



QUANTIFICATION OF SYNERGIES BETWEEN ENERGY EFFICIENCY FIRST
PRINCIPLE AND RENEWABLE ENERGY SYSTEMS

D4.3

Technology data and costs for gas grids in the context of a Smart Energy System



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Executive Summary

The decarbonisation of the gas grids will be an integrated part of the future Smart Energy Systems.

Gas is not just natural gas: it can also be renewable gas, produced from various feedstocks in the forms of biogas, biomethane, hydrogen or synthetic gas. Renewable gas can also be produced from excess electricity generated by variable renewable sources (such as solar and wind).

The existing natural gas transport and distribution infrastructure is well developed and interconnected in Europe. Almost all member states have a natural gas distribution system, although in the Eastern EU countries gas infrastructure is mainly based on gas transit business and not domestic applications.

Gas infrastructure also provides Europe with around 1,500 TWh of cross-seasonal flexibility, mostly thanks to underground storage facilities. In contrast, electricity storage today reaches just 30 TWh.

The European biomethane market has grown significantly in recent years, but has so far only reached a share of around 4% of the gas supply. Its development is limited by the availability of feedstock and agricultural land for its production, and the competition with other fuels. However, biomethane has the advantage that it can be upgraded to gas grid quality and therefore can be injected in existing natural gas infrastructure without requiring changes.

Green hydrogen from renewable sources such as renewable electricity (via electrolysis) or from biomass (via gasification) is currently produced in small volumes that allow blending shares with methane and using existing gas infrastructure for pipeline transport. Currently existing dedicated hydrogen transport infrastructures are industrial clusters in Belgium, North of France and the Netherlands. Some projects have tested the viability of conversion of the pipeline and underground storage from natural gas to hydrogen.

Current investments in large natural gas infrastructure are mainly driven by security of gas supply objectives, wholesale markets' integration and shifts in gas supply.

Some of these investments are questionable as it is expected that the existing gas infrastructure can cope with the future gas demands. However, the need and role for this infrastructure will likely change in the future, because of the need for increased security of supply or increased electrification in the heating sector. In most of the scenarios, the development of the gas networks and related storages will be strongly linked to power-to-gas technologies that can integrate more renewable energy and use the grids as chemical storage.

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Acronyms & Abbreviations

Term	Description
CCUS	Carbon Capture, Utilisation and Storage
DSO	Distribution System Operator
EU	European Union
EU28	The 28 Member States of the European Union
LNG	Liquefied Natural Gas
MSs	Member States
P2G	Power-to-Gas
P2X	Power-to-X
PE	Polyethylene
TSO	Transmission System Operator
WP	Work Package

1 Introduction

The sEEnergies project aims at quantifying the potentials and added benefits of energy savings and energy efficiency by analysing the Energy Efficiency First Principle and identifying energy system synergies with renewable energy for enabling the transition to a decarbonized European energy system. The energy carriers need grids and the energy efficiency potentials of each sector has a major impact in the electricity, gas and thermal grids. There is a potential to redesign the energy system, which requires changes in the grids locally and between countries. The different grids require different approaches to analyse the effects of energy efficiency.

This deliverable D4.3 is associated to task 4.4 “Assessment of role and costs of gas grids and storages” of work package (WP) 4, for which the WP leader is KU Leuven. Aalborg University (AAU) is the lead beneficiary of task 4.4 and responsible for submitting the deliverable. The main objective of this task is to analyse the behaviour and costs of different types of gas grids: natural gas, biogas and hydrogen grids; as well as gas storage solutions. These results will serve as an input for WP6.

The first objective of this report is to present the overall methodology developed for the cost estimates of the existing gas grids and storages in the 28 member states (MSs) of the European Union (EU28).

The second objective is to present the state of play of the gas grids and storages in Europe, in order to understand the diversity of the different gas grids and storages and to present an overview of the key technologies, performance indicators, and costs.

The third objective is to evaluate the impact of renewable technologies on the different types of gas grids and storages in future perspectives.

In Section 2, the framework of this work is presented.

In Section 3, an assessment of the existing gas distribution network types and typologies in the EU28 is conducted, together with a documentation of the current status of European gas interconnections, their capacities and roles, by considering the grid sizes, types and sizes of the gas storage. Different storage options such as salt-caverns, gas grid itself and compressed or liquefied tanks are included. The study also includes the cost assessment of identified sizes and types of networks and storages. Outputs of the assessment are documented in a data sheet.

Section 4 investigates the future role of types of gas, gas grids and storages that will be part of the gas network and market in the future smart energy systems in Europe, by looking into various scenarios and taking into account the uncertainties in different levels.

2 Methodology

2.1 Scope

This report focuses on the transmission, storage and distribution infrastructure of natural gas, biogas and biogas-derived fuels, and hydrogen in EU28. The gathering lines which transport gas from the production site are excluded from the scope of the study, which is illustrated in Figure 1 below.

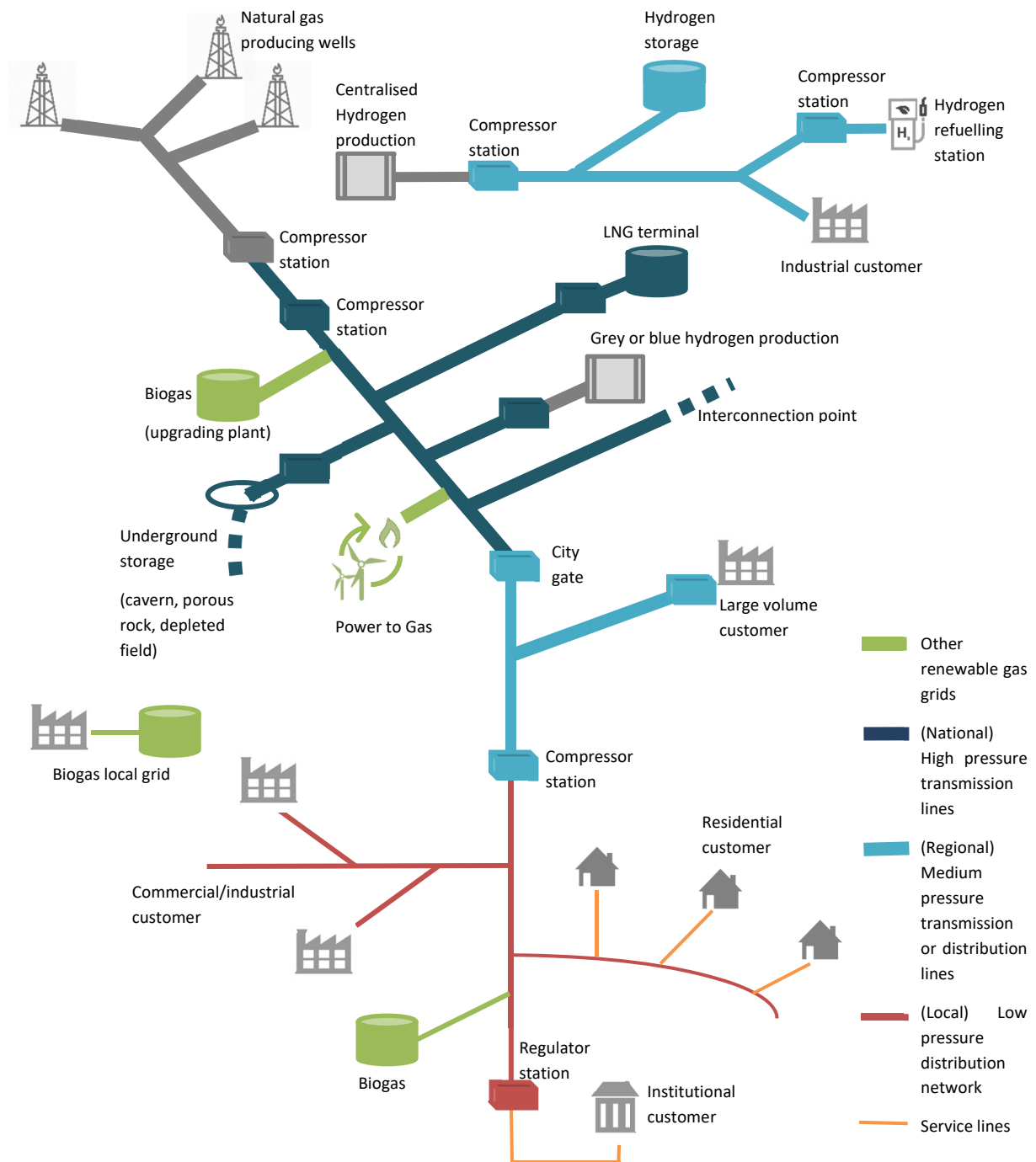


Figure 1. Elements of the infrastructure for natural gas, biogas and biogas-derived fuels, and hydrogen included in the scope of the study (colored) and excluded (grey)

The costs for a grid not only depend on the distance that needs to be bridged, but also on the pressure, flow of the gas, surroundings that need to be crossed and type of gas that needs to be transported. Because of this, it is important to differentiate between the different types of gas (see 0), transmission (high-pressure) and distribution (medium and low-pressure) pipelines (see 2.1.2), and rural and urban areas (see 2.1.4).

In addition, liquefied natural gas (LNG) terminals and the different types of gas storages are included in the scope of this report (see 2.1.3).

2.1.1 Types of gas

Table 1 provides a set of definitions for the different types of gas considered in this study.

Table 1. Types of gas.

Type of gas	Definition	Production process	Main composition
Natural gas	Mixture of gases which are rich in hydrocarbons whose main reserves are deep inside the earth near other solid and liquid hydrocarbons beds like coal and crude oil	Soil extraction through wells and purification	CH ₄
Biogas	Mixture of gases resulting from the biological breakdown of organic material in the absence of oxygen	Anaerobic digestion of biomass	50-80% CH ₄ 20-50% CO ₂
Biomethane	Purified biogas	Upgrading of biogas by removing impurities and carbon dioxide	CH ₄
Syngas	Synthetic methane produced through the hydrogenation of carbon dioxide	Thermal gasification of biomass followed by methanation or separation or Methanation: additional step to electrolysis	CH ₄
Hydrogen	Dihydrogen in gaseous form	Natural gas steam reforming (blue or grey hydrogen) or Electrolysis of water using renewable electricity (green hydrogen)	H ₂

Source: Adapted from (Cătuți, Egenhofer, & Elkerbout, 2019; Danish Energy Agency, 2017)

In Europe, natural gas can be divided into two types depending on its energy content: high-calorific gas (H-gas) and low-calorific gas (L-gas). While both types are composed mostly of methane, H-gas has a higher methane content and therefore a higher energy content. As the L-gas European reserves are nearly exhausted, the concerned EU MSs (the Netherlands, France, Germany and Belgium) are switching from L-gas to H-gas. This leads to updating gas infrastructure by constructing new pipelines and compressor stations and retrofitting end-use appliances. For the sake of simplicity, in this study, no distinction is made between the two types of natural gas infrastructure.

Regarding hydrogen, today's production is mainly either green, blue or grey. Green hydrogen is hydrogen made with renewable electricity via electrolysis. Blue and grey hydrogen is produced mainly from natural gas using steam reforming, which brings together natural gas and heated water in the form of steam. The output is hydrogen and carbon dioxide, with the latter then caught through industrial Carbon Capture, Utilisation and Storage (CCUS) projects in the case of blue hydrogen. Grey hydrogen also refers to any hydrogen created from fossil fuels without capturing the greenhouse gases made in the process, including black and brown hydrogen which is created from respectively black coal or lignite (brown coal) through the process of gasification.

Other hydrogen production technologies exist, such as:

- Turquoise hydrogen: a by-product of methane pyrolysis, which splits methane into hydrogen gas and solid carbon ;
- Pink hydrogen: hydrogen generated through electrolysis powered by nuclear energy ;
- Yellow hydrogen: electrolysed hydrogen made using power of mixed origin;
- White hydrogen: naturally-occurring geological hydrogen found in underground deposits and created through fracking.

As this report focusses on the gas grids and storages, the cost of the different production technologies has not been assessed.

Two types of gases are considered for transport and storage in this study: gas composed mostly of methane (natural gas, biomethane, syngas), and hydrogen (H₂), regardless of the production technology.

2.1.2 Gas grids

The operating pressure is driven by the transportation distance and depends on the material, diameter and thickness of the material of the pipe.

Gas delivery over long distances is done via the high pressure (operating pressure normally between 16-80 bar, up to 200 bar) natural gas transmission system including pipelines, compressor stations, metering and regulating stations, that is capable of transporting gas from producers (or points of transits) to consumers over thousands of kilometres (Guelpa, Bischi, Verda, Chertkov, & Lund, 2019). For this long-haul transmission, gas needs to be compressed multiple times at compressor stations, typically every 120-160 km (Ruan et al., 2009). Compression, distributed over the entire natural gas networks, is needed to maintain pressure within the pipeline sufficiently high to be able to extract gas from the system at the city gates and at the power generators connected to the system at the transmission level. Odorant must be added to the gas at city gates if it is received with insufficient or no odorant to give it its distinctive smell for safety reasons, in order to detect any leaks.

The distribution system consists in medium to low-pressure (usually 5 bar - up to 16 bar - to less than 200 mbar) local gas transport from transmission system to customer meters including distribution pipelines, service lines, and a variety of above ground-facilities such as meter and regulator stations to support the overall system (Marcogaz, 2018a).

Depending on the system boundaries adopted by each company and/or the techniques used (steel, polyethylene (PE)...) the part of the system under 16 bar and above 5 bar can be considered in transmission or distribution. It depends on the ruling of the member state which pressure level is operated by the distribution system operators (DSOs) and which by the Transmission System Operators (TSOs).

It is important to distinguish the main and single lines that are pipes connecting two points in the distribution network, and the service lines that are connections from the distribution network to each consumer's point of connection. It usually includes a valve and a metering device at the connection point.

This report also aims at getting technical and financial data on refurbishment of natural gas grids to hydrogen (injection of hydrogen into the existing gas infrastructure) and new dedicated hydrogen networks. The hydrogen distribution system includes the delivery by pipeline, storage and compressor station. Hydrogen production and fuel dispenser are excluded of the scope of this study.

2.1.3 Gas storages and LNG terminals

Three types of natural gas storages are considered in this study:

- Depleted fields: these are empty natural gas or oil fields and are usually of large volumes.
- Aquifers that have particular morphological characteristics.
- Salt caverns. In order to make them available, salts must be removed by using wells to inject (and afterwards extract) water where salts dissolve.

These are often used to bridge the gap between the demands in different seasons.

Other gasses than natural gas may also be stored underground. That may include hydrogen, but the surface facilities need be designed differently, as hydrogen is much more explosive and also aggressive towards steel structures. If biogas is to be stored underground, it would be instrumental to remove the CO₂ before storage to avoid it to become acidic in contact with water, posing potential problems for the surface facilities. Upgraded biogas having a composition similar to that of natural gas, it can be stored in the same natural gas storages and does not require specific storage facilities.

Liquefied Natural Gas (LNG) terminals also offer additional storage capacity to the natural gas grid through LNG storage tanks, and are therefore included in the scope of the study. In addition, the study considers hydrogen tanks. These are high-pressure steel tanks that can store hydrogen produced by a power-to-hydrogen plant or other facilities before it is used or transported to another location. The size of the storage facility strongly depends on the size of the production plant and utilisation of the hydrogen.

2.1.4 Types of areas

A distribution system is defined as the network of lines that supplies energy to the consumers in a delimited area. Investment and operating costs of gas grids are highly influenced by the energy consumption density of a given area. In a relatively densely populated area with high energy

consumption density the lengths of lines per unit consumption will be shorter, but on the other hand, the unit installation cost per unit length of distribution line is usually also higher due to more difficult burial work, traffic regulation, etc. For a simplification of this approach two different area types have been defined:

- Urban areas: Existing densely populated areas with a high energy consumption density
- Rural areas: Existing sparsely to medium populated areas with low to medium energy consumption density

2.2 Data acquisition

The data on state-of-play of the existing natural gas grids is gathered from the European Network of Transmission System Operators for Gas (ENTSOG), Gas Infrastructure Europe (GIE) and Marcogaz (Technical Association of the European Natural Gas Industry).

The costs data is in general gathered from one well-established source representing a “base-region” i.e. which country the costs are representative for. The sources used are referenced in the tables in Annex 1 - Data sheets. The sources are also used to gather the associated lifetimes of the various technologies. The lifetimes are assumed to be the same across all the countries and the numbers are therefore the same for all the EU28 Member States in Annex 1 - Data sheets.

2.3 Labour indexes and country-specific costs

2.3.1 Country labour index

Difference in labour costs do not only apply to various types of labour costs, but also between the countries. Based on Eurostat data (Eurostat, 2020) it is possible to adjust the share of the total costs associated with installation of the technology (i.e. requiring labour work) according to the labour costs of the given country, when the data costs used for reference are representative from one country.

2.3.2 Investment costs including labour cost differences

A general method to derive costs for all EU28 MSs is based on the principle that all the investigated costs consist of two parts: one part being the component (i.e. physical materials) and one part covering the expenses in relation to the installation until the system is operating normally. After this point, continuous monitoring and maintenance are covered by the operation and maintenance (O&M) costs.

In many cases the cost sources provide the two abovementioned parts (component and installation) separately, i.e. with one part of the cost relating to the materials (the unit), and the other part relating to the labour cost associated to the installation of the unit. The labour cost ratio (i.e. the labour cost share of the total installation cost) is based on the same source as the general cost whenever possible. In cases where this has not been possible, a typical 80/20 relation between the component cost and the labour cost has been used for equipment (i.e. a labour cost ratio of 20%) for the reference, and a 20/80 relation for the pipeline and underground storage costs as their installation requires a lot of labour work. The formula Equation 1 below is used to derive the total investment cost for a given country “X”:

$$C_X = C_{ref} * r_{labour} * I_{country,labour} + C_{ref} * (1 - r_{labour})$$

Equation 1. Total investment cost for a given country X

where

- C_x is the total cost of the unit in question in country “X”
- C_{ref} is the (total) cost of the unit in question from the identified reference
- r_{labour} is the ratio between the share of the total costs related to labour costs and the total cost of the unit (i.e. between 0 and 1)
- $I_{country,labour}$ is an index number representing the ratio between the labour costs of country “X” and the labour costs in the country representing the reference cost (i.e. between 0 and 1)

2.3.3 Operation and maintenance (O&M)

The O&M costs are defined as a percentage of the investment cost and are not depending on the operating hours or supply of energy. This means that the differences in investment costs between the countries are also reflected in the O&M costs – corresponding to the assumption that the ratio between labour related and non-labour related costs are the same for investment costs and O&M costs, respectively.

Variable O&M costs are included at a later stage in the modelling (WP6 for which the results in this report are to be used). However, the variable O&M is in most cases very low for transmission and distribution systems and it is mainly constituted by auxiliary consumption.

2.4 Reviewing outputs

A European survey including the selected data has been sent to all the TSOs, the main DSOs, hydrogen grids operators, National and European gas, biogas and hydrogen associations in order to receive their feedback on the numbers within their field of expertise.

However, the response rate to this survey has been very low. Only seven responses have been received, over more than 200 organisations contacted. In addition, only two stakeholders shared financial data, but not at the expected level of detail.

This raises questions for a sector where data transparency should be the law. One can wonder about the ability of the public authorities to make informed choices in terms of investments without being able to rely on the sharing of financial data on the part of the operators. However, the particular context of this year 2020 impacted by the COVID19 pandemic, which subjects energy operators to exceptional situations, may explain the limited availability of operators to respond to such a survey.

To compensate for this, several sources are used to compare the various investment costs, lifetimes and O&M costs e.g. on a global level. These are used to check the variations between the different sources. As this provides the option of double-checking the background for any significant deviations observed when comparing different sources, this creates a more solid reliability of the chosen final data source.

2.5 Future perspectives for gas grids

Depending on the decarbonisation pathways for gas, the way that we use gas networks in the future may be changed. The analysis of the future role of gas grid and type of gases that will be part of the gas network and market in this study is based on literature review. Reports, documents and papers used can be found under References at the end of the report.

3 Assessment of the role and costs of the existing gas grids and storages in Europe

The results of the cost estimates and technical data can be found in Annex 1 – Technology data and costs for gas grids tables and exist in an Excel file representing the “technology and cost database” for gas grids and storages. This database will be used as an input for the development of sEnergies scenarios in WP6. The sections below discuss the role of the different types and typologies of the existing gas grids and storages in Europe.

3.1 Natural gas system

Natural gas represented in 2018 around 21% of the EU28's overall energy consumption (European Commission, 2020). Figure 2 shows that the European natural gas grid is well developed and interconnected. The network covers most of the EU MSs, except for Cyprus and Malta, which only have a LNG terminal, and the northern parts of Northern countries (Finland and Sweden), which do not have a sufficient gas demand to develop gas grids.



Figure 2. Map of the European natural gas network (ENTSOG, 2019)

However, the use of natural gas infrastructure varies across EU MSs. While the Western EU countries rely on their gas transport and distribution infrastructure for domestic applications, Eastern EU countries gas infrastructure is strongly based on gas transit business (van Nuffel, 2018).

Current investments in large natural gas infrastructure are mainly driven by security of gas supply objectives, wholesale markets' integration and shifts in gas supply (decreasing domestic gas production, conversion of L-gas to H-gas, shift from pipeline gas to LNG) (van Nuffel, 2018). The main investments are listed as projects of common interest (PCIs) by the European Commission. In April 2020, the Commission published the technical document for the 4th PCI list (The European Parliament and the Council of the European Union, 2020), which provides a technical description of all its 32 gas projects, including five LNG import terminals, five gas storage sites and significant pipeline projects such as the Interconnector Greece-Bulgaria, the TAP gas pipeline from Greece to Italy and the EastMed gas pipeline to link Israel and Cyprus to Greece.

3.1.1 Cross-border interconnection points

As of 2019 there are 54 cross-border interconnection points between the EU28 MSs. They are listed in Table 2.

Table 2. Existing natural gas cross-border interconnection points within EU28 (export)

Point		Connected countries	Technical capacity (GWh/d)
1	Zeebrugge	UK – BE	651.7
		BE – UK	803.4
2	Zelzate	BE – NL	271.0
			407.0
		NL – BE	122.0
3	Zandvliet	NL – BE	47.0
4	Hilvarenbeek	NL – BE	642.0
5	(VIP)* Gravenvoeren	NL – BE	340.8
6	Eynatten 1 & 2 // Lichtenbusch / Raeren	DE – BE	132.2
		BE – DE	129.5
		DE – BE	268.3
		BE – DE	160.0
8	Remich	DE – LU	38.4
10	Blaregnies	BE – FR	230.0
11	Bocholtz	NL – DE	400.9
12	Zevenaer	NL – DE	327.6

13	Winterswijk	NL – DE	178.6
14	Vlieghuis	NL – DE	72.0
15	Epe / Enschede <i>(Interconnection points between German storages and Netherlands TSO. The capacities indicated do not allow to enter the German transmission system)</i>	DE – NL NL – DE	314.3 168.7
16	Bunde / Oude Statenzijl <i>(Interconnection points between German storages and Netherlands TSO. The capacities indicated do not allow to enter the German transmission system)</i>	DE – NL NL – DE DE – NL NL – DE	503.2 386.6 429.8 305.3
18	Bacton	UK – UK	651.7
19	Moffat	UK – IE	476.2
21	Oberkappel	AT – DE DE – AT	159.9 199.4
22	Obergailbach / Medelsheim	DE – FR	605.7
23	Überackern	AT – DE DE – AT	174.6 114.0
25	Murfeld / Ceršak	AT – SI	112.5
26	Tarvisio / Arnoldstein	AT – IT IT – AT	1,148.8 193.3
29	Gorizia / Šempeter	IT – SI SI – IT	28.3 21.4
30	Rogatec	HR – SI SI – HR	7.7 53.7
36	Ellund	DE – DK DK – DE	166.5 91.0
38	Mallnow	DE – PL PL – DE	184.8 931.5
40	Brandov / Stegal Olbernhau / Hora Svaté Kateřiny	CZ – DE DE – CZ	0 287.7
41	Hora Svaté Kateřiny / Deutschneudorf	CZ – DE DE – CZ	14.9 95.0
42	Brandov	DE – CZ	951.9

43	Waldhaus	CZ – DE	906.9
44	Cieszyn / Český Těšín	CZ – PL	28.0
45	Lanžhot	CZ – SK	913.7
		SK – CZ	400.4
46	Baumgarten	AT – SK	246.5
		SK – AT	1570.4
47	Mosonmagyaróvár	AT – HU	153.1
53	Negru Voda I, II & III	RO – BG	728.9
54	Karksi	LV – EE	63.0
55	Kiemenai	LT – LV	67.6
		LV – LT	65.1
57	Csanadpalota	HU – RO	52.1
		RO – HU	2.5
58	Dravaszerdahely	HU – HR	78.3
59	Dolní Bojanovice	SK – CZ	74.3
		CZ – SK	95.6
60	Láb	AT – SK	138.3
		SK – AT	138.3
61	Haiming	DE – AT	43.3
		AT – DE	6.3
62	Haidach	DE – AT	267.8
		AT – DE	299.9
63	Haanrade	NL – DE	1.9
67	(VIP)* IBERICO	ES – PT	144.0
		PT – ES	80.0
69	(VIP)* Kiefersfelden-Pfronten	DE – AT	23.0
70	Tegelen	NL – DE	4.7
74	Jemgum / Oude Statenzijl	NL – DE	277.6
		DE – NL	386.2
75	Balassagyarmat / Velké Zlievce	SK – HU	127.0
76	(VIP)* PIRINEOS	ES – FR	224.4
		FR – ES	165.0

78	RC Lindau	DE – AT	25.4
82	(VIP)* GCP GAZ-SYSTEM/ONTRAS	DE – PL	48.7
		PL – DE	0.1
83	Ruse / Giurgiu	BG – RO	7.9
		RO – BG	1.6
84	(VIP)* Brandov-GASPOOL	CZ – DE	183.4
		DE – CZ	72.2
86	(VIP)* VIRTUALYS	BE – FR	620.0
		FR – BE	270.0

* Virtual interconnection points (VIP) consist of two or more interconnection points which are integrated together to provide a single capacity service.

Source: (ENTSOG, 2019)

As shown in Figure 3, the transmission capacities for gas in Europe are much higher than transmission electricity capacities, therefore allowing to bridge the distance between (renewable) energy sources that can produce biomethane and syngas which can be transported in existing gas networks to demand regions

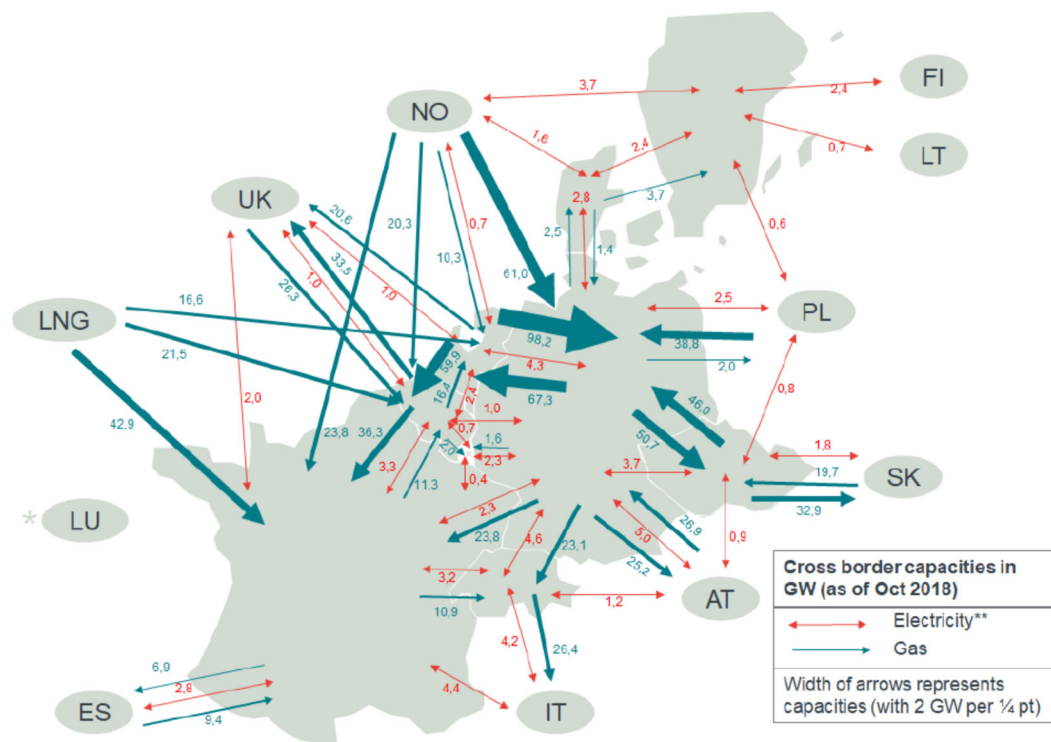


Figure 3. Cross-border transport capacities for gas and electricity in some European countries (Frontier Economics & RWTH Aachen University, 2019)

3.1.2 LNG terminals

This report considers LNG import terminals in Europe, where the natural gas is restored to its gaseous form, in which it can be transmitted through pipelines for consumption by end customers or stored in underground tanks.

Table 3 summarises the technical characteristics of existing LNG terminals in EU28.

Table 3. LNG terminals in Europe

Country	Number of LNG terminals	Regasification capacity (bcm/y)	LNG storage capacity (m ³)
Belgium	1	9.00	386,000
Finland	2	0.50	78,500
France	4	34.25	1,370,000
Greece	1	7.00	225,000
Italy	3	14.78	487,500
Lithuania	1	4.00	170,000
Malta	1	0.70	125,000
Netherlands	1	12.00	540,000
Poland	1	5.00	320,000
Portugal	1	7.60	390,000
Spain	7	68.90	3,616,500
Sweden	2	0.60	50,000
United Kingdom	4	48.30	2,100,000
TOTAL	29	212.63	9,858,500

Source: (GIE, 2019)

There are currently 29 LNG terminals (amongst which 6 are small-scale LNG terminals) operating in Europe with a total send-out capacity of around 212 bcm/y, which is sufficient to cover approximately half of EU28's gas demand, and further capacity is being developed.

LNG currently plays a role in enhancing security and diversification of both sources and routes of supply in Europe, since LNG makes gas reserves around the world accessible to the European market. In addition, LNG offers around 100 TWh additional storage capacity to the grid, thus additional flexibility to the system. However, the additional capacity under development is questionable considering the expected decrease in gas demand.

3.1.3 Transmission grid

The transmission lines are made of large diameter steel pipes operating under high-pressure above 16 bar. Table 4 below summarises the total length of natural gas transmission networks in EU28. Cyprus and Malta are not mentioned as they do not have any gas transport network.

Table 4. Total length of natural gas transmission networks in Europe.

Country Code	Country	Transmission network length (km)
AT	Austria	3,007
BE	Belgium	4,057
BG	Bulgaria	1,835
CZ	Czechia	3,810
DE	Germany	62,500
DK	Denmark	831
EE	Estonia	885
EL	Greece	1,819
ES	Spain	12,987
FI	Finland	1,318
FR	France	37,246
HR	Croatia	2,034
HU	Hungary	5,782
IE	Ireland	2,417
IT	Italy	34,415
LT	Lithuania	2,113
LU	Luxembourg	1,962
LV	Latvia	1,193
NL	Netherlands	11,896
PL	Poland	10,077
PT	Portugal	1,298
RO	Romania	13,110
SE	Sweden	600
SI	Slovenia	1,094

SK	Slovakia	8,533
UK	United Kingdom	7,648
TOTAL		234,467

Source: (Marcogaz, 2018b)

The main cost components for transmission grids are the pipeline and the compressor.

Assumptions on transport costs for transmission pipeline transport vary between 0.05 million EUR/bcma/km and 0.18 million EUR/bcma/km because a labour cost ratio of 75% is assumed and there is a large variation in labour index from MS to MS.

To control pressure drops and ensure that natural gas flowing through pipelines remains pressurised, compression of natural gas occurs periodically along the pipeline. This is accomplished by compressor stations. The investment costs of a compression station are estimated around 2 million EUR/MW of installed compression power.

3.1.4 Distribution grid

Table 5 summarises the main characteristics of natural distribution networks in EU28 (Marcogaz, 2018a).

Table 5. Characteristics of natural gas distribution networks in Europe.

Country Code	Country	Distribution network total length (km)	PE (km)	Steel (km)	Cast iron (km)	PVC (km)	Other (km)	Nb of connected consumers
AT	Austria	43,400	28,683	11,423	2	1,814	1,478	1,349,000
BE	Belgium	71,609	52,561	16,971	430		1,647	3,156,000
BG	Bulgaria	249	128	97	6	13	4	74,000
CZ	Czechia	73,181	42,445	30,736				2,849,000
DE	Germany	498,500	254,235	218,343	11,964	13,958		20,979,000
DK	Denmark	18,229	15,677	2,552				421,117
EE	Estonia	2,150	1,104	842	54	116	35	52,000
EL	Greece	6,087	4,663	1,281	136			325,000
ES	Spain	70,307	59,761	9,281	1,266			7,756,000
FI	Finland	1,911	1,808	83	20			31,000
FR	France	203,092	143,003	53,157	5,681		1,251	11,268,000
HR	Croatia	18,386	9,439	7,197	458	996	296	647,000
HU	Hungary	84,000	43,124	32,879	2,094	4,548	1,354	
IE	Ireland	11,339	11,226	113				661,000
IT	Italy	257,844	72,067	181,690	2,897		1,190	23,203,000

LT	Lithuania	8,300	4,261	3,249	207	449	134	562,000
LU	Luxembourg	1,962	1,007	768	49	106	32	86,000
LV	Latvia	5,500	2,824	2,153	137	298	89	443,000
NL	Netherlands	125,000	21,250	18,750	3,750	78,750	2,500	7,152,000
PL	Poland	170,900	68,360	102,540				6,852,000
PT	Portugal	17,450	15,339	2,094	17			1,382,000
RO	Romania	17,218	8,958	8,260				1,408,170
SE	Sweden	2,720	1,396	1,065	68	147	44	37,000
SI	Slovenia	4,342	2,229	1,700	108	235	70	136,000
SK	Slovakia	33,301	14,519	18,782				1,506,000
UK	United Kingdom	126,335	81,657	7,242	17,362		20,074	23,184,315
TOTAL		1,873,312	961,724	733,248	46,706	101,430	30,198	115,319,602

Source: (Marcogaz, 2018a)

As shown in Table 5, the distribution grid in EU28 mostly consists of polyethylene (PE) pipelines.

Similar to transmission lines, assumptions on transport cost for distribution pipeline transport significantly vary from country to country as a labour cost ratio of 80% is assumed. Investment costs for the main distribution single lines vary between 0.41 EUR/MW/m to 11.00 EUR/MW/m depending on the country and the capacity ranges.

Regarding local distribution single lines, the investment cost also varies depending on the type of area, from 15 EUR/m in a rural area in Bulgaria to 104 EUR/m in an urban area in Denmark. Data sheet in Annex 1 - Data sheets also provides cost estimates for service lines, varying between 492 EUR/unit and 15,000 EUR/unit.

Assumptions on distribution network costs are also provided in the data sheet in Annex 1 - Data sheets, varying from 3 EUR/MWh/y and 140 EUR/MWh/y. These distribution network costs represent the cost to establish distribution networks considering the influence of varying energy consumption density in different area types. These costs depend on the installed capacity, which with a typical load profile corresponds to a yearly energy demand.

3.1.5 Natural gas storages

Gas storage has various advantages. It is usually built as a security reservoir. It represents a surplus of gas that can be used in case of supply problems, such as upstream or downstream failures. It allows balancing the demand evolution, i.e. the difference in consumption over the seasons. Concerning long-term storage, natural gas stored in the gaseous phase is considered the most economical way to store it. The most widespread type of gas storage is the depleted caverns.

Table 6 below summarises the existing underground storage facilities in EU28. Storage capacity in the EU28 is unevenly distributed with large facilities in Italy, France, Germany and the Netherlands. These four countries alone hold more than 60% of the EU storage capacity. For geological reasons, East and

South-East Europe can only use small storage capacities to ensure a continuous gas supply. When well connected by pipelines MSs can benefit from stored gas in neighbouring countries.

Table 6. Natural gas underground storage facilities in EU28

Country Code	Country	Technical Working gas volume (TWh)		
		Depleted field	Salt cavern	Aquifer
AT	Austria	92.22		
BE	Belgium			9
BG	Bulgaria	17.69		
CZ	Czechia	13.87		
DE	Germany	90.15	152.06	4.33
DK	Denmark			10.35
EL	Greece	3.86		
ES	Spain	29.69		2.29
FR	France		16.3	120.91
HR	Croatia	6.41		
HU	Hungary	67.51		
IT	Italy	268.54		
LV	Latvia			24.15
NL	Netherlands	126.93	3.86	
PL	Poland	29.33	17.19	
PT	Portugal		3.57	
RO	Romania	46.13		
SK	Slovakia	39.19		
UK	United Kingdom	4,22	56.16	
TOTAL		835,74	249.14	171,03

Source: (GIE, 2018)

“Line pack” is the ability of any gas grid to store gas through changes of the pressure in the pipe. Every pipe of a TSO or DSO has a maximum pressure, under which it may be operated. The usage of the line pack depends very much on customers connected to the grid and – at least for the DSO – on the

pressure at the connection point. To optimise the volume the TSO and DSO can work together. E.g. in summer some of the pipelines are operated at lower pressure levels as the throughput is lower and therefore a lower pressure is sufficient (CEDEC, Eurogas, & GEODE, 2018).

Gas infrastructure provides Europe with around 1,500 TWh of cross-seasonal flexibility corresponding roughly to the total installed electricity capacity in Europe (CEDEC et al., 2018). Underground storage provides 1,255 TWh (around one third of total annual gas demand). The distribution grid and LNG terminals provide 300 TWh of additional flexibility. In contrast, electricity storage today reaches just 30 TWh (Hydrogen Europe, 2019).

3.1.6 Energy balance

The gas system can provide very high power capacity compared to most other energy carriers, which is required by some parts of the industry. The energy loss is very low compared to other energy distribution and transport systems. The network is supplied with natural gas at a high pressure, however further compression is required to maintain the high pressure in the transmission lines over long distances, and it can be required in the main distribution lines or in the distribution system, which requires electricity consumption.

Reduction of the pressure in the system necessitates preheating, as the gas is cooled by the expansion. The heat is provided by burning an amount of gas corresponding to around 0.10% of expanded gas. However, as there are different pressure levels in different parts of the network, preheating is not always required (Energinet & Danish Energy Agency, 2017).

In average, the energy losses have been estimated to 0.10% in the main lines and 0.26% in local single lines.

3.2 Biogas, biomethane and syngas system

Biogas is produced by anaerobic digestion of biodegradable material. It consists mainly of 50-80 % methane and 20-50 % CO₂. In addition, biogas contains low concentrations of undesirable substances, e.g. impurities, such as hydrogen sulfide, siloxanes, ammonia, oxygen and volatile organic carbons (Danish Energy Agency, 2017). Biogas can be used for the same purposes as natural gas, including heating, electricity generation and, after being upgraded, as a fuel for vehicles. Only purified and upgraded biogases may be injected into the natural gas networks on the basis of operators' technical specifications. This is to avoid different possible risks such as risk for the transmission network because of corrosive compounds, risk for the storage facilities through contamination by bacteria for instance, and Interoperability risk since a gas quality outside the specifications applied for the network may lead to cross-border flows limitations.

Biomethane is biogas that is upgraded to gas grid quality for grid injection. A large number of technologies are available for upgrading, but five technologies stand out as the clearly most common technologies (Danish Energy Agency, 2017):

- Water scrubber
- Chemical scrubber (amine scrubber)
- Membrane scrubber
- PSA (Pressure Swing Absorption) scrubber
- Organic physical scrubbing

Most of the biogas throughout Europe is produced in the North-western part of it, with Germany being a clear champion (about half of the EU28 production volume). Due to technical and cost issues, only a limited share of the biogas is upgraded such that it can enter the grid as biomethane: so far, some 11% only. The rest of the biogas is used for the production of heat and power (Jepma, van Leeuwen, & Hulshof, 2017).

Whereas growth in the biogas market has levelled out slightly in recent years, the biomethane market continues to develop at an impressive rate, with 13% increase in new installations over the course of 2018. By the end of 2018, there were 610 active biomethane-producing plants in Europe, of which as many as 70 were new plants. A total of 22,787 GWh of biomethane or 2.28 bcm was produced in 2018 (GIE & EBA, 2020).

Syngas, or synthetic gas, is methane that can be produced from several sources or processes. Renewable syngas can be produced through gasification of biomass or methanation of carbon with hydrogen that has been produced via electrolysis (power-to-gas).

So far, the greening of the gas system, based on biogas and biomethane, has proceeded to a share of about 4% (Jepma et al., 2017).

3.3 Hydrogen system

As described in Section 2.1.1, there are various hydrogen production technologies. Today, hydrogen is mainly produced from fossil fuels (grey and blue hydrogen) (Fuel Cells and Hydrogen Joint Undertaking, 2019). (Green) Hydrogen can be produced from renewable sources such as renewable electricity (via electrolysis) or from biomass (gasification). However, within the EU28, the currently operating 300 electrolyses produce less than 4% of total hydrogen production (Fuel Cells and Hydrogen Joint Undertaking, 2019).

Pipeline transport of hydrogen can either take the form of blending shares of hydrogen with methane and using existing gas infrastructure, or can be dedicated hydrogen transport. Hydrogen can also be methanised, using carbon from the air or from biogas plants, and can then be transported through existing natural gas infrastructure.

3.3.1 Injection of hydrogen in existing natural gas grid

Hydrogen and natural gas have distinctly different characteristics (calorific value, flow properties, density, flame speed, flame combustion properties, heat characteristics and interaction with the grid). Blending hydrogen to the natural gas stream slightly changes these characteristics. This impacts the downstream facilities and end-users' appliances that need to be compatible with a blend which, furthermore, might be variable in composition.

The permitted concentration of hydrogen in the gas grid varies significantly between MSs (between 0 Vol. % up to 12 Vol. %) and in many EU-countries the hydrogen injection into the gas network is generally not allowed yet. No European standard defining rules for admissible concentration of hydrogen in the natural gas network, this leads to a fragmentation of the gas market and may create problems at cross-border connection points (Hydrogen Europe, 2019).

3.3.2 Hydrogen grids

There are currently 1609 km of pure hydrogen pipelines in Europe (Pacific Northwest National Laboratory, 2016), operating at higher pressure than natural gas networks as hydrogen is a lighter gas.

These dedicated hydrogen transport infrastructures correspond to industrial clusters, and are part of the largest non-natural gas pipeline system in the world which has a length of more than 2,700 km which covers Belgium, the Netherlands and France, of which 964 km is dedicated to hydrogen (Thomas, Mertens, M.Meeus, Van der Laak, & Francois, 2016). This pipeline is currently being used to distribute the hydrogen, oxygen, nitrogen and carbon monoxide produced and sold by Air Liquide to industrial consumers.

Table 7. Total length of existing pure hydrogen pipelines in EU28 summarises the length of the existing pure hydrogen pipelines in EU28.

Table 7. Total length of existing pure hydrogen pipelines in EU28

Country Code	Country	Hydrogen pipelines length (km)
BE	Belgium	613
FR	France	303
DE	Germany	390
IT	Italy	8
NL	Netherlands	237
SE	Sweden	18
UK	United Kingdom	40
TOTAL		1609

Source: (Pacific Northwest National Laboratory, 2016)

3.3.3 Hydrogen storages

Long-term seasonal storage of hydrogen in underground storages is technically feasible, however salt caverns are considered to be more suitable in porous structures.

The technology of storing hydrogen in salt caverns is very similar to the storing of natural gas in these reservoirs. The energy density of hydrogen is however roughly three times lower than that of natural gas, which means that less hydrogen can be stored in the same volume, making hydrogen storage more expensive than the storage of natural gas.

Only a few caverns for hydrogen storage exist currently (Danish Energy Agency, 2018). The first hydrogen cavern was constructed on Teesside in the United Kingdom in 1971–72 and is still in operation, with a storage capacity of 210,000 m³ (Caglayan et al., 2020). However, it is still the only underground hydrogen storage in Europe.

4 Future role of gas grids, storages and types of gas

The future of gas grids is unclear. The decarbonisation and utilisation of the existing gas grids is the preferable option by grid operators as of large investments that are or almost are paid off. Countries that have built up their entire energy system around gas infrastructure such as United Kingdom and Netherlands may be tempted to support such agenda. Studies have shown the potential of using gas grid as a contributor to decarbonisation in the transition period (Navigant, 2019).

Most projections indicate a sustained decline of gas consumption in the EU. The only studies that project a slightly increased or constant demand for gas usually start from the assumption of a large-scale replacement of coal with gas plants and significant innovations in the gas sector. What is clear is that the share of natural gas will drastically decrease, as the make-up of the gas sector will become more complex with the usage of multiple 'gaseous fuels' (i.e. natural gas, biomethane, biogas, syngas, hydrogen) (Cătuți et al., 2019).

The gas system has a number of advantages. It can be supplied with gases from various sources, including green gases, such as upgraded biogas and gases from power-to-gas processes, as long as the gas meets the natural gas specifications. It provides a large storage capacity. These properties may allow integration of large amounts of renewable energy in the energy system.

The gas system has in general reached a high level of security of gas supply and market integration, and future investments would hence mainly focus on maintenance and safety (replacement of ageing assets), refurbishment to accommodate renewable gas, and projects to enhance the adequacy and operational reliability of the energy system (van Nuffel, 2018).

In the perspective of a decarbonised energy system, it is concerning to believe that we can continue with full utilisation of the existing natural gas use as the potential for producing green gases is not necessarily capable of fulfilling the demands.

The following sections describe the different options for the future role of gas grids and storages in a European smart energy system perspective, with a focus on the role of Power-to-Gas.

4.1 Role of Power-to-Gas in the perspective of a Smart Energy System

4.1.1 Smart Energy System principle

Integration of different energy infrastructures (heat, electricity and gas vectors) offers great potential for better managing energy sources, reducing consumption and waste as well as enabling a higher share of renewables, lower environmental impact and lower costs, Smart energy systems represent a framework where various energy vectors interact with each other at various levels, as illustrated in Figure 4.

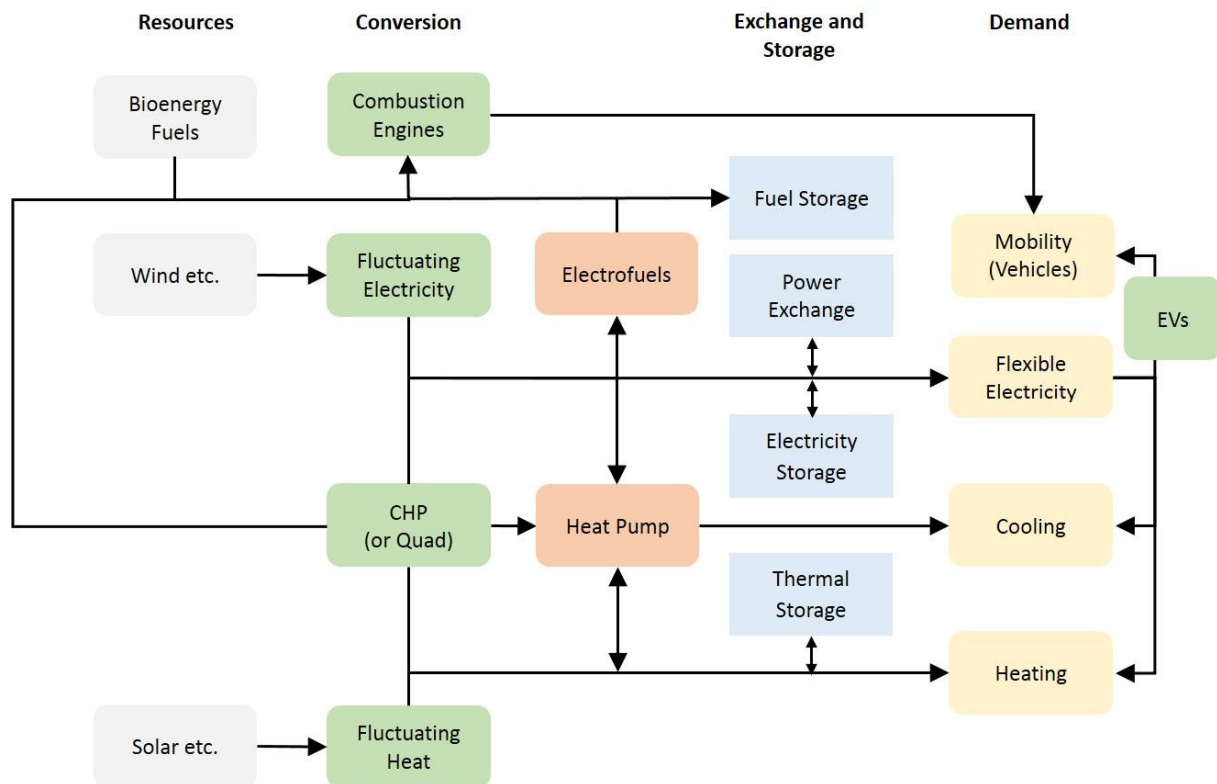


Figure 4. Smart Energy System (Department of Planning, n.d.)

In such a system, smart gas grids is a crucial technology that connects the electricity, heating and transport sector. This enables gas storage to be utilised for creating additional flexibility. In addition, if the gas is refined to a liquid fuel, then liquid fuel storages can also be utilised.

4.1.2 Power-to-Gas technology

One important energy sector link is the one between electricity and gas (Power-to-gas or P2G) or more generally between electricity and chemical fuels (P2X). Such interplay will provide huge energy storage capacity - including seasonal energy storage – and at the same time secure supply of renewable, CO₂-neutral fuels for the transport sector (e.g. heavy trucks, marine transport and aviation).

Power to gas (P2G) is a technology that converts electrical energy to chemical energy thus storing the energy as fuels. P2G is based on electrolysis technologies that utilise electricity to split water/steam into hydrogen and oxygen. The produced hydrogen can in a second step be transformed into CH₄ using CO₂ from the air or from biogas plants. Figure 5 gives an overview of a P2G plant.

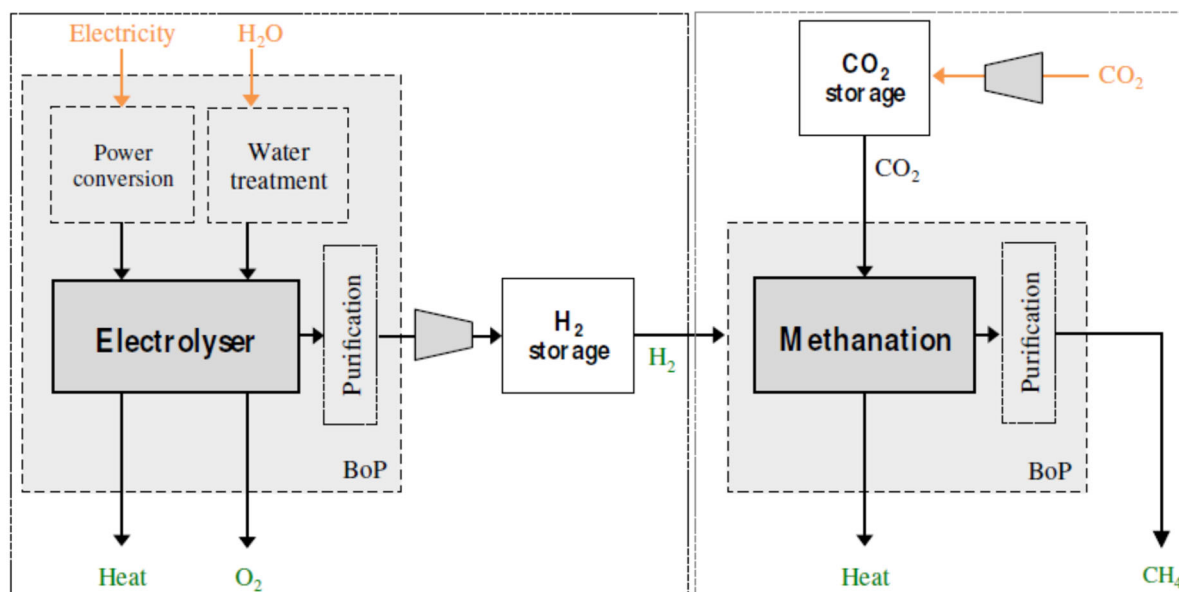


Figure 5. Overview of a P2G plant (Leeuwen & Zauner, 2018)

Among the electrolysis products, hydrogen can be stored locally and reconverted into electric energy when needed, used directly for transport or industry, or injected into the natural gas grid up to a small percentage of the total volumetric composition, e.g. 0-12 vol% depending on the country specific regulation.

Hydrogen can also be used to upgrade biogas (biogas hydrogenation) or to convert CO₂ from the air into methane (methanation). The produced synthetic methane may then be fed into the natural gas grid.

Optimal P2G technology will depend on electrolysis costs and efficiency, the size and transient management of the full chain including methanation, as well as the need for temporary hydrogen storage which is also costly (Guelpe et al., 2019; Voropai, Senderov, & Edelev, 2012).

4.2 Future role of type of gas

The future role of gas depends on three main parameters: the future gas end-uses and demands, the development and scale-up of carbon capture and storage versus an additional increase of wind and solar capacity combined with high energy efficiency improvements, and the production potentials and costs of the different gaseous fuels.

The scenarios that would be developed in WP6 will determine the first two parameters, thus the following sections highlight the potential volumes of renewable methane and hydrogen and their associated costs.

However, it is to be noted here that regarding future gas end-uses and demands, the case of utilising any gas in the heating sector for individual gas boilers has been analysed before for Europe. Results demonstrated that solutions in the form of district heating and individual electric heat pumps present better alternatives due to their potential to reduce energy system costs and biomass consumption, improve sector coupling and allow for the utilisation of new heat sources (Korberg, Skov, & Mathiesen, 2020).

4.2.1 Biogas and derived gas

As explained in section 3.2, biogas and biomethane are the most commercially ready forms of renewable gas. However, biogas conversion to biomethane and injection into the gas grid is still very limited and not yet common practice in all the EU countries (van Nuffel, 2018).

Biogas and biomethane as an intermediate or end-fuel is a potential carbon-neutral solution feasible for all energy sectors, but it is also a solution that needs to compete with other fuels and technologies and is a limited resource.

As a result of the limitations associated with the availability of feedstock and agricultural land for the future production levels of biogas and biomethane, it has not been viewed as a solution for decarbonising the entire gas sector and its use has so far been mostly in rural areas (Cătuți et al., 2019). However, many sources can be used to produce biogas and biomethane: manure, sewage and waste (whether agricultural or municipal). Europe produces millions of tonnes of waste that can be turned into biogas, contributing to the circular economy. Also, new sources of biogas are being developed, such as algae-sourced biogas.

Cost reductions in biomethane production are still possible, as (Navigant, 2019) estimates that by 2050, prices will decrease from 70-90 EUR/MWh to 57 EUR/MWh for anaerobic digestion technologies and from 88 EUR/MWh to 47 EUR/MWh for thermal gasification technologies (Cătuți et al., 2019).

4.2.2 Hydrogen

Production of carbon-neutral hydrogen and transport via the gas grid are in the study and demonstration/pilot phase (van Nuffel, 2018).

Based on its type, the total production potential is influenced by assumptions on technology costs, i.e. learning curves, prices and availability of renewable electricity (in the case of green hydrogen) and natural gas as well as availability of CCUS (in the case of blue hydrogen). The cost of production for blue hydrogen is forecast to be about 36-63 EUR/MWh in 2050 (Cătuți et al., 2019). Depending on the source of renewable energy (wind or solar) and on geographical location, the cost of green hydrogen is projected to be around 44-61 EUR/MWh in 2050 (Cătuți et al., 2019). It should be noted that these cost estimations rely on the availability and access to cheap renewable electricity, which would be required from both dedicated capacity and surplus. The cost estimations for green hydrogen are also based on significant advancements of an electrolyser technology that is currently only used in niche applications and therefore has a high cost-reduction potential, especially in terms of capital costs.

Finally, the projected potential production and costs of syngas obtained through P2G has projected production costs for 2050 of around 74 EUR/MWh, if it is produced using CO₂ captured when upgrading biogas to biomethane. Using CO₂ from other sources would likely imply significantly higher production costs (Cătuți et al., 2019).

4.3 Future role of gas grids and storages

The assessment of the future role of gas grids and storages could be considered in relation to which energy carrier become prevalent in future energy system: electricity; electricity and carbon-neutral methane either as synthetic methane or biomethane; or (green) hydrogen.

The following sections present general considerations to be taken into account in these different options.

4.3.1 Gas grids

Different decarbonisation options such as gas switching to biomethane or hydrogen will vary across regions. Therefore, the future gas grid will need to be capable of accepting either biomethane or hydrogen, or a mixture of both, which may require anything from marginal adjustments to complete replacements. The most straightforward transition based on existing infrastructure would be to biomethane or syngas, which does not require any major technical upgrades to the network. However, projections show that insufficient quantities of renewable methane will be produced to maintain current grid capacity (Cătuți et al., 2019).

Regarding hydrogen, there are limits to the extent hydrogen can be safely blended with methane in the pipeline. Current research shows that blending hydrogen in relatively small concentrations of up to 10-20% can be done safely without major infrastructural upgrades (Cătuți et al., 2019).

As the share of hydrogen in the system increases, the possible conversion of existing gas infrastructure to dedicated hydrogen infrastructure will have to be assessed, with different adaptations and issues to tackle for each of its component, including:

1. Gas grids: Pipeline composition (e.g.: polyethylene vs. steel), compressors, safety and admixture levels, including pipelines which are no longer needed to transport natural gas which might very well be adjusted to transport 100% hydrogen. Many studies show that natural gas grids would be fit for hydrogen transport in some countries. However, in that case, the cost to transport hydrogen would be higher than natural gas because the hydrogen energy density is much lower (factor 3).
2. Storage facilities: Existing underground storage facilities have to be adapted if natural gas/hydrogen admixtures or pure hydrogen are to be stored.
3. End-use: Issues linked to changes of gas characteristics, which might require adapting appliances to meet different needs in different sectors (industry, transport, buildings).

Any such transition would generate significant additional costs and may prove more cost-efficient for hydrogen applications on a local or regional basis.

The viability of such a conversion of the pipeline from natural gas to hydrogen has been tested through projects such as the Gasunie hydrogen pipeline from Dow to Yara and the H21 Leeds City Gate pilot project in the UK.

The potential need for transport technologies for hydrogen will depend on the location of hydrogen generating facilities and the location of the hydrogen demands. This will surely depend on the type of potential hydrogen uses considered: industrial uses can be assumed to be typically concentrated in clusters, whereas other uses such as mobility uses can be assumed to be typically dispersed over a wider region. (Piebalgs, Jones, Dos Reis, Soroush, & Glachant, 2020) .A modelling of the location of hydrogen uses within the EU28 would therefore be useful to assess to what extent substantial transmission infrastructure would be used for transporting hydrogen over long distances in the future (Guelpa et al., 2019).

4.3.2 Gas storages

In a framework of multi-energy systems, an important point concerns the selection of the energy vector for the storage. When energy vectors must be converted into another type, it is possible to choose to store energy before or after the conversion. Furthermore, it may be useful to convert one energy vector into another just to increase the storage performance. Putting all loads on a single

infrastructure, e.g. electricity, would require a massive build-up of grids and additional renewable and back-up generation capacity for a relatively low number of utilisation hours.

As describe in section 3.1.5, there are already many large-scale gas underground storage facilities in Europe. These facilities, and especially the salt caverns, are suited for hydrogen as well. Depleted gas fields seem to be much more expensive than salt caverns for large amounts of hydrogen (Piebalgs et al., 2020). This is really important because without salt caverns the storage cost would be almost as large as the hydrogen itself.

In addition, gas is a compressible fluid which makes the use of pipelines as a mass storage promising for gas (Guelpa et al., 2019), in addition to the existing underground storage facilities.

Gas thus appears as a crucial energy vector for the storage in future smart energy systems in Europe.

However, the potential need for storage technologies will depend on the temporal profile of domestic production or imports on the one hand, and the temporal profile of end-uses on the other hand. In that perspective a modelling for the temporal profile of the different types of renewable gases uses within EU-region would be useful to assess the need for storage technologies in the future (Piebalgs et al., 2020).

Annex 1 - Data sheets

Reference	Base region	Price in base region	r_labour	Units	EU28	Austria	BE	Bulgaria	CY	CZ	DE	Denmark	DK	EE	EL	ES	FI	FR	Croatia	HU	
Transmission grid - National lines																					
Inv. transmission lines																					
Inv. costs compression stations																					
2 EU28		0.13	0.75	M€/bcm/a/km	0.13	0.15	0.17	0.05	0.09	0.08	0.15	0.18	0.18	0.08	0.09	0.11	0.15	0.16	0.07	0.07	
2 EU28		1.97	0.20	M€/MW	1.97	2.06	2.14	1.66	1.82	1.76	2.07	2.20	2.20	1.76	1.80	1.88	2.05	2.09	1.73	1.71	
Transmission/Distribution grid - Regional single lines																					
Inv. single line 0-50 MW																					
1 DK		11.00	0.75	€/NMW/m	6.96	9.15	10.22	3.86	5.96	5.24	9.32	11.00	5.22	5.78	6.77	9.03	9.03	9.51	4.80	4.58	
1 DK		4.00	0.75	€/NMW/m	2.53	3.33	3.72	1.40	2.17	1.91	3.39	4.00	1.90	2.10	2.46	3.28	3.28	3.46	1.74	1.66	
1 DK		2.00	0.75	€/NMW/m	1.27	1.66	1.86	0.70	1.08	0.95	1.69	2.00	0.95	1.05	1.23	1.64	1.64	1.73	0.87	0.83	
1 DK		1.00	0.75	€/NMW/m	0.63	0.83	0.93	0.35	0.54	0.48	0.85	1.00	0.47	0.53	0.62	0.82	0.82	0.86	0.44	0.42	
Distribution grid - Local single lines																					
Inv. single line <1 MW - rural area																					
1 DK		50.00	0.80	€/m	30.41	41.05	46.24	15.37	25.57	22.08	41.86	50.00	21.99	24.68	29.51	40.43	40.43	42.75	19.93	18.86	
1 DK		53.00	0.80	€/m	32.25	43.51	49.02	16.29	27.10	23.41	44.37	53.00	23.31	26.16	31.28	42.85	42.85	45.32	21.13	19.99	
1 DK		68.00	0.80	€/m	41.38	55.83	62.89	20.90	34.78	30.03	56.93	68.00	29.91	33.56	40.13	54.98	54.98	58.14	27.11	25.65	
1 DK		64.00	0.80	€/m	38.95	52.55	59.19	19.67	32.73	28.26	53.58	64.00	28.15	31.58	37.77	51.74	51.74	54.72	25.51	24.14	
1 DK		72.00	0.80	€/m	43.82	59.11	66.59	22.13	36.82	31.80	60.27	72.00	31.67	35.53	42.49	58.21	58.21	61.56	28.70	27.16	
1 DK		104.00	0.80	€/m	63.29	85.39	96.18	31.97	53.19	45.93	87.06	104.00	45.74	51.33	61.38	84.08	84.08	88.92	41.46	39.23	
1 DK		27000	0.20	€/MW	24358	25792	26493	23235	23702	23231	25901	27000	23219	23581	24734	25707	25707	26021	22941	22796	
Distribution grid - Service lines																					
Inv. service line <20 kW - rural area																					
1 DK		1600	0.80	€/unit	974	1314	1480	492	818	707	1339	1600	704	790	944	1294	1294	1368	638	603	
1 DK		15000	0.80	€/unit	9128	12315	13872	4611	7671	6624	12557	15000	6597	7403	8852	12128	12128	12826	5980	5658	
1 DK		140	0.80	€/NMWh/y	85	115	129	43	72	62	117	140	62	69	83	113	113	120	56	53	
1 DK		10	0.80	€/NMWh/y	6	8	9	3	5	4	8	10	4	5	6	8	8	9	4	4	
Natural gas storage																					
Investment costs - salt cavern																					
2 EU28		1.02	0.80	€/m³	1.02	1.21	1.38	0.38	0.71	0.59	1.23	1.50	0.59	0.68	0.83	1.19	1.19	1.26	0.53	0.49	
Investment costs - depleted field																					
2 EU29		0.60	0.80	€/m³	0.60	0.71	0.81	0.22	0.42	0.35	0.73	0.88	0.35	0.40	0.49	0.70	0.70	0.74	0.31	0.29	
Investment costs - aquifer																					
2 EU30		0.90	0.80	€/m³	0.90	1.07	1.21	0.33	0.62	0.52	1.09	1.32	0.52	0.60	0.74	1.05	1.05	1.11	0.46	0.43	
LNG storage																					
Investment costs																					
2 EU28		1.50	0.20	€/m³	1.50	1.57	1.63	1.26	1.39	1.34	1.58	1.68	1.34	1.37	1.43	1.56	1.56	1.59	1.32	1.31	
Hydrogen grids																					
Investment costs dedicated hydrogen transmission pipeline																					
5 DE		2.48	0.80	M€/km	1.77	2.43	2.75	0.83	1.47	1.25	2.48	2.99	1.24	1.41	1.71	2.39	2.39	2.54	1.11	1.05	
Investment costs - Refurbishment of natural gas transmission pipelines																					
5 DE		0.37	0.80	M€/km	0.26	0.36	0.41	0.12	0.22	0.19	0.37	0.45	0.19	0.21	0.26	0.36	0.36	0.38	0.17	0.16	
Investment costs - Compressor stations																					
5 EU28		1.07	0.20	M€/MW	1.07	1.12	1.16	0.90	0.99	0.96	1.13	1.20	0.96	0.98	1.02	1.11	1.11	1.13	0.94	0.93	
Investment costs dedicated hydrogen distribution pipeline - DN100																					
4 DE		0.36	0.80	M€/km	0.25	0.35	0.40	0.12	0.21	0.18	0.36	0.43	0.18	0.20	0.25	0.34	0.34	0.36	0.16	0.15	
Investment costs - Refurbishment of natural gas distribution pipelines - DN100																					
5 UK		0.23	0.80	M€/km	0.19	0.27	0.31	0.08	0.16	0.13	0.28	0.33	0.13	0.15	0.19	0.27	0.27	0.28	0.12	0.11	
Hydrogen storages																					
Investment costs - tanks																					
3 DK		57.00	0.16	M€/GWh	52.60	54.99	56.15	49.21	51.50	50.72	55.17	57.00	50.70	51.30	52.39	54.85	54.85	55.37	50.23	49.99	
3 DK		3.00	0.67	M€/GWh	2.02	2.55	2.81	1.27	1.78	1.60	2.59	3.00	1.60	1.73	1.98	2.52	2.52	2.64	1.50	1.44	
Biogas upgrading plants																					
Upgrading investment costs (M€/MW)																					
6 DK		0.34	0.20	M€/MW-CH4	0.30	0.32	0.33	0.28	0.29	0.29	0.32	0.34	0.29	0.29	0.30	0.32	0.32	0.32	0.28	0.28	
6 DK		0.13	0.20	M€/MW-CH4	0.12	0.13	0.13	0.11	0.12	0.12	0.13	0.13	0.12	0.12	0.12	0.13	0.13	0.13	0.11	0.11	

Reference	Base region	Price in base region	r_labour	Units	EU28	IE	IT	LT	LU	LV	MT	NL	PL	PT	RO	SE	SI	SK	UK
Transmission grid - National lines																			
Inv. transmission lines																			
2 EU28		0.13	0.75	€/bcm/km	0.13	0.14	0.13	0.06	0.17	0.07	0.08	0.16	0.07	0.08	0.06	0.16	0.10	0.07	0.13
2 EU28		1.97	0.20	€/MW	1.97	2.04	1.98	1.71	2.16	1.71	1.78	2.08	1.72	1.78	1.68	2.08	1.84	1.75	1.97
Inv. costs compression stations																			
Transmission/Distribution grid - Regional single lines																			
Inv. single line 0-50 MW																			
1 DK		11.00	0.75	€/MW/m	6.96	8.88	8.07	4.48	10.43	4.58	5.52	9.47	4.72	5.44	4.17	9.45	6.26	5.06	8.01
Inv. single line 50-100 MW																			
1 DK		4.00	0.75	€/MW/m	2.53	3.23	2.93	1.63	3.79	1.66	2.01	3.44	1.72	1.98	1.52	3.44	2.28	1.84	2.91
Inv. single line 100-250 MW																			
1 DK		2.00	0.75	€/MW/m	1.27	1.61	1.47	0.82	1.90	0.83	1.00	1.78	0.86	0.99	0.76	1.72	1.14	0.92	1.46
Inv. single line > 250 MW																			
1 DK		1.00	0.75	€/MW/m	0.63	0.81	0.73	0.41	0.95	0.42	0.50	0.86	0.43	0.49	0.38	0.86	0.57	0.46	0.73
Distribution grid - Local single lines																			
Inv. single line < 1 MW - rural area																			
1 DK		50.00	0.80	€/m	30.41	39.71	35.77	18.41	47.23	18.86	23.42	42.57	19.57	23.06	16.89	42.48	27.00	21.19	35.50
Inv. single line 1 - 5 MW - rural area																			
1 DK		53.00	0.80	€/m	32.25	42.09	37.92	19.52	50.06	19.99	24.83	45.13	20.75	24.45	17.90	45.03	28.62	22.46	37.63
Inv. single line 5-25 MW - rural area																			
1 DK		68.00	0.80	€/m	41.38	54.00	48.65	25.04	64.23	25.65	31.86	57.90	26.62	31.37	22.97	57.78	36.72	28.81	48.28
Inv. single line < 1 MW - urban area																			
1 DK		64.00	0.80	€/m	38.95	50.83	45.79	23.57	60.45	24.14	29.98	54.49	25.06	29.52	21.62	54.38	34.56	27.12	45.44
Inv. single line 1 - 5 MW - urban area																			
1 DK		72.00	0.80	€/m	43.82	57.18	51.51	26.51	68.01	27.16	33.73	61.30	28.19	33.21	24.32	61.18	38.88	30.51	51.12
Inv. single line 5-25 MW - urban area																			
1 DK		104.00	0.80	€/m	63.29	82.60	74.41	38.30	98.23	39.23	48.72	88.55	40.72	47.97	35.13	88.37	56.16	44.07	73.85
Inv. costs regulation stations																			
1 DK		27000	0.20	€/MW	24358	25611	25079	22736	26626	22796	23412	25997	22893	23364	22530	25985	23895	23110	25043
Distribution grid - Service lines																			
Inv. service line < 20 kW - rural area																			
1 DK		1600	0.80	€/unit	974	1271	1145	589	1511	603	750	1362	626	738	540	1359	864	678	1136
Inv. service line > 100 kW - urban area																			
1 DK		15000	0.80	€/unit	9128	11913	10732	5523	14168	5658	7027	12772	5872	6919	5067	12745	8101	6356	10651
Distribution network costs - rural area																			
1 DK		140	0.80	€/MW/h/y	85	111	100	52	132	53	66	119	55	65	47	119	76	59	99
Distribution network costs - urban area																			
1 DK		10	0.80	€/MW/h/y	6	8	7	4	9	4	5	9	4	5	3	8	5	4	7
Natural gas storage																			
Investment costs - salt cavern																			
2 EU28		1.02	0.80	€/m³	1.02	1.16	1.04	0.48	1.41	0.49	0.64	1.26	0.51	0.63	0.43	1.25	0.75	0.57	1.03
Investment costs - depleted field																			
2 EU29		0.60	0.80	€/m³	0.60	0.69	0.61	0.28	0.83	0.29	0.38	0.74	0.30	0.37	0.25	0.74	0.44	0.33	0.61
Investment costs - aquifer																			
2 EU30		0.90	0.80	€/m³	0.90	1.03	0.92	0.42	1.24	0.43	0.56	1.11	0.45	0.55	0.38	1.11	0.67	0.50	0.91
LNG storage																			
Investment costs																			
2 EU28		1.50	0.20	€/m³	1.50	1.55	1.51	1.30	1.64	1.31	1.36	1.59	1.31	1.36	1.28	1.59	1.40	1.33	1.50
Hydrogen grids																			
Investment costs dedicated hydrogen transmission pipeline																			
5 DE		2.48	0.80	€/km	1.77	2.35	2.10	1.02	2.81	1.05	1.33	2.52	1.09	1.31	0.93	2.52	1.55	1.19	2.08
Investment costs - Refurbishment of natural gas transmission pipelines																			
5 DE		0.37	0.80	€/km	0.26	0.35	0.31	0.15	0.42	0.16	0.20	0.38	0.16	0.20	0.14	0.38	0.23	0.18	0.31
Investment costs - Compressor stations																			
5 EU28		1.07	0.20	€/MW	1.07	1.11	1.07	0.93	1.17	0.93	0.97	1.13	0.94	0.97	0.91	1.13	1.00	0.95	1.07
Investment costs dedicated hydrogen distribution pipeline - DN100																			
4 DE		0.36	0.80	€/km	0.25	0.34	0.30	0.15	0.40	0.15	0.19	0.36	0.16	0.19	0.13	0.36	0.22	0.17	0.30
Investment costs - Refurbishment of natural gas distribution pipelines - DN100																			
5 UK		0.23	0.80	€/km	0.19	0.26	0.23	0.11	0.31	0.11	0.14	0.28	0.12	0.14	0.10	0.28	0.17	0.13	0.23
Hydrogen storages																			
Investment costs - tanks																			
3 DK		57.00	0.16	€/GWh	52.60	54.68	53.80	49.89	56.38	49.99	51.02	55.33	50.15	50.94	49.55	55.31	51.83	50.52	53.74
Investment costs - Cavern																			
3 DK		3.00	0.67	€/GWh	2.02	2.49	2.29	1.42	2.86	1.44	1.67	2.63	1.48	1.65	1.34	2.62	1.85	1.56	2.28
Biogas upgrading plants																			
Upgrading investment costs (€/MW)																			
6 DK		0.34	0.20	€/MW-CH4	0.30	0.32	0.31	0.28	0.33	0.28	0.29	0.32	0.28	0.29	0.28	0.32	0.30	0.29	0.31
Injection in the grid (40bar) (€/MW)																			
6 DK		0.13	0.20	€/MW-CH4	0.12	0.13	0.12	0.11	0.13	0.11	0.12	0.13	0.11	0.12	0.11	0.13	0.12	0.11	0.12

	Reference	Fixed part of O&M (% of inv)	Lifetime in years
Natural gas grid			
Transmission lines	2	1	50
Compressor stations	2	4	10
Distribution main single lines (> 25 MW)	1	1	50
Distribution local single lines (< 25MW)	1	2	50
Service line	1	2	50
Natural gas storage			
Depleted field	2	3	100
Aquifer	2	3	100
Salt cavern	2	3	100
LNG storage	2	3	30
Hydrogen			
Hydrogen pipeline	4	5	50
Hydrogen storage - tanks	3	1	25
Hydrogen storage - cavern	3	2	100
Biogas			
Upgrading investment costs (M€/MW)	6	2.5	15
Injection in the grid (40bar) (M€/MW)	6	2.5	15

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