New Generation - Technical Report

Building a clean European electricity system by 2035

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Contents

Chapter 1

Model Overview

The modelling exercise has been carried out using the modelling platform Artelys Crystal Super Grid, a solution dedicated to the analysis of multi-energy systems that is developed and distributed by Artelys. In this analysis, the 2020-2050 horizon is represented by a set of 5-year periods, that is, a total of seven calendar years (2020, 2025, …, 2050). The model allows for a joint optimization of investments and operations (cost-minimising criterion), simulating the operational behaviour of the system with an hourly time resolution and a country-level spatial granularity.

The costs that the model aims at minimising include operational costs, i.e. fuel and CO2 costs, variable O&M costs and loss of load penalties (if any), and investment costs in order to ensure the electricity demand can be met robustly (i.e. with an adequacy criterion of a maximum of three hours of loss of load).

The geographic area taken into account covers the EU27 at country level, as well as Norway, Switzerland, the UK, North Macedonia, Montenegro, Serbia, Bosnia-Herzegovina, Kosovo[1] and Albania. The model simultaneously optimises investments in and operations of all categories of assets, including different generation technologies, flexible consumption technologies, storage assets, and interconnections between areas (cf. Chapter 6 for details of the potentials that have been considered for the considered technologies).

[1] All references to Kosovo, whether the territory, institutions or population, in this text shall be understood in full compliance with United Nations' Security Council Resolution 1244 and without prejudice to the status of Kosovo.

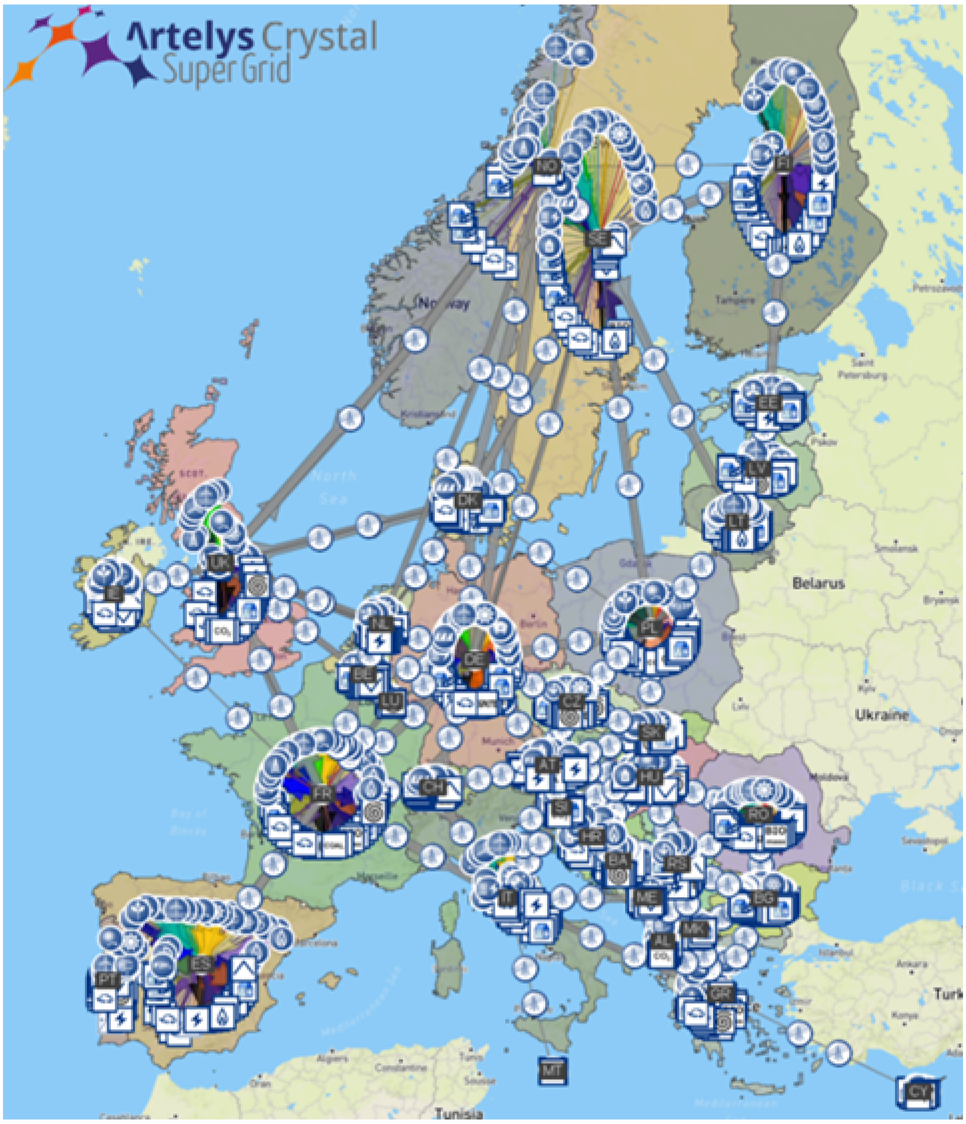

Figure 1.1: Artelys Crystal Super Grid modelling platform

In order to ensure the robustness of the results, three years of weather data are considered for each calendar year of the trajectory. These climatic variations impact both the renewable generation profiles (mainly wind, solar and hydro) and the dynamics of the demand (via the thermo-sensitivity of the heating and cooling demands), and have been constructed from historical data.

Finally, the modelling exercise takes into account, for the Technology Driven and System Change pathways, a carbon budget over the 2020-2050 period that restricts the electricity generation from carbon-intensive technologies. The model is also able to constrain carbon emissions for a specific year, which was used in the study to limit emissions in 2020 (historical emissions) and 2050 (carbon neutrality).

Hourly electricity demand profiles

In order to build hourly demand time series, which are used as inputs of the model, the volumes per country, sector and usages provided by Ember are combined with typical consumption profiles and specific models of flexibility (cf. Section 4.2 for details on flexibility).

Different consumption profiles for heating are distinguished: conventional electric heating, heat-pump heating and cooling. The thermosensitive profiles (heating and cooling) have been constructed from statistical models of the consumption thermos-sensitivity, calibrated on historical country-level load curves and temperature data.

Electric vehicles are divided into two groups, depending on whether they are charged at home, at night, or at work, during the day. The charging of these vehicles can be direct (charging when the vehicle connects) or dynamically controlled by the system, under the constraint of being charged at the end of the charging period. More details regarding the flexibility of electric vehicles are provided in Section 4.2 .

The remaining uses (specific electricity, industry, agriculture, etc.) are aggregated into a standard non-thermosensitive profile.

Model limitations

To cope with the large amount of data required for the analysis, some aspects of the modelling exercise have been restricted for reasons of computing capacity. In particular, ramping constraints of thermal capacities have not been integrated, but internal tests have shown that the results are plausible (in particular for technologies with limited flexibility such as nuclear power) and that the impacts on results are limited. The repowering of renewables or the adaptation of gas-fired facilities to use hydrogen turbines have also not been considered to limit the dimension of the optimization problem. Grid inertia constraints and reserve requirements have not been modelled.

Chapter 2

Carbon budget methodology

The primary climate constraint placed on the Technology Driven and System Change pathways is a carbon budget for in-scope energy supply services, i.e., electricity and CHP. The only additional climate constraint is a requirement for the same energy supplies to reach absolute zero emissions by 2050 and 2040 in the Technology Driven and System Change pathways respectively. The Stated Policy pathway is not constrained by a carbon budget, rather the electricity (and heat) supply capacities are pre-determined based on existing plans up to and including 2035. After this, absolute zero emissions must be reached by 2050, like the Technology Driven scenario. In lieu of a carbon budget, an external carbon price is applied to the Stated policy pathway, starting at 50 Euros in 2020 and increasing by 25 Euros every 5 years. The 2050 zero emissions goal is deemed consistent with the Stated Policy storyline because every country in scope has in some way signalled intent to reach 2050 carbon neutrality. All EU member states have agreed to the 2050 carbon neutrality goal. The 2050 target is in UK law. The six Western Balkan countries have signed the Sofia declaration. Switzerland aims to have net-zero emissions by 2050, and Norway has committed to become a "low-emissions society" by 2050[2]. The remainder of this section discusses the choice of carbon budget for the Technology Driven and System Change pathways, for the sectors in scope.

According to the latest evidence from the IPCC AR6 WGIII[3], the world has a remaining carbon budget of approximately 500GtCO_2-eq if global heating is to be limited to 1.5°C (50% probability). The budget for 2°C (66% probability) of heating is higher at approximately 1150GtCO_2-eq. There is no internationally agreed upon method to allocate a given budget to countries or regions, instead the Paris agreement is predicated on nationally determined contributions, where each country decides what is a fair and equitable share for themselves. There are many ways to divide and allocate carbon budgets, based on factors such as historical emissions and capacity to decarbonise. Every method has shortcomings and it is not the intention of this report to address this issue. Estimates used here are largely based on the results of Integrated Assessment Models (IAMs), which provide regional GHG trajectories based on the economic optimisation of GHG mitigation.

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[2] Switzerland and Norway net zero status according to ECIU Net Zero stocktake 2022.
[3] https://www.ipcc.ch/report/sixth-assessment-report-working-group-3/

As a first step, a budget was estimated for the whole energy sector in Europe. Two principal sources were used for this: IAM data (IMAGE model[4]), and Paris Equity Check project. A budget is allocated to sectors within scope of the model using a combination of existing emissions data, and this is verified by comparison to existing power system modelling studies, including the EU Commission's modelling for the Fit for 55% package.

Energy-related emissions accounted for approximately 78% of Europe's total GHG emissions in 2019, with the power sector approximately 28% of the energy sector. Over the next 30 years, data from the IMAGE model (1.5C low overshoot) shows cumulative emissions of approximately 48GtCO_2 for the energy sector in Europe between 2020 - 2050. The Paris Equity Check project takes a different approach to estimating budgets. Under the so-called pledged warming scenarios, emissions pathways are calculated in which each country follows the least stringent of three equity concepts in order to collectively limit warming to 1.5C or 2C. This attempts to "reconcile the bottom-up architecture of the Paris Agreement with its top-down warming threshold.". Their results show cumulative total GHG emissions of 48GtCO_2-eq for the period 2020 - 2050, of which 37GtCO_2 would come from the Energy sector if the current share was maintained. We estimate the *Fit for 55%* package, if fully implemented, would result in cumulative emissions of approximately 45GtCO_2 for the EU27. On the basis of this evidence, we interpret 40-50GtCO_2 to be a 1.5C compatible budget for the whole European energy sector.

If the power sector maintained its current share of emissions (28%), the budget for 2020 - 2050 would be between 10-14GtCO_2. However, this ignores the reality that the power sector - unlike other parts of the Energy sector - has mature decarbonisation solutions available, enabling faster mitigation of emissions. Indeed, we estimate the power sector according to published pathways representing the Fit-for-55 package would emit 7.9GtCO_2 in the EU27 (or 9.4GtCO_2 if similar ambition is applied to all of Europe). Similarly, data obtained from the IMAGE model results in approximately 9-10GtCO_2 energy sector emissions in Europe. IN acknowledgement of the considerable uncertainty around carbon budgets, and the difficulty in disaggregating between regions and sectors, the clean power pathways are allocated different budgets, according to the level of ambition in the storylines. The Technology Driven and System Change pathways are modelled with carbon budgets of 9 and 8GtCO_2 respectively.

[4] Data kindly provided by the IMAGE modelling team. Model name:

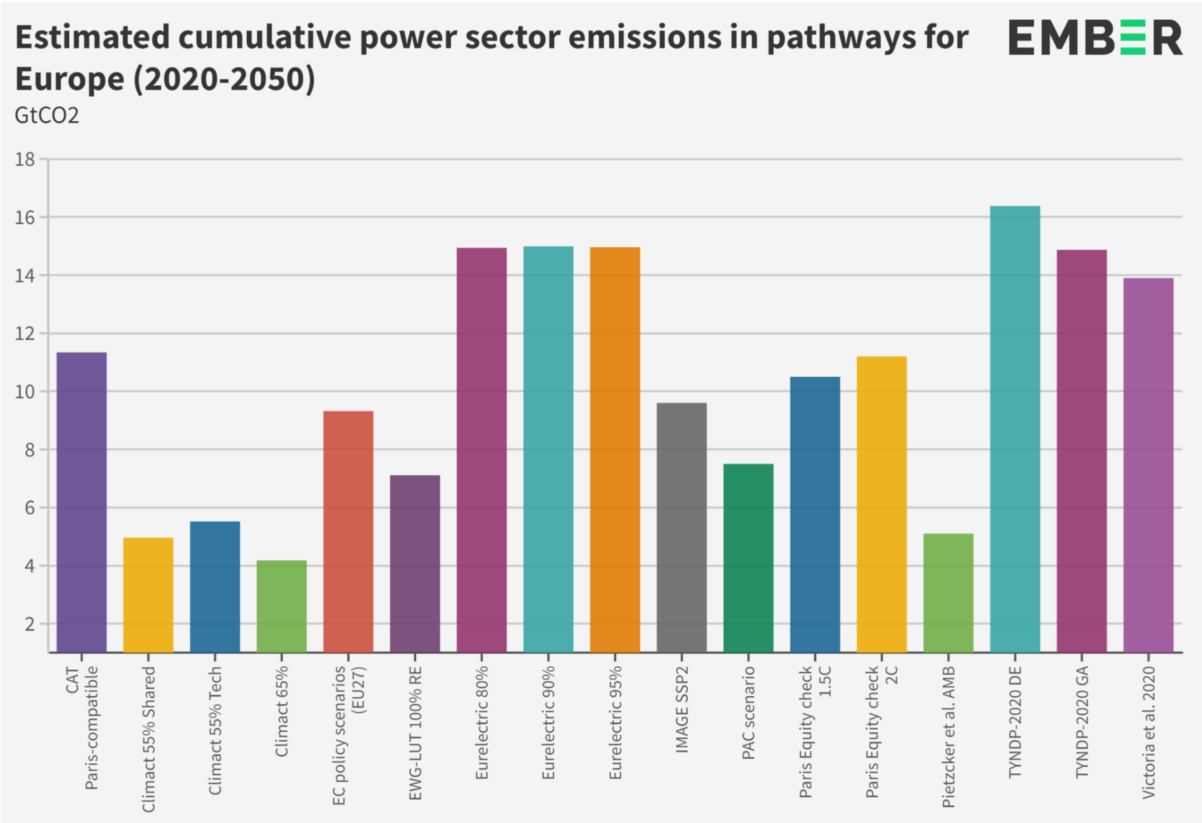


Figure 2.1: Cumulative power sector emissions (2020 to 2050) in recent 1.5C compatible energy scenarios for Europe.

Chapter 3

Final energy demand and electrification

All pathways assume a reduction in overall energy demand. Final energy demand reduces faster in the clean power pathways (TD & SC) through a combination of energy efficiency measures (building renovation and the switch to more efficient technologies) and societal change (shifting transport modes and the shift to a circular economy).

Final energy demand is estimated to reduce by only 8% in the Stated Policy pathway by 2035 (compared to 2019). Two thirds of these savings originate from the buildings sector, as a result of renovations. The remaining third are in transport - largely a result of the switch to electric vehicles, but partially offset by increased transport activity. Industry energy demand is assumed to remain constant.

In the Technology driven pathway, final energy demand reduces by 20% by 2035 and 43% by 2050. Transport and buildings account for the largest share in reductions by 2035, as efficient electric vehicles constitute a much larger share of the fleet, and more action is taken to renovate buildings and roll out efficient electric heat pumps.

Energy demand reduces fastest and furthest in the System Change pathway, decreasing by 35% by 2035 and 54% by 2050. By 2035, energy demand in buildings falls by over 40% due to a high building renovation rate, an increasing share of which are deep renovations. Transport electrification also increases sharply, with all new passenger registrations electric from 2025.

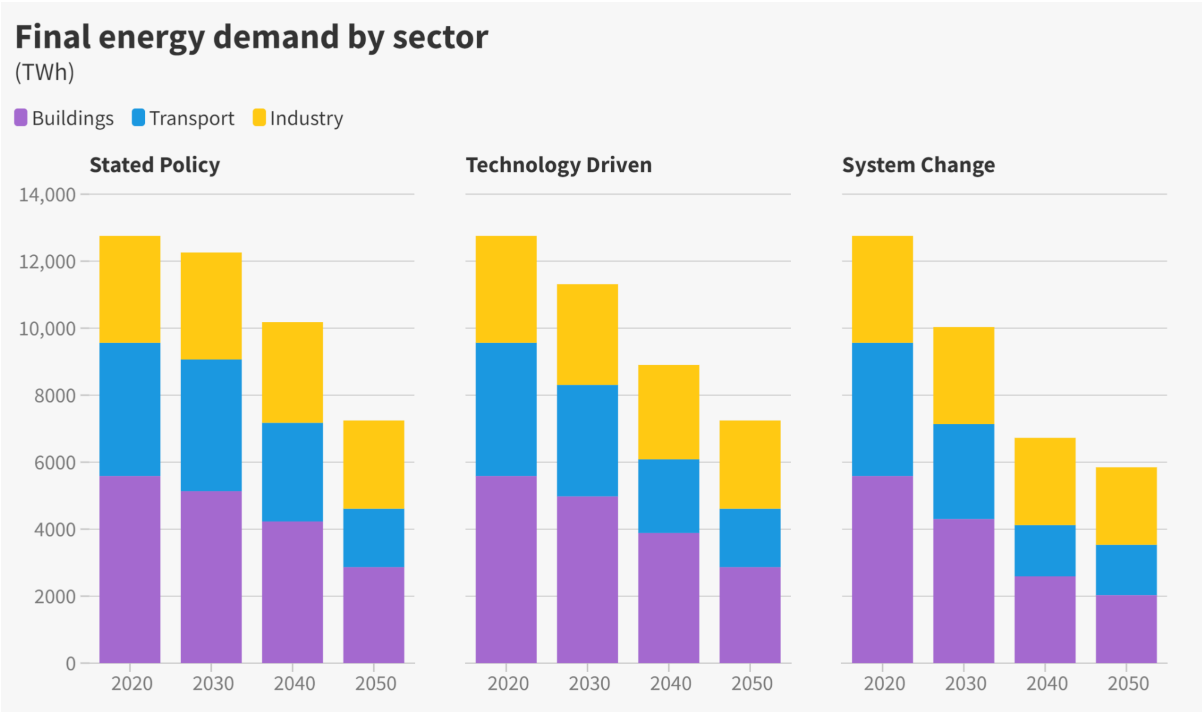


Figure 3.1: Estimated final energy demand by pathway and sector.

Increasing electrification is a near ubiquitous feature of net zero energy pathways. The pathways here are no exception. Specific assumptions regarding electricity demand are covered in the next section. Over time an increasing share of energy demand is supplied by electricity, with the expansion of wind and solar - enabled by system integration and flexibility - powering a cleaner power supply. The production of green hydrogen by electrolysis provides a key link between electricity and gas systems, as well as a major source of power system flexibility. This enables indirect electrification, as green hydrogen (and derived fuels) can decarbonise the end-uses that electricity does not reach. This sections explains assumptions regarding direct electrification only. Indirect electrification is covered in Section 5.

By 2035, direct electrification reaches 40% in the Technology Driven pathway, and 47% in System Change. This is compared with an estimated 30% in Stated Policy. A sector by sector approach is taken to first define the evolution of energy demand, and then the maximum possible electrification, which is typically assumed by the System Change scenario. In 2050, this results System change achieving a 66% direct electrification rate, whereas Technology Driven reaches 60%.

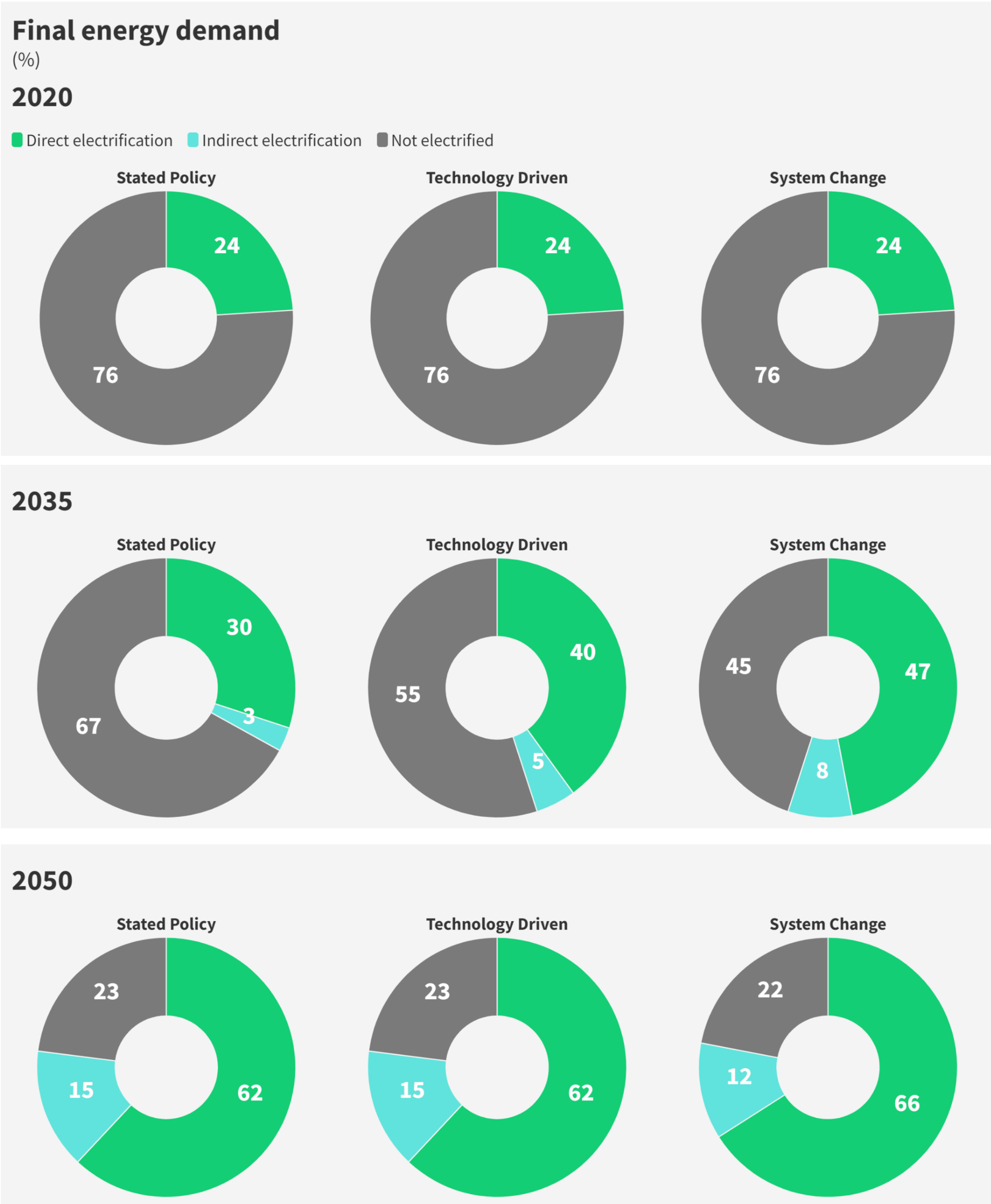
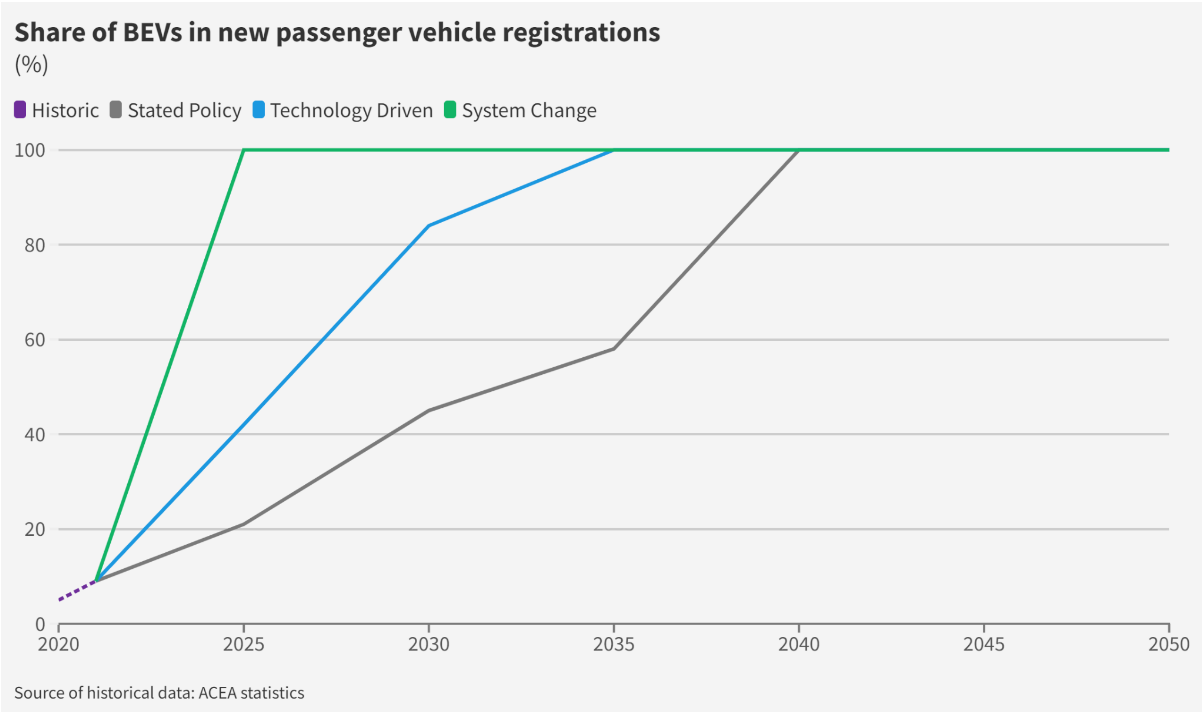


Figure 3.2: Final energy demand and projected shares of direct and indirect electrification in 2020, 2035, and 2050.

Transport

Activity and energy demand trends

Passenger car activity increases in the Stated Policy scenario according to the EU Commission's baseline (BSL) scenario. In the Technology Driven and System Change scenarios, modal shift from cars to buses, trains, and active alternatives reduces car activity by 6% relative to the baseline energy demand by 2030 and 12% by 2050. Car sharing saves a further 5% and 10% in Technology Driven and System Change scenarios by 2030. All of these behavioural effects are assumed to double by 2050. As a result of these behavioural changes, car activity increases until 2035 in the Stated policy scenario, remains flat in the Technology Driven scenario, and reduces over time in the System Change scenario. As a result of modal shifts from cars, passenger rail activity increases by 30-60% by 2035 compared to 2020, between the Stated Policy and System Change scenarios. Freight transport activity increases in all pathways, but the shift from road to electrified rail is fastest in the System Change Pathway. As a result, freight rail activity increases by 60% between 2020 and 2050 in the Technology Driven pathway, and doubles in the System Change pathway.



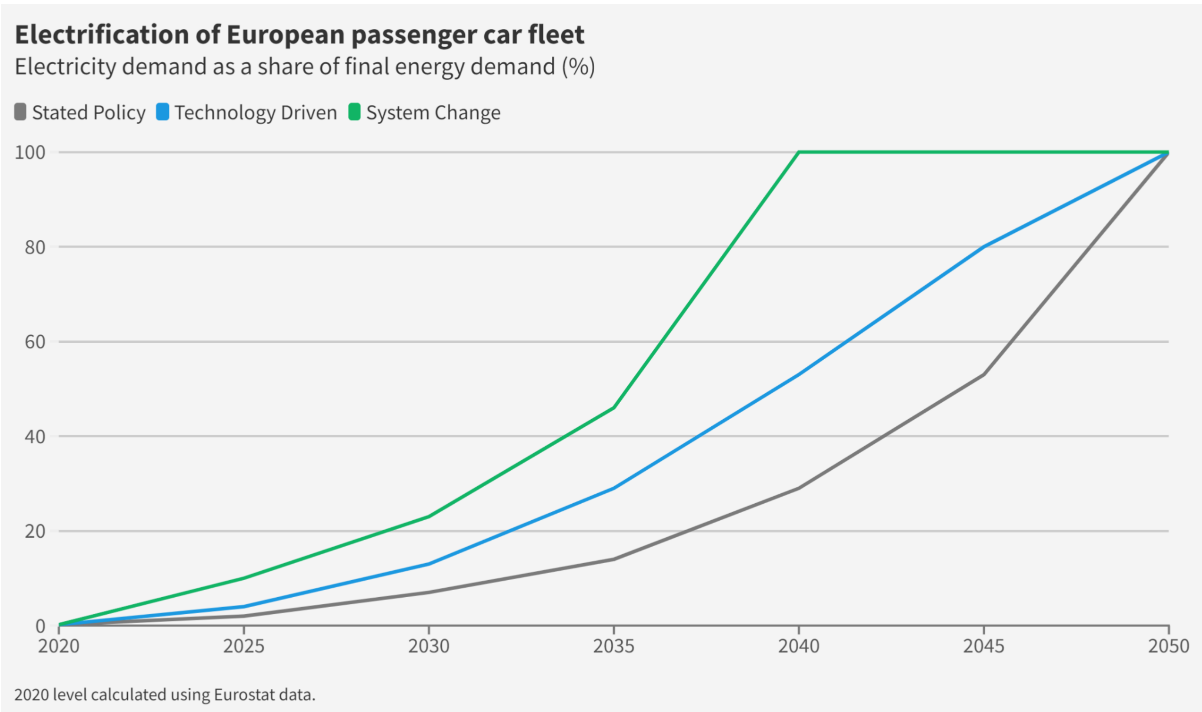


Figure 3.3: (TOP) % of new car registrations that are electric. (BOTTOM) average electrification of passenger car fleet.

Electrification

All pathways assume that BEVs become the dominant form of passenger car transport, with 100% market penetration by 2050. The average age of cars in Europe by country is used to estimate the turnover rate of vehicles, and hence the country-specific pace of electrification. In all pathways the proportion of new car registrations that are BEVs increases every year, with market penetration proceeding fastest in the System Change pathway and slowest in Stated Policy. Figure 3.3 shows the assumed trends in BEV registrations per year. In 2021 BEVs accounted for 9% of new registrations.

The electrification of all road transport is assumed to reduce final electricity demand on average by a factor of three, owing to the improved tank-to-wheel efficiency of electric drive-trains over internal combustion engines.

Heating and cooling

Energy demand trends

All scenarios assume that direct electrification will grow to dominate the supply of space heating, and the final energy required to heat buildings will be reduced by energy saving measures. Indeed, widespread material improvements to building stock are in many countries a prerequisite to the use of efficient electric heat pumps. Scenarios differ in the pace of this electrification, and the speed and extent of energy savings achieved.
Total H&C demand in 2020 and 2030 projections are taken from JRC analysis of NECPs[5]. This 2020 data is taken as the starting point for all pathways, and the 2030 projection as the trajectory of the Stated Policy scenario. Space heating and cooling is isolated from other H&C demand as this is the most temperature dependent and therefore has the biggest impact on electricity demand profiles. This is done by applying the country-level breakdown

[5] Toleikyte, A. and Carlsson, J., Assessment of heating and cooling related chapters of the national energy and climate plans (NECPs), EUR 30595 EN, Publications Office of the European Union, Luxembourg, 2021.

of H&C demand by type, reported by Heat Roadmap Europe (HRE) project[6]. The 2030 data provided by JRC provides the basis for the Stated Policy scenario. Most countries show modest reductions, with total EU27 space heating demand falling 10% by 2030.
In the Technology Driven and System Change scenarios, it is assumed additional efficiency measures - principally building renovation - can accelerate these energy savings. The EUCalc tool[7] was used to project future space heating demand under scenarios with an average renovation rate of 2% or 3%. These assumptions are applied to the Technology Driven and System Change scenarios respectively, and result in savings of 50% and 70% by 2050, relative to 2020.

Space cooling demand is assumed to increase by 70% under the Stated policy scenario, as slow improvements to building efficiency are unable to offset increasing demand for air conditioning in a warming European climate. The System Change scenario assumes an ambitious building renovation program, sufficient to offset the growth in cooling demand. The Technology Driven scenario assumes half as much growth as the Stated policy scenario. This is a proxy for the IEA's finding[8] that efficiency gains in cooling can approximately cut demand growth in half in Europe compared to a baseline case.

District heating

Total H&C demand is split into two broad categories: that which is and isn't supplied by District Heating (DH) networks. This approach allows exploration of different levels of DH penetration, the future of which is uncertain, and hence the contributions of different technology portfolios to H&C supply. Future evolution of heat supply - by DH or individual sources - is not included in the model optimisation. Both the penetration of DH and the technology mix in the H&C sector - by country - are pre-defined for each pathway to minimise computational complexity and retain the study's focus on the power sector.

The penetration of DH in 2020 is estimated at 11%. The Stated Policy and Technology Driven scenarios assume no increase in DH penetration. This is consistent with NECPs until 2030, and could be considered more ambitious than the current outlook, given declines[9] observed

[6] Paardekooper, S. et al. (2018). Heat Roadmap Europe 4: Quantifying the Impact of Low-Carbon Heating and Cooling Roadmaps. Aalborg Universitetsforlag.
[7] http://tool.european-calculator.eu/intro
[8] Future of cooling, IEA, 2018
[9] Delivered heat declined between 2010 and 2020 in Europe (IEA District Heating analysis, 2021)

in some DH systems, particularly in Central and Eastern Europe. The System Change scenario assumes an increase in DH penetration, reaching 20% by 2035 and 32% by 2050. This increase is computed by raising the share uniformly across countries that already have DH systems. The maximum potential DH penetration by 2050 is taken as the optimal level recommended by the HRE study.

Electrification and CHPs

Both DH and non-DH shares of H&C are assumed to electrify over time, with fossil sources from CHPs to individual boilers primarily replaced by highly efficient electric heat pumps. The capacities of fossil CHP plants are not included in the optimised capacity expansion model, instead they are pre-defined according to simplified fossil phase-out trajectories in the heating sector. On DH networks, fossil CHP is assumed to be entirely phased-out by 2050 in the Stated Policy scenario and by 2040 in both the Technology Driven and System Change scenarios. The heat supply from fossil CHPs in each country is assumed to be replaced by a standard mix consisting of: 30% bioenergy CHP, 40% large heat pump, and 40% zero emissions sources including energy savings. Fossil and bioenergy CHP capacities available to the power system model are adjusted accordingly, and are made available for power system dispatch.

In buildings with individual (off-network) heat supplies, it is assumed that electric heat pumps eventually cover all space heating requirements. This occurs by 2050 in the Stated Policy (Delayed action) and Technology Driven pathways, and 2040 in the System Change pathway. The current technology mix in this market segment is estimated by applying detailed HRE statistics to 2020 H&C demand. The share of heat supplied by direct electric (resistive) heating remains largely unchanged until 2030 in all pathways, as it is assumed that fossil heating sources are replaced as a priority. The share of direct electric heating gradually reduces to zero by 2050 in the Technology Driven pathway (and Stated Policy) by 2050, and by 2040 in the System Change pathway.

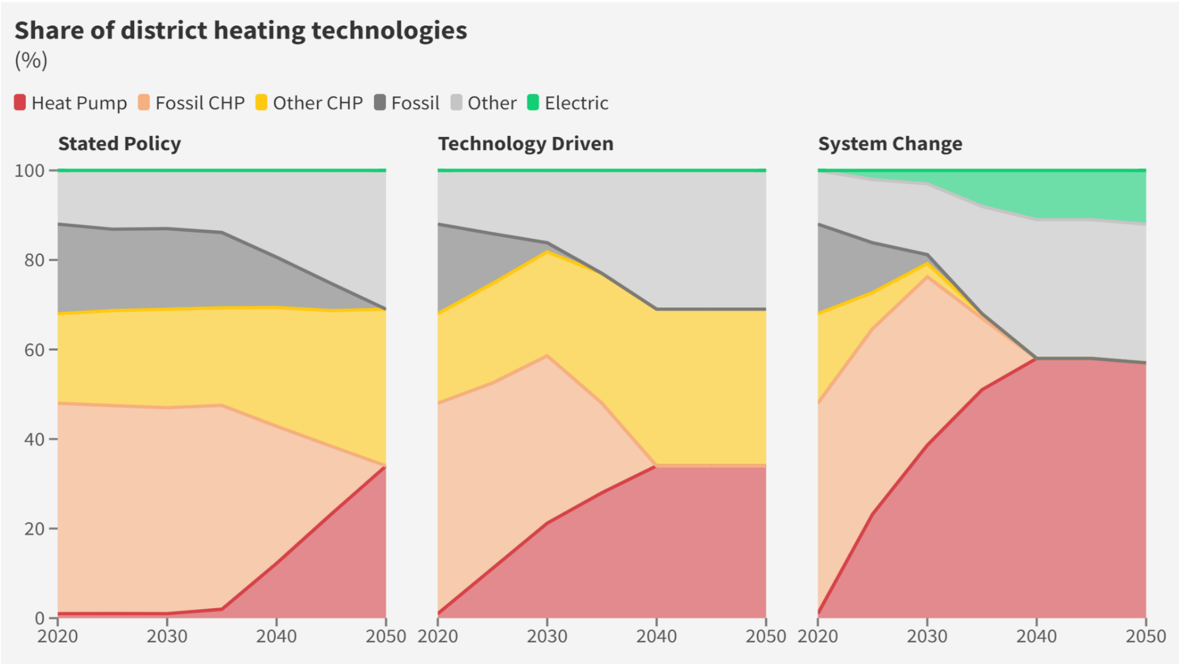


Figure 3.4: Share of district heating technologies across the three core pathways

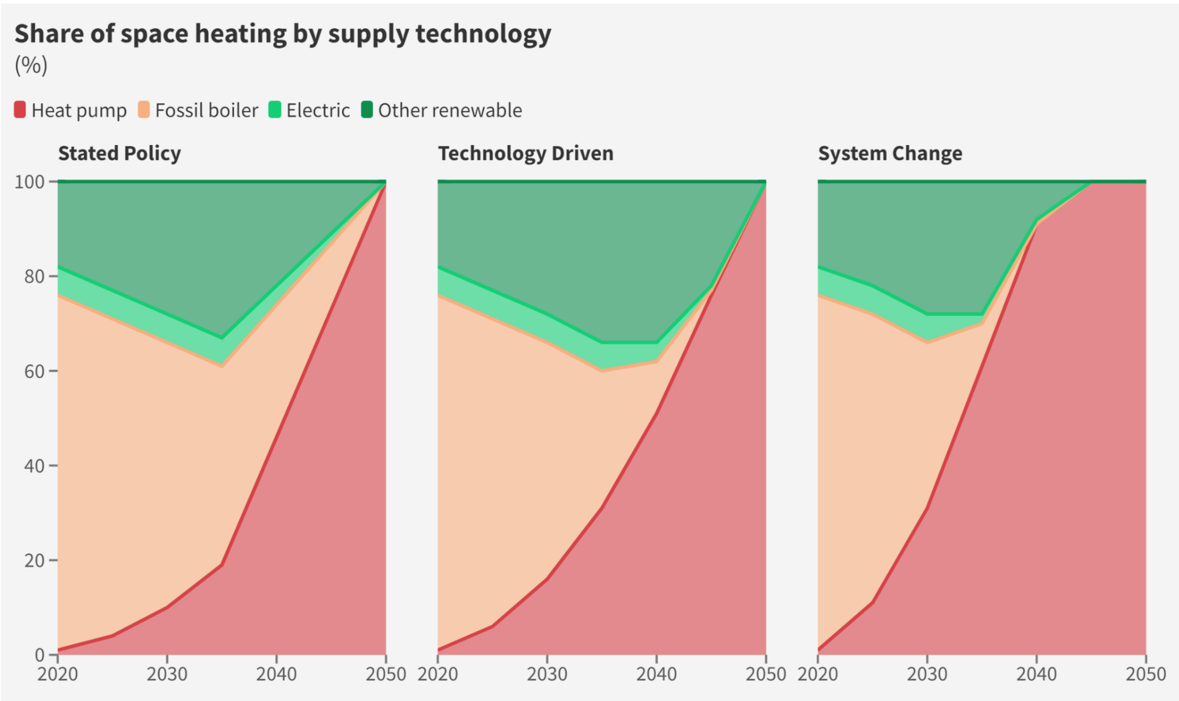


Figure 3.5: Space heating from individual (non-networked) sources - share of final consumption by supply technology (%).

Industry

Energy demand trends

The Stated policy scenario assumes no change in industrial energy demand until 2035. This is broadly consistent with the trend observed in the European Commission's EU Reference scenario (REF2020). After 2035, energy demand reduces to converge with the Technology Driven scenario by 2050. Both the Technology Driven and System Change scenarios assume additional energy saving by increased process efficiency and through the implementation of circular economy principles. The demand reduction potential in each industrial sub sector is taken from CAN Europe's PAC scenario, and applied to each country in the System Change scenario, taking into account the country specific composition of industry. This results in an aggregated 27% reduction in final energy demand between 2020 and 2050. Reductions in energy demand in the Technology Driven scenario are computed in the same way but the full potential is not reached by 2050, resulting in a more moderate 17% reduction in energy demand.

Electrification

Madeddu et al. (2020)[10] estimate the potential for direct electrification in each industrial sub sector. This data is combined with the industrial composition in each country to estimate a maximum potential for direct electrification of industry. The average across all countries of this theoretical maximum - when weighted by industrial energy consumption - is 76%. While it is assumed that direct electrification is prioritised, other low or zero emissions fuels may also play a role. In acknowledgement of this, and in accordance with the differing speeds of electrification in the pathways, electrification reaches 57% in the Technology Driven scenario and 64% in the System Change scenario by 2050. In the Stated Policy scenario, like final energy demand, electrification rates remain unchanged until 2035, before quickly accelerating to reach 57% by 2050.

[10] Madeddu et al 2020, "The CO2 reduction potential for the European industry via direct electrification of heat supply (power-to-heat)", Environ. Res. Lett. 15, 124004.

Chapter 4

Electricity demand

All pathways show a huge increase in electricity demand to 2050, despite reductions in final energy demand resulting from energy savings. This increased electricity demand facilitates clean electrification both directly (to decarbonise space heating and light transport) and indirectly via hydrogen electrolysis (to decarbonise heavy industry and heavy transport).

Power demand (excluding power-to-X) in the Stated Policy pathway is estimated to increase by 17% to 3800TWh by 2035. In the Technology Driven and System Change pathways this growth is 34% and 27%, reaching 4350TWh and 4100TWh respectively. By 2050, electricity demand increases by 50% in the Technology Driven pathway to 4850TWh, while in System Change continued energy saving measures cause power demand to plateau, never exceeding 4250TWh.

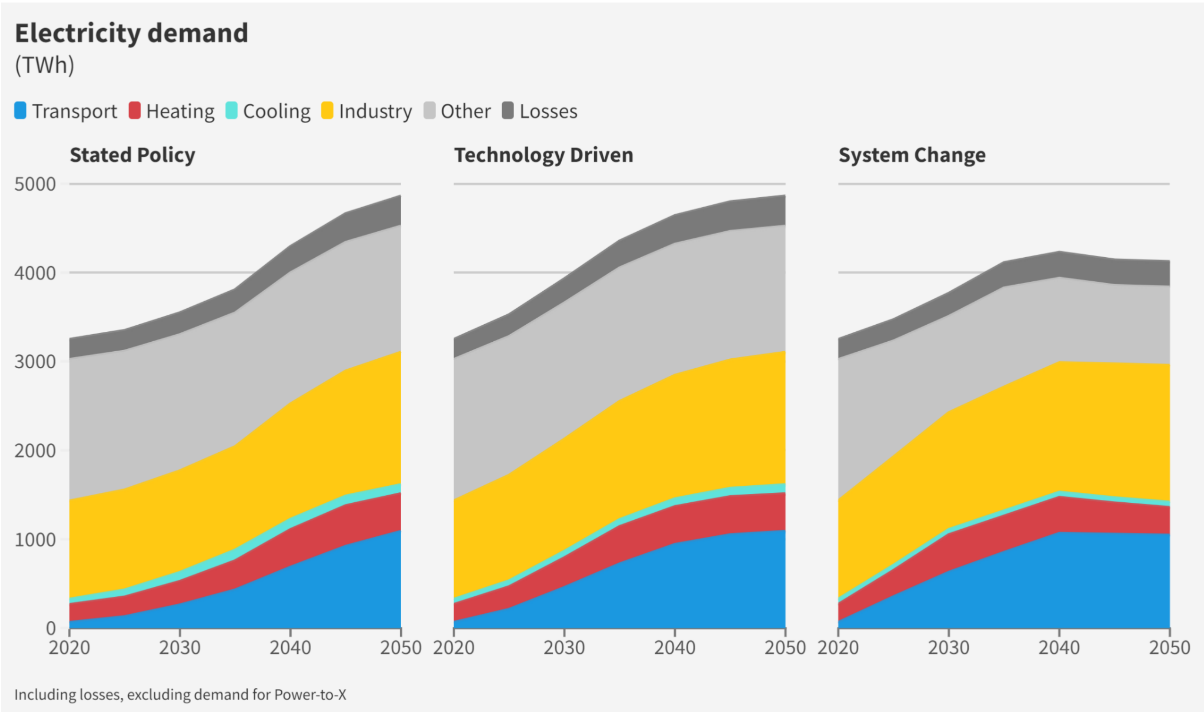


Figure 4.1: Electricity demand by sector, by year, by pathway.

Demand methodology

The characteristics of future demand, as well as the total level, will have critical implications for the economics of power generation. Fast growth in electricity demand from new sectors will profoundly change the hour to hour demands on the power system. With this challenge will come new opportunities to create a more flexible system, with demand reacting to supply availability to create a more flexible and resilient electricity system, to the benefit of both consumers and system resilience.

All pathways share a common starting point - the modelled year 2020. The demand volume in this year is based largely on actual data from 2019, and hence is not pandemic-affected. The model does therefore not take into account the (relatively short-lived) impact of the COVID-19 pandemic on electricity demand and the wider energy system.

Future electricity demand will depend on a complex interplay between social and economic drivers which are difficult to foresee. In an attempt to simplify this problem, the modelled pathways differ mainly in two principal aspects: the speed of electrification across the economy, and the extent to which energy savings are achieved. These concepts are linked, as electrification frequently delivers an efficiency improvement due to the inefficient nature of fossil fuel combustion. The speed and extent of electrification and energy savings will be the result of technical, economic, political, and behavioural drivers. The benefit of creating multiple pathways is that variations across these drivers can be explored, resulting in scenarios that span a feasible range of future demand.

As well as demand volumes, the distribution of load across the hours, days, weeks and months of the year has critical implications for the economics of power generation and storage. These load profiles will also change as electricity becomes a more dominant energy carrier, powering an expanded and more diverse set of end uses.

Multiple steps are taken to estimate future electricity demand and translate these into hourly load profiles:

- Annual volume is estimated sector by sector (transport, buildings, industry, and other) by applying scenario-specific assumptions. In general, the System Change scenario assumes the greatest energy savings combined with the fastest and deepest electrification. In contrast, the Stated Policy scenario proceeds the most slowly in both aspects until 2035, before accelerating to 'catch up' with the Technology Driven scenario by 2050.

- Hourly load profiles are computed for each sector. These consider changes that will be brought about by the growth of new demand sources, combined with assumptions about consumer behaviour and usage patterns (e.g., electric vehicles and heat pumps)
- Sectors are combined, and the resulting total hourly demand is optimised to account for the ability of flexible usage to reduce peak demand, e.g., the smart charging of electric vehicles. The level and characteristics of demand flexibility are scenario specific, with the highest proportion and most engaged end-users in the System Change pathway.

Sectoral demand and flexibility

The modelling presented here includes several aspects of demand side flexibility.

Transport

The transport sector dominates growth in electricity demand in all pathways, principally due to the electrification of the passenger vehicle fleet. Rail services are also electrified, followed eventually by most freight transport. Total electricity demand in the transport sector increases from less than 100TWh in 2020 to over 1000TWh by 2050. The Stated Policy pathway reaches 425TWh electricity demand in transport by 2035. Faster electrification sees Technology Driven and System Change pathways reach 720TWh and 850TWh respectively by 2035.

An increasing proportion of electric vehicles are assumed to charge flexibly, helping to shift demand away from peak times. A subset of this smart fleet is also assumed to provide vehicle-to-grid services, able to discharge to the grid as well as offtake. The proportion of the smart fleet is assumed to increase linearly from 0% to 70% by 2050 in Technology Driven and Stated Policy pathways, and from 0% to 100% by 2050 in System Change, reflecting greater consumer engagement. The fraction of the smart EV fleet providing V2G is assumed to be one third in the Stated Policy and Technology Driven pathways, and two thirds in System Change.

Two forms of flexibility are implemented:

- Smart charging: The charging of EVs is optimised for all vehicles connected to the charging point (depending on hourly arrival and departure time series). The optimisation is subject to a set of constraints, such as each EV needs to be fully charged when leaving the charging point and the charging capacity may not exceed a maximum withdrawal from the grid (around 3 kW per vehicle)
- Vehicle-to-grid (V2G) technology: EV batteries are able to discharge to the grid, as well as offtaking.

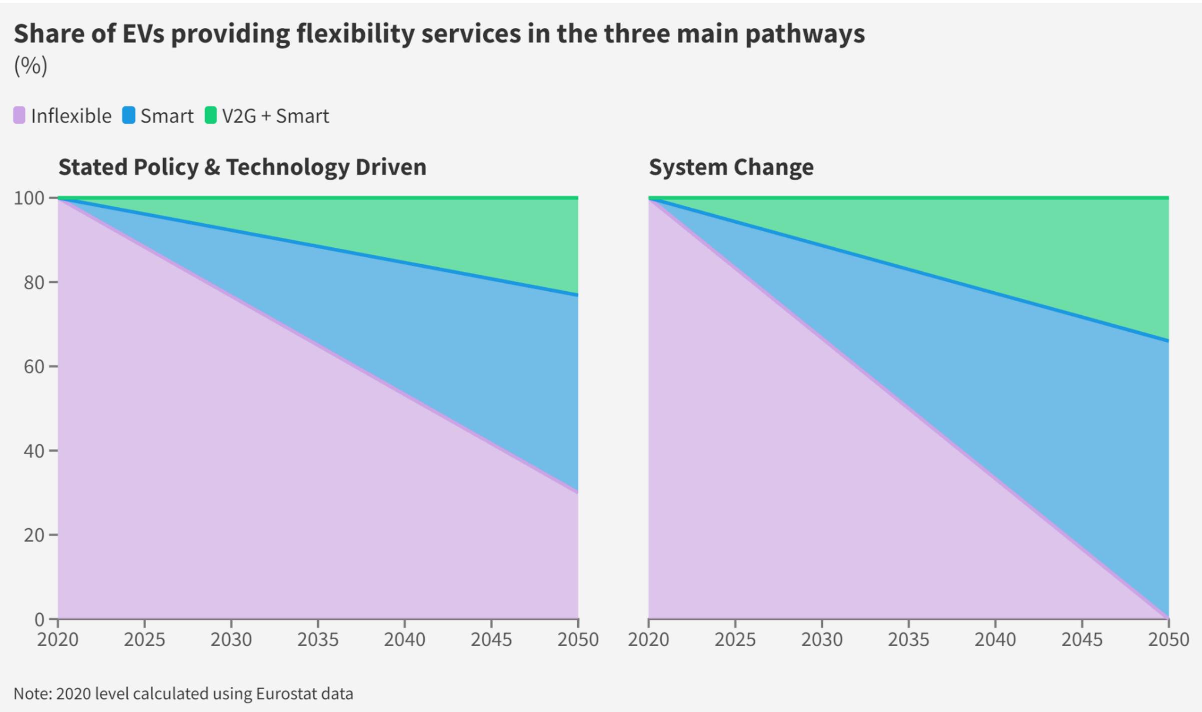


Figure 4.2: The proportion of BEV electricity demand by type: non-flexible, smart charging, and smart + V2G.

Buildings: heating and cooling

The buildings sector is the next largest contributor to demand growth, as electric heat pumps grow to dominate space heating. Electricity demand for heating increases 60% in Stated Policy by 2035. Assumptions about higher building efficiency are not enough to prevent further growth in the clean power pathways, which both see electricity demand for heating double by 2035. The differing speed of electrification means that by 2030, electricity demand for space heating is 265TWh in the Stated policy, compared to 335TWh in Technology Driven and 420TWh in System Change.

Individual heating

Building renovations, often required prior to heat pump installation, will create a building stock with improved thermal inertia. This means heat sources can be shut off during peak times, without indoor temperatures dropping below comfortable levels. Alternatively, heat pumps can be coupled with thermal storage (water tanks), allowing water to be heated at times other than when directly needed - such as times of electricity surplus. To reflect these dynamics, a fraction of heat pumps are modelled with the ability to shift demand up to 2 hours from when needed[11]. This fraction increases to 50% by 2050 to reflect the fact that the required building renovations will not happen overnight.

The ability of individual heat pumps to operate flexibly - while maintaining comfortable indoor temperatures - depends principally on the thermal properties of the building. All scenarios assume an improvement in building renovation rates and depth of renovation. Individual heat pumps are assumed to shift load up to 2 hours, with the fraction providing this service increasing to 50% by 2050. This gradual increase in flexibility represents the time required to perform building improvements. All heat pumps are assumed to operate with a temperature dependent coefficient of performance (COP), averaging COP=3 across all countries over the year.

District heating

DH has the potential to become an important source of flexibility in the energy system. The network itself provides thermal inertia, making it possible to offset heat input and heat offtake by several hours at least. Furthermore large water tanks can be connected to the network, offering a mechanism to absorb excess renewable electricity and discharge heat at

[11] European Commission, Directorate-General for Energy, Decentralised heat pumps : system benefits under different technical configurations : METIS Studies, study S6, Publications Office, 2019, https://data.europa.eu/doi/10.2833/800501

times of low renewables output. DH systems are not explicitly modelled in this study, meaning the full benefits of system integration between power and heat networks is not realised. Some of the available flexibility is captured by an assumption that large heat pumps can shift load up to 5 hours. The fraction of large HPs operating in this way increases to 60% by 2050 in all scenarios.

All heat pumps are assumed to operate with a temperature dependent coefficient of performance (COP), averaging COP=3 across all countries over the year. Due to model limitations, some potential important sources of flexibility are missing, which may bias the results in favour of supply-side flexibility. A notable example is large scale thermal storage (e.g., on district heat networks) which studies[12] have shown can provide measurable benefits to renewables integration and system efficiency.

Industry

Electricity demand from industry is assumed to be unchanged by 2035 in Stated Policy, with an increase from slowly increasing electrification offset by greater efficiency. In the clean power pathways, higher electrification of certain industrial sub-sectors results in electricity demand increasing from approximately 1100TWh in 2020 to 1330TWh (+20%) and 1390TWh (+26%) by 2035, in Technology Driven and System Change respectively. By 2050, demand increases to 1490TWh and 1540TWh respectively.

The industrial sector is assumed to become the largest provider of demand side response, either shifting or destroying demand at times of tight margins on the electricity system. The maximum power allowed to be removed is computed as a fixed percentage of the industrial (and commercial) sector's peak demand, assumed to be 9% in 2025 and increasing linearly up to 12% in 2050 for the three scenarios[13]. This consumption can be eliminated at any time, at a marginal cost of 300 €/MWh. In practice, this cost represents the opportunity cost of stopping an industrial process or switching to a more expensive fuel or back-up power generation. This cost is such that industrial load shedding is used as a last resort before leading to loss of load. No other sources of flexibility from industry are explicitly modelled.

[12] Brown et al. 2018, Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European energy system, Energy, 160.
[13] These percentages are taken from the National Grid (UK) Future Energy Scenarios 2021, according to the pathway with highest consumer engagement (*Consumer Transformation*).

Chapter 5

Hydrogen demand and Power-to-X

Hydrogen demand assumptions

In the industry sector, in the clean power pathways hydrogen is assumed to make up 9-11% of final energy consumption by 2035. This increases to 20% in TD by 2050, but only 15% in SC due to higher direct electrification. Synthetic methane (derived from green hydrogen) is also assumed to contribute 3% by 2035, increasing to 5% by 2050. This results in an industrial hydrogen demand of 370-400TWh by 2035 in clean power pathways, compared to just 290TWh in Stated Policy due to slower industrial transformation.

In the transport sector, hydrogen is assumed to make up an increasing share of non-electrified road and rail transport, reaching 100% by 2050 (2040 in System Change). As a result, hydrogen accounts for 4-12% of road and rail energy consumption by 2035. Domestic shipping and aviation are assumed to gradually switch to consume majority hydrogen (or derived fuels) by 2050, or 2040 in the System Change pathway. As a result hydrogen plus derived fuels account for 20-35% of shipping and aviation energy consumption by 2035, and a maximum of 65% by 2050. In total, hydrogen demand for transport in the clean power pathways is 130-290TWh by 2035. This is compared to an estimated 50TWh in Stated Policy. International aviation and shipping are out of scope, but would increase hydrogen demand markedly if included.

[TWh]	Stated Policy 2035	Stated Policy 2050	Technology Driven 2035	Technology Driven 2050	System Change 2035	System Change 2050
Estimated European hydrogen demand*	350	1130	510	1130	690	720
Transport	60	470	130	470	290	270
Industry	290	660	370	660	400	450

Table 5.1: Estimated hydrogen demand in 2035 and 2050 in the three core scenarios.
*Hydrogen demand includes that consumed directly for energy plus that for the production of derived fuels (ammonia and synthetic methane).

Electricity demand for Power-to-X

Each pathway is modelled with an associated annual demand for hydrogen, defined at the country level, which must be supplied either by the European power system (via electrolysis - green hydrogen) or from alternative production at a fixed price. Gas grids are not explicitly modelled, but in reality they will need to be reconfigured or rebuilt for the transport of hydrogen between countries. In the absence of gas grids, the modelling requires that each country supplies at least 50% of hydrogen from domestic sources. This prevents a large mismatch developing between demand centres and supply centres, and hence limits the impact of omitting gas transmission.

It is assumed by default that all European hydrogen demand is supplied by sources within Europe. Sensitivity modelling was carried out to test the impact on the power system of relaxing this assumption, in a scenario that represents a more open trade in hydrogen both within Europe and externally (see Box 4.3.2 in the main report).

Demand for hydrogen for energy is estimated for the industry and heavy transport sectors. No role for hydrogen is assumed for building heating or light transport, as direct electrification is many times more efficient.

[TWh]	*Stated Policy* 2035	2050	*Technology Driven* 2035	2050	*System Change* 2035	2050
European Hydrogen demand	347	1134	505	1134	691	719
Electricity demand for P2X	439	1436	639	1436	875	910

Table 5.2: Total European hydrogen demand and electricity demand for the production of green hydrogen through power-to-X. Note: Hydrogen demand includes that consumed directly for energy, and that for the production of derived fuels (ammonia and synthetic methane).

In the industry sector, in the clean power pathways hydrogen is assumed to make up 9-11% of final energy consumption by 2035. This increases to 20% in TD by 2050, but only 15% in SC due to higher direct electrification. Synthetic methane (derived from green hydrogen) is also assumed to contribute up to 5% by 2050. This results in an industrial hydrogen demand of 370-400TWh by 2035 in clean power pathways, compared to just 290TWh in Stated Policy due to slower industrial transformation.

In the transport sector, hydrogen is assumed to make up an increasing share of non-electrified road and rail transport, reaching 100% by 2050 (or 2040 in System Change). As a result, hydrogen accounts for 4-12% of road and rail energy consumption by 2035. Domestic shipping and aviation are assumed to gradually switch to consume majority hydrogen (or derived fuels) by 2050, or 2040 in the System Change pathway. As a result hydrogen plus derived fuels account for 20-35% of shipping and aviation energy consumption by 2035, and a maximum of 65% by 2050. In total, hydrogen demand for transport in the clean power pathways is 130-290TWh by 2035. This is compared to an estimated 50TWh in Stated Policy. International aviation and shipping are out of scope, but would increase hydrogen demand markedly if included.

The size of the electrolyser fleet in the Stated Policy scenario is informed by announced European and national strategies until 2030, after which it is determined by economic optimisation. In the Technology Driven pathway, electrolyser capacity is capped at 10GW by 2025 and 60GW by 2030. Any hydrogen demand that cannot be supplied as a result of these constraints is assumed to be supplied from alternative sources. In the System Change scenario, CCS technology is assumed not to be available, and hence green hydrogen is the only available form of low-carbon production. Electrolyser capacity is therefore unconstrained in all timesteps.

In summary, estimated electricity demand for P2X in all pathways is based on assumed demand for green hydrogen (and derived products) from industry and heavy transport sectors. By 2035, estimated power demand for P2X adds 12% to electricity demand in the Stated Policy pathway. In the Technology Driven and System Change pathways, P2X adds 15% and 21% to electricity demand, respectively.

Modelling hydrogen production

The model ensures that the hydrogen demand for industry and transport is supplied annually by optimising electrolyser investments and operations. Electrolyser deployment competes with an alternative hydrogen source, blue hydrogen, except in the System Change scenario where only green hydrogen is allowed. The hydrogen production for the power sector is endogenously optimised.

Moreover the assumptions about the location of hydrogen production (Europe is self-sufficient and there is no extra-Europe exports; 50% of country-specific demand is produced in the country – cf. details above) are integrated into the model by adding constraints on the annual hydrogen consumption.

Additional constraints on electrolysers capacities are also added to reflect national and European strategies for 2025 and 2030. A minimum capacity is installed in each country, equal to already announced national plans, and the total capacity is capped at 10 GW in 2025 and 60 GW in 2030 at the Europe level. This maximum constraint does not apply for the System Change scenario as the modelled demand for renewable hydrogen for the next decade exceeds the European Commission's announcements of 60 GW by 2030.

The blue hydrogen supply is modelled by a fixed price, derived from an investment cost based on the ASSET database, a load factor assumption of 7000 hours and a variable cost based on gas and carbon prices of the scenario. Capture rate and efficiency is assumed to be 83% and 67% respectively, and the resulting blue hydrogen price is shown in Table 5.1.

	2025	2030	2035	2040	2045	2050
Blue hydrogen price (€/MWh)	61.2	66.4	67.59	68.77	69.96	71.14
Blue hydrogen price (€/kgH2)	2.04	2.21	2.25	2.29	2.33	2.37

Table 5.1: Estimated cost of blue hydrogen according to investment cost, and gas and carbon price assumptions. The same costs are used across the modelled scenarios (excluding System Change were blue hydrogen is not considered)

The model integrates a power-to-H2-to-power option by enabling storage of hydrogen to be used later in hydrogen turbines. As the gas and hydrogen infrastructures are not explicitly modelled, sanity checks have been performed to confirm actual hydrogen storage needs are plausible.

Chapter 6

Technology Potentials and Constraints

Overview

Power system modelling has been used to create pathways in which the demand - described above - is matched by supply at the hourly level, at least cost. Both power system investments on timescales of decades, and operation on timescales of hours, are optimised to meet demand at the lowest possible cost in the context of each pathway storyline.

A key difference between the storylines is the power generation technologies made available, and the extent to which different technologies can be deployed. In the Stated Policy pathway, deployment of different generation sources is restricted to what is described by current government plans up to 2035. In the clean power pathways, further deployment is possible, insofar as these remain within technology-specific potentials.

A full range of low-carbon generation assets are available for investment to the Technology Driven pathway (and Stated Policy, after 2035). This includes some technologies that are yet to reach technical or market maturity (gas CCS and hydrogen turbines). The System Change pathway has a greater focus on proven technology, and is designed to reflect the vision of European civil society. As such, neither investment in generation with CCS nor new nuclear power is permitted.

In order to limit model complexity, not all technologies are optimised.

<table>
<tr><th></th><th>Stated Policy</th><th>Technology Driven</th><th>System Change</th></tr>
<tr><td colspan="4">Power only</td></tr>
<tr><td>Solar</td><td rowspan="11">NECP+ until 2035 - optimised after 2035</td><td rowspan="9">Optimised</td><td rowspan="4">Optimised</td></tr>
<tr><td>Wind onshore</td></tr>
<tr><td>Wind offshore</td></tr>
<tr><td>Batteries</td></tr>
<tr><td>Baseload gas (CCGT)</td><td>Phase-out before 2035</td></tr>
<tr><td>Gas peaker (OCGT)</td><td>Phase-out before 2040</td></tr>
<tr><td>Coal</td><td rowspan="2">Phase-out before 2030</td></tr>
<tr><td>Lignite</td></tr>
<tr><td>Nuclear</td><td>No new</td></tr>
<tr><td>Hydrogen turbines</td><td rowspan="2">Optimised (from 2030)</td><td>Optimised (from 2030)</td></tr>
<tr><td>Gas+CCS</td><td>Not included</td></tr>
<tr><td>Oil</td><td rowspan="5">NECP+ until 2040 - not optimised after 2040.</td><td rowspan="5">Not optimised - as Stated Policy</td><td>Phase-out before 2040</td></tr>
<tr><td>Pumped storage</td><td rowspan="4">Not optimised - as Stated Policy</td></tr>
<tr><td>Hydro</td></tr>
<tr><td>Biomass</td></tr>
<tr><td>Other RES</td></tr>
<tr><td colspan="4">Combined heat and power</td></tr>
<tr><td>Biomass CHP</td><td rowspan="4">NECP+ until 2035 - Phase-out by 2050</td><td>Not optimised</td><td>Not optimised</td></tr>
<tr><td>Gas CHP</td><td rowspan="3">Phase-out before 2040</td><td>Phase-out before 2040</td></tr>
<tr><td>Coal CHP</td><td rowspan="2">Phase-out before 2035</td></tr>
<tr><td>Lignite CHP</td></tr>
</table>

Table 6.1: Overview of supply technologies, by pathway, in the least-cost power system modelling reported here.

Deployment of wind, solar, and gas generation by 2025 are all capped. A cap is justified on this time horizon because the deployment timescales for these technologies are such that most projects expected to be operational by 2025 will already be in some stage of planning or construction. By the same logic, deployment of new nuclear - beyond what is already under construction - is only permitted after 2035, as construction times are considerably longer than for wind, solar and gas.

The 2025 deployment caps for wind and solar are based on the IEA's accelerated scenario, which outlines possible deployment if governments swiftly address policy, regulatory and implementation challenges that are hindering deployment.

The capacity of baseload gas generation in 2025 is capped at values according to the (draft) TYNDP 2022 National Trends scenario. This scenario is interpreted as the best estimate of installed capacity, and uses data sourced directly from national Transmission System Operators (TSOs). The resulting maximum possible fleet in 2025 represents an increase on the fleet in 2020.

The capacity of combined heat and power installations follow pre-defined pathways. The heat supply from fossil CHPs in each country is assumed to be replaced by a standard mix consisting of: 30% bioenergy CHP, 40% large heat pump, and 40% zero emissions sources including energy savings. Fossil and bioenergy CHP capacities in the power system are manually adjusted in order to supply the required share of the estimated heating demand over time. The System Change pathway assumed an increase in market share for District Heating systems, whereas this remains at 2020 levels in The Stated Policy and Technology Driven pathways.

Unless otherwise stated, supply technologies that are not optimised technologies (e.g., hydro, biomass, pumped hydro, oil) follow trajectories described by the TYNDP 2020 National Trends pathway until 2040, and are unchanged thereafter.

Demand Side Reduction (DSR) capacity is defined as a fraction of peak demand in each pathway. It is modelled as a separate entity to the demand flexibility arising from transport and buildings sectors. It can therefore be interpreted as large-scale commercial or industrial demand reduction. It is assumed that available DSR capacity in the clean power pathways reaches 9% of peak demand by 2035 and 12% by 2050.

Interconnection

Interconnection between countries allows exchange of electricity in both directions across borders. All pathways evolve identically until 2025, by which point the system is configured according to the TYNDP 2025 reference grid which accounts for projects expected to be commissioned in the short term.

Between 2025 and 2035, the Stated Policy pathway evolves by adding interconnection capacity in accordance with the expected commissioning dates of TYNDP (2020) projects. The clean power pathways are free to expand further, with capacity deployment determined by economic optimisation, up to a maximum potential on each border. This potential is defined as the sum of all TYNDP candidate projects in each border, the estimated costs of which are also used.

The decision to cap interconnection by using candidate projects was taken to ensure a level of technical feasibility while still allowing room for significant expansion above existing plans. This approach is further justified by previous research[14], which demonstrates that the first few multiples of interconnection expansion deliver the vast majority of system value benefit.

Wind and solar potentials

The technical potential of solar and wind is a key modelling input. It is hereby understood to constitute the maximum capacity of a renewable energy technology which can be deployed in a specific area after accounting for topographic and geographic limitations, and land-use constraints. Various methods can be employed to develop such estimates, with the more recent utilising GIS for spatial assessment.

[14] Brown et al. 2018, Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European energy system, Energy, 160.

Abundant literature exists on estimating the technical potential of solar and wind energy in Europe, estimates vary widely due to differences in methodologies and assumptions. In view of this, data on technical potentials was obtained from a single database (to the fullest extent possible) for consistency between country estimates. ENSPRESO[15], an open dataset published in 2019 which uses GIS-based land restriction scenarios to estimate renewable energy technical potentials for the EU27+UK, constitutes the primary data source, except in the case of offshore wind. Complementary sources provided data on the other European countries.

The complete dataset of solar and wind technical potentials used in this project can be found in Annex 1.

Onshore Wind

For onshore wind, the technical potentials from the ENSPRESO Reference scenario were selected, which takes into account current legal requirements for exclusion zones and setback distances for turbines with a hub height of 100m and specific power of 300 W/m2 (which translates to a power density of 5 MW/km2). The technical potential was restricted to those areas with a capacity factor of 20% or higher. These parameters correspond to the quantitative description of the technology class selected for onshore wind costs.

For those countries not included in ENSPRESO, data on suitable land area for onshore wind deployment was taken from a research paper by Ryberg et. al (2019)[16], selected as the scope of assumptions employed are similar. The same power density as that used by ENSPRESO was applied to the suitable land area identified to calculate the technical potential.

Offshore Wind

Data for both fixed-bottom and floating offshore wind potentials were sourced from the World Bank dataset[17] on technical potential for offshore wind development at country level, first published in 2021. This was selected as it includes data on all project countries and the

[15] https://publications.jrc.ec.europa.eu/repository/handle/JRC116900
[16] Ryberg, D.S., Tulemat, Z., Stolten, D. and Robinius, M., 2020. Uniformly constrained land eligibility for onshore European wind power. Renewable energy, 146, pp.921-931.
[17] https://datacatalog.worldbank.org/search/dataset/0037787

results are similar to those from the ENSPRESO Low Restrictions scenario which assumes a low level of exclusion surfaces for wind. The latter was selected for comparison purposes as opposed to the Stated Policy scenario as it includes countries' exclusive economic zones (EEZ) where offshore wind projects are already under consideration; the Stated Policy scenario only includes areas within territorial waters (12 nautical miles).

The World Bank dataset includes all areas within EEZ borders up to a water depth of 50 metres for fixed foundations and 50-1000 metres for floating wind. Areas with wind speeds lower than 7 m/s were excluded. The remaining zones were converted to technical potential by assuming a power density of 3 MW per km2 for wind speeds between 7–8 m/s and 4 MW per km2 for wind speeds greater than 8 m/s.

Solar

The ENSPRESO dataset on solar potentials provides a single scenario for artificial land area suitable for rooftop and facade mounted solar applications; the latter was excluded in this project given the limited readiness and availability of this technology and its significantly higher cost. For ground-mounted solar PV, ENSPRESO provides two scenarios for suitable natural areas; the scenarios are derived through the application of the same exclusion criteria to the total land area but differentiated according to the share of the remaining area considered available for ground-mounted PV (either 100% or 3%). Assuming 100% of the suitable natural areas are available for ground-mounted solar PV results in an unreasonably large share of many countries' total land area (even above 60% in some cases). Therefore, the scenario where 3% of suitable natural areas is considered available for ground-mounted PV was selected.

Three power densities are considered in the ENSPRESO dataset for translating suitable land area into technical potential for solar PV: 85 MW/km2, 170 MW/km2 and 300 MW/km2. The average module area needed to deliver 1 kWp of peak generation capacity is currently 4.9 m2 by today's standard PV modules, translating to 200 MW/km2. When taking account the spacing between tilted modules required to avoid shading, this comes close to the 170 MW/km2 power density provided by ENSPRESO; therefore, this scenario was selected.

Data on the technical potential of solar PV for other European countries not included in ENSPRESO was taken from other sources,.

Build Rates

While solar and wind deployment is optimised on a cost-basis in the model, two sets of build rate constraints informed the model in order to avoid unreasonable scenarios.

A minimum build rate was defined for each country for the first three timesteps (2025, 2030 and 2035) in line with national plans and commitments as at end September 2021. This was applied to ensure that deployment levels in all scenarios (except the sensitivity scenario on “resistance to RES”) reach current targets, with further capacity additions according to cost-optimisation.

A maximum build rate was defined for each country for all the timesteps to represent technical limitations to capacity deployment such as required grid development and reinforcement for integration of new renewable capacities. Given that the project modelling took place during 2022, two years into the first modelled timestep, the maximum build rate was defined according to the most recent estimates of projects expected to be commissioned by 2025 according to the draft 2022 TYNDP and the IEA Renewables 2021 Database (assuming the accelerated case). It was assumed that new solar and wind projects which would be operational by 2025 would already be at planning stage.

For the remaining timesteps, the maximum build rate was defined as a percentage share of the country’s technical potential, with the same share applied across all countries. Long-term outlooks of wind and solar deployment from industry groups such as WindEurope and SolarPower Europe were used to calibrate the percentage share selected; the maximum build rates would allow deployment to reach the maximum capacity projected levels by 2050 for each type of technology.

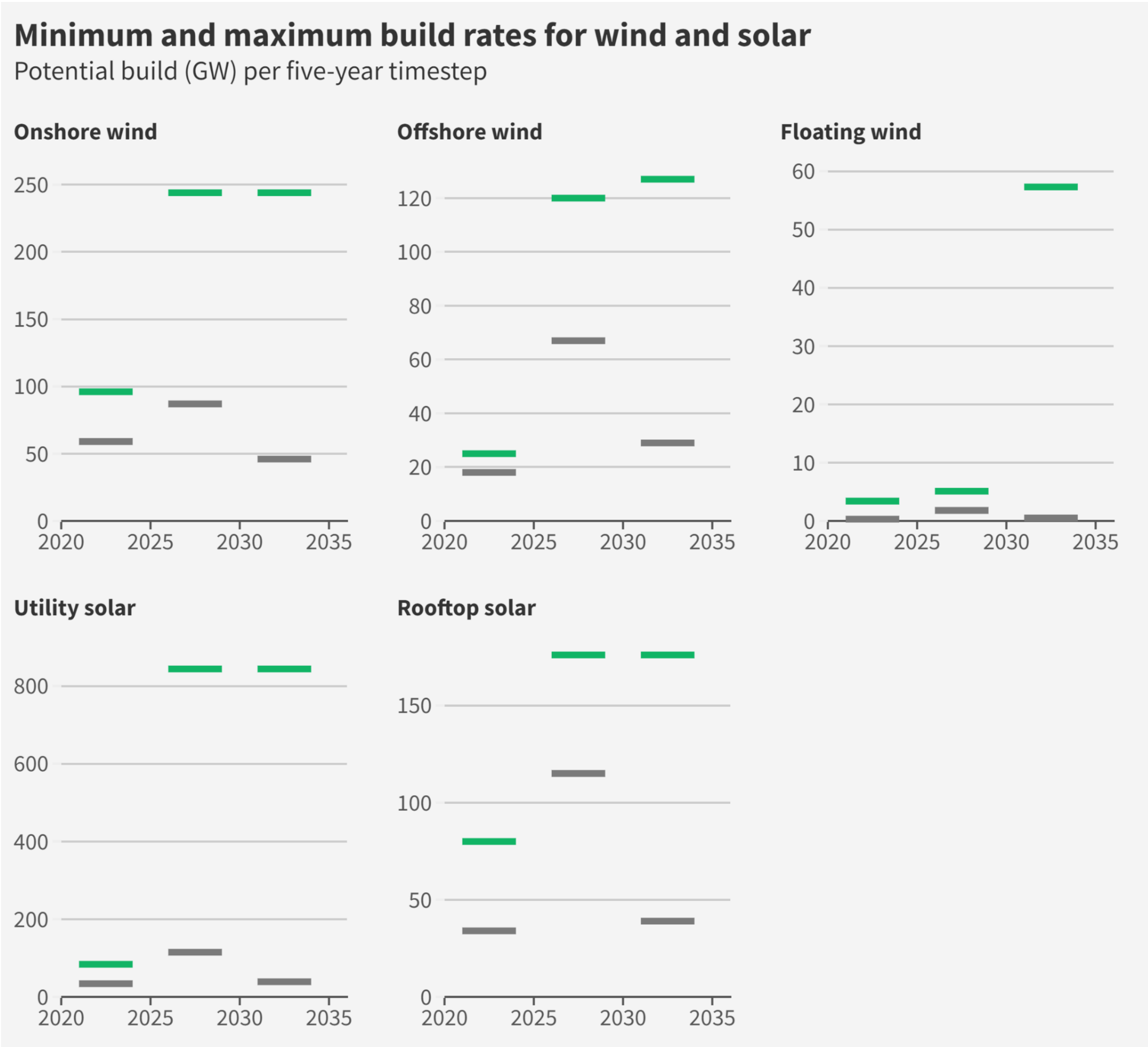


Figure 6.1: The minimum (defined by Stated Policy) and maximum (defined by the method described in this section) build rates of wind and solar technologies between 2020-2035 per five-year timestep.

Modelling wind and solar output

Electricity generation from variable renewable sources (mainly wind and solar) are modelled using installed capacities (scenarized or optimised) and hourly production profiles. The variable renewable generation is also able to be curtailed in case of renewable surplus. Wind and solar technologies are split in several categories:

- Solar: utility-scale solar and solar roof

- Wind onshore: conventional and advanced wind turbines
- Wind offshore: conventional and advanced wind turbines for fixed-bottom turbines, only advanced for floating turbines

Moreover, each category is decomposed between the residual capacity over the trajectory (i.e the historical capacity reaching the end of life over the different years of the trajectory - decreasing by construction) and an additional capacity optimised by the model. This capacity is optimised starting from 0 MW in 2020 (by construction) and is constrained by the technical potential and the minimum and maximum build rates described above/below . The advanced category for wind corresponds to an improvement in the technologies (wind turbines with higher masts, higher rotors, operating with lower winds, etc.), and the annual load factor is higher than the historical, whereas the normal category corresponds to historical and current wind technologies. Wind capacities are allocated to the categories in order to match with the projections of the weighted average load factor from IRENA and WindEurope.

Hourly production profiles are derived from the METIS project, and the country-level profiles are based on historical data and rescaled in order to match with current annual load factors. For wind technologies, the load factor time series for advanced turbines are built from historical profiles to take into account the technological improvements described above.

Chapter 7

Technology Assumptions

Cost and lifetime assumptions

The technology cost assumptions constitute a key element informing the investment cost and dispatch optimisation. Despite differences in storylines, all modelled pathways make use of the same technology cost assumptions. This allows for pathway outcomes and model results to be determined according to the least-cost optimisation for that particular scenario, with no variability introduced from exogenous factors other than the pathways' storylines. This allows for better comparability between pathways.

Overnight investment costs and fixed operating costs feed into the modelling. Values are provided for each timestep of the study between 2020-2050, intended to capture the expected changes to technology costs over time. This is consistent with the approach taken for expected improvements in efficiency.

Two objectives informed the choice of the cost assumptions employed in this study.

1. Consistent: technology assumptions are derived from the same database in order to avoid variability in background inputs and calculations, and expert-advice that informs such assumptions.
2. Latest: the technology assumptions which most closely reflect recent cost trends are used. Latest costs, such as those published by IRENA[18], were used to check against databases of technology cost projections.

[18] IRENA (2021), Renewable Power Generation Costs in 2020, International Renewable Energy Agency, Abu Dhabi.

Based on these objectives, technology cost assumptions used in this study are primarily derived from the ASSET study[19]. This was published in 2018 with the intention of providing key assumptions about the development of technologies for input into modelling exercises, particularly the PRIMES model which provides the energy and climate scenarios used by the European Commission.

However, given the four-year lag between the publication of the ASSET study and the undertaking of this study, the extent of the decline of wind and solar costs, and utility-scale battery storage was not fully captured. For this reason, data from the technology database of the Danish Energy Agency and Energinet was used[20]; this database is updated frequently and thus provided a more realistic trajectory for these technologies. This same database is the primary source of technology data used in the 2022 TYNDP.

Table 7.1 provides the breakdown of technology cost, split into overnight investment costs and fixed operating costs, and lifetime assumptions for all technologies included in the modelling.

Thermal efficiency

Table 7.2 provides the assumed efficiency of thermal generation of electricity for different technologies. For co-generation technologies, this is provided for both power and heat.

Efficiency of the same technology differs according to the age of the generator. For technologies with an existing fleet, distinct efficiency figures are provided for three age ranges:

1. Old: installed post-1990
2. Young: installed pre-1990
3. New: installed after 2020

[19] Please see: https://ec.europa.eu/energy/sites/ener/files/documents/2018_06_27_technology_pathways_-_finalreportmain2.pdf
[20] Please see: https://ens.dk/en/our-services/projections-and-models/technology-data

	Optimised	Investment Costs (€/kW)							Fixed Operating Costs (€/kW/year)							Lifetime
		2020	*2025*	*2030*	*2035*	*2040*	*2045*	*2050*	*2020*	*2025*	*2030*	*2035*	*2040*	*2045*	*2050*	
Utility solar	X	500	429	358	335	311	297	283	8.25	7.54	6.83	6.55	6.24	6.07	5.90	25
Rooftop solar	X	1013	878	773	700	656	633	623	18.23	15.80	13.91	12.60	11.81	11.39	11.21	25
Onshore wind - low LF	X	1057	1048	981	941	900	879	858	13.21	13.10	12.26	11.76	11.25	10.99	10.73	25
Onshore wind - high LF	X	1395	1328	1261	1186	1110	1077	1043	13.0	13.0	13.0	13.0	13.0	12.5	12.0	25
Offshore wind	X	2009	1946	1821	1755	1690	1641	1593	38.17	36.97	34.60	33.35	32.11	31.18	30.27	25
Floating wind	X	3950	3950	3950	3842	3734	3626	3518	89.8	89.8	89.8	84.9	80.1	75.2	70.4	25
CCGT	X	820	795	770	760	750	750	750	15.0	15.0	15.0	15.0	15.0	15.0	15.0	30
OCGT	X	428	420	410	406	400	394	389	7.71	7.56	7.39	7.30	7.20	7.10	7.00	25
Coal	X	1600	1600	1600	1600	1600	1600	1600	25.6	25.6	25.6	25.6	25.6	25.6	25.6	40*
Lignite	X	1800	1800	1800	1800	1800	1800	1800	32.5	32.5	32.5	32.5	32.5	32.5	32.5	40*
Nuclear	X	6000	6000	6000	6000	6000	6000	6000	120.0	117.5	115.0	111.5	108.0	106.5	105.0	60*
CCGT CCS	X	1512	1458	1404	1350	1296	1296	1296	41.0	39.6	38.2	36.6	35.0	34.7	34.3	30
Biomass CCS	X	3800	3625	3450	3270	3090	3045	3000	81.5	75.3	69.1	66.1	63.0	62.2	61.4	40
Electrolysis	X	833	567	300	270	240	210	180	23.3	18.7	14.0	12.8	11.5	10.3	9.0	25
Utility-scale battery	X	969	573	430	418	406	393	381	29.1	17.2	12.9	12.5	12.2	11.8	11.4	20
Hydrogen	X	820	795	770	760	750	750	750	15.0	15.0	15.0	15.0	15.0	15.0	15.0	30

	Optimised	Investment Costs (€/kW)							Fixed Operating Costs (€/kW/year)							Lifetime
		2020	*2025*	*2030*	*2035*	*2040*	*2045*	*2050*	*2020*	*2025*	*2030*	*2035*	*2040*	*2045*	*2050*	
Pumped storage		2320	2240	2160	2152	2145	2137	2130	21.8	21.0	20.3	20.2	20.2	20.1	20.0	75
Oil		1200	1200	1200	1200	1200	1200	1200	15.0	15.0	15.0	15.0	15.0	15.0	15.0	40
Biomass		2000	1900	1800	1750	1700	1700	1700	47.5	43.8	40.1	39.7	39.2	38.8	38.4	40
Other renewable		2000	1900	1800	1750	1700	1700	1700	47.5	43.8	40.1	39.7	39.2	38.8	38.4	40
Hydro		3000	3000	3000	3000	3000	3000	3000	25.5	25.5	25.5	25.5	25.5	25.5	25.5	60
Hydro RoR		2450	2425	2400	2375	2350	2325	2300	8.9	8.6	8.2	8.2	8.2	8.2	8.1	50
Gas CHP		1720	1675	1630	1630	1630	1540	1450	9	9	9	9	9	8	7	30
Coal CHP		1100	1050	1000	1000	1000	950	900	54	54	54	54	54	54	54	35
Lignite CHP		1100	1050	1000	1000	1000	950	900	54	54	54	54	54	54	54	35
Biomass CHP		3600	3500	3400	3300	3200	3100	3000	45	41	36	36	36	32	27	25

Table 7.1: Overview of technology assumptions applied in all modelled pathways
*Note: alternative lifetime assumptions are made for certain technologies according to available plant-by-plant information and announced closure dates. For nuclear specifically, where the situation is open ended, existing nuclear plants are considered to have a lifetime of 50 years in Stated Policy and Technology Driven, 40 years in System Change, and 60 years in the sensitivity scenario Nuclear Plus.

Technology	Age category	Efficiency	Heat efficiency
CCGT	Old	0.44	
	Young	0.57	
	New	0.60	
OCGT	Old	0.35	
	New	0.42	
Gas+CCS	All	0.60	
Gas CHP	All	0.33	0.52
SMR+CCS	All	0.67	
Coal fleet	Old	0.38	
	Young	0.44	
	New	0.44	
Coal CHP	All	0.16	0.69
Lignite fleet	Old	0.35	
	Young	0.41	
	New	0.41	
Lignite CHP		0.16	0.68
Oil fleet		0.35	

Table 7.2: Technological thermal efficiencies for power generation (or hydrogen production for SMR+CCS) according to the age of the generator. For co-generation technologies, the efficiency of heat generation is also provided.

Chapter 8

System Cost Methodology

System costs include investment and operational costs of power system to meet the demand for electricity, including to run power-to-X installations. If scenarios have different scopes (e.g. different electrification levels), an additional cost component is introduced to ensure we are comparing systems that provide the same energy services. The cost unit is in $€_{2020}$ by taking into account discounting between modelled years.

On the electricity supply side, the investment costs in new technologies (production, storage and interconnections) as well as the fixed operational costs in installed capacities are included. Variable operational costs, commodity costs, carbon emission costs, curtailment and loss of load costs are also covered.

The same approach is used for hydrogen supply, taking into account the investments and operational costs of electrolysers, and alternative hydrogen production (blue hydrogen produced by SMR+CCS). For other synthetic products from power-to-X (such as RFNBOs), additional costs representing the investment in methanation and H2-to-liquids (Fischer-Tropsch process) plants are added. The CO2 needs for production of synthetic fuels and gases are also costed.

As the energy consumption of coal, natural gas, oil and biomass differs between scenarios, the corresponding costs are included in the comparison by allocating to each consumption a fixed commodity price. Finally, the costs for district heating development are integrated with reference to the peak heating demand at 107 €/kWth .

For each scenario, the cost differences with the Stated Policy scenario are computed in order to remove modelling bias such as the costs of the historical power system, the costs of transmission and distribution grids, the costs of the gas and hydrogen infrastructure providing power system services (storage, pipelines).

Chapter 9

Definition of Sensitivity Scenarios

In addition to the three main pathways, a set of 10 sensitivity scenarios are provided. Using the Technology Driven pathway as a basis, these pathways explore the consequences of varying key input assumptions or the availability of power system technologies or services. One pathway explored the impact of additional utility-scale battery storage on the other clean power pathway, System Change; however, this is the only scenario which uses the System Change pathway as a basis.

The sensitivities were constructed in order to capture the potential impact of a wide range of uncertainties on the Technology Driven pathway. These uncertainties include:

- Policy choices (e.g. Nuclear Plus)
- Policy failure (e.g. Delayed Interconnection)
- Economic or political factors (e.g. High Fossil Prices, Alternative Hydrogen)
- Social attitudes and behaviours (e.g. Resistance to RES)

The results of these sensitivities, through comparison with the Technology Driven pathway, provide key insights into the requirements of a 1.5C compatible pathway and the potential trade-offs required should certain conditions materialise. The pathway costs, both for the power system and the total energy system, are calculated for the sensitivities, providing some insight into the potential trade-offs of different options; however, in some cases, trade-offs relate more to the risk profile of certain decisions/outcomes as opposed to the economic cost.

The following details the rationale behind each sensitivity scenario and any changes made to modelling inputs. The resulting range in capacity of key technologies in 2035 is illustrated in Figure 9.1. The technologies with the widest relative range can be considered to be the most sensitive to exogenous uncertainties and model assumptions. For instance, it is notable that all the sensitivity scenarios (excluding that of Resistance to RES) see similar deployment levels of wind and solar, within a couple of percentage points. This clearly demonstrates that a least-cost, climate compatible pathway necessitates a rapid scale-up of the wind and solar fleet.

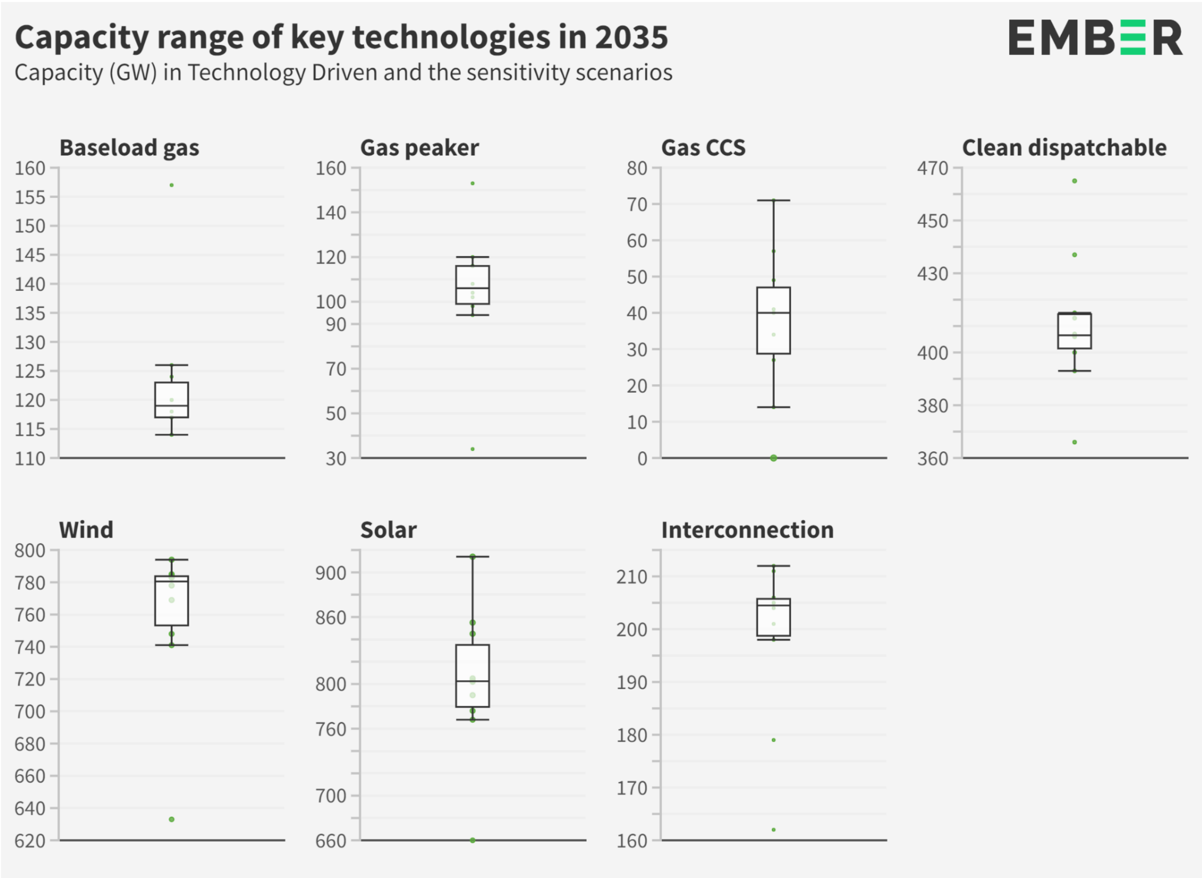


Figure 9.1: Box plot of 2035 capacity range (GW) of key technologies in the Technology Driven pathway and the sensitivity scenarios.

Resistance to RES

Given trends in social acceptance and political decisions observed in a number of European countries, it may be the case that these issues limit land uptake for land-based renewables; this would impact both the technical potential and build rates of onshore wind and utility-scale solar. This was modelled by reducing the agricultural and non-agricultural land considered available for wind and solar deployment, from 3% (the standard assumption of the ENSPRESO database) to 1%. The same percentage share used to define the maximum build rate was applied but to this lower technical potential. These constraints were applied from 2025 onwards, given the likely advanced stage of projects expected to be commissioned by 2025.

Delayed interconnection

Exchange over interconnectors is an important source of grid flexibility, its expansion in the modelled pathways largely driven by the need to accommodate and balance wind and solar. Given the long planning, permitting and construction processes involved in the construction of new transmission lines, there is a risk that grid expansion will be unable to occur at the pace required to support the rapid wind and solar deployment in the two decarbonisation pathways. A combination of lack of preparedness, excessive bureaucracy, or social resistance delay may limit the development of new interconnection projects. This was modelled by restricting the interconnection expansion to planned projects included in the 2020 TYNDP. In this manner, the resulting scenario would demonstrate the required action and additional costs for a climate compatible pathway in the absence of new interconnection projects, in addition to those already planned.

No Gas+CCS

Given uncertainties around CCS, it may be the case that this technology does not reach commercial maturity before 2030, or even 2050. To model this, power plants equipped with carbon capture technology were not included in the model as available for investment.

Nuclear Plus

Nuclear plant lifetimes are widely extended to 60 years (unless already stated to close by a specific date), and all planned new nuclear goes ahead (both conventional and small modular reactor units). This included a total of 10.4GW conventional nuclear (assumed EPR or PWR reactors) added before 2035 across Finland, Hungary, Romania, Poland and the UK, and a further 29.8GW added between 2035 and 2050 across the Czech Republic, France and Poland. In terms of small modular reactors, 2.3GW are added across Bulgaria, Poland, Romania and the UK in 2035 and, between 2035 and 2050, a further 5.4GW are deployed across France, Poland and the UK.

Lower demand flexibility

Demand-side flexibility tends to receive little policy attention. It may therefore be the case that governments and regulators fail to incentivise and enable the uptake of consumer technologies and behaviours which are required to deliver the assumed demand-side flexibility of the Technology Driven pathway. This sensitivity thus explores the impacts of lower demand-side flexibility on future power demand characteristics and the resulting power system. The following assumptions were amended:

- Linear increase from 0% in 2020 to 35% by 2050 of smart charging EVs (compared to 70% in Technology Driven); one third are still considered to provide V2G services
- Fraction of heat-pumps providing flexibility increases linearly from 0% to 25% in 2050 (compared to 50%)
- Capacity of DSR is considered equal to 5% of the peak of power demand from end-use sectors (compared to the increase of 9% in 2035 and 12% in 2050 in Technology Driven)

Reflecting these assumptions in the input power demand data resulted in the portion of demand considered to be flexible being approximately halved in all the timesteps.

Alternative H2 supply

In the modelled pathways, Europe meets its entire energy system demand for hydrogen through domestic production. No off-grid hydrogen production or imports are considered. A sensitivity scenario was constructed in order to assess the impacts of an alternative hydrogen strategy for Europe that factors in these alternative hydrogen supplies; this may represent a strategic decision and/or reflect less coupling between power and gas systems. The hydrogen demand input was modified to reflect off-model hydrogen sources, halving the hydrogen required from European blue or green production.

High Fossil Prices

This sensitivity explores the impact of fossil fuel prices higher than those used in the other modelled pathways. This sensitivity is *not* intended to represent current trends of high prices on the energy markets but rather the potential impact of higher prices in the medium and long-term. The alternative price used for gas between 2025-2034 are based on Dutch TTF futures (checked on 23 March 2022), the alternative price of coal on API2 futures (checked on 23 March 2022), and that for oil on Brent crude oil futures (settlements 23 March 2022). In all cases, the IEA STEPS 2021 figures are applied for 2035 onwards. No changes to fossil fuel prices were applied in the first timestep in order to avoid major changes which may cause difficulties in comparability of this sensitivity to the Technology Driven scenario).

Limited New Gas

In light of geopolitical and security concerns raised by the recent energy crisis and the war in Ukraine, gas has come under a negative lens. This sensitivity scenario explores the impact of a political strategy to build no new unabated gas capacity (either baseload or peaking) after 2025. To implement this sensitivity, the build of baseload and peaking gas plants is defined in line with the draft 2022 TYNDP until 2025 and no additional investment is possible after the first timestep.

Technology Driven B

The modelling approach does not fully capture the full value chain available to battery projects (the scope is limited to the wholesale electricity market), leading to a likely underestimation of battery capacity on the system. This issue was addressed through the introduction of a minimum deployment of utility-scale battery capacity. The utility-scale battery capacity in each time step in each country was defined as the maximum of either 10% of solar capacity or the battery capacity in the draft 2022 TYNDP distributed energy scenario.

The same rationale and approach was employed for a sensitivity on the System Change pathway, where additional utility-scale battery capacity was added to the system in **System Change B.**

Annex 1

Technical Potentials: Wind and Solar

The below table presents the technical potentials assumed for solar and wind in all modelled scenarios, except in the case of the "Resistance to RES" sensitivity scenario, in line with the methodology and references outlined in Chapter 9 of this report.

[GW]	Onshore wind	Offshore wind (fixed-bottom)	Floating offshore wind	Utility-scale solar PV	Rooftop solar PV
Albania	21.0	-	6.2	2.4	2.7
Austria	11.0	-	-	126.6	11.4
Bosnia and Herzegovina	112.9	-	-	3.0	6.4
Belgium	8.1	13.7	-	76.9	15.3
Bulgaria	53.0	2.1	23.7	280.8	10.4
Switzerland	17.2	-	-	63.3	22.3
Cyprus	1.9	-	0.0	14.1	1.2
Czechia	76.2	-	-	197.7	14.3
Germany	107.0	199.0	0.1	796.9	106.8
Denmark	54.7	261.4	66.7	138.0	7.8
Estonia	27.3	75.6	63.7	52.1	1.8
Spain	704.4	12.4	207.2	721.8	53.3
Finland	30.8	169.8	131.6	58.8	7.8
France	812.8	169.4	453.8	1,476.5	85.6
Greece	168.4	9.6	412.5	279.9	13.1

[GW]	Onshore wind	Offshore wind (fixed-bottom)	Floating offshore wind	Utility-scale solar PV	Rooftop solar PV
Croatia	24.3	4.0	13.2	89.1	5.9
Hungary	53.1	-	-	297.3	13.6
Ireland	146.5	50.6	552.7	215.4	6.4
Italy	178.3	6.2	183.2	728.2	73.8
Lithuania	128.3	12.6	14.1	179.3	4.2
Luxembourg	0.7	-	-	4.8	0.8
Latvia	79.5	58.8	53.1	91.5	2.8
Montenegro	27.1	0.0	1.0	0.7	1.2
North Macedonia	28.5	-	-	1.5	3.6
Malta	-	-	158.6	0.4	0.5
Netherlands	48.9	207.1	0.4	96.1	21.3
Norway	326.1	59.8	1,416.6	30.0	50.0
Poland	101.5	58.7	57.2	802.2	51.8
Portugal	39.2	14.2	117.4	87.7	12.6
Romania	168.9	22.4	55.9	713.1	26.9
Serbia	157.5	-	-	6.9	14.4
Sweden	133.9	228.4	360.4	117.3	13.6
Slovenia	2.4	-	-	30.8	2.8
Slovakia	29.3	-	-	106.7	7.5
United Kingdom	230.0	449.4	1,379.5	545.0	81.8