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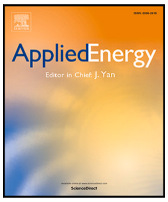

Flattening the peak demand curve through energy efficient buildings: A holistic approach towards net-zero carbon

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ABSTRACT

This study employs a sector-coupled energy system model to co-optimise investments in the supply side, demand side, and efficiency improvements. Beginning with a novel validation exercise of 2023, we demonstrate that the model can accurately reproduce the energy mix with an error of less than 5%. This approach incorporates often-neglected energy carriers, such as coal, gas, and nuclear, providing a holistic view of the current energy landscape. The analysis focuses on the impact of energy efficiency measures and building renovations on seasonal peak heating demand in Europe, featuring a pathway study that examines carbon emission targets for 2030, 2040, and 2050, while incorporating a new focus on efficiency improvements and demand-side response for the heating sector. Results indicate that reducing peak heating demand by up to 49% is cost-optimal and can facilitate annual reductions of 0.2 billion tons of greenhouse gas emissions by 2030, exceeding current emissions targets by 10%. Additionally, the findings suggest potential savings of €44.2 billion in distribution grid investments and a 75% decrease in transmission grid congestion. The study highlights that lowering peak demand could alleviate the need for significant investments in renewable energy infrastructure, potentially eliminating the requirement for 600 GW of onshore wind and 872 GW of solar PV capacity. Furthermore, optimising transmission and supply investments could lead to lower electricity prices, improving equity in pricing across European countries and significantly reducing energy bills for households and industries. Overall, the research underscores the critical role of energy efficiency and flexibility measures in achieving Europe's decarbonisation goals while ensuring affordable energy access.

1. Introduction

By burning fossil fuels directly and consuming electricity for heating and cooling, buildings account for 35% of Europe's energy-related greenhouse gas emissions [1]. As Europe strives to meet its climate targets, there is an urgent need to reduce these emissions by transitioning to a more efficient and renewable energy-based system. This transition is pivotal in combating climate change and addressing social challenges such as ensuring affordable heating, improving public health of citizens, and reducing Europe's reliance on imported fossil fuels.

However, decarbonising the building sector involves several challenges. One primary issue is the dependency of thermal supply and demand on weather conditions [2,3]. During cold periods, particularly when there is little wind and sunshine, the demand for space heating surges while the output from renewable sources such as wind and solar declines [4]. This scenario increases the strain on the grid as the efficiency of technologies such as air-source heat pumps also decreases. Additionally, heating demand shows significant seasonal fluctuations, with peak demands in winter and lower demands in summer, and daily peaks typically occurring in the early morning and late evening when residents use heating and hot water. Previous research has indicated that if the heating demand were more evenly distributed throughout the day [5] or the year [6], the overall strain on the system would be significantly reduced, leading to a cheaper, more stable and more manageable energy system. According to [7] approximately 75% of Europe's building stock is classified as energy-inefficient, and more than 85% of these buildings will still be in use by 2050. Given the long lifespan of existing energy-inefficient buildings, building renovations are widely considered a critical strategy to reduce current and future peak demand. As part of its European Green Deal package, the EU has introduced legislative measures such as the revised Energy Performance of Buildings Directive (EU/2024/1275) [8] and the Energy Efficiency Directive (EU/2023/1791) [9], which set ambitious targets

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for reducing energy use in residential and non-residential buildings and introduced new performance standards for public buildings. The successful implementation of these directives is key to maintaining Europe's trajectory towards climate neutrality. This necessitates an efficient allocation of available resources across Europe's building and economic sectors.

While building heating is a significant source of carbon emissions, it is not the only carbon-intensive sector. Major contributors also include the power, transportation and industrial sectors. The prevailing decarbonisation strategy involves reducing energy demands by improving efficiency, reducing emissions in the power sector and electrifying the remaining sectors [10–12]. However, this approach introduces additional complexities. The decarbonisation of Europe's energy-intensive industries, along with the shift towards electrified mobility, will increase competition for electricity [13] and further strain grid infrastructure [14]. If peak electricity demands are not effectively managed, particularly in the heating sector, the consequences could include elevated energy prices, reduced capacity for decarbonising other sectors, and potential grid instability or blackouts [15].

Energy system modelling can help to better understand the complex interactions within the energy system [16]. Given the intricate relationships between different sectors, it is essential for models to accurately capture these interactions. Effective modelling must account for the interplay between heating, transport, power demand and the supply from both variable renewable and conventional energy sources. It should also include balancing mechanisms such as thermal energy storage or the availability of electricity storage through electric vehicles [11], efficiency improvements and energy storage (particularly thermal energy storage if the heating sector is considered [17–19]), alongside overall electrification trends [10,20,21].

Previous research has explored various aspects of energy efficiency and its impact on heating demand. Studies have investigated how energy efficiency measures can mitigate seasonal [6,22,23] and daily peaks [18,24] in heating demand. These works provide valuable insights but often focus on individual components. Those components could be, for instance, the building stock [25–27] of isolated countries instead of a holistic view that can capture inter-regional balancing mechanisms [10,19,24], or individual sectors [28] rather than the integrated effects of sector coupling [17,18]. Finally, most of the scenario settings are overnight optimisations, which do not take into account the fact that investments in infrastructure development take considerable time. Neglecting the time required to complete renovations does not allow for the consideration of comprehensive policy scenarios or technology improvements, and often assumes a “greenfield” approach that neglects existing infrastructure and does not build on an evaluated network model that can reproduce historical statistics, such as curtailment or the generation mix [6]. This also means that existing technologies, such as coal or nuclear power plants, are not considered.

This study builds upon prior research by employing a top-down, sector-coupled European model that integrates power, heating, transportation and other key industrial sectors, along with stringent carbon dioxide emissions constraints. Building shell efficiency improvements are embedded within the modelling process, not set exogenously, similar to [6].

The novelty of this research lies in the coupling of an endogenised representation of energy efficiency measures in the building stock with optimisation runs that reflect policy-relevant scenarios and storylines, using a myopic decadal optimisation approach from today through to 2050. The model starts with a detailed evaluation of the 2023 European energy system, accurately reproducing the historical electricity mix with less than a 5% error for each energy carrier, including renewable (solar, wind, hydro), fossil fuel (coal, gas) and nuclear generation. It then myopically projects potential energy pathways for 2030, 2040, and 2050, closely aligned with current European climate targets and projected technology cost assumptions.

The contribution of this study lies in providing a holistic system assessment of how building renovation combined with demand flexibility impacts the European energy system under evolving emissions regulations, and the cost-optimal timing for these actions. Therefore, this study introduces key industrial sectors and their interactions with the power and heating system for the first time, along with an improved demand-side flexibility implementation for the heating sector, to align with upcoming regulations, such as the flexibility needs assessments [29], and prior suggestions by research [18,30].

This method enables us to address the following key research questions regarding the future role of energy-efficient and flexible buildings in reducing peak demand curves within a decarbonised energy system:

- *How can energy supply and demand-side measures be co-optimised to achieve cost-effective energy transition pathways in Europe from 2023 to 2050?*
- *How do building renovations and demand-side flexibility affect heat pump sizing, the energy mix, infrastructure needs, and emissions across different pathways?*
- *What are the socio-economic and industrial implications of reduced heating demand for European consumers and industries, and how do these measures affect the competition between decarbonised production processes?*

The outcomes of this study are anticipated to provide substantive guidance for policymakers, delivering actionable recommendations to enhance the resilience and efficiency of Europe's energy system in a cost-effective manner.

The remainder of this article is structured as follows: Section 2 outlines the key components of the sector-coupled energy system model, PyPSA-Eur, detailing the sectoral demands, supplies, and their interactions in 2.1. Section 2.2 focuses on the methodology for incorporating efficiency and flexibility measures, the methodological core of this research. Modelling novelties are discussed in detail in Section 2.3. Finally, Section 2.4 presents the storylines and modelling scenarios that reveal the impact of energy efficiency on the overall system, with the storylines representing a novel aspect of this analysis.

Section 3 presents the modelling results, with a model validation presented in Section 3.1. In Section 3.2, we discuss the effects of energy efficiency measures on the entire energy system across all scenarios and pathways to 2050, including the business-as-usual scenario and 2023 baseline results. Section 3.3 examines the impacts of energy efficiency measures in buildings on specific system aspects, such as final heating demands, heat pumps, carbon emissions, electricity mix, and grid infrastructure. Finally, Section 3.4 explores the implications of reduced heating demand for the private sector, including households and commercial consumers.

This work concludes in Section 4, summarising the key findings and discussing the study's limitations.

2. Methodology

This section describes the PyPSA-Eur model used in this study, focusing on features related to the space heating sector. First, the general architecture of the model is outlined, including an introduction to all considered sectors and technology options. Next, the assumptions for demand, supply, transmission and flexibility are detailed, with an emphasis on representing retrofitting of the building envelope. The PyPSA-Eur model forms the backbone of the proposed energy transition pathways, starting from the present (2023) and projecting trajectories to achieve carbon targets by 2030, 2040, and ultimately carbon neutrality by 2050, in line with the most recent policy and planning guidelines for each planning horizon.

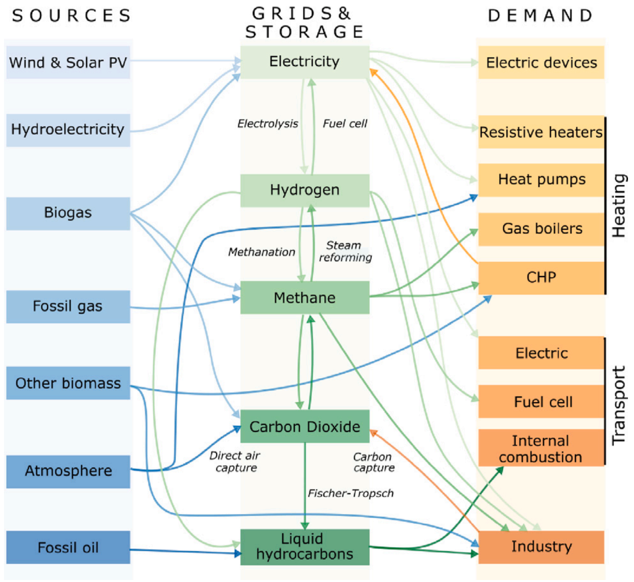


Fig. 1. Interactions of Demand, Supply, Storage and Grids of the sector-coupled PyPSA-Eur model.

2.1. Description of the PyPSA-Eur model

The study was conducted using PyPSA-Eur, which has been customised and adjusted to consistently address the effects of peak demand smoothing within the broader context of the European energy system. PyPSA-Eur is a model of the European energy system built using the open-source PyPSA framework and based exclusively on open data and open code [31]. This means that the model's methodology and assumptions, as well as data and source code, are completely transparent and fully available for modifications and reuse. All modifications made for this study have been contributed to the model and are available in the project's GitHub repository [32].

PyPSA is a modelling framework belonging to the class of bottom-up energy models, according to the classification in [33]. It includes capabilities for power system analysis and supports both investment and operational decision-making. Recent modifications to the PyPSA framework have enhanced its capability to model cross-sectoral interactions, addressing one of the major challenges in energy system modelling [34].

PyPSA-Eur extends PyPSA with an automated data extraction and preprocessing workflow, enabling the building of energy system models for any subset of countries in the European domain. A detailed description of PyPSA-Eur can be found in [35], while custom settings and novel contributions introduced for the purpose of this study are outlined in this paper.

The model encompasses the most carbon-intensive energy sectors that require decarbonisation: power, transport, space heating and industry, as illustrated in Fig. 1. The model treats the efficiency improvements as a variable within the optimisation process, rather than setting these improvements as fixed inputs. It also includes a detailed representation of the relevant transmission infrastructure and demand distribution at a high spatial resolution. To accurately capture system dynamics, especially peaks in space heating demands, the model is built with the highest possible time resolution provided by ERA5 of one hour.

The model operates as an optimisation model that seeks to minimise the total system costs while meeting all demands and carbon emissions targets for a given planning horizon. The considered energy carriers include electricity, heat, methane, hydrocarbon fuels (including synthetic ones), hydrogen and biomass. The transport of each energy carrier is modelled with consideration of the transmission capacity of the respective infrastructure.

2.1.1. Integrated energy system modelling including retrofit optimisation

The model represents the flows of energy carriers and their transformations (PtX), governed by interactions between different energy-related sectors. The following energy sectors are considered: power, heating, transport, and carbon-intensive industries.

The model does not explicitly represent heat loss in buildings but instead captures the effects of building shell retrofits by modelling improvements as reductions in final heating demand. This allows for building shell improvements in an endogenous way and enables a holistic assessment by co-optimising building shell retrofits with the entire energy system, making building renovation investments a model outcome rather than an input. This integrated approach captures trade-offs between energy efficiency measures and heat supply technologies across the system.

2.1.2. Main principles

To ensure that the modelling results are as accurate as possible, we apply a set of specific constraints to the model variables.

Modelling constraints include, but are not limited to:

- the power balance must be satisfied for every energy carrier at every moment in time, taking into account also the energy storage dynamics with charging and discharging cycles, and different types of losses
- meeting spatially and hourly resolved demands across a full weather year at all places and all times
- respecting Kirchhoff's circuit laws which means a proper representation of electricity transmission bottlenecks
- accounting for different types of losses, such as conversion losses between different types of energy carriers, standing losses in storage systems, losses of the transmission and distribution grids
- variability of the available renewable potential in space and time according to the historical weather dynamics using reanalysis datasets
- land-usage restrictions for renewable generators, for example accounting for natural reserves or available rooftop area of buildings.

2.1.3. Demand

The model accounts for the final energy demands for each sector, which are spatially distributed based on statistics on population density, GDP, or industrial sites. Hydrogen demand is generated endogenously in the course of the optimisation, ensuring that the modelling constraints are met in a way that minimises overall costs. Socioeconomic parameters are fixed at their current state to focus on the role of technologies.

Electricity demands are set exogenously for every economic sector included in the model and cover all the types of electricity consumption, including electricity used for space heating, transport, and industry. Openly available demand time-series [36] are used as inputs at the country level. Electricity demand is spatially distributed based on a linear relationship between population and gross domestic product (GDP), using the highest available resolution for these data.

Heating demand includes both space heating and domestic hot water across all sectors considered by the model and is treated as a final energy demand. This setup enables the endogenisation of decarbonisation pathways, allowing the optimisation to determine the supply source. This approach also applies in cases where heating is electrified.

Space heating demand is disaggregated both spatially and temporally, considering the following factors:

- socioeconomic features, such as population distribution and the overall energy consumption by economic sectors
- daily variations due to weather effects
- hourly patterns of space heating demand depending on the type of usage and day of the week.

The spatial and temporal features of demand for space heating in Europe are pre-processed following the methodology of [6]. The ERA5 reanalysis dataset, with its highest available resolution of hourly timestamps, provides input for the ambient air temperature t. A raster of ERA5-derived t time series is used to calculate heating degree days (HDDs), a common indicator of space heating demand. To convert HDD values into space heating demand, a calibration procedure is applied, which incorporates economic and demographic parameters. During calibration, an official Eurostat population dataset at NUTS 3 administrative level is combined with aggregated country-level energy balances, accounting for differences between urban and rural areas, as well as residential and service heating needs.

A single weather year has been considered in the simulations to maintain model tractability. The year 2013 was chosen, as it has been identified in previous studies as representative of average optimal costs for a net-zero transformation of the European power sector over the past 60 years. It is considered conservative, as the total costs for this year fall within the upper median range [37].

Typical hourly dynamics are modelled following the methodology of the German Association of Energy and Water Industries (BDEW) [38]. The space heating demand profiles differentiate between residential and service consumers, as well as between workdays and holidays.

Industry demands include electricity and space heating, as well as chemical substances used in industrial processes, such as coal or hydrogen as a reducing agent for steel production. The mitigation strategies for the industrial sector replace CO_2-emitting processes with net-zero alternatives, wherever possible. Certain processes are not considered candidates for electrification and any remaining emissions are captured by carbon capture technologies. All types of industrial demands are spatially distributed using raster data on industrial emissions and population and are calibrated using nationally aggregated statistical data on industrial production.

Transport demands The model includes the following types of transportation: land transport, which accounts for both heavy and light transport, marine transport, and aviation.

The demand for transport energy carriers is determined exogenously based on available statistics on various transport modes. Land transport uses internal combustion engines, fuel cells, and electric batteries; marine transport is fuelled by oil or methanol; and aviation relies solely on kerosene. The scenarios assume decarbonisation of land and marine transport, necessitating the replacement of fossil fuels with non-emitting technologies. The sources of the energy carriers are determined through optimisation to meet the preset electric or e-fuel demand in the most cost-effective manner while adhering to all technical constraints.

Hydrogen demand is defined by various needs in all sectors, with competition allowed between sectors and different types of hydrogen use. The main applications of hydrogen are the following:

- energy storage
- stationary fuel cells for space heating and power supply
- transport fuel cells
- decarbonisation agent for technological processes in the industrial sector
- as a component to produce synthetic fuels

In the model, hydrogen can be produced by steam methane reforming combined with a water–gas shift reaction or by electrolysis. For the chemical production method, the model can select options with or without carbon capture.

2.1.4. *Energy supply technologies*

Energy sources are optimised for siting and capacity, except for gas turbines, nuclear and coal plants, which are fixed in location based on the current power system or published plans for the respective planning horizon. Nuclear capacities are set exogenously based on planned expansions, as the model does not build new nuclear capacity independently due to its high costs. However, it is essential to include nuclear power, particularly those units that are already in operation or are planned. Similarly, coal and gas are phased out in the model according to current phase-out schedules, as an earlier phase-out appears unrealistic at this time and falls outside the scope of this study. Detailed information can be found in Section 2.3.2, including references on phase-out and commissioning plans.

Energy generation implies electricity and heating supply and is enabled using the following technologies:

- electricity
  - photovoltaic (utility and rooftop)
  - onshore and offshore wind, both AC and DC connected for offshore generation
  - hydropower
  - thermal generation fired with coal, natural gas and biomass
  - nuclear power plants
- space heating
  - air- and ground source heat pumps
  - resistive heaters
  - combined heat and power plants, powered by natural gas and synthetic gas
  - solar thermal collectors
  - gas boilers (natural gas and synthetic gas).

Weather-dependent energy potentials of renewable generation are calculated using the same representative weather year 2013 as for the demand calculations.

Investment and fuel costs for energy generation technologies are provided exogenously and fixed for each planning horizon, incorporating cost evolution due to the learning effect for technologies that have not yet reached maturity. Cost assumptions and technical parameters for electricity generation technologies are detailed in Table A.12, which includes information on investment costs, fixed and variable operating and maintenance costs, efficiency, and technology lifespans. Table A.13 outlines the cost and efficiency assumptions for heat generation technologies. For an overview of cost assumptions for all technologies including storage, power transmission, hydrogen production, transport, and storage, see Appendix A, which includes a full table. Fuel cost assumptions for various technologies are detailed in Table A.15.

All cost assumptions are based on datasets published by Lazard's Levelized Cost of Energy Analysis [39], the Danish Energy Agency [40–46], the International Energy Agency [47–49], the German Institute for Economic Research [50], a PhD thesis by Katrin Schaber [51], Fraunhofer IEE [52], Lauri et. al. [53], Agora Energiewende [54], the International Renewable Energy Agency [55], Reuß et. al. [56], Det Norske Veritas [57], the European Hydrogen Backbone [58], the Energy Watch Group and Lappeenranta-Lahti University of Technology [59], Hagspiel et. al. [60], Palzer [61], Business Analytiq [62,63], Business Insider [64] and the European Comission [65]. They are mostly collected through the technology-data project [66] that was used for this study.

2.1.5. *Emissions management*

Carbon capture and storage (CCS) is incorporated into the model as an additional option that may be needed to meet emission targets. CCS technologies are integrated into combined heat and power (CHP) systems and steam methane reforming processes. The model can choose between options with and without carbon capture for these technologies. Additionally, direct air capture (DAC) technology is considered, which extracts CO_2 directly from the air. DAC is modelled such that it consumes a fixed share of electricity and heat to capture a fixed amount of CO_2. The captured CO_2 can be used in industrial processes, such as the production of synthetic fuels (Fisher-Tropsch synthesis, methanation) or stored underground with the model accounting for the limited capacity of underground storage.

2.1.6. Energy transmission and distribution

Transmission grids are modelled using a graph-based representation, where the grid is presented as a network of buses and branches. Buses represent points where power is injected or withdrawn, such as substations or load centres, while branches represent the physical connections between these points, including transmission lines.

For the power sector, the grid topology data published online by the ENSTO-E [67], using the Gridkit extraction toolkit, is utilised. The PyPSA modelling framework supports the representation of electrical components and their operational constraints, allowing simulations of power flow, optimisation of generation and storage, and assessment of grid reliability and efficiency.

A simplification procedure is applied to the power grid data to ensure numerical tractability while maintaining the integrity of the grid topology and transmission capacity. The result of this simplified representation is shown in Fig. 2.

The model can expand the total volume of the transmission grid to align with published network development plans, aiming for 42840 km and 55TVAkm, representing an approximate 15% increase compared to the transmission grid of 2022 [68]. For 2040 and 2050 we extrapolate the ambitions and assume an increase of the line volume of 30% and 50%, respectively.

Distribution grids are modelled in aggregate, representing them as a single connection between high-voltage (HV) and low-voltage (LV) nodes within the overall energy system. Although the model does not explicitly simulate the detailed operations of local distribution networks, it accounts for their impact through aggregated grid capacity. Residential and mixed industrial zone demands are assigned to the LV node, while utility power generation occurs only at the HV node or can be transmitted between HV nodes, following grid physics and power flow constraints. For example, the electrification of heating through technologies such as heat pumps increases electricity demand at the LV level, which in turn implies the need for expanded distribution grid capacity. However, detailed modelling of local distribution infrastructure, such as LV networks or specific grid components, is not included. Instead, the focus is on system-wide capacity and investment needs, with an emphasis on potential bottlenecks in the energy flow between regions at HV. There are no expansion constraints imposed on distribution grids.

2.2. Efficiency and flexibility measures

Efficiency and flexibility measures are central to the study presented. This subsection therefore begins with a general overview of available measures and then delves into a detailed description of building retrofit.

2.2.1. Overview

The model includes several advanced options for balancing supply and demand without requiring additional energy generation. These options include:

- **Demand-side flexibility** (DSF) through an energy management system, which reduces daily demand peaks according to endogenously derived electricity prices. This approach offers a method for covering daily space heating demand during off-peak hours, in line with the model's cost-optimisation strategy. DSF is applied for heating systems and electric vehicle charging, with varying assumptions across scenarios as presented in Section 2.4.
- Various types of **energy storage**, which decouple energy supply from demand over time: battery and hydrogen storage (for electricity), gas storage and hot water tanks (for thermal storage).
- **Improvements in the thermal quality of a building envelope** reduce the space heating demand, thereby enhancing energy efficiency. This reduction in seasonal demand peaks has several positive effects on the system, which are central to the study's focus and further detailed below.
- **Waste water heat recovery systems** (WWHRS) reduce the demand for hot water in the residential sector.
- **Waste heat recovery** of process heat in the industrial sector.

Table 1
Costs of building envelope renovation.

Building element	Costs $\left[\frac{EUR}{m^2}\right]$
Floor	39.39
Roof	75.61
Exterior walls	70.34
Windows, double glazing	180.08
Windows, triple glazing	225

2.2.2. Representation of buildings renovation

The model includes a representation of the physical and economic effects of improving the thermal performance of buildings through renovation. Renovation involves retrofitting the building envelope by replacing windows and adding thermal insulation layers to the exterior walls. The extent of renovation is determined endogenously through cost optimisation, considering the dynamic effects of energy savings. The model selects optimal shares of three different renovation depths for Europe's building stock: maintenance renovation, moderate renovation, and ambitious renovation.

In the course of an optimisation run, the model determines the cost-optimal share of the building stock which is renovated at a selected renovation depth for each country. The share of buildings requiring envelope renovation is calculated based on the potential heat savings achievable at various renovation depths. Following the methodology proposed in [6], the potential heat savings are treated as an additional resource available for heat generation. The optimisation run determines the optimal utilisation of this heat saving potential within the building stock.

The results are translated into a number of buildings to be renovated for each scenario, based on an estimated total European building stock of 156 million buildings. This estimation is derived from the Hotmaps database [69], incorporating the latest updates from 2023. The database contains both residential and non-residential buildings, including health and education facilities, trade buildings, offices and industrial facilities.

The moderate and ambitious renovations depths differ in the resistance value of the insulation and window glazing. The details of the definitions are given in the annex for both renovation depths in Tables A.10 and A.11.

The performance and costs of envelope retrofitting measures are determined by modelling heat transfer in renovated buildings using first principles and a seasonal balance approach. The main formulation employed in the calculations is presented in Appendix B, with costs assumptions outlined in Table 1.

2.3. Modelling advances introduced by the study

For this study, the PyPSA-Eur model has been enhanced to accurately represent the most recent energy policies. The most dominant novelties are outlined below.

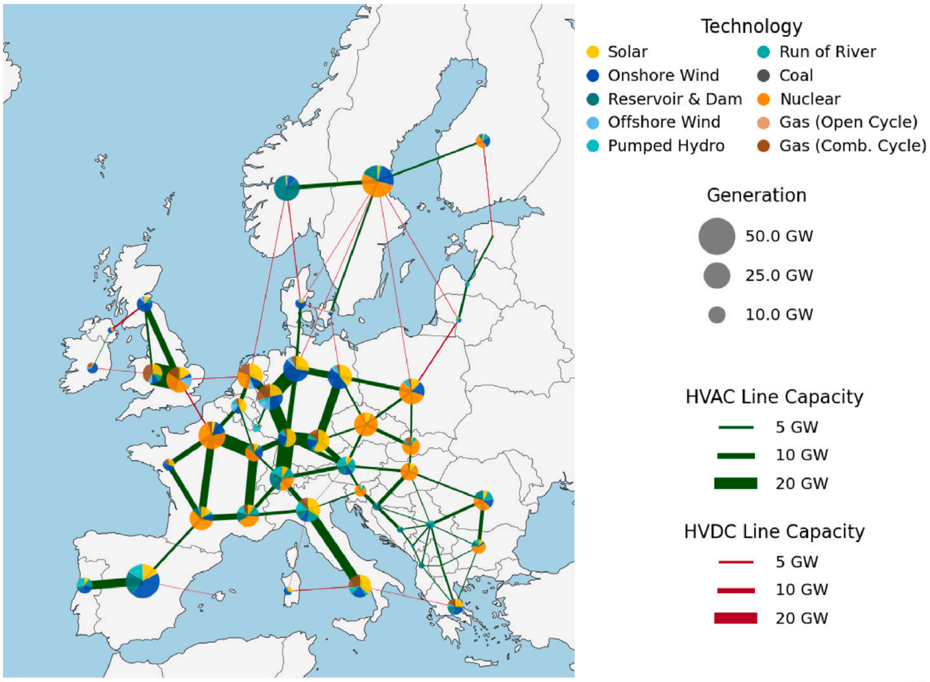


Fig. 2. A representation of the benchmark 2023 power sector assumed for optimisation runs.

2.3.1. *Advanced efficiency methods in buildings*

Originally, PyPSA-Eur's representation of building efficiency focused solely on improvements of the thermal performance of the building envelope, as outlined in Section 2.2.2. This study introduces two significant enhancements: incorporating energy management system in the space heating sector and adding an option for waste water heat recovery at the building level. The energy management system is implemented such that heating demands must be met between 9 am and 9 pm, with flexible shifts allowed for all other hours; however, shifted demands are subject to losses.

2.3.2. *Representation of conventional power plants*

The model assumptions and datasets have been enhanced to provide an improved representation of conventional generation capacities, in particular nuclear power. Specifically, an updated dataset outlines existing conventional generation capacities, including future development plans for nuclear expansion. The dataset is based on a series of updated national development plans [70–89]. In addition, the most recent EU coal and lignite generation capacities have been sourced from an up-to-date dataset as referenced in [90]. Those capacities are set exogenously and are not part of siting and capacity expansion considerations.

Additionally, fuel costs for coal, lignite, gas and uranium have been revised to reflect today's prices [91–93] or projections as proposed in the RePowerEU initiative [94].

2.3.3. *Representation of heat pumps and solar thermal units*

Heat pumps are anticipated to play an increasingly important role in future heat supply, particularly as building renovation progresses. Improved building thermal efficiency directly impacts the operating conditions of heat pumps, especially the required sink temperature, which is the temperature to which the heat pump must heat its output. Since building renovation decreases heat demand, it also allows for lower sink temperatures, thus improving the efficiency of heat pumps. To accurately account for this relationship, PyPSA-Eur includes the dependency of heat pump performance on the sink and source temperatures. Additionally, an iterative solving procedure has been developed and implemented to enhance the model.

In this approach, the heat sink temperature is dynamically reduced depending on the depth of building renovation. Eq. (1) models this reduction by adjusting the sink temperature as a function of the share of saved heat demand, δH, obtained from the first iteration of the optimisation. Here δH represents the proportional reduction in heat demand due to renovation, influencing the sink temperature for the heat pump.

$$T_{\text{heat sink}} = (55 - 21) \cdot (1 - \delta H) + 21 \tag{1}$$

55 °C represents a standard sink temperature for unrenovated buildings, and 21 °C is the ambient indoor temperature.

Different parameter estimates for heat pump and solar thermal units exist depending on the level of details considered. A review of cost inputs and technical parameters for heat pumps and solar thermal units has been conducted to align the cost inputs with available data, including technology learning effects.

2.3.4. *Review assumptions for distribution grids*

Electrification of heating leads to an increased load at low voltage grids, thus requiring an expansion of the existing distribution grid infrastructure. To account for these effects, cost assumptions for distribution grids have been carefully revised [95,96], and are presented in Table A.14.

2.4. *Storylines & modelling scenarios*

To align with current policy guidelines and explore pathways to achieve Europe's ambitious decarbonisation goals, the analysis begins with a 2023 benchmark scenario. All future projections and pathways are based on this initial scenario, with variations depending on assumptions related to building renovation depth and invoked flexibility measures (as detailed in Section 3.2). For longer-term planning horizons, the carbon budget becomes increasingly stringent, compelling the energy sectors to phase out fossil processes wherever feasible. We consider in total 3 planning horizons, where results of the 2030 planning horizon build on the 2023 benchmark scenario, results for the 2040 planning horizon build on the 2030 planning horizon, and results for the 2050 planning horizon build on the 2040 planning horizon. A general overview of the scenarios is presented in Fig. 3 and detailed in later sections.

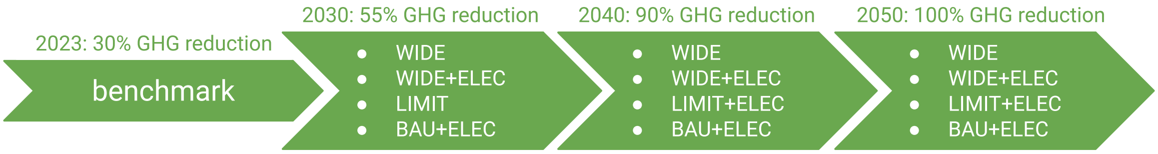


Fig. 3. Overview of scenario and storyline design. The benchmark 2023 scenario is described in Section 2.4.1. Information on the different scenario settings is detailed in Section 2.4.2, while policy settings for distinct planning horizons are detailed in Section 2.4.3.

2.4.1. Benchmark scenario

The **2023 scenario benchmark** models the Europe's energy system as of 2023/24 with existing infrastructure without new interventions. This scenario serves as a benchmark for comparing scenarios. The following assumptions are made to model the 2023 scenario benchmark:

- Electrification levels of 2023 for the transport and industry sector
- No advancements in district heating (DH) networks
- Approximately 30% reduction in GHG emissions compared to 1990s levels
- Includes existing capacities for nuclear and coal plants, solar utility PV, onshore and offshore wind, as well as gas turbines
- No additional investments in solar, wind, or building renovation
- No demand-side flexibility for space heating or transport (no ability to shift power demands to times with high renewable penetration)

Existing installations of heat pumps across Europe were not considered due to a lack of available open data. As a result, today's heating demand is assumed to be fully met by gas boilers, the dominant heating technology in Europe.

2.4.2. Renovation & efficiency scenarios

Widespread Renovation (WIDE) scenarios enable the model to invest in supply technologies, building efficiency, and flexibility measures to minimise total system costs. This scenario outlines the cost-optimal investments in supply technologies and building renovation strategies.

Widespread Renovation and Electrification (WIDE+ELEC) scenarios are similar to WIDE scenarios, with the exception that investments in individual gas boilers are not permitted and all gas boilers are phased out. While this assumption may be unrealistic in reality, this restriction allows for the analysis of the impact of removing a larger share of fossil-based heat supply than currently planned, and its potential effects on the European energy system.

In the **Limited Renovation** (LIMIT) scenario, the model can invest in all space heating supply technologies to minimise total system costs. However, efficiency and flexibility measures in buildings are limited to half of what was deemed optimal in the WIDE scenarios. This setup exists only for the planning horizon 2030 and is replaced by LIMIT+ELEC for the planning horizons 2040 and 2050. It allows for the analysis of the impact when only a fraction of households implements renovation measures.

Limited Renovation and Electrification (LIMIT+ELEC) is similar to LIMIT, with the exception that investments in individual gas boilers are not permitted and all gas boilers are phased out. This setup replaces LIMIT to align with EU regulations that aim for the complete phase of gas boilers after 2030.

Business as Usual and Electrification (BAU+ELEC) scenarios allow the model to invest in space heating supply technologies without incorporating thermal energy storage. In this scenario, individual gas boilers and extra efficiency measures (building retrofit and DSF) are not permitted. This setup highlights the impact on the energy system when buildings are renovated only to maintain the current level of thermal quality and serves as an additional benchmark compared to the 2023 scenario benchmark.

All renovation and efficiency scenarios are summarised in Table 2. Additional assumptions apply depending on the planning horizon.

Table 2
Definitions of renovation scenarios. Efficiency and flexibility in buildings spans building renovation measures and energy management systems. Both a tick and a cross indicate that the parameter is set exogenously to match 50% of the WIDE scenario result.

	efficiency in buildings	**individual gas boilers**	**thermal energy storage**
WIDE	✓	✓	✓
WIDE+ELEC	✓	✘	✓
LIMIT	✓ ✘	✓	✓
LIMIT+ELEC	✓ ✘	✘	✓
BAU+ELEC	✘	✘	✘

2.4.3. Scenario assumptions by planning horizon

In addition to the differences in energy efficiency measures across scenarios, there are varying emission targets and exogenously set parameters for the transport and industry sectors, while the space heating sector is optimised endogenously. In particular, flexibility measures are implemented in all scenarios except BAU+ELEC. This is based on the fact that it is ineffective to implement flexibility measures in homes that have not been renovated, as heat quickly dissipates in poorly insulated buildings, making demand shifting impractical.

For the **2030** planning horizon, the following assumptions are made (for all scenarios):

- 55% net reduction in GHG emissions compared to 1990 levels
- transmission grid can expand by up to 15% in volume (measured in MWkm)
- 65,5 million EVs, possible to charge smartly in WIDE, WIDE+ELEC and LIMIT, and bidirectional EV charging (60% of land transport)
- smart space heating in WIDE, WIDE+ELEC (27% of peak demand can be shifted) and LIMIT (13.5% of peak demand can be shifted)
- technology cost assumptions of 2025
- DH networks progress by 30% (of urban demand not covered by district heating).

For the **2040** planning horizon, the following assumptions are made (for all scenarios):

- 90% net reduction in GHG emissions compared to 1990 levels
- transmission grid can expand by up to 30% in volume (measured in MWkm)
- 157.2 million EVs, possible to charge smartly in WIDE, WIDE+ELEC and LIMIT, and bidirectional EV charging (60% of land transport)
- smart space heating in WIDE, WIDE+ELEC (43.5% of peak demand can be shifted) and LIMIT (21.75% of peak demand can be shifted)

- technology cost assumptions of 2035
- DH networks: progress by 60% (of urban demand not yet covered by district heating).

For the **2050** planning horizon, the following assumptions are made (for all scenarios):

- 100% net reduction in GHG emissions compared to 1990 levels
- transmission grid can expand by up to 50% in volume (measured in MWkm)
- 222.6 million EVs, possible to charge smartly in WIDE, WIDE+ELEC and LIMIT, and bidirectional EV charging (85% of land transport)
- smart space heating in WIDE, WIDE+ELEC (60% of peak demand can be shifted) and LIMIT (30% of peak demand can be shifted)
- technology cost assumptions of 2045
- DH networks: progress by 100% (of urban demand not yet covered by district heating).

3. Results

With the assumptions provided in Section 2, modelling results are presented as follows:

First, we validate the model in Section 3.1, where we compare the resulting electricity mix of the 2023 benchmark scenario against historically reported values of the year 2023 [97]. Then, a general overview of the modelling results is provided by presenting the total system costs in Section 3.2 for all scenarios and planning horizons, including the 2023 benchmark scenario. The analysis includes the shares of building stock renovation, and the share of DSF measures.

In Section 3.3, the impacts of efficiency measures in buildings, namely retrofitting the building envelope and DSF, are analysed with a focus on the effect of these measures on heat demand savings and flattening the peak demand. The demand flattening obtained as a modelling output is a combined result of smoothing the seasonal pattern through improving building insulation and managing daily variations through DSF. Reduced heating demands affect the necessary size of heat pumps required to cover the reduced heating demands, which is accounted for through an iterative optimisation where the sink temperature is reduced in the second optimisation run. The analysis further investigates results of the optimisation runs for CO_2 emissions in the system, total electricity demands, and the electricity mix for future planning horizons. Impacts on infrastructure and grids are discussed too, highlighting the implications of building renovation and DSF on investments and the need for expanding the variable renewable energy sources (VRES) fleet, storage options (battery and H_2), congestion rent, and distribution grids.

This section concludes in 3.4, with a discussion on implications for electricity prices and approximations for operational expenses in the industry sector and energy bills for private households.

3.1. Validation

The resulting electricity generation mix for the benchmark 2023 scenario is shown in Fig. 4 and compared with the historical electricity generation mix from 2023, as reported in [97]. The comparison reveals that the proportions of electricity generated from variable renewable energy sources (VRES), nuclear power, and fossil fuels closely align with the reported historical mix, with an error of less than 5%. This result likely also aligns with recorded carbon emissions in Europe, thereby fostering confidence in the findings presented in the following sections.

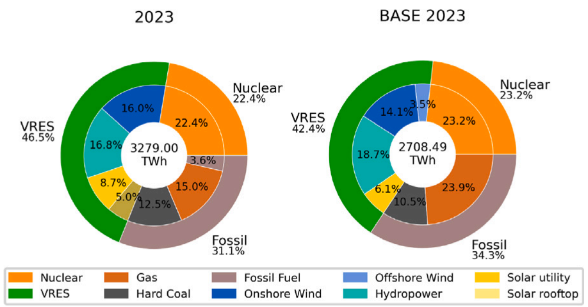


Fig. 4. Electricity generation mix for the 2023 benchmark scenario (left) compared against historic generation (right) [97].

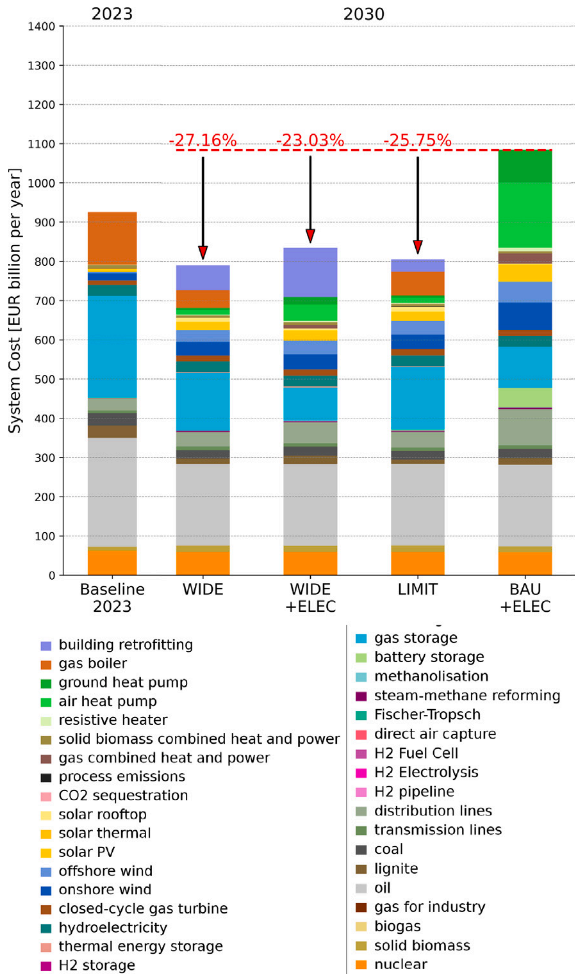


Fig. 5. Total system costs for all scenarios and the baseline 2023, as well as the planning horizon 2030. Results for planning horizons 2040 and 2050 can be found in Appendix C.1, Figure C.15.

3.2. Effects of the efficiency measures on the system

This section begins by analysing the impact of efficiency measures on total system costs, providing a metric for the overall cost savings achieved through building envelope renovations and the implementation of DSF. It then examines the share of buildings that need to be renovated, and the extent of active DSF measures in the heating sector required to achieve these savings.

Table 3

Total system cost (upper) and cost for renovation (lower), in bn €. Note that the LIMIT scenario assumes no remaining gas boilers for the 2040 and 2050 planning horizon, indicated by the brackets in the scenario name.

	2024	2030	2040	2050
	Total system costs			
BASE 2023	926	–	–	–
WIDE	–	790	892	851
WIDE+ELEC	–	835	934	903
LIMIT(+ELEC)	–	806	970	920
BAU+ELEC	–	1085	1278	1245
	Costs for renovation			
WIDE	–	63	120	133
WIDE+ELEC	–	125	151	163
LIMIT(+ELEC)	–	32	60	67
BAU+ELEC	–	–	–	–

3.2.1. *Total system costs*

Fig. 5 illustrates the cumulative expenses associated with the entire energy system for every planning horizon, broken down by each technology. These expenses comprise investment costs for new infrastructure, fixed operational costs, including regular maintenance and administrative expenses, and variable operational costs, such as fuel costs for conventional power plants. Collectively, these components represent the financial requirements for creating, operating and maintaining a future energy system which satisfies the particular emissions targets. The overall objective of the PyPSA-Eur model is to minimise these costs while accounting for the most relevant technical and socioeconomic constraints.

Several observations can be made: (i) When **efficiency measures in buildings are implemented** (scenarios WIDE, WIDE+ELEC, LIMIT+ELEC), the projected total system costs for any future planning horizon are lower compared to the expenses for the 2023 scenario benchmark and lower compared to a projected future system without efficiency measures but with electrified heating (BAU+ELEC). (ii) Implementing the most cost-optimal renovation strategy (WIDE) can result in significant cost savings compared to the 2023 scenario benchmark. For example, 27% can be saved by 2030, and 31% can be saved by 2050 (see Appendix C.1, C.15 for the 2050 result). The WIDE+ELEC and LIMIT+ELEC also demonstrate significant cost savings, though slightly lower than WIDE which confirms a significant role of the flexibility measures. These savings remain within the same order of magnitude. (iii) Compared to BAU+ELEC, 23%–27% of costs can be saved by 2030, with savings increasing up to 31% by 2050 if the most cost-optimal strategy is followed. Even if no gas boilers are used in Europe by 2050, costs savings can still reach 27%, or 26% if energy efficiency measures are less ambitious. Table 3 provides the detailed magnitudes of the total system costs and renovation costs. The annualised investment and operational costs for each scenario can be found in Figs. C.26 and C.27 in Appendix C.2.

These results indicate that the cost reductions associated with building renovations are decreasing, once the most inefficient buildings have been renovated (LIMIT and LIMIT+ELEC). However, retrofitting buildings consistently proves beneficial from a total system cost perspective. This demonstrates that investments in building retrofitting and energy management systems lead to overall cost savings for the energy system, making it a no-regret strategy from the point of view of the complete system.

3.2.2. *Amount of building envelope renovation*

The share of buildings to be renovated is presented in Table 4.

3.2.3. *Amount of active demand-side measures in the space heating sector*

Tables 5 and 6 present the usage of the active upward and downward DSF facilitated by energy management systems for the space heating and transport sectors, respectively, for each scenario and planning horizon. In this context, upward DSF refers to a decrease in demand, while downward DSF refers to an increase in demand. It is evident from the tables that the majority of DSF activity occurs in the transport sector, where electric vehicle charging can be shifted without incurring efficiency losses. However, significant DSF measures are also active in the space heating sector.

Table 4

Amount of buildings to be renovated [millions of buildings (% of the overall building stock)]. Note that the LIMIT scenario assumes no remaining gas boilers for the 2040 and 2050 planning horizon, indicated by the brackets in the scenario name.

	2030	2040	2050
	Moderate		
WIDE	53 (34%)	82 (53%)	82 (53%)
WIDE+ELEC	76 (49%)	85 (54%)	85 (54%)
LIMIT(+ELEC)	26 (17%)	43 (28%)	47 (30%)
BAU+ELEC	–	–	–
	Ambitious		
WIDE	16 (10%)	28 (18%)	28 (18%)
WIDE+ELEC	25 (10%)	28 (18%)	28 (18%)
LIMIT(+ELEC)	8 (5%)	15 (10%)	15 (10%)
BAU+ELEC	–	–	–

Table 5

Active upward and downward DSF in the space heating sector [TWh_{th}]. Note that the LIMIT scenario assumes no remaining gasboilers for the 2040 and 2050 planning horizon, indicated by the brackets in the scenario name.

	2030	2040	2050
WIDE upward	14	41	61
WIDE downward	15	44	65
WIDE+ELEC upward	32	45	
WIDE+ELEC downward	34	47	
LIMIT(+ELEC) upward	9	31	36
LIMIT(+ELEC) downward	9	32	37
BAU+ELEC upward	–	–	–
BAU+ELEC downward	–	–	–

Table 6

Active DSR in the transport sector [TWh]. As there are no losses assumed, upward and downward DSR are equal. Note that the LIMIT scenario assumes no remaining gasboilers for the 2040 and 2050 planning horizon, indicated by the brackets in the scenario name.

	2030	2040	2050
WIDE DSR	185	403	496
WIDE+ELEC DSR	200	392	
LIMIT(+ELEC) DSR	197	441	592
BAU+ELEC DSR	–	–	–

Another observation is that the use of active DSF measures increases significantly in later planning horizons. For space heating, the total load shifted by active DSF measures quadruples across all scenarios when moving from the 2030 to 2040 planning horizon. Electrification of space heating further amplifies the cost-optimal deployment of DSF measures. For instance, in 2030, the WIDE+ELEC scenario, which excludes gas boilers, exhibits double the usage of DSF for space heating compared to the WIDE scenario, where gas boilers still have a substantial role. By 2040, DSF usage converges in both scenarios as gas boilers diminish to a negligible share in the WIDE scenario.

3.3. *Impact of efficiency measures in buildings*

This section analyses the impacts of efficiency measures implemented in buildings on peak demand, examining both daily and seasonal patterns. It evaluates how improved building envelope efficiency and electrification reduce space heating demands, influencing heat pump sizing, CO_2 emissions, electricity demands, and the resulting electricity mix. Finally, the section outlines the required investments and infrastructure requirements for VRES and grid expansion.

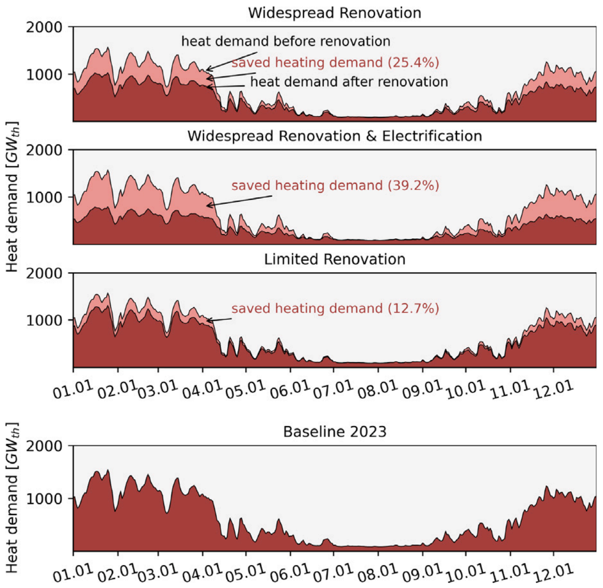
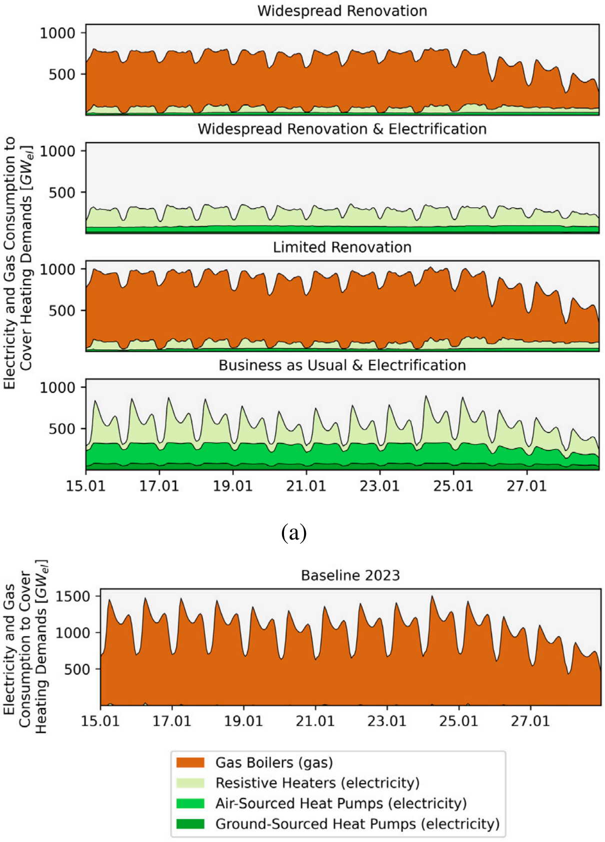


Fig. 6. Space heating demand before and after renovation for the full year for each scenario for planning horizon 2030. Note that the net heat demand for BASE 2023 is the same as the net heat demand in the BAU scenario. Results for planning horizons 2040 and 2050 can be found in Appendix C.1, Figure C.16.



(a)

(b)

Fig. 7. Electricity and gas consumption used to cover space heating demand for each scenario over different horizons: (a) 2030, and (b) BASE 2023. Results for planning horizons 2040 and 2050 can be found in Appendix C.1, Figure C.17.

Table 7
Total installed capacity of heat pumps (in GW_{el}).

	2030	2040	2050
WIDE	34.21	132.92	157.55
WIDE+ELEC	94.81	142.20	168.11
LIMIT	39.39	–	–
LIMIT+ELEC	–	214.81	249.06
BAU+ELEC	331.68	430.17	492.67

3.3.1. *Impact of efficiency measures on peak demand*

Space heating demands are affected by retrofitting building envelopes and the usage of flexibility measures. This effect varies depending on the depth of retrofitting across scenarios and planning horizons. Fig. 6 illustrates the seasonal variations in space heating demand throughout the year for each modelling scenario. The values represent the remaining space heating demand after accounting for building renovations. Additionally, the demand profile is supplemented with shaded areas that represent the respective savings relative to the 2023 benchmark scenario (as well as the BAU+ELEC scenario). To clarify seasonal dynamics, daily aggregation is applied.

DSF measures are not visible in Fig. 6 due to the daily aggregation, but can be seen in Appendix C.2 in Figure C.28, which shows the same variations in space heating demand at hourly resolution over a two-week period. Additionally, Fig. 7 illustrates how space heating demand is met during an exemplary time horizon at hourly resolution, focusing on a limited set of technologies that contribute most to meeting demand peaks. The period covered in Fig. 7 spans approximately two weeks, with the effect of DSF measures visible as a smoothing of daily demand peaks during morning and evening hours.

The first plot, Fig. 6, shows the results for the 2023 baseline scenario, and all scenarios in the 2030 planning horizon. It can be seen that, from a cost-optimal perspective (WIDE), it is economically recommended to reduce space heating demands. Quantitatively, this reduction comprises 25% compared to BAU+ELEC and 2015 levels with a remaining share of 65% that is covered by utilising gas boilers. As has been shown in Section 3.2.1, gas boilers can be fully phased out from the space heating sector with only 4% more total system costs, further decreasing space heating demands by 14% (WIDE+ELEC), totalling a reduction of 39% compared to BAU+ELEC and 2015 levels. In this scenario, additional investments into building insulation are required, as well as an increased number of heat pumps and resistive heaters to cover the remaining space heating demands. Finally, with a restricted share of building efficiency measures (LIMIT), space heating demands are reduced by 12% compared to 2015. To cover the remaining space heating demand, an increase in heat pumps and gas boilers is needed. As space heating demands are not reduced in the BAU+ELEC scenario, and cannot be shifted according to the availability of variable resources (no energy management systems are assumed for this scenario), the dispatch of heat pumps and resistive heaters must adjust according to daily demand patterns, totalling a space heat demand of 4242 TWh_{th}, which is 39% more than in the WIDE scenario.

Results for the planning horizons 2040 and 2050 are inline with these findings and discussed in Appendix C.1.

3.3.2. *Impact of efficiency measures on the number of heat pumps*

Efficiency measures in buildings have two different effects on the roll-out of heat pumps. Improved building insulation reduces space heating demand, allowing for the installation of smaller heat pumps. Meanwhile, the total number of heat pumps required is primarily influenced by the structure and composition of the building stock. Additionally, demand-side flexibility measures, enabled through smart energy management systems, shift peak load in such a way that heat pumps can continuously operate at a lower base load, instead of continuously ramping up and down. Based on these assumptions, the modelling results provide estimates for the required installed heat

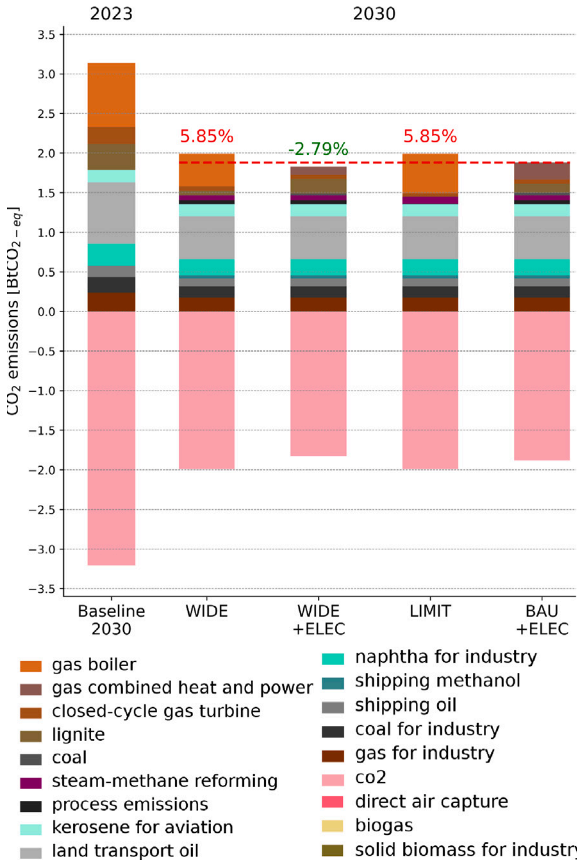


Fig. 8. Total CO_2 emissions for the baseline 2023 and the 2030 planning horizon.

pump capacity across different planning horizons for each scenario, as shown in Table 7.

It can be seen that, under the cost-optimal approach (WIDE), the average required capacity of a heat pump is up to ten times higher in scenarios with limited renovation completed by 2030, assuming the EU target of 60 million pumps to be installed by that year. While this difference decreases for later planning horizons, it remains significant, ranging from 1.5 to 3 times higher by 2050.

3.3.3. Impact of efficiency measures on CO_2 *emissions*

Fig. 8 shows the CO_2 emissions by technology for the baseline 2023 scenario and the 2030 planning horizon. Figure C.19 in Appendix C.1 shows the emissions for the planning horizons 2040 and 2050. The positive part of the bar diagram details different sources of emissions, while the negative values represent different sinks of CO_2. In particular, a pink colour bar denotes the overall amount of CO_2 emitted into the atmosphere, while other sinks represent technological processes that incorporate carbon capture and storage (direct capture of CO_2 from air, as well as production of biogas and solid biomass for industry).

The comparison demonstrates that the scenarios where gas boilers are phased out (WIDE+ELEC and BAU+ELEC) tend to have lower CO_2 emissions than allowed for 2030, compared to the scenarios where gas boilers are still part of the system composition. Gas boilers provide some benefits to the total system costs (see Fig. 5), but remain a significant contributor to CO_2 emissions, especially for the planning horizon of 2030. In these scenarios space heating demands are purely covered by electricity, although gas remains a part of the electricity mix and is consumed by CHP plants or gas turbines. Replacing gas boilers with heat pumps reduces emissions from the space heating sector, however, it also enables a residual share of coal-based emissions to persist in the overall energy mix.

3.3.4. Impact of efficiency measures on the electricity mix

Fig. 9 presents the resulting electricity mix for the 2030 planning horizon, while Figure C.18 in Appendix C.1 illustrates the generation mix for the remaining planning horizons.

Modelled results indicate that the overall share of fossil fuel-based electricity decreases over time for each scenario. When focusing on 2030, Fig. 9 shows that (i) the total electricity demand increases compared to the 2023 scenario benchmark due to electrification rates in all sectors and (ii) the share of coal and gas reduces from 34.4% to 5.5%–13.3%, compared to the 2023 scenario benchmark. An increase in the electricity demand depends on the rate of electrification in the space heating sector which is a modelling result and not set exogenously, in contrast to the transport and industry sectors. The overall demand varies between the scenarios.

While the total electricity demand is relatively similar in all scenarios that allow for efficiency improvements in buildings (WIDE, WIDE+ELEC, LIMIT), the total amount of electricity demand is significantly higher in the BAU+ELEC scenario. A primary reason for that is the absence of building renovation resulting in higher space heating demand with reliance on electric heating technologies. In scenarios where space heating is fully electrified (WIDE+ELEC, BAU+ELEC), the share of fossil fuels is typically higher compared to those scenarios where gas boilers are allowed. But in those scenarios where gas boilers are considered (WIDE for all horizons and LIMIT for 2030), more gas is utilised at worse efficiency through gas boilers, as we have seen in the previous Section (see also Fig. 8). The high electricity demands in the BAU+ELEC scenario also require more expensive gas utilisation, compared to WIDE+ELEC, where a small share of coal (4%) can remain in the mix.

Additional results for the 2040 and 2050 planning horizon are discussed in Appendix C.1.

Furthermore, Fig. 10 shows the level of curtailment for every scenario, highlighting the impacts of improvements to the efficiency of buildings. Curtailment is the amount of VRE that is not fed into the grid due to congestion or overproduction. The figure demonstrates that curtailment increases in all scenarios as time progresses, with the highest rates observed in the BAU+ELEC scenario, peaking at approximately 690 TWh annually in 2040, accounting for nearly 8% of the annual demand. In comparison, curtailment for all other scenarios is always lower by approximately 400 TWh, approximately the annual electricity demand of France in 2023. The scenario BASE 2023 stands out with nearly 0% curtailment, primarily due to the relatively low penetration of VRES and the limited spatial scale of the model [98].

3.3.5. Impact of efficiency measures on the energy infrastructure

An increase in electricity demand requires additional investments in energy infrastructure. Figure C.24 in Appendix C.2 illustrates the projected expansion of infrastructure for all technologies in each scenarios and planning horizons.

Focusing on 2030, it can be seen that there is a trend towards increased infrastructure expansion for VRES generation, power grids, and storage technologies. Solar technologies, including rooftop solar PV and utility solar PV, are experiencing significant growth in all scenarios.

For 2040 and 2050, solar PV expansion accelerates due to the reduced costs. In the case of rooftop solar PV, the assumed upper limit for expansion in Europe is met, covering all available roofs. Energy storage installations also experience rapid growth to meet CO_2 emission reduction goals. The share of battery storage increases proportionally to solar PV infrastructure construction, and H_2 electrolysis increases proportionally to onshore and offshore wind installations. These trends can be observed for all scenarios, with increased investments in the BAU+ELEC and LIMIT scenarios.

Additionally, Table 8 shows the required capacity for wind turbines and solar PV panels for the different scenarios, and how that translates into capital expenditure and land usage. Estimates of land usage for wind turbines and PV panels are based on the typical land requirements

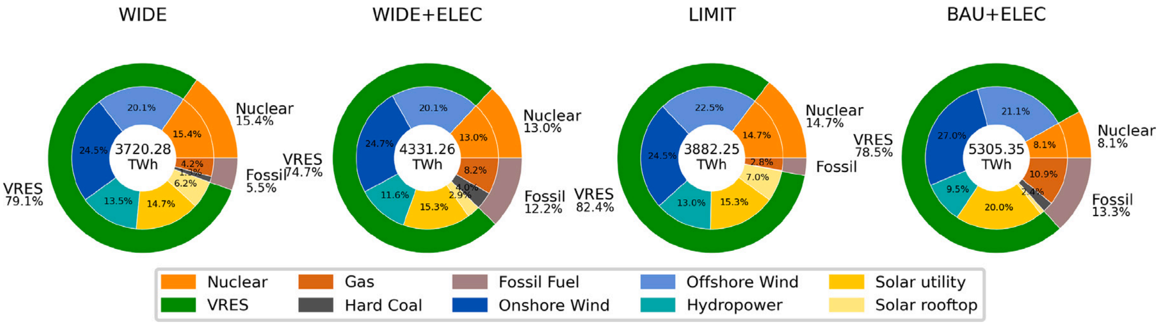


Fig. 9. Electricity generation mix for all scenarios for planning horizon 2030. Results for the remaining planning horizons can be found in Appendix C.1, Figure C.18.

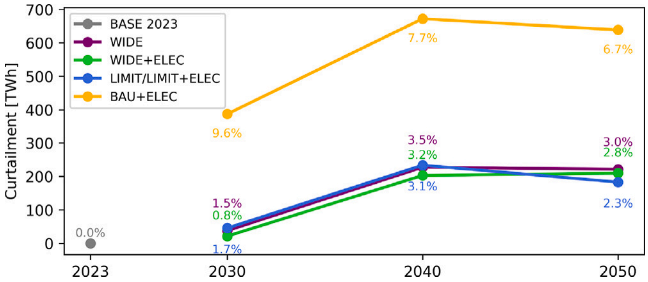


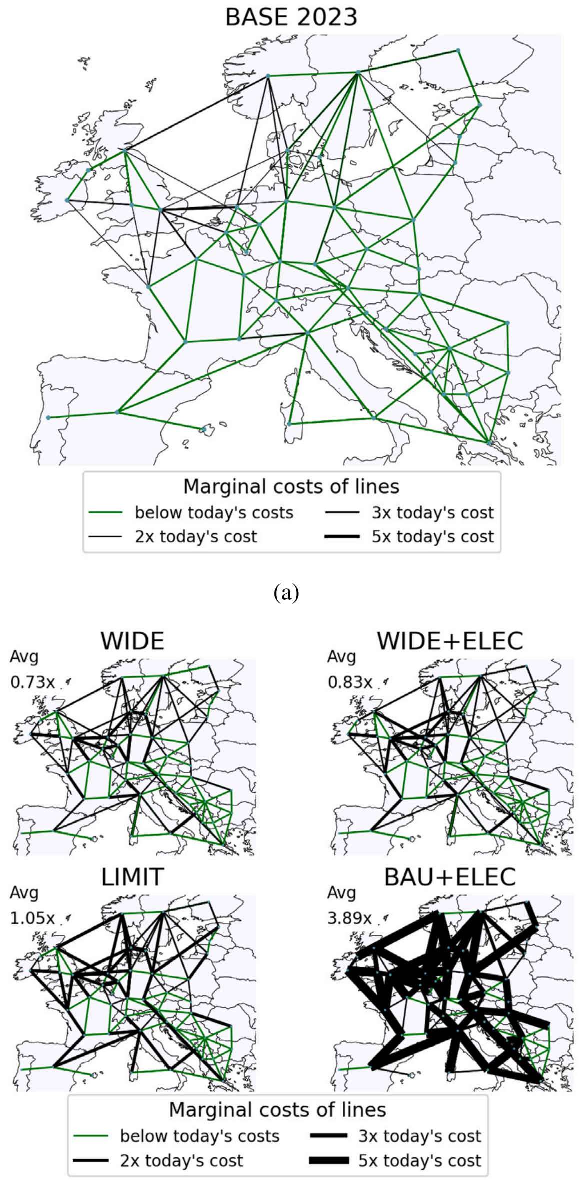
Fig. 10. Curtailment of RES (in TWh and % of total RES generation for all scenarios).

Table 8
Optimal installed capacity (in GW), capital expenditure (in bn EUR), and land usage (in thousands km^2) for solar PV panels and wind turbines.

			2030	2040	2050
Optimal capacities	PV panels	WIDE	647	1859	2405
		WIDE+ELEC	655	1758	2403
		LIMIT	722	–	–
		LIMIT+ELEC	–	2176	2536
		BAU+ELEC	1014	2746	3275
	Wind turbines	WIDE	537	1319	1431
		WIDE+ELEC	617	1305	1414
		LIMIT	596	–	–
		LIMIT+ELEC	–	1633	1692
		BAU+ELEC	1049	1936	2014
Capital cost	PV panels	WIDE	31.4	73.2	84.1
		WIDE+ELEC	30.8	67.6	83.5
		LIMIT	35.1	–	–
		LIMIT+ELEC	–	85.2	88.4
		BAU+ELEC	46.5	102.7	111.7
	Wind turbines	WIDE	64.5	146.1	149.8
		WIDE+ELEC	74.2	144.9	148.4
		LIMIT	72.4	–	–
		LIMIT+ELEC	–	174.2	172.4
		BAU+ELEC	122.4	202.7	201.4
Land usage	PV panels	WIDE	12.9	37.2	48.1
		WIDE+ELEC	13.1	35.2	48.1
		LIMIT	14.4	–	–
		LIMIT+ELEC	–	43.5	50.7
		BAU+ELEC	20.3	54.9	65.5
	Wind turbines	WIDE	185.4	454.9	493.6
		WIDE+ELEC	212.8	450.2	487.7
		LIMIT	205.7	–	–
		LIMIT+ELEC	–	563.2	583.9
		BAU+ELEC	361.8	667.9	694.8

per megawatt (MW) of nameplate capacity. Our estimates assume that wind turbines require approximately 0.345 km^2 per MW which is a conservative estimate according to [99], while we assume that solar utility installations require about 0.02 km^2 per MW [100].

Overall, the results underscore the critical role of solar technologies in the future energy mix, reflecting a transition towards more



(a)

(b)

Fig. 11. Transmission line congestion for each scenario over different horizons: (a) BASE 2023, and (b) 2030. Additional results for the planning horizon 2040 and 2050 can be found in Appendix C.1, Figure C.20.

Table 9
Annual distribution grid investments in bn EUR.

	2030	2040	2050
WIDE	37.0	46.9	48.8
WIDE+ELEC	52.7	52.7	52.8
LIMIT	39.6	–	–
LIMIT+ELEC	–	63.0	63.0
BAU+ELEC	92.4	92.9	93.0

sustainable and renewable energy sources.

The total installed capacities permitted for expansion during the optimisation run are shown in Figure C.25 in Appendix C.2 across all scenarios and planning horizons.

3.3.6. *Impact of efficiency measures on the grids*

Turning to the grid infrastructure, modelling results are examined for both transmission and distribution grids. Table 9 presents the annual investments into the distribution grids for each scenario and planning horizon. Focusing on 2030, the WIDE and LIMIT scenarios, where gas boilers still play a significant role in covering space heating demands, require the lowest immediate investments in the distribution grid, amounting to 37–39 billion EUR annually. In contrast, the WIDE+ELEC scenario, which involves electrifying the space heating completely, necessitates 33% more investment, reaching 52 billion EUR annually. If no efficiency measures are implemented but space heating is electrified (BAU+ELEC scenario), the grid requires 150% more investments compared to WIDE, or 92 billion EUR annually.

Moving to the 2040 planning horizon, distribution grid investments become more closely linked to efficiency measures rather than the availability of gas boilers. The WIDE and WIDE+ELEC scenarios require the lowest investments in the distribution grid, ranging from 46.9 to 52.7 billion EUR annually. In the WIDE+ELEC scenario, the investment levels remain consistent with the 2030 planning horizon, while the WIDE scenario sees delayed investments into the distribution grids, eventually reaching similar amounts by 2040. In scenarios with fewer or no efficiency measures (LIMIT+ELEC and BAU+ELEC), stricter requirements for enhancing the distribution network are evident, with 20% more investments for LIMIT+ ELEC and 75% more for BAU+ELEC compared to the WIDE+ELEC scenario. For the BAU+ELEC scenario, the improvement compared to the 2030 horizon is minimal.

Compared to the 2040 planning horizon, the 2050 projections show minimal increases in distribution grid investments across all scenarios. This suggests that the bulk of the necessary enhancements and investments will have already been made by 2040, resulting in only slight adjustments needed to maintain or marginally improve the distribution grid infrastructure by 2050.

While the model can expand the distribution grids without limits, transmission grid expansion is capped inline with the projected TYNDP scenarios. Therefore, a congestion analysis is performed to understand the impact of efficiency measures in buildings on the operation of the transmission grids. Transmission line congestion occurs when the demand for electricity transfer across a specific transmission line meets its capacity creating inefficiencies in the power grid. In technical terms, it is often quantified using the shadow price of the line capacity constraint. The shadow price is a value that represents the marginal cost of alleviating the congestion. A high shadow price indicates significant congestion, as it reflects the additional cost of supplying one more unit of electricity through the congested line. This situation can arise due to increased electricity consumption, unexpected power plant outages, or the integration of distant renewable energy sources. High shadow prices signal that the grid is operating near its limits, leading to higher electricity prices and increased operational costs as grid operators may need to re-route power or curtail generation to maintain reliability. Addressing congestion and its associated costs often involves infrastructure upgrades, improved grid management, and the use of advanced technologies to increase capacity and efficiency.

The congestion cost measured in EUR/MW/km are visually represented for each line in Fig. 11 for the baseline 2023 results, as well as for the 2030 planning horizon, displaying the annual per MWkm average across the hourly resolved time-series of the shadow prices. Results for the 2040 and 2050 planning horizon can be found in Appendix C.1, Figure C.20. This approach provides a standardised measure of congestion alleviation per kilometer. The cost of building or expanding transmission lines is set at 200 EUR/MW/km for AC lines, and 100 EUR/MW/km for DC lines [101]. The plots provide a relative increase in the congestion alleviation cost as compared to the current costs of building or upgrading the infrastructure. The displayed metric compares the average cost of alleviating the congestion with the construction costs of a new power line. The overall average congestion costs are then calculated by averaging these values across all lines in the network and presented as a single value for each map. This approach helps to identify the most congested parts of the grid and prioritise investments for upgrades to improve efficiency and reliability.

When examining the current situation (Fig. 11(a)), modelled results indicate that the system is not heavily stressed. Most of the infrastructure operates well within existing capacity constraints, suggesting that enhancing the transmission grid would not yield significant economic benefit. However, as electrification rates rise to improve system efficiency and meet 2030 emission targets (Fig. 11(b)), the system becomes more stressed and average congestion increases, varying by scenario.

For the WIDE and WIDE+ELEC scenarios, the system manages to operate within the planned 30% enhancement of the transmission grid assumed according to the TYND. Some congestion is present, but remains economically balanced, as the projected shadow price constraint is below the threshold for further capacity increases. In the LIMIT scenario, congestion rates rise to a level where additional enhancements could provide economic benefits, with the average shadow price constraint exceeding today's transmission infrastructure enhancement costs by 5%. Without any efficiency measures at the building level (BAU+ELEC scenario), the grid becomes heavily stressed, with the shadow price constraint reaching up to 3.89 times the current per-MWkm transmission infrastructure enhancement costs.

Results for the 2040 and 2050 planning horizon are inline with the findings for the 2030 horizon, and are discussed in Appendix C.1.

3.4. *Private sector perspective*

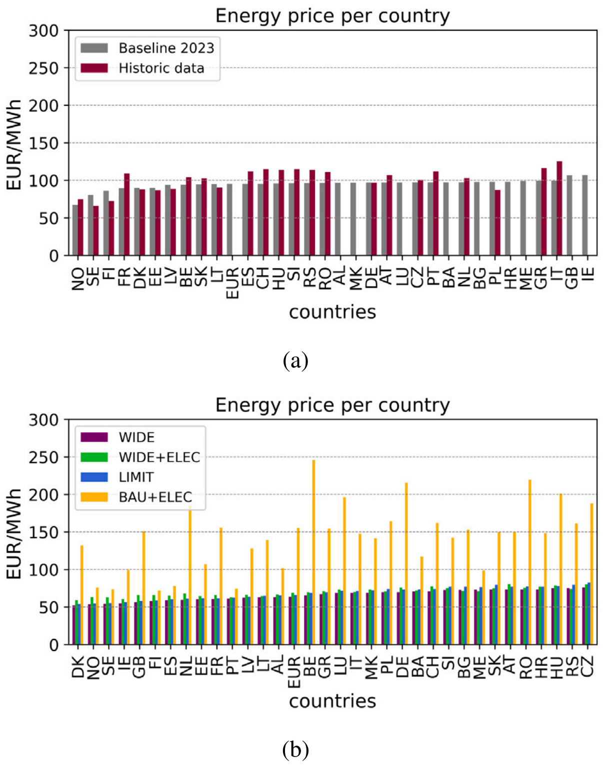
This section delves into the implications of reduced heat demand peaks for the private sector, including private households and industry. First, it outlines endogenously derived electricity prices, which form the basis for subsequent calculations on household energy bills and operating expenses (OPEX) in the industrial sector.

3.4.1. *Electricity prices*

Average annual electricity prices per MWh per country are calculated by considering the endogenously derived hourly electricity price, weighted by demand at each node of the model. Results are presented in Fig. 12 for each scenario, including the baseline 2023 results, and the 2030 planning horizon.

In the 2023 scenario benchmark (Fig. 12(a)), it can be seen that the average electricity prices in central Europe are relatively stable, showing only slight variations between countries. However, notable differences can be observed in other regions: Nordic countries, such as Norway, Sweden and Finland, experience lower prices, with reductions of approximately 18%, while Great Britain and Ireland see increased prices. Although exact margins differ from historically observed costs in 2023, the overall trend aligns closely, effectively reflecting the recent market dynamics.

According to the modelling results for the 2030 planning horizon, electricity prices can vary significantly from current levels, with



(a)

(b)

Fig. 12. Electricity prices per MWh for each scenario over different horizons: (a) BASE 2023, and (b) 2030. Results for planning horizons 2040 and 2050 can be found in Appendix C.1, Figure C.21.

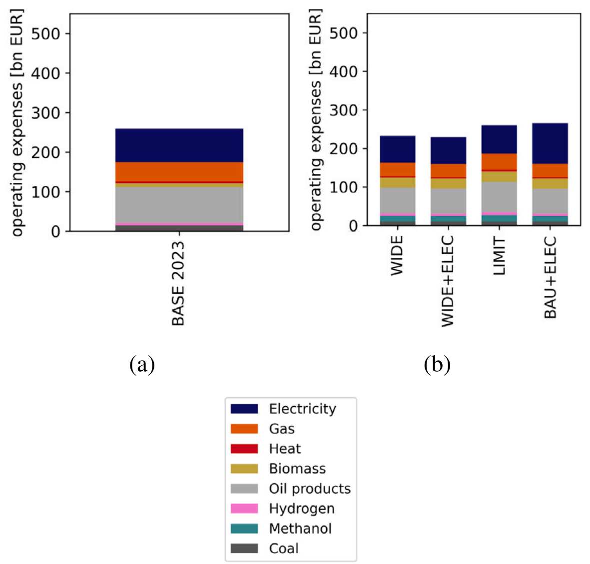
the extent of this variation largely depending on the depth of efficiency measures applied to buildings. In the absence of efficiency measures, the average electricity price in Europe is projected to reach 155.27 EUR/MWh by 2030. In contrast, scenarios with active efficiency measures see a substantial reduction, with prices averaging 63.77 EUR/MWh. Country-specific variations can be even more pronounced, particularly in Belgium, Germany, Romania and Hungary, where average electricity prices in the BAU+ELEC scenario exceed 200 EUR/MWh, representing an increase of approximately 210% compared to scenarios with active efficiency measures.

In scenarios with active efficiency measures, electricity costs become more uniform between countries, leading to a more equitable distribution of electricity prices across Europe. In Nordic countries such as Denmark and Norway, electricity costs remain lower compared to mainland Europe. While some countries may experience slightly higher costs, the cross-national differences are much smaller compared to scenarios without efficiency measures. The electricity costs are not significantly impacted by the availability of gas boilers or the depth of renovation, provided that the most inefficient buildings have already been renovated. The costs remain similar across the WIDE, WIDE+ELEC, and LIMIT scenarios, emphasising that the primary driver for reduced electricity prices is the implementation of efficiency and flexibility measures, rather than the type of space heating technology used.

The findings for the 2040 and 2050 planning horizon are discussed in Appendix C.1.

3.4.2. Operating expenses for the industrial sector

Prices for electricity significantly impact the profitability of the industrial sector, especially as electrification rates increase over time. Fig. 13 illustrates the projected operating expenses (OPEX) for the 2023 scenario benchmark and the 2030 planning horizon, while results for the 2040 and 2050 planning horizon can be found in Appendix C.1.



(a) (b)

Fig. 13. Operating expenses for the industry sector for each scenario over different horizons: (a) BASE 2023, and (b) 2030. Results for planning horizons 2040 and 2050 can be found in Appendix C.1, Figure C.22.

From 2023 to 2030, the cumulative operating expenses for the industry sector remain relatively stable with some exceptions for specific industrial processes, such as pulp and paper production (not discussed here).

In 2030, the depth of the efficiency measures in buildings significantly affects the share of operating electricity-related expenses for the industry. The OPEX associated with electricity is significantly higher for the scenarios LIMIT and BAU+ELEC, compared to the scenarios WIDE and WIDE+ELEC. Increased oil costs can also be observed.

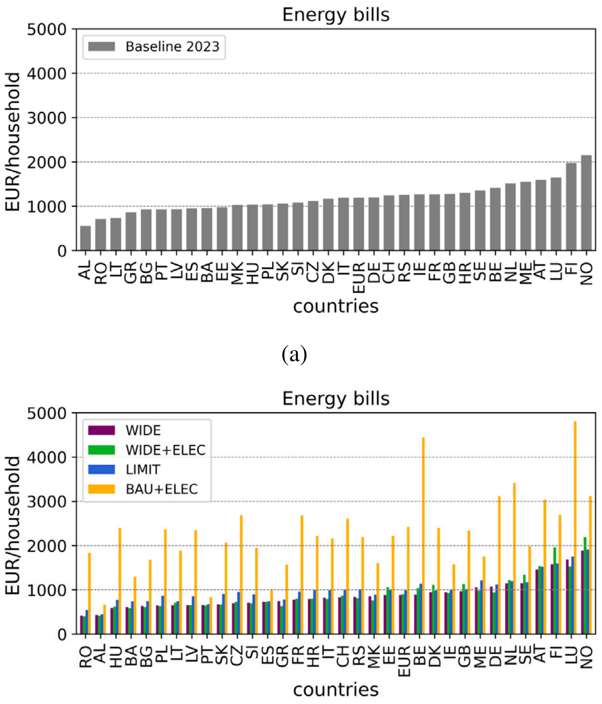
3.4.3. Energy bills for private households

Finally, we present the impact of electricity prices on the resulting energy bills of private households. Fig. 14 shows the average energy bills per country for each scenario for the scenario 2023 BASE and 2030 planning horizon. The bills are derived as a sum of household expenses for electricity and gas, where the electricity prices are evaluated as explained previously. This includes accounting for electrical loads for the household and electrified space heating and transport, such as resistive heaters, heat pumps, and electric vehicle (EV) charging. Gas consumption is estimated based on the usage of residential gas boilers, central gas, combined heat and power (CHP) systems, and micro-CHPs used for space heating.

In the 2023 scenario benchmark, substantial cross-national variations in energy bills are already evident. The most extreme disparities can be observed between Albania and Norway, for which average energy bills can be higher by several orders of magnitude. This variation is primarily driven by the demands for electricity and gas for space heating.

Moving to 2030, the general trend remains consistent, with energy bills being higher in colder countries, a trend that is not significantly altered by the implementation of efficiency measures. Scenarios WIDE and WIDE+ELEC result in very similar average energy bills, while the LIMIT scenario leads to only a slightly higher bill. Phasing out gas boilers has varying impacts on energy bills depending on the country, while the implementation of efficiency measures has a pronounced effect in this case. For example, in some countries, such as Germany, France, the Netherlands, or Sweden, the energy bill could be more than twice as high as the European average (Fig. 14(b)).

For the 2040 and 2050 planning horizons, the results are similar, although the very extreme overhead costs in the BAU+ELEC scenario



(a)

(b)

Fig. 14. Energy bills (including electricity and gas expenses) per household for each scenario over different horizons: (a) BASE 2023, and (b) 2030. Results for planning horizons 2040 and 2050 can be found in Appendix C.1, Figure C.23.

decrease, and lower renovation rates (LIMIT+ELEC) mostly perform worse than WIDE and WIDE+ELEC. Associated Figures can be found in Appendix C.1, Figure C.23.

4. Summary and conclusions

Based on the results presented in Section 3, several conclusions can be drawn about the role of building renovation and energy management systems in achieving a cost-effective transition to a 100% renewable energy system. Implementing energy efficiency measures in buildings can significantly reduce energy transition costs, saving more than €380 billion annually across the entire energy system by 2050. This corresponds to approximately 31% of the costs compared to scenarios without efficiency improvements. The exact savings depend on the extent of the applied efficiency measures and the availability of gas boilers. These findings were observed across all planning horizons from today through 2050, making the entire energy system cheaper to build, maintain and operate. To achieve the most cost-effective benefits, up to 70% of the building stock must be renovated by 2050, with significant progress required already by 2030. Additionally, smart energy management systems are heavily used to achieve these cost reductions, both in upward and downward direction.

Renovating building envelopes can reduce seasonal peak demand by up to 49.5% cost-efficiently by 2050. Even with a less ambitious renovation strategy, it is possible to reach at least 12.7% peak reduction for the space heat demand in 2030. Such a substantial reduction in peak demand has several implications for the remaining energy system:

- Renovation allows Europe to achieve its climate targets more affordably.
- Widespread renovations, combined with decarbonised heating systems, substantially reduce peak and overall heat and electricity demand. This means lower electricity costs, reduced carbon emissions, and a more efficient investment strategy for energy generation and grid infrastructure.
- Building renovation provides the highest savings in electricity price, household bills, and energy infrastructure investments over the next decade. Delaying or opting for less ambitious renovations can lock Europe into financial and environmental losses.
- Up to 150% of distribution grid expansion could be saved through widespread renovation, compared to a scenario without efficiency improvements, as the reduced peak demand diminishes the need for additional infrastructure and capacity expansion.
- Building renovations increase the equality in electricity prices between countries, promoting a more balanced energy market across regions.
- By providing significant energy system savings, widespread renovations can significantly reduce household electricity bills. This makes European households more resilient to energy price shocks. Additionally, improved system efficiency and increased flexibility, driven by energy efficiency improvements, can empower European consumers to become more energy independent and encourage the creation of energy communities.
- Building renovation enables Europe to decrease carbon emissions beyond targets for the 2030 planning horizon.

4.1. Limitations and further work

This study highlights the importance of energy efficiency measures in achieving decarbonisation goals, particularly by reducing demand peaks for electricity and space heating. This emphasises the need to incorporate peak demand effects into power and energy system models for adequacy studies that inform decision-making processes.

While the outputs of this study, including code and data, are publicly available under licences permitting modification and redistribution, the study has several limitations. These limitations are primarily related to data availability and could be addressed with future improvements.

1. Existing heat pumps and resistive heaters are not included in the simulation due to the lack of comprehensive statistical data on their current deployment on the European level.
2. Retrofitting costs are assumed to be an average value across all building types, including single-family houses, multi-family homes and apartment blocks. A future study could differentiate between the different building types, allowing us to derive more exact estimations of the energy bills for end consumers.
3. Region-specific space heating technologies, such as wood pellets or coke, are not taken into account in this study.
4. The expansion of transmission grids is set exogenously in the model, based on existing grid development plans.
5. The transmission capacity of distribution grids is accounted for using a bulk approach, without incorporating the detailed grid topology.
6. Model results are based on TYNDP transmission expansion plans, which may be considered conservative, as transmission development often falls short of targets due to regulatory, financial, and local challenges. Future work could explore more conservative scenarios with slower transmission expansion to better assess the impact of these challenges on the system.
7. The model focuses on technological aspects, assuming invariant electricity demand, population distribution, GDP, building stock, and industrial demand. Future advancements could integrate socioeconomic scenarios to capture these evolving parameters.

CRediT authorship contribution statement

Yerbol Akhmetov: Writing – review & editing, Visualization, Validation, Software, Data curation. **Ekaterina Fedotova:** Writing – review & editing, Writing – original draft, Visualization, Supervision, Software, Project administration, Methodology, Investigation, Formal analysis, Conceptualization. **Martha Maria Frysztacki:** Writing – review & editing, Writing – original draft, Visualization, Supervision, Software, Resources, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Conceptualization.

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Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.apenergy.2025.125421.

Data availability

All code and data are publicly available. The whole workflow can be reproduced from our gihub repository https://github.com/open-energy-transition/heat-demand-peaks.

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