IS GREEN IN THE PIPELINE?

Sensing gas' potential contribution to climate change mitigation

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GROUPE BPCE

ACKNOWLEDGEMENTS

• MAIN AUTHOR
Ivan PAVLOVIC
ivan.pavlovic@natixis.com

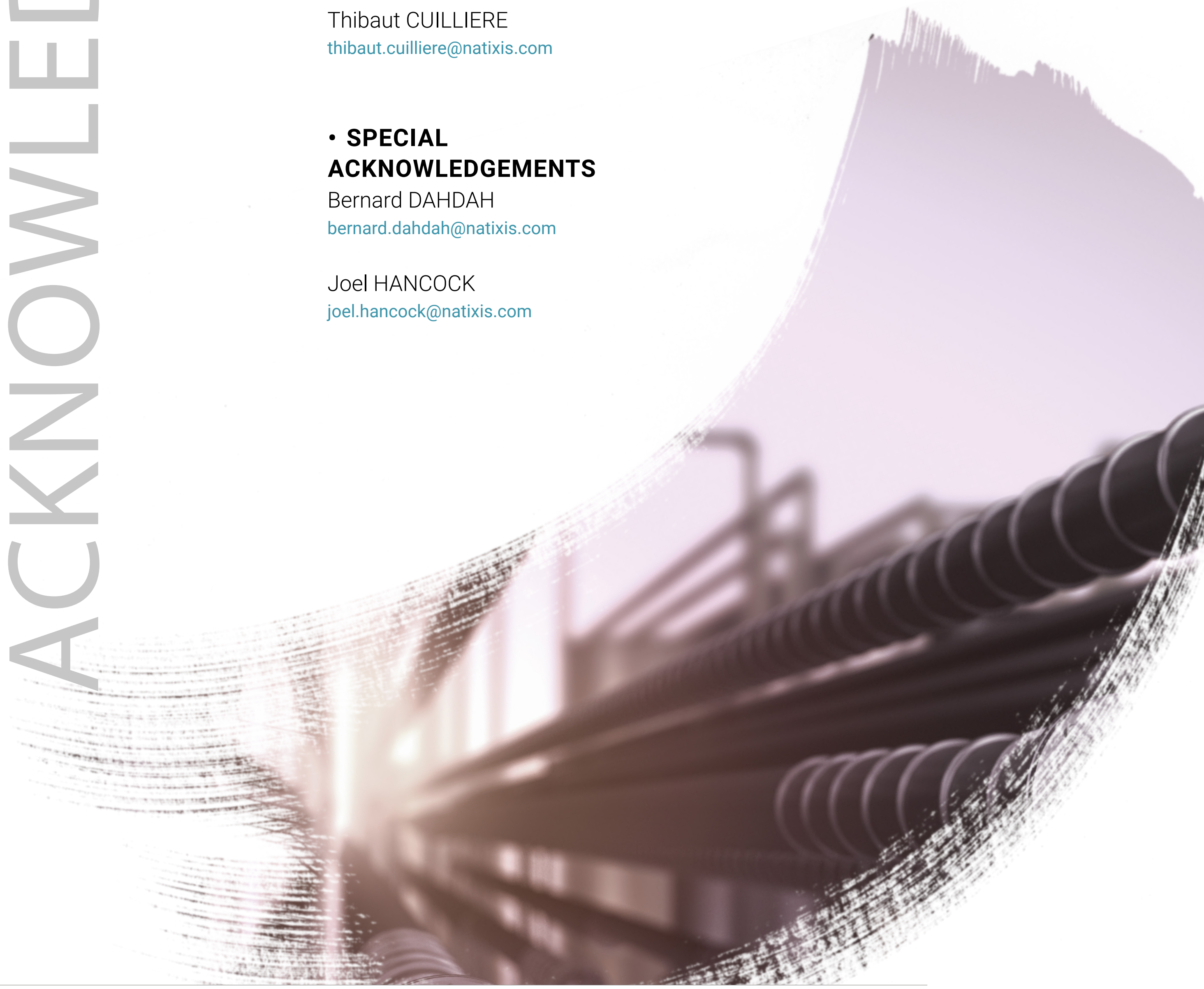
• CONTRIBUTING AUTHOR
Radek JAN
radek.jan@natixis.com

• MANAGING EDITORS
Orith AZOULAY
orith.azoulay@natixis.com

Thibaut CUILLIERE
thibaut.cuilliere@natixis.com

• SPECIAL ACKNOWLEDGEMENTS
Bernard DAHDAH
bernard.dahdah@natixis.com

Joel HANCOCK
joel.hancock@natixis.com



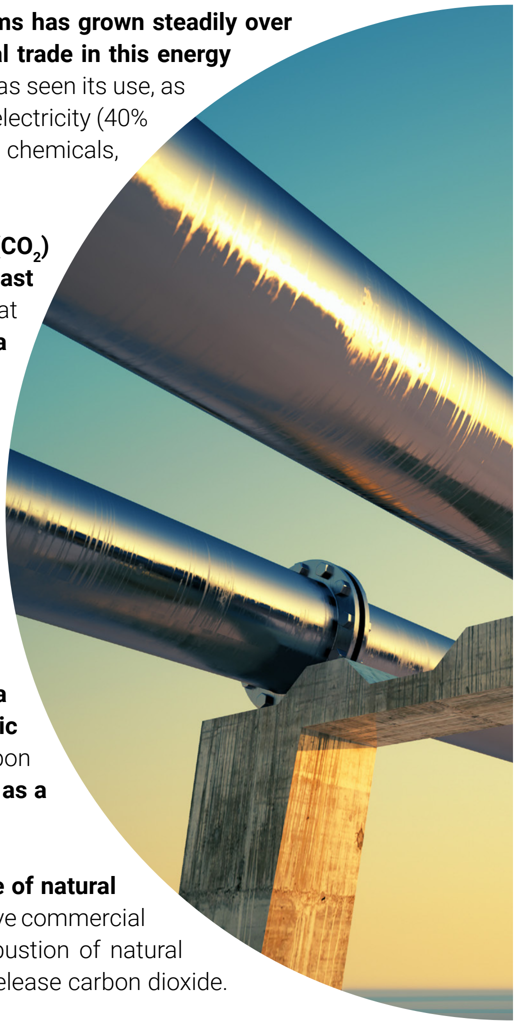
NATIXIS BEYOND BANKING

IS GREEN IN THE PIPELINE?

SENSING GAS' POTENTIAL CONTRIBUTION TO CLIMATE CHANGE MITIGATION

EXECUTIVE SUMMARY

The place of natural gas in contemporary energy and economic systems has grown steadily over the past four decades, in parallel with the development of international trade in this energy commodity. Long considered an unwanted by-product of oil, natural gas has seen its use, as a fuel and/or feedstock, extend to activities as varied as the generation of electricity (40% of current use) and heat, the production of steel, cement, hydrogen and chemicals, being used also in transportation, and so on.



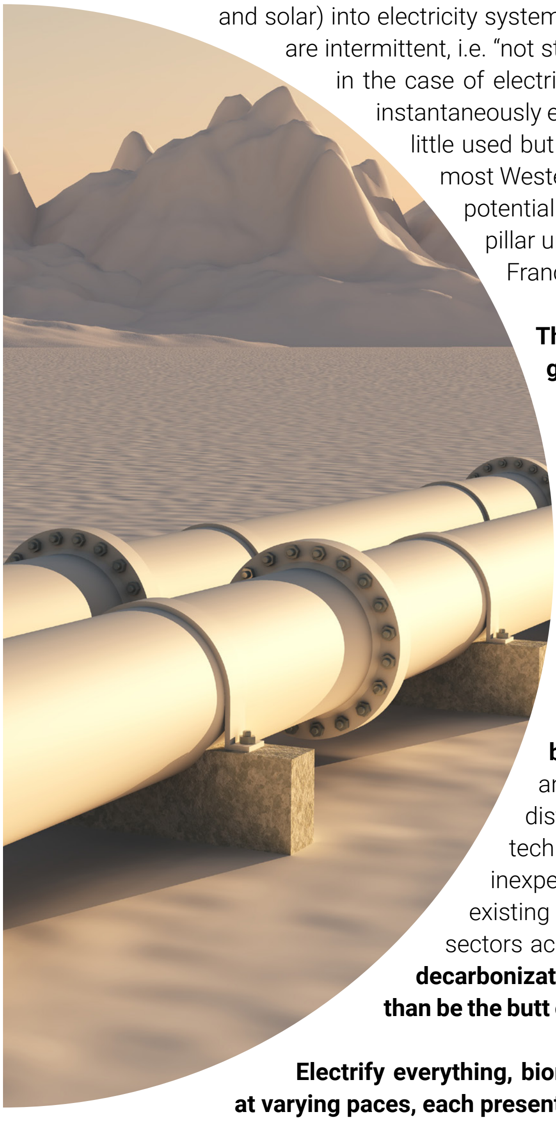
The combustion of natural gas emitting 30% less carbon dioxide (CO_2) than oil and 45% less than coal, this fossil fuel is presented as the least harmful of fossil fuels. Furthermore, in a context where initiatives to combat climate change are being ramped up, **natural gas is often promoted as a "transition fuel"**. With this in mind, increased recourse to natural gas to the detriment of oil and coal would constitute a first phase in the process leading to the achievement of carbon neutrality by 2050, an absolutely necessary condition for achieving the objectives of the Paris Climate Agreement signed in 2015 (in particular keeping the increase in global average temperature to well below 2 °Celsius above pre-industrial levels in this century).

Touting natural gas as a "transition fuel" is, however, controversial. The concept of "energy transition" is as much about the point of arrival – i.e. achieving carbon neutrality by 2050 – as the specific pathway – i.e. a specific process for decarbonizing contemporary energy and economic systems, the first phase in this process being an exit from the most carbon intensive fossil fuels, namely oil and coal. **Any analysis of the role of gas as a "transition fuel" must therefore embrace these two dimensions**.

If we look at the angle of the transition' desired point of arrival, the role of natural gas can only be very limited. In the absence of clear timeline for an extensive commercial rollout of carbon capture and storage (CCS) systems, though the combustion of natural gas emits less carbon dioxide than oil and coal, this fossil fuel does still release carbon dioxide.

Furthermore, an analysis of its life cycle reveals there are undesired climate externalities along the value chain (mainly taking the form of fugitive methane emissions during the Upstream and Midstream operations), compounded by what are still widespread practices in the industry (flaring and venting when associated with oil at the time of extraction), meaning that natural gas can have a bigger climate footprint than oil and even coal, in rarer instances though for the latter. From this standpoint, **its use therefore depletes the planet's carbon budget**, being the absolute amount of carbon dioxide emissions that can be emitted while still having a likely chance of limiting global temperature rise to 2 °Celsius above pre-industrial levels.

When one now considers the transition process under way to decarbonize the global economy, gas plays a more concrete role, though this is still dependent on specific local contexts and should be considered in a limited time window. Recent experiences in the United States and Saudi Arabia show that substituting natural gas for coal or oil in electricity generation has improved carbon intensity in the sector, but without really setting in motion an energy transition strategy / policy aimed at reducing the dependence of these economies on fossil fuels. In the case of **Saudi Arabia, the increased role of natural gas in the domestic energy system can even be seen as having optimized oil's situation rent.** In this country, the replacement of old, oil-fired plants by state-of-the-art combined cycle gas turbines (CCGTs) can indeed be seen as having allowed a more economically efficient use of natural resources since less fuel is eventually burned to generate electricity and eventually more hydrocarbons are available for export. **By contrast, in Western Europe, where energy transition initiatives and policies are far more advanced, natural gas is playing an important role in the decarbonization of existing systems**. Directly, through the flexibility provided by CCGTs, natural gas is contributing to the efficient integration of renewable energies (wind and solar) into electricity systems, such integration proving all the more challenging as these sources are intermittent, i.e. "not steerable" and continue to enjoy fast-paced expansion. Even better, still in the case of electricity generation, natural gas offers a means to just about totally and instantaneously exit coal. As shown recently by Spain, with the simple presence of often little used but fully operational CCGTs, gas can be substituted overnight for coal in most Western European electricity systems, without any incidence on supply. The potential offered by gas needs to be underlined inasmuch as it is an implied pillar underpinning the coal exit policies now being implemented in Germany, France, Italy as well as the United Kingdom.



The growing interest in low-carbon gases (mainly biomethane and green hydrogen produced by green electricity-powered electrolysers) offers new prospects for the gas sector. Stemming from the observation that **without tangible progress in CCS, natural gas is not compatible with a low-carbon economy given its release of CO_2 upon combustion, this interest also highlights the potential use of existing gas infrastructures to initiate a new phase of decarbonization of contemporary energy and economic systems**, supporting or complementing the "electrify everything" approach which is today favored to achieve carbon neutrality by 2050. Still nascent, **biomethane and even more so green hydrogen make it possible to envisage in the long term, through end uses as a fuel and/or feedstock, a decarbonization of the economy that goes far beyond the current energy uses of natural gas** in electricity generation and heating. With this in mind, existing natural gas transmission, distribution and storage infrastructures will play a pivotal role. By their technical and economic characteristics, they offer safe and, at this stage, inexpensive levers for (i) injecting biomethane and green hydrogen into existing systems; but also (ii) for achieving scale effects needed to help both sectors achieve commercial viability. **This role of "integrator" in advancing the decarbonization of the economy allows gas infrastructures to accompany rather than be the butt of these potentially disruptive evolutions in existing energy systems.**

Electrify everything, biomethane, green hydrogen… These options/industries are emerging at varying paces, each presenting specific advantages as well as constraints. Their multiplicity and their potentially conflicting character suggest that **no pathway has yet been defined for achieving carbon neutrality by 2050**. The long-term prospects offered by these options must not detract from the climate emergency: **to avoid further depleting the planet's carbon budget and jeopardizing even more any chance of achieving the objectives**

of the Paris Climate Agreement, the focus right now must be on those carbon emissions that are the most substantial and can be cut most easily. Despite recent changes in Western Europe and North America, the electricity sector still relies massively on those fossil fuels with the biggest carbon emissions, i.e. coal and oil. At world level, these fossil fuels still accounted for 36% and 3% of electricity generation, respectively, in 2019.

All in all, the potential contribution made by natural gas and associated infrastructures to energy transition needs to be considered in **an evolutionary manner**, taking into account the technological developments likely to offer the world economy a clear and optimized decarbonization pathway, while limiting the sources of stranded costs in the various sectors most exposed to possible technological disruptions. **These elements suggest that temporality and contextualization should be taken into account, but also specific requirements for industry players to objectify the positive contribution of gas to energy transition.** This leads to the following conclusions:

(i) Out to 2030, natural gas has a key role to play in exiting coal and oil in electricity generation, mainly in geographical areas (Europe, North America, Japan and, to a lesser extent, China and India) where the existing asset base is sufficiently diversified to allow trade-offs between fuels (i.e. using existing natural gas assets to displace coal and oil assets whenever possible). However, for the positive effect of this coal and oil exit to be objectively measurable, **it is important for the gas industry as a whole (Upstream and Midstream) to assert its ambition to reduce the climate externalities of the natural gas life cycle**, through shared objectives and specific action plans to curb sources of carbon and methane emissions along the value chain.

(ii) Past this horizon, assuming that CCS has still not shown any sign of attaining commercial maturity by 2025, developing the existing asset base in its current configuration (Upstream, Midstream, CCGTs) would have no environmental justification and would in fact perpetuate the carbon lock-in of economic systems.

(iii) In parallel, and probably until 2040-2050, gas infrastructures would play a crucial role in helping the biomethane and green hydrogen industries to attain maturity, without prejudging, to begin with, which of these would impose itself as the decarbonization agent of choice. By playing this role, gas infrastructures can promote the emergence of relatively disruptive technologies while limiting the stranded costs for asset owners as well as the final cost of the various transition initiatives/policies eventually borne by the consumer.

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GENERAL INTRODUCTION:
PUTTING PRESENT DAY USE OF NATURAL GAS INTO PERSPECTIVE

The importance and relevance of natural gas in energy systems has been steadily growing over the past three decades.

In the early days of hydrocarbon extraction, natural gas was largely viewed as a waste product associated with oil production, primarily owing to the fuel's comparatively low energy intensity and requirement for specialised, cost intensive infrastructure for storage and transportation. Compounding matters, gas has no *'natural outlet'* in the way oil enjoys with transportation (60% of oil consumption in 2019); gas must compete with coal, oil, nuclear and in recent years renewable energy sources across the sectors in which it is consumed.

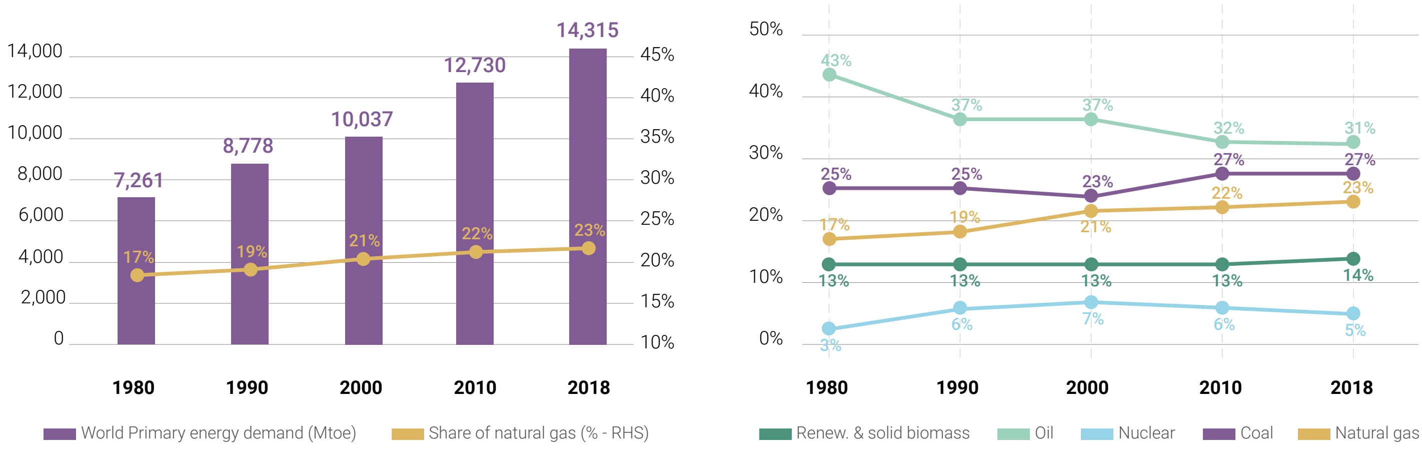
Based on this view of gas as a "marginal" fuel, **gas prices have historically not been based on the fundamentals of the gas market, rather as a price linked to oil or oil products (with which gas competed for market share in the power sector in the 1970s).** A key component of gas market liberalization over the past three decades has been the subsequent removal of oil-linked pricing and the development of competitive, hub-based market pricing for gas.

Due to the physical constraints (predominantly the historic reliance on pipelines for transportation), the majority of gas trade has been purely regional in nature. The development of LNG from the 1970s contributed to the development of international exchanges of the molecule. This dynamic has led to the emergence of new markets (most notable case of Asia-Pacific) but also to a gradual widening of natural gas uses.

Along with gas markets gradually gaining international dimension, the various uses of natural gas have expanded in all sorts of activities (power generation, heating, manufacturing, mobility, etc.) amid technology changes. **In some instances, such expansion has to be put into the context of more efficient, natural gas-based technologies spreading out in sectors such as electricity generation and steel manufacturing[1], with natural gas being used as a fuel and/or feedstock, hereby directly displacing coal and oil.** The emergence of state-of-the-art, natural gas-based technologies in these sectors has indirectly offered new avenues to reduce modern economies' reliance on the most carbon-intensive fossil fuels.

These trends altogether mainly account for the share of natural gas in world primary energy demand steadily growing over the past four decades to reach 23% in 2018 (vs. 17% in 1980).

FIGURE: EVOLUTION OF WORLD PRIMARY ENERGY DEMAND (LEFT) AND SHARE OF DIFFERENT ENERGY SOURCES (RIGHT)



Source: IEA (WEO, 2019)

The role of natural gas is now being scrutinized against the backdrop of mounting awareness on climate change issues. The signing, in December 2015, of the Paris Agreement on climate change now offers a framework for coordinated

1 See section 1.1.3 for a detailed analysis of present-day uses of natural gas.

international action against climate change but also, more crucially, final objectives and clear milestones to achieve them. The agreement sets the objectives of "holding the increase in the global average temperature to well below 2 °Celsius above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5 °Celsius above pre-industrial levels". Such targets entail reaching carbon emissions neutrality around 2050 followed by negative emissions thereafter.

To define a CO_2 emissions trajectory compatible with the abovementioned carbon neutrality objective, scientific experts have developed the concept of "carbon budget", which can be defined as the "feasible" consumption of fossil fuels in a carbon-constrained world. The Intergovernmental Panel on Climate Change (IPCC) offers a summary of the work carried out by the scientific community on this topic. IPCC's estimates are expressed in CO_2 emissions, hereby leaving aside emissions from other GHGs, some of which (notable case of methane) display a global warming potential (GWP) much greater than that of carbon dioxide[2]. The two tables below represent the value estimates for IPCC carbon budgets giving respectively 50% chance and 66% chance of limiting warming to 1.5 °C and 2 °C. IPCC uses several models, which can further include feedback loops within the Earth system. IPCC estimates the remaining carbon budgets giving a 50% chance of limiting warming to 1.5 °C (2 °C) in the range of 480 $GtCO_2$ to 670 $GtCO_2$ (1,400 $GtCO_2$ to 1,690 $GtCO_2$) relative to the start of 2018. Higher probability of achieving the temperature target shrinks the size of carbon budget. The same models used by the IPCC estimate the remaining carbon budgets giving a 66% chance of limiting warming to 1.5 °C (2 °C) in the range of 320 $GtCO_2$ to 570 $GtCO_2$ (1,070 $GtCO_2$ to 1,320 $GtCO_2$), again relative to the start of 2018. Understanding what this means and what are the implications for the size of carbon budget will be a subject to a stand-alone publication by Natixis following this study.

TABLE: CARBON BUDGETS GIVING A 50% AND A 66% CHANCE OF LIMITING WARMING TO 1.5°C AND 2°C ACCORDING TO IPCC MODELS

Reported values for 50% chance of limiting warming to 1.5 °C	Reported values for 50% chance of limiting warming to 2 °C
480 to 770 $GtCO_2$ (from 2018 onwards)	1,400 to 1,690 $GtCO_2$ (from 2018 onwards)
Reported values for 66% chance of limiting warming to 1.5 °C	**Reported values for 66% chance of limiting warming to 2 °C**
320 to 570 $GtCO_2$ (from 2018 onwards)	1,070 to 1,320 $GtCO_2$ (from 2018 onwards)

Source: Rogelj et al (2019) based on IPCC (2018)

The main practical benefit of the concept of carbon budget is to highlight the fact that any use of fossil fuels (oil, coal and natural gas) induces a reduction in the maximal stock of CO_2 emissions compatible with the achievement of carbon neutrality by 2050.

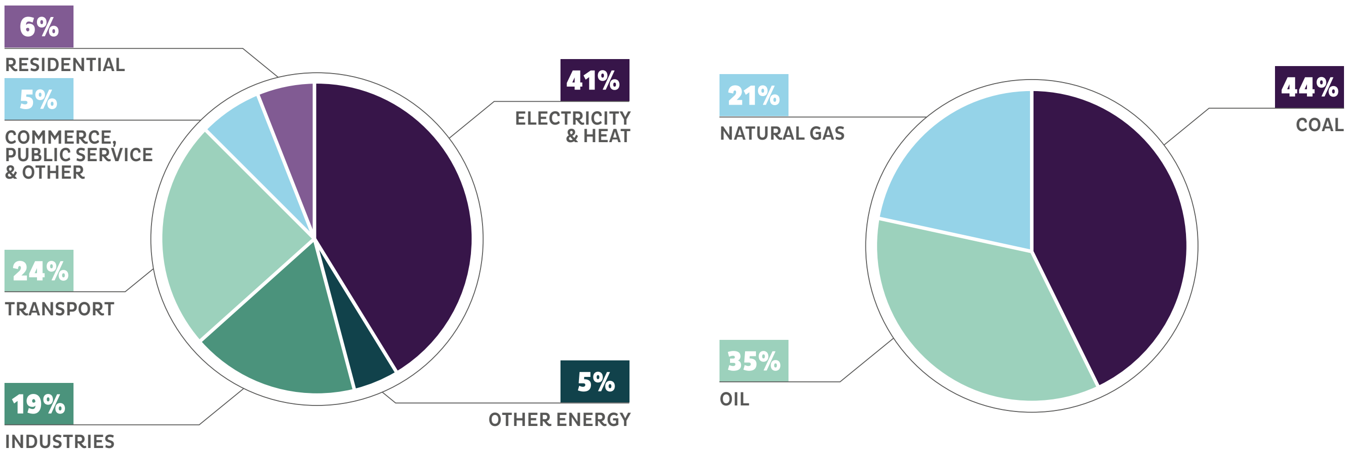
According to the latest data from the IPCC, total annual anthropogenic GHG[3] emissions amounted to 53.5 $GtCO_2e$ in 2017. This amount includes all GHG emissions resulting from human activities, including land-use change. Out of this amount,

2 Each greenhouse gas has a specific capacity to cause global warming, depending on its radiative properties, molecular weight and the length of time it remains in the atmosphere. The global warming potential (GWP) of each gas is defined in relation to a given weight of carbon dioxide for a set time period (for the purpose of the Kyoto Protocol a period of 100 years). GWPs are used to convert emissions of greenhouse gases to a relative measure (known as carbon dioxide equivalents: CO_2-equivalents). As we stress in section 1.2.1., methane indeed ranks among the most potent greenhouse gases, with a global warming potential (GWP) 104 times greater than CO_2 in a 20-year time frame and 28 times greater than CO_2 the latter over a 100-year period.

3 In order, the most abundant greenhouse gases in Earth's atmosphere are: i/ water vapor (H_2O), ii/ carbon dioxide (CO_2), iii/ methane (CH_4), iv/ nitrous oxide (N_2O), v/ ozone (O_3), vi/ chlorofluorocarbons (CFCs), vii/ hydrofluorocarbons (HFCs). Emissions of CO_2 (66%) and CH_4 (17%) together account for 83% of total GHG emissions.

a majority of these GHG emissions relate to the energy systems. **Data from the IEA show that GHG emissions from energy and industrial processes amounted to around 39 $GtCO_2e$ in 2017 (WEO, 2018). Out of this amount, use of primary energy sources[4] was responsible for 32.6 $GtCO_2$ the same year.** As shown in the graph below, from a primary energy perspective, CO_2 emissions predominantly result from the use of coal and oil (79% combined share of the world total), and to a much lesser extent from the use of gas (21% of the world total).

FIGURE: BREAKDOWN OF WORLDWIDE CO_2 EMISSIONS IN 2017 BY SECTOR AND PRIMARY ENERGY SOURCE (TOTAL: 32,840 M TONS)



Source: IEA (WEO, 2019)

The concept of a carbon budget highlights the climate issue arising from the use of fossil fuels in meeting energy needs. The world energy scenarios developed by the IEA in its World Energy Outlook published annually precisely seek to model for 2030 and 2040 the carbon footprint (global CO_2 emissions) associated with existing or emerging energy systems (each with a specific level of dependence on oil, coal and natural gas taken together and individually) that might prevail over these time horizons. **These energy scenarios assume three specific *potential* pathways for the satisfaction of primary energy needs:**

i/ The Current Policies Scenario (CPS) models the perpetuation of existing energy systems;

ii/ The Stated Policies Scenario (SPS) factors in the expected effects of the latest government announcements in the fields of energy systems and climate action and;

iii/ The Sustainable Development Scenario (SDS) describes an energy pathway offering the maximum chance of achieving the objectives of the Paris Agreement but also contributing to the achievement of other sustainable development goals (SDGs)[5].

4 Primary energy is the energy that is harvested directly from natural resources. It can be contained in raw fuels or in other forms of energy received as input to a system (case of wind or solar energy). By contrast, electricity is not a primary energy source but an energy carrier being transformed from various primary energy sources.

5 The IEA defines the SDS as setting out "the major changes that would be required to reach the key energy-related goals of the United Nations Sustainable Development Agenda. These are:
i/ An early peak and rapid subsequent reductions in emissions, in line with the Paris Agreement (Sustainable Development Goal [SDG] 13).
ii/ Universal access to modern energy by 2030, including electricity and clean cooking (SDG 7). A dramatic reduction in energy-related air pollution and the associated impacts on public health (SDG 3.9).
iii/ The trajectory for emissions in the Sustainable Development Scenario is consistent with reaching global "net zero" carbon dioxide (CO_2) emissions in 2070. If net emissions stay at zero after this point, this would mean a 66% chance of limiting the global average temperature rise to 1.8 degrees Celsius (°C) above pre-industrial levels (or a 50% chance of a 1.65 °C stabilization). In the light of the Intergovernmental Panel on Climate Change Special Report on 1.5 °C, we also explore what even more ambitious pathways might look like for the energy sector, either via "net negative" emissions post-2070 or by reaching the "net zero" point even earlier".

FIGURE: WORD PRIMARY ENERGY DEMAND BY FUEL AND SCENARIO (MTOE), ASSOCIATED FOSSIL FUEL SHARE (%) AND CO_2 EMISSIONS (GT)

Mtoe			Current Policies (CPS)		Stated Policies (SPS)		Sustainable Dev. (SDS)	
	2000	**2018**	**2030**	**2040**	**2030**	**2040**	**2030**	**2040**
Coal	2,317	3,821	4,154	4,479	3,848	3,779	2,430	1,470
Oil	2,665	4,501	5,174	5,626	4,872	4,921	3,995	3,041
Natural Gas	2,083	3,273	4,070	4,847	3,889	4,445	3,513	3,162
Nuclear	675	709	811	937	801	906	895	1,149
Renewables	659	1,391	2,138	2,741	2,287	3,127	2,776	4,381
Solid Biomass	638	620	613	546	613	546	140	75
Total	**10,037**	**14,314**	**16,960**	**19,177**	**16,311**	**17,723**	**13,750**	**13,279**
Fossil fuel share	*80%*	*81%*	*79%*	*78%*	*77%*	*74%*	*72%*	*58%*
CO2 emissions (Gt)	**23.1**	**33.2**	**37.4**	**41.3**	**34.9**	**35.6**	**25.2**	**15.8**

Source: WEO (2019)

From the perspective of climate change, the main interest of IEA's modeling work is to highlight:

i/ The implications of climate inaction, as reflected by the continued drift of CO_2 emissions in a business-as-usual scenario. The CPS highlights a still very high dependence on fossil fuels in meeting primary energy needs by 2040 (78% vs. 81% today). The result is a 24% increase in global CO_2 emissions, from 33.2 Gt in 2018 to 41.3 Gt in 2040;

ii/ The likely insufficiency at the global level of the various measures/policies announced thus far. The SPS highlight an energy pathway where primary energy needs remain mostly (74%) satisfied by fossil fuels by 2040. As a result, CO_2 emissions remain on the rise by 2040 (+7% modelled over 2018-2040 to 35.6 Gt) although the trend is less sustained than the one under the CPS;

iii/ The extent of the disruptions necessary in contemporary energy systems to lastingly and significantly reverse the trend in global CO_2 emissions. The SDS describes an energy pathway where reliance on fossil fuels is reduced to 58% by 2040, with low-carbon electricity from renewables and nuclear sources partly displacing coal, oil and to a much lesser extent natural gas, the latter as from 2030[6]. **This scenario features tangible CO_2 emissions reductions (-52% from 2018 level to 15.8 Gt), which are obtained from the partial displacement of fossil fuels in the satisfaction of word primary energy demand, but also from substantial progress in energy efficiency and carbon capture through the deployment of CCS processes (carbon capture and storage)[7/8].**

It is in this twofold context of mounting climate change awareness and persisting uncertainty on the pathway to carbon neutrality by 2050 that natural gas is often presented as a *transition* or *bridge* fuel. Moreover, proponents of natural gas highlight the significant role played by the use of the molecule in the various energy *transition* initiatives across OECD countries. Whilst partially holding true, the abovementioned statements deserve some comment. The notion of energy transition is somehow equivocal, for it characterizes both a process, namely the gradual decarbonization of existing energy

6 In IEA's SDS, natural gas consumption remains on the rise until 2030 (+7% vs. 2018) before starting to decline over the subsequent 10 years (-10%). In IEA's modelling, across energy systems, half of the decline in the use of natural gas is compensated for by strong growth in the use of biomethane and hydrogen.

7 In IEA's modelling work, progress in energy efficiency and the deployment of CCS account for roughly 35% and 5% respectively, of the CO_2 emissions gap in 2040 between the SPS and the SDS (35.6 Gt vs. 15.8 Gt).

8 CCS is the subject of a specific analysis in 1.2.1.

systems, and an end point, namely the achievement of climate neutrality by 2050 (see above). The IRENA[9] well captures such ambiguity, as it defines the energy transition as "*a pathway toward transformation of the global energy sector from fossil-based to zero-carbon by the second half of this century*"[10].

The notion of energy transition encompasses a wide array of policy initiatives or market developments, with varying degrees of intensity/disruption in the transitional process, but generally taking two distinct yet complementary directions:

i/ In the energy sector, the gradual phase out of existing, fossil fuel-centric systems, often through the development of renewable energies such as wind and solar PV. In practice, energy transition policies put a heavy emphasis on the electricity and heat sector where potential carbon emissions reductions are the largest and the easiest to achieve. Indeed, the sector still made up for 41% of worldwide CO_2 emissions in 2017, as it continued to heavily rely on coal (38% of worldwide generated volumes[11]), which accounts for the latter fuel remaining the main source of CO_2 emissions (44%) among all primary energy sources. From these elements, it ensues that coal phase out along with the development of renewable energies or other low-carbon generation technologies[12] is generally seen as the first step in the implementation of energy transition policies;

ii/ In the other economic sectors, the pursuit of energy-efficiency gains with a view to reducing the "energy content" of economic activity.

The purpose of this document is twofold. By providing an in-depth analysis of the underlying value chain, the current uses and environmental externalities of natural gas, it aims to clarify the role this molecule can play to support the transition toward a zero-carbon economy. It also aims to determine the future role of existing natural gas infrastructures in such a zero-carbon economy, particularly in light of the current emergence of low-carbon gases such as biomethane and green hydrogen.

9 International Renewable Energy Agency.

10 https://www.irena.org/energytransition

11 BP Statistical Review of World Energy 2019.

12 In particular nuclear electricity generation.

CHAPTER 1.

Understanding the current uses of natural gas and the related climate risks

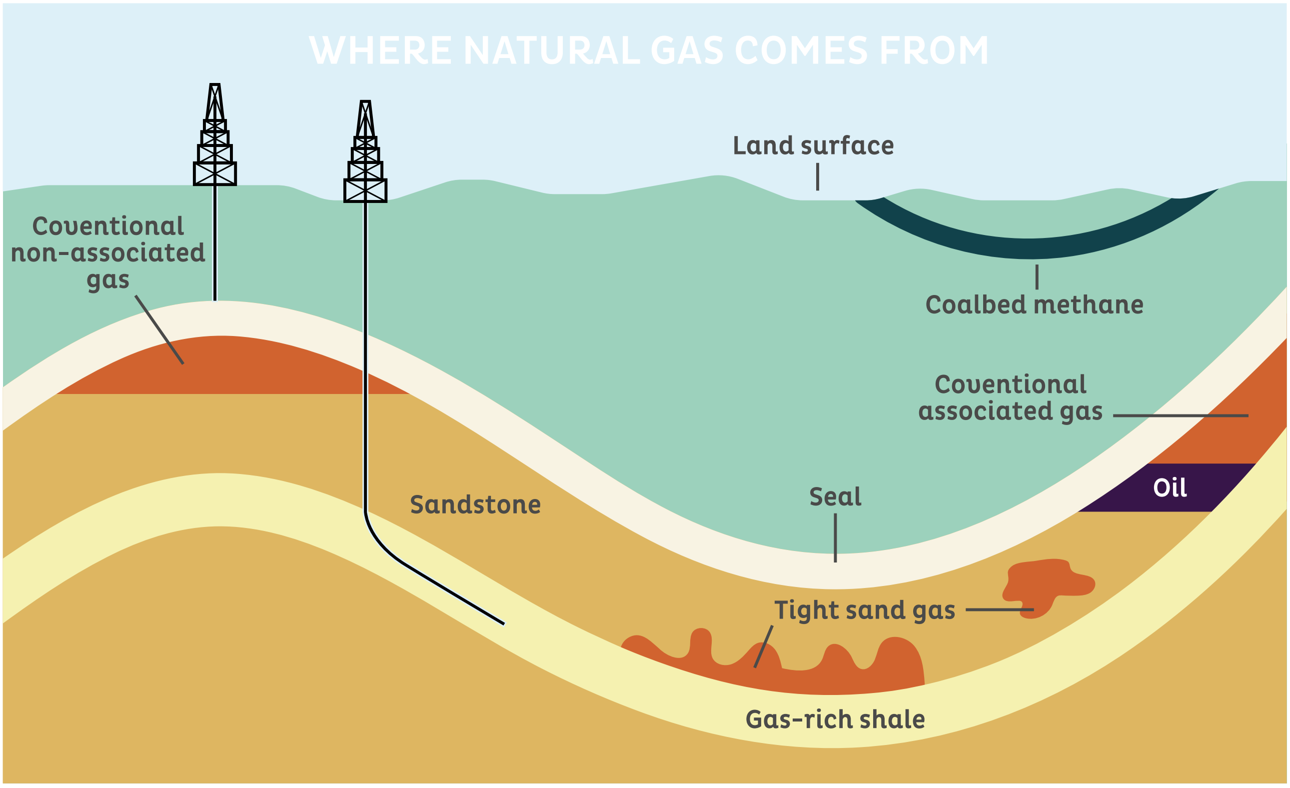
1. UNDERSTANDING THE CURRENT USES OF NATURAL GAS AND THE RELATED CLIMATE RISKS

Evaluating natural gas' potential contribution to climate change fight entails a precise understanding of what natural gas is, how it is produced and transported and how it is used.

In its life cycle, natural gas involves a complex value chain, with a variety of different operational processes involved not only for its production (conventional vs. non-conventional), but also for its delivery from wells to end users (pipelines vs. liquified natural gas - LNG). This variety of potential operational processes at play, as well as the numerous uses of the molecule in present day economies together account for the various controversies around the status of natural gas relative to oil and coal.

Having discussed the processes behind gas extraction and transportation and the current uses of natural gas, we investigate the molecule's carbon footprint with a view to determining under what conditions gas can be safely considered more climate-friendly than oil and coal.

FIGURE: WHERE CAN NATURAL GAS BE FOUND?



Source: https://www.ucsusa.org/resources/how-natural-gas-formed

1.1 NATURAL GAS AND RELATED INFRASTRUCTURE ASSETS

1.1.1 NATURAL GAS AS A SOURCE OF ENERGY: PHYSICS AND CHEMISTRY

Defined in chemical terms, natural gas is a naturally occurring hydrocarbon gas mixture consisting primarily of methane (94%), ethane (4%), nitrogen (1%), carbon dioxide (0.5%).

Like oil, natural gas is a product of decomposed organic matter, typically from ancient marine microorganisms, deposited over the past 550 million years. This organic material mixed with mud, silt, and sand on the sea floor, gradually becoming buried over time. Sealed off in an oxygen-free environment and exposed to increasing amounts of heat and pressure, the organic matter underwent a thermal breakdown process that converted it into hydrocarbons. The lightest of these hydrocarbons exist in the gaseous state under normal conditions and are known collectively as natural gas[13].

There are two general categories of natural gas deposits: conventional and unconventional. Conventional natural gas deposits are commonly found in association with oil reservoirs, with the gas either mixed with the oil or buoyantly floating on top, while unconventional deposits include sources like shale gas, tight gas sandstone[14] and coalbed methane[15]. **The latter deposits are extracted by hydraulic fracturing – commonly known as fracking** which involves drilling an oil or gas well vertically and then horizontally into a shale formation. A mixture of highly pressurized water, chemicals, and sand is injected to create and prop open fissures, or pathways for the gas to flow.

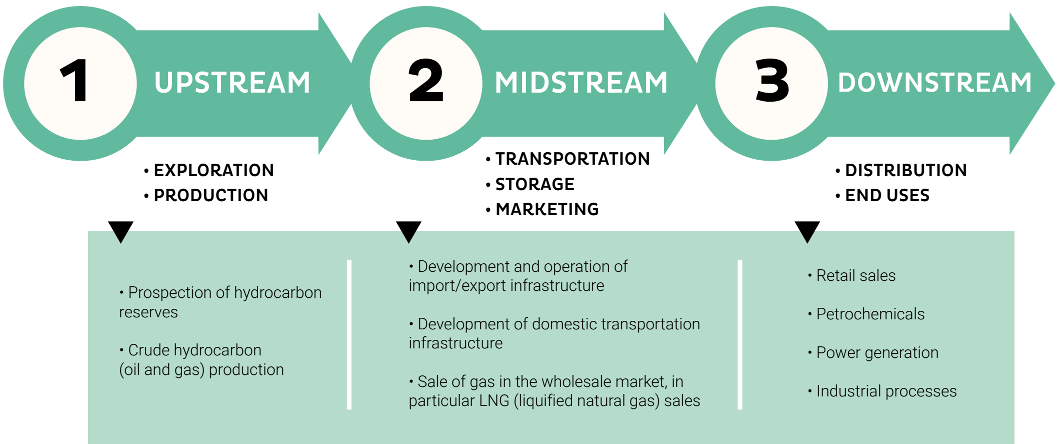
Like other fossil fuels, natural gas is therefore nonrenewable, for it is depleted much faster than new reserves can be created.

1.1.2 NATURAL GAS' VALUE CHAIN: A COMPLEX SET OF CAPITAL-INTENSIVE OPERATIONAL PROCESSES

Production and transport of natural gas to end users entail a fairly complex value chain, which can be summarized as in the chart below.

This value chain has three main components: exploration & production (E&P - the "upstream" segment), transportation, storage and marketing (the "midstream" segment) and the retail side (the "downstream" segment). Noteworthy is natural gas' value chain significantly overlapping with that of oil in the upstream segment, before diverging in the midstream segment.

FIGURE: SIMPLIFIED NATURAL GAS' VALUE CHAIN



Source: Natixis

13 https://www.ucsusa.org/resources/how-natural-gas-formed

14 Tight gas is a natural gas produced from reservoir rocks with such low permeability that massive hydraulic fracturing is necessary to produce the well at economic rates. Tight gas reservoirs are generally defined as having less than 0.1 millidarcy (mD) matrix permeability and less than ten percent matrix porosity. Although shales have low permeability and low effective porosity, shale gas is usually considered separate from tight gas, which is contained most commonly in sandstone, but sometimes in limestone. Tight gas is considered an unconventional source of natural gas.

15 Coalbed methane (CBM) is a form of natural gas extracted from coal beds. In recent decades, it has become an important source of energy in United States, Canada, Australia, and other countries. The term refers to methane adsorbed into the solid matrix of the coal. It is called "sweet gas" because of its lack of hydrogen sulfide. The presence of this gas is well known from its occurrence in underground coal mining, where it presents a serious safety risk. CBM is distinct from a typical sandstone or other conventional gas reservoir, as the methane is stored within the coal by a process called adsorption. The methane is in a near-liquid state, lining the inside of pores within the coal (called the matrix). The open fractures in the coal (called the cleats) can also contain free gas or can be saturated with water.

As mentioned above, **natural gas has originally been developed as a sort of byproduct of oil[16], which accounts for energy companies' E&P businesses comprising two business lines, oil and natural gas, which often overlap**, owing to the abovementioned geological properties of hydrocarbon fields. Indeed, as the physical process underlying gas formation is similar to the one found in the formation of oil, the two hydrocarbons tend to be present in the same fields. **In the E&P jargon, natural gas can be ''associated'' when produced alongside oil (and when oil economics have driven field development) or ''non-associated'' when produced individually**. The former type of production tends to be the most common[17]. In an environmental perspective, **it is important to draw the distinction between "associated" and "non-associated gas", for a substantial proportion of the negative environmental and climate externalities associated with natural gas production are to be found when the molecule is extracted along with oil.** Indeed, as seen with non-associated gas, associated gas production entails costly logistics (treatment and transportation to end users) for the extracted molecule to find actual use. Given the byproduct nature of associated gas, such logistics are not necessarily planned for by oil well owners/developers, which results in associated gas being often vented or flared upon drilling, for lack of a more suitable/economical solution. **This is the main reason why associated gas from oil fields is the main source of flaring as well as a major source of gas that is vented directly to the atmosphere – both major sources of greenhouse gas (GHG) emissions (see 1.2.1.1)[18]**. Together, such non-productive uses of gas continue to represent a substantial portion of associated gas extracted volumes (around 10%), hereby making up for 40% of the indirect (i.e. scope 1 and scope 2 emissions of CO_2e – see 1.2.1) emissions associated with oil production (IEA, WEO 2019). **In section 1.2, we provide extensive analysis of the carbon footprint of natural gas in a full life cycle analysis. We also detail the various flaring and venting practices found in the industry, some of which are linked to pure safety or technical requirements.**

While almost fully aligned in the E&P segment, the value chains of oil and natural gas diverge in the midstream and downstream segments due to the differences between the two fuels in terms of logistics and final use.

The logistics behind natural gas is complex, with substantial developments over the past few decades. **There are basically two ways of transporting gas**:

i/ Either by terrestrial or undersea pipelines, with natural gas remaining in its natural gaseous state;

ii/ Or by tankers, upon completion of a painstaking liquefaction process transforming natural gas into liquefied natural gas (LNG), which is summarized below. LNG's value chain implies two specific transformation steps before the molecule is available for delivery to end users. The first one involves treating the natural gas feed to remove water, hydrogen sulfide, carbon dioxide and other components that will freeze under the low temperatures needed to liquefy natural gas. The second process involves turning the treated natural gas still in a gaseous state to liquid, using liquefaction facilities also known as LNG trains, through refrigeration to less than -161 °Celsius (the boiling point of methane at atmospheric pressure).

Once available, LNG is shipped to import terminals (LNG terminals) where the molecule undergoes a regasification process allowing it to return into its initial gaseous state for delivery to end users using national, high-pressure pipelines (gas transmission networks), then local, low-pressure pipelines (gas distribution networks).

Historically, natural gas has been primarily transported using pipelines covering relatively short distances due to technical constraints. Indeed, natural gas pipelines are impractical across oceans, since gas needs to be cooled down and compressed, as the friction in the pipeline causes the gas to heat up[19]. **In the 1950s and 1960s, the expansion of gas markets and the abovementioned technical constraints associated with the transport of natural gas over oceans spurred the development of LNG**, a technology that had reached commercial viability as early as the 1940s[20].

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16 In the early days of oil production (late 19th century), natural gas was primarily seen as an unwanted by-product of oil extraction, given the technical hazard and disposal problems it caused in active oil fields.

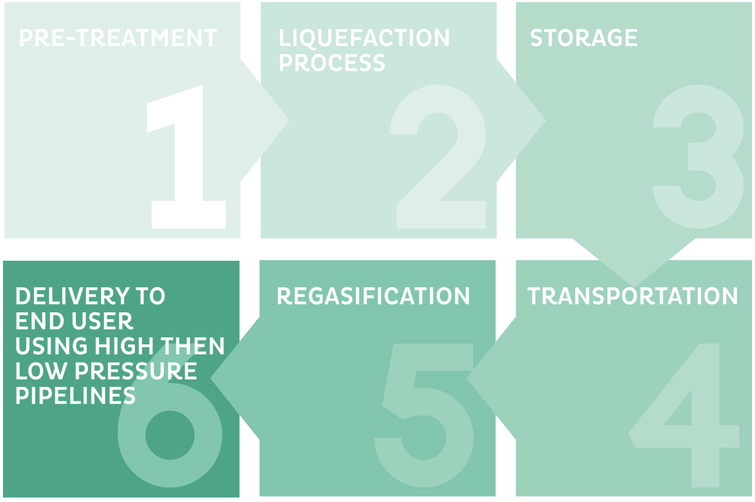
17 Noteworthy is associated gas making up on average for around 10% of the energy content of an oil field, although such proportion is subject to wide variation depending on geological conditions, well design and production method (IEA, WEO 2019).

18 Gas venting is not to be confused with other safety-related intentional releases of natural gas such as those from emergency pressure relief. Emergency pressure relief practice is commonplace in the gas upstream industry for both associated and non-associated gas production. It ensures the safety of the wells through the modulation of the internal pressure level.

19 For these reasons, pipeline is preferred for transportation for distances up to 4,000 km over land and approximately half that distance offshore.

20 The Est Ohio Gas Company built a full-scale commercial liquid natural gas (LNG) plant in Cleveland, Ohio, in 1940 just after a successful pilot plant built by its sister company, Hope Natural Gas Company of West Virginia. This was the first such plant in the world.

FIGURE: SIMPLIFIED OVERVIEW OF LNG VALUE CHAIN



Source: Natixis

At domestic level, delivery of natural gas to end users entails a set of infrastructures, namely:

i/ High pressure and medium/low networks, the former being referred to as transmission grids, the latter being referred to as distribution grids[21] and;

ii/ Storage facilities which are generally developed with the specific purpose of handling the seasonality of gas consumption, hereby ensuring security of supply all year long[22].

An important feature of the domestic infrastructure assets needed to bring natural gas to end users through the various steps described above, namely regasification, transportation, distribution and storage, is that they are regulated. It ensues that their revenues are set by the host country's government or by a dedicated public agency in a cost-reflective manner so as to enable the assets' owner and/or operator to recover the OpEx and CapEx incurred in the operation/maintenance and development of the facilities. Such regulatory schemes governing gas networks come from the monopolistic nature of the activity[23]. Whilst not natural monopolies per se, LNG terminal/ regasification plants on the one hand and storage facilities on the other hand tend to benefit from similar regulation schemes owing to the fact that they directly contribute to the complex logistics chain (case of LNG terminal/ regasification plants), or to the concerned country's security of gas supply (case of storage facilities).

Retail activities, i.e. supply of natural gas to end clients, are generally undertaken by national or local utilities. Such activities can be fully liberalized or governed by a regulatory scheme where the utility involved earns a somehow fixed margin/MWh of gas supplied.

In Western European countries, until a recent past[24], gas utilities tended to be organized following a heavily vertically integrated business model whereby an incumbent player was solely responsible for the provision of transmission, distribution and supply services within an entire country/jurisdiction. **The progress towards an EU-wide integrated energy market has prompted many countries to abandon such vertical integration and to introduce new regulations forcing incumbent players to divest their transmission activities**, under the so-called "ownership unbundling rule". As a result, the general trend in Western Europe is toward gas supply utilities solely retaining ownership of low-pressure distribution networks.

21 As in the electricity sector, distribution activities encompass two separate activities, namely operation and maintenance of the infrastructure assets and metering activities.

22 In particular for heating purposes (see 1.1.3).

23 Natural monopolies are activities where overwhelming capital costs and generally associated economies of scale only allow the presence of a single player. William Baumol (1977) provided the current formal definition of a natural monopoly where "[a]n industry in which multi-firm production is more costly than production by a monopoly".

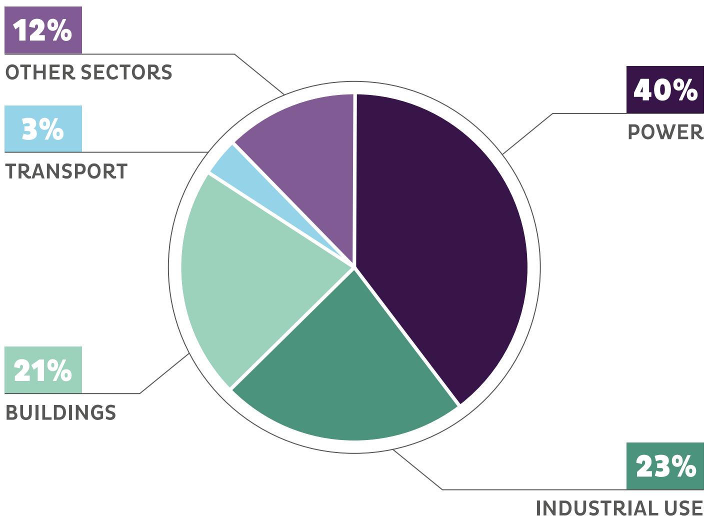
24 Early 2000s.

1.1.3 MULTIPLE END-USES OF NATURAL GAS: POWER GENERATION, INDUSTRY, HEATING, TRANSPORT

As mentioned above, **the share of natural gas in World primary energy demand has grown steadily over the past four decades to reach 23% in 2018 (vs. 17% in 1980)**.

Such trend is partly attributable to the numerous uses natural gas enjoys in present-day economies. In broad terms, **natural gas is predominantly used in four activities/sectors either as a fuel to generate heat or energy upon combustion or as a feedstock.**

FIGURE: BREAKDOWN OF GLOBAL GAS DEMAND BY SECTORS/MAIN USES IN 2018



Source: IEA (WEO, 2019)

Among the main uses natural gas currently enjoys, one may cite:

i/ Power generation (40% of global gas demand in 2018 - see graph above), **where natural gas is used to run gas-fired plants, in particular CCGTs (combined cycle gas turbines**[25]). CCGTs have enjoyed swift development rates over the past three decades to meet ever-growing electricity needs across all continents[26]. **The reasons for the fast development of state-of-the-art CCGTs are numerous:**

- **They enjoy the highest efficiency rates among thermal plants** (50 to 60%, to compare with around 40% for single gas-fired turbines, around 35%-45% for coal-fired plants[27] - see pictogram below);

- With generally 350-450 kgCO_2e/MWh, **they generate fewer CO_2 emissions per MWh produced than their fossil fuel peers**, oil, coal and lignite plants, in the respective proportions of -30%, -45% and -60% (see pictogram below). Gas plants' lower carbon-intensity than coal and oil plants' is the main element supporting the vision of gas as a "bridge" / "interim" fuel;

- **They display relatively low development costs** (particularly when compared with standard coal-fired plants and nuclear reactors) and finally;

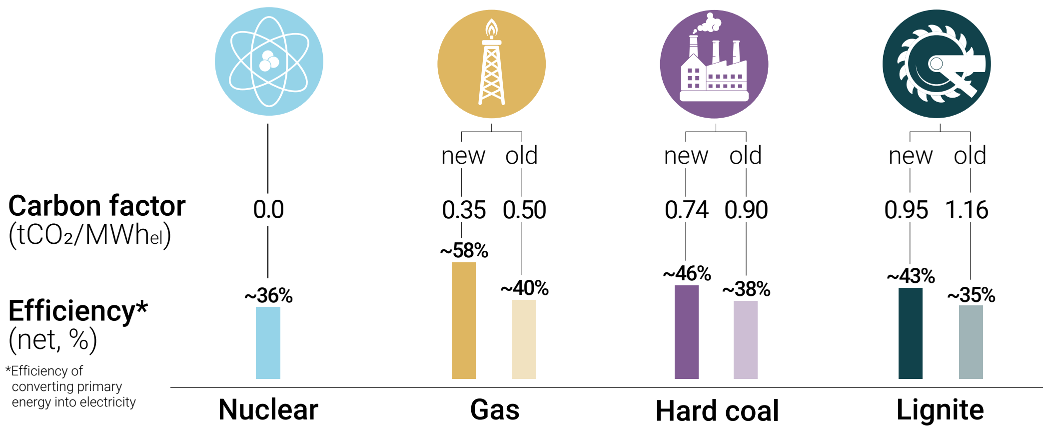
25 A CCGT can be defined as an assembly of heat engines that work in tandem from the same source of heat, converting it into mechanical energy. The working principle behind CCGTs is that after completing its cycle in the first engine, the working fluid (the exhaust) is still hot enough that a second subsequent heat engine can extract energy from the heat in the exhaust. Usually the heat passes through a heat exchanger so that the two engines can use different working fluids.

26 According to the IEA (WEO 2019), global electricity demand nearly doubled from 2000 to 2018, going from 13,152 TWh to 23,051 TWh.

27 Depending on how new the coal-fired plant is. We leave aside the case of ultra-supercritical coal-fired plants that can potentially reach efficiency rates of nearly 50%, for these plants are still under research and development.

- **Relative to other conventional generation technologies, they offer a high degree of versality and flexibility. Such versality primarily comes from CCGTs having two or more cycles, the first of which enjoying the features of a "peaking plant", with the other running on the waste heat of the first.** Such setting allows CCGTs to rapidly start up (for balancing purposes) at reduced efficiency, and then to transition over some hours to a more efficient baseload generation mode. Enjoying low response time through their first cycle, CCGTs have therefore taken over the role of old, single-gas turbines used to play as "peakers" in electricity systems, generally next to coal-fired plants. For single-gas turbines, approximately six minutes are needed from command to full load; in CCGTs, the secondary steam turbine(s) follow(s) after 30 to 240 minutes. In comparison with gas turbines, as is case with CCGTs' secondary turbines, steam turbines have much longer reaction times, in particular in the case of coal-fired plants, the warm start of which is in the range of one to 10 hours. At the other hand of the spectrum, a cold start of nuclear power plant can take up to several days[28]. **CCGTs' potential very low response time is a feature that has been highlighted relatively recently and has to be put in the context of renewable assets' expansion.** CCGTs were originally designed for baseload power generation but the development of subsidized, intermittent renewable capacities benefiting from priority injection into power grids has spurred increased use of CCGTs for system balancing purposes over the past 10 years, in particular in Western Europe. This relatively new use of CCGTs has itself driven technology improvements with a view to further enhancing their suitability for balancing purposes. We extensively discuss these recent developments in section 2.1, when analyzing the role of CCGTs as providers of ancillary services in present-day power systems which heavily rely on intermittent renewable sources;

FIGURE: CARBON FACTORS AND EFFICIENCIES BY TYPE OF POWER PLANTS



Source: RWE

ii/ Industrial uses (23% of global gas demand in 2018) **as a fuel and/or as a feedstock**. In the manufacturing sector, natural gas is used to power furnaces for the production of steel, cement, bricks, ceramics, tile, paper, food, products and many other commodities. Natural gas is also a feedstock for such varied products as steel (iron ore reduction), hydrogen, fertilizers, plastics, pharmaceuticals and fabrics. It is also used to manufacture a wide range of chemicals (such products include ammonia, methanol, butane, ethane, propane and acetic acid, etc.);

iii/ Building heating (21% of global gas demand in 2018). Most of the natural gas consumed in building is for space heating, water heating and air conditioning. In residential buildings, it is also used in stoves, ovens, clothes dryers, lighting fixtures and other appliances;

iv/ Transport (4% of global gas demand in 2018). Use of natural gas to fuel land vehicles or ships is no longer at the R&D phase but remains small-scale, therefore relatively marginal. In the maritime transport business, demand for natural gas in its liquefied form (LNG) could be spurred by the recent entry into force of IMO[29] 2020 regulation which puts a cap on sulfur

28 https://www.energybrainpool.com/fileadmin/download/Studien/Study_2017-09-07_Energy-Brainpool_Study_Flexibility-Needs-and-Options_EUGINE.pdf

29 International Maritime Organization.

emissions[30]. Such cap has indeed generated interest in using LNG as an alternative to high-sulfur fuel oil in the sector, for LNG emits almost no sulfur dioxide or particulate matter and contains up to 90% fewer nitrogen impurities than heavy fuel oil (IEA, WEO 2019). For these reasons, in its latest "Stated Policies Scenario"[31], the IEA expects the use of LNG in international shipping to reach 50 bcm by 2040 from less than 1 bcm today and (to account) for 13% of shipping fuel mix (IEA, WEO 2019);

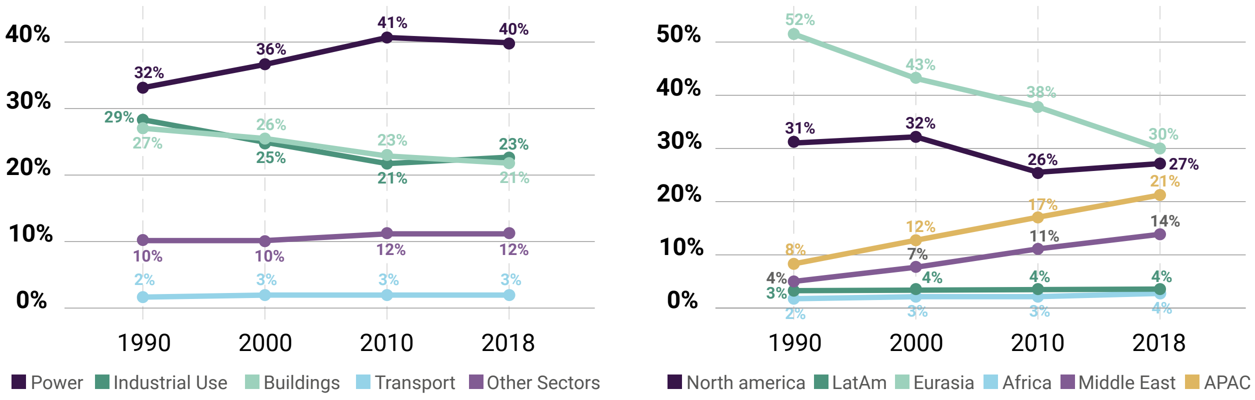
v/ Various other uses (12% of global gas demand in 2018). In the energy sector, natural gas is used for hydrocarbons recovery (through injection into oil wells to create pressure for secondary liquids recovery[32]) and transport (through injection into compressor stations that help "move" natural gas in the pipelines) purposes.

The abovementioned rise of natural gas in the world primary energy mix since 1980 is particularly remarkable when considering the doubling of world primary energy demand over the same period[33]. It has to be put in a twofold context characterized by natural gas:

i/ Taking a new dimension in the US in the wake of the shale hydrocarbons revolution. **Over the past 15 years, the world's biggest economy has moved from a "swing buyer" position to a "swing producer" one**. In other words, while remaining by far the world's largest consumer of natural gas, the US have become the main producing country, making up for 22% of global gas supply. The ensuing cheapness of natural gas in the domestic energy market has spurred a massive coal-to-gas switch we analyze in section 2.2.1;

ii/ Enjoying swift development in emerging countries, **with the share of Asia-Pacific in global gas demand rising from 8% in 1990 to 21% in 2018**. Such trend is primarily attributable to the massive expansion of China's and India's economies over the past two decades, which, as a result, have become the main engines of global energy demand growth. **Albeit still very dependent on coal, in particular for power generation purposes[34], China and India are gradually turning to natural gas to address air quality concerns (specific case of China) but more fundamentally to meet increasingly diverse needs from industrial sectors.** As the IEA stresses, there is mounting use of gas "in steel making and petrochemical production (primarily fertilizers), as well as in a broad range of medium- and small-scale manufacturing (e.g. textile, food processing, glass and ceramics). Gas is (also) well suited to provide adjustable levels of process heat for industrial boilers and furnaces" (IEA WEO 2019).

FIGURE: TREND IN NATURAL GAS USES BY SECTORS (1980-2018, IN %) / TREND IN NATURAL GAS CONSUMPTION BY GEOGRAPHIES (1980-2018, IN %)



Source: IEA (WEO, 2019)

30 From 1 January 2020, the limit for Sulphur in fuel oil used on board ships operating outside designated emission control areas is reduced to 0.50% m/m (mass by mass). This will significantly reduce the amount of Sulphur oxides emanating from ships and should have major health and environmental benefits for the world, particularly for populations living close to ports and coasts.
http://www.imo.org/en/mediacentre/hottopics/pages/sulphur-2020.aspx

31 See: General introduction: putting present day use of natural gas into perspective.

32 Such process is common in Norway, Iran and Venezuela (IEA, WEO 2019).

33 From 7,261 Mtoe in 1980 to 14,315 Mtoe in 2018 (IEA, WEO 2019).

34 Coal made up for 67% and 75%, respectively, of China's and India's electricity mixes in 2018 (source: BP Statistical Review of World Energy 2019).

A few conclusions can be drawn from these recent developments:

i/ The various uses of natural gas have not dramatically changed over the past three decades. **Gas remains primarily used for power generation, manufacturing and heating purposes** (84% of aggregate demand in 2018 vs. 88% in 1990);

ii/ Recent expansion of natural gas in Asia-Pacific has to be put into the twofold context of accelerated industrialization and/or economic modernization across the region. Only in the latter case can gas be considered as having displaced coal amid gas-centered industrial processes displacing less-efficient, coal-centered ones, in particular for what concerns heating systems and boilers. The US power generation sector offers the most clear-cut illustration seen thus far of the role of gas as an immediate, large-scale substitute for coal;

iii/ While holding promises, in particular in the shipping business, use of natural gas in the transport sector remains very limited. Transport sector's still modest share in global gas demand (3%) has to be put into the specific context of mounting initiatives to reduce sector's dependency on oil and oil-related fuels. Interestingly, the main avenues being pursued here are through the use of electricity or green/low-carbon fuels[35] (biodiesels, biomethane, hydrogen), all competing technologies offering the prospect of fully reducing, either directly or indirectly[36], the carbon emissions associated with fuel combustion in the sector. From this angle, noteworthy is oil-to-gas switch in the transport sector offering tangible, yet partial decarbonization potential (-25/-30% fewer CO_2 scope 1 emissions reductions, holding all else equal).

Also of note is the variety of gas uses across geographies. Outside of the OECD, China and the Former Soviet Union, most gas is consumed by power or industry, with very little volumes used for building heating purposes. In contrast, across OECD countries, 28% of gas demand is used in heating. Such differences are worth highlighting, for they evidence the high context-dependency of gas uses as well as the latter's varied climate implications, as we thoroughly discuss in section 2.

1.2 SENSING GAS INDUSTRY'S ENVIRONMENTAL EXTERNALITIES: IS NATURAL GAS REALLY PREFERABLE TO OIL AND COAL?

There are numerous environmental externalities associated with natural gas, the most controversial being found in the upstream part of the value chain. Such externalities include releases of greenhouse gases, mostly taking the form of CO_2 and methane emissions, air pollution, water use and pollution of surface and ground water resources, land use and degradation and seismic risk. Among the various externalities listed above, the most severe, namely air pollution (upon use of toxic chemical products), water use and pollution and increased seismic risk are closely associated with non-conventional extraction processes (shale gas but also coalbed methane, tight gas – see 1.1.2). Noteworthy however is these processes being used at a commercial scale only in a few countries, primarily US and Canada, as well as, albeit to a much lesser extent, Argentina and China.

In this section, we deliberately follow a climate-centric analysis of natural gas' environmental impact, hereby leaving aside other externalities, this for two reasons:

i/ Natural gas' non climate-related externalities tend to be heavily associated with non-conventional processes which enjoy very limited use outside of a few countries; but more fundamentally;

ii/ Proponents of natural gas as a "bridge" or "interim fuel" (concepts we extensively discuss in section 2) **primarily cite its low-carbon intensity *relative to* oil and coal**. While natural gas' carbon intensity upon combustion is much lower than other fossil fuels' (see 1.1.3), **it remains to be seen whether natural gas continues to offer clear-cut climate benefits relative to oil and coal after factoring in the entire value chain's footprint**.

We therefore follow a life cycle[37] approach in order to grasp the various instances under which every link of the value chain, from extraction to final use, can prove harmful from a climate standpoint. **This approach allows us to eventually compare the carbon footprint of natural gas relative to that of oil and coal.**

35 See section 3 for a detailed discussion on the conditions under which "new" gases can claim "greeness".

36 As in the case of biomethane, see part III.

37 ''Life Cycle Assessments and Carbon Footprints give insights in the environmental impacts in the supply chain of a product. This forms a sound basis for companies and organizations which aim to monitor their environmental performance and develop strategies to reduce their impact'' (https://www.agri-footprint.com/life-cycle-assessments-carbon-footprints/).

1.2.1 THE CHALLENGES OF APPLYING LIFE CYCLE ANALYSIS TO NATURAL GAS

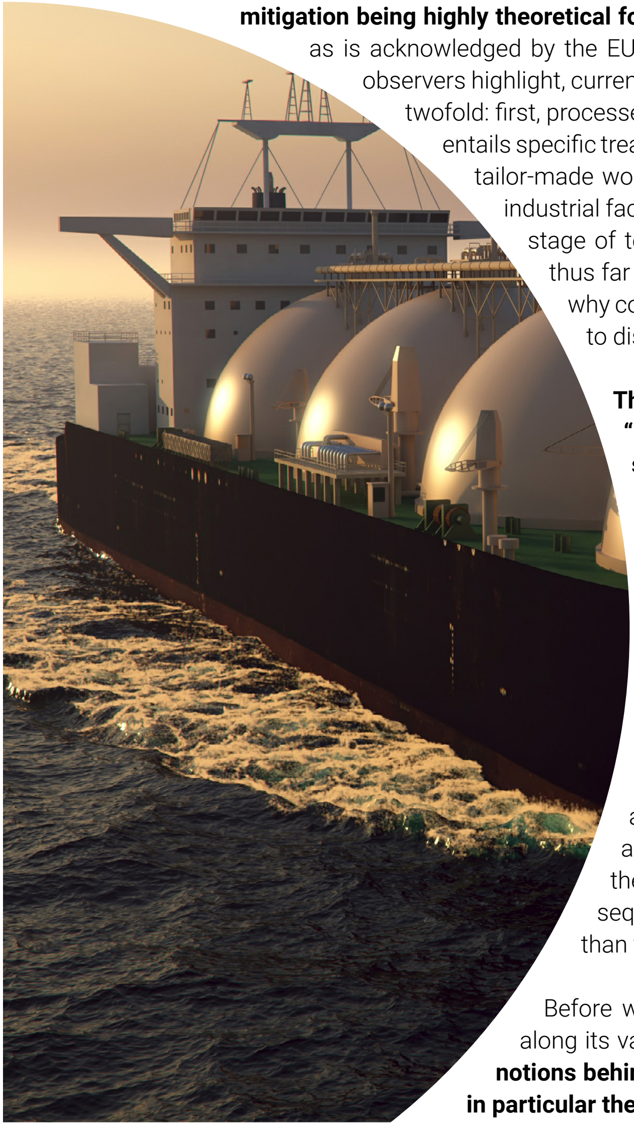
The natural gas industry's carbon footprint has been and is set to remain a highly debated topic. Controversies over the environmental impact of natural gas owe their existence to the absence of widespread, universal data enabling well-documented comparisons of the molecule's carbon footprint with that of other fossil fuels. Such documentation issue itself comes from the **multitude of operational conditions governing the extraction, transportation and, to a lesser extent, the final use of natural gas**.

The carbon footprint of natural gas can greatly differ *depending on whether*:

i/ Natural gas is extracted using conventional processes and is not associated with oil or is extracted using hydraulic fracturing and is associated with oil;

ii/ It is transported in its original gaseous state (pipelines) or in its liquified state (LNG) and;

iii/ The direct emissions associated with its combustion for power generation or in other industrial processes **are mitigated through carbon capture and storage (CCS) processes**. Noteworthy however is this **case of emissions mitigation being highly theoretical for the time being, for CCS processes remain at their infancy**, as is acknowledged by the EU Taxonomy in its take on natural gas (see 2.2.2). As various observers highlight, current challenges associated with large-scale use of CCS are mainly twofold: first, processes currently developed "only" reach a 90% efficiency rate, which entails specific treatment costs for the remaining 10%. Second, use of CCS implies tailor-made work to adapt the process to the specific features of concerned industrial facilities. For this reason, CCS remains hard to industrialize at this stage of technology development and its deployment has been limited thus far to a limited number of pilot projects[38]. This is the main reason why commonly followed life cycle approaches to natural gas continue to disregard CCS when tackling scope 3 emissions.



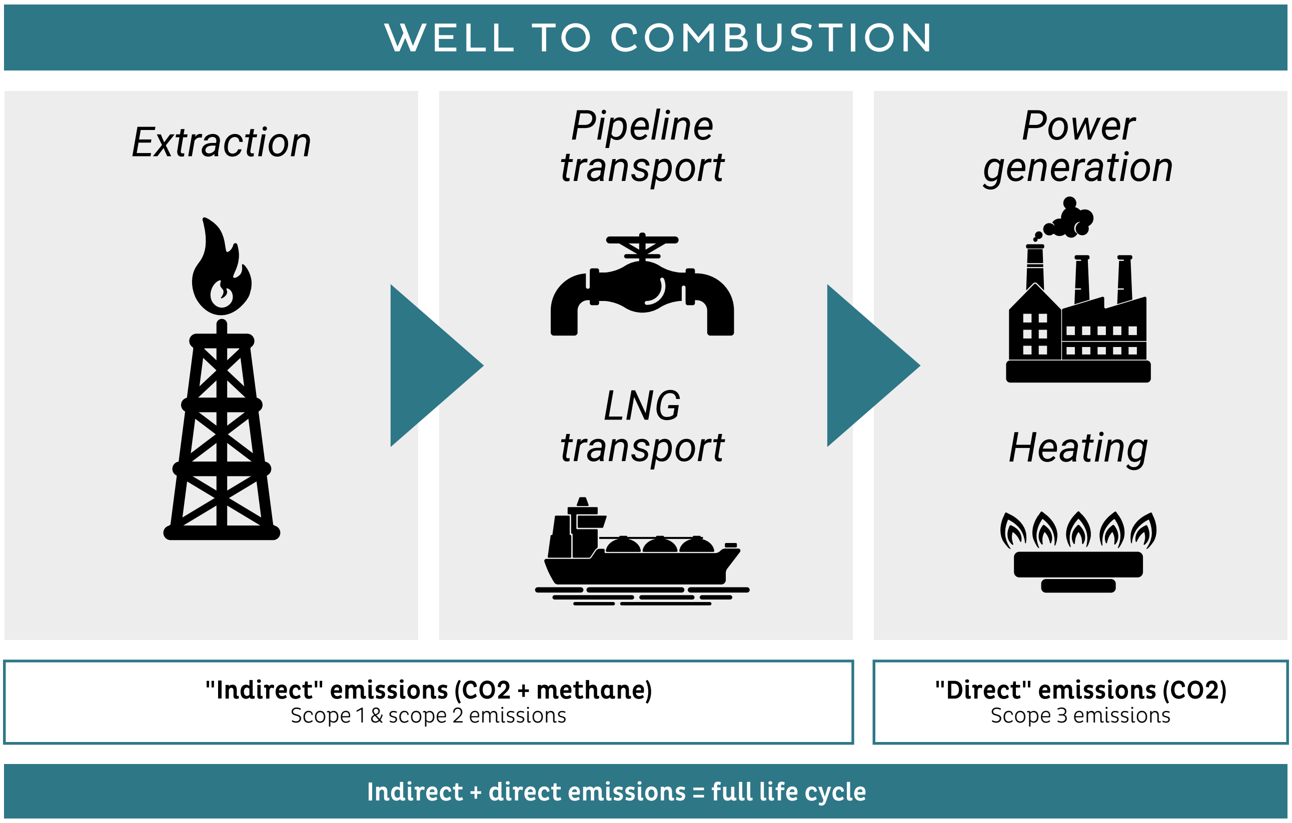
This variety of cases evidences the difficulty to define a "reference" value chain enabling a clear-cut breakdown of scope 1, scope 2 & scope 3 CO_2 and CO_2e emissions along the value chain and ultimately the determination of a universal and comprehensive carbon intensity factor tackling all emissions from extraction to end use.

In the gas industry, **CO_2e emissions are of particular relevance as they stand for the carbon dioxide-equivalent warming effect of all greenhouse gas emissions along the value chain, which mainly includes those of CO_2 and methane. Released in the Earth's atmosphere, methane indeed ranks among the most potent greenhouse gases**, with a global warming potential (GWP) 104 times greater than CO_2 in a 20-year time frame. However, having a far shorter longevity in the atmosphere compared to CO_2 (assuming no change in carbon sequestration rates), methane displays a GWP 28 times greater than the latter over a 100-year period.

Before we thoroughly investigate the carbon footprint of natural gas along its value chain, **it is worth spending some time analyzing the key notions behind the concepts of scope 1, scope 2 and scope 3 emissions, in particular their relevance for the analysis of the industry's climate impact**.

38 With, according to the IEA (2019) "only two large-scale CCUS power projects in operation at the end of 2018 and a combined capture capacity of 2.4 million tons of CO_2 (…) per year".

FIGURE: SIMPLIFIED LIFE CYCLE APPROACH TO NATURAL GAS



Sources: IEA, Natixis

Scope 1 and scope 2 emissions are fairly straightforward concepts**. Outside of the oil and gas sectors, scope 1 emissions refer to direct CO_2 or CO_2e emissions that are generally to be found upon combustion of fossil fuels**, be it to produce electricity (electricity generation) or to run ICE (internal combustion engine) vehicles (transportation). **In the oil and gas sectors, scope 1 emissions relate to the various direct emissions along the value chain**.

These emissions are under considerable scrutiny in the gas industry because of the variety of potential CO_2 or CO_2e emissions from extraction to final use, namely:

i/ The methane emissions from venting practices, the latter being often found with associated gas production (see 1.1.2);

ii/ The fugitive methane emissions occurring upon gas extraction as well as during the transportation phase (pipeline leakages) and

iii/ The direct CO_2 emissions in the extraction phase (**flaring** – see 1.1.2) **as well as during the transportation phase** (LNG tankers' fuel combustion – see 1.1.2).

Scope 2 emissions refer to the concerned activity's indirect emissions, namely the carbon intensity of the purchased electricity, heat and steam needed for the related provision of goods and services. As we suggested above, the main source of scope 2 emissions in the gas industry is to be found in the specific LNG logistic chain, through liquefaction and, to a lesser extent, regasification of natural gas.

Finally, **scope 3 emissions refer to the CO_2 emissions occurring at the final link of the value chain, when natural gas finds its end use**.

Noteworthy is life cycle approaches in the energy sector, in particular in IEA's publications, erasing the traditional distinction between *direct* and *indirect* emissions: instead, such approaches tend to consider the *indirect* emissions intensity of any given fossil fuel as including "all sources of GHG emissions from the point where (the concerned fossil fuel) is extracted to, but not including, where and how it is consumed" (EIA, WEO 2019). **In other words, IEA's indirect emissions approach includes all scope 1 and scope 2 CO_2e emissions along the value chain until final use; it therefore excludes scope 3 emissions caused by the combustion of the molecule.**

The table below provides a simplified overview of natural gas' carbon footprint along the value chain. We combine scope 1 and scope 2 emissions in the upstream and midstream segments of the value chain. **We deliberately focus on three different cases reflecting** the diversity of potential operational processes along the value chain:

i/ Case #1: **"Conventional" natural gas using pipelines for delivery to final users;**

ii/ Case #2: **"Shale" gas using pipelines for delivery to final users;**

iii/ Case #3: **"Conventional" natural gas using LNG for delivery to final users.**

FIGURE: SIMPLIFIED OVERVIEW OF NATURAL GAS' CLIMATE FOOTPRINT ALONG ITS VALUE CHAIN

Specific Logistic Chains Considered	Scope 1 & 2 Upstream	Scope 1 & 2 Midstream	Scope 3 Final use
#1: «Conventional» gas + pipeline transportation	**Methane fugitive emissions (extraction)**	**Methane fugitive emissions**	CO2 emissions upon combustion
#2: Associated «shale» gas + pipeline transportation	**Methane fugitive emissions (extraction)** + flaring (CO2 emissions) and **venting (methane emissions)** practices	**Methane fugitive emissions**	
#3: «Conventional» gas + LNG transportation	**Methane fugitive emissions** (extraction)	Electricity content of liquefaction/ regazeification / LNG tankers' direct emissions	

Source: Natixis

Before analyzing in more detail the climate impacts of the gas value chain (focusing mainly on methane emissions), it is important to underline that the abovementioned flaring and venting practices in the industry do not arise only from purely economic considerations linked to the absence of a commercial outlet for associated gas. They also arise from safety or other technical imperatives along the value chain.

For what concerns gas flaring, a distinction is generally made in the industry between "routine" flaring, on the one hand, and "safety" flaring, "maintenance" flaring or other flaring practices characterized by shorter durations or smaller volumes of gas disposal, on the other hand. The former case mainly refers to the widespread practice of disposing of large unwanted amounts of associated gas during crude oil extraction. By contrast, the latter case refers to various practices developed in the industry to meet safety or other technical requirements in the operation of hydrocarbon fields/processing plants. In the upstream segment of the value chain, after a shale oil/gas well is drilled and hydraulically fractured, a temporary flare is used during well production testing. Testing is important in order to determine the pressure, flow and composition of the gas or oil from the well. Flaring at the well site can last for several days or weeks, until the flow of liquids and gas from the well and pressures are stabilized[39]. Flaring is also commonplace in gas processing plants, where flares are an important safety design. In an emergency situation where equipment or piping becomes over-pressured, special valves on

39 Ohio EPA: https://www.epa.state.oh.us/Portals/27/oil%20and%20gas/Basics%20of%20Gas%20Flaring.pdf

the equipment automatically release gas through piping to flare stacks. In the absence of safety flares, plants would be at higher risk for fires and explosions[40].

The same can be said about venting practices. The generic term of gas venting is not to be confused with other safety-related intentional releases of natural gas such as those from emergency pressure relief. Emergency pressure relief practice is commonplace in the gas upstream industry for both associated and non-associated gas production. It ensures the safety of the wells through the modulation of the internal pressure level.
This distinction is important, for it highlights the technical impossibility for the gas industry to reach absolute climate neutrality in the extraction, processing and transport of natural gas. In other words, there will still have to be flaring and venting for safety or other technical reasons even if the "routine" flaring is eliminated by new regulations and/or by the emergence of economic opportunities to use/sell associated gas instead of flaring and/or venting it.

1.2.2 THE KEY IMPORTANCE OF METHANE EMISSIONS WHEN ASSESSING THE LIFE CYCLE'S CLIMATE IMPACT OF NATURAL GAS

The table above evidences the various occurrences of methane emissions along the value chain. For the entire gas industry, such emissions probably represent the biggest environmental challenge: not only are methane releases/leakages almost everywhere in the extraction and transportation phases of the molecule's life cycle, albeit to varying degrees (see below), but, from a GWP perspective, they are also more much potent than CO_2 emissions.

In its 2020 methane tracker update[41], the **IEA estimates that methane emissions from the oil and gas sector reached close to 82 Mt in 2019, split in roughly equal parts between the two fossil fuels**. Expressed in CO_2e, **these overall methane emissions represented 2.5 billion tons of CO_2e in 2019, i.e. nearly 50% of all the total indirect (scope 1 and scope 2 emissions) GHG emissions from oil and gas operations (5.2 billion tons CO_2e), as well as 7% of worldwide CO_2 emissions**.

In the following sections, we deliberately focus on the various methane emissions along natural gas' value chain, this for three reasons:

i/ Being by far the main source of indirect GHG emissions in the gas industry, methane emissions are now viewed as a key factor influencing the climate benefit of gas relative to coal and oil;

ii/ They enjoy substantial abatement potential; experts emphasize the existence of a wide variety of technologies and measures already available to reduce methane emissions from oil and gas operations, some of them at close to zero net cost;

iii/ Albeit widely discussed, **methane emissions are seldom accounted for in a comprehensive manner including all GHGs.** In practice, this means that it is possible to obtain data for one type of GHG per segment of the value chain but not a comprehensive set of data in a comparable manner for all GHGs in each segment.

1.2.2.1 ASSESSING METHANE EMISSIONS: A PENDING ISSUE

Given the fact methane holds over 28 times more GWP than CO_2 over a 100 year-period (see 1.2.1), the issue of fugitive emissions is highly sensitive and is made even more controversial by the lack of consensus on the assessment of leakage volumes. Scientists are still struggling to agree on a universally accepted approach.

Broadly speaking, there are two approaches to assessing fugitive methane emissions: bottom up and top down. "Bottom-up" estimates physically measure emissions from a representative sample of wells and midstream infrastructures. In contrast, **"top-down" measurements can be performed at a regional scale, using satellite data, airplane flyovers** (i.e. flying an aircraft upwind and downwind of a study area).

Each set of measurement techniques has its shortcomings. Bottom up estimates do not necessarily accurately reflect the emissions of the whole production process. As a result, they tend to underestimate fugitive emissions. On the other hand,

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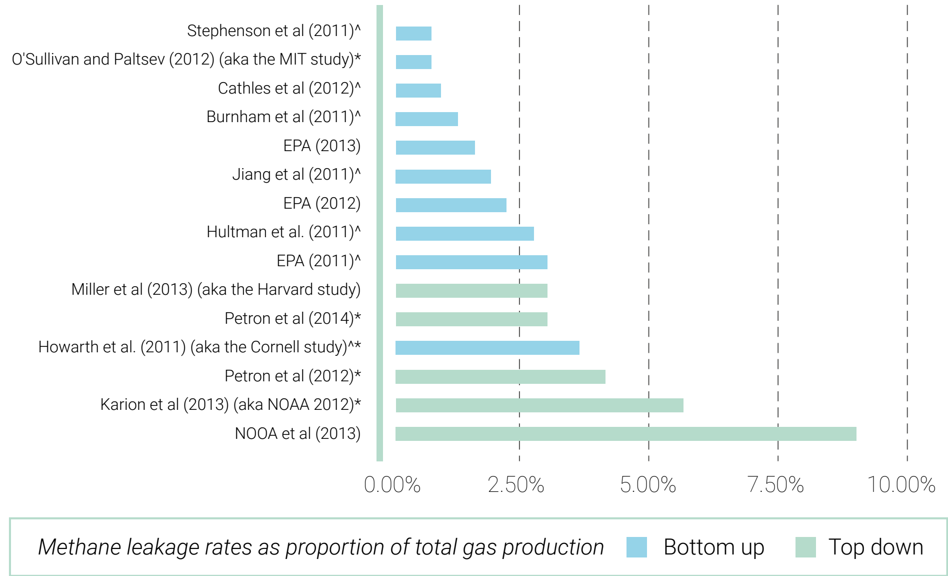
40 Ohio EPA, op. cit.

41 https://www.iea.org/reports/methane-tracker-2020.

top-down approaches can in some instances offer very contrasted results[42]. In addition, top-down approaches confront another, sector-specific difficulty when measuring methane emissions: as Robert Horwath stresses, "the activity of the industry and rates of production in various gas fields are quite variable over time and some of the differences in percentage emission rates may reflect this variability" (Horwath 2015, op. cit).

As a result, estimates of fugitive methane emissions during the gas extraction phase have traditionally shown very wide ranges. Extracted from a study published in 2014 gathering various results from the application of the two methods, the table below presents leakage rate estimates ranging from less than 1% to more than 9%. This table highlights the structural differences between bottom-up and top-down estimates, the latter generally coming up with higher measurements, the grey bars, as they potentially capture a wider source of emissions.

FIGURE: ESTIMATED METHANE LEAKAGE RATES IN THE UPSTREAM SEGMENT OF THE VALUE CHAIN AS PROPORTION OF TOTAL GAS PRODUCTION (%)



*Note: ^ means value is for unconventional – i.e. shale – gas wells only, * means the value in the graph is the mid-estimate or mean of a range where a 'best estimate' is not given.*

**Available at https://www.carbonbrief.org/why-measuring-fugitive-methane-emissions-from-shale-gas-production-matters*

Source: Carbon Brief (2014)[43]

1.2.2.2 SOURCES OF METHANE EMISSIONS ALONG NATURAL GAS' VALUE CHAIN

As we highlighted above, methane emissions occur almost everywhere along the value chain, whatever the specific operational processes involved from extraction to delivery to end users. However, **across the globe and even within the same jurisdiction, the importance of methane releases along the value chain varies greatly depending on a series of factors** discussed in detail in the following paragraphs. In a context of mounting climate awareness, methane emissions are a growing issue in the industry, a source of technical innovation on the part of oil and gas groups but also new environmental regulations on the part of public authorities (see textbox #1).

In broad terms, there are two main types of methane emissions along the gas value chain, namely those in relation to common practices in the industry and those accidental, generally referred to as "fugitive emissions".

The former methane emissions relate to the processing of "unwanted" gas upon extraction, taking the form of venting. As with gas flaring, such practice is **intimately tied to associated gas production. As we highlighted in section 1.1.2,**

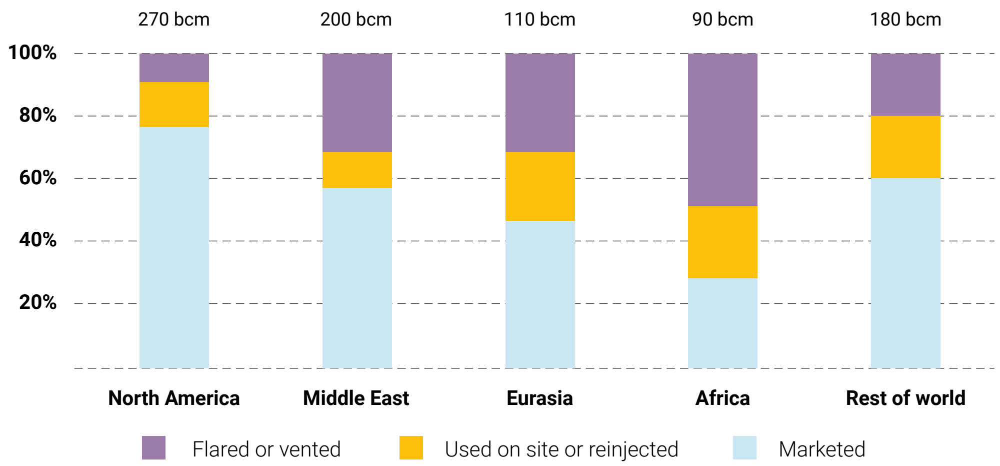
42 In an account of top-down measurement techniques, Cornell University professor R. Horwath stresses that "several other recent studies have estimated upstream methane emissions from shale gas and other unconventional natural gas development (i.e. from tight-sand formations) using more robust and more integrated measurement techniques such as airplane flyovers, but still with highly variable results. Estimates were ~ 30% greater than the satellite-derived data for one gas field".
(See https://www.eeb.cornell.edu/howarth/publications/f_EECT-61539-perspectives-on-air-emissions-of-methane-and-climatic-warmin_100815_27470.pdf).

43 Available at https://www.carbonbrief.org/why-measuring-fugitive-methane-emissions-from-shale-gas-production-matters

associated gas, being a byproduct of oil raises a series of operational challenges. Its use upon extraction entails costly logistics, not necessarily planned for by hydrocarbons wells owners/operators. As a result, natural gas is often vented or flared upon drilling, for lack of a more suitable/economical solution. The IEA estimates that out of the 850 bcm of associated gas produced in 2018, around 20% of the world's gas production, only 75% was used by the industry or brought to market. Of the remaining 200 bcm, 140 bcm was flared and 60 bcm was vented, altogether making up for more than the annual LNG imports of Japan and China combined (IEA, WEO 2019). While sharing the same origin, the two practices have different environmental implications. Gas flaring mainly results in CO_2 emissions, whereas gas venting results in methane emissions.

Associated gas production failing to find use is a widespread phenomenon. Even in countries with well-developed gas markets such as the US, around 10% of associated gas extracted today is flared or vented (IEA, WEO 2019).

FIGURE: USE OF ASSOCIATED GAS BY REGION, 2018



Source: IEA (WEO, 2019)

Unlike venting practices, **fugitive methane emissions, occur all along the value chain, hereby concerning not only extraction wells but also all gas midstream infrastructures**: storage tanks, pipelines, and urban distribution pipes. In such case, methane emissions simply result from accidental natural gas leakages caused by malfunctioning equipment.

In the upstream segment, **such emissions are generally the result of loss of well integrity through poorly sealed well casings due to geochemically unstable cement.** This allows natural gas to escape through the well itself (known as surface casing vent flow) or via lateral migration along adjacent geological formations (known as gas migration). Some leaks are also the result of leaks in equipment, intentional pressure release practices, or accidental releases during normal transportation, storage, and distribution activities. **Methane emissions are not specific to non-conventional oil and gas extraction processes, but there is growing consensus in the scientific community that leakage problems are more likely to happen in unconventional wells, which are hydraulically fractured, than in conventional wells. Another element suggesting the significant impact of non-conventional extraction processes is the number of active wells relative to conventional wells for the same level of final output**, for wells multiplying simply increases the number of potential sources of methane leakage. **Estimates by R. Horwath[44], put average methane emissions[45] at the well site and from gas processing at 1.3% for conventional natural gas and at 3.3% for shale gas.**

In midstream infrastructures, transmission and distribution networks account for the bulk of gas leakages. Generally speaking, within this sub-segment of the midstream industry, **leakage rates are mainly dependent upon the condition/age of the pipes but also upon structural issues which generally account for the differences traditionally observed between transmission and distribution networks. This is a generally accepted view that the former tend to display much lower**

44 Howarth RW, Santoro R, Ingraffea A. Methane and the greenhouse gas footprint of natural gas from shale formations. Climate Change Lett. 2011

45 Along the value chain (upstream then midstream operations), fugitive methane emissions are expressed as a fraction of extracted gas volumes.

leakage rates than the latter. A commonly accepted account for such difference is that being closer to final users, distribution networks are more likely to be subject to third party damage eventually occasioning leakages.

That said, **the detailed analysis of the issue of measuring fugitive methane emissions highlights three different approaches** in the gas midstream industry:

i / A "physical" reality, namely the leakage phenomenon itself;

ii / A "metering" reality, namely the way in which the metering systems used by network operators make it possible to account for this physical reality and

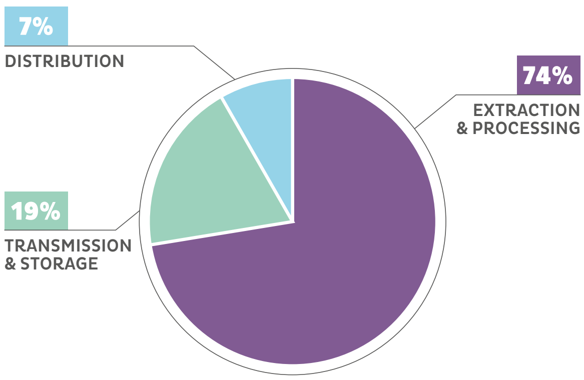
iii / A "regulatory" reality, namely the level of “accepted” leakage rate set by the regulators in the determination of the tariff formulas for the remuneration of gas transport and distribution network operators.

The leakage rates associated with these three types of approaches can vary significantly within one jurisdiction, as well as from one jurisdiction to another, depending on the level of acceptance of gas-related environmental externalities, but also on the perimeters of assets between transmission and distribution (see above). In Western Europe, “accepted” leakage rates levels stand well below 0.5% for state-of-the-art transmission networks (i.e. high-pressure pipelines) and at around 1% for distribution networks i.e. low-pressure pipelines)

All in all, these elements suggest a very strong disparity in the leakage rates observed across the entire midstream segment. Some authors[46] put estimates in a range of 1.4% to 3.6%, while others conclude on much wider ranges (0.2% to 10%).

It is therefore difficult to form a clear view of where fugitive methane emissions primarily occur, even though various studies suggest the high methane intensity on non-conventional extraction processes. The US gas industry offers a telling example. According to the latest estimates published by the US EPA following a bottom up approach (see above), upstream activities accounted for 74% of industry’s methane emissions in 2017.

FIGURE: ESTIMATES OF US GAS INDUSTRY’S 2017 METHANE EMISSIONS (TOTAL: 166 MILLION TONS CO_2e)



Source: US EPA (2019)

Locating and estimating methane emissions remain open questions for the time being. Such questions are nonetheless crucial in estimating the climatic benefit of natural gas relative to other fossil fuels that are more carbon intensive upon combustion, given how sensitive such climate benefit is sensitive to methane leak rates.

These questions are particularly decisive from the perspective of natural gas displacing coal for power generation. According to environmental NGO Climate central, **“assuming that natural gas replaces 2.5 percent of coal-fired power each year (…) even a relatively low overall leak rate of 2% would not achieve a 50 percent reduction in greenhouse gas emissions compared to the current fleet of coal-fired power plants, for over 100 years. If the leak rate were as high as 8%, there would be no climate benefit at all from switching to natural gas for more than 60 years”[47].**

46 Howarth RW, Santoro R, Ingraffea A., op. cit.

47 https://www.climatecentral.org/news/limiting-methane-leaks-critical-to-gas-climate-benefits-16020

TEXTBOX 1 | AVOIDING METHANE EMISSIONS IN THE GAS INDUSTRY

In its latest World Energy Outlook (WEO), the IEA stresses the climate benefit of tackling the two main sources of methane emissions in the upstream industry (voluntary venting practices and involuntary methane leaks), adding that "implementing only the abatement measures that have positive net present values in the WEO's Stated Policies Scenario[1] would reduce the temperature rise in 2100 by 0.07 °Celsius compared with a trajectory that has no explicit reductions".

For what concerns voluntary venting (and flaring[2]) practices, potential responses from the industry and governments are of systemic nature and entail finding/expanding markets for "unwanted" gas. This can be achieved by developing midstream infrastructure enjoying lower breakeven costs (typical case of small-scale LNG projects) to market natural gas eventually displacing coal as source of baseload supply. **Systematic development of gas capture and reuse processes constitutes another response** to the lack of immediate business outlet or infrastructure allowing to process unwanted gas. These processes entail capturing part of the gas extracted from the well with a view to reinjecting it to facilitate hydrocarbons recovery. This process makes it possible to support the pressure level of the given well, hereby increasing the recovery of oil and to a lesser extent of natural gas.

Being a technical issue arising across all upstream and midstream activities, methane leaks can be tackled through the deployment of specific devices and equipment along the value chain. These technical solutions include:

1. **Replacing existing devices/equipment in well sites and pipelines where leaks are likely to occur** due to wear and tear of internal components (typical case of pumps and compressors);

2. **Installing new emissions control devices to capture gas and pair it to an end use that is less harmful than direct release to the atmosphere.** Among the devices serving these purposes, the IEA[3] mentions Vapor Recovery Units (VRUs) which are used to pull off gases that accumulate in oil storage tanks and that are otherwise periodically vented to the atmosphere to prevent explosion, but also flares, in the absence of a better economic solution;

3. **Installing state-of-the-art equipment such as LDAR (Leak Detection And Repair) to locate and repair fugitive leaks in well sites and pipelines.** As the IEA[4] highlights, LDAR encompasses several techniques and equipment types. One common approach is the use of infrared cameras, which make methane leaks visible.

Some practices in the industry stand at the intersection of dealing with unwanted gas and minimizing methane losses. Such is the case with the "green completion" technology. Green completion is an alternate hydraulic fracturing practice that captures the produced gas during well completions and well workovers following hydraulic fracturing. Portable equipment is brought temporarily to the well site to separate the gas from the liquids and solids in the flowback stream, producing a gas stream that is ready or nearly ready for the sales pipeline[5].

All in all, the deployment of these new devises/equipment and/or the development of these good practices may result from:

1/ Industry-led voluntary initiatives such as the Oil and Gas Climate Initiative[6] (OGCI). Established in 2014, the OGCI is an international industry-led organization which includes 12 member companies from the oil and gas industry: BP, Chevron, CNPC, Eni, Equinor, ExxonMobil, Occidental, Petrobras, Repsol, Saudi Aramco, Shell and Total[7]. It has a mandate to work together to "accelerate the reduction of greenhouse gas emissions" in full support of the Paris Agreement. Among the action levers identified by the Organization to contribute to the fight against climate change, is the climate impact (CO_2 and methane emissions) of upstream activities. In this perspective, **OGCI members have set themselves the objective of reducing their upstream carbon intensity by 9-13% over 2018-2025 (from 23 kgCO_2e/boe in 2017 to 20-21 kgCO_2e/boe in 2025), this with a clear focus on methane emissions;**

2/ Strengthened regulations governing methane emissions monitoring and control. In the upstream segment, regulations for methane emissions monitoring and reduction have been developed in the US and Canada at State/Provincial level and at National level. In the midstream industry, methane emissions monitoring and reduction can be part of incentive regulation whereby the regulator will typically set a standard leakage rate and incentivize the network operator to outperform it through a set of financial bonuses and penalties.

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1 See: General introduction: putting present day use of natural gas into perspective.

2 Which mostly result in CO_2 emissions.

3 See https://www.iea.org/reports/methane-tracker-2020/methane-abatement-options#abstract

4 Op. cit.

5 See https://www.ipieca.org/resources/energy-efficiency-solutions/units-and-plants-practices/green-completions/

6 https://oilandgasclimateinitiative.com/

7 It is worth noting that the launch of OGCI builds upon individual initiatives undertaken by major oil & gas companies to reduce the climate footprint of their hydrocarbon operations. Although the underlying data raise questions relating to the comparability of the methods used in their environmental impact reporting by the different oil companies concerned, the trend is overwhelmingly downward in methane emissions in the sample made up by BP, Chevron, Eni, Equinor (ex. Statoil), ExxonMobil, Repsol, Shell and Total over the period 2010-19.

1.2.3 ALL IN ALL, IS NATURAL GAS SIGNIFICANTLY LESS CARBON-INTENSIVE THAN OTHER FOSSIL FUELS?

From the previous sections, two main conclusions can be drawn from the life cycle analysis of natural gas:

i/ Methane emissions (common practice or accidental) are almost everywhere along the value chain (albeit in proportions that remain uncertain); as such, they are likely to noticeably weigh on natural gas' carbon footprint;

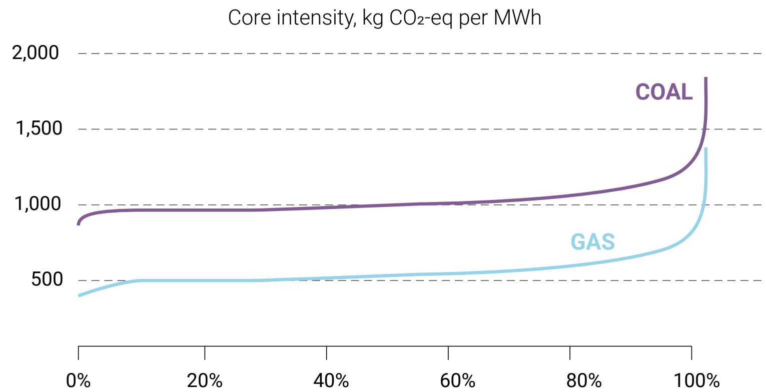
ii/ However, these emissions' importance in absolute as well as in relative terms (share of indirect emissions on the fuel's overall life cycle carbon footprint) **can vary considerably depending on the type of operational process at play from extraction to delivery to end users**.

These elements suggest caution when comparing the respective climate impacts of natural gas, coal and oil. The full life cycle approach developed by the IEA is interesting in that it is based on a comprehensive vision of fossil fuels' respective value chains. Emissions intensities featured in IEA's approach include both indirect (scope 1 and scope 2 emissions) and combustion (scope 3) emissions for coal and gas. Horizontal axes equal the total gas and coal used for heat and electricity in 2018. In addition, IEA's approach takes into account the variety of climate externalities on these value chains, as well as their recurrence. **Its results are as follows:**

i/ The climate benefit of natural gas relative to coal in the power generation is demonstrated in the vast majority of cases, for the agency finds that "an estimated 98% of gas consumed today has a lower life cycle emissions intensity than coal when used for power or heat" [48]. As the table below shows, IEA's estimates point to 80% of natural gas consumed today having a full life cycle CO_2e intensity 55% to 44% lower than that of coal;

Full life cycle emissions intensity (from extraction to combustion) of global coal and gas supply for heat generation, 2018

FIGURE: GLOBAL CONSUMPTION OF COAL AND NATURAL GAS - BREAKDOWN OF THE VARIOUS CO_2e INTENSITIES RECORDED AS A % OF GLOBAL CONSUMPTION, 2018



Source: IEA (2019)

ii/ When comparing the full life cycle carbon footprint of natural gas with that of oil, the IEA reaches similar conclusions overall, while highlighting cases where natural gas can be more harmful than oil. As the IEA stresses, indirect emissions from the most-emitting sources of oil and gas are more than four times higher than those from the least-emitting sources. Indirect emissions from oil are between 10% and 30% of its full life cycle emissions intensity, while for natural gas they are between 15% and 40%[49].

Using scope 3 emissions factors of 408 kgCO_2e/boe and 286 kgCO_2e/boe for oil and natural gas, respectively, one finds that under certain instances natural gas can be up to 5% more CO_2e intensive than oil (see table below).

48 https://www.iea.org/data-and-statistics/charts/full-lifecycle-emissions-intensity-of-global-coal-and-gas-supply-for-heat-generation-2018

49 https://www.iea.org/reports/methane-tracker-2020/methane-from-oil-gas

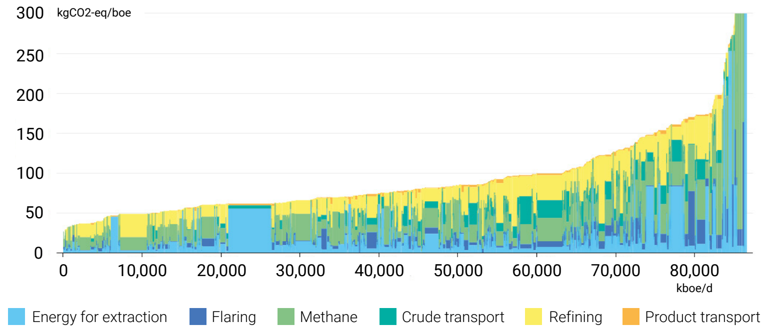
FIGURE: COMPARED FULL LIFE CYCLE ANALYSES OF NATURAL GAS AND OIL BASED ON IEA'S RANGES OF INDIRECT EMISSIONS

Fuel	kgCO2e/boe	«Indirect» emissions (Scope 1 & 2)	«Direct» emissions (Scope 3)	Full life cycle carbon footprint	% indirect emissions on fuel's full life cycle emissions intensity
Oil	Best case	45	408	453	10%
	Worst case	175	408	583	30%
Natural gas	Best case	50	286	336	15%
	Worst case	190	286	476	40%

Sources: IEA, Natixis

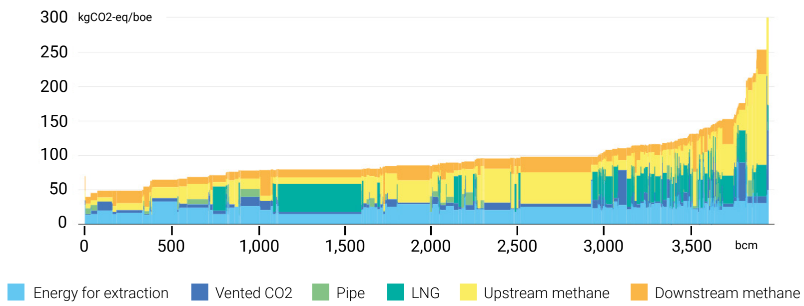
However, as the two graphs below highlight, cases where natural gas is more harmful than oil remain marginal, accounting for less than 5% of gas volumes produced worldwide.

FIGURE: SPECTRUM OF THE WELL-TO-TANK EMISSIONS INTENSITY OF GLOBAL OIL PRODUCTION, 2018



Source: IEA (2019)

FIGURE: SPECTRUM OF THE WELL-TO-TANK EMISSIONS INTENSITY OF GLOBAL GAS PRODUCTION, 2018



Source: IEA (2019)

The fact that the life cycle of gas is less climate harmful than those of coal and oil in most instances does not fully support the vision of gas as an "interim" or "bridge" fuel. While producing fewer CO_2e emissions than other fossil fuels, natural gas remains a fossil fuel with direct and indirect emissions consuming the world's carbon budget (see general introduction). For these reasons, the climate virtues of natural gas appear context-dependent, amid transitioning power systems, as the next section thoroughly discusses.

CHAPTER 2.

Less harmful but still fossil: while natural gas can contribute to energy transition, it is not compatible with a low-carbon economy

2. LESS HARMFUL BUT STILL FOSSIL: WHILE NATURAL GAS CAN CONTRIBUTE TO ENERGY TRANSITION, IT IS NOT COMPATIBLE WITH A LOW-CARBON ECONOMY

As mentioned above, **the potential contribution of natural gas to climate change fight has to be put into the context of intensifying energy transition initiatives,** mostly across OECD countries, in particular Western Europe. To date, in the latter countries, energy transition policies have taken **two main directions:**

i/ Government-backed development of renewables energies with a view to replacing fossil-fueled electricity generation sources by wind and solar PV[50], now or at a later stage, and;

ii/ Energy efficiency measures aiming to reduce the energy intensity of various economic sectors.

The current section explores to what extent increased use of natural gas serves this transitional process as well as the underlying objective of reaching carbon neutrality by 2050 to increase chances of meeting the Paris Agreement.

We deliberately focus on the role of natural gas in the power sector and therefore leave the assessment of natural gas as a "decarbonization agent" for the entire economy to the analysis of the EU Taxonomy's vision of the molecule in the perspective of climate neutrality (see 2.2.2), this for three main reasons:

i/ Taking the case of the European Union (EU), despite the decarbonization effort undertaken over the past two decades, the electricity sector still accounted for 28% of EU's total CO_2 emissions in 2017 (see table below), as it continued to heavily rely on coal for power generation purposes, with hard coal and lignite together still making up for 19% EU 28's generation mix in 2018 (see below). Such reliance is particularly striking in those Western European countries such as Germany that have been to date the most vocal in the field of energy transition. In other words, even in Western Europe, the electricity/heat sector still enjoys substantial decarbonization potential;

ii/ As the IEA highlighted in its latest World Energy Outlook issue, industrial coal today accounts for around one-third of global coal consumption and remains the backbone of the iron/steel and cement sub-sectors, while its use in the chemicals sub-sector keeps rising, particularly in China. Based on these trends, **the IEA stresses the difficulty and expensiveness of finding substitutes for coal in these processes: substituting for coal as a feedstock generally requires an overarching rather than partial overhaul of the implied industrial processes;**

iii/ Furthermore, **the role of natural gas as a decarbonization agent in some sectors (case of transport or industrial processes - see 1.1.3) is already being challenged by other, "greener" gases**. This is typically the case of hydrogen in the fields of clean mobility (fuel cell vehicles) and of steel production, where this molecule is increasingly called to substitute for coal or natural gas as a feedstock in iron ore reduction, a process that produces usable pig (crude) iron to be turned into crude steel.

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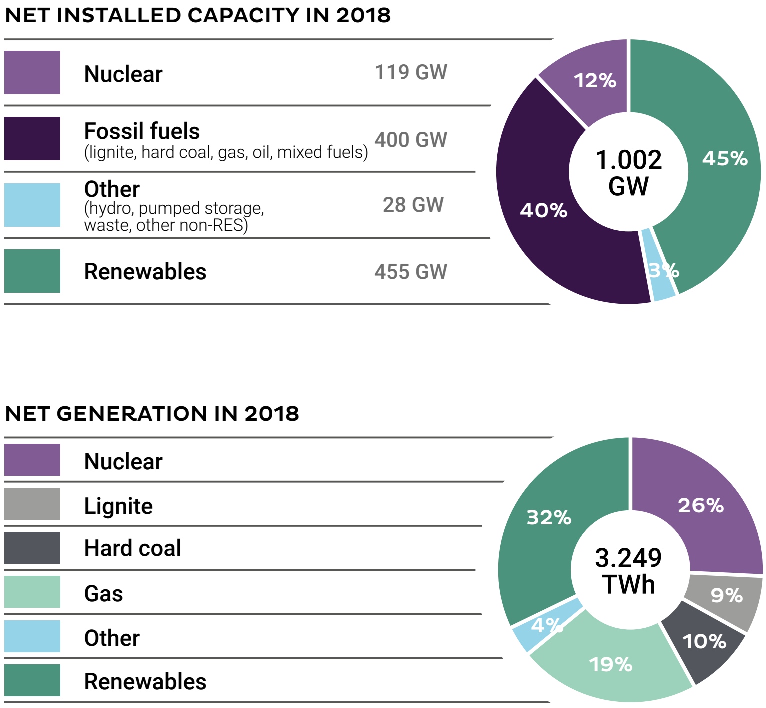
50 As in the case of Germany with the "Energiewende" enacted in 2011, government-sponsored fast-paced development of renewable energies also aimed to replace the nuclear sources (nine reactors commissioned before 1980) shut down in the wake of the Fukushima accident.

FIGURE: EU 28 POWER GENERATION AND CAPACITY MIX IN 2018



Source: RWE (2019)

2.1 THE ROLE FOR NATURAL GAS IN SUPPORTING TRANSITIONING ENERGY SYSTEMS

This section explores under what conditions the use of natural gas supports ongoing energy transition initiatives. As highlighted above, these benefits are mainly to be found in the electricity sector where natural gas can, under a set of specific circumstances, offer tangible, direct or indirect, climate benefits. Gas-fired plants can either complement renewable energy sources to ensure continuity of electricity supply in wind/solar PV-dominated generation mixes or substitute for other, more carbon intensive fossil fuels.

2.1.1 COMPLEMENTARITY OF NATURAL GAS WITH RENEWABLES: CCGTS ACTING AS A BACK-UP FOR INTERMITTENT WIND AND SOLAR ENERGY SOURCES

The first, demonstrable benefit of gas-fired plants amid transitioning energy systems comes from their versatility and flexibility, as evidenced by the various roles CCGTs can play within a given energy system. As we highlighted above (see 1.1.3), enjoying, among all thermal plants, relatively low **construction costs, as well as high efficiency rates and low response times, CCGTs can be run for baseload as well as for peak load purposes, depending either on immediate grid constraints or, more fundamentally, on the structure of the given country's or region's generation mix**[51]. As we highlighted above, such versatility comes from CCGTs having two or more cycles, the first of which enjoying the features of a "peaking plant", with the other running on the waste heat of the first. Enjoying low response time through their first cycle, CCGTs have therefore taken over the role old, single-gas turbines used to play as "peakers" in electricity systems.

51 Such structure general reflects the state of the merit order which is the principle governing electricity prices formation across most developed countries' wholesale markets (see below for a detailed analysis in the context of Western European countries' ongoing energy transition).

With the role of CCGTs evolving over time, peakers have therefore become a generic term to describe gas-fired units that generally run only when there is a high demand, known as peak demand[52] for electricity. Such role is pivotal in any electricity system, for electricity still cannot be massively stored in efficient economic conditions. While battery costs decrease rapidly, they are primarily used for very short term, intra-day storage and accordingly remain unsuitable for longer, seasonal storage. Through their ability to feed the grid when electricity is most in demand, peakers therefore play their part in maintaining a proper balancing of the electricity system.

CCGTs' balancing role has been made even more pivotal since the development of renewable energies which are intermittent by nature. With wind and solar PV now making up for around 30% of electricity generation in such countries as Germany and Spain, system balancing is proving increasingly challenging. **In Germany, these operational challenges are further accentuated by a growing portion of electricity generation coming from sources off the coast in the Baltic sea** (4% of Germany's total generated volumes in 2019 – source: BDEW), far from major consumption centers in Baden Wurttemberg and Bavaria, which puts additional pressure on grid operators to manage increased electricity's intermittency and travelling distances[53].

Such challenges account for Federal government introducing in 2013 the so-called "grid reserve directive", which can be seen as an innovative, balancing-centric strategic reserve[54] arrangement. Pursuant to the scheme, Germany's transmission system operators are entitled, under the supervision of Federal network regulator BundesNETZAgentur, to enter into bilateral contracts with power generators to set aside existing capacity or develop incremental capacity serving pure balancing purposes. As "special grid facilities", contracted capacities are not meant to serve the market but are instead available on short notice any time system reliability is at risk. Two CCGTs, namely Irsching 4 (561 MW) and 5 (846 MW), are operated by Uniper within this framework under an agreement in force until April 2021. What's more, in late June 2018, local TSO TenneT (formerly E.ON Transpower), together with German peers Amprion (formerly RWE Transportnetz) and TransnetBW (a wholly-owned subsidiary of EnBW) extended the scheme by issuing a call for bids throughout Europe for a total capacity of 1,200 MW for special grid facilities without reference to any particular type of technology[55], with 300 MW to be assigned to each of four regions in Southern Germany. For one of these regions, namely Southern Bavaria, TenneT finally awarded the first special grid facility contract in early 2019 to Uniper for the construction and operation of a 300 MW gas-fired unit (a single cycle), named Irsching 6.

2.1.2 GAS ACTING AS AN "INTERIM" SUBSTITUTE FOR COAL AMID TRANSITIONING ENERGY SYSTEMS

The second case where natural gas can provide immediate positive carbon emissions benefit is through substitution for more carbon intensive fossil fuels in the power sector amid transitioning energy systems.

As we highlighted above (see 1.1.3), from a pure CO_2 emissions perspective, upon combustion for power generation purposes, natural gas is 60% and 30% less carbon intensive than coal and oil, respectively, which evidences the theoretical impact of fuel switches benefiting the least harmful fuel in "brown" electricity systems. **Holding all else equal, factoring in the abovementioned carbon intensity upon combustion of the three major fossil fuels, substituting gas for coal and oil[56] in the power generation sector would save around 5,100 million tons of CO_2, hereby reducing world carbon emissions by 15% from their 2019 level[57].**

52 Peak hours usually occur in the morning or late afternoon/evening depending on location. In temperate climates, peak hours often occur when household appliances are heavily used in the evening after work hours. In hot climates, the peak is usually late afternoon when air conditioning load is high, during this time many workplaces are still open and consuming power. In cold climates, the peak is in the morning when space heating and industry are both starting up.

53 For transmission and distribution grid operators, things were made even worse by the relative shortage of baseload electricity generation sources in these regions (Lander) which used to be supplied by a set of nuclear reactors permanently shut down in 2011 in the wake of Fukushima accident (cases of Isar 1, Neckarwestheim 1 and Philippsburg 1 reactors).

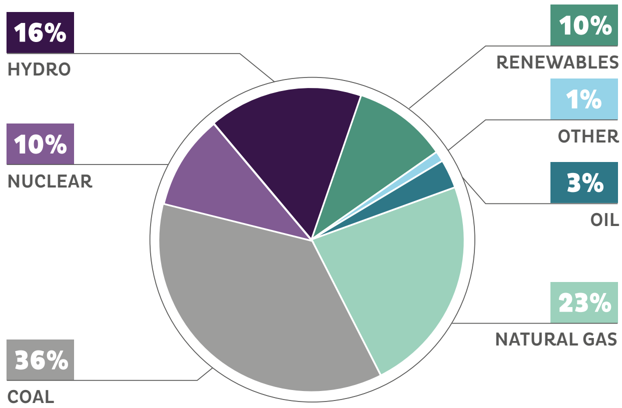
54 Strategic reserve schemes refer to "volume-based, targeted capacity mechanisms in which a centrally predetermined amount of capacity is set aside from the market for use only in exceptional circumstances. For example, a situation in which the market falls to clear could trigger the operation of a strategic reserve" (Kaisa Huhta, Capacity Mechanisms in EU Energy Law: Ensuring Security of supply in the Energy Transition, 2019).

55 Despite the technology-agnostic terms of the call for bids, it was clear that CCGTs were best-placed to serve as a "safety cushion" by supplying power in special emergency circumstances.

56 Either by increasing the load factor of existing gas plant or commissioning new ones.

57 34,169 million tons of CO_2 (source: BP).

FIGURE: 2019 WORLD ELECTRICITY MIX (TOTAL GENERATED VOLUMES OF 27.005 TWh)



Source: BP (2020)

Taking a close look at the trends shaping the energy sector over the past decade, one sees some massive coal or (lesser known) oil-to-gas switches with positive carbon implications across the globe. The IEA estimates that "since 2010, (…) over 500 Mt of CO_2 emissions have been avoided due to coal-to-gas switch, (with) two-thirds of these savings (having) occurred in the power sector, reflecting the lower emissions from gas-fired electricity" (IEA, WEO 2019).

From these figures, one may conclude that higher use of natural gas at the expense of other, more CO_2-intensive fossil fuels could be the first step in an overarching decarbonization journey. Such assertion holds partially true: while potentially bearing positive environmental implications, gas substituting for coal or oil is not by nature a distinctive feature of energy transition. Recent trends in the energy sector highlight cases of increased use of natural gas occurring in countries/regions with no explicit climate agenda, cases we extensively discuss in section 2.2.1.

Our aim in the following paragraphs is therefore to highlight instances where coal-to-gas or oil-to-gas switches (more or less directly) occur in transitioning energy systems or result from the implementation of climate change-centric policies. For this reason, our main focus will be on recent cases of coal-to-gas switch in Western Europe, then, following a more forward-looking approach, on the role natural gas is likely to play in the effective implementation of coal phase out policies in countries such as Germany, Italy, Spain and, to lesser extent, the UK.

2.1.2.1 COAL-TO-GAS SWITCHES AS A RESULT OF TOUGHENING NATIONAL OR EU-WIDE ENVIRONMENTAL STANDARDS: DECIPHERING RECENT ENERGY TRENDS IN THE UK, GERMANY AND SPAIN

Looking at recent trends in the European power sector, **one finds two specific types of coal-to-gas switch triggered by the implementation of climate change-centric environmental policies:**

i/ **Carbon prices-driven coal-to-gas switch (UK since 2013, Germany since 2019): price developments at the EU ETS (Emissions Trading Scheme)[58] level have had tangible implications on UK's and Germany's generation mixes. Higher CO_2 allowances prices (EUAs[59]) have fostered the use of natural gas for power generation at the expense of coal** simply by making gas plants more competitive than coal plants in merit order-governed wholesale markets where electricity prices are determined by reference to the marginal cost[60] of the last unit of production called upon to meet demand. In the UK, the respective shares of coal and natural gas in the overall volumes of electricity produced went from 37% and 27% in 2013 to

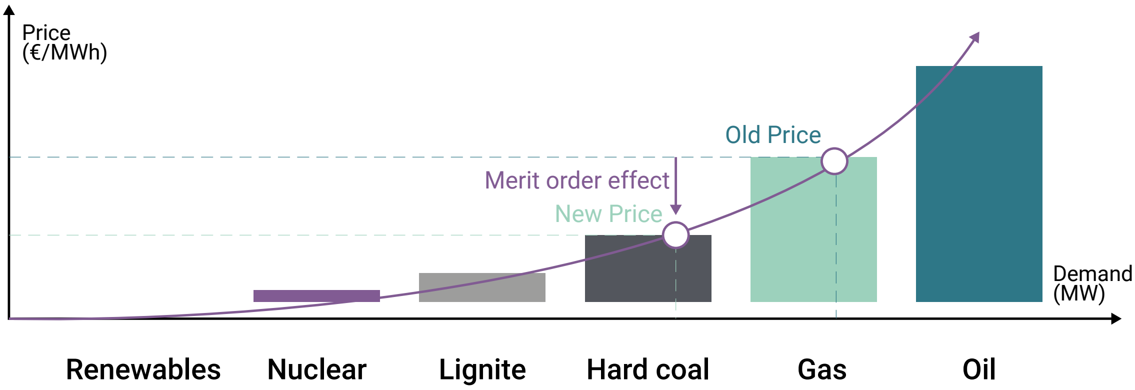
58 The EU-wide carbon allowances market introduced in 2005.

59 EU allowances: carbon allowances issued at Member States' level as part of the ETS. ETS' provisions were in force in the UK until the effective achievement of Brexit (January 2020).

60 For each MWh produced, this marginal cost is itself function of the cost of the fuel, but also of the cost of the carbon allowances purchased to cover the carbon emissions of the plant concerned.

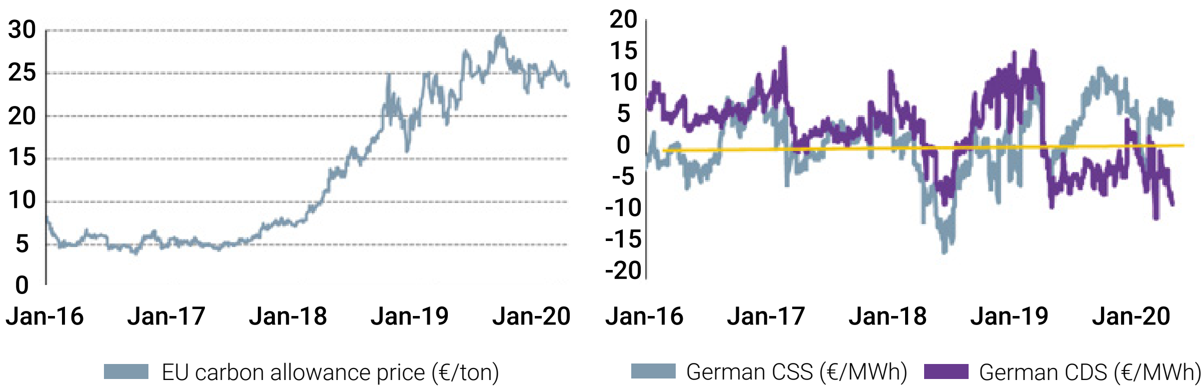
5% and 39% in 2018. The coal-to-gas switch in Germany is much more recent and of limited magnitude to date[61], with the respective shares of lignite/hard coal and natural gas going from 35% and 13% in 2018 to 28% and 15% in 2019, while at the same time the share of renewables (onshore/offshore wind and solar PV) rose from 24% to 28% (source: BDEW). While both being rooted in higher carbon prices, these cases of coal-to-gas switch observed in the UK and in Germany nonetheless display several differences: **in the UK, it is the introduction in 2013 by the government of a £30/ton carbon price floor to supplement EUAs prices that spurred the switch; in Germany, the latter followed the recovery of EUAs as well as a slump in European gas prices which altogether improved the profitability of gas-fired plants at the expense of coal-fired plants'** as evidenced by the respective trends of German clean dark[62] (CDS) and clean spark spreads[63] (CDS) (see charts below);

FIGURE: ILLUSTRATION OF MERIT ORDER MODEL WITH COAL-FIRED PLANTS SETTING THE REFERENCE MARGINAL COST, HENCE THE EQUILIBRIUM PRICE IN A COMPETITIVE WHOLESALE MARKET



Source: RWE (factbook 2019)

FIGURE: TRENDS IN EU ALLOWANCES PRICE (€/METRIC TON OF CO_2 EMISSIONS) AND GERMAN CLEAN DARK (CDS) AND SPARK (CSS) SPREADS, €/MWh



Source: Bloomberg

61 Albeit of limited magnitude to date, such trend is nonetheless likely to continue in the coming years, with EUAs remaining on an upward trend, amid the EU stepping up its efforts toward climate change fight (see our recent update on the EU ETS: Overview of EU ETS – January 2020). **Note however that the ongoing Covid-19 crisis triggered massive power demand contraction across Europe resulting in lower demand for gas for power generation purposes, in particular in Germany.**

62 Gross operating margin indicator for coal-fired plants factoring in the cost of EUAs.

63 Gross operating margin indicator for gas-fired plants factoring in the cost of EUAs.

ii/ **Coal supply-driven coal-to-gas switch, as seen in Spain in 2019 directly after the government announced two policy initiatives aiming to "green up" the country's electricity mix in October 2018**. The first policy initiative concerned the operation of the country's coal mines (which had been very heavily subsidized, hereby distorting competition in the wholesale electricity market), which were effectively closed in end-2018[64]. The second concerned certain costs/taxes holding back gas-fired power generation (suspension of 7% generation tax and exemption from the "green cent" tax) and autonomous solar PV generation (exemption from grid connection fee for the installations concerned). Such announcements had almost immediate effects, with the respective shares of coal and gas in Spain's generation mix going from 14.5% and 11% in 2018 to 5% and 22% in 2019 (source: Red Eléctrica de España). These data are telling. In a merit order-governed wholesale market, most of Spain's coal-fired plants had remained competitive only to the extent that coal prices remained subsidized; accordingly, the end of coal subsidies triggered what can be safely regarded as a permanent change in Spain's generation mix.

2.1.2.2 GAS-FIRED PLANTS ARE KEY ENABLERS OF NATIONAL COAL PHASE OUT POLICIES IN WESTERN EUROPE

While already substantial, these developments seen in Western Europe over the past few years could take on a new dimension amid these countries stepping up their decarbonization effort and taking concrete steps to shut down all existing coal-fired plants.

As the table below shows, main Western European countries have by now announced plans or even enacted legislations to phase out from coal, with very diverse time horizons across France, Germany, Italy, Spain and the UK. While in France the deadline for shutting down coal-fired plants is tight (end-2021), the phase out calendar in Germany is to span across two decades, with the last units being closed by 2038. Such calendar differences can be easily accounted for: France's reliance on coal for power generation is very limited (generally around 2% going down as low as 0.3% in 2019), whilst coal and lignite altogether still made up for 28% of Germany's generation mix in 2019. What's more, Germany has maintained a labor-intensive, domestic lignite extraction industry[65] (around 40,000 workforce), which makes coal phase out a highly sensitive topic, both socially and politically.

FIGURE: WESTERN EUROPEAN COUNTRIES' COAL PHASE OUT PLANS/ENACTED LEGISLATIONS

Country	Share of coal* in the electricity mix		Explicit coal phase out targets / enacted legislations
	2015	2019	
France	2%	0.3%	All coal-fired plants to cease production by 2021
Germany	44%	28%	Gradual phase out to be completed by 2038
Italy**	16%	9%	All coal-fired plants to cease production by 2025
Spain	19%	5%	Government plan to phase out from coal by 2030 still to be translated into legislative framework
UK**	23%	5%	All coal-fired plants to cease production by 2025

** Including lignite / ** In 2018*

Sources: BDEW, REE, RTE, RWE, Statista, Natixis

From an energy system perspective, for these countries, coal phase out can be seen as the first, critical step towards a low-carbon economy. Indeed, save for the case of France, effective implementation of such policies entails shutting down CO_2-intensive assets that despite reduced contributions in these countries' generation mixes (see table below) continue to play a critical role[66]. While renewable energies are to continue their expansion in the coming years amid continuing generation mix transformation initiatives, their intermittent nature will continue to raise key challenges for European grids in the absence of reliable and/or cost-effective large-scale storage or demand-response solutions. Against such backdrop, the case for wind and solar PV solar sources fully substituting for coal-fired is for the time rather theoretical: from a grid perspective,

64 While announcing the closure of the remaining domestic coal mines, the Spanish government also unveiled a series of social and economic measures in the regions concerned.

65 Domestic lignite mines are operated by power generators following a vertically integrated business model.

66 Quite ironically, despite the recent reduction of solid fossil fuel's share in the generation mix, coal remains the "marginal" fuel in the German merit order (see above).

at constant capacity/load factors, intermittent sources do not equal reliable sources able to provide continuous electricity supply under any circumstances. In some countries such as Germany, the challenges associated with energy transition are further exacerbated by nuclear phase out being pursued concomitantly.

It is under this specific instance that the widespread but often misunderstood notion of natural gas as an "interim fuel" makes real sense: in transitioning systems, gas-fired plants can be seen as the indispensable link in the gradual transformation of carbon-intensive, coal-centric energy mixes into low-carbon, renewables-centric mixes. From a pure security of supply perspective, the role of natural gas as an interim fuel can easily be evidenced, looking at main Western European countries' generation and capacity mixes in 2016 just after the COP-21 summit was held and before a series of energy transition initiatives were announced in France, Germany, Italy, Spain and the UK.

For these five countries, what the table below shows is coal (including lignite)-fired plants enjoying by then (much) higher load factors than gas-fired plants, hereby suggesting that the latter enjoying higher but still plausible (55%-60%) load factors could easily substitute for the former. As the gas plants' required load factor estimate evidences, **apart from the special case of Germany (which accounts for coal phase out spanning over two decades), all other countries would experience no difficulty phasing out from coal immediately.**

FIGURE: MAIN WESTERN EUROPEAN COUNTRIES: 2016 ELECTRICITY GENERATION FROM COAL (INCLUDING LIGNITE) AND GAS-FIRED PLANTS AND IMPLIED LOAD FACTORS

Country	Coal (incl. Lignite)			Gas			Gas plants required load factor (%)
	Capacity (GW)	Output (TWh)	Load factor (%)	Capacity (GW)	Output (TWh)	Load factor (%)	
France	3.0	11.0	42%	11.7	33.0	32%	43%
Germany	50.7	276.4	62%	26.7	83.6	36%	154%
Italy	8.7	42.6	56%	44.8	119.3	30%	41%
Spain	10.0	38.0	43%	26.7	54.2	23%	39%
UK	14.3	30.2	24%	36.1	144.3	46%	55%

Sources: Eurostat, Natixis estimates

However, offering various tangible benefits in transitioning energy systems does not mean natural gas can play a significant role in an economy *having successfully transitioned* towards a zero-carbon model. The following section explores the room for natural gas in such model.

2.2 THE OVERALL INCOMPATIBILITY OF NATURAL GAS WITH LOW-CARBON ECONOMY IN THE LONG RU

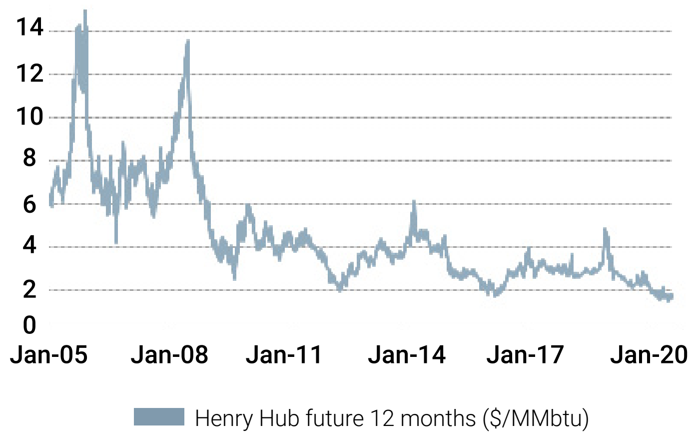
2.2.1 THE FUNDAMENTAL AMBIGUITY OF NATURAL GAS IN HYDROCARBONS-DEPENDENT/ CENTERED ECONOMIES: DECIPHERING RECENT ENERGY TRENDS IN THE US AND IN SAUDI ARABIA

As we highlighted above, while potentially bearing positive environmental implications, natural gas substituting for more carbon-intensive fossil fuels in particular for coal in carbon intensive power generation mixes is not by nature a distinctive feature of energy transition. In this section, we analyze recent fuels switches in the power sectors of such hydrocarbons-producing countries as the US (coal-to-gas switch) and Saudi Arabia (oil-to-gas switch) and emphasize their implications in an overarching climate change mitigation perspective.

As we outlined in section 1.1.3, the "shale revolution" in the US in the early 2000s bore deep, long-lasting implications for the domestic energy market, with natural gas becoming suddenly abundant and cheap (see graph below), which in turn spurred a massive coal-to-gas switch in the electricity sector over the past 10 years. Such a massive switch is evidenced by the respective shares of coal and gas in US' electricity mix going from 45% and 24% in 2010 to 27% and 35%

in 2018[67]. From an environmental perspective, the ambiguity of the US coal-to-gas switch case is worth highlighting: while primarily accounting for a 6% reduction of country's CO_2 emissions over the same period (source: BP), **such large-scale transformation of the electricity mix took place in a still highly hydrocarbons-dependent economy, with no overarching plan or even ambition[68] at Federal level to transition towards a zero-carbon energy system**.

FIGURE: TREND IN HENRY HUB NATURAL GAS 12 MONTHS FUTURE PRICE ($/MMBTU) SINCE 2005



Source: Bloomberg

Oil-to-gas switch in OPEC countries, in particular in Saudi Arabia, is a lesser-known fact deserving attention, for it showcases the ambiguities of higher recourse to natural gas in hydrocarbons-centric economies. The case of natural gas displacing oil is of limited relevance for it has been mainly seen thus far in hydrocarbons-producing countries heavily relying on oil for power generation. Unsurprisingly these countries happen to be significant oil producers in the Middle East, in particular Saudi Arabia, where the development of associated gas production (see 1.1.2) has favored the use of gas over oil in the electricity sector. The economic rationale for such fuel switch is two-fold. First, in its associated form, natural gas comes at a cost close to zero and therefore favorably positions vis-à-vis oil for power generation in a marginal cost perspective. Second, the replacement of old, oil-fired plants by state of the art CCGTs allows a more efficient use of natural resources since less fuel is eventually burned to generate electricity and eventually more hydrocarbons are available for export. As a result, natural gas' share in Saudi Arabia's generation mix which had been until the 2000s relatively at par with oil's rapidly grew in the subsequent decade to reach 58% in 2018 (vs. 42% for oil and less than 0.5% for renewable sources) (BP, 2019).

From an environmental perspective, such fuel switch has led to a reduction in generated volumes' *average* carbon intensity, given the twofold benefit of state of the art CCGTs substituting for old, oil-fired plants: less fuel was spent for power generation purposes with the least CO_2-intensive fossil fuel eventually enjoying preeminence in the national generation mix. **However, in absolute terms, sector's carbon emissions remained on the rise, growing by 18% over 2010-18, whilst electricity consumption was expanding by 52%** (BP, 2019).

By offering a limited environmental benefit and, perhaps more crucially, by strengthening the national oil sector's business model (through a more economically efficient resource allocation), Saudi Arabia's increased use of natural gas for power generation evidences the ambiguities of fossil fuel switches in hydrocarbons-centric economies. **Albeit very specific, the Saudi example offers a telling example of natural gas being potentially instrumental in the consolidation of an oil-exporting model.**

These two cases of fuel switch having a few things in common, there are some conclusions to be drawn from these developments from a climate change mitigation perspective:

i/ It is the cheapness of natural gas, being a byproduct of oil, **which made it more relevant in US and Saudi power sectors;**

67 https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_1_01

68 Let us recall that in June 2017, US President Donald Trump, declared that, further to his electoral promises, his country would not honor this Paris agreement on climate change fight.

ii/ With no real transitioning ambition at government level, the risk that increased use of gas due to its cheapness raises is long-lasting carbon lock-in. From a climate change perspective, the concept of carbon lock-in is key, for it characterizes the self-perpetuating inertia created by large fossil fuel-based energy systems that inhibits public and private efforts to introduce alternative, more environment-friendly energy technologies. In more concrete terms, applied to natural gas, **the concept of carbon lock-in takes two intertwined dimensions in hydrocarbons producing countries**. **Firstly, the cheapness of gas relative to other available but less harmful energy solutions create no economic incentive for currently gas-dependent sectors/activities to explore new avenues to reduce such dependency and ultimately to transition towards *a zero-carbon economic model*. Secondly, increased use of natural gas, in particular in its *associated* form, must be accompanied by the development of infrastructure assets (networks, storage facilities, CCGTs) typically amortized over 20/60 years periods.** Their capital intensity and the time needed for their owners to recover the initial cash outlays together **raise a stranded cost issue**. Before the assets have been fully amortized, in the absence of government-funded subsidies schemes, it simply makes no economic sense for their owners/operators to switch to other infrastructures paving the way for the development of less carbon-intensive energy solutions. As we extensively discuss in the following sections taking a more general approach to gas, **the concept of stranded cost is of particular relevance against the backdrop of emerging forms of low-carbon gases such as biomethane and green hydrogen which can (up to a certain limit for the latter – see 3.1.3) make use of existing gas infrastructures.**

2.2.2 NATURAL GAS AS SEEN BY THE EU TAXONOMY: MOSTLY INCOMPATIBLE WITH DECARBONIZATION OF THE ECONOMY, UNLESS CCS IS SCALED UP AND IS ECONOMICALLY RATIONAL TO USE

The EU Taxonomy for Sustainable Activities currently being developed at the European level as part of EU's intensifying efforts to reach climate neutrality by 2050 **offer perhaps the most authoritative and overarching vision of natural gas' potential climate change mitigation role**.

Having now entered finalization stage, the **EU Taxonomy** does not aim to provide a compulsory list of economic activities deemed "green" but rather to **determine under what conditions the activities in focus (based on the NACE classification with some adjustments) can justifiably claim to provide "substantial contribution to climate change mitigation".**

For each of the 71 economic activities covered thus far[69], the European Commission-appointed Technical Expert Group (TEG)[70] has developed a comprehensive set of technical screening criteria to determine the eligibility conditions.

Once finalized, the EU taxonomy will be the backbone of EU's sustainable finance regulatory framework. When fully in place[71], it will serve as a central foundation for the EU Green Bond Standard (EU GBS) under development: bonds deemed eligible for the EU GBS label are to contribute to financing or refinancing assets or projects that are themselves aligned on the EU taxonomy.

To be deemed EU Taxonomy-eligible, at this stage of this development (covering only climate change mitigation, one of the six EU environmental priority objectives[72]), an activity must meet two cumulative sets of criteria:

i/ Mitigation criteria, in the form of life cycle CO_2 emissions thresholds. These thresholds can draw on the activity's scope 1 / scope 2 emissions assessment or follow a more extensive approach using life cycle analysis (see 1.2).

ii/ Environmental externalities criteria ("Do No Significant Harm"), in the form of specific guidelines/regulations governing the prevention of concerned activity's potential adverse environmental impact on water resources, air pollution, ecosystems, etc.

The comprehensive approach followed by the TEG offers telling conclusions on the potential role of natural gas amid transitioning energy systems**. As suggested above with the emissions threshold set for power generation, the underlying thresholds set for the 71 activities under scrutiny aim for a full decarbonization of EU's economy by 2050**. Although not yet an explicitly binding objective for the EU, this climate neutrality target is seen as desirable by both the European Commission and the TEG, for it stands as one of the conditions for the world to achieve the global warming limitation target set out by

69 From the following seven macro-sectors: (1) Forestry, (2) Agriculture, (3) Manufacturing, (4) Electricity, gas, steam and air conditioning supply, (5) Transportation and storage, (6) Information and communication, (7) Construction and real estate activities.

70 The TEG gathers a set of experts coming from various sectors/fields: scientific research, industry, government, NGOs, etc.

71 December 2021 for climate change mitigation activities.

72 Namely i/ climate change mitigation, ii/ climate change adaptation, iii/ sustainable and protection of water and marine resources, iv/ transition to a circular economy, v/ pollution prevention and control, vi/ protection and restoration of biodiversity and ecosystems.

the Paris agreement (see General Introduction). It ensues that **when investigating the potential eligibility of high-emitting activities, the TEG set stringent thresholds corresponding to their *targeted emissions profile in a zero-carbon economy*.**

In its work, using the NACE classification, **the TEG investigated the potential role of natural gas**:

i/ Either explicitly, for those energy activities such as power generation, CHP (combined heat and power) and heat/cool production **using natural gas as primary energy source**.

In the power sector: to be eligible, generation facilities must operate at **life cycle emissions lower than 100gCO_2e/KWh[73], declining to net-0gCO_2e/KWh by 2050. As the TEG specifies for natural gas-fueled facilities in the technical annex to its latest report, this threshold implies assessing the carbon footprint of natural gas across its entire value chain**, in particular through actual physical measurements of methane leakage from the point of extraction/well-head to production of energy (electricity and/or heat)[74]. **The threshold set by the TEG is particularly stringent and de facto excludes all existing gas-fired power plants. The current 100gCO_2e/KWh threshold means that even regardless of fugitive methane emissions measurements[75], natural gas-fired plants would not be EU Taxonomy-compliant** given their current scope 1 CO_2 emissions (around 400gCO_2/KWh). **The only condition under which these assets could claim eligibility is through the use of carbon capture and storage (CCS) processes** which must themselves show alignment with the EU Taxonomy's criteria. **These processes** could theoretically provide substantial contribution to climate change mitigation but **remain at an exploratory stage** (see 1.2.1). This is the main reason why the three activities forming the CCS value chain, namely capture of anthropogenic emissions, transport of CO_2 and permanent sequestration of captured CO_2, are seen as a key decarbonization instrument (compensation) and deemed EU Taxonomy-eligible without any specific threshold.

Exclusion of natural gas in energy-related activities is further evidenced by TEG's approach to retrofit of gas transmission and distribution activities, where expansion of existing gas networks in their current form is not eligible and where investments on these assets can claim compliance only in so far as they are undertaken with the purpose of integrating hydrogen and other low-carbon gases. The TEG considers two main cases, namely:

- "Any gas transmission or distribution network activities which **enable the network to increase the blend of hydrogen and/or other low-carbon gasses in the gas system"**;

- "The **repair of existing gas pipelines for the reduction of methane leakage is eligible if the pipelines are hydrogen-ready and/or other low-carbon gasses-ready".**

In addition, "retrofit of gas networks whose main purpose is the integration of captured CO_2 is eligible";

ii/ Or implicitly, for those activities currently using natural gas as feedstock (notable cases of steel and hydrogen manufacturing) **or as primary energy source** (cases of transportation and of various energy-intensive manufacturing processes such as aluminum, cement and steel manufacturing).

When it comes to non-energy sectors, TEG's recognition of natural gas' potential contribution is very marginal:

- In **manufacturing activities** using natural gas as feedstock, **the EU Taxonomy recognizes the carbon benefit of natural gas** (acting as a substitute for coal) **only in a few instances.** This is notably **the case of steel manufacturing, with[76] or without[77] CCS**. What's more, when **investigating the potential eligibility of hydrogen manufacturing, the TEG puts emphasis on "green hydrogen"**, that is hydrogen produced using green energy-powered electrolysis (see 3.1.2). Such general approach ***in***

73 However, it should be noted that when examining the activity of aluminum production, the TEG recognizes the potential use of natural gas-fired electricity in the electrolysis process. This recognition is however indirect. It stems from the activity eligibility thresholds set in the Taxonomy. These thresholds take into account the efficiency of the electrolysis process (electricity consumption necessary for the production of one ton of aluminum expressed in MWh/t) and the carbon intensity of the electricity used in this process expressed in Kg CO_2/MWh.

74 The TEG acknowledges that such task is particularly challenging for the time being and "that improved standards and methodologies will develop and recommend that the acceptance of the ISO 14067, GHG Protocol Product Life Cycle Standard and the PCF methodologies is periodically reviewed by the platform".

75 As we analyze (in section 1.2) the importance of fugitive methane emissions along the value chain remains a controversial issue due to the continuing uncertainties surrounding their assessment. It appears from IEA's indirect emissions that at least a portion of the gas produced worldwide has an *indirect* CO_2e intensity as high as 300g /KWh, a level substantially above the 100g CO_2e/KWh regardless of natural gas' *direct* carbon intensity (circa 400 g CO_2/KWh) upon combustion.

76 Case of blast furnace top gas recycling with carbon capture and storage.

77 Case of direct iron ore reduction with natural gas for production of DRI (direct reduced iron) combined with EAF (electric arc furnaces) steelmaking.

***principle* excludes steam methane reforming** (SMR), the currently prevailing process for the production of hydrogen **using coal or natural gas as feedstock which is carbon-intensive on a scope 1 basis**. **Reading between the lines, one finds that the only way for SMR facilities to claim eligibility is through specific mitigation measures, primarily the installation of CCS processes**. Such mitigation measures nonetheless have to be "incorporated into a single investment plan within a determined time frame that outlines how each of the measures in combination with others will (…) enable the activity to meet the thresholds (set for electrolysers)[78]".

- What's more, **decarbonization of the transport sector is primarily targeted through the development of electric or fuel-cell (hydrogen) vehicles given their zero-direct emissions profile.** The threshold set for the various considered activities at 50 gCO2e/km until 2025 (going to 0 gCO2e/km thereafter) ***de facto*** excludes other, fossil fuel-based technologies, in particular CNG[79] - fueled cars or buses whose direct carbon intensity does not meet the abovementioned current threshold set by the TEG. **The underlying rationale for setting such stringent threshold mimics the one followed in the power sector, with a clear emphasis on the *already* climate neutral or near climate neutral technologies to accelerate the EU economy's decarbonization.**

FIGURE: EU TAXONOMY'S APPROACH TO POWER AND GAS ASSETS

POWER		GAS	
Eligible activities	**Non eligible activities**	**Eligible activities**	**Non eligible**
Generation from renewable sources Hydrogen & biogas-fired generation Most T&D activities	Oil and coal-fired generation Natural gas-fired generation*	Manufacture of low-carbon hydrogen Manufacture of biomass, biogas or biofuels Landfill gas capture and energetic utilization Retrofit of T&D activities whose main purpose is the integration of hydrogen/ other low-carbon gases/ captured CO2	Natural gas extraction «Standard» T&D activities

Sources: European Commission, Natixis

All in all, the emission thresholds and criteria used in the development of the EU Taxonomy suggest the prevalence of the electrify-everything approach in determining a path to achieving carbon neutrality by 2050. In this approach, wider uses of a CO_2-free electricity can achieve substantial carbon emissions reductions, in particular in hard-to-abate sectors such as mobility. Such approach accounts for nearly all investments in power transmission and distribution and renewable energies[80] being eligible for green bond financing (see table above).

78 Namely, direct CO_2 emissions of 5.8 tCO_2e/t hydrogen, based on (1) an electricity use for hydrogen produced by electrolysis standing at or lower than 58 MWh/t hydrogen and (2) an average carbon intensity of the electricity produced that is used for hydrogen manufacturing standing at or lower than 100gCO_2e/KWh (current Taxonomy threshold for power generation activities).

79 Compressed natural gas is made by compressing natural gas to less than 1% of the volume it occupies at standard atmospheric pressure. It is stored and distributed in hard containers at a pressure of 20–25 MPa (2,900–3,600 psi), usually in cylindrical or spherical shapes.

80 The latter being characteristically exempted from a full life cycle analysis.

CHAPTER 3.

Emerging forms of gas can make existing gas infrastructures compatible with a low-carbon economy

3. EMERGING FORMS OF GAS CAN MAKE EXISTING GAS INFRASTRUCTURES COMPATIBLE WITH A LOW-CARBON ECONOMY

As we emphasized above, while forming a restrictive view on the compatibility of present-day natural gas uses with the 2050 carbon neutrality target, the EU Taxonomy also highlights the potential role of emerging low-carbon gases as far-reaching decarbonization agents, in particular in hard-to-abate sectors. What's more, when discussing the potential role of natural gas in a lowcarbon economy, **the EU Taxonomy draws an implicit distinction between the molecule itself (with direct and/ or indirect carbon footprint from extraction to final use – see above) and the various associated infrastructure assets forming the sectoral value chain** (gas pipelines, storage cavities, LNG trains[81] – see above). EU Taxonomy's underlying stance is that in some specific instances, these infrastructure assets can enjoy potential use as well as preserved economic value in a low-carbon economy.

This concluding part of our journey throughout the gas sector analyzes **the features, potential benefits as well as current limitations of the two major emerging forms of low-carbon gases, namely biomethane and "green" hydrogen. It then extensively discusses how existing gas infrastructures can play their part in present-day economies for these new gases to reach commercial scale as well as the extent to which active participation in the development of these new gases can help infrastructure operators/owners tackle the long-term asset stranding risk**.

3.1 BIOMETHANE AND "GREEN" HYDROGEN OFFER NEW AVENUES TO ACCELERATE THE WORLD ECONOMY'S DECARBONIZATION

The past few years have seen **rising interest in emerging forms of gas amid intensifying initiatives to decarbonize the energy sector as well as hard-to-abate sectors,** such as transport and manufacturing. These emerging forms of gas are generally referred to as "low-carbon gases" given their improved carbon footprint relative to natural gas, either directly or indirectly, which includes:

i/ Biomethane, a near pure form of methane produced either by upgrading biogas or through the gasification of solid biomass followed by conversion to methane, the latter process being much less frequently used than the former[82].

ii/ Green hydrogen[83], which is hydrogen produced by zero-carbon electricity[84]-powered electrolysis. Being produced through electrolysis, green hydrogen differs from "grey" and "blue" hydrogens which are both produced through steam methane reforming (SMR) using natural gas or coal as feedstock. The latter form, blue hydrogen, uses CCS to reduce most of the direct carbon emissions generated by SMR. CCS faces several limitations to be deployed in a real industrial scale (see 1.2.1), which leads BNEF[85] to expect blue hydrogen to achieve cost abatements by 2050 of much lower magnitude than green hydrogen (estimated range of -7/-9% for the former vs. -64%/-71% for the latter – see below). For this reason, we tend to consider green hydrogen as the most promising form of low-carbon hydrogen;

81 LNG trains are not covered in the EU Taxonomy insofar as these activities are used for the long-distance maritime transport of natural gas. The production of natural gas in Europe serves a regional market and is not meant to be exported to other continents, as is the case for gas produced in the Americas, Africa and the APAC zone.

82 Upgraded biogas accounts for around 90% of total biomethane produced worldwide today (IEA, WEO 2019). In its projections, the IEA expects upgraded biogas to continue to account for the bulk (80%) of worldwide biomethane production in a scenario of accelerated technology expansion, which is why we leave aside the case for scaling up biomass gasification in the following sections. Let's note that according to IEA's estimates, upgraded gas is currently 25% cheaper on average than biomass gasification ($20/MBtu vs. $25/ MBtu).

83 In this section, we focus on the role of green hydrogen in the decarbonization of energy and economic systems, distinguishing it from other sources of hydrogen that are produced by methane reforming. However, as analyzed in detail, the molecule in its use (potential injection into existing gas networks) and its transport (high costs due to hydrogen displaying lower energy density than natural gas) presents specific limitations. For this reason, the analysis of these limitations in the following paragraphs is conducted on the basis of the properties of the molecule, without distinction of how it is produced.

84 In the present section, we primarily discuss the role of renewable sources to power "green" electrolysis. However, we do not rule out the potential role played by nuclear fission to supply electrolysers. Indeed, being non-emitters of CO_2, nuclear reactors can play their part in the development of an energy carrier with next-to-zero carbon intensity on a full lifecycle analysis.

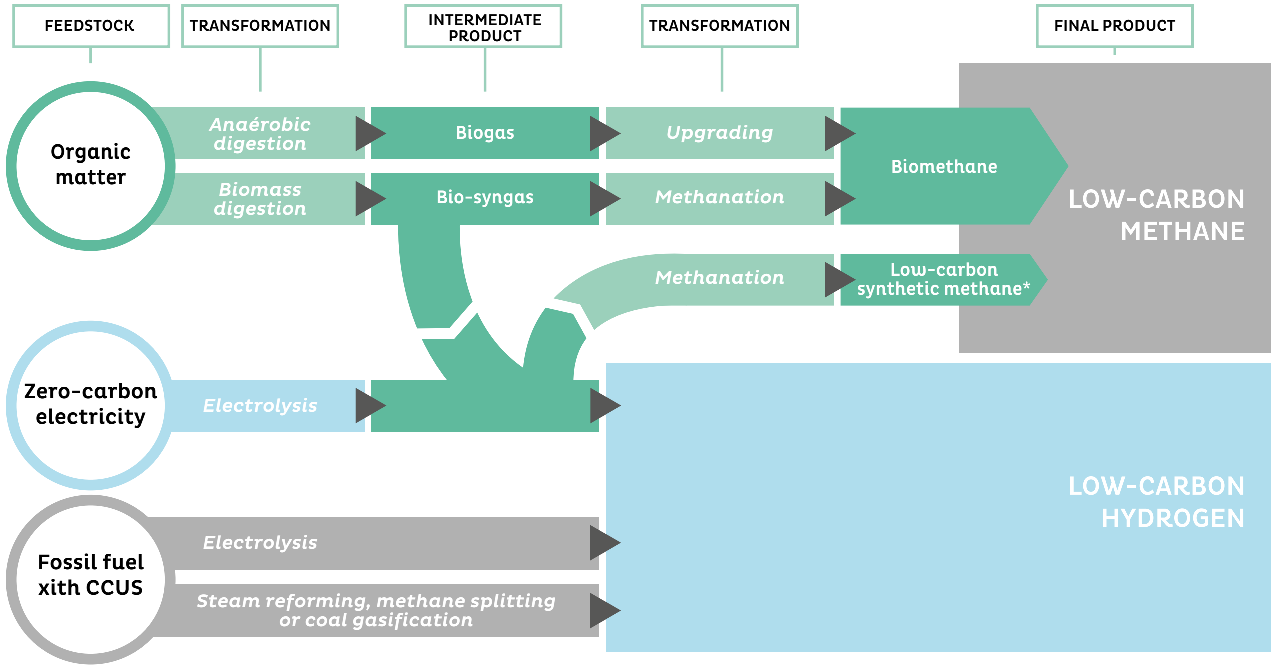
85 Bloomberg New Energy Finance, Hydrogen Economy Outlook, Will hydrogen be the molecule to power a clean economy? March 2020.

iii/ Low-carbon synthetic methane (also known as low-carbon or renewable syngas), which is a form of methane produced through the methanation of low-carbon hydrogen and CO_2 from a biogenic or atmospheric source.

In the following sections, we primarily focus on the first two forms of low-carbon gases. While offering a series of theoretical benefits (potential large scale, systemic use of CO_2, increased flexibility for the electricity grid through implicit storage of renewable power, use of existing gas grids/storage cavities without any retrofit work, etc.), low-carbon synthetic methane remains in its infancy. Its reaching commercial scale is dependent upon a series of mostly exogenous conditions being met, namely key progress of CCS processes (see 2.2.2) as well as substantial costs abatement favoring green electrolysis.

The figure below illustrates the various supply routes to produce low-carbon gases as well as their potential interactions, as in the case of low-carbon syngas.

FIGURE (WEO, 2019): ALTERNATIVE SUPPLY ROUTES TO PRODUCE LOW-CARBON GASES



There are many pathways to produce low-carbon gase. This analysis focuses primarily on the opprtunities and costs of low-carbon hydrogen and biomethane.

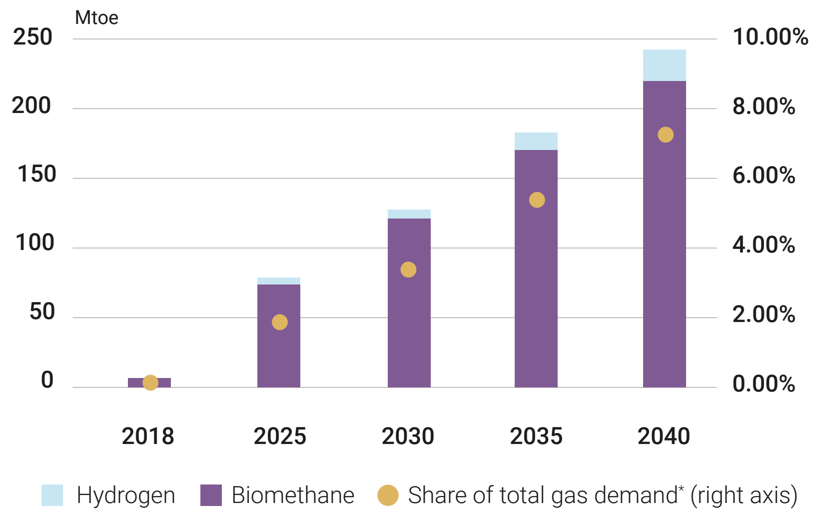
**Synthetix methane is only low-carbon if the CO_2 originates from biogenic sources or the atmosphere.*

Source: Natixis adapted from IEA (WEO 2019)

Despite the enormous decarbonization potential they enjoy, biomethane and green hydrogen remain at a very early stage of both their development and use within energy systems. As IEA's projections show (see figure below), their share in global gas consumption (as reflected by injected volumes into gas grids) is currently negligible (<0.5%) and is likely to remain limited in 2040 even under the most Paris agreement-aligned energy scenarios, like the IEA's Sustainable Development Scenario (SDS)[86]. Under this scenario, 230 Mtoe of biomethane and blended low-carbon hydrogen would be consumed in 2040, making up for around 7% of total gas demand, the former enjoying the lion's share (nearly 90% of this total).

86 This scenario describes various energy options offering 50% chance of reaching the 2° limitation target set by the Paris agreement (see General Introduction).

FIGURE (WEO, 2019): VOLUMES OF GREEN HYDROGEN AND BIOMETHANE INJECTED INTO GAS INFRASTRUCTURE IN IEA'S SDS



*Includes natural gas, biomethane and low-carbon hydrogen blended into gas networks in energy equivalent terms.

Source: Natixis adapted from IEA (WEO 2019)

From a cost perspective, as the table below summarizes drawing upon estimates by the IEA and the European gas industry group "Gas4climate", **biomethane and green hydrogen[87] remain overall much more expensive than natural gas, whereas biomethane from upgraded gas is more competitive than green hydrogen** in most instances.

FIGURE: COST COMPARISON OF BIOMETHANE AND VARIOUS SOURCES OF HYDROGEN (GREY/BLUE/GREEN) VS. NETHERLANDS-BASED TTF[88] NATURAL GAS PRICE QUOTATION (€/MWh)

(€/MWh)	Biomethane (upgraded gas)	Grey hydrogen	Blue hydrogen	Green hydrogen	TTF
BNEF	N/C	19-61	35-90	67-123	12*
Gas4climate	70-90	28	37-41	70-100	
IEA	c.60	N/C	37-61	76-198	

Public pricequotation at 02/07/20

Sources: BNEF, Gas4climate, IEA, Bloomberg, Natixis

87 We include here the cases of "grey" and "blue" hydrogen for the sake of illustration.

88 Dutch TTF is the main price quotation for natural gas in Continental Europe.

These sets of elements call for two types of preliminary conclusions before embarking on an in-depth analysis of the biomethane and green hydrogen sectors:

i/ Being in their infancy, both sectors need to be substantially scaled up for their production costs to go down and ultimately converge towards natural gas';

ii/ Volumes for projected incremental low-carbon hydrogen injections are unlikely in the near future to justify substantial network repurposing investments. In other terms, given the current near absence of hydrogen injections in gas networks and the time needed for these injections to become significant, the constraints linked to the injection of hydrogen into existing infrastructures should probably not hinder these infrastructures' ability to accommodate increasing volumes of hydrogen and thus to participate actively in the scale up of the industry.

3.1.1 BIOMETHANE OFFERS A NEARLY PERFECT SUBSTITUTE FOR NATURAL GAS, WITH INDIRECT CLIMATE BENEFITS

3.1.1.1 TURNING ORGANIC RAW MATERIAL INTO A MOLECULE CHEMICALLY VERY CLOSE TONATURAL GAS...

As we highlighted above, **biomethane is a near pure form of methane. It is mainly produced by upgrading biogas which itself results from the anaerobic transformation of organic raw materials.**

As the figure below illustrates, **the production of biomethane involves three different steps, namely:**

i/ Collection of raw material, mainly green waste, household, agricultural, agri-food or industrial (non-hazardous) waste**.** Although legal frameworks vary from one country to another on the use of agricultural land for the production of biofuels, crop residues represent the main source of raw material, followed by animal manure and municipal solid waste;

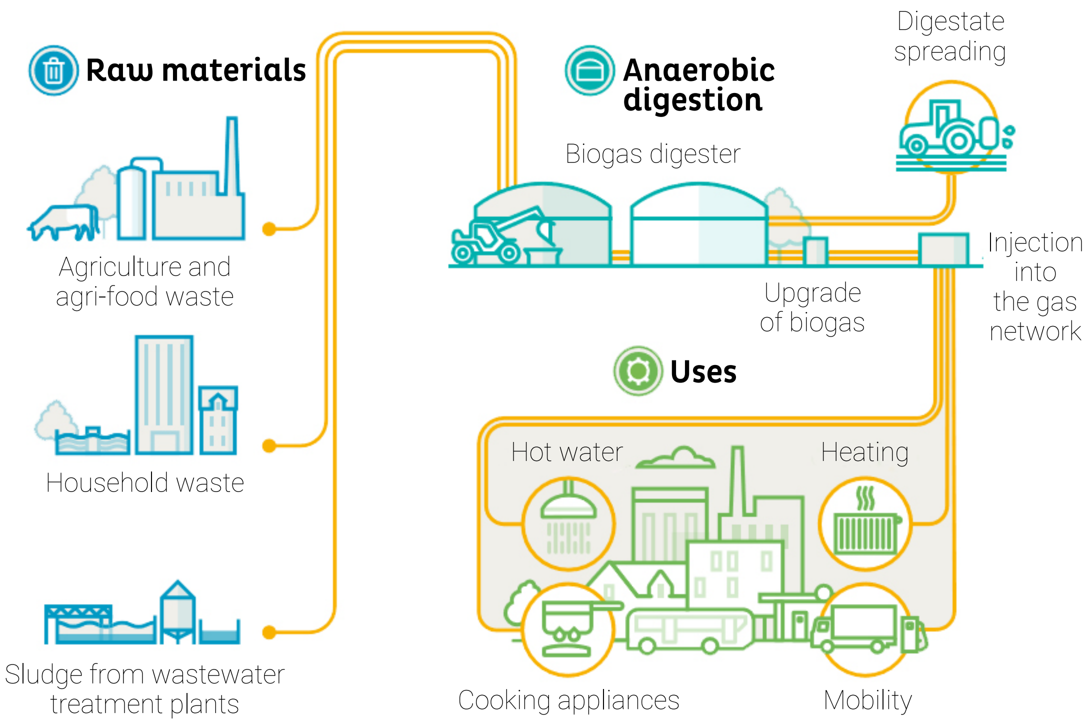
ii/ Anaerobic digestion, which encompasses a series of biochemical processes turning the various sources of raw material listed above into biogas in the absence of oxygen;

iii/ Upgrade of biogas. This third step of biomethane production entails concentrating the methane in biogas to natural gas standards. Such concentration is obtained simply **by removing CO_2, hydrogen sulphide, water and contaminants from the biogas. One commonly found technique for doing this uses amine gas treating[89].**

In addition, the production of biogas generates a **byproduct called digestate. A natural organic fertilizer**, it can be spread on agricultural lands as a substitute for fossil-based mineral fertilizers.

89 Amine gas treating refers to a group of processes that use aqueous solutions of various alkylamines (commonly referred to simply as amines). Interestingly, these processes are fairly established, being commonly found in such facilities as refineries and petrochemical plants.

FIGURE: OVERVIEW OF BIOMETHANE'S VALUE CHAIN: FROM RAW MATERIAL TO END USES



Source: Adapted from GRT Gaz (2019)

3.1.1.2 … BIOMETHANE BRINGS INDIRECT CLIMATE BENEFITS…

Being a near pure form of methane, biomethane brings indirect climate benefits. While its combustion emits CO_2 in the same proportions as that of natural gas (see 1.1.1), its production allows the removal of GHGs, mainly CO_2 and methane, that would have been otherwise released in the atmosphere upon decomposition of the organic raw material used as feedstock for biogas production. **Methane being a very potent GHG (see 1.2.1), biomethane's carbon balance is therefore nearly neutral from a CO_2e perspective using life cycle analysis**, even after factoring in:

i/ The CO_2 release upon final combustion as well as

ii/ The anaerobic digestion-related GHG emissions, mainly in the form of direct (scope 1) GHG releases during the process[90] and the carbon content (scope 2) of the energy consumed.

A study released earlier this year by French environmental and energy consultancy Quantis using life cycle analysis[91] comes up with **an overall carbon-equivalent footprint estimate of 23 kg CO_2e/MWh**. Such life cycle assessment was carried out using the expected mix of biomethane production in France by 2023 (see table below). **Despite the discrepancies observed among the various feedstocks used for biogas production, biomethane's life cycle analysis compares very favorably with that of natural gas** (range of 500-750 kg CO_2e/MWh depending on the magnitude of indirect emissions – see 1.2.3[92]) and evidences the immediate climate benefits of rising biomethane injections into existing natural gas networks.

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90 Those releases can be part of the process or unintentional, notably through leaks from biodigesters. In its accounts of the latter, the IEA cites data suggesting that the average is probably around 2%.

91 Full report available in French only: https://www.grdf.fr/documents/10184/5567990/Evaluation+des+impacts+GES+Biome%CC%81thane+_synthe%CC%80se+Quantis_2017.pdf/0717ef90-8775-006d-3761-8375dff0dfd3?t=1585645299897

92 TWh translation of natural gas' carbon intensity expressed in Boe (range of 336-476 kgCO_2e/boe).

FIGURE: LIFE CYCLE ANALYSIS OF FRANCE'S BIOMETHANE INDUSTRY: CARBON FOOTPRINT BREAKDOWN BY RAW MATERIAL TYPE

Raw material type	Net climate impact (kg CO2e/MWh)	Share in Frances's prospective biomethane production mix
Non hazardous organic waste	-35.6	4%
Household waste	-4.8	6%
Waste water	-36.4	9%
Agriculture waste (crops/animal manure)	35.1	81%
Weighted average CO2e footprint	**23.4**	**100%**

Source: Quantis (2020)

3.1.1.3 … AND OFFERS A NON-DISRUPTIVE OPTION TO DECARBONIZE MOST OF TODAY'S USES OF NATURAL GAS…

According to the IEA (WEO 2019), there are over 700 biomethane plants in operation today producing around 2.5 Mtoe of biomethane globally. Most of these plants are in Europe and North America. **Being an almost perfect substitute for natural gas, biomethane can be safely injected and stored in existing gas networks and storage facilities, the only limitation being for power generation where CCGTs can only use a large proportion of biomethane upon some retrofit work.**

Such chemical properties are key to understanding the techno-economic benefits of biomethane (in particular relative to green hydrogen – see below): the development of biomethane does not involve any retrofitting/repurposing of existing gas infrastructures and in the longer term no asset stranding risk; accordingly, networks and storage sites can safely play a direct role in the progressive substitution of this molecule for natural gas.

As a result, nearly three-quarters of biomethane produced worldwide are injected into existing gas networks and ultimately find some of the main end uses of natural gas (in particular building heating, see 1.1.3). A further 20% of plants deliver biomethane for use in road vehicles through dedicated distribution networks.

Although biomethane represents less than 0.1% of natural gas demand today, its production and use are supported by an increasing number of policies. For example, there are biomethane production targets and ambitions in Italy, India, China and **France.**

In France, biomethane is viewed as a key decarbonization agent for the building sector[93], which accounts for:

93 In France, the tertiary residential sector accounts for slightly over 17% of total GHG emissions, hereby offering substantial decarbonization potential.

i/ **The development target set by the Law on Energy Transition enacted in 2015** (renewable gases to reach 10% of France's overall gas consumption by 2030 from currently less than 1%[94]) but also

ii/ **The introduction in 2011 of a 15-year feed-in-tariff mechanism mimicking the one in place to support power production from renewable sources until 2017**. Such price guarantee has been supplemented by the introduction of a system of guarantees of origin ensuring traceability of biomethane and allowing its valorization near the consumer as part of a green offer.

3.1.1.4 … WHILE STILL FACING SCALE ISSUES

While offering a series of key advantages (indirect decarbonization of the consumption of natural gas through the use of existing infrastructure), **development of biomethane is currently hampered by a lack of cost competitiveness vis-à-vis natural gas**. As we highlighted above, in present market conditions, biomethane remains 5-7 times more expensive than natural gas imported in Europe. Biomethane's persistent lack of competitiveness vis-à-vis traditional fuels mainly **comes from the high costs incurred in the collection / processing of the various feedstocks used for biogas production**. The IEA estimates that these two steps together account for nearly two-thirds of the overall average cost of producing biomethane (€38/MWh vs. €60/MWh), the remainder coming from biogas upgrading. **The preeminence of collection/processing costs is mostly attributable to the wide dispersion of raw material sources in the agricultural sector**. One potential response to such logistics issue is through the development of larger processing facilities to generate economies of scale.

However, improving the economics of biomethane probably entails exploring more systemic avenues such as:

i/ Development of a specific value chain allowing systemic valorization of digestate for agricultural use;

ii/ Valorization of CO_2 captured in the gas upgrade process;

iii/ Generalization of green supply certificates[95] to foster downstream uses of the molecule and;

iv/ Setting a price for the tons of GHG avoided[96] to valorize biomethane's positive externalities. The IEA points out that GHG prices at levels of \$50-\$180 per ton of CO_2e are necessary to compensate for the current cost differential between biomethane and natural gas. Setting GHG price floors at such levels is ultimately a political decision (see 3.2.2).

More prospectively, another factor limiting the systemic use of biomethane as a substitute for natural gas comes from the limits on the quantities of raw materials feeding the anaerobic digestion process. In France, a study published by ADEME[97] in April 2013 estimates the global deposit that can be mobilized by 2030 for anaerobic digestion at 130 million tons of raw material (90% of which coming from agricultural materials), or 56 TWh of primary energy in biogas production[98]. This potential primary energy volume of 56 TWh in 2030 would represent only around 15% of the volumes of natural gas consumed in France according to estimates by gas network operators in France[99].

94 1.2 TWh of biomethane injected into gas grids to compare with an overall gas consumption of 451 TWh / See https://www.grtgaz.com/fileadmin/plaquettes/fr/2020/Panorama-du-gaz-renouvelable-2019.pdf (French version only).

95 This system implemented at national or regional level, has been widely used to incentivize the development of green sources of electricity generation. It relies on placing an obligation on electricity suppliers to source a given proportion of the electricity sold to end customers from renewable sources.

96 This could take the form of GHG emissions credits, such as those introduced for CO_2 emissions by the Kyoto Protocol for developing/transitioning countries.

97 Full report available in French only:
https://www.ademe.fr/sites/default/files/assets/documents/88252_gisements-substrats-methanisation.pdf

98 As Ademe specifies, this mobilizable potential must be compared to the theoretical potential of biogas production from the considered resources of 185 TWh.

99 In the reference scenario followed by GRDF, GRTGaz, SPEGNN and TIGF in their joint study, total gas consumption in France could decrease between 2016 and 2035 (from 413 TWh to 364 TWh). Full report available in French only:
http://www.grtgaz.com/fileadmin/plaquettes/fr/2017/Perspectives-Gaz-2017-2035.pdf

3.1.2 SCALING UP "GREEN" HYDROGEN PROBABLY HOLDS THE KEY TO A FAR REACHING DECARBONIZATION OF THE WORLD ECONOMY

3.1.2.1 IN ITS CURRENT, CARBON-INTENSIVE FORM, HYDROGEN MAINLY MEETS INDUSTRIAL NEEDS

In parallel to the emergence of biomethane, the last few years have seen an **increasing interest in hydrogen as a source of accelerated decarbonization of the world economy. This growing interest comes mainly from the fact that unlike fossil fuels (oil, coal and natural gas), when used as an energy carrier[100], hydrogen does not emit CO_2 upon combustion.** Instead, hydrogen emits water steam, thus suggesting a potential for decarbonization of a wide range of sectors / activities based on the combustion of fossil fuels: power generation, residential and industrial heating, mobility, etc.

Today, around 120 million tons of hydrogen are produced each year, of which two-thirds is pure hydrogen and one-third is in mixture with other gases (IRENA 2019[101]). These quantities of hydrogen are primarily produced through steam methane reforming (SMR), an energy-intensive process using natural gas but also coal as feedstock. **SMR without CCS accounts for over 95% of hydrogen volumes** produced worldwide, with **green and blue hydrogen being both produced** for the time being **in small quantities in pilot plants**. Hydrogen is primarily produced for specific industrial needs, usually as part of a captive process: **in such set-up, feedstock is supplied to a site where the hydrogen is produced and used, mostly in refineries, ammonia plants, or methanol plants.**

As suggested above, being the dominant manufacturing process and for lack of large-scale use of CCS, SMR accounts for the still heavy footprint of hydrogen manufacturing, the median CO_2 emissions ratio for SMR hydrogen production being 9kgCO_2/kg H2[102] production (scope 1 and scope 2 emissions).

At this stage, despite the prospects it offers as an energy carrier, hydrogen is confined to industrial uses in a fossil fuel-dependent, carbon-intensive value chain. The **growing interest in green hydrogen aims precisely to respond to these two current industrial and environmental limitations**, this by:

i/ Taking advantage of the chemical properties of hydrogen to **extend its use to sectors / activities based on the combustion of fossil fuels**, in particular in hard-to-abate sectors such as mobility;

ii/ Decarbonizing the production of hydrogen (scope 1 and scope 2 emissions) to reduce the overall carbon footprint of sectors / activities using it as feedstock.

3.1.2.2 IN ITS EMERGING "GREEN" FORM, HYDROGEN OFFERS NEWS AVENUES TO SPEED UP THE WORLD ECONOMY'S DECARBONIZATION…

As indicated above, the main distinguishing feature of green hydrogen compared to grey and blue hydrogens is that it uses the electrolysis process powered by low-carbon power sources. **Through green electrolysis, hydrogen can therefore be produced without direct (scope 1) and indirect (scope 2) CO_2 emissions.**

Simply put, electrolysis relies on the decomposition of water[103] into oxygen and hydrogen gas due to the passage of an electric current. This reaction takes place in a unit called an electrolyser. Electrolysers can range in size from small, appliance-size equipment that is well-suited for small-scale distributed hydrogen production to large-scale, central production facilities that could be tied directly to renewable or other non-greenhouse-gas-emitting forms of electricity production.

As the figure below illustrates, electrolysers consist of a DC source and two noble-metal-coated electrodes, which are separated by an electrolyte. They also consist of individual cells and central system units (balance of plant). By combining electrolytic cells and stacks, hydrogen production can be adapted to individual needs.

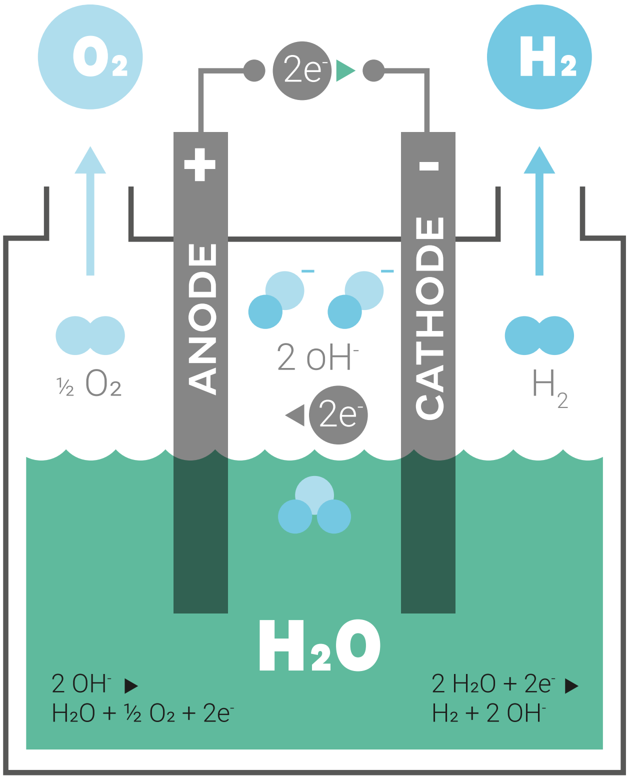
100 An energy carrier is a substance (fuel) or sometimes a phenomenon (energy system) that contains energy that can be later converted to other forms such as mechanical work or heat or to operate chemical or physical processes.

101 https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf

102 Equivalent to 270 kg CO_2/ MWh.

103 It takes approximately 9 liters of water to produce 1kg of hydrogen through electrolysis (see cleanenergypartnership.de)

FIGURE: SIMPLIFIED OVERVIEW OF ELECTROLYSIS-BASED MANUFACTURING OF HYDROGEN



Source: Shell

From a wide climate change perspective, the potential benefits of green hydrogen are far-reaching, extending well beyond the energy sector.

The potential role of green hydrogen as a "systemic" decarbonizing agent of the economy can be grasped by making the assumption (not yet verified at the moment - see below) of green electrolysis reaching commercial viability at some point. Achieving this commercial viability involves two distinct stages so that green hydrogen finds a central place in the energy and economic systems in place: on the one hand, that it reaches the cost levels of grey hydrogen (€28/ton for the latter vs. a wide range of cost estimates - €70-€200/ton for green hydrogen – see 3.1); on the other hand, that its cost aligns with the price of natural gas and other fossil fuels[104].

In this scenario, **the use of hydrogen would gradually spread to all economic sectors: energy, mobility, manufacturing activities**, etc. as part of an integrated value chain as shown below. Electricity generated by wind or solar power plants could, depending on market conditions, be injected into high or medium voltage grids, or supplied to power electrolysers for the decarbonized production of hydrogen for which there would be multiple end-uses in both:

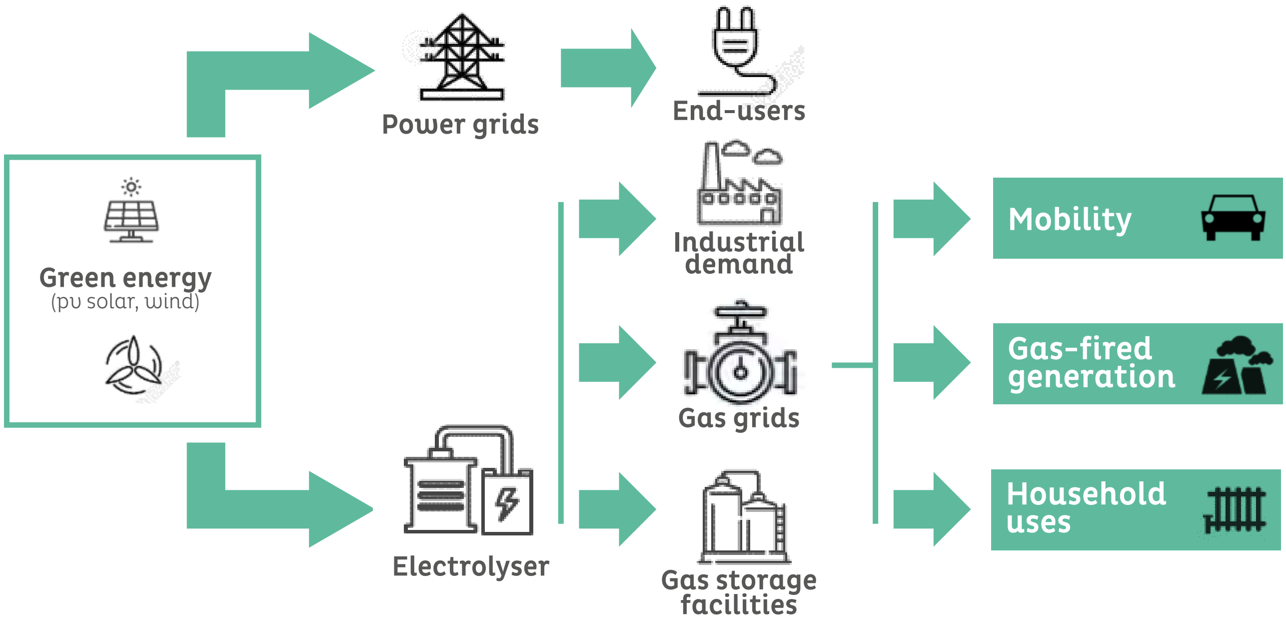
i/ The industrial sector (production of steel, plastics, ammonia, glass, etc.) and

ii/ The energy sector, after being injected into infrastructures (networks, underground storage facilities). In this configuration, **the molecule would end up serving a variety of purposes (mobility, electricity generation, domestic heating,** etc.).

104 As we thoroughly discuss below, this convergence can be envisaged in different, not mutually exclusive, forms: either a drop in the cost price of hydrogen to a level comparable to the international market prices of natural gas, and/or the fixing, for all economic activities, of a price per metric ton of CO_2 emitted at a level resulting in the substitution of green hydrogen for natural gas/oil/coal for strictly economic reasons.

NATIXIS BEYOND BANKING

FIGURE: SIMPLIFIED OVERVIEW OF THE POTENTIAL GREEN HYDROGEN VALUE CHAIN



Source: Natixis

In this scenario, the benefits of green hydrogen would be fourfold, for the molecule would:

i/ Gradually decarbonize the current energy uses of natural gas. This could be achieved through a steady increase in hydrogen blending in existing gas infrastructures. However, such blend is subject to technical limitations, for hydrogen cannot be safely injected into existing gas infrastructures generally in excess of 10%/20% (see 3.1.1.3). In the next paragraphs, we thoroughly discuss these technical limitations, which constitute a potential source of asset stranding for existing infrastructures in a scenario where hydrogen would substantially displace natural gas in existing energy systems;

ii/ Help decarbonize hard-to-abate sectors, either as feedstock or as energy carrier. In the former case, hydrogen can play an important role in the decarbonization of such products as steel[105] and chemicals. In the latter case, there is increasing interest in using hydrogen for heavy-duty transport (buses, trucks, ships, aircrafts, etc.). In these mobility segments, the use of vehicles powered by hydrogen fuel cells makes it possible to respond to the current limitations of electric vehicles. These limitations are diverse: lack of autonomy, significant recharge time, limited range, etc. In this context, a potential overhaul of the transport sector around electricity for light individual vehicles and hydrogen for heavy vehicles seems to be gaining ground;

iii/ Help manage the intermittency of renewable energies. **Given its potential injection into gas infrastructures ("power-to-gas" paradigm), green hydrogen could in fact offer an implicit large-scale storage solution for electricity generated from intermittent sources,** which otherwise risk destabilizing the electricity system. This benefit deserves to be emphasized, given the technical and economic limitations of electric batteries (see 2.1.1) in the management of the electrical system as well as the various direct (strengthening and expansion of power networks) and indirect (need for back-up generation units to maintain system reliability) costs induced by the recent development of renewable energies across Western Europe;

iv/ Pave the way for the integrated management of electricity and gas value chains. In this general scheme, via green hydrogen, the gas and electricity systems would be mutually supportive in order to guarantee security of supply of both energies. As for the electricity sector, as mentioned above, the injection of hydrogen into gas infrastructures would constitute a long-term source of system stability insofar as the share of green energies is still expected to increase in the coming years[106]. In the gas sector, the possibility of injecting green hydrogen would meet the various operational constraints linked to the seasonality of demand.

105 When the molecule is used for iron ore reduction (see 2.2.2)

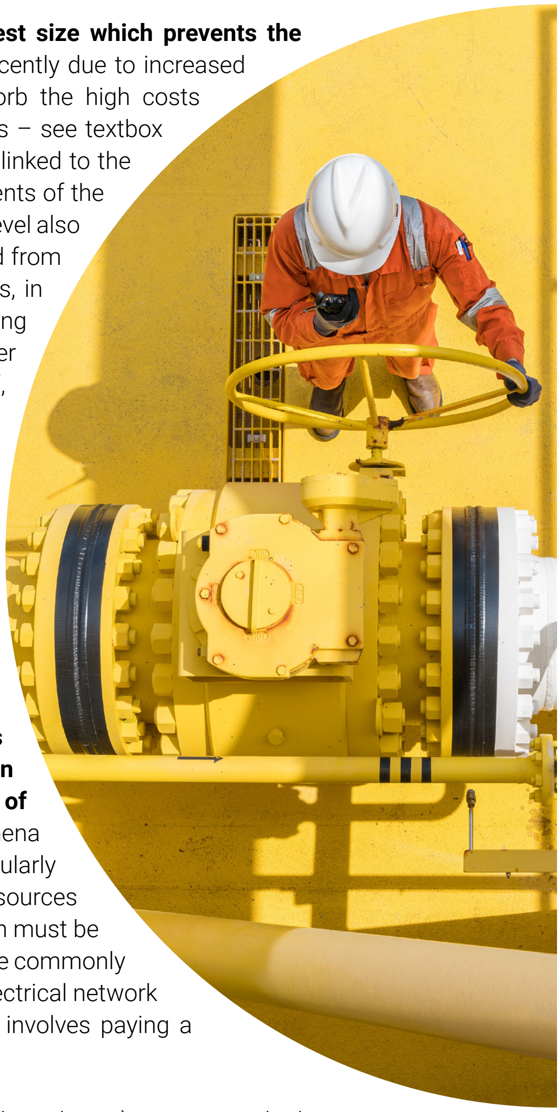
106 As part of the electrify everything approach which underlies for example the elaboration of the EU Taxonomy (see 2.2.2).

3.1.2.3 …WHICH NONETHELESS IMPLIES OVERCOMING A SERIES OF CONSTRAINTS RELATED TO THE INTEGRATION OF THE MOLECULE IN CONTEMPORARY ECONOMIC AND ENERGY SYSTEMS

Although it holds the promise of massive decarbonization of the global economy, the large-scale use of green hydrogen currently faces two main series of limitations and obstacles.

First and foremost, green electrolysis suffers from a lack of competitiveness vis-à-vis other forms of hydrogen and fossil fuels. The currently high costs of green electrolysis can be accounted for by a set of elements, namely:

i/ The high costs of the equipment and their still generally modest size which prevents the generation of economies of scale. Despite some progress made recently due to increased investment in the industry, electrolysers remain too small to absorb the high costs associated with the initial investment (€750/kW for ALK electrolysers – see textbox #2). The importance of initial investment costs in the sector is to be linked to the manufacturing process of electrolysers. In fact, most of the components of the latter are manufactured by hand. The absence of serial effects at this level also accounts for the magnitude of the orders (350 MW-500 MW) required from electrolysers operators to justify investments by equipment suppliers, in the form of industrialization of manufacturing processes. According to BNEF, however, 2019 saw rapid developments on the electrolyser market with growth in ordered volumes and unit size of equipment[107], in addition to increasing involvement of Chinese companies. These elements seem likely to continuously lower the costs of electrolysers in the coming years. In this context, BNEF anticipates a drop in ALK electrolysers' unit costs from a range of $200/kW [108] to $1,000/kW[109] today to a range of $80/kW to $98/kW by 2050;



ii/ The still limited efficiency of the process (usual range of 50%-70%[110]) and finally, in a related way;

iii/ The high energy costs linked to the process. In general, observation of green electrolysis across the globe highlights cases of green hydrogen reaching cost parity with other hydrogen manufacturing processes and even fossil fuels in environments of zero or even negative prices for green electricity. These phenomena are no longer rare in contemporary power systems. This is particularly true in electrical zones characterized by an abundance of renewable sources (wind, solar PV). This proliferation can induce excess production which must be treated to ensure the stability of the electrical system. Two methods are commonly used, a physical one (curtailment) which involves the closing of the electrical network to renewable sources, or an economic one (negative prices) which involves paying a consumer, usually an industrial company, to use excess electricity.

The table below shows that in some instances, even with high capex (electrolysers) costs, green hydrogen can reach cost parity with grey hydrogen thanks to (very) low electricity prices.

107 Still according to BNEF, a majority of the current electrolysis projects come from projects that are over 10 MW in size, which shows a significant increase vis-à-vis the typical size of the projects built in 2018, which was just 2-3 MW.

108 Unitary cost for ALK electrolysers made in China.

109 Unitary cost for ALK electrolysers made in Europe and North America.

110 Such range indicates the proportion of initial energy content use to power the process eventually returned in the form of hydrogen.

FIGURE: COST OF GREEN HYDROGEN WITH VARYING LCOE[111] & LOAD FACTORS ($/KG H2)

Capex elecrolysers

LCOE	$750/kW					$500/kW					$250/kW				
$0/MWh	5.7	2.8	1.9	1.4	1.1	4.2	2.1	1.4	1.1	0.9	2.8	1.4	0.9	0.7	0.6
$10/MWh	6.1	3.3	2.4	1.9	1.6	4.7	2.6	1.9	1.5	1.3	3.2	1.9	1.4	1.2	1
$20/MWh	6.6	3.8	2.8	2.4	2.1	5.2	3	2.3	2	1.8	3.7	2.3	1.9	1.6	1.5
$30/MWh	7.1	4.2	3.3	2.8	2.5	5.6	3.5	2.8	2.5	2.2	4.2	2.8	2.3	2.1	2
$40/MWh	7.5	4.7	3.8	3.3	3	6.1	4	3.3	2.9	2.7	4.6	3.2	2.8	2.6	2.4
$50/MWh	8	5.2	4.2	3.7	3.5	6.5	4.4	3.7	3.4	3.2	5.1	3.2	2.8	2.6	2.4
$60/MWh	10	7.5	6.5	6.1	5.8	8.9	6.7	6	5.7	5.5	5.1	3.7	3.2	3	2.9
Load Factor	10%	20%	30%	40%	50%	10%	20%	30%	40%	50%	10%	20%	30%	40%	50%

<$2/kg $2-3/kg $3-4/kg   >$4/kg   Viable medium-term (i.e. 2030)

Source: Oddo Sustainability Research, citing Hydrogen Council

All in all, for green hydrogen to reach cost parity vis-à-vis grey hydrogen and then fossil fuels, there is a long way to go. Substantial progress needs to be made on each of the abovementioned fronts. If all these conditions were eventually met, the ultimate cost parity with part of the natural gas currently produced in the world (the case of production in the North Sea, in Brazil and India and in China) would be possible but probably not in the near future. BNEF, for its part, expects such parity to be overall achieved by 2050. However, these projected trends should not overshadow the importance of local factors in the development of green hydrogen. **Recent developments in the renewable energy sector suggest that the magnitude of potential cost abatements is likely to vary from one region to another, depending on the trend shaping the cost competitiveness of certain renewable sources**. In this perspective, some players in the industry anticipate a sharp fall in the costs of green hydrogen induced by the continuation of deflationary trends at work in the solar PV sector. In its recent Sustainability day, Italian gas infrastructure operator SNAM emphasized the case of recent solar power tender in Abu Dhabi, with a record-low solar price of 12.1 €/MWh which is likely to drive green hydrogen costs down to 38 €/MWh in the next 2/3 years in Middle East[112].

Leaving aside these particular cases, it is fair to assume that at least up until 2030, the **development of the sector will remain dependent on public policies, which could take the form of:**

i/ Those already in place for biomethane in some countries (feed-in tariffs, "green" supply certificates, see 3.1.1.3);

ii/ The setting of a universal floor price for CO_2 emissions. As mentioned above in the case of biomethane, the current cost differentials between green hydrogen and fossil fuels used either as energy carrier or as feedstock make it necessary to introduce floor prices for CO_2 emissions from all sectors to promote the widest possible adoption of green hydrogen. These cost differentials vary considerably from one sector to another. **According to BNEF estimates, these cost differentials are such that carbon price floors ranging from $32/ton[113] to $145/ton[114] would still be needed in 2050 to displace fossil fuels in a wide set of activities (power generation, manufacturing of aluminum, steel, cement, shipping, etc.).**

111 LCOE – Levelized Cost of Energy - is a concept developed to measure the average net present cost (expressed in $/MWh) of electricity generation for a generating plant over its lifetime.

112 https://www.snam.it/export/sites/snam-rp/repository/file/investor_relations/presentazioni/2020/2020_Sustainability_day.pdf

113 Case of hydrogen displacing natural gas for power generation through hydrogen-ready gas turbines.

114 Case of green ammonia from hydrogen (see 3.2.2.2) displacing heavy fuel oil for shipping.

TEXTBOX 2 | TYPES OF ELECTROLYSERS

Electrolysers are differentiated by the electrolyte materials and the temperature at which they are operated. Three main electrolyser technologies are used or being developed today:

1. **Alkaline (ALK)**: production of hydrogen from ALK electrolysers dates back from the 1920s, initially emerging for non-energy purposes, particularly in the chemicals industry (e.g. chlorine manufacture). This type of electrolyser is characterized by having two electrodes operating in a liquid alkaline electrolyte solution of potassium hydroxide (KOH) or sodium hydroxide (NaOH);
2. **Proton Exchange Membrane (PEM)**: this type of electrolyser differs from the previous one by a solid electrolyte with a proton-conducting polymer membrane;
3. **Solid Oxyd Electrolyser Cell (SOEC)**: this technology is directly derived from the development of the PCFC[1] type fuel cell or SOFC[2] and operates at temperatures in the 400 - 600 °Celsius and 650 - 1,000 °Celsius ranges respectively, which allow high-temperature electrolysis to occur. It proves interesting if it is supplied with both electricity and heat to maintain the high desired temperature; the efficiency can then be greater than 80%. It is essentially intended to be coupled to a solar system with concentration or at a high temperature nuclear reactor.

The first two processes (ALK and PEM) have reached commercial viability (albeit recently for the latter), while the third one (SOEC) is still under development. Compared to ALK electrolysers, PEM electrolysers feature much lower lifetime (ratio of 1:2) and slightly lower efficiency rates (ratio of 1:1.15) but enjoy more flexibility and reactivity, thus offering a wider operating range[3] and a shorter response time. These technical characteristics make PEM a more suitable process for optimizing the use of intermittent energy sources. However, the cost of the polymer membrane and the use of electro-catalysts based of noble metals, lead to more expensive equipment today than ALK electrolysers of the same capacity. In 2018, the IRENA[4] estimated the respective capex associated with ALK and PEM amounted to €750/kW and €1,200/KW. All in all, **while offering less flexibility to optimize the use of intermittent renewable energies than PEM, ALK remains the prominent electrolysis technology.**

1 Protonic Ceramic Fuel Cell.

2 Solid Oxide Fuel Cell.

3 Upward and downward regulation capacity.

4 https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Sep/IRENA_Hydrogen_from_renewable_power_2018.pdf

The other sources of limitation of green hydrogen as a systemic decarbonization agent are of a technical nature and relate to some of the molecule's properties, namely:

i/ Hydrogen displaying much lower energy density than natural gas. Hydrogen's energy density is around a third of that of natural gas. Such property has considerable implications for the value chain's logistics. First, in a scenario of total substitution of hydrogen for natural gas, to transport the equivalent amount of energy, it would entail a **massive resizing of the existing gas infrastructures, disregarding the question of the compatibility of these infrastructures with the molecule**, a question we address in the following paragraph. Second, it means that for an equivalent amount of energy eventually consumed by end-users, **it takes more energy to operate gas pipelines**, in particular to run compressors[115]. Third, when hydrogen cannot be carried by pipelines, the already high costs of transport by truck and by ships are multiplied by the molecule's low energy density. Even in BNEF estimates incorporating scenarios of significant drop in the cost of transporting hydrogen by trucks or ships, these transport means would remain considerably more expensive than pipeline transport[116];

ii/ The undesirable effects of injections of hydrogen in significant quantities in existing gas networks. **These effects currently put a cap on the proportions of hydrogen that can be injected safely into high and medium-low pressure networks[117]**. In spite of some specific cases narrowing the differences generally observed between these two types of infrastructures[118], a general distinction must be made between high-pressure (transport) and medium-low pressure (distribution) networks. Transport networks being generally made of steel, hydrogen injections in excess of 10% are likely to cause a weakening of the structure and an acceleration of the speed of the propagation of existing defects. On their side, polyethylene[119] pipes which appear frequently in the distribution networks withstand hydrogen injections much better than steel pipes. However, above a level of 20%, hydrogen injections are likely to affect their permeability. On the downstream side of the value chain (end uses currently satisfied by natural gas), the 20% threshold observed for distribution networks also seems to be a tipping point. Hydrogen blend in excess of this threshold raises an adaptability issue for both residential (heating systems) and industrial equipment (factory pipelines, internal networks and service pipes, boilers, chromatographs, etc.)[120].

These technical features raise an asset stranding risk insofar as most current gas infrastructures were not initially designed to accommodate hydrogen and should be the subject of a complete retrofit / repurposing to tolerate high hydrogen blends. However, as we highlighted above, gas infrastructures owners/operators are unlikely to confront such repurposing constraint in the near future, given the negligible share of hydrogen in nowadays gas demand and the time required for the sector to reach a critical size. The different scenarios developed by the IEA and BNEF indeed suggest that the place of hydrogen in meeting the energy demand met today by natural gas should remain limited until 2030. In view of the current development prospects of green hydrogen, **it is realistic to expect hydrogen's share in gas demand** (as measured by the share of hydrogen in all volumes injected in existing gas networks) **to remain below 10% by 2030 in Western Europe and North America.**

For existing gas infrastructures, these elements make it possible to envisage for the moment the development of the hydrogen sector more as an opportunity than as a threat.

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115 Compressor stations are an integral part of the natural gas pipeline network that moves natural gas from individual producing well sites to end users. As natural gas moves through a pipeline, distance, friction, and elevation differences slow the movement of the gas, and reduce pressure. Compressor stations are placed strategically within the gathering and transportation pipeline network to help maintain the pressure and flow of gas to market. See https://extension.psu.edu/understanding-natural-gas-compressor-stations

116 Hydrogen transport by ruck and by ships display unit costs of $1.1/kg (for 300-400 km distances) and $2/kg, respectively, to compare with a level of $0.09/kg when hydrogen is transported via a very high-capacity onshore pipeline moving more than 5,000 tons per day over long distances (1,000 km).

117 The technical elements of this section are mainly drawn from an ad hoc study released in June 2019 and carried out by the main gas infrastructure operators in France: GRTgaz, GRDF, Terrega, Storengy, Elengy, Géométhane, Régaz, R-GDF. See below for the link to the publication:
https://www.grtgaz.com/fileadmin/plaquettes/en/2019/Technical-economic-conditions-for-injecting-hydrogen-into-natural-gas-networks-report2019.pdf

118 These differences between transport and distribution infrastructures can vary in intensity from one country to another, depending on the technical characteristics of each type of network. By way of illustration, having been designed to transport a natural gas extracted in the North Sea of lower energy density than that commonly used in Europe, Netherlands' gas high-pressure networks have a better tolerance for hydrogen injections than Western Europeans peers'.

119 The most common plastic in use today.

120 However, the aforementioned 20% threshold does not apply to a part of the industrial users of natural gas whose processes are sensitive to the quality / properties of the gas used.

3.2 THROUGH THE INTEGRATION OF LOW-CARBON GASES, EXISTING GAS INFRASTRUCTURES CAN ACTIVELY CONTRIBUTE TO ONGOING ENERGY TRANSITION INITIATIVES WHILE POTENTIALLY SECURING A FUTURE IN A LOW-CARBON ECONOMY

The question of the role of existing gas infrastructure in the transition to a low-carbon economy must be approached through the lens of time. At this stage of development of biomethane and green hydrogen and probably up until 2030/2035, the use of existing infrastructures presents a certain number of advantages which can prove to be crucial for the development of low-carbon gases. In a very practical way, therefore, gas infrastructures can play a key role in the generation of scale effects for these nascent sectors, while ensuring a sort of smooth transition between natural gas and low-carbon gases. It is only on a still uncertain horizon but probably not earlier than 2030/2035, that the potential development of hydrogen will begin to highlight structural changes in energy systems and therefore the gradual marginalization of fossil fuels in economic systems trending towards carbon neutrality. From this point of view, for existing gas infrastructures, the prospect of green hydrogen gradually displacing natural gas by 2050 constitutes more an opportunity than a risk.

3.2.1 EXISTING GAS INFRASTRUCTURES HAVE A MAJOR ROLE TO PLAY IN THE DEVELOPMENT OF LOW-CARBON GASES IN THE NEXT 10 YEARS…

At this stage, for a number of technical and economic reasons, "domestic" gas infrastructures (networks, underground storage facilities) seem able to respond to some challenges raised by the development of biomethane and green hydrogen. In broad terms, while they can perfectly accommodate increasing flows of biomethane from injection points without technical limitation, gas networks are likely to largely solve the cost problems posed by the transport of hydrogen (see 3.1.1.3).

More generally, as the ad hoc technical study[121] by French operators cited above highlights, **in the perspective of managing an energy system, gas infrastructures share a few features placing them as perfect allies of low-carbon gases,** namely:

i/ Gas networks are capable of transporting energy over long distances at very low cost (see 3.1.1.3), with very low losses[122], hereby offering the best solution to gas[123] transport from a techno-economic perspective;

ii/ They can also transport and deliver very large quantities of energy. This means that their current sizing does not constitute an obstacle to any rapid growth (from today's negligible volumes) **in low-carbon gas blending;**

iii/ Through storage facilities, they already offer an implicit means to tackle cases of potential mismatch between power consumption and power production. Such is the role of natural gas in energy systems regularly confronting this risk either because power demand is characterized by frequent large swings throughout the year[124] and/or because power production is predominantly from intermittent (renewable energies) or not very flexible (nuclear reactors) sources. In such case, **when it cannot be directly substituted for electricity, natural gas can be used to strengthen the electricity system's overall reliability** (case of CCGTs acting as a back-up for intermittent wind and solar PV sources – see 2.1.1). This feature of gas infrastructures highlights their being already instrumental in the complementarity between gas and electricity. **The emerging "power-to-gas" paradigm (see 3.1.1.2) aims precisely to make a systemic use of these sources of complementarity in the combined management of gas and electricity infrastructures;**

iv/ Gas networks have intrinsic flexibility thanks to the use of pressure adjustment. This means that supply and demand do not need to be balanced at all times in the gas system. In the perspective of the abovementioned "power-to-gas" paradigm, this feature offers, at this stage of biomethane and hydrogen development, the possibility of safely injecting quantities of low-carbon gas at any time;

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121 The elements developed below illustrate the potential role of gas infrastructures in the development of hydrogen. Most if not all the arguments developed in this study can be extrapolated to the development of biomethane but also to any developed economy with a complete set of "domestic" gas infrastructures (high / medium / low pressure networks, underground storage facilities).

122 The abovementioned study cites losses in the region of 0.7% for gas transmission networks vs. a range of 2 to 6% for electricity.

123 In the broad sense, that is to say including natural gas, biomethane and hydrogen.

124 Typical case of France where power consumption is highly dependent on atmospheric conditions with frequent demand spikes during the winter season.

v/ In almost any developed country making use of natural gas for residential heating purposes (OCDE, China and the Former Soviet Union - see 1.1.3), existing gas networks have been developed in the perspective of an exhaustive yet tight coverage of the entire territory. This means that gas networks offer the possibility of spreading low-carbon gases across the entire jurisdiction covered. In doing so, they enable a broad and homogeneous decarbonization of the end uses of natural gas. This feature can prove to be particularly valuable from the perspective of developing hydrogen in proportions likely to induce a change of standard in downstream equipment (see 3.1.1.3);

vi/ The infrastructure is for the most part buried and not visible, which helps make it acceptable to the public. This feature is worth highlighting in light of the societal oppositions generally referred to with the acronym "NIMBY" (Not In My Back Yard) unleashed in Europe by the deployment of the various electrical infrastructures necessary for the achievement of the energy transition (onshore wind turbines, overhead high / medium / low voltage grids, etc.).

Schematically, given these various features, existing gas infrastructures can generate a virtuous circle by which:

i/ They facilitate the transport of both biomethane and hydrogen from where they are produced to where are is used; and accordingly;

ii/ They allow biomethane and hydrogen volumes to find secured final use at low marginal costs, but also;

iii/ They create a potential optionality in the commercialization of low-carbon gases: during the development phase of local uses of the molecule (electricity production, manufacturing activities, mobility, etc.), it may be appropriate for developers of biomethane/green hydrogen production projects to have an "injection outlet". By means of injections piloted in the gas network, these project developers benefit from scale effects on their production facilities before they are able to sell their production locally at a potentially reduced cost;

iv/ Ultimately, the use of networks allows scale effects generated upstream and downstream of the cycle to reinforce each other. On the one hand, rising demand is likely to incentivize upstream investments, hereby generating scale effects and driving production costs down. On the other hand, higher volumes and lower costs on the upstream end of the value chain are likely to incentivize downstream uses, some of which may be decorrelated from the use of networks (case of charging infrastructure for fuel-cell vehicles).

3.2.2 THROUGH THE INTEGRATION OF BIOMETHANE, GREEN HYDROGEN AND GREEN SYNGAS, EXISTING GAS INFRASTRUCTURES CAN ALSO ACTIVELY TACKLE THE ASSET STRANDING RISK

As pointed out above, the various avenues implemented or simply envisaged at this stage to decarbonize the world economy imply potentially significant disruptions for the systems in place. This is mainly due to the fact that most economic sectors continue to depend on fossil fuels.

In this perspective, the electrify-everything approach induces major disruptions for the oil and gas sectors since it is based on the principle of decarbonization of the economy by diffusion of the uses of electricity, in particular in hard-to-abate sectors such as mobility. For these sectors, the electrify-everything approach is therefore a source of massive asset stranding risk.

From this angle, making use of all existing infrastructure assets for the time being, the development of low-carbon gases offers the advantage of being less disruptive for the energy and economic systems in place. At the same time, biomethane's and green hydrogen's negligible shares in most of natural gas' end uses and the still very high costs associated with their production make massive upstream investments necessary.

Each of these potential avenues (electrify-everything, biomethane, green hydrogen) has advantages, but also specific drawbacks. None can be at this stage considered a priority and above all a unique option for decarbonizing the world economy. In the specific case of low-carbon gases, infrastructure operators/owners will have to deal with **biomethane and green hydrogen increasingly competing with each other given**:

i/ The abovementioned importance of the necessary investments in the upstream part of both molecules' value chains. These investments will probably not be carried out without very significant public aid (green certificates, feed-in tariffs, CO_2 and/or GHG price floors, etc.) but also;

ii/ Network issues raised by hydrogen blending in excess of 10% / 20%.

The opening decade promises to be rich in technological innovations but also in initiatives aiming to deploy each of these potential solutions in the best conditions possible. It may then allow a privileged solution to emerge.

3.2.2.1 EARLY INVOLVEMENT IN THE EMERGENCE OF BIOMETHANE AND GREEN HYDROGEN OFFERS GAS INFRASTRUCTURE OPERATORS/OWNERS AN ALMOST FREE OPTION TO MANAGE POTENTIALLY DISRUPTIVE TECHNOLOGY CHANGES

From the point of view of gas infrastructure operators, the benefits of early involvement in the development of biomethane and green hydrogen are numerous:

i/ Adaptation capex required for injecting biomethane and, for the time being, hydrogen into existing infrastructure are almost zero. Therefore, biomethane and hydrogen blending offers gas infrastructure operators/owners of these assets an **almost free option at this stage to participate in the emergence of sectors preserving all (biomethane) or at least a large part of the value of relatively recent investments displaying long amortization periods** (generally 40 years);

ii/ With regard to hydrogen, adaptation capex should remain very limited for at least 10 years. The growth of volumes injected into existing infrastructure is likely to be very gradual in the coming years[125] alongside green electrolysis slowly becoming commonplace. For operators/owners of these assets, the associated investment efforts will therefore follow a "stepped approach" before the question of repurposing existing assets arises to further accompany the development of the molecule. **These elements suggest that no investment cliff is to be feared in gas infrastructures before probably 10/15 years.** The figure below presents a summary of capex for adapting gas infrastructures according to the percentage of hydrogen blending in France, based on the technical specifications applying to each asset. As indicated in 3.1.1.3, the injection thresholds of hydrogen triggering replacement capex vary from one asset to another. The figure shows that only limited adaptations are required to be able to inject 6% hydrogen into the networks, with a first real investment threshold at 10% injection rate (replacement of steel pipes in transport networks) then at 20%. As already mentioned above, beyond this level, the increase in hydrogen blend is likely to trigger significant investments both at networks' and end-uses' levels;

iii/ The technical elements above also suggest the developments of biomethane and hydrogen can be managed jointly and therefore without potential conflicts between the two molecules at least in the next 10 years. Through the gradual rise of biomethane and hydrogen blend into networks, gas infrastructures can therefore contribute to the generation of scale effects without running the risk their initiatives and investments in the two molecules cannibalize each other;

iv/ Finally, through involvement in projects around biomethane and green hydrogen, gas infrastructures can participate in the development of responses to certain technical limitations raised by the electrify-everything approach. As indicated above (see 3.1.1.2), the implementation of the electrify-everything approach encounters various practical limitations in hard-to-abate sectors such as mobility. It is precisely in this sector, in particular in the heavy-duty transport segment, that the use of low-carbon gases, mainly green hydrogen, can find meaningful applications. At this stage of biomethane and green hydrogen development, gas networks' involvement in charging facilities could be structuring for the sector. The involvement of power utilities, in particular distribution networks, in the development of recharging infrastructures for electric vehicles shows the importance of "systemic" players directly taking part in the development of "alternative" sectors.

In parallel, alternative avenues could be explored to smooth the integration of green hydrogen in existing gas infrastructures.

One option is to achieve some complementarity between the two molecules through the combination of green hydrogen and CO_2 to produce renewable synthetic gas (see 3) making it possible to maintain the existing gas infrastructures. However, the implementation of such complementarity will be dependent on technological and economic parameters, namely:

i/ Green electrolysis achieving cost competitiveness vis-à-vis grey hydrogen and other gases;

ii/ CCS technology reaching commercial viability and/or benefiting from public support in the form of a carbon price floor.
Another option in the event of a rapid reduction in the costs of electrolysis and the spread of industrial uses of green hydrogen instead of natural gas (steel, cement, chemicals) could take the form of cluster solutions. In this scheme, existing gas networks would be replaced so as to accommodate 100% of hydrogen produced and used in a closed loop system (see textbox #3).

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125 For the time being, French gas operators recommend setting a target capacity for hydrogen blending into the networks at 10% in 2030, then 20% beyond.

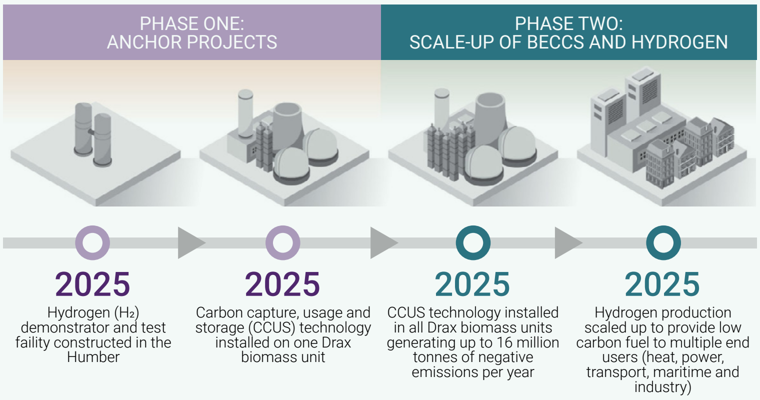
TEXTBOX 3 | HYDROGEN-CENTRIC INDUSTRIAL CLUSTERS

In Europe, a few pilot projects involving hydrogen-centric industrial clusters have been recently announced.

Among these is the Humber project in the North of England[1]. This project is still in the exploratory phase. It brings together UK power producer Drax group, UK energy networks operator National Grid and Norvegian Oil & Gas group Equinor who signed a Memorandum of Understanding in May 2019.

The underlying scheme of this project is that of the production of blue hydrogen by reforming the gas and using the CCS process to capture CO_2. The hydrogen produced is transported for use in power, industry, heat and transport, whilst the CO_2 captured is transported by pipeline to be permanently stored under the southern North Sea. At the same time, Drax will develop a process for capturing carbon at its neighboring power station for producing electricity from biomass (bioenergy carbon capture and storage – BECCS). The CO_2 thus isolated is intended to be stored permanently on the same site as the one isolated during the production of hydrogen.

FIGURE: MILESTONES OF UK's HUMBER PROJECT



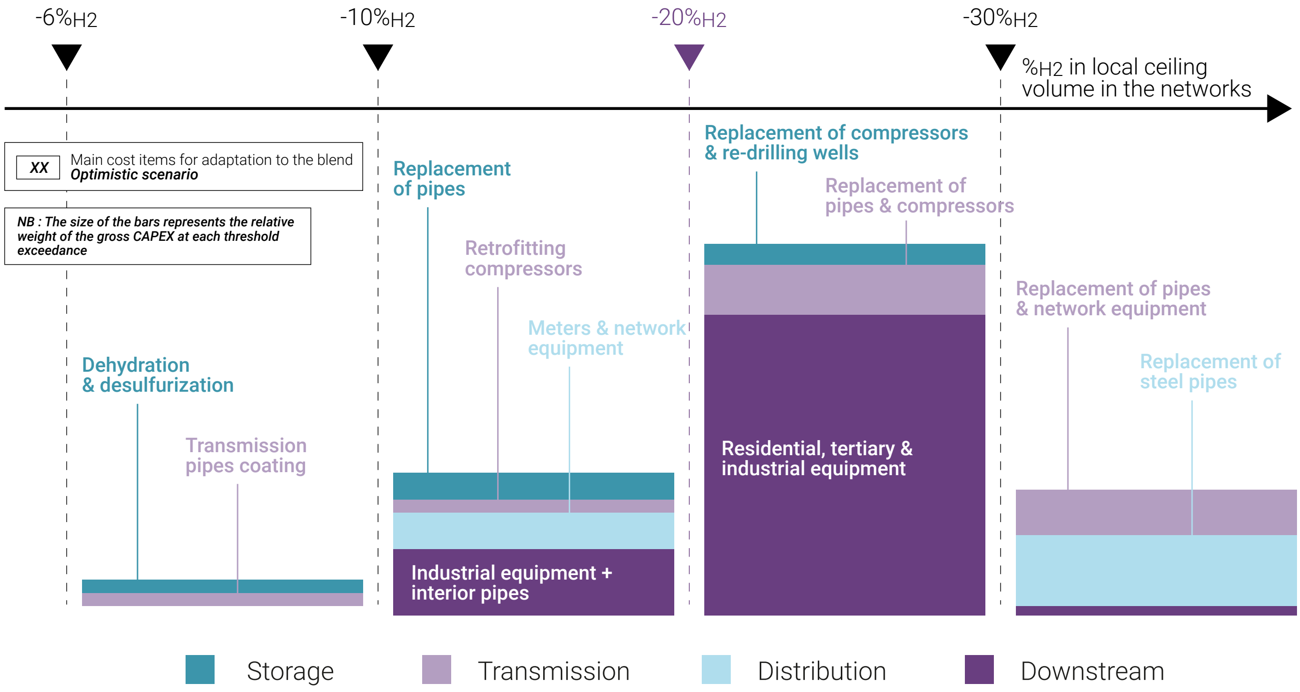
In July 2020, Iberdrola announced that an agreement has been signed with Fertiberia (a leading producer of fertilisers and industrial chemicals) for the construction of what will be the largest plant in Europe for the production of green hydrogen for industrial use (more specifically chemical manufacturing).

Iberdrola is to construct a 100MW photovoltaic plant, a lithium-ion battery installation and a 20MW electrolytic hydrogen production system. The green hydrogen produced will be used at Fertiberia's Puertollano ammonia plan in Spain. For this project, the investment is put at €150m. The Spanish companies are to build the plant in Puertollano (province of Ciudad Real, Castile-La Mancha) and it will be operational in 2021

This green hydrogen project positions itself as the first developed for exclusively industrial use in a closed-circuit logic. For its different components, the project draws upon the geographical proximity of the energy and industrial assets to create a complete value added chain in green hydrogen, spanning the generation of renewable energy through to the use of green hydrogen produced by electrolysis in industrial processes.

1 https://www.zerocarbonhumber.co.uk/

FIGURE: SUMMARY OF ADAPTATION CAPEX FOR GAS INFRASTRUCTURE ASSETS IN FRANCE AT DIFFERENT HYDROGEN LEVELS



Note: the operating costs of H2/CH4 separation upstream of NGV station or groundwater aquifiers take effect from 1% h2

Source: GRTgaz

3.2.2.2 ALL IN ALL, THE ISSUE OF STRANDED COSTS IS STILL FAR AWAY

All in all, **for gas infrastructure operators, the questions of the stranded costs induced by the development of green hydrogen and of the potential need of full repurposing of existing assets remain open,** this due to a set of **persisting uncertainties**:

i / Will hydrogen impose itself against biomethane?

ii / If so, will its uses be systemic or mainly "local", in the form of closed loop systems?

iii / Can the CCS eventually achieve a form of commercial viability allowing a broad preservation of existing infrastructures, either directly via the decarbonization of the end uses of natural gas, or indirectly, via new technological combinations allowing the production of renewable synthetic gas with green hydrogen?

These various elements highlight the still distant nature of the asset stranding risk. They also account for the absence at this stage of precise economic scenarios on the impact of the development of hydrogen on existing infrastructures.

The same observation can be made about the infrastructures linked to LNG (liquefaction trains and regasification terminals). In a scenario of green hydrogen fully displacing natural gas at some point in time, these assets would lose all economic value, unless they are subject to a heavy retrofit.

Indeed, this type of retrofit can be envisaged insofar as the maritime transport of hydrogen (see 1.1.2) and that of natural gas roughly follow the same value chain as that of natural gas (see 1.1.2). Hydrogen has to be liquefied so that it can be conveyed by tanker to an import point where it is regasified before being injected into natural gas networks. However, the liquefaction process which transforms hydrogen into ammonia is more technically demanding, more energy-intensive and therefore much more expensive than the one for natural gas[126]. While cooling to -161 °Celsius “suffices” to liquefy the latter, a temperature as low as -253 °Celsius is required to perform the same operation with the former. Although very expensive, this hydrogen shipping process finds applications, especially in Japan which imports part of the product used locally by sea.

Given how apparently similar both value chains are, a retrofit of liquefaction trains and regasification terminals is therefore conceivable in a scenario of hydrogen partly or fully displacing natural gas at some point in the future.

However, even more than for “domestic” gas infrastructures, this question of retrofit is still purely theoretical for the time being. As mentioned in this study's general introductory part, the development of LNG is relatively recent, having really started in 1970s when the technology took off to overcome certain limitations of gas pipeline transport. Most of the LNG liquefaction trains in operation in the world are less than 20 years old and their accelerated development over the past two decades is inseparable from the internationalization of gas exchanges, the development of the molecule's various end uses, its abundance and ultimately its cheapness in a clearly oversupplied market.

The same general observation can be made for regasification terminals, although we note mounting signs of operators/owners of these infrastructures initiating reflection on their future in a low-carbon economy. At European level, sectoral organizations, such as GIE (Gas Infrastructure Europe[127]) which brings together operators of gas infrastructures in Europe, are starting to tackle the issue and have announced the launch of research work to determine the technical and economic conditions for this retrofit[128].

126 For the sake of illustration, it may be relevant to draw a liquifaction cost comparison using energy equivalent terms. Liquefying natural gas requires about one-tenth of the energy contained in the natural gas, whereas liquefying hydrogen requires about one-third of the energy contained in the hydrogen.

127 https://gie.eu/

128 https://www.euractiv.com/section/energy-environment/news/gas-industry-urged-to-accelerate-transition-to-hydrogen/

CONCLUSION:
BROADENING SUSTAINABLE FINANCE'S PERSPECTIVE ON NATURAL GAS

This long journey throughout the gas sector highlights the ambivalent nature of natural gas in contemporary energy and economic systems, as well as the importance of taking into account geographic, temporal and contextual factors in sensing the contribution of the molecule (and more broadly of the sector) to climate change mitigation.

In the absence of a commercially viable CCS, **the molecule, although less carbon intensive than coal and oil, cannot, in its current final energy uses, be considered compatible with the desired end point of the transition energy, that is carbon neutrality by 2050**. In addition, the multiplicity of environmental externalities associated with its extraction and transport (fugitive methane emissions, flaring and venting practices, etc.) reduces its climatic benefits relative to coal and oil.

That said, the use of natural gas, particularly for electricity generation, can prove to be a key element in accompanying or even supporting energy transition policies. Such is the case in Western Europe, where natural gas indirectly helps renewable energies displace coal and/or more or less explicitly displaces coal on its own, as part of the coal exit policies underway. **The growing interest in low-carbon gases** (biomethane and green hydrogen) **offers new perspectives** for the gas sector from the point of view of climate neutrality: **it is no longer the lesser carbon intensity of the molecule relative to other fossil fuels that is valued but rather the total** (as in the case of biomethane) **or partial** (as in the case of green hydrogen) **compatibility of existing gas infrastructures with these emerging gases**. A huge benefit can be drawn from this compatibility. Gas infrastructures are in fact called upon to play a pivotal role in (i) the progressive integration of these gases in contemporary energy and economic systems and in a correlated manner, (ii) the generation of scale effects benefiting both gases' value chains.

This growing interest in low-carbon gases is part of a multiplication of new initiatives in Europe (as evidenced by the EU Taxonomy currently at the finalization stage) to go beyond the simple exit of coal and concretely trend towards the complete decarbonization of the different parts of the economy by 2050. Biomethane and green hydrogen constitute a path envisaged to achieve this objective, in the same way as the electrify-everything approach, which in turn is based on a systematization of the uses of carbon-free electricity to decarbonize all economic sectors, in particular the hard-to-abate sectors such as mobility.

Electrify-everything, biomethane, green hydrogen… These options/industries are emerging at varying paces, each presenting specific advantages as well as constraints. **Their multiplicity and their potentially conflicting character suggest that no pathway has yet been defined for achieving carbon neutrality by 2050. The prospects offered by these options and the uncertainties arising from the multiplication of systemic levers for the decarbonization of the economy must not detract from the climate emergency**: to avoid further depleting the planet's carbon budget and jeopardizing even more any chance of achieving the objectives of the Paris Climate Agreement, the focus right now must be on those sources of carbon emissions that are the most substantial and can be cut most easily. Despite recent changes in Western Europe and North America, the electricity sector still relies massively on those fossil fuels with the biggest carbon emissions, i.e. coal and oil. At world level, these fossil fuels still accounted for 38% and 3% of electricity generation, respectively, in 2018. This means that **displacing coal in this sector in the next 10 years should be a top priority, this alongside the exploration of new avenues potentially enabling the world economy's full decarbonization by 2050.**

These elements suggest that sustainable finance cannot be limited to supporting nascent technologies enabling carbon neutrality to be hoped for by 2050 but also to support sectors already in place likely to provide immediate climate benefits but only to the extent that these sectors do not jeopardize the achievement of more ambitious objectives at a later stage. In other words, in its approach to the world economy's decarbonization and the use that can be made of natural gas, sustainable finance must avoid the pitfalls of complacency and impracticability. In this approach, a place must be made for natural gas in the energy transition, but on the basis of objective and demanding criteria. The gas industry must do more to reduce its environmental externalities which penalize the climate balance of the molecule and (in rare cases) make it uncertain relative to that of coal. In addition, the role of natural gas must be considered against a still uncertain temporality. From this point of view, the potential time for CCS to reach commercial viability is a key element. In the absence of tangible progress on this front by 2025, the "transitional" role of natural gas can hardly be sustained beyond 2030 because of the underlying risk of carbon lock-in.

In this perspective, **sustainable finance must be redeployed to promote the role of natural gas where and when it is justified, but also by supporting the efforts of the entire industry to improve its climate footprint.** The emerging segment of sustainability-linked loans and bonds constitutes a relevant lever to support the gas industry in its own transition and, on this condition, a useful complement to green bonds.

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30, avenue Pierre Mendès France
75013 Paris, France
Tel. : +33 1 58 32 30 00
www.natixis.com

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