

# What energy infrastructure to support 1.5°C scenarios?

---

Final report

*An analysis on behalf of the European Climate Foundation*



## Executive summary

The ambition of the European Commission is that Europe should become the first climate-neutral continent by 2050. All analytical exercises point to the crucial role of getting the infrastructure right, in order to support a cost-effective and secure transition towards a net-zero economy. In particular, in its 2018 Long-Term Strategy (LTS), the European Commission has designed pathways relying on key pillars: energy efficiency, direct and indirect electrification of end-uses, renewables, electrolysis and biomethane. In such contexts, key questions arise:

- | What is the optimal design of the supporting infrastructure?
- | Where should electrolysis take place?
- | What flexibility solutions should be deployed to meet security of supply requirements?
- | What is the role of the gas infrastructure? As we move from importing natural gas from third countries to a more local provision of bio-methane and hydrogen, the very structure of the gas flows will evolve. How relevant is it to repurpose part of the gas infrastructure?

This report provides an independent and forward-looking assessment of EU's energy infrastructure needs in order to support its global energy ambitions. In order to better understand the role of energy infrastructure and to obtain insights into about the investment challenge Europe faces, we have aimed at optimising the level of infrastructure for several sets of assumptions.

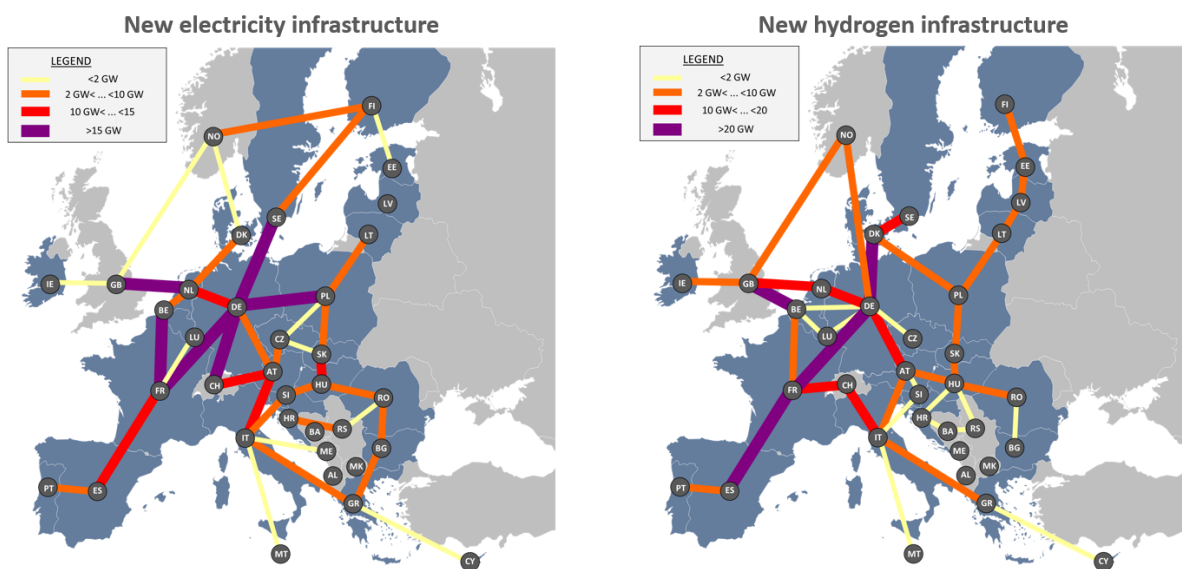
This study is based on a joint power-gas-hydrogen model inspired by the LTS 1.5TECH scenario. The simulations have been performed with Artelys Crystal Super Grid, a multi-energy modelling solution enabling joint power-gas-hydrogen simulations with an hourly time resolution and investment optimisation in infrastructure and flexibility solutions. The interlinkages between countries is explicitly modelled for electricity, methane and hydrogen, and the investments in new infrastructure and repurposing of methane pipelines are optimised. In order to assess the robustness of our conclusions, sensitivity analyses have been undertaken to explore the role of key assumptions: hydrogen demand levels, RES localisation, biomethane production and technology choices for space heating.

Three main findings emerge from this study:

- | **Finding 1:** Major investments in the electricity infrastructure are required. The level of required investments can be mitigated by a smart distribution of RES capacities in a way that is consistent with hydrogen demand centres.
- | **Finding 2:** Investments in hydrogen infrastructure will be required in specific areas. However, the infrastructure requirements are found to be very sensitive to the consistency between the geographic allocation of renewables and the hydrogen demand. In addition, repurposing of the existing gas infrastructure is found to be a cost-effective way to develop the hydrogen infrastructure.
- | **Finding 3:** There is no need for additional investments in methane infrastructure in the EU. Indeed, with natural gas seeing a phase out most of the methane demand will be supplied by locally-produced bio-methane and/or e-CH<sub>4</sub>. Part of the existing infrastructure is found to be characterised by low utilisation rates at the 2050 horizon due to an overall reduction of

methane demand. The repurposing of part of the existing gas infrastructure is found to be relevant to support the cross-border transport of hydrogen.

In this study we quantify the need for electricity, methane and hydrogen infrastructure for different scenarios. In the scenario derived from key 1.5TECH assumptions, and the associated sensitivity analyses, we find that the majority of investments is going to the electricity infrastructure (between 60 and 80 billion EUR), accompanied by a development of a cross-border hydrogen network (between 15 and 25 billion EUR)<sup>1</sup>. In total, the capital cost of the identified 2050 cross-border infrastructure can be estimated to be between 75 and 105 billion EUR.



**Figure 1 - New electricity and hydrogen cross-border infrastructure at the 2050 horizon in a reference scenario based on LTS 1.5TECH**

Crucially, we have found that the need for electricity infrastructure is relatively stable across scenarios, while the need for gas infrastructure varies considerably depending on the geographic allocation of renewables:

- | **Electricity:** Around 10% of new electricity interconnection investments could be avoided if the geographic allocation of RES is consistent with the hydrogen demand centres in Europe.
- | **Methane:** A smart allocation of renewables results in no additional infrastructure being required in the EU.
- | **Hydrogen:** While reducing the hydrogen demand by 30% is found to reduce the need for hydrogen infrastructure by around 20%, this same demand reduction combined with a smart

<sup>1</sup> The investment figures only refer to the capital costs of cross-border infrastructure, and do not include the costs related to generation, conversion, update of end-uses technologies, and infra-national networks.

geographic allocation of renewables is found to lead to a decrease of 60% of hydrogen infrastructure needs compared to the reference situation.

**Depending on the considered scenarios, the repurposing of gas pipelines could represent between 35% and 50% of the global hydrogen infrastructure.** The development of biomethane is found to be competing with the repurposing of pipelines, leading to different levels of repurposing and investments in new hydrogen pipelines depending on the assumed level of bio-methane injection.

**A large number of non-repurposed methane pipelines are characterised by very low use rates,** potentially leading to potential decommissioning where not useful to support cross-border trade of hydrogen.

The key findings can be translated into **recommendations** for the revision of the TEN-E regulation:

- Given the magnitude of the investment challenge, procedures (e.g. related to permitting) should be streamlined and simplified
- Scenarios and guidelines for cost-benefit analysis should favour a consistent deployment of renewable technologies and hydrogen consumption centres in order to avoid unnecessary investments in pipes and wires
- The assessment of system needs at the 2050 horizon should be conducted jointly for the electricity and gas systems (including an explicit distinction between hydrogen and methane)
- There is no need for additional investments in methane infrastructure to ensure security of supply within the EU. Further investments in CH<sub>4</sub> infrastructure should be ruled out so as to avoid creating stranded assets, unless they set forward the repurposing of existing pipelines in line with demonstrated future hydrogen needs

## TABLE OF CONTENTS

EXECUTIVE SUMMARY	3
TABLE OF ILLUSTRATIONS	8
GLOSSARY	10
<b>1 CONTEXT AND OBJECTIVES</b>	<b>12</b>
1.1 AN AMBITIOUS DECARBONISATION EFFORT	12
1.2 KEY QUESTIONS RELATED TO INFRASTRUCTURE NEEDS	16
<b>2 KEY FINDINGS</b>	<b>18</b>
2.1 FINDING 1 – MAJOR INVESTMENT LEVELS IN ELECTRICITY INFRASTRUCTURE	23
2.1.1 A HIGH ELECTRIFICATION AND SHARE OF VARIABLE RES IN 2050	23
2.1.2 TRANSMISSION CAPACITIES AS AN IMPORTANT PROVIDER OF FLEXIBILITY	25
2.1.3 THE IMPACT OF RES AND ELECTRIFICATION ON THE INFRASTRUCTURE	26
2.2 FINDING 2 – TRADE-OFF BETWEEN LOCAL HYDROGEN PRODUCTION AND INFRASTRUCTURE	28
2.2.1 INVESTMENTS IN HYDROGEN INFRASTRUCTURE WILL BE REQUIRED IN SPECIFIC AREAS	28
2.2.2 EVOLUTION OF THE INFRASTRUCTURE WITH A MORE LOCAL PRODUCTION	30
2.2.3 WHAT IS THE MOST APPROPRIATE SOLUTION BETWEEN REPURPOSING AND LAYING DOWN NEW HYDROGEN PIPELINES?	32
2.3 FINDING 3 – THE CHANGING ROLE OF METHANE INFRASTRUCTURE	34
2.3.1 A LOWER METHANE CONSUMPTION IS EXPECTED IN 2050 COMPARED TO 2020	34
2.3.2 THE GAS SUPPLY TENDS TO BE LOCAL RATHER THAN GLOBAL	35
2.3.3 FEW CONSTRAINT AREAS	35
2.3.4 AS A RESULT, THE METHANE INFRASTRUCTURE IS UNDER-USED	37
<b>3 APPENDIX – KEY ASSUMPTIONS</b>	<b>40</b>
3.1 APPENDIX A – MODELLING OF THE EUROPEAN ENERGY SYSTEM	40
3.1.1 GENERAL METHODOLOGY	40
3.1.2 DEMAND	42
3.1.3 SUPPLY	44
3.1.4 INFRASTRUCTURE	48
3.1.5 COMMODITY PRICES	50

---

3.1.6	A BOTTOM-UP OPTIMISATION APPROACH	50
3.2	APPENDIX B – SENSITIVITY ANALYSES	51
3.2.1	A LOWER HYDROGEN DEMAND AND A SMARTER ALLOCATION OF VRES CAPACITIES	51
3.2.2	A LOWER BIOMETHANE POTENTIAL	52
3.2.3	A HIGHER ENERGY EFFICIENCY AND A DEEPER ELECTRIFICATION	53

## Table of illustrations

Figure 1 - New electricity and hydrogen cross-border infrastructure at the 2050 horizon in a reference scenario based on LTS 1.5TECH	4
Figure 2 – Power generation capacities. Source: EC LTS	13
Figure 3 – Power generation capacities. Source: EC's 55% impact assessment	14
Figure 4 - Workflow of the Artelys Crystal Super Grid software	16
Figure 5 – General methodology for designing the reference scenario	19
Figure 6 - RES installed capacities in the reference scenario (R) and the sensitivity (S) for specific countries	20
Figure 7 - 650 TWh biomethane supply breakdown in the sensitivity scenario	21
Figure 8 - 355 TWh heat pump demand repartition in the sensitivity and comparison with the 270 TWh of the reference scenario	22
Figure 9 - Power demand decomposition and power generation mix for the reference scenario	24
Figure 10: Installed capacity of flexibility assets in the reference scenario	24
Figure 11 - Additional transmission needs in the reference scenario compared to ENTSO-E's system needs	25
Figure 12 – Additional investments in interconnection infrastructure and underlying system equilibrium	26
Figure 13: Additional investments needs in the reference scenario compared to the hydrogen sensitivity.	27
Figure 14: Additional investments needs for the electrification sensitivity compared to the reference scenario.	27
Figure 15 - Repurposed and new hydrogen pipelines in the reference scenario	29
Figure 16 : Total hydrogen infrastructure (refurbished pipelines and new H2 pipes) and underlying system equilibrium that explain the investments for the reference scenario	30
Figure 17 -Hydrogen demand decomposition for the reference scenario and the hydrogen sensitivity scenario	31
Figure 18 - Electrolysis capacities for the reference case and in the sensitivity analysis	31
Figure 19 - Comparison between the hydrogen infrastructure in the reference scenario and in the hydrogen sensitivity	32



Figure 20 - Distribution of investment between repurposing and new H2 pipelines for the reference scenario and the 3 sensitivity analyses.	33
Figure 21 – Repurposing considered in the different scenarios	33
Figure 22 – Overall gas supply mix evolution between 2015 and 2050.	34
Figure 23 – Methane consumption and supply shares in the different scenarios	34
Figure 24 – Local and imported shares of H2 and CH4 production in the reference scenario over EU34	35
Figure 25 - New installed gas capacities in the reference scenario	36
Figure 26 - Total gas infrastructure (excluding repurposed pipes) and gas flows directions in the reference scenario	36
Figure 27 - Use rate of gas pipelines in the reference scenario	38
Figure 28 - Methanation installed capacity evolution between the reference scenario and biomethane sensitivity	38
Figure 29 - Use rate of gas pipelines in the electrification sensitivity	39
Figure 30 - General methodology for designing the reference scenario	40
Figure 31 - Schematic overview of the modelling structure of the European power, gas and hydrogen systems	41
Figure 32 - Demand decomposition by usage	42
Figure 33 – Final energy demand breakdown in the reference scenario	44
Figure 34 - Power generation capacity in the LTS 1.5TECH scenario	45
Figure 35 – Renewable capacity breakdown in the reference scenario	46
Figure 36 - 825 TWh biomethane production breakdown in the reference scenario	48
Figure 37 - Investment costs (including FOC) of h2 pipelines	50
Figure 38 – vRES installed capacities in the reference and sensitivities scenarios	52

## Glossary

**CH4:** See methane

**Biomethane:** Gas mostly composed of methane that is produced via anaerobic digestion of biomass and purification/upgrading. Biomethane has the required characteristics to be injected in the natural gas system.

**E-gas:** Synthetic methane produced from hydrogen obtained by electrolysis

**ENTSO-E:** European Network of Transmission System Operators for Electricity

**ENTSO-G:** European Network of Transmission System Operators for Gas

**Gas infrastructure:** This term gathers all the infrastructure used to import, transport and store gases. It includes pipelines, storage assets, liquefied gas terminals and regasification units for overseas imports. The methane infrastructure cannot be directly used for hydrogen operation. Nevertheless, part of the methane infrastructure can be repurposed to be able to handle hydrogen. For example, an existing pipeline can either be used for methane (natural gas or biomethane) transport or can be repurposed in order to be used for hydrogen transport.

**H2:** See hydrogen

**HHV:** Higher heating value, equal to gross calorific value (GCV)

**Hydrogen:** Term referring to a gas formed by molecules binding two hydrogen atoms (di-hydrogen). Hydrogen is considered to decarbonise hard-to-abate end-uses. Hydrogen can be produced via a number of processes, e.g. electrolysis, steam methane reforming, etc.

**Integrated gas-power approach:** Approach used to assess gas infrastructure needs by considering simultaneously the gas (hydrogen and methane) and power systems (integrating electricity supply, storage, transmission and demand-response), and their synergies/interdependencies.

**LTS reference document:** Document published by the European Commission to support COM (2018) 773, containing a description of the different pathways considered in the Long-Term Strategy scenarios, and their key characteristics<sup>2</sup>.

**Methane:** Main constituent of natural gas. Biomethane and synthetic methane can be transported with the same infrastructure as the one developed for natural gas.

**Natural gas:** Fossil fuel mostly composed of methane.

---

<sup>2</sup> Available online - [https://ec.europa.eu/clima/sites/clima/files/docs/pages/com\\_2018\\_733\\_analysis\\_in\\_support\\_en\\_0.pdf](https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf)

**NECP:** National Energy and Climate Plan. NECPs are 10-year integrated plans that cover the period from 2021 to 2030. NECPs have been introduced under the Regulation on the governance of the energy union and climate action (EU/2018/1999).

**NTC:** Net Transfer Capacities.

**Scenario:** Description of a European energy context in a prospective approach. It includes e.g. levels of energy demand, commodity prices, power generation mix, etc.

**TEN-E:** Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure. The TEN-E regulation is currently being revised by the European Commission to better align it with the objectives of the Green Deal, in particular climate-neutrality.

**vRES:** variable Renewable Energy Sources. Renewable power sources whose production cannot be monitored.

# 1 Context and objectives

## 1.1 An ambitious decarbonisation effort

### Setting the scene – The European Green Deal

The European Green Deal<sup>3</sup> sets out the European Commission’s ambitions in tackling climate and environmental-related challenges. The Green Deal targets a 55% reduction in greenhouse gases emissions at the 2030 horizon compared to 1990 levels, and aims at achieving climate neutrality by 2050.

Reaching these targets will require colossal efforts in energy efficiency - to reduce the demand, in particular by renovating the European building stock<sup>4</sup> -, in the deployment of decarbonised energy sources - to support the direct and indirect electrification of end-uses -, and in infrastructure to enable dynamic interlinkages between sectors and vectors to materialise.

Several technological pathways can lead to the decarbonisation of most sectors of the European economy. For example, in the transport sector, it is likely that electric vehicles and fuel cell vehicles will both appear on European roads, even though electric vehicles enjoy a strong economic advantage over competing technologies for most applications. In other sectors, the direct electrification of end-uses is not always an option. For example, high-temperature industrial processes will likely still be based on the combustion of gaseous fuels, but of different origin. As the consumption of natural gas will reduce, alternative options will have to grow. These options include bio-methane, “green hydrogen” (produced via electrolysis powered by renewable electricity), so called “blue hydrogen” (produced from natural gas, e.g. via a steam methane reforming process, combined with carbon capture), hydrogen produced from pyrolysis, etc.

At the 2050 horizon, the European Commission foresees a decarbonisation of hard-to-abate sectors via renewable hydrogen and associated processes (e.g. Fischer-Tropsch to produce synthetic methane, Haber-Bosch to produce ammonia, etc.), with blue hydrogen playing a role mainly during the transition.

### Electrons *and* molecules – Energy System Integration and Hydrogen Strategies

While direct electrification allows for a more efficient use of energy in most cases, a strongly integrated energy system relying on the use of electrons and molecules can help keeping the costs of the transition under control. Indeed, hybrid systems may allow for substantial cost savings to emerge

---

<sup>3</sup> COM/2019/640 final

<sup>4</sup> See e.g. <https://euase.net/need-for-speed-decarbonising-europes-buildings-with-available-solutions-and-no-use-of-hydrogen>

(avoided generation capacity, avoided infrastructure reinforcement costs, etc.). The question is therefore not to choose between electrons and molecules, but to design the system that will allow for synergies between energy vectors and sectors to emerge, for flexibility to be shared between sectors, so as to decarbonise the European economy in the most cost-effective way.

The Energy System Integration Strategy<sup>5</sup> and Hydrogen Strategy<sup>6</sup> that have been presented by the European Commission during the summer 2020 precisely aim at transforming the currently still siloed design of the European energy sector into a much more integrated system. One of the technologies that interlinks the electricity and gas systems is electrolysis. The strategy devoted to the emergence of a European hydrogen economy foresees building 40 GW of electrolysis capacity in the EU by 2030. It is estimated that the electrolysis capacity will have to reach between 400 and 500 GW by 2050 in order to meet the demand for decarbonised gases.

### Long-term Strategy and Climate Target Plan

The European Commission has performed multiple modelling exercises aiming at designing transition pathways, based on different technological options and behavioural assumptions. The Long-Term Strategy, published in November 2018, has been used by many stakeholders to analyse the role of technological options, especially in the so-called 1.5TECH scenario. This scenario, which reaches carbon neutrality at the 2050 horizon, foresees a dramatic increase in generation capacity compared to current levels, as can be read from the following figure, extracted from the European Commission’s Long-Term Strategy.

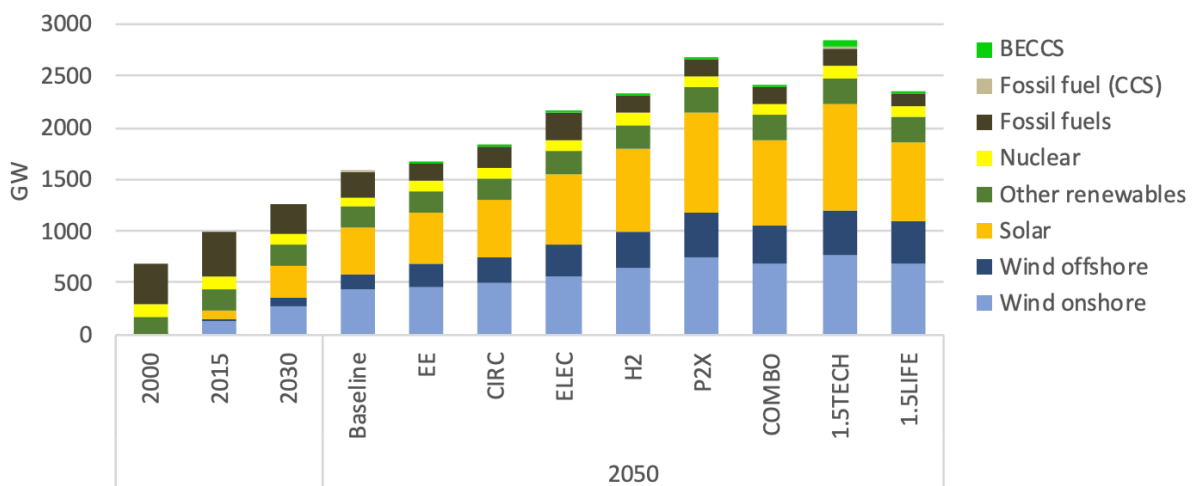


Figure 2 – Power generation capacities. Source: EC LTS

5 COM(2020) 299 final  
6 COM(2020) 301 final

A more recent modelling exercise has been undertaken to support the impact assessment of setting a more ambitious greenhouse gases emissions reduction target at the 2030 horizon. While the current target is a 40% reduction compared to 1990 levels, which is reached by the current ambitions of Member States according to the analysis of the NECPs performed by the European Commission<sup>7</sup>, the Commission has proposed a plan that aims to reduce EU greenhouse gas emissions by at least 55% by 2030. The scenarios developed to support the decision-making process relative to the revision of the 2030 target foresee similar levels of installed capacities at the 2050 horizon, however with different allocation of efforts between decades, and a stronger role for onshore wind power compared to the pathways of the Long-Term Strategy.

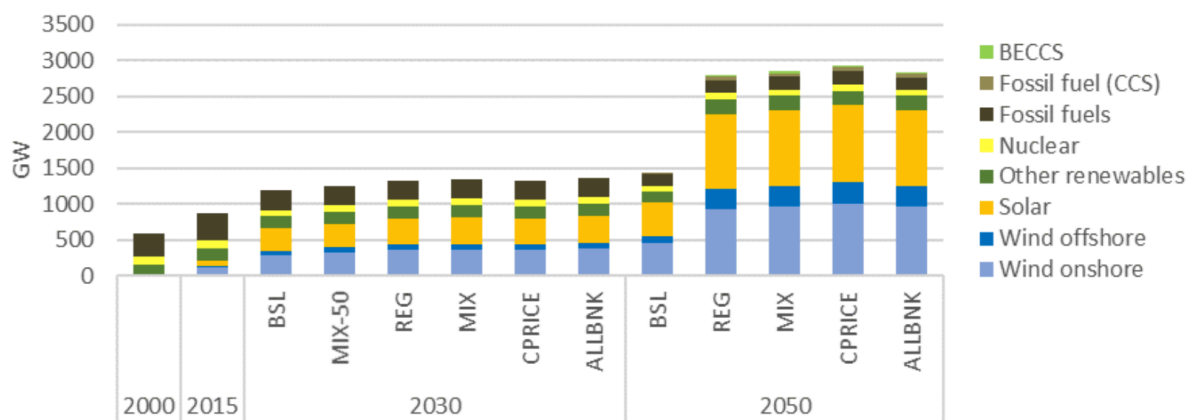


Figure 3 – Power generation capacities. Source: EC's 55% impact assessment

### Infrastructure as a key enabler of a cost-effective decarbonisation – Need for a revised TEN-E

The combination between an important deployment of variable renewables, the interlinking of methane, hydrogen, electricity and heating infrastructure, and the flexibility services that can be offered by end-uses will need to be supported by the right type of infrastructure. While it is commonly expected that the infrastructure in the electricity sector will require substantial investments in the coming decades to help integrate renewables, a key question that remains unanswered is related to the balance between investments in the electricity, hydrogen and methane infrastructure, both at the level of cross-border exchange capacity and at the local level. Indeed, several strategies can be pursued (e.g. electrolysis close to generation or close to consumption, repurposing of existing methane infrastructure to make it compatible with 100% hydrogen, etc.), leading to vastly different investment needs. In all cases, a system-wide, integrated and forward-looking approach is required to shed light on these issues, as it can identify synergies and interdependencies between vectors and sectors, and provide insights into the optimal level of energy infrastructure to support a 1.5°C-compatible economy.

<sup>7</sup> COM(2020) 564 final

As a consequence, the European regulation on infrastructure (TEN-E) needs to be revised to ensure these objectives can be met. Previous studies have helped identify the following key aspects of the TEN-E that should be updated. The key principle underpinning the recommendations that have already been identified is the need to approach the identification of infrastructure needs, the assessment of candidate projects and their selection in the PCI process in a holistic manner, across energy vectors and decades. More concretely, this amounts to:

- In the **scenario building** phase
  - Build economically consistent, plausible and contrasted transition pathways for the entire energy system, covering at least 2020-2050 with various assumptions on levels of energy efficiency.
  - For electrolyzers, consider the impacts of (a) dedicated RES vs network-connected electrolyzers; (b) operational modes (baseload, price-responsive, etc.).
- In the **project assessment** phase
  - Cost-benefit guidelines should include sustainability indicators that assess the impacts of the use of the infrastructure on emissions (including from leakages).
  - An interlinked model should be used to assess the benefits of projects, especially in highly integrated scenarios where power-to-gas technologies may impact the valuation of hydrogen, methane and electricity projects.
  - The cost-benefit assessment should consider the entire lifetime of the considered project, and evaluate the compatibility of projects with a net-zero economy for all the scenarios that have been built.
- In the **PCI selection** phase
  - The PCI selection process should consider the results of the entire set of scenarios, the risks associated with projects (e.g. is it found to be viable in all scenarios? How is its assessment impacted if its commissioning is delayed?)
  - The selection process should not select electricity, hydrogen and methane projects independently from each other, but rather aim at ensuring consistency between selected projects.

Additional recommendations based on the findings described in this study are presented in the Executive Summary.

## 1.2 Key questions related to infrastructure needs

This report aims at proposing a multi-energy modelling framework to evaluate the needs for infrastructure in a 2050 1.5°C-compatible scenario, and to apply it on the 1.5TECH scenario as well as on variations of this scenario. Many aspects of exercise are still characterised by an important level of uncertainty (e.g. cost of repurposing pipelines, economic case for hydrogen distribution networks, cost of electrolyzers, etc.). Therefore, we have focused the analysis on four high-level questions:

1. **Cross-border methane** – Is there a need to reinforce the European methane infrastructure beyond its current level? Due to the change of the structure of gas flows that can be expected at the 2050 horizon, are there pipelines with very low utilisation rates?
2. **Cross-border electricity** – How important is the need for cross-border electricity interconnectors, considering the impacts of electrolyzers and their geographical allocation?
3. **Cross-border hydrogen** – Is there a case for the cross-border transport of hydrogen? If yes, could part of the existing methane infrastructure be repurposed?
4. **Robustness** – How does the need for infrastructure depend on key assumptions, especially the consistency between the geographical allocation of renewables and of hydrogen demand?

In order to provide insights into these questions, we have performed a modelling exercise where we jointly optimise the capacity of hydrogen, methane and electricity infrastructure and their use, for a given 1.5°C-compatible scenario at the 2050 horizon. We have assessed the robustness of the conclusions to several key assumptions by performing sensitivity analyses with respect to hydrogen demand levels, bio-methane supply, and wider use of direct electrification to supply low-temperature heat.

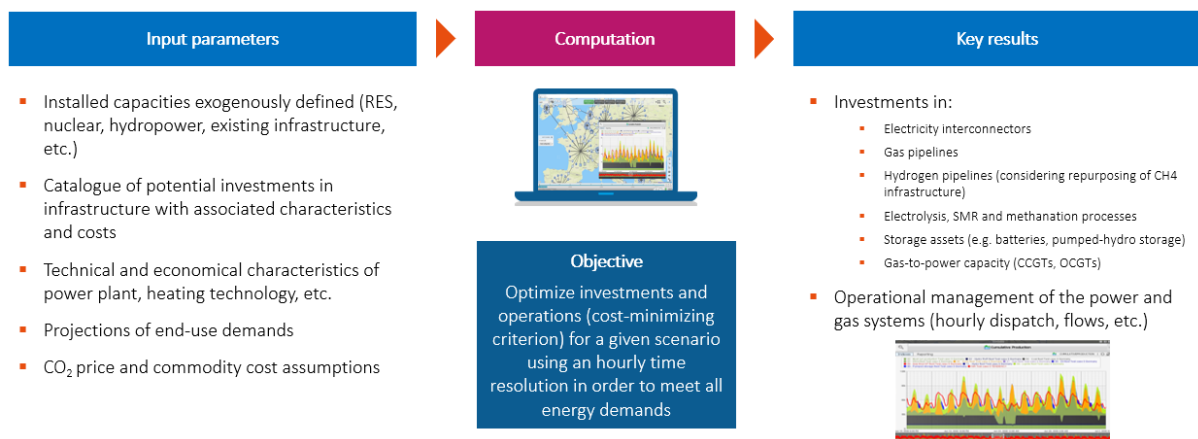


Figure 4 - Workflow of the Artelys Crystal Super Grid software



---

This study does not aim at identifying the precise set of infrastructure project that should be built at the 2050 time horizon, but rather to identify key lessons that can be learned from this exercise, and to translate them into recommendations for the revision of the TEN-E regulation. The analysis framework that has been developed could support further analysis of infrastructure needs, and in particular the construction of entirely new transition pathways.

Section 2 presents each of the three findings of the study in details.

Section 3 presents the key assumptions used in the modelling exercise and provides details on the design of the sensitivity analyses that have been conducted.

## 2 Key findings

In this paragraph, we provide the key findings of the study, and present the way the simulation results support these findings.

### FINDINGS IN A NUTSHELL

- | **Finding 1:** Major investments in the electricity infrastructure are required. The level of required investments can be mitigated by a smart distribution of RES capacities in a way that is consistent with hydrogen demand centres.
- | **Finding 2:** Investments in hydrogen infrastructure will be required in specific areas. However, the infrastructure requirements are found to be very sensitive to the consistency between the geographic allocation of renewables and the hydrogen demand. In addition, repurposing of the existing gas infrastructure is found to be a cost-effective way to develop the hydrogen infrastructure.
- | **Finding 3:** There is no need for additional investments in infrastructure to transport methane (natural gas, e-CH<sub>4</sub>, biomethane) on top of already identified reinforcements to guarantee security of supply. Indeed, most of the methane demand is supplied by locally-produced biomethane and/or e-CH<sub>4</sub>. Part of the existing infrastructure is found to be characterised by low utilisation rates at the 2050 horizon due to the structural evolution of gas flows. The repurposing of part of the existing gas infrastructure is found to be relevant to support the cross-border transport of hydrogen.

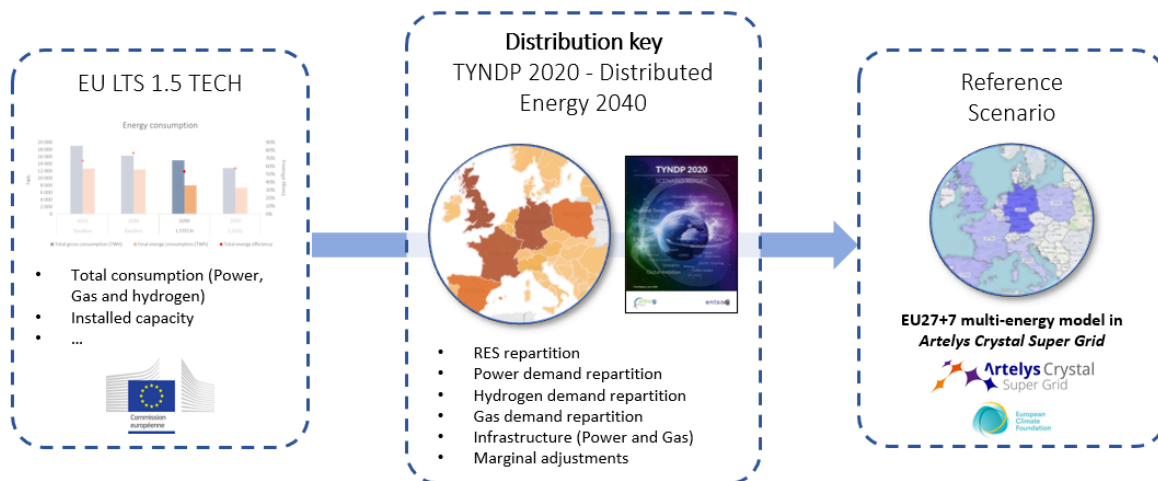
These findings have been identified by evaluating the required investments in electricity, methane and hydrogen infrastructure in several 2050 scenarios, on the basis of the assumptions of the European Commission's LTS 1.5TECH scenario. The set of scenarios in this report consists of a central scenario, and of three sensitivity analyses. In the paragraphs below, we present the key characteristics of the scenarios, an overview of the infrastructure optimisation process, and then proceed with a more in-depth analysis of each of the findings in Sections 2.1 to 2.3.

## REFERENCE SCENARIO

The reference scenario is largely inspired by the LTS 1.5TECH multi-energy European system at the 2050 horizon. Since the country-level assumptions of the LTS pathways have not been made publicly available, the following methodology has been applied to generate the reference scenario:

- Adopt the EU-wide assumptions of the LTS 1.5TECH scenario (e.g. total demand by fuel, total installed capacity for each technology, etc.)
- Disaggregate these assumptions at country level using distribution keys. In practice, most of the distribution keys are based on the use of country-level assumptions published in the ENTSOs' TYNDP 2020. The plausibility of the disaggregated figures is then analysed via a literature review (e.g. compatibility with RES potentials, order of magnitude of hydrogen demand, etc.)

The following figure provides a graphical illustration of the process that has been put in place to generate the assumptions underpinning the reference scenario.



**Figure 5 – General methodology for designing the reference scenario**

Based on these assumptions (country-level demands for energy, country-level installed capacities, commodity prices, existing infrastructure levels, etc.), the Artelys Crystal Super Grid model is used to optimise the investments in additional infrastructure projects in order to ensure the electricity, hydrogen and methane demands can be met at all times (see Figure 4). The catalogue of investment options and their techno-economic characteristics are described in Section 3.1.

### THREE SENSITIVITY ANALYSES

Alongside the reference scenario, three sensitivity analyses have been built in order to explore the impacts of changing specific assumptions of the reference scenario:

- 1- **Hydrogen sensitivity:** reduction of the hydrogen demand and geographic re-allocation of RES installed capacities.
- 2- **Biomethane sensitivity:** reduction of the biomethane production (reaching LTS 1.5LIFE scenario’s assumption), and adjustment of RES installed capacities to compensate for the reduced availability of biomethane.
- 3- **Electrification sensitivity:** Additional heat pumps are introduced to replace the remaining gas boilers for space heating usages.

We provide more details of the way the assumptions of the three sensitivity analyses differ from the reference scenario in the following paragraphs.

#### HYDROGEN SENSITIVITY SCENARIO WITH BETTER RES ALLOCATION

In this scenario we adapt the reference scenario by reducing the hydrogen demand by 30% to match with the PAC scenario<sup>8</sup> (1050 TWh vs 1600 TWh in the LTS1.5TECH), where hydrogen is limited in sectors like industry or shipping instead of more widespread use. As far as production is concerned, we reallocate the RES production to have a more consistent match between power demand (including power for hydrogen demand), in a way that is compatible with existing RES potentials (see Section 3 for more details).

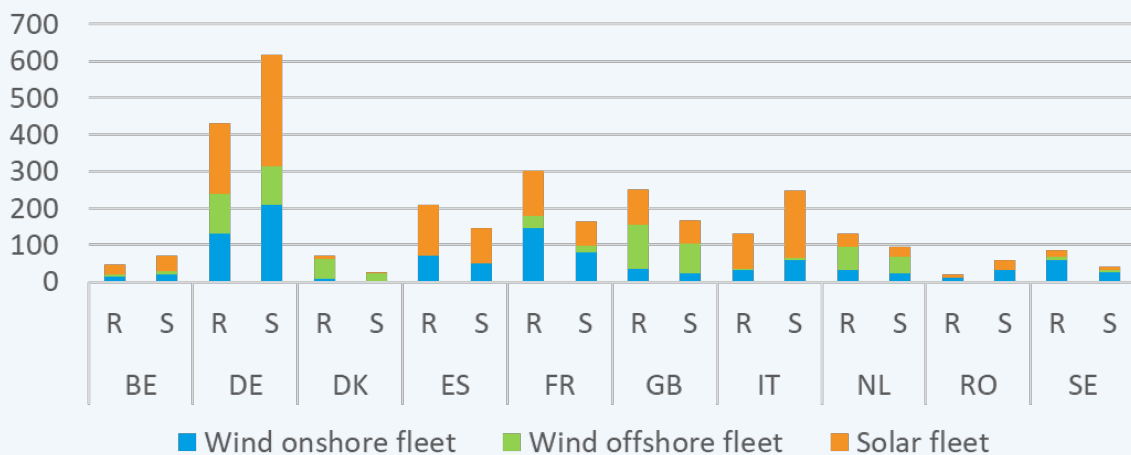
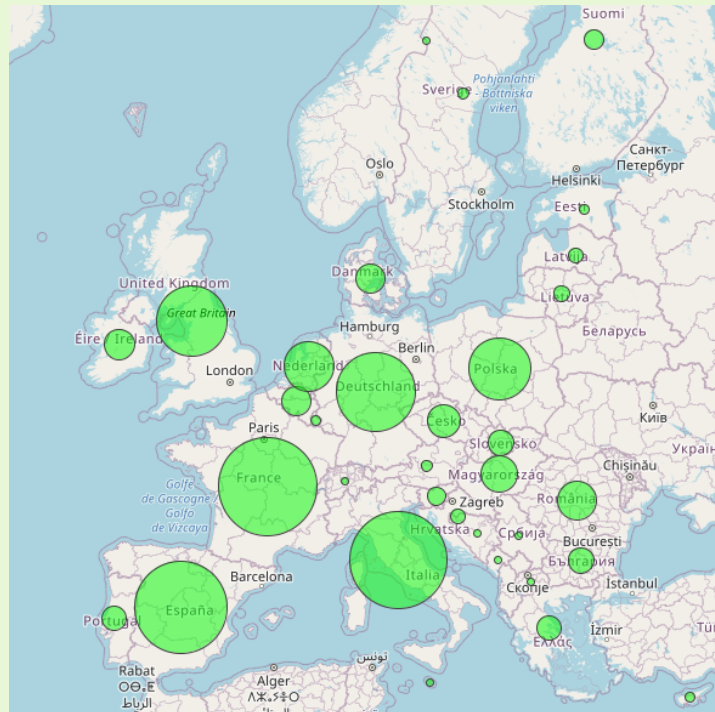


Figure 6 - RES installed capacities in the reference scenario (R) and the sensitivity (S) for specific countries

<sup>8</sup> CAN Europe/EEB: Building a Paris Agreement Compatible (PAC) energy scenario, June 2020, <http://www.caneurope.org/docman/climate-energy-targets/3620-pac-scenario-technical-summary-jun20-embargo>

### BIOMETHANE SENSITIVITY SCENARIO

In this scenario we adapt the reference scenario by reducing the biomethane supply capacity in each country to match with the LTS 1.5 LIFE scenario. Overall, biomethane supply is reduced by 25% to reach 650 TWh instead of 825 TWh.



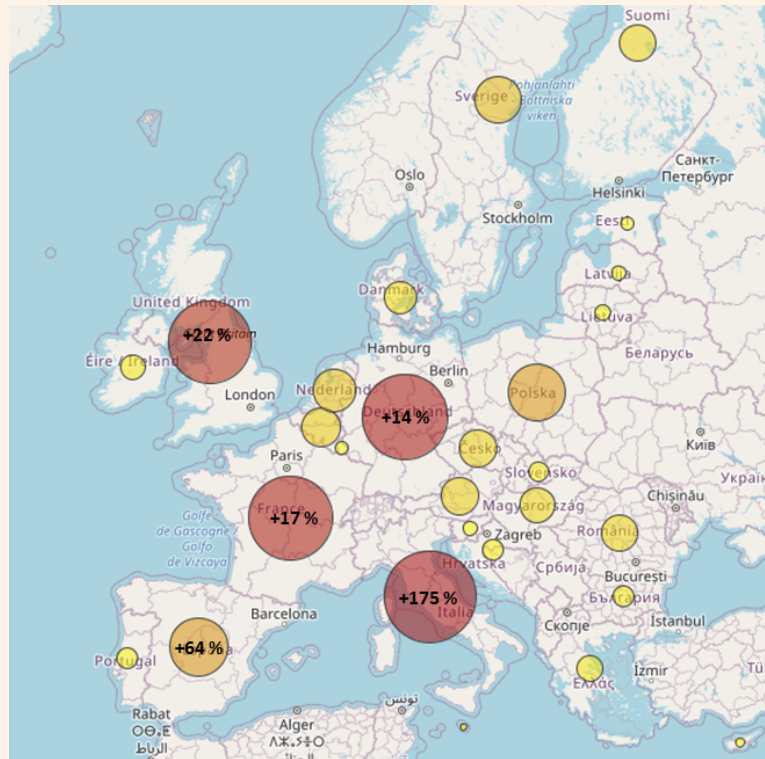
**Figure 7 - 650 TWh biomethane supply breakdown in the sensitivity scenario**

The way the biomethane supply has been reduced also considers the methane demand, so as to focus the supply of biomethane in countries where methane is to be consumed rather than to produce it elsewhere and to export it. In other words, the biomethane production has been capped at the methane consumption level.

The decrease in biomethane production is compensated by an increase in RES capacity to allow for the production of additional volumes of synthetic methane.

**HIGHER ENERGY EFFICIENCY AND ELECTRIFICATION SENSITIVITY SCENARIO**

In this scenario, the entire gas demand for heating in the residential and tertiary sectors is substituted by ambient and geothermal heat captured by electric heat pumps. The aim of this sensitivity is to simulate the replacement of gas boilers by more efficient options, inspired by the PAC scenario.



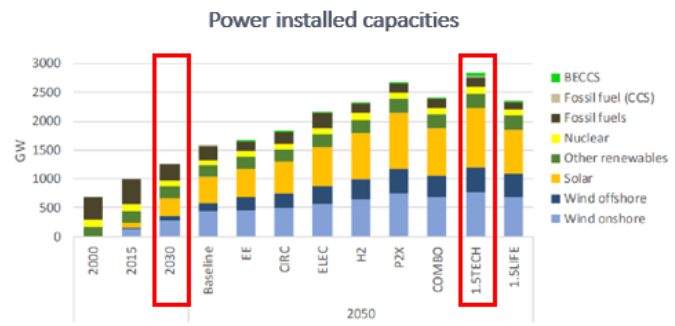
**Figure 8 - 355 TWh heat pump demand repartition in the sensitivity and comparison with the 270 TWh of the reference scenario**

As with the other sensitivities, the generation capacity of renewables has been adapted in order to cope with the new electricity consumption.

In total, the process illustrated by Figure 4 (optimisation of the investments in infrastructure and flexibility solutions) has therefore been repeated four times: once for the reference scenario, and three times during the sensitivity analysis. Instead of presenting the results for each of these four scenarios one by one, we proceed by exploiting the results of relevant simulations to provide the reader with the evidence on which the three key findings presented at the beginning of this section are based.

## 2.1 Finding 1 – Major investment levels in electricity infrastructure

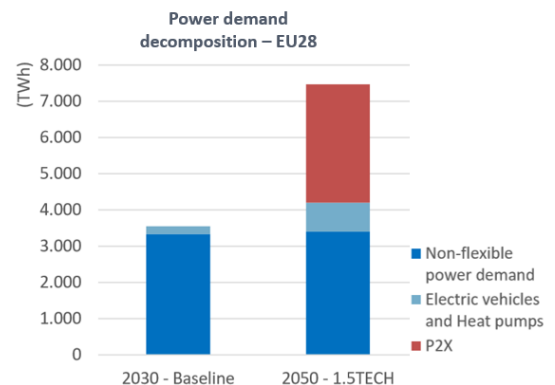
The decarbonation of the energy sector is associated to important investments in the power infrastructure with a growing importance of electricity compared to other energy vectors. In a 1.5TECH-inspired scenario, most of the primary energy supply is provided by the power sector and more precisely by variable renewable technologies such as solar PV, onshore wind and offshore wind. In order to ensure the security of supply criteria are met for all vectors, major investments in the power infrastructure are found to be required. With the assumptions we have used herein, a substantial share of these investments is found to be allocated to cross-border interconnections.



Source: Eurostat (2000, 2015), PRIMES.

As far as demand is concerned, the electricity sector will undergo a deep evolution. The direct or indirect electrification of currently carbon-based usages is indeed a must to reach the GHG emissions reduction targets of the 1.5TECH scenario. The electrification of end-uses can materialise in two ways:

- Direct electrification** of end-uses (e.g. heat-pumps, electric vehicles, low temperature heat for industrial processes). The newly electrified end-uses are imposing constraints on the system (additional need for electricity, ceteris paribus), but are also the source of flexibility potentials, e.g. via the smart charging of electric vehicles, load shifting in the industry, etc.
- Indirect electrification** of end-uses (via the use of hydrogen produced via electrolysis in processes including high and very high-grade heat, in mobility applications for long haul heavy transport, maritime/aviation after conversion of hydrogen into e-fuels, in heavy industry, such as steel and chemicals production)

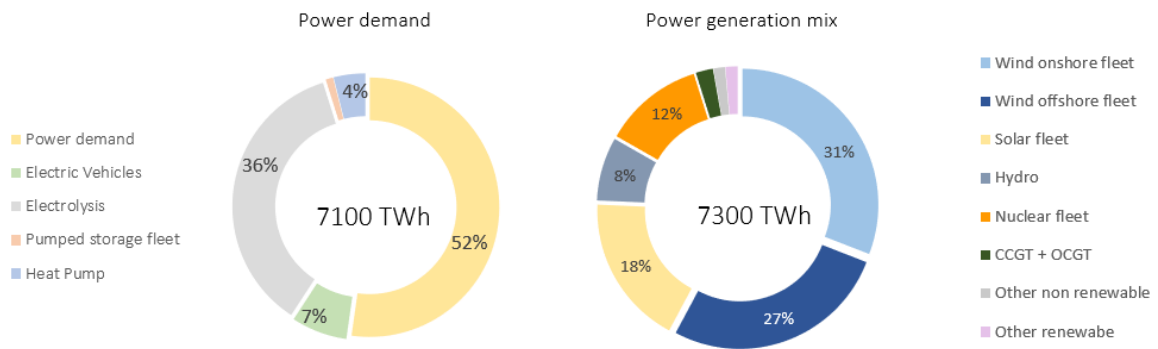


The combination of direct and indirect electrification of end-uses results in a doubling of the electricity generation requirements at the 2050 horizon in the 1.5TECH scenario compared to a 2030 baseline.

### 2.1.1 A high electrification and share of variable RES in 2050

Both the volume and the dynamics of the demand- and generation-side of the electricity system influence the relevance of investments in electricity infrastructure projects:

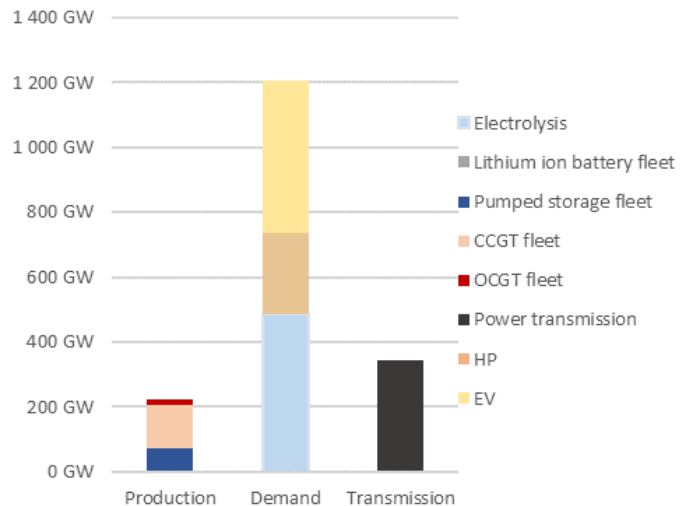
- | The massive electrification of end-uses required to reach the greenhouse gas emissions reduction target will lead to a much more important power generation volume compared to today's levels.
- | The power demand will be mainly supplied by variable renewable energies (mainly solar and wind power), leading to greater flexibility needs on each timescale, from the infra-hourly (driven by forecasting errors) to seasonal (driven by the thermo-sensitivity of the demand, the seasonal pattern of wind and solar generation), via the daily and weekly levels (mainly driven by the dynamics of the demand and the deployment of solar PV and wind power respectively).



**Figure 9 - Power demand decomposition and power generation mix for the reference scenario**

These two phenomena combined (higher variability in the demand due to electrification and higher variability in the supply due to RES) lead to a structural mismatch between consumption and production patterns, leading to the need to invest in flexibility solutions. The main types of assets can provide flexibility services to the power system are active demand-side management, conversion and storage assets, and networks.

Our results show that there will be a substantial need for new interconnections to ensure one can cost-effectively provide flexibility on all timescales in all the scenarios of the study.

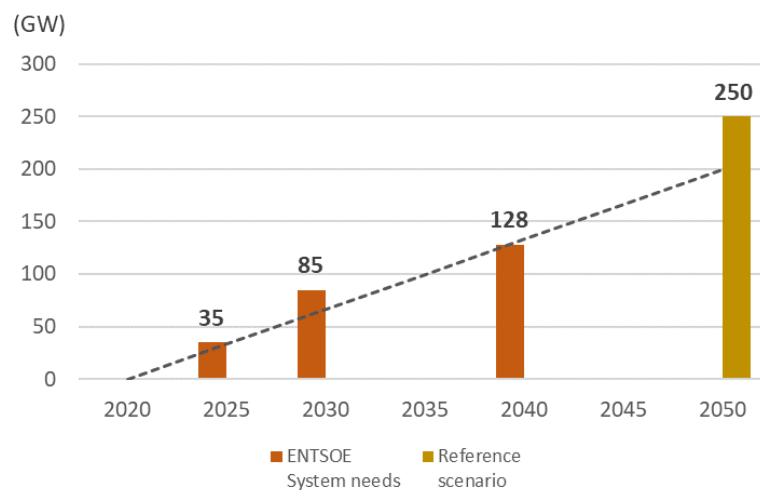


**Figure 10: Installed capacity of flexibility assets in the reference scenario**



## 2.1.2 Transmission capacities as an important provider of flexibility

In 2020, transmission capacities are reaching almost 100 GW within the considered scope, corresponding to EU27 + 7 neighbouring countries (Best Estimate 2020 from TYNDP 2018). In the following, the system needs that will be shown are to be understood as additions compared to this level. An **additional need of 250 GW of electricity interconnectors** is found to be required in the reference scenario. As a comparison, in its *Power system needs in 2030 and 2040*<sup>9</sup> report, ENTSO-E has identified that cross-border interconnection capacity needs to increase by 128 GW by 2040 in the National Trends scenario of the TYNDP 2020. The investments we have identified would correspond to around 70 billion EUR, based on the costs of transmission projects included in TYNDP 2018<sup>10</sup> as detailed in Section 3.1.4.1.

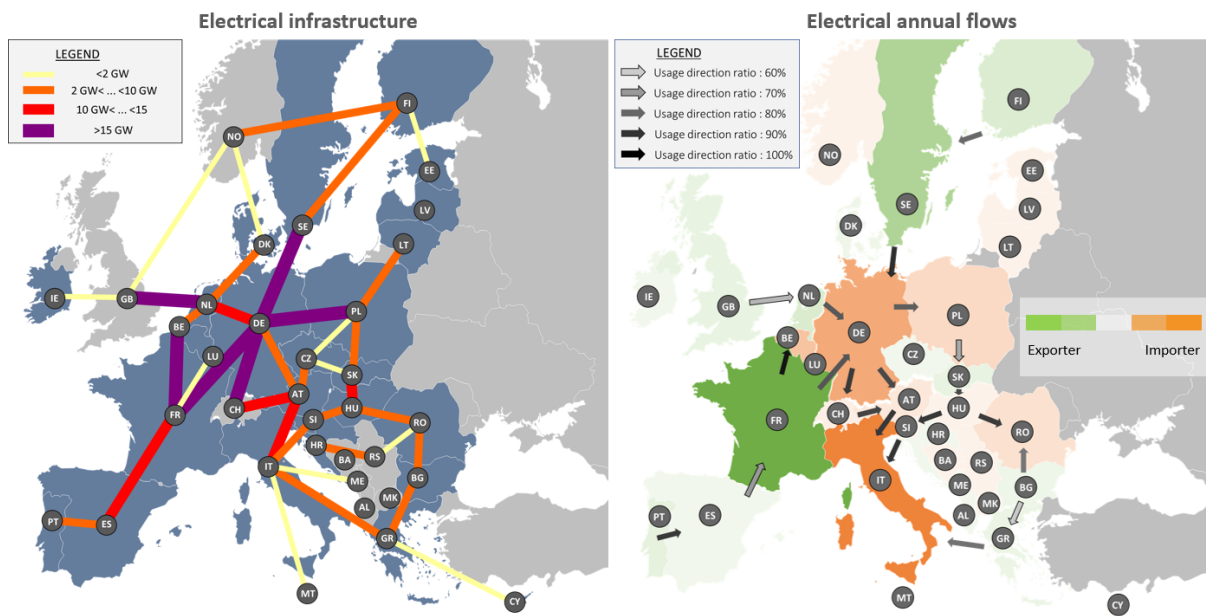


**Figure 11 - Additional transmission needs in the reference scenario compared to ENTSO-E's system needs**

Investments would be concentrated around countries that structurally need to import electricity (Italy, Germany, Belgium, Poland, Romania) as shown in Figure 12.

<sup>9</sup>[https://eepublicdownloads.azureedge.net/tyndp-documents/loSN2020/200810\\_loSN2020mainreport\\_beforeconsultation.pdf](https://eepublicdownloads.azureedge.net/tyndp-documents/loSN2020/200810_loSN2020mainreport_beforeconsultation.pdf)

<sup>10</sup><https://tyndp.entsoe.eu/tyndp2018/projects/>



**Figure 12 – Additional investments in interconnection infrastructure and underlying system equilibrium**

Some countries like the Netherlands, Spain, Switzerland or Austria will have to have very high interconnection capacities with their neighbours as they are found to be located on major transit routes in the reference scenario:

- | GB > NL > DE
- | PT > ES > FR > DE
- | FI > SE > DE
- | DE > CH > AT > IT

### 2.1.3 The impact of RES and electrification on the infrastructure

The hydrogen and electrification sensitivities (sensitivity analysis 1 and 3, respectively) are used in order to assess the impacts of a better geographical allocation of renewables and of a greater power demand on the infrastructure requirements. The results shown in this section are expressed as the difference between the considered sensitivity analysis and the reference scenario.

A reduction of the hydrogen demand and optimal allocation of RES capacity among the EU countries can lead to a significant decrease of infrastructure needs. On the electricity side, around 25 GW of electricity interconnectors could be avoided compared to the reference scenario, which represents 10% of the additional need that has been identified in that scenario. This would represent the lower bound of estimated investments in electricity infrastructure, circa 60 billion EUR.

In Figure 13, the green lines represent routes where lower investments are needed and red lines the routes where an additional power capacity is installed. The reallocation of RES leads to more RES capacities being installed in importing countries (BE, DE, IT), in a way that is compatible with local RES potentials, and thus reduces the transmission needs.

On the other hand, the switch from fossil boilers to heat pumps as it is studied in the third sensibility will accentuate the need for transmission capacities. Countries where the need for interconnection was already high are also those where the switches between boilers and heat pumps are the most important (e.g. DE, IT).

Our results show that the route from GB to IT, via by NL, DE and AT is reinforced compared to the reference scenario. In total, **30 additional GW of cross-border electricity interconnectors would be needed in this situation**. This would represent the higher bound of estimated investments in electricity infrastructure, circa 80 billion EUR.

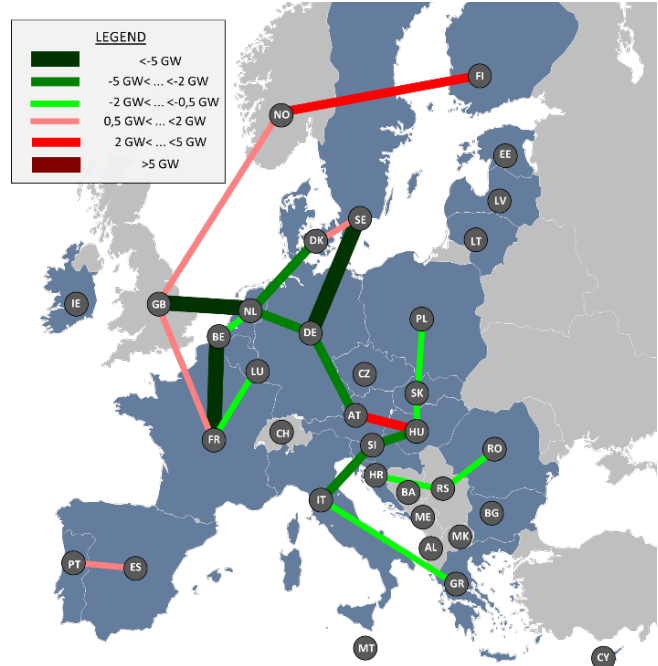


Figure 13: Additional investments needs in the reference scenario compared to the hydrogen sensitivity.

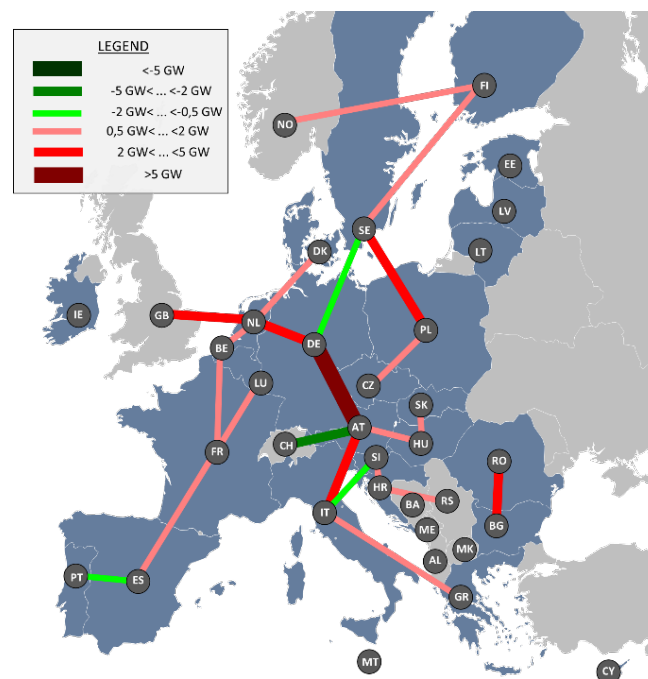


Figure 14: Additional investments needs for the electrification sensitivity compared to the reference scenario.

## 2.2 Finding 2 – Trade-off between local hydrogen production and infrastructure

In the 1.5TECH scenario of the European Commission, and in multiple other net zero scenarios, hydrogen is an energy vector that plays a major role at the 2050 horizon, particularly in the decarbonisation of hard-to-abate sectors. Electrolysis within Europe is the preferred hydrogen production technological option in the 1.5TECH scenario, and more in general in the Commission's Long-Term Strategy<sup>11</sup>. In the 1.5TECH scenario, hydrogen plays different roles:

- | It is consumed by industry, either as feedstock or as a replacement to carbon-intensive options.
- | It is a building block for the production of e-gases and e-liquids. Synthetic methane, produced by combining hydrogen and CO<sub>2</sub>, can be used for applications where methane is difficult to be replaced in an economical way. E-liquids can power long-distance energy transportation means, in road, maritime and aviation sectors.
- | Finally, electrolyzers (when connected to the electricity grid) and hydrogen storage assets can provide flexibility services on all timescales, thereby allowing for a cost-effective integration of renewables. Indeed, the operational behaviour of electrolyzers can adapt to RES generation patterns, and hydrogen storage can enable shifting part of the hydrogen demand to periods of highest RES generation.

In total, 2250 TWh of hydrogen (or roughly 65 Mt) are found to be generated in the reference scenario. The optimal level and geographic allocation of investments in electrolyzers (should they be close to RES generation centres or to hydrogen consumption areas?) and in hydrogen infrastructure to transport hydrogen across Europe are the key questions we explore in the following paragraphs.

### 2.2.1 Investments in hydrogen infrastructure will be required in specific areas

The transition between the current situation where gas is mostly imported from external supply sources to a 2050 situation with a more local generation of gases (biomethane, hydrogen, e-CH<sub>4</sub>) will cause a structural evolution of gas flows across Europe. As a consequence, some of the current methane infrastructure may not be required for methane transport anymore, and could be repurposed so as to support the use of hydrogen. Moreover, local hydrogen networks have already shown their relevance for industrial clusters. Repurposing would have the advantage to benefit from the current infrastructure and avoid useless additional pipe constructions (thus reducing costs).

Nevertheless, repurposing parts of the gas infrastructure must be considered from a multi-energy point of view as gas pipelines are still likely to be used for methane transport in countries where the

---

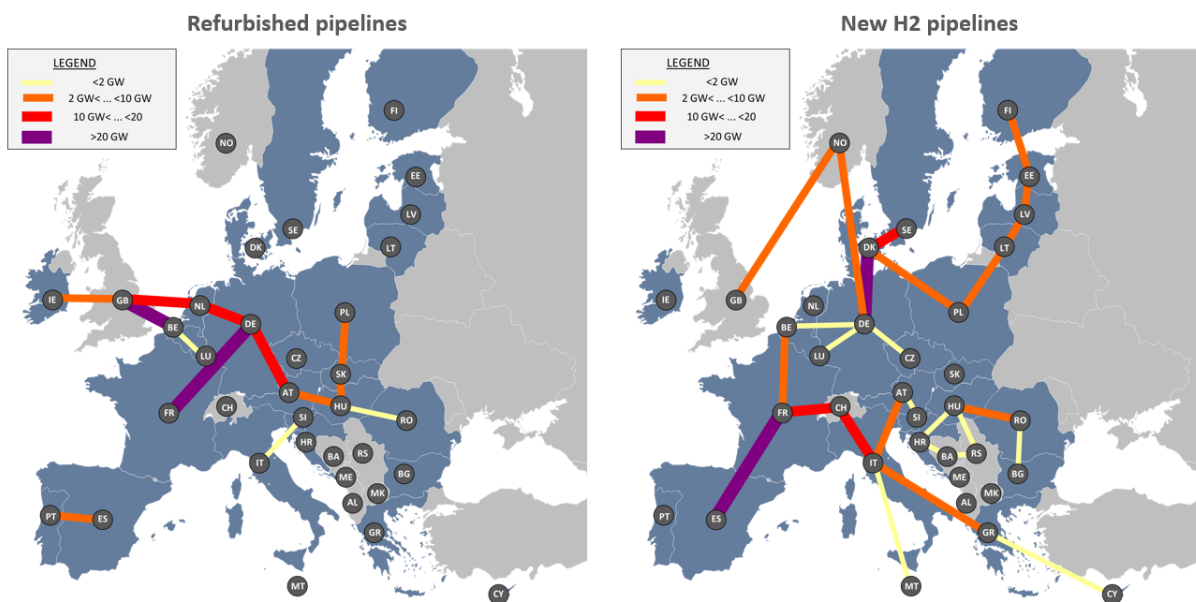
<sup>11</sup> Several strategies are being considered by industry to supply part of the European hydrogen demand from third countries. The corresponding choice of import routes could have important impacts on the required infrastructure for hydrogen, but also for methane and electricity.

local biomethane production does not match the projected methane demand. Our simulations show that some pipes are particularly well adapted for repurposing.

A targeted refurbishment of some important pipes can lead to a significant reduction of new hydrogen infrastructure requirements. In the reference scenario we estimate that 320 GW of gas pipeline is repurposed leading to 260 GW of hydrogen capacities. This investment corresponds to the major routes connecting Germany, which lies at the centre of the hydrogen system in the reference scenario, to the rest of Europe.

Additionally, 310 GW of new hydrogen pipelines (aggregating both directions) would also be necessary in the reference scenario. On some of these routes, methane pipelines exist but two reasons might lead to the preference for new pipelines:

- | The need for hydrogen capacity does not reach by far the existing methane pipeline capacities.
- | The methane pipeline is used for methane flows.



**Figure 15 - Repurposed and new hydrogen pipelines in the reference scenario**

In total, around 570 GW of hydrogen pipelines would result from repurposing or new constructions. Using recent estimates of associated costs, the investment for cross-border infrastructure corresponds to circa 25 billion EUR. See Section 3.1.4.3 for more details on the underlying assumptions.

The hydrogen infrastructure enables to connect main hydrogen exporters (the Netherlands, Spain and France) to the main hydrogen importers (Germany, Italy and Poland).

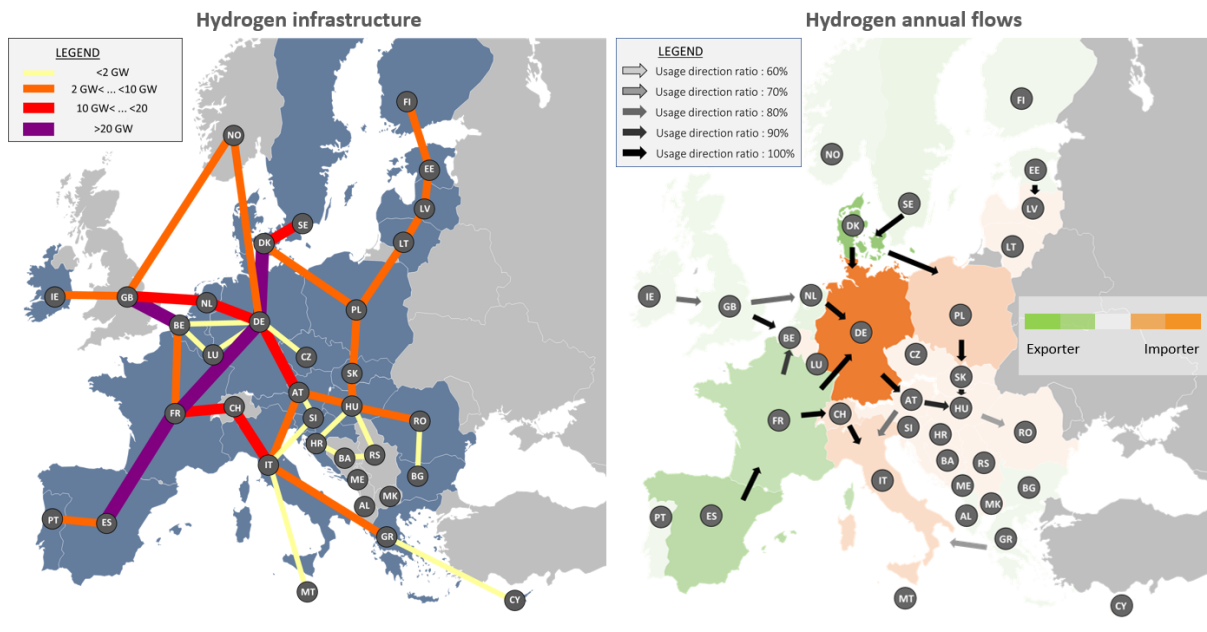


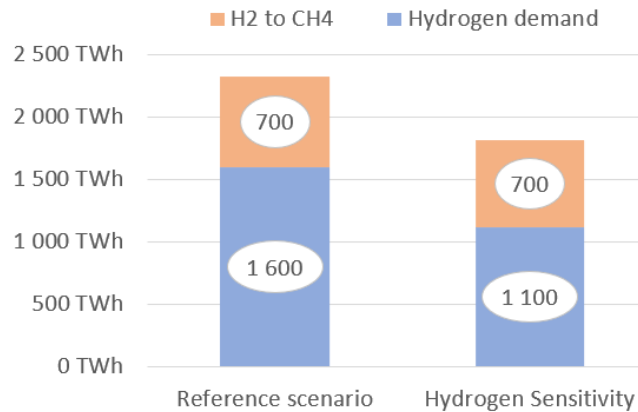
Figure 16 : Total hydrogen infrastructure (refurbished pipelines and new H2 pipes) and underlying system equilibrium that explain the investments for the reference scenario

Some countries (NL, DK, AT) serve as transit towards central Europe. The major transit routes are found to be:

- | ES > FR > DE or BE
- | ES > FR > CH > IT
- | IE > GB > NL > DE
- | SE > DK > DE
- | DE AT > IT or HU

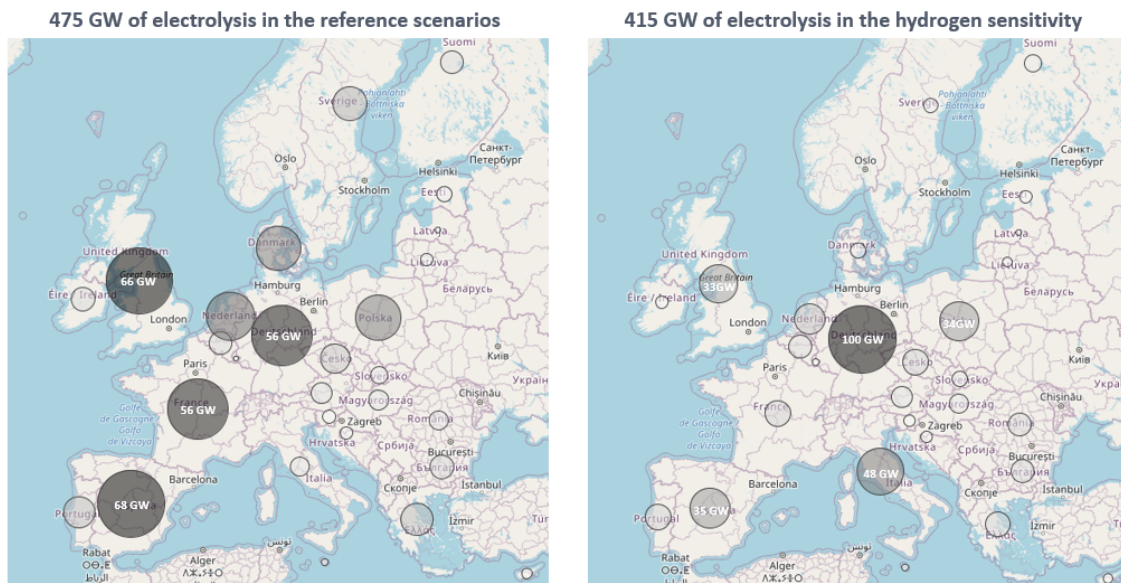
## 2.2.2 Evolution of the infrastructure with a more local production

The level of hydrogen demand is an important factor in the sizing of the hydrogen infrastructure. More importantly, our simulations (the first sensitivity in particular) show that a geographical allocation of renewables that is better aligned with the levels of hydrogen demand leads to significantly different levels of investments in infrastructure, and in particular in electrolysis and hydrogen transport capacity.



**Figure 17 -Hydrogen demand decomposition for the reference scenario and the hydrogen sensitivity scenario**

In the hydrogen sensitivity, the capacity of electrolysers is found to be lower, and reallocated closer to RES productions areas (which are assumed to be better aligned with hydrogen demand centres).



**Figure 18 - Electrolysis capacities for the reference case and in the sensitivity analysis**

Our simulations show that the combination of a 30% decrease of hydrogen demand (representing a limitation of the role of hydrogen to hard-to-abate sectors, in line with the PAC scenario) and a better allocation of renewable production lead to a 60% decrease of the required hydrogen infrastructure. Only 240 GW of cross-border hydrogen infrastructure are found to be required in the hydrogen sensitivity compared to 570 GW in the reference scenario. This would also correspond to a decrease in associated investments, reaching circa 15 billion EUR.

In the hydrogen sensitivity scenario, we no longer see the need for large-scale routes, as hydrogen investments have a capacity under 10 GW in almost all cases.

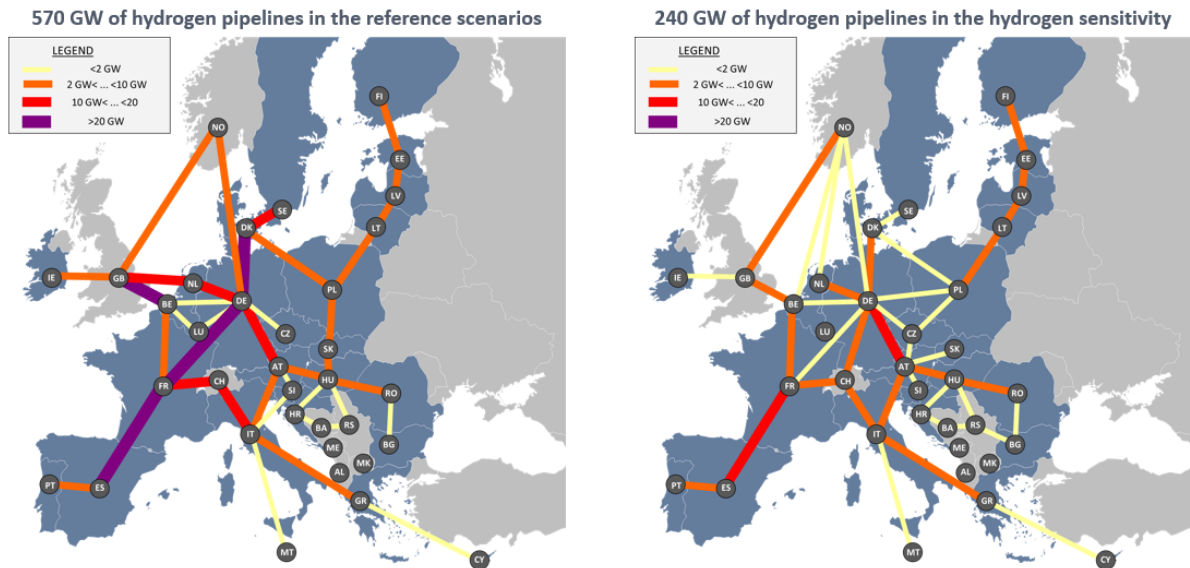


Figure 19 - Comparison between the hydrogen infrastructure in the reference scenario and in the hydrogen sensitivity

On the other hand, a decrease of biomethane production leads to a higher level of investments in hydrogen infrastructure. Finally, the electrification sensitivity does not impact the hydrogen infrastructure needs. However, as gas flows reduce, repurposing the infrastructure is found to be preferred to laying new pipes in more cases. Of the 570 GW hydrogen pipelines, slightly more than half (up to 290 GW) can be obtained by repurposing existing gas infrastructure (against 260 GW for the reference scenario).

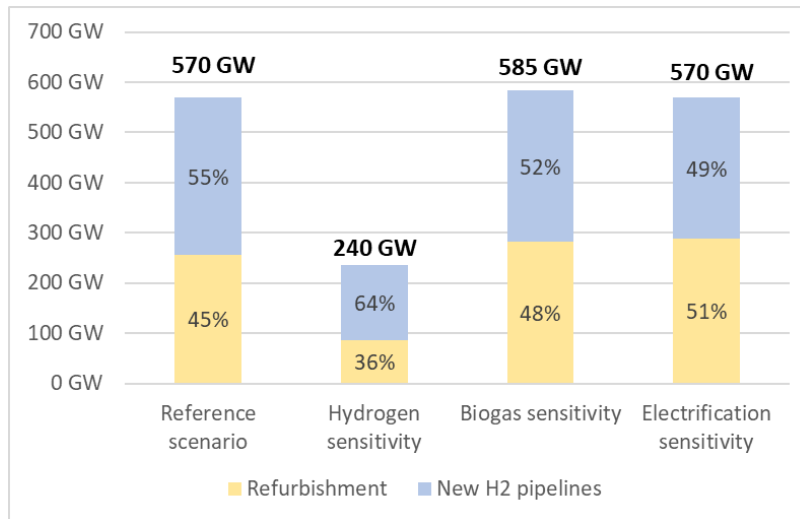
This sensitivity shows that an objective of exporting biomethane to neighbouring countries could harm the ability of the gas system to switch to hydrogen.

### 2.2.3 What is the most appropriate solution between repurposing and laying down new hydrogen pipelines?

The simulations demonstrate that two key factors are impacting the trade-off between repurposing the gas infrastructure and laying down new hydrogen pipelines:

- | The **volume of hydrogen in the system**: repurposing is a binary process, the lower the hydrogen demand is, the less likely it is that repurposing be favoured as the existing gas pipelines have capacities that may be too high compared to the need to transport hydrogen. Investing in a dedicated hydrogen solution might be cheaper in some cases.
- | The **volume of CH<sub>4</sub> flows in the system**: if the methane flows remain important, the system needs to keep a sufficient level of CH<sub>4</sub> infrastructure. Reducing the biomethane injection or CH<sub>4</sub> demand and considering biomethane as a local supply - as in the two last sensitivities - will leave more room to repurposing.

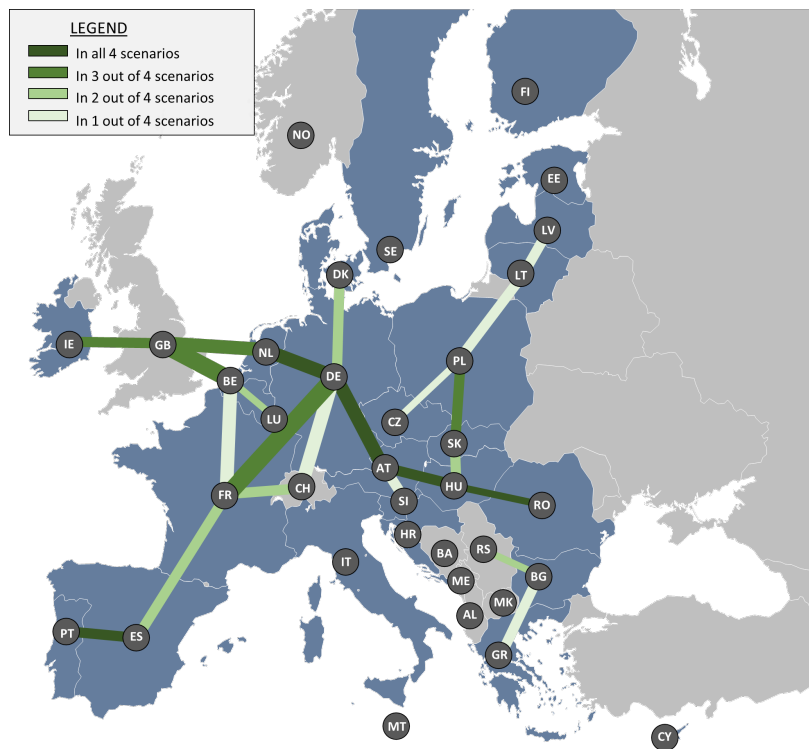




**Figure 20 - Distribution of investment between repurposing and new H2 pipelines for the reference scenario and the 3 sensitivity analyses.**

Based on the results of all scenarios, we have aimed at identifying the regions where repurposing seems to be relevant in most cases. This analysis, which could be refined should additional scenarios be developed, could constitute the basis of a “no regret” approach to repurposing.

In our case, five links are found to be repurposed in all scenarios: PT-ES, NL-DE, DE-AT, AT-HU, HU-RO, as depicted in Figure 21.



**Figure 21 – Repurposing considered in the different scenarios**

## 2.3 Finding 3 – The changing role of methane infrastructure

This section presents the role of the methane infrastructure, that has been designed with as its primary objective to enable the import of natural gas from a number of third countries. In the previous section, we have seen that, under our assumptions, it is economically relevant to repurpose part of the existing infrastructure so that it can handle hydrogen. In this section, we discuss the role of the rest of the methane infrastructure and whether any additional infrastructure needs are identified.

### 2.3.1 A lower methane consumption is expected in 2050 compared to 2020

As a consequence of energy efficiency measures and of switches to using decarbonised fuels, the total methane consumption is expected to decrease dramatically in the 1.5TECH scenario, which is the basis of our reference scenario. The supply tends to switch to local production with a high level of biomethane, e-gas and hydrogen.

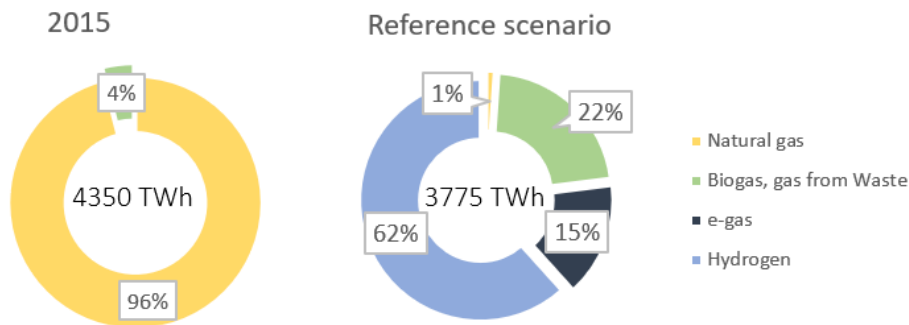


Figure 22 – Overall gas supply mix evolution between 2015 and 2050.

On the methane side, supply is shared between biomethane and e-gas, with natural gas only playing a marginal role. The share of e-gas is mostly a function of the biomethane volumes that are assumed to be injected into the gas network, as can be read from the following figure:

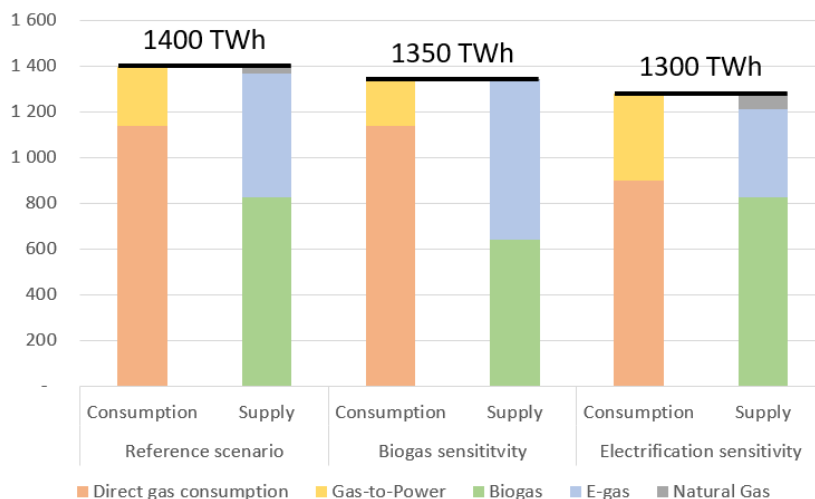


Figure 23 – Methane consumption and supply shares in the different scenarios

### 2.3.2 The gas supply tends to be local rather than global

The role of the current gas infrastructure will deeply evolve due to the emergence of new gas production and consumption patterns, which lead to a very different structure of gas flows compared to the current situation. Today the infrastructure is designed to import large quantities of natural gas from a small number of suppliers (Norway, Russia, Algeria, Libya, and LNG markets). In a 1.5TECH-like scenario, the methane mainly comes from renewable sources, either in the form of biomethane or e-gas. As a result, most of the required methane can be locally produced, either via local biomethane production or via electrolysis coupled to H<sub>2</sub>-to-CH<sub>4</sub> processes. As a result, the role of the current gas network linking countries to supply sources, with diversification of suppliers taken into account, is changing.

The distinction between local production (production consumed inside the country where it is produced), imports inside EU27 + 7 (the gas is produced by another EU27 + 7 country) and imports from third countries can be depicted on Figure 24.

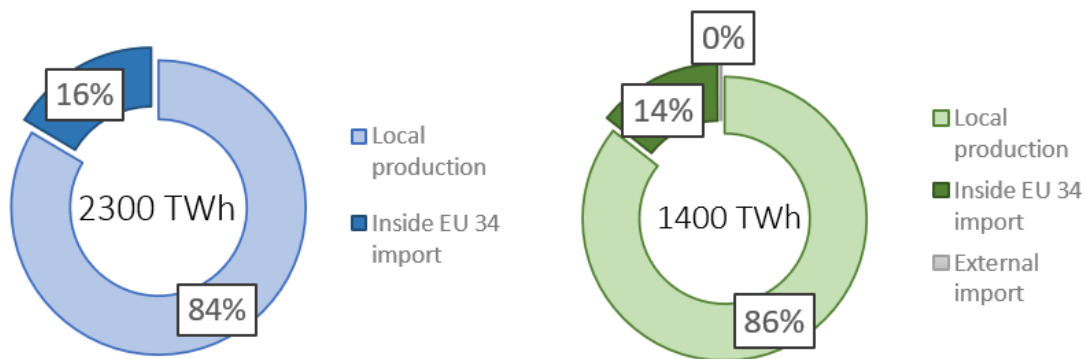


Figure 24 – Local and imported shares of H<sub>2</sub> and CH<sub>4</sub> production in the reference scenario over EU34

### 2.3.3 Few constraint areas

The key finding in terms of methane infrastructure is that no additional projects are required to ensure security of supply within the EU. Only a very small number of new projects (with very low capacities, under 1 GW) emerge as being potentially relevant: in the Baltics, in South-Eastern Europe to assist non-EU countries, and between FR and CH. All but the investments in South-Eastern Europe disappear in the sensitivity analyses.

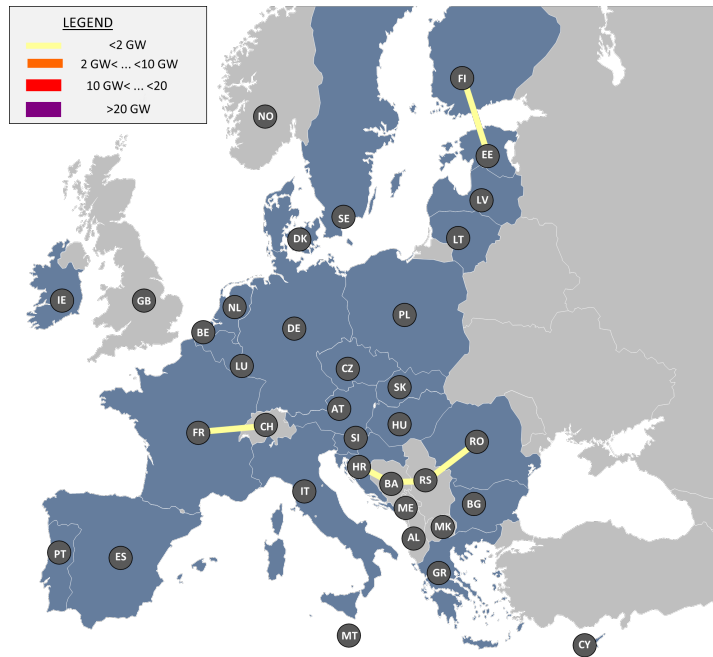


Figure 25 - New installed gas capacities in the reference scenario

The observation of the flows and in particular the direction in which the pipelines are used can help explain the drivers of these investments as depicted in Figure 26.

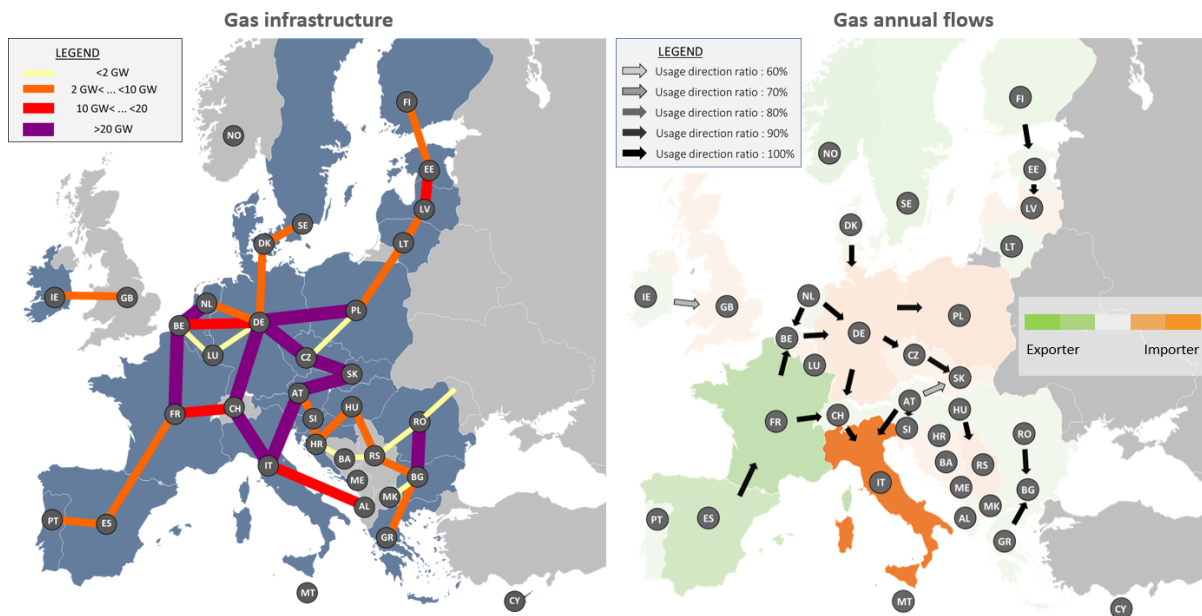


Figure 26 - Total gas infrastructure (excluding repurposed pipes) and gas flows directions in the reference scenario

As a reminder, the flows map depicts the importing countries in green and the importing ones in orange (we only consider here the annual net imports/export balance). The arrows are only shown for the major routes and are helping to understand the underlying rationale of a given investment. The different levels of grey indicate the directionality of the use of the infrastructure. A black arrow

represents pipes that are only used to transport gas in one direction over the year whereas light grey arrows represent pipes that are used in both directions.

The analyses of the sensitivities confirm that only the reinforcement in the Balkans, which had also been identified in a previous analysis on gas supply security in the EU energy transition<sup>12</sup>, may be relevant to ensure security of supply of third countries. A more thorough analysis of the potential role of increased energy efficiency efforts should be conducted to assess the best portfolio of investments to solve this local issue. The FI-EE and FR-CH interconnection only appear in the reference scenario and are not linked with security of supply issues, but are rather due to peculiarities of the scenario. As a consequence, no additional methane projects are required to ensure the EU's security of supply.

### 2.3.4 As a result, the methane infrastructure is under-used

Overall, the methane infrastructure that is not repurposed is found to be characterised by low use rates. The use rate is calculated as the sum of the flows in each direction divided by the maximum theoretical flows and is depicted Figure 27.

Biomethane and e-gas are transported to areas where methane is needed (e.g. IT, Balkans, DE, PL) via specific routes. In addition to its CH<sub>4</sub> needs, DE remains a transit region but some surrounding methane infrastructure have very low use rates (with BE, LU, PL and CZ for example). On the other hand, a number of methane routes are still being used.

Most of the remaining pipelines are used only for occasional transfers. Some of them have use rates below 1%. Therefore, the decommissioning of some of the remaining infrastructure (excluding repurposed pipes) could be explored, e.g. by analysing the system-level impacts of a decommissioning in terms of energy efficiency efforts and/or investments in alternative infrastructure.

---

<sup>12</sup> <https://www.artelys.com/wp-content/uploads/2020/01/Artelys-GasSecurityOfSupply-UpdatedAnalysis.pdf>

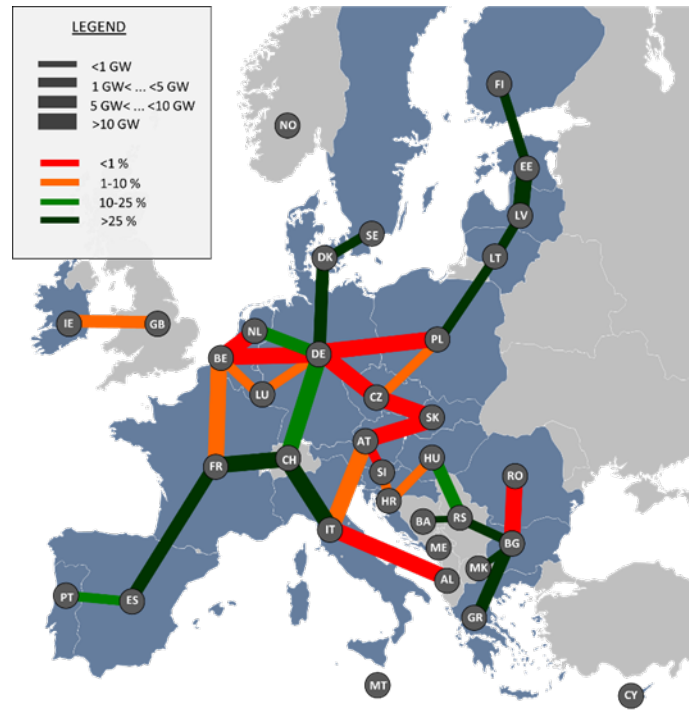


Figure 27 - Use rate of gas pipelines in the reference scenario

**IMPACT OF BIOMETHANE ON CH4 INFRASTRUCTURE**

The share of biomethane in the system has an impact on H2-to-CH4 (methanation) installed capacity. In the biomethane sensitivity, this capacity increases by 20%, see Figure 28. Indeed, the CH4 demand remaining the same, the system compensates by increasing the production of e-gases, and therefore invests in more H2-to-CH4 conversion assets. Alternatives such as investing in energy efficiency or switching to other vectors (hydrogen or electricity) have not been explored in this sensitivity analysis.

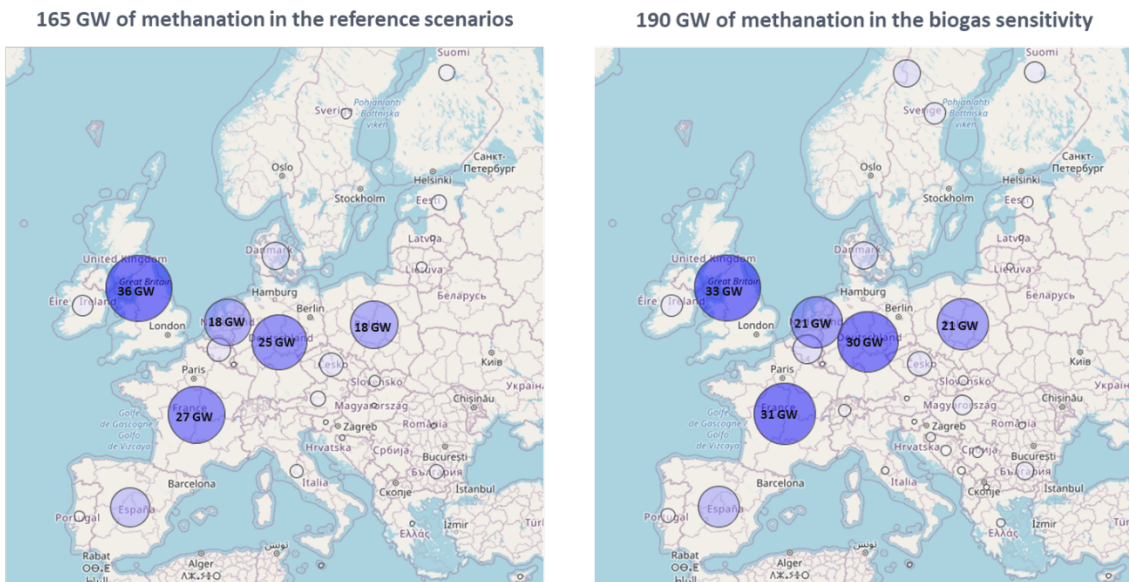
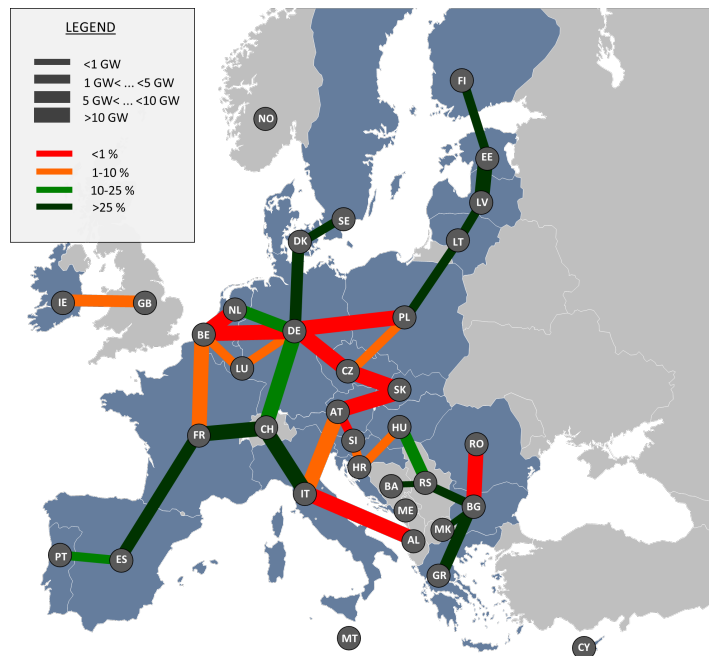


Figure 28 - Methanation installed capacity evolution between the reference scenario and biogas sensitivity

**IMPACT OF ELECTRIFICATION ON CH4 INFRASTRUCTURE**

As a consequence of the lower volumes of CH4 being required in the electrification sensitivity analysis, more pipes are found to have very low use rates compared to the reference scenario. Germany and Italy are especially impacted by the assumed reduction of CH4 consumption, as they are characterised by a sizable thermosensitive share in their CH4 consumption. As a consequence, additional pipelines are refurbished in this sensitivity analysis. For example, in this particular case, the NL-DE pipe is not used to transport CH4 anymore, leaving the opportunity to repurpose it for hydrogen use.



**Figure 29 - Use rate of gas pipelines in the electrification sensitivity**

Finally, lower methanation capacities are installed due to the reduction of CH4 demand.

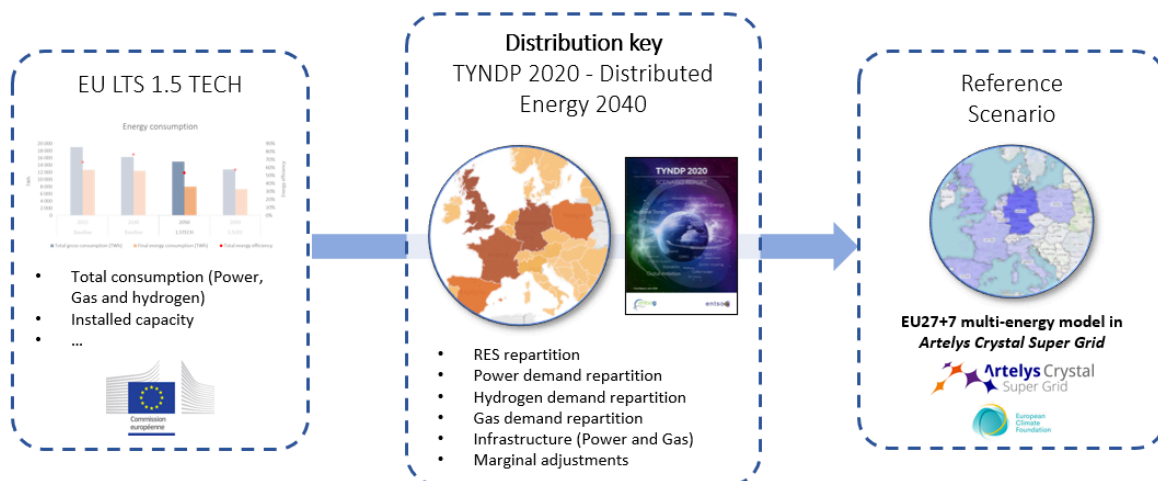
## 3 Appendix – Key Assumptions

### 3.1 Appendix A – Modelling of the European energy system

#### 3.1.1 General methodology

In order to analyse the energy infrastructure needs in Europe by 2050, this study relies on a joint bottom-up model of the European power, gas and hydrogen systems using a country-level granularity. The reference scenario is based on the publicly available data of the Long-Term Strategy 1.5TECH scenario from the European Commission<sup>13</sup>.

Since the publicly available data of the LTS 1.5TECH scenario is provided at the EU-level, a distribution key is needed to breakdown all figures at the country level in order to build a consistent EU27+7 scenario with explicit representation of all countries (the so-called reference scenario). For this purpose, we have used the 2040 Distributed Energy scenario from TYNDP 2020 (which is defined at the country level) to disaggregate the LTS 1.5TECH scenario data (for example annual energy production and demand, installed capacities, etc.). Moreover, infrastructure datasets from the TYNDP 2018 and other scenarios of TYNDP 2020 are also used to benchmark and complement our dataset.



**Figure 30 - General methodology for designing the reference scenario**

The Artelys Crystal Super Grid model allows for a joint modelling of the electricity, hydrogen and methane systems. For this study, we have chosen to explicitly represent the cross-border links between countries for the three vectors. Based on this multi-energy model, we are able to represent all relevant interlinkages between the different systems. An overview of the links between the various aspects of the considered system is provided in Figure 31. To summarise:

<sup>13</sup> LTS 1.5Tech scenario data are derived from the LTS reference document (see Glossary).



- For each energy vector, the hourly supply-demand equilibrium is enforced. The production dispatch between all technologies (in the case of electricity: vRES, biomass, nuclear, hydropower, gas-fired power plants, etc.) is optimised as well as cross-border flows, storage units' operations and different types of demand-side response technologies (e.g. smart charging of electric vehicles).
- The supply-demand equilibria of different energy vectors are linked by assets converting one into another (electrolysers, methanation plants, gas-fired power plants, SMR plants, etc.).
- The investments in electricity, hydrogen and methane cross-border capacities as well as other flexibility providers (pumped hydro-storage, batteries, power-to-X technologies, etc.) are optimised (jointly with the dispatch of the entire system).

In the following sections we provide an overview of the modelling of the key aspects of the European energy system and of the design of the reference scenario.

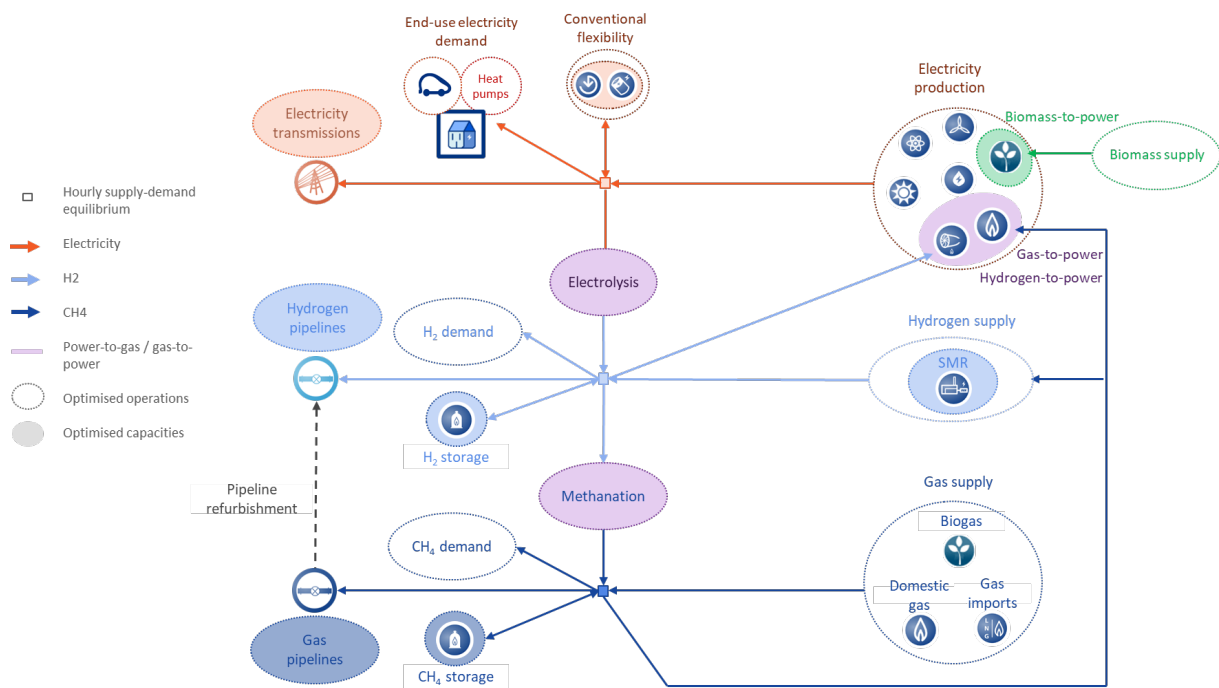


Figure 31 - Schematic overview of the modelling structure of the European power, gas and hydrogen systems

### 3.1.2 Demand

For the three energy vectors, the demand modelling is performed via a similar process. First the annual projected consumption for each country and different end-uses are computed (see Figure 32) for each final energy vector (electricity, gas and hydrogen). Then, the annual volumes are distributed on end-use demand time-series, excepted when flexible demands are modelled explicitly (electric vehicles and heat pumps).

For each energy vector, key usages are identified. The explicit usages correspond to the usages for which we use an explicit modelling of the loads. The rest of the load is separated into its thermo-sensitive part and its non-thermosensitive part. The thermosensitive demands mainly correspond to the heating demand in the residential sector and the tertiary sector, while the non-thermosensitive usages include all the other usages (industry, non-heating usages, transports).

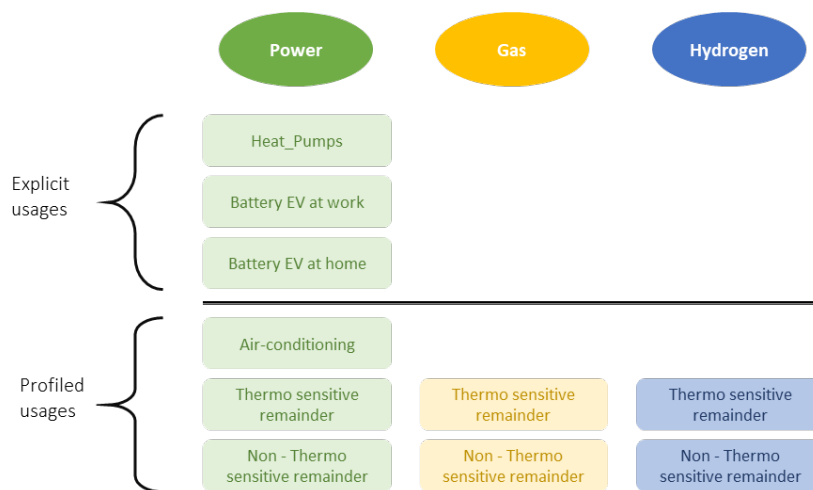


Figure 32 - Demand decomposition by usage

#### 3.1.2.1 Electricity demand

The LTS reference document provides an end-use power demand of around 4 000 TWh in the 1.5TECH scenario at EU level. In order to model electric vehicles and heat pumps consumption behaviour, annual consumption for both usages have been computed based on the LTS document (around 500 TWh and 250 TWh for electric vehicles and heat pumps respectively). Then, the EU Member States country breakdown has been performed by using assumptions based on the Distributed Energy scenario of the TYNDP 2020 and on the METIS 2050 scenario<sup>14</sup>: electricity consumption by sector and end-use is used as distribution key.

For non-EU countries, the annual electricity demands are based on an analysis of the TYNDP 2020 data for each usage.

<sup>14</sup> For further information regarding the METIS 2050 scenario, the reader is referred to the METIS project (see [https://ec.europa.eu/energy/data-analysis/energy-modelling/metis\\_en](https://ec.europa.eu/energy/data-analysis/energy-modelling/metis_en).)

Finally, several demand-side flexibilities are included in the modelling of the European power system:

- | Smart charging patterns of electric vehicles are optimised, depending on the user profiles (home charging/work-charging): it is assumed that 70%<sup>15</sup> of electric vehicles have a smart charging behaviour.
- | The functioning of heat pumps is simulated by optimising the heat production from heat pumps (driven by the outside temperature), the thermal storage and the heat production by electric back-up heaters<sup>16</sup>.

### 3.1.2.2 Gas and hydrogen demand

The LTS EU volumes for gas and hydrogen have been extracted from the LTS reference document.

The e-gas (mainly methane created by methanation) was considered as a methane demand and e-liquids demand was transformed into a hydrogen demand with an efficiency based on the ASSET database<sup>17</sup>.

For methane, a decomposition by sector based on an analysis of TYNDP 2020 has been used. Moreover, the portions of heating demand present in this scenario were also used to separate the residential & services share into a thermosensitive demand. The non-energy, industry, non-heating share of residential & services and transport energies have been gathered in a non-thermosensitive demand. The final methane demand (that does not include the methane used for power generation, since this is optimised by the model itself) in the reference scenario represents around 1200 TWh HHV.

For hydrogen, the TYNDP 2020 Distributed Energy scenario at the 2040 horizon provides a distribution per country for the transport and industry sectors, but only considers a very small portion of hydrogen for the residential and tertiary sector (less than 5 TWh HHV). In order to define a more suitable allocation key for these sectors, where the 1.5TECH scenario and the TYNDP 2020 visions diverge, an ad-hoc disaggregation key based on an analysis of the share of methane in residential and tertiary sectors has been used here. The final hydrogen demand (without the hydrogen used for power generation, since this is optimised by the model itself) in the reference scenario represents around 1600 TWh HHV.

The resulting demand levels have been compared to country-level publications for selected countries in order to ensure a plausible allocation of the 1.5TECH demand levels is used for the reference scenario.

---

<sup>15</sup> The 70% figure is extracted from the EC's study "Contribution to the security of the electricity supply in Europe" (available [here](#)).

<sup>16</sup> Because the coefficient of performance of heat pumps degrades with low outside temperatures, an electric back-up heater is associated to the heat pump, to ensure the heat demand can be met.

<sup>17</sup> See <https://asset-ec.eu/home/advanced-system-studies/cluster-3/technology-pathways-in-decarbonisation-scenarios/> for additional information regarding the ASSET database.

a) Electricity: 4 000 TWh

b) Methane: 1 200 TWh

c) Hydrogen: 1 600 TWh

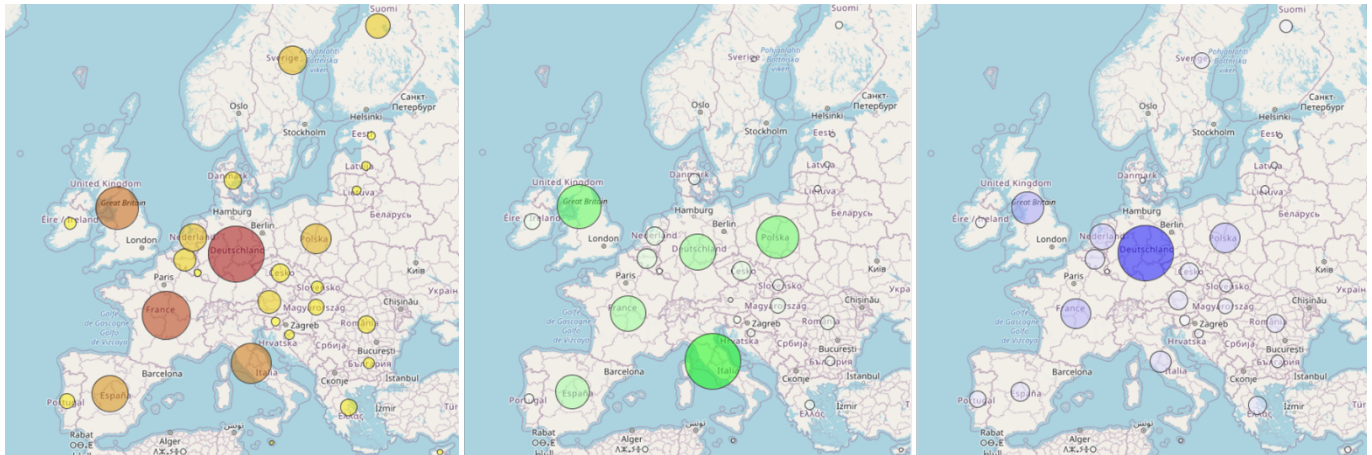


Figure 33 – Final energy demand breakdown in the reference scenario

### 3.1.2.3 Hourly profiles

The demand profiles are constructed according to the statistical method developed for the METIS project<sup>18</sup>, which are calibrated using historical datasets and take into account the thermo-sensitivity of the various end-uses.

## 3.1.3 Supply

### 3.1.3.1 Electricity supply

#### 3.1.3.1.1 Installed capacities

In order to model the European power system in the LTS 1.5TECH scenario, the power generation capacities at the EU level have been extracted from the LTS reference document (see Figure 34). The LTS 1.5TECH capacity mix includes a high share of variable renewable capacities with respectively around 1000 GW and 1200 GW of solar and wind capacities (around 750 GW of onshore wind and 450 GW of offshore wind). Other renewable capacities (including in particular hydropower, biomass and biomethane fleets) are also significant with around 250 GW of installed capacities. The thermal fleets complete the capacity mix with around 120 GW of nuclear capacity, 50 GW of bioenergy capacities with carbon capture and storage (BECCS) and 135 GW of fossil fuel-based capacities (including 90 GW of gas-fired capacities and 45 GW of coal and oil-fired capacities, mainly used as reserve).

<sup>18</sup> For further information regarding the METIS project, the reader is referred to [https://ec.europa.eu/energy/data-analysis/energy-modelling/metis\\_en](https://ec.europa.eu/energy/data-analysis/energy-modelling/metis_en).

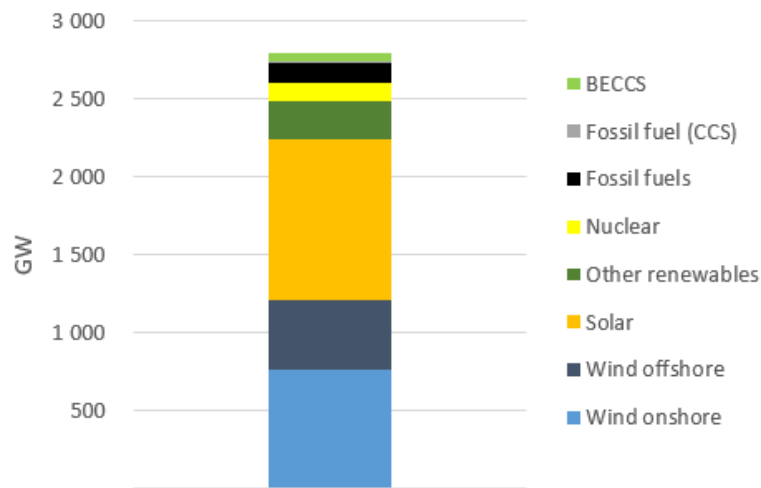


Figure 34 - Power generation capacity in the LTS 1.5TECH scenario

The breakdown of these figures at the EU Member States level has been carried out on the basis of the Distributed Energy scenario of TYNDP 2020, and by taking into account particularities of each generation technologies. The coal, lignite and oil power plants have been directly split by using the Distributed Energy scenario data for the year 2040. The same method has been used for the disaggregation of the EU’s nuclear capacity, except for France where 57 GW of nuclear power has been assumed<sup>19</sup>.

Wind and solar capacities have also been split using the Distributed Energy scenario of the TYNDP 2020. However, since the TYNDP 2020 capacities data at country level for solar and wind fleets are only available for years 2030 and 2040, the figures have been extended to 2050 to take into account the pace of installation of renewable power plants by country. The resulting capacities have been confronted to the technical potential of each country as provided by the ENSPRESO datasets<sup>20</sup>, and where overestimation have been revealed by this comparison, we have adapted our figures accordingly. The vRES capacity results of the country breakdown are exhibited on Figure 35 for the reference scenario. In the sensitivity analysis we have reshuffled technologies across Europe to better align them with the electricity and P2X needs.

From the country breakdown of the offshore wind fleet, one can observe that offshore wind plants are only located in the North Sea in the reference scenario (compared to other potential locations such as the Mediterranean Sea and the Baltics Seas). The model can easily be adapted to study alternative locations for offshore wind, and in particular the impacts of hybrid projects linking several countries.

<sup>19</sup> French nuclear capacity has been extracted from the “Easy nuclear extension” trajectory of the French electricity mix published by ADEME (see <https://www.ademe.fr/trajec-toires-devolution-mix-electrique-a-horizon-2020-2060> for additional information).

<sup>20</sup> ENSPRESO is an open data, EU-28 wide, transparent and coherent database of wind, solar and biomass energy potentials (see <https://data.jrc.ec.europa.eu/collection/id-00138> for further information).

a) Solar PV: 1000 GW

b) Wind onshore: 750 GW

c) Wind offshore: 450 GW

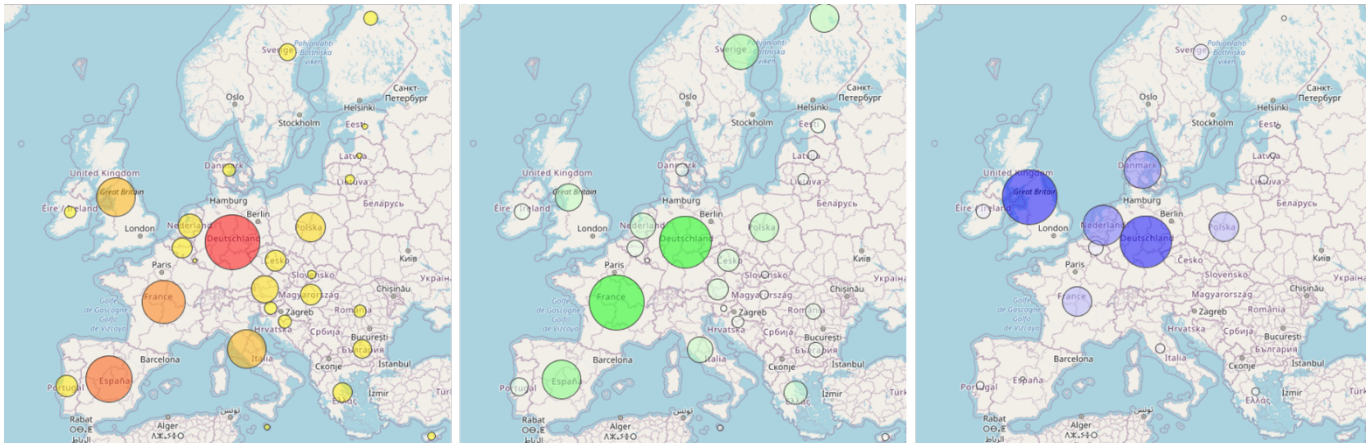


Figure 35 – Renewable capacity breakdown in the reference scenario

Finally, regarding other renewables and BECCS, a specific approach has been designed. The deployment of biomass and biomethane power plants is optimised based on a technical potential at country level, and the modelling of the hydroelectric fleet is based on our database, which is based on various sources, including TYNDP 2018 dataset and publicly available statistics. The remaining other renewables capacities (including geothermal plants, waste-fired plants, etc.) are assumed to adopt a baseload behaviour, and the EU from LTS 1.5TECH scenario is disaggregated using the TYNDP 2020 dataset.

Finally, installed capacities for non-EU countries are based on the TYNDP 2020 datasets since these countries are not included in the LTS datasets.

### 3.1.3.1.2 Optimised capacities

In order to ensure plausible results, the investment options include power generation capacities. Gas-fired power plants (including CCGTs and OCGTs) are optimised, and both asset categories can use either natural gas, synthetic gas or biomethane (see Figure 31). However, the biomethane volume available for power production is limited by the 1.5TECH figure. Investment costs for both technologies are extracted from the ASSET database<sup>17</sup>. Finally, biomass-fired power plants are also optimised with a maximum volume for biomass supply.

### 3.1.3.2 Hydrogen supply

Hydrogen demand, including end-use demand and additional demand for further conversion into synthetic gas or fuels, can be supplied either by electrolysis or by SMR (see Figure 31). In this study, hydrogen is assumed to be supplied by EU27+7 countries, the model does not import hydrogen from outside the EU. This assumption has been made to reflect the choices of the Commission when designing the LTS pathways.

Thanks to the joint optimisation of power, hydrogen and gas systems, the impacts of the capacity expansion of electrolyzers and SMR facilities are taken into account: power consumption of

electrolysers and gas consumption of SMR participate in the power and gas demand-supply equilibriums. The management of electrolysers is optimised by the model, and avoids non virtuous behaviours such as simultaneously running gas-fired power plants and electrolysers (which would amount to burning methane to produce electricity to power electrolysers). SMR capacities are optimised by assuming a 78 % efficiency, whereas an 85% efficiency is assumed for electrolysers. Efficiencies and investment costs for both technologies are derived from the ASSET database<sup>17</sup>.

### 3.1.3.3 Gas supply

As for hydrogen, the methane demand includes end-use demand, demand from SMR facilities and gas-to-power consumption. It can be supplied by different routes. Indeed, methane can be provided from the domestic production of natural gas and biomethane, the synthetic gas production via methanation plants, and potentially via imports from LNG traditional routes (Russia, Norway, Libya and Algeria).

Biomethane overall potential is extracted from the LTS and estimated at 825 TWh in the reference scenario. TYNDP 2020's Distributed Energy Scenario was considered as an allocation key and led to the breakdown presented on Figure 36.

The domestic production capacity of natural gas is also taken into account and is based on TYNDP 2020's Distributed Energy scenario. The gas supply potential has been estimated for 2050 for each country, leading to 200 TWh of available domestic gas production at EU level. TYNDP 2020 data also provides gas import capacities, which have been used for modelling natural gas imports via gas pipelines or LNG terminals.

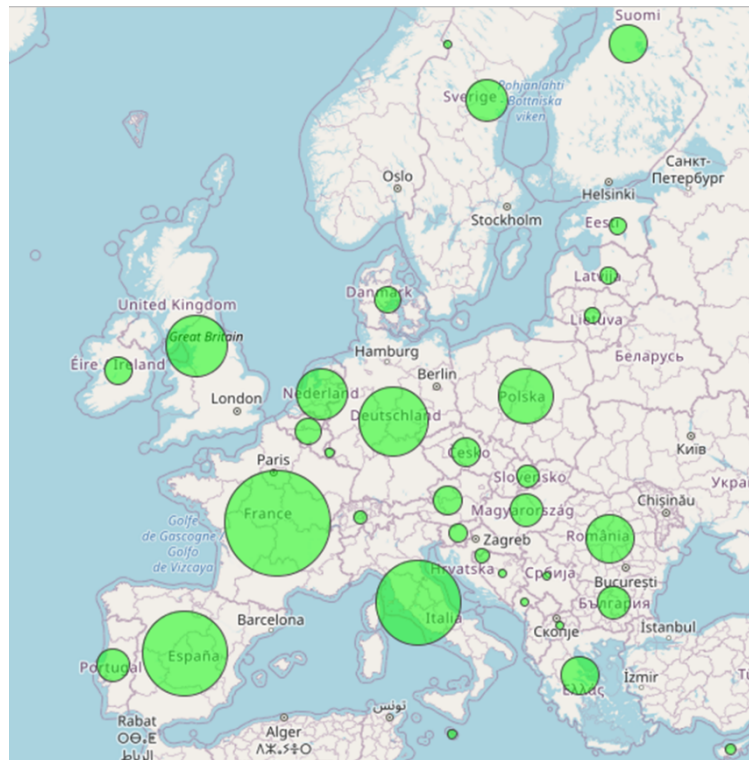


Figure 36 - 825 TWh biomethane production breakdown in the reference scenario

### 3.1.4 Infrastructure

In order to balance demand and supply of the European power, hydrogen and gas systems, the investment options include cross-border capacities for the three energy systems.

#### 3.1.4.1 Electricity

Electric interconnections are optimized starting from the NTCs provided in the 2020 Best Estimate scenario of the TYNDP 2018, representing the current European power grid. The installable capacities are limited to 20 GW per border, as costs and impacts on internal networks become very uncertain for high levels of additional interconnection capacity.

Investments costs are based on line-by-line transmission projects included in TYNDP 2018<sup>21</sup>: for each cross-border interconnector, an aggregated cost per MW of additional NTC are calculated (for CAPEX and OPEX).

#### 3.1.4.2 Methane

Cross-border pipelines are optimized starting from the “Low” scenario of the TYNDP 2018. Data includes the existing infrastructures in 2018 and projects with Final Investment Decision status representing the minimum level of infrastructure development considered for the identification of

<sup>21</sup> See <https://tyndp.entsoe.eu/tyndp2018/projects/> for additional information.



infrastructure gaps. It has been assumed that both directions of gas interconnectors are able to transport the same capacity by 2050 (the additional costs to enable reverse flows are not taken into account). Investment costs in additional pipelines are based on the transmission project list provided by ENTSOG in the 2018 edition of the TYNDP<sup>22</sup>.

In order to consider refurbishment (see 3.1.4.3), the number of pipes was estimated on the basis of GIE's map<sup>23</sup> for each interconnection.

### 3.1.4.3 Hydrogen

For hydrogen, we start from a situation without cross-border infrastructure, and allow the model to build some, either by repurposing methane interconnections or by building new hydrogen interconnections. Hydrogen storage assets are also part of the investment options.

#### HYDROGEN AND REPURPOSING OF METHANE INTERCONNECTIONS

While it is possible to build new hydrogen pipelines to transport hydrogen, two recent studies published in July 2020: European Hydrogen Backbone, *Gas for Climate* (herein referred as EHB) and Hydrogen Generation in Europe, *Guidehouse* on behalf of the European Commission, DG ENER (herein after referred as HGE) provide a range of the costs involved in the repurposing of methane infrastructure into hydrogen infrastructure.

The model used for this study optimises the repurposing of methane pipelines and investments in new interconnection capacities, with the following assumptions (NB: the "medium assumptions" were taken for EHB figures):

- | If an interconnection is bidirectional, the capacity of the repurposed pipeline will be the same in both directions.
- | 1 MW of interconnection capacity for methane is refurbished into 0.8 MW of hydrogen (source: EHB)
- | Cost of a new 48-inch hydrogen pipeline: 2 750 000 €/km (source: EHB)
- | Cost of refurbishment an existing 48-inch pipeline: 500 000 €/km (source: EHB)
- | Hydrogen compressor cost: 3 400 000 €/MW (source: EHB)
- | Compressor rate (power of compressor / interconnection capacity): 1% (based on the analysis of recent data, including 4<sup>th</sup> PCI list)
- | Lifetime of a refurbished pipeline & new hydrogen pipeline: 42.5 years (source: EHB)
- | Lifetime of a hydrogen compressor: 24 year (source: EHB), thus two compressors are taken into account in the overall interconnection investment costs, though the second one is installed 24 years after the construction of the interconnection, benefiting from the actualisation rate
- | Actualisation rate: 4% (Artelys hypothesis for large infrastructure)

<sup>22</sup> For further information regarding the TYNDP18 data of the ENTSO-G, the reader is referred to <https://www.entsog.eu/scenarios#entsog-ten-year-network-development-plan-2018>.

<sup>23</sup> <https://www.gie.eu/index.php/gie-publications/maps-data/gse-storage-map>

- Fixed Operating Costs (FOC): 1.25% of the CAPEX (source: EHB) which was taken for both new and refurbished pipeline

This leads to the following annualised investment costs for interconnections:

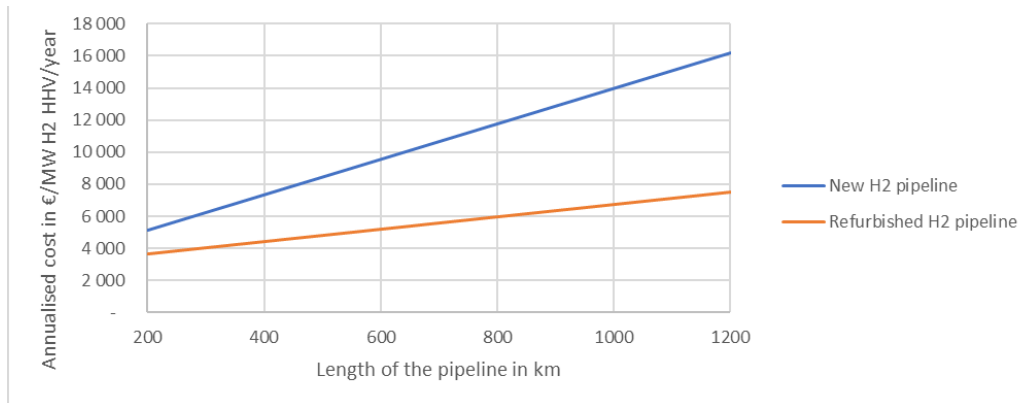


Figure 37 - Investment costs (including FOC) of h2 pipelines

## HYDROGEN STORAGE

We start from a situation without hydrogen storage, and with the ability for the model to invest in such a technology. For this type of infrastructure, the figure of 334 € / MWh of stored hydrogen was taken from the HGE study, corresponding to the value of salt cavern storage. Several values for discharge time, withdrawal and injection rates have been tested, based on an analysis of the current values of the gas storages.

### 3.1.5 Commodity prices

The commodity prices are based on different sources, including ENTSOs' TYNPD, IEA WEO and EC scenarios. Since the CO<sub>2</sub> price is a key assumption for the modelling, the figure we have adopted comes directly from the LTS 1.5TECH scenario: 350 €/tCO<sub>2</sub>.

### 3.1.6 A bottom-up optimisation approach

The modelling exercise has been carried out using the multi-energy systems modelling platform Artelys Crystal Super Grid (see Figure 4). In this analysis, a joint model of the European electricity and gas systems was used. The model allows for a joint optimisation of investments and operations (with a cost-minimising criterion) for a given year using an hourly time resolution and a country-level spatial granularity.

The costs that are considered include operational costs, i.e. fuel and CO<sub>2</sub> costs, variable O&M costs and loss of load penalties (if any), and investment costs in order to ensure the electricity and gas demands can be met at all times in the considered areas (EU27 + Norway, Switzerland, the UK, Macedonia, Montenegro, Serbia and Bosnia-Herzegovina).

The model is able to simultaneously optimise the operations of and investments in all categories of assets, including different generation technologies, flexible consumption technologies, storage assets, interconnections and pipelines between areas.

The catalogue of investment options includes:

- Cross-border infrastructure for electricity, hydrogen (incl. via repurposing) and methane
- Hydrogen storage assets
- Electrolysis, SMR and methanation assets
- Batteries and pumped-hydro storage assets
- Gas-to-power assets (CCGTs and OCGTs)

## 3.2 Appendix B – Sensitivity analyses

Three sensitivity analyses have been carried out to test the robustness of the evaluation of the infrastructure needs of the European energy systems, by modifying different assumptions of the reference scenario.

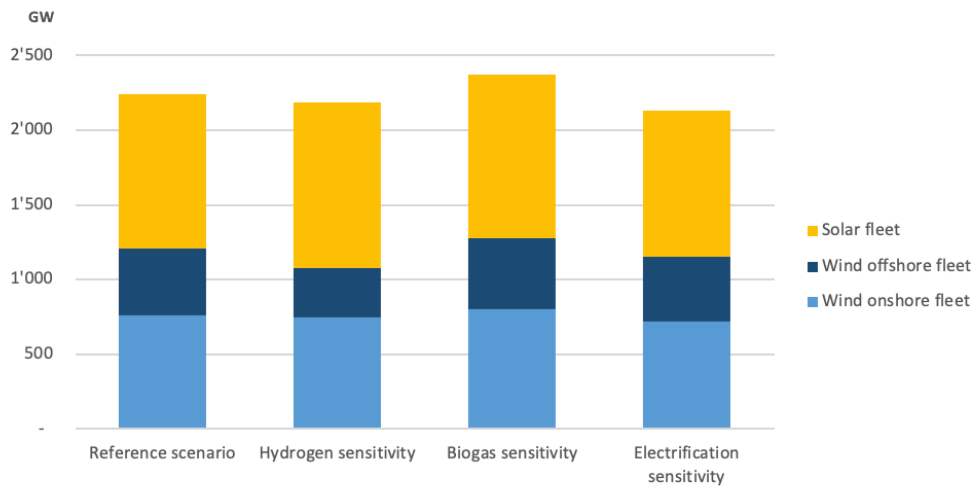
### 3.2.1 A lower hydrogen demand and a smarter allocation of vRES capacities

This sensitivity analysis assumes a lower hydrogen consumption by around 30% compared to the reference scenario, in order to reach the PAC scenario's level of hydrogen demand, which is around 1100 TWh at EU-level. The decrease is shared homogeneously between all countries.

Due to the lower hydrogen demand, less renewable power capacities (wind and solar) are required to power electrolyzers. Therefore, we have assumed that, considering an efficiency of 85% for electrolyzers, around 600 TWh of renewable power generation can be removed in this analysis.

Compared to the reference scenario, the allocation of vRES capacities per EU Member States has been achieved by taking into account a more coherent match between net electricity demand (considering direct uses only) and hydrogen-related demand.

The resulting vRES capacities in this sensitivity are shown on Figure 6 for selected countries. This smarter allocation of renewable capacities has resulted in shifts of vRES plants from countries such as Spain, France and United Kingdom to other countries such as Germany and Italy resulting in different evolution for solar and wind capacities.



**Figure 38 – vRES installed capacities in the reference and sensitivities scenarios**

The objective of this sensitivity is to assess the impacts of two important factors, especially in terms of the level of hydrogen infrastructure:

- | The amount of hydrogen in the system
- | The ability to produce it locally

In order to disentangle the impacts of each of the two assumptions, an intermediate modelling run (with a lower amount of hydrogen) has been performed.

### 3.2.2 A lower biomethane potential

The second sensitivity analysis assumes a lower biomethane potential at EU level, by reducing the capacity supply to reach the level of the LTS 1.5LIFE scenario<sup>24</sup>: around 600 TWh of biomethane production are assumed in this sensitivity compared to 825 TWh in the reference scenario. Similarly, as for the first sensitivity, the biomethane reduction has been performed with the objective of building a more consistent alignment between biomethane supply and CH4 demand (see Figure 7).

Reducing biomethane potential is compensated by increasing synthetic gas production via electrolyzers and methanation plants. Thus, additional renewable capacities have been installed in the sensitivity in order to cope with the additional carbon neutral power generation induced by the synthetic gas needs. With a respective efficiency of 85% and 79% for electrolyser and methanation plants, around 300 TWh of renewable power generation (wind and solar) are added in this sensitivity.

The new vRES capacities are shown on Figure 38. The country-level breakdown follows the same methodology as described in the design of the reference scenario.

<sup>24</sup> The reader is referred to the LTS reference document for further details about the LTS 1.5LIFE scenario.

The objective of this sensitivity is to assess the impact of a lower biomethane supply and analyse the effects of a more local biomethane use.

### 3.2.3 A higher energy efficiency and a deeper electrification

The third sensitivity analysis assumes a higher energy efficiency via a deeper electrification of the heating end-uses in the residential and tertiary sectors: gas boilers are replaced by heat pumps, reflecting the PAC scenario assumption of a gas boiler phase out. Since the overall efficiency of producing heat from synthetic-gas-fired boilers is lower than the heat pump efficiency, this sensitivity induces a reduction in electricity demand compared to the reference scenario.

In the reference scenario, the gas demand for boilers reaches around 250 TWh. With an 85% efficiency assumption for boilers, the heat demand covered by gas boilers in the reference scenario would reach a little more than 200 TWh. In order to transfer this heat demand to be produced by heat pump, the following assumptions are used:

- | 95% of this heat demand is covered by heat-pumps
- | The remaining heat is provided with an electrical back-up heater
- | Average COP of 3.6 for heat pumps
- | Electrical heater's efficiency of 100%

The 200 TWh of heat demand would thus be produced with a little more than 50 TWh of electricity consumption from heat pumps.

As with the other sensitivities, the vRES capacities have been updated in order to adapt to the lower electricity consumption (since part of the boilers were using electricity-derived gases). The resulting capacities are shown on Figure 38 at the EU level, and the country breakdown methodology follows the same approach as the reference scenario.

The objective of this sensitivity is to assess the impact of a deeper electrification of the heat sector on energy infrastructure needs.