and do not penetrate for green gas production. A deeper analysis of power to gas will be done in chapter 5. Hence, green gas from biomass represents the majority in green gas production mix.

For Europe, the increase in biomethane production follows this same rule of competitiveness for biomethane production cost compared to natural gas prices. However, there is a stagnation and small reduction at the end of the century for biomethane production because (and it will be illustrated next section) the second limitation for the technologies development is reached: the limitations in available potentials.

1.1.3. Resource competition for green gas production

In this section, we consider the biomass as the resource used for bioenergy purpose. As a reminder, food requirements are assumed already matched when calculating the potential remaining dedicated to bioenergy (IIASA 2019). Arbitration of biomass energy allocation and use are presented in **figure 35**. We gather here the potentials that can be dedicated to methanisation and gasification (see chapter 3 section 4.2.)

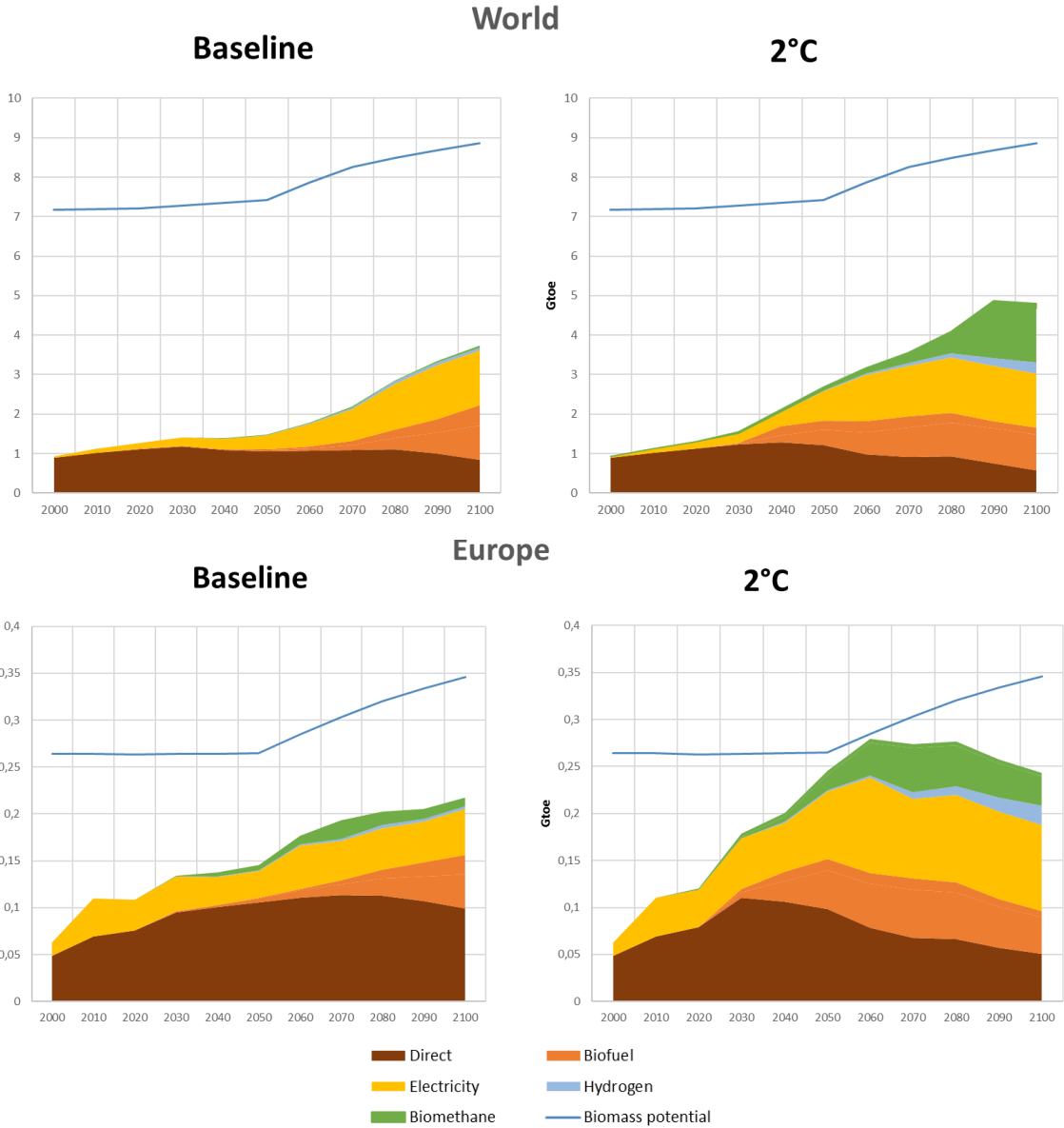


Figure 35 : World and European bioenergy allocation and biomass potential Scenarios baseline and 2°C POLES-GAEL

We see that the world biomass potential for bioenergy is more used in 2°C scenario compared to baseline. The total bioenergy potential is used at 33% in 2050 and 55% in 2100 compared to 20% and 40% in the baseline. Indeed, there would be fuel switch where bioenergy would replace fossil fuels consumption in the presence of climate policies for decarbonisation purposes following the pillar two of decarbonisation.

Hence, the allocation of biomass is different. We see a drop after a small increase until 2035 in direct valorization that represent a relatively low efficient bioenergy valorization in heat. This feedstock is used in the 2020s to decarbonise heat for example. Then, new vectors will arise. Biomass valorization in electricity and biofuel will develop massively from 2025. It can be explained because these energy carriers represent decarbonised vectors to meet the second decarbonisation pillar that is the fuel switch. After, we see a raise in green gas production after 2035. Last, we see a slight development of hydrogen production from biomass after 2060.

To sum up, biomass would substitute other fossil fuels to produce heat, electricity, fuels and to answer some gas needs. Therefore, the development of green gas from green electricity via power to gas is also marginal because the “green hydrogen” remains too expensive in comparison with gas price and other hydrogen sources.

Moreover, we notice that the biomass consumption in Europe in scenario 2°C do not increase after 2050 while the potential increases. It is likely due to the limitation of global energy consumption in Europe in the second part of the century thanks to higher effort made in sobriety and efficiency in the first pillar of decarbonisation presented in chapter 1.

Next, we present these four European countries green gas trends for which we have some historical data to see regional patterns for biomethane development.

1.2. Regional specificities for green gas production

Here we still study differences for 2°C scenario for four European countries: France, Germany, Great Britain and Italy.

Figure 36 shows the gas consumption and green gas production for these 4 countries. First, we note that for all those countries as all other European countries, gas consumption decreases very strongly through XXIst century in a climate policy scenario. It is interesting to note that for all countries except for France, green gas is almost not produced, except for France. How can it be explained? Being in the same gas market and having assumed the same technological costs evolution, there is no differences between these four countries in terms of gas market prices or CO₂ taxes.

However, the difference can be explained by the biomass consumption represented **figure 37**. Indeed, we considered that bioenergy can be allocated to green gas production only if there is a remaining local potential. This rule comes from our modelling based on the business model of green gas production that is the use of local (and not traded) resource (see chapter 3), even if biomass importation is allowed to fulfil the other energetic needs. This hypothesis translates an expected local resource valorization for green gas production. All in all, we see that there is only a remaining potential in France after 2030, so that green gas is produced only in France. Other countries as Italy or Germany would probably meet their climate objectives with biomass by dedicating the resource even imported if needed in electricity or hydrogen at the end of the century.

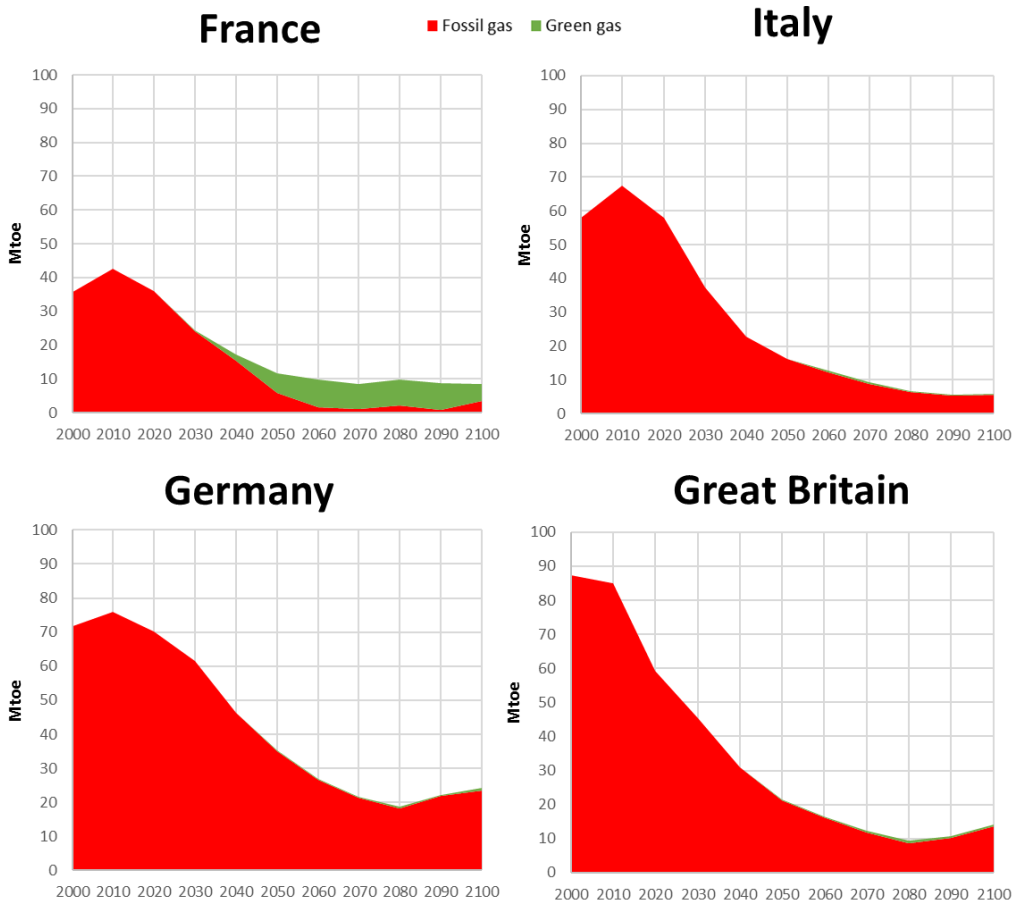


Figure 36 : France, Italy, Germany and the United Kingdom gas consumption and green gas production Scenario 2°C POLES-GAEL

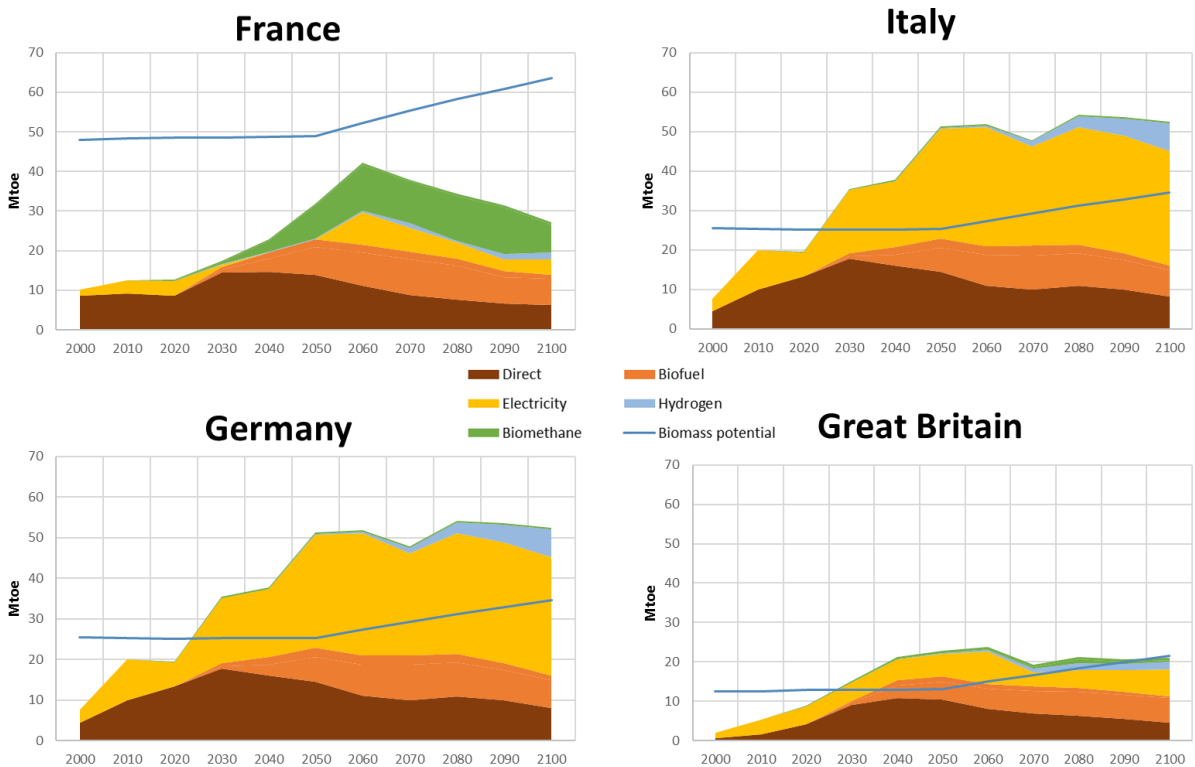


Figure 37 : France, Italy, Germany and the United Kingdom bioenergy allocation Scenario 2°C POLES-GAEL

Figure 38 represents the average green gas production cost and the gas price with carbon tax in scenario 2°C for France, Italy, Germany and Great Britain. It allows us to explain why and when the green gas production increases: after 2030 in France and a bit after 2070 in Great Britain. In our model, green gas is expected to produce as soon as green gas production cost is lower than natural gas with the carbon tax. Graphically, it is seen when the dots curves undertake the full line curve representing European market price for gas. At these points, swings can occur because of an increase in natural gas price and a decrease in gas production costs technologies. Green gas production cost is increasing because of the cost of biomass that increases when the available potential is shrinking. That is why in countries where bioenergy potential is saturated, the price of biomass is high, so that the average technological production cost is not overtook by gas price and do not allow technological penetration.

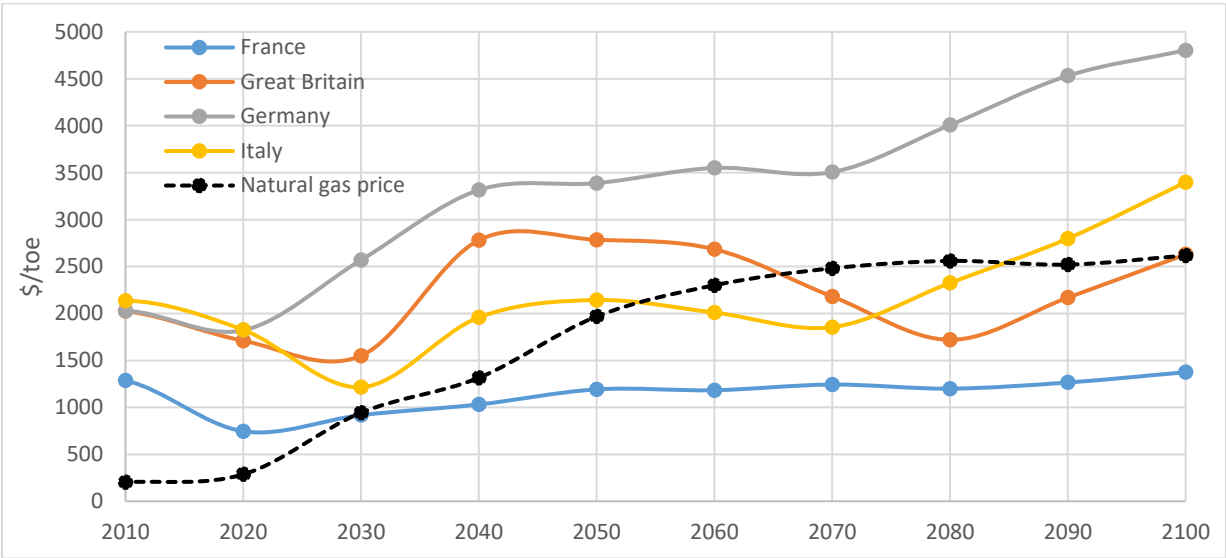


Figure 38 : average green gas production cost and natural gas price with carbon tax Scenario 2°C POLES-GAEL

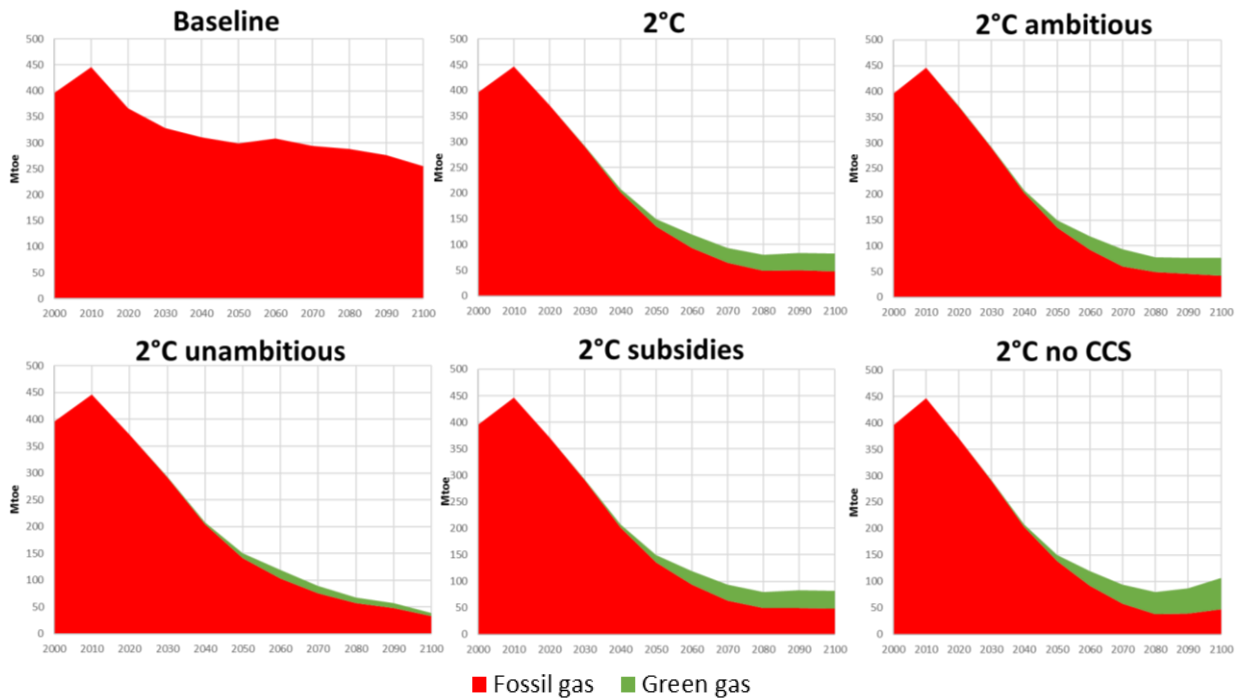
These trends may also be expected for the rest of the world in climate policies scenario according to local potential and local carbon taxation specificities.

1.3. Scenarios sensitivity for green gas and fossil gas production

In this section, we still study differences between scenario 2°C and the other declinations of 2°C scenario aiming at seeing the influence of technological development, the influence of subsidies and the influence of CCS in the green gas field development.

Figure 39 shows the gas consumption and green gas production for Europe for the six scenarios described in chapter 3 section 5.

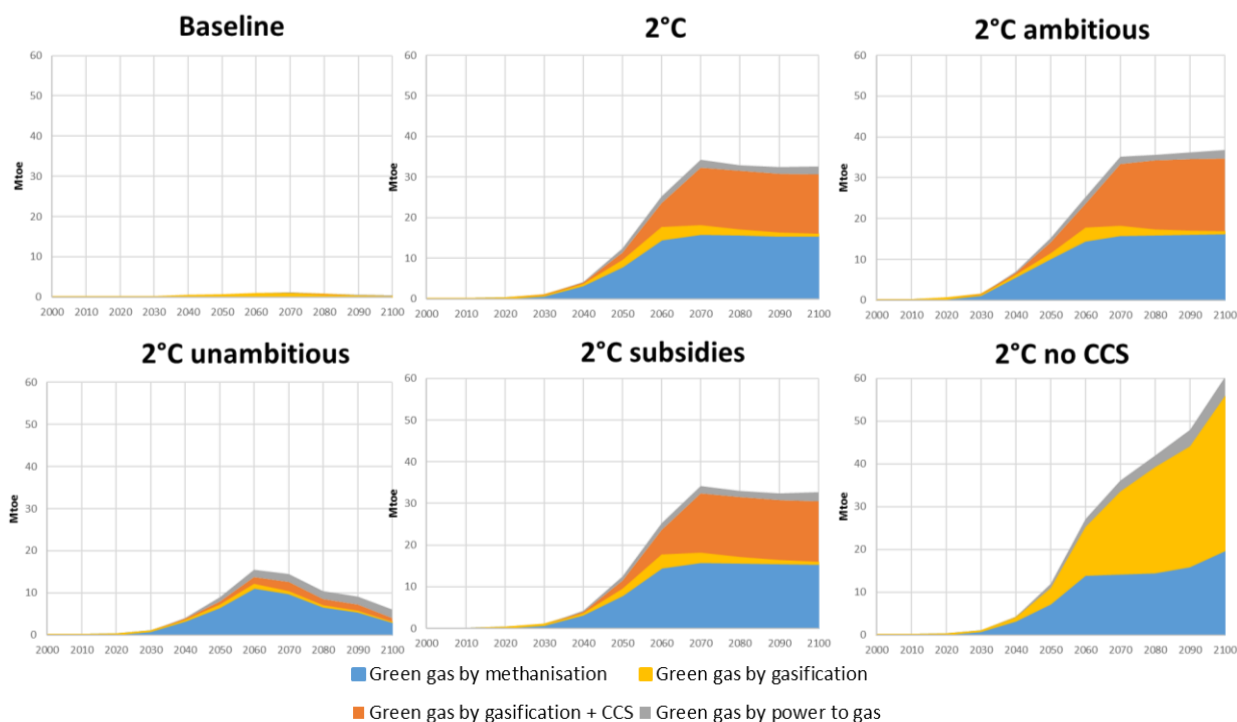
First, we see that the general pattern is not changed deeply so that the main mechanisms in green gas development are kept. The development rhythm in the first part of the century is still limited because technologies are still in progress and because natural gas even with carbon taxation remains too cheap. Then, technologies may develop at a higher pace after 2030 and slow between 2050 and 2060 because many European countries reach the limits of their bioenergy potential. As seen before, total energy and total gas consumption in Europe would be limited after 2050 thanks to energy sobriety and efficiency, so that green gas production stagnate and even decrease slightly.



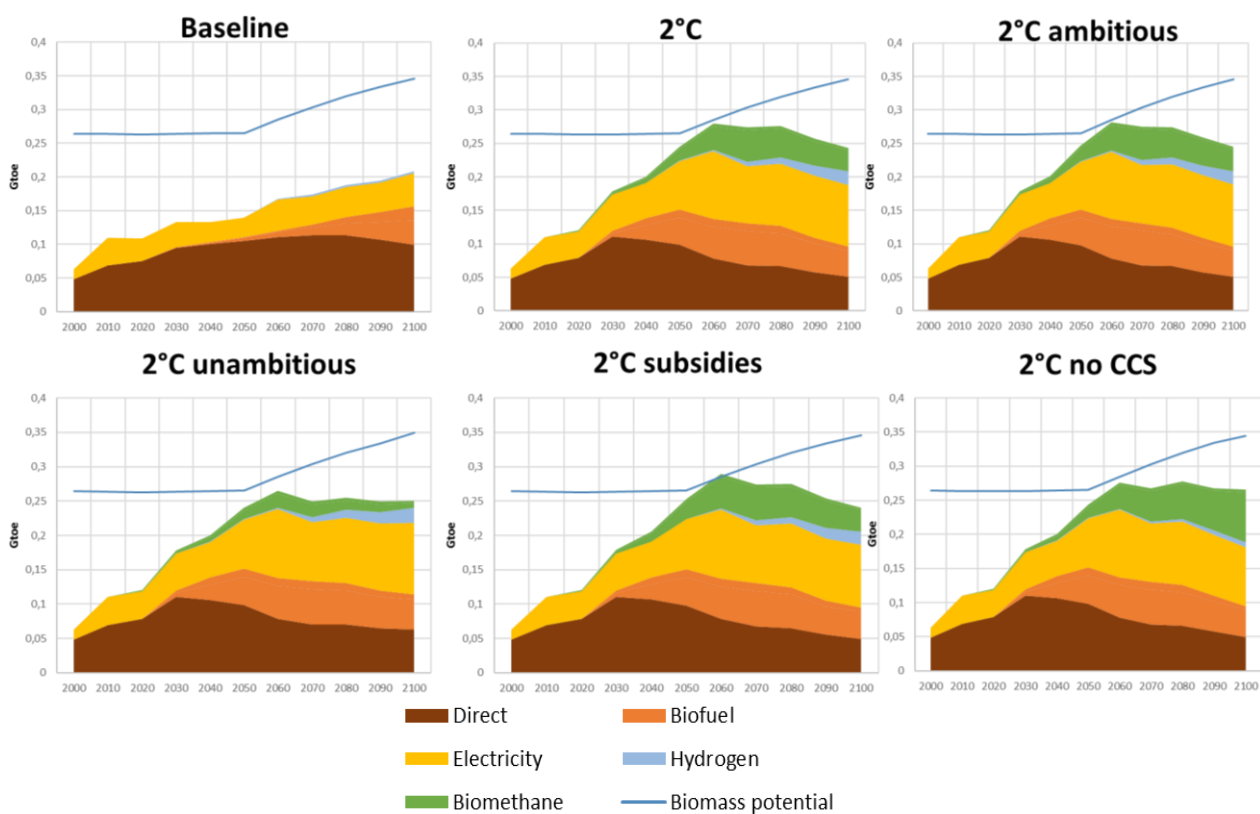
**Figure 39 : Europe gas consumption and green gas production
Six POLES-GAEL scenarios**

We represent in **figure 40** the European green gas production by technology. We see that the influence of technological progress and costs are not massive, but not negligible. Indeed, in scenario (3) where technological progress is more ambitious than in the scenario (2), the development of green gas begins a bit earlier and the share of green gas in the gas production mix is 10% higher on average in 2050 and 20% in 2100. For 2050, differences are very slight because there is the limitation of biomass potential that limit the development of green gas as Europe saturates its own potential. Conversely, the scenario (4) with unambitious technological progress produce a lower development of green gas technologies and green gas production as the production cost of green gas remain more expensive than natural gas price. In scenario (5), with subsidies to launch the green gas production at the beginning when natural gas remains cheaper, green gas develops also a bit earlier than in standard 2°C scenario. However, as for the ambitious scenario (3), bioenergy potential limits the development of green gas production. The scenario 2°C without CCS drives to a faster expansion of green gas production after 2050. Green gas, with an assumed zero carbon content, is a way to “replace” the decarbonisation reached by CCS in some sectors as transportation, electricity production with CCS or in industrial processes with CCS. This green gas production development is mainly due to gasification without CCS after 2060.

Figure 41 shows the biomass allocation for energetic valorization. The biomass allocation for scenario (6) looks like the 2°C scenario: biomass potential utilization grows and is used at 75% in 2050 and 80% in 2100 for bioenergy, at bit more than scenario (2) and largely higher than in the baseline. Besides, we see the same trend for direct valorization growth and drop, a relative constant valorization in biofuels and a growing part for green gas production. The main difference with scenario (2) concerns gas and electricity: in the scenario without CCS, less biomass is dedicated to electricity production and to hydrogen production while more biomass may produce green gas.



**Figure 40 : European green gas production by technology
Six POLES-GAEL scenarios**



**Figure 41 : European bioenergy allocation
Six POLES-GAEL scenarios**

1.4. Conclusion for greening gas supply

The expansion of green gas comes from the combination of two factors: the competitiveness of the green gas production cost in comparison with gas price with carbon taxation and the remaining potential for biomass.

Our study shows that incitation policies and technological progress are necessary but not sufficient to development green gas technologies. Indeed, resource potential management is also key and represent the limitation of green gas development in the middle of XXIst century in many countries, at least in Europe.

Besides, technologies are complementary as they allow the valorization of different types of biomass but their spread would be limited by their development rates like gasification that should not develop in the next ten years based on expected progress. The development of technologies will not follow the same trend for each region of the world even with the techno-economic parameters because they are differences in local availability concerning the resource potential.

Finally yet importantly, the CCS technology development is also key to map green gas decarbonisation possibilities as the presence or not of CCS may change more than the gas production. It may deeply transform the energetic landscape and produce cross sector effects that would change the consumption pattern resources as we saw it for biomass energetic allocation.

2. Gas role in transport decarbonisation

Transport is the second largest contributor of greenhouse gases behind the production of energy and electricity. It releases around 8GtCO₂ in 2016 worldwide (IEA 2019). Besides, transportation sector is fueled in majority by fossil fuels as seen **figure 42**.

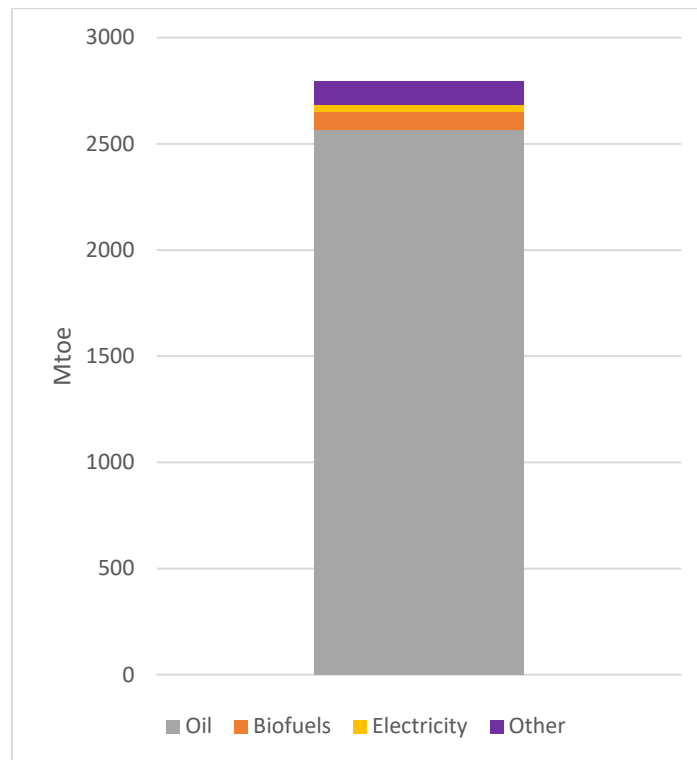


Figure 42 : World energy consumption for transport in 2017
Data from (IEA 2018)

As oil represents more than 90% of total transportation sector energy consumption, this sector would probably be very difficult to decarbonize deeply in the future. CO₂ emissions from transport depend on several factors: the total distance traveled, the fuel used or the type of travel ⁶. In this section, we will focus on the road transportation that is the main GHG emissions contributor for transports. The share of road transport emissions reaches 74% of all transportation sector emissions. In comparison, air transportation is responsible of 12% of transportation emissions, maritime 11% and rail the last 3%. Moreover, this contribution to GHG emissions and global warming is projected to increase by considering an expected growth in world-fleet of vehicles that will triple by 2050 (Mamalis, Spentzas et Mamali 2013). Besides, it is worth studying in particular road transportation as it is where it exists credible alternatives to replace Internal Combustion Engines (ICE) responsible of emissions, which is less the case for air or maritime transport. For example, electric mobility is relevant for vehicles, but not for planes or boats because of the size, the weight and the materials needed for batteries (IEA 2018).

After presenting the road transportation structure and the gaseous mobility, we will assess the green gas role in transportation decarbonisation thanks to POLES scenarios.

⁶ This counting does not consider the indirect emissions from infrastructure such as grey energy related to networks or vehicles construction. It would be discussed in paragraph 2.4

2.1. Current road transportation structure

2.1.1. The actual park

There were 1.4 billion vehicles travelling in the world in 2017 and the growth rate for the number of vehicles in service is accelerating since 2000 (**figure 43**), driven by southern countries development. That represents on average 182 vehicles for 1000 people nowadays. However, the repartition is very heterogeneous: in the USA, there are 832 vehicles for 1000 people, but only 39 vehicles for 1000 people in Africa (International Organization of Vehicle Manufacturer 2017) (Davis and Boundy 2019).

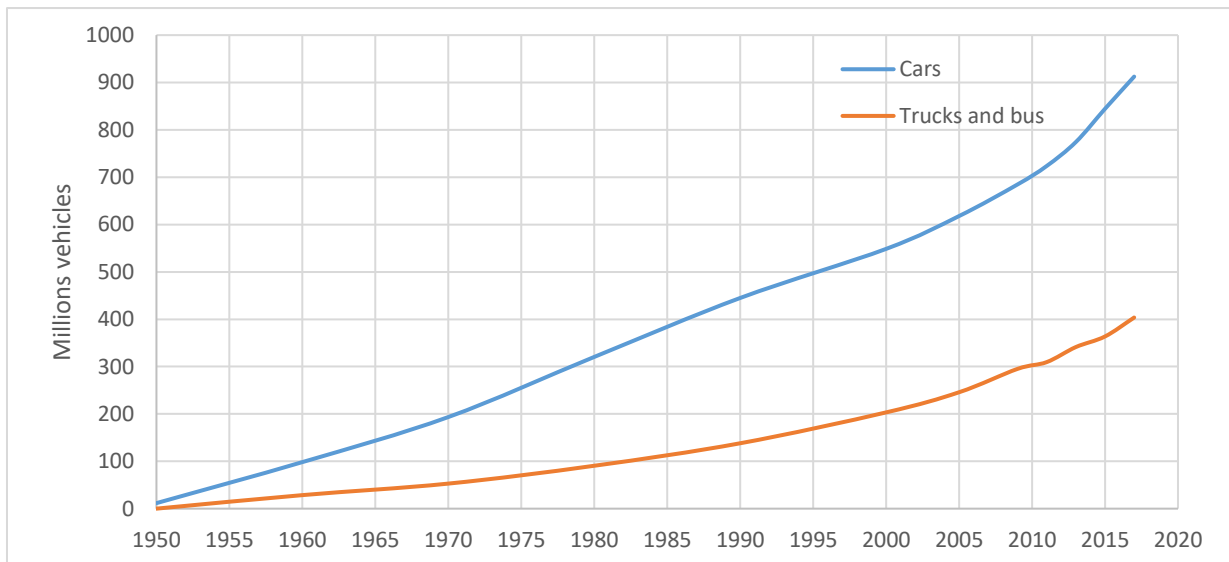


Figure 43 : Number of vehicles worldwide from 1950 to 2017

Based on (International Organization of Vehicle Manufacturer 2017) (Davis and Boundy 2019).

There are different motorizations for vehicles, but the world park is dominated at 98% by oil ICE, approximately fifty/fifty for gasoline and diesel. In this 2017 mix, 1.8%, around 26 million, are NGV (whose repartition will be presented in next section), while only 0.2% are represented by hybrid or electric vehicles (EV) with 3 million vehicles. Only few thousands vehicles are fuelled with hydrogen (Frost & Sullivan's 2019).

Table 11 sums up the main advantages and drawbacks of these technologies

Table 11 : Advantages and drawbacks of each road transportation technology

	Advantages	Drawbacks
Conventionals	<ul style="list-style-type: none"> Fueling station available everywhere Quick refueling Autonomy 	<ul style="list-style-type: none"> CO₂ and particles releases, smells Fuel cost Engine noise
Plug in hybrid	<ul style="list-style-type: none"> Consume a bit less oil as conventional cars, and so release less CO₂ and particles Autonomy 	<ul style="list-style-type: none"> Reduced impact but same drawbacks as conventional Heavy cars Higher grey energy

Electric	<p>No direct CO₂ and particles releases from tank to wheel</p> <p>No engine noise</p> <p>Reduced maintenance needed</p>	<p>Carbon content of the electricity : well to tank relative emissions</p> <p>Grey energy and emission for batteries production</p> <p>Length of charge</p> <p>Still expensive (+60% with a conventional equivalent)</p> <p>Limited autonomy</p> <p>Charging station network still to be spread</p>
Hydrogen	<p>Output for H₂ produced with low carbon electricity electrolysis</p>	<p>Expensive (+100% with a conventional equivalent)</p> <p>Hydrogen is still mainly produced with natural gas</p> <p>Fueling stations very rare</p> <p>High pressure for tank : hazard</p>
Gas	<p>Cost effective compared to conventional cars for fuel and maintenance</p> <p>Possibility of low carbon fuel with green gas use</p> <p>Reduced GHG, particulate and NOx emissions compared to ICE</p>	<p>Fueling stations very rare in most countries</p> <p>High volume or pressure for tank</p>

Based on (IEA 2019, Ajanovic et Haas 2018, Garcia-olivarès, Solé et Osychenko 2018).

In spite of EV's low share in the mobility mix, the sales are recently expanding widely. In 2018, the global electric car fleet exceeded 5.1 million, 2 million more than in 2017. China remains the world's largest electric car market with almost half of the electric park of the world, followed by Europe and the US, respectively around a quarter of the world park. Norway is the global leader in terms of electric car market share: almost half of the total national park (46%) is composed of electric vehicles. (IEA 2019).

More numerous in the world than electric cars, gas vehicles are typically used in light-duty commercial vehicles fleets and in city buses (more information to come in section 1.2). Hydrogen vehicles are not very developed, only in small fleets used as demonstrators or in isolated niches for this field.

2.1.2. Road transportation emissions mitigation solutions

As highlighted before, transportation sector is responsible of one third of global GHG emissions worldwide. We underlined a large growth for people mobility until now and the dependence of ICE that are always the main solution for mobility. For example, road transportation is responsible of 94% of GHG emissions for internally journeys in the EU with almost 850MtCO_{2eq}/year. Likewise, widely dominated by consumption of petroleum products, transportation sector is the largest emitter of

greenhouse gases in France with 38% of emissions in 2018 as seen in **figure 44** (CITEPA 2017). The transport sector is the only sector in France, which has not reduced its emissions since 1990. Its emissions have a bit dropped between 2017 and 2018, but they still exceed the emissions target for this sector by 12.6%. This is due to an increase of the number of cars and the road freight on the rise that do not fully compensate the increase in energy efficiency (Observatoire climat énergie 2018).

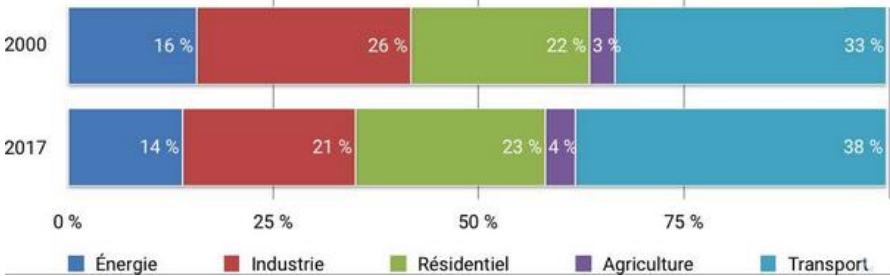


Figure 44 : GHG emissions in France by sector
Taken from (CITEPA 2017)

However, solutions exist to reduce the carbon footprint of road transportation. **Figure 45** sums up the GHG emissions for cars according to their fuel (IRENA 2017). Biofuels can reduce the carbon content of ICE of 33% for gasoline and 40% for diesel. That is a good way to decarbonise the park with actual infrastructures but that is not enough to decarbonise deeply the mobility. Moreover, biofuels represent only 6% of the fuel consumed in ICE and their share is limited and regulated in order to avoid resource conflicts with food supply (REN21 2019). On the other hand, natural gas fuel release 24% less CO₂ than gasoline and 20% less than diesel. Hence, natural fossil gas helps to reduce the carbon content of mobility that is mainly composed of ICE nowadays (98% of the entire park). Even if it were depending of the resource, biomethane use in mobility would allow a deeper GHG reduction compared to gasoline and is a good solution toward reaching a complete decarbonised mobility because it is not so complicated to convert an ICE to a gas-fuelled car.

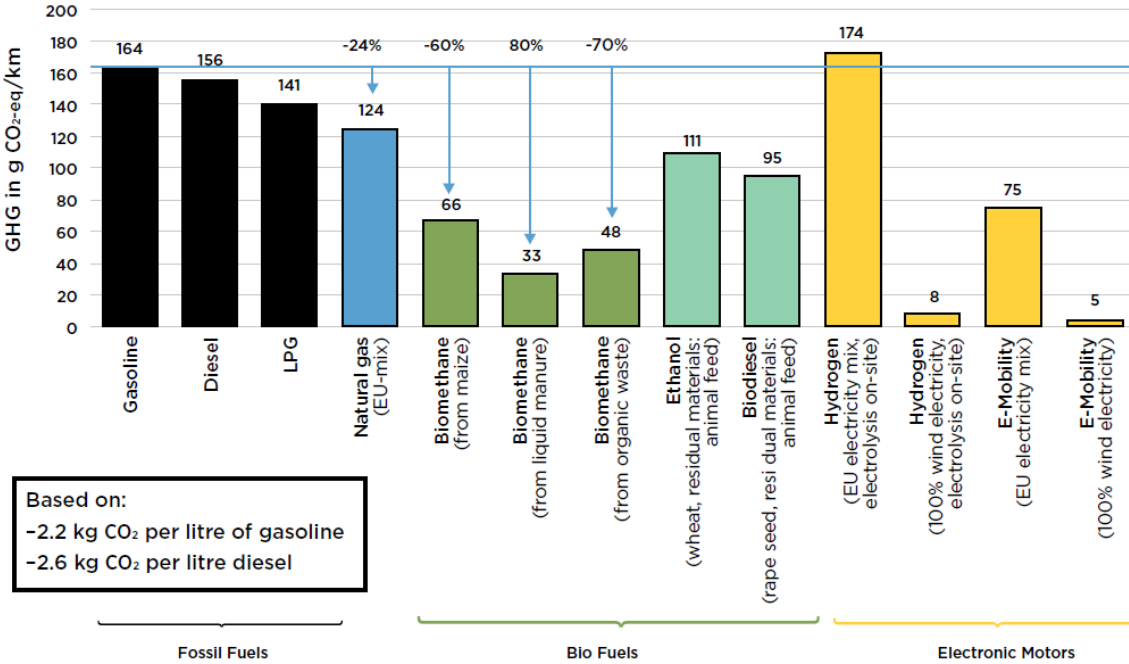


Figure 45 : GHG emissions from passenger cars for different fuels
Taken from (IRENA 2017)

Finally yet importantly, electricity is often seen as a silver bullet to decarbonise mobility but this is not obvious. Indeed, it depends of the way the electricity is produced where only electric mobility with decarbonised electricity is more competitive in term of GHG emissions than biomethane considering an whole life cycle analysis (LCA) from well to wheel. Nevertheless, other problems that will be discussed further are not considered here such as the non-negligible environmental impact of the battery in electric vehicles (EV) (McManus 2012).

2.1.3. Transportation related policies

Some policies may incentivise the development of cleaner vehicles or non-ICE vehicles in order to decarbonise road transportation sector. It allows also reducing low particles emissions and air pollution. Incentives measures can be divided into two main categories. There are direct incentives, as grants, tax benefits, emissions standards and indirect incentives as sales quotas that are written, polled and set by States (France stratégie 2018).

With direct incentives, politicians foster the development of non-conventional vehicles because they remain more expensive and less competitive than conventional vehicles. (European Parliament 2018) (Davis and Boundy 2019). The most spread tool used is bonus malus mechanism that gives a subsidy for vehicles that emits low quantities of CO₂ and a malus for those that emits a lot. It is an aid for the purchase of less emissive vehicles in order to push car buyers toward low emissions vehicles. As long as the cost of the electric vehicle is higher than that of the thermal vehicle, the maintenance of current financial aid remains necessary. This is linked to the fact that the EV will only take off when it is accessible to the majority of households. For instance, in France in 2019, there is a malus when the vehicle emits more than 116gCO₂/km and a bonus for electric vehicles that release 0gCO₂/km from tank to wheel (economie.gouv.fr 2019). Another example, in the USA, purchasers of plug-in hybrids and electric vehicles received a Federal tax credit of up to \$7,500 for select 2015-2017 vehicles along with possible state credits. In any case, the removal or reduction of subsidies too quickly leads to a collapse of sales because they are mandatory to bridge the cost gap between ICE and alternative mobility. For instance, in the Netherlands, EV sales share were close to 10% in 2015, but subsidies cuts drove to a division by four of EV car sales (IEA 2019).

There are also indirect incentives to develop non-conventional vehicles. There are some norms set by countries with engine emission standards that become stricter year after year. Since 2010 diesel engine emissions standards are stricter in the USA by 0.2 grams per horsepower-hour (g/HP-hr) for nitrogen oxides and 0.01 g/HP-hr for particulate matters (U.S. Environmental Protection Agency 2020). In Europe, since the nineties, every 5 year, a new norm Euro strengthen the standards for diesel emissions is edited. The last was the Euro 6d-TEMP for light vehicles in application since September 2019 and the Euro VI norm for heavy vehicles since 2014. By regularly lowering the emission standards of the average of new vehicles, a form of quota is actually used, which is an incentive and not negligible on the strategy of manufacturers (European Commission 2007) .

Furthermore, some policies ambitions aim at cutting off the sales of ICE in the XXIth century. **Table 12** gathers the countries that declared the cessation of sales of ICE and the milestone considered.

Table 12 : Countries that aim at forbidding the sales of ICE

Country	Deadline
Austria	2020
China	Deadline not yet fixed
Costa Rica	2050
Denmark	2040
Egypt	2040
France	2040
Germany	2030
Iceland	2030
India	2030
Ireland	2030
Israel	2030
The Netherlands	2030
Norway	2025
Singapore	2040
Slovenia	2030
Spain	2040
Sri Lanka	2040
Sweden	2030
Taiwan	2040
The United Kingdom	2035 (Scotland 2032)

Based on (Muio 2017) (Burch et Gilchrist March 2020).

Other indirect incentives help to develop alternative mobility as free motorway tolls for EVs, free access to car parks with charging stations, differentiated parking rates, authorization to use reserved lanes, access to restricted traffic zones as it is implemented in Norway. The regions, metropolitan areas, and local unions are the engines to implement these kind of incentives. There are also measures to develop the industrial sector with larger budgets unlock for R&D to improve battery performance for EV, autonomy, costs. Moreover, training have to be proposed for actors to appropriate these new mobility patterns.

The development of infrastructure surrounding fleets like charging stations is key to foster ICE alternatives. There is a need of necessary public and private investments and the deployment should be done at the right pace and in the right places to answer the new and growing demand. For example, in Sweden, green gas support is dedicated to fuel vehicle charging stations and not to gas grid injection to promote gaseous mobility (Svensson 2016).

2.2. The gaseous mobility

As mentioned in the previous section, there are currently almost 28 million-gas vehicle in the world, with 32500 associated NGV fuelling stations. The repartition is very concentrated in few countries as illustrated in **figure 46** (Natural Gas Vehicle Knowledge Base 2019). Indeed, NGVs are very concentrated in Asia, almost 20 million vehicles for 20000 stations, in Latin America, around 5.5 million for 6000 stations and 2 million in Europe for 5000 stations. The remaining park, less than 0.5 million vehicles for 2000 stations is spread between North America and Africa.

Europe does not have a large NGV park compared to other continents. Only Italy have a noticeable amount of gas vehicles, more than 1 million coupled with 1100 dedicated filling stations (Maggioni 2017). Whereas the market share of hybrid-electric vehicles in the EU was 4.1 % of all new car sales in 2017, the share for gas vehicles is 1.3% and is largely driven by Italy where it reaches 8.6% (ICCT 2019). However, the actual trend is to develop the gaseous mobility that is a cost effective alternative to replace step-by-step ICE and having less negative impact on the climate and local air pollution. The countries leading the way with biogas for transportation are Sweden, Switzerland and Germany, even if other countries have a potential that can be exploited (IRENA 2017).

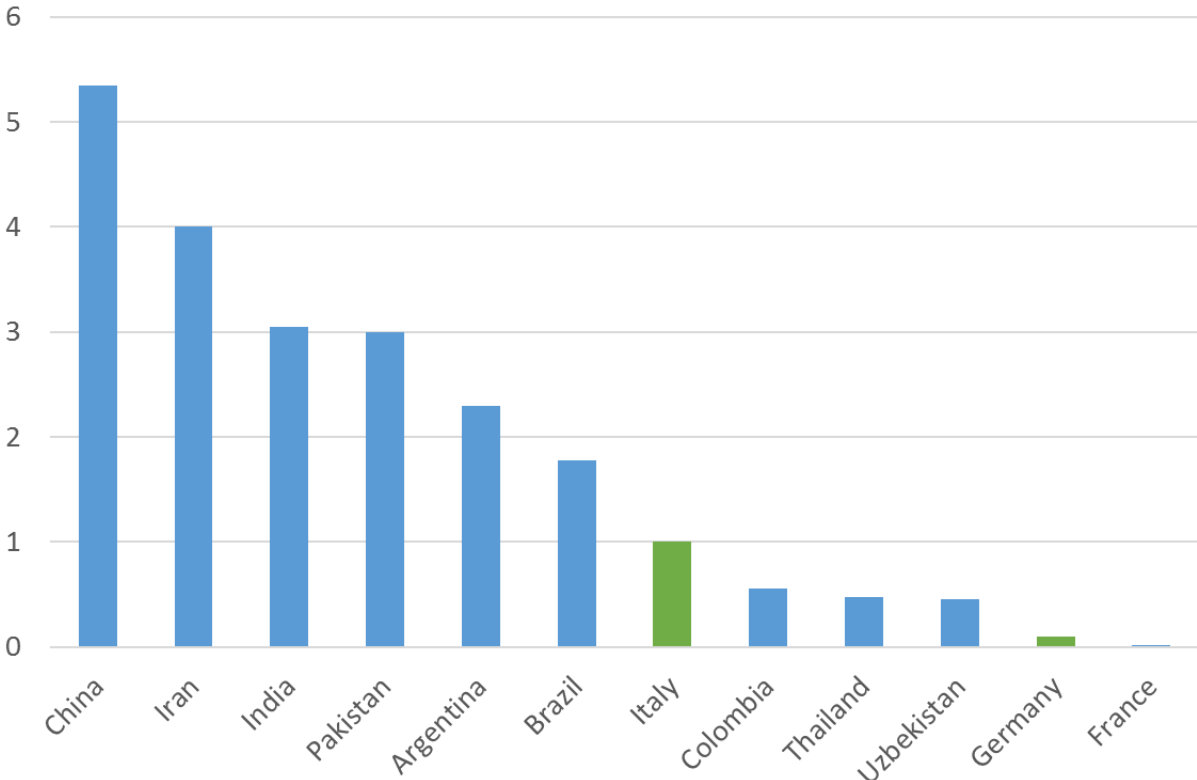


Figure 46 : Number of NGVs (in million) for principal NGV countries in 2019
Based on (Natural Gas Vehicle Knowledge Base 2019)

Among its 39 million vehicles, the French gaseous fleet was constituted of only 17,796 vehicles including 2282 heavy weights and 3199 bus in November 2018 (CCFA 2018). The quantities of vehicles and charging station in stake remain very low in 2018: 230 gaseous charging stations and only 118 public in France (AFGNV 2019) (Gaz mobilité 2019) compared to the 150000 public charging stations available in France for electric and plug-in hybrid vehicles (Gouvernement français 2019). Nevertheless, France has become the most dynamic market in Europe on the heavy vehicle segment. Fifteen years after the arrival of NGV buses, it is now more than 12% of the bus fleet that runs on gas, in particular in big cities, thanks to an increase for dedicated supply stations. The use of NGV in these stations is also supported by national initiatives: the Mobility Law will deal in particular with the implementation of a legislative framework for biomethane consumed directly in NGV stations that is not the case yet. However, it remains the responsibility of private or local actors to set up gas charging stations that are ten times more expensive than gasoline or diesel fuelling station (Ministère de la Transition écologique et Solidaire 2019). For example, several bus manufacturers now offer gas buses and some cities develop gas buses fleets for public transport (Gaz mobilité 2019).

2.3. Expected future for road mobility

2.3.1. Benchmark

2.3.1.1. Future of mobility patterns

Some studies estimate the future repartition of the mobility park. However, despite the fact that there are scenarios that encourage alternative modes of transport through various incentives, road transport remains the main mode of travel (Kaufmann et Ravalet 2016). In the Sustainable Development Scenario of the IEA World energy Outlook, avoid and shift policies lead to a decrease in global CO₂ emissions of 30% of total transport emissions by 2040 compared to 2017 thanks to a reduction in passenger car stock of 200 million vehicles. The effect is partly offset by an increase in public transport use and rail (IEA 2019).

The use of biofuels allows a small GHG intensity for transportation but the levels of emissions remain high. Besides the competition for the resource between food and energetic purpose is a limit for biofuels development as develop in chapter 4 section 1. Nevertheless, the use of biofuel can be useful for transportation decarbonisation in perimeter where the alternatives to ICE are unappropriated. For instance, in air transportation, the use of synthetic fuels could be a viable low carbon option to meet aviation sector's energy demand and decarbonisation need because of the non-competitiveness for electric, hydrogen or gas motorization (Malins 2017).

The future of mobility patterns depends on the quality of transportation options available in different countries as well as the urbanisation rate that may change mobility patterns. To go further, a transformation toward a less carbon-intensive transport sector depends on understanding behavioural choices, which depends partly on communication, quality of service and people habits. These changes are more complex to install than a simple economic equation and will not be discussed further in this work.

2.3.1.2. Future of gaseous mobility

The Annual Energy Outlook 2015 (US EIA, 2015) projects that natural gas will be the fastest-growing fuel in the transportation sector, with an average annual demand increase of 10% from 2012 to 2040 particularly for heavy vehicles. However, NGV park is assumed to account for just 1% of new vehicle sales by 2025. In contrast, a report by ACT Research suggests that, if certain conditions favourable to natural gas persist, it could power up almost to 50% for heavy vehicles by 2025 (ACT Research, 2014).

Other studies' projections suggest that natural gas-fuelled vehicles can achieve market penetration rates of about 15% to 20% around 2030. (Frost & Sullivan's 2019) (Kar 2012) (National Research Council 2014) (TIAX 2012) (NPC, 2012). For example, the number of light vehicles running on natural gas in circulation across Europe could increase from 1,3 to 12,6 million until 2030. This will allow the NGV to represent 12% of new vehicle sales by this time. On the heavy-duty side, trucks powered by CNG or LNG could rise from 11500 to 470000 units, of which 290000 are LNG-powered. This allows the segment to conquer 25% of the market. Buses and coaches may also increase significantly. From 16000 to 110000 units, they could gain 33% market share by 2030 (NGVA Europe 2018). This growth would be coupled with a sharp rise in the number of refuelling stations. On a European scale, the number of CNG stations could thus go from 3300 to 10000 and the LNG stations from 140 to 2000 by 2030.

In addition to this gas development in mobility, biogas represents a strong potential to decarbonize road mobility. For light vehicles, commercial vehicles and even heavy vehicles, the use of an engine powered exclusively by bioGNV gives the best results in terms of GHG emissions according to a

complete LCA (**figure 45**). Electric vehicles are penalized by the carbon content of electricity production and by batteries manufacturing. Conventional are penalized by the carbon content in fuel (IFP Energies Nouvelles 2019)

For example, Europe may be able to produce nearly $45\text{Gm}^3 = 471\text{TWh} = 40,5\text{Mtep}$ of green gas by 2030, compared with less than 2Gm^3 currently (see chapter 2 on the potential of biomethane). The share of biogas absorbed by the transport sector should represent around 30% of the LNG and CNG consumed. A percentage that will still result in a significant decrease in greenhouse gas emissions, approximately a 45% reduction compared to conventional fuels in a "well to wheel" approach. However, the current regulatory framework for transportation takes into account emissions from the "tank to wheel" to designate the most virtuous vehicles, so that it tends to penalize vehicles running on biogas in favour of electric mobility, even if the electricity is produced by fossils (NGVA Europe 2018).

2.3.2. Mobility module in POLES and analysis

The mobility infrastructure is modelled in POLES model with the consideration of mobility needs for people and goods (**figure 47**). The number of kilometres (that depends on the region) multiplied by the number of goods or passenger define the mobility need for one region. Then, POLES uses mobility technologies, light or heavy vehicles, with different motorization possible to fulfil this demand. The arbitration between the technologies is an economic one. Many parameters plays in this arbitration: the lifetime of each technology, the investment costs for vehicles, the surrounding infrastructure investments, the variable costs for the fuel and maintenance charges. The two types of vehicle, light and heavy vehicles are separated in five different technologies. First conventional vehicles that gather gasoline and diesel engines, then plug in hybrid vehicles that can be recharged in electric charging stations. There are also electric vehicles fueled by batteries, hydrogen vehicles that have an electric engine fueled thanks to a fuel cell and a hydrogen tank and gas natural vehicles fueled by compressed natural gas (CNG) or liquefied natural gas (LNG). After simulations, we have access to the vehicle parks, the energy consumption by fuel and the relatives GHG emissions for each scenario considered.

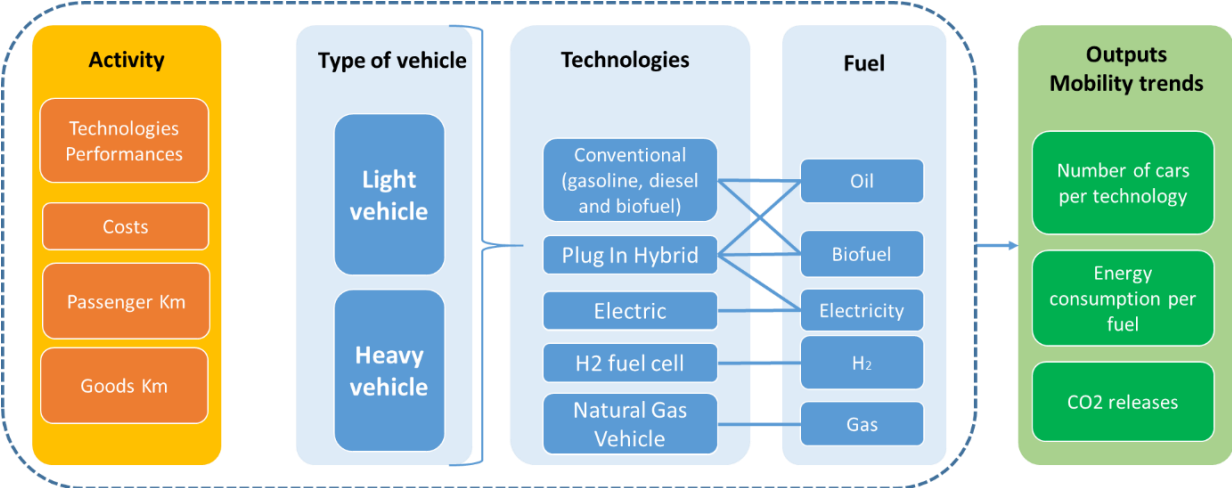


Figure 47 : POLES modelling for road mobility

The total cost of operation of the vehicles expressed in dollar per kilometer (\$/km) are calculated as presented in **figure 48**. There is a separation between fixed and variable costs. Fixed costs are composed of the investment cost for the vehicles and the cost associated to R&D including vehicles

enhancing performance research, network and infrastructure development. Variable costs are split in two parts: the cost for the fuel to make the vehicle moving and the operational and maintenance cost for vehicles due to operation. All the costs are calculated depending of the number of kilometer traveled by year for the vehicles, their lifetime and the consumption of the engine.

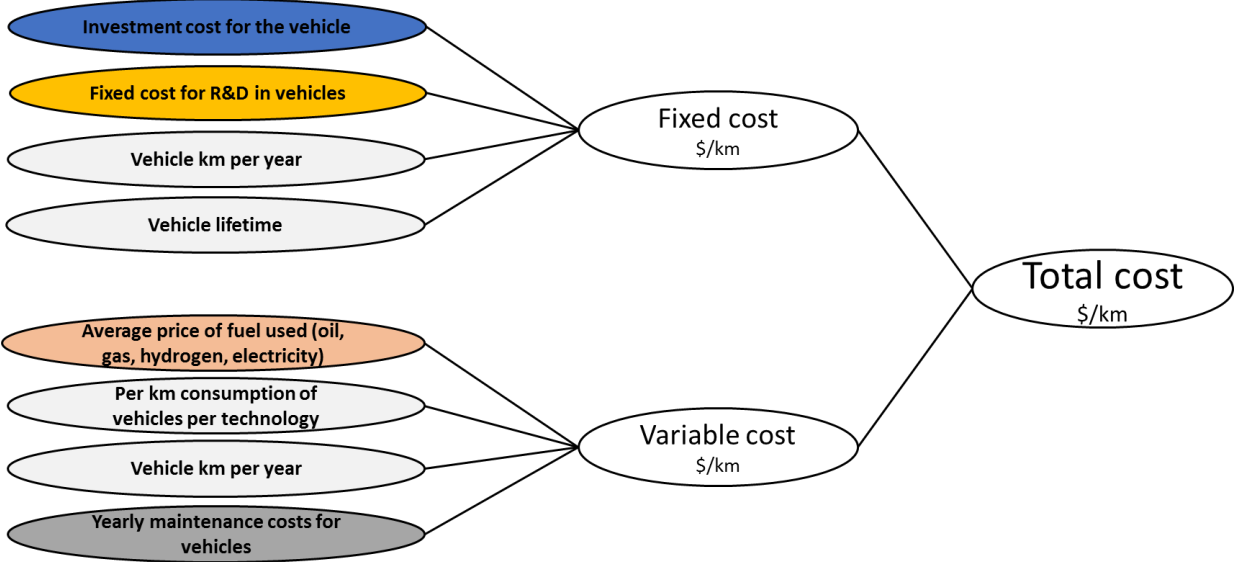


Figure 48 : Vehicles costs repartition in POLES model

Costs are divided according to the **figure 49** for the five technologies.

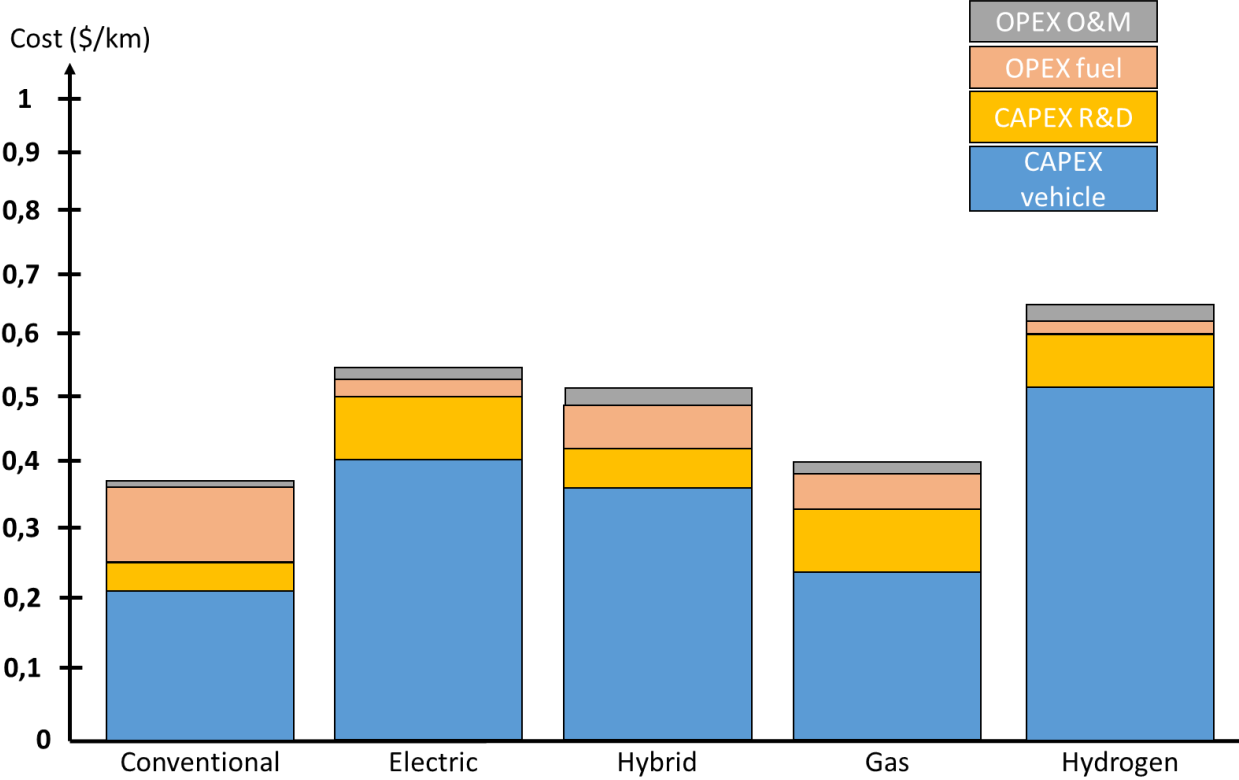


Figure 49 : Vehicles costs structure in POLES model in 2017

It is worth noticing that concerning conventional alternatives, the main cost is represented by the investment cost of the vehicle. Depending of the technology, the R&D investment or the fuel cost represent the second cost. At the end, O&M costs are very small compared to the overall, representing

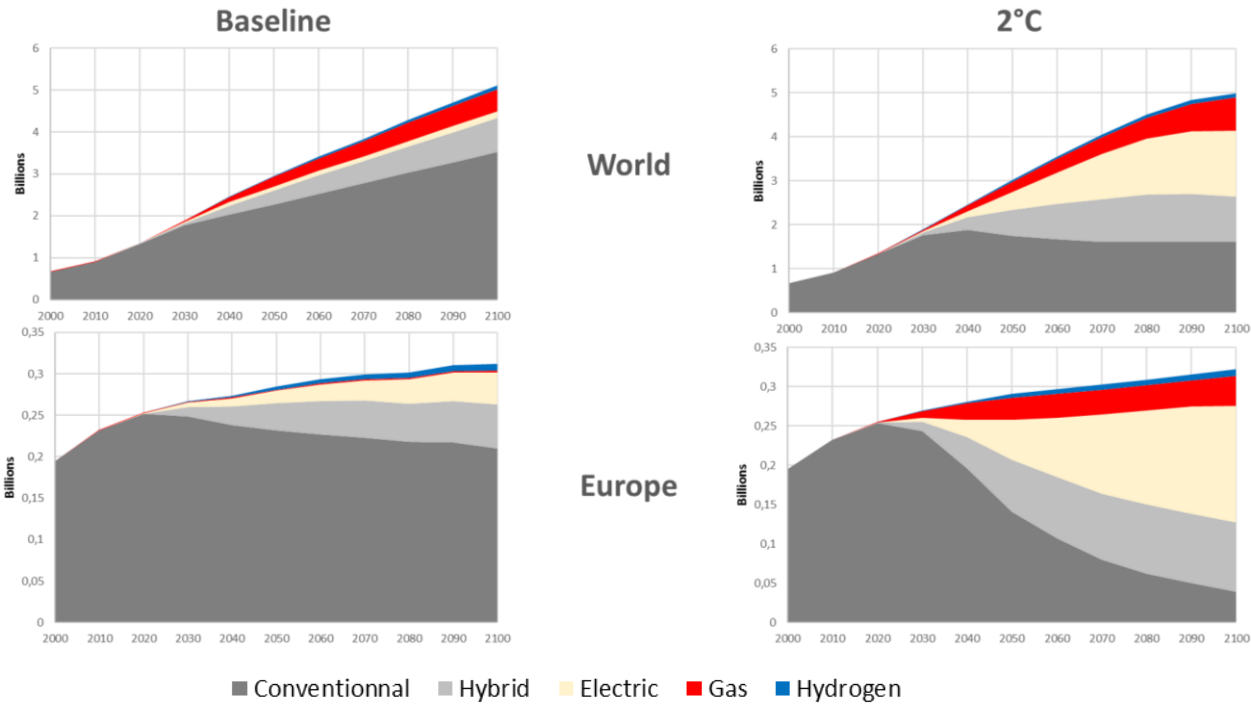
between 1 and 5 cents per km. In this work, we have updated the data for the technologies in stake with a recent literature review: the costs, the performances and the installed parks for POLES regions. These parameters are summarized in **table 13**.

Table 13 : Techno-economical parameters for vehicles in 2017

	Conventional	Hybrids	Electric	Gas	Hydrogen
Average investment cost (€)	20000	27000	30000	24000	60000
Maintenance cost (€/year)	500	650	350	400	350
Fuel cost (€/year)	1125	845	225	495	1140
Cost per distance (€/100km)	19,5	22,5	19,7	18	41

Hypothesis: lifetime 12 years, 15000km/year, 4% actualisation
 Based on (IEA 2019, ICCT 2019, CCFA 2018)

Considering the scenario described in chapter 3, we have access to the vehicle park in operation in the world, the energy consumption for road mobility, and its relative CO₂ emissions. We present in **figure 50** the parks evolution in the world and Europe for baseline and 2°C scenario. It is worth noticing that the hypothesis that consider the activity as unchanged based on exogenous GDP parameter would not change the number of vehicle between a baseline and a 2°C scenario as the mobility need is not considered as different. Therefore, the number of km and the need for passenger km remains constant. This is the park in operation and the type of energy consumed (and so the relative GHG emissions) that will change whether you are in a baseline or a 2°C scenario.



**Figure 50 : World and Europe individual parc structure
 Scenarios baseline and 2°C – POLES-GAEL**

In the baseline scenario, conventional vehicles continue to grow, because they remain the less expensive vehicles to buy, the infrastructures are still in place and fuel, diesel or gasoline, is not so expensive and not penalized by a carbon tax. Hybrids and electric expand also thanks to the progress expected for these technologies in the near future, so that they become competitive. However,

hydrogen vehicles would not enter a lot in the markets because they remain too expensive and because networks may be too expensive and too long to be developed and reach cost effectiveness. In the climate policies, conventional vehicles withdraw because they are not the most competitive vehicles anymore from a cost perspective. While conventional have an expected increase of their variable cost for the fuel (there is an increase of oil price in (IEA 2018) forecasts and there is a carbon tax in climate policies scenarios), alternative motorizations see a decrease for their costs, passing under 0,5€/km, thanks to reduction of their CAPEX. Hence, the cost per km is higher for ICE, so that ICE vehicle number would drop.

Figure 51 represents the energy consumption and in parallel the vehicle park for road transportation for the 2°C scenario.

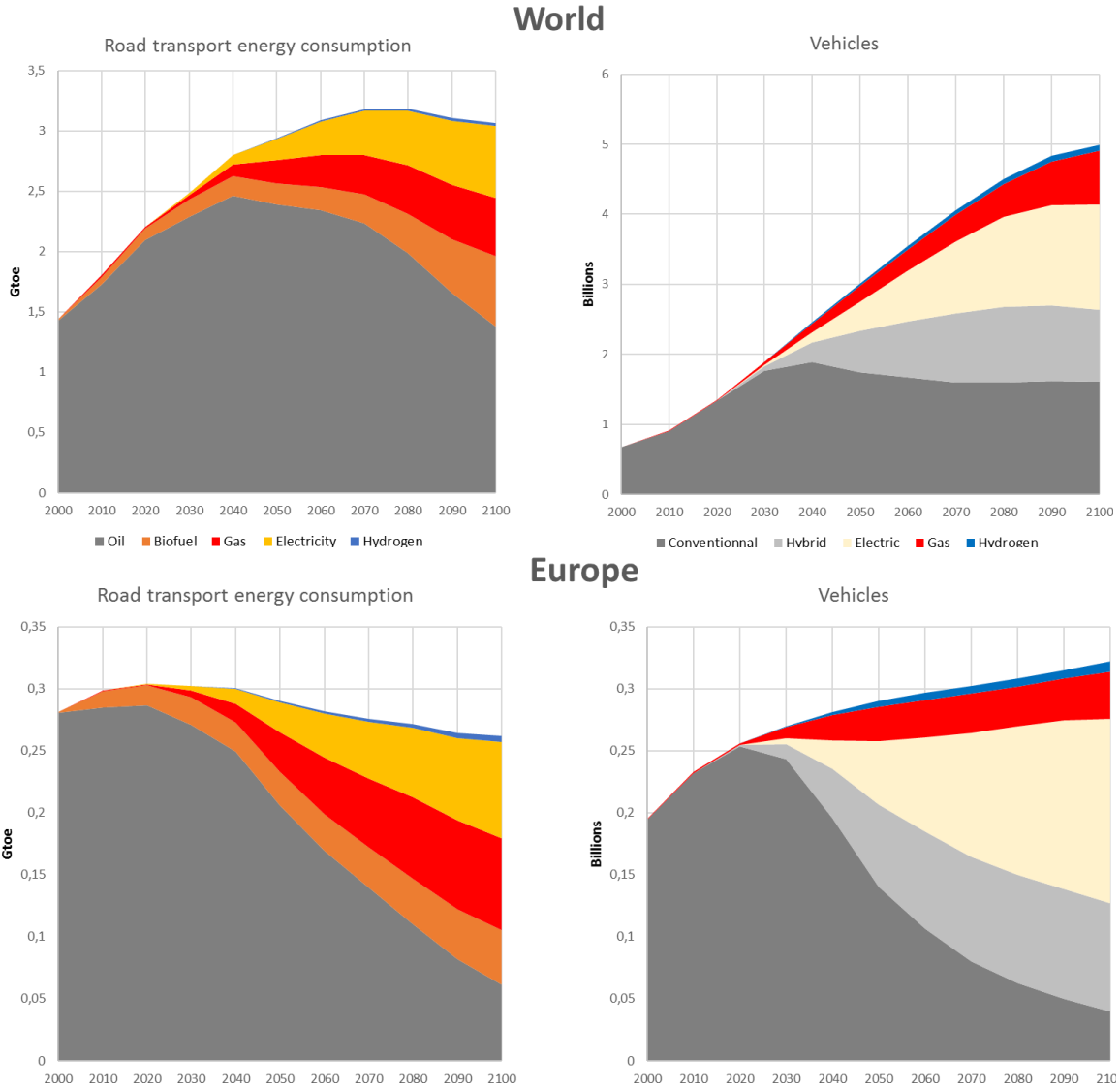


Figure 51 : Road mobility energy consumption Scenario 2°C – POLES-GAEL

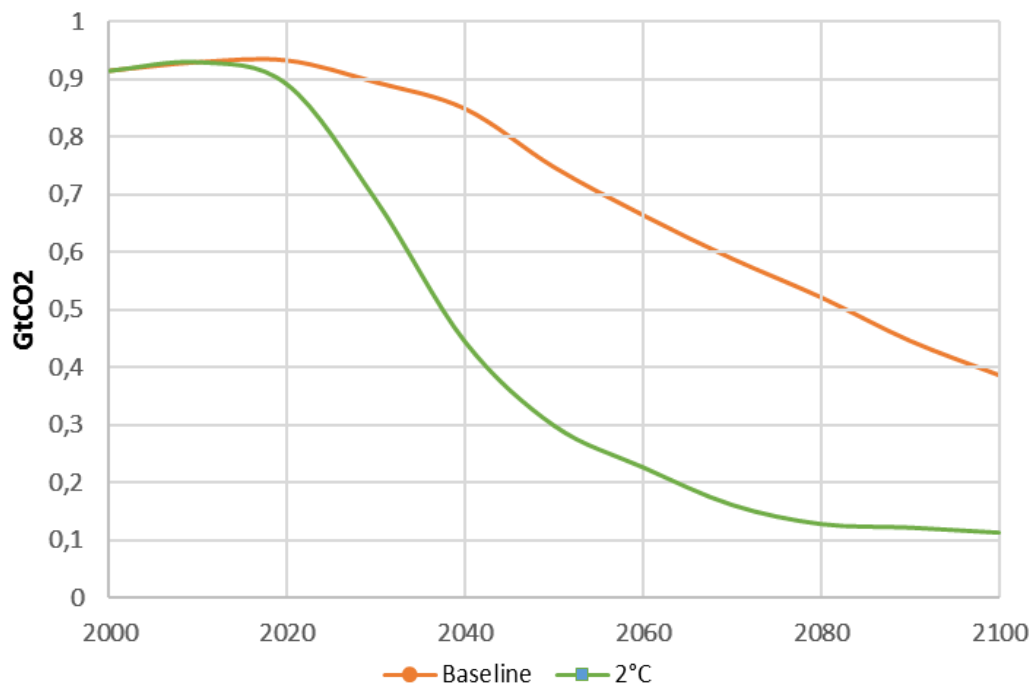
The efficiencies for vehicles are improving through XXIst century, decreasing from 20 to 50% according to the technology, so that the energy intensity to run through a kilometre is lower. It explains why the road energy consumption stagnates or decrease in our simulations, while the number of vehicles increase, particularly in the second part of the century. Two reasons may explain this decrease: the

efficiency gain for motorization as told before, and the fuel switch between vehicles and the associated energy carrier use. Electric, hydrogen and gas vehicles are more efficient compared to conventionals, so that they use less primary energy per km travelled (Johnson et Joshi 2017). Take for example electric vehicles: their energy efficiency coefficient is 80 to 90%, that is to say that 80 to 90% of the electricity consumed actually serves to propel the vehicles, while this ratio does not exceed 20 to 25% for vehicles with oil engine (Schneider Electric, et al. 2019).

The ICE withdrawal favours the electric mobility that is the low carbon alternative with the lowest operational cost and that knows an increase in performances, a large development of infrastructures and an investment costs decrease. Gas mobility develops just a bit more than in baseline and hydrogen remains negligible. This trend is accentuated with the endogenous development method in POLES where “a learning by doing” is important concerning the development of technologies that translate the scale costs reduction and the optimisation of technologies by learning thanks to return of experiences. Hence, when an alternative starts to develop, simulations foster the development of this particular technology in the disfavour of other emerging technologies.

However, progress concerning electric or gas vehicles generates a large development of these technologies and a large change in the energy consumption for road mobility. Electric vehicles would be the major technology developed at the end of the century and even drive to a large reduction of conventionals that are no more competitive in this scenario. Nevertheless, according to our simulations, gas vehicles would also know a non-negligible development in the 2°C scenario, about 10% of the vehicle park and 30% of the energy consumed, because these vehicles are more cost competitive compared to conventionals and produce less GHG emissions.

European road transportation emissions are falling in all scenarios (**figure 52**) until reaching almost zero emissions in 2100 for climate policies scenarios. The norms for vehicles are stricter so that the carbon intensity to make a kilometre is lower for a given technology (ICE, hybrid or gas) and make baseline scenario emissions decreasing. Therefore, in the 2°C scenario, coupled with electric vehicles expansion and oil consumption reduction in conventionals, there is an increasing share of gas vehicles that are fuelled on average by a growing share of green gas reaching 50% at the end of century (see chapter 4 section 1). This greening drives to a reduction of the carbon impact of the fuel. The carbon tax contribution in the total cost of the vehicle makes the vehicle more competitive.



**Figure 52 : CO₂ emissions for European road transportation
Scenarios baseline and 2°C - POLES-GAEL**

2.4. Discussion

Mobility as buildings, industry, services, etc. has to follow the three pillars to reach a complete decarbonisation: energy sobriety to reduce consumption, energy efficiency combined with fuel switch and low carbon energy production and use. Hence, even with a large change in vehicle motorization, for example with electrical or gaseous vehicle (renewables), in order to emit less CO₂, it is crucial to think about reducing our mobility need (sobriety) as well as the energy consumption for each km covered (efficiency).

2.4.1. The need of reducing mobility environmental footprint

A first concern for sobriety is about having less need for mobility, especially calling carbon mobility (cars, trucks, planes): the less we move with fossil fuels, the less we release greenhouse gases. Particularly, long travels more than 200km and especially more than 800km should be reduced and be coupled with a limitation of flights. For example, substitution from air to rail should be encouraged (Garcia-olivarès, Solé et Osychenko 2018). Transport emissions respond to the interaction of three parameters on which we can play on transport flows by reducing the number of trips, and / or the number of people and products transported, and / or the distances traveled. For example, the French SNBC calls for encouraging teleworking and carpooling to limit the growth in demand. The mode of transport play also a role in transportation decarbonisation: the modal shift from carbon-based transport (plane, truck, car, etc.) to less carbon-based transport (boat, train, bicycle, walk, etc.). Here, urban planning is key to have adapted solutions for territories and, even if cleaner technologies exists and are developing, people habits and behavior are key to change the mobility operation.

Second, in the way for the transition to zero emissions mobility, the first action for efficiency gain can be the modification of conventional cars fuel consumption in order to change their need from 6-7L for 100km to 1.5-2L/100km (The Shift project 2019). Simple technology adaptation is possible, for example limiting the engine cubic capacity (anyway we are not allowed to move quicker than 130km/h in most countries) or limiting the number of electronic devices in new cars to reduce the electrical vehicle

consumption. The weight is also a main concern because it is less demanding to move a lighter car. Therefore, objectives and norms should be set to encourage the manufacturers to change the actual features of ways of transportation to be less gourmand (Duysinx 2018). These measures will help countries to reduce transportation emissions, with competitive costs for CO₂ emissions avoided, and, in the same time, give time to manufacturers to develop more efficient and cost competitive hybrid, electrical, gaseous or even hydrogen ways of mobility.

Another point is also the consideration of local environment, in particular the local electric mix. Electric or hybrid vehicles could contribute to the reduction in some problems in the transport sector, especially to the reduction in local air pollution. However, their contribution to the reduction in GHG emissions is very dependent on the electricity mix used: electric or hybrid cars are able to perform best for decarbonisation purpose when green electricity is used. If, however, a Polish or German electricity mix is used, with lots of coal power plants, it is not the case anymore (Ajanovic et Haas 2018). Plug-in hybrids would achieve no substantial improvement with application of the current mix Germany even when compared to the conventional gasoline engine. In this case, natural gas cars should be the best option for GHG cuts. The natural gas car can also benefit massively from biomethane production to decarbonise even more the gas mobility (Jungmeier, et al. 2019)

Finally, yet importantly, complementary measures can be taken in order to round off these emissions' reduction policies, for instance lower the speed regulations, add carpooling incentives, urban toll for individual and carbon vehicle, etc. to promote the reasonable use of mobility technologies to decarbonise this sector. In spite of all these scenarios, the political decisions are key to foster or slow the development of one technology as well as the accompaniment of people for the appropriation of measures. A known case study concerns China, who has reduced and cut EV subsidies. This makes the world EV sales falling down to 14% in July 2019 compared to July 2018, as China is the main contributor of EVs sales worldwide. This Chinese decision to withdraw subsidies for the purchase of EV is explained by a new orientation aimed at favoring hydrogen vehicles. If this technological choice appears at least risky, it should be noted that the main Chinese EV manufacturers have suffered significant financial losses since 2018, which casts some doubt on the future of the concept in the minds of decision-makers. Indeed, the largest Chinese manufacturer of EVs, BYD, saw its sales fall by 12% in one year. Sales of NIO's high-end electric models peaked last November and have since been decreasing. The Chinese market for rechargeable hybrids was particularly affected by a 10% drop in one year. The July downturn is not catastrophic in itself, but it calls for cautious handling of all predictions of exponential growth in EV sales and stories that internal combustion vehicles are condemned in the short term. In recent years, there have been comparable declines in all countries where government support has been reduced or canceled, suggesting that the EV market remains dependent on promotional measures (Gauthier 2019).

2.4.2. The gas mobility role in mobility mixes

As developed in mobility technologies presentation, gas vehicles are globally more environmental friendly compared to conventionals, in particular by gathering a reduced amount of CO₂ released from tank to wheel even without greening the gas and achieving negligible small particles emissions. Gas vehicles may decrease the impact of mobility for global warming and for local air pollution. However, doubts exists about the claims of the truck manufacturers about the emission benefits of NGV compared to conventionals because tests are not representative of the real behavior of vehicles uses and emissions are higher than the figures assessed (Transport & Environnement 2019). It would

highlight the wide variability of results based on several technical characteristics, including the type of LNG packaging (compressed CNG or liquefied LNG) that do not perform as well. In this case, for greenhouse gas emissions, NGV models perform just slightly better than the average diesel models based on a tank-to-wheel analysis and by adding upstream fuel emissions, no engine has a net advantage over the other. Hence, in terms of climate impact, the usual natural gas LNG does not decarbonize deeply road transport. Only renewable gas, including biomethane used as bioGNV, can reduce greenhouse gas emissions compared to the use of diesel (TNO 2019). To sum up, and confirmed by POLES simulations, NGVs are unlikely to fundamentally transform the energy mix of the road transportation, in spite of conventional vehicles phase out projections. For instance, in the case of light vehicles, electric vehicle may remain more competitive than NGVs to achieve GHG emissions cuts. Moreover, for light commercial vehicles, the NGV use may not produce the desired effect since it emits more greenhouse gases on its lifespan than a new diesel utility (Carbone 4 2018).

Nevertheless, as electric vehicles do not represent the silver bullet for each mobility need, NGV will play a role in mobility mixes with the future displacement of conventional oil cars. NGVs could be seen as a catalyst for a reduction in transportation energy consumption and for CO₂ emissions cuts. NGVs are nowadays the most developed fleet of non-conventional vehicles because they already represent a cost effective alternative especially in local fleets, long transportation modes and trucks. In particular, NGVs know an appreciable development for heavy vehicles, in particular for public and goods transportation. They represent an alternative in short term to mitigate transport emissions and local air pollution, and in the long term to have a diversified road transformation mix where each motorization answers a different mobility need. NGVs are compatible with long transportation need where it answers the problem of autonomy, quick tank charging and cost competitiveness. Besides, having a larger rate of green gas in the network or even a dedicated green gas refueling infrastructure make these vehicles more environmentally competitive in order to reach climate policies objectives, air pollution and GHG emissions limitations. The speed of the NGV diffusion largely depends on performance improvements, government push on infrastructure development, subsidies for vehicle acquisition and tax advantages for gas versus oil.

As certain uses currently provided by petroleum products, such as maritime or air transport, may not find an alternative in electricity, natural gas could be the solution to decarbonise these sectors, including in the long term without other alternatives existing (Ecube et CRE 2018). Indeed, the technical and economical performances of batteries are far from guaranteed in these heavy transportation segments. Seen today, the main credible decarbonized alternative in these segments seems to be hydrogen mobility, but the large-scale deployment of this solution remains very uncertain and far away. Natural gas, which is not decarbonised but emits less than diesel, could therefore remain the most relevant alternative in the long term for heavy goods vehicles and for maritime transport. Green gas development would be a way to decarbonise it even more deeply by replacing natural gas at reasonable costs.

The question in stake is that is it appropriate to use natural gas, i.e. mainly fossil gas nowadays, as an energy transition solution for road transport, to prepare the ground before generalizing renewable gas. On the other hand, given the large but still limited potential for renewable gas production, will there be enough to decarbonize also the other uses of gas, for heating, in electricity generation or in industrial processes?

3. Other sectors decarbonisation

3.1. Buildings

3.1.1. Overview of energy consumption in buildings

Buildings accounts for 39,5% of final energy consumption and 27% of CO₂ emissions worldwide. It is therefore another target for public energy and climate policies in order to reduce global GHG emissions (IEA 2018). **Figure 53** shows the world energy consumption in buildings.

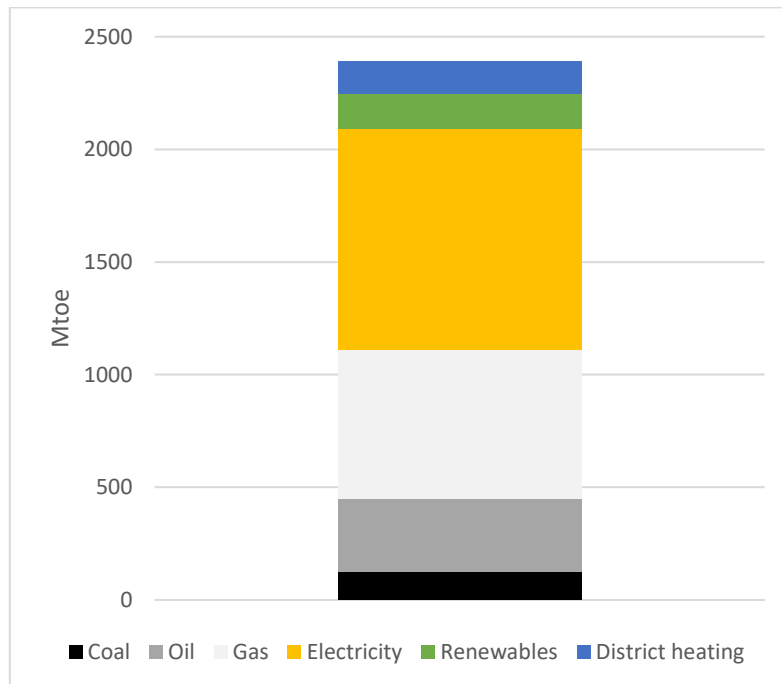


Figure 53 : World buildings energy consumption in 2017
Data from (IEA 2018)

Whereas we can compare the mobility and the vehicle parks composition for all countries in the world, it is more complex to easily compare buildings through the world. Their conception, construction, exploitation depend on the type of the building (residential that can be houses, flats, etc. or tertiary buildings with offices, classrooms, shops, etc.), the site where they are implemented in a hot, cold or humid environment, the materials used for the construction, etc.

Being the major energy consumptions sites in buildings, heating and cooling have to be tackled for decarbonisation. However, there are less considered compared to power sector or transportation sector for decarbonisation purposes. Nevertheless, they represent an important consumption sector, around 50% in the EU, which is highly carbonated, because around 80% of the heat comes from fossils. The remaining renewable part is provided by woody biomass in majority (REN21 2019).

Thanks to its contribution to the heat sector, between 30 to 40% of total gas consumption according to the season (IEA 2019), natural gas plays an essential role in the winter tip crossing, a role that will remain essential in most European countries in the future. The pace at which the heat sector can evolve is limited by the investments required in the new and existing fleet to renew heating facilities. By way of illustration, in France, there are currently 9 million homes equipped with individual heating with natural gas. By assuming an average renewal rate of heating equipment of the order of 5%, still 50% of existing individual natural gas boilers will still operate in 2030 (Ecube et CRE 2018).

Concerning France, buildings represent 45% of the country energy consumption and only 25% of all GHG emissions. This proportion has been declining for 30 years thanks to energy efficiency efforts and the decline in fuel oil in favour of electric⁷ heating. France has also set a target of reducing final energy consumption in this sector by 28% by 2030 compared to 2005.

Let’s see how buildings energy consumption would evolve in POLES modelling.

3.1.2. Results and analysis

Figure 54 shows the buildings energy consumption for baseline and 2°C scenario for the world and Europe from POLES. For the world in baseline, energy consumption increases, principally electricity, due to an increase in world population, buildings number and economy tertiarization in developing countries all around in the world. This increase is more contained in scenario 2°C thanks to sobriety and efficiency policies implemented that would decrease the amount of energy consumed for a same need. In Europe, the consumption decreases a bit in baseline because of a stagnation of European population and limited rural exodus compared to developing countries that would increase the building park in those countries. Besides, projected energetic renovations should allow a reduction of energy consumption compared to actual building park. This drop is deeper in scenario 2°C for the same reasons of climate policies impacts on energy consumption.

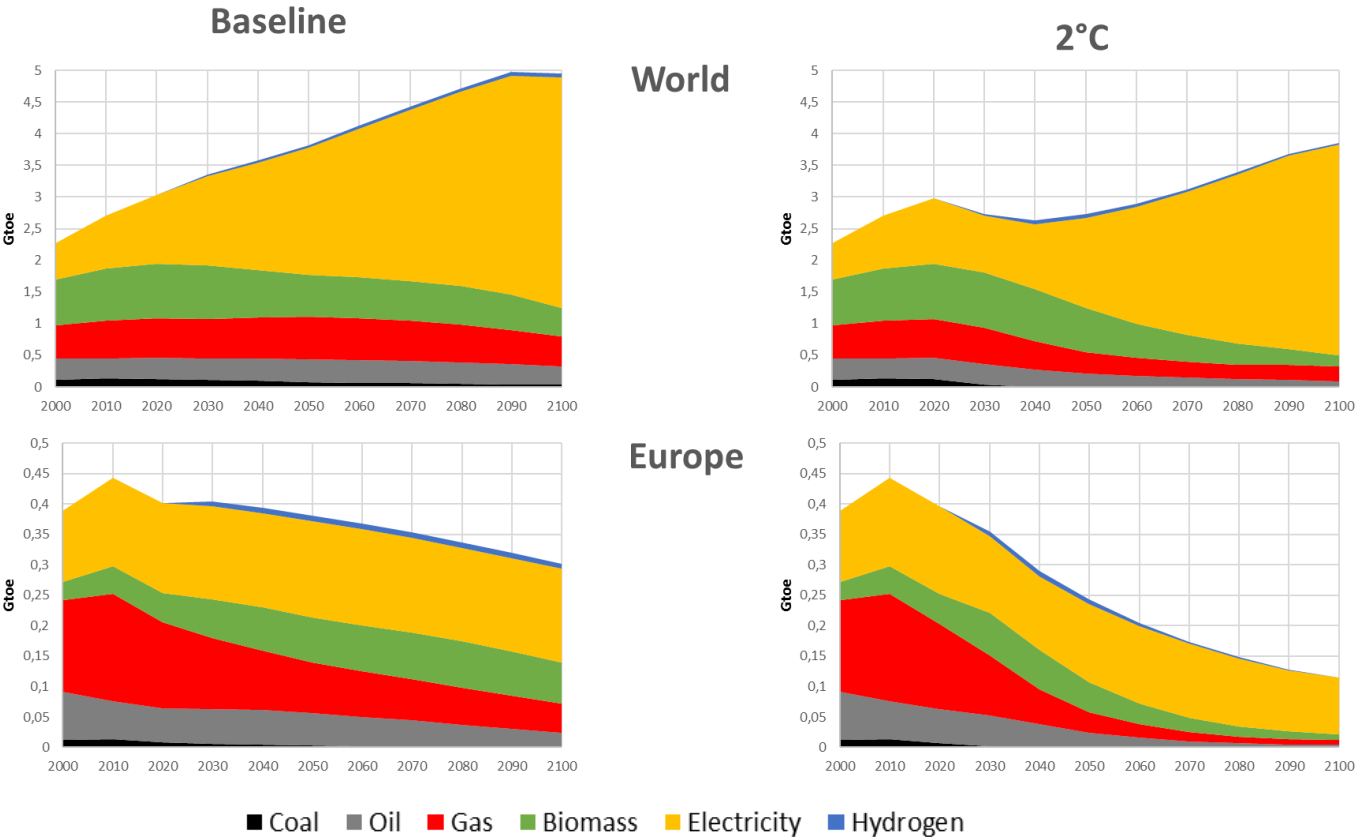


Figure 54 : World and Europe buildings energy consumption Scenarios baseline and 2°C - POLES-GAEL

⁷ Mainly coming from low carbon sources like nuclear and hydro, but coming from fossil power plants in peak load periods.

We notice that for decarbonisation purpose, electricity is mainly privileged. Hence, gas and green gas would not know a huge penetration for decarbonisation in buildings sector. Besides, the shrinking of total building energy consumption in Europe and low expansion in the world may not allow a widespread of gas consumption, as many consumptions are not gas switchable except for heat production, but that is in competition with electric and district heating.

The drop of CO₂ buildings emissions in **figure 55** can be explained by the impact of the three decarbonisation pillars. The first is the energy sobriety and efficiency that reduce the total energy consumption in buildings. Second is the massive use of electricity in both scenario that is the decarbonisation of uses. Last is the fact that electricity is more decarbonised in 2°C scenario than in the baseline that is the decarbonisation of the energy carrier.

In this case, the impact of greening the gas on buildings decarbonisation is limited at the decarbonisation of electricity production consumed in buildings as there are very limited quantities of gas consumed in buildings in our scenarios.

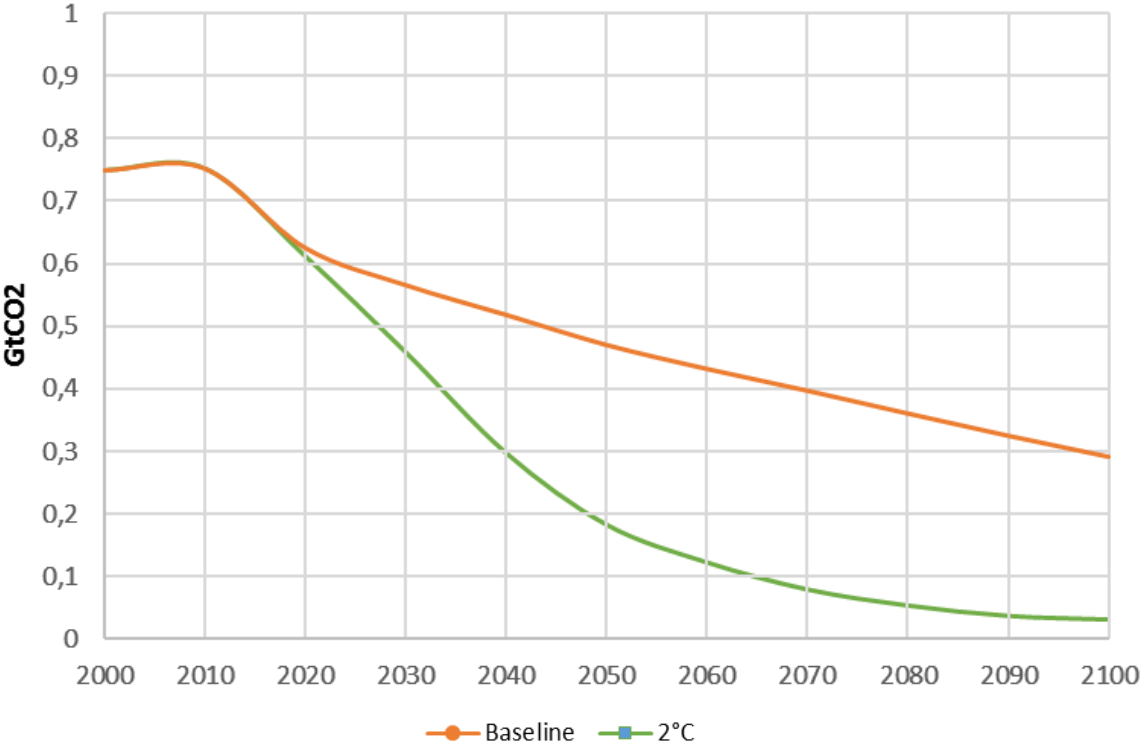


Figure 55 : European buildings GHG emissions Scenarios baseline and 2°C - POLES-GAEL

3.1.3. Discussion

Policies are important to make a huge step toward buildings decarbonisation. For instance, Denmark banned oil and gas heating in new buildings in 2013. In addition, since 2016, oil heating is also prohibited in existing buildings located in an area served by a heat or natural gas network. The Netherland has also banned the fossil fuel heating in buildings since January 2020 (Désaunay 2020). With a higher percentage of the world’s population now living in urban areas than ever before, cities are also lead actors in shifting the world toward a decarbonized building sector.

France has a carbon neutrality objective in 2050, so that it leads to a fleet of zero carbon emission buildings by this deadline (Ministère de la transition écologique et solidaire 2019). The implementation of measures dealing with the actual building park, combining insulation walls and substitution of fossil heating by low carbon energy, may allow meeting political objectives for this sector. In this way, objectives are high concerning the energy renovation plan of the buildings: 500 000 buildings should be renovated each year. It corresponds to a high rhythm for actual buildings renovation. In practice, this figure, which is below the objective of 700 000 to have a fully decarbonized building park in 2050, is not reached with just 300 000 renovations in 2018 so that effort have to be accentuated (Sebi 2019).

Another active choice, with renovation building is the change of heating energy from fossil fuels to electric (heat pump) or bioenergy (pellets, wood modern boiler). It is a powerful decarbonisation lever whose effects are coupled with a reduction of dependence import of hydrocarbons for people and the country but gas and green gas should not penetrate a lot in buildings decarbonisation. Nevertheless, our simulations do not show a large penetration of this technology instead of electric devices. Other “buildings scenarios” may be considered by subsidizing these equipments to see if buildings consumption patterns would change.

Even if transportation and buildings represent the two main sector for energy consumption (around 65%) and GHG releases, the other sectors are not negligible so far. Therefore, they represents consumptions that can be harder to decarbonise especially thanks to electricity. Let’s focus on industry and agriculture sectors.

3.2. Industrial decarbonisation feedstock

3.2.1. Overview of energy consumption in industry

Industry is often presented as a sector where it is difficult to reduce GHG releases because these emissions are at the core of industrials processes because of fossils fuels consumption as inputs. **Figure 56** presents world energy consumption in industry in 2017.

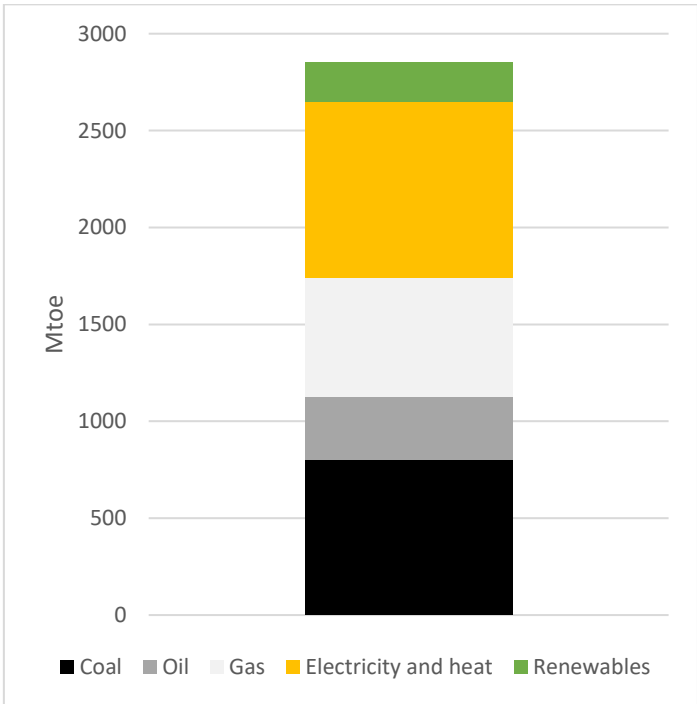


Figure 56 : World industry energy consumption in 2017
Data from (IEA 2018)

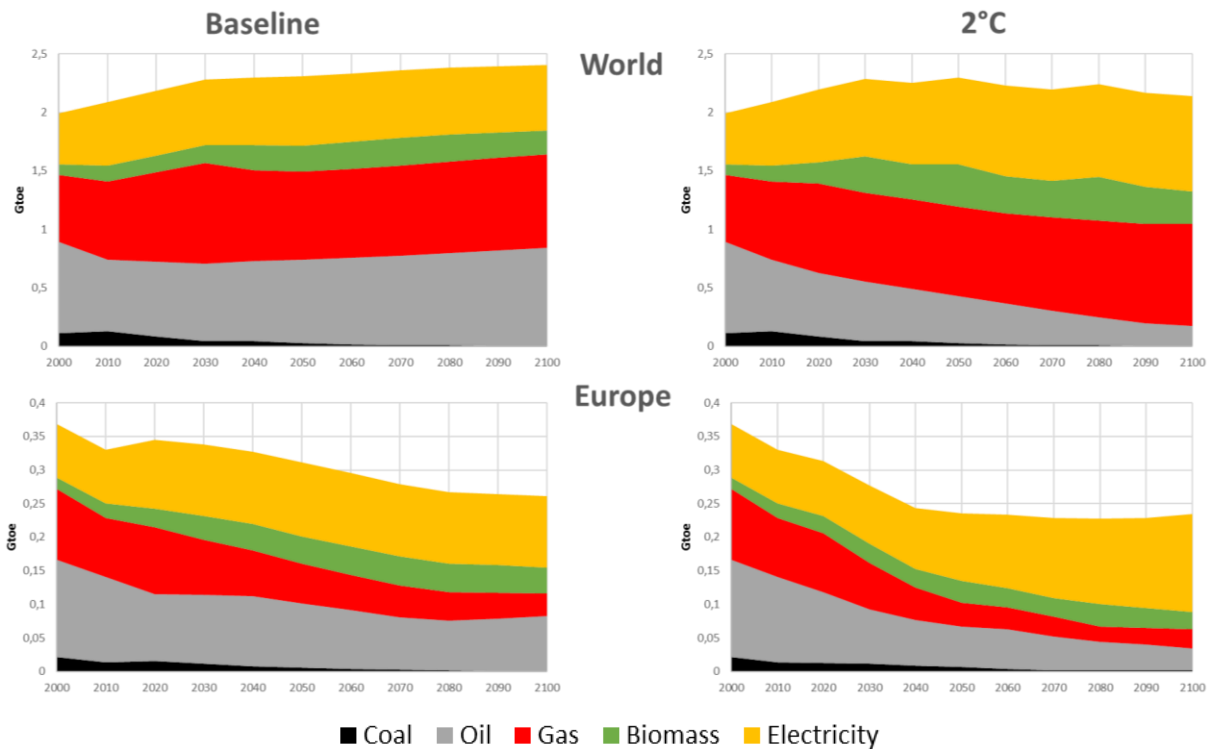
Fossil fuels account for more than 50% of the total energy consumption in industry. This final energy consumption accounted for a third of global energy use and 19% of global GHG emissions in 2017, 15% in the EU, 18% in France (IEA 2018) (OIES 2019) (Carbone 4 2018). Global industrial gas demand is projected to increase by 40% by 2040, in the IEA's Sustainable Development Scenario (IEA 2018). Hence, industry will account for the largest share in primary energy demand growth to 2040 and become a higher contributor to GHG release (29%).

Nevertheless, decarbonisation could be improved in this sector. Reducing energy demand and emissions from the industrial sector, without compromising economic and social development goals, will require energy efficiency strategies, switching to lower-carbon fuels and raw materials, and use the best available technologies, such as CCS. For instance, switching industrial boilers from coal to gas is a first step to reduce GHG emissions and local air pollution (see chapter 2 that is a strong point for gas as a transition energy). The substitution of heating fossil fuel by heat pumps high temperature is also a cost effective solution (Carbone 4 2018). Likewise, in cement factories, responsible for 7% of world emissions and around 40% of industrial sector (IEA 2018), more than 90% of the energy used is fuel combustion. Using gas instead of coal to heat these furnaces can result in almost no SO_x emissions and half of the CO₂ emissions and even beyond if using biomethane (IGU 2019). However, with climate policies objectives, even if various options of decarbonisation can be considered, a common point is a decrease of energy consumption in industry by 2050 and 2100 (OIES 2019).

3.2.2. Results and analysis

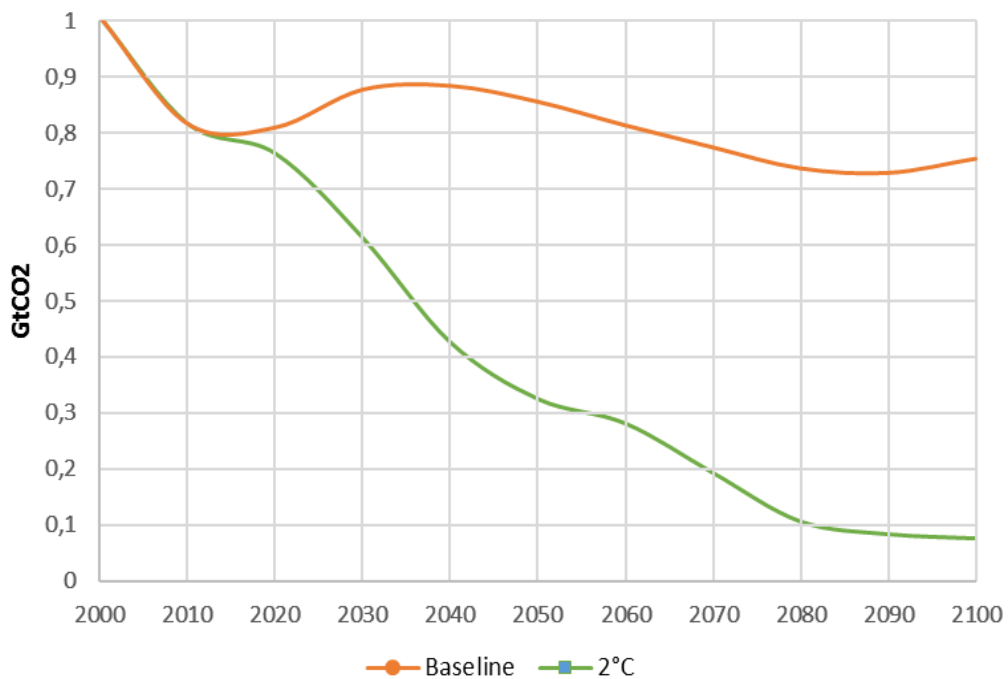
Figure 57 shows the industrial energy consumption for the world and Europe for scenario baseline and 2°C calculated with POLES model. The slight increase of energy consumption is approximately the same for both scenario for the world. The energy mix is just more electrified and less oil based in scenario 2°C compared to baseline. In addition, gas consumption increases a bit in this climate policies scenario, from 0,5 to 0,6 Gtoe, among it a non-negligible green gas share up to 50%.

In Europe, the amount of energy consumed decrease slightly by 20% in the second part of the century in scenario 2°C compared to baseline. Mainly electricity would replace oil in the mix. Gas would not develop more but the green gas produced would help to decarbonize industrial sector



**Figure 57 : World and Europe industrial energy consumption
Scenarios baseline and 2°C - POLES-GAEL**

Figure 58 shows the drop of industrial emissions in Europe in a climate policies scenario. It represents more than 50% in 2050 and more than 80% in 2100. It can be explained by the little decrease of total energy consumption, a withdrawal of coal and oil consumption, and the transformation of half the gas in green gas. Thus, we can interpret this tendency by a combination of the three pillar of decarbonisation.



**Figure 58 : European industrial GHG emissions
Scenarios baseline and 2°C - POLES-GAEL**

In order to reach the decarbonization with the fuel switch, new equipments can be installed. For instance, the installation of a very high temperature heat pumps instead of a fossil boilers for heat-consuming industries is an already developed solution, which is very efficient to reduce heating induced emissions. It is also economically profitable compared to an industrial boiler fueled by fossils.

At a lower scale, the industries using hydrogen could also use the hydrogen produced by water electrolysis in climate policies scenarios, instead of hydrogen produced by steam reforming of fossil gas natural or other carbonated process.

3.3. Agriculture decarbonisation

3.3.1. Overview of energy consumption in agriculture

Today’s food and land use systems are confronted with a great variety of challenges. This includes delivering on universal food security and better diets in the future. Even if there is a growing awareness about food security in the world and there are more efforts to provide food to everybody, the number of people suffering from hunger has been rising again from below 800 million in 2015 to over 820 million people nowadays (Food and Agriculture Organization s.d.). In the same time, agriculture, forestry and other land use currently account for around 24% of greenhouse gas emissions caused by human activities (IPCC 2019). The transformation of the food and land use system will play a critical role in both managing climate risks and bringing the world onto a sustainable development trajectory. It offers an opportunity to enhance sustainable food production besides GHG emissions.

Current structure of agricultural emissions is separated as follow (*figure 59*): the main emissions of this sector comes from the herd of ruminants (mainly cattle, and more marginally sheep and goats), because of the methane formed in their digestive system and released in the air. The second comes from emissions of nitrous oxide from agricultural soils after the spread of nitrogen fertilizers. Energy - essentially diesel from agricultural mechanization - is only far behind. Given that 80% of agricultural land is used for animal feed, we can therefore see that the bulk of agriculture's carbon footprint is the result of the consumption of meat, especially large animals, without even taking into account the soy or palm trees induced deforestation (AEE 2019).

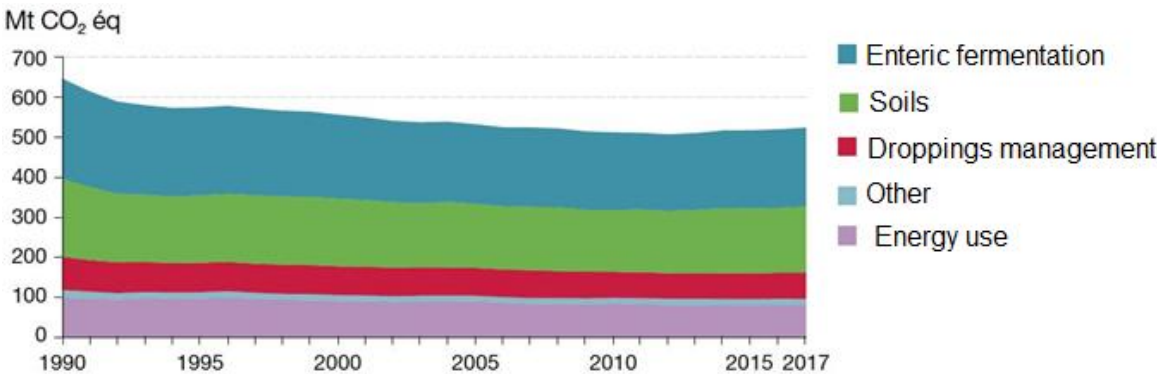


Figure 59 : Agricultural GHG emissions in EU28 by sub-sector excluding LULUCF
Taken from (AEE 2019)

The Afterres2050 scenario assesses that the energy consumption in agriculture could be divided by 2 reaching 64TWh – 5,5Mtoe in 2050, thanks to changes in systems and practices as fuel use for plowing or fertilizer use, and improvements techniques as low consumption hothouses, irrigation thrifty or tractor engines (Solagro, Afterres2050 2016).

Hence, regarding these consumption patterns, the fuel switch and decarbonisation impacts modelled with POLES model take into account only a little part of the agricultural emissions and this is a limit of this energy modelling.

3.3.2. Results and analysis

Figure 60 shows the agricultural sector energy consumption for the world and Europe for baseline and 2°C scenario simulated with POLES.

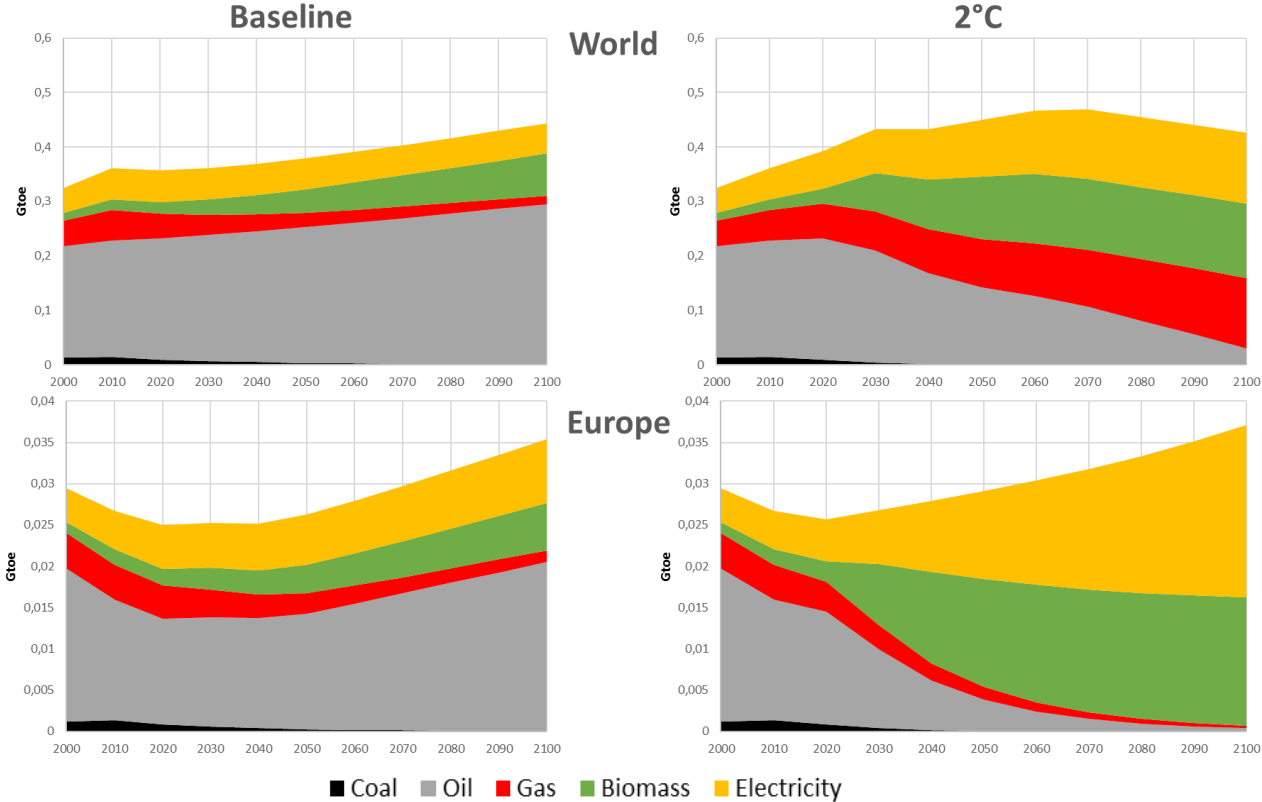


Figure 60 : World and Europe agricultural energy consumption Scenarios baseline and 2°C - POLES-GAEL

First, it is worth noticing that the order of magnitude is a bit different from previous consumption sectors: while energy quantities were about 2 to 5 Gtoe for the world (respectively 0.3 to 0.5 Gtoe for Europe), the agriculture sector deals with 0,3 to 0,5 Gtoe (respectively 0,02 to 0,04 Gtoe).

In baseline, oil is still predominant while overall energy consumption increases a bit. In scenario 2°C, oil is replaced by electricity, biomass and gas for the world perimeter. For Europe, it is the same trend except for gas that would not penetrate. It may be explained by the increasing use of biomass as a biofuel to decarbonize current machineries and by an electrification expected of agricultural processes for breeding or farming. Hence, gas and green gas could take part of agriculture decarbonisation but is probably not the most efficient way to decarbonize deeply agriculture.

Agriculture knows a high dependency in agricultural mechanization. So, agriculture is locked in fossil fuels because of the nature of agricultural machinery that are difficult to electrify as tractors. The change of motorization of agriculture is limited and could probably not be higher than 22% of its energy use according to (Harchaoui et Chatzimpiros 2018). Ways of decarbonisation could be achieved with energy efficiency gains reducing the overall energy consumption or thanks to decarbonisation of

energy vector. As illustrated in scenario 2°C output, biofuels may decarbonize more deeply machineries. Nevertheless, they are still regulatory limitations concerning the ratio of biofuels that can be melted with the oil based fuel.

This sector is facing challenges through energy transition. Because agriculture, forestry and other land uses currently account for around one quarter of human GHG emissions, global systems can be rethink in shifting towards more sustainable practices. Land use changes are also a major driver behind the worldwide loss of biodiversity. Hence, systems thinking is key in shifting towards more sustainable and efficient practices. Reductions in methane and nitrous oxide emissions from enteric fermentation, manure management and fertilizer application may be considered (Gil, et al. 2019). For instance, a major opportunity to decrease carbon content of agriculture is to change the agricultural model with reducing feed production or by decreasing the enteric fermentation responsible more than a half of agricultural GHG releases worldwide (Harchaoui et Chatzimpiros 2018). Agriculture can be also intensified per unit area, with a change of production strategies. New models for food production have also to be considered to address the problem of fertilizers releases by using less herbicide, less chemical fertilizers (Browne 2017).

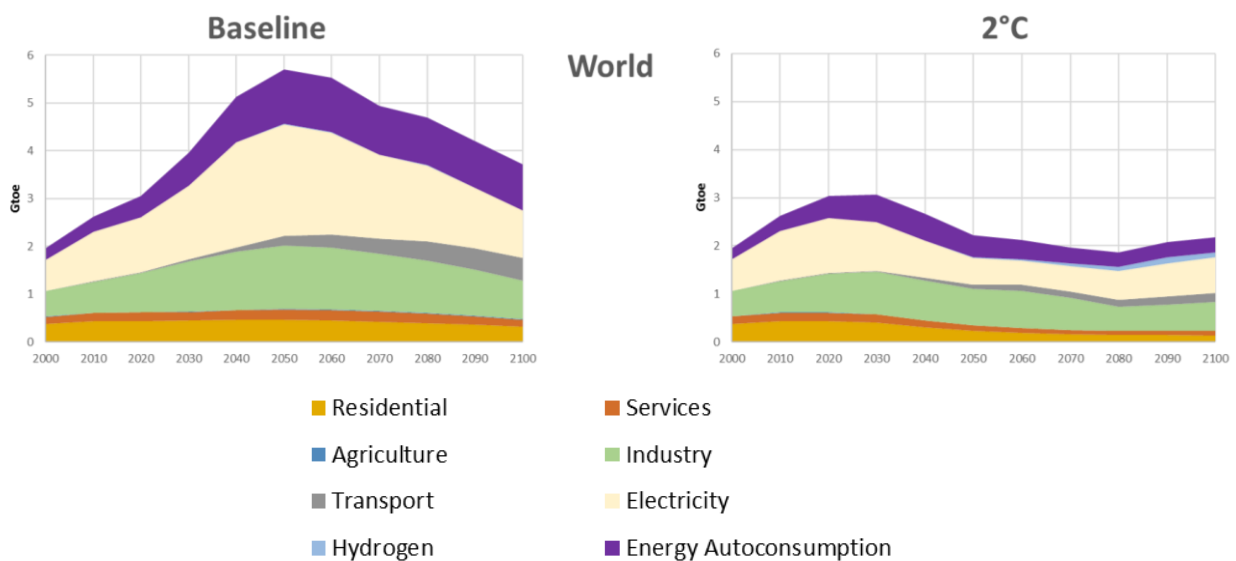
Given the high costs of increasing production efficiency further, there is a need for a lot more ambitious policy targets and behavior systemic changes. For example, focusing on the resource use efficiency, there is a need to reduce the consumption of meat and dairy at the global level, so it implies a change in humans' habits concerning meat consumption. Others studies show that shifting towards healthy diets not only improves human health, but also reduces pressure on land, thereby helping to improve the solution space for addressing climate change and halting biodiversity loss (Sperling 2019).

4. Conclusion of chapter 4

We presented in this chapter the decarbonisation of gas production and the role of gas and green gas in consumption sectors decarbonisation.

Green gas knows a noticeable growth in climate policies scenarios and can reach around half of total gas consumption in spite of local differences and specificities for green gas production, in particular because the availability of local potential.

Gas and green gas are not negligible in this decarbonisation as gas remains consumed globally in many sectors in particular in power, industrial and transportation sectors for the world (**figure 61**). However, gas consumption would be reduced in residential and tertiary buildings in a climate policies scenario and gas consumption would not penetrate deeply in agriculture sector.



**Figure 61 : Gas consumption for world
Scenarios baseline and 2°C - POLES-GAEL**

In a climate constraint scenario, the overall energy consumption and the gas energy consumption is shrinking, in our example by around 40% in the world at the end of the century. Therefore, greening the energy consumption thanks to green gas cannot expand widely because of this constraint of total expected gas consumption limitation.

Figure 62 shows gas consumption details for Europe for baseline, 2°C scenario and 2°C scenario without CCS. Beyond the reduction of the total gas consumed between 2010 and 2100, the repartition of this consumption among the sectors is different. In particular, gas consumption share for transportation would increase a lot while those for residential and services would drop. The share for industry would increase a bit for climate policies scenario.

In addition, techno-economic parameters like technological competitiveness are a necessary but not sufficient condition on the green gas development. Other constraints appears for green gas development as the availability of potential. Besides, the scenario without CCS shows another landscape of green gas production as green gas may develop more in this scenario and gas consumptions sectors would change like for transportation: its share raises from 30% to 40% of total

gas consumption in our simulations. We bring out here that another technological development (CCS) implicate other cross effects that may change the quantity but also the repartition of gas consumption. In our case, more gas is dedicated to transport and industry decarbonisation in the absence of CCS. It may be explained by another cross-sectoral effect: CCS are not possible for electricity production, so that transport would privileged gas and green gas consumption to decarbonise rather than electricity that may be more carbonated.

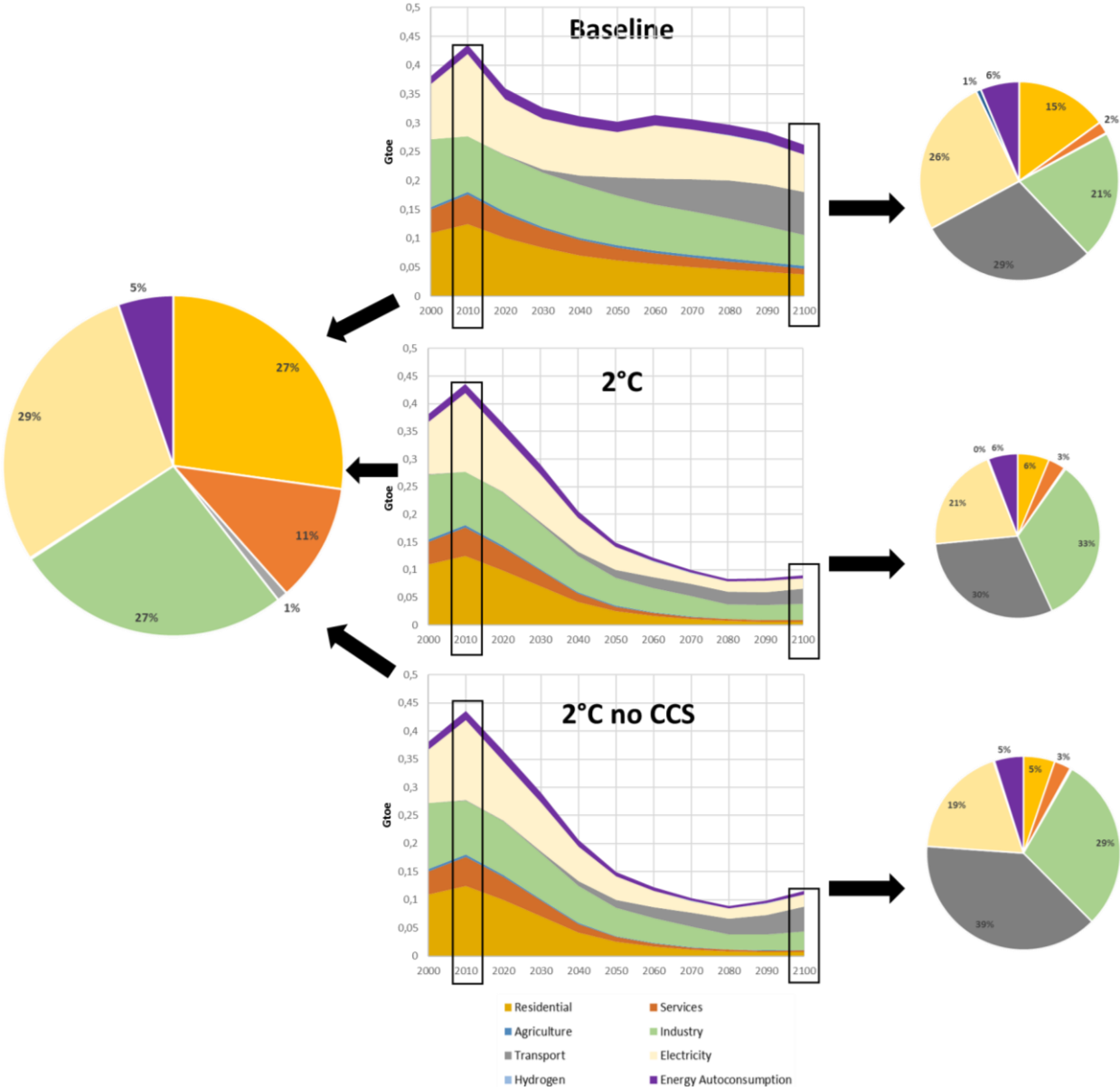


Figure 62 : European gas uses
Scenarios baseline, 2°C and 2°C no CCS - POLES-GAEL

All in all, green gas would green the gas energy vector, more or less according to local resource availability and technological development rates, although sobriety and efficiency measures taken in a climate constraint scenario would limit the total quantity of gas and green gas consumption. Besides, complex cross-sectoral effects may occur with other decarbonisation technologies that may change simulated patterns on the green gas development.

Chapter 5: electricity and gas networks interactions

As seen and assessed thanks to POLES scenarios, green gas helps in decarbonisation of energy systems by switching gas supply into a low carbon source and by modifying energy patterns in consumption sectors. After presenting the stakes for electricity production in a decarbonization context, this chapter will deal with the power to gas business model. Indeed, the question of positioning gas to power and power to gas in the energy system, as a whole, will undoubtedly be a determining factor in the contribution of this technology in the energy transition and green gas fields by coupling electric and gas systems in order to help networks to deal with variable renewable electricity production.

1. The electricity system in the decarbonisation context

Electrification is seen as the main option for decarbonisation purposes. When consumed, from a tank to wheel life cycle analysis, electricity does not release any GHG or particle emissions (IEA 2018). Electricity allows replacement of direct fossil fuels consumption and the related direct GHG emissions for heating, moving, lighting, etc. However, electricity production can be done from different primary sources of energy and some of them release GHG.

This first section of this chapter presents why the electric sector relies mainly on fossil fuels nowadays and why electricity is still carbonated. Then we will focus on how electricity production may be decarbonated and what it would imply for the electric system in terms of flexibility needs and long term storage possible by green gas.

1.1. The electricity generation mix

1.1.1. Current electricity production overview

Figure 63 presents the electricity production in the world.

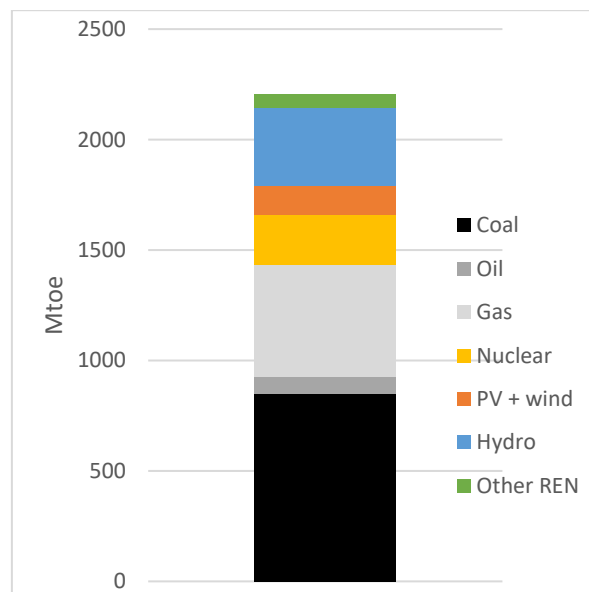


Figure 63 : World electricity production in 2017
Data from (IEA 2018)

In 2017, around 65% of electricity production in the world is done thanks to fossil fuels, 38% by coal, 23% by gas and 4% by oil. It is interesting to note that in 1997, there was the same ratio of 63% fossil based power and 37% from low-carbon sources. In 2018, there is the same ratio in spite of higher wind and solar power development (World Energy Council 2019). Hence, the development of variable renewable energy is coupled with an increase of fossil fuels power capacities and decrease of nuclear share after Fukushima. Because two third of world electricity is done with those fossil fuels, electricity production represents the first sector that release CO₂ in the atmosphere: 40% of carbon emissions comes from power generation worldwide (IEA 2018).

1.1.2. The merit order mechanism for power plants allocation

The choice for power plants that are called to produce electricity is done based on the “merit order” rule. This logic consists of calling upon the different electrical production units, as and when they are required, according to their increasing marginal variable costs (Boiteux 1956). Following this rule, the first units of production called are those producing the so-called "fatal" or “run-off” electricity, i.e. the electricity "lost" if it is not used at a given moment. This is the case for variable renewable energies wind and solar, as well as hydraulic run-of-the-river. Then, pilotable production plants are used. Nuclear power plants with their lower variable costs are called, before fossil plants (coal, gas and oil) that produce electricity mid load and peak consumption (Hildmann, Ulbig et Andersson 2015).

Figure 64 represents this merit order logic and the set of electricity spot price

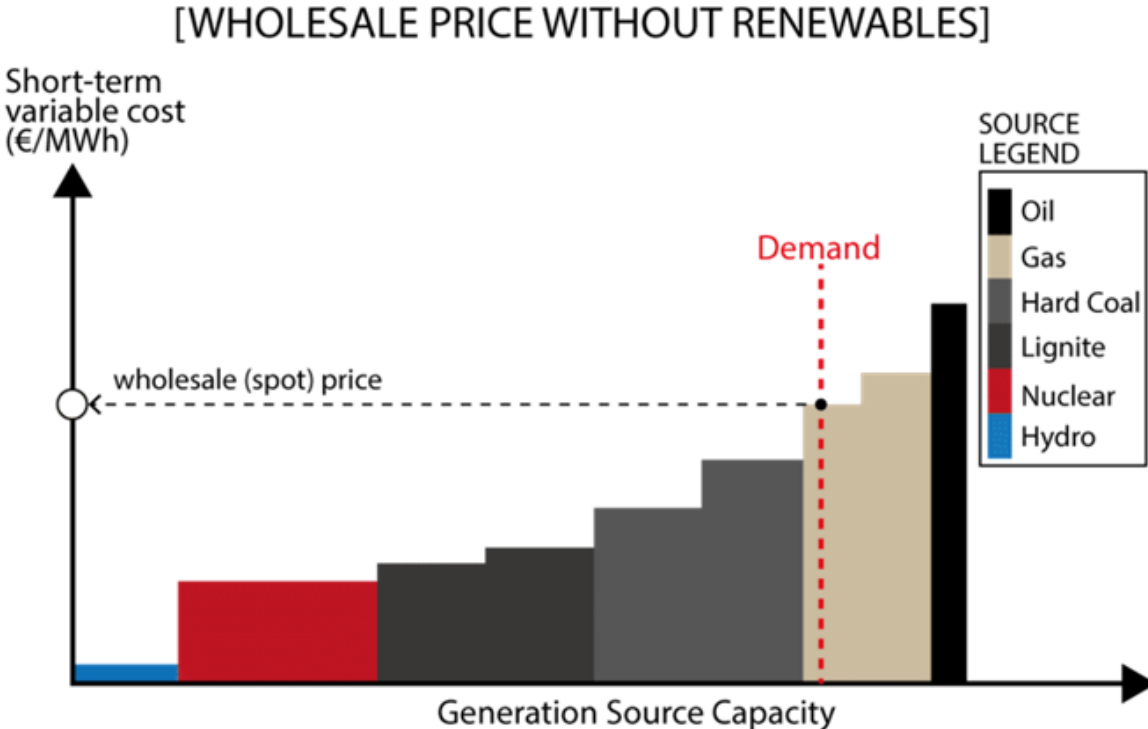


Figure 64 : The merit order principle for electricity production
 Taken from (Bumpus et Wainstein 2016)

At equilibrium, on average over the year, the electricity price should cover the full cost of the plants in regard of their production. Indeed, following this rule, the cost of production increases when demand is higher because power plants that are more expensive to operate are called to meet the higher demand. This marginal cost is the cost of production for the last power plant called: it is the additional cost induced by the last unit produced. It is represented by the spot price that is to pay for this plant

to recover its production costs and the investment of the other power plants (Hasan, D. Galiana et Conejo 2008).

The increase of VRE installed power drives to an increase of almost zero marginal cost production capacity. Besides, because of political targets for renewables development, some countries put some support mechanisms for integration of renewable energy, so that VRE production are prioritized for grid injection. The merit order curve is then shifted to the right as seen in **figure 65**.

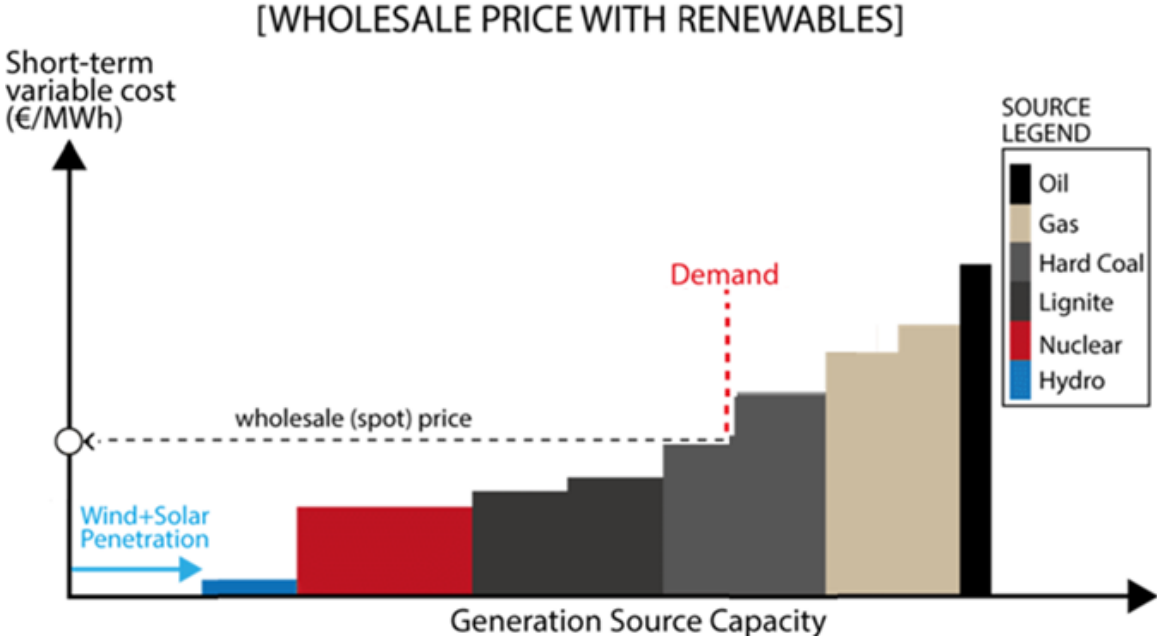


Figure 65 : Merit order changes with VRE incorporation
 Taken from (Bumpus et Wainstein 2016)

The VRE incorporation in power mix changes this framework. Being with almost zero variable costs, “non-controllable” and intermittent renewable power plants are first called. This leads to a decrease of “controllable” plants production. Another reason is that VRE production can be injected in priority in some countries because of ambitious targets concerning VRE production (RTE 2019). This induces an increase in the production cost of “controllable” plants because the increase of VRE production reduces the load factor of these plants so that the cost per unit of energy is higher because of their incomputable fixed costs. As seen in **figure 66**, benefits will be lower or the power plant operator, that is a concern for its viability.

It is worth noticing that the merit order logic is also impacted with capacity withdrawals (for example shutdown of a plant for maintenance), with national energy policy (for example subsidies to a source of energy) or with markets as it is possible to import electricity abroad when it is less expensive. It would change the power plants ranking presented above. Besides, the order of the units of production also varies if their CO₂ emissions are taken into consideration. An additional variable cost is put in the form of a carbon tax. For instance, the coal-gas order in favor of coal has switched as the carbon price in the European Union Emissions Trading System (EU ETS) rose above €20 t/CO₂ and gas prices fell. It pushes the gas generation and reduce the coal generation because gas fuel became cheaper than coal fuel throughout 2019 (Myllyvirta, Jones et Buckley 2019).

[WHOLESALE PRICE WITH RENEWABLES]

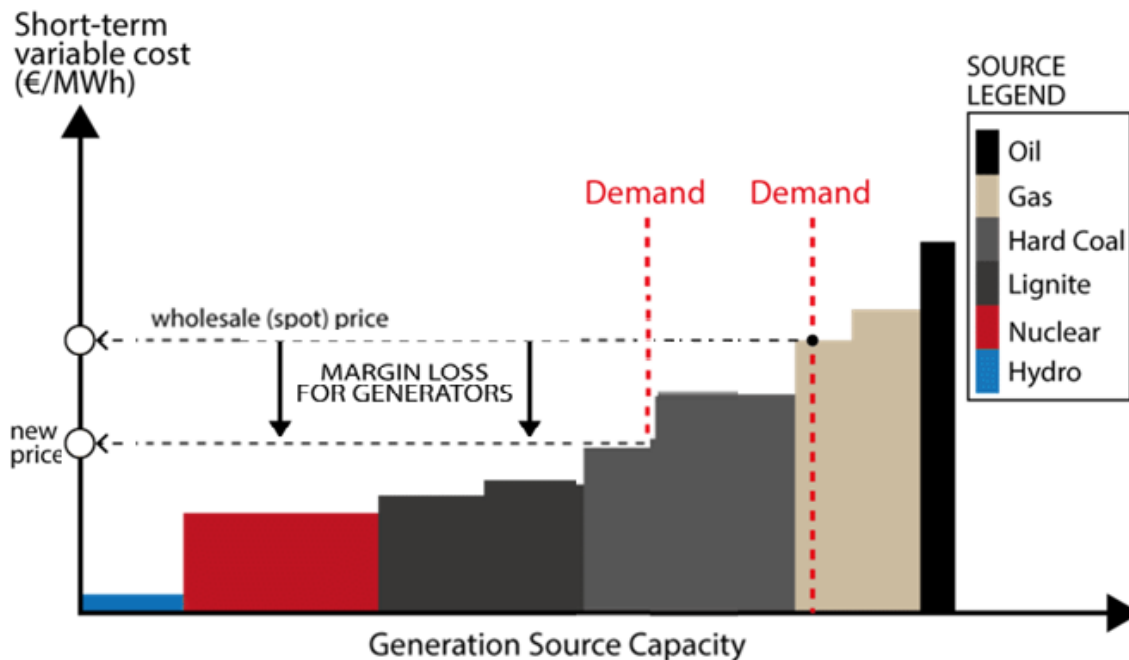
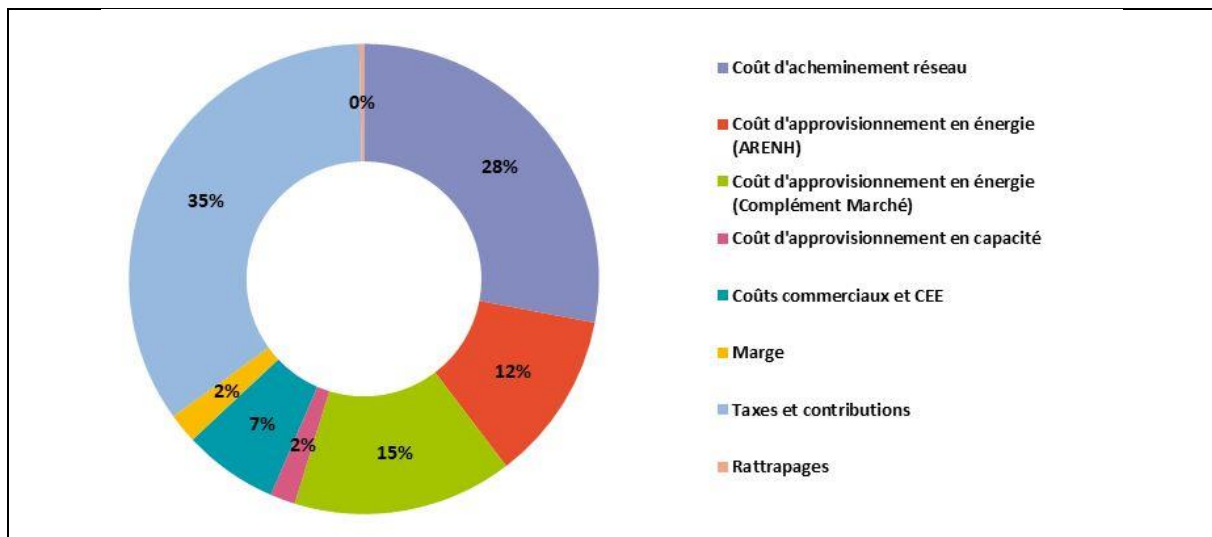


Figure 66 : VRE incorporation effect in price and operator revenues
Adapted from (Bumpus et Wainstein 2016)

In addition, to compare the cost of electricity generation by plants, the availability of the plants is a parameter to take into account. For instance, it is a non-sense to compare the marginal costs of VRE production with dispatchable power plants without taking into account the low load factor of those plants. For example, dispatchable plants operators can use other markets as the capacity market to be remunerated as their power plants can guarantee to be available for critical periods for grid balance as in peak demand and/or very low VRE production. Hence, a comparable cost is a life cycle analysis (LCA) cost with an average cost of a "non-dispatchable" plant considering back up strategies to provide the energy when VRE are not producing, as well as all hidden costs "from cradle to grave". Others parameters "externalities" are essential: environmental degradation, health risks, dependence on strategic metals and rare earths, destruction of jobs (Percebois 2019).

Insert : consumer electricity regulated prices in France

The electricity prices seen by consumers follow another logic than the marginal production cost defined by markets and merit order rules. These prices include three types of contributions: the cost of generating the electricity itself: this is the cost directly linked with the merit order logic presented above where the price is represented by the marginal production plant variable cost. Second is the delivery costs: this is the cost of electricity network. In France, this is the TURPE (Tarif d'utilisation des réseaux publics d'électricité - Usage Tariff for Public Electricity Networks) and covers the costs of delivering electricity from power generating facilities across high voltage lines and local distribution lines managed by the Transport and Distribution Systems Operators (TSO and DSO) national companies. The last part of the tariff is the taxes. Each part of the tariff represents approximately one third in the final price for customers in France. Small differences can occur in other countries because of differences in the regulation framework and the plants mix (CRE, Marché de détail de l'électricité 2019).



1.2. The need of different flexibility solutions

VRE productions are intermittent and produce energy only when climatic conditions are appropriate. Hence, renewable production do not correspond exactly to demand patterns: there are fluctuations in VRE production, which may lead to surplus generation compared to demand, grid congestion and even curtailment. The electric system has to adapt to these new patterns.

The increasing use of VRE implies higher need for flexibility in the electric sector. The definition of flexibility has been a topic of debate (Cruz et al. 2018; Lund et al. 2015) but it can be summarized as the possibility to provide energy to respond to a particular demand. The need for flexibility is the ability of the power system to react and absorb surplus or deficits of energy supply or demand because of the non-controllable VRE production and demand side variability. The objective is to smooth the residual load, which means counterbalancing variations in VRE production and demand patterns. Thus, the grid needs flexible tools to absorb this VRE production and balance the network, which is the golden rule for electric sector, and then having the possibility to incorporate even more renewables in the mix.

Rising flexibility needs require a response through adequate technological solutions. Flexibility options can be divided into 3 main groups presented below.

1.2.1. Dispatchable production plants.

Some dispatchable production plants can be started or switched off in a short period of time, so that these plants can respond to production and/or demand fluctuation very quickly. This is the case of gas turbines and combined cycle gas turbines but also coal power plants. They have fast ramping capabilities to compensate VRE production variation, so that they can be started in a very short time and vary their output power very quickly if VRE would not produce all of a sudden. Nuclear power plants can also provide flexible power for load following purposes as it is the case in France (RTE 2020). These plants represent also backup for situations when VRE production is low to fulfil the demand.

Dispatchable power plants offer flexibility, but these plants may become uneconomical at the low running hours implied by renewables-based power systems. Hence, their load factor would be lower than their nominal operation. These capacities have in this case an operating model with lots of starts and stops. To sum up, power plants qualified as flexible do not provide only fast ramping but also

frequent startups/shutdowns and operation at minimum stable generation power over long time daily (HadjSaid 2010). Paradoxically, these fossil and controllable plants are also a way to incorporate more VRE production plants as they can produce the electricity needed when VRE do not produce. The well-known example is Germany where VRE development is combined with coal and gas power plants operation to play the back-up role when sun or wind do not produce the electricity needed (OIE 2016). Hence, stakes are complex because like in this example, adding VRE in electricity mix may imply an increase of fossils plants capacity to increase the back-up capacities.

There are several networks services for the electricity networks, with different timescale and market designs. Business models of these back-up installations should change with other remunerations than the energy price on the market such as the capacity market, the reserve market and the balancing markets (Luickx, Delarue et D'haeseleer 2010). Indeed, the co-optimization of energy costs and ancillary services in a wholesale market implies that gas plants are committed often only for providing the flexibility services without being selected as economic in the merit order to produce electricity. Therefore, over a long period every day, the gas plants get revenues even below variable costs and cannot be paid back for the increasing O&M costs due to flexibility. Remunerating flexibility services outside the wholesale market seems unavoidable, for example thanks to a capacity payment focusing on resources able to deliver flexibility, and by improving and extending the need of ancillary services as it has been implemented in France in 2017 (Kannavou et Capros 2016).

1.2.2. Flexibility brought by demand

The flexibility from the demand is also called demand side management (DSM). This is a way to equilibrate supply and demand by controlling the demand and increasing or decreasing it in regard of the production: demand can be lowered when production is not strong enough or can be increased when there is a production surplus. For example, you can switch off electric heating during a small period when production is lacking without touching the comfort (Le Dréau 2016) or you can charge your electric vehicle or your hot water tank when there is a surplus, an afternoon sunny day or during the night (Aghaei et Alizadeh 2013). Usually, demand response can meet a daily flexibility need as it correspond to a limited capacity, in general taken up to 5% of peak load (Cortez 2019).

Two types of demand response are typically distinguished: the load shedding and the load shifting (European Commission, Mainstreaming RES - Flexibility portfolios - Design of flexibility portfolios at Member State level to facilitate a cost-efficient integration of high shares of renewables 2017). Load shedding represents the temporary shut-down of selected (usually industrial) electricity consumers, implying that the related energy service will not be delivered and the load shifting means an occasional reduction in power consumption which is compensated at a later stage in time, still ensuring the full provision of the energy service (e.g. charging of electric vehicles, heat pump). Hence, it is important to take into account the rebound effect that characterizes the impact of a load shift that directly follows a load shedding (O'Connell, et al. 2014). Depending on the electrical appliance, the rebound effect can be lower or higher than the curtailed load. Some important electrical load that could be controlled are the charging of hot water tanks, and also the EV thanks to smart chargers whose development can represent a major part of the future of DSM (Junker, et al. 2018).

1.2.3. Storages systems

The storage of electricity consists of conserving, temporarily a certain amount of electrical energy so that it can be used later. Except for applications still under research (such as electromagnetic storage by superconductors), electricity is not stored as such. In practice, therefore, electricity is transformed

in another energy carrier, and even twice: a first time to convert it into another form of energy, which allows its storage, and a second time to proceed to the opposite operation, the reconversion into electricity. Many storage technologies exist, with different patterns for time energy and capacity-scale that are summarized in **figure 67** (Luo , et al. 2015).

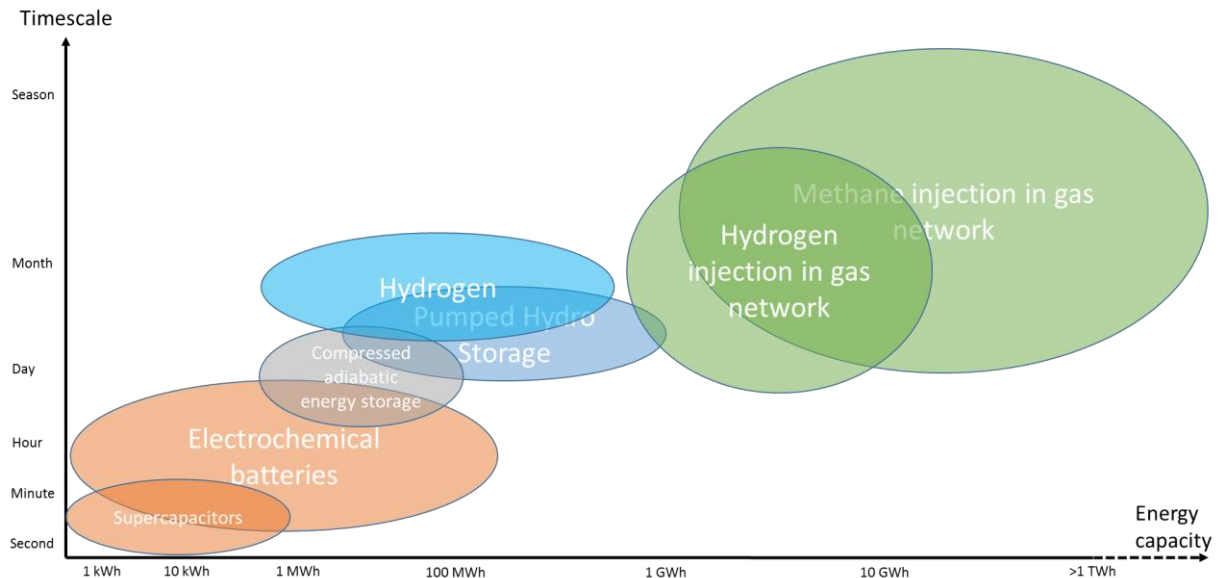


Figure 67 : Overview of storage devices scale
Based on (Luo , et al. 2015)

High-power storage includes flywheels, Superconducting Magnetic Energy Storage (SMES) and supercapacitors that can respond very quickly to a demand but for a very limited time. Others capacity storage devices are chemical batteries with different electrochemical lead-acid, lithium-ion, and nickel batteries that are coupled with cadmium, iron, zinc or metal hydride. Less energy can be stored in these storage systems, but they are compatible with non-stationary applications such as mobility.

Another storage system is Compressed Air Energy Storage (CAES), which can store a bit more energy of the mechanical energy of compressed air in caverns or pipelines, before releasing it in turbines. The technology have still low efficiency, so that it is not widely developed (Budt, et al. 2019).

The most used technology today is Pumped Hydro Storage (PHS): the existing world park for PHS in 2018 raises more than 180 GW when the total electricity storage installed is of the order of 190 GW (DOE 2019). They store electrical energy by using electricity to pump a quantity of water from a lower dam to a higher reservoir, and release the potential energy of the water by turbining this water from the higher to the lower reservoir. It allows a daily and even a weekly storage for big PHS. These installations can be also fueled by natural contribution from ice melting or precipitations according to the site where they are installed. Efficiencies of PHS are between 75% and 80% (Ursat , Jacquet Francillon et Rafai 2011).

Last but not least, and what will interest us in this chapter, the highest energy potential for long-term energy storage may be the conversion of electricity into a gas that would be injected in the gas network : the power to gas (see chapter 2 section 2.2). For example, in France, the gas network represents a 100TWh storage energy capacity. This amount of energy is almost a quarter of France electricity yearly consumption (ADEME, GRTgaz, et al. 2014).

Last, interconnections can be seen as a sharing of these sources of flexibility. The flexibility brought by the grid allows interconnecting several locations in order to generate energy flux between areas. The enhanced interconnection of countries and regions allows to better exploiting the complementarity in the national power generation mixes, weather conditions (so VRE production), demand profiles and flexibility option availability. In its infancy, the transportation and distribution grids have been developed to connect the centralized production plants to all the consumption loads. It allows also the renewables connection to the grid in order to connect its production to all the loads connected to this grid.

1.3. The different time-horizons of flexibility

Different flexibility needs are needed with increasing VRE generation. First of all, very short-term variation of power generation is introduced with solar or wind capacities. For instance, it is difficult to forecasts the effects of clouds, minute by minute, on PV generation. Some network, ancillary and capacity services as primary and secondary reserves are needed to guarantee frequency stability (CRE 2019).

High PV shares create a residual load hole at midday that requires balancing through dedicated flexibility solutions. The ramping between the afternoon and the night is also steeper. This hourly effect is known as the duck curve (CAISO 2013) and needs to cope with this short power fluctuation. Therefore, short timescale and low energy capacities storages systems as batteries can be relevant as well as demand side management or back up productions as hydro or gas power plants.

In the same time, weekly flexibility needs are due to wind power generation. Given a long term unpredictable character of wind generation, adding wind capacities to the power system directly implies an increase in flexibility needs, occurring from situations when no or less wind is available, during anticyclones for example. Hence, the flexibility needs change because there is a need to supply more energy during a longer time. Medium storages systems as larger batteries, pumped hydro storage (PHS) or hydrogen can be appropriate and back up production plants are still needed.

Finally yet importantly, seasonal variation in demand across the year linked with the VRE share determine annual flexibility needs. For instance, solar generation is highest in summer season, when demand is relatively low (at least in most Central and Northern European countries with reasonable amount of air conditioners) but low in winter season, when demand is high. Besides, there is more or less more wind in winter than in summer but wind is impossible to forecast for weeks because it is very dependent on meteorological previsions. Therefore, an increase of VRE share would thus increasing the imbalance of residual load between the two seasons and causing longer timescale flexibility needs. Long-term hydrogen or gas network storage is appropriate to store high quantity of energy and cope with these threats for grid stability.

A brand portfolio of flexibility solution is required because each one has its own “competitive zone”. There are back-up production, DSM and short term storages as batteries for frequent but shallow flexibility needs, typically daily cycles and other long-term storage and production capacity as power to gas to power for flexibility needs of great depth, typically inter-seasonal needs or corresponding to long periods of production deficits. As a controllable production asset, P2G is also precious in the event of high demand (in power) to avoid over-sizing of electrical and hydrogen storage (s. c. Ecube 2020).

Costs arbitrations and systems availability are drivers to activate or not these options, expected lower costs for storage and power-to-gas technologies will help the development of flexibilities options. The use of flexibility technologies would be efficient with a market-based solution. While storage services that can be bought by transport or distribution systems operators (TSO or DSO) should remain a market activity, DSOs may be allowed to own and operate grid-scale storage for their needs, in order to secure the technical operation of the grid within the approved regulated activities. For efficient market procurement, regulatory oversight is needed to avoid that flexibility providers make simultaneous offers based on the same flexibility resources through different services in the same timeframe. Therefore, these flexibility options are certified by TSO in the capacity mechanism and the availability of their capacity is to respond to power fluctuation (CEDEX, et al. 2018).

Moreover, the flexibility needs of a specific country depend on its individual national specificities and those of its neighbors. Hence, it is important to design tailor-made portfolios of flexibility technologies for each individual country as a function of regional capacities and market design. This design procedure needs to take into account all kinds of flexibility solutions in order to determine the cost-optimal flexibility portfolio for this area (European Commission 2018).

Table 14 summarizes the flexibility options presented above

Table 14 : Flexibility options for electric system

Flexibility option	Technologies	Timescale	Energy reserve	Capacity reserve
Production back-up	Fossil, Nuclear power plants	Short to long term : second to year	X	X
	Hydro power plants	Short to mid-term : second to week	X	X
Storage systems	Capacitors	Short term : second to day		X
	CAES, PHS, Hydrogen	Mid-term : day to week		X
	Hydrogen, gas	Long term : month to year	X	X
Demand side management	Load shedding, load shifting	Short term : second to day		X

Hence, other technologies have to develop more to be complementary with existing flexibility options as PHS or batteries to cover long-term and high-energy flexibility needs. Developing linkages between electricity and gas network and power to gas storage technology is a possible option to answer these problems.

2. Interactions between gas and electricity networks

Territories have a large number of collective networks: gas, electricity, heat, water, telecom, etc. Historically, they have been designed and installed independently. However, dialogue between these networks would now make it possible to optimize their services and to make users benefit from their accumulated advantages, each of which provides its specific assets. **Figure 68** coming from GRDF, the French gas Distribution System Operator shows the links existing between electricity, gas and heat and how these networks can communicate (GRDF 2013).

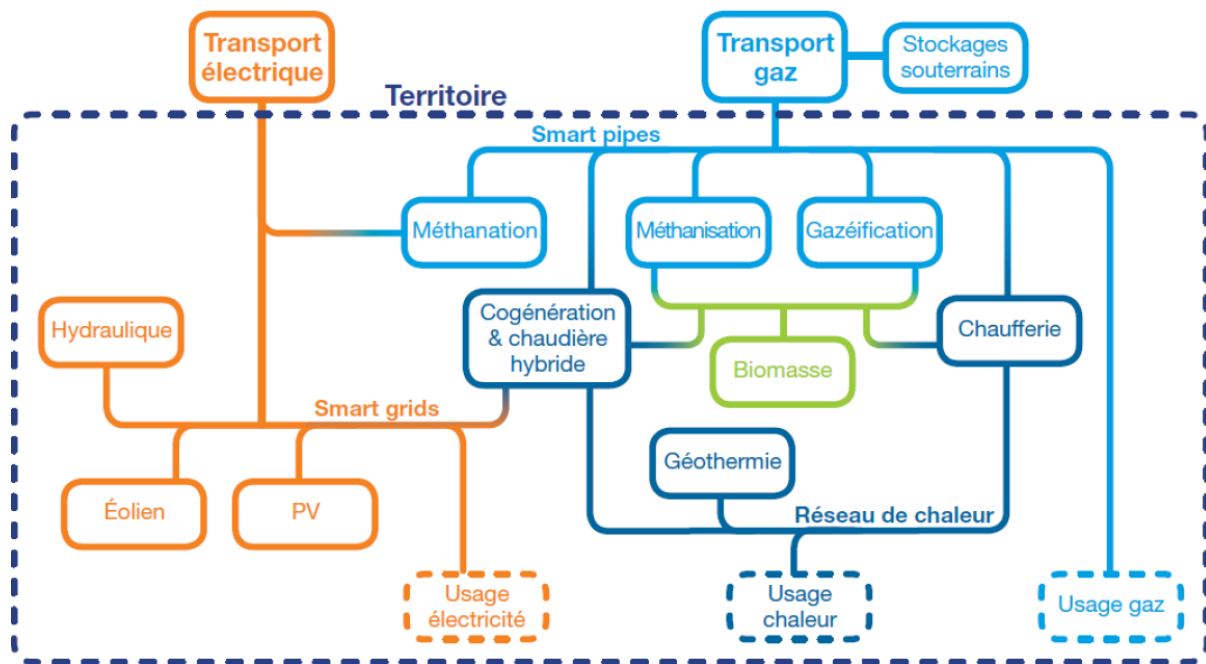


Figure 68 : Linkages existing between gas, electricity and heat networks
Taken from (GRDF 2013)

Nowadays, gas and electricity networks are mainly considered independent in many countries. They are just connected in gas power plants where gas is used to produce electricity. Gas is considered as a source for electricity production that compete with other sources for electricity production as coal, hydro, solar, wind, nuclear, etc. It is a unidirectional link where gas is seen as an input, a source for energy conversion and electricity an output, a vector of energy for end uses.

2.1. Limits of electrification and high rates of renewables incorporation

The increase in VRE shares expected in the future may result in a VRE production surplus during an increasing number of hours throughout the year when production overcome demand. In case of lacking system flexibility to absorb this surplus (e.g. storage, interconnection, demand response), this production needs to be curtailed and represent a miss to win for producers. Likewise, the increasing of VRE share may result with a production deficit during an increasing number of hours when VRE production and back-up capacities are not sufficient to fulfil demand. This lack of production could imply grid instability or even unserved load that drives to unexpected social costs because demand is not met. Eventually, rising VRE shares implies an increased mobilization of flexibility options to cope with a possible gap between production and demand.

Besides, variable production of solar and wind will increase the short-term price volatility at wholesale markets. Due to the nearly zero variable costs of power generation, VRE further impact wholesale markets by pushing conventional generation capacities out of the market and lowering the average price level and change the merit order for production plants. This may affect the profitability of current and future investments in power generation and storage plants.

From a use perspective, electricity, making echo to pillar number 3 of decarbonization, is seen as a key and even the main option for final energy decarbonisation. Nevertheless, as seen in chapter 4, electricity is not applicable to decarbonize all uses. Therefore, a way to transform the renewable electricity production by VRE may be relevant to have an appropriate energy carrier to decarbonise the sectors that are difficult to decarbonise with electricity. Power to X technologies to produce

decarbonised heat, fuels or gas may be appropriate but these technologies and their operation are still in prospect. We will tackle power to gas below.

2.2. Power to gas technological costs

As already mentioned in chapter 2, first step of power to gas is to take an amount of electricity and consume it in an electrolyzer to convert water in hydrogen. Different technologies of electrolyzers exist, such as alkaline electrolysis, polymer electrolyte membrane electrolysis (PEM), solid oxide electrolysis (SOEC) that are at different rate of development and costs. Here, we will not discuss these different technologies and we will take averages figures for costs, efficiency, power and lifetime based on (Miao et Chan 2018) (Maroufmashat et Fowler 2017) (Gotz, et al. 2015) (IEA 2019) (Cloete et Hirth 2019) (s. c. Ecube 2020) and summed up in **table 15**. The fuel and variable cost of P2G installations takes into account the electricity price.

Table 15 : Current technical parameters for power to gas

Power to gas CAPEX (hydrolysis + methanation)	2000€/kW
Fuel OPEX	The price of electricity
O&M OPEX	2.2% of CAPEX per year
Electrolysis efficiency	70%
Methanation efficiency	78%
Lifetime of installation	20 years
Discount rate	8%

Based on (Miao et Chan 2018) (Maroufmashat et Fowler 2017) (Gotz, et al. 2015) (IEA 2019) (Cloete et Hirth 2019) (s. c. Ecube 2020)

An expected business model as presented in (ADEME 2016) to meet the investments costs is to buy the electricity very cheap, store it in the gas system, use the gas stored to produce electricity in gas power plants and sell it at a higher price because demand to production ratio is higher. The difference in prices to operate should also take into account the efficiency round trip of the storage system to consider the losses in the process.

The production costs of P2G are influenced by various technical and economic factors, with CAPEX requirements, conversion efficiency, electricity costs and annual operating hours. This last parameter is key for profitability calculation and business model setting in particular for very capital intensive installations. In the expected business model, this load factor may be quite low because it is assumed that the electricity used for electrolysis is principally the VRE production that should have been curtailed in the absence of P2G (ENEA Consulting 2016).

At the end, it is important to consider the cost per energy produce, so that both CAPEX and variable electricity prices are taken into account in regard of the total running hours per year. We will discuss this business model in the next section by studying the cost of electrolysis in regard of running hours and electricity merit order.

2.3. Power to gas business model assessment

2.3.1. Methodology

One of the current limitation in POLES modelling is that P2G is not linked with an hourly price of electricity. The model uses only a base price, setting the price for 80% of time and a peak price, setting the price for the remaining 20%. It does not reflect the hourly variation of the price as it is impossible

to do that in a global and yearly model because of simulation duration. Actually, the spread of prices between base and peak hours are not well represented, so that it is difficult to model the appropriate P2G and electrolyzers business model in regard of the cost of electricity.

That is why we will use another model called EUCAD (European Unit Commitment and Dispatch), which is a GAMS optimization model. Its objective is to minimize the electricity production system cost composed by production, ramping and starting costs. It is an hourly timescale simulation, so that we have access to the electricity production cost for each hour. The inputs of the optimization are the electricity demand, set hour by hour, and the power system characteristics of all European countries that are the installed capacities for each electricity production technology, their relative marginal costs and other technical constraints such as the ramping time to go from 0 to nominal production. The outputs are the production or storage of each technology and the importations or exportations, for each hour of the day (Desprès, Criqui, et al. 2014). Here, we will use the single country version called UCAD in order to have access to the price of electricity hour by hour in regard of the demand and the production by each power plant in France.

We will analyze the P2G cost according to its load factor and in relation with the cost of electricity. We will follow what did IEA in their report (IEA 2019) for electrolyzers costs assessments (figure 69).

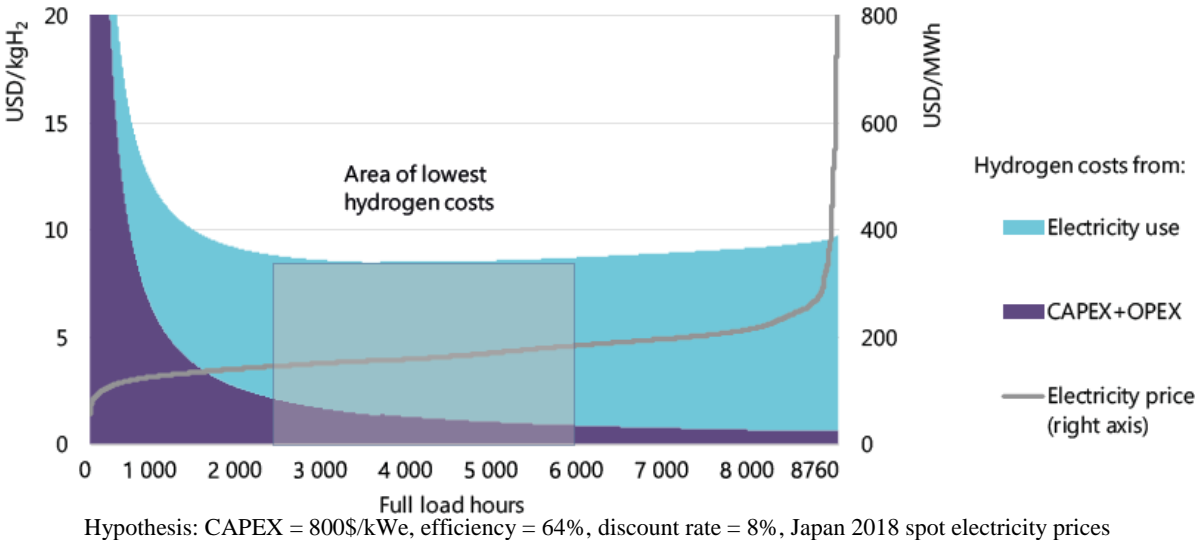


Figure 69 : Hydrogen production costs from electrolysis using grid electricity prices
Taken from (IEA 2019)

In this study, as operating hours increase, the impact of CAPEX costs on the levelised cost of hydrogen from electrolysis would decline. In the same time, the impact of electricity costs rises because the marginal cost of electricity production increases. So, a low utilization of the installation reflects high CAPEX costs even if electricity prices are very low. With increasing running hours, electricity prices increase, but the higher utilization of the installation leads to a decline in the CAPEX cost and it sets a total producing cost to an optimum level. Beyond that, higher electricity prices during peak hours lead to an increase in production costs even if the CAPEX cost by unit of hydrogen produced is even lower. At the end, an optimal running window for electrolyzers has been calculated and the relative hydrogen production cost assessed.

This analysis is dependent of the electricity mix used because it is the type of power plants used that set the electricity prices (see chapter 5 section 1). If there were more VRE capacities installed, there

would be likely more running hours at a low electricity price. Likewise, if there were more dispatchable power plants, electricity prices may increase.

Hence, to study this sensitivity for power to gas, it is worth changing the daily available VRE and zero marginal cost power capacities and the residual demand. Hence, we will take into account several scenarios for the installed production park and the demand for France. We take the 2019 French electricity prices and electricity production in France. Then, we model 2030 scenarios for projected demand. We consider a baseline, based on POLES scenarios following the scenario baseline studied in chapter 4. Here, there is no climate policies, many fossils power plants, and a high level of demand. We consider also two-energy transition scenarios based on RTE adequacy report (RTE 2017). We take the capacities from Ampere scenario that correspond to a development of renewables, a phase out of coal and oil power plants and a reduction of projected demand compare to baseline, following a 2°C scenario trajectory. At the end, we consider also a scenario that we called Ampere², which is the same Ampere scenario but with the double installed capacities for VRE. This scenario should not be very realistic but it is worth incorporating it in our study to see what could be the business model of power to gas in case of an extreme development of VRE production plants. Last but not least, Ampere scenario was built by RTE in order to reach the objective of 50% of nuclear in the energy set by the last revision of French energy transition law. Hence, the nuclear capacities installed are a bit lower for Ampere and Ampere² than in the baseline scenario.

Table 16 sums up the different electric mixes taken into account for France in this analysis. The detailed description for installed production parks is in **appendix 4**.

Table 16 : Electricity mixes characteristics and scenarios considered

Scenario	Annual demand (TWh)	Fossil power plant capacities (GW)	VRE capacities (wind + solar) (GW)	Nuclear capacities (GW)
2019	537	18,5	25,9	63,1
2030 baseline	705	51,5	55,6	44
2030 Ampere	590	13,2	103	38,4
2030 Ampere ²	590	13,2	206	38,4

2.3.2. P2G business model discussion

Figure 70 presents the CAPEX and fixed O&M costs production cost of methane from electrolysis and methanation by unit of energy produced by taken into account the cost of the technology and the load factor of the installation in the year. Data are taken from **table 15**.

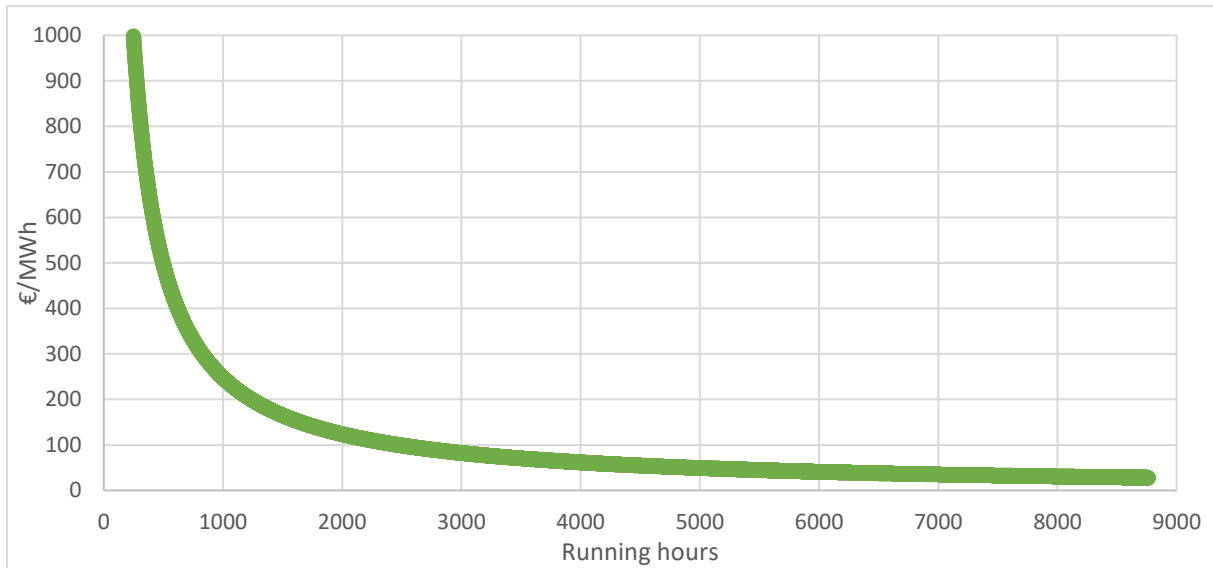


Figure 70: CAPEX and fixed O&M cost for power to gas installation in function of running time

The cost of production by unit of energy produced decreases when the load factor increase, but varies more slightly, between 20 and 50€/MWh, after 5000 running hours. Hence, there is a kind of threshold of running hours to reach in order to have acceptable CAPEX costs for P2G by unit of energy. We can tell that P2G has to run in a base/semi-base pattern in order to make P2G competitive. Indeed, we see that for a low rate of running time, less than 20%, costs overtake 200€/MWh that is ten to twenty times current gas prices, so that P2G cannot be competitive for gas production.

Figure 71 presents the electricity spot price for French electricity production for 2019 and the three scenarios in the future. The graph represents the value ranked by ascending merit order.

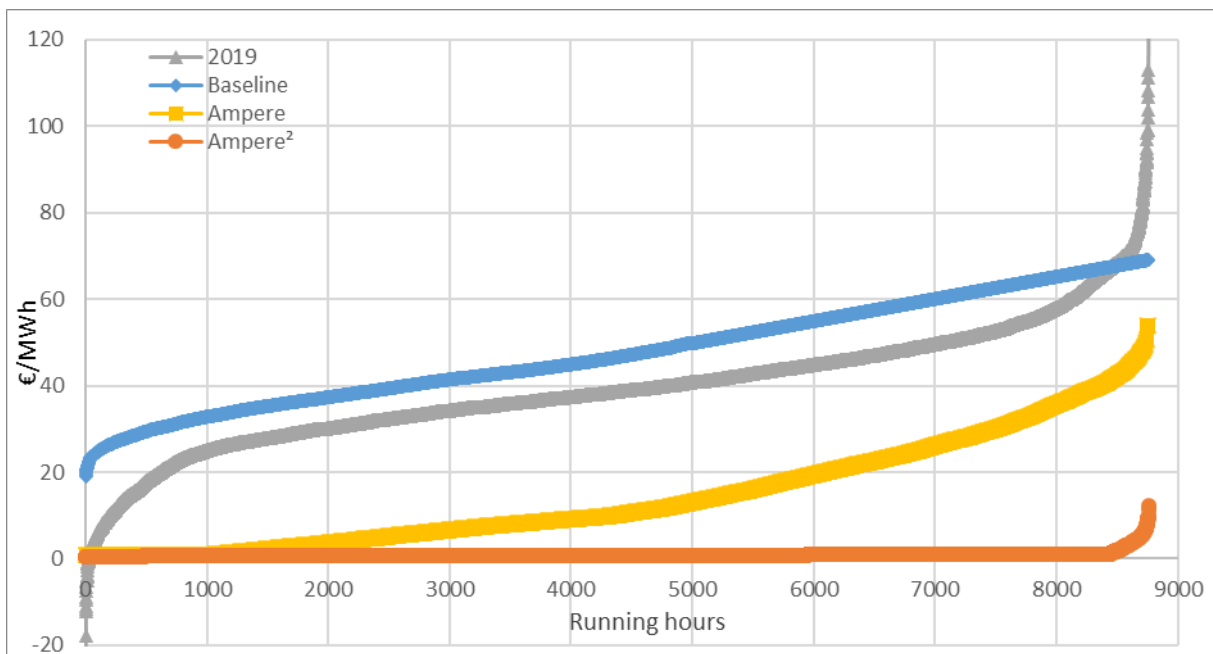


Figure 71 : 2019 electricity spot price duration curve and marginal variable cost for electricity production for 2030 scenarios

First, it is worth noticing that there is not negative prices for scenarios in the future, as these prices are calculated in UCAD based on the marginal cost for the last power plant called, so that our calculations

do not produce negative prices. In grey is the curve that represents the operation of French electricity mix in 2019. There are some exceptional hours where the price of electricity is very low and even negative when production, in particular from VRE, is in surplus compared to demand. On the right hand side, there are few hours where there are difficulties to fulfil a high demand so that price increase because of the need of calling expensive peak power plants. Between, there is a linear increase at relatively low costs thanks to a large production base by nuclear.

Concerning the 2030 baseline scenario, prices are on average higher than in the baseline scenario because the increase of the overall demand drives to the call of production plants that have higher variable costs as fossil power plants gas and coal.

For Ampere scenario, as VRE production plants have more capacities, VRE represents more often the marginal production plant, so that the prices are very low for a large part of the year. On the right hand side, there is a call of dispatchable power plants with higher variable costs, nuclear and gas, which increases a bit the price for the hours with more tension on the network. In the situation of Ampère², there are so many VRE production plants during all the year that VRE production is usually the marginal production plant, so that electricity prices remain almost zero during all the year. There are just few hours where dispatchable production plants (in this case nuclear) are needed to meet the demand when there is almost zero VRE production.

Figure 72 shows the production cost of hydrogen from electrolysis taken into account both the cost of the technology and the cost of electricity. It is represented as a function of the number of running hours through the year. We consider here the case of the 2019 electricity prices.

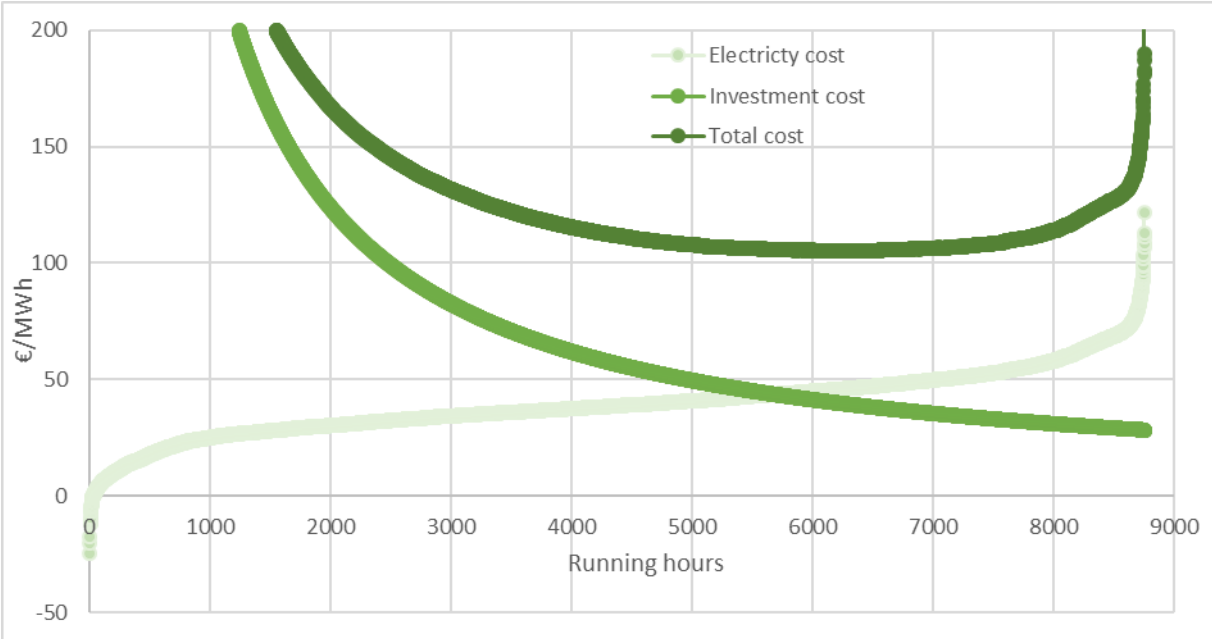


Figure 72 : P2G total cost in function of the running hours per year - 2019 case

The investment cost is the main contributor of the settlement of P2G production cost for low running hours because the price of electricity is low and the CAPEX is not spread over many energy produced. However, we see that for high running hours, the cost of P2G would increase because of the contribution of electricity price that is high for peak hours. Higher utilization rates would reduce the impact of CAPEX, but the electricity price would increase, so that the lowest green gas production costs from P2G is achieved in mid-load operation. So, the total production cost of P2G reaches a minimum

for the optimal load factor of the P2G plant. In this case, the optimal point is around 6200 hours a year, which is a load factor of 70%, for a production cost raising to 105€/MWh.

Figure 73 shows this same graph for the 2030 scenarios. Investment costs for power to gas installations are assumed 25% lower compared with today because of technological progress expected and based on (ENEA Consulting 2016).

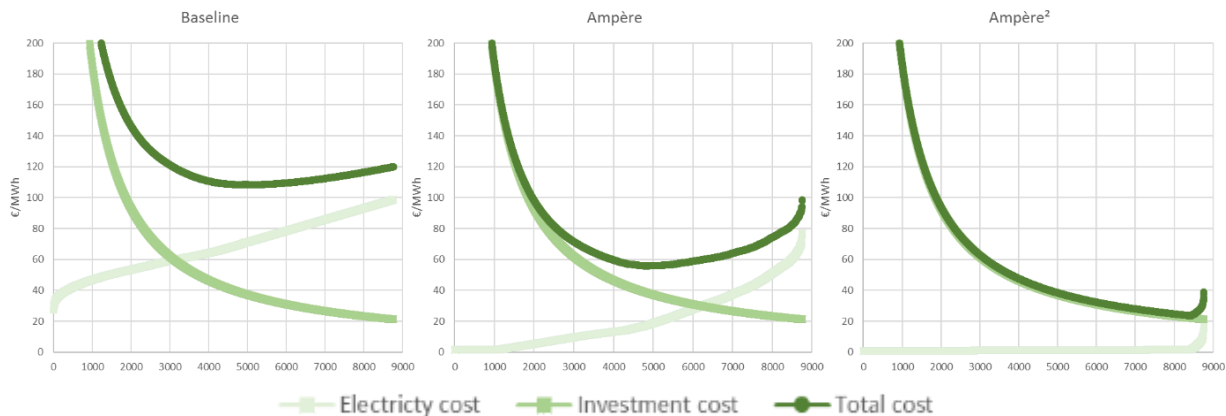


Figure 73 : P2G total cost as a function of the running hours per year for 2030 scenarios

The analysis for baseline is the same that for 2019. Besides, costs are more or less the same because the expected progress and the decrease of CAPEX contribution is counterbalanced by the increase of electricity prices. In this case, the optimal operating point is around 4500 hours during the year, a load factor of 50% and for a production cost of 105€/MWh.

For Ampère scenario, as the electricity price is lower during a large part of the year and increases for peak hours, the optimal functioning point is not the same. Here, we see that the optimal load factor is around 57% with 5000 running hours during the year. In addition, because of lower electricity prices, P2G optimal production cost is only 58€/MWh.

The Ampère² extreme scenario shows that the CAPEX cost is the determinant of the P2G production costs in case of extreme development of VRE. In this case, VRE electricity production is usually marginal, so that marginal electricity production costs are very low. Therefore, for almost all running hours, electricity prices are below 5€/MWh. The optimal load factor is in this case at 8500 running hours during the year, which is a load factor of 95% with a total production cost of 20€/MWh.

This extreme case shows the limitations of the unique consideration of variable production costs to assess the electricity cost for power to gas installation. Here, the P2G operator see only an almost zero electricity cost but, in the same time, the VRE production operator earn almost zero by selling its production, so that he would not meet its investments. Hence, rather than the variable operational electricity cost, the consideration of a larger electricity cost that take into account the investments may be more precise to build electricity cost for P2G installation and power to gas business model.

2.3.3. The question of CO₂ cost accounting

We will discuss in this section the influence of a non-negligible parameter in power to gas business model: the cost of CO₂. We will take two points of view. First is the cost of CO₂ associated with carbon taxes that increase the cost of natural gas. It can help the P2G development by reducing the cost gap. Second is the supply cost of the CO₂, seen as a resource to feed the methanation process and represent an expense for P2G operator.

First is to see the influence of a carbon tax on the price of natural gas. A carbon tax set at 100€/tCO₂ would increase the cost of natural gas by 12€/MWh. Hence, we are able to see what changes occur for the P2G business model and its competition with natural gas by considering the carbon tax contribution in **figure 74**. We look at it here for the P2G costs built in the baseline scenario in 2030.

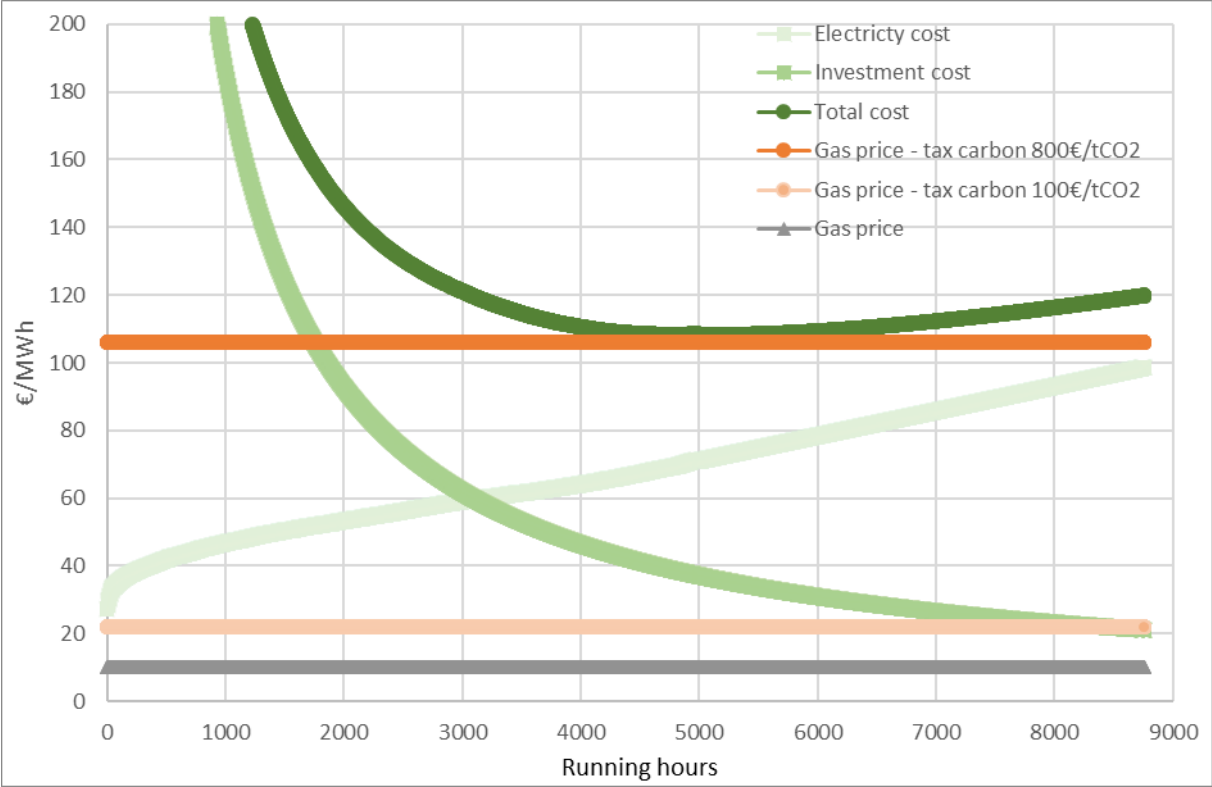


Figure 74 : P2G total cost and gas price in function of carbon tax – Baseline case

We note that with the current price of natural gas, taken on average at 10€/MWh (more details for gas prices in chapter 2 section 1), power to gas is much more expensive and cannot penetrate based on a market arbitration. For P2G optimal operating window around 5000 yearly running hours per year, the delta amounts to 100€/MWh. Then, we take a carbon tax of 100€/tCO₂ as this carbon tax is the one planned in France in 2030 (Ministère de la transition écologique et solidaire 2017). This planned carbon tax in 2030 would not likely change anything as gas price would remain very low, around 20€/MWh if natural gas prices will not increase. Hence, to make P2G competitive compared to natural gas price, carbon tax have to be high. Here, for the optimal load factor of 50%, the carbon tax should be around 800€/tCO₂ for natural gas to reach around 110€/MWh and be at the same level than green gas from P2G.

This assessment is done to set a floor carbon tax for comparison with other scenarios. Indeed, no carbon taxation should occur in the baseline because there is not climate policies implementation and no related carbon pricing.

Let’s do the same analysis for Ampere case in **figure 75**. The aimed carbon tax of 100€/tCO₂ in 2030 is not enough to make P2G competitive as green gas production cost may remain around 40€/MWh more expensive than natural gas price. In this case, a carbon tax of at least 400€/tCO₂ is required to make green gas from P2G competitive compared to natural gas in the Ampere 2030 scenario its optimal running window.

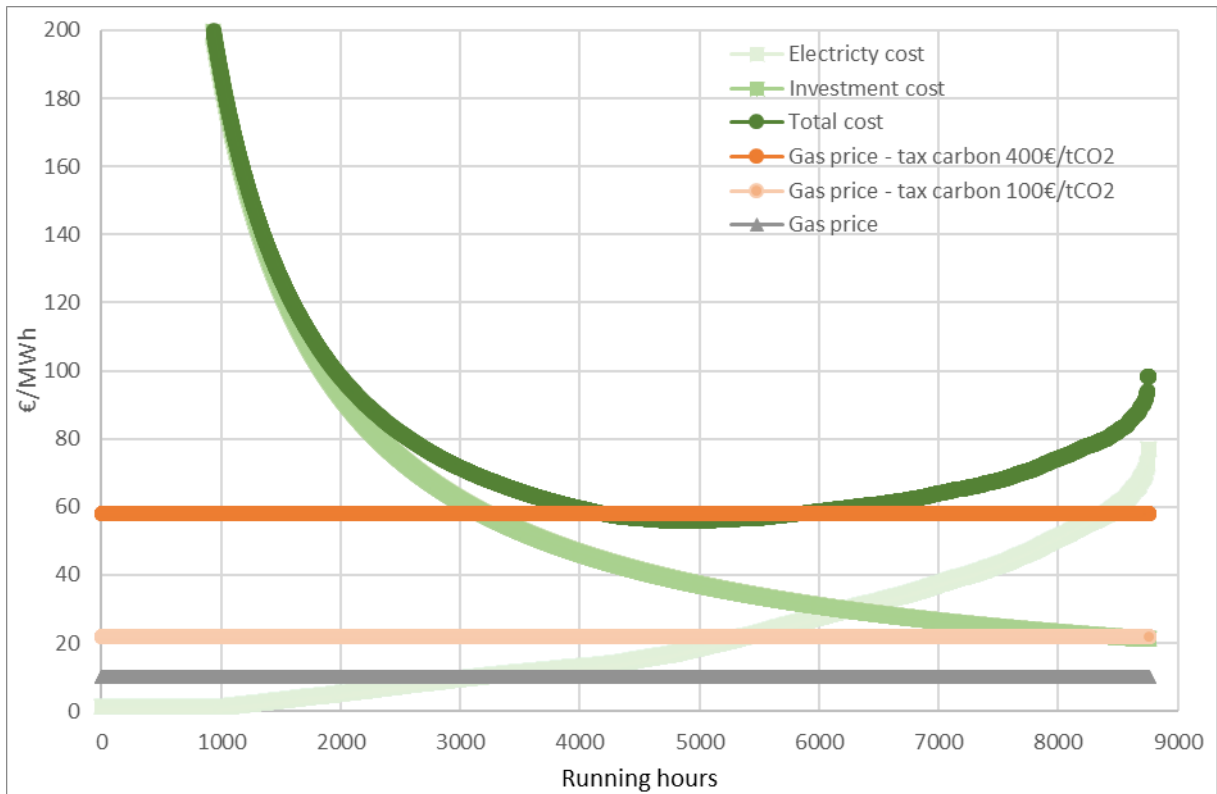


Figure 75 : P2G total cost and gas price in function of carbon tax – Ampere case

It is only in the extreme case of Ampere² (figure 76) with a huge and unlikely deployment of VRE that P2G should be competitive only for very high load factor (above 90%) with a carbon tax of 100€/tCO₂.

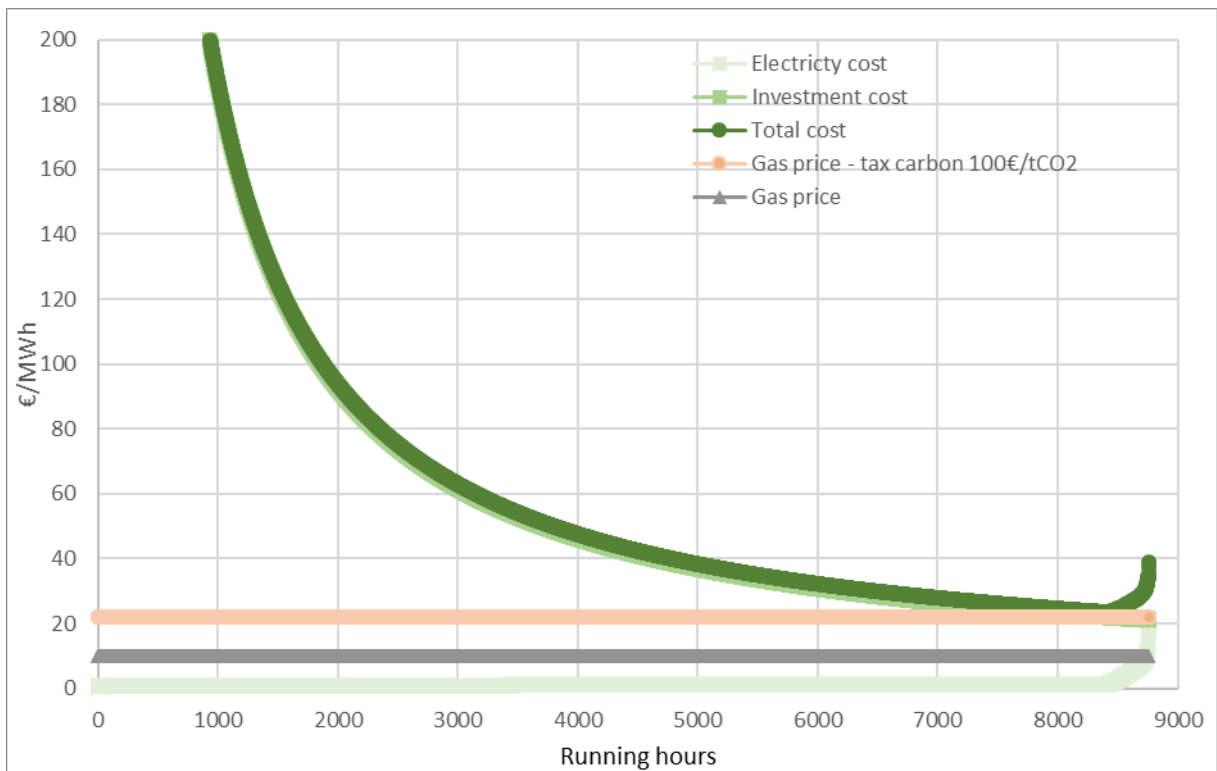
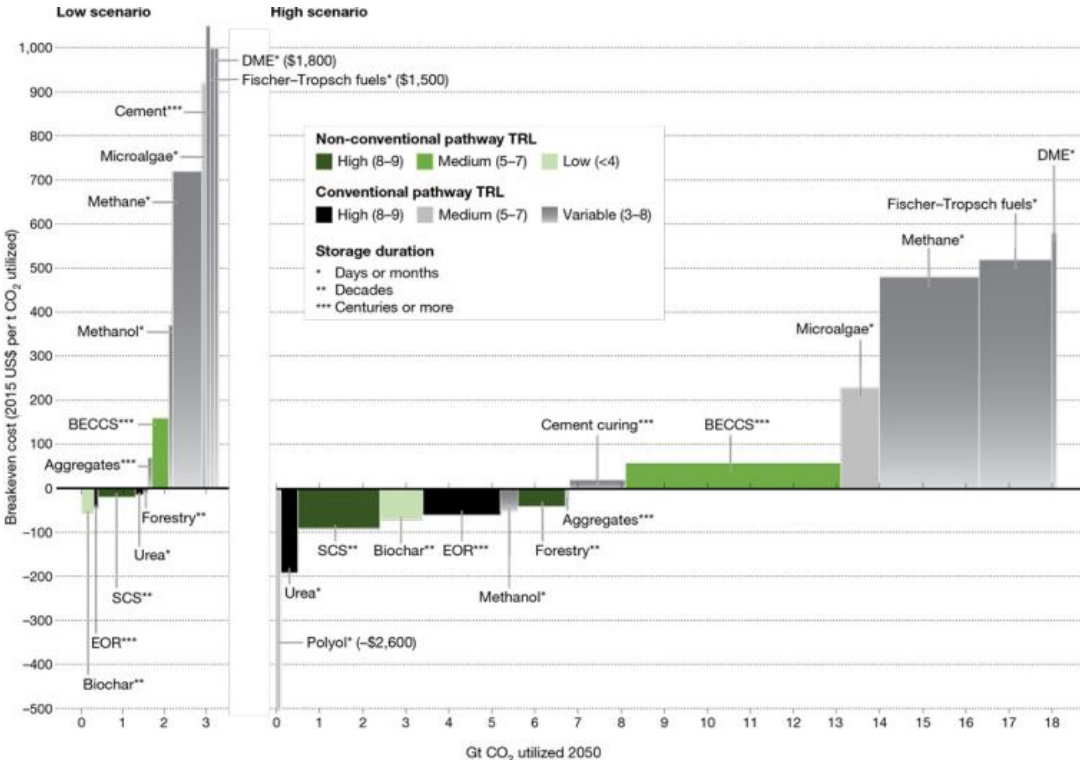


Figure 76 : P2G total cost and gas price in function of carbon tax – Ampere² case

These scenarios illustrate that competitiveness of power to gas based on expected progress from experts and based on markets rules without subsidies, without credit for ancillary services or capacity, can be reached only with a high taxation of CO₂ to penalize natural gas. There is also a need of a noticeable operational load factor, at least 50%, and even higher if VRE penetration would increase a lot. Hence, the development of P2G may occur only at a more distant time horizon when carbon taxation should be higher.

Beyond a CO₂ cost from a carbon tax that penalizes natural gas consumption, there is a possible cost for the CO₂ supply in P2G process that would increase its costs. In this case, the CO₂ is seen as a resource with an associated supply cost for the process. We can assess that the cost of CO₂ furniture for P2G process could be about the same as the cost of the system used to capture, store and transport the CO₂. Although, in reality, we may consider a potential margin for the supplier, we will not discuss it in our study. The complexity of the problem is that CO₂ capture costs spread through a large range depending of the capture technology considered. Besides, it is largely dependent about the hypothesis done about the R&D progress expected because these technologies are currently in early or middle TRL rates. **Figure 77** from (Hepburn, et al. 2019) present these ranges.



Estimated CO₂ utilization potential (GtCO₂ in 2050) and breakeven cost (2015\$/ton) of different sub-pathways in low (left) and high (right) scenarios for R&D development rate. Conventional pathways in grey are industrial utilization approaches; non-conventional pathways in green are biological utilization approaches. TRL refers to technological readiness levels, which range between 1 and 9. SCS is soil carbon sequestration; EOR is enhanced oil recovery; BECCS is bioenergy with carbon capture; and DME is dimethyl ether (a type of CO₂ fuel). These cost and scale potentials could change substantially with advances in R&D.

Figure 77 : Potential and cost of the ton of CO₂ captured by technology
Taken from (Hepburn, et al. 2019)

According to R&D development hypothesis and to the technology used for CO₂ captures, the range spreads between -180\$/tCO₂ (-14€/MWh) and 1800\$/tCO₂ (135€/MWh). For instance, if we take a CO₂ source from BECCS, the CO₂ would cost between 50 and 150\$/tCO₂ according to R&D progress expectations. This means that the cost of P2G would be increased from 4 to 12€/tCO₂ according to the source of CO₂ and make P2G less competitive.

2.4. Conclusion

2.4.1. P2G business model

While it is not still possible to store electricity on a large timescale in economic conditions with already mature storage systems as PHS or batteries, power-to-gas represents a promising option with significant large and long-term capacities for energy storage. Besides, electrolyzers can have an effect on demand-side flexibility because it is another consumption site to valorize a VRE production that would have been curtailed.

According to our simulations, it is worth noticing that P2G should run with a quite high load factor, minimum 50%, to optimize the production cost. These results may be modified by taken into account revenues for the P2G installation from other markets as capacity or ancillary services. This conclusion goes against a common assertion meaning that P2G would only run on VRE production surplus at low load factors. Hence, the general assumption we made in chapter 3 to model P2G in POLES should be modified by incorporating into the power to gas feedstock other sources of electricity than the only solar and wind hydrolysis.

This analysis also allows us to determine carbon tax thresholds needed for P2G to be competitive compared to natural gas, for different electric mixes and demand. We see that the 100€/tCO₂ carbon tax expected in 2030 is not sufficient for P2G to be competitive against natural gas price, even with climate policies where the gas price takes into account a carbon cost. For noticeable penetration of renewable, a carbon tax of several hundreds of euros, in our model 400€/tCO₂ is required. Moreover, the study shows that to take into account the cost of CO₂ either with a carbon tax, or with a cost of CO₂ supply for methanation process can change radically the competitiveness of P2G and projects leaders have to think about it when conceiving a P2G installation.

ADEME agency estimates that, in the case of France for a particularly strong economic constraint of 1000€/tCO₂, close to 186TWh of electricity per year could be converted into methane in 2050, which would then allow it to satisfy 71 % of the annual gas requirements of France. However, with 100€/tCO₂, the valuation of renewable electricity in heat and gas would remain negligible (ADEME 2017).

2.4.2. Demonstration projects and challenges

Power to gas meets some challenges and different fields of research and development (see chapter 2 section 2). The first one is improving performances like efficiencies and costs, particularly through growing electrolyzers capacities from kilowatts to megawatts or gigawatts scale. There are also three different technologies of electrolyzers, alkaline, PEM and SOEC that are at a different development state. Currently, alkaline electrolysis is the cheapest and most reliable technology, while PEM electrolysis could replace them soon thanks to a better performance and high work on R&D on it. Last, SOEC is still in an early development phase, but, it has a high potential for coupling with heat production (Gotz, et al. 2015). There is also progress to be done on methanation process which has quite low efficiency of around 60% (Sapy 2019). Others challenges are the process stability and temperature control.

At the end, P2G needs have a high improvement for the efficiency and the cost of the technology to be competitive in the energy mix as underlined by (Quarton et Samsatli 2018). It implies a huge dilemma which needs to be resolved: from an economical point of view, power-to-gas is a prospective required technology but is not worthwhile to operate today mainly because of an unsuitable framework, too high costs and low efficiencies. To go further, the cost of CO₂ to supply the

methanation process may differ according to the source, so that it is difficult to assess this cost. In case of fossil CO₂ source, the net balance of transforming this CO₂ in input into methane and then using it would still be positive. Therefore, CO₂ tax would have to be paid eventually and shared between the fossil fuel user and the end user of gas, as P2G will double the energy of the combined process for the same initial CO₂ emitted.

To open up the discussion, in 2019, the European Commission and France recognized hydrogen as one of the strategic technological sectors on which the resources of public authorities and manufacturers must be concentrated so that investment and R&D programs should be expected as well as a technological development and spread (Gouvernement français 2020). Concerning power to gas and gas networks, some projects work on the hydrogen rate that can be incorporated in gas networks to decarbonize it. However, it can occur with a limited ratio, estimated of a maximum at 20% in volume. Experimentations are in operation such as GRHYD or Jupiter1000 to study this pathway (GRTgaz 2018) (Engie 2017). There is also the case of providing a CNG fuel that permanently contains a high hydrogen content, limited by the maximum acceptable given by the technical specifications in force for gas engines. The challenges will therefore be to optimize, technically and economically, the sizing of production assets with regard to the volumes and profiles of hydrogen production and consumption, to evaluate the critical links and to propose solutions for improvement and optimization (Engie 2017).

The potential development of P2G may encounter many obstacles because the very capital-intensive techniques they use are only profitable with a high utilization rate, which depends on the length of periods of low price of electricity in electrical systems with strong shares of VRE. Overcoming these obstacles requires strong energy governance. Power-to-Gas necessarily interacts transversely between gas and electricity infrastructure and the electricity and gas markets. It is therefore non-suited to the current structure of some energy sector, inherited from a long history and still marked by partitions between electricity and gas in the organization of players and by competing visions in the collective imagination of decision-makers such as in France. In contrast, the Danish example of a single operator of the electricity and gas transmission networks, Energinet.dk, is striking. The often-sterile competition between these two vectors and their operators does not take place in the country where it is replaced by the evidence of their complementarity, as well as with the heating networks, which supply more than half of the buildings. As a result, the emergence of Power-to-Gas is natural in this kind of regulation country with a permanent practice of dialogue and a culture of cooperation to optimize technically and economically the networks and install the equipments needed to build this transition (ADEME, GRTgaz, et al. 2014).

Conclusion and perspectives

The production of green gas can respond to multiple challenges. Those of the countries, which wishes to encourage, through incentive laws, projects to reduce greenhouse gas emissions and enhance energy security. Those of local authorities who gain autonomy and attractiveness through the circular economy. Those of farmers and industrialists who are behind the projects, and whose primary motivation is often to improve the management of organic waste while providing a secondary source of income with the production of renewable energy.

Green gas: an important option for energy system decarbonisation

Green gas can be produced thanks to several valorisation paths: methanisation, gasification from different types of biomass and power to gas from low carbon electricity. The possibilities to produce biogas and biomethane are widely distributed around the world thanks a large potential. The biomass feedstocks available for sustainable production of biogas and biomethane are huge, assessed respectively for the world and Europe at 7,1 Gtoe and 0,26 Gtoe. Only a fraction of this potential is used nowadays: in chapter 4, respectively 20% and 40% of the world and Europe biomass potential would be used in 2020.

Biomethane brings for the energy system all the benefits of natural gas without the associated net emissions thanks to the renewable source mobilization and transformation. Biomethane offers a local source of low carbon energy for power, heat and fuel. According to POLES simulations, green gas can represent 50% of the worldwide gas production in the second part of the century in climate policies scenarios. Globally, green gas would be used for transportation, industry and agricultural decarbonisation and not as much in buildings.

Necessary but not sufficient conditions for green gas production are the competitiveness for green gas technology compared to natural gas prices and the availability of resource potential and its relative cost. Our simulations show that green gas would not develop in the baseline scenario where natural gas price remains too low compared to green gas production costs. In a climate policies scenario, a carbon tax may allow the penetration of green gas technologies after 2030 in some regions. Green gas production would develop until the local potential is saturated as we see it for many countries in Europe around 2050.

However, these global trends cannot be declined for each region. Each country has its own resource potential and local energy consumption pattern so that decarbonisation with green gas may be possible or not. That is why global trends between the world and Europe would be different. We saw also that some countries do not have a sufficient local potential to develop the technologies, so green gas is not well adapted to these local specificities at least at a large scale. Besides, some countries have an expected growth for energy consumption while others would likely have a reduction. Hence, the development of green gas is estimated to be stronger in developing countries because they will probably know an increase of their total energy consumption unlike in developed countries as in Europe where climate policies scenarios induce a contraction of total energy consumption with the contribution of the first pillar of decarbonisation.

Green gas: fostering the circular economy and contributing to energy security

The circular economy aims to reuse and recycle wastes, so that it becomes resources again and may replace fossil resources. Biogas and biomethane producers can take organic residues, wastes or potentially curtailed electricity and turn them into a valuable source of clean energy that can be used instead of natural gas in many sectors. Likewise, local actors like farmers can have secondary revenues or a decrease of their charges by selling the biogas they produced and by recycling their wastes. Green gas production can be also a way to develop local economy by having local and non-relocated jobs to work on the green gas production chain. It may also transform the gas operator work and the gas network monitoring by adding many local sources of gas. Hence, a framework may be set to structure the fields, from land management and resource supply to output collection, storage and use as well as co-products treatment. This planning may be declined for several perimeters from countries objectives to local projects implementation.

Green gas productions would be used for local heat, electricity and fuel production and also as some valuable co-product like fertilizers. Therefore, these green gases would limit their consumption of hydrocarbons since they can substitute natural gas of fossil origin and replace synthetic fertilizers in agriculture. Energy security and many geopolitics stakes may be improved by reducing the importations of fossil fuels. Another positive effect for the local importing economies is the improvement of the importation balance sheet that can be used to sustain local actors with their associated jobs.

Green gas: a long term electricity storage option

Nowadays, and even if various flexibility options exist in order to cope with the VRE production variability at scales shorter than the week such as pump hydro storage, back-up production plants or demand side management, there is a missing long term energy storage to incorporate high rates of renewables. Indeed, in scenarios with high share of VRE, high scale storage systems are needed to cope with a longer-term intermittency of VRE production. The transformation of VRE electricity into gas when production exceed demand is a solution providing this flexibility. Hence, power to gas may be a key technology with high renewables incorporation in the electric system, but with still high R&D needed to be scaled up. Current costs are very high and, seen as an electricity storage, efficiency remains low compared to other storage systems. Our study shows that the power to gas investment can be economically interesting only in cases of using electrolyzers more than 4000 hours per year. Power to gas business model may go beyond the single use of VRE production surplus as often assessed in high VRE penetration related studies.

There is also the problem of the CO₂ supply for the methanation process because if the scale of installations would increase, the supply of CO₂ should follow. P2G installation may think about a large CO₂ supply from industrials for instance and may take into account the cost of the CO₂ to define the business model of their installation. Many demonstration projects particularly in Europe are currently in operation and will tackle these problems.

Greening gas supply: still a prospective field?

Some green gas production chains are already well developed as methanisation and political objectives are high for green gas development in some countries. However, the technologies have to improve their performance, the business models have still to be precised, and many R&D projects and demonstrations are working on it. Even if our study is based on projections from industrials who are waiting for technological developments, the capacity of the sector to develop renewable gas in significant volumes and at a reasonable cost remains uncertain, and represents an industrial challenge whose feasibility have still to be demonstrated in particular for gasification and power to gas technologies. For example, although the theoretical pool of resources available for the production of renewable gas is important, the level of development of the sector is still low, or very low in Europe, compared to electrical variable renewables. The significant decrease in costs in the latest solar and wind bids illustrates the maturity gap between electric VRE and the green gas technologies which still need political incentives such as subsidies or high feed in tariffs to spread. All in all, some R&D strategies are still needed to improve performances in order to make green gas technologies competitive even without incentives.

Besides, fossil gas price should increase because of resource depletion but even if some studies try to assess future gas and oil price, it seems impossible to forecast them in the long-term, in particular after the COVID-19 period. Finally yet importantly, the implementation of carbon tax in carbon constraint scenarios would outbid the natural gas price and the gap with green gas production cost. Likewise, it is directly dependent on political willingness to set high carbon tax levels as well as the social acceptance of this price increases. Eventually, it is worth noticing that the real market deployment of biomethane production potential will be determined both by the energy market conditions, but also by the states capability to create infrastructure, and stimulate biomass collection and industry by a coherent set of supporting initiatives (Prussi, et al. 2019).

Threats and concerns with gas and green gas use and development

Other decarbonization options may progress and become more interesting than green gas for energy transition towards CO₂ neutrality. For instance, if carbon-free hydrogen production and valorization chains are supported by countries, as it is the case in Japan nowadays, it may have a supply of green hydrogen in large quantities and at a competitive cost. Therefore, it could compete with green gas in some end uses and has the advantage to use a molecule that would not release any carbon in the atmosphere. Obviously, the deployment of hydrogen uses like mobility will be also based on the achievement of a reduction of the production cost announced by some industrial players, as well as on the development of a fueling infrastructure that is very limited and almost nonexistent today. The hydrogen transport and distribution question will also arise, because it appears that it is not possible to use the natural gas infrastructure to transport more than a few percents of the gas in the form of hydrogen. Building two parallel grids to supply on the one hand hydrogen and in the other hand gas for the same consumptions and uses is a non-sense so that choices and prioritization for one carrier will likely have to be done.

Besides, gas sector is one of the energy sectors where the risks of 'stranded assets' is high for current gas networks and gas installations like industries or power plants, so that, even if green gas development is a good point from global warming point of view, it is not seen as a gift for historical gas

producers. Therefore, it can create reluctances for these lobbies and powerful entities to foster this green field and change the current gas market structure.

Last but not least, it is worth focusing on methane releases in energy processes and in the gas field and paying attention to methane leaks in all the gas energetic chains. Indeed, it may have higher negative side effect than the expected biomethane decarbonisation contribution. Hence, the green gas production fields could be not so environmentally friendly if the processes are not well structured, implemented and controlled (Nisbet, et al. 2019).

Perspectives of this work

Some perspectives of this work can be set to further improve the analysis of the role of the green gas for decarbonisation strategies. The modelling can be even more precised. There is a need of more data to calibrate more regions to see more local specificities. Other prospective scenarios could be analysed by coupling green gas injection in gas networks and green gas off grid consumption like in transportations fleets or for industrial consumption. Besides, the hypothesis, in the modelling and in the expected business model of green gas, concerning the local use of the resource to produce green gas should be discussed as it does not allow biomass trade between regions and could limit green gas development.

Besides, the actual modelling of power-to-gas in POLES may be improved by regarding other feedstocks for electricity dedicated to electrolysis and by considering more elaborated electricity prices to simulate the arbitrations done by the power-to-gas operator.

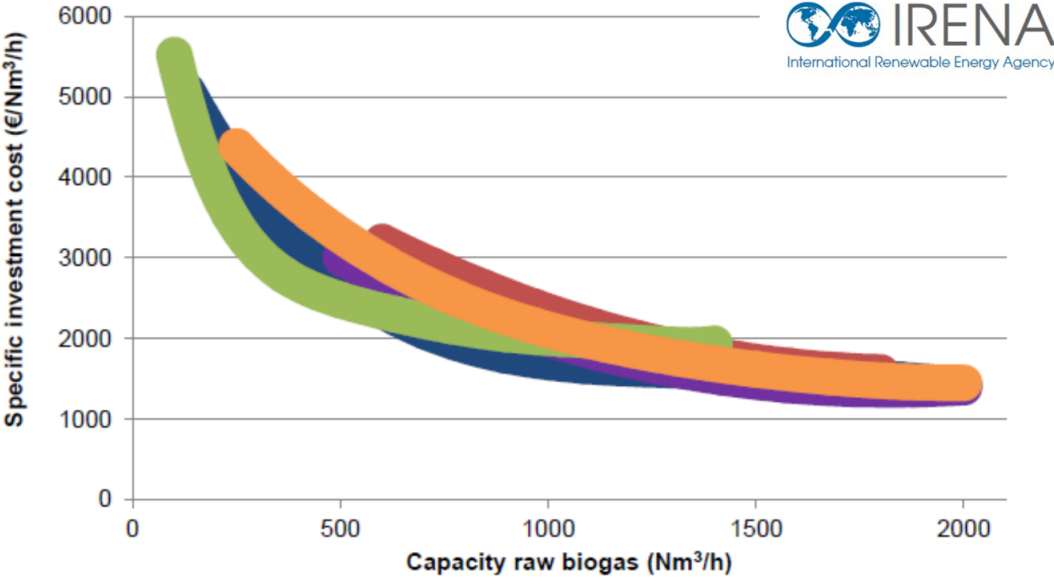
In addition, the analysis shows complex cross-sector effects with some competition for between green gas and hydrogen or CCS. Focus analysis on one sectoral decarbonisation or one technological arbitration could be precised better. The outcomes of these scenarios would help to better assess the role of each valorisation path for sectoral decarbonization. Return of experience from hydrogen, power to gas or CCS demonstrators may be useful to go further in the analysis.

Appendix

Appendix 1: Biomethane detailed techno economic parameters

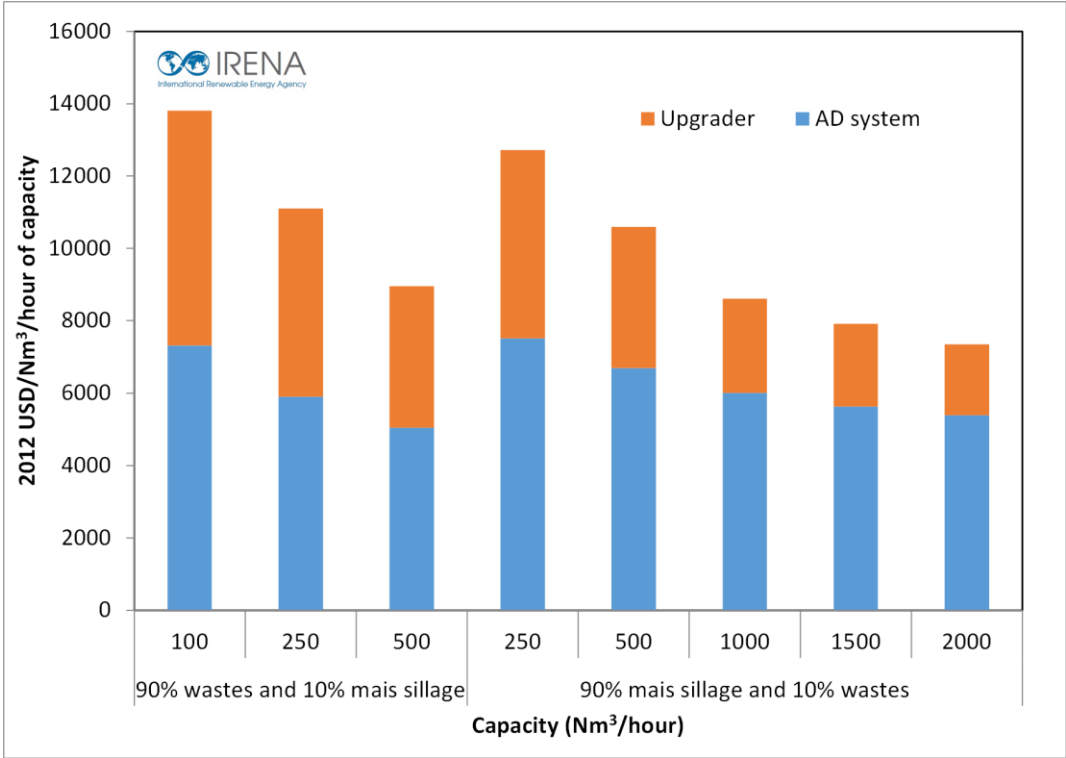
We represent below different graphs mapping the economic parameters of green gas technologies and the spread between the different types of installations. There are the different cost detailed for methanisation and the cost for power to gas.

Annex: methanisors CAPEX



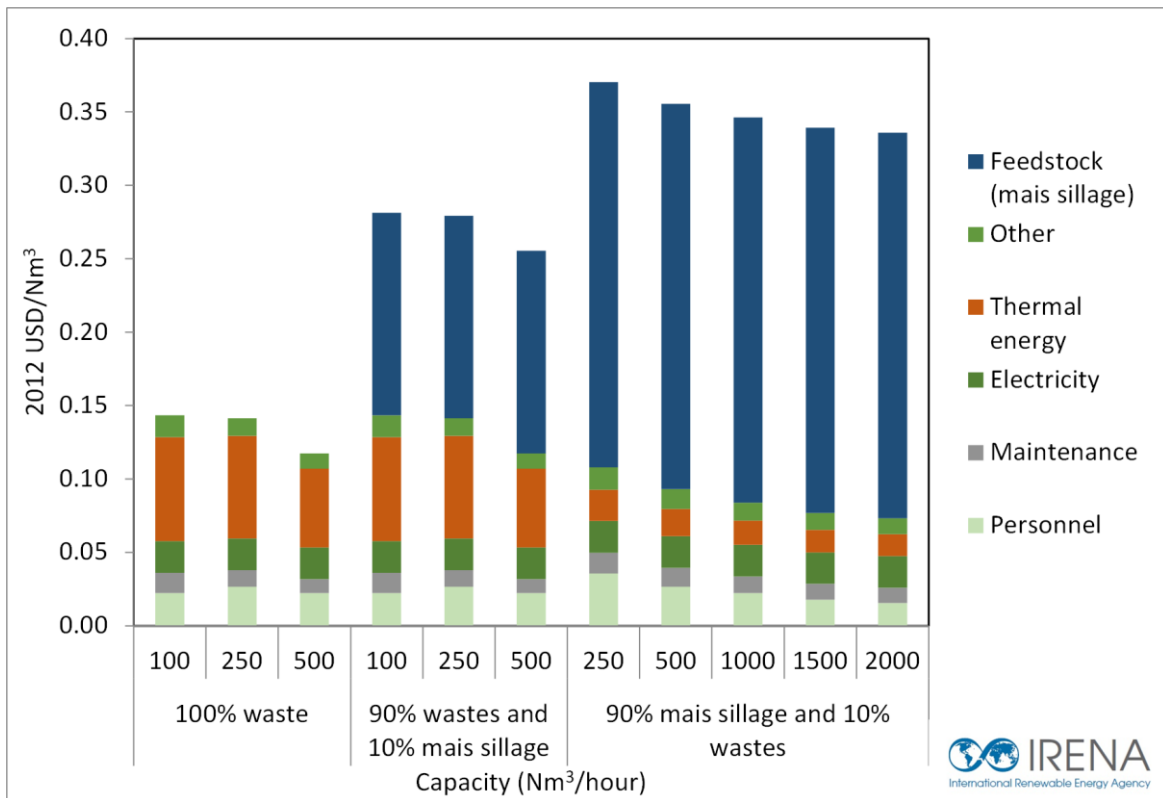
Taken from (IRENA 2017)

Annex: methanisors CAPEX spread



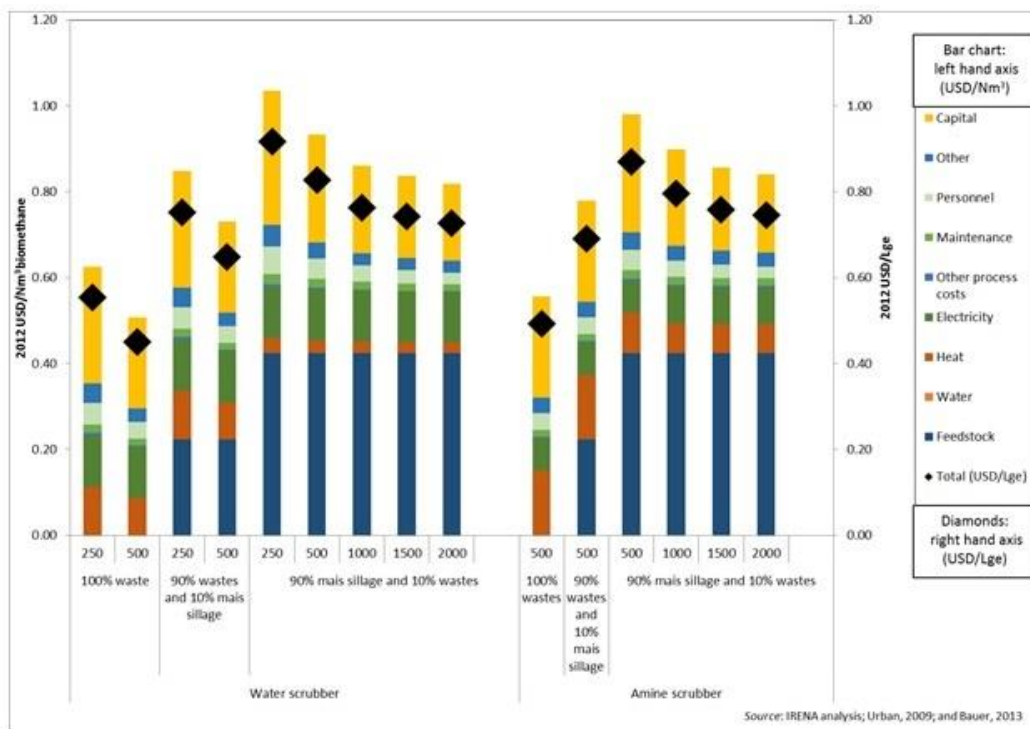
Taken from (IRENA 2017)

Annex: methanisors OPEX spread



Taken from (IRENA 2017)

Annex: methanisors stacking costs (IRENA 2017)

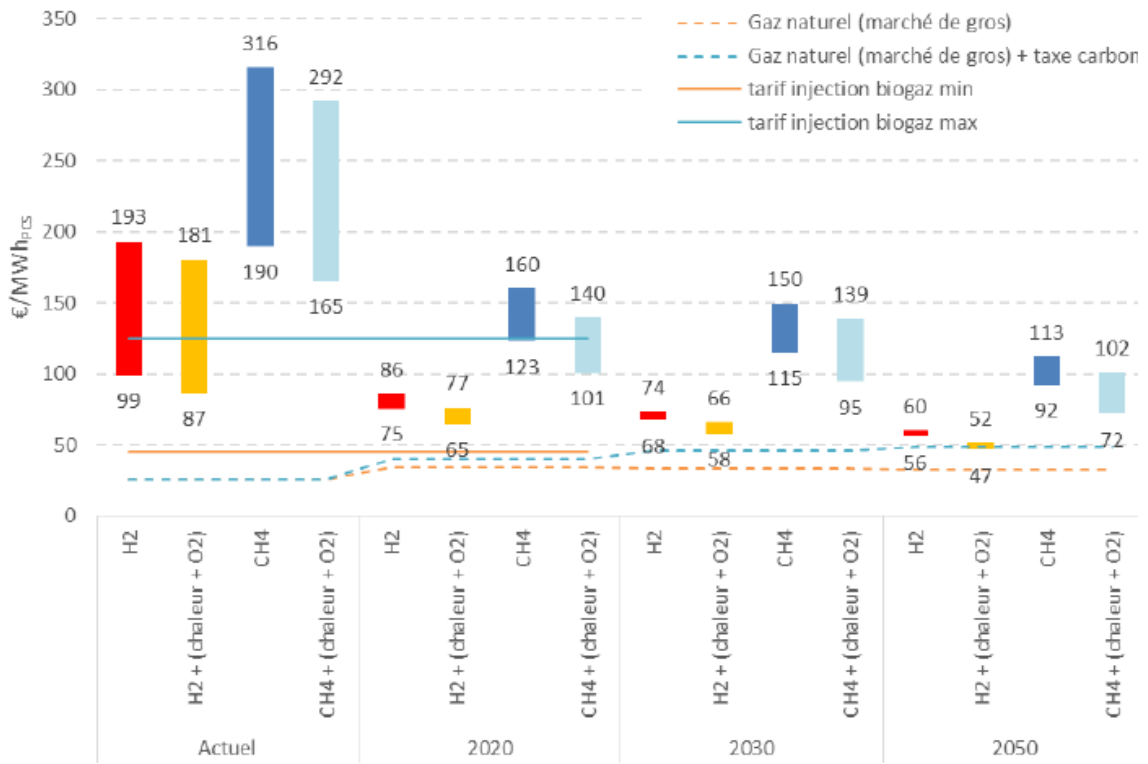


Source: IRENA analysis; Urban, 2009; and Bauer, 2013



Taken from (IRENA 2017)

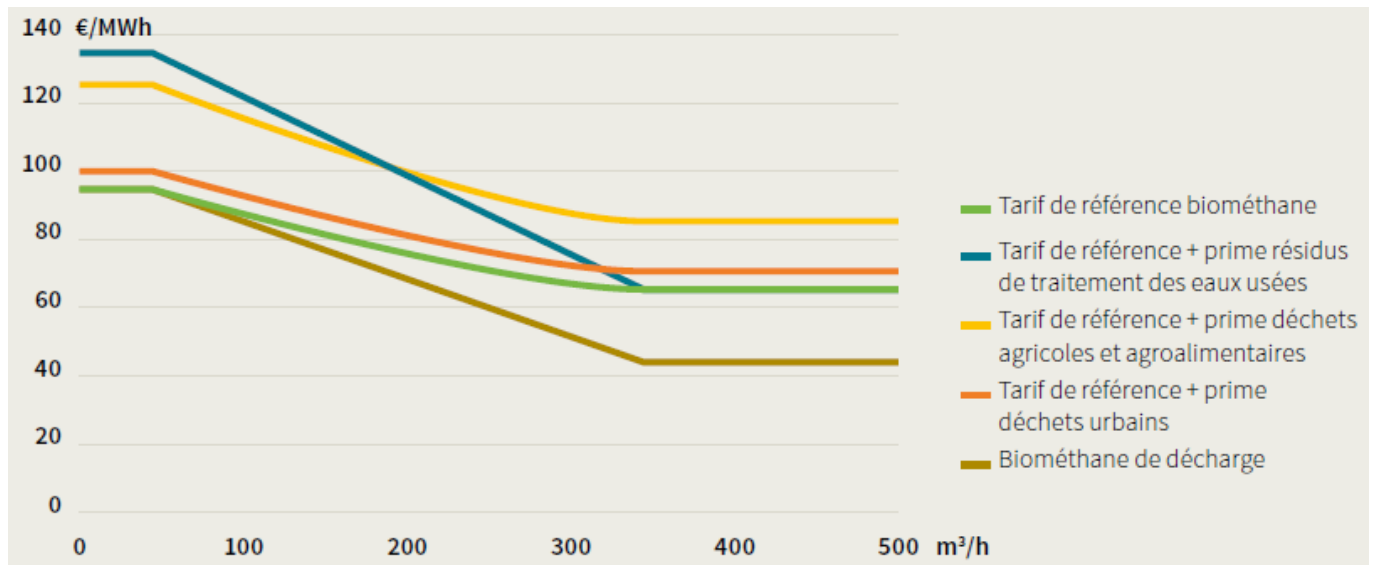
Annex: Power to gas cost evolution spread



Taken from (ADEME, GRTgaz, et al. 2014)

Appendix 2: Biomethane feed in tariffs in France

We represent below the feed in tariffs in France for biomethane from methanisation. These tariffs depend on the type of inputs and the size of the installation.



Taken from (GRDF, GRTgaz, et al. 2019)

Appendix 3: Green gas production database

The table below gathers the initializations for biomethane production for model POLES

Ktoe	2015	2016	2017	2018	2019
France	7,1	18,5	34,9	61,4	103,2
Germany	782,5	842,6	859,8		
Italy			8,6		
Great Britain		172	309,5		
Austria		20,6	21,5		
The Netherlands			77,4		
Denmark	30,9	32,7	154,8		
Sweden	16,3	40,4			
Switzerland	11,2	26,5	29,2		
Spain			2,0		
Norway	10,3	14,1			
Finland	6,9	8,4	8,6		
Luxemburg			5,3		
Ireland			34,4		

Appendix 4: Electric mixes for P2G business model study

The table below details the installed power for each power plant technology for the four electric mixes considered in chapter 5

Capacities (GW)	2019	Baseline 2030	Ampere	Ampere²
Coal	3,0	0	0	0
NewCoal	0	13,4	0	0
Nuclear	63,1	42,4	36,8	36,8
NewNuclear	0	1,65	1,65	1,65
OilTurbine	3,3	3,3	1	1
OilThermal	0	0	0,5	0,5
GasTurbine	0	0	0,6	0,6
GasThermal	7,4	20,9	4,4	4,4
GasCC	4,8	13,5	6,7	6,7
Biomass	1,2	9	7	7
BiomassOther	1,0	6,5	0	0
Geothermal	0	0	0	0
HydroRunOf	10,3	10,3	10,3	10,3
HydroLake	11	11	11	11
HydroPumping	4,2	4,2	4,2	4,2
DemandResponse	0,8	0,8	2,5	2,5
Solar	9,4	16,6	36	72
Wind	16,4	39	67	134

Glossary

BECCS: Bioenergy with Carbon Capture and Storage

BioNGV: Biogas Natural Gas Vehicle

CAES: Compressed Air Energy Storage

CAPEX: Capital Expenditure

CCS: Carbon Capture and Storage

CDR: Carbon Dioxide Removal

CH₄: Methane

CNG: Compressed Natural Gas

CO: Carbon monoxide

CO₂: Carbon dioxide

DICE: Dynamic Integrated Climate-Economy

DSM: Demand Side Management

DSO: Distribution Systems Operators

EU: European Union

EU ETS: European Union Emissions Trading System

EV: Electric Vehicles

EUCAD: European Unit Commitment And Dispatch

GDP: Gross Domestic Product

GHG: Green House Gases

GLOBIOM: Global Biosphere Management Model

GWP: Global Warming Power

H₂: Dihydrogen

H₂O: Water

ICE: Internal Combustion Engines

IPCC: Intergovernmental Panel on Climate Change

JRC: Joint Research Center

LCA: Life Cycle Analysis

LCOE: Levelized Cost Of Energy

LNG: Liquefied Natural Gas

LULUCF: Land Use, Land Use Change and Forestry

NGV: Natural Gas Vehicle

NO_x: Nitrogen Oxide

OPEC: Organization of Petroleum Exporting Countries

OPEX: Operational Expenditure

P2G: Power to Gas

PEM: Proton Exchange Membrane

PHS: Pumped Hydro Storage

POLES: Prospective Outlook on Long-term Energy Systems

ppm: parts per million

PRIMES: Price Induced Market Equilibrium System

SMES: Superconducting Magnetic Energy Storage

SNG: Synthetic gas or syngas

SOEC: Solid Oxide Electrolysis Cells

SO_x: Sulfur Oxide

TIMES: The Integrated MARKAL-EFOM System

TIAM: TIMES Integrated Assessment Model

TRL: Technology Readiness Level

TSO: Transport Systems Operators

VRE: Variable Renewable Energy. It gathers wind and solar.

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Executive summary

The problems linked to global warming imply the reduction of anthropogenic emissions of greenhouse gases. There are three pillars for decarbonizing energy systems, including the use of renewable energy. These are often assimilated to the electrical energy produced by the sun, wind, hydraulics or biomass. However, this electrical energy does not allow a deep decarbonization of all consumption sectors. The use of gas produced from these renewable energies and called "green gas" can overcome this by substituting fossil gas. The study of the penetration of these "renewable gases" is the subject of this thesis. To analyse the contribution of green gas to the decarbonization of energy sectors, the work carried out uses the long-term prospective model POLES (Prospective Outlook on Long-term Energy Systems). A module was created in the model to include a detailed representation of the green gas production system, linking resources to uses. The technologies of anaerobic digestion, gasification of biomass and the transformation of electricity into gas called power-to-gas have been modelled and their contributions in the energy consumption of consumption sectors estimated. The results show that renewable gas technologies play a role in the energy transition by doubling the production of fossil gas in the second half of the XXIst century. This gas allows the decarbonisation of the transport, industry and agriculture sectors. Nevertheless, the deployment of technologies is directly linked to the technical progress expected in the future because, at present, these technologies are for the majority too expensive to be competitive with the use of natural gas without carbon tax. In addition, development stems from the availability of local potential in terms of the biomass resources mobilized. Development trajectories are therefore quite different depending on local contexts, both in terms of resource availability and in terms of the political incentives to promote the deployment of green gases.

Résumé exécutif

Les problématiques liées au réchauffement climatique impliquent de devoir diminuer les émissions anthropogéniques de gaz à effet de serre. Il existe trois piliers de décarbonation des systèmes énergétiques parmi lesquels l'utilisation des énergies renouvelables. Ces dernières sont souvent assimilées à de l'énergie électrique produite par le soleil, le vent, l'hydraulique ou la biomasse. Néanmoins, cette énergie électrique ne permet pas une décarbonation profonde de tous les secteurs de consommation dont l'électrification est difficile. L'utilisation de gaz produit à partir de ces énergies décarbonées et appelé « gaz vert » peut palier cela en diminuant l'usage du gaz fossile. L'étude de la pénétration de ces « gaz renouvelables » est l'objet de cette thèse. Pour analyser l'apport du gaz vert sur la décarbonation des secteurs énergétiques, le travail mené utilise le modèle de prospective long terme POLES (Prospective Outlook on Long-term Energy Systems). Afin de représenter de manière détaillée le système de production de gaz vert, nous avons créé un module dans ce modèle, liant les ressources aux usages. Ainsi, les technologies de méthanisation, gazéification de la biomasse et la transformation d'électricité en gaz appelé power-to-gas ont été modélisées et leurs contributions dans la consommation énergétique des secteurs de consommation estimées. Les résultats montrent que les technologies de gaz renouvelables jouent un rôle dans la transition énergétique en permettant de doubler la production de gaz fossile dans la seconde partie du XXI^{ème} siècle. Ce gaz permet la décarbonation des secteurs du transport, de l'industrie et de la production électrique. Néanmoins, le déploiement de ces technologies est directement lié aux progrès techniques attendus à l'avenir car ces technologies sont pour la majorité trop chères pour être compétitives face à l'utilisation du gaz naturel à l'heure actuelle. De plus, ce développement découle de la disponibilité de potentiels locaux au niveau des ressources de biomasse mobilisées. Ainsi, les trajectoires de développement sont différentes, région par région, en fonction du contexte local, tant au niveau de la ressource disponible que des incitations et programmes politiques mis en place pour promouvoir le déploiement des gaz verts.