European Commission

METIS 2

Study S6

Assessing the balance between direct electrification and the use of decarbonised gases in the 2050 EU energy system

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ABBREVIATIONS AND DEFINITIONS

ABBREVIATIONS

Abbreviation	Definition
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CHP	Combined heat and power
EV	Electric vehicle
LTS	Long Term Strategy
NTC	Net transfer capacity
OCGT	Open cycle gas turbine
PHS	Pumped hydro storage
PV	Photovoltaic
RES	Renewable energy sources
SMR	Steam methane reforming
vRES	Variable RES

METIS CONFIGURATION

The configuration of the METIS model used in the present study is summarised in Table 1.

Table 1 - METIS Configuration

METIS Configuration	
Version	METIS v2.0 Beta (non-published)
Modules	Power system and demand modules
Scenario	METIS 1.5 scenario
Time resolution	Hourly (8760 consecutive time-steps per year)
Spatial granularity	Member State

1 EXECUTIVE SUMMARY

If Europe is to meet its 2050 decarbonisation objectives, a change of paradigm needs to materialise. The energy sector cannot be understood any more as the sum of independent silos consisting of different energy vectors. Indeed, a large number of technologies that are essential to meeting our decarbonisation targets are linking systems and markets currently being planned and operated without fully considering the potential benefits of adopting a holistic approach.

If this situation is to persist, large-scale sub-optimalities are likely to emerge if the planning and operations of the different components of the energy system will not be able to capture synergies and interdependencies between energy vectors and markets.

Interlinkages between systems are appearing between all vectors, both at the planning and operation levels. In the case of hydrogen, these links are especially important, as hydrogen technologies are linking the electricity, methane and heat sectors (via electrolysis and hydrogen turbines, repurposing of gas assets, and hydrogen boilers, respectively). Sector integration can allow to capture benefits both in terms of planning and operations:

- The production of electrolytic hydrogen poses important challenges in terms of **planning** the deployment of renewable energy (RES) and electrolyser capacities in a way that ensures that the overall carbon emissions decrease in an effective and cost-efficient manner. Furthermore, key questions related to the benefits of co-locating renewable capacities, electrolysers and hydrogen demand centres can only be explored if a holistic perspective is adopted. Finally, synergies can also appear if planning decisions are taken jointly between the electricity, hydrogen and methane sectors as the optimal set of hydrogen infrastructure projects strongly depends on the ability to source electrolysers (link with the electricity sector) and on the possibility to repurpose part of the current infrastructure (link with the methane sector)
- Similarly, **operational** considerations also advocate for an integrated approach as electrolysers can provide important flexibility services to the electricity sector if provided with appropriate price signals.

These considerations provide the motivation for this study, which aims at performing a detailed examination of planning decisions and operational management of a 2050 power system with a focus on comparing different decarbonisation options for the provision of heat of different temperature levels.

The key findings are that adopting a precise depiction of the operational management of the energy system when considering investment decisions can lead to significant benefits in terms of avoided investments, thanks to a better detection of synergies between sectors that can only emerge when investigating hourly dynamics.

In particular, we have compared the investment decisions in the Long-Term Strategy (LTS) 1.5TECH scenario for the year 2050, as published by the European Commission, and the investments the METIS model identifies as being optimal when taking the hourly dynamics into account. The results show that there are significant impacts in terms of use of hydrogen per sector, and in terms of need for gas-fired power generation to help balance the power grid.

The reduced level of gas-fired generation capacity (and usage of this capacity) being identified by METIS as being required to balance the power grid induces shifts in the technology portfolio supplying high-temperature heat. The remaining volume of biogas is

indeed favoured to using electrolytic hydrogen, thereby impacting investments in the different RES technologies and investments in electrolysers.
A series of sensitivity analyses have confirmed the robustness of this finding: it is essential that (a) interlinkages between sectors and (b) the hourly dynamics of the operations of the resulting system are well taken into account when building energy transition pathways towards a decarbonised EU energy system.

The findings of this study reinforce the relevance of the approach of the European Commission consisting in putting sector integration at the centre of its approach to decarbonising the European economy. It can be expected that adopting such principles at the level of national and regional systems (e.g. in NECPs or network development plans) would also translate into important benefits in terms of investments savings.

2 INTRODUCTION

The **EU Green Deal**, as presented by the European Commission in late 2019, fixes the objective to make Europe the first climate-neutral continent, i.e., to achieve net-zero greenhouse gas emissions by 2050. One of the challenges to tackle is the fact that the current energy system is still largely built on several parallel, vertical energy value chains, where specific energy resources are rigidly linked with specific end-use sectors. This very segregated approach is unlikely to deliver a climate-neutral economy in a cost-efficient way, and risks being technically and economically inefficient.

The **EU Strategy for Energy System Integration** (COM(2020) 299 final) proposes concrete policy and legislative measures at EU level to gradually shape a new integrated energy system, aiming at achieving a more coordinated planning and operation of the energy system 'as a whole', across multiple energy carriers, infrastructures, and consumption sectors. It sets energy efficiency at the core of a more circular energy system and foresees an electrification of end-uses where deemed possible and cost-efficient (as direct electrification is generally a more cost-efficient way to decarbonise end-uses compared to other options that require conversion processes to be introduced).

The Energy System Integration Strategy also considers that renewable and low-carbon fuels (such as hydrogen, renewable gases and liquids) can play a key role for deep decarbonisation, notably for sectors that are technically and/or economically challenging to electrify directly (e.g., specific end uses in transport or industry). Hydrogen can be produced from renewable or low carbon electricity (other alternatives include steam methane reforming combined with CCS), and is a potential significant contributor to the decarbonisation of the European economy if combined with an adequate deployment of renewable electricity generation technologies. The **EU's Hydrogen Strategy** (COM(2020) 301 final) sets out an overall approach to tap the full benefits of an economy relying to an increasing extent on hydrogen. It shall trigger the deployment of hydrogen and ensure a widespread use of hydrogen by 2050.

The Green Deal and the different strategies are underpinned by a set of scenarios published in the context of the **EU Long-Term Strategy** (LTS, COM(2018) 773 final). They indicate different pathways of technology deployment to achieve carbon neutrality by 2050. These scenarios and a number of similar studies showcase that **electrons and molecules** are expected to play a role in the future EU energy mix. The ratio between the two has been analysed in different assessments under various angles, with respect to energy efficiency, infrastructure requirements, exploitation of RES potentials, etc. The present study has for objective to combine the different dimensions and provide a holistic analysis of the role of the different energy carriers and conversion technologies. A specific focus is set on the **coupling of the electricity, gas and heat sectors and on power-to-X technologies**.

This **study intends to contribute to the current debate and to provide new insights** in two regards. From a **policy perspective**, the study helps to identify potential barriers to a GHG neutral energy system (for instance with respect to the exploitation of RES potentials). It reveals the implications of the climate neutrality goal on the need to integrate the energy system with all demand sectors (mobility, industry, buildings). Further, the study sheds light on the benefits of different decarbonisation routes for end-uses from a holistic perspective. Such approaches are well suited to examine the potential misalignments between the cost-minimising solutions from an end-user perspective and the one from a system perspective (that considers impacts on the entire value chain, including infrastructure), and can provide insights on ways policies and measures can be formulated to incentivise the optimal solution from a system perspective to emerge.

Methodology-wise, the study pushes the limits beyond the state-of-the-art of long-term energy system modelling. The METIS model was configured for this study to apply a joint capacity and dispatch optimisation approach to determine the cost-optimal configuration of the EU's power, gas (incl. hydrogen) and heat sectors. The approach relies on an hourly granularity, focussing on an entire year (2050). This is particularly important to properly capture the system dynamics in a context with high RES penetration (which increases the variability of power generation and the need for flexibility on all timescales), and an increasingly flexible electricity demand (due to electrification of demand sectors and hybrid demand assets such as heat pumps with gas back-up boilers).

To determine the cost-optimal balance between electrons and (synthetic gas) molecules, power-to-X capacities are jointly optimised with renewable electricity generation capacities, considering country-specific RES-E cost curves. Finally, the capacity optimisation scope integrates the heat supply technologies in the industry and residential sectors, allowing for a least-cost configuration of the heat supply mix considering the entire upstream energy value chain. Compared to "power system only" models, METIS integrates industrial heat in the model, allowing to showcase that the energy supply of the heat sector represents an important lever of an efficient decarbonisation strategy. Indeed, these sectors are of an important size, and various options exist to meet their energy needs, with different levels of flexibility being associated to the different options.

The report is structured as follows. Section 3 introduces the METIS 1.5 scenario which is used in the present analysis and which integrates elements from the 1.5 TECH scenario of the EC's Long-Term Strategy. Section 4 presents the results of the scenario assessment, with a distinct focus on the heat sector, cross-sectoral energy flows and the operational dynamics in the power sector. A set of sensitivities shedding light on selected parameters and their effect on the overall results is presented Section 5. Section 6 provides the overall conclusions and gives an outlook for further modelling work. Details related to the methodology and all major assumptions can be found in the Annex.

3 STARTING POINT AND ORIGINS OF SYNERGIES

This section is devoted to providing a high-level overview of the starting point of this study. We assume that we are in a configuration of the energy system that is compatible with net zero emissions at the 2050 time horizon, inspired by the 1.5TECH scenario developed by the European Commission in its Long-Term Strategy, and then proceed to adapt this scenario by optimising the deployment of a selection of technologies (generation, flexibility solutions, and part of the heat provision end-uses).

We begin by providing an overview of the 1.5TECH scenario, followed by a description of the approach we have developed to refine investments in several sectors compared to the original 1.5TECH scenario.

3.1 KEY FEATURES OF THE 1.5TECH SCENARIO

3.1.1 OVERVIEW OF THE SCENARIOS OF THE EU LONG-TERM STRATEGY

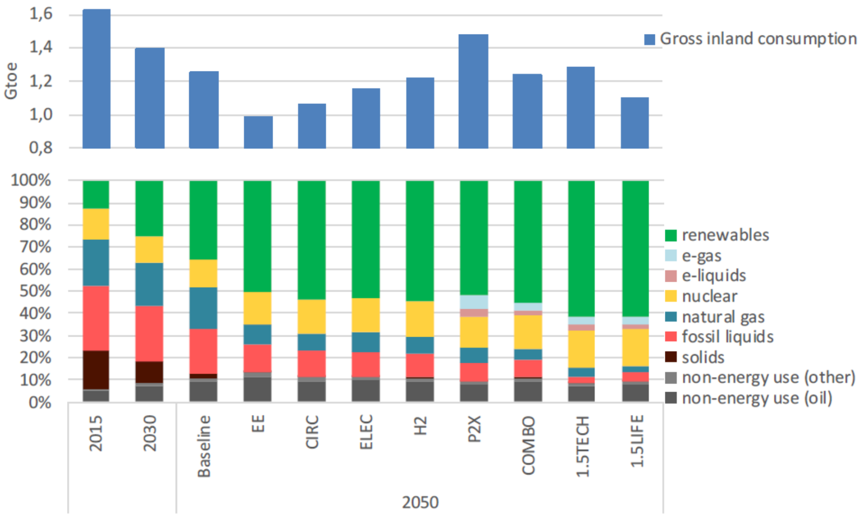
The EU Long-Term Strategy[1] has analysed different pathways that can lead the European Union's economy to reach the Paris agreement target of keeping the temperature rise "well below 2°C by 2100". A first pathway called "Baseline" was created to include the policies agreed in the year 2018, such as a reformed EU emissions trading system and different target for energy efficiency and renewable production. In 2050, this pathway reaches a reduction of 60% of greenhouse gas emissions, which is not sufficient to respect the objectives of the Paris Agreement.

In addition to the Baseline, 5 different pathways have been created to meet the objectives of the Paris Agreement, each of them based on different approaches to decarbonise the EU economy: energy efficiency, circular economy, electrification, hydrogen and power-to-X. Finally, three additional scenarios have been built by combining these approaches. The first one, COMBO, is a cost-efficient combination of the 5 options described before. It reaches a 90% GHG emissions reduction, including carbon sinks.

The two final pathways are the most ambitious ones, with the goal of keeping the temperature increase "around 1.5°C by 2100" compared to pre-industrial levels. When taking carbon sinks into account, these two pathways reach carbon neutrality by 2050. The 1.5TECH scenario combines the technologies used in the 5 pathways described previously to reach climate neutrality in 2050. The 1.5LIFE scenario is also based on the different technological pathways, but with a stronger effort assumed in terms of lifestyle changes leading to a lower EU energy consumption.

The figure below presents the demand levels for all considered pathways and the associated shares of the energy mix. While the 1.5TECH and 1.5LIFE have similar technological shares, their deployment differs due to the important difference in demand levels, leading to 1.5TECH being the most challenging net zero compatible scenario in terms of RES deployment.

[1] (European Commission, 2018)



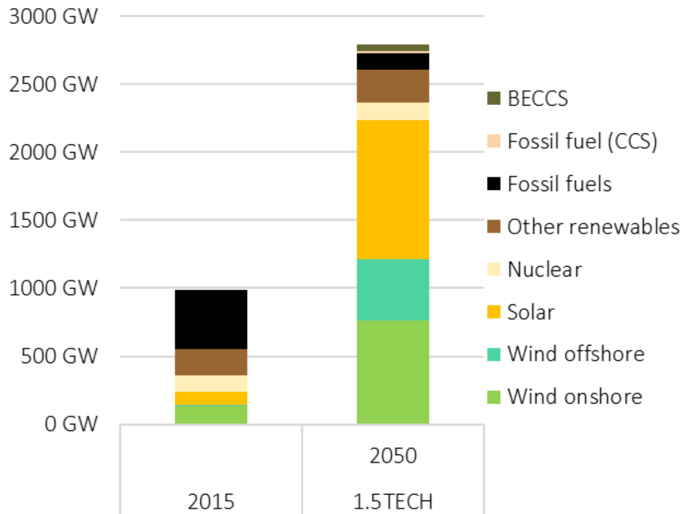
Source: Eurostat (2015), PRIMES.

Figure 3-1: Gross inland consumption

3.1.2 FOCUS ON THE 1.5TECH SCENARIO

For this study, the 1.5TECH scenario has been selected as it meets climate neutrality in 2050 and primarily relies on the use of clean technologies, and more moderately on behavioural changes compared to the 1.5LIFE scenario. The role of clean technologies in reaching the Paris Agreement goals is highest in the 1.5TECH pathway, leading to greater challenges in terms of the magnitude of investments and the provision of flexibility services than in the 1.5LIFE pathway. Therefore, it is also the scenario that has the greater potential for cost-reducing refinements by exploring synergies between sectors and energy vectors.

In the 1.5TECH scenario, the decarbonisation of the EU economy relies mainly on massive deployment of variable RES such as solar PV and wind power capacities. As Figure 3-2 shows, wind and solar PV capacities soar between 2015 and 2050, rising from a 2015 level of circa 670 GW at the EU27+UK level to 2240 GW at the 2050 time horizon in the 1.5TECH scenario.



Source: EU Long Term Strategy

Figure 3-2: Power generation capacities – EU27+UK

This additional decarbonised power generation capacity is used to switch from burning fossil fuels to using electricity, both via direct and indirect electrification routes (i.e. via power-to-gas and potential subsequent conversion processes). The 1.5TECH scenario assumes a large deployment of power-to-gas technologies in Europe by 2050, leading to the production of synthetic fuels such as e-gases and e-liquids from hydrogen produced via electrolysis, eventually replacing their fossil counterparts. In addition to the switch to decarbonised fuels, the mobility and heat sectors are largely electrified, and high end-use efficiency is reached in the residential sector notably thanks to a large number of renovations and the use of efficient technologies such as heat pumps. These combined factors allow for a decrease of the European annual final energy from more than 12 000 TWh in 2015 to 8 000 TWh in 2050.

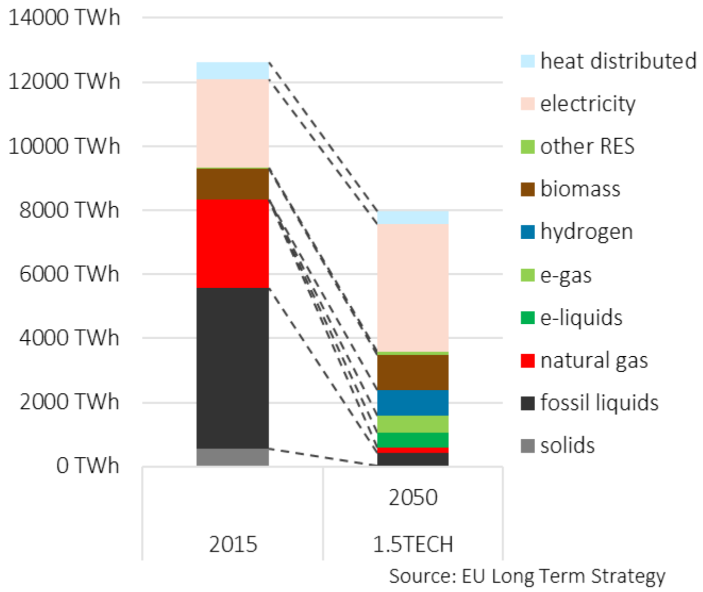


Figure 3-3: Final energy consumption by energy carrier – EU27+UK

As a consequence of the large volumes of e-gases and e-liquids that are required in the 1.5TECH scenario to decarbonise the European economy, the demand for electricity drastically increases. In 2050, circa 46% of the electricity demand comes from the synthesis of carbon-free fuels via electrolysis. Direct electrification also contributes to increasing the final power demand to levels above 4 000 TWh. Combined, direct and indirect electrification lead to a total power demand more than twice higher in 2050 than it was in 2015.

Note on the Climate Target Plan

This study has been performed before the publication of the Climate Target Plan (CTP). However, conclusions can be expected to remain valid as the challenge is reaching similar orders of magnitude at the 2050 horizon, although the pathways deviate significantly in the near future due to the more ambitious 2030 target explored in the CTP.

Indeed, according to the Climate Target Plan impact assessment[2], a scenario complying both with the Paris Agreement for 2050 and the increased ambition of 55% GHG

[2] (European Commission, 2020)

emission-reduction by 2030 sees its electricity generation more than double between 2030 and 2050, from 3000 TWh to about 6900 TWh at the EU27 level.

In the industry sector, the 1.5TECH scenario assumes a transition of the European industry to the use of decarbonised fuels and processes. Hard-to-abate sectors are decarbonised thanks to electrification and/or the use of bio or synthetic fuels in their energy mix. Process emissions are tackled with a switch to innovative processes, involving hydrogen or electricity as the main fuel or feedstock. As a consequence, only a small share of industries rely on CCS to reduce carbon emissions. The switch from fossil fuels to direct and indirect electrification puts the power system at the centre of this new energy system in terms of energy supply.

3.2 Refinement of the Long-Term Strategy 1.5TECH scenario

The METIS 1.5 scenario is defined as 2050 net-zero compatible scenario for the European power system. It is built using the METIS model, a solution developed by Artelys on behalf of the European Commission. METIS is a multi-energy model enabling the analysis of the entire European energy system with a high granularity (in time and technological detail), and to assess impacts on Member States (see Section 8.1 for a general introduction to the METIS model).

In order to thoroughly account for all aspects of the energy system when optimising the balance between electrification and the use of decarbonised fuels, this study includes the coupling of the electricity sector and industrial heat supply in its modelling scope, enabling an optimisation of the share of each energy carrier in industrial final heat demand (with technological options that depend on the temperature levels that have to be supplied).

Starting from the annual demand volumes by end-use of the LTS 1.5TECH scenario, we use METIS capabilities, and in particular its demand modelling framework, to allow for the exploration of alternative energy supply mixes. This exploration is particularly valuable and insightful since, in contrast to other modelling approaches, it is carefully considering the hourly dynamics of the different sectors and the associated synergies and interdependencies that can emerge when coupling sectors with one another.

To allow for such an exploration of alternative configurations, the industrial heat demand volumes are analysed leading to a distinction between non-substitutable (for e.g. chemical processing reasons) and substitutable shares of the industrial heat demand compared to the original LTS 1.5TECH scenario. The substitutable share is then eligible to supply mix refinements, endogenously optimised with METIS. We allow for investments in specific heat supply assets, with technology options varying depending on temperature levels of the heat that needs to be supplied, including both direct and indirect electrification options (heat pumps with different backup options, electric and hydrogen boilers), alongside gas, biogas and biomass boilers or CHPs.

Once supplied with investment options and the technical potential of different technologies to supply heat in the considered sectors, METIS jointly optimises electricity, heat, hydrogen and other power-to-X production capacities as well as their hourly dispatch (8760 consecutive time-steps per year). The objective of METIS is to find **cost-minimising configurations** considering investment costs, fixed operational and maintenance costs, variable operation and maintenance costs, fuel costs and the costs of CO_2 emissions.

Details related to the way demands are modelled in the different sectors are described in Section 8.2. Section 8.3 provides more details on the energy supply modelling and describes investment options available to meet the different demands, in particular for the different temperature levels of heat demand.

4 A COST-OPTIMAL ENERGY SYSTEM IN 2050

This section is devoted to presenting the results of the joint capacity and dispatch optimisation performed with METIS. The sensitivity of the results to various assumptions is explored in Section 5.

4.1 FOCUS ON INDUSTRIAL HEAT PROVISION

For each of the three temperature levels considered in this study), the industrial heat supply mix is optimised according to the available technological options, which depend on the temperature of the heat to be provided. Three temperature levels are distinguished: low temperature covers 0-150 °C, medium temperature refers to 150-500 °C and high temperature exceeds 500 °C. While for most high-temperature end-uses a direct electrification route is not economically or technically relevant, it can be for lower temperatures via heat pumps and electric boilers.

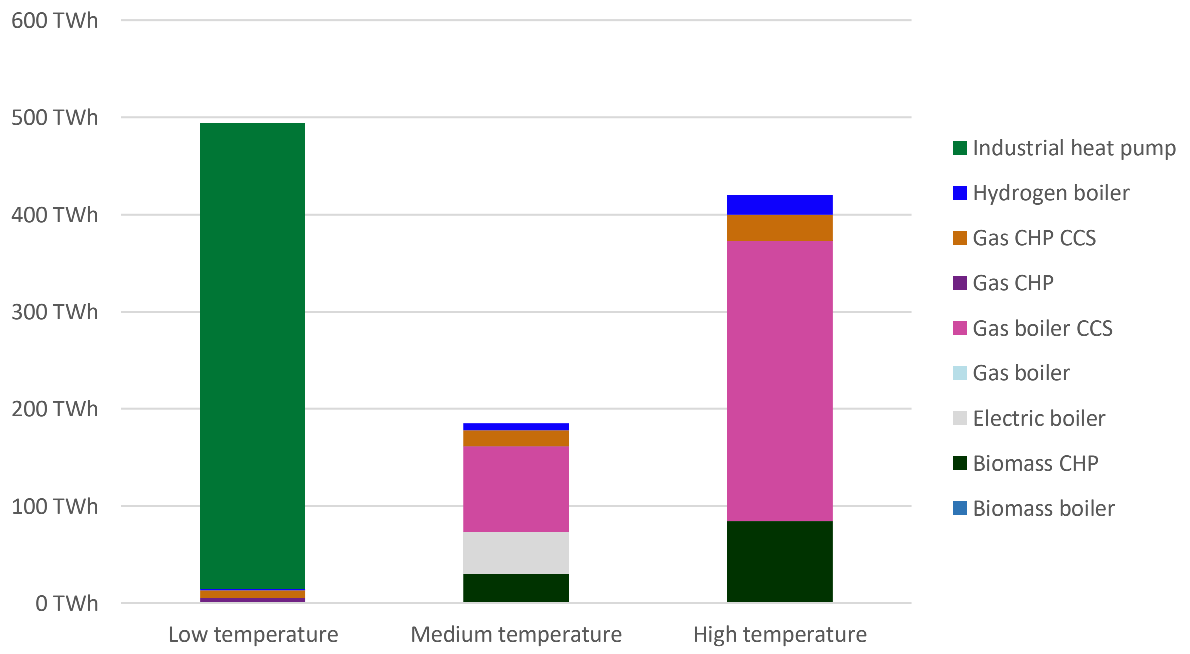


Figure 4-1: Heat generation per technology and temperature level in the METIS 1.5 scenario, EU27+UK[3] (substitutable heat scope)

Low temperature heat

For low temperature heat, used notably in various chemical processes, the heat supply mix is found to be massively electrified, as the system leverages large renewable electricity potentials and the high efficiency of heat pumps. Gas CHPs[4] still provide circa 13 TWh of heat to spare some electricity during low wind weeks that can materialise in winter. The

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[3] Industrial heat supply is not optimised outside the 1.5TECH perimeter

[4] In section 4.2, it is observed that, given low gas consumption volumes, this consumption is actually primarily met by biogas.

commissioning of gas CHPs is found to mainly occur in countries where variable RES generation is structurally lower in winter (high PV shares in the mix).

Medium temperature

The medium-temperature heat, required for instance by the paper and pulp industry, is supplied with a more balanced mix between direct electric heat (which relies on the electric boiler only), indirect electrification and the use of biofuels.

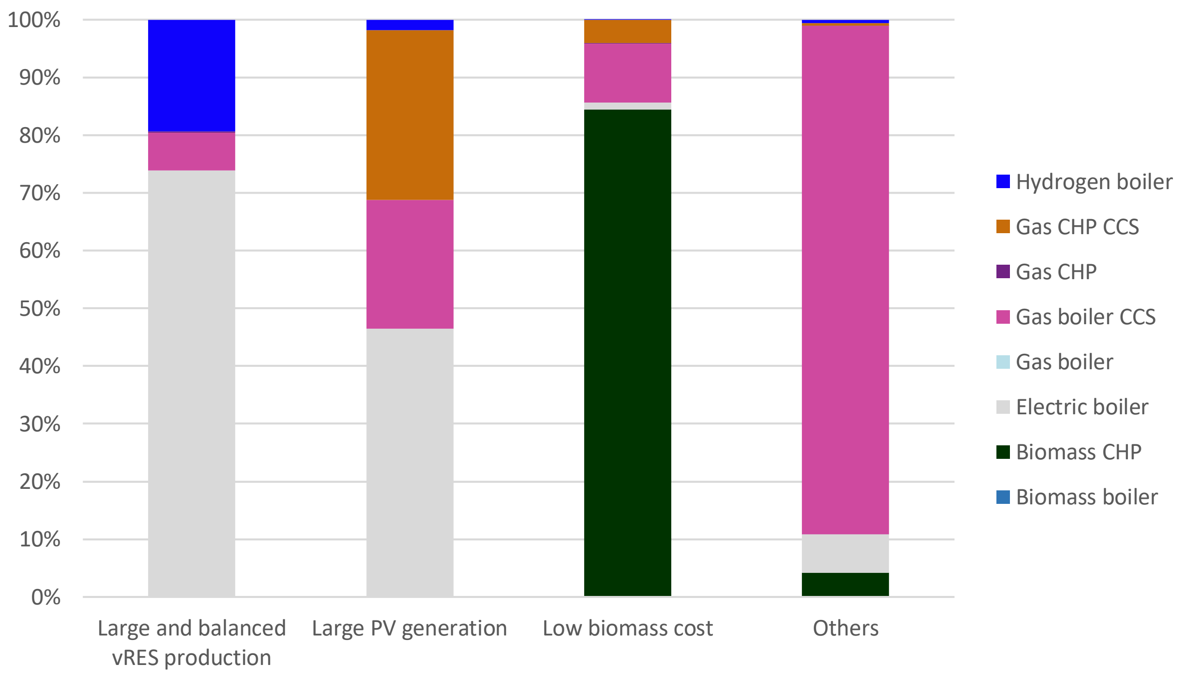

Figure 4-2: Medium temperature heat supply mix per country archetype

When investigating the results at country level, four types of countries can be identified to rely on significantly different strategies to supply medium temperature heat:

- Countries with very large variable RES production (exceeding end-use power and P2X demands) may feature 100% of direct or indirect electrification. In these countries, the model commissions large PV capacities, so that summer power production can meet both direct power demand and industrial heat needs. Summer heat needs can then be supplied via direct electrification, while additional electrolysis and hydrogen storage are installed to generate hydrogen with solar power during summer, then used by hydrogen boilers during the winter (indirect electrification). The latter then supplies 20% of medium-grade heat demand, while the remaining 80% are provided by electric boilers. The optimal mix between direct and indirect electrification is notably depending on seasonal power prices spreads.

- Countries with very significant shares of PV in their production mix feature more seasonal variations of the power supply. During summer, the large amounts of low-cost power during daytime enable direct electrification. The corresponding electric boilers fleet must be complemented by biogas boilers and CHPs that can support the power system and provide heat during times of electricity scarcity.

- Countries with lower biomass costs (about 30% lower than the European average) massively rely on biomass CHPs.

- The remaining countries, that feature poorer renewable potentials, mainly commission biogas boilers.

High temperature heat

No direct electrification route is assumed to be available for the highest considered temperature level[5], widely used e.g., in the steel industry, meaning that available options deliver heat with prices that are constant over the entire year (hydrogen storage facilities are sufficient to smoothen out price differentials with our assumptions). The cost-optimal balance is therefore primarily based on fuel prices and load factors. CAPEX-intensive technologies are therefore found to run with important full load hours and hydrogen is used for peak demand only (see Section 8 for the list of techno-economic parameters and their values).

CHPs account for a high share of the high temperature heat supply mix in areas where power systems require balancing support, such as solar-dominated countries (need support in winter) and countries relying on imports. Biomass is still largely used in countries enjoying low biomass costs.

4.2 Overview of the EU energy system

The following figure provides an overview of the starting point of this study, namely the LTS 1.5TECH scenario, before the optimisation of the provision of industrial heat by METIS.

[5] Direct electrification technologies are progressing rapidly in numerous sectors where they were not expected to play a role even a few years ago. Challenging this assumption could be the topic of sensitivity analyses in upcoming studies.

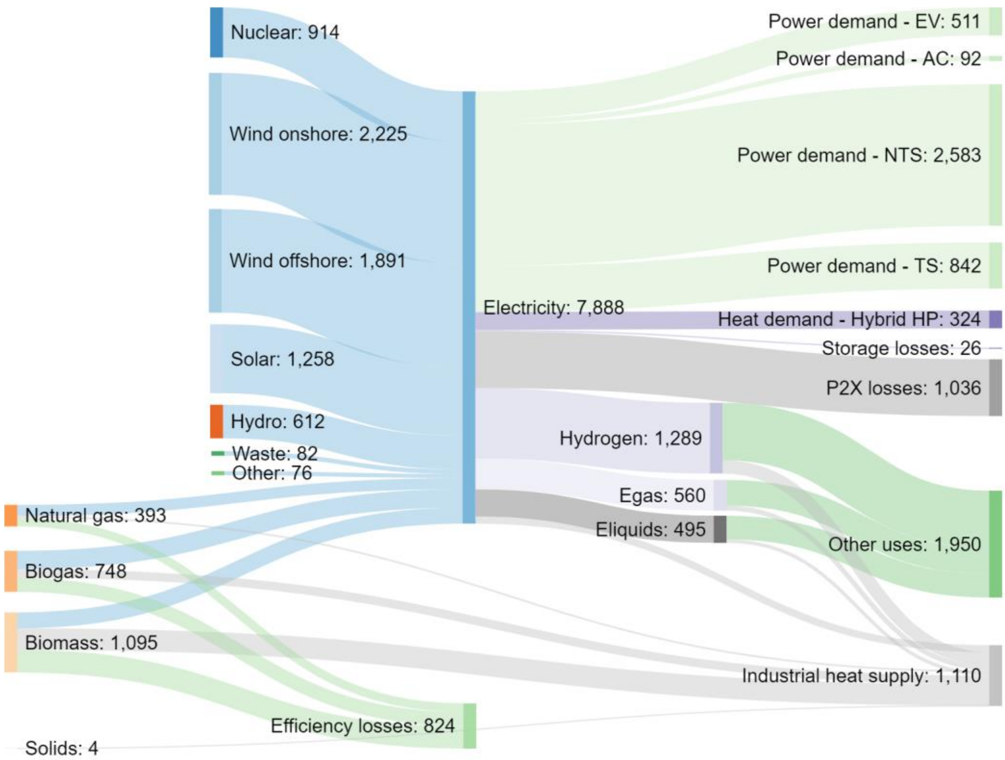

Figure 4-3: The European energy system in the 1.5TECH scenario (EU27+7) [TWh]

This second figure shows how the energy flows are impacted by the optimisation of the heat supply in the industry.

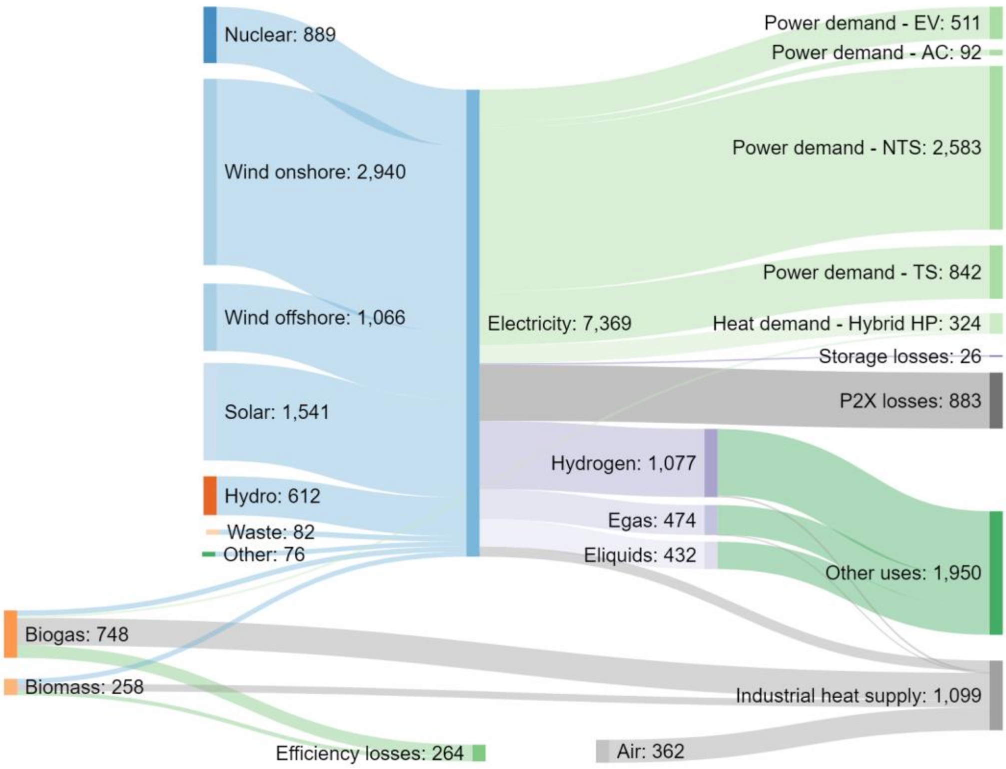

Figure 4-4: The European energy system in the METIS 1.5 scenario (EU27+7) [TWh]

The Sankey diagrams displayed above show that the optimisation of energy supply and demand of the 1.5TECH scenario, resulting in the so-called METIS 1.5 scenario. Important impacts in terms of redistribution of the use of fuels between end-uses and sectors can be observed. Indeed, by capturing the hourly dynamics of the energy system, the METIS model allows for the refinement of the use of synergies between sectors and vectors compared to the ones originally considered in the LTS 1.5TECH scenario, and in particular the use of power-to-X technologies, which strongly link the various sectors.

In addition to other flexibility solutions such as electrolysers, networks and storage, the LTS 1.5TECH scenario relies to a significant degree on gas (natural gas and biogas) and biomass. The hourly simulation of the system equilibrium performed in this study indicates that the need for thermal generation could actually be lower than what is being foreseen in the LTS 1.5TECH scenario. Biomass and gas consumption by the power system is found to be drastically reduced in the METIS 1.5 scenario. Natural gas is found to be completely phased out.

This reduction of thermal uses is enabled by the commissioning of large amounts of renewable power generation capacities, in line with the LTS 1.5TECH levels (the total variable RES generation in the METIS 1.5 scenario only increases by 170 TWh compared to the 1.5TECH scenario). However, the equilibrium is largely changed in favour of onshore wind (increases from 750 GW to 1050 GW), at the expense of offshore[6] wind (decreases from 470 GW to 250 GW)[7].

As explained in section 4.1, a new supply mix is obtained for industrial heat supply. When possible, direct electrification is preferred to indirect electrification, which contributes to lowering P2X needs. Biofuels, that are found not to be used by the power system and compensated for by a further deployment of variable RES technologies, are mobilised by the heat supply fleet as well. Furthermore, the use of industrial heat pumps increases the system's energy efficiency and lowers primary energy supply.

The switch from indirect electrification to biofuels reduces P2X demand, and consequently P2X losses: the total power demand shrinks by 500 TWh compared to the 1.5TECH scenario.

Hydrogen: at the crossroads of the energy system

Investments in variable RES capacities and P2X technologies are endogenously determined by METIS (together with other technologies – see Section 8) in order to meet the hydrogen demand. This demand consists of two components: a first one directly derived from the 1.5TECH scenario (in the sectors that are not re-optimised in this study) and the endogenously determined demand that combines hydrogen for heat and hydrogen for e-CH_4, which may then be consumed by both heat and power sectors in complement to natural gas or biogas.

The level of hydrogen demand has a strong impact on the dimensioning of the power supply, and notably on the deployment of variable RES. Since variable RES capital costs per unit of energy depend on national circumstances (based on the extent and quality of the available potential), hydrogen production costs (including capacity costs) vary between Member States.

[6] Hybrid offshore projects like offshore wind power islands connected to multiple countries, were not considered.

[7] The Climate Target Plan IA scenarios consider between 285 GW and 301 GW of offshore wind capacities in 2050 (EU27).

Countries facing limited economic renewable power potentials happen to rely on electricity imports to meet the national hydrogen demand through electrolysis. Results show that, in all cases, electrolysis is competitive against local provision via SMR+CCS in 2050. In the areas relying on electricity imports, times with low power prices are scarcer, which leads to a more conservative dimensioning of electrolysers with relatively higher load factors (see Figure 4-5).

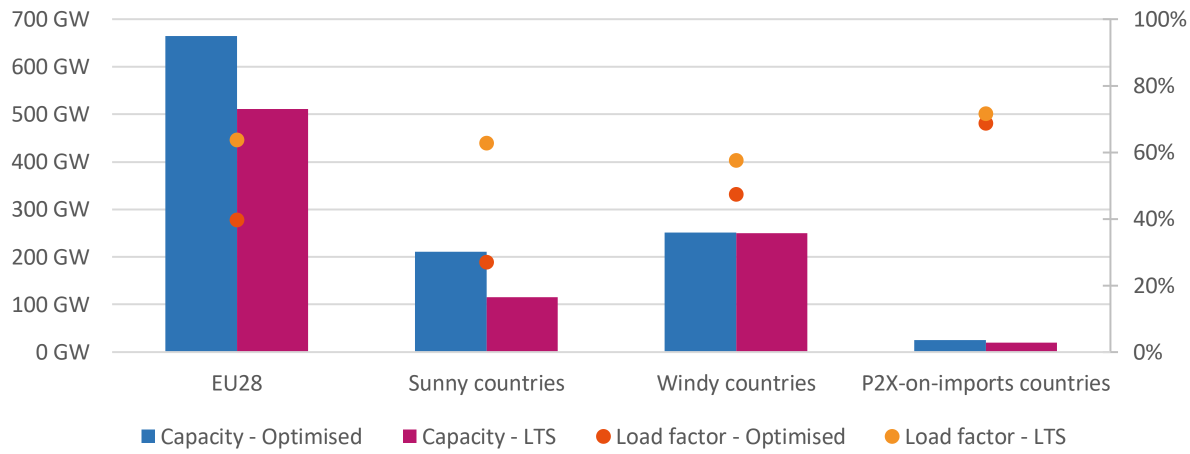

Figure 4-5: Electrolyser installed capacities and load factors

In the METIS 1.5 scenario, the electrolysis capacity exceeds the capacity foreseen by the LTS 1.5TECH scenario (664 GW vs 511 GW at the EU27+UK level) while hydrogen annual volumes are found to be lower than in the LTS 1.5TECH scenario (respectively 2300 TWh and 2850 TWh), with a significantly lower share of hydrogen and e-gas in the heating system in the METIS 1.5 scenario, as can be read from the Sankey diagrams shown above.

Consequently, the load factor of electrolysers is found to exhibit strong differences between the two scenarios, with respectively 40% in the METIS 1.5 scenario and 64% in the LTS 1.5TECH scenario. In the METIS 1.5 scenario, the representation of the hourly dynamics allows for the capture of intra-day flexibility value of electrolysers (see Section 4.3 below), which compensates for the lower hydrogen-generation related revenues.

In a nutshell

The key impacts of the optimisation of the way heat is being supplied to the industry sector in the METIS 1.5 scenario compared to the original 1.5TECH scenario can be summarised as follows:

- Flexibility brought by deployed grid-connected electrolysers lowers the level of remaining flexibility needs to be provided to the power system. This enables biofuels to be used in the industrial heat mix instead of being used for flexibility purposes.

- Biofuels replace most of hydrogen consumption in the industrial heat supply.

- Reduced hydrogen demand lowers P2X needs – and losses – and consequently the level of electricity demand, thereby leaving room for increased direct electrification of industrial heat.

4.3 FUNCTIONING OF THE POWER SYSTEM

In the METIS 1.5 scenario, the use of hydrogen, and the associated deployment of electrolysers, drives the commissioning of variable RES across Europe. As a consequence, the need for flexibility increases on all timescales in order to integrate these additional variable power sources and to balance the system in a cost-effective way. The assumed flexibility on the hydrogen-demand side (notably via storage) allows electrolysers to dynamically adjust to the power supply and demand equilibrium on various timescales. The endogenously determined European (EU27+7) hydrogen storage needs is circa 400 TWh in the METIS 1.5 scenario, equivalent to around two months of hydrogen consumption. The sensitivity analyses (see next section) reveal that electrolysers provide more flexibility to the system than the associated deployment of RES require, thereby bringing in flexibility value to the system. The remaining daily, weekly and seasonal flexibility needs have to be provided by the other flexibility solutions (peakers, batteries, pumped-hydro storage, electric vehicles smart charging schemes, networks, etc.).

4.3.1 ASSESSMENT OF FLEXIBILITY NEEDS AND SUPPLY

The need for flexibility is defined as the need to use dispatchable assets to meet the electricity demand. Flexibility needs can be defined on various timescales (daily, weekly, seasonal), and relate to the variations of the residual load (demand – vRES generation) on these timescales. Flexibility needs are highly correlated with the system's variable RES installed capacities: countries with greater PV shares may feature higher daily flexibility needs, due to the midday generation peak, while windy countries are more likely to experience fluctuations at the weekly scale due to some wind regimes lasting for several days.

Figure 4-6 below shows the level of flexibility needs on three timescales in the optimised METIS 1.5 scenario and the share of each of them being met by the flexible operation of electrolysers.

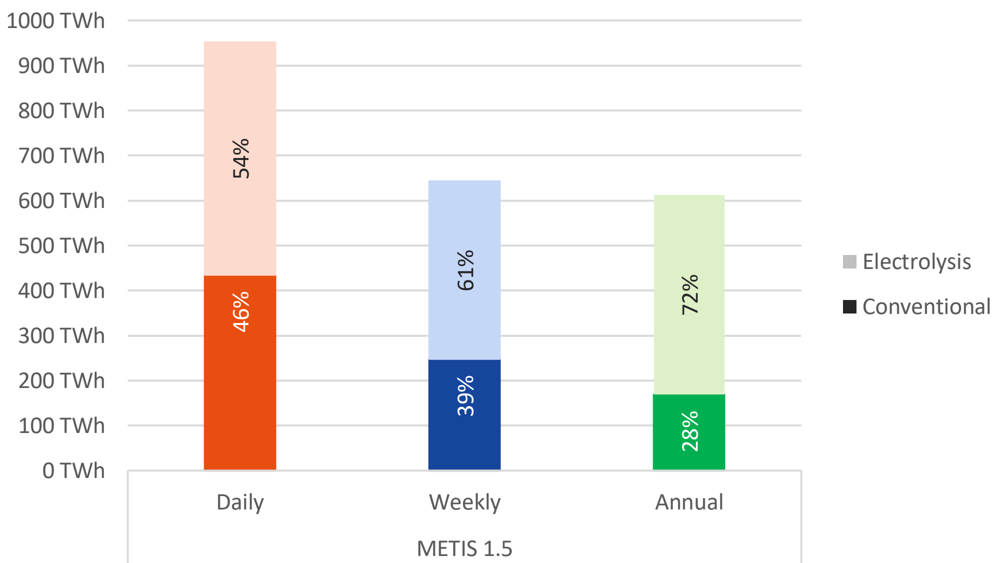

Figure 4-6: Flexibility needs and supply computed annually (EU27+7) - Electrolysis contrasted with other sources

An analysis of the ability of electrolysers to adapt their consumption on all timescales is performed in Section 4.3.2. The following paragraphs concentrate on the provision of the remaining flexibility needs by other flexibility solutions.

Provision of daily flexibility

Daily flexibility needs typically originate from the daily variations of PV generation and the change of consumption patterns between the hours of the day. Short-term flexibility solutions, notably batteries, PHS, peaking units and demand flexibility of HPs and EVs provide the usual daily flexibility. Figure 4-7 displays how remaining daily needs, after provision by electrolysis, are covered. These remaining needs represent 435 TWh out of 950 TWh before the contribution of electrolysers is subtracted.

Electric vehicles are an essential provider of daily flexibility services via their ability to adapt their power withdrawal within a pre-defined plug-in time-range (smart-charging). In particular, charging-at-work electric vehicles can switch by a few hours their charging patterns in order to match mid-day peak solar PV production. This intra-day charging optimisation allows for fewer stationary batteries to be commissioned in the METIS 1.5 scenario compared to the LTS 1.5TECH scenario.

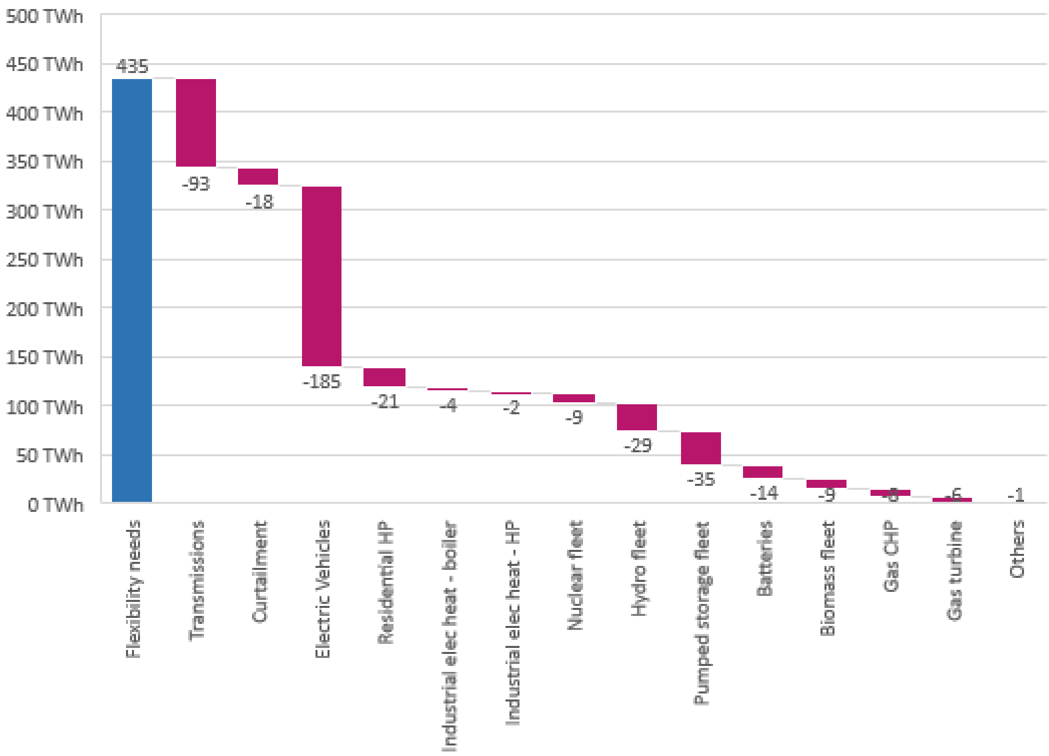

Figure 4-7: Contribution to remaining daily flexibility needs per technology - Electrolyser contribution: 516 TWh

Provision of weekly flexibility

Weekly flexibility needs typically derive from wind power variations from a day to another and from the difference in demand levels and dynamics between working days and weekends. Interconnections are found to be the main contributors of weekly flexibility services since they allow countries with different wind patterns to share resources and exploit synergies between their electricity systems.

Demand-side flexibility (notably from EVs and HPs) becomes less significant for weekly flexibility, as they typically enable flexibility within a day.

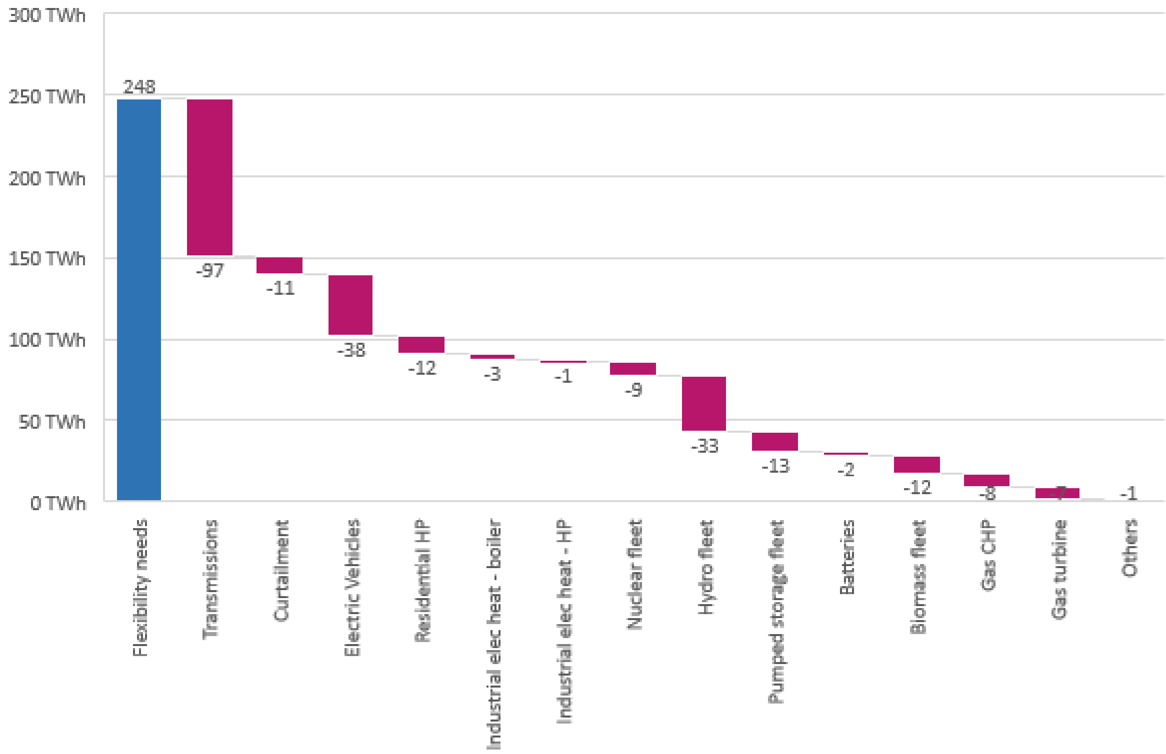

Figure 4-8: Contribution to remaining weekly flexibility needs per technology - Electrolyser contribution: 394 TWh

Provision of seasonal flexibility

The thermo-sensitivity of the demand (heating in winter, cooling in summer) and variable RES fluctuations within the year (more solar PV generation in summer, more wind output in winter) drive seasonal flexibility needs. Electrolysers, together with the flexibility of hydrogen demand, can cover more than 70% of these needs (see Figure 4-6). On this timescale, the provision of remaining flexibility needs is well distributed over the various technologies in place as shown on Figure 4-9.

Again, interconnectors allow for resource sharing between countries across the year, alongside baseload/semi-baseload capacities like nuclear, hydropower, biofuels plants (turbines and CHPs).

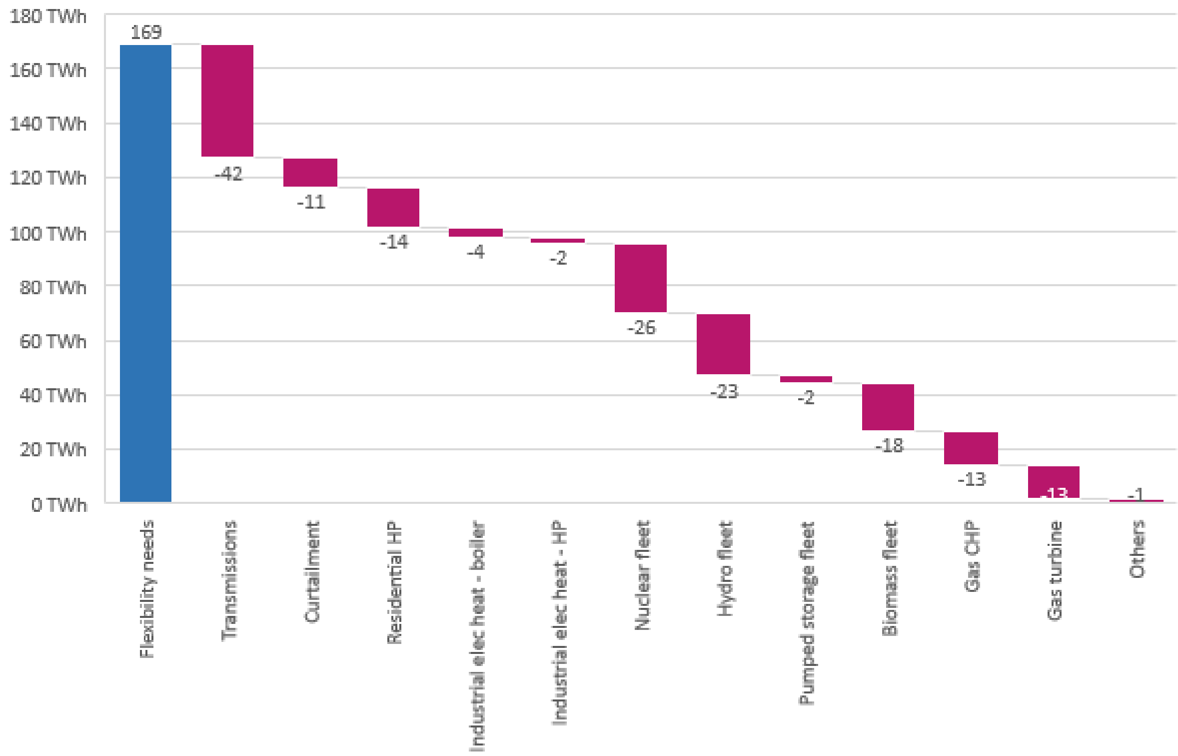

Figure 4-9: Contribution to remaining annual flexibility needs per technology - Electrolyser contribution: 443 TWh

Stake of conventional flexibility

As a result of the way flexibility is provided to the power system, significantly fewer stationary batteries are deployed in the METIS 1.5 scenario compared to the LTS 1.5TECH scenario (resp. 25 GW vs 69 GW), and they are found to be distributed over countries with high shares of solar PV only. In terms of thermal generation, 38% of gas turbines are CHPs (resp. 8% for biomass turbines), totalling 44 GW of installed CHP capacities. CHPs are also deployed in countries with high PV shares as they can compensate for lower variable RES generation levels during the night and in winter. While high shares of PV drive both storage and turbines deployment, the optimised levels are lower than what was foreseen in the 1.5TECH scenario.

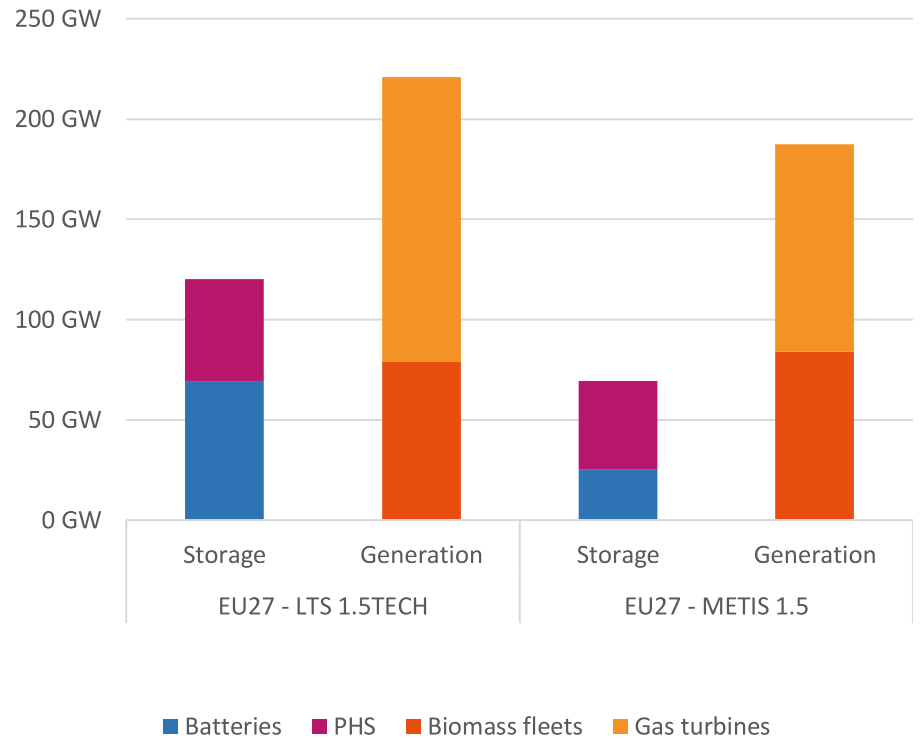

Figure 4-10: Power flexibility providers - turbine and storage installed capacities

In a nutshell

- The massive investments in electrolysis capacities deployed across Europe cover most of the power system flexibility needs, on all timescales.
- On the daily timescale, the remaining flexibility needs (45%) are mainly covered by demand-side flexibility, notably the smart-charging of EVs, especially if connected to the grid during daytime (charging-at-work EVs). Consequently, fewer stationary batteries are deemed economic and commissioned than foreseen by the 1.5TECH scenario.
- In power systems dominated by variable RES, the ability to efficiently use resources is key to minimising system costs. As a result, interconnectors are a key contributor of flexibility services on all timescales.
- On weekly and seasonal timescales, after contribution of electrolysers are subtracted (covering respectively 40% and 70% of the needs), the remaining contributions are evenly distributed over the available technologies. High shares of PV in the mix increase daily and seasonal flexibility needs, thereby driving the need for stationary batteries and biofuels turbines.

4.3.2 ELECTROLYSIS: A KEY CONTRIBUTOR TO THE PROVISION OF FLEXIBILITY

The jointly optimised investments in variable RES and in electrolysers, driven by both the LTS-derived, exogenous hydrogen demand, and the endogenously determined hydrogen demand dedicated to the heating and power sectors (the latter may have an impact on hydrogen demand by consuming e-CH_4), result in large power generation fleets. Electrolysers coupled with significant hydrogen demand-side flexibility can adapt the dynamics of their demand profiles on all timescales: hourly, daily, weekly and seasonal timescales.

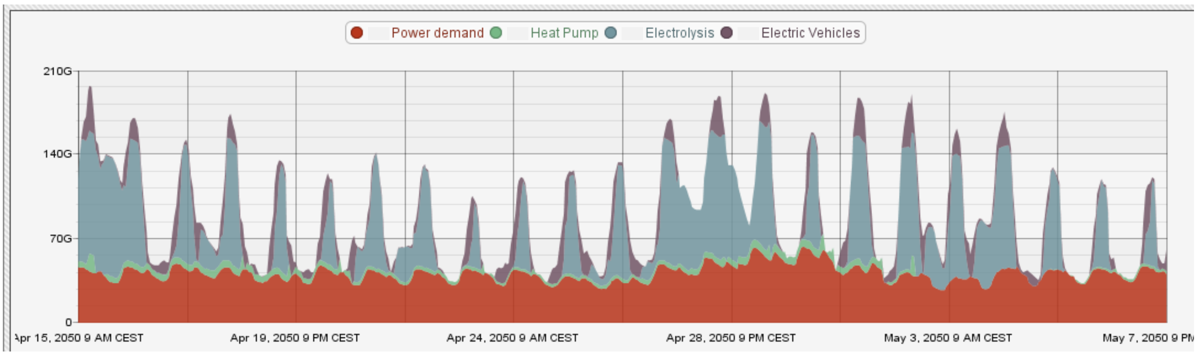

Figure 4-11: Example of an hourly power demand decomposition in a country. The electrolysers can be seen to absorb large shares of the power generated by renewables.

The case of power mixes dominated by solar PV

In countries with important deployments of solar PV, electrolysers provide flexibility by adjusting their consumption patterns to hours of negative residual load within the day. Figure 4-12 and Figure 4-13 display the balance between supply and demand in a country with a high PV share.

During the day, the solar production peak is indeed mainly consumed by flexible electrolysers and plugged-at-work EVs. At the same time, there is still room for storage, in addition to total demand (red line on both figures), to charge in order to support the system when the night comes.

Flexible plugged-at-home EVs also have a role as they refrain from charging at the end of the day and wait for the night (lower EV demand on the 17-21h period, higher on the 23-6h period). During this period, hydropower, batteries as well as CHPs and imports allow to ensure the supply-demand equilibrium is met.

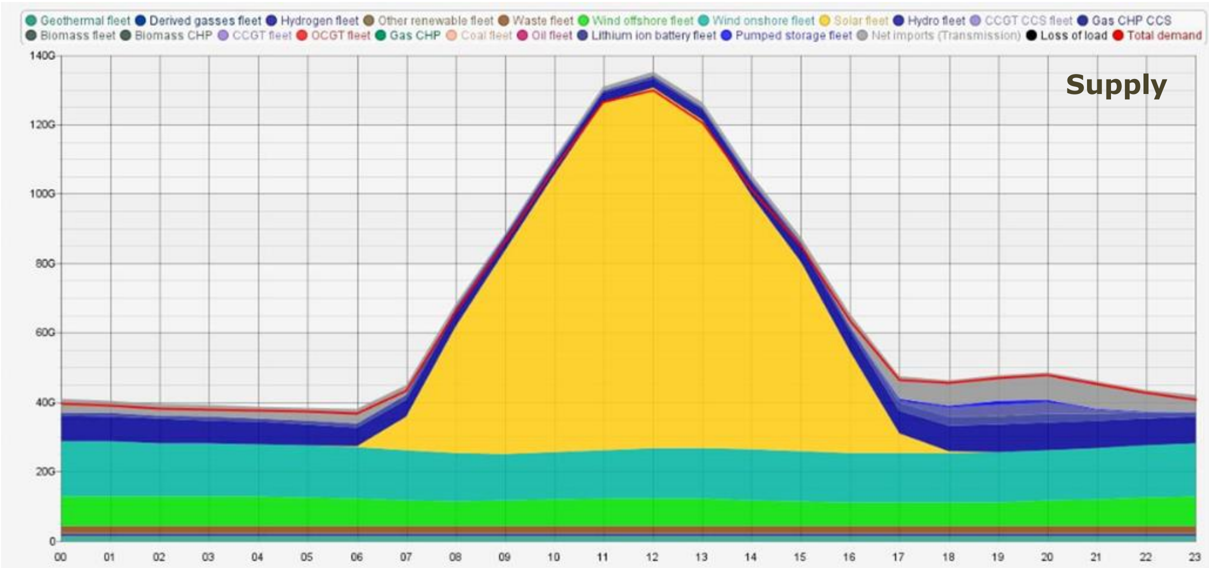

Figure 4-12: Average daily generation profile in a country with high PV shares

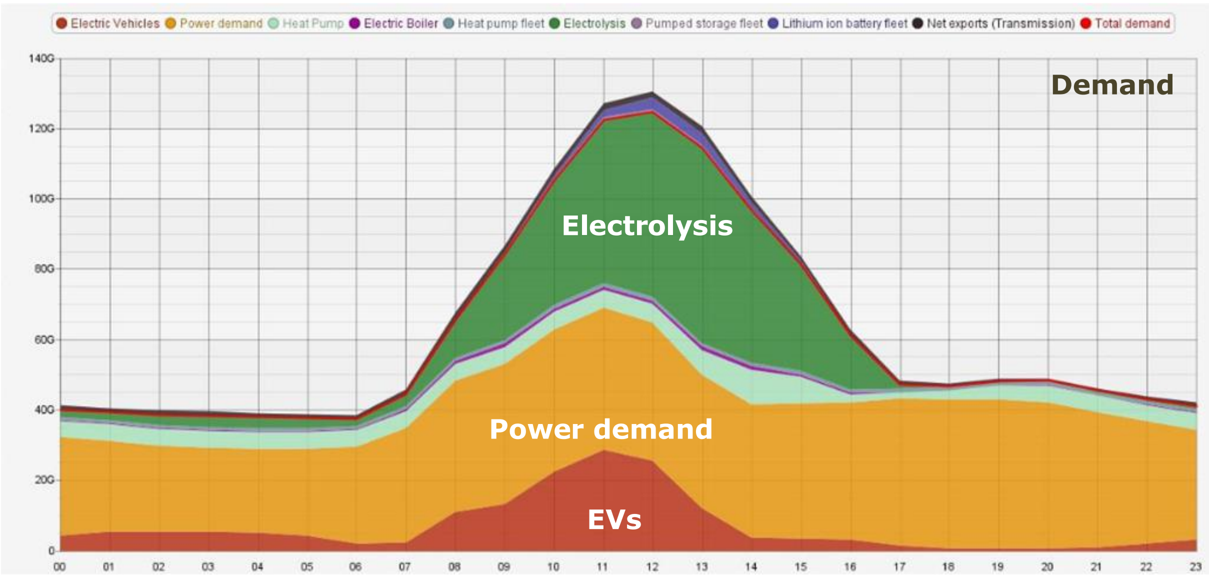

Figure 4-13: Average daily demand profile in a country with high PV shares. Electrolysers (green band) and electric vehicles (red band) provide most of the flexibility.

System operation under low renewable generation

Figure 4-14 and Figure 4-15 show the same solar-dominated power system during an episode of low renewable generation, happening in December.

On day 1, high wind generation combines with low solar output. The resulting amount of available power allows electrolysers to run (green band on Figure 4-15) and storage capacities to charge. On top of national power demand, high levels of wind power generation allow for exports on day 1.

On day 2, the low levels of wind power have to be partially complemented by hydro and imports. During the night from day 2 to day 3, there is very limited wind power. The supply then relies essentially on, in this order: hydropower (dark blue), biogas-fuelled gas CHP (purple), biomass turbines (dark grey), CCGTs, batteries and pumped hydro as well as imports. On the demand-side, only non-flexible demand is served during these hard times. Charging-at-home EVs have to charge during the night anyway.

The dispatch below shows that EVs avoid charging from stored power, i.e. at times when the production mix includes storage assets: home-EVs night-peaks on day 2 and 3 are consecutive to storage discharging times-steps. On the other hand, batteries happen to charge on imports (purple bands exceeding total demand red line on the second chart, on days 2 and 3).

Day 3 combines low levels of both solar and wind generation. All flexible generation technologies and imports can be seen to support the system around midday, serving only non-flexible demand (plugged-at-work EVs have to charge during the day anyway).

Overall, the electrolysers happen to be operated only during the first day, when important RES power generation was available. During periods where the renewable generation is low, only the required non-flexible demand is served, which can induce the need to operate other flexible generation technologies.

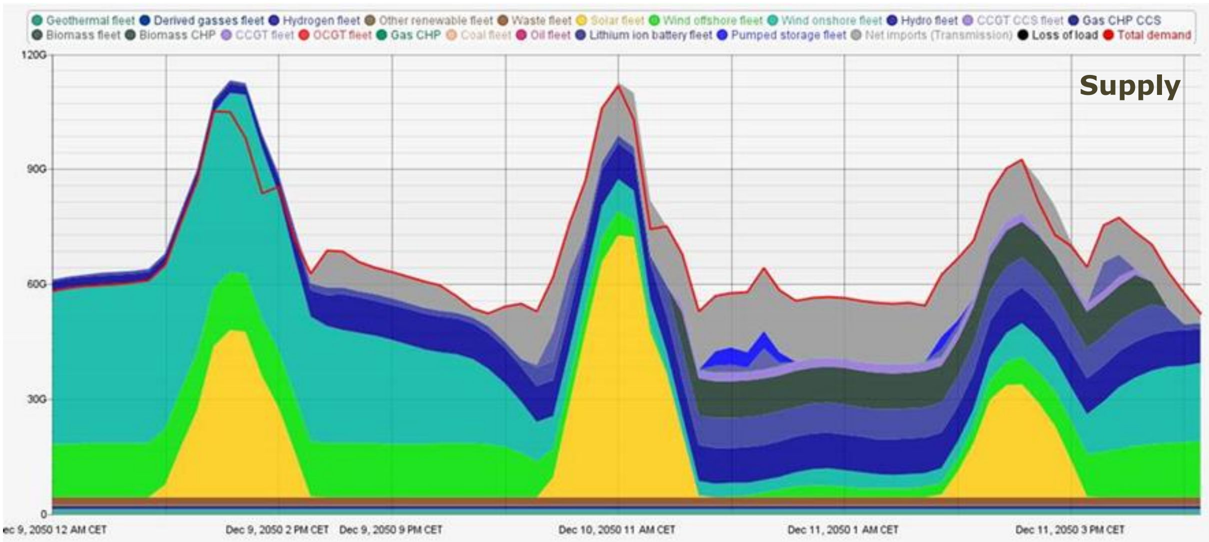

Figure 4-14: Hourly generation profile in a solar country during low-wind winter times

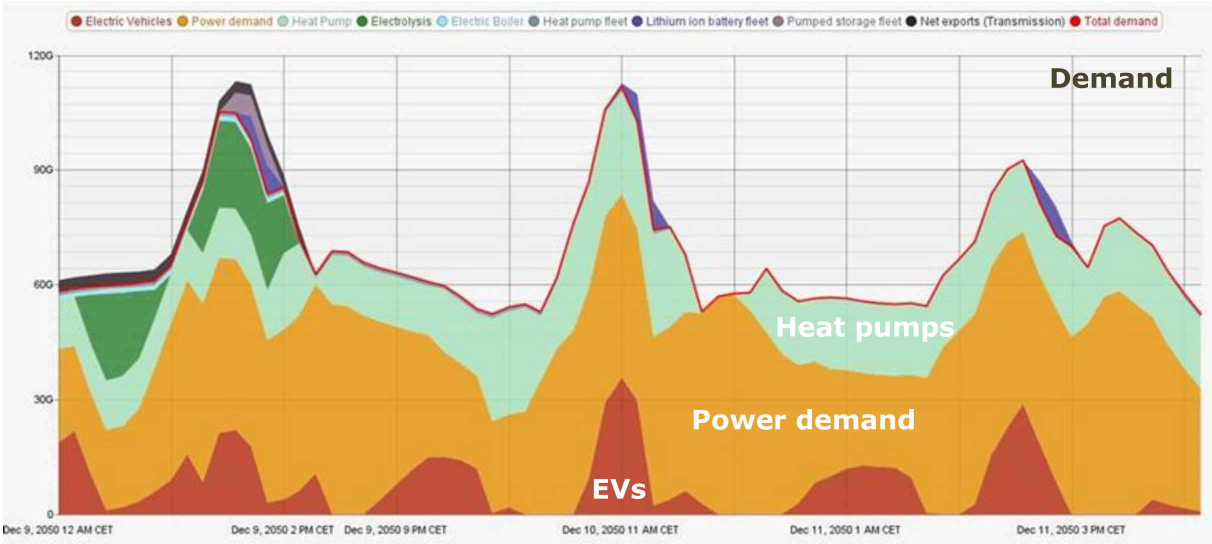

Figure 4-15: Hourly demand profile in a solar country during low-wind winter times

The examples above show that electrolysers can adapt their load to both large and scarce renewable instantaneous generation. Provided sufficient flexibility can be provided by the hydrogen demand side (e.g. via storage), this allows electrolysers to run only when low-cost and low-carbon power is available, while meeting the overall hydrogen demand.

Adaptability of electrolyser operation

The hourly electrolyser operation mainly depends on the country's renewable generation mix. Figure 4-16 shows the aggregated hourly operations of electrolysers in typical solar-dominated and wind-dominated countries. In countries with high shares of solar PV, the electrolyser operations are mainly limited to daytime, concentrated from spring to autumn. In windy countries, as wind episodes generally last for several days, electrolysers run during longer time-periods, which occur statistically more often in winter. However, as the heart of winter drives demand up due to thermo-sensitive end-uses, electrolysis operations then take place mostly in late autumn and early spring.

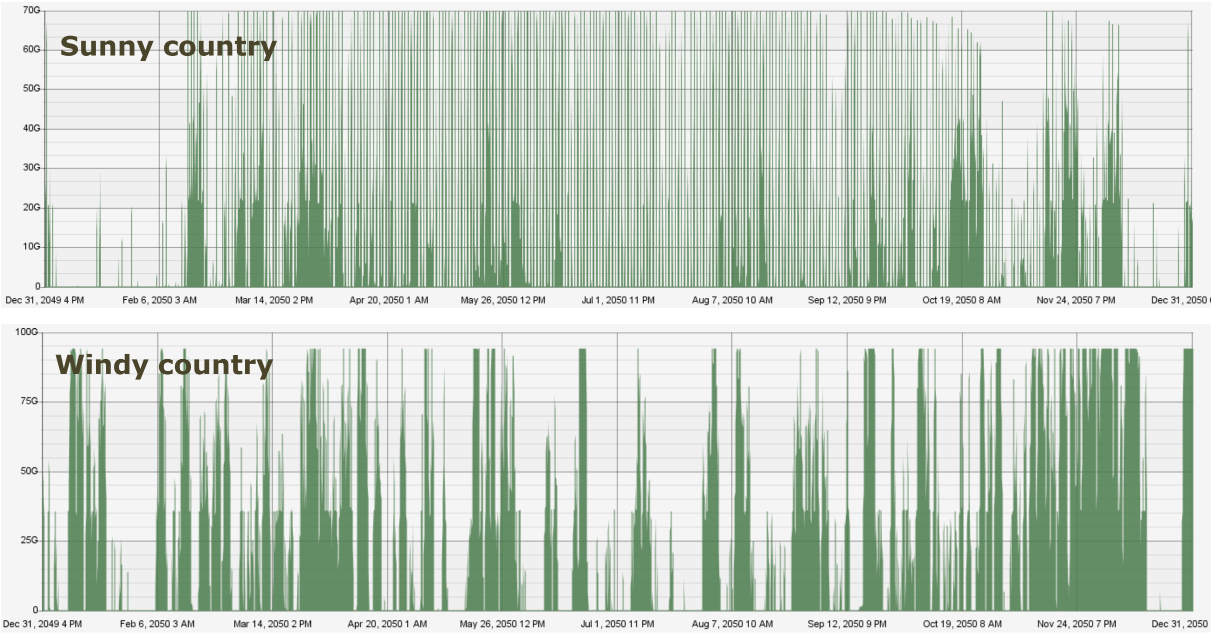

Figure 4-16: Year-long hourly electrolyser operation in a country with high PV generation (up) and in a country with high wind generation (down)

In a nutshell

- Overall, high hydrogen demand and electrolysers' flexibility drive investments in variable RES capacities. Electrolysers then capture excess energy when available, with low RES generation levels still being sufficient to cover most of the power demand.

- The mix of variable RES technologies depends on the area's resources. Then, electrolysers adapt their operations to match instants of low-cost, low-carbon power. As a consequence, the way electrolysers are operated may vary widely from an area to another, e.g. concentrating on sunny days, windy weeks, summer or winter.

5 Sensitivity analyses

A series of sensitivity analyses has been carried out to test the robustness of the METIS 1.5 scenario to key parameters. Seven sensitivity analyses have been designed to capture METIS response in terms of optimal dimensioning and operations of the integrated system: power, hydrogen and heat supply fleets as well as flexibility needs and the provision of flexibility services. The sensitivity analyses are carried out along three major dimensions: system flexibility, hydrogen market structure, resources availability.

5.1 Definition of the sensitivity analyses

Constrained system flexibility

The sensitivity **lowH2Stock** is designed to explore the impact of the level of hydrogen demand flexibility on the whole system. In the METIS 1.5 scenario, the endogenously determined European (EU27+7) hydrogen storage capacity is 400 TWh, equivalent to two months of hydrogen consumption. This variant assumes that national hydrogen storage capacities are halved.

As shown in Section 4.3.1, the smart charging of electric vehicles is the highest contributor to daily flexibility needs after electrolysis as EVs are able to adapt their charging profiles, responding to the need of the system. The sensitivity **EVnoFlex** explores the dimensioning and operation of the whole system in the case EVs are not equipped with smart charging schemes: they start charging when as soon as they connect to the grid, until the charge is complete.

Industrial heat pumps deployment in low temperature levels for industry is still under development and may not be suitable for temperatures up to 150°C by 2050. In the version **noIndusHP**, heat pumps are not considered as an option to supply industrial heat. This reduces the total system energy efficiency (other technologies having lower efficiencies), which can be expected to drive up the need for variable RES and to result in a new balance between direct electrification and decarbonised gases.

Competition of electrolysis with other sources of hydrogen

The Long-Term Strategy's 1.5TECH scenario assumes that the European hydrogen demand is entirely met by production within Europe. Two sensitivity analyses are built to assess the response to:

- Volume competition: 50% of hydrogen demand being supplied through an alternative hydrogen production source, leaving only 50% of the hydrogen demand to be supplied within the METIS model. This is the **lowH2Demand** sensitivity.

- Price competition: the **lowH2Price** variant considers that the European countries can import hydrogen from outside Europe. The price for these imports is set equal to the endogenously determined METIS 1.5 scenario average electrolytic hydrogen production cost: 48.8 €/MWh, i.e. 1.46 €/kg_{H2}.

Hydrogen supply from alternative sources lowers both the need for additional electricity generation and the potential contribution of electrolysis in balancing variable RES generation. In addition, as only the most cost-efficient renewable potentials are exploited, it results in a lower average hydrogen production cost which may have an impact on the endogenous hydrogen demand levels, notably in the industrial heat supply mix.

Limited natural resources availability over Europe

Bio-energies are one of the enablers of the energy transition, as these carbon-neutral fuels can replace fossil fuels. Yet, their deployment is limited over Europe, notably due to the required space for crops and the competition with food production. The sensitivity **lowBiogasAvail** captures the energy system response to a 50% reduction of the considered biogas potential.

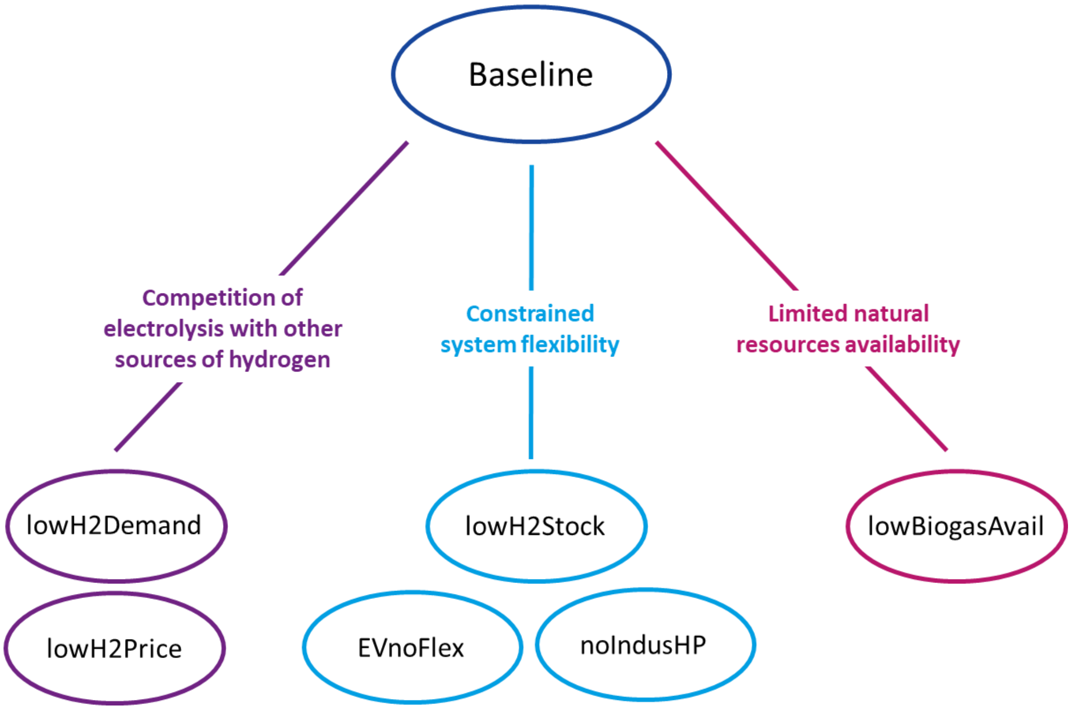

Figure 5-1: Set of sensitivity assessments

5.2 CONSTRAINED SYSTEM FLEXIBILITY

The constrained system flexibility series of sensitivity analyses investigates the system response to reduced hydrogen storage sites, limited EV smart-charging deployment and fewer technology options in sector coupling portfolio (no industrial heat pumps). This limited available flexibility for the system results in an adaptation of vRES capacities and a redistribution of contributions over flexible technologies.

As discussed in the previous sections, electric vehicles featuring smart charging schemes are the largest contributors to the provision of daily flexibility services after electrolysis. As the EVnoFlex sensitivity scenario assumes that their energy demand is completely determined by the EV arrival time at the charging point, the flexibility portfolio has to adapt to replace the EVs' flexibility services. As a matter of fact, the system first adapts by limiting flexibility needs by reducing midday power surplus occurring with maximal PV production (see Figure 5-2). In the METIS 1.5 scenario, EVs adapt their charging schedule to match the midday power production peak. As smart-charging is not available anymore in the EVnoFlex sensitivity, the power system introduces a shift from PV (-60 GW) to wind generation capacities (+30 GW).

In the noIndusHP sensitivity, direct electrification options for low temperature heat are limited to electric boilers, replacing the heat pumps largely deployed in the base scenario. As an energy-efficient technology is removed from the technology portfolio, total energy demand rises, leading to the installation of 150 GW of additional variable RES capacities, mainly shared between wind onshore (+90 GW) and PV (+60 GW).

Providing that sufficient storage is available, hydrogen is a key contributor in balancing variable renewable production over the year. The high PV production in the baseline in summer is turned into hydrogen, which is stored over the months and consumed in winter when available power is scarcer due to the dynamics of the residual load. A more constrained hydrogen demand (lowH2Stock scenario) requires a flatter annual vRES profile, resulting in a shift from solar (-159 GW) to wind power (+57 GW). In addition, the total vRES capacities are reduced to avoid renewable curtailment in summer. As the available hydrogen storage is limited to a month consumption, a large share of winter demand cannot be supplied with summer production, allowing alternative hydrogen sources such as SMR+CCS to meet part of the hydrogen demand in winter. In total, 4% of hydrogen demand is then produced via alternative sources such as SMR+CCS.

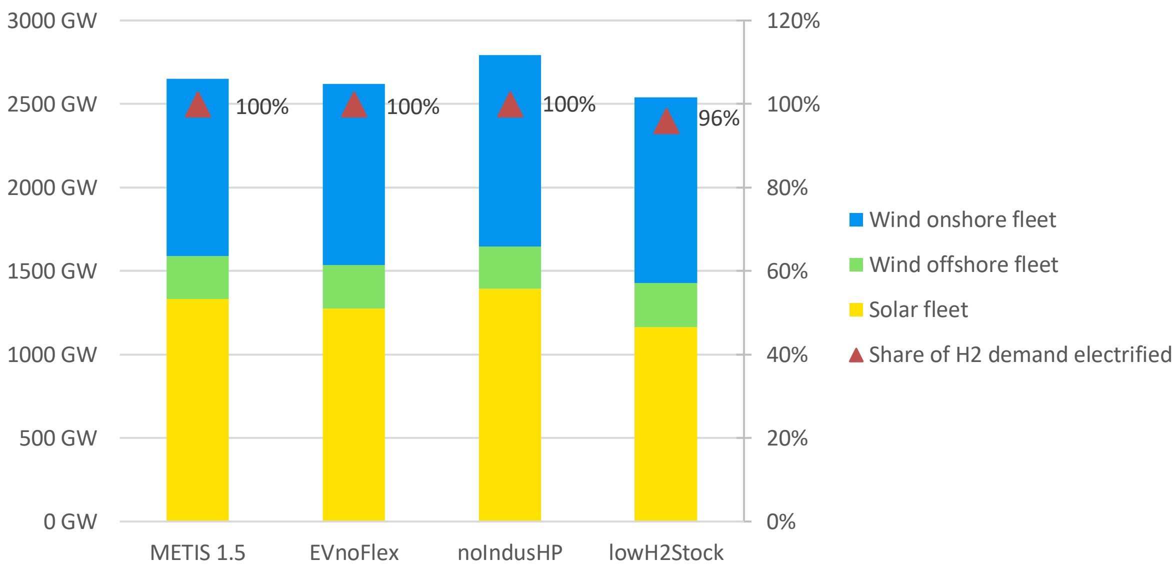

Figure 5-2: vRES installed capacities (EU27+7 scope)

The operation of SMR+CCS in winter to meet the hydrogen demand is a response to higher power prices, while the opposite behaviour happens in summer as power prices fall due to excess renewable electricity and limited ability of electrolysers to absorb surplus (due to the limited storage). Therefore, the seasonality of the heat supply technology mix increases and reflects the underlying balance: a higher share of both direct (+23 TWh) and indirect electrification (+37 TWh) for months when hydrogen storage levels are high; and a larger operation of CHPs, needed when vRES cannot meet power demand (leading to high power prices), while baseload gas-fuelled boilers lose ground.

The removal of industrial heat pumps from the available options to supply heat impacts the balance between direct electrification and the use of gaseous fuels. Even if industrial heat pumps are partially replaced by direct (+226 TWh for electric boilers, see Figure 5-3) and indirect electrification (+ 156 TWh), the heat demand electrification share shrinks from 50% in the METIS 1.5 scenario to 41% in the NoIndusHP sensitivity analysis.

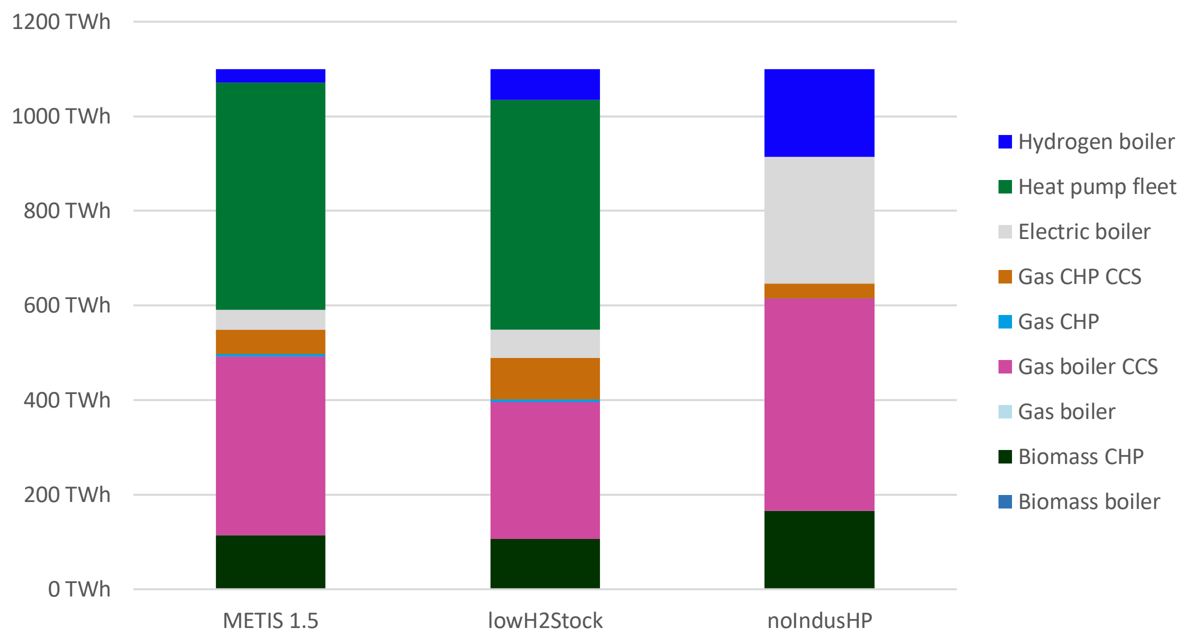

Figure 5-3: Industrial heat supply technology mix

The removal of any of these three technologies, namely hydrogen storage, EVs with smart charging schemes, or heat pumps, is found to result in an adapted RES portfolio and hence is impacting the level of flexibility needs.

The flexibility needs are highly correlated with the deployment of the different variable RES technologies. As Figure 5-4 shows, when wind replaces solar, flexibility needs are transferred from the daily to the weekly timescale: for both lowH2Stock and EVnoFlex scenarios, daily flexibility needs decrease (-90 TWh and -20 TWh, respectively) and shift to weekly flexibility needs (+20 TWh and +15 TWh, respectively). As in the noIndusHP scenario one installs more variable RES, the total flexibility needs increase on all timescales, yet they are compensated by a higher contribution of electrolysers.

The lowH2Stock and EVnoFlex scenarios reset the balance between the contribution to flexibility needs between electrolysers and other technologies. As EVs were the main contributors to daily flexibility services, they are partially replaced by a higher contribution from electrolysers. On the contrary, a more constrained hydrogen demand limits the possible contribution from electrolysers from a season to another, leading to higher a contribution of conventional solutions (+80 TWh).

EVs contribution to daily flexibility needs in the METIS 1.5 scenario (185 TWh, see Figure 5-5) is redistributed over the remaining flexible technologies, with the largest share for batteries (+85 TWh).

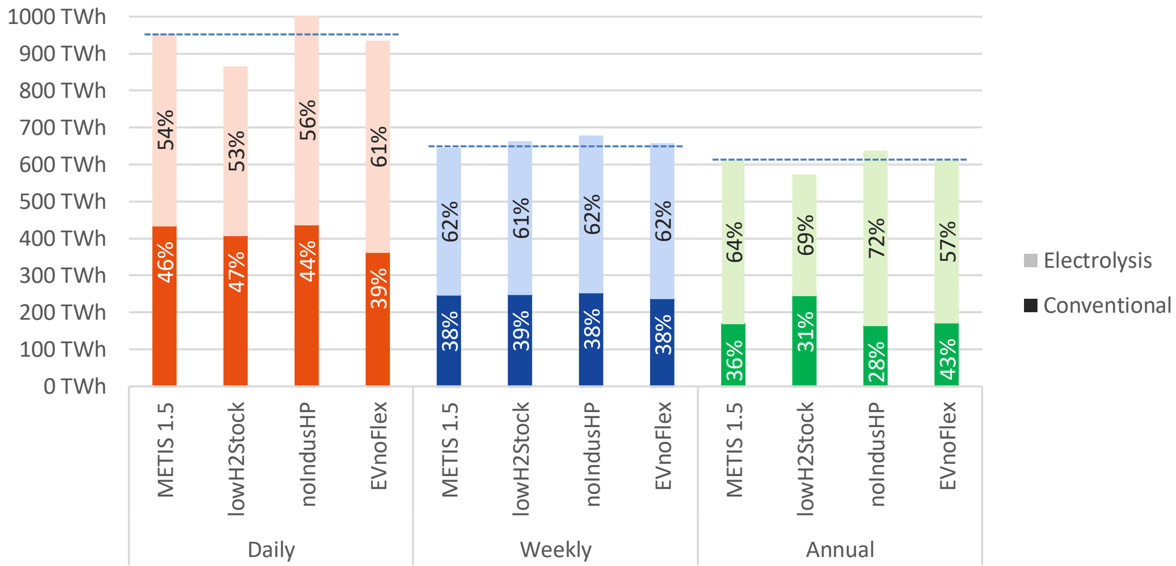

Figure 5-4: Flexibility needs - electrolysis contribution highlighted

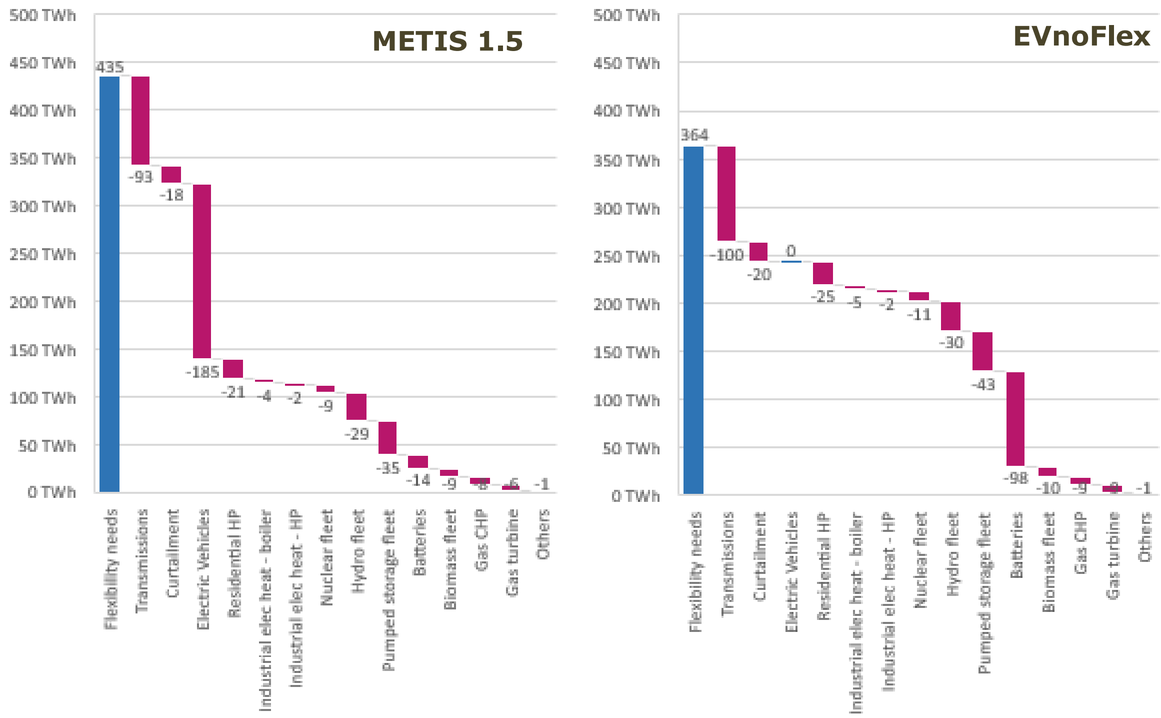

Figure 5-5: Conventional contribution to flexibility needs (Baseline - left - and EVnoFlex - right)

In the lowH2Stock scenario, the increase in conventional contribution to annual flexibility needs is distributed over a larger use of interconnectors (contribution increases by 50 TWh) and a larger contribution of sector coupling technologies (+27 TWh). Indeed, electric boilers and CHPs balance each other in providing flexibility in summer (absorption of excess renewables with electric boilers) and winter (additional power generation with CHPs).

The removal of industrial heat pumps does not change the balance between conventional and electrolysers contribution, yet the removal of heat pumps from the technology portfolio is compensated by a higher contribution from electric boilers (contribution to daily flexibility needs increase by 13 TWh) and batteries (3 TWh increase).

5.3 COMPETITION WITH OTHER SOURCES OF HYDROGEN

As discussed in the previous sections, hydrogen plays an important role in the decarbonisation of the energy system, both by being used across all the sectors of the economy and by balancing variable renewable production. In this section, two systems with lower hydrogen production levels in Europe are investigated, be it because of easier imports of hydrogen from extra-EU sources, or because of a reduced demand. In the first case, lowH2Price, imports of hydrogen are available at competitive cost (determined as the METIS 1.5 scenario average hydrogen production cost); in the second case, lowH2Demand, 50% of hydrogen demand is considered as being supplied via another source.

In the first case, METIS determines that hydrogen imports should supply 20% of total hydrogen demand, meaning that 80% of hydrogen volumes are still produced via electrolysis and have a production cost lower than the assumed import price (48.8 €/MWh). As more hydrogen is supplied through imports, less renewable generation is needed to feed the electrolysers, and variable RES installed capacities decrease. Based on the cost-potential curves[8], the decrease in variable RES capacities starts with its most expensive layers, making total renewable production cheaper and consequently decreasing hydrogen production cost. The decrease stops when inland hydrogen production cost falls under the import price.

Similarly, as hydrogen demand decreases (lowH2Demand), renewable capacities fall. Of the 2650 GW of variable RES capacities, only 1950 GW remain in the sensitivity analysis, enough to supply around 53% of total hydrogen consumption. These 53% of total hydrogen demand consist of the 50% of exogenous demand whose supply mix has to be optimised by METIS and additional endogenously determined demand in the industry or power sectors.

[8] Further information on the cost potential curves considered in the present study is available in the dedicated Technical Note accompanying this study.

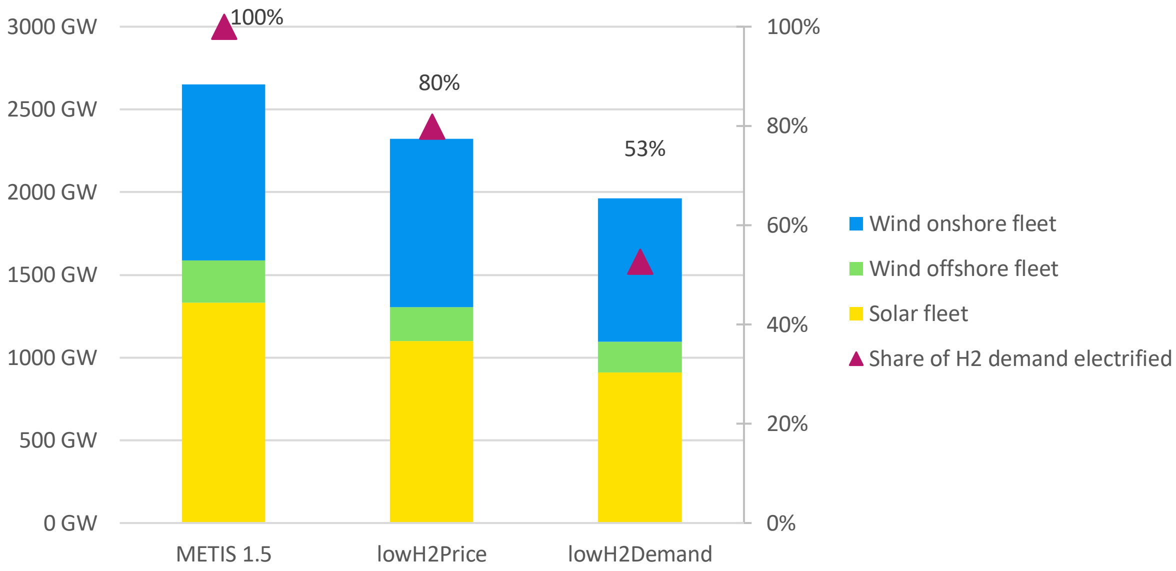

Figure 5-6: Variable RES installed capacities (EU27+7)

The reduction in variable RES capacities removes the most expensive layers of investments in RES and lowers both renewable electricity and hydrogen production costs. The industrial heat supply mix then evolves in favour of direct and indirect electrification. Indeed, the share of electrified heat evolves from 50% (METIS 1.5 scenario) to 51% (lowH2Price) and 61% (lowH2Demand). The increase is limited in the first scenario as hydrogen (and renewable electricity) production cost decreases only in countries where the METIS 1.5 production cost was higher than the import price. In countries endowed with favourable RES potential, where the production cost is under the average, no imports are economically relevant and hydrogen or renewable electricity costs do not change.

Increased electrification is primarily replacing biogas and biomass-based heat supply. The avoided fuel consumption is redirected towards power generation to help meet flexibility needs. Indeed, reduced operation (and capacities) of electrolysers increase the flexibility needs that have to be met by other technologies on all timescales (up to 32% for annual needs in the lowH2Demand scenario). The missing flexibility needs are met with increased contribution from turbines and CHPs (+30 TWh of flexibility provision on the seasonal timescale).

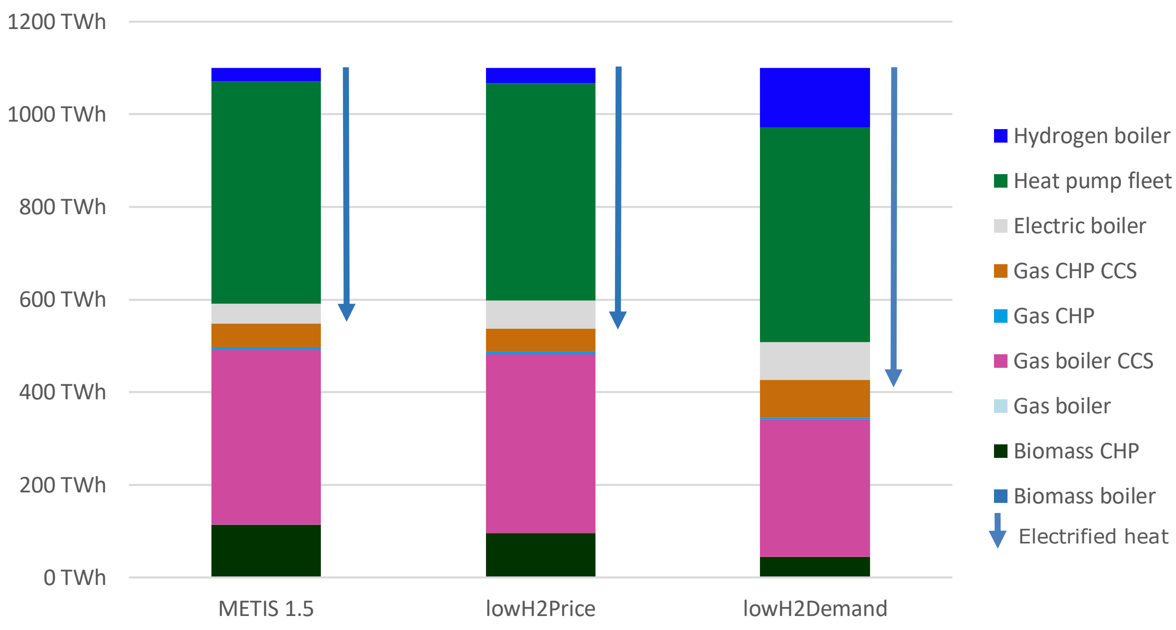

Figure 5-7: Industrial heat supply technology mix

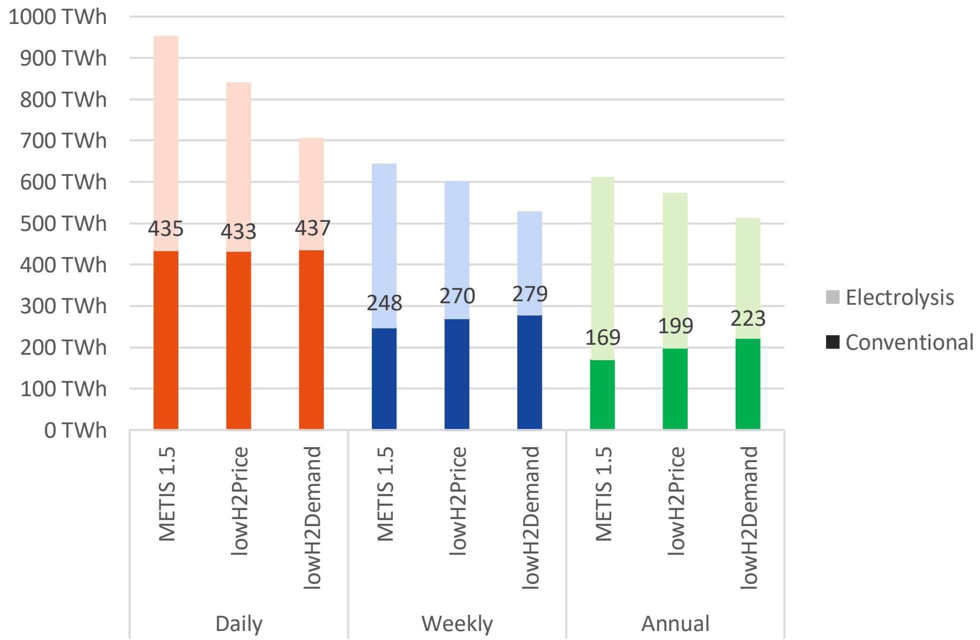

Figure 5-8: Flexibility needs - electrolysis contribution highlighted

Figure 5-8 displays the flexibility needs for the two sensitivities, and the contributions of electrolysers and conventional technologies respectively. In the two sensitivities explored in this section, variable RES capacities are reduced, therefore lowering total flexibility needs. In the meantime, electrolyser capacities are reduced, too, as is their contribution in covering the flexibility needs. Yet, the contribution of electrolysers reduces more rapidly than total needs (then increasing the contribution of conventional technologies). When considered the other way, electrolysers provide more flexibility to the system than what they cause by driving up the deployment of variable RES.

5.4 LIMITED NATURAL RESOURCES AVAILABILITY OVER EUROPE

In this section, the system response to a limited bio-resources availability is captured. The scenario assumes a 50% reduction in biogas availability, leaving only 374 TWh for the EU27+7 scope.

As the biofuel availability for power and heat thermal generation is reduced, a redistribution between biofuels and direct or indirect electrification occurs. First, additional variable RES capacities are required to replace missing electricity generation: 43 GW of solar PV, 4 GW of offshore wind and 52 GW for onshore wind are installed on top of the capacities of the METIS 1.5 scenario. The entire hydrogen demand is met by electrolytic hydrogen, and SMR+CCS is not found to be an economically viable alternative.

Limited biogas availability reduces the contribution to flexibility needs of thermal technologies and triggers a fuel switch from biogas to biomass. Indeed, biomass consumption in the energy mix rises by 103 TWh, both for heat and power generation (CHPs and biomass turbines). The remaining missing flexibility is provided by increased contribution of batteries and interconnectors.

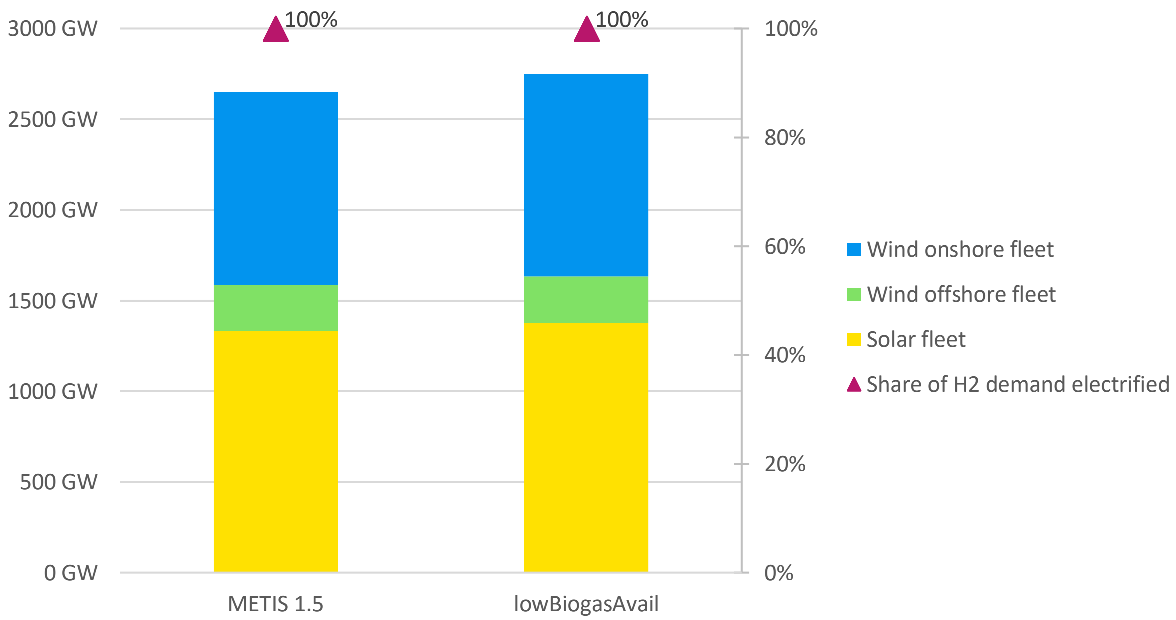

Figure 5-9: Variable RES installed capacities (EU27+7)

As competition for biogas increases, a new balance in industrial heat supply is emerging. Along with an increase in biomass consumption, the electrification rate grows from 50% to 65%, with the highest increase for indirect electrification (+126 TWh of hydrogen-based heat). The increase of direct electrification is limited due to the restricted availability of heat pumps to low-temperature grades and electric boilers to low and medium-temperature grades respectively. In addition, biogas is a dispatchable resource that can be used when electricity prices are high and can thereby alleviate the stress on electricity generation. As hydrogen can easily be stored, indirect electrification can offer similar services and notably provide flexibility services.

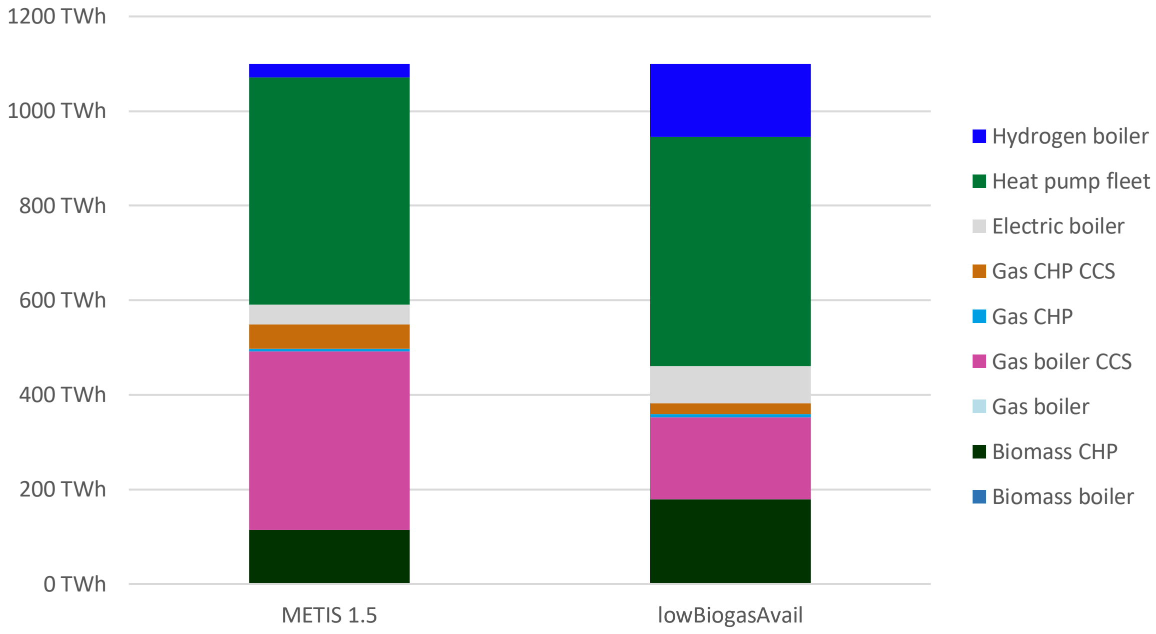

Figure 5-10: Industrial heat supply technology mix

6 CONCLUSIONS AND OUTLOOK

This study has demonstrated the importance of carefully considering the interactions between the electricity, hydrogen and heat systems, and the hourly dynamics of these systems, when considering planning decisions. The simulations performed with METIS have shown that the portfolio of investments in RES capacities, flexibility solutions and routes to decarbonise heat can be impacted when a holistic approach is adopted.

Indeed, holistic approaches to system planning allow for synergies and interdependencies between systems to be identified, enabling the emergence of a set of investment decisions characterised by a lower overall cost, while maintaining the same level of security of supply. These findings have been exemplified by considering the European Commission's Long-Term Strategy (1.5TECH scenario) and by building an alternative with the METIS model by allowing for a reshuffling of the heat supply portfolio and for new investments to be made in e.g., RES and flexibility solutions, while keeping the same level of useful demand as in the original scenario.

Similar benefits can be expected to emerge when applying integrated planning approaches at the Member State or regional levels (e.g., in NECPs or network development plans). Upcoming scenario building exercises should therefore carefully consider the impacts of sector integration, as it can result in flexibility being made available by numerous sectors, allowing to reduce investments in traditional flexibility solutions.

The risks associated with various portfolios of investments should continue to be investigated, under several perspectives: risks related to climate change and resilience of investment choices to climatic variations, potential risks leading to stranded assets or to lock-in effects (and level of no-regret investments in technologies such as electrolysers), risks related to the level of development of a hydrogen infrastructure, etc. Many of these aspects are to be explored in METIS 2 Study S4.

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8 ANNEX

8.1 THE METIS MODEL

METIS is being developed by Artelys on behalf of the European Commission DG ENER. The model includes assumptions on exogenous parameters, policies, datasets and comes with a set of pre-configured scenarios. These scenarios usually rely on the inputs and results from the European Commission's projections of the energy system, for instance with respect to the capacity mix or energy demand per sector. Based on this information, METIS allows to perform the hourly dispatch simulation (over the duration of an entire year, i.e., 8760 consecutive time-steps per year). The result consists of the hourly utilisation of all generation, storage, conversion and cross-border capacities as well as demand side response assets in each country. In addition, in this study, the investments in a large number of technologies are jointly optimised by METIS together with the hourly demand-supply equilibrium. This report relies on the use of these scenario-building features to assess the equilibrium between investments in direct and indirect electrification. These features will be further enhanced during the remainder of the METIS project to better represent the cross-border flows of hydrogen in particular.

For more information about the METIS model, please refer to the EC METIS website: https://energy.ec.europa.eu/data-analysis/energy-modelling/metis_en.

8.2 END-USE LEVEL DEMAND MODELLING

8.2.1 POWER DEMAND MODELLING

Power demand from the LTS 1.5TECH scenario is modelled in METIS based on historical hourly data and annual volumes by end-use as provided by the scenario. In order to allow for refinement of the industrial heat supply mix, the corresponding power consumption as considered by the LTS is disentangled from the other non-thermosensitive end-uses and industrial heat demand is modelled as end-use demand to be fed by biofuels, natural gas, direct/indirect electrification etc.

National electricity demands are split into thermosensitive and non-thermosensitive parts, based on the decomposition into the end-uses shown in Table 2. For each of these, demand is calibrated to match the annual consumption scenario (here LTS 1.5TECH scenario), the aggregation of them all corresponding to the total power demand (see Figure 8-1).

End-use	Processes
Heat pumps **Air conditioning** **Domestic hot water** **Other thermosensitive end-uses**	Thermosensitive end-uses
Plugin Hybrid electric vehicles **Battery electric vehicles** **Other non-thermosensitive end-uses**	Non-thermosensitive end-uses

Table 2: Power demand decomposition per end-use

The power demand is also split between flexible and non-flexible shares of each end-use. For instance, heat pumps are equipped with either electric or gas backups and a share of them can be coupled to a heat storage, allowing them to displace their electricity consumption to hours more accommodating to the whole system (e.g. with higher renewable production in the instantaneous power mix). Electric vehicles may feature smart-charging. National fleets are split between charging-at-work and charging-at-home categories, which has an implication on the time-period when vehicles are plugged onto the network, able to charge. Electric vehicles do not feature vehicle-to-grid. Electric vehicles and heat pumps are considered flexible on daily timescales, provided they meet the required demand for services.

Hourly historical load curves, obtained from the ENTSO-E Transparency Platform[9], are split into thermosensitive and non-thermosensitive parts. The relation between temperature and demand is calibrated based on the analysis of several historic years. A statistical model is calibrated to fit the thermosensitive part with reference temperatures for each country. The statistical model used is a GAM model (Generalised Additive Model). The model (one for each country) takes into account calendar days, exceptional days (public holidays, summer holiday period and winter holiday period) and hourly temperatures. Then, the statistically obtained profiles are scaled according to the demand scenario, resulting in calibrated load curves by end-use.[10]

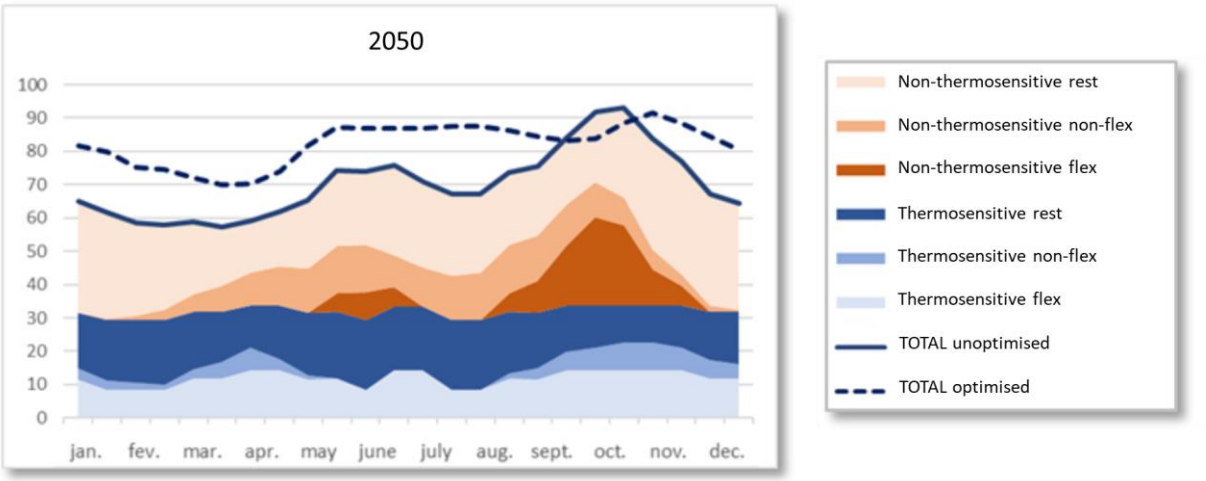

Figure 8-1: End-use decomposition of power demand

8.2.2 HEAT DEMAND MODELLING (INDUSTRIAL USES)

As the transition to a decarbonised European industry implies a switch to carbon-neutral fuels (direct and indirect electrification, biofuels), the balance between direct electrification and decarbonised gases can only be optimised taking into account the potential coupling between the electricity sector and the industry, and notably through the industrial heat supply.

A literature review has been performed and has shown that an endogenous assessment of the optimal industrial heat mix has to consider that all potential heat supply technologies cannot provide all temperature levels, which may vary significantly between industrial processes; and that all industrial heat uses cannot be substituted with other fuels, either for operational, chemical, or technical reasons.

[9] https://transparency.entsoe.eu/

[10] For further details, check the METIS Technical Note 8 (https://energy.ec.europa.eu/document/download/f4728733-6593-4ae1-be58-ce5161621945_en)

Indeed, in some industries, heat delivery is strongly linked to the consecutive operations of several processes within a single plant. For instance, flue gases from an upstream process may be used to provide heat downstream. In such a case, substituting the energy carrier of the upstream process may remove or change the physical characteristics of the flue gases and consequently the heat supply of the downstream process.

Industrial processes can chemically rely on the energy vector. In blast furnaces for instance, coke is both used to supply heat and reduce the iron oxides, preventing a switch to another fuel without re-engineering the entire process.

Eventually, some processes rely on very specific technologies, hampering the use of another fuel that would be incompatible. That is the case for secondary iron, which is mostly melted in electric arc furnaces that run exclusively on electricity.

The literature review allowed for the identification of substitutable and process-specific uses and the disentangling of the latter between three temperature levels, which impact the set of heat supply technological options and their techno-economic parameters. Three standard categories for heat temperature have been considered: the lower temperature level stands for temperatures below 150°C, medium temperatures ranges between 150°C and 500°C, while temperatures above 500°C form the high temperature level.

The following sectors are considered in the study: iron and steel, non-ferrous metals, chemicals, non-metallic minerals, paper and pulp, and other industries. The following processes are considered: blast furnaces, thermal processing, steam uses, low enthalpy heat, electric processing, and specific electricity.

Building on the literature review, the available options to decarbonise the heat mix are determined based on the 1.5TECH data, based on the following methodology:

1. Industrial processes are classified as substitutable or non-substitutable heat demand
2. A temperature level is assigned to each substitutable process, which will affect the set of available heat provision options
3. The substitutable shares of 1.5TECH industrial heat demand volumes, provided at the process level, are then identified and assigned a temperature level. This data processing phase leads to one annual, end-use industrial heat demand per temperature level and Member State, whose final supply mix is to be endogenously determined.

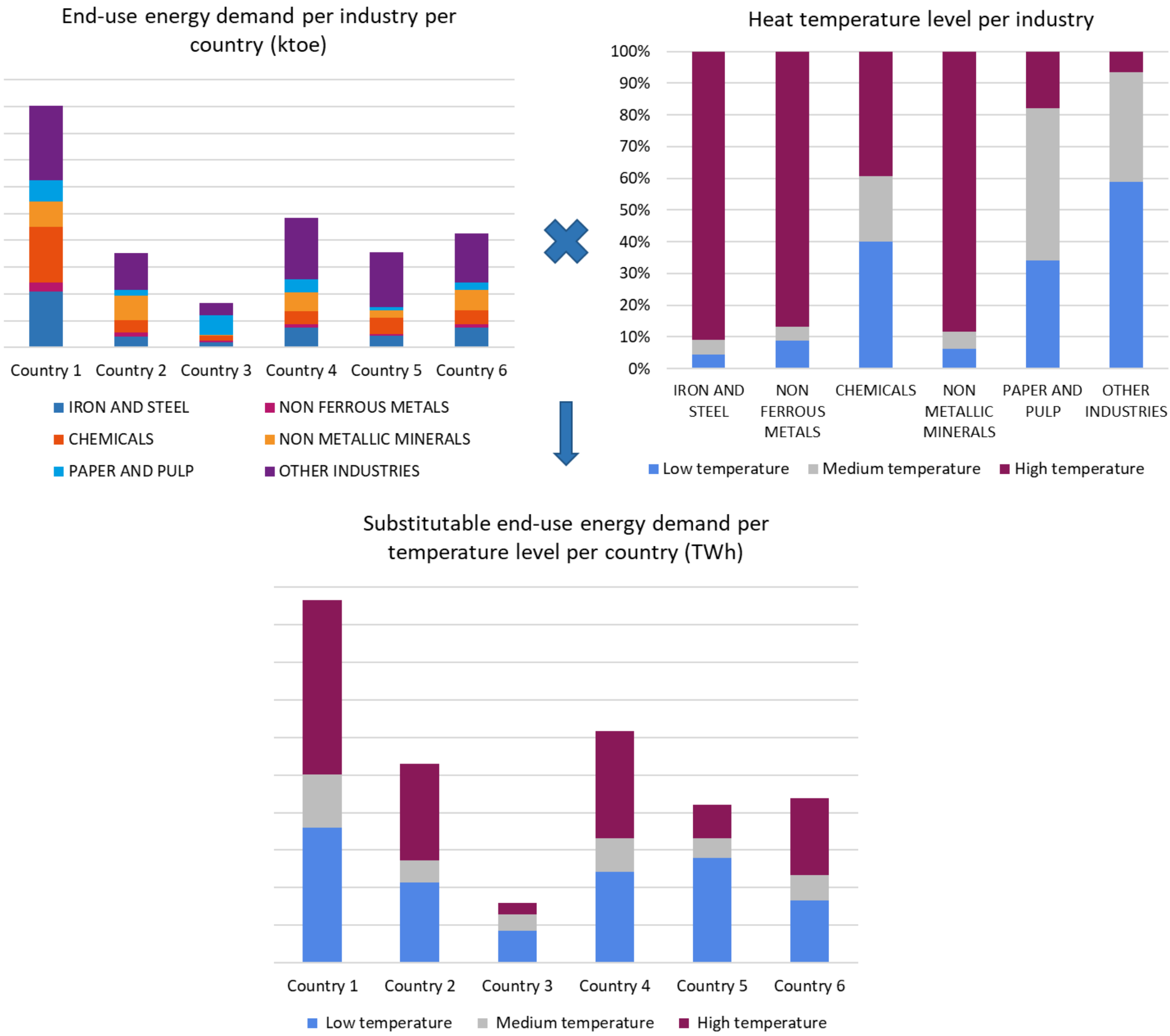

Figure 8-2: Methodology for the integration of industrial heat demand in the METIS model

This process, once applied to the European industry, results in around 1530 TWh of industrial heat demand, 1020 TWh of which being substitutable. High temperature heat represents the highest share of the substitutable scope.

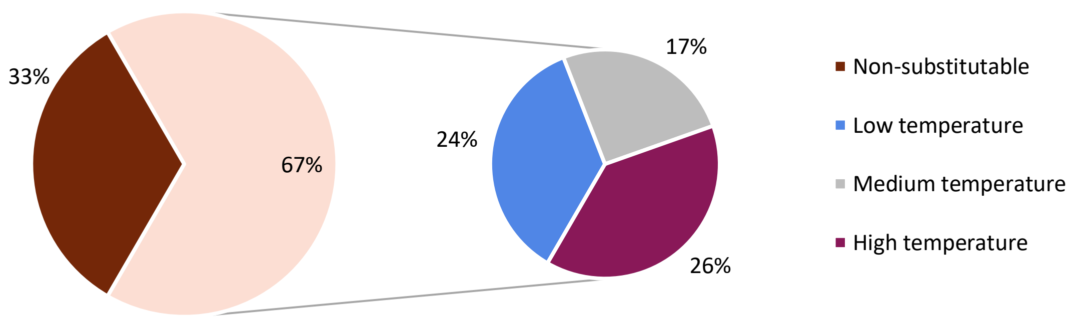

Figure 8-3: European industrial heat demand in 2050 (1530 TWh, 1020 TWh substitutable)

8.2.3 HYDROGEN DEMAND MODELLING

The 1.5TECH scenario assumes a major role for hydrogen in the decarbonisation of the European economy. Hydrogen synthesised from electricity via electrolysis is either used as such or later converted in e-gases or e-liquids through methanation or Fischer-Tropsch processes. Hydrogen, e-gases and e-liquids are then consumed in the industrial, residential, tertiary, power and transport sectors as substitutes to fossil fuels. As consecutive conversion losses along the power-to-X value chain gradually increase the fuel costs, e-liquids only emerge in 1.5TECH as a solution for sectors and uses where hydrogen or e-gases are not suitable.

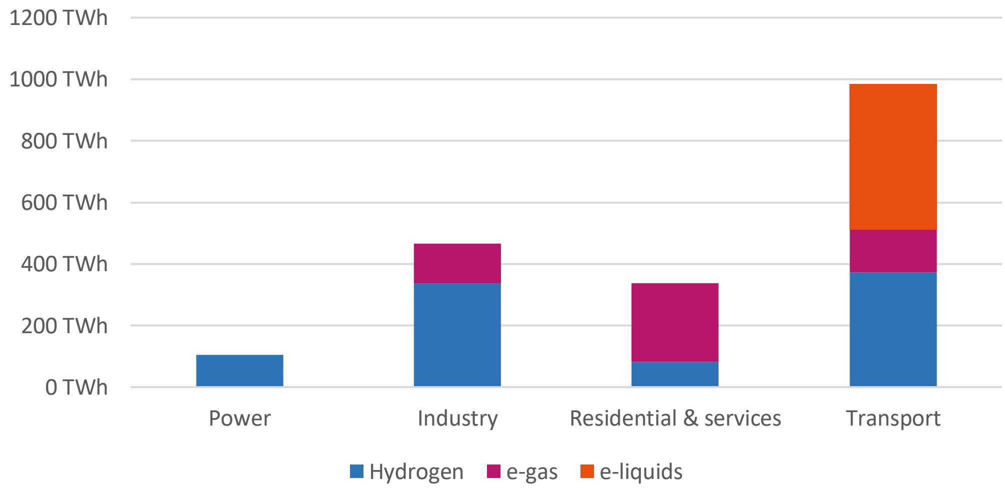

Figure 8-4: 1.5TECH end-use hydrogen and e-fuels consumption per sector in 2050

Total hydrogen demand then consists of:

- An exogenous share, directly taken from the 1.5TECH scenario figures. This share itself accounts for hydrogen, e-gas and e-liquids end-uses, for energy and non-energy usage (e.g. hydrogen used as feedstock for ammonia production). Hydrogen employed by substitutable shares of industrial heat demand is not aggregated to this exogenous share, as well as hydrogen used for power generation

- An industrial heat-related share, which is a result of the endogenous optimisation of the supply mix of industrial heat (hydrogen boilers are considered as a heat provision option, see section 8.3.2 below)

- A power-related share, result of the optimisation as well, that accounts for the power-to-gas-to-power energy route.

Since the possible flexibility on the end-user side is difficult to evaluate (possible local storage of hydrogen, refurbishment of existing network and storage for e-gases, flexibility of the fuel supply for vehicles, etc.), we have chosen to assume a certain flexibility of hydrogen demand and to measure the sensitivity of our results to this level of end-user flexibility assumption. On the demand-side of hydrogen, e-gas and e-liquids, our central assumption is that sufficient flexibility is available (namely via storage and pipelines) to only consider an annual volume constraint. The impact of limited storage capacities and reduced hydrogen demand flexibility is assessed in the sensitivity analyses.

As the power-to-X loop is jointly optimised with the power system, re-optimising the supply mix foreseen by the LTS but may lead to different needs in power generation (and flexibility) capacities compared to the ones identified in the LTS. This is a consequence of the modelling approach of a more precise representation of the dynamics of interlinkages than in the modelling supporting the LTS and the expanded set of industrial heat provision options.

We consider that the supply-demand equilibrium for hydrogen has to be met at Member State level, with potential alternative supply modelled as SMR equipped with CCS[11]. The impact of putative low-cost hydrogen imports on the European energy system dimension and operations is studied as a sensitivity analysis.

8.3 ENERGY SUPPLY MODELLING

8.3.1 POWER SUPPLY AND FLEXIBILITY MODELLING

Power supply

The power supply fleet consists of both exogenous and endogenous installed capacities. Exogenous capacities are taken as is from the LTS as their development is not driven by economic considerations only. The corresponding technologies are:

- Fossil fuel fleets (oil, coal and lignite)
- Waste fleet
- Nuclear fleet
- Hydro fleet (reservoir and run-of-river).

Other power generation technologies are subject to optimal dimensioning within METIS, given the exogenous demand derived from the LTS, jointly with the endogenous electrification of e.g. heat demand.

The corresponding technologies are:

- CCGT fleet (can be equipped with CCS)
- OCGT fleet
- Biomass fleet
- Gas CHP (can be equipped with CCS)
- Biomass CHP

[11] SMR is only one of the alternative technologies, other technologies such as ATR, steam reforming of biogas, or pyro-gasification of biomass can be considered.

- Variable renewable energy sources, whose deployment is based on cost-potential curves[12]:
    - Solar PV panels
    - Offshore wind
    - Onshore wind

Biofuels (biomass and biogas) are subject to limited resource deployment in order to respect the consumption potentials assumed in the 1.5TECH scenario. The resource is supplied continuously over the year, and can be consumed anytime. Biogas potential is distributed over the European Union and can be subject to cross-border exchanges between Member States. Biomass is considered as a domestic consumption resource.

Resources' costs are derived from 1.5TECH assumptions, and combined with the IEA's World Energy Outlook cost-potential curves when the resource has limited availability.

	Natural gas	Biogas	Biomass	CO2
Cost (€/MWh HHV or €/t CO2)	43.8	61.2	40.6	350
Limited availability		✓	✓	

Table 3: Fuel costs

Gas turbines and CHPs can be fed in with either biogas, natural gas or e-gas; the cost-efficient gas mix is determined endogenously, taking into account constraints such as a limited biogas potential.

Power storage

As storage technologies are key assets to ensure cost-effective power supply and demand balance at all times, they are endogenously dimensioned and operated in METIS.

Pumped Hydro Storage (PHS) is one of the most conventional storage solutions, but their remaining deployment potential is limited and might vary considerably from one country to the next. In this study, two PHS categories are considered: existing PHS, representing 2020 capacities and new PHS, in which METIS can decide to invest.

Batteries can be leveraged to provide short-term flexibility to the system. Four types of battery are considered, with storage duration of 1, 2, 4 or 8 hours. No maximum deployment is considered for these assets. Their CAPEX and other technical parameters can be found in Table 4.

Cross-border exchanges

Electricity interconnectors have a significant role in the provision of flexibility to power systems, allowing countries to benefit from each other's resources and flexibility. They enable exports and imports of energy between countries with different energy prices and levels of vRES share, helping avoid RES curtailment, load curtailment and make better use of generation fleets.

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[12] The building approach for these cost-potential curves is described in the METIS Technical Note accompanying this study.

The investments in interconnectors are optimised within bounds derived from the EUCO3232.5 scenario (minimum values) and the TYNDP 2018 Global Climate Action scenario (maximum values), which are shown on Figure 8-5.

		Optimised capacity	Investment cost (€/kW)	Fixed O&M costs (% CAPEX)	Efficiency	Lifetime
Interconnectors	Additional capacities	✓	Based on line-by-line projects		-	50
Back-up power plants	OCGT	✓	600[13]	3%	40%	25
	CCGT	✓	750	2%	63%	30
	CCGT with CCS	✓	1500	2%	49%	30
Storage capacities	Pumped Hydro	✓	1212[14]	1,20%	81%	60
	Batteries	✓	120€/kW + 120€/kWh[15]	4,30%	90%	10

Table 4: Technical parameters for flexibility solutions

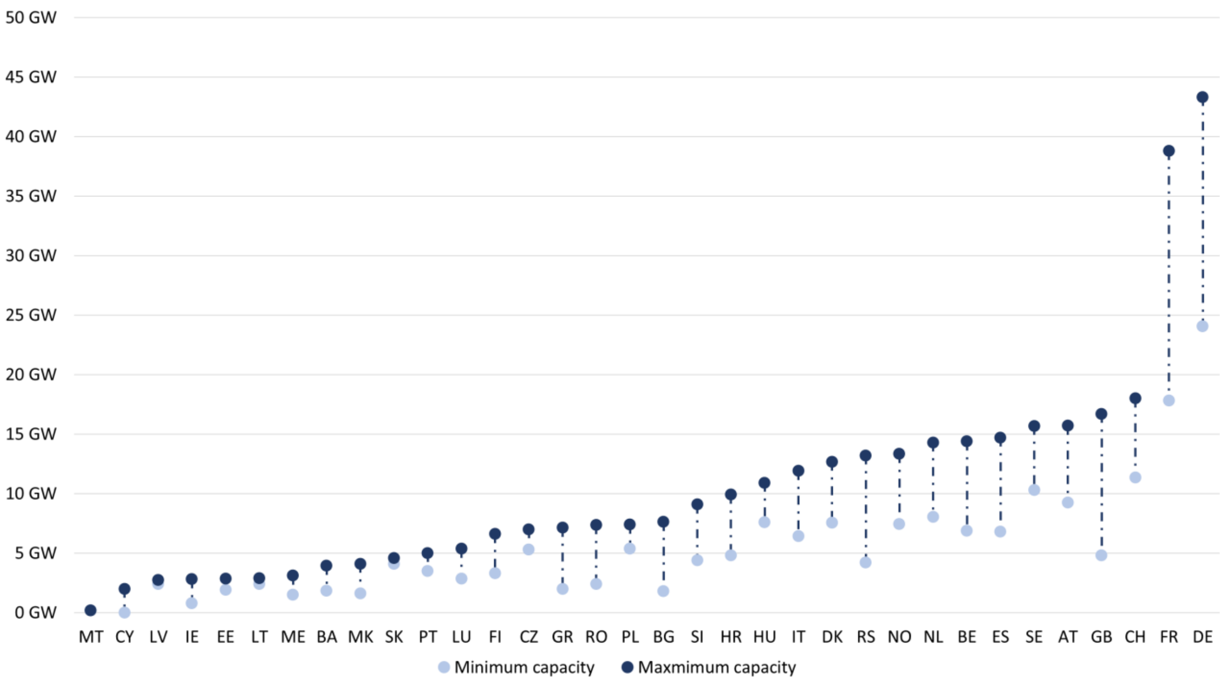

Figure 8-5: Interconnectors potential for EU countries

8.3.2 HEAT PROVISION MODELLING

8.3.2.1 Residential/tertiary heat supply

As mentioned in Section 8.2.1, the power demand for residential heat pumps is modelled as being flexible. In addition to a 2 hours heat storage, heat pumps are equipped with

[13] CAPEX source: (E3Modelling, Ecofys, Tractebel, 2018)
[14] CAPEX source: (Artelys, 2018)
[15] (Artelys, 2018)

backup boilers able to supply peak heat demand. The first option allows for the provision of daily flexibility by shifting the electric load to hours with less stress on the power system (e.g. larger local vRES generation or available imports). The second option enables heat pumps to mitigate peak power demand that occurs when low air temperature impairs the heat pump's coefficient of performance (which may go below 1) and output capacity while exacerbating heat demand.

Covering heat demand peaks exclusively with heat pumps would indeed imply a costly over-dimensioning of the equipment and higher capital costs. To that extent, low CAPEX back-up heaters are installed, and the heat pump is dimensioned to cover 5% of the heat demand only[16]. The trade-off between investing in gas or power back-up heaters is optimised by METIS, based on endogenous gas and power prices, and on the capital costs of the various options.

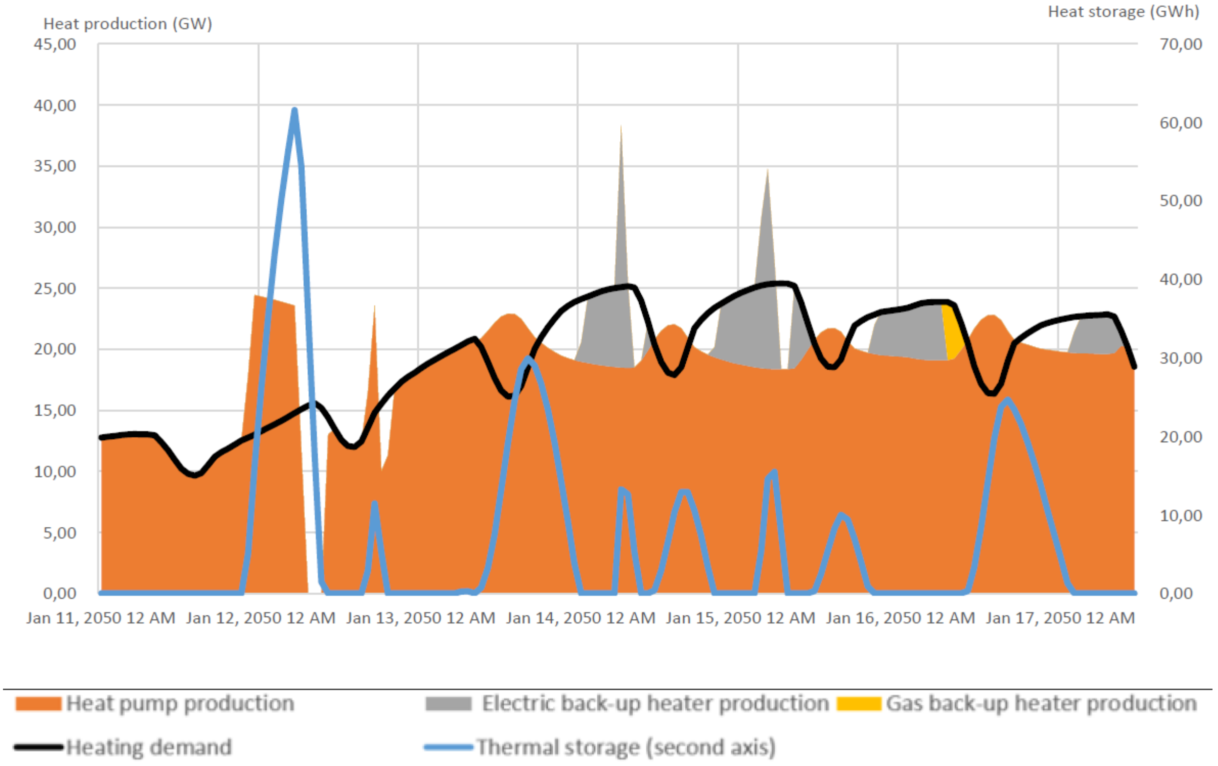

Figure 8-6: Typical heat pump utilisation in winter

8.3.2.2 Industrial heat supply

A literature review has helped identify heat generation technologies that can be expected to be available in 2050 and their characteristics[17]. The technology portfolio depends on the type of heat demand, most importantly on the heat temperature. The identified technologies have been clustered into three groups, according to the temperature levels they can supply, i.e. low temperature heat (below 150°C), medium temperature heat (between 150°C and 500°C) and high temperature heat (above 500°C).

Among the available technology options, it has been found that industrial heat pumps were eligible for low temperature heat only, whereas electric boilers can provide both low and medium temperature heat. At high temperature levels, furnace heat is provided by gas or

[16] (Artelys, 2018)

[17] (JRC, 2018)

biofuels burners. Cost assumptions for all these technologies were based on the ASSET database[18] and may be subject to rapid evolution.

In order to thoroughly model the industrial heat coupling with the power sector, relevant technologies can either be derived as heat-only boilers or CHP technologies. Cogeneration has a role in a limited-resources scenario as it brings in energy savings through their higher efficiencies.

In line with 1.5TECH assumptions, thermal-based heat production technologies can be equipped with CCS. As a result, these units feature higher capex and slightly lower efficiencies.

e.g. low temperature:

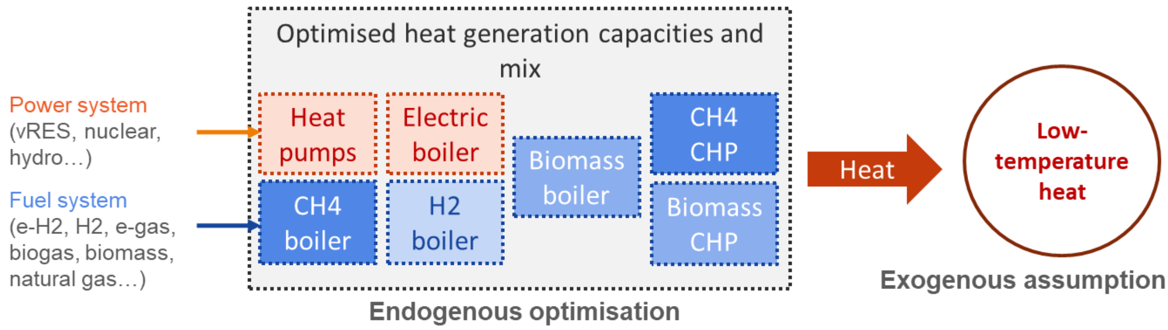

Figure 8-7: Illustration of low-temperature heat supply mix optimisation

		Investment cost (€/kWth)	Fixed O&M costs (% CAPEX)	Efficiency (HHV)	Lifetime
Residential	Gas back-up	220	-	86%	25
	Electric back-up	140	-	100%	25
Industrial	Heat pumps	540	0.5%	410%	25
	Electric boiler	333	1.5%	100%	25
	Biomass boiler	807	0.5%	90%	25
	Gas boiler	124	1%	98%	25
	Gas boiler with CCS	480	2%	76%	25
	Hydrogen boiler	149	1%	98%	25

Table 5: Techno-economic parameters for heat supply technologies (excluding CHPs)[19]

	Investment cost (€/kWe)	Fixed O&M costs (% CAPEX)	Thermal efficiency	Electric efficiency	Lifetime
Gas CHP	810	1%	52%	33%	35
Gas CHP + CCS	1640	2%	33%	33%	35
Biomass CHP	3000	1%	66%	27%	30

Table 6: Techno-economic parameters for CHP technologies[20]

[18] (E3Modelling, Ecofys, Tractebel, 2018)
[19] Derived from (E3Modelling, Ecofys, Tractebel, 2018)
[20] Derived from (JRC, 2017)

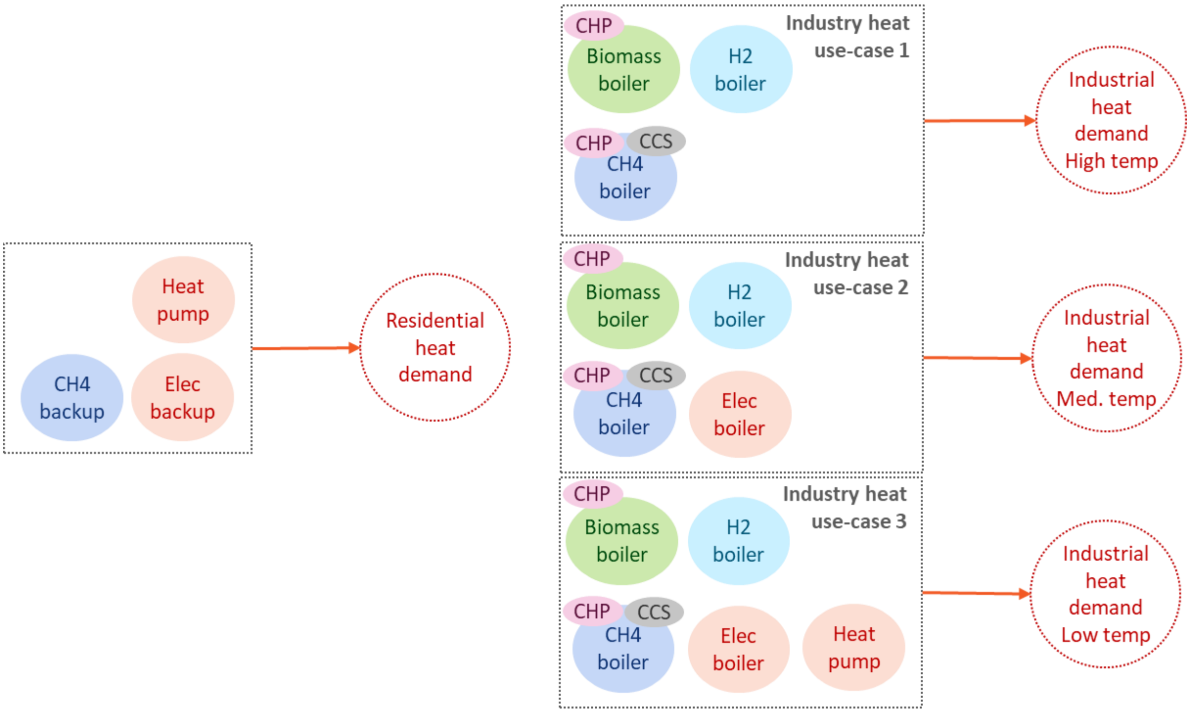

Figure 8-8: Technology portfolio per temperature level, including CHP/CCS variants

8.3.3 HYDROGEN AND E-GAS SYNTHESIS MODELLING

As an energy vector enabling cross-sector synergies to materialise, hydrogen is expected to play a key role in future energy systems. In order to capture the effects of hourly dynamics on sector coupling and thereby ensure an adequate dimensioning and operation of the system, the complete Power-to-X chain is represented in METIS. In addition to triggering synergies between sectors, hydrogen generation can indeed facilitate the integration of vRES through a flexible operation of electrolysers and enable further electrification (indirect) of end-uses.

In the modelled scenario, exogenous e-gas and e-liquids demands are accounted for in the hydrogen exogenous annual demand. In this context, the deployment by METIS of additional methanation plants, that convert hydrogen into e-CH4, can only be dedicated to meeting the endogenous CH4 demand, e.g. to fuel endogenously commissioned gas-fired power plants and boilers, if deemed economic by METIS given the competition with natural gas and biogas.

All technical parameters of the optimisation for both electrolysis and methanation plants are listed below on table 5. Electrolysis parameters are considered equivalent to the alkaline electrolyser as it is the cheapest technology considered in the LTS.

Hydrogen production from electrolysis can be complemented by SMR combined with CCS. The associated production cost is 90€/MWh, which may come in economic at times when power prices are high.

	Investment cost (€/kW)	Fixed O&M costs (% CAPEX)	Efficiency	Lifetime
Electrolysis	180[21]	5%	85%	20
Methanation	263	3,5%	79%	25

Table 7: Technical parameters for power-to-X technologies

The figure below represents the multi-energy system modelled in METIS to establish the scenarios described in this study.

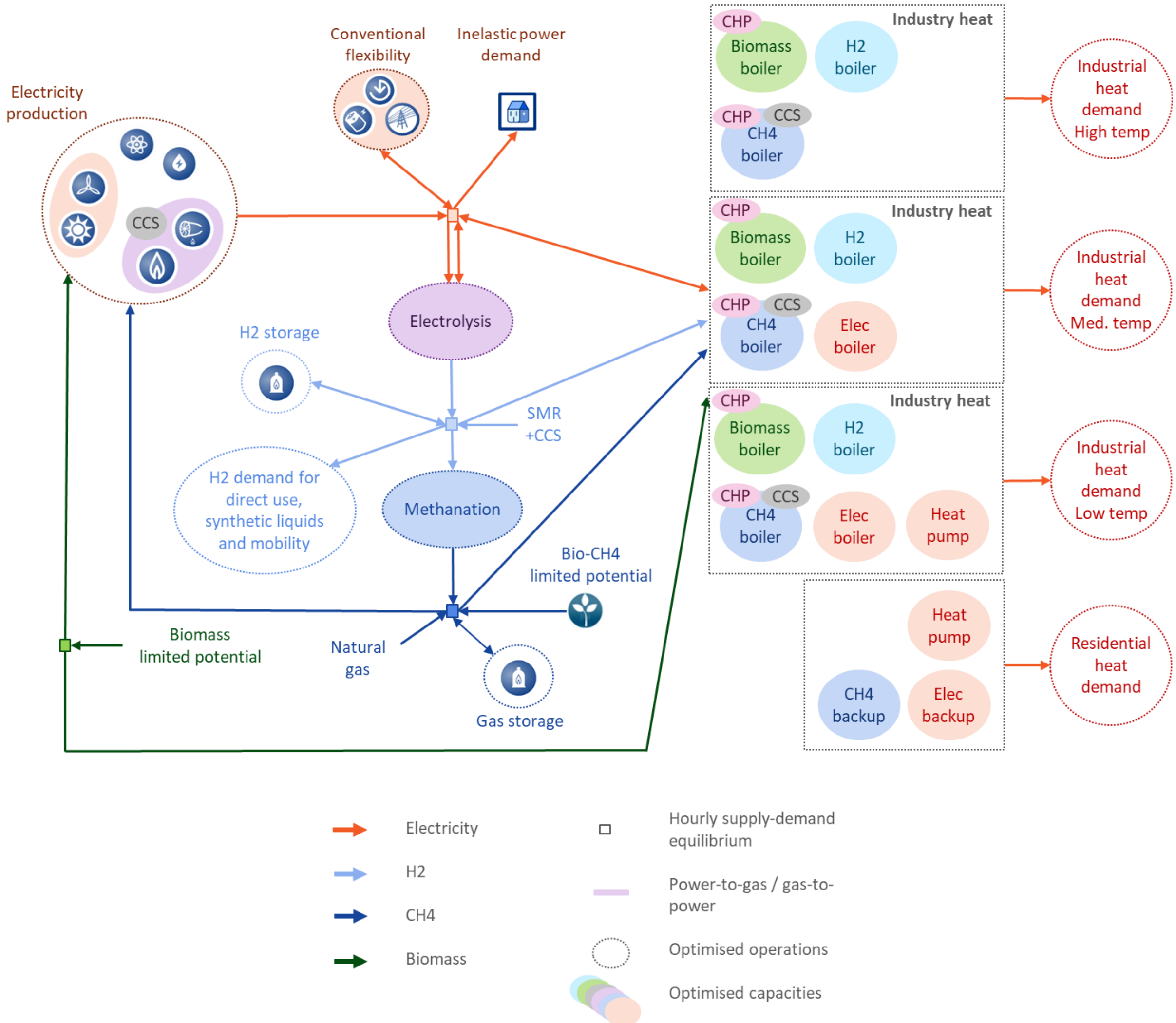

Figure 8-9: METIS multi-energy model used for the building of the METIS 1.5 scenario

[21] CAPEX and efficiency sources: (E3Modelling, Ecofys, Tractebel, 2018), (Artelys, 2018)

8.4 FLEXIBILITY NEEDS DEFINITION

Flexibility is defined as the ability of the power system to cope with the variability of the residual load curve at all times, namely the difference between demand and vRES generation, also called net demand. The dynamics of the residual load curve are driven by a number of phenomena on several timescales. Hence, flexibility needs are assessed based on daily, weekly and seasonal variations on the residual load. They were initially defined in the METIS study Mainstreaming RES[22].

Daily flexibility needs

On a daily basis, a flat residual load could be met by baseload units with a constant power output during the whole day, thus without requiring any flexibility to be provided by dispatchable technologies.

Daily flexibility needs are therefore defined to represent how much the residual load differs from a flat residual load. They are obtained by applying the following procedure:

1. Compute the residual load over the whole year by subtracting non-dispatchable generation (e.g. vRES) from total demand

2. Compute the daily averages of the positive residual load (light-green area shown below)

3. Sum the result obtained over the 365 days. The result is expressed as a volume of energy per year (TWh per year).

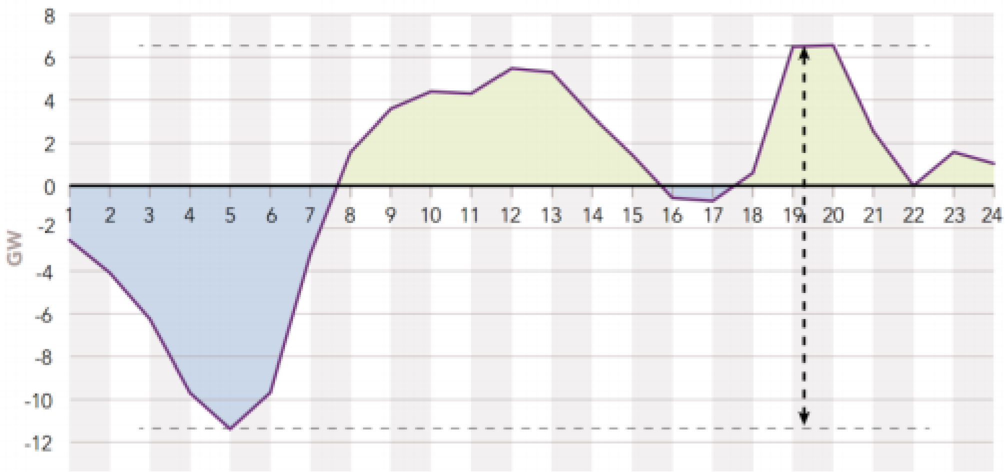

Figure 8-10: Illustration of daily flexibility needs (the solid purple line measures the deviation of the residual load from its daily average for a given day).
Source: RTE, Bilan prévisionnel de l'équilibre offre-demande, 2015

Weekly flexibility needs

[22] Mainstreaming RES, European Commission, 2017

The same reasoning applies to weekly flexibility needs. However, in order not to double-count the daily needs, the following procedure is adopted:

1. Compute the daily average of residual load over the whole year by subtracting non-dispatchable generation (e.g. vRES) from the demand

2. Compute the weekly average of the residual load (52 values per year)

3. For each week of the year, compute the difference between the daily residual load and its weekly average (light green area shown below). The result is expressed as a volume of energy per week (TWh per week).

4. Sum the result obtained over 52 weeks. The result is expressed as a volume of energy per year (TWh per year).

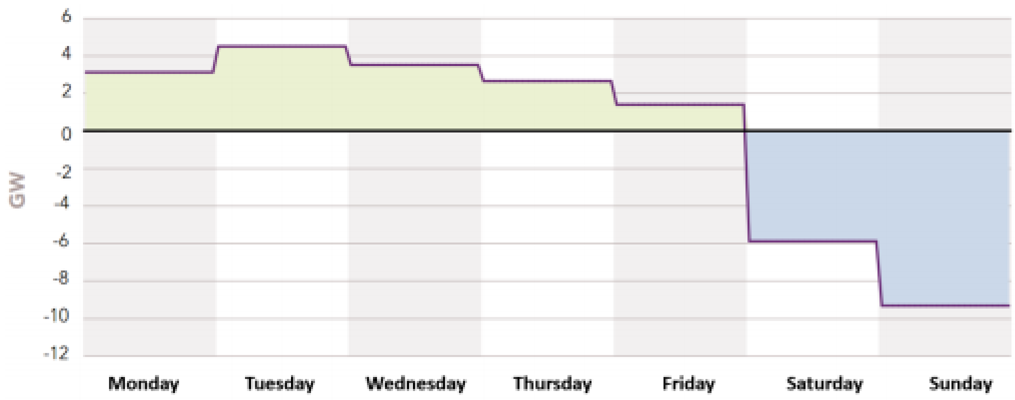

Figure 8-11: Illustration of weekly flexibility needs (the solid purple line measure the deviation of the residual load from its daily average for a given week).
Source: RTE, Bilan prévisionnel de l'équilibre offre-demande, 2015

Seasonal flexibility needs

Finally, the seasonal flexibility needs are assessed in a similar way:

1. Compute the daily average of residual load over the whole year by subtracting non-dispatchable generation (e.g. vRES) from the demand

2. Compute the annual average of the residual load

3. Compute the difference between the monthly residual load and its annual average. The result is expressed as a volume of energy per year (TWh per year).

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