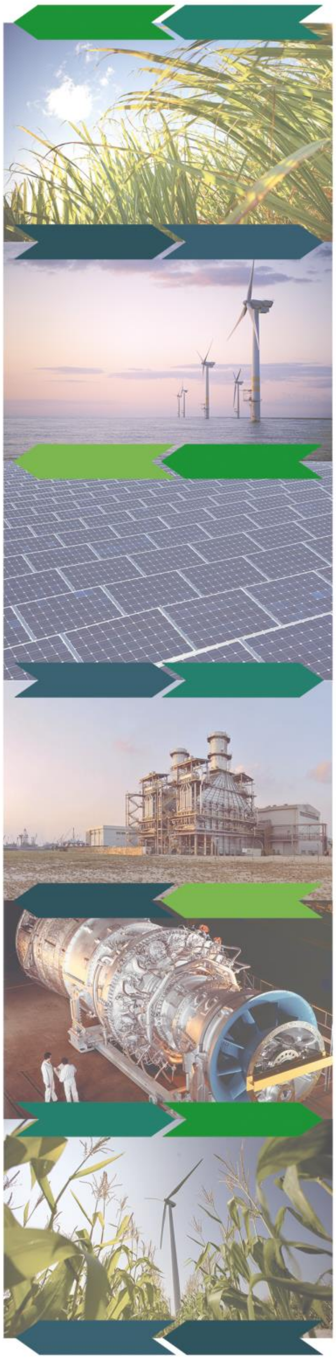
Navigating the Roadmap for Clean, Secure and Efficient Energy Innovation



D7.8: Summary report - Energy Systems: Supply Perspective

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SET-Nav
Strategic Energy Roadmap

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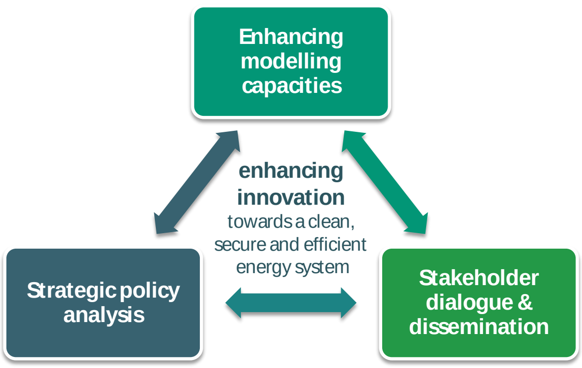
About the project

SET-Nav aims for supporting strategic decision making in Europe's energy sector, enhancing innovation towards a clean, secure and efficient energy system. Our research will enable the European Commission, national governments and regulators to facilitate the development of optimal technology portfolios by market actors. We will comprehensively address critical uncertainties facing technology developers and investors, and derive appropriate policy and market responses. Our findings will support the further development of the SET-Plan and its implementation by continuous stakeholder engagement.

These contributions of the SET-Nav project rest on three pillars: modelling, policy and pathway analysis, and dissemination. The call for proposals sets out a wide range of objectives and analytical challenges that can only be met by developing a broad and technically-advanced modelling portfolio. Advancing this portfolio is our first pillar. The EU's energy, innovation and climate challenges define the direction of a future EU energy system, but the specific technology pathways are policy sensitive and need careful comparative evaluation. This is our second pillar. Ensuring our research is policy-relevant while meeting the needs of diverse actors with their particular perspectives requires continuous engagement with stakeholder community. This is our third pillar.



Who we are?

The project is coordinated by Technische Universität Wien (TU Wien) and being implemented by a multinational consortium of European organisations, with partners from Austria, Germany, Norway, Greece, France, Switzerland, the United Kingdom, France, Hungary, Spain and Belgium.

The project partners come from both the research and the industrial sectors. They represent the wide range of expertise necessary for the implementation of the project: policy research, energy technology, systems modelling, and simulation.

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Executive Summary

This report explores pathways towards deep decarbonisation of European energy supply. We develop an unprecedented modeling framework to analyse possible developments in a high temporal, spatial and technological resolution. Our analysis shows that deep decarbonisation of European energy supply is possible in very different pathways with regards to technology choice and preference on infrastructures. In all pathways fluctuating renewables, especially wind energy, become a major source for electricity supply. We can show that electrification of heat supply in heat grids is a robust result which requires efficient linkage between the close to real time markets for electricity and the dispatch decisions in heat grids. Although some of our pathways are based on the idea of national champions or local production limiting possible extensions of grid infrastructures electricity trade increases heavily to ensure an efficient balancing of the energy supply system. This is also the case if CCS and nuclear technologies are utilized. This underlines the importance of European cooperation. Our results indicate that strengthening electricity grids is an important strategy to lower the cost of decarbonisation. Another important aspect which shows up in our analysis is the issue of acceptance for generation infrastructures. Our spatial analysis visualizes that considerable amounts of the renewable generation potential are utilized which raises issues of land use and public acceptance e.g. for wind turbines or utility scale photovoltaics. The choice of using secondary energy carriers such as hydrogen for the electrification of the demand sectors such as industry and transport increases the pressure on the generation infrastructure since additional losses occur for the conversion of electricity into hydrogen.

1 Introduction

This reports summarizes the work package on energy supply in the SET-Nav project. The main goal of this work package is to develop a very detailed modelling framework for the analysis of energy supply in deep decarbonisation pathways. The chapter on methodology describes the modelling approach and the main assumptions developed in this project. Chapter 3 we show the main results of our analysis on deep decarbonisation. The main findings are summarized in chapter 4. Please note that the data platform of this project provides additional information and data on our modelling results.

2 Methodology

This chapter describes the methodology developed in SET-Nav for the analysis of energy supply in decarbonisation pathways for Europe. In the first section three Case Studies are summarized which have been used to improve the modelling frame work in SET-Nav and to investigate important issues regarding energy supply. The second section describes the modelling approach and models of energy supply used in SET-Nav. In the third section important assumptions regarding the definition the pathways and the modelling of renewables are presented.

2.1 Case study: Input for Pathway analysis

In this project, case studies support the analysis of pathways for the decarbonisation of the European energy system. Besides the contribution to important topics regarding the transformation of the energy system, the case studies provide additional data and establish linkages between the models of the modelling framework. The following sections describe the case studies of this work package. Detailed results for each case study can be found in the corresponding case study reports.

2.1.1 Case Study: Diffusion rate of renewable electricity generation

This case study is dedicated to elaborate on *the diffusion of renewable electricity generation, aiming to gain insights on the suitable/optimal share renewables may take in Europe's future electricity supply.* Generally, renewable electricity generation (RES-E) is estimated to cover a high share of the future electricity demand in the EU. The possible diffusion of RES-E generation depends on the overall policy ambition in our combat against climate change, the relative costs of RES-E to its (low-carbon) alternatives, and the capability of the system to accommodate volatile generation. All these determinants are dynamic and therefore can change over time, and, most important, their impact on the optimal RES-E share has been analysed in the course of this case study. Below we report on some key findings.

Under assessed *default framework conditions* (i.e. 27% RES by 2030, optimal market design, etc.) a RES-E share of about 50% is reached in 2030.

Technological learning has an impact on these developments as observable from the related scenarios where either a 20% (compared to default) lower or a 20% higher learning rate is assumed for key technologies like wind energy and photovoltaics. As a consequence of the comparatively limited time span until 2030, only a small impact on the resulting 2030 RES-E share and on corresponding cost, analysed here through e.g. the resulting support expenditures, is applicable. The default RES-E share would for example decline by 0.5 percentage points by 2030 in the case of low learning, and the share increases by 0.2 pp in the case of high learning. By 2050 these effects are getting more pronounced: here low learning of wind and photovoltaics would cause a decline of the RES-E share by 2.8 pp.

An even more pronounced impact on the optimal RES-E share is applicable for *electricity market design*, or, in other words, the capability of the system to provide flexibility to cope with high shares of variable renewables in electricity supply. Less or more flexibility of the power system and electricity market design in general, has technical and operational consequences and determines also the economic viability of RES-based electricity supply. Our modelling focusses here on some core issues that impact RES-E integration, including grid development, electricity market design, and sector coupling / demand-side response. In a scenario reflecting less optimal framework conditions on these aspects it turns out that the optimal RES-E share is strongly affected: a decline of the RES-E share by 0.9 pp in 2030 and by 9.5 pp in 2050. This underpins the often called need to adapt or redesign our market framework to foster renewable integration.

Different *policy-related aspects* have been analysed within our modelling exam. For each topical subject under consideration one scenario has been defined to gain further insights on the resulting impacts as outlined below:

- Within our analysis of how policy design may facilitate or hinder the uptake of decentral RES prosumers, we showcase the impact of whether or not a *prioritisation of decentral generation*, exemplified for the case decentral PV, will be given in future years post 2020. Under default conditions (i.e. reference scenario “27% RES”) the assumption is taken that a prioritisation of decentral PV is maintained in future years, leading to a strong uptake of decentral PV in future years and, thus, affecting also total RES-E deployment. In the absence of a special prioritisation of decentral PV, we treat decentral PV systems (similar to other forms of central electricity supply) as a supply option to compete in the wholesale electricity market. Consequently, decentral PV is then lacking behind default trends. The optimal RES-E share by 2030 is consequently also affected, declining e.g. by 0.5 percentage points below the reference by 2030, and by 4.5 pp by 2050.
- Pronounced impacts are also applicable for the scenario where *high carbon prices* (as a consequence of a major ETS reform) are prevailing. We assume here a strong uptake of carbon prices within the ETS in future years, building on outcomes of recent PRIMES modelling in this topical area. Results show that a stronger increase in carbon prices leads to a faster uptake of renewables in the electricity sector.
- *Strong 2030 targets for RES (and energy efficiency)*: Here, we analyse how the overall policy ambition for renewables (and for energy efficiency) determines the required uptake of RES in the electricity sector, exemplified by the assumed overall 2030 target set for RES within the EU. More precisely, we take the assumption that at EU level the 2030 RES target is set at 30% (instead of 27% as default).[1] This leads to an accelerated uptake of RES electricity, reaching a demand share of 54.6% (instead of 49.7% as default) by 2030. As recent modelling proves the optimal RES-electricity share would increase further to around 58%-60% if an overall RES share of 32% is aimed for by 2030.

[1] We are aware that this is still below the actually agreed one (i.e. 32% - as agreed in Council and Parliament during 2018) – but since it is here combined also with a lower energy efficiency target (i.e. 30% instead of 32.5%) this causes a comparatively similar level of overall RES ambition. Thus, in other words, the RES volumes required for meeting 30% RES in combination with a 30% energy efficiency target are comparatively similar than to strive for 32% RES combined with 32.5% energy efficiency. If accounted precisely, the required RES volumes by 2030 would be less than 3% smaller under the assessed combination (i.e. 30% RES, 30% EE) than under the politically agreed one (i.e. 32% RES, 32.5% EE).

2.1.2 Case Study: Unlocking unused flexibility and synergy in electric power and gas supply systems

The case study results involved in the analysis of gas supply are described in detail in the summary report on infrastructures in work package 6.

2.1.3 Case Study: Perspectives for nuclear power – a closer look at cost developments

This case study reports the development and diffusion patterns since connecting the first reactor to the grid on a global scale followed by a country-by-country analysis of implantation. Nuclear energy is among the most important innovations of the twentieth century, and it continues to play an important role in twenty-first century discussions. In particular, there is a debate about the potential contribution of nuclear power to policies of climate change mitigation and energy security in both, industrialized and emerging countries. In this context, many existing nuclear countries, and others considering entering the sector, are facing questions of how to structure organizational models for nuclear power, and what lessons to be learned from the past seven decades of civilian use of nuclear power.

The objective of this case study was to trace the development of nuclear power in form of a data documentation since its beginnings, by providing both a technological and a country-specific perspective, to allow a better understanding of issues on nuclear power going forward and to determine how to deal with these in energy system modelling.

A historical analysis of the emergence of nuclear power since 1945 lets us distinguish four periods. The most recent, post-Fukushima (2011) is characterized by the implosion of nuclear power in Western capitalist market economies, and the closure of nuclear power plants, often before reaching technical lifetimes, due to economic reasons; many of the newly built projects were abandoned, too. This leaves the current development of nuclear power to “other”, non-market systems, where countries hang on to nuclear development, for political, military-strategic, or other reasons, mainly the nuclear superpowers China and Russia.

In addition, initial hopes placed on “Generation IV” and/or small modular reactors (SMRs) have not been fulfilled. Although some Gen IV research reactors are developed, no technology has any perspective of becoming economically competitive, neither with current nuclear technologies, nor with conventional fossil or renewable generation in combination with storage.

The case study thus fills a research gap in the literature, in that it provides bottom-up, evidence-based proof that nuclear power follows no economic rationale, but some other logic linked to “science and warfare”. None of the 674 reactors analysed in the case study has been developed based on what is generally considered “economic” grounds, i.e. the decision of private investors in the context of a market-based, competitive economic system. Given current technical and economic trends in the global energy industry, there is no reason to believe that this rule will be broken in the near- or longer-term future.

In consequence, nuclear power capacities in our pathway analysis are set in form of exogenously determined time series. The used time series for each analysed pathway are illustrated in section 2.3.4 of this report.

2.2 Modelling Approach

2.2.1 Data exchange concept for pathway analysis

The following section describes the interplay between the different models used for this analysis of the European energy system from the supply perspective. A schematic sketch of the modelling approach is shown in Figure 1.The approach links very detailed sectoral models to provide an unprecedented level of detail for the pathway analysis.

In a first step, the demand for energy carriers such as electricity, heat, and hydrogen in the different pathways is calculated with the models *Forecast* for the industry sector, *Invert* for the building sector, and *ASTRA* for the transport sector (see the corresponding summary report on the demand side in work package 5). The modelled demand is given as input to a first optimisation of the energy supply with *Enertile*® (see model description in Section 2.2.2.1). The total electricity demand and the resulting market values for renewable energy technologies are then passed over to the *Green-X* model (see model description in Section 2.2.2.3). The rationale of linking Green-X and Enertile is the different modelling approach regarding deployment of renewables. Green-X simulates deployment of renewables based on policy interventions like dedicated RES targets or corresponding support schemes dedicated to renewables. This appears more adequate for the analysis of short to medium term developments concerning RES deployment than the optimisation procedure in Enertile. Thus, within the pathway analysis *Green-X* is used to calculate the capacity and generation of renewables in the period up to 2030, considering the recently agreed overall 2030 EU RES target. The resulting renewable electricity generation values from the year 2030 are then used as minimum conditions to a second optimisation with Enertile. In 2030 the renewable generation in the *Enertile* optimisation has to be equal to the *Green -X* values. In the years 2040 and 2050 renewable expansion is optimised in Enertile, the renewable generation may be higher but not lower than in 2030. The results from the second *Enertile* optimisation serve as an input for the *TEPES* model (see model description in Section 2.2.2.2), which recalculates the expansion of the transmission grid. The Enertile model contains a transport model of interconnectors between countries. This representation is improved by the detailed calculations in the grid model TEPES: The revised grid is then fixed in the third and last optimisation with *Enertile* based on the results of the TEPES model. The results of this last optimisation are analysed in detail and provided to the gas supply models and the macroeconomic models for further analysis.

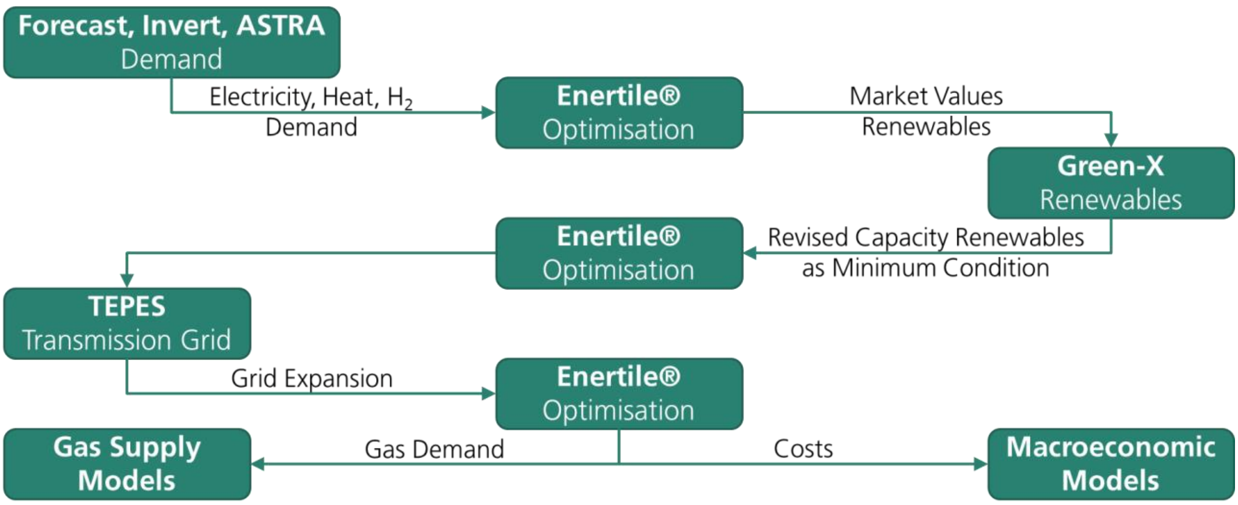


Figure 1: Modelling approach and interlinkages between models for pathway analysis

2.2.2 Models used for the analysis of energy supply

The following sections describe the main models involved in the analysis of energy supply. These are Green-X for the modelling of the diffusion of renewable electricity generation technologies, Enertile® for the optimisation of energy supply and TEPES for the detailed analysis of the electricity grid. All models involved in the analysis of gas supply are described in detail in the work package 6 summary report.

2.2.2.1 Enertile

2.2.2.1.1 Model description

Enertile® is a model for energy system optimization developed at the Fraunhofer Institute for Systems and Innovation Research ISI. The model strongly focuses on the power sector but also covers the interdependencies with other sectors such as the heating and transport sector. It is used 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.

Enertile conducts an integrated optimization of investment and dispatch. It 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 as demand-side-management (DSM) and power-to-heat and storage technologies. The model chooses the optimal portfolio of technologies while determining the utilization of these in all hours of each analysed year.

The model currently depicts and optimizes Europe, North Africa and the Middle East. In this project only Europe is analysed. 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 features a full hourly resolution: In each analysed year, 8760 hours are covered. Since real weather data is applied, the interdependencies between weather regions and renewable technologies are implicitly included.

Enertile includes a detailed picture of renewable energy potential and generation profiles for the optimization. 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 2 shows a simplified structure of the input and output of the Enertile optimization model.

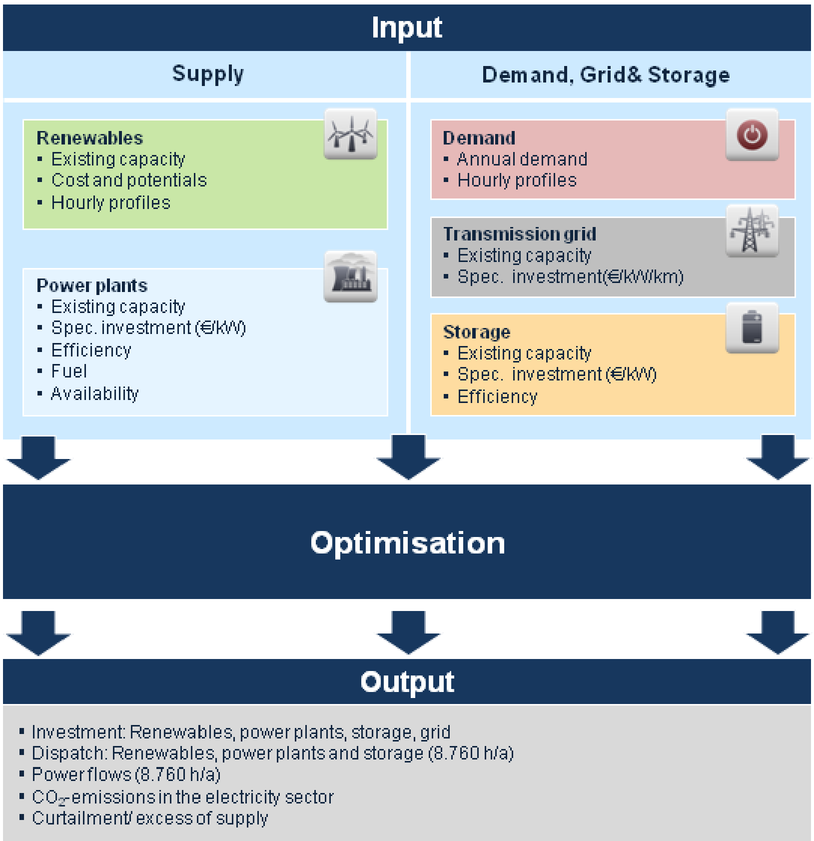


Figure 2: Simplified structure of the Enertile® optimization model

2.2.2.1.2 Model extensions

Enertile has a strong focus on the electricity sector in Europe and neighbouring countries. The integration of rising shares of renewable energy in the electricity sector is a crucial task for the next decades. On one hand, this can be addressed by additional flexibility within the electricity sector. On the other hand, a stronger linkage to other sectors could help to integrate renewable electricity. Within the SET-Nav project, Enertile has been expanded by several modules to integrate demand and flexibility from other sectors. In the heating sector decentralised heat pumps and district heat grids are taken into account. In the transport sector flexible electric mobility and inflexible electricity demand from trolley trucks and trains are considered. Hydrogen demand from transport and industry is also covered. These model extensions are described in detail in the following sections.

2.2.2.1.2.1 Decentralised heat pumps

For decentralised heat pumps an hourly heat demand profile is used as a basis for the analysis. The flexibility is provided by the use of a heat storage representing storage capacity of the building as well as a hot water storage integrated in the heating system. The hourly operation of the heat pump is integrated in the overall optimization problem. The modelling includes changing efficiencies of the heat pumps dependent on outside air temperature, heat losses of the heat storages as well as impacts on the electricity system as the possible use of excess renewable electricity generation or costs of electricity generation during high electricity demand and low production of renewable electricity.

2.2.2.1.2.2 District heat grids

In heat grids, flexibility can be even higher than for decentralised heat pumps, as often more than one energy carrier covers heat generation in district heating. Depending on heating technologies used in a heat grid, flexibility can be provided by a switch between different heating technologies as well as the use of heat storages. Within the developed module for heat grids, several technology options can be used to cover the heat demand. These are combined heat and power (CHP) plants, heating boilers based on fossil fuels or hydrogen, electric boilers, large heat pumps based on electricity and ambient heat, and hot water storages. In the developed module, heat grids for district heating are considered. District heating grids provide mainly heat for hot water and heating purposes in buildings and have a typical seasonal pattern in their heat demand. Within the developed flexibility module for heat grids the operation as well as the installation of heating technologies - including power to heat facilities - and heat storages can be integrated in the optimization problem.

2.2.2.1.2.3 Transport

Rising shares of electricity utilization in the transport sector increase the total electricity demand. Assuming an intelligent loading infrastructure and sufficient incentives for customers to load vehicles flexibly, the additional electricity demand in the transport sector is flexible to a certain degree. The load profile of the additional demand as well as the potential flexibility in the transport sector strongly depend on driving profiles and time slots for charging. Different driving profiles for different vehicle types are used in the flexibility module for the transport sector. The profiles define charging times and necessary charging states for certain points of time. For example, many battery electric (BEV) and plug-in hybrid vehicles (PHEV) have to be charged in the morning to allow commuting to work. When they return back home in the evening, charging does not necessarily have to start immediately. If the owners are willing to participate in smart charging, the charging process can be postponed to times that are more cost efficient for the power system. The share of willing owners can be defined for each country and year. In contrast to the flexible demand from BEVs and PHEVs, the electricity demand from trolley trucks, trains and trolley busses are considered as inflexible demands, as we assume there is no possibility of load shifting for these categories. To derive the hourly demands from the annual demands for those categories different driving profiles for the respective categories are used.

2.2.2.1.2.4 Hydrogen

One mitigation option to reduce CO_2 emissions in the industry sector is to provide hydrogen by electrolysis rather than by steam reforming natural gas. The same applies to the transport sector with the usage of electrolysis-based hydrogen in fuel cell electric vehicles instead of fossil fuels. This fuel shift has two main implications for the electricity sector. On the one hand, the hydrogen production with electrolysis increases the total electricity demand. On the other hand, hydrogen has the potential to provide flexibility to the power system. Due to its long-term storage property, it can be used as an electricity storage. In hours of small loads and high electricity generation by renewable energies, hydrogen can be produced and stored. Hydrogen demands in the transport and industry sector can be met by this storage. Later, in hours of high load and small renewable generation, the hydrogen can be used in a gas turbine to generate emission free electricity. Therefore, the hydrogen module in Enertile consists of a formal description of three components: An electrolyser, a hydrogen storage that can meet both exogenous demands from the transport and industry sector and endogenous demands for electricity generation, and a reconversion instance like a gas-fired power plant. The modelling approach assumes that electrolysers are installed decentralized at the fuelling stations or industrial facilities. A hydrogen network infrastructure is not explicitly modelled. The model tends to overestimate the amounts of electricity generation by firing hydrogen in gas turbines or boilers, as transport costs from small, decentralized electrolysers and hydrogen storages to more centralized gas turbines are neglected.

2.2.2.2 TEPES

2.2.2.2.1 Model description

The intermittent nature of the output of most renewable energy resources (RES), its non-homogeneous distribution and the deployment of a large share of this generation is expected to result in a significant increase in the power flows among areas in large-scale systems. As a result of this, the development of the transmission network should be planned in an integrated way and the number of operation snapshots to consider in the planning process should probably be high. Identifying the main optimal transmission network corridors to reinforce and the extent of reinforcements needed in them, and other operation variables affected by the existence of the grid, like the investment cost of grid additions, network losses incurred, CO2 emissions produced, overall production by technology and fuel production costs is a major challenge for large-scale systems. Different future RES generation strategies associated with different RES targets may also strongly influence this network development.

Transmission expansion planning (TEP) determines the investment plan for new facilities (lines and other network equipment) for supplying the forecasted demand at minimum cost. Tactical planning is concerned with time horizons of 10-20 years. Its objective is to evaluate the future network needs. The main results are the guidelines for future structure of the transmission network.

TEPES model presents a decision support system for defining the transmission expansion plan of a large-scale electric system at a tactical level. A transmission expansion plan is defined as a set of network investment decisions for future years. The candidate lines are pre-defined by the user, so the model determines the optimal decisions among those specified by the user, or identified automatically by the model. Candidate lines can be HVDC or HVAC circuits.

The model determines automatically optimal expansion plans that satisfy simultaneously several attributes.

Dynamic

The scope of the model corresponds to several years at a long-term horizon.

The model represents hierarchically the different time scopes to take decisions in an electric system: Year, Period, Sub-period and Load level.

This time division allows a flexible representation of the periods where system operation is evaluated. For example, by a set of non chronological isolated snapshots, by a set of representative days for different seasons of the year or by a stepwise load-duration curve covering the duration of a year.

Stochastic

Several stochastic parameters that can influence the optimal transmission expansion decisions are considered. The model considers stochastic scenarios related to operation and to reliability. The operation scenarios are associated to: renewable energy sources, electricity demand, hydro inflows, and fuel costs. The reliability scenarios evaluate N-1 generation and N-1 transmission contingencies.

The optimization method used is based on a functional decomposition between an automatic transmission plan generator (based on optimization) and an evaluator of these plans from different points of view (operation costs for several operating conditions, or reliability assessment for N-1 generation and transmission contingencies). The model is based on Benders' decomposition where the master problem proposes network investment decisions and the operation subproblem determines the operation cost for this investment decisions and the reliability subproblems determine the not served power for the generation and transmission contingencies given that investment decisions.

The operation model (evaluator) is based on a DC load flow although a simpler transportation representation is allowed for some or all the lines. Network losses can also be considered. By nature the transmission investment decisions are binary although can also be treated as continuous ones. The current network topology is considered as the starting point for the network expansion problem.

The main results of the model can be structured in these themes:

- Investment: investment decisions and cost
- Operation: output of different units and technologies (thermal, storage hydro, pumped storage hydro, RES), fuel consumption, RES curtailment, hydro spillage, hydro reservoir scheduling, line flows, line ohmic losses, node voltage angles
- Emissions: CO2
- Marginal: Short-run Marginal Costs, Transmission Load Factors (TLF)
- Reliability: ENS (Energy Not Served)
- Cost to go function or future cost function

The resulting expansion plan for the transmission network can be represented in Google Earth for easy visual inspection.

Figure 3. Example output for TEPES.

TEPES has been used in several projects and appears in over 20 academic publications.

2.2.2.2.2 Model extensions

TEPES had to be extended to link it to the other models in project SET-Nav.

2.2.2.2.2.1 Modelling of innovative transmission technologies

TEPES has been extended to include the option to use innovative transmission technologies in the expansion of the transmission system:

- Phase-Shifting Transformers (PSTs) have been incorporated as a way of alleviating congestion without investing in new lines. These Flexible Alternating Current Transmission Systems (FACTS) are sometimes the most efficient way of alleviating operation problems due to Kirchhoff's Voltage Law.
- Combinations of AC transmission lines and PSTs.

- HVDC (High-Voltage Direct-Current) lines.

The model performs an automatic search of the most attractive investment candidates within these categories, builds an approximation of investment cost and considers them for the most efficient expansion. Then, they are included in the expansion options that are fed back to system optimization.

2.2.2.2.2.2 Integration with supply-side models: disaggregation procedure

TEPES performs a detailed expansion of the transmission grid:

- Considering hundreds or potentially thousands of nodes (nodal level).
- Integration with supply-side models: providing useful outputs for integrated system expansion

System expansion is performed at a more aggregate level (we will refer to it as zonal level). Therefore, it is necessary to disaggregate these data. The results for the system expansion include conventional generation capacity, demand profiles, installation and use of storage (power injection and withdrawal) and intermittent generation. These are calculated, in this case, by ENERTILE.

- Generation, demand and storage data at zonal level are allocated to nodes according to previously defined shift keys;
- Conventional generation is located according to their existing locations;
- Demand is disaggregated according the share of the existing nodal consumption from ENTSO-e data;
- Storage and renewable generation are located according to their potential for each node. Each renewable or storage technology (wind onshore, solar PV, run-of-the-river hydro) is disaggregated according to the share of its existing nodal production from ENTSO-e data)

2.2.2.2.2.3 Integration with supply-side models: feedbacks for system optimization

TEPES calculates the detailed network expansion, which is fed back to the system optimization. In addition to this, the best options for increasing net transfer capacity between zones are calculated.

We make a distinction between the unit cost of reinforcing each corridor up to its optimal development state, as computed using TEPES, and the unit cost of reinforcing this corridor beyond this point.

1) Computation of the unit cost of reinforcing each corridor up to the optimal amount of transmission capacity:

    i) TEPES is run to compute the optimal operation of the system in each snapshot and development of the network. The network reinforcements to undertake in the system are determined, as well as the annualized cost of each reinforcement.
    ii) The fraction of the annualized cost of each reinforcement is allocated to the considered snapshots proportionally to the aggregate size of overflows created in these snapshots in the original network if capacity constraints are relaxed.
    iii) The cost assigned to each MW of power flowing through a reinforcement in a particular snapshot is assigned according to the net flow through the reinforcement in that particular snapshot.
    iv) The unit cost of reinforcing each corridor between two zones is calculated by simulating a transaction between these two zones. The use of reinforcements by each transaction gives the proportion of the cost that should be allocated to the corridor.

These calculations result in a unit cost of the reinforcement of each corridor up to the level of optimal expansion.

2) Computation of the unit cost of reinforcing the network beyond its optimal capacity level.

In this case, once the optimal expansion of the grid has been computed, the unit cost of reinforcing each corridor is computed as the cost of allowing an incremental transaction between zones A and B, linked by corridor C, in both possible directions of it, on top of the power injections and withdrawals resulting from the economic dispatch in all the snapshots considered.

The unit cost of allowing this incremental transaction is the per-unit cost of expanding the system to allow the incremental transaction between these two zones.

2.2.2.3 Green X

2.2.2.3.1 Model description

The Green-X model is used in this project to perform a detailed assessment on the future deployment of renewable energies in the European Union. The Green-X model is a well-known software tool with respect to forecasting the deployment of RES in a real-world policy context. This tool has been successfully applied for the European Commission within several tenders and research projects on renewable energies and corresponding energy policies, e.g. FORRES 2020, OPTRES, RE-Shaping, EMPLOYRES, RES-FINANCING and has been used by Commission Services in the "20% RE by 2020" target discussion. It fulfils all requirements to explore the prospects of renewable energy technologies:

- It currently covers geographically the EU28 (all sectors) as well as neighbouring countries and regions (e.g. the Contracting Parties of the Energy Community, Northern African countries, Norway, Switzerland).
- It allows investigating the future deployment of RES as well as accompanying generation costs and transfer payments (due to the support for RES) within each energy sector (electricity, heat and transport) on country- and technology-level on a yearly basis up to a time-horizon of 2050.

The modelling approach to describe supply-side generation technologies is to derive dynamic cost-resource curves by RE option, allowing besides the formal description of potentials and costs a suitable representation of dynamic aspects such as technological learning and technology diffusion.

It is perfectly suitable to investigate the impact of applying different energy policy instruments (e.g. quota obligations based on tradable green certificates, (premium) feed-in tariffs, tax incentives, investment subsidies) and non-cost diffusion barriers.

Within the Green-X model, the allocation of biomass feedstock to feasible technologies and sectors is fully internalised into the overall calculation procedure, allowing an appropriate representation of trade and competition between sectors, technologies and countries. Moreover, Green-X allows an endogenous modelling of sustainability regulations for the energetic use of bioenergy.

Within Green-X a broad set of results can be gained for each simulated year on a country-, sector-, and technology-level:

- RES generation and installed capacity,
- RES share in total electricity / heat / transport / final energy demand,
- Generation costs of RES (including O&M),
- Capital expenditures for RES,
- Impact of RE support on transfer costs for society / consumer (support expenditures),
- Impact of enhanced RES deployment on climate change (i.e. avoided CO_2 emissions)
- Impact of enhanced RES deployment on supply security (i.e. avoided primary energy)

Modelling support policies:

With Green-X a thorough assessment of impacts of various forms of energy policy interventions on RES deployment can be performed. The model is perfectly suitable to investigate the impact of applying different energy policy instruments to facilitate the market deployment of low carbon energy supply technologies – e.g. quota obligations based on tradable green certificates, (premium) feed-in tariffs with administrative price setting or price determination through auctions / tenders, tax incentives, investment subsidies as well as the impact of non-cost diffusion barriers. The model contains a support policy database of all current RES support policy instruments, including their concrete implementation via design elements, for the EU28, Switzerland, Norway, the Western Balkan countries, North Africa and Turkey.

Green-X database:

The input database of the Green-X model provides a detailed depiction of the past and present development of the individual RES technologies - in particular with regard to costs and penetration in terms of installed capacities or actual & potential generation. Besides also data describing the technological progress such as learning rates is available which serves as crucial input to further techno-economic analysis.

2.2.2.3.2 Model extensions

Within the course of this project TU Wien's Green-X model and/or its application has been extended for two aspects as elaborated below.

Re-establish a suitable model coupling

One key feature of this project was to re-establish the linkage between Green-X and its power system companion Enertile.

More precisely, Green-X was used within the case study works as well as within the pathway analysis to deliver a first picture of future RES developments under distinct energy policy trends and cost assumptions. For assessing the interplay between RES and the future electricity market, Green-X was complemented by its power-system companion, i.e. the Enertile model. Thanks to a higher intertemporal resolution than in the RES investment model Green-X, Enertile enables a deeper analysis of the merit order effect and related market values of the produced electricity of variable and dispatchable renewables and, therefore, can shed further light on the interplay between supply, demand and storage in the electricity sector.

Figure 4 gives an overview on the interplay of both models. Both models are operated with the same set of general input parameters, however in different spatial and temporal resolution. Green-X delivers a first picture of renewables deployment and related costs, expenditures and benefits by country on a yearly basis (2010 to 2030). The output of Green-X in terms of country- and technology-specific RES capacities and generation in the electricity sector for selected years (2020, 2025 and 2030) serves as input for the power-system analysis done with Enertile, assessing the interplay between supply, demand, and storage in the electricity sector on an hourly basis for the given years. The output of Enertile is then fed back into the RES investment model Green-X. In particular, the feedback comprises the amount of RES that can be integrated into the grids, the electricity prices, and corresponding market revenues (i.e. market values of the electricity produced by variable and dispatchable RES-E) of all assessed RES-E technologies for each assessed country. Subsequently, with Green-X a recalculation is undertaken where outcomes are then taken up for the follow-up analysis done with Enertile.

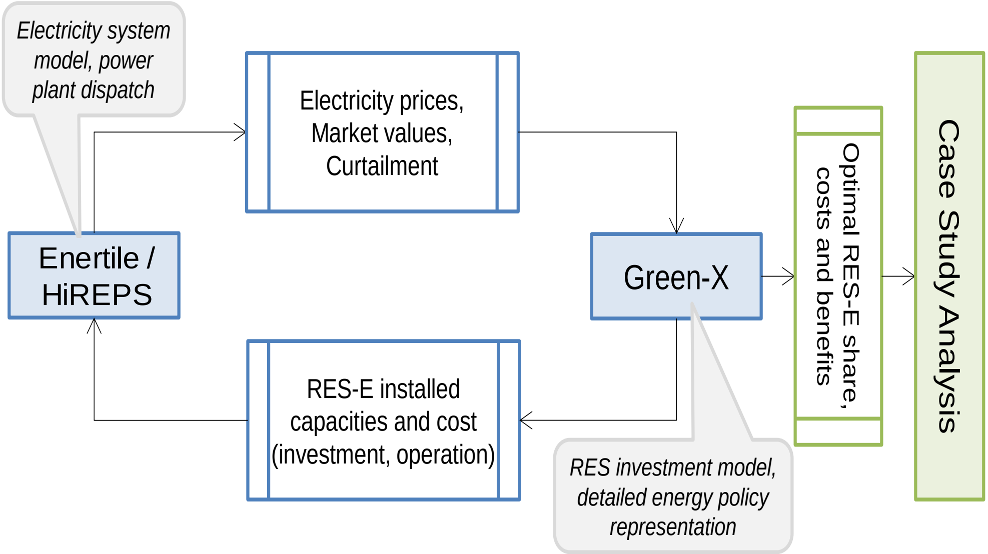


Figure 4: Model coupling between Enertile (left) and Green-X (right) for a detailed assessment of RES developments in the electricity sector

Extend the technology coverage

Apart from technical and economic aspects, the deployment of energy technologies is also driven by policies that change the framework conditions of the sector. One remarkable example is renewable support in the EU. National member states apply support schemes for renewable thus changing the in-vestment rationale of actors in the sector. This renewable policy perspective is covered by the Green-X model within SET-Nav.

Within this project the TU Wien team has extended the system boundaries and technology coverage in the Green-X model. Technology-wise nuclear power and CCS has been included in the technology option catalogue, incorporating the findings of the respective case studies for a sound representation of these technology options. Moreover, an improved representation of decentralised PV systems could be achieved throughout the course of SET-Nav, incorporating the (possibly higher) economic value of decentral supply under certain framework conditions and policy measures.

Against the initial plan, we have failed to broaden the policy coverage of Green-X with technology push instruments due to a lack of empirical evidence provided by the innovation analysis conducted within WP2 of this project.

2.3 Data and assumptions for the pathway analysis

The SET-Nav project analyses four distinct pathways that allow an effective decarbonisation of the energy sector: 1) Diversification, 2) Localization, 3) Directed Vision and 4) National Champions. Figure 5 shows a short overview of the general concept of the four pathways. A detailed description of the pathway definition is given in the summary report of work package 9.

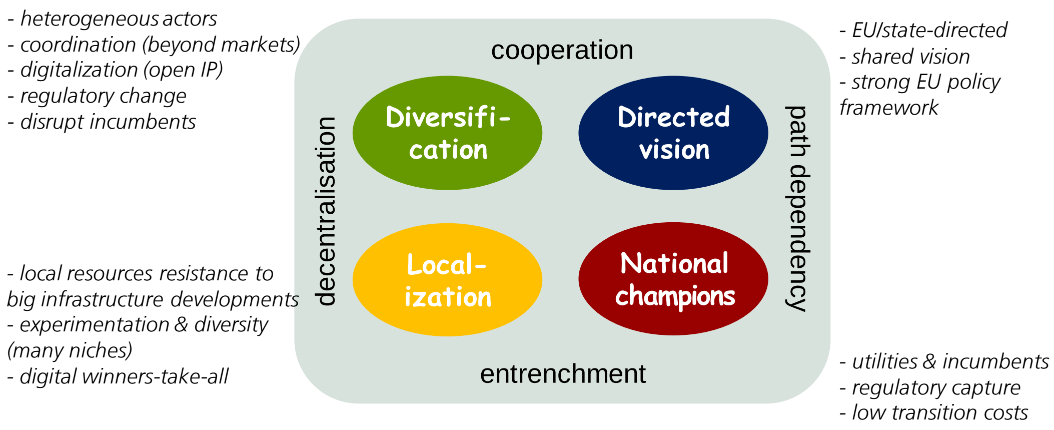


Figure 5: SET-Nav pathways definitions and storylines at a glance

The following sections describe the data and assumptions used for the pathway scenarios introduced in the previous paragraph. The pathway analysis for the supply side is conducted for the scenario years 2030 until 2050 in steps of 10 years.

2.3.1 General input data

The interest rate for the calculation of capital cost is assumed to be constant at 7% for all technologies in Enertile. The fossil fuel prices, which are given in Table 1, are based on the IEA 450 scenario of the World Energy Outlook 2016 (International Energy Agency 2016).

Table 1: Development of fuel prices in the pathway analysis with Enertile

Fuel prices in €/MWh_{th}	gas	hardcoal	oil	lignite	nuclear
2030	28.9	7.4	48.4	3.7	3.1
2040	30.5	6.6	44.5	3.7	3.1
2050	31.2	6.2	42.5	3.7	3.1

The pathway calculations take into account a carbon budget to assure comparability between the four pathways. The carbon budget is based on the PRIMES EUCO30 scenario and includes all CO_2-emissions to the atmosphere from the electricity sector and district heating in Europe (European Commission 2016). The carbon budget is implemented as an upper bound for CO_2-emissions in all four pathways and given in Table 2. In 2030 not more than 734 Mt of CO_2 may be emitted into the atmosphere. The other limits are 146 Mt of CO_2 in 2040 and 60 Mt of CO_2 in 2050.

Table 2: Carbon budget in the pathway analysis with Enertile in Mt

2030	2040	2050
734.4	146.0	60.3

2.3.2 Demand for electricity, heat and hydrogen

As described in section 2.2.1, the resulting demand for electricity, heat and hydrogen from the demand models Forecast, Invert and Astra are used as input to the supply model Enertile. The demand data comprises five categories: 1) the general demand for electricity from all sectors, 2) the heat demand for heat grids in the building sector, 3) the heat demand for decentralized heat pump systems in buildings, 4) the electricity demand in the transport sector and 5) the hydrogen demand in the industry and transport sector. The development of the European demand in the four different pathways is shown in Figure 6.

All four pathways have an increasing electricity demand from 2030 until 2050. The Diversification and the Localization pathway have a higher electricity demand than the Directed Vision and National Champions pathways. The heat demand for heat grids in the Diversification pathway is moderate and constant in Europe. The Directed Vision pathway has a strong rise in heat demand and the highest demand in comparison, whereas the National Champions has a decreasing and rather low heat demand. The heat demand for heat pumps in buildings is increasing in all four pathways. The Localization and the Diversification pathway have a substantially higher demand than the other two pathways. The electricity demand from the transport sector is similar in all four pathways in 2030 and increases until 2050. The demand in the Diversification and Localization increases moderately, whereas the demand in the Directed Vision increases substantially. The four pathways differ tremendously in terms of hydrogen demand in industry and transport sector. The National Champions pathways has a hydrogen demand close to zero and the Directed Vision pathway has a comparatively low hydrogen demand. The Diversification and Localization pathway have a much higher hydrogen demand. Differences between the pathways are particularly pronounced in the scenario year 2050 for all demand categories.

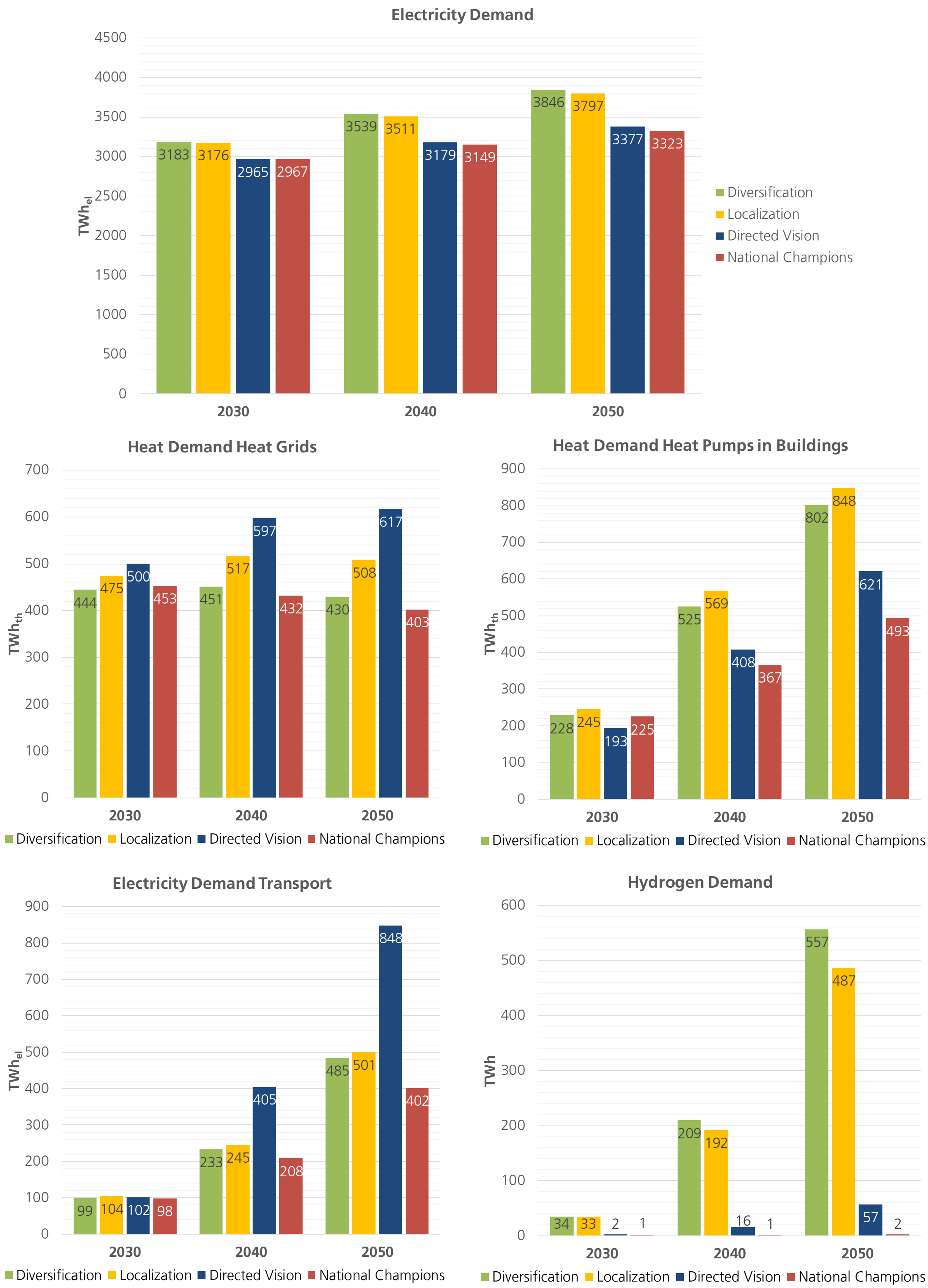


Figure 6: Development of the European electricity, heat and hydrogen demand in the four different pathways

2.3.3 Representation of renewable energy technologies

For the pathway analysis, the generation of renewables in the period up to 2030 is calculated with the *Green-X* model first and then given as input for the Enertile optimisation (cf. section 2.2.1). The rationale of linking Green-X and Enertile, and of putting for the 2030 perspective Green-X upfront is the different modelling approach regarding deployment of renewables. Green-X simulates deployment of renewables based on policy interventions like dedicated RES targets or corresponding support schemes dedicated to renewables. This appears more adequate for the analysis of short to medium term developments concerning RES deployment than the optimisation procedure in Enertile. Thus, within the pathway analysis *Green-X* is used to calculate the capacity and generation of renewables in the period up to 2030, considering the recently agreed overall 2030 EU RES target. The resulting renewable electricity generation values from the year 2030 are then used as minimum conditions to a second optimisation with Enertile. In 2030 the renewable generation in the *Enertile* optimisation has to be equal to the *Green -X* values.

In the follow-up period, i.e. the years 2040 and 2050, renewable expansion is purely optimised in Enertile since here, from a policy perspective, decarbonisation serves as the guiding principle and no longer a dedicated sectoral policy intervention.[2]

2.3.3.1 Green-X modelling of future RES deployment up to 2030: a least-cost allocation acknowledging the conception of pathways

Within the pathway analysis the Green-X model is used to deliver an outlook of future RES deployment across EU Member States in the period up to 2030, with particular focus on the electricity sector. In this context, Green-X modelling incorporates the following aspects:

- It derives a least-cost allocation of RES deployment across all sectors, technologies and countries in accordance with the given 2030 EU RES target
- It incorporates differences in financing conditions for (renewable) energy technologies in modelling and applies a distinction on that across assessed pathways
- In certain pathways it assumes and exemplifies the impact of a prioritisation of decentral supply solutions, shown for the case of decentral PV.

Below we describe the assumptions taken in this respect in further detail.

Deriving the optimal renewable electricity share (in accordance with the overall 2030 EU RES target):

As a general concept for all SET-Nav pathways, a least-cost approach is followed to allocate RES deployment across EU Member States in the period up to 2030. Once the Council agreement was taken in June 2018, we modified our assumption on the overall EU RES target for 2030, now set to 32% as RES share in gross final energy demand at EU level. Then, a least-cost approach as described in Box 1 was taken to derive the allocation of future RES deployment across sectors, countries and technologies.

[2] A constraint was however implemented in modelling: renewable generation in 2040 and 2050 may only be higher but not lower than in 2030.

Box 1: A least-cost approach to allocate investments in RES technologies post 2020

The selection of RES technologies in the period post 2020 in all assessed pathways follows a least-cost approach, meaning that all additionally required future RES technology options are ranked in a merit-order, and it is left to the economic viability which options are chosen for meeting the presumed 2030 RES target. In other words, a least-cost approach is used to determine investments in RES technologies post 2020 across the EU. This allows for a full reflection of competition across technologies and countries (incorporating well also differences in financing conditions etc.) from a European perspective. Support levels and related expenditures follow then the marginal pricing concept where the marginal technology option determines the support level (like in the ETS or in a quota/certificate trading regime, or similar to the concept of liberalised electricity markets).

Incorporating the impact of investor's risk – the (possible) impact of cooperation:

Green-X is capable of incorporating the impact of risks to investors on RES deployment and corresponding (capital / support) expenditures. In contrast to any detailed bottom-up analysis of illustrative financing cases as conducted e.g. in the RE-Shaping study (see Rathmann et al. (2011)), Green-X modelling aims to provide an aggregated view at the national and European level with fewer details on individual direct financing instruments. More precisely, the debt and equity conditions resulting from specific financing instruments are incorporated by applying different weighted average cost of capital (WACC) levels.

Determining the necessary rate of return is based on the weighted average cost of capital (WACC) methodology. WACC is often used as an estimate of the internal discount rate of a project or the overall rate of return desired by all investors (equity and debt providers). This means that the WACC formula[3] determines the required rate of return on a company's total asset base and is determined by the Capital Asset Pricing Model (CAPM) and the return on debt.

Within the model-based analysis, a range of settings is applied to accurately reflect the risks to investors. Risk refers to three different issues:

A "**policy risk**" is related to the uncertainty about future earnings caused by the support scheme itself – e.g. refers to the uncertain development of certificate prices within a RES trading system and / or uncertainty related to earnings from selling electricity on the spot market

A "**technology risk**" refers to uncertainty about future energy production due to unexpected production breaks, technical problems, etc... Such problems may cause (unexpected) additional operational and maintenance costs or require substantial reinvestments which (after a phase-out of operational guarantees) typically have to be borne by the investors themselves. In the case of biomass, this also includes risks associated with the future development of feedstock prices.

The third risk component is named as "**country risk**": At present differences across Member States with respect to financing conditions are commonly acknowledged, see e.g. Boje et al. (2016). This leads to a higher risk profiling of investments in countries more strongly affected by the financial and economic crisis compared to more stable economies within Europe. In modelling we assume that an alignment of these conditions might take place, depending on the chosen policy framework:

- Thus, for the two pathways where cooperation represents a common attitude – i.e. the pathways "Diversification" and "Directed Vision", this might be driven by a further "*Europeanisation*" of RES policy making. Examples for that include a market opening of

[3] The WACC represents the necessary rate a prospective investor requires for investment in a new plant.

national policy schemes, enhanced RES cooperation between Member States or at the ultimate extent via harmonisation. This approach would trigger a convergence of country-specific financing conditions in the period beyond 2020.

- For the other two pathways (i.e. “Localization” and “National Champions”) where entrenchment acts as guiding principle, differences in country-specific financing conditions remain for the years up to 2030.

The assumptions taken concerning country-specific risks are shown in Figure 7, distinguishing between the default risk profiling for the year 2020 and the alternative profiling where a smoothening / alignment of risk factors will take place driven by “Europeanisation”. Default risk profiling used in our modelling builds on statistical data concerning current (2016) financing conditions as specified in Table 3. Here we specifically take into account indicators on long-term governmental bonds and national credit rating. Please note further that country risk settings are assumed to change over time, aligned to general GDP/capita trends taken from PRIMES modelling.

Please note that all risk components are considered as default in the assessment, leading to a different – typically higher – WACC than the default level of 6.5%.

Table 3: Country-risk profiling: Statistics on financing conditions used for deriving default and alternative risk profiling

Country risk profiling		EU28	Austria	Belgium	Bulgaria	Croatia	Cyprus	Czech Republic	Denmark	Estonia	Finland	France	Germany	Greece	Hungary	Ireland
Statistics on financing parameter (2016 data)	*weighting factor*															
Eurostat - long term government bond yields	*10%*	**1.17**	**0.36**	**0.47**	**2.42**	**3.64**	**3.87**	**0.41**	**0.33**	**0.00**	**0.37**	**0.43**	**0.07**	**8.64**	**3.12**	**0.74**
RES deployment times risk ranking		1978.5	19.2	9.1	46.9	30.1	8.7	11.2	12.7	0.0	26.2	111.9	18.2	279.6	64.6	14.2
National Credit Rating	*90%*	**0.84**	**0.89**	**0.89**	**0.56**	**0.56**	**0.56**	**0.89**	**1.00**	**0.89**	**0.89**	**0.89**	**1.00**	**0.44**	**0.67**	**0.78**
RES deployment times risk ranking		1418.8	47.0	17.1	10.7	4.6	1.2	24.2	37.9	9.2	62.7	232.3	255.6	14.4	13.8	14.9
Ease of getting credit	*0%*	0.62	0.60	0.45	0.70	0.55	0.60	0.70	0.70	0.70	0.65	0.50	0.70	0.50	0.75	0.70
RES deployment times risk ranking		1054.9	31.7	8.7	13.5	4.5	1.3	19.1	26.5	7.2	45.9	130.8	178.9	16.2	15.5	13.5
Average risk rating																
Default risk rating (moderate smoothening)		**100%**	**94%**	**95%**	**128%**	**134%**	**135%**	**94%**	**89%**	**93%**	**94%**	**94%**	**88%**	**172%**	**120%**	**102%**
Risk smoothening due to Europeanisation		**100%**	**97%**	**98%**	**111%**	**113%**	**113%**	**98%**	**96%**	**97%**	**98%**	**98%**	**96%**	**127%**	**108%**	**101%**

Country risk profiling		Italy	Latvia	Lithuania	Luxembourg	Malta	Netherlands	Poland	Portugal	Romania	Slovakia	Slovenia	Spain	Sweden	United Kingdom
Statistics on financing parameter (2016 data)	*weighting factor*														
Eurostat - long term government bond yields	*10%*	**1.40**	**0.53**	**1.09**	**0.26**	**0.93**	**0.28**	**2.94**	**3.05**	**3.30**	**0.49**	**1.26**	**1.42**	**0.58**	**1.20**
RES deployment times risk ranking		160.9	7.2	15.8	0.6	0.5	14.6	293.0	120.2	196.9	5.8	10.4	210.6	52.1	237.5
National Credit Rating	*90%*	**0.67**	**0.78**	**0.78**	**1.00**	**0.78**	**1.00**	**0.78**	**0.56**	**0.67**	**0.78**	**0.78**	**0.67**	**1.00**	**0.89**
RES deployment times risk ranking		76.7	10.5	11.2	2.3	0.4	52.1	77.4	21.8	39.8	9.3	6.4	98.8	90.3	176.2
Ease of getting credit	*0%*	0.45	0.85	0.70	0.15	0.70	0.50	0.75	0.45	0.85	0.65	0.35	0.60	0.55	0.75
RES deployment times risk ranking		51.9	11.5	10.1	0.4	0.4	26.0	74.7	17.7	50.8	7.8	2.9	89.0	49.6	148.8
Average risk rating															
Default risk rating (moderate smoothening)		**113%**	**101%**	**103%**	**89%**	**103%**	**89%**	**111%**	**131%**	**121%**	**101%**	**104%**	**113%**	**90%**	**98%**
Risk smoothening due to Europeanisation		**105%**	**100%**	**101%**	**96%**	**101%**	**96%**	**104%**	**112%**	**108%**	**100%**	**101%**	**105%**	**96%**	**99%**

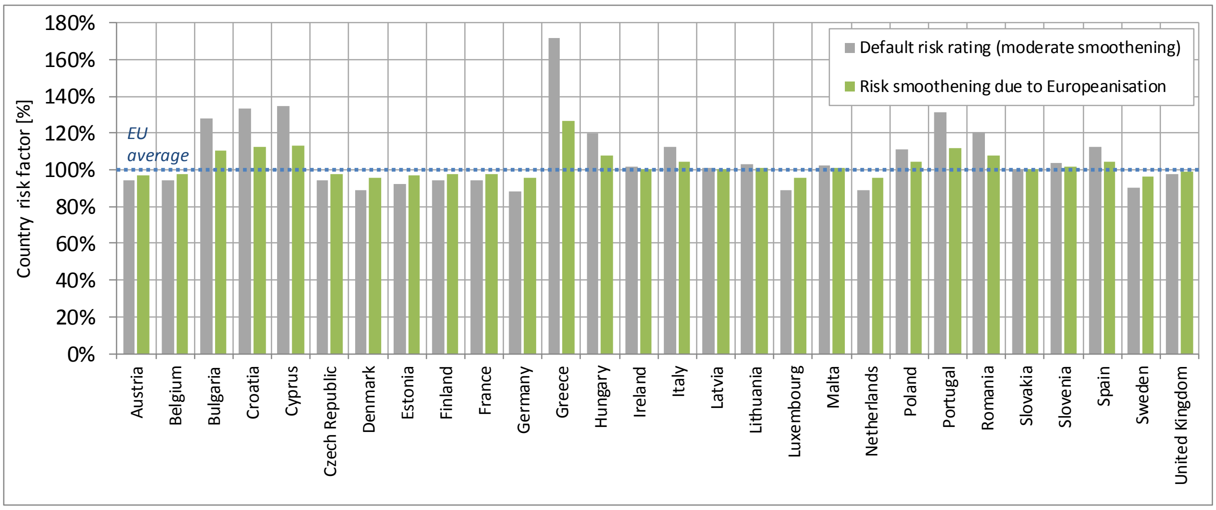


Figure 7: Country risk profiling used for the period post 2020 (specifically for the year 2021) (Green-X modelling)

Prioritisation of decentral (PV) supply in selected pathways:

One guiding question within the conception of SET-Nav pathways has been how decentral or central our (energy) future may look like – i.e. if a centralised approach is taken, or if preferences exist to prioritise decentral solutions. In the supply-related modelling we take this question up and incorporate it in the pathway conception. More precisely, two distinct scenario settings come into play:

- **No higher market value for decentral PV (at the retail level):** This scenario serves to illustrate the impacts that arise if no prioritisation of decentral PV generation will be undertaken in future years (and in modelling). Thus, within the pathways "Directed Vision" and "National Champions", we treat decentral PV systems similarly to other forms of central electricity supply as a supply option to compete in the wholesale electricity market. In other words, we do not acknowledge the higher value of decentral generation that is applicable at household level for prosumers when used for self-consumption.
- **Higher market value of decentral PV (at the retail level)***:* In contrast to above, within the pathways "Diversification" and "Localization", we take the assumption that a prioritisation of decentral PV is maintained in future years. In other words, we acknowledge the higher value of decentral electricity supply when used for self-consumption (as represented by the energy-related part of retail electricity tariffs). With regard to the future development of retail electricity tariffs, we take the assumption that a convergence and alignment of tariff structures will take place across the EU. As part of that process we assume that capacity-related fees increase by 50% compared to default, and that, in turn, the energy-related part is reduced accordingly.

2.3.3.2 Enertile optimization of renewable energy technologies: techno-economic assumptions about endogenously developed renewable technologies

In this section, the assumptions on RES technologies are presented, which are endogenously expanded in the Enertile optimization model. This concerns technologies that offer high potential on the one hand and low costs on the other: wind and solar energy. The existing installations are fed into the model. The model makes expansion decisions autonomously on the basis of the technological and economic assumptions and any expansion targets created in the scenarios.

The calculation of the potentials for renewable energies takes place in five steps:

1. determination of the usable area
2. determination of the installable capacity
3. calculation of the possible output
4. calculation of specific generation costs
5. aggregation of potentials within a region

The method for determining the usable area is methodically identical for all technologies. Therefore, this step is described in this superordinate section. The remaining steps differ in the respective technologies and are described in the corresponding subsections.

Determination of the usable area

The starting point for modelling the potentials of renewable energies is a model grid that is applied to the entire modelled region. This model grid has an edge length of 10 km at the height of the equator. Due to the shape of the earth, this edge length decreases with increasing distance from the equator. In Germany the edge length is about 7 km. On the basis of this grid different geographical information and meteorological data are combined.

In a first step, those areas within the tiles that are unsuitable for the use of the respective technology are removed. These include, for example, well-known nature reserves and areas with very steep slopes. The remaining area is assigned to a specific land use category based on available land use data. For each of these land use types, shares of the area are released for the use of renewable electricity generation. In case of PV and CSP the required area is actually covered by the plant, in case of wind energy utilized area is defined as area that is influenced in terms of wind speed by the rotor of the plant. An overview of land use types and land shares that can be used for renewable energies can be found in Table 4.

Table 4: Overview of land use factors for renewable energies

Type of land use	Utility scale PV	CSP	Wind Onshore
Fallow land	20%	15%	25%
Cultivation areas	2%	2%	20%
Forest	0%	0%	10%
Grassland	3%	2%	25%
Savannah	3%	15%	25%
Bush land	3%	15%	25%
Ice rinks	5%	0%	15%
Constructed area	0%	0%	0%
Water surface	0%	0%	0%
Wetlands	0%	0%	0%

In the case of rooftop PV, it is assumed that 20% of the built-up area are suitable for use. This assessment was made for Germany with a detailed projection of suitable roof areas using map evaluations and satellite data for the state of North Rhine-Westphalia as an example. In the case of offshore wind energy, the use of 50% of the available sea surface with water depths of less than 50 m is assumed. In total, the available area on a "tile" for a given power generation technology is calculated according to the following formula:

$$Available\ area = \sum_{land\ use} tile\ size \cdot share_{land\ use} \cdot land\ use\ factor_{land\ use}$$

2.3.3.2.1 Photovoltaics

Within the project, two types of photovoltaic systems are built in the model. Rooftop PV and utility scale PV are differentiated. The potential of these types is calculated as follows. After the available area has been calculated, the potential of the installable power is calculated. In the case of utility scale PV, an installable capacity of 40 MW per km² is assumed. Based on the available and the specific area requirement, the installable capacity can be calculated per "tile":

$$Potential\ in\ MW = available\ area\ \cdot specific\ area\ requirement$$

In the next step, the possible power generation of the technology within the tile is determined. For this, the solar radiation data from HELIOCLIM-320[4] are assigned to the corresponding "tiles" in hourly resolution and a regional resolution of 50 x 50 km. With the help of an individual output model, the possible power generation of an optimally aligned plant is then determined for the utility scale PV.

The impressive cost reductions that have been achieved for photovoltaics in recent years make it difficult to estimate the future course of costs. The starting point for the calculations is the interim report of the "Solar Radiation Energy" project of the EEG Experience Report (Kelm et al. 2014). From this, the costs and the distribution of the costs among the components - differentiated according to system types and size classes - were used. From these, two system types, a rooftop PV system and a utility scale PV system, were parameterised using the following methodology.

For the determination of the specific investments and operating costs, an average system size of 30 kW is assumed for rooftop PV systems. This means that an average value of small PV systems (output approx. 5 kW peak) on private roofs and large PV systems on commercial and public buildings (output up to approx. 300 kW peak) is selected, which is based on the data of the existing plant register. These rooftop PV systems cost approx. 1,300 EUR/kW at the end of 2013, which is chosen as the starting point for the learning curve. As an average size of the utility scale PV plants an output of 5 MW was chosen. These PV systems cost approx. 1,000 EUR/kW at the end of 2013. Analogous to conventional power plants, this is a so-called "overnight cost" for the entire project, i.e. plant costs plus ancillary project costs.

The cost reductions of the PV systems are specified exogenously. Here different learning rates are assumed for the individual components, which are shown in Table 5.

Table 5: Annual cost reduction of photovoltaic systems by components

Time period	PV modules	Inverter, substructure, cables, connection and others
2014-2020	7.0% p.a.	0.5% p.a.
2021-2030	6.0% p.a.	0.5% p.a.
2031-2040	4.0% p.a.	0.5% p.a.
2041-2050	2.0% p.a.	0.5% p.a.

4 MINES ParisTech / Transvalor HelioClim-3 Archives (2019) http://www.soda-pro.com/soda-products/hc3-archives

Fixed operating costs until 2020 are estimated as 1.5 % of the investment sum per year. This value gradually rises to 2% in 2050.

For the two example installations, the resulting cost values are given in Table 14. The specific investments reduce by 2050 compared to 2014. For rooftop PV systems by 40 %, for utility scale PV systems by even 48 % due to the higher share of faster falling module costs in total costs. It should be noted that the optimization model calculates economic efficiency on the basis of the mean values between the modelled years.

Table 6: Investment and operating costs of the PV systems

Year	Utility scale PV system (5 MW)		Rooftop PV system (30 kW)	
	Specific investment €/kW	Fixed operating costs €/(kW a)	Specific investment €/kW	Fixed operating costs €/(kW a)
2014-2020	875	15	1,173	19
2021-2030	715	14	1,004	18
2031-2040	601	13	879	17
2041-2050	541	11	806	16

At the end of this process, central information can be stored at the level of each individual tile on the basis of cost data and geographical data. Each tile contains information on the available potential in MW, a possible pre-allocation by existing plants, the full load hours of the individual technology, the specific generation costs and an hourly production profile for the selected weather year.

2.3.3.2.2 Concentrating solar thermal power (CSP)

Concentrating solar thermal energy is not available in German latitudes as it is not economically attractive due to the relatively low solar radiation. In southern latitudes, this technology is an option due to its flexibility, despite its higher electricity production costs compared to PV. The optimal size of the storage is calculated at the respective location and is in the scale of daily storage tanks (approx. eight full load hours). The design of the relationship between field and generator is site-specific. This can lead to a certain variance in costs. Therefore, the specific investments in Table 7 are to be understood as orientation values.

Table 7: Cost assumptions CSP

Year	Lifetime	Specific investment €/kW	Maintenance and operation cost €/(kW a)
2014-2020	30	4,500	73.5
2021-2030	30	3,300	64.0
2031-2040	30	3,050	54.5
2041-2050	30	2,660	45.0

2.3.3.2.3 Wind onshore

The calculation of the usable area on a single tile for wind energy is carried out according to the procedure already described. However, there are two central characteristics for wind energy. The area required in terms of wind "shading" depends on the rotor area. The optimal rotor area, however, depends on the conditions of the location. For this reason, the available potential and power generation costs are calculated on a more detailed level. Power generation and the costs of wind energy depend on the following key factors:

- **The hub height of the turbine** determines how much the turbine can benefit from the increasing wind speeds at higher altitudes. However, higher towers also lead to rising costs.
- **The ratio of generator power to rotor area** determines the turbine's design for energy output at times of low or high wind speeds. The lower the specific generator power per rotor area, the higher the relative outputs in times of weak wind. In return, the output decreases during periods of high wind speeds, as the generator then already generates its nominal capacity. The rotor size and generator power are central factors for the costs of a wind turbine.
- **The efficiency of a turbine** is shown in the turbine characteristic curve when it is adjusted for the effects of the rotor size.

Hub height and the specific generator power per rotor surface are two central factors Indicators that are in constant technological development. In the past, there has been an overall trend towards ever higher turbines and a reduction in generator output per rotor surface for increased energy generation in times of low wind speeds (so-called weak wind turbines). The challenge is to map the future development of these factors up to the year 2050 and at the same time to project the associated costs.

The potential calculation in the Enertile model is used in such a way that the model can select the optimum system configuration within certain limits. The choice of the limits not only reflects the limits of the available technology, but is also intended to ensure the validity of the selected cost calculation. In individual cases, other parameters may be technically feasible in reality, but the costs are likely to be significantly higher in most cases.

For the **hub height**, the model selects the plant configuration with the lowest specific generation costs within the approved corridor for each tile in steps of ten metres. The selection of the parameters is based on the assumptions of a study on the cost-optimal expansion of renewable energies (Agora 2013). The maximum permitted height rises over time to 160 m (cf. Table 8).

Table 8: Optimization range of the hub height in the generation model

Time period	Range of hub height in m
2014-2020	90-140
2021-2030	90-150
2031-2040	90-160
2041-2050	90-160

In terms of **efficiency**, a distinction is made between strong wind locations (IEC Class 1) and weak wind locations (IEC Class 2-4), since strong wind turbines have a different characteristic of the performance curve and different requirements to the plant design are imposed. For the calculations of the wind energy outputs, the Enercon E82/3000 turbine characteristic curve for strong wind locations and the Enercon E82/2000 characteristic curve for the remaining locations was taken as a basis. The plant characteristic curve is included in the calculation in the form of the relative output in relation to the plant output.

In the range of the specific generator power per rotor area, in the past there has been a tendency towards ever lower specific capacities. The rotor thus becomes larger in relation to the generator. As part of the potential calculations, a location optimization in steps of 10 W/m² is mapped in the model. A permitted range is specified for each period. This range is widened in the course of time according to the currently anticipated development trends (cf. Table 9).

Table 9: Optimization range of generator power per rotor area

Time period	Weak wind turbines W/m²	Strong wind turbines W/m²
2014-2020	350-320	450-390
2021-2030	350-270	450-370
2031-2040	350-260	450-360
2041-2050	350-250	450-350

The calculation of the plant output at a specific site is performed according to the following calculation scheme for each hour or class of Weibull distribution at the site under consideration:

1. calculation of the wind speed at hub height
2. output of the wind turbine

$$P1 = \frac{A_{ref}}{A_1} \cdot P_{ref}(wind\ speed)$$

P_1 Capacity in relation to the installed system capacity (max. 100 %)
P_{ref} Capacity of the reference plant in relation to the installed plant capacity (max. 100 %)
A_{ref} Specific generator power per rotor area of the reference turbine
A_1 Selected specific generator power per rotor surface of the optimized turbine

A central step in the calculation process is the determination of costs of the respective system parameters. The calculation of these costs is based on the Agora study and has been extended. The study estimates the cost components of the wind turbines as follows: The tower of a wind turbine is responsible for 26% of the costs of a wind turbine. The costs for the tower are driven to 80% by the hub height. Further 10% of which are the rotor diameter and the nominal capacity. The proportion of the rotor blades to the total costs is 22% in this calculation. Sole cost driver is the rotor diameter. The remaining cost components (e.g. generator, power electronics etc.) achieve a cost share of of 52% and are determined by the nominal capacity.

Table 10: Cost components for wind turbines (source IRENA 2012)

Component	Share of costs in %	share of cost driver in costs in %		
		Nominal capacity	Rotor diameter	Hub height
Tower	26%	10%	10%	80%
Rotor blades	22%	0%	100%	0%
Other	52%	100%	0%	0%

However, an increase in the cost drivers, such as an increase in the hub height, has different effects on the costs of the individual components. The IRENA study estimates the cost drivers as shown in Table 11 (IRENA 2012).

Table 11: Cost drivers wind turbines

Driver	Cost driver factor
Capacity	1
Rotor diameter	2
Hub height	2

In concrete terms, these numbers can be translated as follows using the example of the increase in hub height: A 10% increase in hub height must be multiplied by the cost driver factor 2 and the

80% share of the cost driver. In this example, increasing the hub height increases the cost of the wind turbine tower by 16%. The other costs of the wind turbine remain unchanged, as the hub height only drives the tower costs.

In addition to the turbines, a wind energy project consists of further ancillary project costs, which exceed the costs of the actual plants. The ancillary project costs are stored as an additional component that is transferred linearly to the cost calculation. The initial values for the reference installation are derived from derived from a report on wind energy (IE Leipzig 2014). In order to perform the calculation, a corresponding cost driver (rotor, hub height, capacity) and a cost driver factor must be assigned to these project ancillary costs. This assignment is not always clear in reality. Here the best driver from the three categories is chosen. In the selected example, doubling the specific capacity with the same number of plants leads to doubling the costs for grid connection, other costs and the internal cabling of the wind park. In the case of an increase in the plant capacity from 1 MW to 2 MW, the costs of grid connection would thus rise from EUR 79,000 to EUR 158,000.

Table 12: Cost drivers project costs wind energy

Category	Driver	Cost driver factor	Costs reference plant €/kW
Exploitation	Rotor diameter	1	63
Grid connection	Capacity	1	79
Compensation	Rotor diameter	1	33
Planning & approval	Rotor diameter	1	44
Foundation	Hub height	1	58
Other	Capacity	1	24
Internal cabling of wind park	Capacity	1	24

The following formula is used to calculate the cost of a wind turbine:

$$Costs = \sum_{Components} \left(\sum_{Drivers} \left(\frac{p}{p_{ref}} - 1 \right) \cdot kf \cdot cc \cdot scc \right)$$

p Parameters (e.g. rotor diameter)

p_{ref} Parameter of reference turbine (e.g. rotor diameter E82)

kf Cost driver factor

cc Component costs (e.g. tower costs of reference turbine)

scc Share of cost driver size in the component costs of the reference plant

Cost assumptions

The reference plant has a hub height of 114 m and the plant output is approx. 2,500 kW with a rotor diameter of 90 m. The specific investments amount to 1,200 EUR/kW. Due to the dynamic development of the various plant parameters an estimation of the learning curve of the individual components is difficult. In the projection to 2050, a certain technological learning will take place through the release of higher hub heights and larger rotors at today's cost rates. In addition, an annual learning rate of 0.5% on the basic components of the wind turbine is assumed. This results in the following corridors for the specific total investment of wind energy; the upper limit jumps in each case in the years in which turbine types (hub heights, rotor-generator ratio) are newly approved in the model.

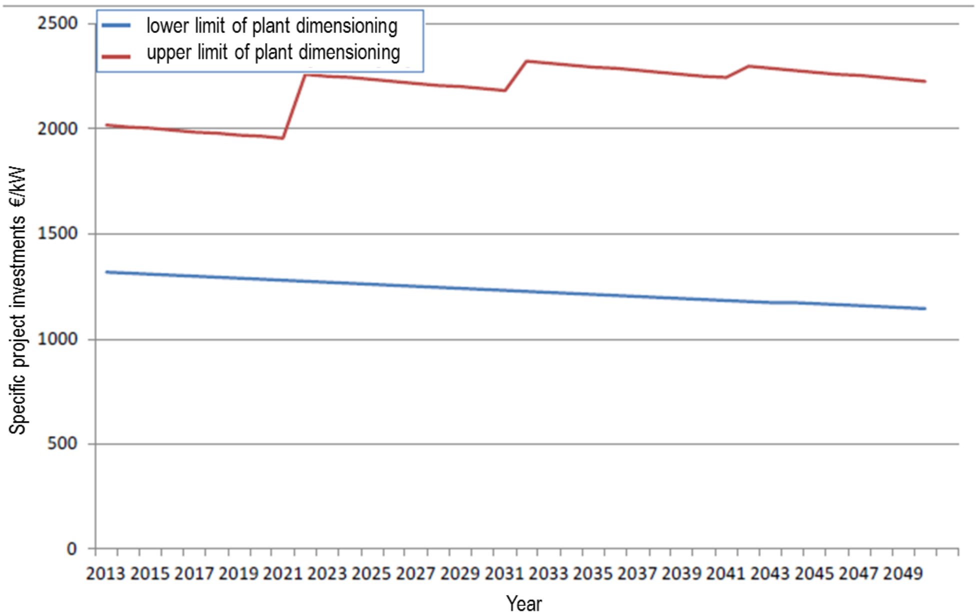


Figure 8: Costs range of onshore wind energy

The costs for maintenance and operation are assumed to be 60 EUR/kW in the start year 2013. A reduction of 0.5 % per year is assumed.

On the basis of this coupling of cost drivers and plant dimensioning, hub height and specific generator output can be optimised in the model. Figure 9 shows the results of the hub height optimization for the years 2020 and 2050. These results are identical for all scenarios without variation of the technical assumptions of wind energy. The illustration shows that the model selects the maximum turbine height in large parts of the inland and only determines lower tower heights as the optimum solution at good locations and near the coast.

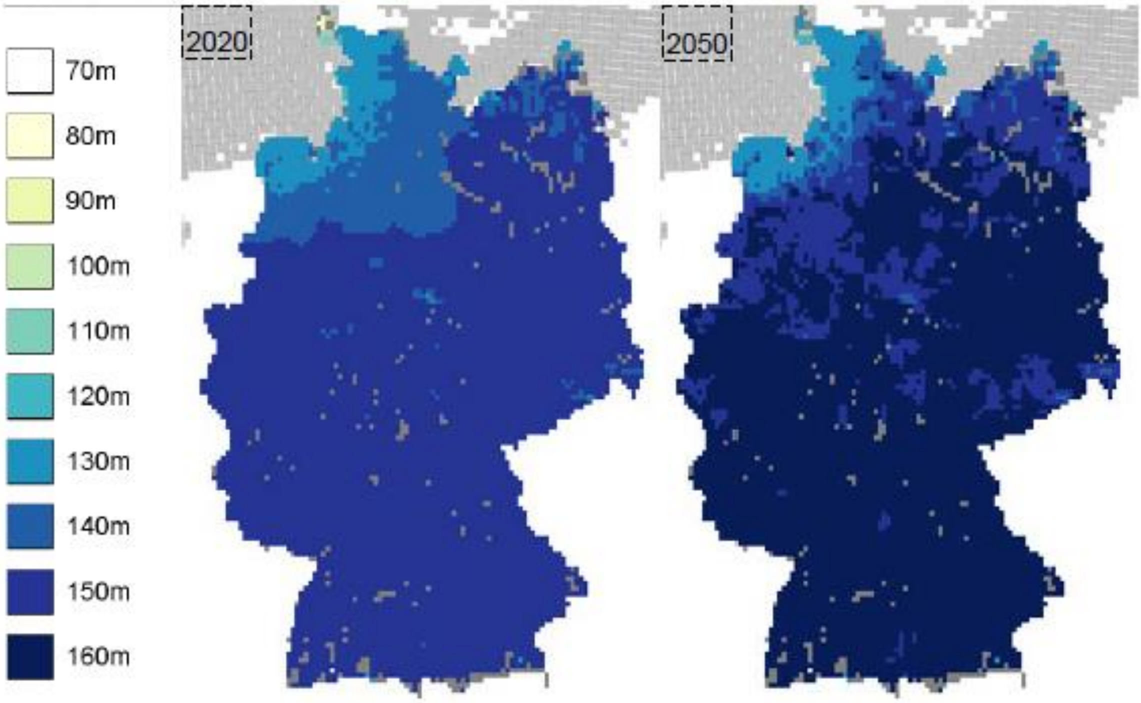


Figure 9: Results hub height optimization (exemplary for Germany)

The results of the optimization of the specific generator capacity for the year 2050 are shown in Figure 10 for Germany. This shows a distribution based on wind conditions. At weak locations, the minimum specific generator power of 250 W/m² is selected. With increasing site quality, the specific generator power is higher.

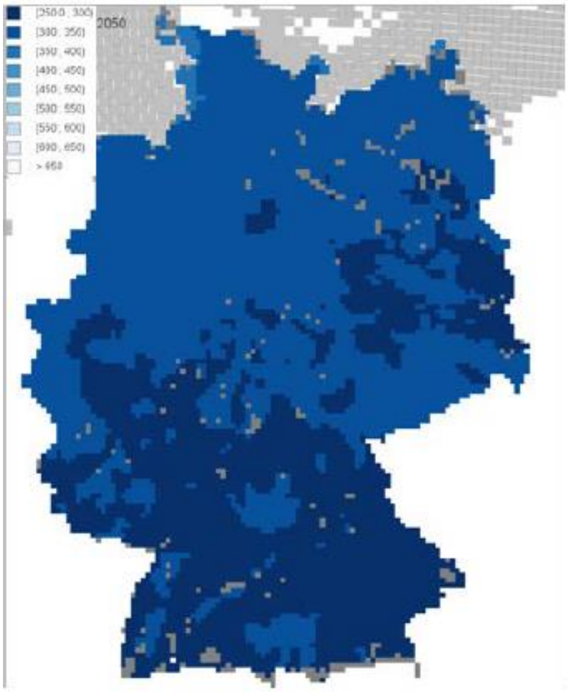


Figure 10: Results of the optimization of the specific generator power in 2050 in W/m² (exemplary for Germany)

After completion of the system optimization, the specific area requirement per MW can be calculated. The specific area requirement of a plant is calculated according to the formula that corresponds to a reasonable distance control within a wind farm. Here, a distance of 5 rotor diameters between the turbines and 9 rotor diameters in the main wind direction is often recommended to reduce the park effect. Since surfaces do not always follow an optimal geometry in reality, a correction factor of 90 % has been added.

$$Specific\ area\ requirement = \frac{5 \cdot rotor\ diameter\ per\ MW\ \cdot 9\ \cdot rotordiameter\ per\ MW}{90\%}$$

The potential for each individual tile can then be determined on the basis of the specific area required and the available capacity.

$$Potential\ in\ MW = \frac{available\ area}{specific\ area\ requirement}$$

The annual electricity generation of a plant on a tile is calculated by assigning a grid point of the weather data set COSMO-EU[5] to each tile. This weather data set has a spatial resolution of 7.5 x 7.5 km. The long-term generation output potential is calculated by the Weibull distribution of wind energy for a site using the weather data 2007-2012. The generation output is calculated for the plant dimensioning according to the classical methods of output calculation including correction of the air pressure.

5 Deutscher Wetterdienst (2016) Regionalmodell COSMO-EU

https://www.dwd.de/DE/forschung/wettervorhersage/num_modellierung/01_num_vorhersagemodelle/regionalmodell_cosmo_eu.html

The hourly load profile is also calculated on the basis of the selected weather year for the selected system design. In order to take the long-term site quality into account, however, this profile is corrected once again in order to achieve the long-term average output. In this correction, great importance is given to ensuring that the characteristics of extreme weather conditions with very strong or very weak feed-in are not influenced.

At the end of this complex and very computationally intensive process, each tile contains information on the available potential in MW, a possible pre-allocation by existing plants, the full load hours of each technology, the specific production costs and the hourly production profile for the selected weather year.

2.3.3.2.4 Wind offshore

The methods used to calculate electricity generation from offshore wind energy are based on the calculation of onshore wind energy. Due to the significantly more homogeneous wind situation in the offshore area and the lower influence of the detailed turbine design on the overall costs, a complex, site-dependent turbine design is not required for offshore wind energy. The following parameters are decisive for the cost calculation:

- Assumed reference plant: Repower 6.2M152
- Hub height: 110 m
- Maximum water depth: 50 m
- Maximum coastal distance: 200 km

Plant costs of 1,500 EUR/kW are assumed for 2013. The other costs e.g. for grid connection and permits range between 1,300 and 3,000 EUR/kW. The total costs for the most expensive locations are thus in the range of 4,500 EUR/kW. The annual costs for maintenance and operation are 4% of the investment. For the plants, an annual learning rate of 0.5% p.a. is assumed, analogous to the development of wind onshore. For the often significantly higher other project costs, a higher learning rate of 2% p.a. is initially assumed, which then drops to 1.5% p.a. after 2030 and to 1% p.a. by 2050. Overall, this results in the following corridor for the specific project investment costs.

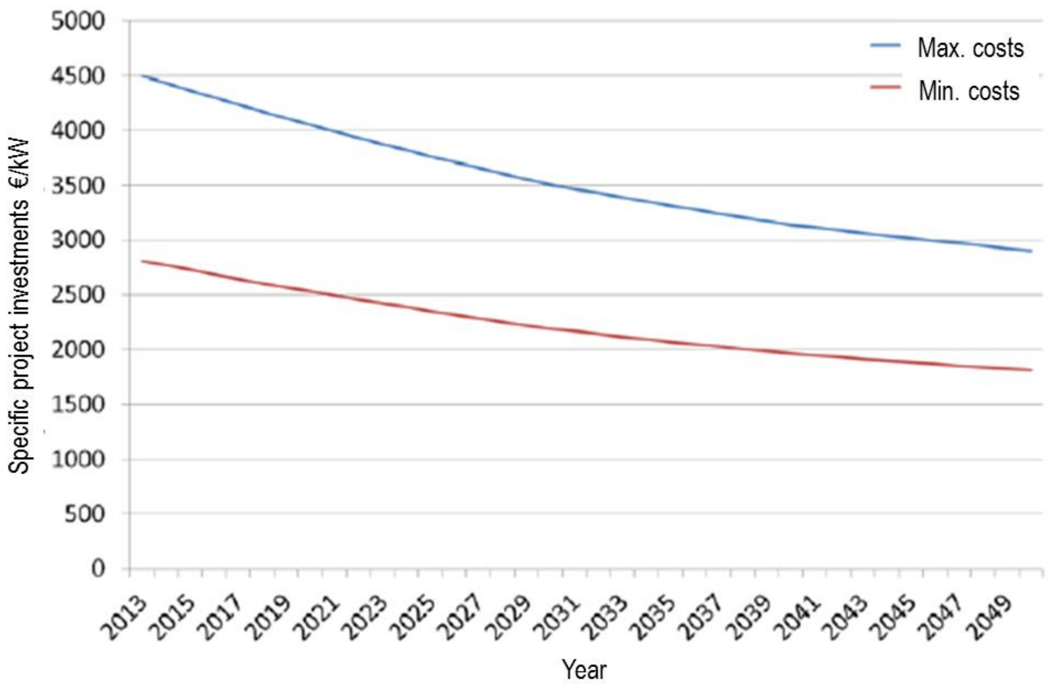


Figure 11: Costs range of offshore wind energy

The calculation of the available potentials and the complex handling of the weather data for wind offshore is identical to the calculations for wind onshore. At the end of this process, each tile contains information on the available potential in MW, a possible pre-allocation by existing plants, the full load hours of each technology, the specific generation costs and an hourly generation profile for the selected weather year.

2.3.3.2.5 Aggregation and disaggregation of RES potentials

The regional calculation of the potentials is based on the resolution of more than 9,000 tiles in Germany and more than 360,000 tiles in the entire modelled region. Europe accounts for about 228,000 tiles. For each individual tile, the following data are collected on the basis of the methodology already described for the blending of land use and weather data: potentials, power generation costs and full load hours for the individual technologies. Due to the high number of variables, not every single tile can be included in the optimization of the power supply. For this reason, within a region such as "DE", tiles with comparable production costs for a production technology are grouped together into a "potential step". This potential step contains the following information:

- Sum of the production potential of the individual tiles,
- average full load hours of the tiles,
- the average generation costs of the tiles, and
- the aggregated weather profile of each tile.

The resulting potential steps in a region are then extended within the framework of the supply system optimization. The results of the optimization are disaggregated again in a downstream step. As a result of the optimization, the expanded capacity of each potential level in every evaluated year is known. In the further analyses, this exploitation of potential is disaggregated on the individual tiles according to their share on total potential and therefore the installed capacity on each tile is determined. The installed capacity per tile, for example, represents an important input date for model network analyses to determine the expansion requirement in the distribution networks. At the same time it is possible to determine the feed-in time series of the different RES technologies based on the network nodes that can be used for load flow analyses in the transmission grid.

The aggregated cost potential curves for generation of renewable energies in Europe for the scenario years 2030, 2040 and 2050 are shown in Figure 42 in Appendix 5.1.

2.3.4 Role of CCS and nuclear

The techno-economic characteristic of other system components like generation plants and storage technologies are given in Appendix 5.2. The cost assumptions for all generation technologies are the same for all four pathways with the exception of CCS technologies. The availability and cost of CCS is a defining part of the storyline of the pathways. CCS plants are only available in the two pathways Directed Vision and National Champions. In the Directed Vision pathway, CCS is available at quickly decreasing costs, whereas in the National Champions pathway CCS is available but at relatively high costs (cf. Table 16 and Table 17). These assumptions are based on case study results and described in detail in the summary report of work package 6.

Another defining part of the storyline of the pathways is the role of nuclear. Our analysis in the case study regarding the role of nuclear shows that nuclear power generation is driven by political preferences rather than economic decision-making. Therefore nuclear generation capacity is not subject to the cost optimisation procedure in the pathways but is a defining part of the storyline and therefore included as an exogenous assumption. The installed capacity of nuclear power plants is exogenously fixed based on the case study results in this work package (cf. section 2.2.1). Figure

12 shows the total installed nuclear capacity in Europe for the four different pathways. In the Diversification pathway, the lifetime of nuclear plants is fixed to 40 years, which results in a fast nuclear phase out. The Localization pathway allows a lifetime extension of the nuclear power plants up to 60 years but replacements are not allowed. In the Directed Vision pathway, the European nuclear power park develops according to the PRIMES EUCO30 scenario. In the National Champions pathway, nuclear power plants are prolonged and replaced. In comparison, the Diversification has by far the lowest nuclear capacity and the Directed Vision has the highest installed capacity.

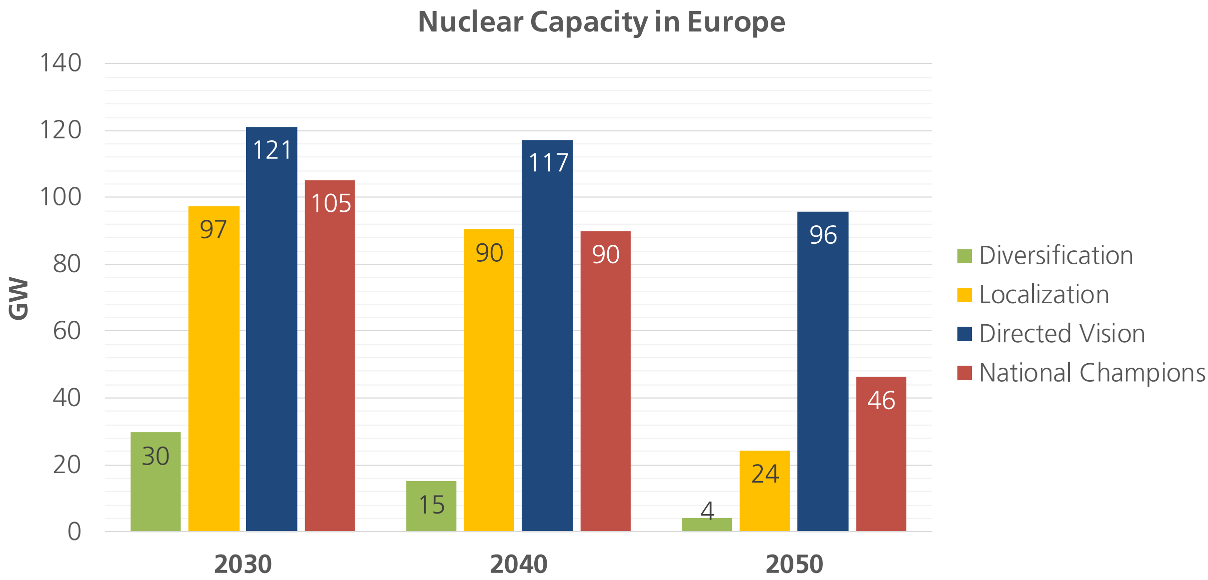


Figure 12: Development of installed nuclear capacity in Europe in the four different pathways

2.3.5 Expansion of the electricity grid

In all pathways we assume that the current Ten Year Network Development Plan of ENTSO-E in 2018 is implemented as a minimum status for the transmission grid in 2030 (ENTSO-E 2018). The expansion of cross border transmission capacities is subject to the optimisation procedure in Enertile. However, the limits set for the expansion of the transmission grid are defined by the storyline of the pathways. This parameter reflects public acceptance and willingness for European cooperation. The allowed expansion of these capacities differs in the four pathways. In the Diversification pathway, the expansion is not limited at all. In the Directed Vision, the values in 2030 are fixed and no increase in capacity is allowed, but in the years 2040 and 2050 there is no limit on capacity expansion. In the Localization pathway, the capacity of every single interconnection can increase by a maximum of 15% per decade. Similar restrictions apply to the National Champions pathway with a maximum increase by 30% per decade. Table 13 gives a short overview of the assumptions concerning the expansion of the electricity grid in the pathways. The cost of each interconnector is determined in the interaction between the Enertile and the TEPES model

Table 13: Assumptions on the electricity grid expansion in the pathway analysis

	Diversification	Localization	Directed Vision	National Champions
Min. grid	TYNDP 2018	TYNDP 2018	TYNDP 2018	TYNDP 2018
Max. grid	unlimited	2030: TYNDP 2018 2040: 2030 +15% 2050: 2040 +15%	2030: TYNDP 2018 2040: unlimited 2050: unlimited	2030: TYNDP 2018 2040: 2030 +30% 2050: 2040 +30%

3 Electricity, heat, and hydrogen supply

This chapter analyses results on energy supply for the decarbonisation pathways. The presentation is structured along the energy carries. We start with the analysis of electricity supply, which is followed by an analysis of heat supply and the supply and use of hydrogen. Additional sections deal with exemplary analysis of the dispatch situation for electricity and heat, market values and the resulting CO_2 prices.

3.1 Electricity supply

This section presents the results on electricity supply starting with a general overview on the European supply mix followed by an additional analysis of renewables and electricity trade

3.1.1 Overview supply mix

3.1.1.1 Generated electricity

The evolution of the supply mix of generated electricity, aggregated over all the 30 European countries, is shown in Figure 13. In the comparison of the four pathways, the differences in total electricity demand, the availability of CCS and the restrictions concerning nuclear power become apparent. Wind power is the most important energy source in all the pathways. The generated amount of electricity from wind in 2050 ranges from 3364 TWh in the Diversification and 3304 TWh in the Localization pathways to 2042 TWh in the Directed Vision and 1857 TWh in the National Champions pathways, which has the lowest electricity demand. The most important countries in terms of wind power generation are the UK, France, Germany, and Poland.Wind power is mainly used onshore, only in the Localization pathway the more expensive offshore wind power is extended in 2050 (mostly in Germany and the Netherlands), because areas with lower onshore wind generation costs are already largely used in these countries and the transmission grid restrictions do not allow for a higher electricity import.

After wind, solar power is the most important energy source. The generated amount in 2050 ranges from 1332 TWh in the Diversification and 1254 TWh in the Localization pathways to 695 TWh in the National Champions and 668 TWh in the Directed Vision pathways. The countries with the largest solar power generation are Spain, Italy, France, and Germany. Solar power mainly consists of photovoltaics (PV, both utility scale and roof top), but concentrated solar power (CSP) also plays a role in southern Europe especially in the Diversification and Localisation pathways due to the high demand for electricity generation.

In all pathways most of the electricity comes from renewable sources. As the capacities of biomass and hydro are fixed in the model, the share of volatile wind and solar power increases with time, especially in the pathways with high electricity demand and no or little nuclear (Diversification and Localization).The generation of nuclear power, of which the installed capacities are strongly determined by political decisions (cf. section 2.3.4), in 2050 ranges from 801 TWh in the Directed Vision pathway, over 372 TWh in the National Champions pathway, and 164 TWh the Localization pathway, to 29 TWh in the Diversification pathway.In the pathways without CCS (Diversification and Localization), coal disappears almost completely and gas plays a minor role due to high CO_2 prices, while CCS allows a higher (though still rather low) share of fossil fuels in the Directed Vision and National Champions pathways in 2050. The amount generated with fossil fuels (excluding nuclear) in 2050 ranges from 504 TWh in the Directed Vision and 429 TWh in the National Champions pathways to 148 TWh in the Localization and 122 TWh in the Diversification pathways. A large part of this generation occurs in Germany and Italy.

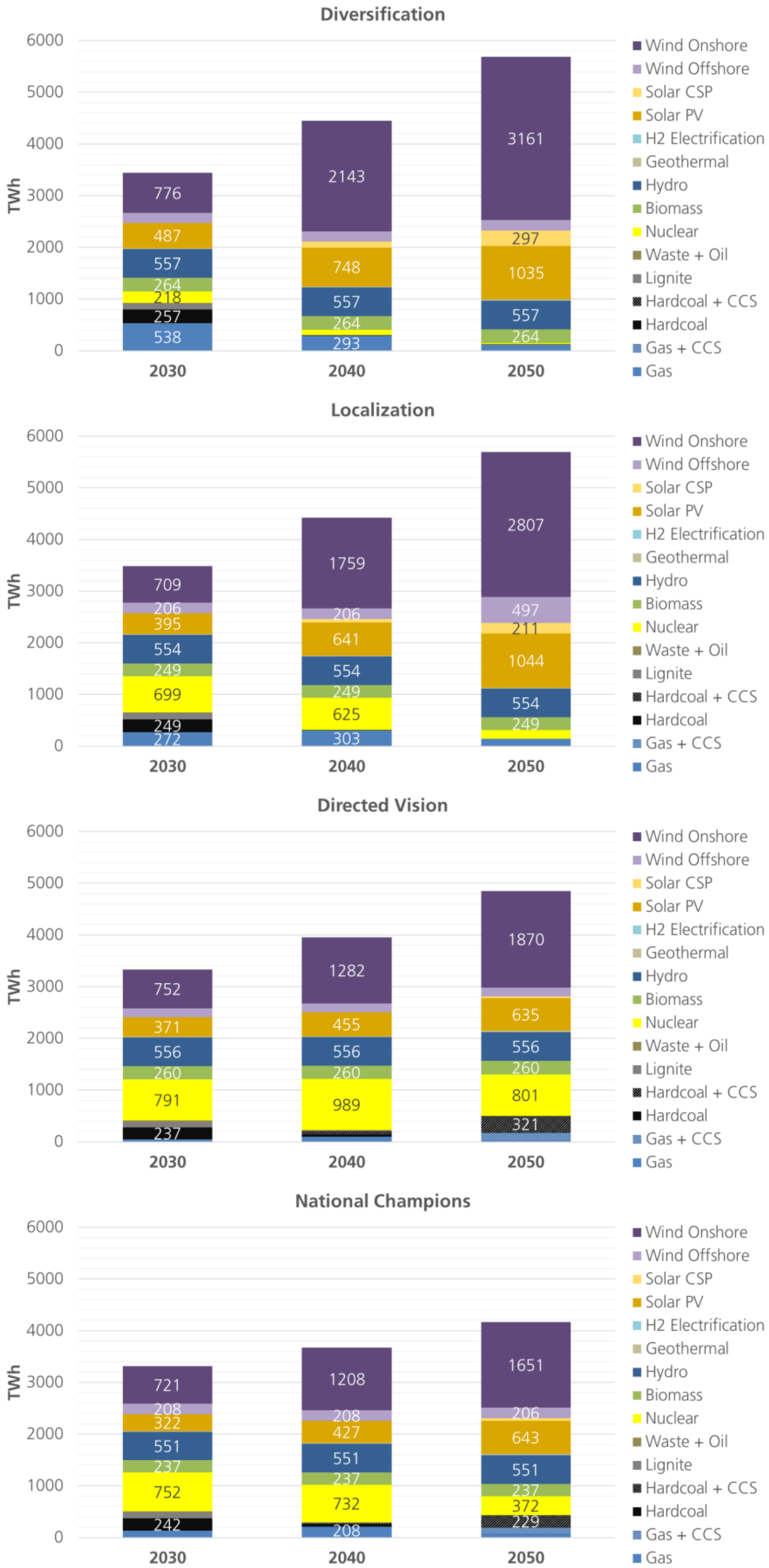


Figure 13: Evolution of the European electricity supply mix in the four pathways.

3.1.1.2 Installed capacity

In order to generate the amount of electricity discussed above, certain capacities have to be installed. Figure 14 shows the capacities installed in Europe in the years 2030, 2040, and 2050.

Total capacities increase from roughly 1200 GW in 2030 (in all the pathways) to about 2400 GW in 2050 in the Diversification and Localization pathways, about 1600 GW in the Directed Vision, and 1500 GW in the National Champions pathways. This means that hundreds of GW (predominantly wind and solar power) have to be installed per decade.

Between 2030 and 2050, the capacity of wind power increases by more than a factor of 3 in the Diversification and Localization pathways (about 300 to 400 GW per decade) and still by a factor of 2 in the Directed Vision and National Champions pathways (100 to 150 GW per decade). In the same time, solar power capacity increases as well by a factor of 2 to 3, i.e. 200 to 400 GW per decade in the Diversification and Localization pathways and 60 to 180 GW per decade in the Directed Vision and National Champions pathways.

In all the pathways, wind and solar power have the highest capacities and are of the same order within each pathway in 2050. However, due to higher full load hours of wind power (about 3500 hours/year onshore and 4400 hours/year offshore) compared to solar power (about 1200 hours/year for PV and 3900 hours/year for CSP) wind power generates 2 to 3 times more electricity than solar power.

The resulting full load hours of fossil gas-fired power plants in 2050 are in average 300 hours/year (for gas turbines) and 1400 hours/year (for gas CHP) in the Diversification pathway, 800 and 1400 hours/year in the Localization pathway, 2000 and 1100 hours/year in the Directed Vision pathway, and 2000 and 1600 hours/year in the National Champions pathway. The utilisation is relatively low because gas, especially in gas turbines, is mainly used to balance shorter periods of lower wind/solar power generation. A higher utilization is prevented by the high CO_2 prices. This also means that capital and other fixed costs make up an important fraction of the generation costs of gas-fired power plants. In contrast, when CCS is available (in the Directed Vision and National Champions pathways) fossil coal-fired power plants are used as a base load technology with 8200 hours/year.

The strong grid restrictions and the high share of volatile wind and solar power in the Localization pathway are responsible for relatively high capacities of electricity storage and hydrogen gas turbines (H_2 electrification). These provide the necessary additional flexibility that the limited transmission grid extensions cannot cover. However, in all the pathways electricity storage does not play such an important role as one might expect regarding the high share of volatile renewables. Storage capacities range from 40 GW in the Directed Vision to 70 GW in the Localization pathway. This means that the main mechanism in the model to handle fluctuating electricity generation from wind and solar power is not simple electricity storage, but transmission grid extension and flexibility on the demand side (e.g. electrolysers, power-to-heat, charging of electric vehicles; cf. section 3.4).

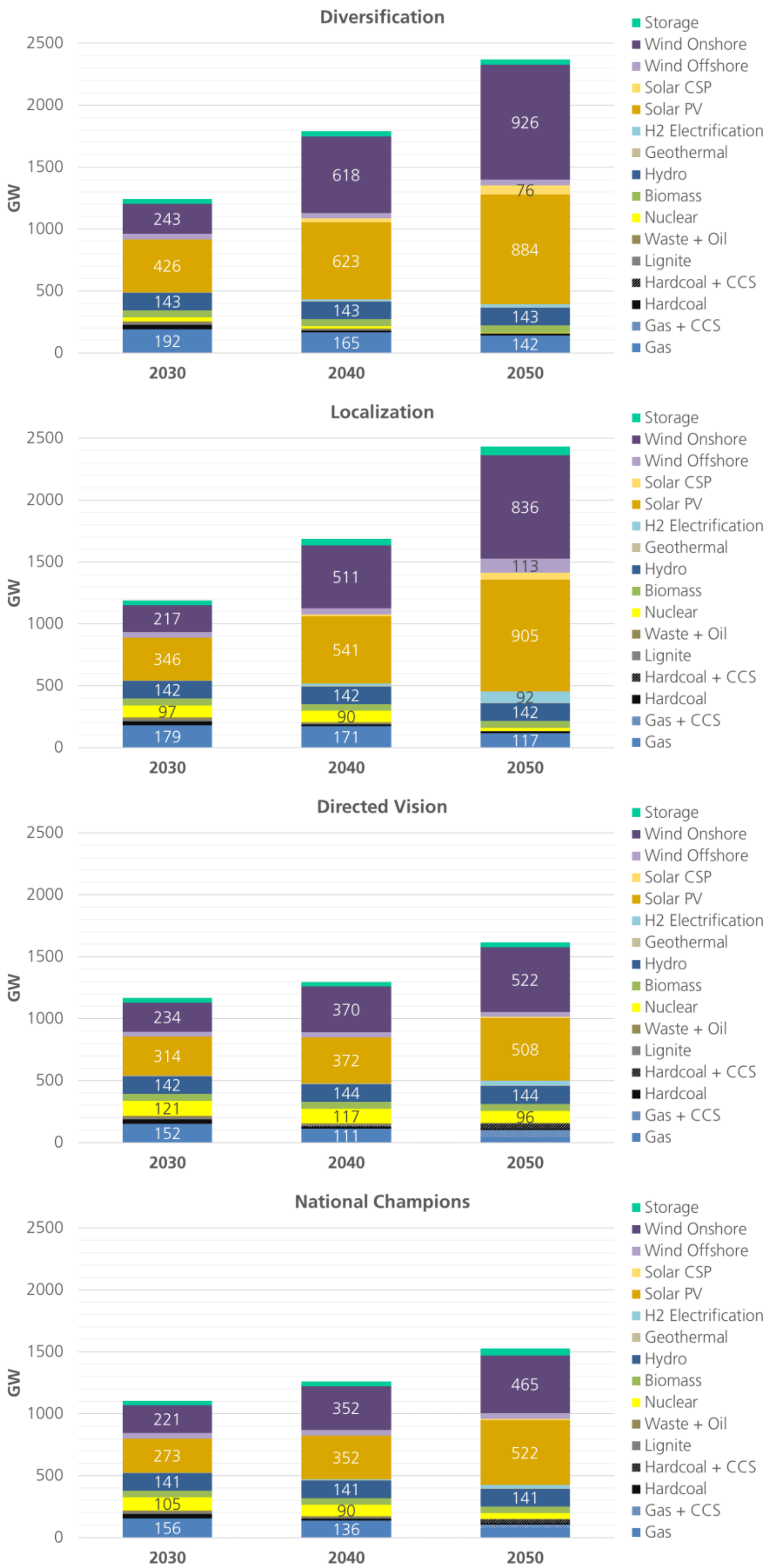


Figure 14: Evolution of the electricity generation capacity installed in Europe in the four pathways.

3.1.2 Renewable electricity generation

3.1.2.1 Renewable generation development to 2030

Within the pathway execution, the Green-X model is used to deliver an outlook of future RES deployment across EU Member States in the period up to 2030, with particular focus on the electricity sector. As outlined in section 2.3.3.1, Green-X modelling thereby seeks to incorporate the following aspects:

- Within all pathways the Green-X model derives a *least-cost allocation* of RES deployment across all sectors, technologies and countries in accordance with the given 2030 EU RES target (of striving for 32% RES share in gross final energy demand by 2030)
- It incorporates differences in financing conditions for (renewable) energy technologies in modelling and applies a distinction on that across assessed pathways, leading to a smoothening of financing conditions across countries in pathways characterised by more cooperation / Europeanisation – i.e. the pathways “Directed Vision” and “Diversification”.
- In certain pathways it assumes and exemplifies the impact of a prioritisation of decentral supply solutions, shown for the case of decentral PV. This prioritisation is taken in the pathways “Diversification” and “Localization”.

Table 14 summarises the assumptions taken in Green-X modelling to incorporate the pathway characteristics in an adequate manner.

Table 14: Pathway-specific assumptions used in Green-X for modelling RES deployment in the 2030 context

Pathway-specific assumptions used in Green-X modelling	**Diversification**	**Localization**	**Directed Vision**	**National Champions**
General approach for allocating RES deployment (up to 2030)	Least-cost allocation across all countries, sectors and technologies (in line with 32% RES by 2030 at EU level)			
Financing conditions / Country risk	Smoothening (due to “Europeanization”)	Default (differences across MSs remain)	Smoothening (due to “Europeanization”)	Default (differences across MSs remain)
Priorization of decentral (PV) systems	Yes	Yes	No	No

Below we provide an illustration of the outcomes, indicating for 2030 for all assessed pathways technology-specific RES-E deployment at EU level (Figure 15) and, complementary to that in Figure 16 overall country-specific RES-E deployment. The corresponding illustration in relative terms, indicating RES use as share in gross electricity demand at country level, is provided by Figure 17. These graphs allow for a comparison among the pathways that is a consequence of the perceptions taken in Green-X modelling as summarised above – but it is also a consequence of differences in the underlying electricity demand, i.e. specifically the amount of sector-coupling that is prescribed by demand modelling in the overall SET-Nav modelling suite.

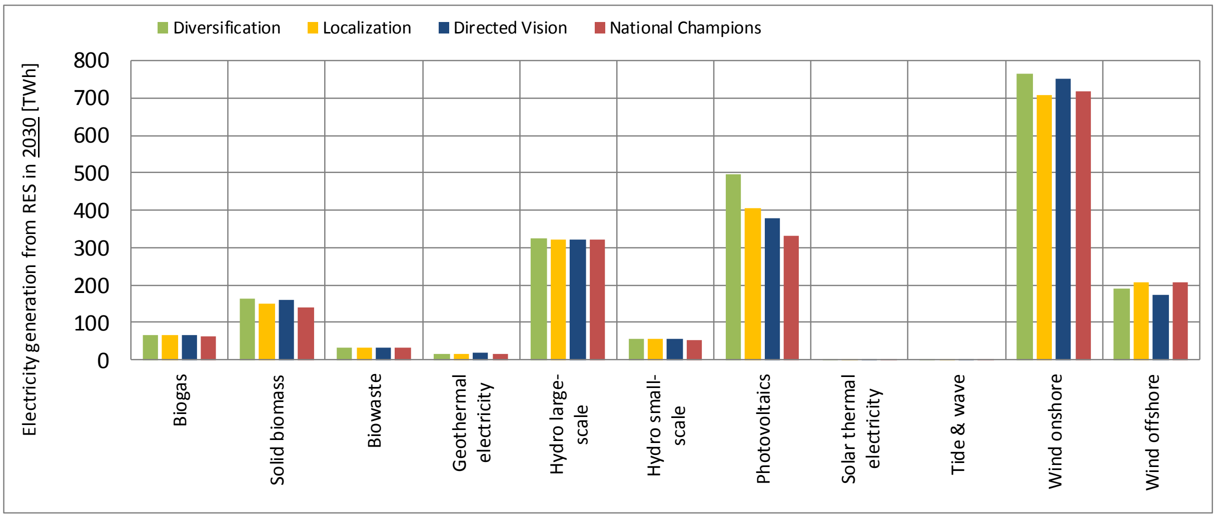


Figure 15: Technology-breakdown of electricity generation from RES in 2030 at EU level according to SET-Nav pathways (Green-X modelling)

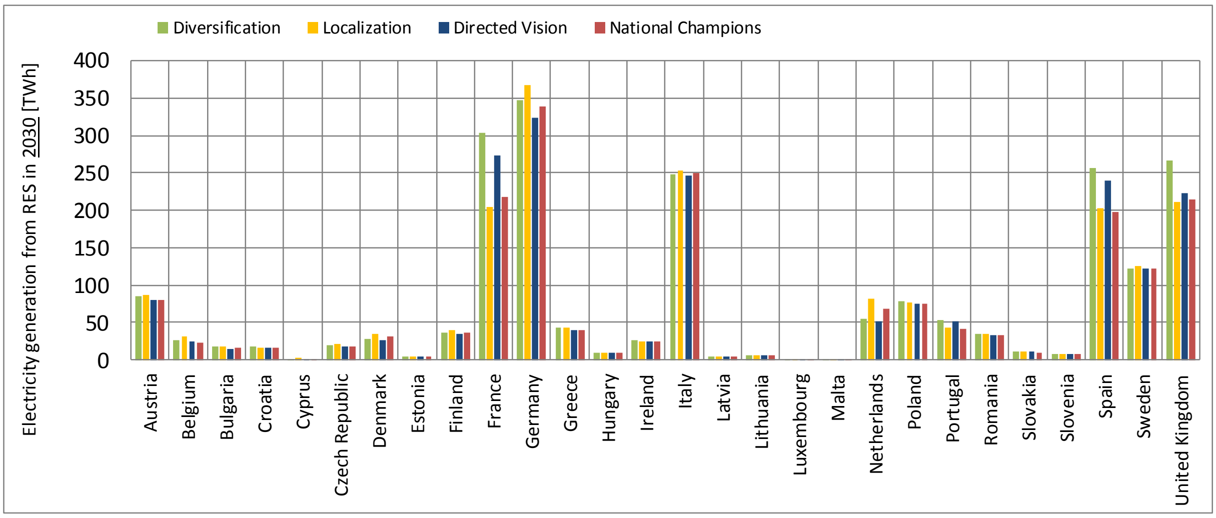


Figure 16: Country breakdown of electricity generation from RES in 2030 according to SET-Nav pathways (Green-X modelling)

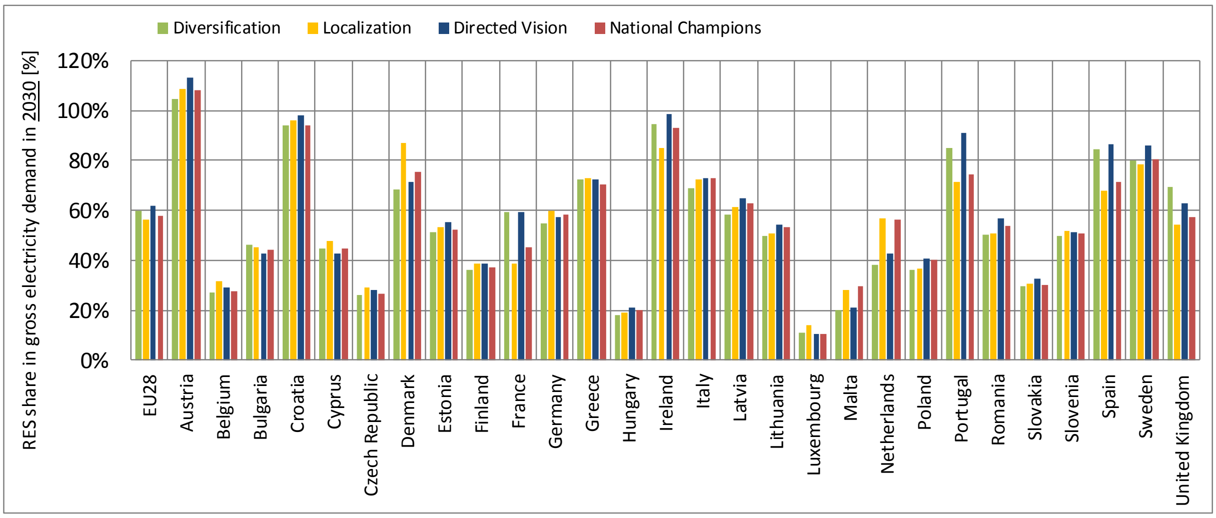


Figure 17: Country-specific RES share (in gross electricity demand) in 2030 according to SET-Nav pathways (Green-X modelling)

The graphs above illustrate the overall ambition level imposed by both the pathway conception (where a deep decarbonisation is aimed for in subsequent years until 2050) and the agreed political target set for RES by 2030 at EU level. Thus, a strong uptake of renewables is needed in the near to mid future to achieve the given RES target of 32% overall RES share by 2030 at EU level. A technology comparison as provided by Figure 15 then confirms the central role wind energy, and here specifically onshore wind, has to play. A strong contribution by 2030 is however also applicable in the case of photovoltaics – here the differences in policy conception across pathways is also observable: the SET-Nav pathways like Diversification or Localization (where a priorisation of decentral PV systems is presumed) lead to a (substantially) higher overall PV deployment in 2030. Country-specific differences in financing conditions affect investments in RES and, consequently, overall RES deployment but impacts are generally smaller in magnitude compared to other differences and assumptions taken in the pathway conception.

3.1.2.2 Renewable Potential Usage in 2050

The expansion of wind and solar energy in Enertile is based on a spatially highly resolved potential analysis, in which a model grid forms the basis for the potential calculation. The resulting expansion after optimisation of the energy supply with *Enertile* can be visualized with maps. The following sections show the renewable potential usage in the scenario year 2050 for the technologies wind onshore and solar PV.

3.1.2.2.1 Wind onshore

The maps in Figure 18 show the fraction of the wind onshore potential used in 2050 in the four different pathways.

Due to the optimisation in the Enertile model, renewable capacities first extend on areas with the lowest cost (i.e. in the case of wind often near the coast) and then spread to areas with higher generation cost. However, this does not hold completely on the European level, because the results of the Green-X model serve as minimum conditions (in terms of electricity generated per technology and country) for the optimisation. Therefore, potentials are used to a certain degree in every country, even if generation cost in comparison to other countries are higher.

The wind potential is used to a high degree in the northwest of Europe (i.e. northern France, Belgium, the Netherlands, northern Germany, Denmark, UK), but also in certain parts of the Mediterranean region, eastern Central Europe and around the Baltic Sea.

In the Localization and the National Champions pathways, the potential usage is lower in some regions with low generation cost (e.g. UK and Denmark). This is caused by the fact that lower transmission grid capacities do not allow for the export of more electricity. In contrast, in the pathways with unlimited expansion of the transmission grid (Diversification and Directed Vision) the installation of renewable capacities is more concentrated on areas with low cost potential.

The high renewable electricity demand in the Diversification and the Localization pathways causes a higher usage of areas with medium generation cost (e.g. further away from the coast), because areas with low generation cost are already largely used.

The absolute capacity installed per model tile is a problematic quantity because it strongly depends on the land use (the area usable for renewables) within the tile and on the surface area of the tile (which varies with the latitude). But the total European capacity can be helpful to interpret the abstract potential usage distribution. The potential usage in 2050 shown on the maps corresponds to installed wind onshore capacities of 926 GW in the Diversification, 836 GW in the Localization, 522 GW in the Directed Vision, and 465 GW in the National Champions pathway. These maps underline that public acceptance of these infrastructures is a crucial issue for the pathways. Moving parts of these capacities offshore is an option but it comes with additional cost and the possible necessity of additional grid infrastructures. From scientific perspective this maps also show that the land use assumption for the possible utilisation of land for wind generation units presented in chapter 1 is an important factor for the results.

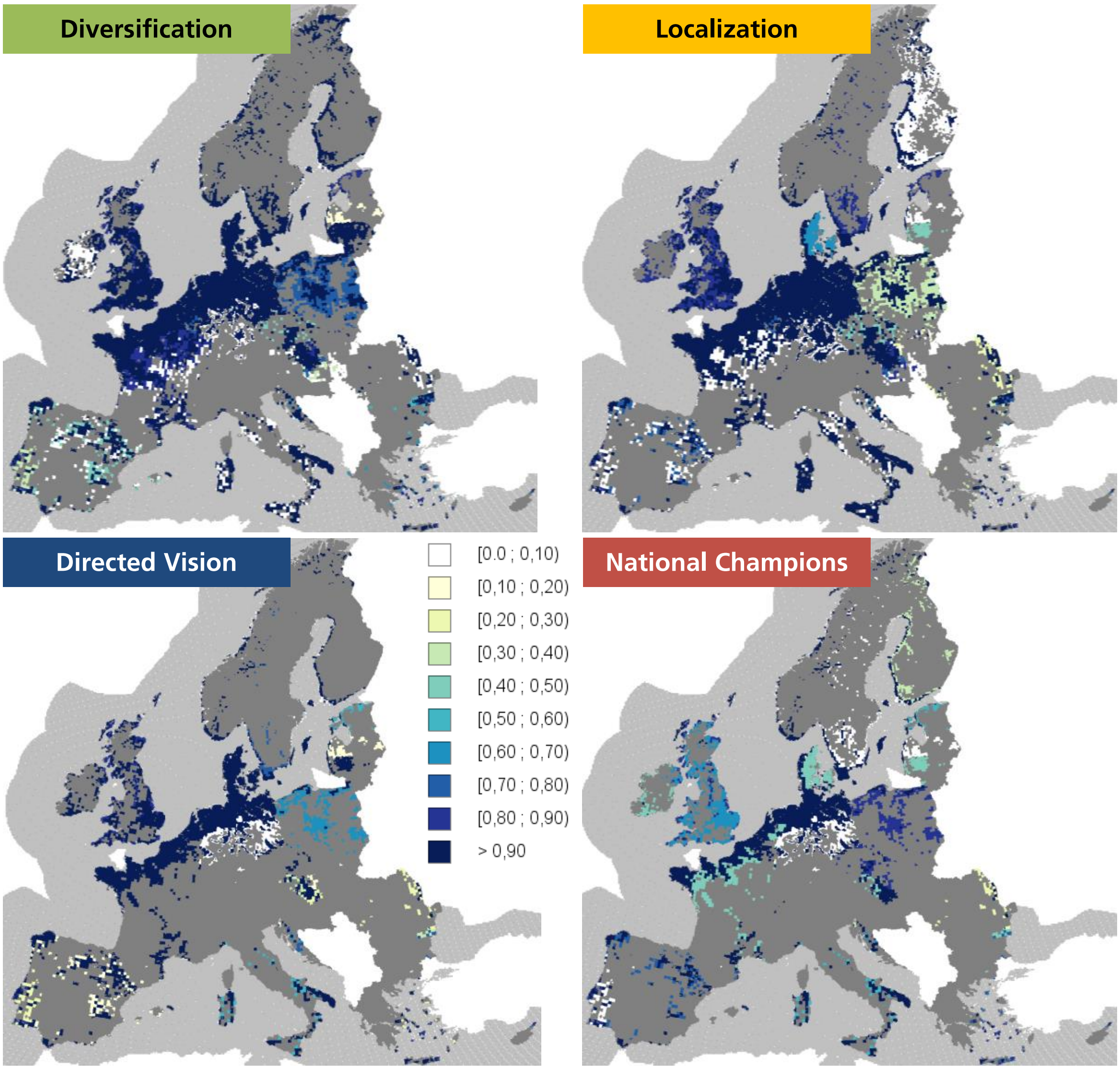


Figure 18: Fraction of the wind onshore potential used in 2050 in the four different pathways.

3.1.2.2.2 Solar PV

The maps in Figure 19 show the fraction of the utility scale photovoltaic (PV) potential used in 2050 in the four different pathways. As stated in the section above, certain minimum conditions for the electricity generated with a certain technology are fixed for every country. But apart from this, the model can optimise the installation of renewable capacities.

The result of the optimisation procedure is a very high utilisation of the existing generation potential for utility scale PV in Europe. It is used to a high degree in southern and central Europe, but also in certain parts of northern and eastern Europe. Overall, the potential usage is higher for utility scale PV than for wind power and distributed more homogeneously over and within most of the countries. This is caused by the fact that the regional differences in solar radiation are lower than the differences in local wind conditions.

In the pathways with restricted electricity grid (Localization and National Champions), low cost potentials in Southern Europe cannot be utilised completely, because additional electricity export is not possible. For the same reason, potential usage is higher in countries with higher generation cost (e.g. Finland, Ireland, and Poland) in these pathways.

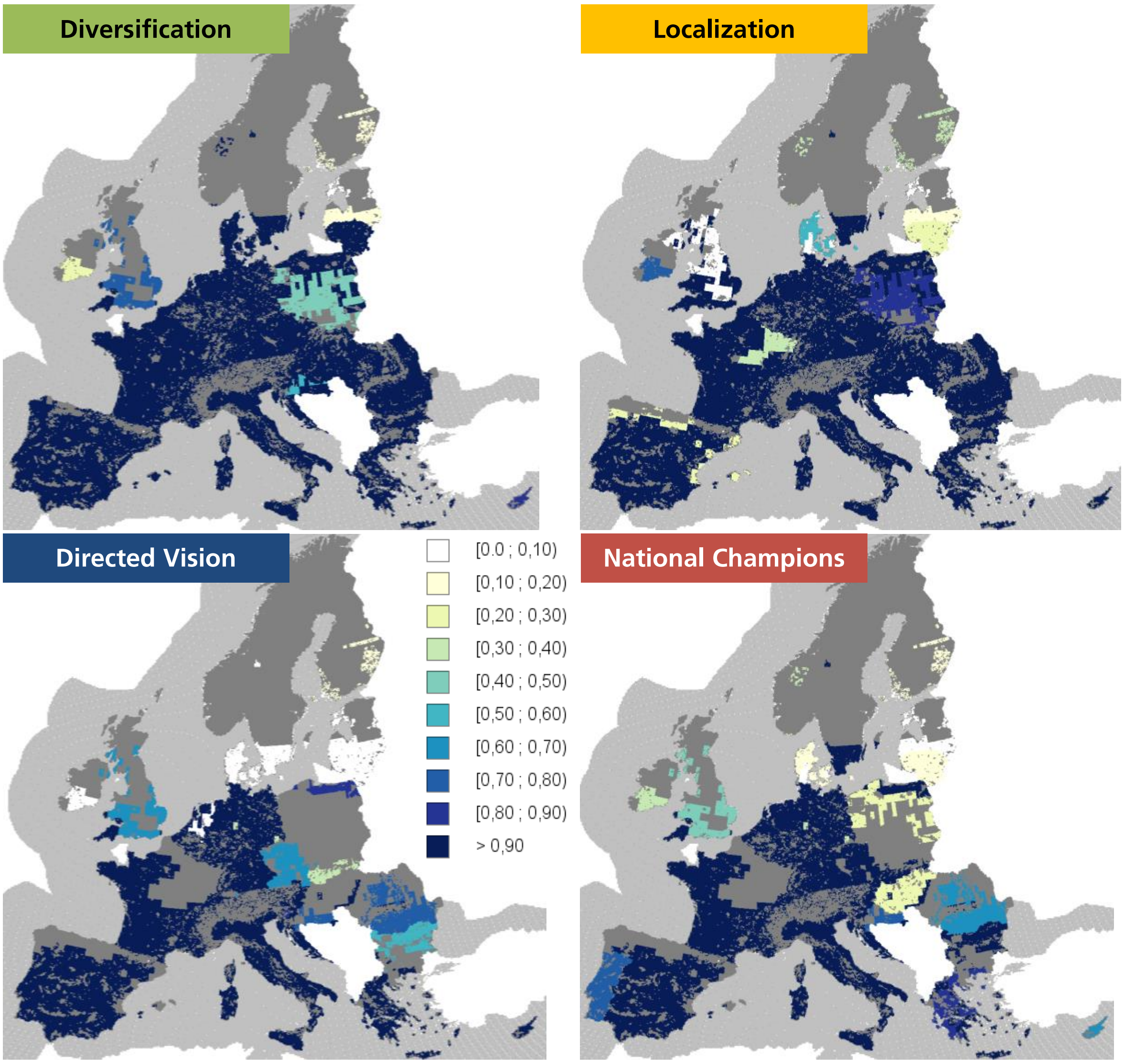


Figure 19: Fraction of the utility scale solar PV potential used in 2050 in the four pathways.

Due to the higher electricity demand, the solar potential usage is higher in the Diversification and the Localization pathways, especially towards the North and East, where potentials are not used to a high degree in the Directed Vision and the National Champions pathways due to the lower demand. Again these high utilisation rates of the existing renewable generation potential show that assumptions and land use and the public acceptance for these infrastructures is a crucial aspect.

The potential usage of rooftop PV in 2050 is shown in Figure 20. Generally, the optimisation procedure prefers utility scale PV to rooftop PV due to the lower generation cost. This can be seen in the overall lower potential usage of rooftop PV. In most of the countries, potential usage is high in the South where generation cost is lower. Potentials are (almost) not used in Northern Europe, where utility scale PV is preferred to reach national minimum targets for PV. In contrast, rooftop PV potentials are used more where there are only few utility scale PV potentials left (especially in Italy and Germany).

The potential usage in 2050 shown on the maps corresponds to installed solar PV capacities of 595 GW (utility scale) and 289 GW (rooftop) in the Diversification, 579 GW (utility scale) and 325 GW (rooftop) in the Localization, 367 GW (utility scale) and 141 GW (rooftop) in the Directed Vision, and 405 GW (utility scale) and 117 GW (rooftop) in the National Champions pathway.

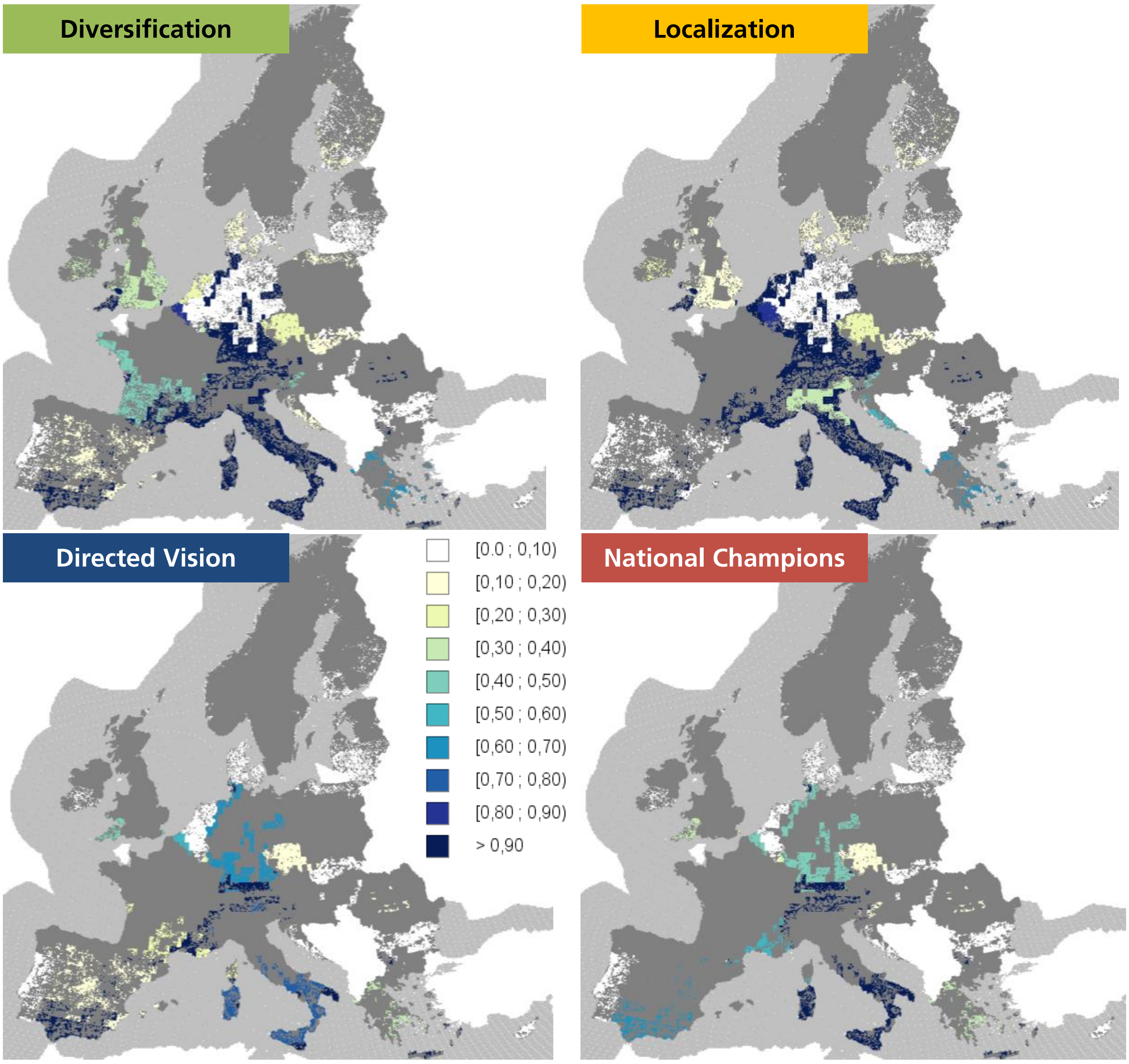


Figure 20: Fraction of the rooftop solar PV potential used in 2050 in the four pathways.

3.1.3 Electricity Grids & Trading

The transmission grid represents an important flexibility option to handle the volatility of wind and solar power generation. The capacity of the cross-border transmission grid interconnections in the four different pathways is shown in Figure 21. It increases over time in all the pathways, but with different growth rates (cf. section 2.3.4).

In 2050, interconnections with a capacity of 835 GW are installed in the Diversification pathway. This represents an extreme increase with respect to the current state of the electricity grid, but the optimisation in Enertile favours these strong grid extensions over other options that would result in higher costs. In the Directed Vision pathway, still 489 GW interconnection capacity are installed, while the stronger grid restrictions in the remaining pathways result in lower 2050 capacities (349 GW in the National Champions and 329 GW in the Localization pathway).

In the Localization pathway, grid extensions are limited to 15 % per decade (for every single connection). With 13 % per decade, the actual growth on the European level almost reaches this limit, meaning that most of the interconnections are extended by 15 % and only few are not extended to the limit. In the National Champions pathway, grid extensions are limited to 30 % increase of net transfer capacity per decade (for every single connection). With 19 and 14 % per decade, the actual growth on the European level stays well below the limit, probably due to the lower share of volatile wind and solar power in this pathway and the overall lower electricity demand. In the Directed Vision pathway, the grid is only limited in 2030 and then subject to free optimization. In the first decade, a very high increase of 64 % occurs, while it is only 15 % in the second decade. Finally, the Diversification pathway does not include any restrictions concerning the grid. This results in the strongest grid extensions: One first large step in 2030, then 59 % increase in 2040, and another 31 % increase in 2050.

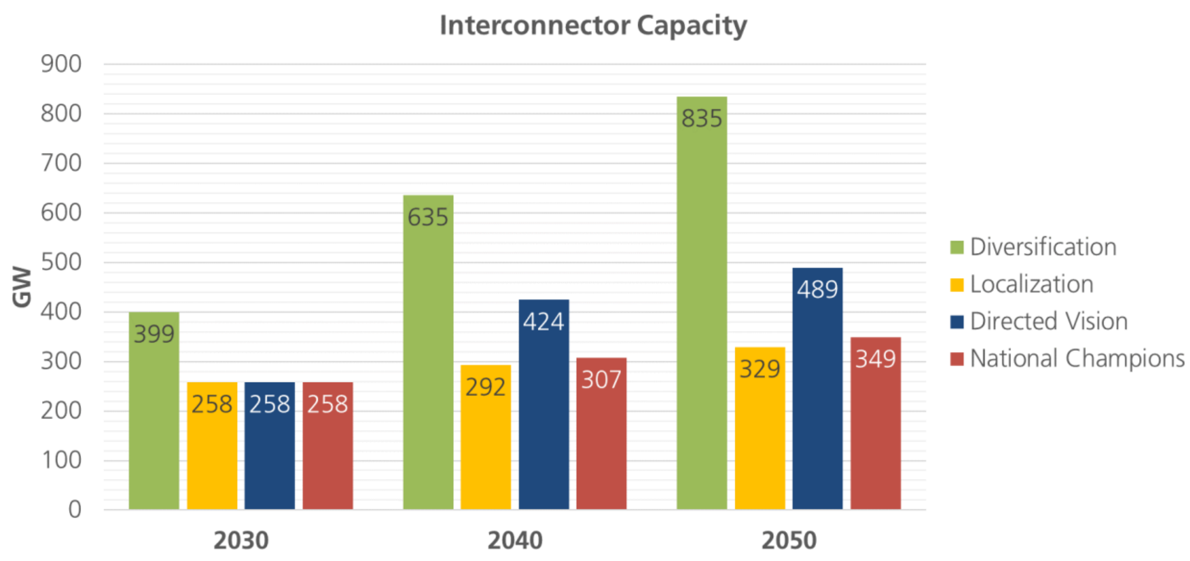


Figure 21: Capacity of cross-border transmission grid interconnections in the four different pathways.

The volume of the cross-border electricity trade, which is shown in Figure 22, evolves in a similar way. Interestingly, in 2050 it is only slightly smaller in the Localization pathway than in the Directed Vision pathway and larger than in the National Champions pathway, although the interconnector capacities are considerably lower. This is probably due to the high electricity demand and the higher share of wind and solar power in the Localization pathway, which increases the need for cross-border electricity trade. This indicates that international trade is still crucial in an energy aimed for more local production.

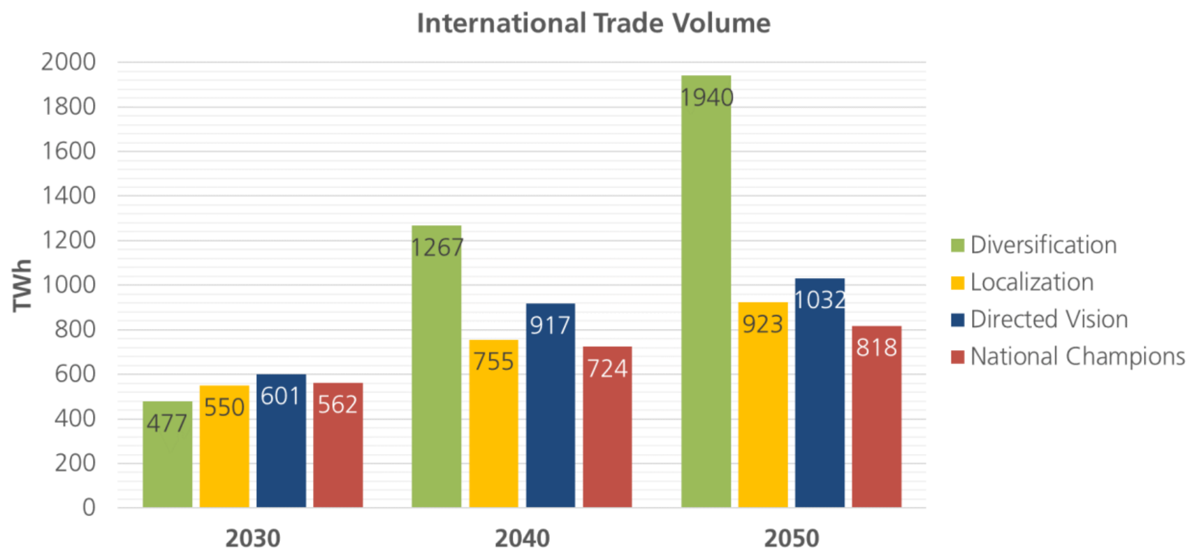


Figure 22: Volume of cross-border electricity trade in the four different pathways.

Figure 23 shows maps of the cross-border transmission grid interconnection capacities in the different pathways. The connection France–Spain has the highest capacity in 2050 in the pathways without grid restrictions (Diversification and Directed Vision). In the Diversification pathway, other strong interconnections (in the order of their capacity) are Germany–Poland, France–Germany, Denmark–Germany, France–UK, Norway–Sweden, and Lithuania–Poland, while in the Directed Vision pathway it is Denmark–Germany, France–Italy, France–UK, France–Germany, and Denmark–Norway. The strongest interconnections in the National Champions pathway are France–UK, Germany–Poland, France–Italy, Austria–Germany, and Germany–Switzerland. In the Localization pathway it is Austria–Germany, France–UK, Italy–Switzerland, Germany–Switzerland, and Germany–Poland. The maps indicate that the model tries to establish strong North-South and East-West backbones in the electricity grid if possible.

The differences in the transmission grid between the pathways presented in this section have a large impact on many other results. They affect energy costs and the choice and usage of energy supply technologies.

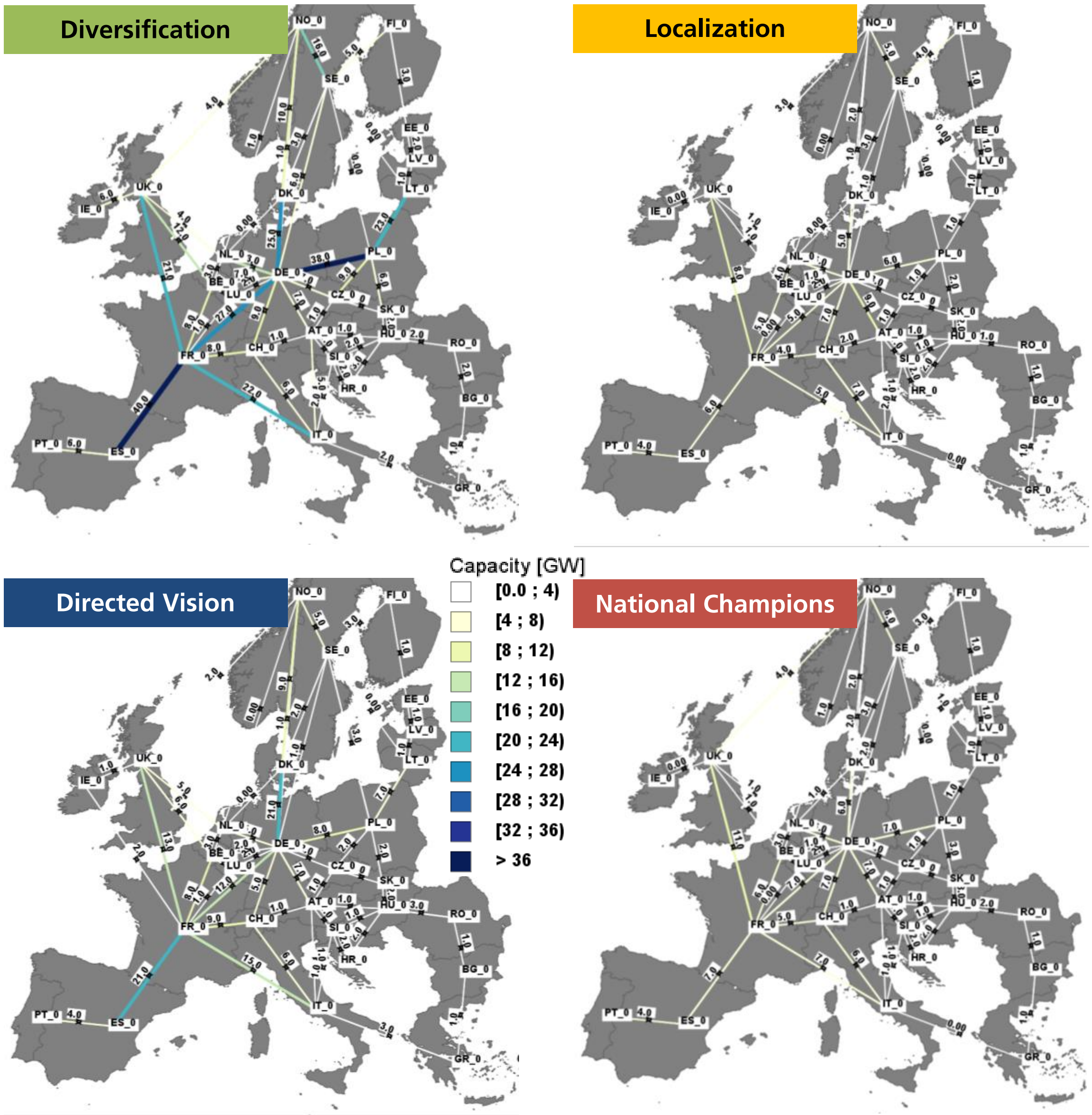


Figure 23: Transmission grid interconnection capacity in 2050 in the four different pathways.

3.2 Heat supply

This section describes the heat supply modelled with Enertile, which comprises district heat grids with multivalent heating on the one hand and decentralized heat pump systems on the other.

3.2.1 District heat grids

Figure 24 shows the heat supply mix in heat grids in Europe in the four different pathways. There are several technology options available to cover the heat demand in heat grids. These are combined heat and power plants (CHP), gas boilers, electric heaters and large heat pumps based on electricity and ambient heat. Additionally, hydrogen boilers can be used in the Localization pathway.

The Diversification pathway has a rather constant and low heat demand in heat grids. In 2030 no electricity-based heating technologies are used and the heat demand is fully covered with gas-fired technologies. Gas CHP is used more often than gas boilers. From 2040, electricity based heating technologies replace major parts of the fossil heat generation. This fuel switch also becomes apparent in the electricity supply mix as the amount of gas fired electricity generation decreases after 2030 (cf. section 3.1.1). In 2040 the heat pumps become relevant and are the major supply technology in 2050. Electric heaters cover small shares of heat demand in 2040 and 2050. Heat pumps are heavily used when residual load in the electricity sector is around zero, whereas electric heaters in hours with negative residual load.

The Localization pathway has a medium heat demand. In 2030 gas-fired technologies dominate in the heat supply mix, whereas gas boilers cover a larger share of heat demand than gas CHP. In 2040 and 2050 gas CHP becomes more important than gas boilers. However, the use of heat pumps and electric heaters increases strongly over time. In 2050 the major share of heat demand is covered with the heat pump. As grid expansion is very limited and international electricity balancing of renewable energies is constrained, the electricity-based heating technologies can provide flexibility for the energy system. The Localization pathway is the only pathway with hydrogen boilers in the heat grids. These hydrogen boilers are only used in 2050, where they cover a small share of heat demand and replace the gas boilers. It is the only pathway where the availability of hydrogen boilers may be important as it has very high energy demand, fast reduction of nuclear capacities, very limited grid expansion and CCS is not available. This results in a high decarbonisation pressure and high CO_2 prices, where the use of hydrogen boilers in heat grids becomes a relevant option.

The Directed Vision pathway has an increasing and very high heat demand in heat grids. The heat pump dominates in the generation mix and already covers about half of the heat demand in the year 2030. The share of heat pumps in the heat grid increases strongly to around 80% in 2050. Gas boilers cover the remaining share of the heat demand until 2040. Gas CHP is only used for small amounts, predominantly in 2040. The electric heater is primarily used in 2030. In 2040 and 2050 electric heaters are hardly used any more. This pathway has a high nuclear capacity, grid expansion is unlimited after 2030 and CCS is available. Therefore, the market potential of CHP technologies in the electricity sector is limited, which is also apparent in the heat supply mix. Furthermore, this is the only pathway where the CHP gas turbine (GT) is preferred over the CHP gas and steam turbine (GUD or CCGIT). The CCGT has higher efficiencies but is also associated with higher investments requiring a higher utilization to be competitive. As the electricity side is already adequately covered, the CHP technologies have only a small application range in the heat supply. The heat demand not met by the heat pumps and the CHP is therefore covered with the use of gas boilers.

The National Champions pathway has a decreasing and low heat demand in heat grids. Already 2030 the heat pump covers the largest share of the heat demand. The use of heat pumps increases in 2040 and 2050, whereas the use of gas boilers declines considerably over time. There are no electric heaters in the supply mix in this pathway. Gas CHP is mostly used in 2040 and covers about 25% of heat demand. In 2030 and 2050 gas CHP plays a minor role. The National Champions pathway has a general low demand and the availability of CCS and the amount of nuclear capacity limit the use of CHP in the electricity and heat supply. The electric heater is not used as the electricity grid and the use of heat pumps in heat grids provide sufficient flexibility for the electricity sector.

Overall, the heat pump is the most important technology in the generation mix for all pathways. From 2040 onwards, the heat pump is increasingly used in the heat grids. Gas boiler and CHP are mainly relevant in 2030 and partly in 2040. Later on, the fossil generation is drastically reduced to achieve the high decarbonisation in 2050. In highly decarbonized energy systems, the heat grids should be expanded and modified in such a way that heat pumps can be integrated efficiently. The role of CHP technologies is more uncertain as they are a transition technology and their use is very limited in highly decarbonized energy systems. The hydrogen boiler may become more relevant when CO_2 prices reach a very high level. Our analysis does not include renewable heat technologies as the availability of solar thermal heat generators, geothermal heat, waste heat or biomass heavily depend on the local situation. This will be an upcoming task for future model extensions. We do expect that renewable heat generation technologies can help to ease the pressure on carbon savings in heat supply. On local level these technologies can have a substantial impact but we do not expect that the general trends in our analysis are likely to change if res heat is taken into account.

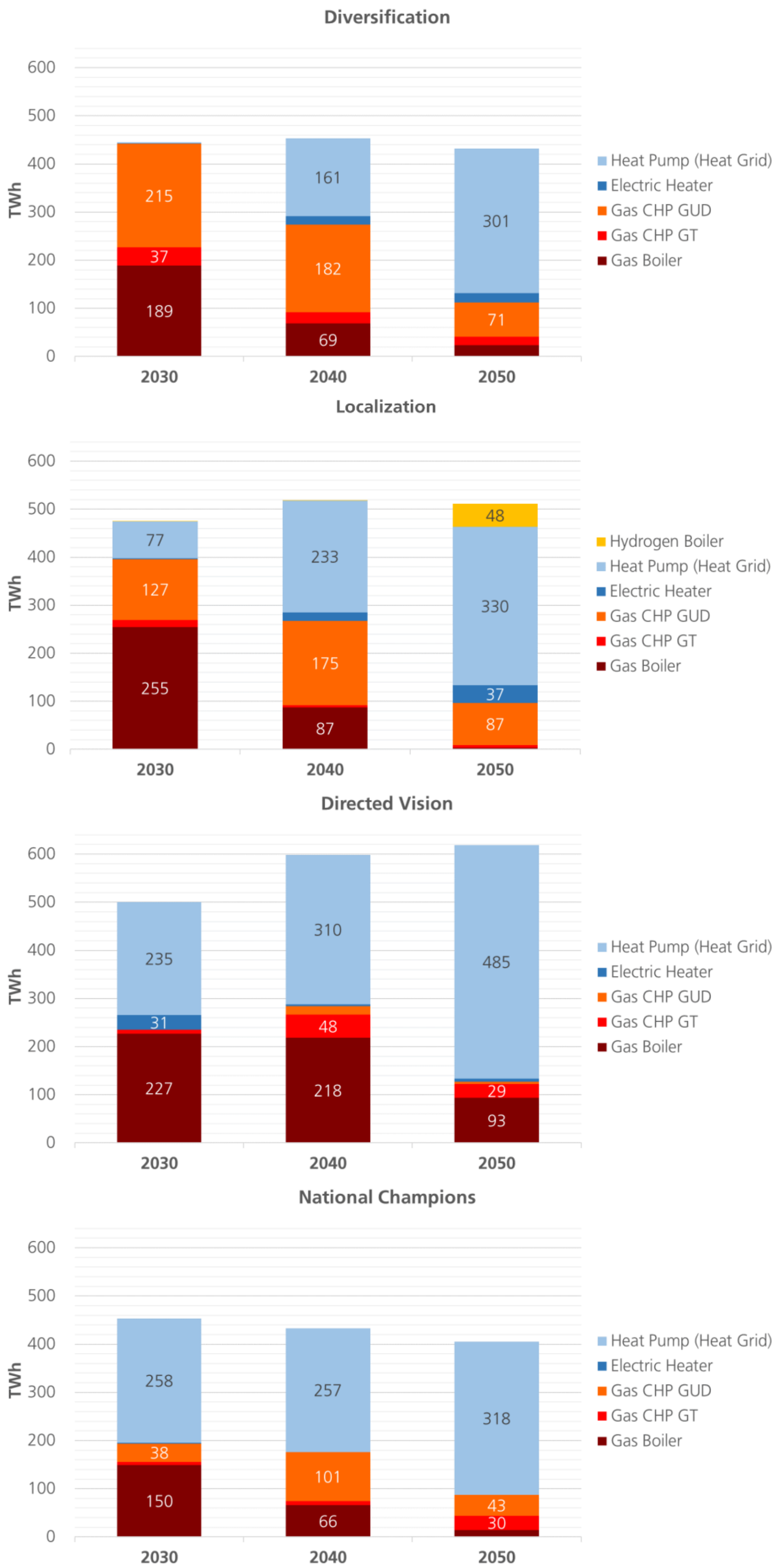


Figure 24: European heat supply mix in district heat grids in the four pathways

3.2.2 Decentralised heat pumps

3.2.2.1 Heat demand

Figure 25 shows the development of heat demand in buildings with heat pumps in the four pathways. The heat demand rises from 2030 to 2050 in all pathways. The Diversification and Localization pathway have a substantially higher heat demand than the Directed Vision and National Champions pathway (cf. section 2.3.2).

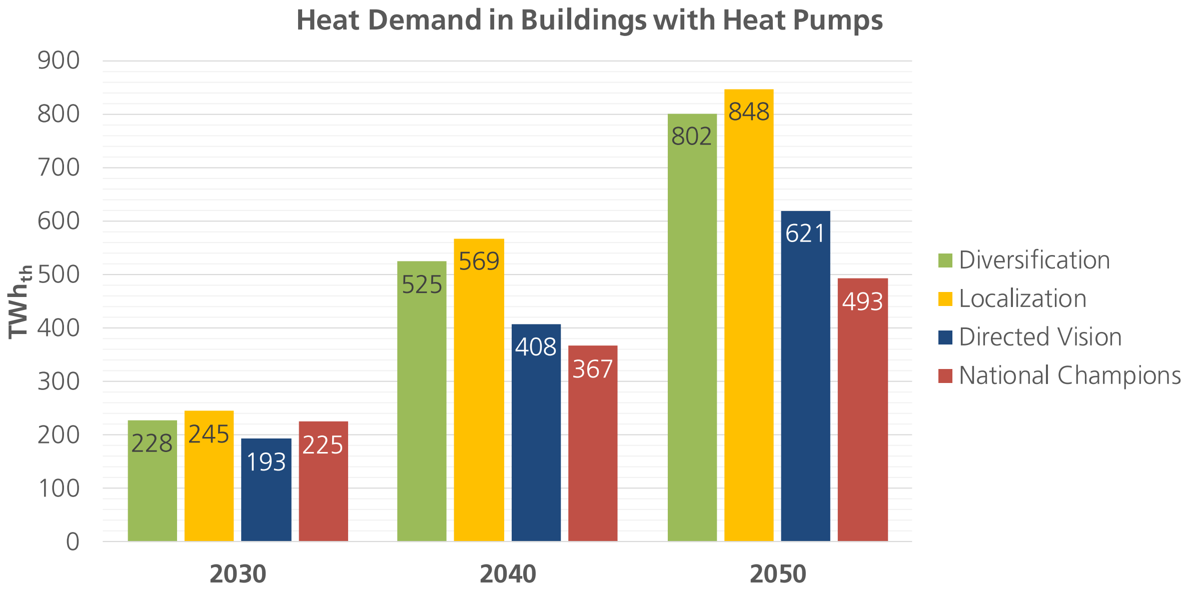


Figure 25: Heat demand in buildings with heat pumps in the four pathways

3.2.2.2 Annual coefficient of performance of heat pumps in buildings

The decentralised heat pumps are modelled as air-based heat pumps, which use ambient air as a heat source. As the efficiency of an air-based heat pump is strongly dependent on the variable temperature of the outside air, the efficiency is determined in hourly resolution as a function of the ambient temperature and therefore also affected by the dispatch decision of the model. The coefficient of performance (COP) states the efficiency of heat pumps. It is defined by the ratio of heat generated to electrical power used by the heat pump. Figure 26 shows the annual COP of heat pumps per country in the Diversification pathway in the year 2050. These values are examples as the differences between scenario years and pathways are negligible. Heat pumps in countries with rather higher outside temperatures, like Portugal or Greece, achieve higher efficiencies. In contrast to this, heat pumps in countries with lower outside temperatures, like Sweden or Finland, have lower annual COPs.

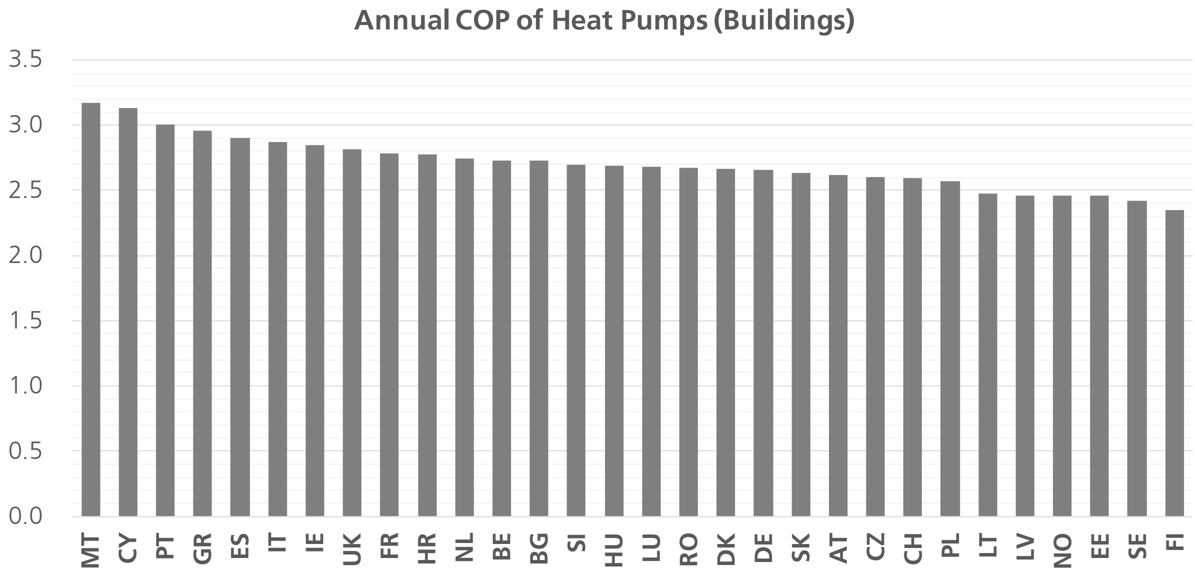


Figure 26: Annual coefficient of performance (COP) of heat pumps per country

3.2.2.3 Specific heat generation costs of heat pumps

Figure 27 shows the specific heat generation costs of heat pumps in the four pathways. These values do not include investments in heat pump and storage. Differences between the pathways arise in relation to the electricity costs and CO_2 prices. In general, the specific heat generation costs increase from 2030 to 2050 in all four pathways. The Localization pathway has the highest specific heat generation costs, whereas the Directed Vision pathway has the lowest specific costs. These costs depend on the electricity price and the dispatch decision of the model. The values correspond to wholesale prices and the actual heat generation costs are typically higher due to taxes and levies.

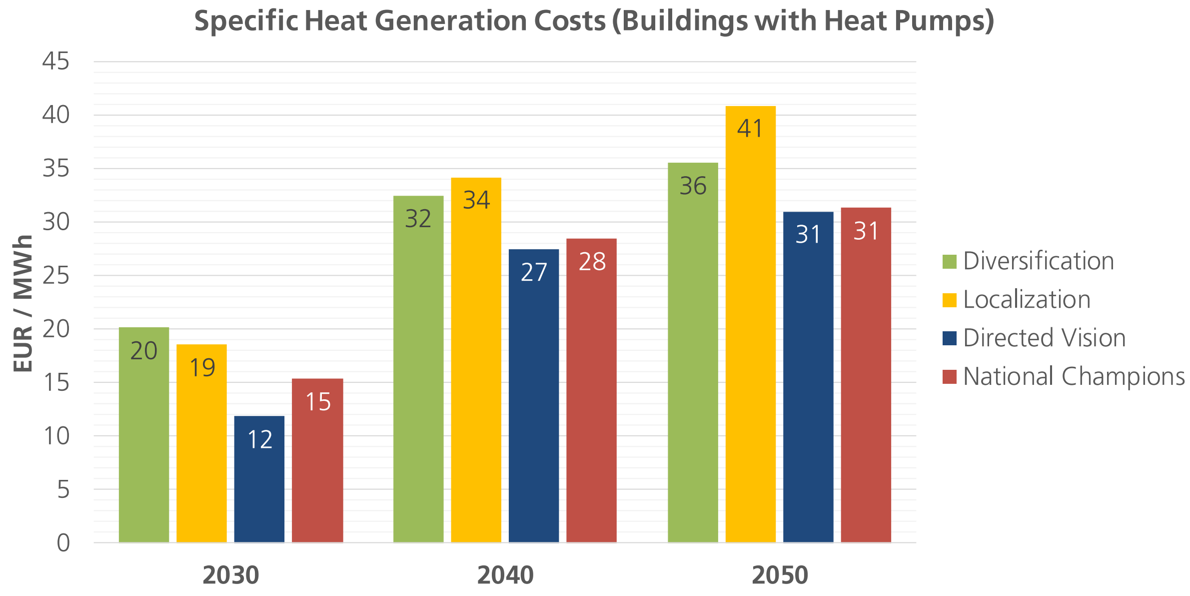


Figure 27: Specific heat generation costs of heat pumps in the four different pathways (averaged over all the 30 countries, weighted with the national heat demand in buildings with heat pumps).

3.3 Hydrogen supply

This section describes the hydrogen supply modelled with Enertile. Unless otherwise noted, results for the year 2050 are shown and discussed, because the hydrogen economy does not reach a relevant size before this date.

3.3.1 Overview Hydrogen Demand

The demand for hydrogen in the different pathways, mainly for the use in the industry, but also in the transport sector, is a result of the demand side modelling and given as a minimum condition to the optimisation. Additional hydrogen production can result from the reconversion of hydrogen for electricity or heat supply. Figure 28 shows the evolution of the European hydrogen demand (excluding reconversion). Obviously, with roughly 500 TWh in 2050 the demand is much higher in the Diversification and Localization pathways than in the Directed Vision (60 TWh), and National Champions (24 TWh) pathways. This results in even larger differences in electricity demand (which, excluding hydrogen, is already higher in the Diversification and Localization pathways).

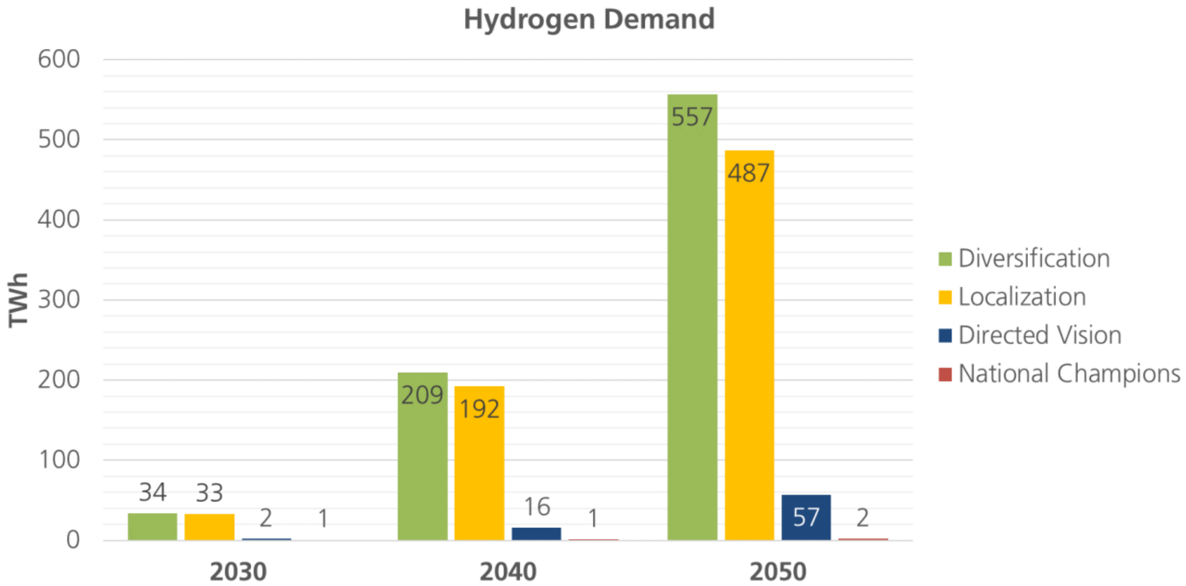


Figure 28: European hydrogen demand (excluding reconversion) in the four different pathways.

In order to generate the required amount of hydrogen, a certain electrolyser capacity has to be installed. The European electrolyser capacity in 2050 is 281 GW in the Localization, 231 GW in the Diversification, 30 GW in the Directed Vision, and 13 GW in the National Champions pathway.

It is important to note that we do not assume cross-border transport of hydrogen in the model. Therefore, electrolysers able to supply the domestic hydrogen demand have to be installed in every country. We also assume unlimited storability of hydrogen. As most of the hydrogen demand is arises in industrial processes the assumption of localised electrolysis seems to be adequate.

Figure 29 shows the distribution of the electrolyser capacity over the European countries in 2050 in the different pathways, while Figure 30 shows the generated amount of hydrogen per country. Both, capacity and generation are distributed over many countries in the Diversification and Localization pathways, but the large countries Germany, France, and the UK dominate. In the Directed Vision and National Champions pathways, the UK clearly dominates and only few countries have relevant electrolyser capacities.

The utilisation of the electrolysers which is the result of the optimisation procedure is highest in the Diversification pathway (3153 full load hours/year), of the same order in the Directed Vision (2941 hours/year), Localization (2836 hours/year) pathways, and lowest in the National Champions pathway (2298 hours/year), which also has the lowest electrolyser capacity.

These low to medium utilisation values of hydrogen electrolysers are far from base load operation. Therefore, the relatively high capital cost and fix operation and maintenance (O&M) cost of the electrolysers makes up about 30 % of the total cost of hydrogen (cost of electricity, capital, and fix O&M) in the Diversification and Localization pathways, about 40 % in the Directed Vision, and over 60 % in the National Champions pathway.

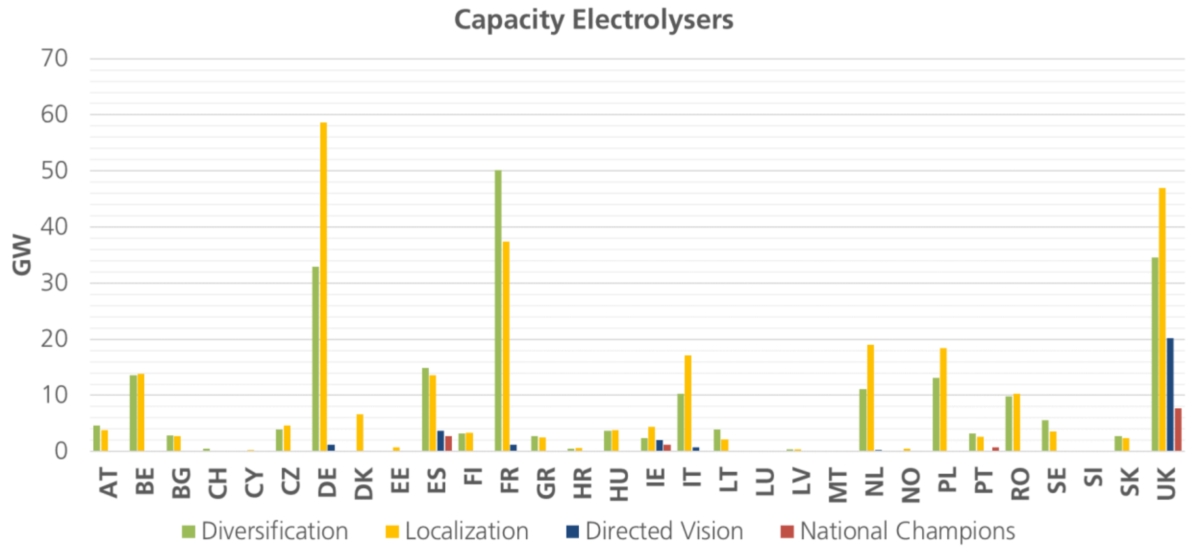


Figure 29: Capacity of electrolysers for hydrogen generation per country in 2050 in the four different pathways.

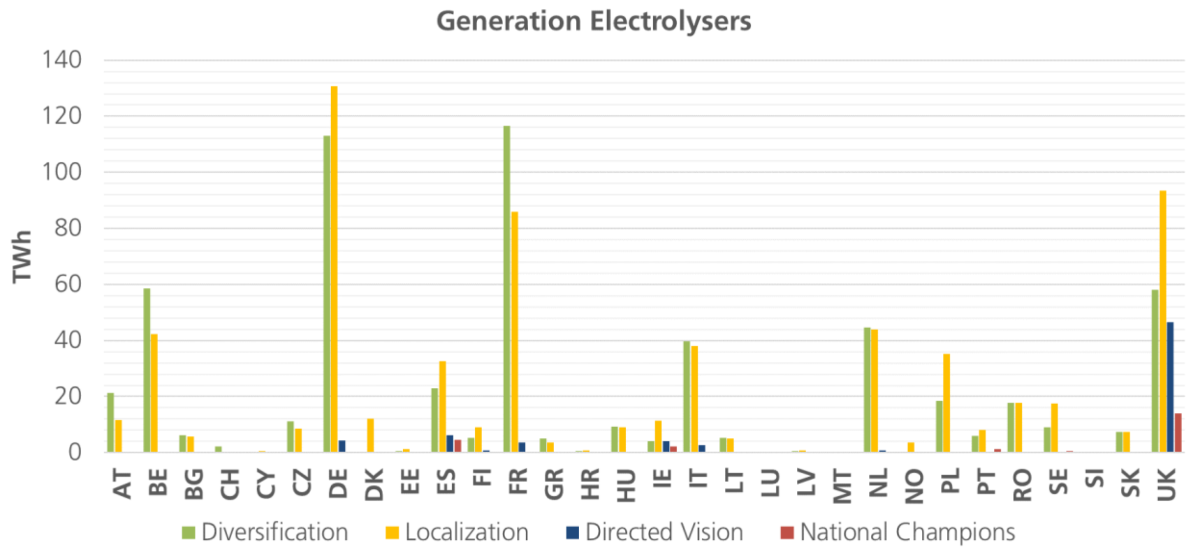


Figure 30: Generation of hydrogen with electrolysers per country in 2050 in the four different pathways.

3.3.2 Reconversion of Hydrogen

Besides its direct use in the industry and the transport sector, hydrogen can also be used to generate electricity with hydrogen gas turbines (with an assumed efficiency of 40 %), or to generate heat with hydrogen boilers (only implemented in heat grids in the Localization pathway).

The installed hydrogen gas turbine capacity in Europe in 2050 is 92 GW in the Localization, 38 GW in the Directed Vision, 27 GW in the National Champions, and 24 GW in the Diversification pathway. These capacities generate an electricity amount of 39 TWh in the Localization, 5 TWh in the Directed Vision, 9 TWh in the National Champions, and 11 TWh in the Diversification pathway. These numbers indicate that hydrogen is only used to cover peak demand due to the high fuel cost.

Figure 31 shows the distribution of the hydrogen gas turbine capacity over the European countries in 2050 in the different pathways, while Figure 32 shows the generated amount of electricity generated from hydrogen per country. The electricity generation from hydrogen mainly takes place in countries in the European periphery with a high share of wind and solar power, e.g. in the UK, Ireland, and Spain (except for the Diversification pathway, where grid interconnections of Spain are strongly extended). There, hydrogen electrification serves as a flexibility option for compensating, at least partly, for the limited electricity import and export capacity. Additionally, in the Localization pathway, a relatively large amount of electricity is generated from hydrogen in the rather central countries France and Poland.

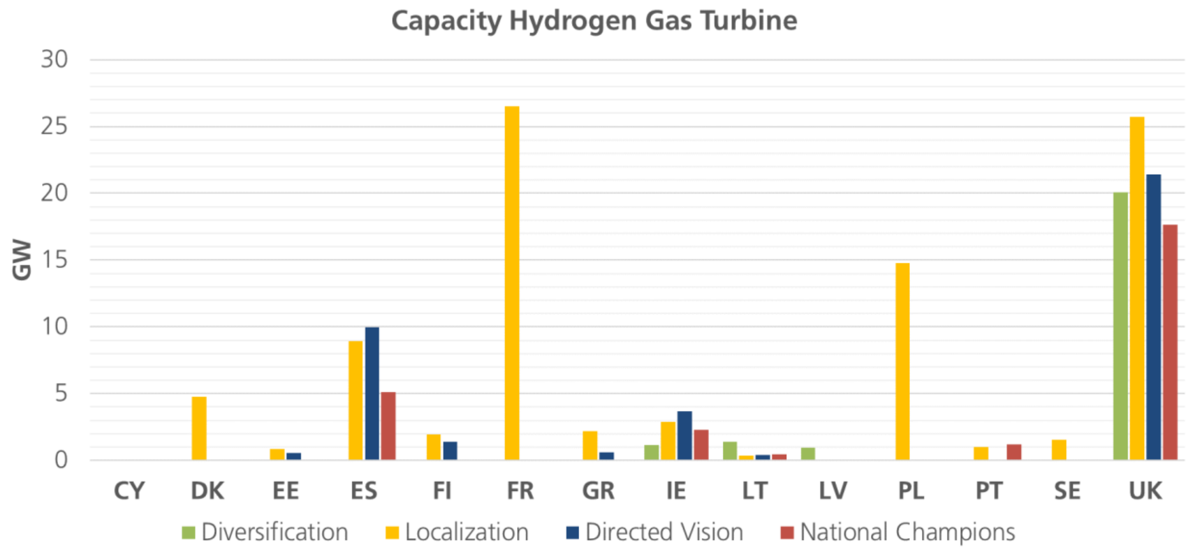


Figure 31: Capacity of hydrogen gas turbines for electricity generation per country in 2050 in the four different pathways.

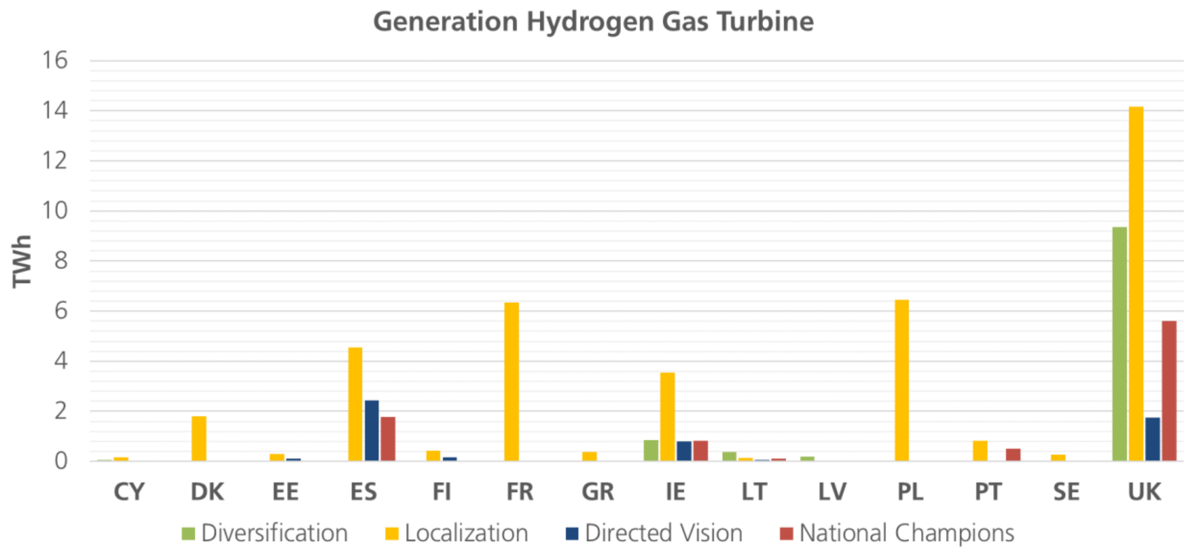


Figure 32: Generation of electricity with hydrogen gas turbines per country in 2050 in the four different pathways.

The gas turbines used to generate electricity from hydrogen have much lower utilisation values than the electrolysers. Here again, the utilisation is highest in the Diversification (458 hours/year) and Localization (431 hours/year) pathways, considerably lower in the National Champions pathway (331 hours/year), and lowest in the Directed Vision pathway (140 hours/year).

The utilisation is rather low for hydrogen gas turbines, because they are mostly used for short periods of peak load. Fossil gas turbines, which would usually serve for this purpose, are partly replaced by hydrogen due to the high decarbonisation pressure (low CO_2 cap, high CO_2 price), especially in the Localization pathway.

The hydrogen boiler, available only in the Localization pathway, in 2050 has a capacity of 42 GW and generates 48 TWh of heat in the heat grids. Figure 33 shows the distribution of the hydrogen boiler capacity over the European countries in 2050, while Figure 34 shows the generated amount of heat per country. Hydrogen boilers are most used in the UK and France, but also in the Nordic and a few other countries.

With 1219 hours/year, the utilisation of hydrogen boilers is considerably higher than the one of hydrogen gas turbines. Hydrogen boilers are mostly used as an alternative to fossil gas boilers and CHP when less electricity is available for heat pumps.

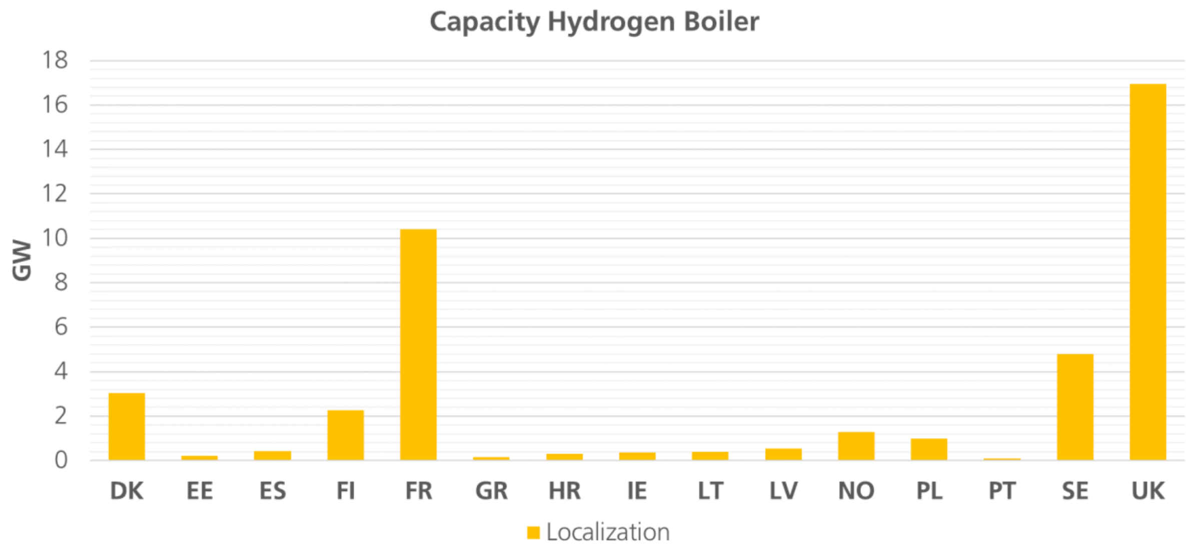


Figure 33: Capacity of hydrogen boilers for heat generation per country in 2050 in the Localization pathway.

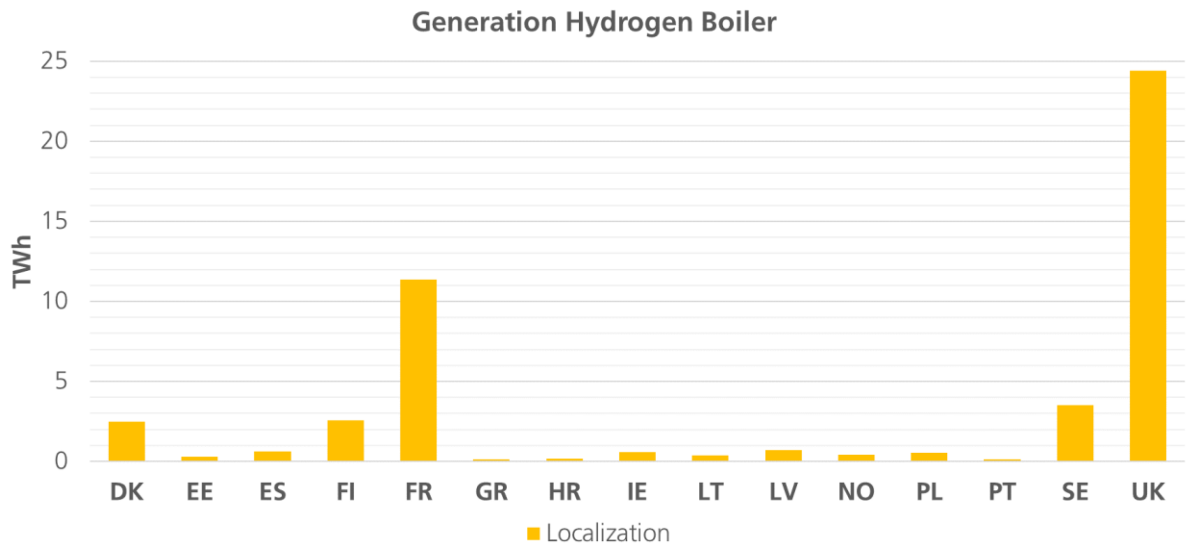


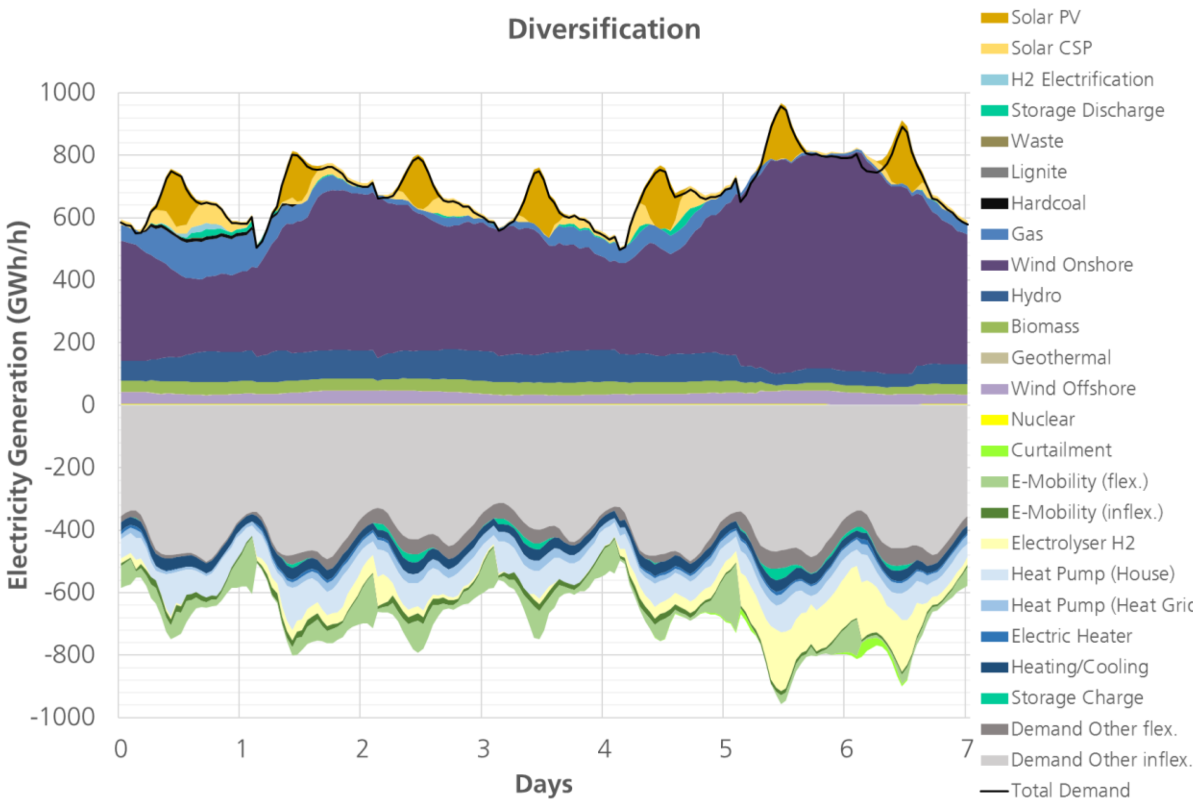
Figure 34: Heat generation with hydrogen boilers per country in 2050 in the Localization pathway.

3.4 Hourly dispatch

In this section we analyse, how the dispatch of electricity and heat in heat grids in Europe is done on the hourly scale in an exemplary week in winter and in summer. For this purpose we choose the year 2050 in the Diversification pathway, which shows the largest effects.

3.4.1 Winter week

Figure 35 shows the hourly dispatch of electricity and heat in Europe in a week in January 2050. One can see that the generation of wind power, the dominating energy source, fluctuates significantly in the course of the week. Periods of weaker wind are mainly compensated by an increase in gas based power supply and, to a smaller extent, by hydrogen gas turbines, and the discharge of electricity storages. In times of strong wind, gas decreases and even dispatchable hydro power is reduced.



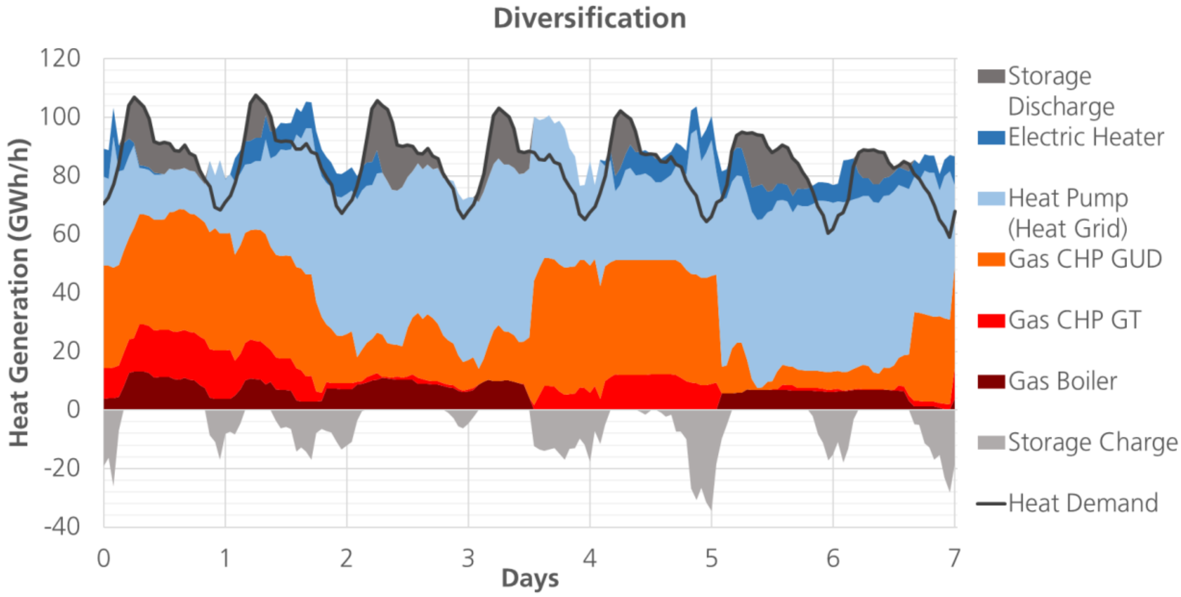


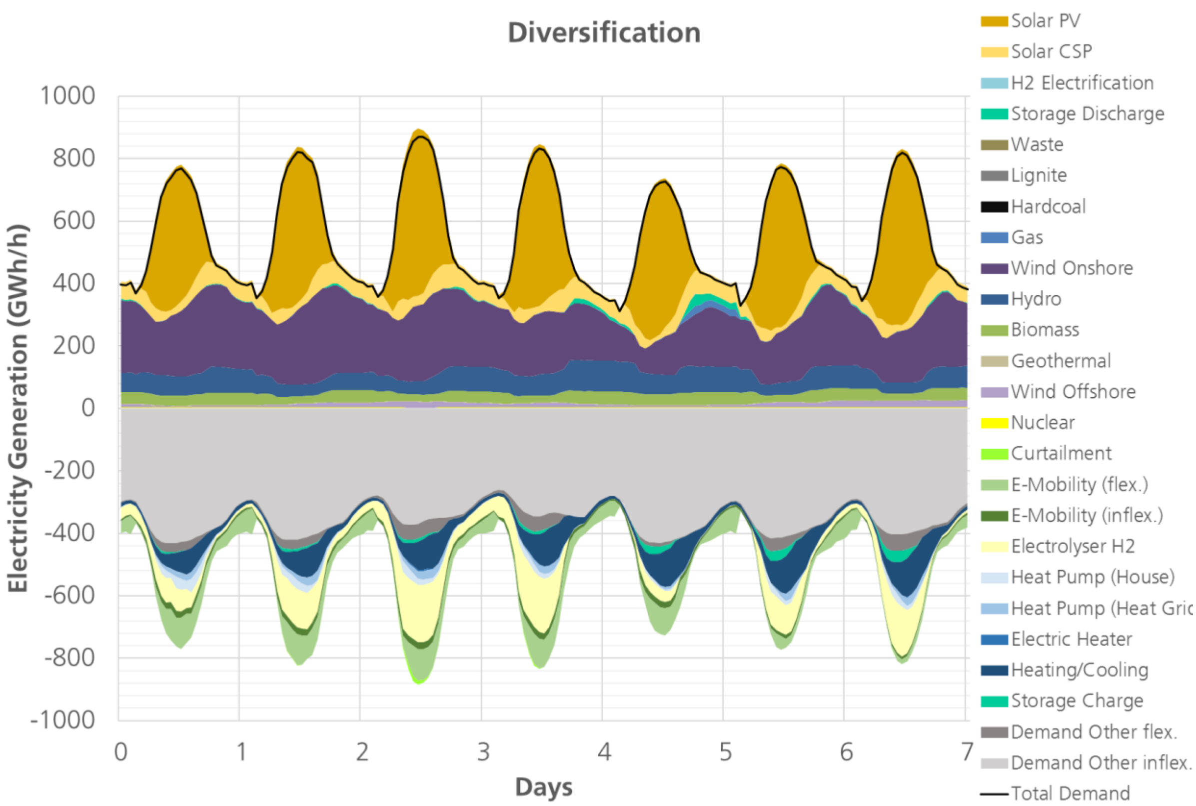
Figure 35: Hourly generation and demand of electricity and heat (in heat grids) in Europe in an exemplary week in January 2050 in the Diversification pathway.

The electricity demand is able to respond to these fluctuations to a certain degree. Electrolysers for hydrogen production are an important sink in times of strong wind, but power-to-heat is also used to a larger extent in these periods (see below), and electricity storages and electric vehicles are charged. Nevertheless, there are still short periods in which curtailment of renewables takes place.

The heat supply in heat grids is tightly linked to the power supply through sector coupling by CHP and power-to-heat. Therefore, the technology used for heat generation strongly depends on the electricity sector. In strong wind periods heat pumps clearly dominate the heat supply, but electric heaters are also relevant. At the same time, gas boilers stay active while gas CHP is reduced. In weak wind periods gas CHP dominates the heat supply, because (in contrast to gas boilers) it can supply both, the heat and the electricity demand. Heat storages are mainly charged in the evening and are then used to cover the peak load during the day.

3.4.2 Summer week

The significantly different behaviour of the heat and power supply in summer (mid-June) is shown in Figure 36. The largest differences are the higher generation of solar power, the reduction in wind power and the much lower heat demand.



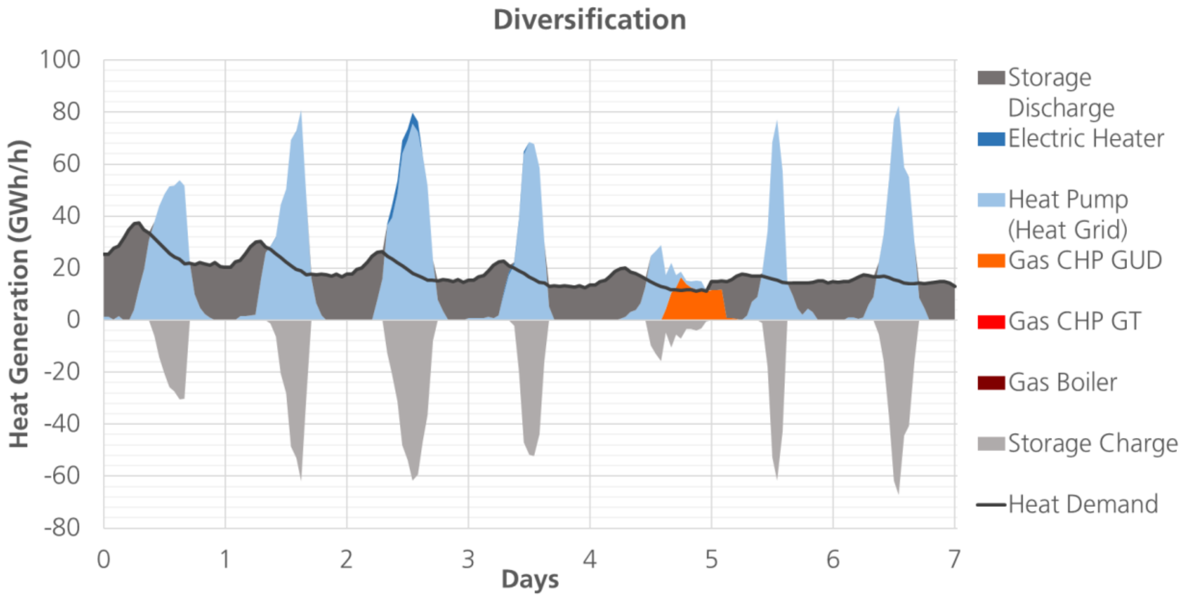


Figure 36: Hourly generation of electricity and heat (in heat grids) in Europe in an exemplary week in June 2050 in the Diversification pathway.

Now solar power is the dominant energy source, mostly PV but also CSP (especially towards the evening). Wind power also shows a daily cycle with a maximum in the afternoon/evening. During the midday peak generation of solar power, biomass and hydro power are reduced.

The electricity demand responds to the daily cycle of supply through a strong increase in hydrogen production, charging of electric vehicles and power storages around midday. The demand peak of air conditioning in the afternoon (due to the daily temperature maximum) also helps to consume the large supply of solar power. Curtailment only occurs once for a short midday period during this week.

Heat is mostly generated with heat pumps using the PV peak, stored during the day and taken from the heat storage during the night. Gas is hardly used at all, except for one evening, when the heat storage is empty and there is less wind available for heat pumps.

These model results demonstrate that the energy system is able to cope with strong fluctuations of power supply over the day or the week, as long as sufficient flexibility options (hydrogen, power-to-heat, e-mobility) are available. The transmission grid, which is strongly extended in the discussed Diversification pathway, also represents an important flexibility option that is already included in the shown profile of electricity generation.

3.5 CO_2 prices

In the pathway calculations, we use a carbon budget to assure comparability between the four pathways (cf. section 2.3.1). Figure 37 shows the carbon budget (CO_2 cap), which is implemented as an upper bound for CO_2-emissions in all four pathways. Furthermore, Figure 37 shows the CO_2 emissions in the pathways. Captured CO_2-emissions with CCS technologies are accounted for separately for the pathways, where CCS options are available. These emissions are not emitted into the atmosphere and therefore not included in the carbon budget. Figure 37 also shows the captured CO_2-emission by CCS technologies in the pathways where CCS is available, which applies to the Directed Vision and National Champions pathway. The costs for CCS technologies differ between the two pathways and therefore the amount of electricity generation with CCS and the captured emissions. CCS technologies are introduced in the year 2040 and they still play only a moderate role in 2050, which is also apparent in the electricity mix (cf. section 3.1.1). The captured emissions in the Directed Vision pathway are higher than in the National Champions pathway as the CCS technologies are more expensive in the National Champions pathway (cf. section 2.3.4).

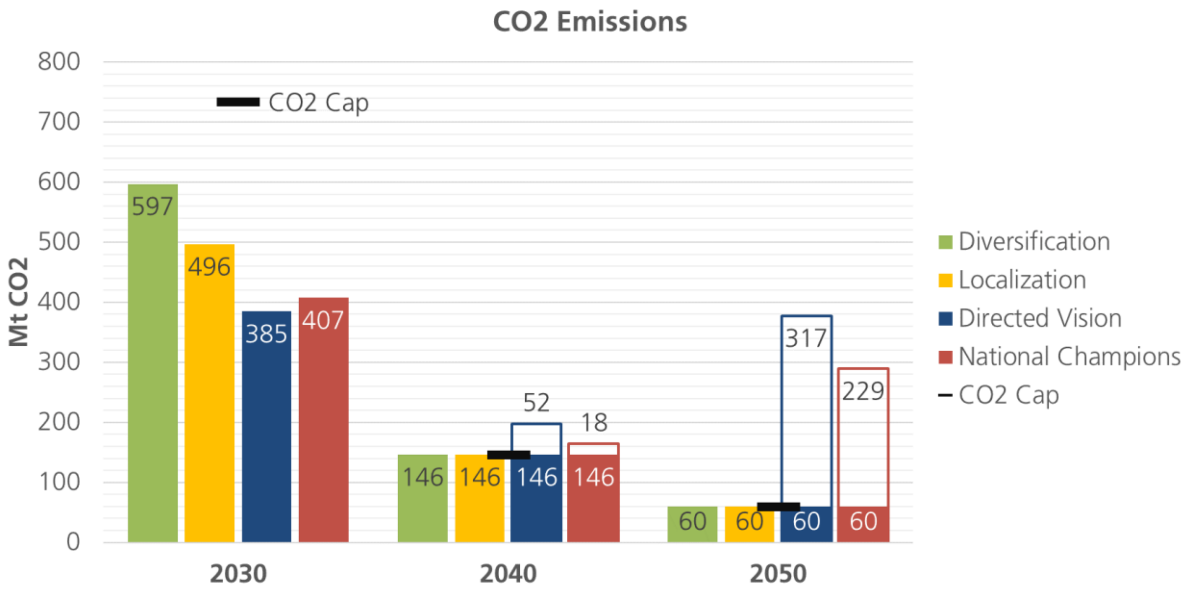


Figure 37: CO_2-emissions into the atmosphere, captured CO_2-emissions (hollow bars) and carbon budget (CO_2 cap) from the electricity sector and district heating in Europe in the four pathways.

By using a carbon budget in the optimization the corresponding CO_2-prices are a part of the solution. The CO_2-prices are the shadow costs of the emission equation in the linear problem formulation. Figure 38 shows the resulting CO_2 shadow costs in the four pathways. The National Champions pathway has with 139 €/Mt the lowest CO_2 price in 2050. In 2040, the Directed Vision has a lower CO_2 price. The Localization pathway has the highest CO_2 prices in all scenario years and the price reaches a level of nearly 300 €/Mt in 2050. The CO_2 prices in the Diversification and Directed Vision pathway rises close to 200 €/Mt in 2050. Compared with current levels of the CO_2 price this means a drastic increase until 2050. The emissions in 2030 are below the CO_2 cap in all pathways, which results in CO_2 shadow prices equal to zero. This means the carbon budget for this year is sufficient and does not exert pressure on the electricity generation. This does not mean that Europe will reach these emissions automatically but it is a result of the definition of the pathways in 2030. Even if the CO_2 shadow prices in 2030 are zero they rise substantially in the years afterwards.

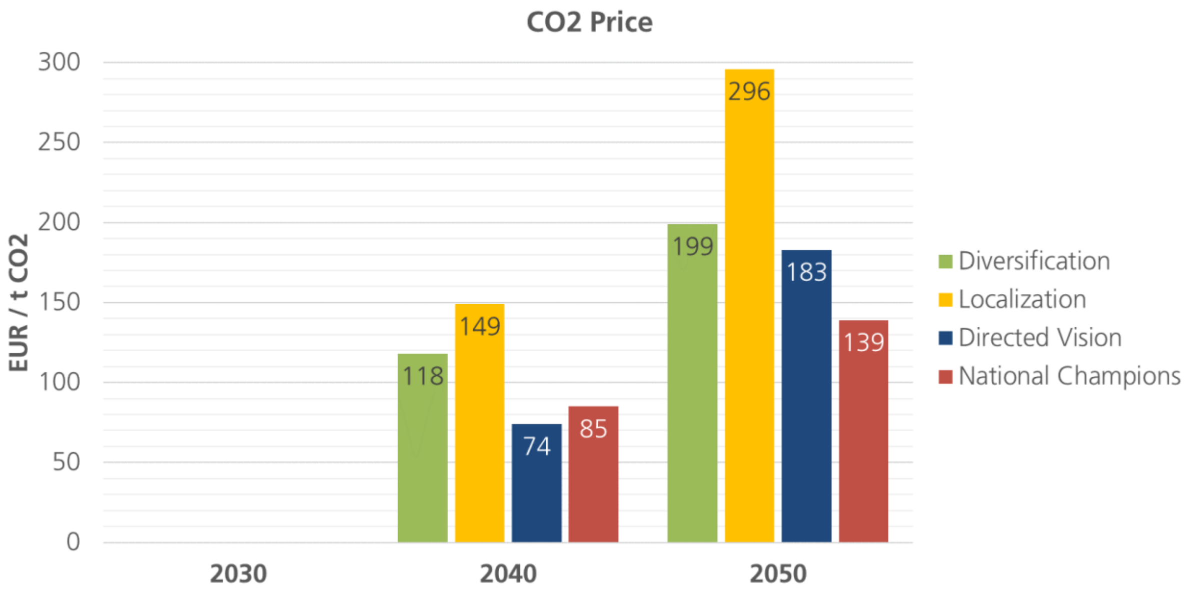


Figure 38: CO2 shadow prices in the four pathways.

3.6 Market values

In this section we analyse the market values of electricity, heat and hydrogen in the four pathways. Whereas most other quantities discussed in this report can easily be summed up in order to analyse them on the European level, market values have to be averaged in a certain way over the 30 considered countries. We choose to weight the national market values with the national demand when computing a European average.

The market value of electricity in the different pathway is shown in Figure 39 for the years 2030, 2040, and 2050. In all the pathways, the market value shows a strong increase between 2030 and 2040, while it increases much less or even remains constant between 2040 and 2050. The market value is highest in the Localization pathway (except for 2030), followed by the Diversification pathway. The Directed Vision pathway has the lowest market value, but the one in the National Champions pathway is only slightly higher.

Figure 40 shows the same for the market value of heat in heat grids. The general trend is similar to that of electricity, with a larger increase in the first and a smaller increase in the second decade. Again, the Localization pathway has the highest market value, followed by the Diversification and the Directed Vision pathway. The National Champions pathway has the lowest market value of heat in heat grids.

The market value of hydrogen, shown in Figure 41, has a more complex behaviour. It is highest and does not vary much in the Diversification pathway (except for 2040). It is also high in the Localization pathway, where it increases in the first and decreases again in the second decade. An initial increase followed by a decrease of the market value, can also be observed in the Directed Vision pathway, which has overall much lower values than the pathways described above. The market value of hydrogen is lowest in the National Champions pathway, but this should be interpreted cautiously due to the very small scale of the hydrogen economy in this pathway.

Overall, the market value of hydrogen is considerably lower than the one of electricity, although the generation of 1 MWh of hydrogen requires more than 1 MWh of electricity. This is because electrolysers are mostly used in periods with low electricity price due to large supply of renewables.

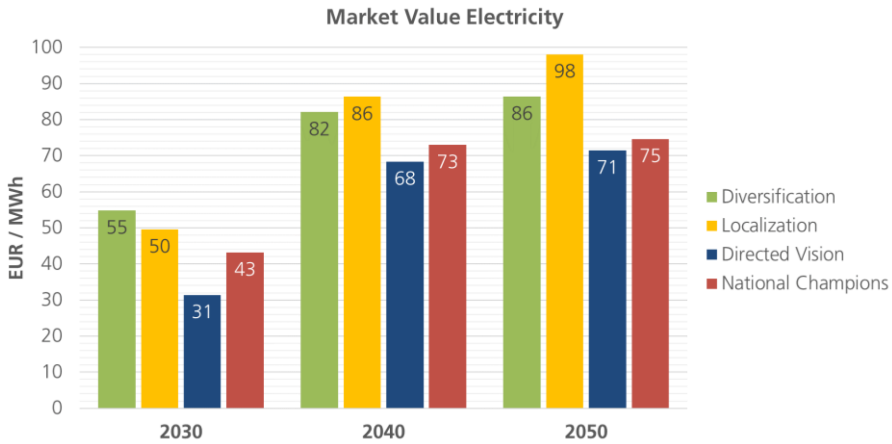


Figure 39: Evolution of the market value of electricity in the four different pathways (averaged over all the 30 countries, weighted with the national inflexible electricity demand).

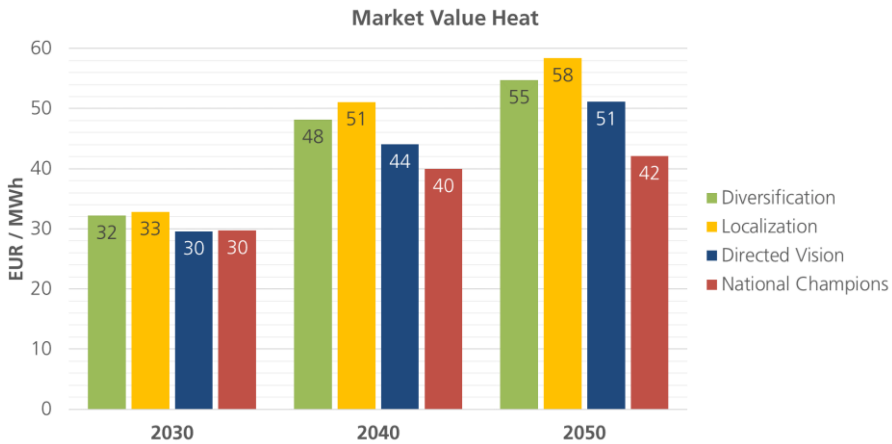


Figure 40: Evolution of the market value of heat (in heat grids) in the four different pathways (averaged over all the 30 countries, weighted with the national heat demand in heat grids).

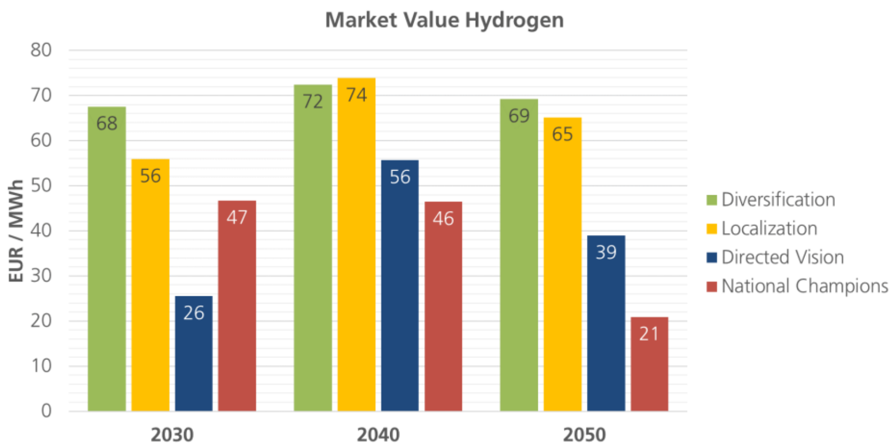


Figure 41: Evolution of the market value of hydrogen in the four different pathways (averaged over all the 30 countries, weighted with the national hydrogen demand).

4 Summary & Conclusion

This reports presents the analysis of energy supply in strong decarbonisation pathways for Europe. The developed bottom-up modelling framework is characterized by an unprecedented high level of detail in spatial temporal and technological resolution.

The modelling results presented in this report demonstrate, that a stable European electricity and heat grid system is possible even for the ambitious decarbonisation goal of 96 % reduction. In order to achieve this GHG emission target, CO_2 prices will have to be much higher than today, in our results well above 100 €/t in 2050. However, energy prices do not show such a large increase, because the energy supply mix is dominated by low carbon technologies. In order to achieve this result efficient regulation of linkages between the different energy sectors is required. Heat supply and energy supply of other sectors such as the transport sector need to follow the real time situation of the electricity sector in an undisturbed way to react to weather situations.

The four scenarios discussed above show that there are different technology pathways to reach the target. But despite the differences it is a robust finding, that renewable energy sources and especially wind power will play a major role in the future energy supply. Furthermore, heat grids able to distribute heat from fossil or renewable fuels or power-to-heat are an important option to adapt to different developments in technology.

A strong power transmission grid helps to limit the energy system costs, because it allows to generate renewable electricity where generation costs are lowest and it reduces the need for other (more expensive) flexibility options. Another important measure to keep costs low, is the direct use of electricity in other sectors such as power-to-heat in heat grids or electric vehicles for transport.

The direct use of electricity in other sectors reduces the requirements for the generation infrastructure compared to pathways with a stronger usage of hydrogen or "synthetic hydrocarbons", because these result in less efficient conversion processes.

Our results show that in world which is heavily dominated by renewable electricity generation electrolysis of hydrogen is a shoulder load technology rather than a base load technology. This results in a high share of capital costs in overall hydrogen production cost. The reconversion of hydrogen to electricity is mainly an option to cover rare peaks which cannot be covered with natural gas in a world with tight carbon budget.

The comparison of the pathways and the spatial results for the allocation of renewable generation units clearly indicates that public acceptance for generation infrastructure will be crucial aspect for the road ahead. All pathways show infrastructures which will raise acceptance issues, such as grid renewables deployment, CCS or nuclear. Even the localisation pathway requires large amounts of generation infrastructures which are concentrated in certain regions of Europe.

5 Appendix

5.1 Cost potential for generation of renewable energies

Figure 42 shows the aggregated cost potential curves for generation of renewable energies in Europe for the scenario years 2030, 2040 and 2050.

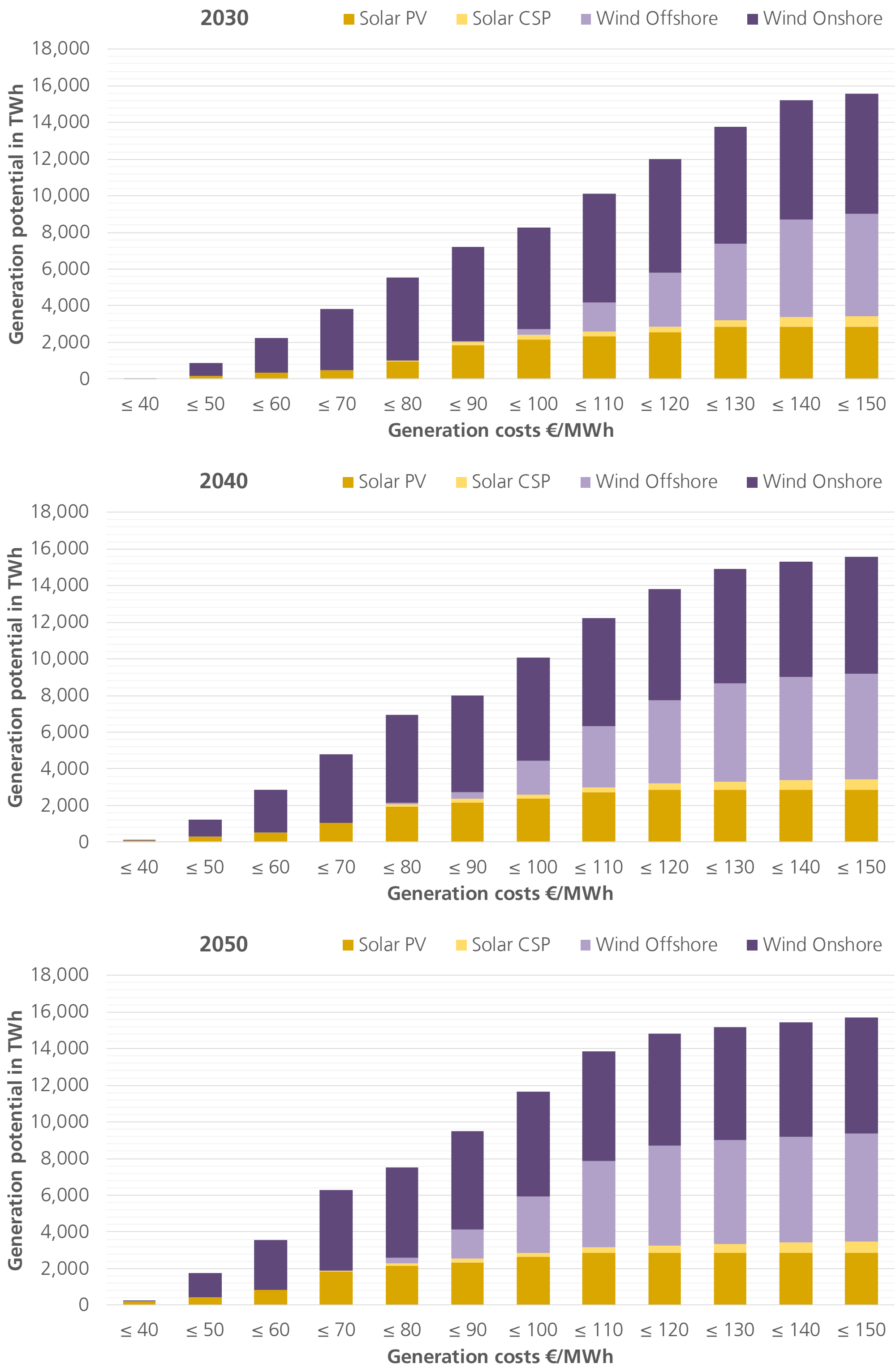


Figure 42: Generation potentials of renewable energies in Europe for the years 2030 to 2050

5.2 Cost assumptions for conventional and heating technologies

The assumed cost parameters for technology extension in the power sector and district heat grids for the years 2030 to 2050 are outlined in the tables below. This includes the parameters for central power plants (Table 15), for CCS plants (Table 16 and Table 17), for central CHP plants (Table 18) and for heating and storage technologies in heat grids (Table 19).

Table 15: Overview of central power plant parameters in all pathways

Technology	Availability year	Efficiency	Lifetime a	Investment €/kW	Fixed O&M €/(kW*a)	Variable O&M €/MWh
Coal steam plant	2030	48%	40	1700	42.5	1.5
	2040	49%	40	1700	42.5	1.5
	2050	49%	40	1700	42.5	1.5
Combined cycle gas turbine	2030	60%	30	950	11.3	3.0
	2040	60%	30	950	11.3	3.0
	2050	60%	30	950	11.3	3.0
Gas turbine	2030	40%	30	450	7.5	2.7
	2040	40%	30	450	7.5	2.7
	2050	40%	30	450	7.5	2.7
Lignite steam plant	2030	47%	40	1900	57.0	1.5
	2040	47%	40	1900	57.0	1.5
	2050	47%	40	1900	57.0	1.5
Pumped storage	2030	91%	40	1000	10.0	0.5
	2040	91%	40	1000	10.0	0.5
	2050	91%	40	1000	10.0	0.5

Table 16: Overview of CCS plant parameters in the Directed Vision pathway

Technology	Availability year	Efficiency	Lifetime a	CO_2 capture rate	Investment €/kW	Fixed O&M €/(kW*a)	Variable O&M €/MWh
Coal steam plant with CCS	2030	38%	40	93%	3400	85.0	8.4
	2040	38%	40	93%	3200	80.0	8.4
	2050	38%	40	93%	3000	75.0	8.4
Combined cycle gas turbine with CCS	2030	54%	30	95%	1500	22.5	7.6
	2040	54%	30	95%	1350	20.3	7.6
	2050	54%	30	95%	1200	18.0	7.6
Lignite steam plant with CCS	2030	37%	40	92%	3800	114.0	9.5
	2040	37%	40	92%	3600	108.0	9.5
	2050	37%	40	92%	3400	102.0	9.5

Table 17: Overview of CCS plant parameters in the National Champions pathway

Technology	Availability year	Efficiency	Lifetime a	CO_2 capture rate	Investment €/kW	Fixed O&M €/(kW*a)	Variable O&M €/MWh
Coal steam plant with CCS	2030	38%	40	93%	4080	102.0	8.4
	2040	38%	40	93%	3840	96.0	8.4
	2050	38%	40	93%	3600	90.0	8.4
Combined cycle gas turbine with CCS	2030	54%	30	95%	1800	27.0	7.6
	2040	54%	30	95%	1620	24.3	7.6
	2050	54%	30	95%	1440	21.6	7.6
Lignite steam plant with CCS	2030	37%	40	92%	4560	136.8	9.5
	2040	37%	40	92%	4320	129.6	9.5
	2050	37%	40	92%	4080	122.4	9.5

Table 18: Overview of central CHP plant parameters in all pathway

Technology	Availability year	Electric capacity MW	Investment €/kW	Lifetime a	Power to heat ratio	Efficiency CHP	Electrical efficiency	Fixed O&M €/(kW*a)	Variable O&M €/MWh
Gas turbine CHP	2030	90	730	30	0.63	85%	33%	30.0	2.7
	2040	90	730	30	0.63	85%	33%	30.0	2.7
	2050	90	730	30	0.63	85%	33%	30.0	2.7
Combined cycle gas turbine CHP	2030	100	950	30	1.19	88%	48%	30.0	3.0
	2040	100	950	30	1.19	88%	48%	30.0	3.0
	2050	100	950	30	1.19	88%	48%	30.0	3.0

Table 19: Overview of central heating and storage technologies in district heat grids in all pathways

Technology	Availability year	Thermal capacity MW	Efficiency	Lifetime a	Investment €/kW	Fixed O&M €/(kW*a)	Variable O&M €/MWh
Gas boiler	2030	5	94%	20	52.7	2.1	0.0
	2040	5	94%	20	51.1	2.0	0.0
	2050	5	94%	20	49.6	2.0	0.0
Electric heater	2030	10	95%	20	100.0	5.5	0.0
	2040	10	95%	20	100.0	5.5	0.0
	2050	10	95%	20	100.0	5.5	0.0
	2030	10	variable	20	600.0	2.4	0.0

Large heat pump	2040	10		20	600.0	2.4	0.0
	2050	10		20	600.0	2.4	0.0
Heat storage	2030	4.5	99%	20	22.2	0.0	0.0
	2040	4.5	99%	20	22.2	0.0	0.0
	2050	4.5	99%	20	22.2	0.0	0.0
Hydrogen boiler (Localization pathway)	2030	5	94%	20	52.7	2.1	0.0
	2040	5	94%	20	51.1	2.0	0.0
	2050	5	94%	20	49.6	2.0	0.0

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