Potentials and levels for the electrification of space heating in buildings

Final Report

2023

Tom Dröscher, Alexander Ladermann, Christoph Maurer, Bernd Tersteegen, Sebastian Willemsen (CONSENTEC)

Anna Billerbeck, Christoph Kiefer, Jenny Winkler, Christiane Bernath, Frank Sensfuß (FRAUNHOFER ISI)

Lukas Kranzl, ... (TU WIEN)

Andreas Müller (E-THINK)

Peter Kotek, Borbála Tóth (REKK)

October 2023

EUROPEAN COMMISSION

Directorate-General for Energy

Directorate C — Green Transition and Energy System Integration

Unit C1 — Renewables and Energy System Integration Policy

Contact: Matthieu Ballu

E-mail: matthieu.ballu@ec.europa.eu

European Commission
B-1049 Brussels

Potentials and levels for the electrification of space heating in buildings

Manuscript completed in June 2023

PDF	ISBN 978-92-68-07626-2	doi: 10.2833/282341	MJ-04-23-902-EN-N

Luxembourg: Publications Office of the European Union, 2023

Table of Contents

Abbreviations

CAPEX	capital expenditures
CH4	methane (fossil or synthetic)
CHP	combined heat and power
CSP	concentrated solar power
CW	calendar week
EU	European Union
GHG	greenhouse gas
H&C	heating and cooling
H2	hydrogen
IA	impact assessment
IC	interconnector capacities
LCOE	levelized costs of electricity
LWIC	length-weighted interconnector capacity
MENA	middle east and north Africa
MS	member states (of EU-27)
OPEX	operation and maintenance costs
PS	pump storage
RES	renewable energy sources
RFNBO	renewable fuels of non-biological origin

Executive Summary

For reaching the EU's climate goals the space heating sector is of exceptionally high relevance. Heating and cooling accounts for 50% of the EU final energy consumption; approximately 75% of the heat demand is covered from fossil fuels and around 60% of the overall heat demand is consumed in buildings. These numbers illustrate that decarbonising the space heating sector is a crucial factor for reaching greenhouse gas neutrality in the EU by 2050.

Several studies and scenarios point to electrification as a main solution for decarbonisation of space heating. However, there are different possible implementations for electrification of heat: One option is direct electrification, in particular by installing decentral heat pumps in buildings or central heat pumps in district heating and, partially, direct electric boilers. Another option is indirect electrification based on synthetic energy carries produced from electricity from renewable energy sources (RES-E), namely hydrogen or e-fuels (in particular synthetic methane). The objective of this study is to quantitatively analyse different possible levels of these various ways of direct and indirect electrification. The analysis looks at such scenarios from a technical and economic perspective. As a result the scenario with the lowest costs (i.e. a cost-effective level of direct and indirect electrification) is identified and barriers (from today's viewpoint) for realising this cost-effective level are discussed.

For these analyses a modelling framework consisting of eight interacting sector models was applied covering the building stock, the energy supply (power, synthetic energy carriers, district heat) sector and infrastructures (electricity and gaseous energy carriers). The (cost) optimisation and simulation models cover all EU-27 member states (MS) with a high spatial, temporal and technological resolution. Due to close interaction of the heating sector with other energy sectors the modelling framework covered not only space heating but the whole European energy system also including e.g. the energy demand of the transport sector and industry. The modelling covers the time period up to 2050, where greenhouse gas neutrality is to be reached in the EU. Even though the year 2050 is in the focus of this study, the time steps in between were modelled as well. At the core of the scenario design is a set of in total 12 scenarios each reflecting a particular target for one energy carrier in terms "share of heated floor area" (e.g. the scenario "direct electrification 60%" defines a scenario in which 60% of the heated floor area in all MS has to be heated by direct electric heating system; the mix of heating technologies for the remaining 40% were optimised by the building stock model).

Based on the assessment of differences and similarities between the scenarios, the following conclusions can be drawn:

- From the viewpoint of an economic optimisation, in the building stock there seems to be a clear merit order of energy carriers / heating technologies: Heat pumps and district heating (where heat densities are sufficiently high) are economically viable. Liquid and gaseous energy carriers (hydrogen and e-methane) are expensive, the latter one increasingly also due to high distribution costs with lower utilization of grid infrastructure.

- Both, decentral and central (via district heating) direct electrification, leads to lower overall systems costs when compared to scenarios with higher shares of heating using hydrogen or e-fuels. The main technology used for direct electrification are heat pumps. Each of the scenarios results in a strong decrease of direct electric resistance heaters, where applied today.

- The optimal distribution between central and decentral direct electrification with respect to system costs is reached between a level of 40% and 80% of direct electrification. In the scenarios explicitly modelled, the lowest system costs are reached with 60% direct electrification of decentral heating systems. In such a scenario, significant amount of the remaining heat demand is covered by district heating.

- Increasing the efficiency of buildings is a robust, no-regret strategy for decarbonisation of the space heating sector. A cost-optimal transformation of heating in buildings based on high shares of decentral direct electric heating requires slightly lower efforts with regards to building renovation when compared to the other scenarios. Due to much higher variable energy costs when applying higher amounts of hydrogen- or e-fuels-based heating systems in such scenarios even deeper building renovations measures are cost-efficient to reduce the energy demand for heating. Since heat pumps show their highest performance (COP) in buildings with low heating systems' supply temperature and thus in highly insulated buildings, building renovation is still important also in scenarios with high direct electrification.
- The scenarios with a comparatively low share of decentral direct electrification and at the same time no minimum requirements for hydrogen or e-fuels show that a higher use of district heating is cost-efficient. Heat pumps are the dominating technology in district heating in all modelled scenarios in 2050, accounting for the vast majority of heat generation. Hydrogen-based heat generation technologies provide important backup services in district heating systems.
- Compared to today, an expansion of electricity generation from RES, especially solar PV and onshore as well as offshore wind, is necessary in all scenarios independent from the specific technology mix for space heating. Hence, this can be seen as a robust, no-regret measure. The massive, further expansion of RES-E production from cost-efficient fluctuating technologies (solar PV, wind) is complemented in all scenarios by a significant expansion of the European electricity transmission grid. Higher amounts of available interconnector capacity allow for increased cross-regional electricity exchange. In all scenarios, this reduces the demand for more costly flexible technologies used primarily for system balancing purposes, such as concentrated solar power, hydropower, biomass and in some MS nuclear power plants.
- Apart from higher costs, scenarios with higher shares of hydrogen and e-fuels lead to either even higher requirements of RES-E generation (and thus electricity grid expansions) or higher imports of hydrogen / e-fuels from outside the EU. The higher demand for RES-E generation is also a driver for grid expansion needs at the electricity distribution grid level. This effect outperforms the effect of decreasing expansion demands with lower peak loads when lower amounts of heat pumps are installed. Hence, scenarios with higher shares of hydrogen and e-fuels in heating systems lead to additional costs for electricity distribution grids.
- In the scenario with the lowest costs only a small fraction of the floor area is still heated with gaseous energy carriers. With a coordinated planning of the distribution networks for gaseous energy carriers, substantial cost-reduction can be achieved by reducing the grid length needed to further supply the remaining buildings using gaseous energy carriers for heating.
- Regarding transmission infrastructure for gaseous energy carriers, all scenarios show that this infrastructure needs to be retrofitted or decommissioned on the long-run. Blending of hydrogen to natural or synthetic gas[1] (CH4) in the existing gas grids (CH4-grids) is not a long-term solution for hydrogen transport. The total hydrogen network to be available by 2050 in the EU-27 varies between 18,000 and 20,000 kms in the scenarios (mostly retrofitted pipelines, partially also new-build). This approximates to

[1] Natural gas is methane (CH4) in its chemical composition. In addition to naturally occurring methane, methane can be produced from biomass (biogas) and via various chemical production paths, including through electrolysis of hydrogen with the help of renewable electricity (produced from e.g. wind energy or solar photovoltaic), and mixed with CO_2 and water to produce methane molecules.

about 10% of today’s 225,000 kms CH4 transmission infrastructure. The majority of the hydrogen network needs to be in place already in by 2030.

The comparison of scenarios leads to the final conclusion that directly electrifying a substantial amount of the heat demand of buildings seems to be beneficial both in terms of costs but also with regards to infrastructure and import requirements.

Regarding potential barriers that hinder reaching the above described cost-efficient transformation of the space heating sector and related policy measures to address these barriers this study comes to the following conclusions:

- Heat pumps, as the most relevant electric heating technology, are currently associated with a variety of barriers to reach the cost-efficient transformation. These are (1) financial economic barriers, such as high capital costs (CAPEX) and operational and maintenance costs (OPEX), (2) institutional-structural, market-oriented and technical barriers, comprising e.g. a lack of regulation and standardisation and (3) social barriers, such as lack of knowledge of installer or biased perception of consumers.
- A holistic policy mix, including economic, regulatory and information-based policy measures, is needed. There are interdependencies between the different policy measures and the specific design of one measure can influence the needed intensity of another measure (i.e., high CO2 prices can lead to a reduced need for financial support for renewable heat).
- The key policy recommendations on MS level are:
    - Economic policy measures should be considered to make heat pumps cost-competitive against fossil-fuel heating technologies from an end-consumer perspective, i.e., financial investment support for heat pumps and operative support as well as economic measures to expand district heating networks, e.g. investment support. The current energy crisis and situation on the energy markets can highly influence the competitiveness of different heating technologies, which needs to be taken into account.
    - Regulatory policy measures to reach higher shares of renewable heating technologies (including heat pumps using RES electricity) are recommended, i.e., minimum obligations for renewable heat, as well as regulatory measures for the uptake of building renovations.
    - Information-based measures can support the uptake of heat pumps, i.e., educational programs for change agents, clear strategies for the role of hydrogen and measures to find decarbonisation solutions locally and to increase participation of various stakeholders, i.e., strategic heat planning.
- The key policy recommendations on EU level are:
    - As proposed in the revised RED II, binding targets for the heating sector are necessary to drive market deployment of RES heating technologies. Similarly, the district heating and cooling sector would benefit from mandatory targets and thus the proposed indicative target in revised RED II could be strengthened.
    - In addition, the proposed third party access for district heating and cooling and further transparency measures can contribute to the necessary expansion of renewable district heating supply and the decarbonisation of existing district heating systems.
    - Furthermore, the obligations for renewable heating systems in buildings could be strengthened through more ambitious RES target for the EU building stock reflecting higher RES level requirements and being binding in their nature.

- The regulatory measures for building renovation, such as the minimum performance standards as foreseen in the proposed recast of the EPBD, embedded in an effective, broad policy package, are essential to exploit the huge efficiency potentials in the sector.
- Instead of encouragement, an obligation for strategic heat planning seems essential for at least larger cities due to the need for accurate and well-developed local strategies, as the first step in the process of rolling out renewable and carbon-neutral heating technologies and solutions, as these are mostly local in nature.
- Measures focusing on taxation and other price signals could, as proposed in the EU emissions trading system (ETS) directive, take the form of higher targets in the ETS and in the extension of the ETS for heating in buildings. Furthermore, the proposal for the review of the energy taxation directive (ETD) introduces a new structure of tax rates based on the energy content and environmental performance of the fuels and electricity, which can support heat pump deployment.
- In the context of the EU hydrogen strategy, a more explicit statement on the role of hydrogen in space heating could prevent lock-ins. This clear statement should emphasise the limited role of decentralised hydrogen solutions, i.e., that hydrogen-based decentralised heating systems are not cost-effective. At the same time, the possible role of hydrogen in district heating supply should be outlined (i.e., hydrogen-based boilers, modern CHP and other technologies with a backup role for district heating e.g. in times of electricity shortages). At the same time, the possible specific role of hydrogen in district heating supply (i .e. hydrogen-based boilers, modern CHP and other technologiesfor backup purposes in situation with scarce electricity supply) should be outlined.

1. Background of this study

Climate change is one of the greatest challenges of our time. The European Union (EU) has therefore set itself ambitious targets for reducing its greenhouse gas (GHG) emissions progressively. Key climate and energy targets are to reduce GHG emissions by at least 55% below 1990 levels by 2030. EU-wide climate neutrality are to be reached by 2050.

Beyond 2030 and on the longer term, the EU is committed to fully decarbonise the energy sector, including heating and cooling in buildings and industry, in order to arrive to a net-zero GHG emissions economy by 2050.

Heating and cooling (H&C) is the single most important energy demand sector in Europe. It accounts for about 50% of the European total final energy consumption (see Figure 1). While this share varies to some degree across the EU-27 member states (MS), the importance of H&C is very high in all MS. Around 75% of heating is based on fossil fuels, while consumption is mostly inefficient, especially in buildings. Only around 20% is based on renewable energy sources (RES), mostly on biomass, which is currently the main renewable heating source[2].

[2] The share of renewables in heating was 23% in 2020; Eurostat, SHARES (Renewables) - Energy - Eurostat (europa.eu).

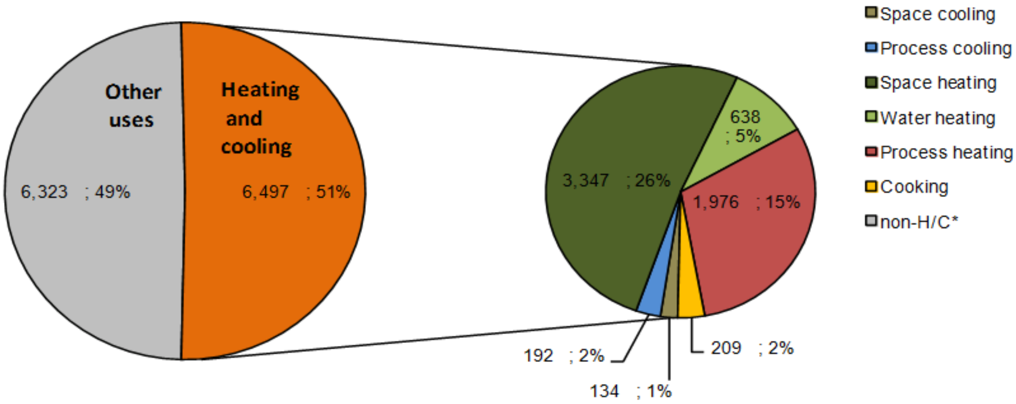

Figure 1: EU final energy demand for heating and cooling in 2012 (Fleiter, Ragwitz, and Steinbach 2017)

The European H&C sector is characterised by a high level of heterogeneity with many small actors at local and national levels. There is a wide diversity in supply modes, technologies, and energy sources as a result of various climate and geographical conditions, historical energy supply, infrastructure, and conditions of existing technical equipment. For example, there is a well-functioning and mature district heating sector in Sweden and Denmark. On the contrary there is nearly no district heating in Spain and Portugal. Driven by their resources, H&C is dominated by various types fuels, such as natural gas in some EU MS (e.g. the Netherlands, Germany, Italy, Slovakia and Hungary), or biomass in countries with abundant wood resources (e.g. Sweden, Latvia and Lithuania) or coal where coal mining has strong traditions (Poland, Czech Republic) or heating oil in countries characterised by remote areas or sparse settlement structures (Ireland, Malta) or electricity in countries where large base load power generation capacities historically played a dominant role (France). I. Due to this diversity, strategies for decarbonising the European heating sector are complex and difficult to define. Although there are already well-engineered and established technologies and solutions for zero carbon heating available on the market, their market penetration is limited and slow. This underlines the need for supportive policy and regulatory frameworks at national, regional, and local levels.

Electrification is often seen as the main solution for decarbonisation of space heating. In many current studies on this topic, the future energy system is characterized by a strong coupling and integration of sectors. Some studies concentrate on the link between electricity and gas sectors and its infrastructures although the potential of sector integration and sector coupling can be much larger. The key objective of sector coupling is to find effective ways to reach the EU GHG emission targets at low costs and in time. The opportunities of using existing infrastructures and providing energy for different application, which today use rather emission-intensive energy carriers, very efficiently (e.g. by means of heat generation by heat pumps) is seen as major merits of sector coupling.

This study analyses the effects of different types of electrification of space heating in buildings in order to contribute to the decarbonisation of the energy system. The objective of the study is to analyse the possible levels of electrification of heating and the impact of the different types of electrification on the related demand for renewable electricity production, hydrogen production and electrolyser capacities, synthetic e-fuels (e-gas/e-liquids)[3], grid infrastructures (in particular electricity, heating, gas[4] and hydrogen), building upgrades and changes in heating equipment. The impacts of possible levels of electrification of heating on the energy system

[3] The term "e-fuels" will be used throughout the text as synonym for synthetic, hydrocarbon-based gaseous or liquid fuels produced based on electricity from RES.

[4] If not further specified, the term „gas“ is used throughout the text whenever it is referred to any gaseous energy carriers relevant for the energy sector (H2, fossil or synthetic methane, biogas).

are also determined in terms on their impact regarding overall system costs. Moreover, this study discusses possible changes in the legal and regulatory framework, necessary for electrification of heating to contribute achieving the renewable energy targets[5] set by the European Union.

This study covers both direct electrification via direct use of renewable electricity for heating[6] and indirect electrification via hydrogen and e-fuels produced from renewable electricity. By way of quantitative modelling of scenarios, the study aims to propose the cost-effective levels of different mixed ways of electrification of space heating. Although this study focuses on the space heating / building sector[7], the interactions with the transport and industry sectors cannot be ignored due to the very nature of sector coupling and the parallel electrification of the transport and industry sectors: the consequences of different levels of electrification in the space heating sector differ depending on the way the other sectors are decarbonised. Hence, such interactions are considered in the modelling framework. This study geographically covers the EU-27 MS, in general, with a timeframe being considered until 2050.

The report is structured as follows: Section 2 describes the general model architecture for the scenario analysis. It is giving an overview on the scenario design and framework conditions as well as general assumptions for the scenarios / modelling. The results for the reference scenario and the technology scenarios are discussed in section 3. In section 4 all model results are combined and analysed in an overarching scenario comparison. In this analysis the scenario with the lowest costs is identified. Barriers for this (cost-)optimal scenario and policy recommendations are presented in section 5. The Annex A includes detailed descriptions of the models used for the quantitative analyses. Annex B lists the relevant literature for the barrier and policy analysis.

2. Model architecture and main scenario assumptions

2.1. Model architecture

To quantitatively analyse the manifold technology scenarios as well as the reference scenario a complex model architecture is applied containing several different, interacting models. Figure 2 gives an overview on the model architecture, the different models applied, their main outputs and the interactions between these models.

---

[5] Most relevant are the heating & cooling, district heating & cooling targets and the overall EU renewable energy target under Article 23, 24 and 3 of the Renewable Energy Directive (2018/2021/EU, RED II) and its review proposal (COM(2021) 557, 14.7.2021.), respectively.

[6] Direct electrification in the study means the use of electricity driven heat pumps. In today's regulation they are considered in the counting of renewable heating, if the heat pumps efficiency is at least 2.5 or higher, expressed in terms of seasonal performance factor (SPF) (or coefficient of performance, COP). The main heating energy sources used via electric heat pumps are geothermal energy (ground source heat pumps) and ambient energy (air source- and water source heat pumps), both of which are defined as renewable energy (see Article 2(1)-(3) of RED II). For heat pumps to extract and transfer geothermal and ambient energy from the environment, electricity is needed. As the EU transitions towards a carbon-neutral energy system, a key consideration is to move electricity production from fossil to renewable sources and technologies, and thus to ensure that, overtime, heat pumps electricity consumption is supplied from renewable sources. It is emphasized that in the modelling of this study the reduction of greenhouse gases (GHG) as a constraint, which indirectly requires the models to provide enough GHG-neutral electricity to power heat pumps in order to reach the target of reducing GHGs. Hence, the current regulatory framework regarding the counting of heat pumps as renewable heating is not a relevant constraint in the modelling of this study.

[7] The term "space heating (sector)" will be used throughout the text as synonym for the space and water heating in buildings.

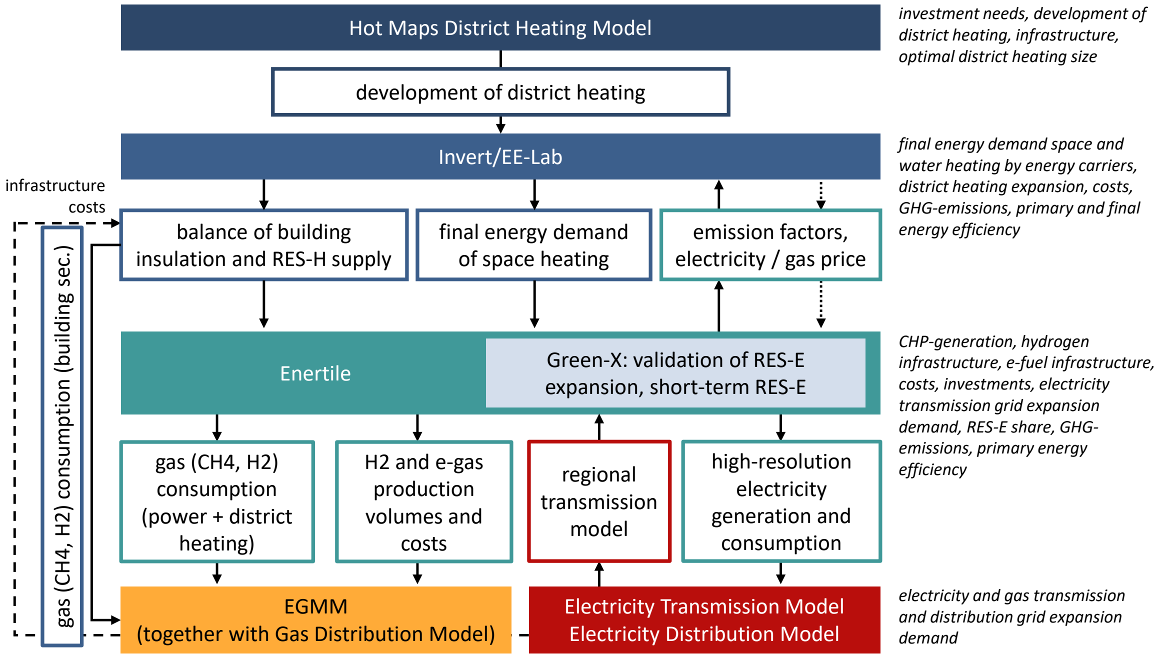

Figure 2: Overview on model architecture

The following models are applied: the Hotmaps district heating model, Invert/EE-Lab, Enertile, Green-X and Consentec's electricity transmission and distribution model, Consentec's gas distribution model and EGMM (REKK's gas market and transmission model).

With regard to district heating, the study refers to the Hotmaps district heating model.[8,9] This model calculates the investment needs related to the expansion and development of district heating infrastructure and derives the optimal district heating size associated with different input data and restrictions. As the model calculates on a hectare-level resolution for all EU countries, it is able to capture very specific local situations with regard to heat demands. The spatial distribution of the heat demands is based by the approach developed in Müller et al, 2019.

The building-stock simulation-model Invert takes this development of district heating from the Hotmap model as an input and provides the demand for space heating and hot water (both individual and district heating), the mix of individual supply solutions and corresponding load profiles. Moreover, the Invert Cost-Curve module[10] also delivers cost-curves for emission reduction in space heating to derive and visualize cost-optimal balances between thermal insulation and the supply of heat. The load-profile module within Invert provides hourly profiles, by such representing the seasonal and daily variations of heat demand and related fuel or energy consumption.

The energy-system optimisation-model Enertile is an energy-system optimization-model focusing on the power sector, but also covering the interdependencies with other sectors, especially the heating and cooling as well as the transport sector. A major feature of the model is its high technical and temporal resolution. Enertile optimizes the investments into all major infrastructures of the power sector, including conventional power generation, heat generation from district heating including combined-heat-and-power (CHP), renewable heating (RES-H)

[8] (Fallahnejad et al. 2018), for the online version see also: The Hotmaps Toolbox: https://www.hotmaps.hevs.ch/ and https://gitlab.com/hotmaps/heat

[9] (Fritz 2016)

[10] (Toleikyte, Kranzl, and Müller 2018)

and power-to-heat, renewable power technologies, hydrogen supply, e-fuel supply, cross-border electricity transmission grids, and storage technologies. To cover specific demands for electricity-based hydrogen and e-fuels, necessary investments in electrolysers are included. The model chooses the optimal portfolio of technologies, while determining the utilization of these for all hours of each year. Since real, historic weather data is applied, seasonal, daily, and weekly variations in heat demand as well as in electricity supply are included in the optimization. At the same time, spatial characteristics and interdependencies between different regions and renewable technologies are implicitly included. A more detailed description of the Enertile model is provided in the Annex.

Green-X provides diffusion pathways for the expansion of renewable electricity (RES-E) generation and, hence, validates the short-term results (2030) for the RES-E generation development from Enterile. Furthermore, it provides RES investments and support costs for RES-E generation as an output.

Regarding the CH4- and H_2 grid and storage infrastructure, the EGMM gas market and transmission infrastructure model is used as a basis. EGMM, however, only represents the gas transmission grid and storage infrastructure. Up to a specific level, current gas transmission networks may function without major investment also for the transport of H_2. Above this level, dedicated infrastructure for hydrogen transportation needs to be developed. Costs associated with this new infrastructure development is assessed in this study.

The models for the electricity transmission and distribution system and the gas distribution system build on the results of the aforementioned models with regard to the characteristics of the supply task, such as peak demand and injection, grid user characteristics, etc. On this basis, the effects of changes in the supply task on the network required to fulfil the supply task are modelled and derived. With respect to the electricity transmission grid, Enertile already optimises the transmission grid expansion demand needed to transport electricity from generation to demand sites at any point in time. The calculation of transmission grid expansion is based on a nodal grid presented in Consentec's Electricity-Transmission Model, which is aggregated to a regional model for Enertile for the sake of reduction of computational efforts. The transmission expansion demand, however, is validated in a second step by applying the hourly generation and demand patterns from Enertile to the Consentec Transmission Model and doing a contingency analysis ((n-1) outage simulation) on nodal level. Regarding distributions grids, Enertile delivers geographically disaggregated information on capacities, generation and demand for the electricity sector and Invert delivers information on demand, installed power of gas boilers and heated floor area for the gas sector to Consentec's Distribution Models being used to calculate distribution expansion demands.

2.2. Main scenario assumptions

2.2.1. Overview

The work mainly focuses on the different scenarios for the electrification of the space heating sector, exploring different levels and means of electrification (technology scenarios). All of these scenarios will need to achieve GHG-neutrality, not only in the space heating sector but in the overall energy system. All of these scenarios build on a common set of so-called "anchor assumptions". The anchor assumptions form a GHG-neutral scenario for all sectors except the space heating sector based on ongoing increased decarbonisation efforts. These assumptions mainly aim on providing a GHG-neutral frame to the technology scenarios also being GHG-neutral. Assumptions on all sectors except space heating are kept constant in the technology scenarios based on the anchor assumptions.

In addition to these scenarios a reference-scenario is modelled, which builds on the current policies and targets (as of the moment in time when the modelling in this study started) assumed to remain in place, i.e. a "business-as-usual" scenario, without further increased decarbonisation ambition[11].

Figure 3 illustrates the general scenario design, which is explained in more detail in the following.

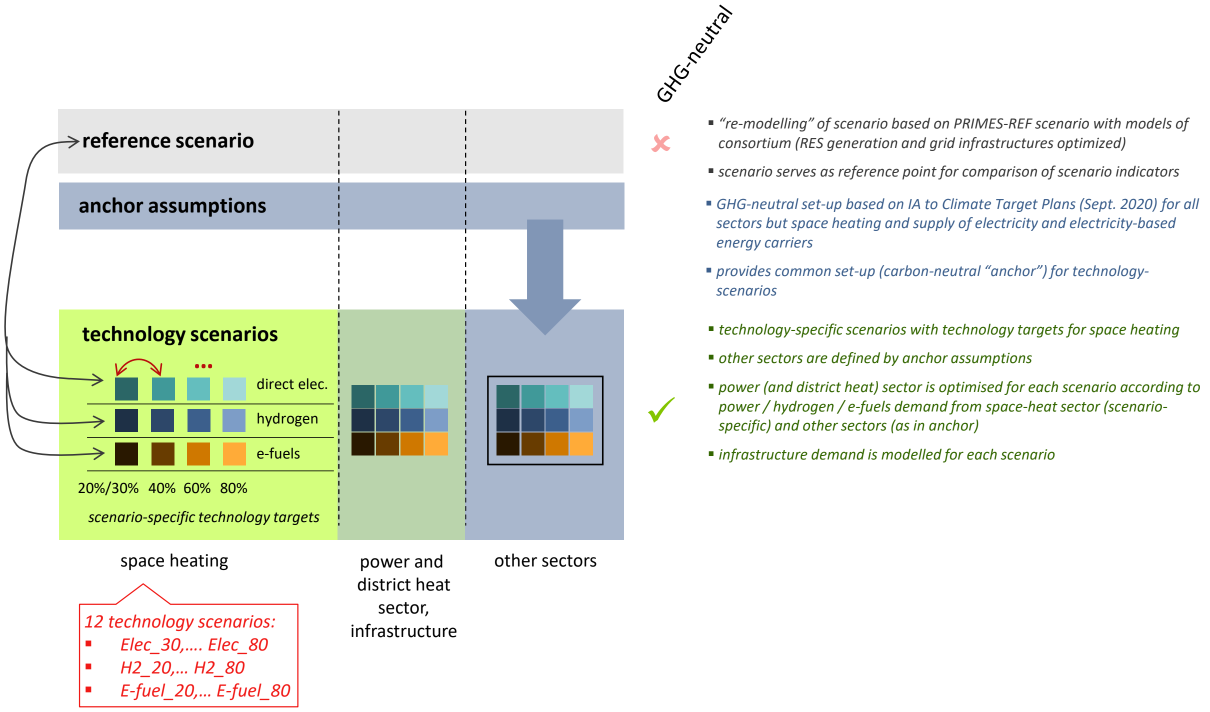

Figure 3: Overview on the general setup of the scenario design

As explained, the modelled reference scenario builds on the assumption that current policies and targets remain in place. It does consequently not achieve carbon neutrality until 2050 and is mainly based on a preliminary version of the PRIMES reference scenario, more specifically PRIMES reference scenario 2020 (E3 Modelling 2020), in the following referred to as Primes Ref 2020 scenario[12], provided by the EU Commission. This scenario serves as a reference for calculating the indicators for the evaluation of the technology scenarios (for example additional capital investments in networks, in heating systems, benefits in terms of reduced GHG emissions). Thus, the results of the technology scenarios are to be compared to the reference scenario.

The anchor assumptions are a GHG-neutral framework for all sectors except the space heating sector based on ongoing increases in decarbonisation efforts. These assumptions provide a GHG-neutral anchor to the technology scenarios, which are per definition required to be GHG-neutral. This is realized for the technology scenarios by "fixing" basically the whole energy system to the anchor assumptions with two exceptions: the space heating sector is not fixed but varies depending on and according to the specific definition of each technology scenario. Further, the power sector (including district heating and production of electricity-based energy carriers such as hydrogen and e-fuels) varies per technology scenario as the direct or indirect electricity demand varies in the space heating sector in each technology scenario. Only that

[11] This scenario reflects national planning as postulated by EU MS's in National Energy and Climate Plans as submitted in the years 2019 and 2020. In practical terms modelling is here aligned to the outcomes of the latest PRIMES reference scenario as provided in draft by end of January 2021, i.e., EC 2020 Reference Scenario.

[12] (European Commission. Directorate General for Energy., European Commission. Directorate General for Climate Action., and European Commission. Directorate General for Mobility and Transport. 2021).

way, technology-specific effects caused by changes in space heating can be identified, quantified and interpreted. For example, the transport sector is a highly relevant demand sector for the energy demand as its characteristics (demand, degree of electrification, and demand for e-fuels) for example determines to a significant extent the overall RES-E demand in Europe. Even though this sector is not the focus of this study, it needs to be taken into account both conceptually and in the modelling work in order to provide meaningful results for the space heating sector. This is due to the fact that the heat sector, as any other energy sector, cannot be studied in isolation and there are direct and strong interactions within other sectors. The level of RES-E demand induced by the transport sector, for example, significantly influences the incremental costs for additional RES-E capacities needed to fulfil the RES-E demand deriving from the space heating sector. The higher the RES-E demand of the transport sector the higher the costs for additional RES-E used in the space heating sector due to the cost-curves of RES-E. The anchor assumptions are "constructed" as a combination of the Primes Ref 2020 (in terms of macro drivers, fuel prices, possibly level of energy services) and an analysis of the GHG-neutral scenarios taken from the Impact Assessment of the Climate-Target Plan[13]. For that purpose, publicly available data was used wherever available and to the maximum extent possible. Where such public data was unavailable, expert estimations were used and carefully elaborated. Defining the anchor assumptions is an important step in the development of a meaningful framework for the comparison of technology-focussed scenarios.

After having determined the corner stones of the reference scenario and the anchor assumptions the specification of the technology scenarios is to be elaborated. This includes questions as regards how to determine the technology mix for the supply of the part of the space heating demand that will not be restricted according to specific scenario settings or how district heating will be affected by the scenarios or how the technology specific targets exactly will be defined.

The following section describes in more detail how relevant different assumptions for the reference scenario, the anchor assumptions, and the technology scenario are clearly defined.

The following tables show the main settings in the different sectors. More explanations of the scenario settings follow below.

Table 1: Scenario settings building sector

parameter	reference scenario	anchor assumptions	Elec_xx	H2_xx	E-Fuel_xx
			technology scenarios		
thermal efficiency	Primes Ref 2020 (draft)	assumptions regarding upper and lower limit of buildings being retrofitted	optimised under anchor assumptions		
biomass potentials	Primes Ref 2020 (draft)	no growth of solid biomass resource use, country specific upper			

[13] see European Commission, "COMMISSION STAFF WORKING DOCUMENT IMPACT ASSESSMENT Accompanying the document COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS Stepping up Europe's 2030 climate ambition Investing in a climate-neutral future for the benefit of our people", https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020SC0176, September 2020

<table>
<tr><th rowspan="2">parameter</th><th rowspan="2">reference scenario</th><th rowspan="2">anchor assumptions</th><th>Elec_xx</th><th>H2_xx</th><th>E-Fuel_xx</th></tr>
<tr><th colspan="3">technology scenarios</th></tr>
<tr><td></td><td></td><td>limit of heated floor area</td><td colspan="3" rowspan="2"></td></tr>
<tr><td>solar thermal</td><td>Primes Ref 2020 (draft)</td><td rowspan="5">country specific upper limit of heated floor area</td></tr>
<tr><td>direct electric heating</td><td>Primes Ref 2020 (draft)</td><td rowspan="2">30%-80% (a)</td><td colspan="2" rowspan="2">optimised under anchor assumptions</td></tr>
<tr><td>heat pumps</td><td>Primes Ref 2020 (draft)</td></tr>
<tr><td>hydrogen</td><td>Primes Ref 2020 (draft)</td><td>optimised under anchor assumptions</td><td>20%-80% (a)</td><td>optimised under anchor assumptions</td></tr>
<tr><td>e-fuels</td><td>Primes Ref 2020 (draft)</td><td colspan="2">optimised under anchor assumptions</td><td>20%-80% (a)</td></tr>
</table>

Table 2: Scenario settings distrcit heating

<table>
<tr><th rowspan="2">parameter</th><th rowspan="2">reference scenario</th><th rowspan="2">anchor assumptions</th><th>Elec_xx</th><th>H2_xx</th><th>E-Fuel_xx</th></tr>
<tr><th colspan="3">technology scenarios</th></tr>
<tr><td>expansion of grid</td><td>Primes Ref 2020 (draft)</td><td>N/A</td><td colspan="3">optimised</td></tr>
<tr><td>biomass</td><td>Primes Ref 2020 (draft)</td><td>reduced deployment</td><td colspan="3" rowspan="3">anchor assumptions</td></tr>
<tr><td>solar thermal</td><td>Primes Ref 2020 (draft)</td><td>increasing deployment</td></tr>
<tr><td>deep geothermal</td><td>Primes Ref 2020 (draft)</td><td>increasing deployment</td></tr>
<tr><td>heat pumps</td><td>optimised</td><td rowspan="4">N/A</td><td colspan="3" rowspan="4">optimised under anchor assumptions</td></tr>
<tr><td>direct electric heating</td><td>optimised</td></tr>
<tr><td>hydrogen</td><td>in accordance with Primes Ref 2020 (draft) no deployment</td></tr>
<tr><td>e-fuels</td><td>in accordance with Primes Ref 2020 (draft) no deployment</td></tr>
</table>

Table 3: Scenario settings power sector

parameter	reference scenario	anchor assumptions	Elec_xx	H2_xx	E-Fuel_xx
			technology scenarios		
electricity demand in other sectors	Primes Ref 2020 (draft)	exogenously determined assumptions (in line with scenarios from the IA of the Climate Target Plan)	anchor assumptions		
biomass	Primes Ref 2020 (draft)	reduced deployment	anchor assumptions		
other direct RES	optimised	N/A	optimised		

Table 4: Scenario settings electricity networks

parameter	reference scenario	anchor assumptions	Elec_xx	H2_xx	E-Fuel_xx
			technology scenarios		
trans-mission level	optimised grid expansion	N/A	optimised grid expansion (grid expansion partially limited to avoid extreme results at some borders)		
distribution level	necessary grid according to electricity demand and generation requirements of this scenario	N/A	grid necessary to fulfil to electricity demand and generation requirements of the specific scenario is determined		

Table 5: Scenario settings H2 and e-fuels generation

parameter	reference scenario	anchor assumptions	Elec_xx	H2_xx	E-Fuel_xx
			technology scenarios		
hydrogen demand in other sectors	Primes Ref 2020 (draft)	exogenously determined assumptions (in line with scenarios from the IA of the Climate Target Plan)	optimised		
hydrogen import	not necessary	N/A	allowed at high prices (optimised)		
e-fuels demand in other sectors	Primes Ref 2020 (draft)	exogenously determined assumptions (in line with scenarios from the IA of the Climate Target Plan)	anchor assumptions		
e-fuels import	not necessary	N/A	allowed at very high prices (optimised)		

Table 6: Scenario settings H2 / CH4 networks

parameter	reference scenario	anchor assumptions	Elec_xx	H2_xx	E-Fuel_xx
			technology scenarios		
trans-mission level	Primes Ref 2020 (draft)	N/A	grid necessary to fulfil to CH4/H2 demand requirements of the specific scenario is determined		
distribution level	necessary grid according to gas demand requirements of this scenario	N/A	grid necessary to fulfil to CH4/H2 demand requirements of the specific scenario is determined		

The following describes the assumptions used for modelling the reference scenario.

2.2.2. Reference scenario

Energy and carbon price trends, interest rate

Assumptions on the future development of energy prices concerning fossil fuels (i.e., fossil natural gas, oil, coal) were aligned with the PRIMES reference scenario 2020 (E3 Modelling 2020), also referred to as “Primes Ref 2020 ” in the following. These price trends will be the same for all assessed scenarios in the course of this study, including the technology scenarios.

Concerning carbon prices, i.e., prices for emission allowances within the EU ETS, for the reference scenario a price trajectory within this study from the Primes Ref 2020 is applied. In contrast to the reference, we will assume higher carbon prices for the technology scenarios (which will build on an identical carbon price trend).

Furthermore, an interest rate of 2% (real prices) is assumed across all models and all scenarios.[14]

Buildings

The overall demand and energy carrier mix for space heating and hot water will be guided by the Primes Ref 2020 (draft). Due to the different modelling logic between the scenario development of the model Invert/EE-Lab and the Primes Ref 2020 (draft) scenario, there will be slight deviations, in particular for some MS.

District heat generation

In the reference scenario, the use of biomass, solar thermal and deep geothermal for district heat supply is based on data from the Primes Ref 2020 (draft) scenario. The deployment of large heat pumps and direct electric heating is optimised in Enertile. Hydrogen and e-fuels are not deployed for district heating purposes as these fuels are not used in the Primes Ref 2020 (draft).

Power sector

In the reference scenario, the electricity demand in other sectors and the use of biomass is based on data from the Primes Ref 2020 (draft). The same is applied to nuclear generation. The electricity generation mix and other direct RES such as solar and wind energy are optimised in Enertile.

H_2 and e-fuels generation

In the reference scenario, hydrogen and E-fuels demand in other sectors is based on the Primes Ref 2020 (draft). These fuels play a very limited role, used in industry and in transport. No hydrogen is used for electricity generation.

Electricity Transmission grid

The expansion of the electricity transmission grid (in terms of cross-border capacities) is optimised in Enertile considering on the one hand costs of transmission grid expansion and on the other hand, power sector benefits within the general costs optimisation of Enertile.

As some of the aspects under this scenario are optimised endogenously in Enertile this will lead to deviations in terms of technology development compared to the Primes Ref 2020 calculations.

[14] An exception from this general trend applies for the estimation of RES support done by use of the Green-X model. Here latest trends in RES financing conditions are taken into consideration for the status quo as analysed in the H2020 project AURES2. On average, technology-specific WACCs presently (i.e. 2018 to 2020) range from 1.5% to 4.5% (real prices), with differences between countries and technologies. For the period up to 2050 an alignment and a decline in WACCs are assumed bringing the RES-related WACCs closer to 2% rate as presumed for the general interest rate within this project.

The necessary grid infrastructure to fulfil the demand for electricity exchange as determined within the optimisation of Enertile is then determined based on the Enertile results (hourly load and generation profile with high spatial resolution).

Electricity Distribution grid

The distribution grid infrastructure necessary to cope with the electricity demand and distributed electricity generation as optimised endogenously in Enertile will be determined based on the results from Enertile regarding electricity demand (regional peak loads distinguished by sector) and distributed electricity generation (regional installed capacity distinguished by generation technology).

Transmission grid for gaseous energy carriers (both H2 and CH4)

The gas transmission grid analysed in the reference scenario will be built based on ENTSOG capacity map. Additionally, advanced gas infrastructure projects from TYNDP 2020 will also be included into the reference gas grid.

The need for additional future gas transmission capacity (if any) to fulfil the gas demand determined by Enertile in the analysed scenarios will be checked based on EGMM modelling results.

Gas transmission grid needs are examined both for H2 and CH4 transport and are modelled separately. The necessary H2 infrastructure-development will be analysed based on Enertile and Invert results on H2 production and demand by country, allowing for retrofitting existing gas infrastructure. For the detailed methodology see annexes.

Distribution grid for gaseous energy carriers (both H2 and CH4)

The distribution grid infrastructure necessary to cope with the gas demand as determined in Enertile and Invert will be determined based on the results from Enertile and Invert for gas demand. Gas distribution grid needs are examined both for H2 and CH4 and are modelled separately.

2.2.3. Anchor assumptions

The following will describe the anchor assumptions used for the modelling of all technology scenarios.

Energy and carbon price trends, interest rate

Similar to the reference scenario, assumptions on the future development of fossil fuels' prices are be aligned with the Primes Ref 2020.

Concerning carbon prices, higher carbon prices than in the reference scenario are assumed for the anchor assumptions / technology scenarios. The assumption is aligned with carbon price trends underlying the scenarios of the Impact Assessment of the Climate Target Plan. Here the Impact Assessment shows a quite broad range of carbon price-trends, differing across assessed scenarios due to varying policy approaches on how to meet climate neutrality by 2050. A price trajectory that fits best to the storyline for other key parameter such as e-fuels, hydrogen or the role of e-mobility was selected. The following table shows the final carbon price-assumptions.

Table 7: Carbon price-assumptions for anchor and technology scenarios

carbon price (EUR2018/t CO2)	modelling year
65	2030
200	2040
500	2050

An interest rate (real prices) of 2% is considered across all models.[15]

Power sector

The demand for electricity in other sectors (i.e. all sectors excluding space and water heating) is exogenously determined and based as an anchor assumption on assumptions in line with the scenarios from the Impact Assessment of the Climate Target Plan (see below). Comparable to the deployment of biomass for district heat supply, we assume that the available biomass for electricity supply is also strongly declining until 2050. The electricity generation mix and other direct RES such as solar and wind energy is optimised for each technology scenario in Enertile.

H2 and e-fuels generation

The demand for hydrogen and e-fuels in other sectors is exogenously determined and based as an anchor assumption on assumptions in line with the scenarios from the Impact Assessment (IA) of the Climate Target Plan (see below). These electricity-based fuels can either be produced with renewable electricity within the EU or be imported from countries with very good potentials for renewable electricity generation outside the EU (typically the Middle East and North Africa (MENA) region). As an anchor assumption, the import of hydrogen and e-fuels is generally allowed but at high prices to prioritise production in the EU. Generally, the import prices for e-fuels exceed the import prices for hydrogen.

Demand for electricity, hydrogen and e-fuels

The exogenously defined demand for electricity, hydrogen and e-fuels in other sectors is based on assumptions in line with the scenarios of the Impact Assessment (IA) of the Climate Target Plan. Unfortunately, the data publicly available from these scenarios is limited to overall values for Europe in 2050. This leaves important data gaps for our scenario assessment as demand values for 2030 and 2040 are missing and each European country is modelled separately in this study. Therefore, we used the similar demand assumptions such as in the "Renewable Space Heating under the Revised Renewable Energy Directive" project (ENER/C1/2018-494) (thereafter: RES-H project). In the RES-H project, the demand data is based on total demand in 2050 for Europe according to the 1.5TECH scenario (European Commission, A Clean Planet for all[16]). For the development before 2050 and the demand distribution between European countries, other sources were used. The national distribution and the development until 2050 are based on the SET-Nav pathway "Diversification".[17]

In the RES-H project, a consistent data set for demand from other sectors was compiled very elaborately and specifically for the Enertile model.[18] This work process was very resource intensive and should accordingly be used in subsequent projects with similar scope. By using this demand data set, a quick start of the modelling with Enertile is possible. The demand data set used in the RES-H project is very consistent with the demand developments in the scenarios from the IA of the Climate Target Plan, and therefore used for the anchor

[15] As stated for the Reference scenario, an exception from this general assumption applies for the estimation of RES support done by use of the Green-X model. Here latest trends in RES financing conditions are taken into consideration for the status quo as analysed in the H2020 project AURES2. On average, technology-specific WACCs presently range (i.e. assessment period: 2018-2020) from 1.5% to 4.5% (real prices), with differences between countries and technologies. For the period up to 2050 an alignment and a decline in WACCs is assumed which brings the RES-related WACCs closer to the 2% range as presumed for the general interest rate within this project.

[16] Brussels, 28.11.2018 COM(2018) 773.

[17] The diversification pathway depicts a decentralised but cooperative world where many new entrants and heterogeneous actors determine the market. Digitalisation, prosumers, and high support for coordination as well as regulatory opening characterise this pathway (see the project website: https://www.set-nav.eu/ and the final report: https://www.set-nav.eu/sites/default/files/common_files/deliverables/d11/D11.14%20Final%20Report%20on%20SET-Nav%20Policy%20Briefs.pdf).

[18] The demand from other sectors was elaborated with various assumptions, while space and water heating were modelled in the RES-H project (see forthcoming project report).

assumptions. To ensure this consistency, we closely examined both data sets and compared them intensively.

2.2.4. Technology scenarios

In the following the assumptions used for the modelling of the technology scenario are described.

Energy and carbon price trends, interest rate

Energy and carbon price assumption and interest rates are set according to the anchor assumptions.

Buildings

Determining the "remaining" mix of heating technologies

The different scenarios for the direct and indirect electrification of the space heating sector are determined by the share of the building floor area to be supplied by certain electrification technologies and related energy carriers according to Table 1. The mix of technologies[19] supplying the remaining part of the building stock are determined based on a least-cost optimisation and consider certain constraints of technology diffusion in the building stock. These constraints are set as loose as possible only to consider e.g., boundaries of grid infrastructure and current pre-dominance of certain technology by Member State (see Table 8 for an example).

Determining building insulation in the scenarios

Based on the setting of constraints as described above, the cost-minimising algorithm in the model Invert/Opt identifies those combinations of heating systems and energy efficiency improvement, which meet the constraints regarding the targeted GHG-emission reduction by 2050 and the other constraints on technology diffusion mentioned above. For example, the model Invert/Opt considers explicitly the effect that heat pumps achieve a higher COP in case of higher insulation levels (due to lower required inlet temperature after renovation).

For more details on the calculation methodology, we describe the modelling approach and some of the constraints in the annex.

Technology targets on Member State or EU level

The technology targets specified in the electrification scenarios in general are implemented on MS level, i.e., each MS needs to fulfil the same share of technologies. However, if this would lead to a need for extreme infrastructure uptake in some MS (e.g., gas grid uptake in Malta) we would allow flexibility between MS, ensuring the achievement of the overall targets on EU-level. The following example demonstrates the approach (A1) we are going to use.

[19] Hybrid heating systems (providing heat through a combination of heat pumps and other solutions, in particular oil or gas) in other studies are discussed as a way to overcome certain barriers and to achieve faster and more cost-effective decarbonisation in staged renovation processes. Due to the fact that in our study we focused more on the long-term target state in the year 2050 than on the near-term transition pathway, we did not focus on such hybrid heating systems. In the assessment of such solutions it would need to be considered to which extent the gas grid has to be maintained for a longer period with very low amount of gas supplied through the remaining grid.

Table 8: Exemplary data of a three-country region to demonstrate the assignment algorithm

Country	Heated floor area	estimated upper boundary of gas diffusion considering current infrastructure
A (e.g., Germany)	10000	75%
B (e.g., Finland)	1000	20%
C (e.g., Austria)	1000	60%

As an example, if we assume that the scenario settings require a gas utilization of 60%, this means, that in the modelling and as a first step, each modelled member state needs to achieve 60%, unless the defined upper limit is lower than 60%. In this case only the upper limit is reached. In our example, this means that in the first step a utilization rate of (6000 + 200 + 600) / 12000 is achieved, with 60% in country A und C and 20% (upper limit) in country B. The overall utilisation rate is 56,67%. To reach the 60% target, an extra 400 area units are required to be heated by gas to meet the target of 60%. In order to fulfil the 60%, each country needs to increase the share by 400 / 12000 = 1/30. This will finally lead to the following country specific targets: country A: 63,3%, country B: 63,3 %, country C: 23,3%.

We decided to favour this approach over alternatives, as to our opinion it prevents some drawbacks of alternative assignment methodologies. If (A2) we assigned the remaining area to those countries only which have additional potential (Country A: + 400 units or 4%) this would lead to a “high burden” for some countries in scenarios with high gas penetration (60% and 80%). If, as a third alternative (A3), we assigned each country the same utilization rate, defined against the estimated upper boundary of the existing infrastructure, we would not be able to derive the correct results as regards how we implemented the scenario setup.

Table 9: Resulting demanded gas utilization of three different assignment methodologies

	E_fuel_80 scenario			E_fuel_60 scenario		
	assignment approach			assignment approach		
	A1	A2	A3	A1	A2	A3
AT	85%	79%	87%	66%	65%	65%
BE	89%	84%	92%	66%	68%	69%
BG	50%	38%	42%	38%	32%	31%
CY	19%	1%	1%	7%	1%	1%
CZ	73%	65%	72%	61%	55%	53%
DE	94%	90%	99%	66%	72%	74%
DK	56%	45%	49%	44%	38%	37%
ES	54%	43%	47%	42%	36%	35%
EE	72%	64%	70%	60%	54%	52%

	E_fuel_80 scenario			E_fuel_60 scenario		
	assignment approach			assignment approach		
	A1	A2	A3	A1	A2	A3
FI	35%	20%	22%	23%	17%	16%
FR	83%	77%	85%	66%	64%	63%
GR	57%	46%	51%	45%	39%	38%
HR	80%	73%	81%	66%	62%	60%
HU	92%	88%	96%	66%	71%	72%
IE	67%	58%	64%	55%	49%	47%
IT	91%	86%	95%	66%	70%	71%
LT	53%	41%	46%	41%	35%	34%
LU	86%	80%	88%	66%	66%	66%
LV	50%	38%	42%	38%	32%	31%
MT	47%	34%	38%	35%	29%	28%
NL	98%	100%	100%	66%	82%	86%
PL	55%	44%	48%	43%	37%	36%
PT	58%	47%	52%	46%	40%	39%
RO	63%	53%	59%	51%	45%	44%
SE	36%	21%	23%	24%	18%	17%
SI	63%	53%	59%	51%	45%	44%
SK	86%	80%	88%	66%	66%	66%

District heating

District heating potentials and grid expansion

The economic district heating potentials is determined by the status quo (current district heating share) and the future district heating potential on the country level. The future district heating potential has been estimated based on the future heat densities (considering the local building stock, see also Hotmaps project) on the hectare level, and an upper limit on the district heating expansion rate. For countries (e.g. Denmark, Austria (rural areas), where the current district heating exceeds the estimated current district heating potential, we adopted the threshold level (GWh energy demand / km² and connection rate in district heating areas), so that current economic potential roughly matches the status quo.

The estimated district heating potential is calculated based on the heat demand according to the anchor assumptions. These results for district heating potentials are not modified in the different scenarios, although the exploitation of the potentials according to the results from Invert/Opt will be different.

District heat generation

In the technology-specific scenarios, the assumptions for the use of biomass, solar thermal and deep geothermal for district heat supply are based on the anchor assumptions. The deployment of large heat pumps, direct electric heating, hydrogen and e-fuels is optimised in Enertile.

Power sector

In the technology-specific scenarios the demand for electricity deriving from other sectors is kept constant according to the anchor assumptions. The same applies to biomass available for electricity supply. The electricity generation mix and other direct RES such as solar and wind energy are optimised in Enertile.

Demand for electricity, hydrogen and e-fuels

The demand for electricity, hydrogen, and e-fuels in other sectors than the heat sector is exogenously defined based on the anchors assumptions in line with the scenarios of the IA of the Climate Target Plan. For details, see above.

Electricity transmission and distribution

Transmission grid

In the modelling the electricity transmission infrastructure necessary to serve the needs for regional electricity exchange will be determined. The needs for electricity exchange are a result of the power sector model (Enertile, see above). Within the power sector model, the maximum capacities for electricity exchange between MS are a matter of degree and defined to some extent whereby:

- the minimum available exchange capacity is set by the existing transmission grid plus the infrastructure expansion plans according ENTSO-E's Ten Year Network Development Plan 2018 (TYNDP 2018) for 2030
- additional exchange capacity is available for 2040 and 2050 as a result of the overall cost-optimization on the power sector model; i. e., within the power sector model the expansion of exchange capacity has some degree of freedom, however, it is related to costs (based on actual transmission grid expansion costs); how much grid expansion is actually used is a scenario-specific result based on the cost-minimization problem in the power sector model.
- Cost assumptions for network equipment (lines / cables) will be based on empirical values as used by the German grid operators for their network development plan ("Netzentwicklungsplan"). We assume that (new) transmission lines are on average 20% cable / 80% overhead-lines.

Distribution grid

General task: Determination of grid expansion needs using model network analysis. The main driver for the grid dimensioning is the electricity demand and distributed generation (mainly PV, wind).

Relevant input data are (country-specific):

- area ("effective supply area")
- number of Housing units (→"baseload" today)
- number of buildings (→number of grid connections)
- RES expansion (PV, Wind onshore)
- load development differentiated by demand types (e.g., conventional load, heat pumps)

We assume that area and number of buildings do not change over time so that mainly the development of the electricity demand and the distributed generation are the key influences on the necessary grid.

The development of electricity demand and distributed generation in the different scenarios is simulated in Green-X and Enertile and the corresponding results are used as input for the model analysis.

Mix of gaseous energy carriers

The share of hydrogen, synthetic methane and biogas in the gas grid and the share of e-liquids and bio-oil in the mix of heating oil is determined exogenously in the different scenarios. The corresponding shares are shown in the following table.

Table 10: Scenario assumptions regarding share of different fuel types in gaseous and liquid heating fuels per group of scenarios and modelling year

Scenario (down) / Fuel (right)	Hydrogen			e-gas			biogas			e-liquid			biooil		
	Share on gaseous heating fuels									Share on liquid heating fuels					
	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050	2030	2040	2050
Reference	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Hydrogen	5%	34%	90%	0%	2%	5%	0%	1%	2%	0%	2%	5%	14%	36%	90%
E-fuels	0%	2%	5%	5%	34%	90%	0%	1%	2%	5%	34%	90%	1%	2%	5%
Direct RES-H / Electrification / District Heating	1%	4%	10%	1%	4%	10%	12%	31%	77%	1%	4%	10%	13%	34%	85%

H2 and e-fuels generation

In the technology-specific scenarios, the demand for hydrogen and E-fuels from other sectors is kept constant and anchor assumptions are used. Import of hydrogen and E-fuels is allowed at high prices.

CH4 and H2 transmission and distribution

Transmission grid for gaseous energy carriers (both H2 and CH4)

The gas transmission grid analysed in the reference scenario will be built based on ENTSOG capacity map. Additionally, advanced gas infrastructure projects from TYNDP 2020 will also be included into the reference gas grid. Gas transmission grid needs are examined both for H2 and CH4 transport and are modelled separately.

The need for additional future CH4 transmission capacity (if any) to fulfil the CH4 demand determined by Enertile in the analysed scenarios will be checked based on EGMM modelling results. As there is no increase in CH4 demand, there is no additional investment need for CH4 infrastructure foreseen.

The needed H2 infrastructure-development will be analysed based on Enertile and Invert results on H2 production and demand by country, allowing for retrofitting existing CH4 infrastructure. For the detailed methodology see annexes.

Distribution grid for gaseous energy carriers (both H2 and CH4)

The necessary distribution grid infrastructure necessary to cope with the gas demand as determined in Enertile and Invert will be modelled taking into account the results from Enertile and Invert for gas demand. Gas distribution grid needs are examined both for H2 and CH4 and are modelled separately.

General task: Determination of grid expansion (or decommissioning) needs using model network analysis. The main driver for the grid dimensioning is the gas demand of the respective infrastructure.

Relevant input data are (country-specific):

- area ("effective supply area")
- number of Housing units (→"baseload" today)
- number of buildings (→number of grid connections)
- area coverage
- demand development

We assume that area and number of buildings do not change over time, so that mainly the development of the gas demand is the key influence on the necessary grid.

The development of gas demand (differentiated with respect to H2 vs. CH4) in the different scenarios is simulated in Invert/EE-lab and Enertile and corresponding results are used as input for the model analysis

3. Results of technology scenarios

3.1. Building stock

The starting point of the scenario development of space heating demand in the model Invert/Opt is the share of heated floor area by energy carrier (Figure 4) in the year 2050. The different technology scenarios with their technology focus are first of all driven and defined by a given share of heated floor area being heated by the respective "target" technology, e.g. 30% of floor area to be covered by electricity driven heating systems in the scenario "Elec_30". This share is implemented as a model constraint.[20] While the "target" technology is kept within the technology scenario's constraints, the model is free to choose the mix of other technologies according to a cost-minimisation approach.

[20] The figure shows that some of these constraints are not exactly met. In particular, the scenarios with high shares (80%) of H2 and E-fuels show slightly under-achievement of these constraints. This is due to the fact that different model restrictions, e.g., regarding the expansion of H2 and gas grids, are in conflict to the minimum share of the target energy carrier. Thus, it should be considered that the H2_80 and E-fuel_80 scenarios actually represent a slightly lower share of the floor area covered by these energy carriers.

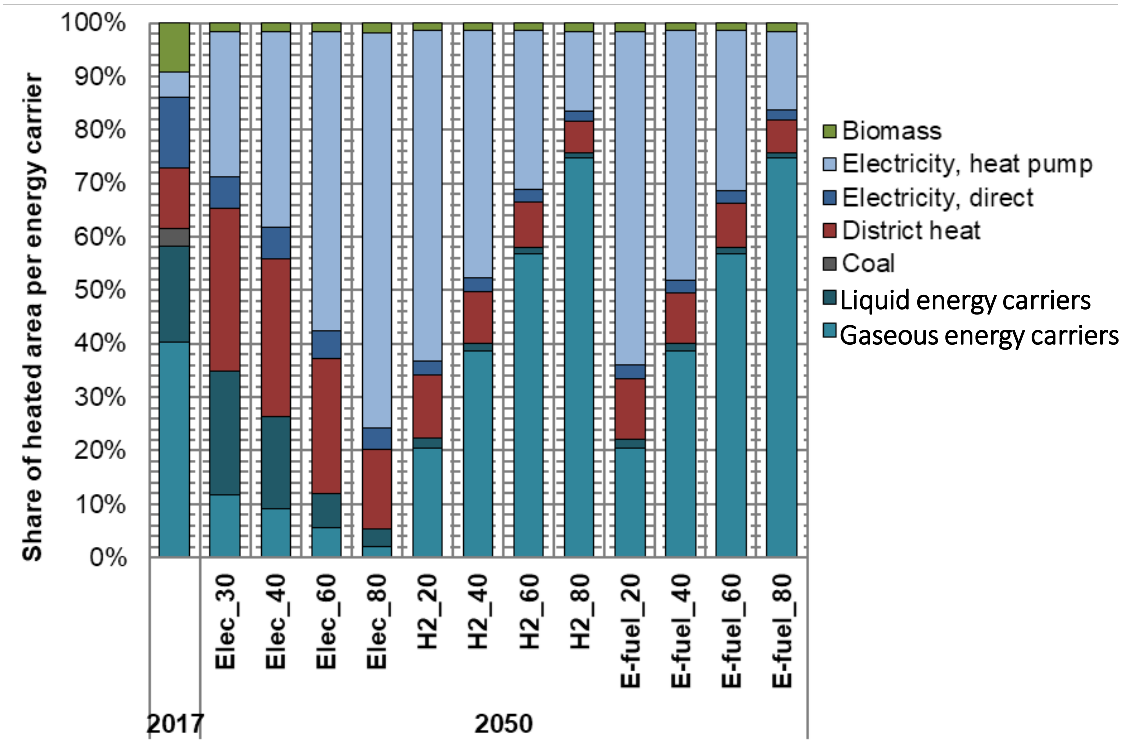

Figure 4: Share of heated floor area by energy carrier and per modelled technology scenario, EU-27

In the scenarios Elec_30, Elec_40 and Elec_60, the remainder of the floor area is covered by a high share of district heating. However, district heating is restricted to the part of the building stock with sufficiently high heat densities and resulting acceptable heat distribution costs. Buildings outside these suitable areas are not considered for district heating. Thus, the remaining part of the building stock, which cannot be supplied by district heating under cost-optimum considerations are covered by (renewable) fuel oil and gas. While the model assumes district heating to be implemented in densely populated areas, the costs for gas distribution networks are a decisive factor for choosing the cost-optimal energy carrier on other areas. The gas network cost increases considerably on a per-kWh-basis considering the strongly reduced overall gas demand. For this reason, the model in the scenarios Elec_30 and Elec_40 chooses a higher share of (renewable) fuel oil than (renewable) gas.

In the H2 and e-fuel scenarios, the remaining part of the building stock is mainly supplied by heat pumps, however, also including a considerable share of district heating. Overall, by 2050 the share of district heating on the supplied floor area is lower than in the base year in the H2_80 and E-Fuel_80 scenarios, about the same in the H2 and E-Fuel_40 and -60 scenarios, while it increases, partly significantly in the other scenarios. The H2_80 and E-Fuel_80 scenarios show that the main competition in areas with high heat density is between district heating and gaseous energy carriers, while in rural areas, sometimes none of them is available, leaving room for heat pumps. This is a key reason why, in order to force the high share of H2 and e-gas in these technology scenarios, district heating grids would need to be partly decommissioned. Since a certain share of district heating grids will need re-investment in the coming decades, a decommissioning of district heating grids is not excluded in our assumptions. Rather, developments in the past decades in some, mainly Eastern European countries have shown that such developments can take place if no counteracting policies are in place. The share of floor area heated by electricity driven systems increases in all scenarios, including in the scenarios H2_80 and E-Fuel_80, despite the fact that these latter do not leave sufficient room for a fully optimised expansion of heat pumps. However, it should be noted that in the base year the majority of the electricity driven heating systems are direct electric resistance heaters, while their share strongly reduces by 2050, but still holding a minor share. Biomass heating systems are restricted regarding their role, since the overall assumption is that scarce biomass resources are needed for high-exergy applications rather than for low-temperature end-uses such as space heating.[21]

Figure 5 shows how the share of heated floor area translates into total energy demand for space and water heating and the resulting energy carrier mix.

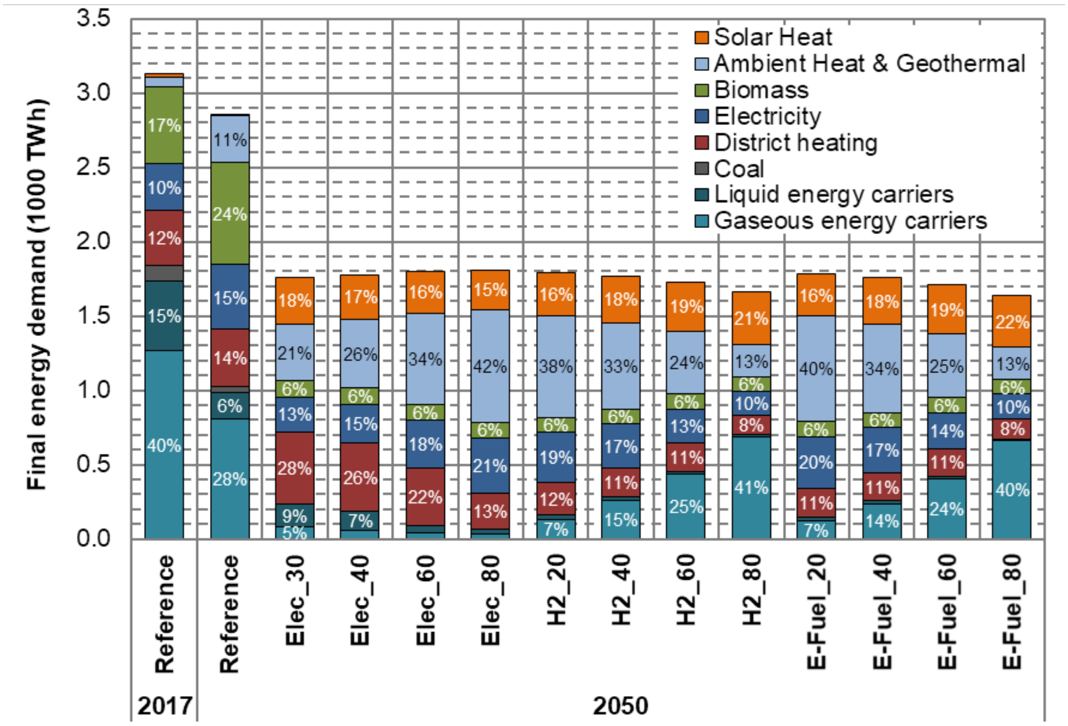

Figure 5: Final energy demand for space and water heating by energy carrier and scenario, EU-27

A first finding is that all technology scenarios lead to a significantly higher uptake of building renovation and related energy savings than in the reference scenario: the total final energy demand in 2050 reduces by 42-47% compared to the base year. Still, there are differences in the uptake of renovation measures. Given the full decarbonisation target, renovation is an economically viable measure in all scenarios. Renovation rates are somewhat higher in scenarios with a (forced) high share of synthetic energy carriers. However, the difference in the rate between H2-/E-fuel- and Elec-scenarios is somewhat influenced by the fact that the upper limits set in the models for renovation are reached in many scenarios, reflecting real-life restrictions of renovating buildings for different reasons (technical, aesthetical, socio-economic, etc.). A second finding is that the share of energy carriers on total final energy demand is not identical to the share on total floor area in Figure 4: The share of electricity and ambient heat in the Elec_80 scenario by 2050 amounts to 63%. One or the reason for this deviation is that solar heat is also included (as secondary heating system) in Figure 5. In addition, in our modelling result – and in reality – the distribution of heating systems and related energy carrier is not homogenous over the building stock. The model tends to apply heating systems with lower variable energy prices in buildings with poor envelope quality. Moreover, the heating system supply temperature, being affected also by the envelope quality, has an impact on the COP of heat pumps and thus their economic performance compared to other

[21] Figure 4 does not include "solar" as category because we consider solar heat (either via photovoltaics or solar thermal collectors) as energy carrier additional to a main energy carrier. Thus, the figure only includes the main energy carrier, in order to avoid double counting.

solutions. Overall, this results to this lower share of finale energy demand compared to the share of floor area. However, the difference is even higher for the share of gas on total final energy demand in the H2_80 and E-Fuel_80 scenarios by 2050, with 40-41%. This difference is due to high variable costs of e-fuels and H2. Thus, if applying e-fuels and H2 at all, it is most economic in combination with solar energy and in most efficient buildings. This is why the share of solar heat[22] increases with higher share of H2 and e-fuels in our modelling results. The use of biomass for space and water heating in the model is restricted by a resource potential constraint, which the model uses to its upper limit.

Compared to the reference scenario (which is not derived with an optimisation approach but rather to get close to the PRIMES reference scenario 2020, see section 3.2.2), all technology scenarios lead to a substantial higher amount of capital costs for building renovation and individual heating systems, whereas the direct running costs for individual heating systems are substantially lower. It should be noted that Figure 6 is not a full system cost analysis, which will be shown below in section 4 and elaborate in more detail in subsequent stage of the project of the project. Rather, it highlights the costs occurring only directly in the building stock, not in the upstream supply sector to supply electricity, district heating, H2 or e-fuels. The fact that high variable energy costs for H2 and e-fuels lead to higher uptake in building renovation, as discussed above, leads to highest capital costs for building renovation under these scenarios. The result that higher H2 and e-fuels do not lead to significantly lower capital costs for individual heating systems can be explained by the fact that the economic optimisation suggests adding solar heat installations to the gas boiler, leading to higher related capital costs.

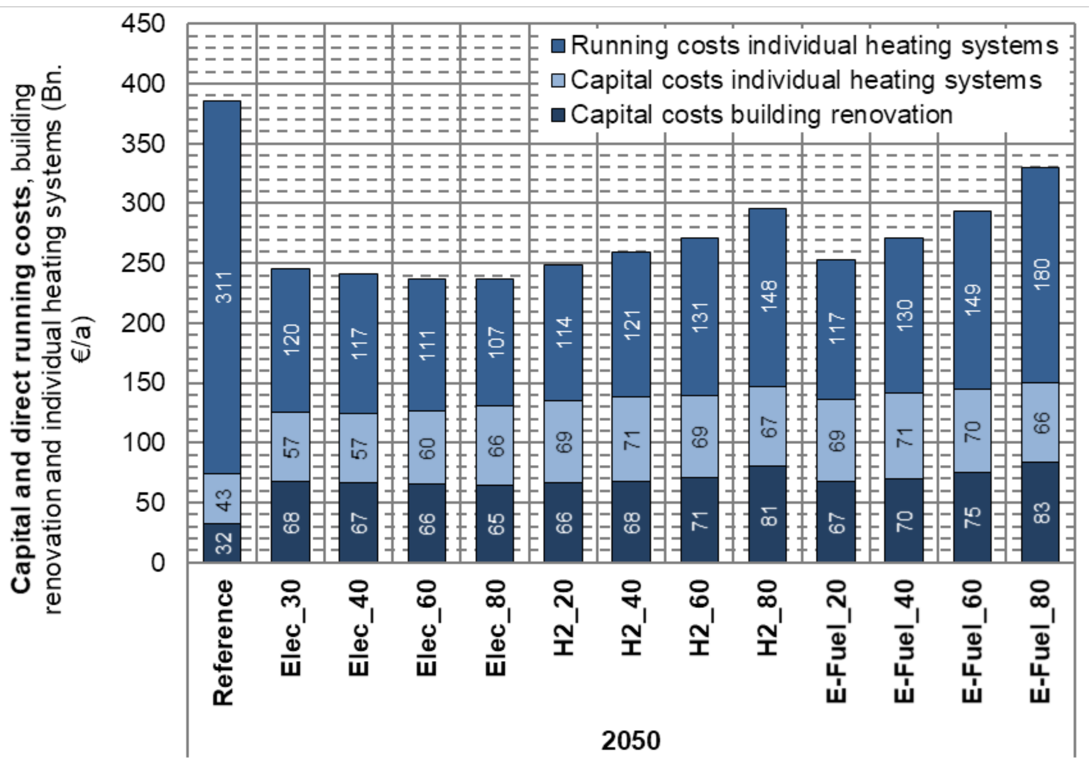

Figure 6: Capital costs and direct running costs for building renovation and heating systems by scenario, EU-27

Limitations and uncertainties of the presented modelling results can be seen mainly in the following points: (1) Costs and achieved savings of renovation are subject to questions of

[22] Solar heat in Figure 5 represents the total of photovoltaics self-consumption for space heating and solar thermal collectors.

behavioural changes, technological progress, development of skilled construction workers and many more aspects. While at least some parts of the rebound effects are explicitly modelled, still open questions in this are to be further analysed and discussed. (2) The technological development which might occur for several heating systems and technologies and related, possible cost developments is subject to uncertainty. E.g., new district heating concepts, including such with substantially lower system temperatures might open up new opportunities to exploit low-cost renewable heat sources. Not all of these potential developments can be fully modelled and might lead to an underestimation of the role of district heating. (3) The question how future markets of secondary energy carriers will evolve and how generation and supply costs will translate into retail prices is a considerable uncertainty which might lead to different relation of retail energy prices than assumed in our modelling approach.

Overall, we do not expect that these limitations would affect the conclusions derived below and the relative ranking of scenarios.

Sector conclusions

- From the view of an economic optimization in the building stock there seems to be clear merit order of energy carriers / heating technologies: Heat pumps and district heating (where heat densities are sufficiently high) are economically viable. Liquid and gaseous energy carriers (H2 and e-methane) are expensive, the latter one increasingly also due to high distribution costs with lower utilization of grid infrastructure.
- If e-fuels must be used, they should be combined with solar heat and increased renovation measures.
- High levels of building renovation and related energy savings is part of the economic optimum in the largest part of the building stock: Heat pumps, which hold a high share of the heated floor area, show their highest COP in buildings with low heating systems' supply temperature and thus in highly insulated buildings. H2 and and e-fuels have the highest variable energy prices which triggers high renovation activities also in these buildings.
- Each of the scenarios results in a strong decrease of direct electric resistance heaters.
- Biomass for space and water heating is mainly reduced due to the assumed resource constraints.

3.2. Power and district heat (including RES investments)

Power sector

In the following, the results of the technology scenarios for the power sector are presented. Figure 7 shows the electricity generation in EU-27 in 2050 in all technology scenarios and the reference scenario. Note that - opposed to the reference scenario - all technology scenarios reach GHG-neutrality by 2050 and no fossil generation technologies remain in the mix.

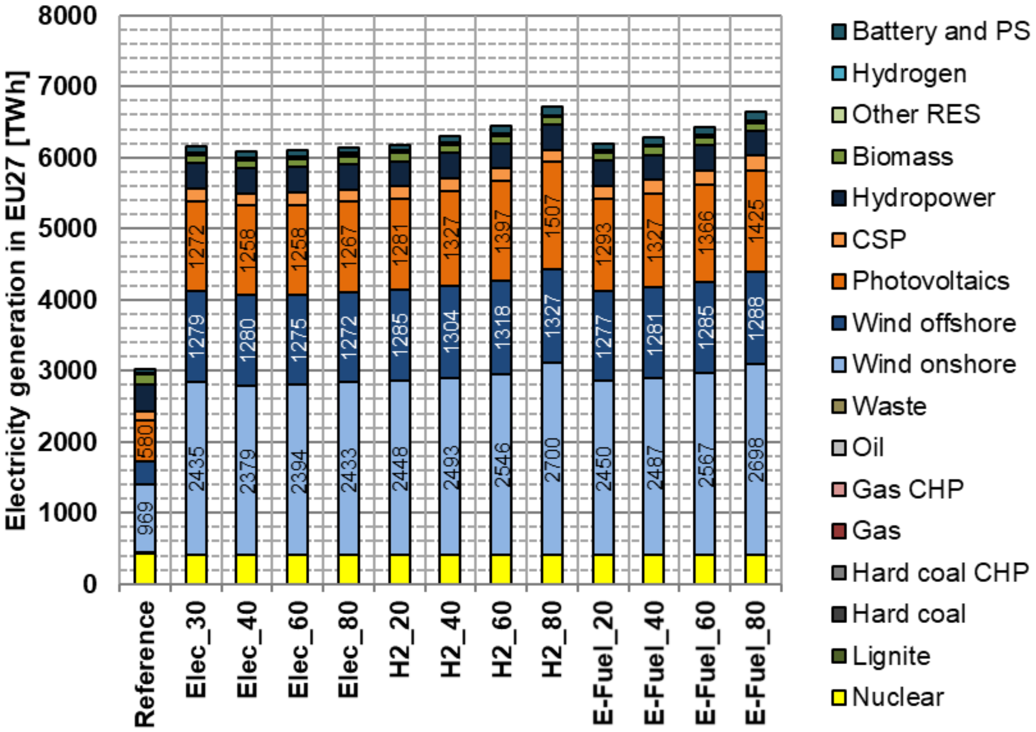

Figure 7: Electricity generation in EU-27 in 2050 in the technology scenarios compared to the reference scenario[23]

Figure 8 shows the demand for electricty equivalents in 2050 in all technology scenarios and the reference scenario. This visulations includes electricity equivalent of hydrogen and methane imports from outside EU-27, as the corresponding amount of electricity must be produced elsewhere (non-EU-27).

[23] Gas composes fossil natural gas. In 2050, in the technology scenarios, fossil natural gas is completely phased out in the electricity sector.

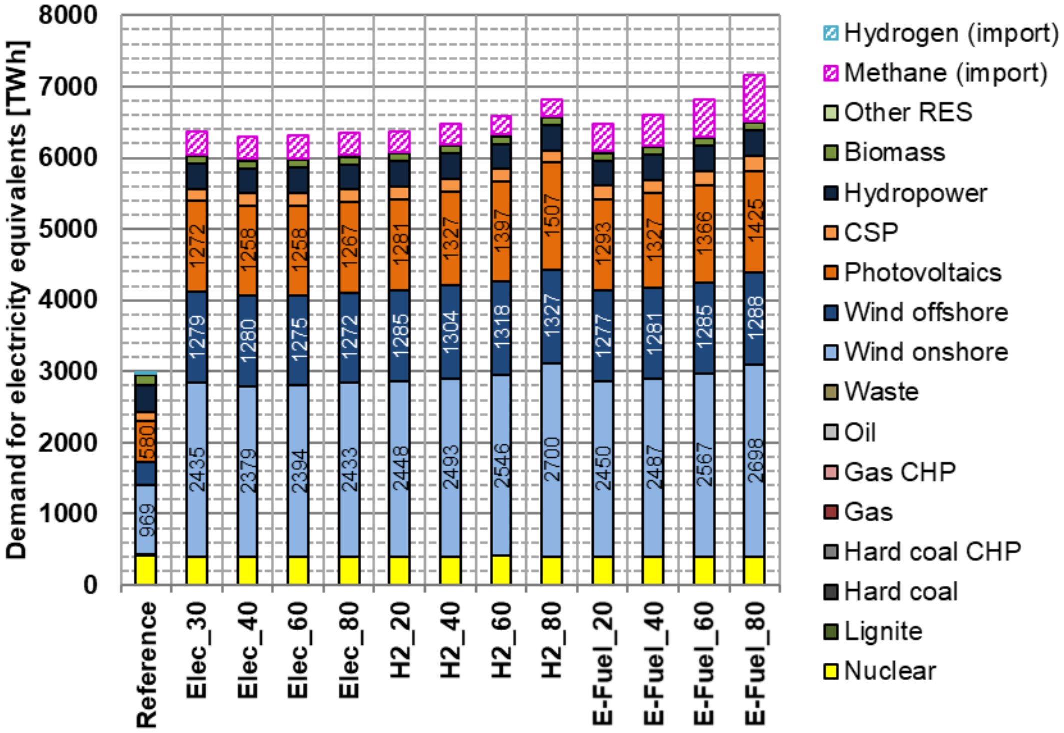

Figure 8: Demand for electricity equivalents in 2050 in the technology scenarios compared to the reference scenario[24]

Despite overall rather large variations in total electricity generation across the 12 technology scenarios, ranging from slightly over 6.200 to 6.700 TWh, the generation mix across all scenarios is fairly similar in terms of technology composition (see Figure 7). Regarding similarities, all scenarios consist of the dominant technology of onshore wind, followed by photovoltaics and offshore wind. Taken together, these three technologies provide the vast majority of the electricity in the system, due to their high resource availability throughout the EU-27 and comparatively low price in terms of LCOE[25]. The electricity system is furthermore complemented by flexible renewable energy technologies: Hydropower, Concentrated Solar Power (CSP) and biomass. The former two depend on adequate geographical conditions (i.e., land with little slope in the case of CSP), and the latter depends on physical resource input. The three technologies have higher cost in terms of LCOE, but, as flexible renewable energy technologies, they are capable of providing important generation-shifting[26] and balancing services, explaining their lesser (but still very important) presence in the electricity generation mix. Lastly, nuclear power in some European countries complements that mix[27]. Furthermore, Figure 8 shows that in all scenarios imports in the form of synthetic methane from outside Europe, add an important part of renewable electricity that needs to be generated.[28]

[24] Displayed is the electricity generation (solid colours) as well as the electricity equivalent of hydrogen and methane imports from outside the EU-27 (dotted colours. The conversion factors assumed are 0.7 for hydrogen and 0.5 for synthetic methane.

[25] Levelized cost of electricity

[26] The generation of power does not strictly depend on weather conditions, i.e., CSP can shift electricity production to times without sunshine due to its storage capabilities.

[27] The capacities of nuclear power are fixed according to national strategies (i.e. phase-outs) of the MS. Thus, for many MS this capacity (actual or target) is zero. Enertile optimizes the generation based on fixed installed capacity freely.

[28] Note that Enertile models production of both hydrogen and synthetic methane in EU-27 with their generation cost (which is part of the model results). Alternatively, both energy carriers can be imported from outside of Europe at the following import cost: Hydrogen:

However, there are also very clear differences across the 12 technology scenarios. Two major and overlapping effects can be observed. Firstly, the H2 and E-Fuel scenarios require an overall larger amount of generated electricity than the Elec scenarios. This is due to the fact that energy conversion from electricity (electrons) towards hydrogen and hydrogen derivate such as e-fuels (molecules) is technologically not possible in a loss-less manner and the efficiency of the conversion ranges below one. As a result, for a set amount of hydrogen or e-fuels, a larger amount of electricity is required as input. Secondly, within the scenarios, the higher the penetration of a given energy carrier (hydrogen and e-fuels), the higher is the total amount of electricity that needs to be generated, and vice-versa. A partial exception to this effect are the Elec scenarios, in which the two intermediate penetration scenarios (Elec_40 and Elec_60) require an overall lower generation when compared to the outer scenarios. The reason for this "U type" shape lies in the electricity demand for heat generation (i.e., heat pumps and electric boilers) in combination with renovation rates (see also building stock results in section 3.1).

Across all scenarios, the lowest total electricity generation, including indirect generation through energy imports (see Figure 8), takes place in the Elec_40 and Elec_60 scenarios, whereas the highest overall generation takes place in the E-Fuel_80 and H2_80 scenarios. Imports are substantial in all scenarios, although to a larger extent in the E-Fuel scenarios than in the Elec and H2 scenarios With regards to the nature of those imports, the energy is exclusively imported in the form of synthetic methane. Hydrogen imports do not occur. This is so, because European hydrogen generation is indeed cost-competitive with other world regions such as MENA[29]. Despite lower generation cost in some regions outside Europe, caused by better renewable energy potential and thus lower LCOE, the additional transport costs to Europe exceed the savings in electricity, thus making that hydrogen more expensive than European hydrogen. Hydrogen plays only a very small role in the electricity sector, as the stabilizing and shifting services can be more cost-effectively realized by flexible renewable energy technologies (see above). In that sense, a large European electricity exchange in combination with an integration of flexible renewable energy technologies into the system avoids the integration of more costly backup technology (such as hydrogen backup) in the national electricity sectors, thus leading to an overall cheaper system.

With regards to individual electricity generation technologies within the mix, most of the variation in overall generation is realized by onshore wind and photovoltaic technology, and, although to a lesser extent, by offshore wind. This indicates that EU-27 does indeed possess adequate renewable energy resource potential; and that even more of that can be used if needed (with a natural limit). The untapped potential is not evenly distributed across all MS. Large southern states have huge photovoltaic, and also wind potential, in combination with high land availability. This is i.e., the case of Spain. Atlantic-neighbouring countries and northern countries have large potentials for offshore wind in their respective offshore wind zones, although that technology is not as abundantly implementable for obvious space restrictions.

In essence, all 12 technology scenarios are totally feasible from a resource perspective and reach GHG-neutrality as required. Those systems will vastly be "sun and wind based".

EUR 100 /MWh (2030), EUR 90 /MWh (2040), EUR 80 /MWh (2050); Synthetic methane: EUR 160 /MWh (2030), EUR 145 /MWh (2040), EUR 130 /MWh (2050). The modelling results show that all hydrogen demand in 2050 can be produced more cheaply in EU-27, and consequently no hydrogen import takes place. However, parts of the methane demands are covered by imports because import is cheaper than local production. Around 80% of the synthetic methane demand in 2050 across all technology scenarios is produced locally in EU-27. The remaining 20% of the methane demand is imported from outside of Europe (i.e., MENA region), because production is cheaper outside Europe (i.e., additional electricity capacities inside Europe would be more expensive).

[29] The production of hydrogen inside the EU-27 is explicitly modelled and can become part of the solution with corresponding installed capacities of electrolysers, their location, their operation and thus electricity input need, as well as the overall resulting cost of hydrogen on a year and country basis. Between countries, hydrogen can be traded freely. Alternatively to this endogenous solution, hydrogen can also be imported from outside the Europe at an ex-ante fixed price per year (2030, 2040 and 2050), consisting of hydrogen production cost and a transport supplement.

European electricity exchange (trade) eases national requirements for backup etc. technology, resulting in a cheaper overall system.

Figure 9 shows the installed capacities per technology in the power system of the EU-27 in 2050. All technology scenarios and the reference scenario are shown.

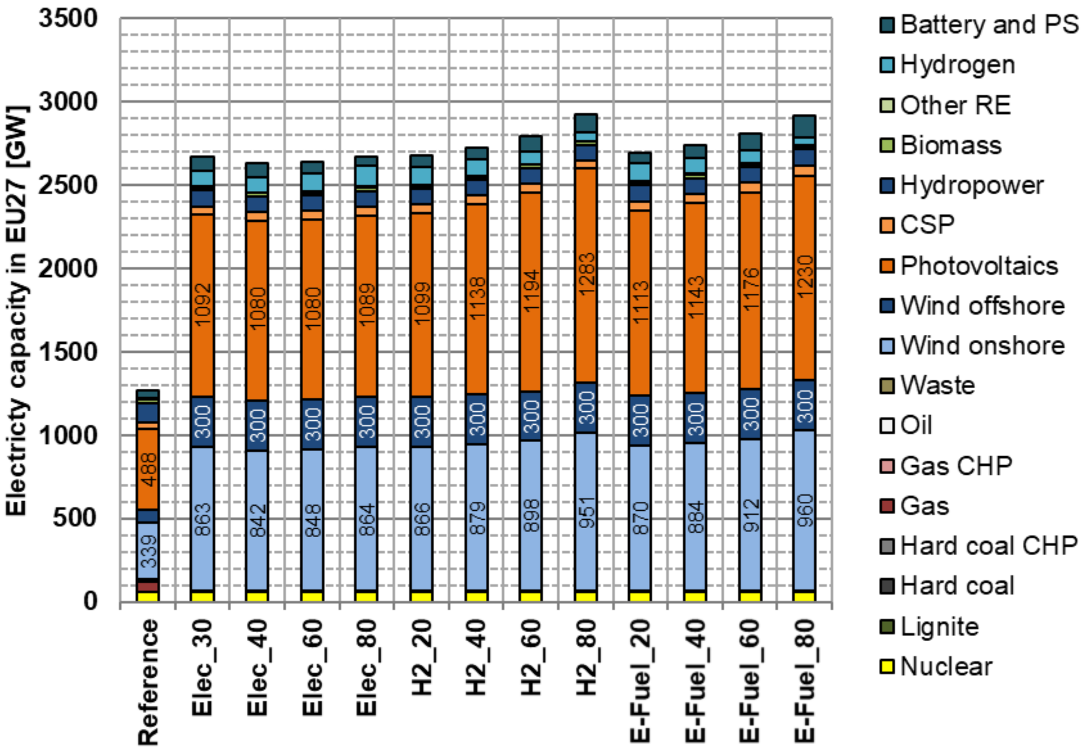

Figure 9: Electricity capacity in EU-27 in 2050 in the technology scenarios compared to the reference scenario

Similarly, to the generation, the capacities develop along a similar pattern across the technology scenarios and the penetration levels, i.e., the installed capacity of electricity generation technologies corresponds in all scenarios with the generation volumes. Overall capacities are largest in the E-Fuel and H2 scenarios, and lowest in the Elec scenarios. Regarding penetration levels, installed capacities are smaller in lower penetrations of hydrogen and e-fuels, respectively. The Elec scenarios again show the "U type" relationship between the penetration level of electricity in the district heating sector and the installed capacities in the power sector.

Unsurprisingly, the three dominating technologies in terms of generation also dominate the installed parks of renewable energy technologies, but also a major difference is observable. Solar photovoltaic accounts for the majority of the total installed capacity, followed by onshore wind. Offshore wind is the third-largest technology in terms of capacity. This slight shift with regards to generation is due to the fact that offshore wind has the highest full load hours, followed by onshore wind. Solar photovoltaic operates comparatively less, as it is only operational during daytime. Apart from nuclear, that remains present in the EU-27's park of installed capacities in the electricity sector, the renewable technologies of biomass, hydropower and CSP assume a stabilizing role in the electricity generation in all scenarios. In the same vein, hydrogen (as a new and currently not present technology) enters the system with a relevant share of installed capacity in all scenarios by 2050. Thereby, the share is highest in the electrification scenarios followed by the low-penetration scenarios of both the hydrogen and e-fuels scenarios, and it is least in the high-penetration hydrogen and e-fuels scenarios. In all scenarios, hydrogen provides electricity generation when other backup technologies cannot assume this role, hence its comparatively rather large installed capacity in 2050.[30] The role of hydrogen is further described in the subsequent sections on dispatch analyses.

In essence, in order to reach a decarbonised electricity system in 2050, it seems absolutely necessary to expand onshore wind, solar photovoltaics and offshore wind. Additionally, policy attention may focus to flexible renewable energy technologies that are also necessary, but to a lesser extent, to stabilize a fluctuating renewables-dominated system, i.e., through the adequate expansion of CSP. Hydropower and biomass may be complementary in this regard. Apart from these flexible RES, hydrogen provides an important backup role to the electricity system. Furthermore, facilitating electricity exchange with infrastructure in the EU-27 can be a complementary aspect worth highlighting (see also the following section on networks).

In the following, an additional dispatch analysis is provided (see Figure 10). As outlined above, renewable energy is generated, exchanged and consumed cross-regional throughout the EU-27. It is therefore of interest to analyse individual energy systems to better understand how system balancing is achieved and the electricity / heat demand is adequately covered in a situation where the dominant energy sources are fluctuating RES. As this is an extensive task for the high spatial and temporal resolution of those systems, an overview will be provided consisting of an exemplary country. For this example, Germany was chosen, as it is the major energy generator and consumer, and for its geographically central place in the EU as well as it's -in some cases- challenging renewable resource potentials. Furthermore, an exemplary summer week, i.e., calendar week 24, was chosen, as it is challenging for its absence of wind. In addition, an exemplary winter week, i.e., calendar week 5, was chosen for its quick changes in the availability of wind combined with high demands for heating etc. due to very cold temperatures. The analysis is performed for the Elec_30, Elec_80, H2_60 and E-Fuel_60 scenarios.[31]

The dispatch analysis allows to infer some insights. First and foremost, the scenario comparison across Elec, H2 and E-Fuel scenarios shows that these are relatively similar at a given point in time (i.e., winter or summer, respectively), but also some differences emerge. The electricity demand in Germany can independently of the scenario both in winter and in summer only be met by substantial electricity imports; in winter at all times but especially to complement the low domestic photovoltaic generation around noon, in summer especially at night without photovoltaic generation. Hydrogen has a backup function at very challenging times; both in winter and summer at night with low domestic and European wind generation (the effect is more pronounced in winter and only minimal in summer).

With regards to heating, heat pumps in houses and district heat grids expectedly play only a minor role in the exemplary summer week. Their demand pattern concurs with domestic photovoltaic generation. In the exemplary winter week, this picture changes. The overall demand grows strongly and covers all 24 hours of the day, with the slight exception of a few of the very early morning hours. Large-scale heat pumps in district heat grids enter first and are complemented by heat pumps in houses around the middle of the week in all scenarios. In the exemplary weeks, in the Elec_30 scenario the relative share of heat pumps in houses (decentral heat provision) is higher when compared to Elec_80 (where the relative share of central heat is higher). The overall heat demands in heat grids is higher in the Elec scenarios when compared to the H2 and E-Fuel scenarios. Also, in the latter two when compared to the Elec scenarios, the relative share of decentral heat generation increases slightly but notably

[30] Compared both inter-technology-wise to other flexible renewable electricity generation technologies (i.e., CSP) as well as intra-technology-wise (generation and installed capacity of hydrogen). The latter comparison indicates a peak role for hydrogen-based electricity generation.

[31] The decision for these scenarios was based on the idea to provide an overview of two extremes of a scenarios (hence the Elec_30 and Elec_80 scenarios), and to provide an adequate overview of the hydrogen world (hence the H2_60 scenario) and the e-fuels world (hence the E-fuel_60 scenario), under the consideration of the high complexity of such an analysis (hence restricting it to 4 scenarios in two exemplary weeks, 8 in total).

(but not in absolute terms) when compared to central heat generation. The scenarios are thus not only different with regards to primary energy carriers used for space and water heating, but also in how this heat is provided (central versus decentral).

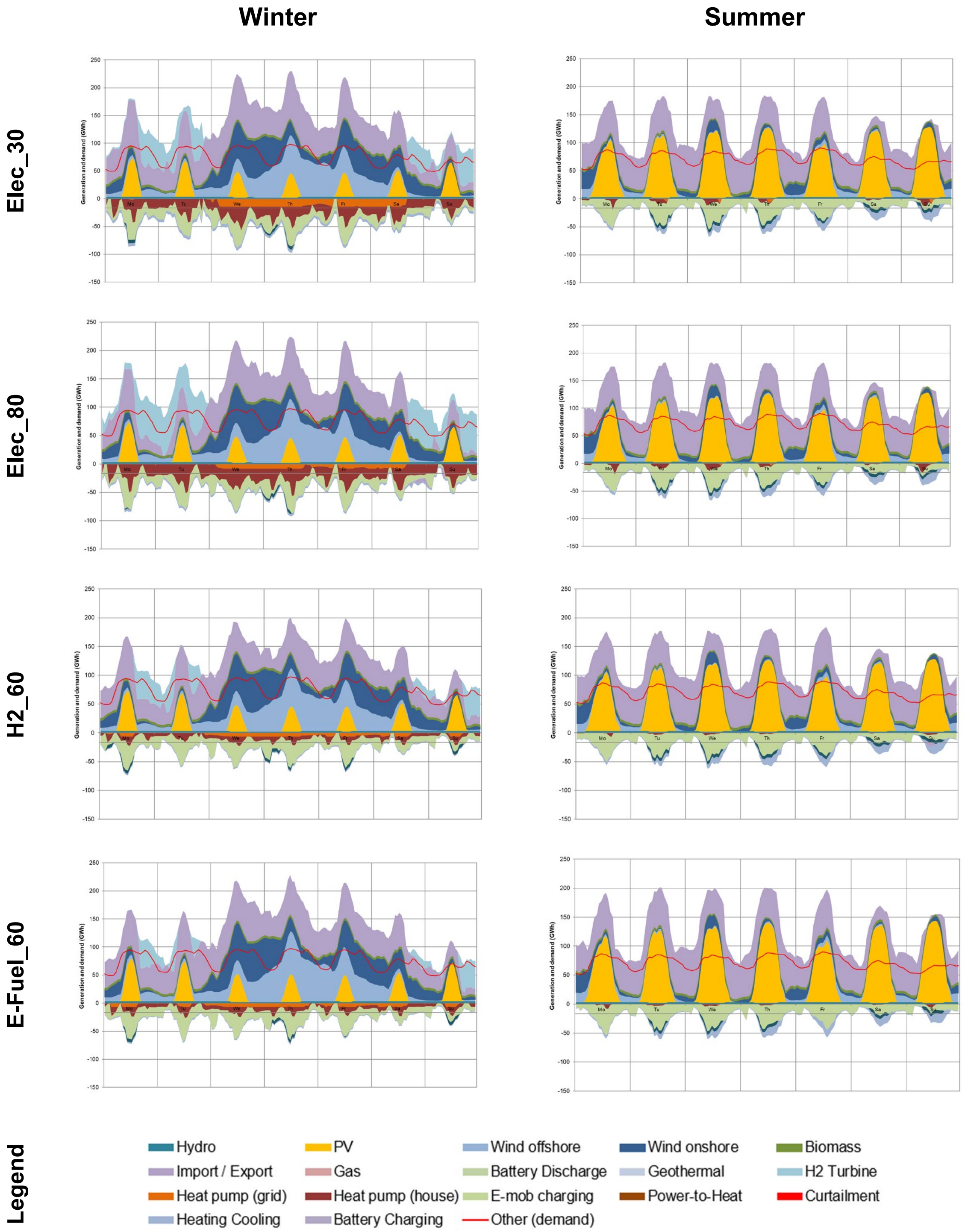

Figure 10: Dispatch analysis in the power sector (Germany, CW 5 and CW 24 in 2050)

District heating sector

In the following, the results of the technology scenarios for district heating are presented. Figure 11 shows the heat generation in the district heat grids in the EU-27 in 2050 for all technology scenarios and the reference scenario. In the district heat optimisation, the amount of heat provided from district heat grids is taken as an input from the results of the building stock model (cf. section 3.1). Optimised in Enertile is, however, the technology mix for the given amount for district heat.

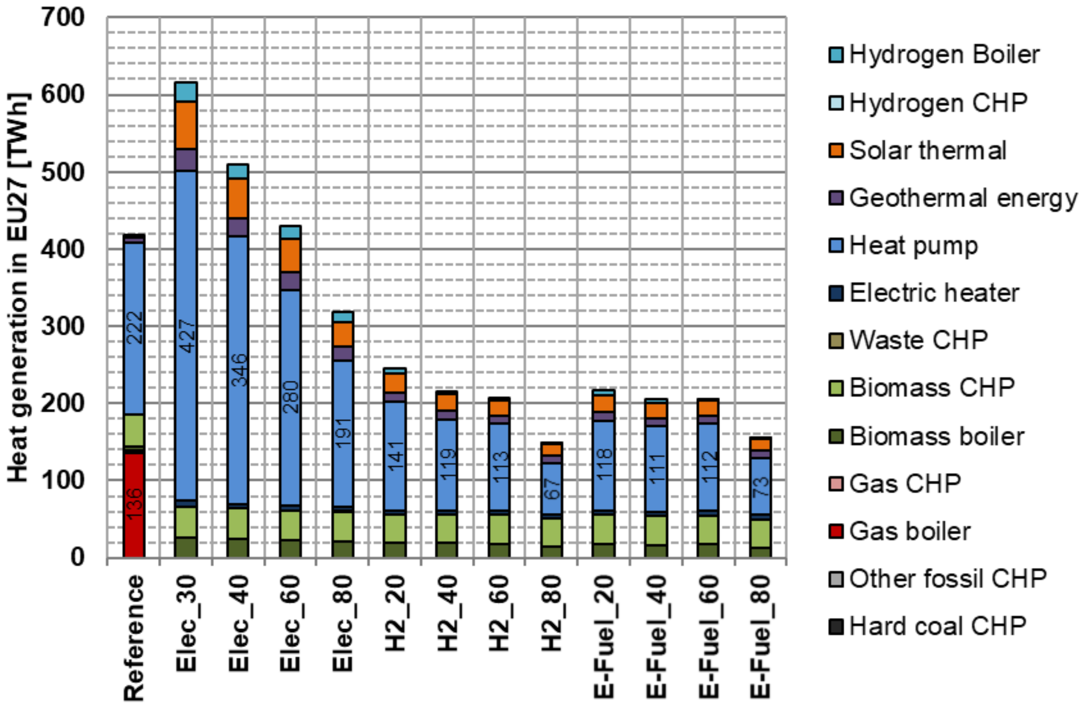

Figure 11: District heat generation in EU-27 in 2050 in the technology scenarios compared to the reference scenario[32]

All technology scenarios have in common that there is a phase-out of fossil fuels in the district heating generation mix. However, there are significant variations in the total district heat generation across the scenarios: The highest share of district heating and thus the highest generation is reached in the Elec_30 scenario with slightly over 600 TWh; The lowest share of district heating and thus the lowest generation occurs in the H2_80 scenario (around 140 TWh), followed by the E-Fuel_80 (around 160 TWh) scenario. This variation is based on the optimisations in Invert, i.e., the modelling of the building stock (see section 3.1).

What becomes clear is that the higher the penetration rate of a given energy carrier (electricity, hydrogen, or e-fuels), the lower heat generation and provision through heat grids, i.e., an increase in the penetration rate causes more decentralized heat generation, as per scenario definitions. This has direct effects on the technology composition of heat generation in the district heating grids: Heat pumps clearly become the dominating renewable technology in the district heating generation mix by 2050, accounting on average for over half of the generation in the EU-27 and up to 80% in certain scenarios. Furthermore, heat pumps cover most of the variations between the scenarios (i.e., the increase in overall heat generation between the scenarios are almost entirely provided by additional heat pumps). Biomass (both boiler and CHP), solar thermal and geothermal complement the system. Finally, hydrogen enters the

[32] Gas composes fossil natural gas. In 2050, in the technology scenarios, fossil natural gas is completely phased out in the district heating sector.

district heat grids in 2050. Thereby, hydrogen boilers are included on a small scale as a backup technology.

Heat pumps can provide the majority of the heat in the district heat grids, together with complementary heat generation technologies, even if the total district heat demand strongly rises as in the Elec_30 scenario. Thus, heat pumps can cover any additional demands, highlighting their relevance for district heating.[33]

Figure 12 shows the heat capacities in the district heat grids in the EU-27 in 2050 for all technology scenarios and the reference scenario.

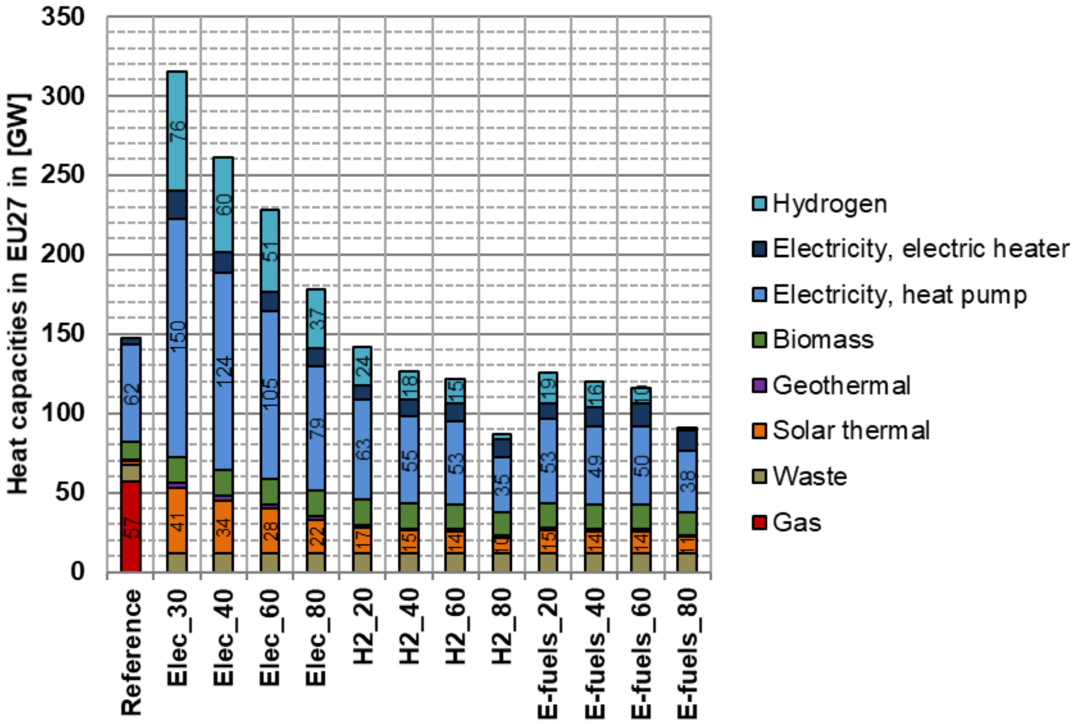

Figure 12: District heat capacities in EU-27 in 2050 in the technology scenarios compared to the reference scenario

The installed capacity of district heat generation technologies corresponds in all scenarios with the generation volumes. In line with the generation, heat pumps clearly dominate the generation park in 2050 in the EU-27. Hydrogen reaches rather high capacities, even though the generation is low, clearly indicating its backup role for district heating. Other renewables technologies, such as solar and biomass also have a relevant share.

In the following, a dispatch analysis of the district heat sector is provided (see Figure 13). The same country, calendar weeks and scenarios as in the dispatch analysis of the electricity system were chosen (i.e., Germany, CW4 and CW24, and the Elec_30, Elec_80, H2_60 and E-Fuel_60 scenarios).

---

[33] Heat pumps will play a dominant role in future district heating grids. In specific local contexts, other sources such as industrial waste heat or waste to energy will most likely play a decisive role. Due to the limitations of the Enertile modelling, such technologies or district heating types are not reflected.

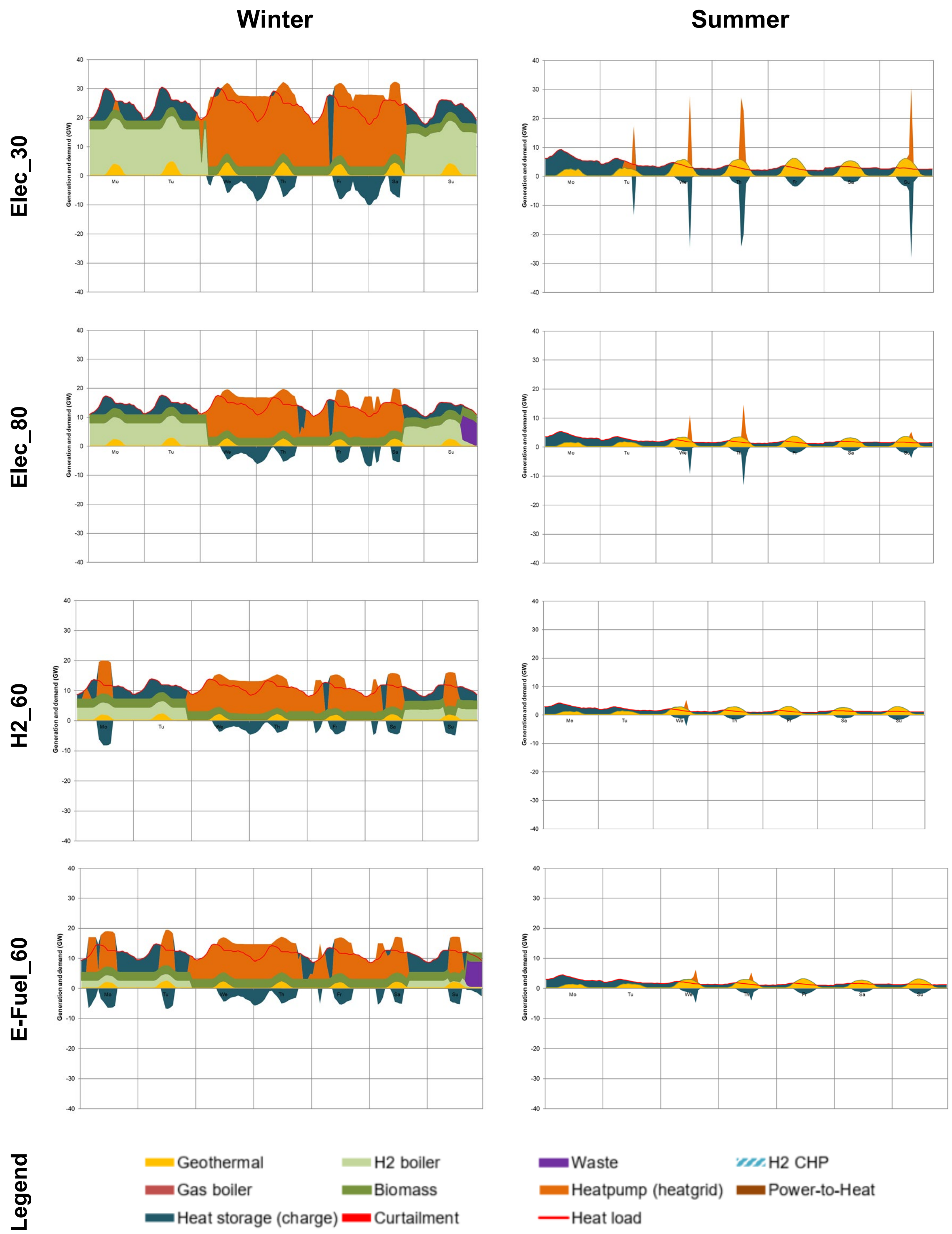

Figure 13: Dispatch analysis in the district heat sector (Germany, CW 5 and CW 24 in 2050)

The district heating sector is especially affected by the yearly seasons, which is why there are naturally great differences between the winter and summer weeks. In summer, heat demand in the district heating grids is low, and dominated by solar thermal and geothermal as well as heat pumps. During daytime, solar thermal and geothermal are not capable of meeting the total demand, except around noon where it even surpasses the demand in most days. At these times, they charge up the heat storages. Additionally, heat pumps take up a very large amount of electricity from photovoltaic generation at and shortly after noon. This electricity is entirely used to fill up the heat storages (it prevails curtailment). Heat storages are later discharged for heat provision at night-time and in days with low sun and wind. This picture is homogeneous across all scenarios, but some slight differences are also observable: The heat pump peaks (corresponding to photovoltaic electricity generation) are much less pronounced in higher penetration scenarios (i.e., the 80% scenarios) when compared to the lower penetration ones. Also, the peaks are less pronounced in the H2 and E-Fuel scenarios than in the Elec scenarios. Both effects overlap and reinforce each other, leading overall to rather "flat and consistent" heat provision in district heating grids in the H2 and E-Fuel scenarios, whereas in the Elec scenarios, especially the lower penetration ones, the heat pump peaks are much more observable (and causing impact on district heat system design with regards to installed capacities, see above).

Furthermore, in winter, the heat demand in district heat grids is much higher and the dispatch differs clearly from summer. Most importantly, the patterns of heat generation changes profoundly, when compared to summer, and in all scenarios. Heat pumps have a steadier generation profile, indicating their operation at maximum capacity over longer periods of time. This is especially the case in the middle and towards the end of the winter week, where renewable electricity is abundantly available from the electricity sector due to the resource potentials at that time (see above). During those times, heat pumps account for almost all heat generation, and the slight excess generation is used to fill up heat storage, which, in turn, is discharged mostly in the late morning hours (every day) and during times of low sun and wind availability (beginning and end of the week). Solar thermal and geothermal contributes mostly around noon, but only on a very small scale. Other technologies enter heat generation to supply the demand: Hydrogen boilers provide heat at challenging times (i.e., low availability of electricity due to low sun and wind, which is especially observable at the beginning and end of the winter week) in a relevant amount. The system stabilization role of hydrogen boilers in the district heat grids is thus essential. Biomass also contributes to heat generation in winter, although much less than hydrogen boilers and heat pumps, and operates mostly in a stable manner around its maximum capacity. At certain points in time, waste incineration also contributes to heat generation in district heat grids.

With regards to differences within the scenarios, the differing overall centralized heat demand, provided through district heat grids, has obvious impacts: the higher the decentralized heat generation, the lower the heat generation in the district heat grids which, correspondingly, reduces the individual technologies' contribution more or less equally, with the exception of heat pumps. This technology operates, when it can, at its maximum. It is thus a robust conclusion that heat pumps are essential in district heat grids. The same accounts for heat storages that are mostly filled by heat pumps. The role of hydrogen boilers is largest in the Elec scenarios and lowest in the e-fuels scenarios. Its share is also higher in the lower penetration scenarios, where more heat is provided centrally.

Generally, some overall insights can be generated from the dispatch analysis. The larger the central heat provision, the more important the role for heat pumps and heat storage in the district heating grids. System-stabilization by hydrogen boilers and (partly) biomass are complementary actions. In summary, the district heat systems do not vary that much between scenarios in terms of technology mix; they rather vary in terms of volume and precise technology shares.

System costs

The following section presents the annual system costs of the power and district heating sector with Figure 14 visualising the system costs for the EU-27 in the view of all technologies scenarios in 2050. Thereby, the reference scenario serves as a baseline. The costs shown, thus, correspond to the respective difference to the reference scenario. The data shown can thus be interpreted as an indication of additional system cost that is necessary to reach GHG-neutrality through one of the technology scenarios. Note that this is not a full system cost analysis, as only system costs of the power and district heat system are presented. A full system cost analysis, including all modelling results, is presented in section 4.

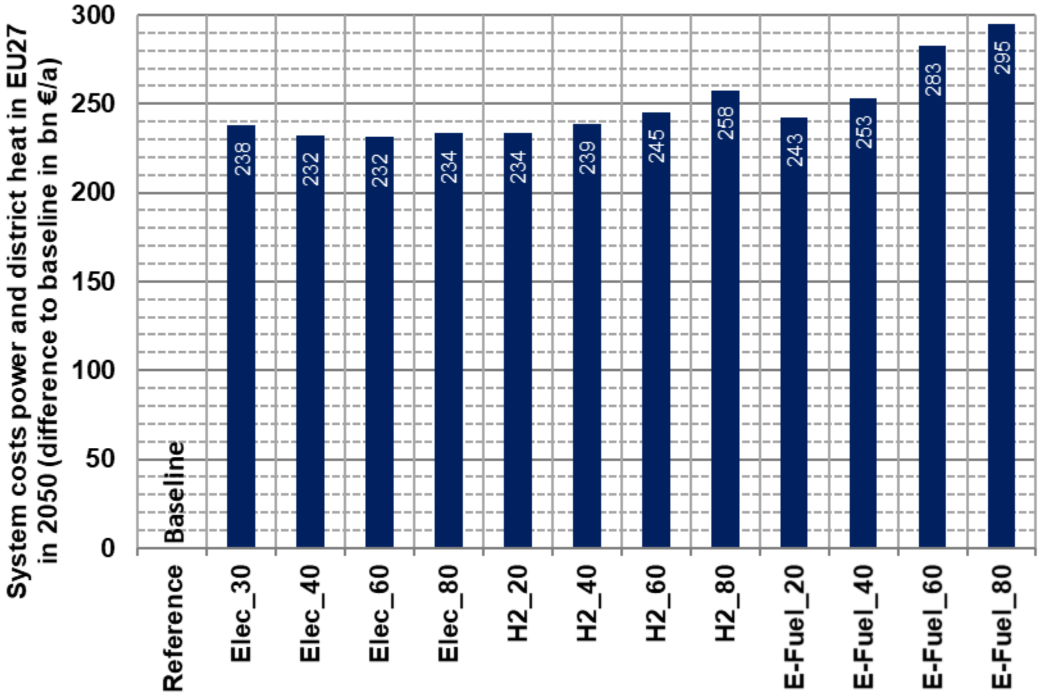

Figure 14: System cost power and district heat sector for EU-27 in 2050 (reference scenario as baseline)

The system costs include capital expenditures, operation, and maintenance costs as well as variable energy costs for the EU-27 power and district heat generation. Infrastructure costs for electricity and district heat grids are not included. Similar to the generation, the costs develop along a comparable pattern across the technology scenarios and the penetration levels. Hence, the costs correlate in all scenarios with the generation volumes. Overall system costs are lowest in the Elec_40 and Elec_60 scenarios (it is very (cost-)efficient to directly use electricity) and largest in the E-Fuel_80 and E-Fuel_60 scenario (where energy carrier conversion losses occur). The H2_80 shows also rather high costs. The electricity scenarios again show the "U type". Furthermore, the H2_20 scenario achieves the same cost level as the Elec_80 scenario.

Investments and support expenditures for RES in the electricity sector

Complementary to the above, this section informs on future developments in RES-related investments and support expenditures in accordance with the modelled future RES deployment. The results are derived from dedicated modelling done by use of the Green-X model and build, concerning energetic trends (i.e. electricity generation from RES), on the outcomes of the power system analysis done by use of the Enertile model as discussed above.

<u>RES investments</u>

Figure 15, Figure 16 and Table 11 inform on the outcomes of the analysis undertaken concerning required RES-investments according to assessed scenarios. More precisely, these graphs and the corresponding table compare yearly investments in RES technologies at EU-27 level for all scenarios under consideration, broken down by technology for the overall period 2021 to 2050 (cf. Figure 16 and Table 11) and by decade (i.e. 2021-2030, 2031-2040 and 2041-2050) for the total of RES-related investments in the electricity sector (cf. Figure 15 and

Table 11). This allows for identifying technology-specifics trends as well as underlying dynamics.

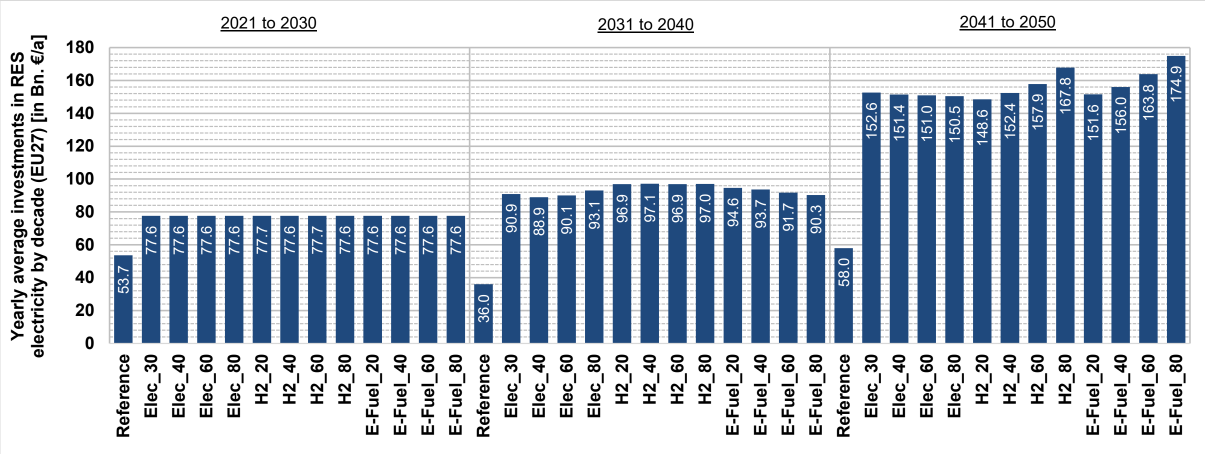

Figure 15: Yearly average investments in RES-electricity at EU-27 level broken down by decade (2021-2030, 2031-2040, 2041-2050) according to assessed scenarios (Source: Green-X and Enertile modelling)

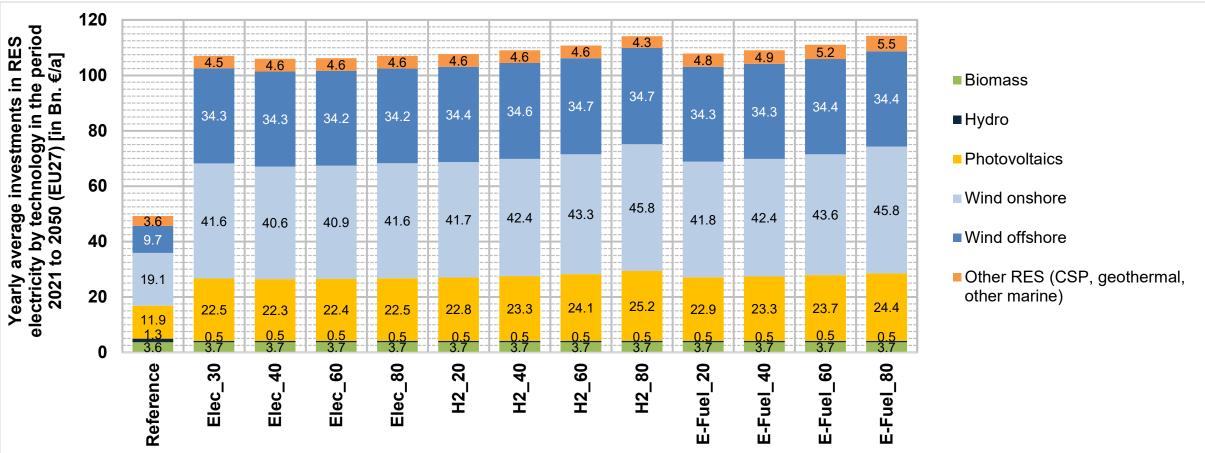

Figure 16: Yearly average technology-specific investments in RES-electricity at EU-27 level in the period 2021 to 2050 according to assessed scenarios (Source: Green-X and Enertile modelling)

In the reference scenario total RES investments are significantly lower compared to all assessed decarbonisation scenarios. The difference is smallest within this decade (2021 to 2030), with RES-related investments at € 53.7 bn in the reference scenario and at € 77.6-77.7 within all other scenarios. Driven by the underlying decarbonisation objective, the difference between the reference and all other scenarios is increasing significantly in forthcoming decades. Then RES-related investments in the reference scenarios amount to only about one third of the volumes invested in all other scenarios. In accordance with underlying deployment trends, onshore wind, solar PV and offshore wind account for the largest part of these investments in the reference scenario, followed – at a significantly lower amount - by biomass, other RES (including CSP, geothermal and other marine technologies) and hydropower.

In the decarbonisation scenarios with varying underlying technology-specific deployment targets for the heat sector decarbonisation and electrification, respectively, a different trend is observable compared to reference: here RES investments increase over time, and also the technology-specific distribution changes. In total, RES investments increase from € 77.6-77.7 bn (2021-2030) to € 88.9-97.1 bn (2031-2040) and finally peak at € 148.6-174.9 bn (2041-2050). During the first decade solar PV holds the largest share in total RES investments whereas in the subsequent decade onshore wind takes over. In the final decade, when onshore sites are already utilized, offshore wind takes over and accounts for the majority of RES-related investments. Those trends are common across all technology scenarios but differences are observable between individual scenarios as discussed below:

- In overall terms, investment needs differ only to a comparatively small extent across assessed technology scenarios: yearly average (2021-2050) total RES investments vary between € 106.0 bn and € 114.3 bn. The lower range refers to scenarios with moderate technology targets, e.g. a targeted direct electrification share between 30% and 60% (Elec_30, Elec_40, Elec_60), or a targeted hydrogen or e-fuel share of 20% (H2_20, E-Fuel_20). The upper range refers to extreme cases from today's perspective – i.e. the scenarios that aim for a hydrogen or e-fuel share of 80% (H2_80, E-Fuel_80).
- A comparison of observed trends under all technology scenarios (where full decarbonisation is presumed) points out that the underlying RES ambition, i.e. the generated electricity from RES, determines the investment needs. This is getting apparent from Table 11 which, in addition to RES investments, also informs on trends in electricity generation from RES.
- Apart from the underling RES ambition, also assumed technological progress influences future investment needs. Here moderate assumptions for future cost developments of the various RES technologies have been applied, in accordance with historic trends and related topical studies.
- The technology selection also has an impact but is influenced by the RES ambition due to limits in resource availability e.g. for onshore wind. For example, offshore wind requires 1.5 to 3 times higher investments than onshore or solar PV.

Table 11: Comparison of the underlying RES ambition and of corresponding RES-related investments at EU-27 level according to assessed scenarios (Source: Green-X and Enertile modelling)

Scenario comparison	[Unit]	Reference	Elec_30	Elec_40	Elec_60	Elec_80	H2_20	H2_40	H2_60	H2_80	E-Fuel_20	E-Fuel_40	E-Fuel_60	E-Fuel_80
2050 RES ambition (i.e. electicity generation from RES) in comparison to Reference	%	100%	223%	220%	221%	223%	224%	229%	234%	244%	225%	228%	233%	241%
Indicators on RES-related investment needs (at EU27 level)														
Average yearly investments (21-30)														
Biomass	Billion €	1.1	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Hydro	Billion €	2.8	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Photovoltaics	Billion €	14.6	26.7	26.7	26.7	26.7	26.7	26.7	26.7	26.7	26.7	26.7	26.7	26.7
Wind onshore	Billion €	20.4	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3	21.3
Wind offshore	Billion €	14.6	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Other RES (CSP, geothermal, other marine)	Billion €	0.2	1.3	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.2	1.2	1.2	1.2
RES-E total	Billion €	53.7	77.6	77.6	77.6	77.6	77.7	77.7	77.7	77.6	77.6	77.6	77.6	77.6
Average yearly investments (31-40)														
Biomass	Billion €	4.1	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Hydro	Billion €	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Photovoltaics	Billion €	8.1	17.6	17.1	17.6	18.2	19.7	19.8	19.5	19.6	18.9	18.6	18.1	17.9
Wind onshore	Billion €	15.0	64.2	62.6	63.4	65.9	68.4	68.6	68.6	68.4	66.3	65.4	63.9	62.4
Wind offshore	Billion €	5.8	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Other RES (CSP, geothermal, other marine)	Billion €	2.6	2.6	2.7	2.6	2.5	2.2	2.2	2.3	2.4	3.0	3.1	3.3	3.5
RES-E total	Billion €	36.0	90.9	88.9	90.1	93.1	96.9	97.1	96.9	97.0	94.6	93.7	91.7	90.3
Average yearly investments (41-50)														
Biomass	Billion €	5.7	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Hydro	Billion €	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Photovoltaics	Billion €	13.1	23.3	23.1	22.8	22.7	22.1	23.6	26.0	29.4	23.2	24.6	26.4	28.6
Wind onshore	Billion €	21.8	39.2	38.0	38.0	37.6	35.5	37.2	39.9	47.7	37.9	40.5	45.7	53.6
Wind offshore	Billion €	8.9	75.9	75.9	75.7	75.6	76.1	76.7	77.1	77.1	75.8	76.0	76.1	76.2
Other RES (CSP, geothermal, other marine)	Billion €	7.9	9.7	9.8	9.8	10.0	10.4	10.3	10.2	9.1	10.1	10.4	11.0	11.8
RES-E total	Billion €	58.0	152.6	151.4	151.0	150.5	148.6	152.4	157.9	167.8	151.6	156.0	163.8	174.9
Average yearly investments in the period 2021 to 2050														
Biomass	Billion €	**3.6**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**
Hydro	Billion €	**1.3**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
Photovoltaics	Billion €	**11.9**	**22.5**	**22.3**	**22.4**	**22.5**	**22.8**	**23.3**	**24.1**	**25.2**	**22.9**	**23.3**	**23.7**	**24.4**
Wind onshore	Billion €	**19.1**	**41.6**	**40.6**	**40.9**	**41.6**	**41.7**	**42.4**	**43.3**	**45.8**	**41.8**	**42.4**	**43.6**	**45.8**
Wind offshore	Billion €	**9.7**	**34.3**	**34.3**	**34.2**	**34.2**	**34.4**	**34.6**	**34.7**	**34.7**	**34.3**	**34.3**	**34.4**	**34.4**
Other RES (CSP, geothermal, other marine)	Billion €	**3.6**	**4.5**	**4.6**	**4.6**	**4.6**	**4.6**	**4.6**	**4.6**	**4.3**	**4.8**	**4.9**	**5.2**	**5.5**
RES-E total	Billion €	**49.2**	**107.1**	**106.0**	**106.2**	**107.1**	**107.7**	**109.0**	**110.8**	**114.2**	**107.9**	**109.1**	**111.0**	**114.3**

Results on RES support expenditures

In a similar way as presented for RES investments, Table 12 informs on the outcomes of the analysis undertaken concerning required RES-related support expenditures according to the reference scenario. RES support is here defined as the direct financial transfer to the RES producer to cover the gap between financing needs and market revenues. Complementary to the table, a graphical illustration of modelled future trends is provided by Figure 17 and Figure 18. More precisely, these graphs and the corresponding table compare yearly support expenditures for RES at EU-27 level for all scenarios under consideration, broken down by decade (i.e. 2021-2030, 2031-2040 and 2041-2050) (cf. Figure 17 and Table 12) and by technology for the overall period 2021 to 2050 (cf. Figure 18 and Table 12) for the total of RES-related support expenditures in the electricity sector. Please note that, in contrast to RES investments in new generation assets, also the existing stock of RES installations (installed until 2020) is included in this depiction and, as proven by other analyses, accounts for the majority of the total, specifically within this decade.

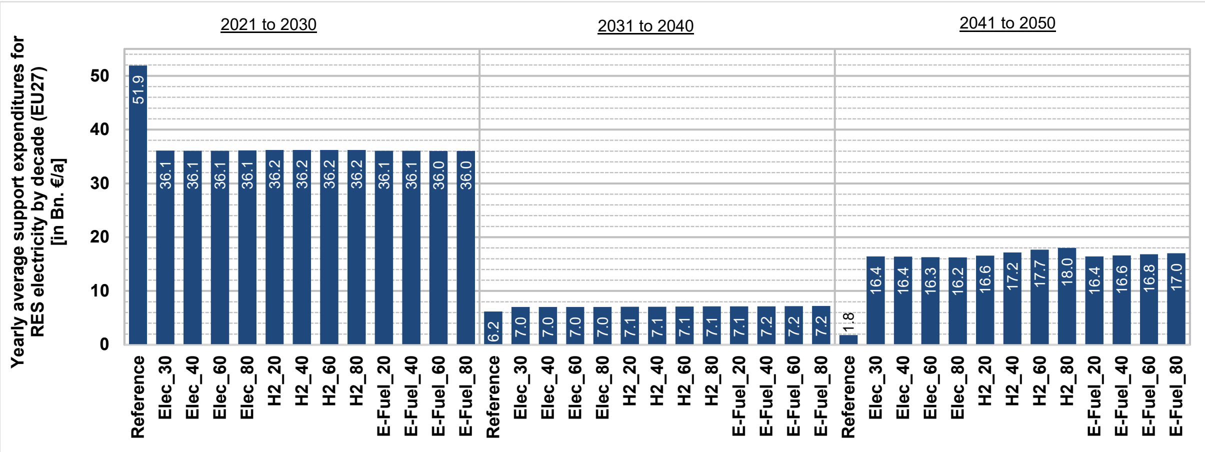

Figure 17: Yearly average support expenditures RES-electricity at EU-27 level broken down by decade (2021-2030, 2031-2040, 2041-2050) according to assessed scenarios (Source: Green-X and Enertile modelling)

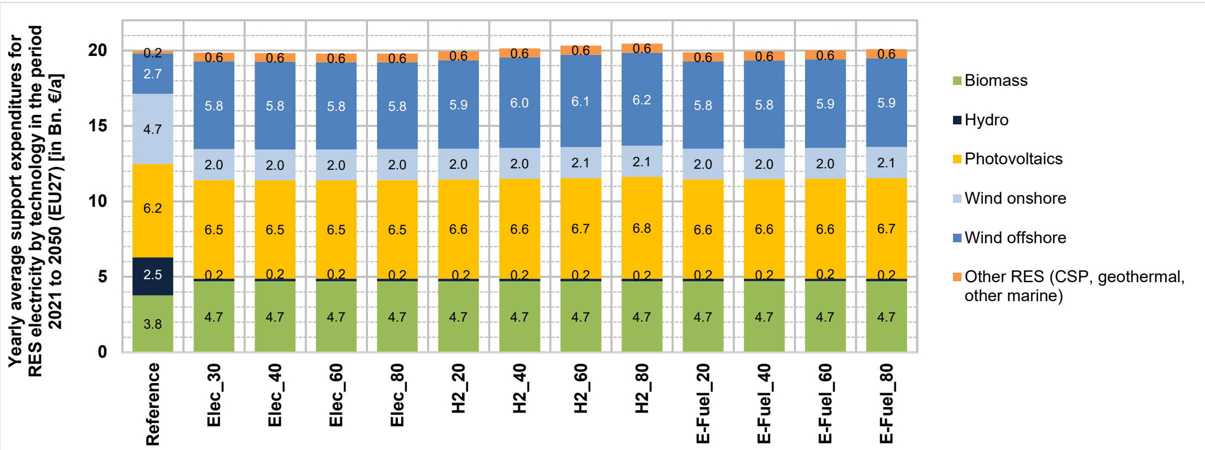

Figure 18: Yearly average technology-specific support expenditures for RES-electricity at EU-27 level in the period 2021 to 2050 according to assessed scenarios (Source: Green-X and Enertile modelling)

In the reference scenario total RES support expenditures peak within this decade (2021 to 2030) at € 51.9 bn. Later on, a strong decline is observable, down to € 6.2 bn. In the next decade (2031-2040), and to € 1.8 bn. Within the final decade (2041-2050). Reason for that strong decline is the phase-out of (generation based) support for the existing stock of RES power plants during this and the forthcoming decade. Differences in support cost between the various RES technologies are observable. As a general pattern, one can observe that biomass, marine technologies (incl. offshore wind) come at higher generation cost (LCOE) than solar

PV or onshore wind. In terms of support cost, the differences are even stronger since then, metaphorically speaking, market revenues are subtracted from LCOE which increases the cost spread.

In the technology scenarios (with presumed full decarbonisation) overall RES-related support is on average across the whole assessment period similar in magnitude compared to reference – despite the large differences in overall RES deployment by 2050. This is mainly caused by different trend assumptions concerning carbon prices within this decade when comparing reference with all other technology scenarios (cf. section 3.2). Lower wholesale prices as applicable in the reference scenario lead to higher RES support that comes in addition to market revenues for a RES producer. Another important aspect is the increasing competitiveness of renewables – i.e. new RES installations come a significantly lower cost thanks to technological learning and advancements in operation practices. Apart from overall support volumes also a different dynamic trend is observable when comparing the reference scenario with all technology scenarios (that presume full decarbonisation in contrast to reference): in the technology scenarios RES investments first decline from € 36.0-36.2 bn (2021-2030) to € 7.0-7.2 bn (2031-2040) but, later on, in the final decade (2041-2050) increase again, reaching € 16.2-18.0 bn per year on average throughout that period in time. During the first decade solar PV holds the largest share in total RES support cost whereas in later years offshore wind takes over. Those trends are common across all technology scenarios but differences are applicable between individual scenarios as discussed below:

- In overall terms, only minor differences in support expenditures are applicable across assessed technology scenarios: yearly average (2021-2050) total RES support costs vary between € 19.8 bn and € 20.3 bn. The lower range refers to scenarios aiming for direct electrification, more or less independent which deployment share is envisaged, and for other technology fields to scenarios with moderate technology targets, e.g. a targeted hydrogen or e-fuel share of 20% (H2_20, E-Fuel_20). The upper range comprises extreme cases from today's perspective – i.e. the scenarios that aim for a hydrogen or e-fuel share of 60% or 80% (H2_60, H2_80, E-Fuel_60, E-Fuel_80).

- Similar to RES investments, the comparison of observed trends under both scenarios points out that the underlying RES ambition, i.e. the generated electricity from RES, determines the trends in support expenditures. This is getting apparent from Table 12 which, in addition to RES support, also informs on trends in electricity generation from RES.

- The technology selection also has an impact on RES-related support cost – but, as stated above, is influenced by the RES ambition due to limits in resource availability e.g. for onshore wind. For example, offshore wind requires 3 to 4 times higher RES support than onshore or solar PV.

Table 12: Comparison of the underlying RES ambition and of corresponding RES-related support expenditures at EU-27 level according to assessed scenarios (Source: Green-X and Enertile modelling)

Scenario comparison	[Unit]	Reference	Elec_30	Elec_40	Elec_60	Elec_80	H2_20	H2_40	H2_60	H2_80	E-Fuel_20	E-Fuel_40	E-Fuel_60	E-Fuel_80
2050 RES ambition (i.e. electicity generation from RES) in comparison to Reference	%	100%	223%	220%	221%	223%	224%	229%	234%	244%	225%	228%	233%	241%
Indicators on support expenditures for RES (at EU27 level)														
Average yearly support expenditures (21-30)														
Biomass	Billion €	7.6	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Hydro	Billion €	7.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Photovoltaics	Billion €	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Wind onshore	Billion €	12.7	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Wind offshore	Billion €	7.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Other RES (CSP, geothermal, other marine)	Billion €	0.1	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.2
RES-E total	Billion €	51.9	36.1	36.1	36.1	36.1	36.2	36.2	36.2	36.2	36.1	36.1	36.0	36.0
Average yearly support expenditures (31-40)														
Biomass	Billion €	2.2	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Hydro	Billion €	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Photovoltaics	Billion €	1.8	1.8	1.7	1.8	1.8	1.8	1.9	1.8	1.8	1.8	1.8	1.8	1.8
Wind onshore	Billion €	1.2	0.7	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.6	0.6	0.6	0.6
Wind offshore	Billion €	0.5	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Other RES (CSP, geothermal, other marine)	Billion €	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.4	0.4	0.5	0.5	0.5	0.6
RES-E total	Billion €	6.2	7.0	7.0	7.0	7.0	7.1	7.1	7.1	7.1	7.1	7.2	7.2	7.2
Average yearly support expenditures (41-50)														
Biomass	Billion €	1.6	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Hydro	Billion €	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Photovoltaics	Billion €	0.2	1.2	1.2	1.2	1.2	1.3	1.4	1.6	1.8	1.3	1.4	1.5	1.6
Wind onshore	Billion €	0.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Wind offshore	Billion €	0.0	11.8	11.8	11.7	11.6	11.9	12.4	12.7	12.8	11.7	11.8	11.9	12.0
Other RES (CSP, geothermal, other marine)	Billion €	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RES-E total	Billion €	1.8	16.4	16.4	16.3	16.2	16.6	17.2	17.7	18.0	16.4	16.6	16.8	17.0
Average yearly support expenditures in the period 2021 to 2050														
Biomass	Billion €	**3.8**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**	**4.7**
Hydro	Billion €	**2.5**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**
Photovoltaics	Billion €	**6.2**	**6.5**	**6.5**	**6.5**	**6.5**	**6.6**	**6.6**	**6.7**	**6.8**	**6.6**	**6.6**	**6.6**	**6.7**
Wind onshore	Billion €	**4.7**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.1**	**2.1**	**2.0**	**2.0**	**2.0**	**2.1**
Wind offshore	Billion €	**2.7**	**5.8**	**5.8**	**5.8**	**5.8**	**5.9**	**6.0**	**6.1**	**6.2**	**5.8**	**5.8**	**5.9**	**5.9**
Other RES (CSP, geothermal, other marine)	Billion €	**0.2**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**
RES-E total	Billion €	**20.0**	**19.9**	**19.8**	**19.8**	**19.8**	**19.9**	**20.1**	**20.3**	**20.5**	**19.9**	**19.9**	**20.0**	**20.1**

Sector conclusions

Power sector

- The higher generation in 2050 in the H2 and e-fuels scenarios compared to the Elec scenarios is due to the higher demand for synthetic, electricity-based energy carriers and the related conversion losses. The lowest overall generation ocurs in the Elec_40 and Elec_60 scenarios; differences to the Elec_30 and Elec_80 are, however, comparably small.
- In 2050, the electricity system is vastly dominated by fluctuating renewables, i.e. wind and photovoltaics. The system is balanced by nuclear, CSP, hydropower and biomass.
- Increases in electricity generation throughout time are vastly met by onshore wind and photovoltaics expansion
- Large amounts of electricity are exchanged within EU-27. Hydrogen is produced only within Europe. E-fuels are imported from outside of Europe in all scenarios in revelant amounts

- Several no-regret options can be derived, as these are useful in all scenarios: a renewable energy technolology expansion, especially photovoltaic and onshore wind, but also offshore wind. Complementing, flexible technolgies, such as CSP, should also be integrated into the systems, as well as hydrogen. The more EU-27-wide electricity is exchanged, the less of these are needed in the electricity systems.

District heating sector

- Heat pumps are the dominating technology in all technology scenarios in 2050, accounting for the vast mayority of heat generation and an important share of the installed capacities, followed by biomass boiler and CHP. Hydrogen-based heat generation technologies provide backup services.
- The results suggest that any additional heat demand in heat grids that may surge over a baseline, can be met most cost-effectively by an additional expansion of heat pumps.

System costs

- Overall annual system costs of the power and district heating sector are lowest in the Elec_40 and Elec_60 scenarios and highest in the e-fuels_80 and e-fuels_60 scenario.Only minor differences in support expenditures are applicable across assessed technology scenarios: yearly average (2021-2050) total RES support costs vary between EUR 19.8 bn and EUR 20.3 bn. The lower range refers to scenarios aiming for direct electrification, more or less independent which deployment share is envisaged, and for other technology fields (H2, E-fuels) to scenarios with moderate technology targets. The upper range comprises extreme cases from today's perspective – i.e. scenarios that aim for a hydrogen or e-fuel share of 60% or 80%.

RES support expenditures

- One can observe the strong impact of carbon prices on the need for dedicated (additional) RES support as well as that the majority of support costs within this decade refer to existing RES generation assets (installed up to 2020). That leads to a remarkable outcomes: In the technology scenarios (with presumed full decarbonisation) overall RES-related support is on average across the whole assessment period similar in magnitude compared to reference – despite the large differences in overall RES deployment by 2050.
- Only minor differences in support expenditures are applicable across assessed technology scenarios: yearly average (2021-2050) total RES support costs vary between € 19.8 bn and € 20.3 bn. The lower range refers to scenarios aiming for direct electrification, more or less independent which deployment share is envisaged, and for other technology fields (H2, E-fuels) to scenarios with moderate technology targets. The upper range comprises extreme cases from today's perspective – i.e. scenarios that aim for a hydrogen or e-fuel share of 60% or 80%.

3.3. Transmission infrastructure (electricity)

Modelling approach

With regard to the electricity transmission network, the objective of this study is to determine changes in transmission demands and related effects on grid lengths and costs. To derive these results, a detailed transmission grid model is used for the entire area under consideration (EU-27). Further descriptions and details of the model as well as the methodology used for the estimation of grid expansion requirements are described in the annex.

In this section, results for the European electricity transmission grids are shown for the technology scenarios. For this purpose, at first results are shown that can serve as an indicator on how the cost-optimal demand for cross-regional electricity exchange differs between the scenarios. The power system optimisation used in this study and performed by the model Enertile (cf. section 3.2) includes the optimisation of the extension of cross-regional interconnector capacities (IC). Second, results on the actual grid expansion needs and costs in each of the scenarios are shown. These are determined by applying a detailed model of the European interconnected electricity grid.

Results on Interconnector capacity

In order to compare the scenario-specific cost-optimal level of cross-regional IC the so-called "length-weighted interconnector capacity" (LWIC) on a EU-27-level is derived. This indicator involves a distance weighting of the different borders, which is derived from the region model. Furthermore, this approach takes into account the effect of so-called loop flows, i.e. the fact that additional trading capacity between two regions not only requires expansion at this border, but also at other points in the transmission grid, as the physical flow is distributed according to the electrical properties of the power lines.

Figure 19 compares the LWIC for the reference and the technology scenarios. As a additional reference the LWIC for 2030 is shown in the figure. As part of the scenario assumptions, the IC for 2030 are exogenously given and fixed for all scenarios at the same level. For 2050 in all scenarios, the resulting LWIC considerably exceed the capacities in 2030. For all technology scenarios the total LWIC in 2050 are approximately on the same level: The highest LWIC of approx. 237 GW*thousand km occurs in the E-Fuel_80 scenario, while the lowest amount occurs in the H2_80 scenario with 218 GW*thousand km. This means that for all technology scenarios the length-weighted capacities in 2050 are more than four times as high as the corresponding value in 2030 (51 GW*thousand km) and about one and a half times as high as in the reference scenario (143 GW*thousand km). Compared to this the spread among the technology scenarios is rather low. In conclusion, in all technology scenarios a significantly stronger electricity grid is needed to fulfil the objective of a carbon-neutral energy system in a cost-effective way.

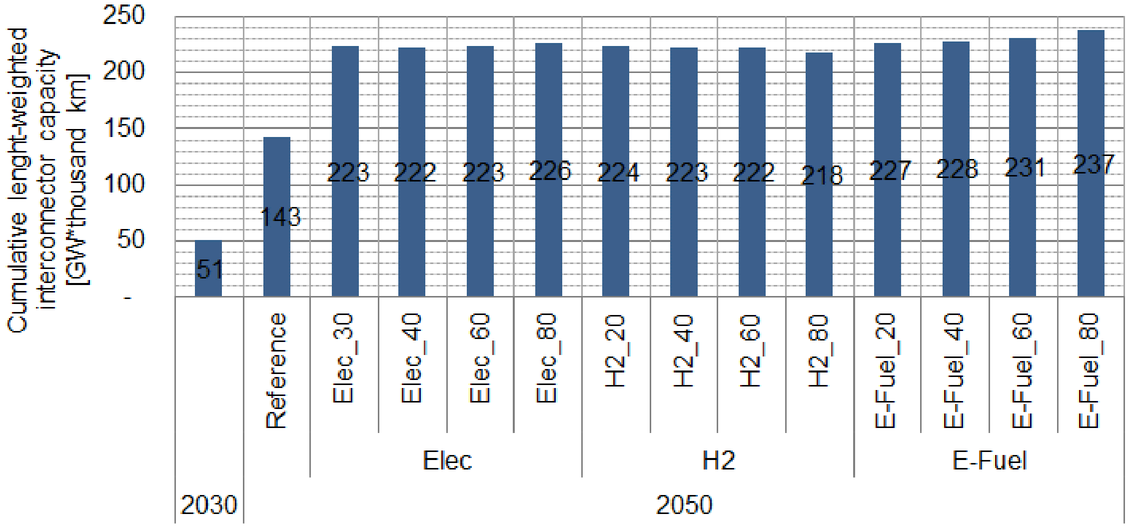

Figure 19: Comparison of cumulative length-weighted interconnector capacities between EU-27-countries (IC at the borders to non-EU-27 countries (CH, UK, NO) are taken into account at half) for the technology scenarios with reference (2050) and initial capacities in 2030

The following Figure 20 graphically shows how IC per border compare between the technology scenarios and also the reference scenario. Also, the initial IC for 2030 are shown[34]. As the differences between the technology scenarios are very small, only the 80% scenarios and the reference scenario are shown in the following figure. The significant increase that can already be observed in the reference scenario is also evident in all technology scenarios. Although the increase in capacities may vary for different borders, the absolute level is very similar between all technology scenarios.

[34] Please note: The interconnector capacities modelled in Enertile are not fully comparable with today's NTC market trading capacities. One assumption for the modelling is that no grid expansion beyond the actual grid + TYNDP is possible for the year under consideration 2030. Hence, the power system must accommodate with the “given” grid, which means that in the detailed transmission grid model no grid congestion may occur. To achieve this, the NTC values (based on today's market NTCs + NTC increases according to TYNDP) for 2030 were partly reduced for individual cross-border connections. The further expansion for 2040 and 2050 then takes place on the basis of these possibly reduced NTCs.

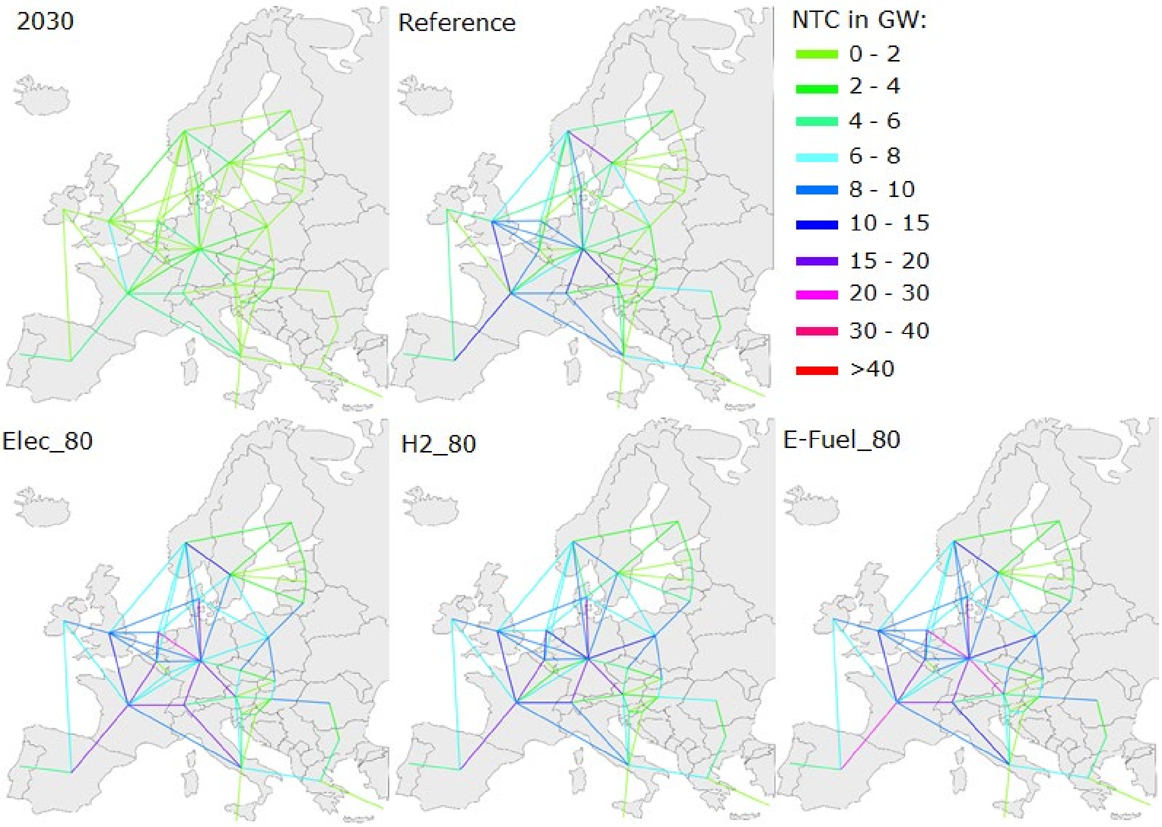

Figure 20: Comparison of interconnector capacities between EU-27-countries for the technology scenarios with reference scenario (2050) and initial capacities available in the model in 2030

The variations in border-specific IC between scenarios are illustrated and explained using the example of border between Spain and France. Varying IC at this border can be explained to a large extent by the different installed capacity of renewable energy plants in one of the countries that are connected via this border. The wind and solar plant capacity in Spain is 236 GW in the Elec_80 scenario, 352 GW in the H2_80 scenario and 277 GW in the E-fuel scenario. Ceteris paribus this leads to increased (peak) exports at times of high RES-production. On the other hand, flexible loads, in electrolysis (combined with extended hydrogen grids), will to some extent absorb the higher RES-production on a regional level, because the dispatch of the electrolysis will in tendency be shifted to situation with increased RES-production. This reduces peak exports (or otherwise curtailment) and, hence, the need for increased interconnector capacity. For example, the capacity of electrolysers in Spain is 26 GW in the Elec_80 scenario, 75 GW in the H2_80 scenario and 35 GW in the E-fuel scenario. This results in the highest IC between Spain and France in the E-Fuel_80 scenario with 20 GW, followed by the H2_80 scenario with 18 GW and the Elec_80 scenario with 15 GW, which means that flexibilities can have a significant impact on grid expansion needs.

Table 13: Interconnector capacities, installed capacity wind, solar and electrolysers in Spain

	Elec_80	H2_80	E-Fuel_80
installed capacity solar and wind in GW	236	352	277
installed capacity electrolyser in GW	26	75	35
interconnector capacity Spain - France in GW	15	18	20

The increased IC have a considerable impact on the line loadings that result from the outage simulations in the detailed grid model. The maximum grid loads occurring in at least one of the 8.760 modelled situations for the 80% penetration setups of technology scenarios and the reference scenario scenarios are shown in Figure 21. As the differences between the technology scenarios are very small, only the 80% penetration setups of technology scenarios and the reference scenario are shown in the following figure. For all scenarios there is a significantly high number of congestions in the area under consideration. Again, the extensive additional transmission requirements, that had to be expected already based on the Enertile results shown in the previous figures, are thus confirmed by the detailed grid model.

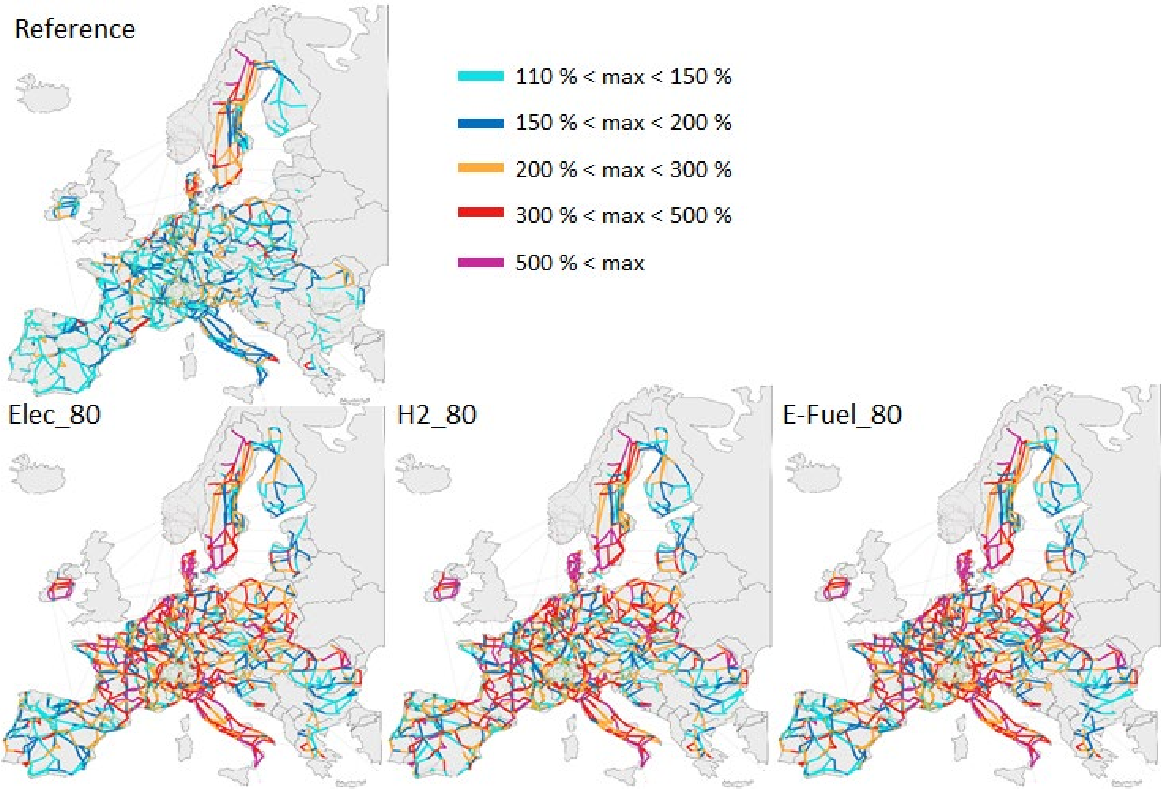

Figure 21: Maximum line loading in (n-1)-case in 2050 for EU-27 (before grid expansion) comparing technology scenarios with reference scenario

According to the maximum grid loads, a significantly expanded electricity transmission grid is necessary by 2050. Figure shows that in the reference scenario the length of the transmission grid needs to be increased by 25% to meet the requirements of the energy system and in the technology scenarios by more than 50%. This means that the differences in grid expansion needs for these scenarios are even smaller than the differences in LWIC as shown in Figure 19. While the LWIC only reflects the demands for cross-regional transport needs, in the detailed grid modelling also internal congestions become evident. In particular, the grid lengths of the H2 scenarios are at the same level as the E-fuel scenarios, as the higher installed RES generation capacity leads to higher local line loads within the countries although the cumulative LWIC are smaller in the H2 scenarios.

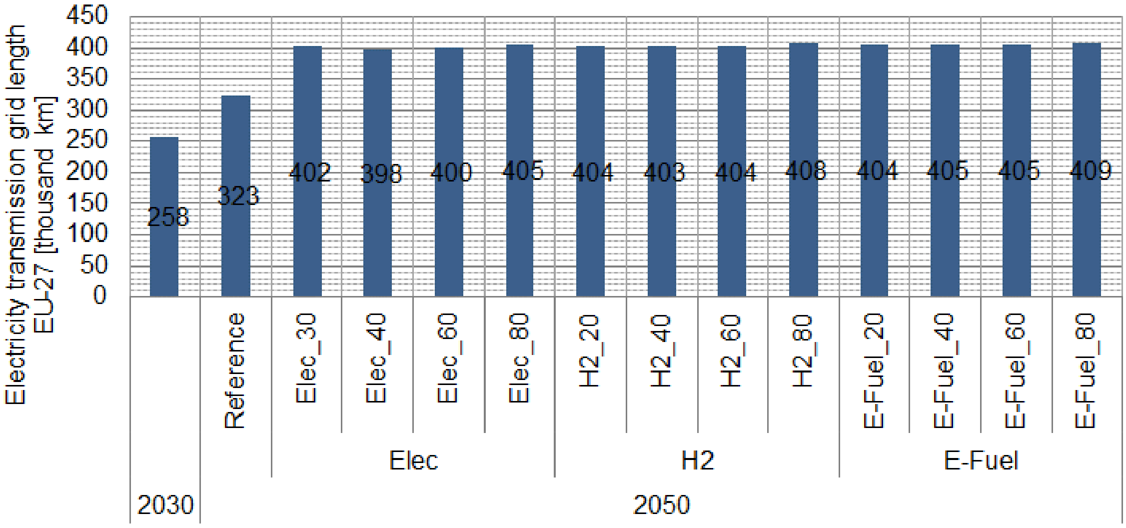

Figure 22: Electricity transmission grid length EU-27 comparing technology scenarios with reference

Figure 23 shows that the need for grid expansion is almost identical in all scenarios (except reference). Shown is increase in transmission grid length from 2030 to 2050 for each country. As the differences between the technology scenarios are very small, only the 80% scenarios and the reference scenario are shown.

In all scenarios, a strong increase in grid length and IC is seen in the Netherlands and Belgium. Their geographical location between regions with good wind potential such as the North Sea, the United Kingdom and Scandinavia and, on the other hand, importing countries such as France and Germany, leads to a comparatively strong increase in IC and necessary grid expansion.

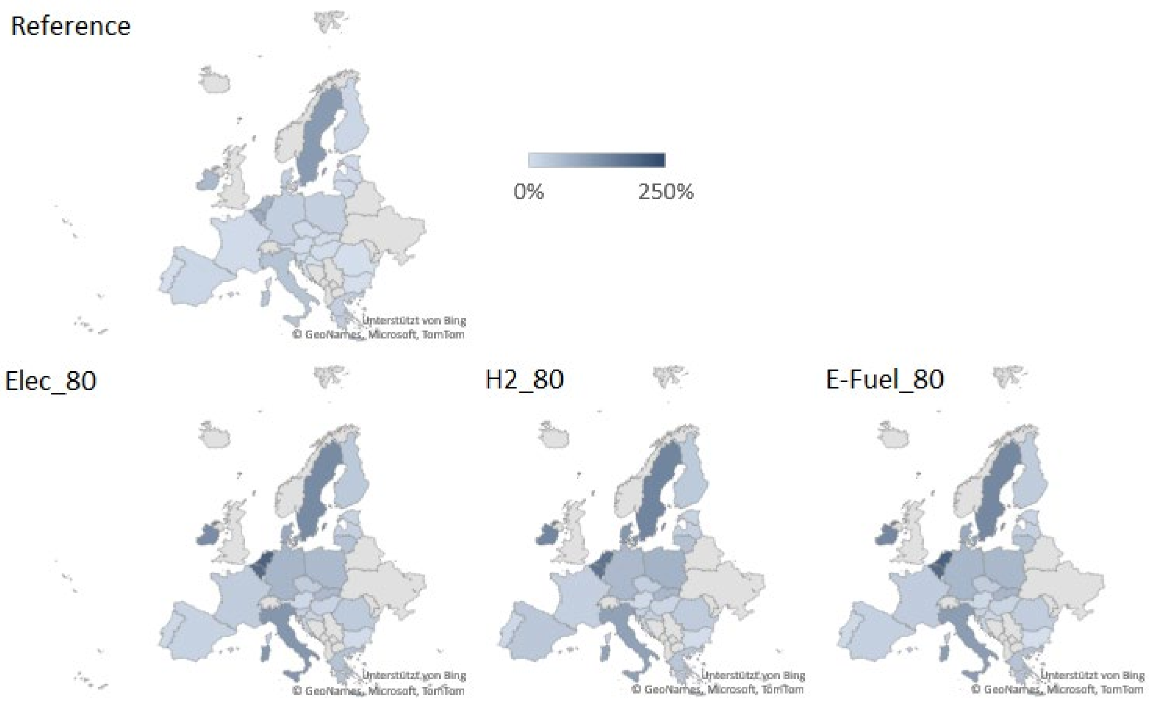

Figure 23: Growth of grid length from 2030 to 2050 for EU-27 by country comparing technology scenarios with reference and scenario

Corresponding investment costs and resulting annual costs of the electricity transmission grid (including costs for operation and maintenance) are shown in Figure 24 and Figure 25.

Figure 24 shows, that the highest investment costs across all considered scenarios can be seen for the scenarios H2_80 with EUR 765 billion from 2030 until 2050, followed by E-Fuel_80 (EUR 762 billion). The Elec scenarios, with a maximum of 751 billion in the Elec_80 scenario, are slightly below the equivalent H2 and E-fuel scenarios. The investment requirement increases in all technology scenarios by about 60% compared to the reference scenario.

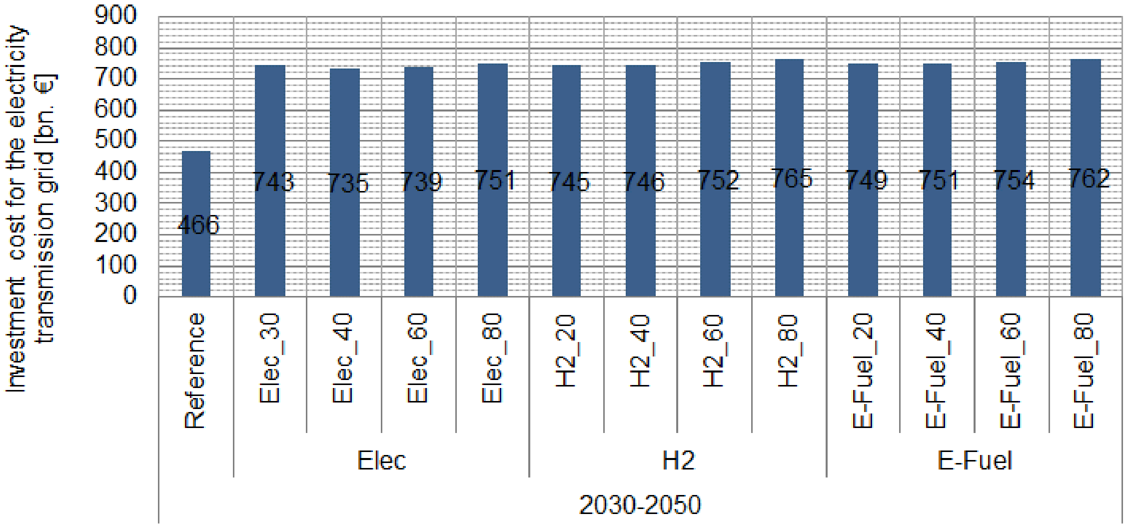

Figure 24: Investment cost for necessary grid expansion from 2030 to 2050 for EU-27 comparing technology scenarios with reference scenario

Accompanying the investment costs, the annual costs for the electricity transmission grid in EU-27 shown in Figure 25 consistently increase the most until 2050 for H2_80 and E-Fuel_80 to EUR 31 billion per year. For the Elec_80 scenario the annual costs in 2050 are slightly lower but with EUR 30 billion per year on the same level. This consequently means that for all technology scenarios the annual costs almost triple compared to the initial annual grid costs in 2030 (EUR 12 billion per year). The annual cost increase between the technology scenarios and the reference scenario amounts to about 30-35% related to the EUR 23 billion per year that were identified for the reference scenario.

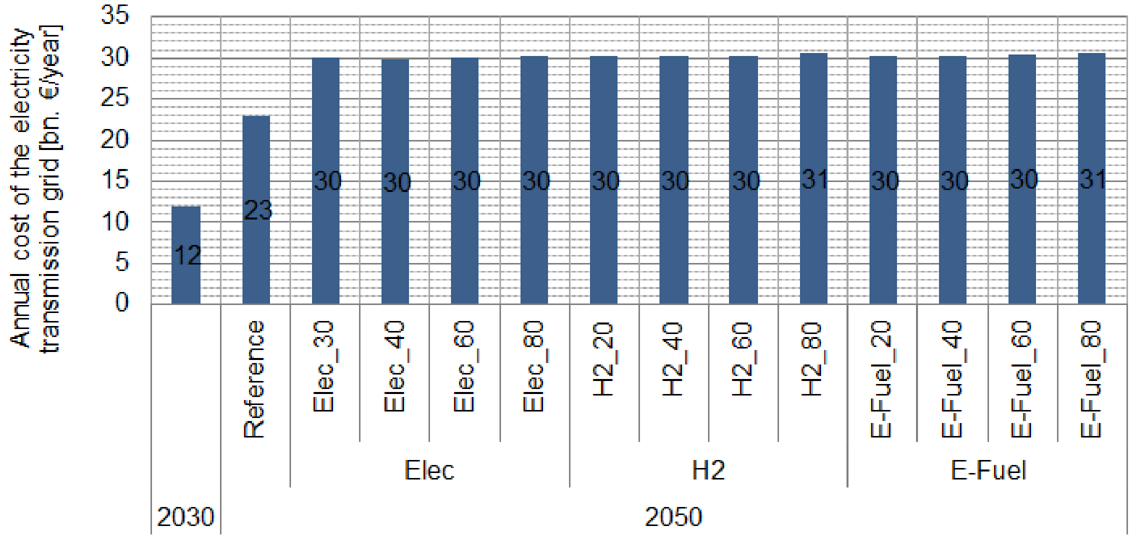

Figure 25:Annual cost in 2050 including necessary grid expansion from 2030 to 2050 for EU-27 comparing technology scenarios with the initial grid in 2030, reference scenario

Sector conclusions

- The increase in installed RES-generation capacities and the increased cross-regional exchange of electricity leads to an increase in the required interconnector capacities and causes a need for the expansion of the European electricity transmission grid.
- Flexible loads, for example electrolysers combined with a respective hydrogen infrastructure can reduce the additional infrastructure needs in a cost-efficient manner, if the dispatched accordingly.
- In all technology scenarios a significant expansion of electricity transmission grid infrastructure is needed to fulfil the objective of a GHG-neutral energy system in a cost-effective way. In all GHG-neutral scenarios modelled in this study, the grid length of the EU-wide transmission grid in 2050 increases by means of expansion (additional lines) by approx. 50% compared to 2030 values.
- The variation in the grid expansion needs between the modelled technology scnearios is very low. Whilst the increase in grid length from 2030 to 2050 in EU-wide on average 145.000 km, this increase varies only by +/- 5.000 km between the technology scenarios.
- This comparably low variation of the overall grid expansion needs is despite the fact, that installed RES-generation capacities as well as installed loads vary to a substiantially higher degree between the scenarios.This partial decoupling of grid expansion needs and the growth of typical drivers of grid requirements (installed generation and load capacity) is in our modelling achieved by a systemw-ide coordinated transformation of the energy system and a cost-efficient dispatch of flexible loads also considering grid aspects (see above). The coordinated transformation of the energy system relates in patricular to choosing types and locations of needed RES-generation units and locations of large-scale flexible loads (electrolysers). In our modell these choices are taken from a perspective of a European wide cost-optimisation also considering grid investments and, hence, avoiding in particular over-investments in grids. To achieve this not only in modelling but also in real world, a high level of coordination between MS and entities responsible for infrastructure investment decissions is crucial.
- For all technology scenarios the overall annualised costs of the European electricitcity transmission grid almost triple compared to the initial annual grid costs in 2030. In accordance with the low variation of the grid expansion needs between the technology scenarios, also the annualised costs show only small differences between the modelled technology scenarios.

3.4. Transmission infrastructure (CH4 + hydrogen)

Input and demand according to other models and basic parameters

For the modelling of the CH4- und H2-transmission infrastructure, we at first step used the EGMM gas market model (EGMM-Gas) to quantify the gas flows and utilization of gas infrastructure in the different scenarios, taking into account the modelled gas demand by Invert-E (building sector) and Enertile (power and heat sector) models. Industry gas demand was not modelled, accordingly we assumed to follow the same trajectory as the other two sectors. This allows us to indicate where hydrogen blending is possible and where are additional interconnectors/repurposing of infrastructure is possible. Then, as a second step, we carried out the hydrogen modelling using our modified gas market model (EGMM-Hydrogen), where we include the hydrogen demand and production by countries modelled by Enertile. Countries are interconnected with existing gas pipelines, as well as some additional links were added to facilitate the unconstrained flow of hydrogen. We used hydrogen production cost as suggested by Enertile modelling. Originally, EGMM was calculating an equilibrium outcome with perfect competition in place. The modified model considered only the feasibility of a transport problem, i.e., how much is the current gas network capable to host the future hydrogen flows? (For more detailed description of the modelling approach see Annex). Using the results of EGMM-Gas and EGMM-Hydrogen, investment need for the hydrogen infrastructure was calculated. Figure below shows the decision matrix about how we decided on the necessary hydrogen investment. In case of retrofit of gas pipelines and construction of dedicated hydrogen pipeline we differentiated in investment cost based on the modelled flows.

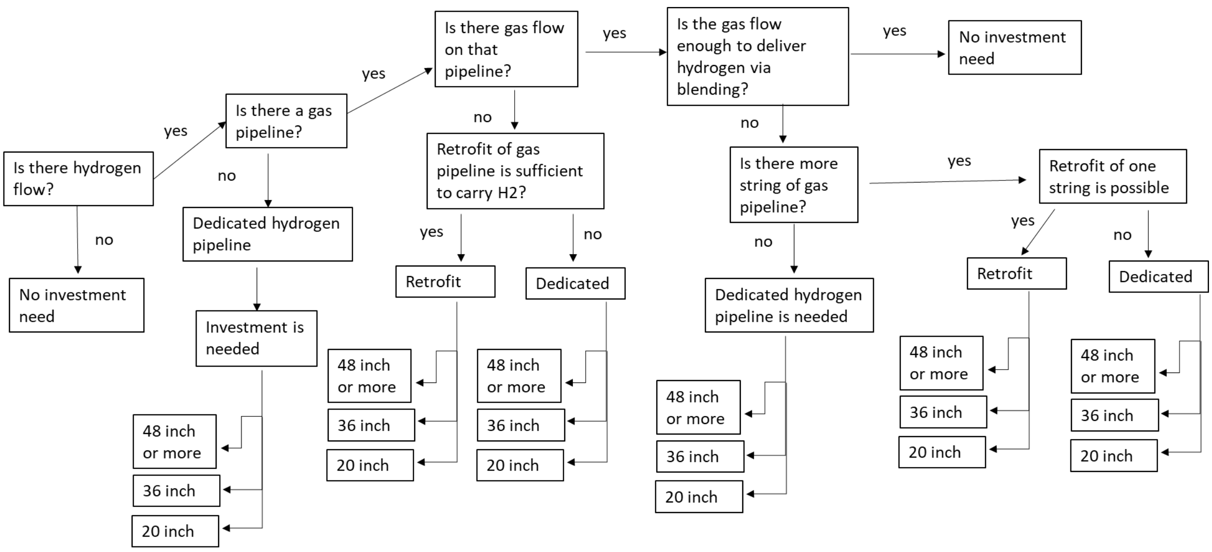

Figure 26: Decision tree for hydrogen investment need estimation

These three charts (Figure 27 to Figure 29) summarize the CH4 demand (fossil methane, biogases, biomethane, e-methane) and hydrogen demand in the EU-27. Following the logic of the draft renewable gases and hydrogen directive, we use the following definition for gases:

- 'CH4' means all gases that primarily consist of methane, including biogas and gas from biomass, in particular biomethane, or other types of gas, that can technically and safely be injected into, and transported through today's CH4 infrastructure (primarilly used for fossil natural gas); CH4 also referes to e-methane
- 'renewable gas' means biogas including biomethane,

- ‘gases’ mean CH4, renewable gas and hydrogen;[35]

It is apparent that in 2020 for all scenarios fossil gas makes up nearly all the gas demand. By 2050, two main tendencies must be highlighted: (i) gas demand will significantly decrease from 3500 TWh/year to 1500-2000 TWh/year (ii) share of fossil gas, which makes up over 90% of current CH4 demand will drop significantly, a share of hydrogen by 2050 will increase to 30-60% in the gas demand.

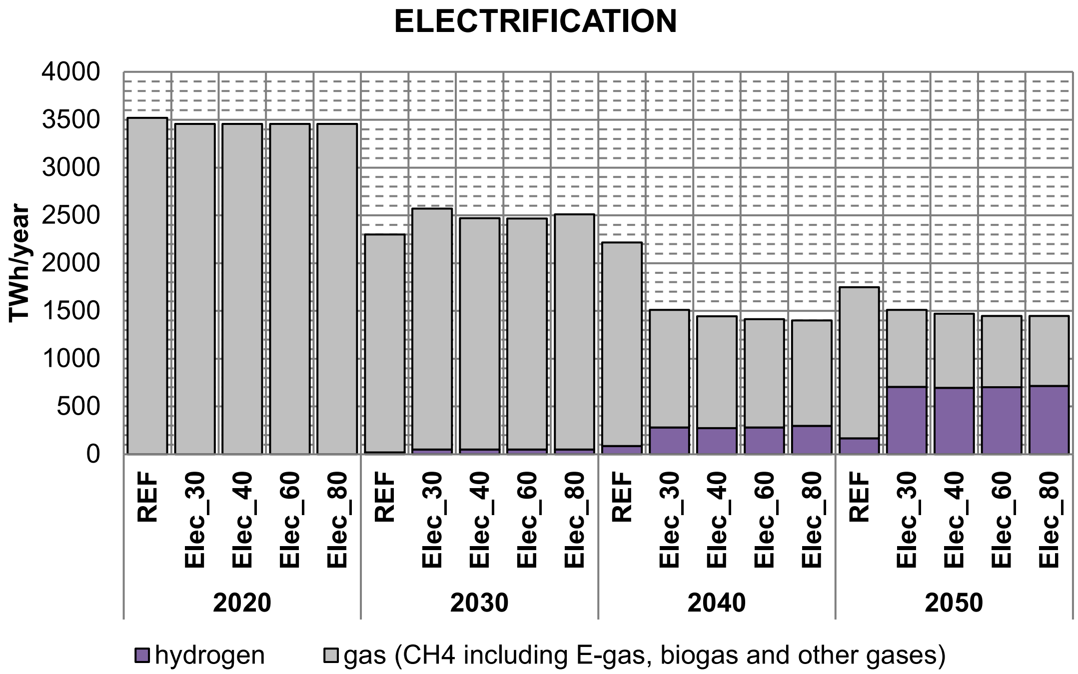

Figure 27: CH4 (including biomethane and biogases and e-methane) and hydrogen demand in Electrification scenarios (EU-27)

[35] Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on common rules for the internal markets in renewable and natural gases and in hydrogen COM(2021) 803 final 2021/0425 (COD). https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM:2021:803:FIN

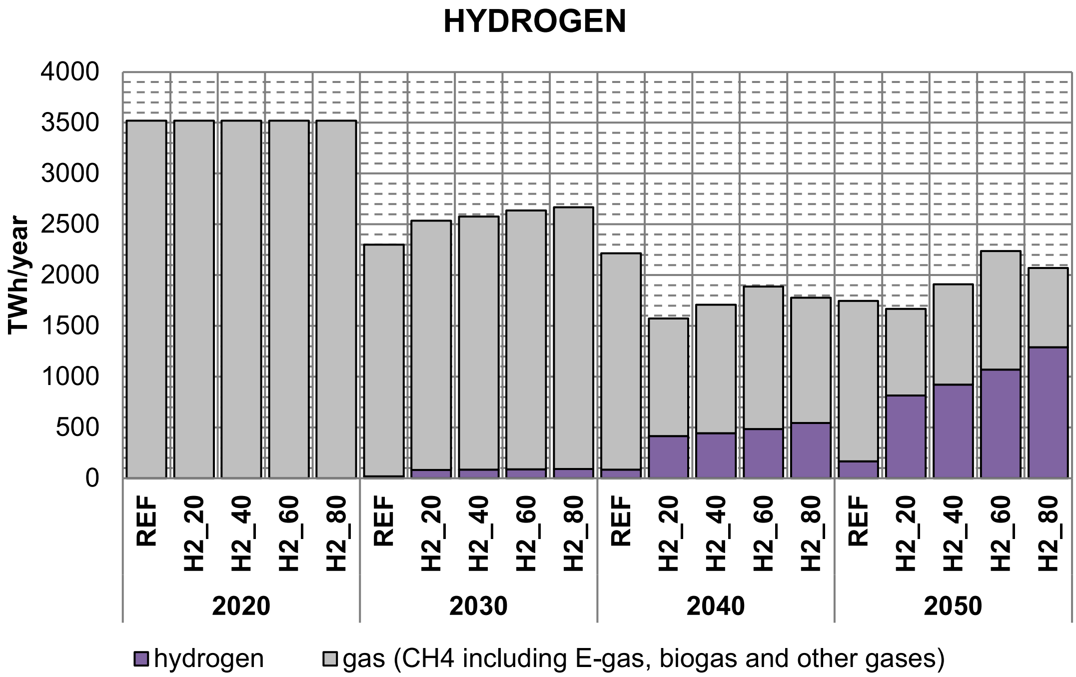

Figure 28: CH4 (including biomethane and biogases) and hydrogen demand in Hydrogen scenarios (EU-27)

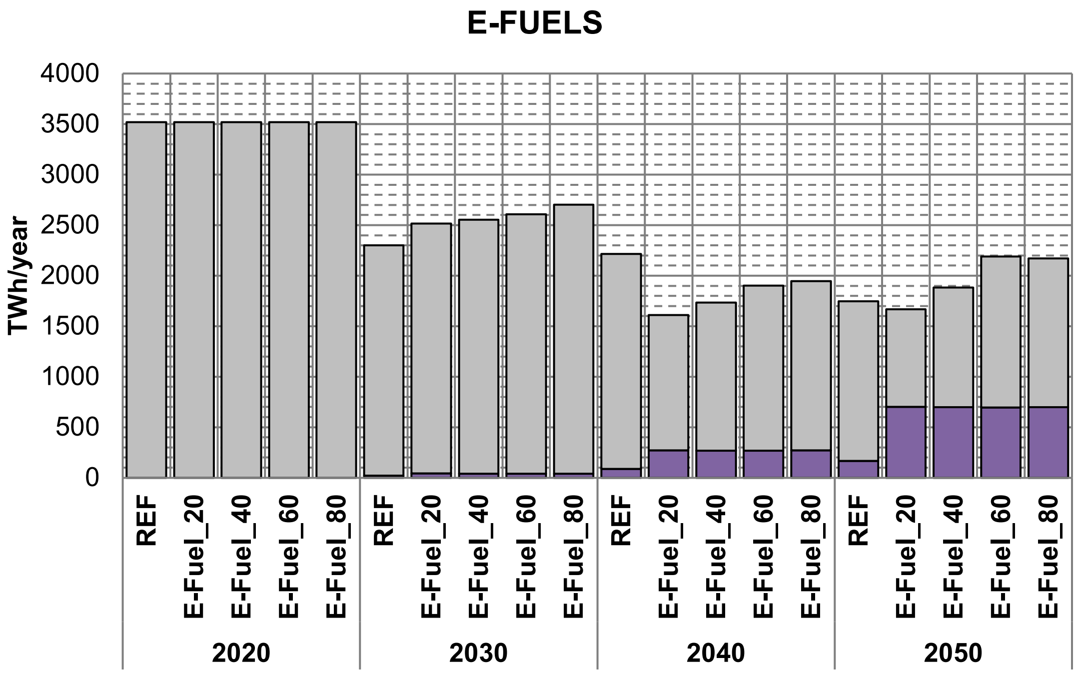

Figure 29: CH4 (including biomethane and biogases) and hydrogen demand in E-fuels scenarios (EU-27)

According to Enertile results hydrogen demand is met by EU sources, hence no import is needed from third countries. Concerning the hydrogen and CH4 demand of the industry sector we assumed that it develops in the same pattern as electricity and heat and building sector demand.

It can be seen that the total volume of CH4, H2 and other gases in the EU-27 drops from 3500 TWh/year in 2020 to 1500-2000 TWh in 2050. Due to decreasing CH4 demand, no new gas pipelines are expected to be built. Gas network investment relate to retrofitting existing gas pipelines to accommodate H2 flows, while hydrogen network investment denotes dedicated new hydrogen pipelines.

Modelling results: investment need and annualized system costs

Main question of the modelling exercise was to quantify the investment need and annual cost of the joint hydrogen and CH4 system. The cost estimation is based on the approximate length of the hydrogen network and the utilisation and flows on the joint hydrogen-gas infrastructure.

Total investment need ranges from bn EUR 18.8-24.7 bn. Two third of the network is made up of repurposed pipelines used for CH4 / natural (mainly fossil) gas today. The table below displays total CAPEX of the networks.

Table 14: Total investment need of the hydrogen network, bn EUR/yr (EU-27)

		2020-2030	2030-2040	2040-2050	Total
REF	bnEUR	0.0	0.0	0.0	0.0
Elec_30	bnEUR	13.3	3.0	5.0	21.3
Elec_40	bnEUR	11.8	3.8	4.4	20.0
Elec_60	bnEUR	12.2	2.8	4.7	19.6
Elec_80	bnEUR	12.3	2.6	3.9	18.8
H2_20	bnEUR	15.1	3.4	4.5	23.0
H2_40	bnEUR	15.9	2.4	3.3	21.6
H2_60	bnEUR	16.9	2.4	3.6	22.9
H2_80	bnEUR	16.8	3.1	4.9	24.7
E-Fuel_20	bnEUR	14.3	3.5	5.1	22.9
E-Fuel_40	bnEUR	12.5	3.8	4.7	21.0
E-Fuel_60	bnEUR	13.4	3.6	5.0	21.9
E-Fuel_80	bnEUR	12.9	4.1	3.6	20.6

OPEX is derived from cumulated CAPEX costs, assuming a flat rate of 3%. By 2030, OPEX of the hydrogen network is EUR 0.4-0.5 bn /year, in the following years this increases to EUR 0.6-0.7 bn /yr. OPEX in this sense is financing non-flow related operation costs.

Table 15: OPEX need for the hydrogen network, Bn EUR/yr (EU-27)

		2020-2030	2030-2040	2040-2050
REF	bnEUR	0.4	0.5	0.6
Elec_30	bnEUR	0.4	0.5	0.6
Elec_40	bnEUR	0.4	0.5	0.6

Elec_60	bnEUR	0.4	0.4	0.6
Elec_80	bnEUR	0.4	0.4	0.6
H2_20	bnEUR	0.5	0.6	0.7
H2_40	bnEUR	0.5	0.5	0.6
H2_60	bnEUR	0.5	0.6	0.7
H2_80	bnEUR	0.5	0.6	0.7
E-Fuel_20	bnEUR	0.4	0.5	0.7
E-Fuel_40	bnEUR	0.4	0.5	0.6
E-Fuel_60	bnEUR	0.4	0.5	0.7
E-Fuel_80	bnEUR	0.4	0.5	0.6

Variable system costs are indicated for gas and hydrogen networks separately. These costs are derived from modelled flows on the network multiplied by the applicable network tariffs. Although the current proposal for the regulation of the European hydrogen markets foresees no cross-border transmission tariffs, we applied distance-based hydrogen transmission tariffs as costs of operating the network. Likewise, (natural) gas transmission tariffs applicable in 2020 are estimated as the costs of operating and maintaining the gas transmission.

Variable system costs for gas are making up most of the system operation by 2030 (EUR 2.4-2.6 Bn), as CH4 flows are still high compared to the total gas demand. By 2050, this drops to EUR 0.7-1.2 bn.

Variable system costs of hydrogen make up EUR 0.7-1.7 bn /year by 2050.

Table 16: Variable system costs of the CH4 network (EU-27)

		2020-2030	2030-2040	2040-2050
REF	bnEUR/a	2.8	2.2	1.9
Elec_30	bnEUR/a	2.5	1.1	0.7
Elec_40	bnEUR/a	2.5	1.0	0.7
Elec_60	bnEUR/a	2.4	1.0	0.7
Elec_80	bnEUR/a	2.5	1.0	0.7
H2_20	bnEUR/a	2.5	1.0	0.7
H2_40	bnEUR/a	2.5	1.1	0.8
H2_60	bnEUR/a	2.6	1.2	0.9
H2_80	bnEUR/a	2.6	1.1	0.7

E-Fuel_20	**bnEUR/a**	2.5	1.2	0.8
E-Fuel_40	**bnEUR/a**	2.5	1.3	0.9
E-Fuel_60	**bnEUR/a**	2.6	1.4	1.2
E-Fuel_80	**bnEUR/a**	2.6	1.5	1.2

Table 17: Variable system costs of the hydrogen network (EU-27)

		2020-2030	2030-2040	2040-2050
REF	**bnEUR/a**	0.0	0.0	0.0
Elec_30	**bnEUR/a**	0.1	0.3	0.7
Elec_40	**bnEUR/a**	0.1	0.3	0.7
Elec_60	**bnEUR/a**	0.1	0.3	0.7
Elec_80	**bnEUR/a**	0.1	0.3	0.7
H2_20	**bnEUR/a**	0.1	0.5	0.9
H2_40	**bnEUR/a**	0.1	0.6	1.1
H2_60	**bnEUR/a**	0.1	0.6	1.3
H2_80	**bnEUR/a**	0.2	0.7	1.7
E-Fuel_20	**bnEUR/a**	0.1	0.3	0.7
E-Fuel_40	**bnEUR/a**	0.1	0.3	0.8
E-Fuel_60	**bnEUR/a**	0.1	0.4	0.9
E-Fuel_80	**bnEUR/a**	0.1	0.4	0.9

To allow for an easy comparison between the various scenarios, CAPEX costs have been annualised and this way all cost-categories can be added up and represent the annual cost of hydrogen and gas transmission. To annualise CAPEX, 60 years of lifetime and 2% discount rate were applied, resulting in an annuity factor of ~3%. Until 2030, the costs of managing the CH_4 transmission network will clearly be the main cost component, with hydrogen system costs being negligible. By 2050 this relation shifts. As total flows on the network drop, total costs of keeping up the CH_4+H_2 system is lower than the current (2020) CH_4 system costs. By 2050, total costs of keeping up CH_4 and H_2 system ranges from EUR 2 to 3 bn (including annualised investment costs). Costs of hydrogen system is on par with or higher than the CH_4 system upkeep by 2050.

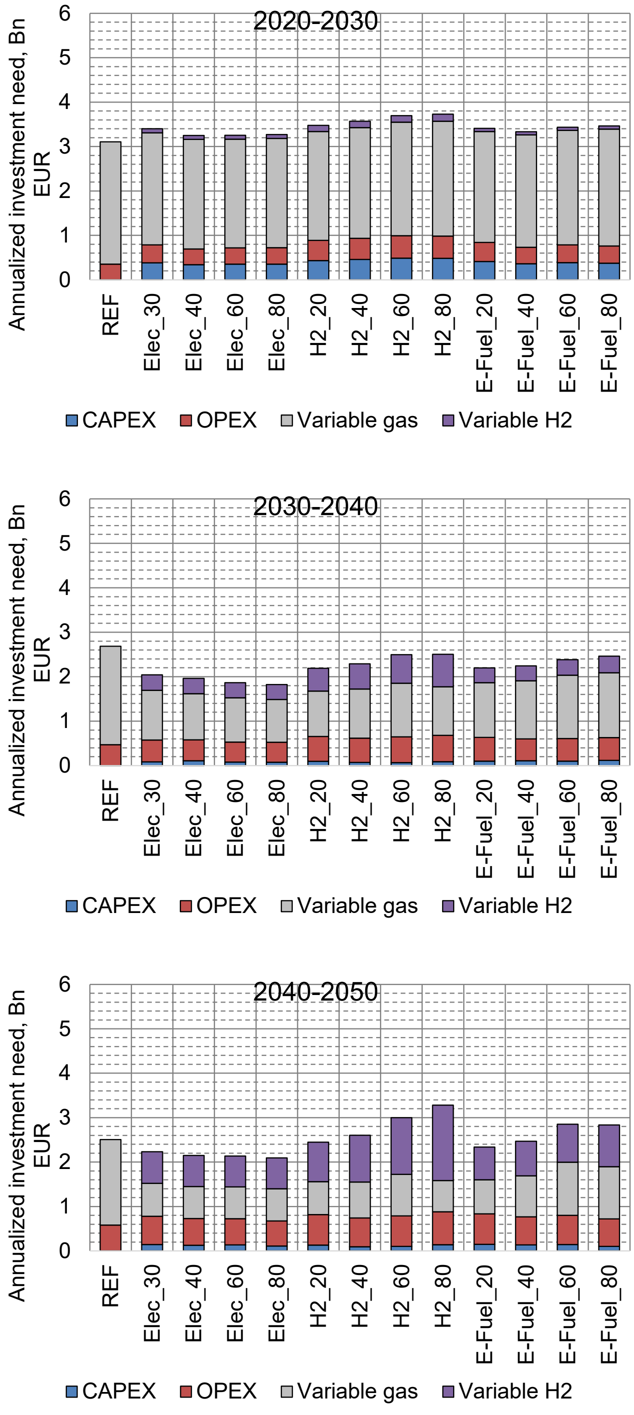

Figure 30: Annualised CAPEX, OPEX and variable system costs

In the technology scenarios, the distribution of the investment costs among the countries varies between 0% and 14% of the CAPEX, with Italy bearing the largest costs, usually followed by UK and Poland. Other countries with outstanding CAPEX (above 7% of total modelled CAPEX of the region) are Germany and Greece.

Table 18: CAPEX modelled for 2020 until 2050 (EU-27+CH+NO+UK)

	REF	Elec_30	Elec_40	Elec_60	Elec_80	H2_20	H2_40	H2_60	H2_80	E-Fuel_20	E-Fuel_40	E-Fuel_60	E-Fuel_80
AT	0	1.1	1.1	0.8	0.8	1.0	1.0	1.0	1.1	1.0	1.0	1.1	1.0
BE	0	0.7	0.6	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
BG	0	0.2	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.1	0.2	0.1	0.1
CH	0	0.4	0.4	0.4	0.4	0.8	0.7	0.9	0.7	0.6	0.4	0.3	0.2
CY	0	0.2	0.2	0.2	0.2	0.2	0.2	0.5	0.5	0.2	0.2	0.2	0.2
CZ	0	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.1	0.1	0.1	0.3
DE	0	1.8	1.9	1.5	1.4	1.6	1.5	1.6	1.5	1.9	1.1	1.1	1.1
DK	0	1.3	1.3	1.3	1.3	1.0	1.0	1.2	1.2	1.3	1.3	1.3	1.3
EE	0	0.2	0.6	0.6	0.6	0.3	0.3	0.3	0.7	0.2	0.2	0.2	0.2
ES	0	0.9	0.9	1.3	0.9	1.3	1.3	0.9	1.3	1.3	1.3	1.3	1.3
FI	0	0.2	0.3	0.3	0.3	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.2
FR	0	1.2	1.2	1.2	1.2	1.5	1.5	1.8	1.5	1.5	1.5	1.2	1.2
GR	0	1.8	1.8	1.8	1.8	1.8	1.8	2.5	3.0	1.8	1.8	1.8	1.8
HR	0	0.2	0.5	0.2	0.2	0.2	0.5	0.2	0.5	0.2	0.6	0.6	0.6
HU	0	0.7	1.1	0.8	0.8	1.1	1.4	0.7	1.6	1.1	1.2	1.2	1.2
IE	0	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
IT	0	3.4	2.3	2.4	2.2	3.6	2.0	2.4	2.6	3.4	2.2	3.5	2.1
LT	0	0.5	0.5	0.5	0.5	0.7	0.7	0.7	0.7	0.5	0.5	0.5	0.5
LU	0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
LV	0	0.1	0.3	0.3	0.3	0.1	0.1	0.1	0.4	0.1	0.1	0.1	0.1
MT	0	0.2	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.2	0.0	0.2	0.0
NL	0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
NO	0	1.1	1.3	1.3	1.3	1.1	1.1	1.3	1.7	1.1	1.1	1.1	1.2
PL	0	1.9	0.9	1.0	0.9	2.5	2.4	2.8	1.1	1.9	1.9	1.9	1.9

PT	0	0.1	0.1	0.3	0.1	0.3	0.3	0.1	0.3	0.3	0.3	0.2	0.2
RO	0	0.3	0.2	0.2	0.3	0.7	0.8	0.3	0.8	0.7	0.3	0.2	0.2
SE	0	1.2	1.2	1.2	1.2	1.1	1.1	1.5	1.5	1.2	1.2	1.2	1.2
SI	0	0.5	0.6	0.5	0.5	0.5	0.2	0.5	0.5	0.5	0.5	0.6	0.5
SK	0	0.8	0.5	0.5	0.5	0.7	0.8	1.0	1.0	0.8	0.8	0.8	0.8
UK	0	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
total	0	25.0	23.9	23.6	22.7	27.2	25.7	27.4	29.5	26.8	24.9	25.5	24.4
Total EU-27	0.0	21.3	20.0	19.6	18.8	23.0	21.6	22.9	24.7	22.9	21.0	21.9	20.6

Hydrogen infrastructure findings

The hydrogen transmission system length to be built by 2050 is between approx. 18,000 to 20,000 km, with the majority of the network needed to be in place already in the first decade. The e-fuels scenarios requires the shortest network, while the Electrification scenarios demands the longest network. The investment demand is at its lowest in the E-gas scenario, given that the approximately same hydrogen demand is coupled with a higher CH4 flow, hence the possible utilisation of the existing gas infrastructure is larger than in the electrification Elec- and hydrogen H2-scenarios.

Table 19: Length and composition of hydrogen transmission pipelines (EU-27)

	hydrogen Transmission pipeline length				repurposed gas transmission pipeline length				dedicated hydrogen transmission pipeline length				share of repurposed pipeline
	2020-2030	2030-2040	2040-2050	Total	2020-2030	2030-2040	2040-2050	Total	2020-2030	2030-2040	2040-2050	Total	Total
	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	1000 km	%
REF	0	0	0	0	0	0	0	0	0	0	0	0	0
Elec_30	11.46	3.14	4.43	19.03	6.25	2.39	2.71	12.10	4.24	1.09	1.43	7.67	60%
Elec_40	10.13	4.35	4.53	19.01	5.72	3.26	2.69	11.36	5.20	0.75	1.72	7.34	61%
Elec_60	11.11	3.48	5.00	19.59	6.70	2.73	3.22	11.67	4.41	1.09	1.85	6.95	65%
Elec_80	11.26	3.14	4.53	18.93	6.85	2.39	3.12	12.65	4.41	0.75	1.79	6.56	65%
H2_20	12.04	3.73	3.24	19.02	6.62	2.93	1.90	12.37	4.41	0.75	1.40	7.58	60%
H2_40	12.49	2.52	3.11	18.13	6.79	2.18	2.35	11.44	5.43	0.80	1.35	6.82	62%
H2_60	11.98	2.30	3.65	17.93	6.79	1.95	2.86	11.31	5.71	0.35	0.77	6.33	65%
H2_80	12.22	3.89	3.45	19.56	6.96	3.54	1.81	11.60	5.19	0.35	0.79	7.25	63%
E-Fuel_20	12.68	3.95	3.23	19.87	7.14	3.21	1.01	12.31	5.26	0.35	1.64	8.51	57%

E-Fuel_40	11.41	3.70	3.94	19.05	7.00	2.51	2.17	11.36	5.54	0.75	2.22	7.37	61%
E-Fuel_60	12.03	3.55	4.06	19.64	6.83	2.42	2.23	11.68	4.41	1.19	1.77	8.16	58%
E-Fuel_80	11.99	3.96	2.74	18.69	7.14	2.83	1.35	11.48	5.20	1.13	1.83	7.37	61%

Hydrogen blending ranges from 0 to 7 TWh/year, remains far below the theoretical blending potential (5% of total pipeline flows) thus playing a very negligible role. Highest blending is modelled in the 80% hydrogen scenario, where blended hydrogen is 7.4 TWh in the 2030, that is about 7% of the total hydrogen trade. By 2050, only 3% of total hydrogen trade is using blended solutions. Hydrogen trade is performed mainly on a retrofitted or dedicated pipeline infrastructure.

Table 20: Total modelled hydrogen blending (TWh/year), (EU-27+CH+NO+UK)

	hydrogen blending, TWh/year		
	2020-2030	2030-2040	2040-2050
REF	0.0	0.0	0.0
Elec_30	2.89	0.13	0.14
Elec_40	3.27	0.08	-
Elec_60	2.62	0.06	-
Elec_80	2.47	0.18	-
H2_20	5.77	0.01	0.05
H2_40	5.96	0.01	0.19
H2_60	6.10	2.09	2.75
H2_80	7.38	0.30	0.03
E-Fuel_20	5.17	0.06	0.05
E-Fuel_40	5.16	0.07	2.68
E-Fuel_60	5.19	1.34	2.78
E-Fuel_80	5.66	0.82	2.70

By 2050, most of the network will be used for hydrogen and abated methane transport, transforming the current fossil natural gas transmission-network to a cleaner one. In the Elec-scenarios, the gas transmission network and the newly built hydrogen pipelines will be used with a share of about 42 to 44% for the hydrogen transport and with 56 to 58% for the methane transport. In the H2-scenarios, the transmission networks are used more, with a split of 47 to 64% for hydrogen and with a split of 36 to 53% for methane. The E-fuels-scenarios shows a similar network use compared to the case of the H2-scnearios, but with a reverse split of 33 to 42% for hydrogen and 58 to 67% for methane.

Table 21: Internal trade of CH4 and hydrogen in the European infrastructure by 2050, TWh/year, (EU-27+CH+NO+UK)

	hydrogen trade volume	methane trade volume	blended hydrogen trade volume	total
	TWh/year	TWh/year	TWh/year	TWh/year
REF	-	-	0.0	-
Elec_30	717	983	0.14	1 700
Elec_40	714	936	-	1 650
Elec_60	712	914	-	1 626
Elec_80	718	915	-	1 634
H2_20	907	1 002	0.05	1 909
H2_40	1 064	1 141	0.19	2 206
H2_60	1 258	1 348	2.75	2 610
H2_80	1 580	878	0.03	2 458
E-Fuel_20	764	1 065	0.05	1 829
E-Fuel_40	797	1 329	2.68	2 129
E-Fuel_60	876	1 747	2.78	2 626
E-Fuel_80	959	1 712	2.70	2 674

The technology scenarios require a very similar hydrogen network setup. There are a few interconnections that are retrofit in one scenario and a dedicated pipeline in another, but it is rare that a pipeline is needed in only one scenario (e.g., PL-DE in Elec_80-scenario). By 2050, there is only the H2_80-scenario with the cross-border natural (mainly fossil) gas pipeline blending being an option.

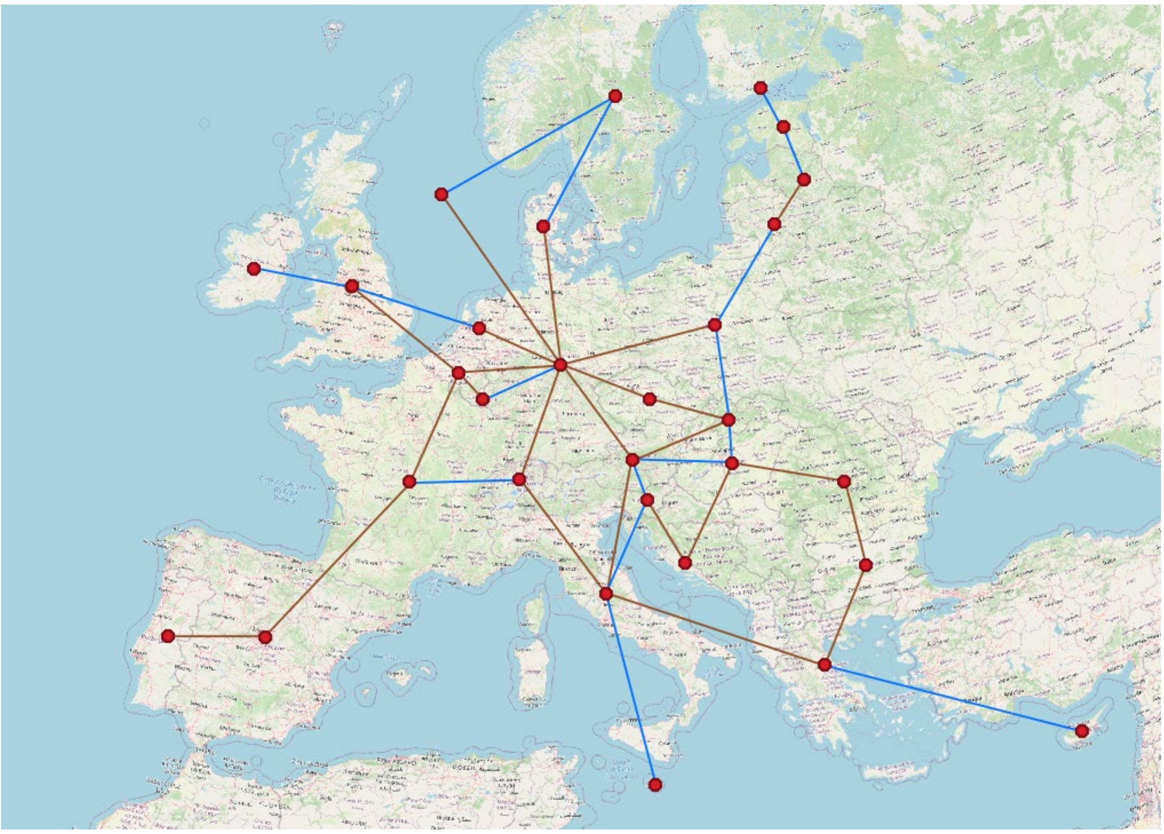

Figure 31: Hydrogen transmission infrastructure by 2050, Elec_80 scenario
(blue lines: dedicated hydrogen; brown lines retrofitted gas pipelines used for CH4 / natural (mainly fossil) gas today)

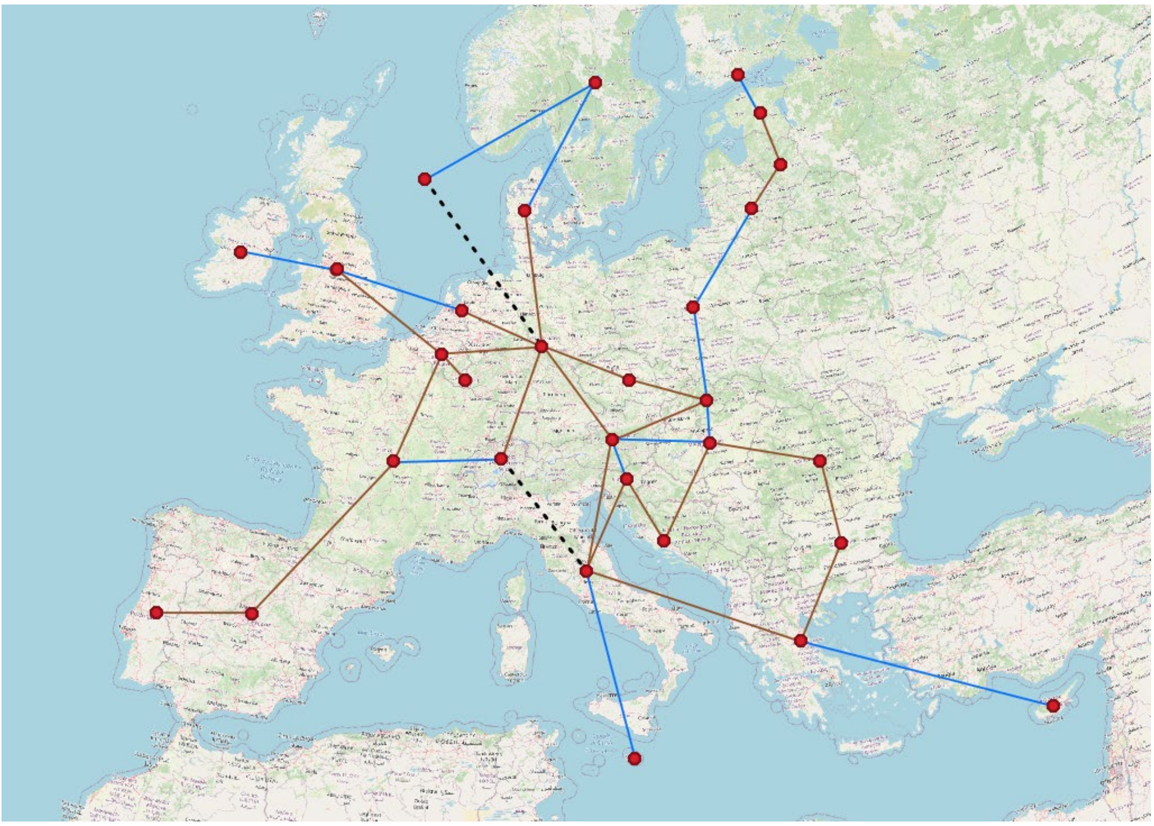

Figure 32: Hydrogen transmission infrastructure by 2050, E-Fuel_80 scenario
(blue lines: dedicated hydrogen; brown lines retrofitted gas pipelines used for CH4 / natural (mainly fossil) gas today; dashed lines: blending)

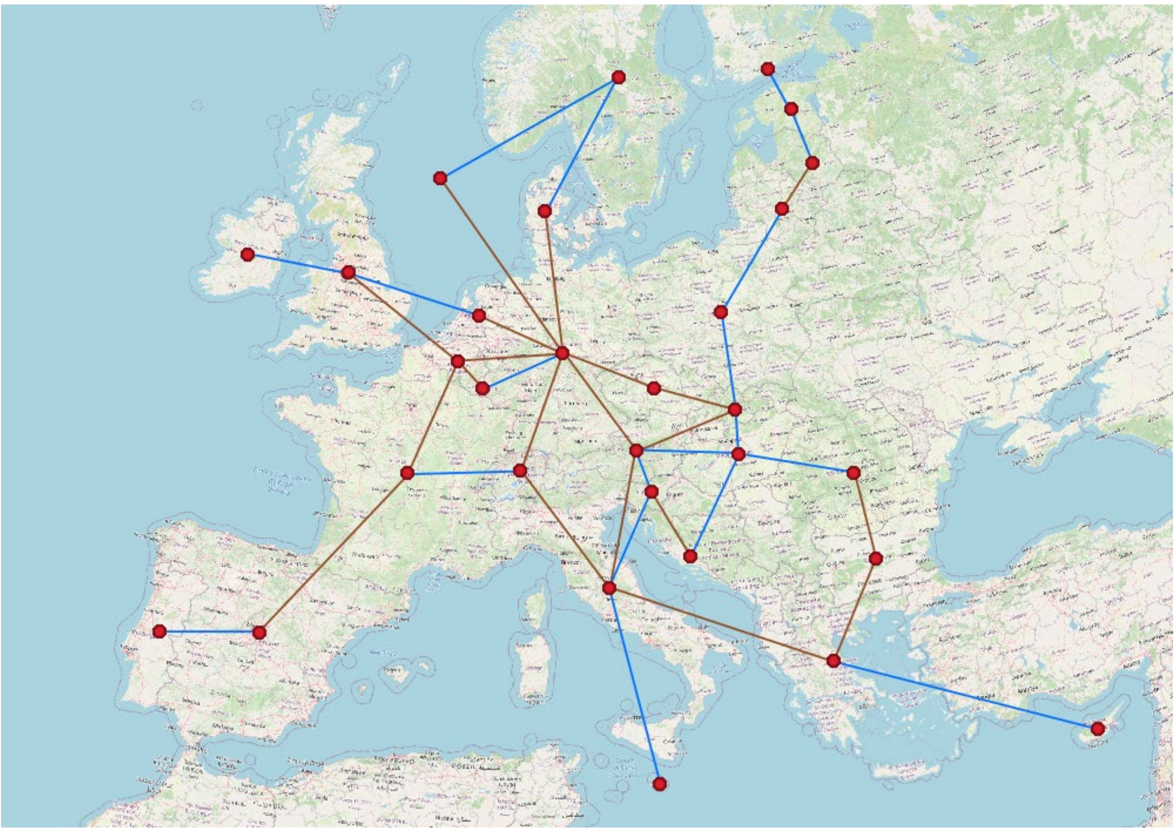

Figure 33: Hydrogen transmission infrastructure by 2050, H2_80 scenario
(blue lines: dedicated hydrogen; brown lines retrofitted gas pipelines used for CH4 / natural (mainly fossil) gas today)

CH4 infrastructure findings

The figure below shows the modelled utilisation of the CH4 network (annual gas flow divided by available technical capacity). Compared to the current situation (see REF 2020 on the left on Figure 34, the utilisation of pipelines drops apparently in the 80% technology scenarios by 2050. Blue colouring of pipelines indicates the need for retrofitting one or more strings for the hydrogen network of the cross-border pipeline. Despite this alternative use of the network, we see an increasing number of unused pipes. The use of import pipelines to the EU falls considerably.

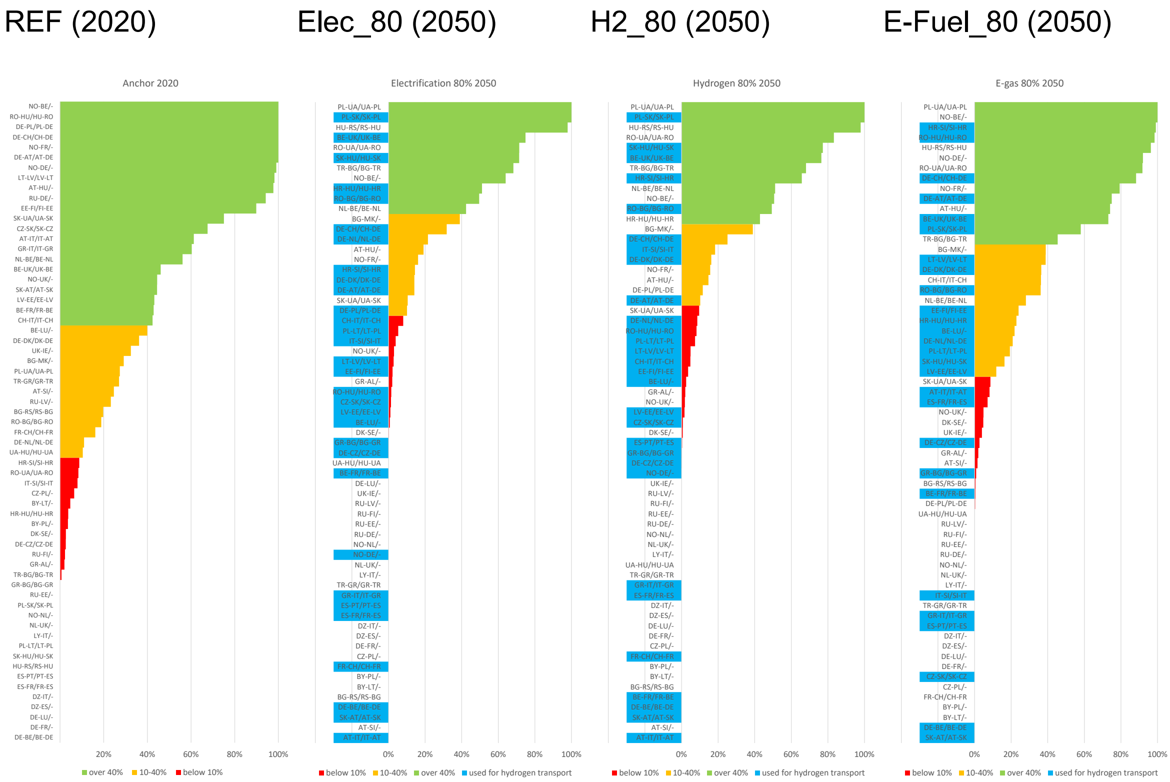

Figure 34: Utilisation of methane transport network (flow/capacity %) (Source: REKK modelling. Red bars indicate capacity utilisation below 10%, orange between 10-40%, green above 40%; blue colouring shows that the pipeline or one of its string is retrofitted for hydrogen.)

We have condensed the capacity utilisation in one single indicator, showing the capacity of the used pipelines divided by the capacity of the total network. This means that if a pipeline is used only for 10%, we consider the full capacity of the pipeline needed. In 2020, this indicator showed 70%, while in the 2050 this drops to 33 to 36% in the Elec- scenarios, followed by 37 to 40% in the H2-scenarios and highest utilisation in the E-fuel-scenarios 38 to 45% (see B/A column in Table 22). Part of the methane-gas pipeline system is retrofitted to accommodate hydrogen flows. When we account for this hydrogen retrofit, the capacity ratio of the used pipelines increases to 50 to 56% in all scenarios (see C/A column in Table 22). This implies that the 30% capacity of unused pipelines of 2020 increases to 44 to 50% by 2050 in the technology scenarios (see 1-C/A column in Table 22).

Table 22: Utilization indicators for gas transmission pipelines (EU-27+UK+NO+CH)

	A	B	C	B/A	C/A	1-C/A
	pipeline capacity	pipeline capacity with flow (methane)	pipeline capacity with flow (methane plus hydrogen retrofit)	capacity utilised (methane)	capacity utilised (methane and hydrogen retrofit)	capacity not in use
	TWh/year	TWh/year	TWh/year	%	%	%
REF 2020	15407	10709	10709	70%	70%	30%
Elec_30 (2050)	16635	5868	8339	35%	50%	50%
Elec_40 (2050)	16635	6013	8358	36%	50%	50%
Elec_60 (2050)	16635	5552	8302	33%	50%	50%
Elec_80 (2050)	16635	6049	8746	36%	53%	47%
H2_20 (2050)	16635	6235	8351	37%	50%	50%
H2_40 (2050)	16635	6392	8751	38%	53%	47%
H2_60 (2050)	16635	6483	8531	39%	51%	49%
H2_80 (2050)	16635	6575	9343	40%	56%	44%
E-Fuel_20 (2050)	16635	6244	8613	38%	52%	48%
E-Fuel_40 (2050)	16635	6888	8811	41%	53%	47%
E-Fuel_60 (2050)	16635	7529	8708	45%	52%	48%
E-Fuel_80 (2050)	16635	7182	9239	43%	56%	44%

Comparing results with the European Hydrogen Backbone study

In 2020, a number of European gas TSOs commissioned a thorough and detailed study[36], which aimed to show a possible use for the existing gas networks and offer a vision for the future European hydrogen supply infrastructure. As the results and the scope of the study and our task overlap, the main outcomes of the European Hydrogen Backbone study is to be presented and compared to our results.

[36] Guidehouse (2021): Extending the European Hydrogen Backbone. A EUROPEAN HYDROGEN INFRASTRUCTURE VISION COVERING 21 COUNTRIES. https://gasforclimate2050.eu/sdm_downloads/extending-the-european-hydrogen-backbone/

First and foremost, we must point out that there were considerable differences between the methodological approach, geographical coverage and a number of assumptions. The version of April 2021 of the Hydrogen Backbone covered 21 countries, while our study covered 30 countries.[37] The Hydrogen Backbone study modelled a network up to 2040, while we aimed at a 2050 outcome. The Hydrogen Backbone included the possible inter-regional trade with third countries (e.g., North Africa and Ukraine), while due to our modelling inputs provided by Enertile, we had to assume a balance within the hydrogen network and no imports from these regions (i.e., all hydrogen produced in the modelled countries gets consumed in the modelled countries).

The total investment costs for the 2040 network was estimated at bnEUR 43-81 in the Hydrogen Backbone study, while our estimate is much lower (bnEUR 19-25 bn).

The investments in our results occur in the first decades, while the hydrogen backbone has a more gradual approach. This difference is due to the assumed locations of hydrogen generation and consumption and the demand for international hydrogen trade.

According to the Hydrogen Backbone study, nearly 69% of the hydrogen network will be made of retrofitted pipelines. Our modelling suggests 57-65% for this figure.

Even though the geographical scope of our modelling is larger, we see a smaller network with lower investment need than the Hydrogen backbone study. The reason for this may be:

- The more detailed network represented in the Hydrogen Backbone study
- Difference in methodological approach – our modelling considered gas pipeline flows on the existing network and the potential for hosting blending and retrofitting unused pipelines
- Difference in assumptions: hydrogen backbone considered much higher hydrogen consumption for the modelled countries

37 Covered in this study : AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GR, HR, HU, IE, IT, LT, LU, LV, MT, NL, NO, PL, PT, RO, SE, SI, SK, UK ; Covered in Hydrogen Backbone study : AT, BE, CH, CZ, DE, DK, EE, ES, FI, FR, GR, HU, IE, IT, LU, NL, PL, SE, SI, SK, UK ;

Table 23: Comparing the results of the Hydrogen Backbone study and our analysis

	indicator	retrofit pipeline length	dedicated hydrogen pipeline length	total hydrogen network length	Total costs
	unit	km	km	km	bnEUR
Hydrogen Backbone study	Hydrogen backbone low	27200	12450	39650	43
	Hydrogen backbone medium	27200	12450	39650	56
	Hydrogen backbone high	27200	12450	39650	81
REKK modelling	Reference	0	0	0	0
	Elec_30	11359	7670	19029	21.3
	Elec_40	11666	7343	19009	20.0
	Elec_60	12645	6949	19594	19.6
	Elec_80	12366	6564	18929	18.8
	H2_20	11444	7575	19019	23.0
	H2_40	11310	6820	18130	21.6
	H2_60	11601	6331	17931	22.9
	H2_80	12315	7248	19563	24.7
	E-Fuel_20	11359	8507	19866	22.9
	E-Fuel_40	11680	7371	19051	21.0
	E-Fuel_60	11476	8160	19636	21.9
	E-Fuel_80	11319	7371	18690	20.6

Sector conclusions

- Blending of hydrogen to CH4 in CH4-grids is not a long-term solution for hydrogen transport. Blending requires CH4 flows to be present to allow for the hydrogen to be blended. Combined with this constraint, the amount of hydrogen blending turned out to be negligible.
- Hydrogen is transported via retrofitted CH4-pipelines or dedicated new hydrogen infrastructure. The total hydrogen network to be built by 2050 in the EU-27 varies between 18,000 and 20,000 kms depending on the considered technology scenario, which is approx. 10% of today's 225,000 kms CH4 transmission infrastructure.[38] The majority of the hydrogen network needs to be in place already in by 2030. About 57 to 65% of the network is a retrofitted gas pipeline in the technology scenarios.
- Investment costs for hydrogen systems are robust between the scenarios, totalling EUR ~19-25 bn from 2020 to 2050 for the EU-27.
- During the transition, there is a risk for over-investment to host flows that might be re-routed later on.
- Gas infrastructure needs to be retrofitted or decommissioned on the long-run. By 2050, no unabated fossil gas will be transmitted on the EU network. By 2050, only 33 to 45% of the 2020 capacities will be used for methane transport (opposed to 70% in 2020).

3.5. Distribution infrastructure (electricity)

Modelling approach

To analyse the effects of different possible levels of electrification of heating, on the power distribution networks precisely and in detail, many influencing factors would have to be considered with a high degree of accuracy. However, this is neither justifiable nor necessary in the context of this study, because the technical and economic effects of the various scenarios on the electricity distribution grids are being estimated for the EU-27 MS in sufficient regional resolution and not calculated exactly for each sub-grid. Furthermore, the focus of the study is on the comparison of different scenarios and not on the exact determination of network reconstruction and expansion requirements in a regionally high resolution.

The methodical approach of model grid analysis is well suited to determining the effects of various developments in the buildings' electricity demand on the distribution grids. The model grid analysis is based on the idea of describing the supply task in a highly abstract form with only a few input variables, so that the essential interrelationships between these input variables (spatial distribution of grid users, demand of consumers, output of generation plants, typical specifications for grid design) and the output variables (quantity of the grid elements required to fulfil the supply task and consequently grid costs) can be easily investigated, detached from case-specific individual influences. This method of model network analysis has been implemented in the EXOGON tool developed by Consentec and has already been used successfully in numerous studies.

[38] ENTSOG TYNDP 2018. https://www.entsog.eu/sites/default/files/2018-12/ENTSOG_TYNDP_2018_Infrastructure%20Report_web.pdf

The effects of different possible levels of electrification of heating on the costs of the distribution grids depend on various aspects:

- Spatial distribution of buildings: From the point of view of distributed networks, the spatial distribution of buildings must be considered to determine in which network areas there are buildings and to what extent. Information on the quantity of buildings on NUTS2 level was taken from public EU databases. The distribution of buildings remains constant in each scenario considered.
- Peak load of the buildings: The peak demand, more precisely the peak power consumption (or - in the case of (small scale) power plants - the maximum feed-in power), determines how the lines and transformer stations must be dimensioned. Information on the current peak power demand was taken from ENTSO-E publications and information on the present installed power of onshore dispersed generation from Primes Ref 2020 (draft). The further development of load and dispersed generation is one key result of the energy system model Enertile.
- Consumption characteristics: The aforementioned peak power demand depends on the equipment of the buildings with power consumption devices and, above all, on the application characteristics of the devices. The latter significantly determines the sum of the simultaneous output of several buildings, which is ultimately relevant for the design of the grid the buildings are directly connected to as well as further upstream grids. The increasing use of electric heat pumps typically leads to an increase in the simultaneous use of appliances. Especially for the comparison of the different scenarios, it is crucial to explicitly analyse the respective effects on the simultaneous and thus for the network dimensioning relevant peak power values. This is done in close coordination with the aforementioned analyses of the building and electricity market.

Finally, the main input parameters were set in such a way that the network quantities determined by the model will meet published values with a good degree. Further, the calculated network costs are based on the network quantity structures determined by means of the model network analysis (line lengths, number of transformer stations). From our experience, it makes sense to assume that the network costs related to these assets are directly proportional to the network quantity so that the corresponding network costs (and their changes) are being calculated directly from the network quantity frameworks (or their changes).

Results for technology scenarios

According to ENTSO-E, the system load in the considered countries (EU-27) equals to approximately 460 GW in 2018. The system load is defined as the maximum power withdrawn from the transmission grid. It includes contributions from loads connected to the different distributions levels, such as household loads, small and large scale heat pumps, e-vehicle charging devices as well as industry. Also dampening effects due to individual load characteristics (e.g., peak load at different hours of the day) are considered when determining the relevant peak load for the dimensioning of the individual distribution grid levels. In addition to these loads there are further loads, such as electrolysers being directly connected to the transmission system accordingly not considered in the distribution grid. The installed power of onshore wind and photovoltaics amounts to nearly 280 GW in 2020 according to Primes Ref 2020 (draft). In the reference scenario both system load and dispersed generation increase to approximately 650 GW (system load), respectively 830 GW (generation) in 2050.

In the technology scenarios, which unlike the reference scenario are carbon neutral, system load and generation capacity continue to increase significantly. The system load reaches values between approximately 840 GW and 950 GW in 2050 (roughly +200 to +300 GW compared to the reference scenario). As expected, highest system load values occur in scenarios with higher degree of electrification, whereas scenarios with high share of gas (both methane and hydrogen) show lower increases of system load.

Parallelly, the installed RES generation capacity (onshore wind and photovoltaics) roughly doubles the load level and reaches values between 1900 GW and 2200 GW in 2050 (approx. +1100 to +1300 GW compared to the reference scenario). Regarding the relation between system load and installed RES generation capacity two aspects need to be kept in mind. In addition to the system load also load directly connected to the transmission system, mainly electrolysers needed to balance seasonal fluctuation of RES generation and demand, needs to be supplied by the RES generation units. Further, the system-wide peak generation of photovoltaics and onshore wind is far less than the sum of the installed power, as generation profiles from onshore wind and photovoltaics differ significantly (usually high solar radiation comes along with low wind speed and vice versa).

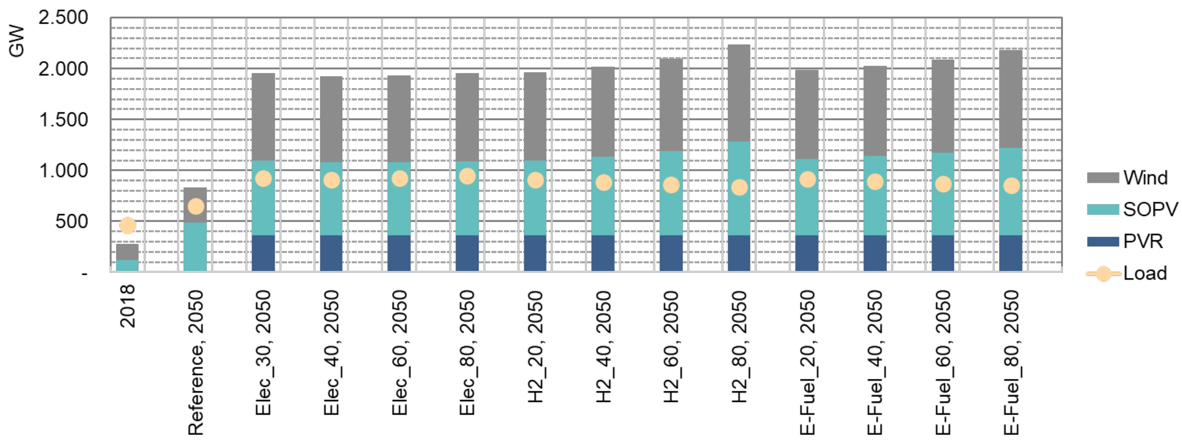

Figure 35: System load and installed RES generation capacity connected to distribution grids in 2050 for each scenario

However, the grid must be dimensioned in such a way that it is able to handle the net peak demand and the peak injection at any time (curtailment of generation and/or load is not explicitly modelled with respect to distribution networks). As the distributed grids' dimensioning is primarily dependent on peak power and peak power of load and generation is far above today's values, the distribution grid needs to be reinforced and expanded to handle these values. So, network costs increase significantly in any of the considered scenarios. In the reference scenario costs (annuities) increase nearly by 50% until 2050, whereas costs of the technology scenarios increase by approximately 110% to 140%. In our model, network equipment is always built simultaneously with the changing supply task. In practice, however, due to planning and construction times, the expansion of the electricity grid infrastructure must take place before the change in the supply task, so that in reality costs will already occur before the target year of 2050.

The cost differences between scenarios seem closely related to installed RES capacity differences as many grids must be extended due to high installed RES capacity. Load seems to play only a minor role in terms of grid extension needs. Even though, compared to today the system load doubles and the generation capacity is increased by nearly a factor of seven, grid costs rise far less than the increase of the RES capacity. This makes it obvious that this capacity is certainly a cost driver, however, there are also further factors which are even more relevant.

Taking a look at the technology scenarios, there are only minor cost differences in the scenarios with a low share of synthetic gases (e-gas or hydrogen). These scenarios (all Elec-scenarios and H2- and E-fuel-Scenario with a penetration equal to or lower than 20%) also show only smaller differences of installed RES capacity and system load. With nearly EUR 93 billion per year (237% related to today's cost) the H2_80-scenario shows the highest cost of all scenarios followed by the E-Fuel_80-scenario with nearly EUR 92 billion per year (228%).

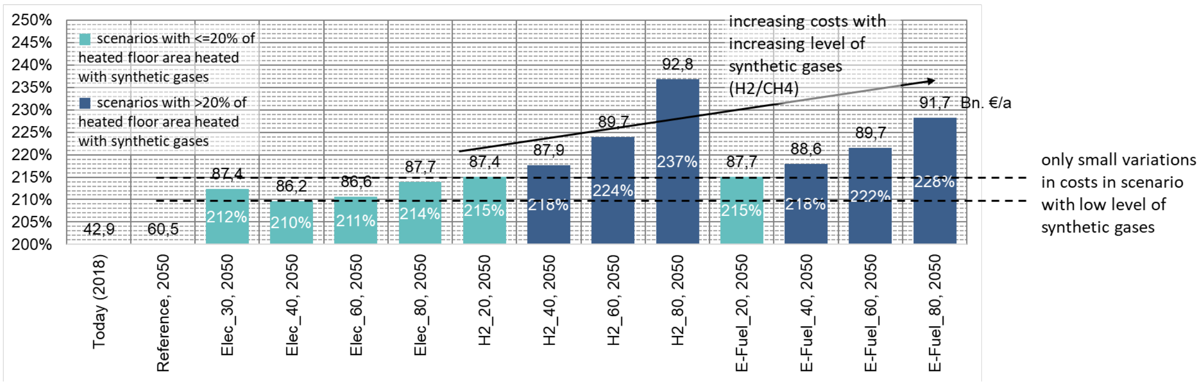

Figure 36: Annual cost in 2050 including necessary grid expansion from 2030 to 2050 for EU-27 comparing technology scenarios with the initial grid in 2030, reference scenario

Sector conclusions

- GHG-neutral technology scenarios' costs of the electricity distribution networks are are higher than these costs in the reference scenario
- But even the reference scenario's costs are nearly 50% higher than today's costs
- Among the technology scenarios H2_80 shows the highest cost increase
- Differences between 20 to 60% penetration scenarios are only small
- Even though, system load doubles, RES capacity increased by ~7, grid costs rise far less than the increase of the RES capacity
- Regardless of this, cost differences between scenarios seem closely related to RES capacity differences as many grids must be extended due to high RES capacity and load only plays a minor role
- Hence electricity scenarios show lowest cost increases among technology scenarios even though they face the highest load

3.6. Distribution infrastructure (CH4 + hydrogen)

Modelling approach

In principle, the approach of the gas model corresponds to one of the electricity model (section 3.5) but there are energy-carrier-specific characteristics of gas compared to electricity related to technical criteria (e.g. diameter and resistance (roughness) of pipelines, upper limit for the flow velocity, upper and lower nominal pressure and flow capacity of pressure regulator stations), planning specifications, network structures (e.g. assignment of network levels according to functional criteria to the usual practical levels of "local final distribution", "local transport" and "regional transport") etc. All these characteristics have been implemented in a gas distribution system specific version of the EXOGON tool that was used to determine the effects of the different scenarios on the necessary gas distribution grids. Technical differences between CH4 and H2 are also considered. The model approach and the coupling to the preceding models is outlined in the following figure.

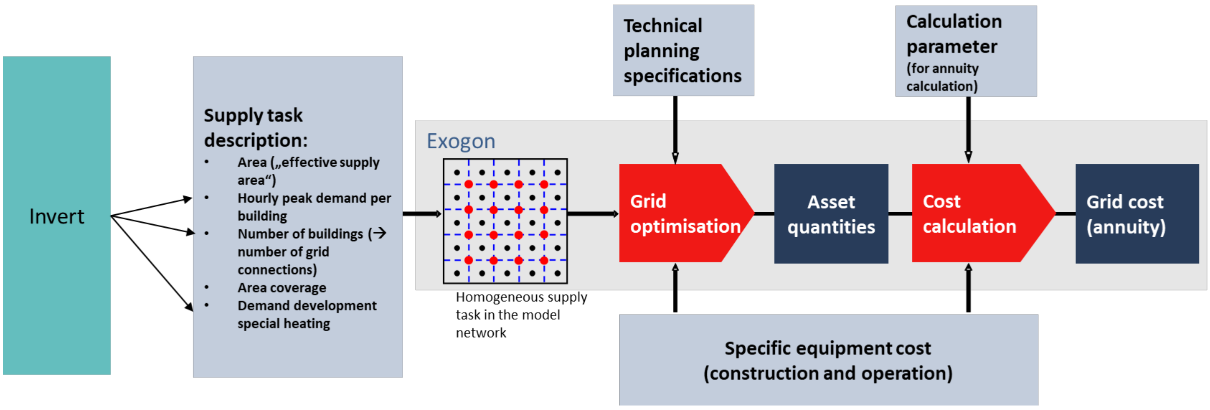

Figure 37: Model approach of the gas distribution grid model EXOGON an coupling to upstream models

Unlike electricity networks, gas networks usually cover only part of the total geographic area assigned to a network operator (supply area / concession area). Both the degree of area covered, defined as the share of the area covered by gas grids in the total supply area, and the degree of connection, which indicates the share of the buildings actually connected to the gas grid in the total number buildings existing within the area covered (and thus potentially connectable), have to be considered when describing the supply task of a (partial) supply area for the distribution model. To set up a model for today's situation, this information has been gathered from public sources[39]. Where such public data was unavailable, expert estimations were used and carefully elaborated based on typical values from similar countries or regions. Within a calibration step the main input parameters were set in such a way that the network quantities (line length, number of pressure regulator stations) determined by the model for today's situation will meet published values with good degree.

In the future we can expect that carbon neutral scenarios without usage of gases for space heating, gas demand will be significantly reduced. Such drop in the demand can be caused by different developments in the building sector[40] that have individual effects on the gas distribution grids:

- Decreasing number of buildings using gaseous energy carriers for heating: buildings are heated with other energy carriers (e.g., direct use of electricity in heat pumps); the gas demand of a building not heated with an alternative remains unchanged
- Reduced individual gas demand per building supplied with gas: number of buildings connected to the gas distribution grids remains unchanged but due to efficiency measures utilisation hours or peak demand are lowered

If the number of buildings supplied with gas decreases either the connection rate in the area covered or the area covered (or a mixture of both) depending on the individual situation will be reduced. If only the connection rate can be reduced the spatial extent of the grid will not significantly be reduced (case 1 in Figure 38). In case the area covered can be reduced also grid's spatial extent will be lowered (case 2 in Figure 38).

[39]e.g., https://ec.europa.eu/energy/eu-buildings-database_en and https://episcope.eu/building-typology/

[40] Today, gas distribution grids supply space heating as well as users from other sectors, e.g., small industry. Within modelling we assume that developments, e.g., gas demand, in other sectors using gas distribution grids are the same as in the space heating sector.

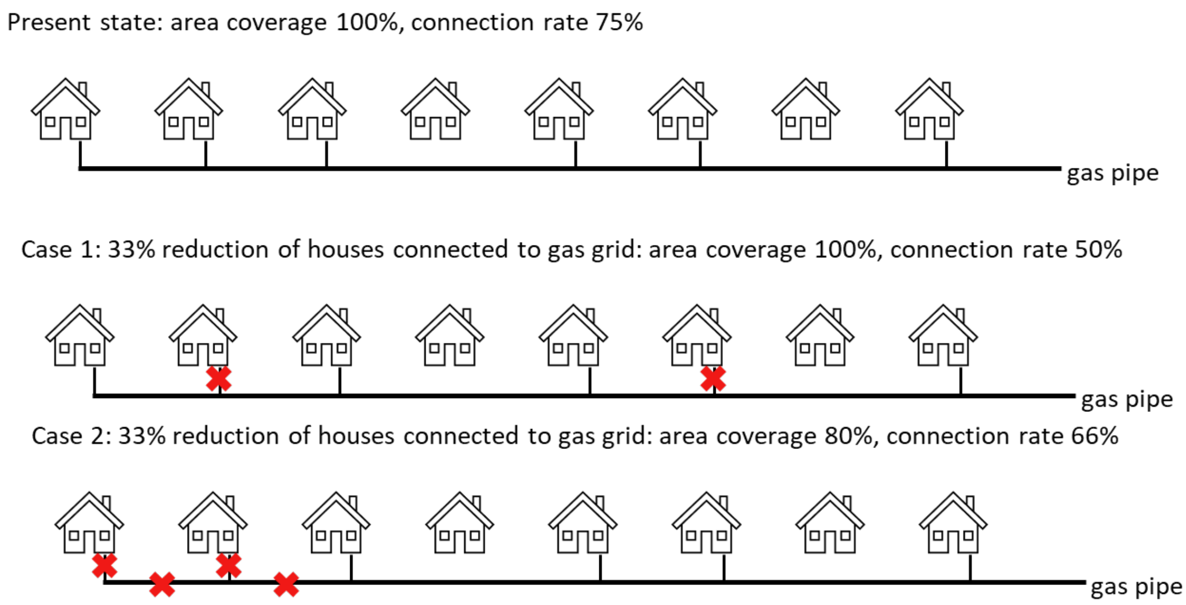

Figure 38: Example of grid effects due to different ways of modelling demand reduction

If the area coverage and the connection rates remain unchanged and a demand reduction is caused e.g. by efficiency measures or usage of alternative energy carriers such as solar thermal energy, the grid effects depend on whether utilisation hours or peak demand is reduced. Since grid dimensioning is influenced by peak demand, among other factors, but not by the total amount of energy transported, a change in utilisation hours without a change in peak demand has almost no effect on network quantities. Even if peak demand is changed a change of the supplied area will have a larger effect on grid quantities as test calculations show. In reality, a mixture of all the influencing variables mentioned above will result.

To meet the country specific target values that result from the Invert model for the technology scenarios focussed on E-fuel and H2 the area covered was increased in all regions that presently have lower shares of buildings heated with gaseous energy carriers than the target value. In the reference and especially in the electricity scenarios the demand is significantly reduced and according to that we assumed the number of buildings supplied with gaseous energy carriers to be reduced in the same ratio. As discussed before a decrease of connections must not lead to a decrease of the supply area in the same magnitude. Therefore, two variants were calculated to cover the range of results. Firstly, it was assumed that the area supplied would only decrease by 20% (respectively 10% in the reference scenario), as buildings and commercial premises would continue to be supplied with gas. Secondly, it was assumed that the area supplied would decrease in the same proportion as demand.

Besides the spatial distribution of the gas connections the dimensioning of the grids also depends on the level of the peak hourly gas demand of the heating devices connected to the distribution grids, and not on the annual downstream. Therefore, also the installed power of heating devices is considered as an output from the Invert building stock model.

The main result from the Exogon distribution grid model are grid quantities (line lengths, number of stations) that are necessary to meet the supply task. These quantities were multiplied with specific costs for investments and operation for which uniform (non-country-specific) values were used. In a second step these costs were transferred into annuities applying the interest rate commonly applied in this study of 2%. The annuities shown as results do not contain any costs for the decommissioning of pipes. Specific costs for decommissioning are in the magnitude of approximately 15% to 30% of the specific pipe costs. But these costs cannot simply be treated as investment costs and transferred into annuities because the depreciation time is not clear as there is no regular usage time for decommissioned equipment. Therefore, decommissioning costs are not included in the annuities. Further, no costs for retrofitting of pipes and stations have been taken into account. Even today many pipes used in distribution grids are ready to run on high shares of H2 and on the long run existing pipes and stations will be renewed and replaced by H2-ready material. Therefore, determined cost for distribution grids shown in the following can be regarded as kind of a lower estimate.

Results for technology scenarios

As previously outlined, the model is calibrated so that the model result approximates today's (2017) quantity structure of the pipes and pressure regulator stations in each of the EU-27 MS modelled considered. With the used specific investment costs and the interest rate of 2% the sum of today's (2017) annuities for the considered EU-27 equals approximately EUR 22.1 bn per year.

In the reference scenario the demand of gaseous energy carriers in the space heating sectors is reduced by approximately one third according to the Invert and Enertile model results. As a consequence, grid costs in the reference scenario are reduced by 17% to approximately EUR 18.3 bn per year (see Figure 39).

The demand of gaseous energy carriers of the space heating sector develops significantly different in the technology scenarios. Whereas the energy demand of the space heating sector to be supplied by the gas distribution infrastructure is compared to today significantly reduced by 2050 in the electricity scenarios (e.g. nearly zero in the 'elec-80' scenario), the gas (CH4 and H2) demand in the H2- and e-fuel-scenarios decreases as well but far less than in the electricity scenarios. Despite the demand of the space heating sector is reduced in these two scenarios (H2 and e-fuel) the peak hourly gas demand of the heating devices is increased substantially, compared to today, with increasing share of gas usage. This is reasonable because currently in many countries the heated floor area heated with gas is notably less than the target value in some the technology scenarios. Hence, many heating devices must be installed to meet the target value. However, the rated power of the individual heaters is lower than today because the peak heat demand is lower due to efficiency measures or usage of alternative energy carriers such as solar thermal energy.

As a result, it can generally be stated that gas distribution network costs differ significantly between the scenarios considered (costs range from approximately EUR 1.1bn /a to EUR 37.3 bn /a). The costs in the Elec-scenarios are lower than in all other scenarios. Looking at the "pessimistic" parameter set in terms of cost reduction grid costs decrease to 60% in 2050 in the 'elec-80' scenario that shows the lowest cost of all scenarios considered, whereas the cost decline to around five percent using the "optimistic" parameters. As mentioned above these values do not include costs for decommissioning of pipes. Furthermore, the costs of the four Elec-scenarios are significantly closer together than those of the other scenarios. Generally, the Invert model tends to try to minimise the use of gas. Unlike in the other scenarios, Invert has a larger margin of optimisation in the Elec-scenarios to minimise gas costs, which leads to more similar costs between the Elec scenarios than in the other scenarios.

The costs in the H2-scenarios are higher than in the corresponding E-fuel scenarios, which is mainly due to low energy density of H2. Further, all hydrogen scenarios result in higher cost than today, whereas all electricity scenarios and the E-fuel scenarios with low shares result in lower costs than today.

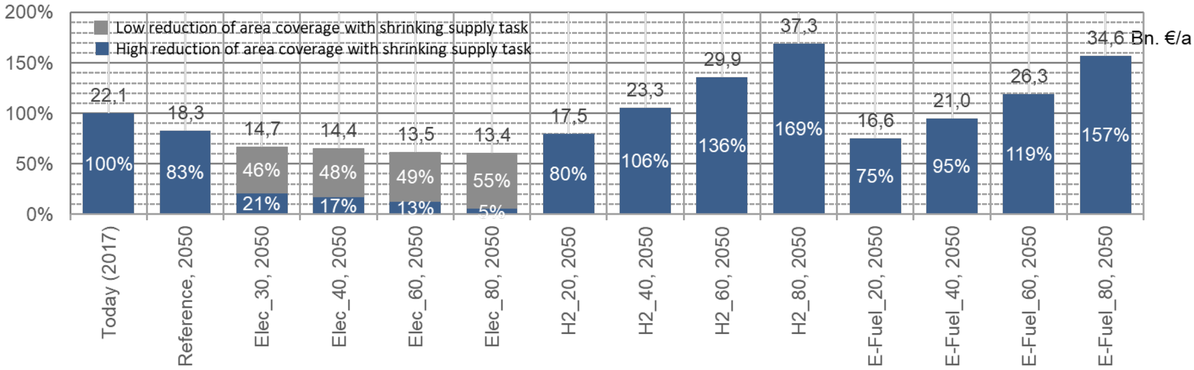

Figure 39: Development of gas distribution grid annuities (investments and operation costs) for reference and technology scenarios for 2050 related to today's cost (2017) for EU-27

The costs in the gas scenarios (E-fuel, H2) with gas shares above 40% are higher compared to all other scenarios because grids must be extended, and unsupplied areas must be developed in many countries. In countries with currently low connection degrees, such as Bulgaria, Finland, Sweden, Estonia, where today less than 10% of the buildings are connected to a gas network, a relative cost increase is significantly higher than in countries with larger degrees (Figure 40 exemplary for H2-scenarios). The smallest cost increase can be observed in the Netherlands, Italy, and Poland, which have high connection degrees already today. As these counties have already large gas distribution networks today, they dampen the relative average cost increase weighted with system size. In more than 50% of the countries the country specific relative cost increase is – partly significantly – higher than the relative average cost increase weighted with system size.

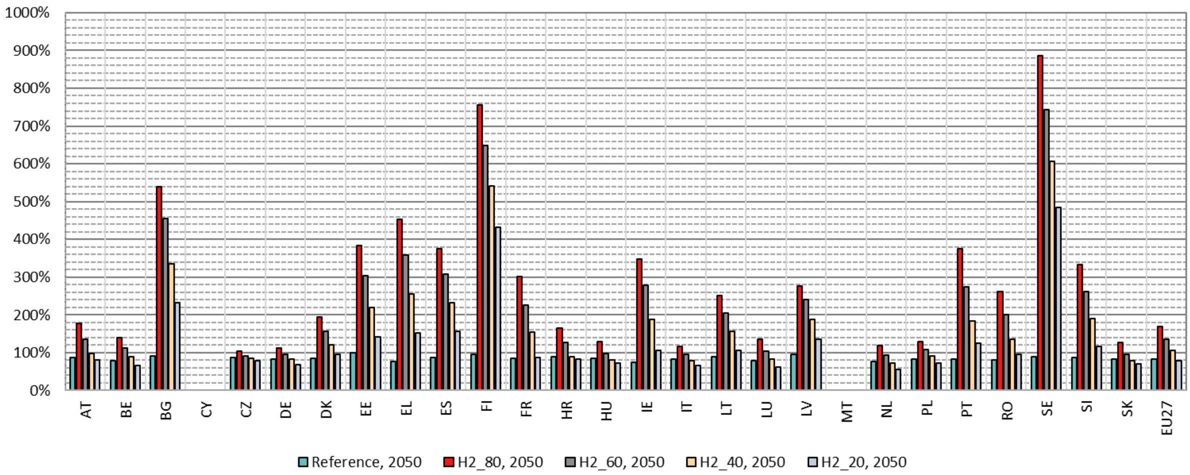

Figure 40: Relative cost increase per country in the H2-scenarios

Results indicate that in MS with low connection rates and, hence, only limited or regionally concentrated gas distribution networks today, scenarios with a high penetration of gas fired heating systems lead to a very significant cost increase. Naturally, this increase is very high in relative terms. But this increase is also high in absolute values and substantially contributes to the overall cost increase. Further analysis show that members states with today only small gas distribution networks are mostly countries which are characterised by low population density. This appears reasonable because with identical offtake, a higher network length is required to supply widely spaced buildings than more densely populated areas, so the offtake-related costs are higher in sparsely populated areas, making them less competitive with alternative heating options. Hence, at least for MS with low population density and thus only small gas distribution networks today, it is appears to be clearly not beneficial to significantly increase the share of gas fired heating system in such member state / regions. As in such MS buildings are not connected to gas networks but in any case to electricity networks, the "anyway-existing" electricity network should be used to distribute the energy used for heating. However, should sources other than electricity be used for spatial heating in those countries, e-liquids are more likely to be an economic alternative than grid-bound gaseous energy sources. For MS with today already substantial gas distribution networks the economic profitability of the different heating alternatives is subject to the overall scenario comparison. In any case substantial cost reductions can be achieved with a coordinated planning of gas networks. If a certain share of buildings is be heated with (carbon-neutral) gaseous fuels and grids must be extended for this purpose, preference should be given to areas with high demand and connection density.

Sector conclusions

- Costs in Elec-scenarios are approx. 30% to 95% lower than today, but not zero as gas is used also in these scenarios (with different shares)
- Any of the four Elec-scenarios has lower gas distribution grid costs than the other scenarios.
- Highest cost increases occur in H2-scenarios with higher penetration and in the 'E-Fuel_80' scenario; highest relative cost increases occur in countries currently having only small gas grids, whereas countries with already large systems today dampen the average relative EU-27-wide cost increase
- Results indicate that in MS with low connection rates and, hence, only limited or regionally concentrated gas distribution networks today, scenarios with a high penetration of gas fired heating systems lead to a very significant cost increase.
- Hence, at least for MS with low population density and thus only small gas distribution networks today, it is appears to be clearly not beneficial to significantly increase the share of gas fired heating system in such member state / regions. As in such MS buildings are not connected to gas networks but in any case to electricity networks, the “anyway-existing” electricity network should be used to distribute the energy used for heating. However, should sources other than electricity be used for spatial heating in those countries, e-liquids are more likely to be an economic alternative than grid-bound gaseous energy sources.
- For MS with today already substantial gas distribution networks the economic profitability of the different heating alternatives is subject to the overall scenario comparison.
- In any case substantial cost reductions can be achieved with a coordinated planning of gas networks. If a certain share of buildings is heated with (carbon-neutral) gaseous fuels and grids must be extended for this purpose, preference should be given to areas with high demand and connection density. In case of a decommissioning of existing grids, such areas with low connection densities should preferably be decommissioned first.

4. Scenario comparison

4.1. Scenario comparison based on different indicators

In the following, the results of the overall comparison between all scenarios are presented (i.e., combination of all model results). The main objective of this section is the identification of the (cost-) optimal technology scenario in order to derive recommendations for the cost-effective level of electrification and technology mix in a decarbonised space heating sector.

In addition to the different aspects already presented in the previous sections, Figure 41 shows the annualised system costs[41] occurring in the different technology scenarios compared to the costs of the reference scenario in the specific year. It has to be noted that the reference scenario (opposed to the technology scenarios) does not reach the goal of GHG-neutrality by 2050 and system costs do <u>not</u> include costs of missing GHG-reduction targets. Figure 42 shows furthermore the annualised system costs compared to the average costs of all technology scenarios. It becomes clear that while cost differences between the scenarios are rather low in the period up until 2030, cost difference in the coming decades become much more substantial.

In general, scenarios with a comparatively low usage of hydrogen or e-fuels in the heating sector, i.e., all Elec scenarios and the scenarios where hydrogen or e-fuels are fixed to 20% of the heated floor area (H2_20 and E-Fuel_20), have lower costs. The reason for this result is that at least under the given assumptions (see section 2), in these scenarios heat pumps, both on decentral level or as part of the district heating system, are the dominating technology. Heat pumps are also the cheapest solution for heating. There seems to be an (cost) optimum with regards to the share of direct decentral and central electrification when the use of direct decentral electric heating is in the range of 40% and 80%. Among the scenarios analysed, the Elec_60 scenario is the cheapest with a very small difference compared to Elec_40 and Elec_80. Compared to these more cost-efficient scenarios, the H2_80, E-Fuel_80 and E-Fuel_60 scenarios result in a substantial cost increase (compare Figure 41 and Figure 42).

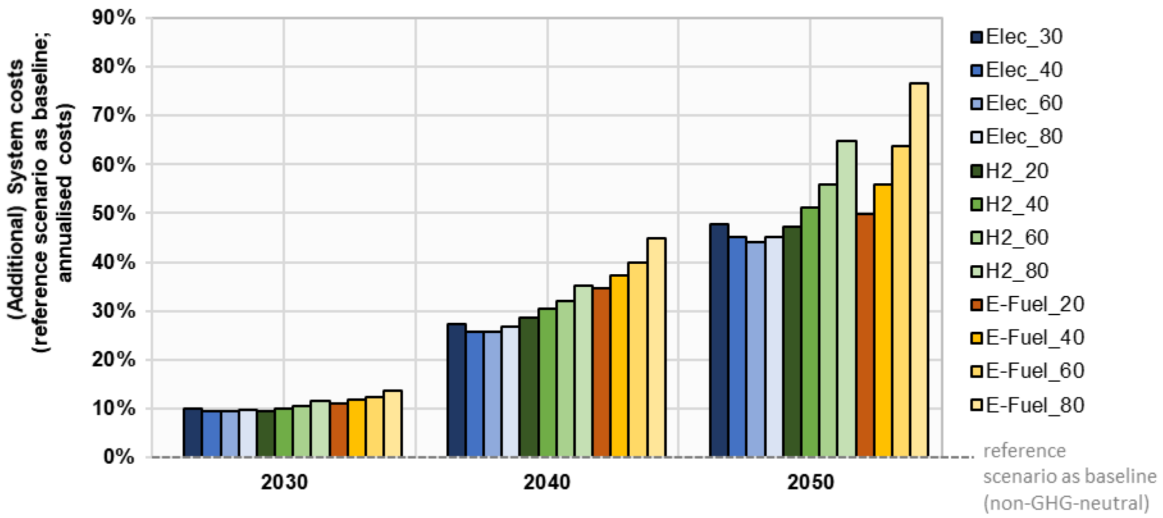

Figure 41: System costs of technology scenarios with (non-GHG-neutral) reference scenario as baseline; system costs do <u>not</u> include costs of missing GHG-reduction targets in reference scenario

---

[41] The system costs include capital expenditures, operation and maintenance costs as well as variable energy costs of all models used in this study. The district heating infrastructure costs are estimations that were calculated with specific costs in EUR/MWh elaborated from the Hotmaps district heating expansion module.

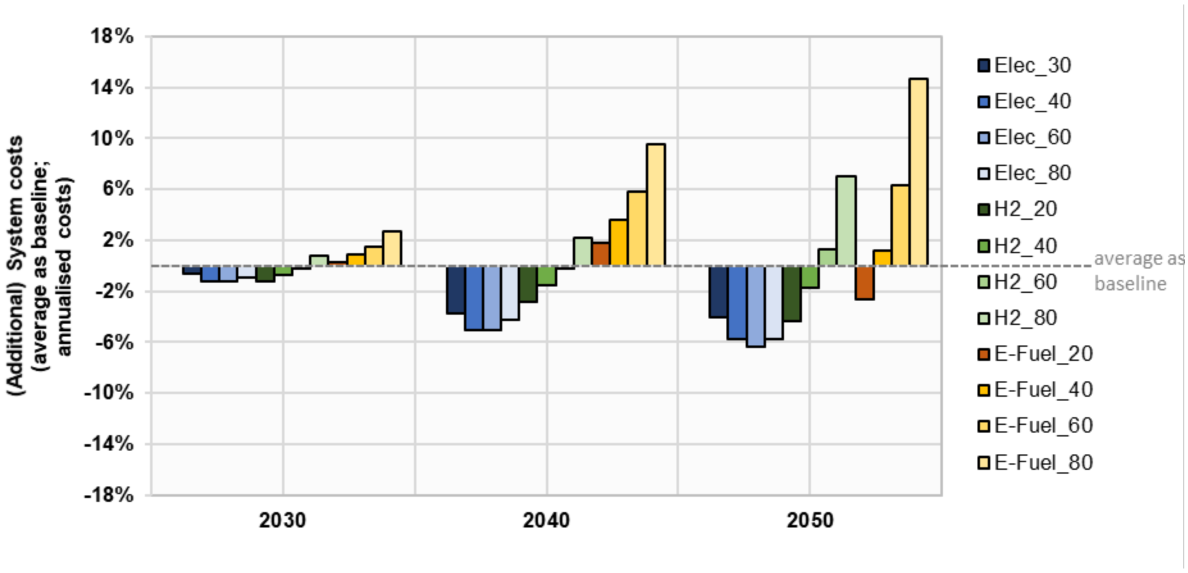

Figure 42: System costs of technology scenarios with average of technology scenarios as baseline

Figure 43 visualises the breakdown of the system costs in 2050 in capital expenditures (CAPEX), operation and maintenance costs (OPEX) as well as variable energy costs (i.e., fuel costs and electricity for heat generation). Differences between the scenarios are mainly due to higher CAPEX for (decentral and central) heat generation and higher OPEX and variable energy costs (for decentral heating). In particular, scenarios with a high penetration of hydrogen or e-fuels have higher variable energy costs for decentralised heating. In absolute terms, the H2_80 has up to six times and the E-Fuel_80 up to ten times higher variable energy costs (in €) for decentral heating compared to the Elec_60 scenario.

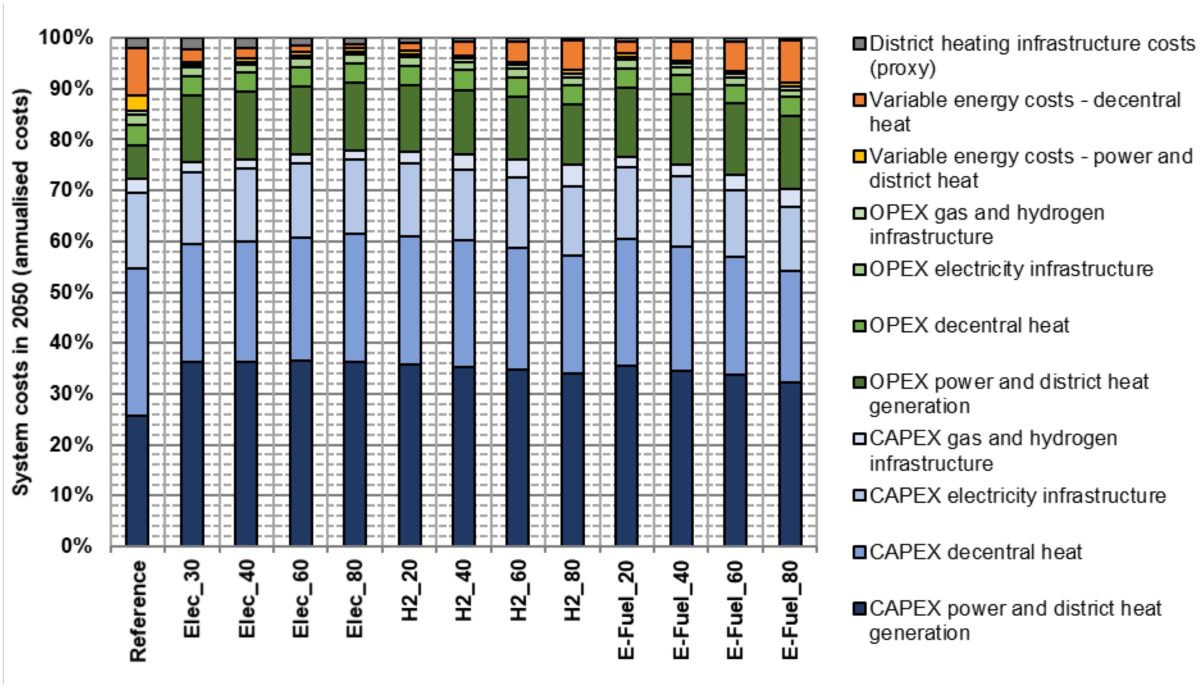

Figure 43: System costs in 2050 divided in CAPEX, OPEX and variable energy costs (i.e., fuel costs and electricity for heat generation)

Figure 44 shows the cumulative investment requirements from today until 2050 for all scenarios within the EU-27 MS[42]. Figure 46 visualises the differences between the technology scenarios more clearly by showing the difference of the cumulative investments to the average investments of the technology scenarios, i.e. average of investments is used as a baseline. While in comparison to the non-decarbonized reference scenario, all technology scenarios have a much increased investment need and differences between the scenarios are moderate. Still, all Elec scenarios (i.e., the scenarios with low hydrogen or e-fuels penetrations) imply a lower need for investment. The E-Fuel_80 and the H2_80 scenarios have the highest investment requirements. In all technology scenarios, investments in electricity infrastructure have a high share of around 20% of the total investments (see Figure 44). In absolute numbers, investments in electricity grids are highest in the H2_80 and the E-Fuel_80 scenarios. The production of hydrogen or e-fuels require higher electricity generation within the EU, which reasons higher investment needs in electricity grids.

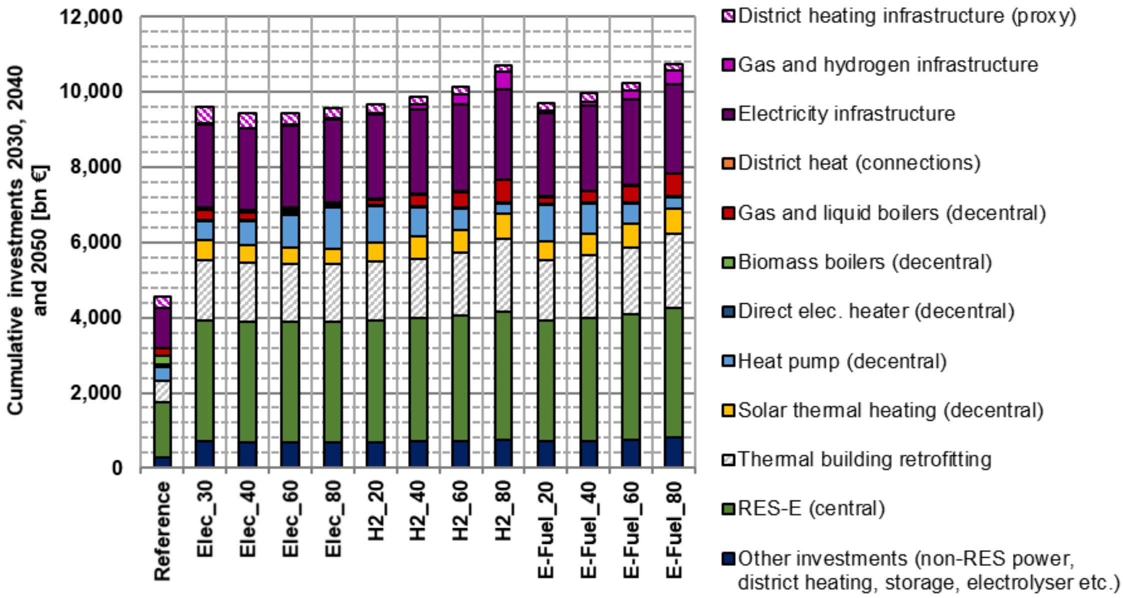

Figure 44: Cumulative investments in technology scenarios and reference scenario (2030, 2040, 2050) (price basis: € 2018)

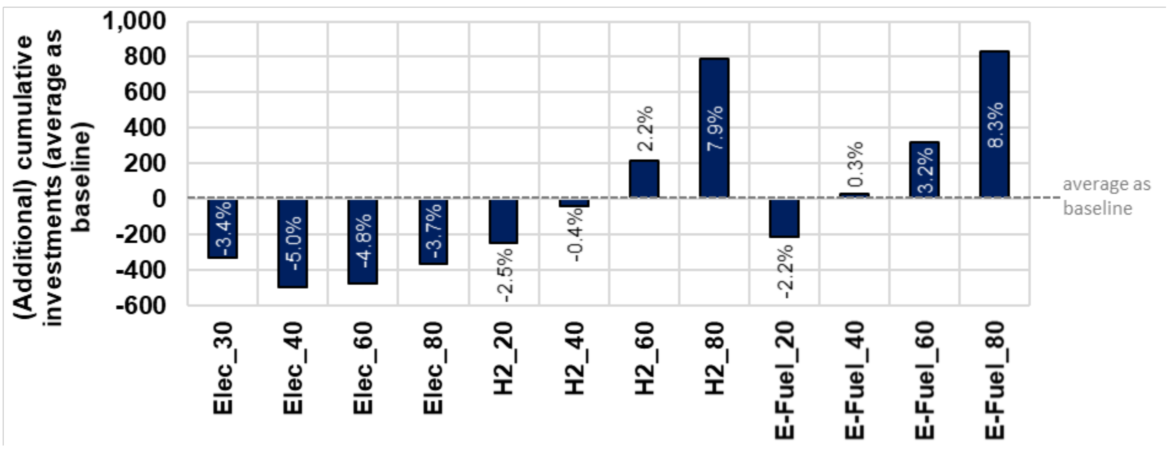

Figure 45: Cumulative investments (2030, 2040, 2050) with average of technology scenarios as baseline (price basis: € 2018)

[42] Note that the investments do not include investments in the replacement of existing electricity grids. Besides, further investments of varying amounts might be necessary in the different scenarios outside EU-27 to serve the EU-27 energy demand, e.g. RES-E-production facilities producing electricity transported to EU-27 MS via the interconnected electricity grid. Such investments are not included in the graph. Further note that the start year in the different models slightly differ, i.e. in some models it is 2018, while others start in 2020.

Apart from the total system costs and the investments, some other parameters are of interest when assessing the characteristics and performance of different scenarios. These include the necessity to build additional grid infrastructure for electricity, hydrogen, and district heating; the overall need for RES electricity within EU-27 as well as the additional (electricity) demand for energy carrier conversion to hydrogen and e-fuels; the requirement for imports of e-gas; and the overall useful energy demand for heating and cooling[43] (as an indicator for the required renovation rate in buildings[44]).

Table 24 gives an overview of these indicators for all technology scenarios including, again, the indicators system costs and investment needs discussed more thoroughly above. With regards to useful energy demand, while differences are relatively small, the scenarios with high hydrogen and e-fuels shares (H2_80 and E-Fuel_80) have a lower useful energy demand compared to high electrification (Elec_80) and thus require more efforts with regards to building renovation rates. If these rates cannot be achieved these scenarios would even lead to higher system costs than shown above.

Differences in RES electricity generation within the EU-27 are not very pronounced either. However, the highest values are required in the scenarios with high shares of hydrogen or e-fuels. Similar, the demand of gaseous energy carriers (i.e., hydrogen, e-gas and biogas) in buildings is highest in the scenarios with high shares of hydrogen or e-fuels. While e-gas imports from outside the EU are required in all scenarios, clearly the scenarios with high e-gas shares have the highest needs here, with quite substantial differences especially compared to the corresponding hydrogen scenarios. This is due to the fact that e-fuels on the one hand require even higher amounts of electricity for the production and on the other hand, can be transported more easily than hydrogen.

With regards to grid infrastructure requirements, the Elec scenarios need more district heat grids due to the higher district heating demand, especially at low degrees of decentral electrification (i.e., Elec_30). Electricity grid expansions are at a very similar level in all scenarios and slightly higher in the scenarios with high hydrogen shares due to the higher renewable electricity generation within the Europe.

[43] Useful energy demand in the case of space heating is based on the standard Energy performance of buildings (ISO 13790:2008): Energy needs for heating or cooling to be delivered to, or extracted from, a conditioned space to maintain the intended temperature conditions during a given period of time. Thus, useful energy is the energy needed for heating and it is basically the balance of losses and gains.

[44] The necessity for major changes in the heating system (i.e., from a gas boiler to a heat pump system which also implies changes in the heating equipment in individual rooms) as another indicator for renovation requirements would also be useful. However, as the modelling optimizes total system costs in each scenario which results in e-fuels and hydrogen heating in renovated buildings this indicator cannot be used to compare the calculated scenarios.

Table 24: Scenario comparison along different indicators

indicator / scenario	Elec_30	Elec_40	Elec_60	Elec_80	H2_20	H2_40	H2_60	H2_80	E-Fuel_20	E-Fuel_40	E-Fuel_60	E-Fuel_80
system costs in 2050 compared to average of technology scenarios [%]	-4.0%	-5.7%	-6.4%	-5.8%	-4.3%	-1.7%	1.3%	7.0%	-2.7%	1.2%	6.3%	14.7%
cumulative investments 2030, 2040 and 2050 [bn €]	9,598	9,429	9,455	9,566	9,681	9,887	10,148	10,719	9,716	9,960	10,249	10,759
useful energy demand in 2050 [TWh]	2,015	2,028	2,046	2,060	2,047	2,029	2,002	1,953	2,042	2,015	1,979	1,935
RES electricity generation in 2050 [1000 TWh]	1,284	1,284	1,280	1,276	1,289	1,308	1,323	1,331	1,281	1,286	1,290	1,292
demand of gaseous energy carriers in buildings in 2050 [TWh]	88	59	37	31	129	258	433	688	120	237	405	658
e-gas imports (outside Europe) in 2050[45] [TWh]	320	313	314	319	293	280	254	222	381	438	521	649
district heating demand in 2050 [TWh]	546	460	388	278	221	195	187	134	196	185	186	139
electricity transmission grid in 2050 [1000 kms]	402	398	400	405	404	403	404	408	404	405	405	409
electricity distribution grid in 2050 [system costs in bn €]	87	86	87	88	87	88	90	93	88	89	90	92
new hydrogen and e-gas transmission grid in 2050[46] [1000 kms]	19	19	20	19	19	18	18	20	20	19	20	19
hydrogen and e-gas distribution grid in 2050 [system costs in bn €]	15	14	14	13	18	23	30	37	17	21	26	35

Overall, the comparison of scenarios shows that directly electrifying a substantial amount of the heating demand of buildings seems to be beneficial both in terms of costs but also with regards to infrastructure and import requirements (see Figure 42, Figure 44 and Table 24). Among the modelled scenarios, the Elec_60 scenario reaches the lowest costs. Further, for high shares of direct electric heating the cost-efficient level of building renovation measures is slightly lower than in the scenarios with high shares of hydrogen or e-gas used for space heating. In the latter scenarios (slightly) higher efforts with regards to building renovation are cost-efficient to avoid the high variable energy costs of hydrogen and/or e-gas. In addition, scenarios with higher shares of direct electric heating lead to either slightly lower requirements

[45] There are no hydrogen imports from outside Europe (see section 3.2).

[46] Dedicated and retrofitted pipelines.

of RES electricity generation (and thus electricity grid expansions) or lower import requirements. Thus, we conclude that the Elec_60 scenario is the (cost-) optimal scenario out of the modelled scenarios.

4.2. Characteristics of the (cost-) optimal scenario

The scenario comparison shows that the Elec_60 is the scenario with the lowest costs of all modelled scenarios (see section 4.1). In detail, this scenario comprises the following characteristics:

- In 2050, 60% of the heated floor area is covered by electricity driven heating systems (in line with assumptions; see section 2 and 3), i.e. 60% of decentral direct electrification with around 50% heat pumps and around 10% electric boilers. The remainder of the floor area is covered by a high share of district heating, i.e., around 25% in 2050. Decentral heating systems that use gasoues and liquid energy carriers (hydrogen, e-fuels, biofuels) reach only shares of around 12% of the heated floor area in 2050. Solar thermal and biomass (decentral) also reach rather lower shares (i.e. 16% and 6% respectively of the final energy demand of buildings). Cumulative investment from today to 2050 for decentral heating systems, including district heating connections, amount to about 1,491 billion €.
- District heating generation is dominated by central large-scale heat pumps with a share of around 60% of total generation. This is followed by biomass with around 20%, solar thermal energy with around 10% and geothermal energy of around 5%. Hydrogen boilers are only used as a backup technology with around 3% of the generation and around 20% of the heat generation capacity. Cumulative investment requirements for for district heating infrastructure and generation reach around 536 billion €.
- Hydrogen and e-gas transmission grids reach around 20,000 km in 2050, which includes ~12,600 km (65%) dedicated pipelines and ~6,900 km (35%) retrofitted pipelines. Distribution grids reach around 1,318,000 km. Cumulative investments in hydrogen and e-gas infrastructure amount to 20 billion € and, hence, remain very low to compared investments needs in other parts of the energy systems.

Furthermore, some (major) developments are common across all scenarios:

- An uptake in building renovation, particularly comprising deep retrofitting, is costs-efficient in all scenarios. In the Elec_60 scenario energy saving of around 45% (based on energy needs) and a renovation rate[47] of 1.5-2.0% (deep renovation equivalents), corresponding to more than doubling of renovation rates compared to the reference scenario, on EU-27 average must be reached for a period of 30 years. Thermal building retrofitting investment requirements in the Elec_60 scenario amounts about 1,550 billion € from today to 2050.
- Dominating technologies in the EU-27 electricity mix are onshore wind, followed by photovoltaics and offshore wind in all scenarios. In 2050, in the Elec_60 scenario, RES generation reaches a share of around 92% of the electricity generation and 3,187 billion € cumulative investments in RES generation are needed. Hydrogen plays a minor role in the electricity generation (same accounts for e-gas) and is mainly used as a back-up technology in hours with low RES generation and when other flexibility options are not sufficient.

[47] Renovation rate is calculated with the total refurbished area divided by total area per year. Measures that affect the heat supply system only, are not considered within this indicator.

- A strong increase in electricity transmission grid length and interconnection capacities can be observed in all scenarios. In addition, distribution grid capacities need to be expanded. Cumulative investments from 2030 to 2050 in electricity infrastructure in the Elec_60 scenario reach 2,185 billion €.

In the following, results on MS level are presented. Figure 46 shows the difference of the system costs in 2050 between the scenario with the lowest costs, i.e., Elec_60, and the scenario with the highest costs, i.e., E-Fuel_80. In Croatia and Luxembourg, the costs in the Elec_60 are more than 50% lower compared to the E-Fuel_80. Only in Malta the system cost in the Elec_60 are slightly higher (5%), which can be explained by Malta being an island.

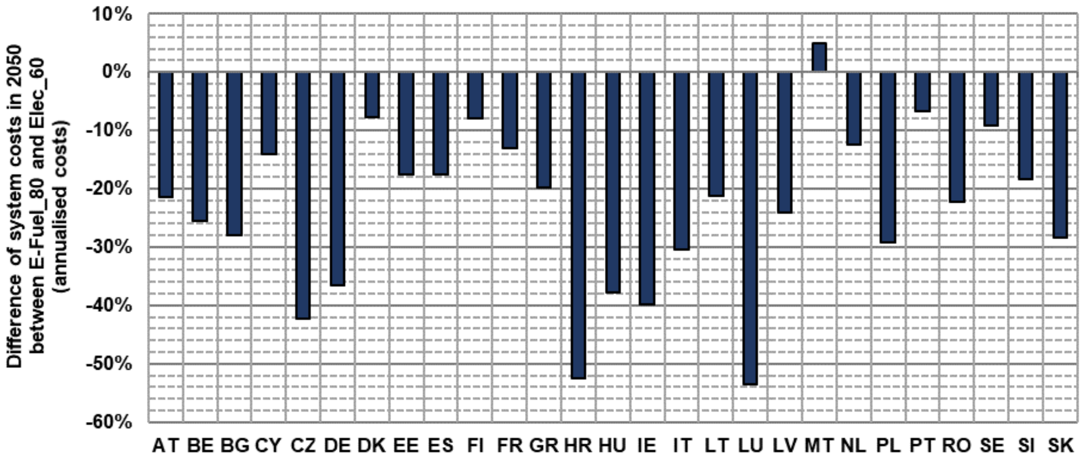

Figure 46: Difference of system costs in 2050 between the Elec_60 and the E-Fuel_80 scenario

For selected MS, Figure 47 compares the breakdown of the system costs in CAPEX, OPEX and variable energy costs in the Elec_60 and the E-Fuel_80 scenario. In most MS, differences in the (absolute) costs result in particular from higher CAPEX for (decentral and central) heat generation as well as higher OPEX and variable energy costs for decentralised heating in the E-fuel_80 compared to the Elec_60 scenario. In Malta, the Elec_60 scenario entails higher OPEX for decentralised heating.

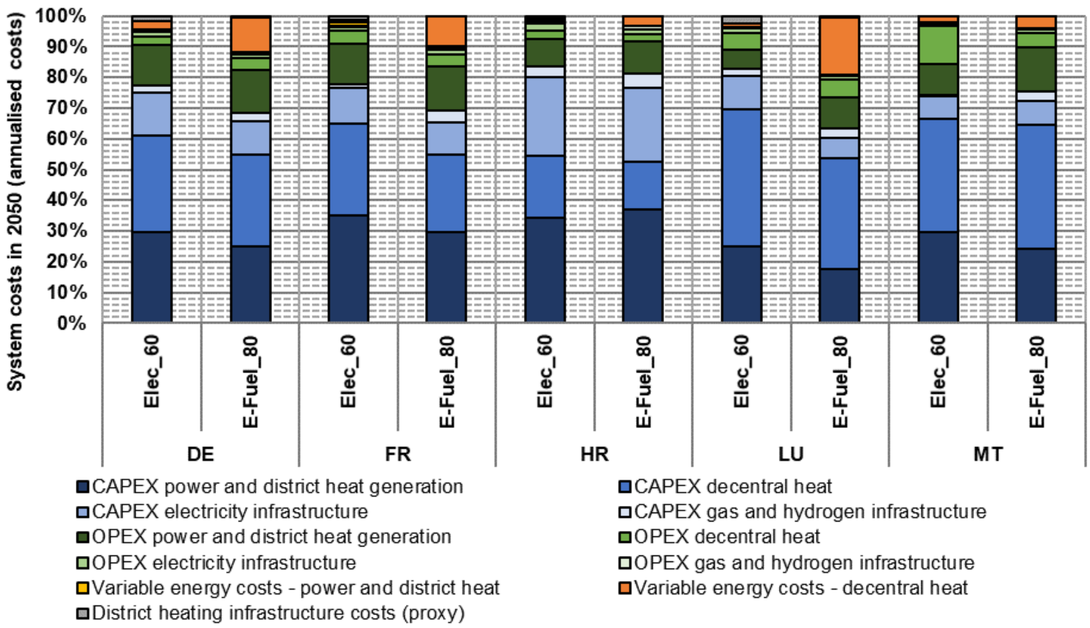

Figure 47: System costs in 2050 divided in CAPEX, OPEX and variable energy costs in the Elec_60 and E-Fuel_80 scenario for selected MS

Lastly, Figure 48 compares the cumulative investments in the MS in the Elec_60 and the E-Fuel_80 scenario. The E-Fuel_80 scenario has higher investments need in all MS (except for Italy). Besides, the figure visualises that (comparatively) high investments are required in Germany, France, Spain, Italy, the Netherlands and Poland.

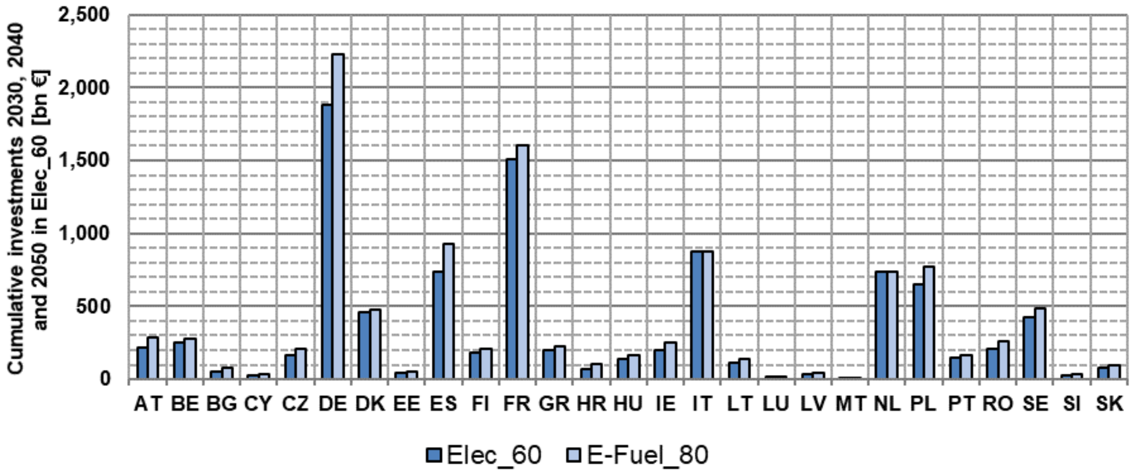

Figure 48: Cumulative investments 2030, 2040 and 2050 in Elec_60 and E-Fuel_80 scenario in bn €

Conclusion

Based on the assessment of differences between the scenarios, the following conclusions can be drawn:

- Both decentral and central (via district heating) direct electrification leads to lower costs for heating when compared to both hydrogen and e-fuels. The main technology used for direct electrification are heat pumps.
- The cost-optimal distribution between central and decentral direct electrification is reached between the 40% and 80% Elec scenarios. In the analysis drawn, the lowest system costs are reached in the Elec_60 scenario.
- A cost-optimal transformation of heating in buildings based on high shares of decentral direct electric heating requires slightly lower efforts with regards to building renovation when compared to the other scenarios.
- Apart from higher costs, scenarios with higher shares of hydrogen and e-fuels lead to either slightly higher requirements of RES electricity generation (and thus electricity grid expansions) or higher import requirements.
- The scenarios with a comparatively low share of decentral electrification and at the same time no minimum requirements for hydrogen or e-fuels imply higher district heating expansions (i.e., Elec_30 scenario).
- In the scenario with the lowest costs (i.e., Elec_60), only a small fraction of the floor area is still heated with gaseous energy carriers. According to the optimization results, these are predominantly buildings, which have been constructed most recently and use a fairly new gas-based heating, and which do not need to change their heating systems from a technical point of view. Furthermore, the future gas demand is also defined by the current gas utilization. Countries, where gas currently plays an important role are going to have somewhat higher gas demand in the future. With a coordinated planning of the gas distribution networks

substantial cost-reduction can be achieved by reducing the grid length needed to further supply the remaining buildings using gaseous energy carriers for heating.

- The comparison of scenarios leads to the final conclusion that directly electrifying a substantial amount of the heating demand of buildings seems to be beneficial both in terms of costs but also with regards to infrastructure and import requirements. The ideal distribution between decentral direct electric heating and central direct electric heating based on district heating grids is in the range of the Elec_60 scenario (65% of energy demand is based on electricity and ambient energy used in heat pumps).

5. Barriers and policy recommendations

In the previous sections, technology scenarios with different degrees of direct and indirect electrification of space heating[48] were modelled and analysed. Overall, some commonalities, but also major differences between the scenarios exist. The scenario with the lowest costs is the Elec_60 scenario (see section 4). In the following, barriers are identified and an overview of the policy landscape relevant for the transition as outlined in the Elec_60 scenario is provided.

The analysis builds on a comprehensive literature review. In this process, different types of literature, such as studies and reports as well as scientific publications were considered. Overall, around 40 publications including over 75 barriers and 50 policy measures were analysed (see list of publications in Annex B).

The scenario comparison in section 4 shows that in all scenarios a strong uptake in RES electricity generation as well as electricity infrastructure development are needed. In addition, a substantial uptake of building renovations is necessary. These developments are part of all scenarios with small variations and thus can be seen as key elements of a transition towards a climate-neutral energy system in general and a climate-neutral space heating sector in particular by 2050. To reach the scenario with the lowest costs (i.e., Elec_60), a strong uptake of direct electric heating technologies, especially heat pumps, is needed. At the same time, an expansion of district heating is cost-efficient, whereby the increased district heat demand is supplied to a large extent by large-scale heat pumps. This underlines the key role of heat pumps on a decentral level as well as in district heating systems. However, direct renewables also show an increasing share in decentral and in district heating systems, compared to today. Lastly, there is also a market ramp up of hydrogen, which is of less relevance for decentral heating solutions. In district heating, hydrogen is used as a backup technology. These elements of the transition are the basis for the analysis of barriers and policies.

The focus of the barrier and policy analysis lies on the electrification of space heating, i.e. decentralised heating and (centralised) district heating to meet the heat demand in buildings. Process heat for industrial processes is not covered in this study. Besides, barriers to and policies for RES electricity generation and electricity infrastructure development are not in the scope of the analysis, as barriers in theses contexts are no specific issue for the transformation of the space heating sector but rather a general issue for the overall transformation of the energy system. However, barriers and policies for RES electricity generation and electricity infrastructure have already thoroughly been discussed in recent literature: For details on such

[48] As stated in the beginning of the report, the term "space heating" is used throughout the text as synonym for space and water heating in buildings.

barriers and policies see, for example, the European projects DIA-CORE[49], RE-frame[50] or AURES[51]. Besides, district heating expansion and direct use of renewable heat (e.g. direct use of heat with geothermal or solar thermal plants, biomass boilers etc.) are only partly discussed. For details on barriers and policies regarding district heating and the direct use of renewable heat see the European projects DHC Trend[52], RES Heat[53] and H&C Pathways[54].

5.1. Barriers to the recommended cost-effective scenario

In the following an overview of barriers to the electrification of space heating is provided. To display the analysed barriers in a holistic structure, three types of barriers are distinguished[55]: (1) financial-economic barriers, (2) institutional-structural, market-oriented and technical barriers, and (3) non-market social barriers. Furthermore, the affected side (i.e., the supply side, the demand side or both), the pathway that is concerned (i.e., direct electrification, indirect electrification or both) and the heating areas (i.e., decentral or central/district heating) is indicated.

Three types of barriers

Financial-economic barriers affect technology market penetration due to their negative impact on the economic or financial viability. Typical for barriers of this kind are high costs associated with electrification technologies.

Institutional-structural, market-oriented and technical barriers derive from lacking or disadvantage legislation and framework conditions. Further, market-related and technical issues of integrating new technologies into the energy system as well as the challenges of specific technologies itself are included.

Non-market social barriers relate to the lack of awareness, familiarity, knowledge, acceptance and comfort of new technologies in society.

Source: Own elaboration based on Saccani et al. 2020 and Chassein et al. 2017

(1) Financial-economic barriers

Table 25 presents an overview of financial-economic barriers for the electrification of space heating. Technologies to generate heat from electricity typically require higher initial investments than fossil-based alternatives.[56] These higher upfront costs make the technologies today less costs competitive and hinder their uptake. Besides, in many MS, end consumer electricity prices are quite high mostly due to levys, taxes and tariffs, resulting in higher operation/variable energy costs compared to fossil-based alternatives. Thus, the price ratio between electricity and fossil fuels represents rather unfavourable economic conditions for the electrification of heat.[57] Furthermore, the decision for a more modern, i.e., in most cases a non-

---

[49] Policy Dialogue on the assessment and convergence of RES policy in EU Member States (DIA-CORE); https://www.isi.fraunhofer.de/de/competence-center/energiepolitik-energiemaerkte/projekte/dia-core_330663.html

[50] Renewable energy framework (RE-frame); http://www.re-frame.eu/

[51] AUctions for Renewable Energy Support II (AURES II), http://aures2project.eu/

[52] Overview of District Heating and Cooling Markets and Regulatory Frameworks under the revised Renewable Energy Directive (ENER/C1/2018-496)

[53] Renewable Space Heating under the revised Renewable Energy Directive (ENER/C1/2018-494)

[54] Renewable Heating and Cooling Pathways, Measures and Milestones for the implementation of the recast Renewable Energy Directive (ENER/C1/2019-482)

[55] Based on Saccani et al. 2020 and Chassein et al. 2017

[56] Saccani et al. 2020; Thomaßen et al. 2021

[57] Gaur et al. 2021; Golling et al. 2019

standard heating alternative, requires more 'hassle', i.e., information search and often administrative effort, thus adding to the economic costs.[58]

In addition, in several MS, a so-called 'split-incentive dilemma' can be observed.[59] While the home owners are typically the ones financing the measure, they are not the direct beneficiary of the investmentas in most cases, tenants are financially benefiting from reduced energy bills as a consequence of the measure financed by the home owner. Lastly, the lifetime of the asset is a crucial factor.

Table 25: Overview of financial-economic barriers

Sub-type	Barrier	Side	Pathway	Area
CAPEX	High upfront investment/ CAPEX/ lifetime costs of technologies hinders uptake	Supply and demand	Direct and indirect electrification	Decentral and district heating
	Split-incentive dilemma, where the investing home owner is not the direct beneficiary of savings from electrification (owner vs. tenant)	Demand	Direct and indirect electrification	Decentral heating
	High infrastructure investment costs for expanding district heating grids (in particular in dense urban areas)	Supply	Direct and indirect electrification	District heating
OPEX	High operating/variable cost due to high end-consumer prices for electricity makes technology less cost-competitive; (currently) unfavourable fuel price ratio between electricity and fossil sources	Demand	Direct and indirect electrification	Decentral and district heating
Other economic factors	Consumers face additional transaction costs for non-standard technologies, i.e., decision requires more effort and information	Demand	Direct and indirect electrification	Decentral heating

Source: Own elaboration based on various sources (see Annex B)

(2) Institutional-structural, market-oriented and technical barriers

Table 26 lists relevant institutional-structural, market-oriented and technical barriers for the electrification of space heating. Overall, there seems to be a lack of regulation and standardisation for electric heating technologies, such as heat pumps or hydrogen boilers.[60] Authorities lack the capacities and competencies to handle applications (from home owners) efficiently and procedures are often complex and lengthy (funding and installation).[61] Furthermore, investment security is a crucial enabling factor. However, a clear pathway for heat decarbonisation with concrete targets seems to be lacking, resulting in a low investment security. In addition, a clear pathway seems to be more difficult to map out, due to the technological diversity in the heating sector.[62]

Electric heating technologies not only face difficulties being recognised in regulation, but further, the value they can provide (e.g. energy system balancing and harnessing of excess

---

[58] Doble 2008; IEA 2019

[59] Bauknecht et al. 2017; Fleiter et al. 2017

[60] Gaur et al. 2021; Golling et al. 2019

[61] Chassein et al. 2017; Doble 2008

[62] Gaur et al. 2021; IRENA 2020; Saccani et al. 2020

variable RES) does not seem to be visible in the wider public.[63] However, generating heat from electricity (especially with large-scale heat pumps) can also lead to an increase in the peak load and put pressure on the electricity grid, which may pose a challenge for some regions.[64] Our modelling results show that the pressure on electricity grids is even higher in scenarios with lower penetration of heat pumps (i.e., H2 and E-Fuel scenarios) due to the higher number of installation RES-generation units needed to meet the higher electricity demand in these scenarios.

Looking at gas infrastructure, even more barriers become visible. A high share of direct electrification, as in the Elec_60 scenario, necessitates much less gas networks. This results in a decision of what to do with the existing assets. At the same time, owners and operators of the current infrastructure are lobbying against a decommissioning of these assets.

In addition the technologies themselves might be associated with several barriers. Due to their technological characteristics, some electric heating technologies impose stronger requirements on the operation conditions than systems based on burning fossil fuels. For example, heat pumps require a certain environment heat potential and are dependent on well-insulated buildings.[65] However, the modelling results show that indirect electric heating technologies such as hydrogen boilers equally (or even more) require renovated buildings to be cost-efficient (see section 3 and 4). Besides, the new technologies also exhibit their own challenges to a sustainable heating future. A possible issue is, for example, the leakage of highly climate effective refrigerants in heat pumps.[66] Further, the decision to invest in a new heating system mostly originates from the old one reaching the end of its lifetime and most heating technologies have quite a long lifetime, which hinders fast electrification uptake.

Table 26: Overview of institutional-structural, market-oriented and technical barriers

Sub-type	Barrier	Side	Pathway	Area
Regulation and market	Lack of regulation for technologies, i.e. lack of recognition of technologies in heating/ energy legislation	Supply and demand	Direct and indirect electrification	Decentral and district heating
	Lack of capacity in authorities to handle support and permit applications; complex administrative processes for non-standard technologies and lengthy permitting procedures	Supply and demand	Direct and indirect electrification	Decentral and district heating
	No clear transition pathway to decarbonised and renewable heat and thus uncertainty hinder investments; policy focus in the past rather on renewable electricity than on heat	Supply and demand	Direct and indirect electrification	Decentral and district heating
	Missing incentives and market signals for electric heating technologies, i.e. no level playing field in terms of regulation, subsidies and taxes	Supply and demand	Direct and indirect electrification	Decentral and district heating
	Complicated access to financial support due to intransparent funding landscape	Supply and demand	Direct and indirect electrification	Decentral and district heating

63 Golling et al. 2019; IRENA 2020

64 Gaur et al. 2021; IEA 2019; Staffell et al. 2019

65 Baldino et al. 2020; Gaur et al. 2021; Staffell et al. 2019

66 Gaur et al. 2021

Sub-type	Barrier	Side	Pathway	Area
	Buildings energy codes to decarbonise heating and cooling only slowly become more stringent	Demand	Direct and indirect electrification	Decentral (and district) heating
	Separate planning of gas and electricity infrastructure fails to recognise sector integration benefits	Supply	Indirect electrification	Decentral and district heating
	Lack of global hydrogen quality standards and production certificates (colours of hydrogen)	Supply	Indirect electrification	Decentral and district heating
	District heating networks are in most cases unregulated monopoles and low (price) transparency leads to low acceptance and hinders uptake	Supply	Direct and indirect electrification	District heating
Infra-structure	Challenging grid balance between supply and demand through heat pumps; i.e., especially large-scale heat pumps diffusion could increase peak load	Supply	Direct electrification	District heating
	Lack of dedicated hydrogen infrastructure	Supply	Indirect electrification	Decentral and district heating
	Technical limitations to hydrogen feed-in on supply side (e.g. downstream turbines, pipelines); Different national hydrogen blending thresholds	Supply	Indirect electrification	Decentral and district heating
	Technical limitation to hydrogen feed-in on demand side (e.g. hydrogen tolerance of heating systems)	Demand	Indirect electrification	Decentral and district heating
	High share of direct electrification of heating requires much less gas networks, so it is open what to do with the existing assets	Demand	Indirect electrification	Decentral and district heating
Technology	Suitability of heat pumps is dependent on energy-efficient building stock (i.e. also referring to low temperatures in district heating)	Demand	Direct electrification	Decentral and district heating
	Heat pumps might not work as single-source heating systems in cold climate conditions; less mature for larger buildings	Demand	Direct electrification	Decentral and district heating
	Instalment limitations of heat pumps due to space (radiators) or geological (geothermal) requirements; heat pumps require a heat source (e.g. air, ground, water) and availability of heat sources depends on the geographic and geological characteristics	Demand	Direct electrification	Decentral and district heating
	High greenhouse warming potential of refrigerant leakage in heat pumps can offset positive effects on climate	Supply	Direct electrification	Decentral and district heating
	Low efficiency of power-to-gas technologies	Supply	Indirect electrification	Decentral and district heating

Sub-type	Barrier	Side	Pathway	Area
	Manufacturers refuse to enable or facilitate the technologies	Supply	Direct and indirect electrification	Decentral and district heating
	Long lifetime and replacement cycles of heating system hinder fast uptake; lock-in effects in fossil fuel technologies	Demand	Direct and indirect electrification	Decentral and district heating

Source: Own elaboration based on various sources (see Annex B)

(3) Non-market social barriers

Table 27 provides an overview of non-market social barriers, such as lack of knowledge, education and training, lack of awareness and perception bias for the electrification of space heating. One main barrier seems to be that consumers as well as installers lack knowledge of and experience in dealing with modern electric heating systems such as heat pumps or hydrogen boilers.[67] Furthermore, a lack of awareness of electrification benefits is reported.[68] At the same time, the uncertainty around cost-effectiveness, future energy prices and regulations can be subject to biased perception. Thus, consumers assign lower utility to uncertain options and oppose long payback times.[69] Above all, when making the decision for a new heating technology, consumers often prefer the least-worst alternative, which is in most cases the standard technology, instead of responding to and being motivated by positive attributes, such as environmental benefits.[70]

Table 27: Overview of non-market social barriers

Sub-type	Barrier	Side	Pathway	Area
Awareness and knowledge	Lack of public awareness of environmental and cost benefits; low public understanding	Demand	Direct and indirect electrification	Decentral and district heating
	Lack of skilled installers familiar with technologies	Supply	Direct and indirect electrification	Decentral and district heating
Acceptance	Resistance against change and new habits; low acceptance for higher hurdle rates for non-standard technologies; visible intrusion (e.g. no heat pump in my garden)	Demand	Direct electrification	Decentral heating
	Low public acceptance of indirect heating technology (e.g. hydrogen boiler) due to safety concerns	Demand	Indirect electrification	Decentral (and district) heating
	"Not in my backyard" attitude among groups of citizens is hindering electricity grid upgrade measures	Supply	Direct and indirect electrification	Decentral (and district) heating

[67] Chassein et al. 2017; Doble 2008; IEA 2019

[68] Gaur et al. 2021; Pezzutto and Grilli 2017

[69] Costello 2018; Sheikh and Callaway 2019

[70] Williams et al. 2018

Sub-type	Barrier	Side	Pathway	Area
	Some policy makers perceive direct electrification of heat as disruptive; some policy makers perceive heat decarbonisation as a large complex and unpopular effort of limited importance	Supply and demand	Direct and indirect electrification	Decentral and district heating
Bounded rationality	Consumers perceive uncertainties about cost-effectiveness, future energy prices and regulations in a biased way	Demand	Direct and indirect electrification	Decentral and district heating
	Consumers oppose the long pay-back periods of investments in (electric) heating technologies	Demand	Direct and indirect electrification	Decentral heating
	Consumers typically prefer the least-worst heating option (standard) rather than responding to positive factors of a technology	Demand	Direct and indirect electrification	Decentral heating

5.2. Policy measures for the cost-effective scenario

In the following, policy measures that address the barriers analysed above and are needed to realise the scenario with the lowest costs, i.e., Elec_60 scenario, are presented. Thereby, (1) policy measures on MS level (i.e., national legislation) and (2) policy measure on EU level (i.e., EU legislation) are discussed. The policy measures are based on various sources.[71] The focus lies on policy measures that aim at a high share of electrification of space heating in line with the Elec_60 scenario (see section 4). Measures that address other areas, such as RES electricity or flexibility[72], are not in the scope of this analysis. The following short box briefly summaries the most important measures for electricity infrastructure.

[71] E.g. Bacquet et al. 2022; Braungardt et al. 2022; Chassein and Roser 2017; IRENA et al. 2018; Kranzl et al. 2022; Steinbach et al. 2017; see also Annex B

[72] The increasing number of heat pumps (in the optimal scenario) should be integrated into the electricity market and offer flexibility, which might need to be facilitated by specific policy measures.

Measures for electricity infrastructure

The extension of electricity infrastructure both on transmission and distribution level is a crucial factor for any scenario aiming to reach the EU climate targets. There are various measures that can help to promote necessary investments in electricity infrastructure, some of which being as follows:

- Local acceptance for electricity infrastructure projects remains the biggest barrier. Hence, measures increasing acceptance are very important. As underground cables seem to find higher acpetance, regulation should acknowledge this and network operators / grid owners should not be penalised (e. g. within a regulatory benchmarking) when investing in such inherently more costly technologies.
- Furthermore, innovative technologies, which under specific circumstances partially can serve as an alternatives to conventional grid extension (building lines), become ready for the market. Such technologies / solution are sometimes related to a higher share of OPEX (as opposed to CAPEX) considering the full life-time of the investment. Today's regulation rather incentivises CAPEX-based solutions. Hence, regulation should encourage a balanced consideration also of OPEX-based solution.
- Regarding cross-border infrastructure projects a harmonisation of the approach for the cost-benefit analysis carried out in the context of the TYNDP process and the cross-border cost allocation method is recommended.

Source: Own elaboration

(1) Policy measures on MS level

This sub-section focuses on the most relevant policy measures on MS level for the electrification of space heating in line with the Elec_60 scenario. Thereby, it should be noted that, depending on the national or regional situation, some measures might be less relevant than others (i.e., countries with no or small district heating markets and low potentials might not need measures for district heating). Furthermore, there are interdependency between the different policy measures and the specific design of one measure can influence the needed intensity of another measure (i.e., high CO2 prices can lead to a reduced need for financial support for renewables). However, the measures presented in this sub-section comprise relevant policy recommendations that aim at a successful electrification of space heating. Together, the listed policy measures form a promising policy mix for the (cost-optimal) electrification of space heating.

To structure the measures, it is indicated if the measure addresses decentral heating, district heating or both, i.e. overarching policy measures. Thereby, overarching measures also include measures that address building renovation, as both decentral as well as district heating need an uptake in renovations. Furthermore, three types of policy measures are distinguished, i.e., (1) economic measures, (2) regulatory measures and (3) information-based measures.[73] For a complete policy mix, economic measures as well as regulatory and information based measures should be combined. Besides, as stated above, the policy measures should be aligned with each other (i.e., a high CO2 price may conditions less support).

[73] Adopted from Bouwma et al. 2015.

Three types of policy measures

Economic policy measure are, for example, subsidies, loans, grants or taxes. Most measures of this type exhibit a voluntary character and incentivize the targeted actors by reward or financial discourage. Economic policy measures mainly address financial-economic barriers, such as high CAPEX or OPEX of the envisaged technologies (see barriers in Table 25). However, economic policy measures may (indirect) also reduce institutional-structural, market-oriented and technical barriers.

Regulatory policy measure are binding rules through legislation, which can be prohibitive or prescriptive for targeted actors. Regulatory measure mainly address institutional-structural, market-oriented and technical barriers (see barriers in Table 26), but can also address (indirect) economic or information based barriers.

Information-based policy measure intend to address knowledge and awareness gaps and disseminate information to the targeted actors. Typically, these instruments include information campaigns, educational programs or interactive workshops and discussions. Information-based mainly address social barriers (see barriers in Table 27).

Source: Own elaboration based on Bouwma et al. 2015

Table 28 presents the relevant **policy measures for decentral heating** on MS level (additional overarching measures are listed in Table 30). One key economic measure is financial investment support for heat pumps to address the barrier of high upfront investment costs (i.e., CAPEX). This economic measures should be combined with a ban of fossil fuel heating sytsmes (e.g. ban of oil boilers as already implemente in some MS) and minimum obligations in new and/or existing buildings (i.e., quotas) for renewable heat including electric heating systems using renewable electricity (see Table 28). A key information-based measure is the provision of educational programs for change agents, because the barrier analysis showed that there is a lack of skilled installers.

Table 28: Decentral heating policy measures on MS level

Type	Name	Description and addressed barriers
Economic measures	Financial investment support for heat pumps; replace-ment schemes	Financial investment support for decentral heat pumps, to address the barrier of high upfront investment (i.e., CAPEX). This support could be combined or implemented as scrappage and replacement schemes encouraging the replacement of fossil fuel heating systems.
Regulatory measures	Ban of fossil fuel heating	A ban of fossil fuel heating technologies (e.g. ban of decentral oil boilers) can fasten the technology change from fossil fuel heating systems to electric heating systems as well as systems based on renewables, such as solar or biomass.
	Minimum obligations in buildings	Minimum obligations in new and/or existing buildings (i.e., quotas) for renewable heat including electric heating systems using renewable electricity increase the uptake of the technology change to reach higher shares of decentral heat pumps and other renewable heating technologies.
Information-based measures	Provide educational programs for change agents (and qualification requirements)	Educational programs (e.g. courses, webinars, and trainings) for change agents such as installers, architects, planners etc. should be provided. The high share of decentral electric heating systems, especially heat pumps, is liked to a high need of qualified installers. At the same time, the barrier analysis showed that there seems to be a lack of skilled installers. Thus, attractive educational programmes are highly necessary. This measure can be combined with qualification requirements and measures to ensure the availability of qualified change agents.

Source: Own elaboration based on various sources (see Annex B)

Table 29 presents the relevant **policy measures for district heating** on MS level (additional overarching measures addressing also OPEX are listed in Table 30). In the Elec_60 scenario, district heating is dominated by large-scale heat pumps. To address the barrier of high upfront investment needs for large-scale heat pumps, financial investment support should be provided. Thereby, pilot and demonstration projects should be financed for technology upscaling and market introduction. Besides, infrastructure development should be financially supported to reach the needed district heating expansion and promote modernisation of existing grids. Furthermore, limited financial support for hydrogen is most likely needed. In the Elec_60 scenario hydrogen plays only a small role (see section 4). However, hydrogen still contribute, i.e., as backup in district heating.

The financial support measures should be supplemented with regulatory measure, such as minimum obligations for renewable heat, i.e., renewable quotas, including heat pumps using renewable electricity. Further relevant regulatory measures are mandatory connection for end-consumers (in specific zones, e.g. new development areas), a regulatory framework for third-party access, an obligation for transformation plans for existing district heating networks as well as an obligation to explore waste heat potentials form industries and other potential waste heat providers. Information-based measures are also highly relevant, especially the dissemination of successful pilot project and best practises, which can fasten the uptake of heat pumps (peer-to-peer learning).

Table 29: District heating policy measures on MS level

Type	Name	Description and addressed barriers
Economic measures	Financial investment support for large-scale heat pumps	Financial investment support for large-scale heat pumps in district heating to address the barrier of high upfront investment. Pilot and demonstration projects should be financed in the coming years for technology upscaling and market introduction.
	Financial investment support for renewables and waste heat	Financial investment support for renewables and waste heat[74] in district heating addressing the barrier of high upfront investment and investment insecurities connected to these technologies (especially relevant for solar thermal and geothermal energy and connection/ integration of waste heat resources). In addition, risk hedging support, especially for geothermal, can increase the uptake of renewable district heat technologies.
	Financial investment support for district heating infrastructure	The scenario with the lowest costs (Elec_60) shows a significant expansion of the district heating infrastructure with high investment needs. At the same time, high investment costs for infrastructure development are an obstacle. Thus, financial investment support for district heating infrastructure expansion is needed.
	(limited) Financial support for hydrogen	Financial support for electrolyser capacity, hydrogen heat generation technologies (especially for district heating) and transport infrastructure (especially transmission grids) are required, because the scenario with the lowest costs (Elec_60) shows a need for hydrogen as back-up technology in district heating. This support should foster the technology development with focus on pilot and demonstration projects.
	Minimum obligation in	Minimum obligation in district heating networks (i.e., quotas) for renewable and waste heat including electric heating systems

[74] Waste heat in district heating networks is not explicitly modelled in Enertile, but the efficiency of heat pumps can be increased if they use, for example, industrial waste heat or waste water from a sewage treatment plant as a source. In addition, waste heat can (in some cases) be fed directly into the district heating grid and thus contribute to an efficient and decarbonised heat supply.

Type	Name	Description and addressed barriers
Regulatory measures	district heating networks	using renewable electricity can increase the uptake of the needed technology change (alternatively, CO_2 limits could be introduced).
	Mandatory connection to district heating systems	Obligations for end-consumers to connect to their local district heating systems (i.e. in new development areas) can significantly increase district heating connection rates. This measure provides security for investments in district heating infrastructure. The scenario with the lowest costs (Elec_60) shows a high increase in connection rates, which (most likely) can only be achieved with connection obligations (may even needed in existing district heating area, e.g. in connection with investments in modernisations).
	Regulatory framework for third-party access	A regulatory framework for third-party access to district heating networks for renewable and waste heat producers, including large-scale heat pumps, is missing in several MS. Such a framework can create new dynamics in DH markets and might facilitate the uptake in large-scale heat pumps. This framework should include specific technical specifications for the connection of independent heat producers to existing grids, in order to create transparency and facilitate third-party access of renewable and waste heat producers.
	Obligation for transformation plans for existing district heating networks	Existing (large) district heating networks should be obliged to develop transformation plans to reach climate neutrality in 2050. These plans should include modernisation measures of the existing grid; the integration of renewable and waste heat sources, etc..
	Obligation to explore waste heat potentials	Industry and other actors, such as for example sewage treatment plants, should be obliged to explore and provide their waste heat potentials that can be fed into their local district heating network. This obligation can be combined with the obligation to develop strategic heat plans.
	Quality standard for hydrogen	To ensure interoperability of markets for pure hydrogen, common quality standards (e.g. for purity and thresholds for contaminants) or cross-border operational rules may be necessary (for hydrogen use in district heating).
Information-based measures	Dissemination of information	Dissemination of successful pilot project and best practises can fasten the uptake of heat pumps (and renewable and waste heat) in district heating networks (peer-to-peer learning).
	Increased transparency in district heating markets	District heating networks are mostly unregulated natural monopolies with low (price) transparency, which lowers acceptance and hinders a fast uptake of connection rates. A regulatory framework for district heating with transparency rules could address this barrier.

Source: Own elaboration based on various sources (see Annex B)

Table 30 presents the relevant **overarching measures** on MS level, i.e., policy measures that address decentral heating and district heating. One key economic measure is financial operational support for electric heating (i.e., addressing operational/variable energy costs), especially for heat pumps (decentral or central). The barrier analysis showed that a barrier for the uptake of heat pumps are high OPEX (see Table 25). Reducing electricity taxes and levies or closing the gap between electricity and fossil fuel heating prices with a CO2 tax addresses this barrier. Further relevant overarching economic barriers are investment support for building renovations, addressing the 'split-incentives dilemma' as well as providing resources for authorities (see Table 30). Relevant overarching regulatory measures are efficiency requirements in building codes and an obligation for strategic heat planning, i.e. development of heat plans by municipalities to find solutions and decarbonisation pathways on the local level. Key information-based measures are strategies for electric heating with clear targets, allocation strategies for limited resources and lastly efforts to simplify funding processes (see Table 30).

Table 30: Overarching policy measures on MS level

Type	Name	Description and addressed barriers
Economic measures	Financial operational support, i.e. CO_2 tax	Introduction or increase of a CO_2 tax/ price for heat (ETS or national scheme) addresses the barrier of high OPEX of electric heating technologies (main focus on heat pumps) and the unfavourable fuel price ratio between electricity and fossil sources, i.e., creates a level playing field. A CO_2 tax for heat also increases the competiveness of renewable heating technologies, such as solar and geothermal energy.
	Financial investment support for building renovations	Financial investment support for renovation measure incentivises the needed uptake in building renovation, especially deep retrofitting. This measure address the barrier that renovations can be expensive and home owners may not have the means to finance them. At the same time electric heating systems need (in most cases) well-insulated buildings (including low temperature district heating).
	Address 'split-incentives dilemma'	Financial participation of home owners on costs for carbon taxes (e.g. up to 90% of the costs if building is not renovated) could address the 'split-incentives dilemma' und thus incentivises the change of fossil fuel heating systems and the uptake in building renovations. The financial participation of the owner should be higher for not renovated buildings and lower for already renovated, i.e., more efficient, buildings. Alternatively, the 'split-incentives dilemma' could be addressed in a regulatory measure, i.e., combined with mandatory building retrofitting (see below).
	Additional resources for authorities	Increase capacities for authorities that handle permit and funding applications. The analyses of barriers showed that authorities seem to lack the capacities and competencies. Thus, resources for authorities (to increase personal capacities and competences) should be provided.
Regulatory measures	Efficiency requirements in building codes	Transparent and ambitious efficiency requirements in building codes promote the construction of highly efficient new buildings. Depending on the design, this measure can also promote the uptake of renovations of existing buildings. Thus, this policy measures addresses the barrier that all renewable heating technologies need well-insulated buildings (including low temperature district heating).
	Mandatory building retrofitting; rental ban address 'split-incentives dilemma'	An obligation for building retrofitting or minimum energy performance standards for existing buildings, as currently discussed in the proposed recast EPBD, can be established to address existing buildings. Furthermore, focusing on rented buildings, a rental ban could be used, i.e., dwellings not fulfilling a certain energy performance standard cannot be rented out after a certain period of time. This measure would also address the 'split-incentives dilemma' (see above).
	Obligation for strategic heat planning	Municipalities should be obliged to develop strategic heat plans to decarbonise their local heat structure, e.g. screen which areas could be used for district heating, which renewable potentials could be integrated, what locally measures are needed etc.. Thereby, a systemic approach should be taken, i.e., electrification

Type	Name	Description and addressed barriers
		of heat and, where necessary, the exploitation of electricity grids and renewable electricity generation capacities.
Information-based measures	Strategies for electric heating mainly based on heat pumps	Strategies with clear targets and pathways for electric heating to increase investment security are still missing in several MS. Thus, clear targets and pathways should be developed and communicated to increase investment security. This should include clear targets for district heating, direct electric heating as well as use of hydrogen and e-gases in district heating (i.e., not in decentral heating).
	Allocation strategies for limited resources	Allocation strategies for limited resources determine the distribution of limited resources to different areas/ sectors. Hydrogen, e-gases, and biomass are limited due to the restricted availability. At the same time, these resources are mostly needed for other energy needs, e.g. for high-temperature process heat or in the transport sector, where fewer alternatives are available. Therefore, strategies for allocating the limited resources (e.g. defining priority use areas) are needed.
	Simplify funding processes	Simplify funding processes to fasten the uptake of electric heating technologies. The analyses of barriers showed that administrative processes are often complex. Thus, the funding landscape and process should be simplified.

Source: Own elaboration based on various sources (see Annex B)

(2) Policy measures on EU level

Measures on EU level can create favourable framework conditions for the transition towards decarbonisation via electrification of space heating. In the following relevant policy measures on EU level to reach a high share of electrification of space heating in line with the Elec_60 scenario are described.

Key measures of the revised **Renewable Energy Directive (RED II)** and their potential improvement are described below, whereby the latest proposal to amend the RED II[75] (i.e., 2021 revision of RED II) forms the basis of the recommendations.

- **Introducing binding targets for the heating sector**. Under the 2021 revision of the RED II a binding target for renewables in the heating and cooling sector is under discussion. The latest proposal to amend the RED II requires MS to increase each year the share of renewable energy in heating and cooling by at least 1.1 percentage points until 2030 (Art. 23 (1)) (additional indicative MS specific top-up targets in Annex 1a). A binding target is strongly needed to drive the heating sector towards full decarbonisation. However, the range of the current renewable shares in the MS is very wide, e.g. Sweden with 66% and Ireland with only 6% renewables in their heating and cooling sector[76]. In order to make the target more equitable, MS specific or staggered targets could be introduced, e.g. MS with shares above 50% need to increase 1.1 percentage points and MS below need to increase 1.2 percentage points. Furthermore, caps on the level of biomass (used for space heating, not including process heating)

[75] Proposal for RED II (14.07.2021), https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52021PC0557&from=EN

[76] Share of renewables in heating and cooling in 2020 according to SHARES, https://ec.europa.eu/eurostat/de/web/energy/data/shares

allowed could be included in the target, to reduce the risk of high biomass use and low heat pump uptakes[77].

- **Introducing binding targets for district heating**. The 2021 revision of the RED II currently foresees a non-binding target for district heating. MS shall endeavour to increase the share of energy from renewables and from waste heat and cold in district heating and cooling by at least 2.1 percentage points per year until 2030 (Art. 24 (4)). This target should be binding. A clear and binding target for district heating in terms of shares of renewable and waste heat (including heat pumps using renewable electricity) could boost the needed technology change.
- **Obligations for renewable decentral heating systems** (including heat pumps using renewable electricity) in buildings. The 2021 revision of the RED II introduces an indicative target for renewable heating in buildings. The proposal includes an indicative EU target of renewables in buildings by 2030 of 49%. Furthermore, it states that MS shall set an indicative target for the share of renewables in final energy consumption in their buildings sector in 2030 that is consistent with the overarching EU target of at least 49% (Art. 15a (1)). This provision could be strengthened with binding and more ambitiuous targets.
- **Introducing third-party access requirements for district heating**. Third-party access is currently under discussion in the 2021 revision of the RED II. The proposal states that MS shall ensure that operators of large district heating or cooling systems (above 25 MWth) are obliged to connect third-party suppliers of energy from renewables and from waste heat and cold (under specific circumstances, e.g. capacity needs) (Art. 24 (4a)). Alternatively operators can offer to connect and purchase heat and cold from third-party suppliers based on non-discriminatory criteria (Art. 24 (4a)). Third-party access can create a new dynamic and facilitate uptake of renewables and waste heat and cold, which argues for its introduction in large networks. Therefore, the third-party access requirements should be kept in the final amendment.
- **Introducing transparency measures for district heating**. The 2021 revision of the RED II foresees that information on energy performance and share of renewables in district heating and cooling systems should be provided to final consumers (Art. 24 (1)). Transparency in district heating can contribute to a positive perception and higher acceptance, and thus, the proposed requirements are highly needed.
- **Strengthening qualification requirements for installers**. The 2021 revision of the RED II adresses qualification for installers by stating that MS shall ensure that certification schemes are available for installers and other actors (Art. 18 (3)). Furthermore MS shall ensure that trained and qualified installers are available in sufficient numbers, e.g. by providing sufficient training programmes. In order to strengthen qualification requirements, an obligation for installers to participate in certification or equivalent qualification schemes could be introduced. Besides, requirements that at least one certified installer has to be involved in planning, design, construction and renovation of building could be introduced.

[77] Due to the overall low potential of sustainable biomass its (energy) use should be restricted to areas where direct electrification is not possible. In addition, biomass can also be used non-energetically, e.g. in the building sectors and contribute to lower emissions by replacing more emission-intensive materials like cement and steel.

Measures under the **Energy Performance of Buildings Directive (EPBD)** and the **Energy Efficiency Directive (EED)** are described in the following. Thereby, the latest proposal for the recast of the EPBD[78] and the EED[79] are used as the basis for the recommendations.

- **Strengthening energy performance requirements in new buildings**. In line with the 2021 revision of the EPBD, new buildings and buildings under major renovation need to meet the high buildings standards. Strengthening these requirements could support the uptake of heat pumps and renewable heating systems (decentral and in district heating systems, because of lower temperature levels). In particular, the introduction of the zero-emission-building standard may be expected to further push high efficiency standards and renewable heating systems.
- **Minimum energy performance standards.** Art 9 in the proposed recast EPBD (2021) foresees the introduction of minimum energy performance standards for existing buildings, gradually renovating and thus phasing out the least performing buildings. In particular for rented buildings and apartments this would mean a strong instrument overcoming the split-incentive dilemma.
- **Introducing heat planning requirements**. An obligation for municipal strategic heat planning could be integrated into the EED, as currently discussed under the 2021 revision. The proposal for the recast of the EED states that MS shall encourage regional and local authorities to prepare local heating plans (Art 23 (5)). Instead of encouragement, an obligation for strategic heat planning should be introduced for larger cities.
- **Clarify definition of efficient district heating and cooling.** The EED includes provisions for defining efficient district heating and cooling in Art 24 (1) EED and high-efficiency cogeneration in Annex II of the EED. The current provisions, however, leave room for fossil natural gas, risking a lock-in into fossil fuels. With the 2021 revision of the EED, some improvements have been proposed (Art 24). However, the proposed provisions still incentivise fossil natural gas through high emission levels in Annex III of the proposal for the recast of the EED. Therefore, stricter emission levels, which would exclude fossil natural gas, should be introduced and are currently under discussion.[80] Overall, the definition of an efficient district heating and cooling systems should strictly prevent lock-in into fossil fuels and promote renewable energies, waste heat and in particular large-scale heat pumps.

Measures focusing on taxation, i.e., under the **EU Emission Trading System (ETS) Directive**[81] and the **Energy Taxation Directive (ETD)**[82], are described in the following.

- **EU ETS with higher targets and a scheme for heating in buildings.** The 2021 proposal to amend the ETS Directive foresees that the emissions reduction targets of the MS are updated and that the system is overall more ambitious. In addition, a new, separate emissions trading system (ETS 2) to cover emissions from fuels used in road transport and buildings is foreseen. The new system is designed to start from 2026. It will boost up the use of renewable heating, including heat pumps that use renewable electricity.

---

[78] Proposal for EPBD (15.12.2021), https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52021PC0802&from=EN

[79] Proposal for EED (14.07.2021), https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52021PC0558&from=EN

[80] See further information: https://caneurope.org/position-on-energy-efficiency-directive-recast/#:~:text=In%20order%20to%20allow%20for,up%20to%202030%20than%20the

[81] Proposal for ETS Directive (14.07.2021), https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52021PC0551&from=EN

[82] Proposal for ETD (14.07.2021), https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52021PC0563&from=en

- **Increasing the relative price of fossil fuels compared to electricity**. The majority of MS tax most energy products and, in some cases electricity, considerably above the ETD minimum rates. The proposal of th ETD introduces a new structure of tax rates based on the energy content and environmental performance of the fuels and electricity. Furthermore, it includes more products and removes some of the current exemptions and reductions. This revision can support heat pump deployment by increasing the relative price of fossil fuels compared to electricity, especially if the exemptions are not applied too loosely.

Lastly, the modelling results and the scenario comparison are reflected in the context of the **EU hydrogen strategy**.[83]

- **The model results of this study are in line with the EU hydrogen strategy**. Many of the key points of the strategy can be supported by the model results, in particular:
  - Hydrogen plays an increasingly important role in balancing the European electricity system being dominated by electricity production from renewable energy sources. The amount of hydrogen needed for this purpose, however, is overall limited.
  - There is a need for a European hydrogen transport back-bone network. Most of this network can be based on retrofitted existing gas pipelines used for CH4 / natural (mainly fossil) gas today and the need for dedicated new hydrogen transport pipelines is limited.
  - The role of hydrogen blending is very limited and even less relevant in the later phase of the transition.
  - Large, centralized hydrogen storage capacity are a decisive factor to fully develop the benefits of (green) hydrogen for the decarbonisation of the energy system.
- **A more explicit statement on the role of hydrogen for space heating could prevent lock-ins**. The EU hydrogen strategy does not mention the space heating sector among the demand sectors with a particular priority for using hydrogen, which is in line with modelling results. However, using hydrogen also for decentral heating is currently part of the public debate. Thus, a more explicit statement that the use of hydrogen for decentral heating is not an efficient option could be helpful. Using or not using hydrogen (or other gaseous energy carriers) in buildings is thereby a decisive factor for the future role of gas distribution networks.
- **Clear statement on the role of hydrogen in district heating**. The modelling results show that district heating has an important role in the cost-efficient scenarios for decarbonizing the space heating sector. Hydrogen-based boilers are an important element of the cost-efficient solution as they can provide flexible heat production on more centralized heat supply systems. This flexibility is not used often, but is helpful to balance heat supply and demand in some rather rare situation, e. g. with particularly low renewable generation and high heat demand. As it is not used often, energy costs (cost of hydrogen per kWh) are not a decisive factor. Beneficial are, however, the low capital costs of hydrogen boilers.
- **Local clusters can reduce costs for the distribution infrastructure for hydrogen**. The hydrogen strategy mentions the use of hydrogen for the provision of heat for buildings only in the context of local hydrogen clusters, such as remote areas or islands. Even though our modelling covers a very large geographic area (at least EU-27) but also has a high spatial resolution, it does not cover very specific, local constellation

[83] A hydrogen strategy for a climate-neutral Europe (08.07.2021), https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52020DC0301&from=EN

where the use hydrogen of might be a good solution. Hence, from the modelling in this study, no conclusions regarding such local hydrogen clusters can be drawn. However, the results of this study support the hydrogen strategy to that extent that whenever there is a small remaining amount of hydrogen (or other gaseous energy carriers) used in buildings in some MS, local clusters could reduce costs for the distribution infrastructure for hydrogen.

Calculation methods for the share of renewable heating from renewable electricity, from renewable hydrogen and from synthetic e-gases and e-liquids

When calculating the shares of renewable energy in electricity, heating and transport it is important to avoid double-counting. Therefore, it needs to be clearly specified in which sector the renewable energy is accounted for.

With regards to heating based on electricity, hydrogen and synthetic e-gases and e-liquids, the following rules currently apply:

- Electricity-based heating:

  The electricity used for heating is not counted as renewable in the heating sector. The heating demand covered by electricity-based heating (e.g. direct heating and heat pumps) is not counted as heating demand but remains in the electricity sector. In the case of heat pumps the ambient energy and geothermal energy used is accounted for as renewable in the heating sectors, and indirectly and partially the electricity that is needed to transfer those renewable sources from the environment into the heated space or water. As a consequence, heat pumps increase the share of renewable heating. This calculation methods is sensible as it can be an incentive for MS to expand the use of the most efficient heat pumps.

- Heating based on hydrogen, e-gases and e-liquids:

  The RED II Art 7 foresees that renewable fuels of non-biological origin are accounted for in the sector where they are used. At the same time, the electricity used to produce renewable fuels of non-biological origin (RFNBO) is not calculated as electricity consumption. This enables imports of RFNBOs to be accounted for as renewable. A definition of RFNBOs is currently defined and negotiated in a Delegated Act.

As a consequence, both heat pumps and green hydrogen and e-liquids count towards the renewable energy shares in heating. The electricity used in both cases is however treated differently. In the case of direct electric heating, the electricity consumed and generated remains in the electricity sector statistics. In the case of RFNBOs however, the electricity used for generating those is taken out of the electricity sector.

Conclusion and key policy recommendations[84]

- The analysis of barriers has shown that electric heating technologies are currently associated with a variety of barriers. These are (1) financial economic barriers, such as high CAPEX and OPEX, (2) institutional-structural, market-oriented and technical barriers, comprising e.g. a lack of regulation and standardisation and (3) social barriers, such as lack of knowledge of installer or biased perception of consumers.
- To overcome the barriers and to reach a scenario with lowest possible costs (i.e. Elec_60 scenario in the modelling with a high share of direct electrification and a

[84] The recommendations are based on the barrier and policy analysis, the expertise of the project team and are in line with the modelling work.

strong contribution of district heating) a holistic policy mix, including economic, regulatory and information-based policy measures, is needed.

- There are interdependencies between the different policy measures and the specific design of one measure can influence the needed intensity of another measure (i.e., high CO_2 prices can lead to a reduced need for financial support for renewable heat). In addition, depending on the national or regional situation, some policy measures might be less relevant than others in one MS compared to another MS.

- The key policy recommendations on MS level are:
  - Economic policy measures to make heat pumps cost-competitive against fossil-fuel heating technologies (decentral and in district heating) from an end-consumer perspective, i.e. financial investment support for heat pumps and operative support (e.g. introducing CO_2 prices or reform taxes, levies and grid tariffs to mitigate financial biases to the disadvantage of electricity compare to other energy carriers) as well as economic measures to expand district heating networks, e.g. investment support.
  - Regulatory policy measures to reach higher shares of renewable heating technologies, including heat pumps using RES electricity (decentral and in district heating), i.e., minimum obligations for renewable heat, as well as measures for the uptake of building renovations, i.e., efficiency requirements in building codes and/or mandatory building retrofitting.[85]
  - Information-based measures for the uptake of heat pumps, i.e., educational programs for change agents, clear strategies for the role of hydrogen (not efficient in decentral heating and backup role in central heating) and measures to find decarbonisation solutions locally and to increase participation of various stakeholders, i.e., strategic heat planning.

- The key policy recommendations on EU level are:
  - As proposed in the revised RED II, binding targets for the heating sector are necessary to drive market deployment of RES heating technologies. Similarly, the district heating and cooling sector would benefit from mandatory targets and thus the proposed indicative target in revised RED II could be strengthened.
  - In addition, the proposed third party access for district heating and further transparency measures can contribute to the necessary expansion of renewable district heating supply and the decarbonisation of existing district heating systems.
  - Furthermore, the obligations for renewable heating systems in buildings could be strengthened through more ambitious RES target for the EU building stock reflecting higher RES level requirements and being binding in their nature.
  - The regulatory measures for building renovation, such as the minimum performance standards as foreseen in the proposed recast of the EPBD,

[85] Measures for the uptake of building renovations are not a policy measure to address barriers specifically related to heat pumps; building renovations is rather a cost-efficient measure in all scenarios and, hence, contributes to a cost-efficient space heating system independent from the heating systems used.

embedded in an effective, broad policy package, are essential to exploit the huge efficiency potentials in the sector.

- Instead of encouragement, an obligation for strategic heat planning seems essential for at least larger cities due to the need for accurate and well-developed local strategies, as the first step in the process of rolling out renewable and carbon-neutral heating technologies and solutions, as these are mostly local in nature.
- Measures focusing on taxation and other price signals could, as proposed in the ETS directive, take the form of higher targets in the ETS and in the extension of the ETS for heating in buildings. Furthermore, the proposal for the review of the ETD introduces a new structure of tax rates based on the energy content and environmental performance of the fuels and electricity, which can support heat pump deployment.
- In the context of the EU hydrogen strategy, a more explicit statement on the role of hydrogen in space heating could prevent lock-ins. This clear statement should emphasise the limited role of decentralised hydrogen solutions, i.e. that hydrogen-based decentralised heating systems are not cost-effective. At the same time, the possible role of hydrogen in district heating supply should be outlined (i.e., hydrogen-based boilers, modern CHP and other technologies with a backup role for district heating in times of electricity shortages).

References

Bacquet et al., 2022. Overview of District Heating and Cooling Markets and Regulatory Frameworks under the Revised Renewable Energy Directive. forthcoming.

Baldino, C., O'Malley, J., Searle, S., Zhou, Y., Christensen, A., 2020. Hydrogen for heating? Decarbonization options for households in the United Kingdom in 2050. https://theicct.org/sites/default/files/publications/Hydrogen-heating-UK-dec2020.pdf.

Bauknecht, D., Förster, H., Hünecke, K., et al., 2017. Study on Technical Assistance in Realisation of the 2016 Report on Renewable Energy, in preparation of the Renewable Energy Package for the Period 2020-2030 in the European Union: Task 1 & 2. https://ec.europa.eu/energy/studies/study-technical-assistance-realisation-2016-report-renewable-energy-preparation-renewable_en.

Braungardt et al., 2022. Renewable Heating and Cooling Pathways, Measures and Milestones for the implementation of the recast Renewable Energy Directive and full decarbonisation by 2050. forthcoming.

Chassein, E., Roser, A., 2017. Boosting renewable energy in heating and cooling: Summary of best practices, success factors and recommendations based on literature, interviews and surveys in six case studies. progRESsHEAT Fact Sheet - Success Factors general. https://ec.europa.eu/research/participants/documents/downloadPublic?documentIds=080166e5b74644ca&appId=PPGMS.

Chassein, E., Roser, A., John, F., 2017. Using Renewable Energy for Heating and Cooling: Barriers and Drivers at Local Level: An analysis based on a literature review and empirical results from local case studies. progRESsHEAT. http://www.progressheat.eu/IMG/pdf/progressheat_wp3.2_report_publication.pdf.

Costello, K.W., 2018. Electrification: The nexus between consumer behavior and public policy. The Electricity Journal 31, 1–7. https://doi.org/10.1016/j.tej.2018.01.005.

Doble, C., 2008. Barriers to Renewable Heat: Part 1: Supply Side. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/42957/1_20090501125221_e____2Part1FinalReportv70.pdf.

Fleiter, T., Steinbach, J., Ragwitz, M., et al., 2017. Mapping and analyses of the current and future heating/cooling fuel deployment - Scenarios for heating & cooling demand and supply until 2020 and 2030: WP 5 Barriers, Best Practices and Policy Recommendations. https://ec.europa.eu/energy/sites/default/files/documents/mapping-hc-final_report-wp5.pdf.

Gaur, A.S., Fitiwi, D.Z., Curtis, J., 2021. Heat pumps and our low-carbon future: A comprehensive review. Energy Research & Social Science 71, 101764. https://doi.org/10.1016/j.erss.2020.101764.

Golling, C., Reemt, H., Seidl, H., Uhlig, J., 2019. Roadmap Power to Gas: Component of an Integrated Energy Transition. https://www.dena.de/fileadmin/dena/Publikationen/PDFs/2019/Roadmap_Power_to_Gas.pdf.

IRENA, 2021. Green Hydrogen Supply: A Guide to Policy Making. https://www.irena.org/publications/2021/May/Green-Hydrogen-Supply-A-Guide-To-Policy-Making.

IRENA, 2020. Green hydrogen: A guide to policy making. https://www.irena.org/publications/2020/Nov/Green-hydrogen.

Kranzl et al., 2022. Renewable Space Heating under the Revised Renewable Energy Directive. forthcoming.

IEA, 2019. Perpectives for the Clean Energy Transition: The Critical Role of Buildings. https://iea.blob.core.windows.net/assets/026bff1b-821d-48bc-8a0e-7c10280c62bc/Perspectives_for_the_Clean_Energy_Transition_2019.pdf.

Pezzutto, S., Grilli, G., 2017. European Heat Pump Market Analysis: Assessment of Barriers and Drivers. International Journal of Contemporary ENERGY, 62–70. https://doi.org/10.14621/ce.20170207.

IRENA, 2018. Renewable Energy Policies in a Time of Transition. https://www.irena.org/publications/2018/apr/renewable-energy-policies-in-a-time-of-transition.

Saccani, C., Pellegrini, M., Guzzini, A., 2020. Analysis of the Existing Barriers for the Market Development of Power to Hydrogen (P2H) in Italy. Energies 13, 4835. https://doi.org/10.3390/en13184835.

Sheikh, I., Callaway, D., 2019. Decarbonizing Space and Water Heating in Temperate Climates: The Case for Electrification. Atmosphere 10, 435. https://doi.org/10.3390/atmos10080435.

Staffell, I., Scamman, D., Velazquez Abad, A., Balcombe, P., Dodds, P.E., Ekins, P., Shah, N., Ward, K.R., 2019. The role of hydrogen and fuel cells in the global energy system. Energy Environ. Sci. 12, 463–491. https://doi.org/10.1039/C8EE01157E.

Steinbach, J., Popovski, E., Fleiter, T., Hummel, M., Chassein, E., Bedoya, I., Rex, M., 2017. Policy recommendations to decarbonise European heating and cooling systems: progRESsHEAT D5.5. http://www.progressheat.eu/IMG/pdf/progressheat_d5.5_inclannex_forupload_2017-12-06.pdf.

Thomaßen, G., Kavvadias, K., Jiménez Navarro, J.P., 2021. The decarbonisation of the EU heating sector through electrification: A parametric analysis. Energy Policy 148, 111929. https://doi.org/10.1016/j.enpol.2020.111929.

Williams, H., Lohman, T., Foster, S., Morrell, G., 2018. Public acceptability of the use of hydrogen for heating and cooking in the home: Results from qualitative and quantitative research in UK. Madano.

Annex A: Model descriptions

Invert/EE-Lab, Invert/Opt, Hotmaps

The **building stock model Invert/EE-Lab** is a bottom-up model to simulate energy related investment decisions in buildings focusing on space heating, hot water generation and space cooling. It is based on a highly disaggregated description of the building stocks in the different countries of the EU (+ Norway, Iceland, Switzerland, UK) including type of building, age, state of renovation, existing heating systems, user structure as well regional aspects such as availability of energy infrastructure for e.g. district heating or natural gas on a sub-country level. It simulates investment decisions in the building shell and the heat supply and distribution systems via a combination of a discrete choice approach and technology diffusion theory. This makes it possible to study the influence of various side-conditions including policy measures on the decisions of the actors.

The derived model version **Invert/Opt** is able to calculate cost optimal scenarios based on a combination of technology options available in different years – both for heat savings (retrofitting measures mainly regarding the building envelope) and heat supply (mainly replacement of heating and hot water supply systems) – and considering diffusion constraints10F[86] such as limited availability of (tradeable) biomass, energy infrastructure or e.g. available roof area suitable for solar technologies) options (see also chapter 3.4.1). Due to the high level of disaggregation (varying from country to country between a few hundred to a few thousands building segments split in several climate regions) of the existing buildings and the high level of detail in the possible renovation options for each of the building types the model leads to a wide spread technology mix even in the optimization mode.

The Invert model has been developed and applied in national and international projects in the EU for more than 10 years now, in many of them reflecting the entire EU building stocks (Invert/EE-Lab 2020).

A more detailed description of the model can be found below.

Invert/EE-Lab is a dynamic bottom-up simulation tool that evaluates the effects of different framework conditions (in particular different settings of economic and regulatory incentives) on the total energy demand, energy carrier mix, CO2 reductions and costs for space heating, cooling and hot water preparations in buildings. Furthermore, Invert/EE-Lab is designed to simulate different scenarios (price scenarios, insulation scenarios, different consumer behaviors, etc.) and their respective impact on future trends of energy demand and mix of renewable as well as conventional energy sources on a national and regional level. More information is available on www.invert.at or e.g. in (Lukas Kranzl et al. 2013) or (Müller 2012).

The basic structure and concept are described in Figure 49.

[86] For the implementation of the cost-optimal solution under diffusion constraints see (Andreas Müller 2015).

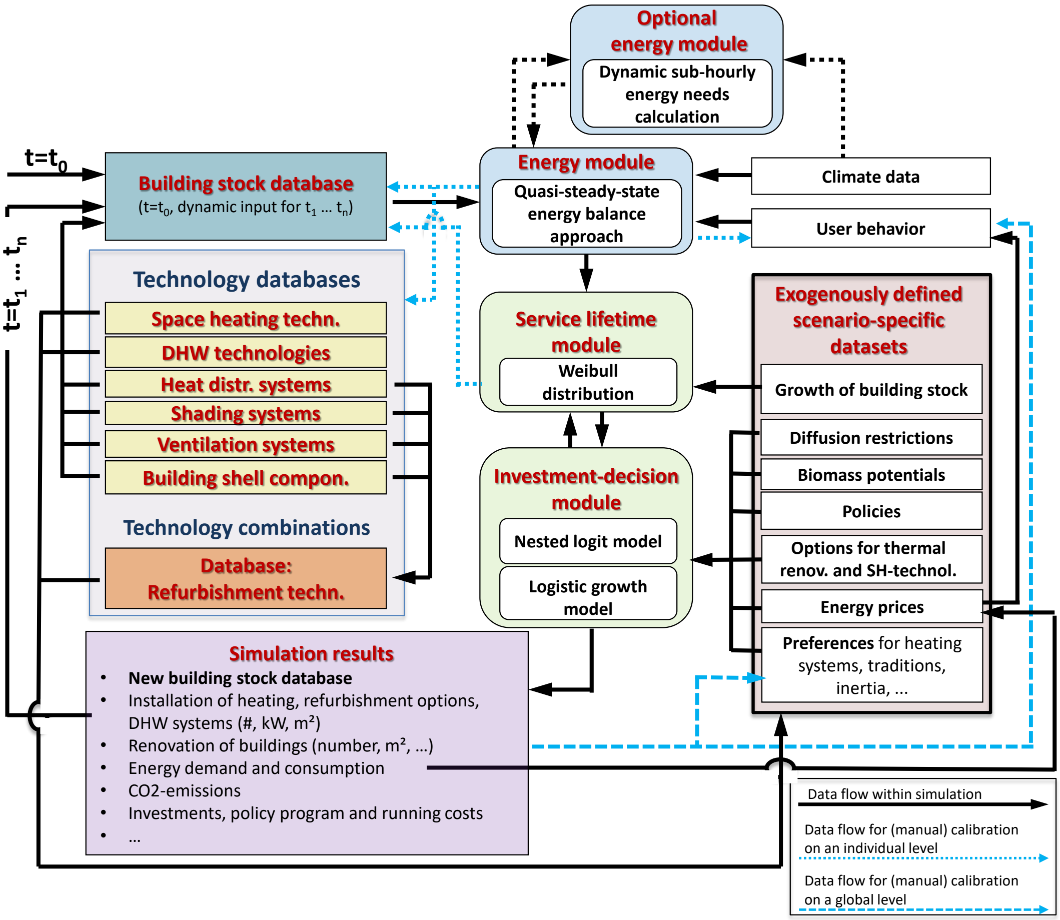

Figure 49: Overview structure of Simulation-Tool Invert/EE-Lab

Invert simulation tool originally has been developed by TU Wien/EEG in the frame of the Altener project Invert (Investing in RES&RUE technologies: models for saving public money). In more than 40 projects and studies for more than 30 countries, the model has been extended and applied to different regions within Europe, see e.g. (Lukas Kranzl et al. 2012), (Lukas Kranzl et al. 2013), (Biermayr et al. 2007), (Haas, Müller, and Kranzl 2009), (L. Kranzl et al. 2006), (Lukas Kranzl et al. 2007), (Nast et al. 2006), (Schriefl 2007), (Stadler et al. 2007). The modification of the model in the year 2010 included a re-programming process and accommodation of the tool, in particular taking into account the inhomogeneous structure of decision makers in the building sector and corresponding distributions (Müller 2010), (Müller 2015).

The basic idea of the model is to describe the building stock, heating, cooling and hot water systems on highly disaggregated level, calculate related energy needs and delivered energy, determine reinvestment cycles and new investment of building components and technologies and simulate the decisions of various agents (i.e. owner types) in case that an investment decision is due for a specific building segment. The core of the tool is a myopic, multinomial logit approach, which optimizes objectives of “agents” under imperfect information conditions and by that represents the decisions maker concerning building related decisions.

The model Invert/EE-Lab up to now has been applied in all countries of **EU-27 (+ GBR, NOR, CH, ISL)**. A representation of the implemented data of the building stock is given at www.entranze.eu.

Invert/EE-Lab covers residential **and tertiary buildings.**

As efficiency technologies Invert/EE-Lab models the uptake of different levels of renovation measures (country specific) and the diffusion of efficient heating and hot water systems.

The core of the simulation model is a myopic approach which optimizes objectives of agents under imperfect information conditions and by that represents the decisions concerning building related investments. It applies a nested logit approach in order to calculate market shares of heating systems and energy efficiency measures depending on building and investor type. The following equation depicts the market share calculation as logit-model – in order to reduce complexity in the representation:

$$ms_{n\,jb,t} = \frac{e^{-\lambda_b \cdot} r_{njb}}{\sum_{j=1}^{J} e^{-\lambda_b \cdot} r_{njb}}$$

$$r_{njb,t} = \frac{V_{njb,t}}{\sum_{j=1}^{J} ms_{njb,t-1} \times V_{njb,t}}$$

$\mathrm{ms_{njb}}$ = market share of alternative j in building b for investor type n at period t

$\mathrm{r_{njb}}$ = relative utility of alternative j in building b for investor type n

The model enables the definition of a various number of different owner types as instances of predefined investor classes: owner occupier, private landlords, community of owners (joint-ownership), and housing association. The structure is motivated by the different perspectives regarding building related investments. For instance, energy cost savings are only relevant for those owners which occupy the building. The corresponding variable relevant to landlords is a refinancing of energy savings measures through additional rental income (investor-tenant dilemma).

Owner types are differentiated by their investment decision behaviour and the perception of the environment, the former is captured by investor-specific weights of economic and non-economic attributes of alternatives. The perception relevant variables – information awareness, energy price calculation, risk aversion – influence the attribute values.

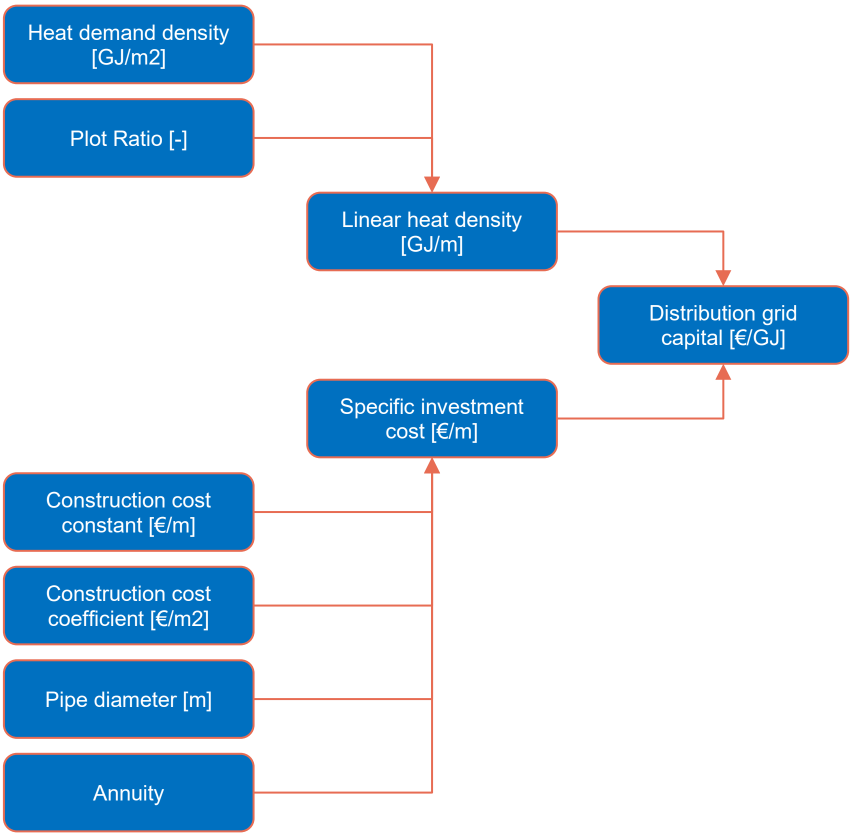

Figure 50: Procedure to calculate district heat distribution grid capital costs

To apply this method uniformly to the whole country, uniform data on heat demand densities and gross floor area densities are required. From the gross floor area densities, plot ratio can be obtained. Hotmaps[87] project provides such a data set for the basis year of 2015 covering EU-28 countries. The Hotmaps project renovation scenario is further used to obtain heat demand density and heated gross floor area density maps of year 2050.

One key concept when assessing DH network investment cost is the linear heat density and is defined as the ratio of delivered heat to the DH system (Q_T) in a year to the total DH trench length (L).

$$LinearHeatDensity = \frac{Q_T}{L} \quad [GJ/(m.a)]$$

The linear heat density can also indicate the level of heat losses in the grid.

[87] www.hotmaps.eu

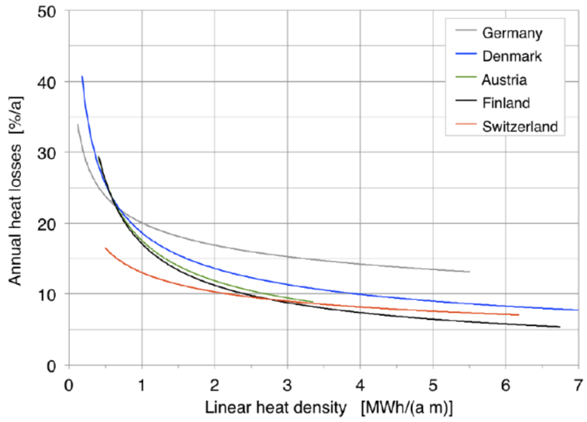

Figure 51: Annual heat losses as a function of linear heat density. Only the potential trendlines are displayed (Source: Nussbaumer and Thalmann 2014)

To calculate the linear heat density analytically, Persson and Werner used demographic data and introduce the concept of effective width (*w*), which describes the relationship between a given land area (or plot ratio, *e*) and the length of the district heating trench length within this area.

$$w = A_L/L = \begin{cases} 137.5e + 5 & [m] \quad 0 < e \leq 0.4 \\ 60 & [m] \quad e > 0.4 \end{cases}$$

Accordingly, the linear heat density can be formulated as follows:

$$LinearHeatDensity = \frac{Q_T}{L} = e * q * w = q_T * w \qquad [GJ/(m.a)]$$

$$q = Q_T/GFA \qquad [GJ/(m^2.a)]$$

$$q_T = Q_T/A_L \qquad [GJ/(m^2.a)]$$

Using the linear heat density, the average pipeline diameter (d_a) in meter is calculated as follows:

$$d_a = 0.0486 \cdot ln(Q_T/L) + 0.0007 \qquad [m]$$

The specific investment cost (I/L) of the distribution grid may be derived using the following formula. The slop and the intercept of the linear formula are referred as to construction cost coefficient (C2) in EUR/m2 and construction cost constant (C1) in EUR/m, respectively. These values are obtained empirically based on the existing networks. Figure 52 depicts the interpolation.

$$\frac{I}{L} = C_1 + C_2 * d_a \qquad [\frac{€}{m}]$$

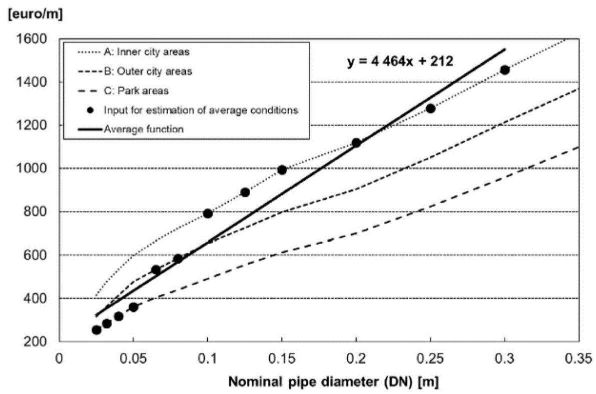

Figure 52: specific investment cost as a function of pipe dimension (Source: Persson et al. 2019)

We assume a constant heat supply by DH grid over its lifetime. Accordingly, the annual capital cost of the DH distribution grid per unit of delivered heat can be obtained as follows:

$$C_{d,T} = \frac{C_{1,T} + C_{2,T} \cdot d_a}{n \cdot \frac{Q_T}{L} \cdot \sum_{t=0}^{n} (1+r)^{-t}}$$

Cd,T	Annualized distribution grid cost per unit of delivered heat [€/GJ]
L	Total trench length [m]
C1,T	Construction costs constant [€/m], here 212 €/m
C2,T	and Construction costs coefficient [€/m2], here 4464 €/m2
da	Pipe diameter [m]
n	Depreciation time, here 30 years
QT	Heat demand supplied by DH in year “T” [GJ]
QT / L	Linear heat density [GJ/m]
r	Interest rate, here 5%

The method described is used to do identify coherent areas, in which the average distribution grid cost does not exceed the grid cost ceiling are extracted as potential DH areas to determine district heating constraints.

Enertile

Enertile is an energy system optimization model developed at the Fraunhofer Institute for System and Innovation Research ISI. The model focuses on the power sector, but also covers the interdependencies with other sectors, especially heating and cooling, electricity based fuel production (Power to X) and the transport sector. It is a used mostly for long-term scenario studies and is explicitly designed to depict the challenges and opportunities of increasing shares of renewable energies. A major advantage of the model is its high technical and temporal resolution.

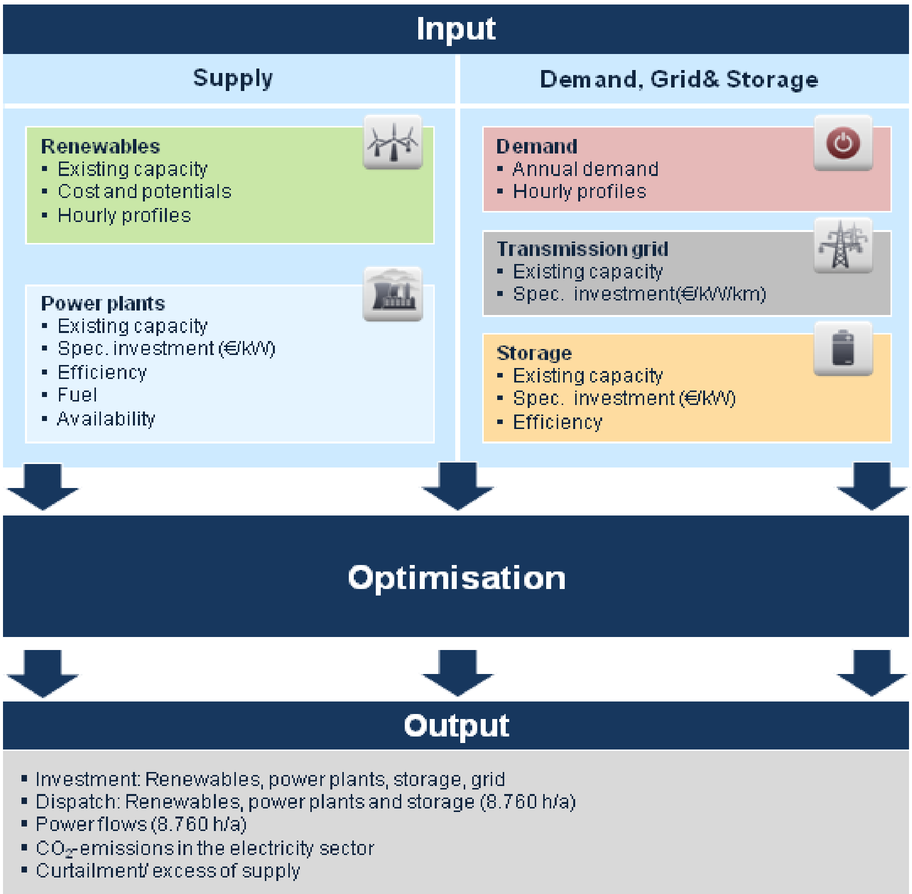

Figure 53: Simplified structure of the model Enertile

Integrated optimization of investments and dispatch

Enertile optimizes the investments into all major infrastructures of the power sector, including conventional power generation, combined-heat-and-power (CHP), renewable power technologies, cross-border transmission grids, flexibility options, such demand-side-management (DSM), power-to-fuel and power-to-heat storage technologies. The model chooses the optimal portfolio of technologies while determining the utilization of these for in all hours of each analysed year.

High temporal resolution

The model features a full hourly resolution: In each analysed year, 8,760 hours are covered. Since real weather data is applied, the interdependencies between weather regions and renewable technologies are implicitly included.

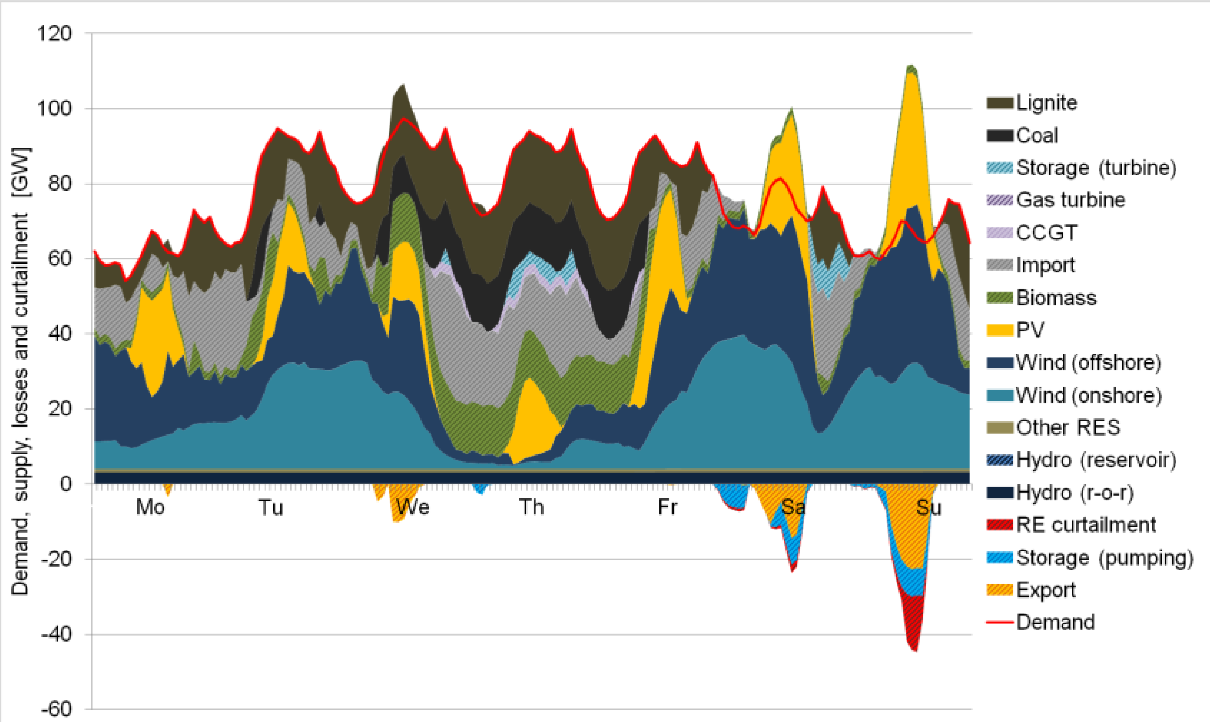

Figure 54: Example of the hourly matching of electricity supply and demand.

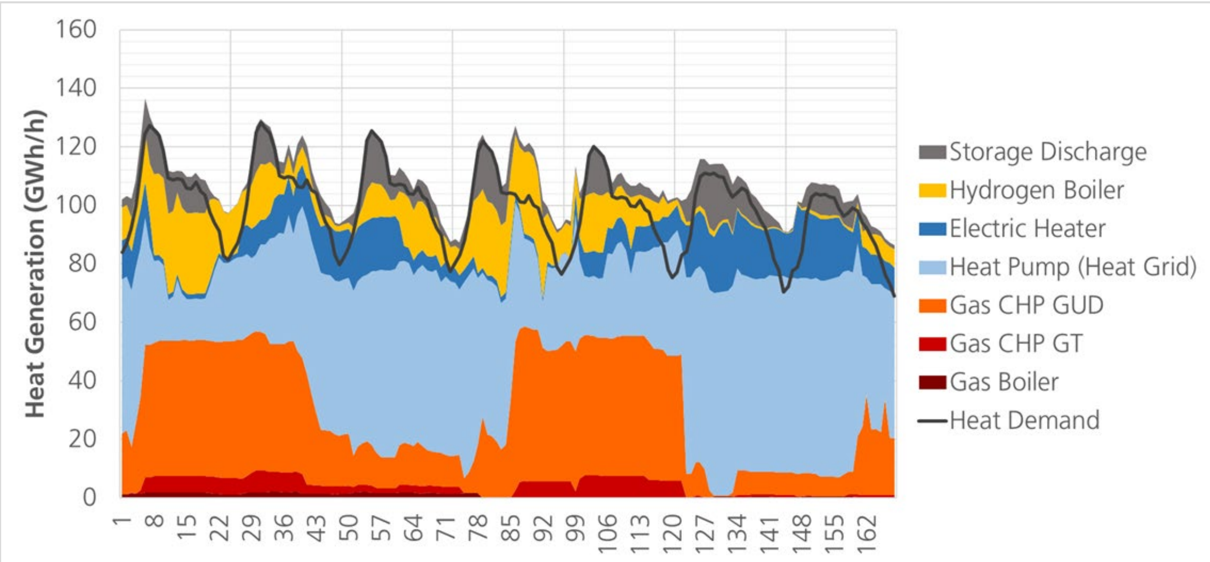

Figure 55: Example of the hourly matching of heat supply and demand in heat grids (sum of all heat grids in Europe).

Detailed picture of renewable energy potential and generation profiles

The potential sites for renewable energy are calculated on the basis of several hundred thousand regional data points for wind and solar technologies with consideration of distance regulations and protected areas. The hourly generation profile is based on detailed regional weather data.

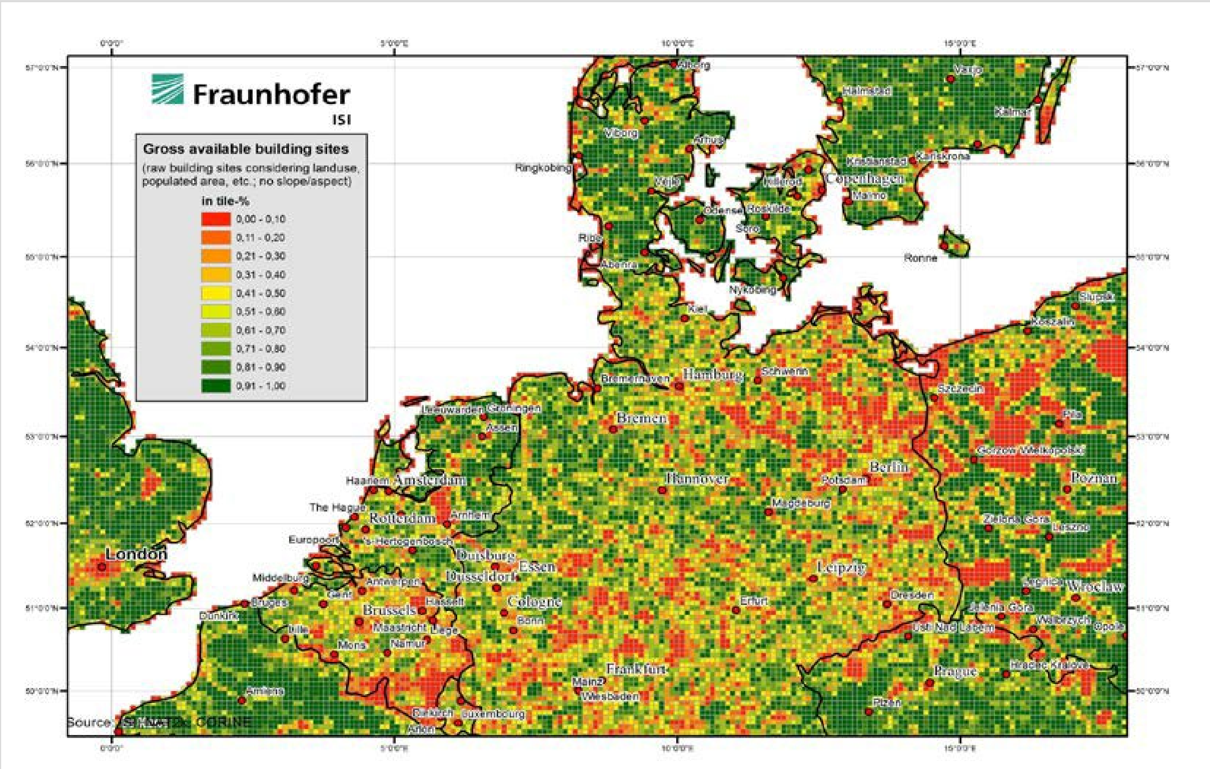

Figure 56: Example of the calculation of solar photovoltaic potential.

Cross-sectoral modelling

Although the model focuses on the power sector, cross-sectoral interdependencies are taken into account. The effects of heat demand on CHP plants considered, as well as the flexibility provided by heat pumps or other power-to-heat systems. The production of electricity based fuels is endogenously optimised. Investments in electrolysers as well as additional electricity production is part of the optimisation problem. The charging of electric vehicles can be performed “smart”, allowing delaying consumption in accordance with the preferences of the users.

High spatial coverage

The model currently depicts and optimizes Europe, North Africa and the Middle East. Each country is usually represented by one node, although in some cases it is useful to aggregate smaller countries and split larger ones into several regions. Covering such a large region instead of single countries becomes increasingly necessary with high shares of renewable energy, as exchanging electricity between different weather regions is a central flexibility option.

The model contains all required data on existing power plants, transport corridors and extensive geospatial and weather data for the assessment of renewable electricity generation cost and profiles.

Outputs from Enertile

- Installed capacity of generation units including renewables
- Location of renewable generation units
- Hourly generation profiles

- Installed capacity of transmission corridors
- Hourly trading flows on transmission corridors
- Annual cost for the modelled parts of the electricity system
- CO2-Emissions, GHG-Emissions
- Hourly Shadow prices on each node

Consentec Electricity Transmission Model

Consentec has developed a load flow data model of the European transmission grid (220 and 380 kV level) exclusively based on freely usable sources (in particular schematic circuit diagrams of the transmission system operators as well as network cards, published information on conductor cable capacities or types, etc.) that can be used without restrictions. In addition to passive grid elements (transmission lines, transformers and switchgear), this also includes the regional distribution of power demand and consumer load, power plant locations and electricity feed-in renewable energy sources. The network model was validated by comparative calculations with published network calculation results.

Due to the limited scope and level of detail of the publicly available information (e.g. on electrical parameters of transmission lines or on the switching state in transformer substations), the network model does not achieve the accuracy as a TSO's model and that would be necessary for specific statements for electrical equipment, e.g. on the concrete dimensioning of individual lines. However, it is possible to identify congestion regions and quantify network expansion requirements on a regional basis. This is also proven by a wide variety of successful applications, e.g. in studies for European power plant operators on price zones or on power plant positioning, as well as on behalf of the German Federal Ministry of Economics and Technology for the monitoring report on the state of supply security in electricity supply.

As described, the model is based on data published by transmission grid operators and other public sources (e.g. ENTSO-E grid maps and data) and therefore consists of transmission lines and grid nodes in a very high level of detail (approximately 3.500 nodes and 5.000 lines for EU-27). In addition to today's actual grid, expected grid expansion projects as stated in the TYNDP (until 2030) are implemented for the initial grid model that is used as a starting point for the transmission grid calculations. An illustration of this grid model used for this study is shown in Figure 57. Please note that in addition the area under consideration for this study (EU-27) Norway and Switzerland are contained in the detailed grid model for modelling reasons (analogous to enertile). Thus, the general impact of supply and demand of those countries on EU-27 is taken into account within the load flow and outage simulations. However, for all grid-related results (additional line lengths and costs) only EU-27 is evaluated.

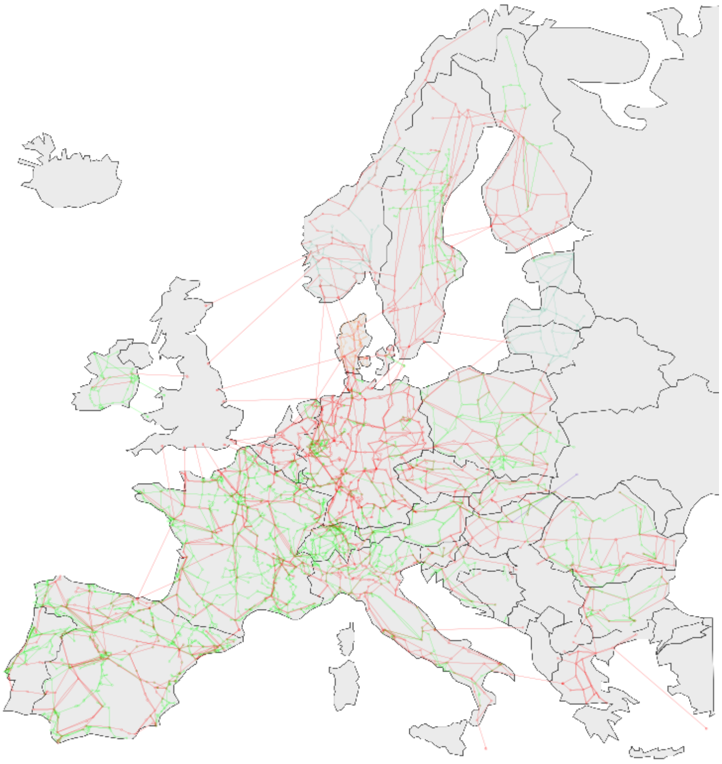

Figure 57: Detailed transmission grid model for EU-27

Within this detailed grid model electricity supply and demand based on enertile results is mapped to grid nodes which provides a very high geographical resolution in this model. The dispatch of cross-zonal HVDC connections is taken from the enertile result by the hourly exchange of two zones. To also consider the effect of innovative (controllable) grid equipment (intra-zonal HVDC connections, phase shifting transformers and grid boosters), the dispatch of these assets is optimized with the goal of reducing grid loads and consequential grid expansion requirements.

This given set of parameters then can be used to derive transmission grid loads from full year (hourly) load-flow calculations and (n-1) outage simulations.

The line loading (and especially overloading) as exemplarily shown in Figure 58 offers a plausible indicator for the estimation of necessary grid expansion for each scenario. The procedure for the estimation of grid expansion requirements, which is based on these calculated results for grid loads, is described in the following paragraph.

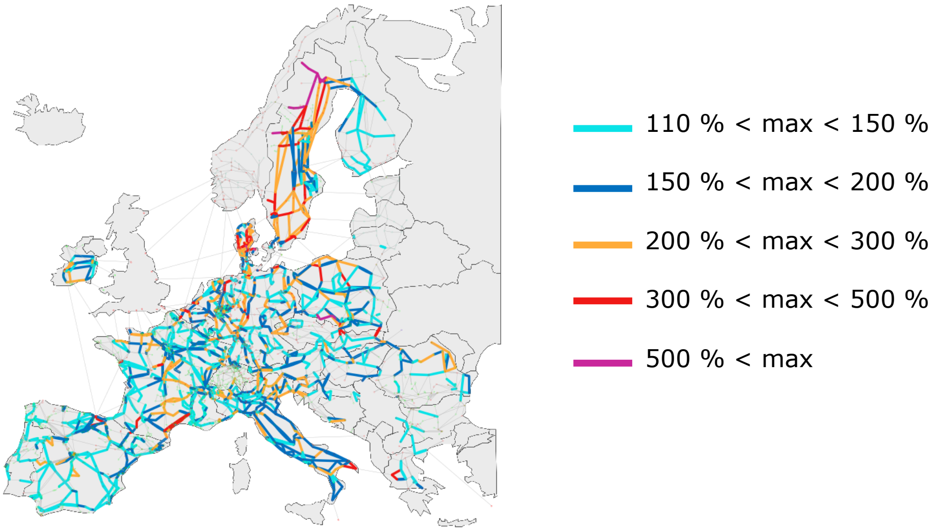

Figure 58: Exemplary results for maximum line loading in (n-1)-case for EU-27

Estimation of grid expansion requirements

To estimate the necessary grid expansion for each scenario within the large area under consideration in this study, a methodology has been developed with which it is possible to derive the line length that needs to be expanded based on calculated line overloading. Within the calculations a line is identified as overloaded if its loading rate is higher than 110% in more than 20 hours of the year. These parameters to select overloaded lines have been chosen to cut off outlier values in the grid loading that result from modelling effects and that would lead to implausible overestimation of grid expansion needs.

With regard to identified line overloading the methodology basically consists of the following steps (note: Since the scope of this study aims for overall grid expansion needs and not a detailed grid planning, this approach is chosen to reduce complexity in such a large area under consideration):

- If a line is not overloaded (as per above criterion), no grid expansion is necessary for this line
- If a line is overloaded, at least one additional line of the same length is required. If the overload exceeds the transmission capability of one additional line, further new lines are required. The sum of the transmission capacity of the additional lines must be at least equal to the overload.

In addition to this basic methodology further refinements and assumptions are made to derive plausible results:

- Overloading on lines is solved by additional parallel lines and existing lines remain in the grid model (no dismantling)
- To reflect “state of the art” technology for the future (at least from today’s point of view) for the expansion of overloaded lines the usage of 380 kV AC high-current technology (3.600 A) is assumed.
- Due to this assumption no additional HVDC-lines, phase shifting transformers or grid boosters are used for grid expansion. This of course is a result of the assumptions within this methodology (and could diverge under different assumptions), not a result of detailed grid planning.

Since grid expansion on one line can (due to the physics of load flow) relieve parallel lines, using the sum of the line length determined by above approach would also result in an overestimation of grid expansion needs. Therefore, for this study an additional “reducing factor”, that reflects the relieving of parallel lines, has been derived from previous detailed grid expansion studies (where the expansions have been implemented line-sharp and iterative in the detailed grid model). To depict this effect for various initial grid states for the countries in the area under consideration, two different factors, that are multiplied with the total line length in each grid groups (i.e. countries), have been determined and are used for this study:

- For grid groups with a higher proportion (> 30 %) of parallel systems, a factor of 0.75 is used
- For grid groups with a lower proportion (< 30 %) of parallel systems, a factor of 0.875 is used

As a result, this methodology provides the additional line length (grid expansion) necessary for each country.

On this basis corresponding grid costs (investments needs and annual costs) can be derived. For this, cost assumptions for network equipment (lines / cables) based on empirical values as used by the German grid operators for their network development plan (“Netzentwicklungsplan” NEP2030 (V2019)) are used. Furthermore, for this cost assessment it is assumed that (new) transmission lines are on average 20% cable / 80% overhead-lines (this is an assumption to represent an average usage of cables within the electricity transmission grid in the future and is not a result from detailed grid planning).

Consentec Gas and Electricity Distribution Models

In order to analyse the effects of different possible levels of electrification of heating, on the electricity and gas distribution networks precisely and in detail, many influencing factors would have to be taken into account with a high degree of accuracy. However, this is neither justifiable nor necessary in the context of this study, because the technical and economic effects of the various scenarios on the electricity and gas distribution grids should be estimated for EU member states in sufficient regional resolution and not calculated exactly for each subgrid.

The methodical approach of model grid analysis is well suited to determining the effects of various developments in the buildings' electricity and gas demand on the distribution grids. The model grid analysis is based on the idea of describing the supply task in a highly abstract form with only a few input variables, so that the essential interrelationships between these input variables (spatial distribution of grid users, demand of consumers, output of generation plants, typical specifications for grid design) and the output variables (quantity of the grid elements required to fulfil the supply task and consequently grid costs) can be easily investigated, detached from case-specific individual influences. This method of model network analysis (MNA) has been implemented in the EXOGON tool developed by Consentec and has already been used successfully in numerous studies.

The MNA considers the supply task for a specific area to be homogeneous and determines a cost-optimal network, considering relevant constraints and several planning specifications, assuming a "green-field situation". Theoretically, all network levels must be included in a closed optimization at the same time during network planning. However, due to the complexity of such a task, this is so far impossible. It is more common practice to decouple the entire planning task into spatial and technical (according to network levels) more or less delimited subtasks. In order to come as close as possible to the goal of optimal overall planning, network operators have derived planning specifications for the individual network levels that are tailored to their supply area from practical experience and basic studies. Such planning specifications concern, for example, the selection of equipment regarding its dimensioning. The MNA is also oriented towards this decoupling. The determination of the quantities of resources required for a given (homogeneous) supply task is based here on the assumption that the planning process can be broken down into sub-steps in which the network is essentially dimensioned "bottom-up" from the lowest network level, i.e. without significant repercussions of the planning results of a higher level on the design of the lower level.

Based on these fundamental considerations, independent modelling approaches for the MNA were developed for electricity and gas networks. In the following sections, the uniform aspects of modelling for both network divisions are first presented, followed by the special characteristics of the models for electricity and gas networks.

Modelling of the supply task

The supply task forms the basis for network design and comprises all planning relevant characteristics of a supply area and the network users located there that cannot be influenced by the network operator. For an individual grid level under consideration, it mainly comprises the following information:

- Places where loads or - in the electricity grid - generation plants must be connected to the grid (connection points)
- the technical characteristics of each individual load or generation unit (e.g. maximum load, energy demand, maximum generation capacity, etc.)
- Locations and load characteristics of stations for feeding into subordinate grid levels (substations or gas pressure regulating stations)

The above-mentioned properties of the area and load structure are simulated in the MNA in highly abstract form under the assumption of a homogeneous arrangement (per network level). It is assumed that there are uniform load characteristics at all connection points to be considered in a network level and that all connection points are evenly distributed over the area of the considered supply area. Furthermore, it is assumed that all edges of the rectangular surface sections around the connection points can be used as line routes and all intersection points of the line routes as possible locations for feed-in stations from the superimposed network level.

In this way, the structure of a supply area can be described with regard to the design of a certain considered network level essentially by information on the area of the area, the number of load connection points as well as the (uniform) height of the loads (in particular the annual maximum load).

Subsection approach

If the MNA is used to investigate the effects of the characteristics of real supply areas on the network assets required there and the associated network costs, for example for comparative analyses of different supply areas, the abstract description of the supply task based on area-wide averages may be too inaccurate to obtain robust results. In such studies, the accuracy can be increased by dividing each service area into sub-areas and applying the MNA for each sub-area separately. In this case, it is only assumed that each sub-area can be approximated by a homogeneous supply task. These partial supply tasks, on the other hand, can differ from sub-area to sub-area. The results obtained for the sub-areas of a supply area (plant inventory, grid costs) are summed up in this procedure in order to obtain results for the entire area.

The subdivision of coverage areas into subareas should be chosen in such a way that the required input variables for the MNA can be made available subarea-specifically according to the selected boundaries. For example, it may make sense to classify MNA according to municipalities or other districts that are included in statistical databases. In principle, the smaller the sub-areas are, the more accurate the analysis will be. However, in order to avoid the MNA designing degenerate networks, the sub-areas should always be significantly larger than the "elementary" areas per connection point (e.g. property sizes at the final distribution level). This limit resulting from the "granularity" of the supply task differs depending on the network level under consideration.

Input variables to describe the load model

The MNA requires the following information as input variables to describe the homogeneous load model for a considered network level in a (part of) coverage area:

- Number of connection points: This includes connection points for the supply of end customers as well as (except in the final distribution level) for feeding into subordinate network levels via transformer or gas pressure regulating stations. The number of the latter connection points results from the dimensioning of the subordinate level in the case of bottom-up optimization over several network levels. In contrast, the number of connection points for end customers must be explicitly specified for each grid level. This should not be confused with the usually significantly higher number of metering points. The connection points at which the network operator's area of responsibility ends are relevant for the MNA. However, several metering points can be supplied from such a connection point, e.g. in an apartment building.
- The MNA determines the total number of connection points to be taken into account from the sum of the connection points for end customers and for feeds into the lower level and assigns these connection points a "incremental load" calculated as a weighted mean value in order to arrive at a uniform load model despite any different load heights of the two connection point types.
- (Uniform) maximum load per connection point: This information is only required for connection points for end customer supply, since the load at feeds into the lower level results from the dimensioning of the transformer or gas pressure regulator station. The load per connection point in the final distribution level can alternatively also be defined by the load per residential unit and the average number of residential units per connection point, which is particularly obvious in supply areas characterised predominantly by residential buildings (part of the supply areas).
- The maximum load of end customers who are supplied directly from a substation or gas pressure regulator station, e.g. via customers' own lines, must be distinguished from this load specification for each connection point. Loads of this type do not affect the design of the pipeline network but can be taken into account by the MNA when designing the transformer or gas pressure regulating stations.
- Covered area of the (partial) supply area: Only that part of the total area of the area under consideration that is actually covered by the network at a particular network level is to be taken into account.

In addition to these basic specifications, a homogeneous supply task is characterized by the shape of the "elementary" area piece that is assigned to each connection point. The MNA always assumes quadratic areas on each network level. At the level of the final distribution, however, this assumption is not realistic, since plots tend to be cut to rectangular shape with the short side facing the road. In order to be able to analyze this effect, the MNA offers the possibility of providing rectangular elementary surfaces at the lowest mesh level and explicitly specifying the aspect ratio.

Planning requirements

When designing a network for a given supply task, the network planner has various degrees of freedom, especially regarding

- the number of network levels used and their nominal voltages or pressure stages,
- the equipment used (above all line types as well as dimensioning and technical equipment of transformer substations and gas pressure regulating stations),
- the grid structure (e.g. radial, ring or mesh structure) and thus the redundancy of the net, and
- the definition of the technical constraints to be considered during network planning (e.g. voltage and pressure limits as well as load limits for the equipment depending on their technical properties).

In principle, network design is to be understood as an optimisation task with the aim of using these degrees of freedom in such a way that the overall network costs are minimised and at the same time all constraints that cannot be influenced by the network operator as well as the ancillary conditions determined by the network operator itself are complied with. Auxiliary conditions that cannot be influenced can be, for example, specifications by laws, standards, regulations or the regulatory authority that relate to security requirements, network interoperability or other objectives. Influensible ancillary conditions, for example, affect the desired level of grid reliability, especially in the case of electricity grids.

In practice, however, network planning is not treated as such a complex optimization task in every individual case, since the effort involved would not be justifiable and, above all, in most cases extensive restrictions of the degrees of freedom resulting from planning decisions already made in the past must already be taken into account. Therefore, it is usual to define a large part of the mentioned degrees of freedom on the basis of experience or basic investigations. This results in planning principles that are treated as fixed requirements in individual cases. It is quite common that the planning principles are differentiated according to certain characteristics of the supply task, i.e. that a different network structure is aimed for in inner-city areas than in rural areas.

The MNA is also based on this planning practice: the above-mentioned degrees of freedom are not optimized by the model, but are determined by a series of planning specifications. However, these are not specified during model development, but can be entered during the application of the model.

In detail, the MNA offers the following options for influencing the planning specifications for network design:

- Number of network levels: The MNA can take into account up to three line network levels with largely freely parameterisable nominal voltages or pressure levels as well as the respective superimposed station levels (transformer or gas pressure regulating stations).
- In principle, these model network levels can be applied to all real network levels, with one limitation: For the supra-regional transport level (transmission level for electricity networks and pipeline level for gas networks), the MNA is hardly suitable because of the concept, since the significance of the results is very limited due to the comparatively small number of large-volume individual plants at these levels and the strong abstraction in the description of the supply task (cf. Section 3.2).

- Equipment properties: The MNA assumes that - in accordance with normal practice - uniform operating resources (above all line and station types and dimensions) are used at each network level for the same functions within a homogeneously structured (part of) supply area with simultaneous construction ("greenfield approach"). The equipment used and its technical properties are not selected on the basis of optimisation, but are determined by the user of the model in the sense of planning specifications.
- Net structure: The MNA offers the possibility of selecting one of three standardized net structures (radial, ring and mesh) separately for each considered net level. Although the spectrum of the structures present in real networks, which is characterized in particular by combinations of these basic structures, cannot be depicted comprehensively differentiated, this allows a rough estimate of the influence of the selected network structure on plant inventory and network costs.

In practice, the selection of the optimal network structure requires a consideration of the network costs and the network redundancy aimed at for operational and reliability reasons. Network structures with higher redundancy tend to result in higher network costs due to additional line connections, redundant station layouts and an additional need for switching and positioning options. In order to be able to use the higher redundancy operationally, reduced load limits for the operating equipment must also be considered, which in turn tends to lead to higher costs. The MNA can simulate the cost effects mentioned, but not the other criteria to be considered when selecting the optimal network structure, such as reliability level and operational processes.

For the final distribution level, in addition to the basic form of the network structure, it can be specified whether supply lines are provided only on one side of the street (or in the middle of the street) or on both sides of the street and thus the buildings on both sides of the street (in the case of "one-sided street occupation") or only the buildings on one side of the street (in the case of "two-sided street occupation") are supplied via one line.

- Technical constraints: The MNA takes into account both equipment-related limits, in particular for the maximum load (in addition to specifications for margins to be adhered to in order to take account of uncertainties and future load growth) and system-related limits such as voltage and pressure limits at the load connection points.
- Load mixing: The fact that the maximum loads at the different load connection points occur at different times and that the "simultaneous" maximum load of a load spectrum is thus lower than the sum of the "non-chronic" individual loads, is taken into account in the MNA - as is customary in planning practice - by specifying simultaneity factors, whereby differently detailed modelling of the load mixing is possible.

Grid design

The algorithm for the network design of the MNA is based, as explained above, on the assumption that a network comprising several network layers can be designed layer by layer from the lowest level without having to consider repercussions of superimposed layers on subordinate layers. This simplistic assumption is permissible within the framework of the generally highly abstract modelling approach of the MNA under the conditions,

- that realistic planning specifications are defined, the determination of which already anticipates a considerable part of the complexity of the optimization task "network design", and
- that, in the case of specified, uniform equipment dimensioning, it can always be assumed to be more cost-effective to exploit the capacity of the equipment on a lower level as fully as possible (taking into account all technical ancillary conditions) than to leave parts of the

capacity unnecessarily unused and thus to leave a larger part of the transport task to be performed to a higher level.

The first condition must be considered when applying the MNA. It should be noted that, depending on the characteristics of the supply task, different combinations of planning principles can be useful and customary in practice.

The second condition can generally be regarded as fulfilled under the usual cost ratios of equipment and can therefore be used as a basis for the MNA, which conceptually considers the "average" and not the individual special case which may deviate from it.

This results in the following calculation steps for the network design:

- First, for the lowest grid level under consideration (e.g. the end user distribution level), it is determined how long a line branch (in the case of electricity grids referred to as an "outlet") from the station feeding into this level (substation or gas pressure regulating station) to the last load connection point to be supplied can be maximum, taking into account the technical constraints.
- On this basis, it is determined how many such branches can be supplied from one feed station, considering both secondary conditions for the line network and the (specified) capacity of the substation or pressure regulator station.
- This determines how many feed stations are required at this network level in the (partial) supply area under consideration. This concludes the network design for this level. From the results, aggregated quantities such as the line length of this level in the area under consideration are determined, considering the selected network structure.
- The number of required feed-in stations from the superimposed level is included in the design of the superimposed grid level, along with other input variables. This follows the same calculation scheme, whereby at the beginning the total number of load connection points to be considered is determined from the number of connection points for end customers and the number of stations to be fed into the lower level and an "equivalent load" is assigned to all these connection points.

The result of this algorithm - corresponding to the homogeneous supply task - is homogeneously structured model networks, which consider all the usual planning specifications and, in the fictitious case of a supply task that actually has this structure, could also be implemented in this way. The abstraction that takes place in the MNA therefore primarily affects the supply task, not the network design based on it.

When designing the network, the technical constraints to be met are checked by means of load flow calculations. Due to the symmetry properties of the model networks, the load flow calculation takes on a simplified form here. However, no approximate form is used.

When determining the total loads of the load connection points supplied via a line branch or a station, information on the extent of load mixing can be considered, i.e. on the contribution of each individual load to the maximum total load.

In addition to the secondary conditions to be checked by load flow calculation, structural secondary conditions such as specifications for the maximum length of lines, the maximum number of connection points per line or - particularly common in electricity grids - the maximum number of "outgoers" per transformer station can be taken into account.

The network design algorithm described above initially only considers the supply lines from which the final line sections for supplying buildings (house connection lines) are branched off, but not the house connection lines themselves. Their length is then determined based on the number of connection points to be considered and the average house connection line length to be specified by the user of the model. A model endogenous determination of the average house connection line length is not possible, since the MNA has no information about the location of the connection points within the property areas.

In the previous representation of the network design algorithm, it is assumed that the lowest network level is the final distribution level. If the analysis is to begin at a higher network level, the MNA offers the possibility of explicitly specifying the number of feed-in stations to be considered into the next subordinate (and no longer to be considered) network level. This specification then replaces the numerical value that would otherwise be determined as the result of the design of the subordinate level.

Depending on the task at hand, it may also be of interest to specify a fixed number of stations for the design of a station level (transformer or pressure regulator station) so that the network design algorithm no longer has to determine the number but the load of the individual stations. The MNA also offers this possibility.

Cost determination

The network design step described above provides a quantity structure (mainly line lengths and station numbers) of the cost-minimum network designed for the supply task under consideration, differentiated according to system types (network levels, line types, etc.). The costs for this are then determined based on standardised investment and operating costs approaches, which are also differentiated according to plant type. An annuity cost model is used, which converts investment costs into constant annual costs, considering useful lives and calculation interest rates. Operating costs can be considered as a percentage of the investment costs, which is added annually, or as an absolute cost contribution per year, which is specific to the type of plant. With the MNA for electricity grids, the grid loss costs are also calculated as a component of the operating costs.

Gas specific modelling approaches

Supply task

Gas networks usually cover only part of the supply area of a network operator. Both the degree of area coverage, defined as the share of the area covered by gas grids in the total supply area, and the degree of connection, which indicates the share of the buildings actually connected to the gas grid in the total number buildings existing there (and thus potentially connectable), are usually more or less well below 100 %. This must be considered when describing the supply task of a (partial) supply area for the distribution model. Incomplete development is considered by excluding populated but undeveloped areas from the coverage area of the area. It should be noted that undeveloped areas, like open spaces, have different effects depending on the network level. For example, untapped districts can be completely excluded at the final distribution level, while they can be relevant for consideration at superimposed network levels depending on their size and the large-scale structure of the supply task, because, for example, they are traversed or circulated by the regional transport network. Assuming a constant average connection rate and knowing the number of buildings connected to the grid as well as the total number of existing buildings in the area under consideration, it is possible to deduce the share of developed buildings in the total populated area.

An incomplete connection rate within the developed area is considered by informing the MNA not only of the number of actually realised connection points but also of the total number of existing buildings in the developed area as input variables for describing the supply task at the final distribution level. The total number of buildings, which includes not only the realised but also the potentially realisable connection points in the developed area, is required in order to be able to define a "grid" of the homogeneous supply task corresponding to the real conditions on average.

The MNA then assumes that pipelines are routed past buildings not yet connected in the entire developed area, so that further connections only require the installation of further house connection lines. Only in the case of a radiation network structure (see below) is it considered that certain road sections can remain unpiped if no connections can be made there. Since the MNA has no knowledge of the actual distribution of the connection points in the area under consideration, an average assessment is made.

Planning requirements

Regarding gas networks, the information on the planning requirements for MNAs can be clarified as follows:

- The up to three network levels that can be modelled can be assigned to the usual practical levels of "local end user distribution", "local transport" and "regional transport" according to functional criteria. A transition between different nominal pressure levels between these functional levels is possible, but not necessary. Therefore the MNA allows a free assignment of pressure levels to the functional levels. If (and only if) the pressure levels of two directly adjacent levels are different, gas pressure regulating stations are provided at the connection points.
- The following variables must be considered as relevant technical properties of the equipment in gas networks:
  - Diameter and resistance value (roughness) of the pipelines
  - Upper and lower nominal pressure and flow capacity of pressure regulator stations
- The basic forms of the network structure in the MNA for gas networks are the radial, ring and mesh network structures. In principle, it is assumed that starting from a feed point from the upstream (functional) network level with or without pressure regulator station, the distribution takes place first via a more strongly dimensioned line and from there branching via less strongly dimensioned lines to the connection points or in the final distribution to the branching points of the house connection lines. The dimensions of the two line sections are not specified, but result from the network design. The network structures only differ in terms of whether and to what extent the branches obtained in this way are connected to each other at the end by ring or mesh connections.
- It is important to note that the complexity of real network structures cannot be comprehensively represented by these basic forms. In practice, for example, there are often structures with a high degree of intermeshing in the densely populated core of a location and more radial extensions towards the edge of the location. The MNA is conceptually not able to map such structures under consideration of the actual (inhomogeneous) distribution of the connection points. The selection of basic structures presented here therefore serves as a basis for fundamental investigations of the influence of network redundancy on plant inventory and network costs.

As technical constraints, the following can be defined for each network level

- upper and lower pressure limits at the network nodes (supply and connection points) and
- an upper limit for the flow velocity in pipelines can be specified. The latter is considered in practice for reasons of safety and noise development.

Electricity specific modelling approaches

Supply task

Generation plants must be considered as a sector-specific feature when designing electricity model grids. These can be simplified in the modelling approach developed here by adding the number of additional connection points required for the connection of generation plants in a supply area to the number of load connection points and taking into account the generation capacity "reliably" available at the peak load time as a negative load contribution in the specification of the load height. In addition, the voltage limits to be defined as planning specifications can be adjusted at the network nodes (see below) in order to take into account the fact that generation plants can lead to a voltage increase in low load situations, whereby part of the permissible voltage band is "consumed".

In this way, the essential effects of the grid integration of generation plants can be taken into account approximately, whereby it is assumed that the installed generation capacity in each grid section (e.g. each outgoing line) is lower than the maximum load and thus the grid design is primarily determined by the load height and not by the generation capacity.

Planning requirements

When designing electricity model grids, the following planning specifications can be considered:

- Up to three grid levels can be simulated. These are permanently assigned to the low, medium and high voltage levels. A transformer level (stations with transformers) is simulated to supply each of these network levels from the respective superimposed voltage level.
- The main technical characteristics of the equipment relevant for planning are considered by the following specifications:
    - Transmission capacity, reactance and resistance of the lines
    - Transformer capacity, no-load and short-circuit loss factors of the transformers as well as number of transformers per transformer station
- The MNA for electricity grids considers radial, ring and mesh grid structures as fundamental forms of the grid structure. It is assumed that a rectangular section of the considered supply area is supplied from each substation feeding into the considered network level. The dimensions of this section are not specified, but are the result of the network design. The supply takes place via several outgoing lines, also resulting from the network design, which, depending on the network structure, are not connected to each other (radial network) or are connected to each other by ring or mesh connections. For the determination of the plant quantity structures, which is the focus here, it is irrelevant whether an open (with separation points) or closed mode of operation is assumed in normal operation.

  The ring and mesh network structures take into account that the associated structural network redundancy only contributes to increasing network reliability if sufficient load reserves of the equipment are planned in order to enable continued or re-supply via the remaining equipment without violating technical limits (especially the transmission capacity of the remaining equipment) in the event of a fault.

  The modelling approach of the MNA is based on the assumption that the entire network in a considered (part of) coverage area is consistently structured according to one of the three basic forms considered. This is logical in view of the supply task assumed to be homogeneous and the "greenfield approach", since there is no reason to implement different structures within a homogeneously structured area, unless the historical development of the network argues otherwise.

When comparing with real networks, however, it should be noted that these generally do not have a uniform structure throughout, but mixed forms of these and other conceivable basic structures. When designing target networks as an orientation for long-term network development, however, it is quite common practice to assume a largely uniform structure, which is selected after weighing up network costs, reliability targets and other influencing factors.

In addition to the load limits to be specified for the equipment, the maximum voltage drop between the injection point from the superimposed plane and the "rearmost" load connection point is considered as a technical secondary condition for each network level.

REKK's European Gas Market Model

EGMM is a competitive, dynamic, multi-market partial equilibrium model that simulates the operation of the wholesale natural gas market across the whole of Europe. It includes a supply-demand representation of EU28 countries, Switzerland, the Contracting Parties of the Energy Community[88] and Turkey, including gas storage and transportation linkages. Large external markets, including Russia, Norway, Libya, Algeria, Azerbaijan, Iran and LNG exporters are represented exogenously with market prices, long-term supply contracts and physical connections to Europe.

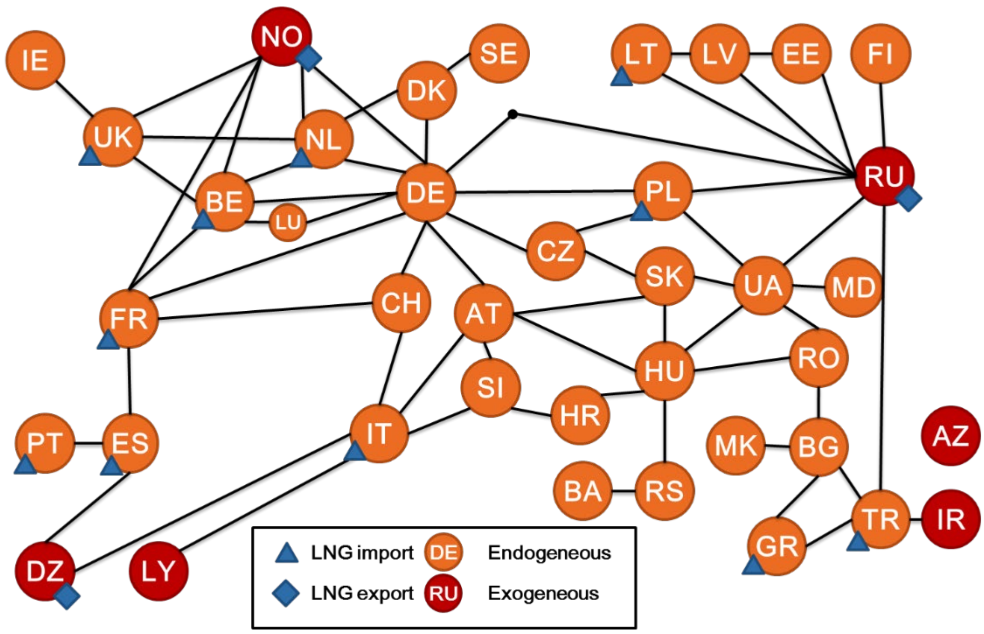

Figure 59: Geographical representation of the EGMM model (Source: REKK)

The timeframe of the model covers 12 consecutive months and market participants have perfect information over this period. Dynamic connections between months are introduced by

[88] Contracting Parties of the Energy Community Treaty are: the European Union and AL, BA, GE, GR, ME, MK, MD, RS, UA

the operation of gas storages and take-or-pay constraints (minimum and maximum deliveries are calculated over the entire 12-month period, enabling contractual flexibility).

The European Gas Market Model consists of the following building blocks: (1) local demand; (2) local supply; (3) gas storages; (4) external markets and supply sources; (5) cross-border pipeline connections; (6) LNG infrastructure (7) long-term take-or-pay (TOP) contracts; and (8) spot trading.

1. Local demand is represented by demand functions. Demand functions are downward sloping, meaning that higher prices decrease the amount of gas that consumers want to use in a given period. For simplicity, we use a linear functional form, the consequence of which is that every time the market price increases by 0.1 €/MWh, local monthly consumption is reduced by equal quantities (as opposed to equal percentages, for example). The linearity and price responsiveness of local demand ensures that market clearing prices will always exist in the model. Regardless of how little supply there is in a local market, there will be a high enough price so that the quantity demanded will fall back to the level of quantity supplied, achieving market equilibrium.
2. Local supply shows the relationship between the local market price and the amount of gas that local producers are willing to pump into the system at that price. In the model, each supply unit (company, field, or even well) has either a constant, or a linearly increasing marginal cost of production (measured in €/MWh). Supply units operate between minimum and maximum production constraints in each month, and an overall yearly maximum capacity.
3. Gas storages are capable of storing natural gas from one period to another, arbitraging away large market price differences across periods. Their effect on the system's supply-demand balance can be positive or negative, depending on whether gas is withdrawn from, or injected into, the storage. Each local market can contain any number of storage units (companies or fields). Storage units have a constant marginal cost of injection and (separately) of withdrawal. In each month, there are upper limits on total injections and total withdrawals. There is no specific working gas fee, but the model contains a real interest rate for discounting the periods, which automatically ensures that foregone interest costs on working gas inventories are considered. There are three additional constraints on storage operation: (1) working gas capacity; (2) starting inventory level; and (3) year-end inventory level. Injections and withdrawals must be such during the year that working gas capacity is never exceeded, intra-year inventory levels never drop below zero, and year-end inventory levels are met.
4. External markets and supply sources are set exogenously (i.e. as input data) for each month, and they are assumed not to be influenced by any supply-demand development in the local markets. In case of LNG the price is derived from the Japanese spot gas price, taking into account the cost of transportation to any possible LNG import terminal. As a consequence, the price levels set for outside markets are important determinants of their trading volumes with Europe.
5. Cross-border pipelines allow the transportation of natural gas from one market to the other. Connections between geographically non-neighbouring countries are also possible, which allows the possibility of dedicated transit. Cross-border linkages are directional, but physical reverse flow can easily be allowed for by adding a parallel connection that "points" into the other direction. Each linkage has a minimum and a maximum monthly transmission capacity, as well as a proportional transmission fee. Virtual reverse flow ("backhaul") on unidirectional pipelines or LNG routes can also be allowed, or forbidden, separately for each connection and each month. The rationale for virtual reverse flow is the possibility to trade "against" the delivery of long-term take-

or-pay contracts, by exploiting the fact that reducing a pre-arranged gas flow in the physical direction is the same commercial transaction as selling gas in the reverse direction. Additional upper constraints can be placed on the sum of physical flows (or spot trading activity) of selected connections. This option is used, for example, to limit imports through LNG terminals, without specifying the source of the LNG shipment.

6. LNG infrastructure in the model consist of LNG liquefaction plants of exporting countries, LNG regasification plants of importing countries and the transport routes connecting them. LNG terminals capacity is aggregated for each country, which differs from the pipeline setup, where capacity constraints are set for all individual pipeline. LNG capacity constraints are set as a limit for the set of "virtual pipelines" pointing from all exporting countries to a given importing country, and as a limit on the set of pipelines pointing from all importing countries to a given exporting country.
7. Long-term take-or-pay (TOP) contracts are agreements between an outside supply source and a local market concerning the delivery of natural gas into the latter. Each contract has monthly and yearly minimum and maximum quantities, a delivery price, and a monthly proportional TOP-violation penalty. Maximum quantities (monthly or yearly) cannot be breached, and neither can the yearly minimum quantity. Deliveries can be reduced below the monthly minimum, in which case the monthly proportional TOP-violation penalty must be paid for the gas that was not delivered. Any number of TOP-contracts can be in force between any two source and destination markets. Monthly TOP-limits, prices, and penalties can be changed from one month to the next. Contract prices can be given exogenously, indexed to internal market prices, or set to a combination of the two options. The delivery routes (the set of pipelines from source to destination) must be specified as input data for each contract. It is possible to divide the delivered quantities among several parallel routes in pre-determined proportions, and routes can also be changed from one month to the next.
8. Spot trading serves to arbitrage price differences across markets that are connected with a pipeline or an LNG route. Typically, if the price on the source-side of the connection exceeds the price on the destination-side by more than the proportional transmission fee, then spot trading will occur towards the high-priced market. Spot trading continues until either (1) the price difference drops to the level of the transmission fee, or (2) the physical capacity of the connection is reached. Physical flows on pipelines and LNG routes equal the sum of long-term deliveries and spot trading. When virtual reverse flow is allowed, spot trading can become "negative" (backhaul), meaning that transactions go against the predominant contractual flow. Of course, backhaul can never exceed the contractual flow of the connection.

Equilibrium

The European Gas Market Model algorithm reads the input data and searches for the simultaneous supply-demand equilibrium (including storage stock changes and net imports) of all local markets in all months, respecting all the constraints detailed above.

In short, the equilibrium state (the "result") of the model can be described by a simple no-arbitrage condition across space and time. However, it is instructive to spell out this condition in terms of the behaviour of market participants: consumers, producers and traders. Infrastructure operators (TSO, storage and LNG operator) observe gas flows and their welfare is not factored in the equilibrium.

Welfare

Welfare calculations are done ex post. The maximized value of the objective function is adjusted to properly account for actual welfare in the market. The operating profit of transmission and storage system operators is added using estimates for their marginal costs, and the expenditure on import contracts is increased by the take-or-pay fixed cost element.

Welfare components are assigned to regional and outside markets based on location. For consumer and local producer surplus, long-term contract profit,19 storage operating income and congestion rent, the assignment is straightforward. Pipeline operating income is shared in the ratio of entry and exit fees and pipeline congestion rent is shared equally by the neighbouring markets. LNG-related welfare components are assigned to the market hosting the terminal." REKK EGMM model description based on Kiss, Selei and Tóth (2016)

Outputs

Outputs of modelling are the wholesale gas market prices per country and the natural gas flows. Based on those outputs the model also calculated welfare on country and stakeholder level (consumer, producer, traders, infrastructure operators).

Data sources

Data for the modelling scenarios is derived from publicly available sources: infrastructure capacity data on transmission, LNG and storage from Gas Infrastructure Europe, demand and production data from Eurostat and for future forecast from Primes Ref 2020 (draft) and other modelling teams (Enertile and Invert). For publicly not available data on long term contract prices the foreign trade statistics formed the basis of estimates.

Table 31: Summary of modelling input parameters and data sources (Source: REKK)

Category	Data Unit	Source
Consumption	Annual Quantity (TWh/year) Monthly distribution (% of annual quantity)	Primes Ref 2020 (draft), Enertile, Invert
Production	Minimum and maximum production (GWh/day)	Primes Ref 2020 (draft), Enertile,
Pipeline infrastructures	Daily maximum flow (GWh/day)	GIE, ENTSO-G, Energy Community data
Storage infrastructures	Injection (GWh/day), withdrawal (GWh/day), working gas capacity (TWh)	GSE
LNG infrastructures	Regasification capacity (GWh/day)	GLE, GIIGNL
LTC contracts	Yearly minimum maximum quantity, Seasonal minimum and maximum quantity	Gazprom, National Regulators Annual reports, Eurostat, Platts, Cedigaz
Storage, LNG regasification and transmission tariffs	€/MWh	TSO, SSO, LSO webpages

Assumptions

Pricing strategy for major importers to Europe strongly determines the market outcomes and network flows on the European gas grid. For this reason, price decisions of Norway and Russia was based on a profit-maximizing behaviour of these countries.

LNG supply to Europe was set at a constant level and unchanged between scenarios.

Long-term contract price was set at 2020 levels and unchanged for the modelling timeframe.

Tariffs for infrastructure use (pipeline, storage and LNG) were also set at 2020 levels and unchanged for the modelling period.

Gas infrastructure included the developments of FID projects of ENTSOG TYNDP to 2030, and no new investment occurred from that time on in the gas network.

Natural gas consumption was explicitly modelled for the power&heat (Enertile) and the building sector (Invert). Industry sector gas consumption was assumed to decrease at the rate of the other two sectors for each scenario. Transport sector gas consumption was not modelled either and not considered in this study.

Natural gas production was assumed to develop according to Primes Ref 2020 (draft). Additionally, synthetic gas production modelled by Enertile was added to the gas supply in each scenarios. Biogas production was not considered.

EGMM-Hydrogen

EGMM-Hydrogen is a modified version of EGMM, with the aim of assessing the feasibility of hydrogen transport, taking into account the existing gas infrastructure. The geographical coverage of the model is EU27+CH,NO and UK as depicted on the chart below.

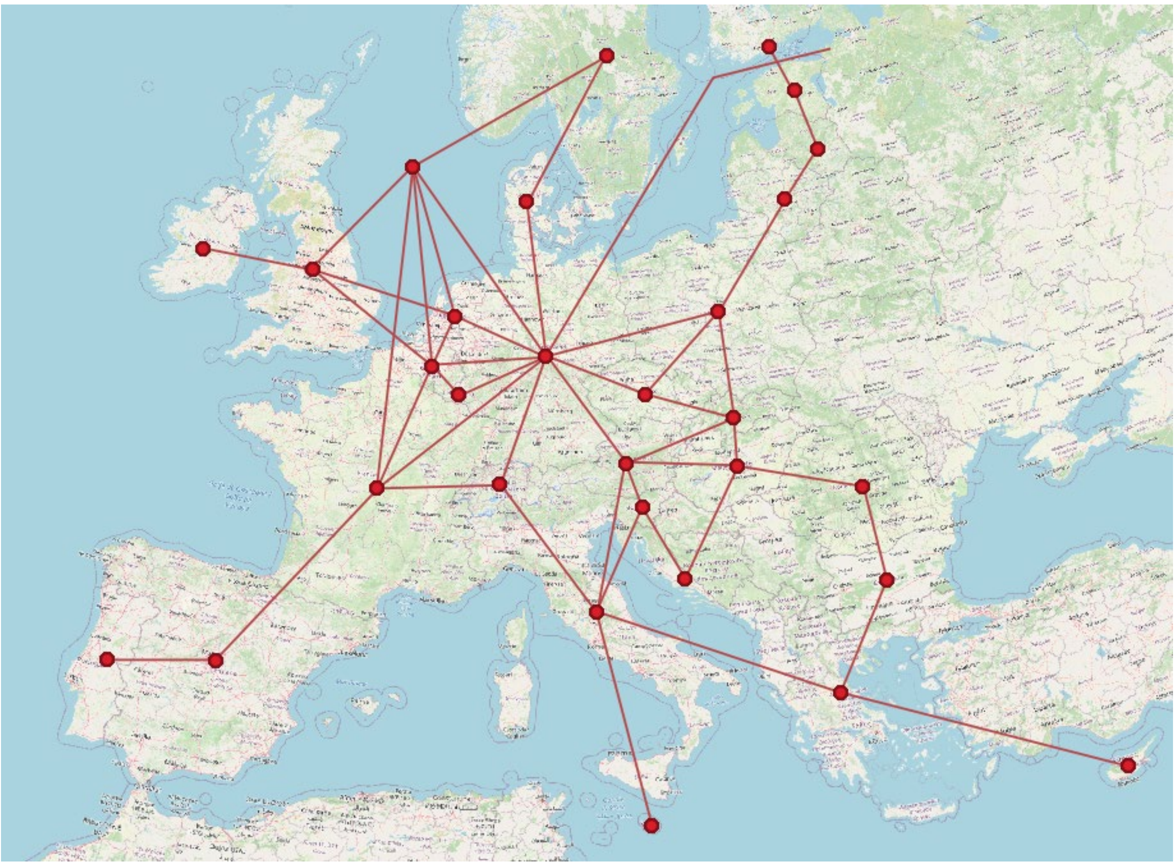

Figure 60: Topology of the simplified hydrogen model (EGMM-Hydrogen) (Source: REKK assumptions)

EGMM hydrogen is comprised of the same building blocks as EGMM, except for LNG trade and long-term TOP contract restriction. We opted to disregard retrofitting LNG terminals for hydrogen use, as this was not in the focus of this study. However, gas storages are considered as a potential for hydrogen storage. Long-term legacy take-or pay contracts are important for the natural gas market but currently we have no information on the future development of the contractual arrangements on the hydrogen markets.

The timeframe of the model covers 12 consecutive months and market participants have perfect information over this period. Dynamic connections between months are introduced by the operation of storages.

Building blocks of the model include: (1) local demand; (2) local supply; (3) gas storages; (4) external markets and supply sources; (5) cross-border pipeline connections; and (6) spot trading.

1. Local demand is represented by demand functions. Demand functions are downward sloping, meaning that higher prices decrease the amount of hydrogen that consumers want to use in a given period. For simplicity, we use a linear functional form, the consequence of which is that every time the market price increases by 0.1 €/MWh, local monthly consumption is reduced by equal quantities (as opposed to equal percentages, for example). The linearity and price responsiveness of local demand ensures that market clearing prices will always exist in the model. Regardless of how little supply there is in a local market, there will be a high enough price so that the quantity demanded will fall back to the level of quantity supplied, achieving market equilibrium.

2. Local supply shows the relationship between the local market price and the amount of gas that local producers are willing to pump into the system at that price. In the model, each country has a constant marginal cost of production (measured in €/MWh). Supply units operate between minimum and maximum production constraints in each month, and an overall yearly maximum capacity.
3. Storages are capable of storing hydrogen from one period to another, arbitraging away large market price differences across periods. Their effect on the system's supply-demand balance can be positive or negative, depending on whether hydrogen is withdrawn from, or injected into, the storage. Storage units have a constant marginal cost of injection and (separately) of withdrawal. In each month, there are upper limits on total injections and total withdrawals. There are three additional constraints on storage operation: (1) working gas capacity; (2) starting inventory level; and (3) year-end inventory level. Injections and withdrawals must be such during the year that working gas capacity is never exceeded, intra-year inventory levels never drop below zero, and year-end inventory levels are met.
4. External markets and supply sources are set exogenously (i.e. as input data) for each month, and they are assumed not to be influenced by any supply-demand development in the local markets.
5. Cross-border pipelines allow the transportation of natural gas from one market to the other. Connections between geographically non-neighbouring countries are also possible, which allows the possibility of dedicated transit. Cross-border linkages are directional, but physical reverse flow can easily be allowed for by adding a parallel connection that "points" into the other direction. Each linkage has a minimum and a maximum monthly transmission capacity, as well as a proportional transmission fee.
6. Spot trading serves to arbitrage price differences across markets that are connected with a pipeline. Typically, if the price on the source-side of the connection exceeds the price on the destination-side by more than the proportional transmission fee, then spot trading will occur towards the high-priced market. Spot trading continues until either (1) the price difference drops to the level of the transmission fee, or (2) the physical capacity of the connection is reached. Physical flows on pipelines equal spot trading.

Equilibrium

The European Gas Market Model algorithm reads the input data and searches for the simultaneous supply-demand equilibrium (including storage stock changes and net imports) of all local markets in all months, respecting all the constraints detailed above.

In short, the equilibrium state (the "result") of the model can be described by a simple no-arbitrage condition across space and time. However, it is instructive to spell out this condition in terms of the behaviour of market participants: consumers, producers and traders. Infrastructure operators (TSO and storage) observe gas flows and their welfare is not factored in the equilibrium.

Data sources

Production and consumption are supplied by Enertile and Invert for hydrogen. We assumed that the hydrogen production cost is uniform, 60 €/MWh in all countries, as suggested by Enertile. Pipeline and storage infrastructure for hydrogen is based on the existing natural gas infrastructure, external connection beyond the geographical coverage of the modelling are not included. Transmission cost of hydrogen considers the length of the pipelines connecting to consumption nodes.

Table 32: Summary of modelling input parameters and data sources (Source: REKK)

Category	Data Unit	Source
Consumption	Annual Quantity (TWh/year) Monthly distribution (% of annual quantity)	Primes Ref 2020 (draft), Enertile, Invert
Production	Minimum and maximum production (GWh/day)	Primes Ref 2020 (draft)t, Enertile,
Pipeline infrastructures	Daily maximum flow (GWh/day)	GIE, ENTSO-G, Energy Community data
Storage infrastructures	Injection (GWh/day), withdrawal (GWh/day), working gas capacity (TWh)	GSE
Storage and transmission tariffs	€/MWh	simplified distance based tariff (REKK calculation)

REKK-EGMM: Gas and hydrogen infrastructure modelling

Modelling approach

As a first step using EGMM model we quantified the gas flows and utilization of gas infrastructure in the different scenarios, taking into account the forecasted gas demand by Invert and Enertile models. This allows us to indicate where hydrogen blending is possible and where are additional interconnectors/repurposing of infrastructure is possible. (EGMM-Gas)

Then, as a second step, we carried out the hydrogen modelling using our modified gas market model, where we include the hydrogen demand and production by countries provided by the Enertile. Countries are interconnected with existing gas pipelines, as well as some additional links were added to facilitate the unconstrained flow of hydrogen. We assumed that the hydrogen production cost is uniform, 60 €/MWh in all countries, as suggested by Enertile. Originally, EGMM was calculating an equilibrium outcome with perfect competition in place. The modified model considered only the feasibility of a transport problem, i.e. how much is the current gas network capable to host the future hydrogen flows? (EGMM-Hydrogen)

We allowed unconstrained hydrogen flow between all countries under different tariff scenarios:

equal tariffs scenario: we assume a uniform 1 €/MWh tariff on all interconnectors (0.5 €/MWh on entry and 0.5 €/MWh on exit)

existing tariffs: current gas tariffs are used as hydrogen tariff

distance-based tariffs: distance-based tariffs are applied based on the distance between the central nodes of neighbouring countries. This scenario will be used when detailed results are shown, while the other two serve as sensitivities.

Distance-based tariffs were estimated based on the simple distance between the central nodes of each EU Member State (plus Norway, Switzerland and the UK). Central nodes were obtained from EU NUTS 2021 classification.[89] Two nodes (FI, NO) were moved to better represent actual location of supply and consumption. We considered all distances between neighbouring countries, where a gas pipeline was present, as well as for countries without current pipeline gas access the nearest neighbour was selected (e.g. IT-MT, CY-GR). This approach has some drawbacks as it does not exactly represent pipeline routing and the location of the central node may not always be the location of the consumption centres but is still a sound high-level estimation of network length and related investment costs.

The main output of this modelling exercise are the hydrogen flows between countries.

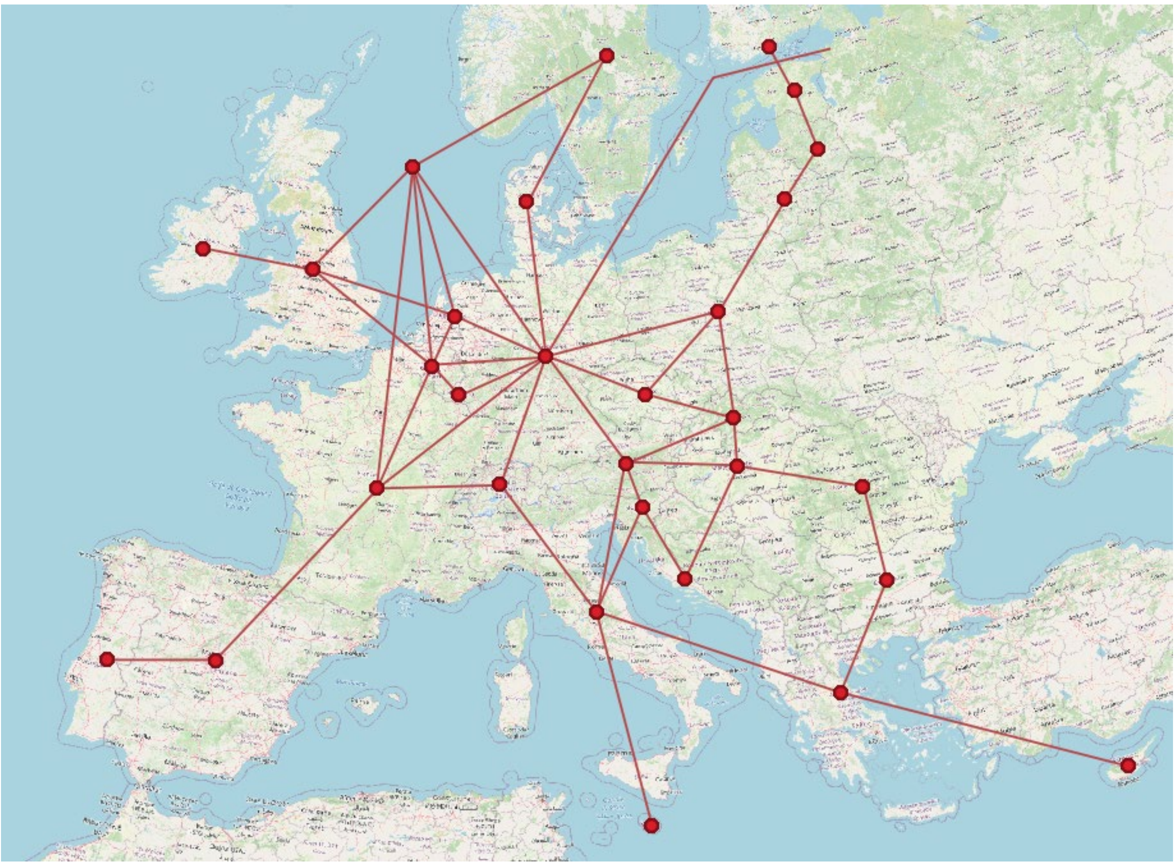

Figure 61 : Topology of the simplified hydrogen model (EGMM-Hydrogen) (Source: REKK assumptions)

Then, as a next step we merged and compared the outputs of natural gas (EGMM-Gas) and hydrogen (EGMM-Hydrogen) modelling, and we examined to what extent the modelled hydrogen transport need can be satisfied by the existing gas infrastructure via blending or retrofitting existing pipelines and where new, dedicated hydrogen pipelines are needed. Finally, we calculated the necessary investment cost to transport hydrogen and to what extent can the gas network be decommissioned.

We carried out the following analysis step by step for each interconnector where we have modelled positive hydrogen flow (summarized in Figure):

First, we checked whether there exists a gas pipeline.

If no, dedicated hydrogen pipeline is needed.

[89] https://ec.europa.eu/eurostat/web/gisco/geodata/reference-data/administrative-units-statistical-units/nuts#nuts21

If yes, we checked whether there is CH_4 flow on that pipeline.

If no, retrofit of this pipeline is possible, it can be used for hydrogen transport in the future without crowding out gas flows.

If yes, we tested whether this gas flow is enough to deliver the necessary hydrogen via blending.

If yes, no additional infra is necessary, the investment need is 0.

If no, we checked if there is more string of that pipeline.

If yes, one can be used for hydrogen transport. Investment for retrofit is needed.[90]

If no, gas pipeline is necessary for the transport of natural gas and a dedicated hydrogen infra is needed.

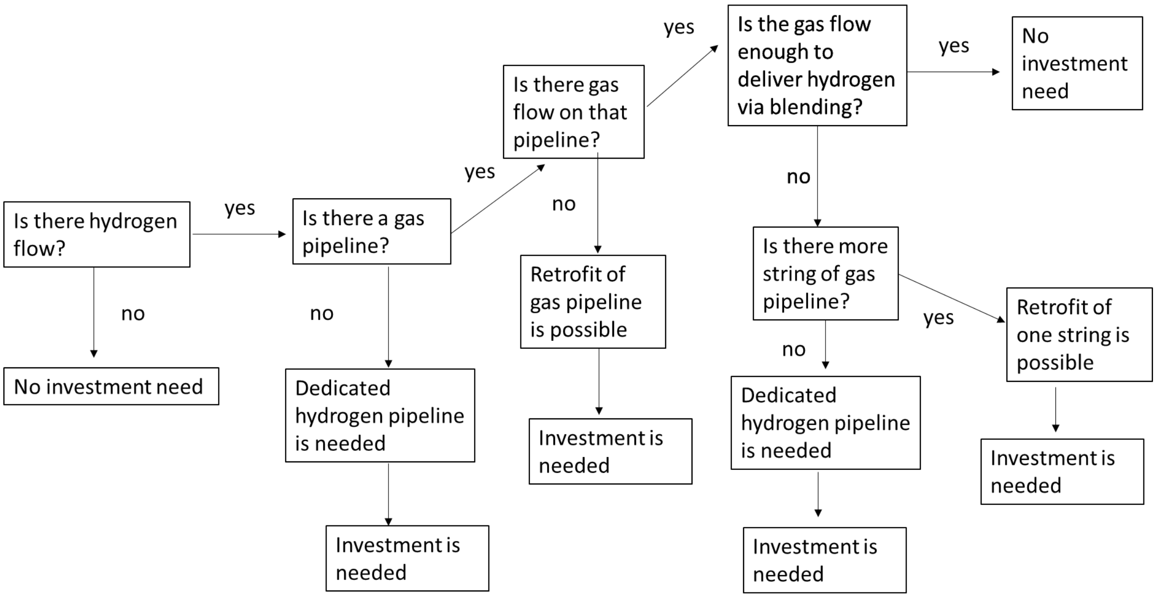

Figure 62: Methodological approach of hydrogen investment need estimation

Investment cost was based on the outcomes and assumptions of the European Hydrogen Backbone study.[91] The necessary investment cost of hydrogen transportation consists of the pipeline and compressor investments, as well as CAPEX and OPEX:

Cost of hydrogen blending: we assume the CAPEX of compressors to be 0.05 m€/km and no CAPEX concerning pipelines.

Retrofit cost of existing gas pipelines: we assume 0.5 m€/km CAPEX and 0.62 m€/km OPEX.

---

[90] ENTSOG capacity map was utilised to assess whether multiple strings are available or not. ENTSOG - The European Natural Gas Network (Capacities at cross-border points on the primary market) – 2019 https://www.entsog.eu/sites/default/files/2020-01/ENTSOG_CAP_2019_A0_1189x841_FULL_401.pdf It was assumed that in case there are multiple strings one sting can always be retrofited for hydrogen transport.

[91] Extending the European Hydrogen Backbone. A European Hydrogen infrastructure vision covering 21 countries. April 2021. https://gasforclimate2050.eu/?smd_process_download=1&download_id=669

Cost of new dedicated hydrogen pipeline: we assume 2.8 m€/km CAPEX and 0.62 m€/km OPEX.

The necessary length of the hydrogen infrastructure is estimated based on the distance between the central nodes of the countries.

We performed the abovementioned modelling tasks for the years 2030, 2040 and 2050. These corner years were modelled independently, so no direct interlinkage of investments was considered. Therefore, the outputs obtained needed to be reviewed, in order to make sure an investment occurs only once. For instance, if an interconnector is needed in all modelled years (2030, 2040 and 2050), it needs to be commissioned only once, in 2030.

The table below illustrates the decision made on investments based on the individual model runs.

Table 33 : Decision matrix for investments (Source: REKK modelling)

INDIVIDUAL MODEL RUN			INVESTMENT DECISION		
2030	**2040**	**2050**	**2030**	**2040**	**2050**
No inv.	No inv.	No inv.	No inv.	No inv.	No inv.
		Blending	No inv.	No inv.	Blending
		Retrofit	No inv.	No inv.	Retrofit
		Dedicated H2	No inv.	No inv.	Dedicated H2
	Blending	No inv.	No inv.	Blending	No inv.
		Blending	No inv.	Blending	No inv.
		Retrofit	No inv.	Blending	Retrofit
		Dedicated H2	No inv.	Blending	Dedicated H2
	Retrofit	No inv.	No inv.	Retrofit	No inv.
		Blending	No inv.	Retrofit	No inv.
		Retrofit	No inv.	Retrofit	No inv.
		Dedicated H2	No inv.	Retrofit	Dedicated H2
	Dedicated H2	No inv.	No inv.	Dedicated H2	No inv.
		Blending	No inv.	Dedicated H2	No inv.
		Retrofit	No inv.	Dedicated H2	No inv.
		Dedicated H2	No inv.	Dedicated H2	No inv.

Annex B: References for the barrier and policy analysis

Author(s)/editor	Year	Title	Link
Bacquet et al.	2022	Overview of District Heating and Cooling Markets and Regulatory Frameworks under the Revised Renewable Energy Directive	https://op.europa.eu/en/publication-detail/-/publication/4e28b0c8-eac1-11ec-a534-01aa75ed71a1/language-en
Baldino et al.	2020	Hydrogen for heating? Decarbonization options for households in the United Kingdom in 2050	https://theicct.org/sites/default/files/publications/Hydrogen-heating-UK-dec2020.pdf
Bauknecht et al.	2017	Study on Technical Assistance in Realisation of the 2016 Report on Renewable Energy, in preparation of the Renewable Energy Package for the Period 2020-2030 in the European Union: Task 1 & 2	https://ec.europa.eu/energy/studies/study-technical-assistance-realisation-2016-report-renewable-energy-preparation-renewable_en
Braungardt et al.	2022	Renewable Heating and Cooling Pathways, Measures and Milestones for the implementation of the recast Renewable Energy Directive	https://op.europa.eu/en/publication-detail/-/publication/16710ac3-eac0-11ec-a534-01aa75ed71a1/language-en
Bundes-netzagentur (Germany energy regulator)	2020	Regulierung von Wasserstoffnetzen: Bestandsaufnahme (Regulation of hydrogen networks: Assessment of the current situation)	https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/NetzentwicklungUndSmartGrid/Wasserstoff/Wasserstoffpapier.pdf?__blob=publicationFile&v=2
Chassein and Roser	2017	Boosting renewable energy in heating and cooling	https://ec.europa.eu/research/participants/documents/downloadPublic?documentIds=080166e5b74644ca&appId=PPGMS
Chassein et al.	2017	Using Renewable Energy for Heating and Cooling: Barriers and Drivers at Local Level	http://www.progressheat.eu/IMG/pdf/progressheat_wp3.2_report_publication.pdf
Connor et al.	2015	The development of renewable heating policy in the United Kingdom	https://www.sciencedirect.com/science/article/abs/pii/S0960148114006831?via%3Dihub
Costello	2018	Electrification: The nexus between consumer behavior and public policy	https://www.sciencedirect.com/science/article/abs/pii/S1040619018300010
DENA	2019	Roadmap Power to Gas	https://www.dena.de/fileadmin/dena/Publikationen/PDFs/2019/Roadmap_Power_to_Gas.pdf
Doble	2008	Barriers to renewable heat - Part 1: Supply side	https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/42957/1_20090501125221_e____2Part1FinalReportv70.pdf
Doble	2008	Barriers to renewable heat - Part 2: Demand side	https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/42958/1_20090501125239_e____3Part2FinalReportv10.pdf
Eguiarte et al	2020	Energy, Environmental and Economic Analysis of Air-to-Air Heat Pumps as an Alternative to Heating Electrification in Europe	https://www.mdpi.com/1996-1073/13/15/3939

Author(s)/editor	Year	Title	Link
European Commission	2020	Communication: A hydrogen strategy for a climate-neutral Europe	https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf
Fleiter et al.	2017	Mapping and analyses of the current and future heating/cooling fuel deployment - Scenarios for heating & cooling demand and supply until 2020 and 2030: WP 5 Barriers, Best Practices and Policy Recommendations	https://irees.de/wp-content/uploads/2021/01/Barriers-Best-Practices-and-Policy-Recommendations.pdf
Gaur et al.	2021	Heat pumps and our low-carbon future: A comprehensive review	https://linkinghub.elsevier.com/retrieve/pii/S221462962030339X
Guminski et al.	2018	System effects of high demand-side electrification rates: A scenario analysis for Germany in 2030	https://onlinelibrary.wiley.com/doi/full/10.1002/wene.327
Hughes	2008	Geothermal (Ground-Source) Heat Pumps: Market Status, Barriers to Adoption, and Actions to Overcome Barriers	https://www.osti.gov/biblio/948543
IEA	2019	The Future of Hydrogen	https://www.iea.org/reports/the-future-of-hydrogen
IEA	2019	Perspectives for the Clean Energy Transition - The Critical Role for Buildings	https://iea.blob.core.windows.net/assets/026bff1b-821d-48bc-8a0e-7c10280c62bc/Perspectives_for_the_Clean_Energy_Transition_2019.pdf
IEA	2021	Net Zero by 2050	https://www.iea.org/reports/net-zero-by-2050
IEA	2020	Heat Pumps: Tracking progess	https://www.iea.org/reports/tracking-buildings-2020/heat-pumps
IRENA	2020	Green hydrogen: A guide to policy making	https://www.irena.org/publications/2020/Nov/Green-hydrogen
IRENA	2021	Green Hydrogen Supply: A Guide to Policy Making	https://www.irena.org/publications/2021/May/Green-Hydrogen-Supply-A-Guide-To-Policy-Making#:~:text=Green%20hydrogen%20is%20a%20viable,is%20not%20yet%20fully%20developed.
IRENA, REN21, IEA	2018	Renewable Energy Policies in a Time of Transition	https://www.irena.org/publications/2018/apr/renewable-energy-policies-in-a-time-of-transition
Johnstone et al.	2017	Policy mixes for incumbency: Exploring the destructive recreation of renewable energy, shale gas ‘fracking,’ and nuclear power in the United Kingdom	https://www.sciencedirect.com/science/article/pii/S2214629617302712?casa_token=9ONy1ue4In0AAAAA:fcuwhjgayXx_Y54MU0hR6g250MaUlO1tFAuZtTCWSe0aa3Qwkzgo6oT6YCNhvel6oN_JvYqp92o
Kircher, Zhang	2021	Heat purchase agreements could lower barriers to heat pump adoption	https://www.sciencedirect.com/science/article/abs/pii/S0306261921000490
Kranzl et al.	2022	Renewable Space Heating under the Revised Renewable Energy Directive	forthcoming
Lim et al.	2016	Energy use and carbon reduction potentials from residential ground source heat pumps considering spatial and economic barriers	https://www.sciencedirect.com/science/article/pii/S0378778816305497?via%3Dihub

Author(s)/editor	Year	Title	Link
Lowes and Woodman	2020	Disruptive and uncertain: Policy makers' perceptions on UK heat decarbonisation	https://www.sciencedirect.com/science/article/pii/S0301421520302408
Lowes et al.	2020	Heating in Great Britain: An incumbent discourse coalition resists an electrifying future	https://www.sciencedirect.com/science/article/pii/S2210422420300964
Maruf et al.	2021	Classification, Potential Role, and Modeling of Power-to-Heat and Thermal Energy Storage in Energy Systems	https://arxiv.org/abs/2107.03960
Pezzutto et al	2017	European Heat Pump Market Analysis: Assessment of Barriers and Drivers	https://www.researchgate.net/publication/321035756_European_Heat_Pump_Market_Analysis_Assessment_of_Barriers_and_Drivers/link/5a09c1940f7e9b7b4168e0aa/download
Richard et al.	2022	The perfect fit: Shaping the Fit for 55 package to drive a climate-compatible heat pump market	https://www.raponline.org/knowledge-center/the-perfect-fit-shaping-the-fit-for-55-package-to-drive-a-climate-compatible-heat-pump-market/
Ruhnau et al.	2019	Direct or indirect electrification? A review of heat generation and road transport decarbonisation scenarios for Germany 2050	https://doi.org/10.1016/j.energy.2018.10.114
Saccani et al.	2020	Analysis of the Existing Barriers for the Market Development of Power to Hydrogen (P2H) in Italy	https://www.researchgate.net/publication/345088595_Analysis_of_the_Existing_Barriers_for_the_Market_Development_of_Power_to_Hydrogen_P2H_in_Italy
Sheikh and Callaway	2019	Decarbonizing Space and Water Heating in Temperate Climates: The Case for Electrification	https://www.mdpi.com/2073-4433/10/8/435/htm
Snape et al.	2015	Will domestic consumers take up the renewable heat incentive? An analysis of the barriers to heat pump adoption using agent-based modelling	https://www.sciencedirect.com/science/article/pii/S0301421515002013?via%3Dihub
Staffel et al.	2019	The role of hydrogen and fuel cells in the global energy system	https://pubs.rsc.org/en/content/articlepdf/2019/ee/c8ee01157e
Steinbach et al.	2017	Policy recommendations to decarbonise European heating and cooling systems	http://www.progressheat.eu/IMG/pdf/progressheat_d5.5_inclannex_forupload_2017-12-06.pdf
Thormaßen et al.	2021	The decarbonisation of the EU heating sector through electrification: A parametric analysis	https://doi.org/10.1016/j.enpol.2020.111929
Ueckerdt et al.	2021	Potential and risks of hydrogen-based e-fuels in climate change mitigation	https://publications.pik-potsdam.de/pubman/faces/ViewItemOverviewPage.jsp?itemId=item_25599
Veum et al.	2016	Study on the impact assessment for a new Directive mainstreaming deployment of renewable energy and ensuring that the EU meets its 2030 renewable energy target	https://ec.europa.eu/energy/studies/study-impact-assessment-new-directive-mainstreaming-deployment-renewable-energy-and-ensuring_de
Watson et al.	2019	Decarbonising domestic heating: What is the peak GB demand?	https://www.sciencedirect.com/science/article/pii/S0301421518307249

Author(s)/editor	Year	Title	Link
Williams et al.	2018	Public acceptability of hydrogen in the home	https://www.theccc.org.uk/publication/public-acceptability-of-hydrogen-in-the-home-madano-and-element-energy/

Publications Office
of the European Union