Managing the Seasonal Variability of Electricity Demand and Supply

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Abstract

Electrification of end-uses and the growth of solar and wind is changing how electricity systems operate on all time scales. This report analyses how seasonal variations in both demand and supply affect electricity system operations to 2050 – in Europe, India, Indonesia and Korea – and what sources will be used to manage them. Seasonal variations are put in context with the annual electricity mix and short-term (hourly) variability. Each of the analysed regions has a unique electricity mix today, available resources, geographies, and patterns of electricity demand. Each has charted a different course for their clean energy transitions and is located in different climatic zones. This study also recognises that weather conditions are uncertain and vary from year-to-year, exploring their impact on system operations and power system costs. The study finds that, in each system, both short-term and seasonal flexibility needs rise considerably to 2050. Flexibility, currently provided by thermal power plants and hydro, will increasingly come from new sources – demand response and batteries on shorter timescales and hydrogen across weeks to seasons – with low emissions thermal power plants and hydro remaining important providers of seasonal balancing. As the systems become more capital-intensive, consumers are increasingly insulated from the impact of weather variations on power plant operations and the volatility of fossil fuel prices.

This work expands on the report Managing Seasonal and Interannual Variability, published in April 2023 which assesses the impact of weather-related variability on system operations across seasons and between years in different climatic zones.

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Executive summary

The changing nature of electricity demand and supply calls for more flexibility within a day, but also across seasons

The nature of electricity demand and supply is changing rapidly with clean energy transitions. Wind and solar PV represented 12% of global electricity supply in 2023, but rise to 40% by 2030 on the path to net zero emissions by 2050. Combined with new sources of demand for electricity, from electric vehicles to residential heat pumps, power systems will look and operate differently than they have to date and electricity security will become ever more important.

This work represents the second phase of analysis following the publication of Managing Seasonal and Interannual Variability in April 2023 which focused on assessing the consequences of raising the share of annual electricity generation from variable renewables to above 70% in example systems in four distinct climatic regions.

This report examines the impacts of seasonal variations in demand and supply on electricity systems in three regions: Europe, India, and Indonesia. These three regions provide many insights into the deep changes between today and 2030 or 2050, as they start from different power systems today, with unique patterns of electricity demand and mixes of electricity sources. Each has charted different courses for their clean energy transitions and are located in different climatic zones. The Announced Pledges Scenario (APS), in which countries meet their 2030 targets and longer-term net zero or carbon neutrality pledges is the basis of this analysis, including the European Union's target to be climate-neutral by 2050, India's ambition to achieve net zero emissions by 2070 and Indonesia's commitment to reach net zero emissions by 2060 or before.

The analysis is based on a joint electricity and hydrogen dispatch model, newly developed for this report and incorporated into the Global Energy and Climate Model, representing hour-to-hour operations for all hours of the year.[1] Each region is separated into multiple sub-regions and grid interconnections between those sub-regions are represented. Data from 30 historical years of temperature patterns affecting electricity demand for heating and cooling, wind and solar availability, and inflows to hydropower projects are used to analyse each system in 2030 and 2050. This analysis also incorporates a detailed representation of demand response by end-use.

The overall approach enables the assessment of the seasonal variability of electricity demand, determines how flexibility will be provided, along with the changing picture for short-term flexibility and adequacy, and quantifies the related system costs.

This report also includes additional analysis on Korea's power system evolution and flexibility needs. In Korea, the pursuit of net zero emissions by 2050 calls for increases in wind, solar PV and nuclear

[1]The model is based on the open-source power modelling framework Python for Power System Analysis (PyPSA).

power. This analysis focuses on the role of nuclear as a source of flexibility for the power system.

Seasonal flexibility needs are set to grow faster than electricity demand

In each of the three main regions (Europe, India and Indonesia) covered in this report, electricity demand is set to increase substantially over the period to 2050, by over 80% in Europe from 2022 to 2050 and more than 2.5 times in India and 3 times in Indonesia. Yet, in each region, the need for seasonal flexibility in power systems rises even faster – measured by the highs and lows across the year of net load (total demand minus the output of wind, solar PV and run-of-river hydropower) which then need to be balanced by dispatchable resources and energy storage. In Europe and India, seasonal flexibility needs increase by 60% and 30% respectively more than total electricity demand from 2022 to 2050. In Indonesia, seasonal flexibility needs increase five times more than electricity demand. In each case, this means that across the year, much larger swings would need to be accommodated by the rest of the power system than is the case today.

Rising shares of wind and solar PV, and changes in patterns of electricity demand are the driving factors of the increased seasonality in all regions. In Europe, increased seasonality is due mainly to the sixfold increase in wind power from 2022 to 2050 and its strong seasonality – with higher production in winter – along with the growth of temperature-sensitive electricity demand including space heating. In India, the seasonality of net load is mostly driven by the rise of solar PV and the increase of cooling, which are both influenced by monsoons. In Indonesia, the multiplication of seasonal flexibility needs marks a shift from a system currently with minimal seasonality to one with significant amounts due to strong uptake of solar PV and wind beyond 2030.

The provision of seasonal flexibility comes from traditional and new sources

Currently, hydro and thermal dispatchable power plants manage almost all the flexibility requirements in all three systems for each timescale (from short-term to seasonal). To 2030, this remains the case in each of the three regions, with over 80% of seasonal flexibility provided by hydro and thermal sources in Europe, and over 95% in India and Indonesia. By 2050, hydro remains a key provider of seasonal flexibility, along with low-emissions thermal power plants, but the transition away from unabated fossil fuels in each region reduces the overall role for thermal power.

By 2050, the flexible operation of electrolysers becomes an important part of providing seasonal flexibility as systems are largely decarbonised. Indeed, electrolysers have the possibility to take advantage of periods of abundant renewable output to produce hydrogen at lower costs. At the same time, they can lower their electricity consumption during peak periods for the electricity system and ease strains on the grid. This contribution is linked to having significant volumes of hydrogen storage available. Sector coupling between electricity and hydrogen systems thus has the potential to play an important role in providing seasonal balancing and making the best use of the available renewable generation.

Limited and strategic curtailment of wind and solar PV generation during abundant production hours is part of the cost-effective operation of power systems with high shares of variable renewables and also plays an important role in seasonal flexibility provision.

Maintaining electricity security will call on a wide set of resources and needs well-developed grids

Maintaining electricity security throughout the year requires balancing electricity demand and supply on an hour-to-hour basis in all hours of the year. In each of the three regions, the changes in electricity demand and supply also raises hour-to-hour (or short-term) flexibility needs, also set to rise faster than electricity demand. Strong deployment of solar PV, as in India and Indonesia, increases the short-term flexibility needs 5-times and 4-times more than electricity demand respectively from 2022 to 2050, while in Europe, short-term flexibility needs grow twice as fast as demand.

Batteries and demand response emerge as key technologies to address short-term variability in all systems. Because of their high degree of responsiveness, both have the ability to quickly adjust their operations based on the ramping needs of the system. Batteries are particularly well suited to compensate for the variability of solar PV output to minimise curtailment, a topic explored in depth in a forthcoming IEA special report on the topic. Demand response, particularly from smart charging electric vehicles and adjusting when space and water are heated, also helps align demand with the hours when renewables are most abundant, reducing curtailment and fuel costs, and further reducing stress on grids at those times.

Thermal power plants continue to play a role in short-term and seasonal flexibility and ensuring sufficient supply of electricity. To 2030, the installed capacity of thermal power plants – including nuclear power, bioenergy, hydrogen and hydrogen-based fuels and fossil fuels – increases in India and Indonesia, while declining in Europe. By 2050, total thermal capacity declines by 5%-10% in India and Indonesia, and 40% in Europe. In the most difficult hours to meet electricity demand (i.e. those with the highest peak net load), thermal power plants were called on to a high degree, often utilised at 70% of their full capacity or more. As this high utilisation only occurs in a small number of hours, the impact on CO_2 emissions is minimal, where regulation supports flexible operations for thermal plants. To deliver on emissions goals, it will be critical that the unabated use of fossil fuels is limited to the extent possible.

Ensuring electricity security at all times will also critically depend on well-developed grid infrastructure, including interconnections, and well-managed operations. A robust grid can expand balancing areas, reducing flexibility needs first, and enabling the best use of available sources of flexibility. Representing the full complexity of electricity grids was outside the scope of this analysis and so grid congestion within sub-regions was not captured. The effect of additional grid congestion would be to increase the challenges described, potentially limit the availability of some resources and raise system costs.

Clean energy transitions can decrease costs to consumers and limit their volatility

The transition to low-emissions technologies is projected to reduce total power system costs per unit of electricity across the three systems in the long run, in large part due to the low costs of solar PV and wind.[2] Compared with a recent average from 2020 to 2022, the total costs of electricity by 2030 are slightly lower in Europe and slightly higher in India and Indonesia as the transitions gain momentum. In an average weather year, the total costs of electricity per unit decline by 15-25% in Europe, India and Indonesia from 2022 to 2050.

As the system becomes more capital-intensive and less dependent on the fluctuations of fossil fuel prices, consumers are increasingly insulated from the impact of weather variations on power plant operation and the volatility of fossil fuel prices. Across the 30 weather years, total power systems costs vary by less than 5% in nearly all instances.

The variability of operating costs are more pronounced, varying by up to 20% in each region depending on the weather year, though their importance declines over time. With a higher proportion of low-marginal-cost sources of electricity, the share of operating costs, primarily fuel costs, is projected to decrease from about two-thirds currently to 30% or lower by 2050. The decarbonisation of electricity generation comes with a lower utilisation rate of thermal dispatchable power plants, running on potentially expensive fossil fuels. Fuel costs currently account for 30-60% of the costs of electricity generation in all three systems. By 2050, the share of fuel costs falls below 10%, though significant variability across weather years remains.

Regions face unique challenges but there are common principles for all

In Europe, the importance of wind power and increasing electrification of space heating create a unique challenge related to periods of low wind and cold temperatures (often referred to as dark doldrums). Having confidence that future power systems can remain reliable during these periods, which occur in the historical record but at irregular intervals, is essential for all stakeholders. Our analysis shows that robust electricity grids, the availability of some dispatchable thermal capacity and, critically, sector coupling with the hydrogen system and flexible operation of electrolysers maintain electricity security while decarbonising.

In Korea, the absence of electricity interconnections with other countries and geographical constraints pose unique challenges for integrating wind and solar, necessitating the use of thermal power

[2] Costs related to the production, transport and storage of hydrogen are not included in total power system costs, except for the fuel costs for hydrogen used to generate electricity.

plants for seasonal flexibility. Nuclear power's dispatchability, low emissions and high capacity factors make it a stabilising force in Korea's power system. Nuclear power can also help to address seasonal flexibility needs through scheduled refuelling, strategically timed during periods of low demand, ensuring continuous availability during high-demand periods.

Despite differences and the need for tailored solutions in each region, there are a number of common elements that would support clean energy transitions in all regions. Policymakers must align investments with decarbonisation goals while maintaining energy security throughout clean energy transitions. Updated planning methods are crucial to manage seasonal variability in electricity demand, requiring flexibility in existing thermal assets. Incentivising demand response, storage solutions and removing regulatory barriers are key for system reliability and market efficiency. Hydro reservoirs, long-term hydrogen storage and robust grid infrastructure play vital roles in managing seasonal variability and ensuring supply security. Clear signals in early planning stages are needed for the role of clean energy technologies, preventing inefficiencies in investment and operation. Reforms are necessary to financially reward essential power plants and storage technologies providing a broad set of services to power systems with high shares of variable renewables. Market-based systems should efficiently reflect technical and economic constraints, valuing electricity generation or consumption based on time and location.

Introduction

Managing seasonal and interannual variability in electricity systems

This report aims to analyse how seasonal variations in both demand and supply affect electricity system operations. Global electricity demand is projected to increase significantly over the next 25 years, driven by the expansion of economic activity and the progressive electrification of additional end-uses, most notably through the rise of electric vehicles and the accelerating adoption of electric heat pumps and air conditioners in many parts of the world. In the Announced Pledges Scenario (APS) of the World Energy Outlook (WEO) 2022, global electricity demand in 2050 is more than double its 2022 level.

In parallel, the deployment of wind and solar PV is accelerating, cutting emissions in the power sector, and these technologies are set to dominate power systems around the world by 2050, and in some regions by 2030. These developments represent a seismic shift in the way power systems are operated in the future. With the rise in electric heating and cooling, demand is set to become more temperature-sensitive, while the increasing adoption of wind and solar PV makes the supply much more weather-dependent. As the share of wind and solar continues to grow, system-level surpluses and periods of lower output expand beyond hourly or daily variations to seasonal timescales. Managing seasonal variability of renewables means that flexibility resources will be needed to varying extents across the year, even on a week-to-week or month-to-month basis.

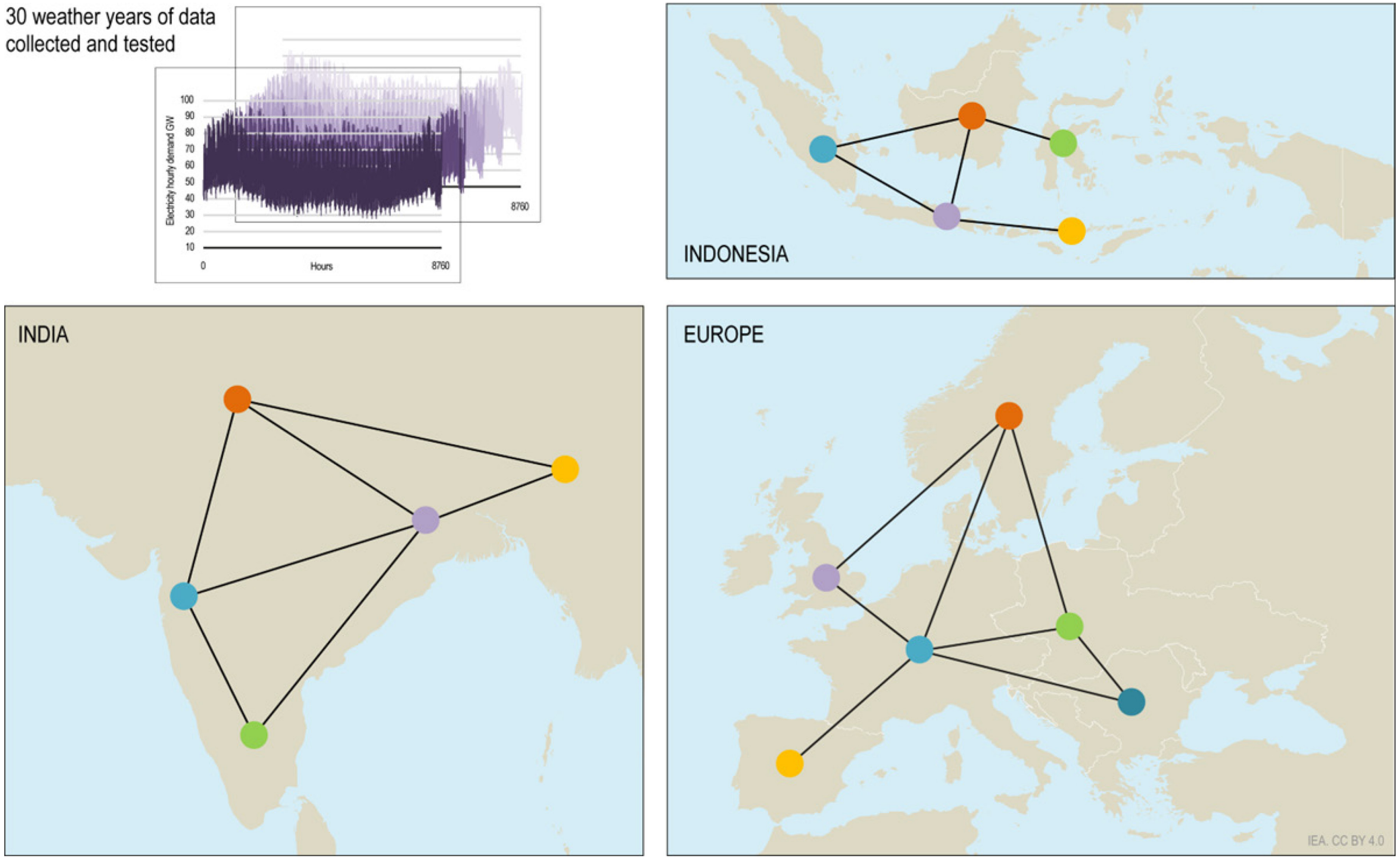
The IEA first analysed this issue in its report Managing Seasonal and Interannual Variability, published in April 2023, which assesses the impact of increasing the penetration of variable renewables to above 70% in typical systems representing four different climatic regions, quantifying the need for seasonal flexibility provided by dispatchable sources such as thermal and hydroelectric power plants. The study found that both sources will remain important pillars of the seasonal flexibility supply well into the 2040s, even as short-term variations are increasingly addressed by battery storage and demand response.

This report expands on this work to analyse the impact of weather-related variability on system operations, system flexibility needs and system costs in power systems located in different climatic zones. Its purpose is to develop detailed insights on how both demand- and supply-side variability can be managed – not only across seasons and years but on shorter timescales as well – what technologies will be crucial to do so reliably, and what this implies for system costs. We examine the power systems of Europe, India and Indonesia as they are projected to evolve in the APS of the *WEO 2022*. The first section summarises the key common findings on the impact of seasonality on electricity systems. The second section provides an in-depth analysis of power system changes in the APS and power system operations and the management of variability of the net load across all timescales, individually for each region. The final section assesses the impact of weather variability on total power system costs. An additional spotlight assesses the role of baseload generation in managing seasonal variability, using the power system of Korea.

Model set-up and methodology

Regional electricity systems covered by this analysis

Figure 1. Regional electricity systems



Note: This document, as well as any data and map included herein, are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Model description

To capture the effects of seasonal variability across different climatic zones and analyse its impact on system operations, flexibility needs, adequacy and costs, we model three separate power systems: Europe, which spans mostly across the temperate and continental climatic zone; India, a monsoonal climate with distinct wet and dry seasons; and Indonesia, which provides an example of a tropical climate. Each region is split into several nodes (Figure 1), reflecting constraints in the transmission system.

The analysis is based on the projections of the World Energy Outlook 2022's APS for the years 2030 and 2050, and power system operations in each year are simulated for 30 distinct weather years. A weather year is a set of weather parameters such as temperature, solar radiation, wind speed and precipitation compiled from historical records to create curves of hourly loads and renewables output.

The modelled regions are disaggregated into several nodes that can exchange electricity among one another, with the exchanges limited by the overall capacity of the transmission system between each node. The nodes reflect local specificities such as the spatial distribution of demand, the generation mix and any limitations on transmission capacity. It assumes that electricity flows freely within nodes, and disregards local congestion which can generate redispatch needs, increase flexibility requirements and potentially raise the need for dispatchable capacity.

To analyse the impact of weather-induced variability on power system operations and long-term flexibility needs in systems characterised by rising shares of variable renewables and temperature-sensitive end-uses such as electric heating and cooling, a newly developed hourly joint electricity and hydrogen dispatch model is used. Building on the annual projections of the IEA's Global Energy and Climate Model (GEC), it is applied to quantify power system flexibility needs on timescales ranging from hours over days and weeks to seasons, and to identify how these needs can be met in a cost-optimal manner. It represents all hours in a year, setting the objective of meeting electricity demand in each hour of the year at the lowest possible cost, while respecting operational constraints. The model was built in Python using the Python for Power System Analysis (PyPSA) open-source Python environment for energy system modelling and is solved using linear optimisation. The optimisation ensures that power plants, energy storage technologies, demand response and electrolysers are operated in a way that minimises the total system cost (thus maximising their utility for the system).

Production profiles for wind, solar PV and run-of-river hydro, as well as inflow profiles for reservoir hydro, were generated using the Atlite open-source Python library, which provides functions that convert weather data such as wind speeds, solar irradiance, temperature and runoff into hourly wind power, solar power, run-of-river hydro power and hydro reservoir inflow. Demand profiles are developed at the hourly resolution for each electricity end-use, to properly reflect the impact of the full scope of demand-side integration measures. Load profiles are derived from historical load and temperature data along with survey data where available. To assess the potential variability of weather-dependent renewables and temperature-dependent demand across years and capture extreme events, weather data for 30 historical weather years (1987-2016) were obtained from the ERA5 reanalysis dataset of the European Centre for Medium-Range Weather Forecasts (ECMWF), which covers the entire globe at 30 kilometre resolution. The model includes a detailed representation of reservoir and pumped storage hydro, as well as temperature-sensitive demand and demand response, hydrogen electrolysers, and hydrogen storage. Hydro reservoir and pumped storage dispatch is constrained by water levels in reservoirs, with natural inflows derived based on run-offs and hydrological basins for each hydropower plant. To model the possible interactions between the electricity and hydrogen systems, the model optimises the operation of grid-connected electrolysers, hydrogen storage and thermal power plants using hydrogen, while considering hydrogen production from off-grid electrolysers connected to dedicated renewables as well as demand profiles for other uses of hydrogen.

The model is designed to capture flexibility requirements at various timescales and their evolution over time, and its outputs should be used carefully with respect to its inherent limitations. The model optimises generation, demand, storage and grids at the hourly resolution over the year with perfect foresight. It can impact the operation of long-term storage such as hydro reservoirs, which would operate in a high uncertainty environment in the real world. The thermal capacity is modelled as a fleet, and unit commitment constraints are not covered.

Consumer contribution to flexibility needs through demand response is another area where high uncertainty remains. There are several barriers today to making electricity consumers active in power systems, and the widespread deployment of enabling measures, such as time-of-use or dynamic tariffs, remains to be proven. For these reasons, the report assumes conservative uptake for demand flexibility, and focuses on the end-uses with the largest potential. Results mostly reflect the adjustment of electricity consumption patterns to smart tariffs, rather than explicit response through aggregators.

Hydrogen demand is based on the APS, yet high uncertainties remain about its role in future energy systems, including whether electricity will be sourced from the grid, dedicated renewables, or a mix of both. The model assumes the flexible operation of electrolysers (except when they serve industrial demand). While hydrogen storage is modelled explicitly, the hydrogen transmission network is not covered in the report. These uncertainties on the design of future hydrogen systems can significantly impact its integration with the power sector and role in flexibility provision, potentially redistributing its contribution to other flexibility solutions.

Defining variability and flexibility needs

Flexibility describes the ability of a power system to manage the variability and uncertainty of supply and demand reliably and cost-effectively across all relevant timescales. As power systems evolve, rising shares of variable wind and solar PV, and rising temperature-sensitive electricity demand, for instance from air conditioning and electric heating, increase the variability of the net load[3] (also called residual load) across all timescales, including seasonally.

Flexibility has always been a complicated concept that has had many definitions in the analysis of power systems. It can be associated with the notion of security of supply in the sense that flexible capacity is able to meet electricity demand at all times. However, flexibility encompasses more than just short-term needs, extending to longer-duration imbalances. In this report, flexibility needs are defined depending on the timescale analysed, as different solutions exist for each duration.

To account for the specific flexibility needs of the system, we distinguish between short-term, weekly and seasonal flexibility needs. Short-term flexibility needs are calculated as the average hourly ramp (difference in the residual load between a given hour and the previous hour) of the residual load over the top 100 hours with the highest upward ramps, divided by the average hourly electricity demand for the year (which does not include battery charging, pumped storage pumping, electricity consumption from electrolysers or net exports).

For longer timescales, flexibility needs can be understood as the balancing effort required to smoothen the net load over a given timescale (which could then be satisfied with baseload capacity). Weekly flexibility needs are assessed by computing the absolute difference between the daily and weekly averages of the residual load, divided by the annual electricity demand. Similarly, seasonal flexibility needs are assessed by computing the absolute difference between the weekly and annual averages of the residual load, divided by the annual electricity demand (see Annex: Flexibility needs for a more detailed description).

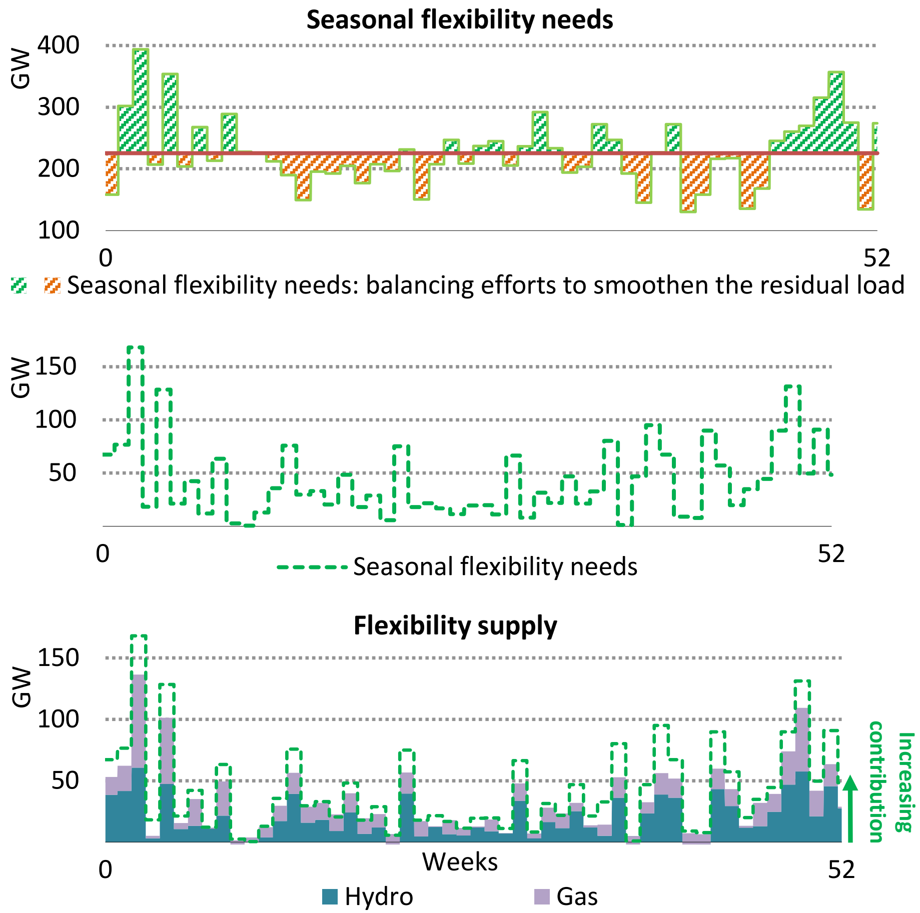
[3] The net load is defined as the difference between electricity demand (excluding battery charging, pumped storage pumping, electricity consumption by electrolysers and net exports) and variable renewable generation (solar PV, wind and run-of-river hydro). It can also be referred to as the residual load. In this analysis, electricity demand for electrolysers is not included in the net load as they are treated as a source of flexibility.

Assessing the drivers of flexibility needs and the supply of flexibility by technology

We quantify the supply of flexibility by technology by measuring the percentage of the system's overall flexibility requirements met by each technology. A resource contributes positively to the seasonal flexibility supply when its average weekly supply is adjusted in line with the average weekly evolution of the residual load, compared with annual averages. However, a given resource may also increase the need for flexibility from other resources when constraints – such as reduced inflows in the case of hydro or plant outages – restrict its ability to respond to variations in the residual load. The drivers of flexibility needs are assessed by breaking down the residual load into its different components: electricity demand and variable renewable generation. One of these elements will contribute towards increasing flexibility needs more than the others if its weekly output is the furthest away from its annual average. Short-duration flexibility refers to the ability of flexibility sources to cope with hourly variations of the residual load while seasonal flexibility refers to the ability of those resources to respond to longer-duration energy imbalances.

The top graph of Figure 2 shows the evolution of the weekly residual load compared with the annual average. The middle graph shows the net seasonal flexibility needs week by week across one year, while the bottom graph shows how weekly average generation from hydro and gas power plants contributes to the seasonal flexibility supply, as their weekly average operations respond to the weekly variations of the residual load.

Figure 2. Profile of seasonal flexibility in Europe

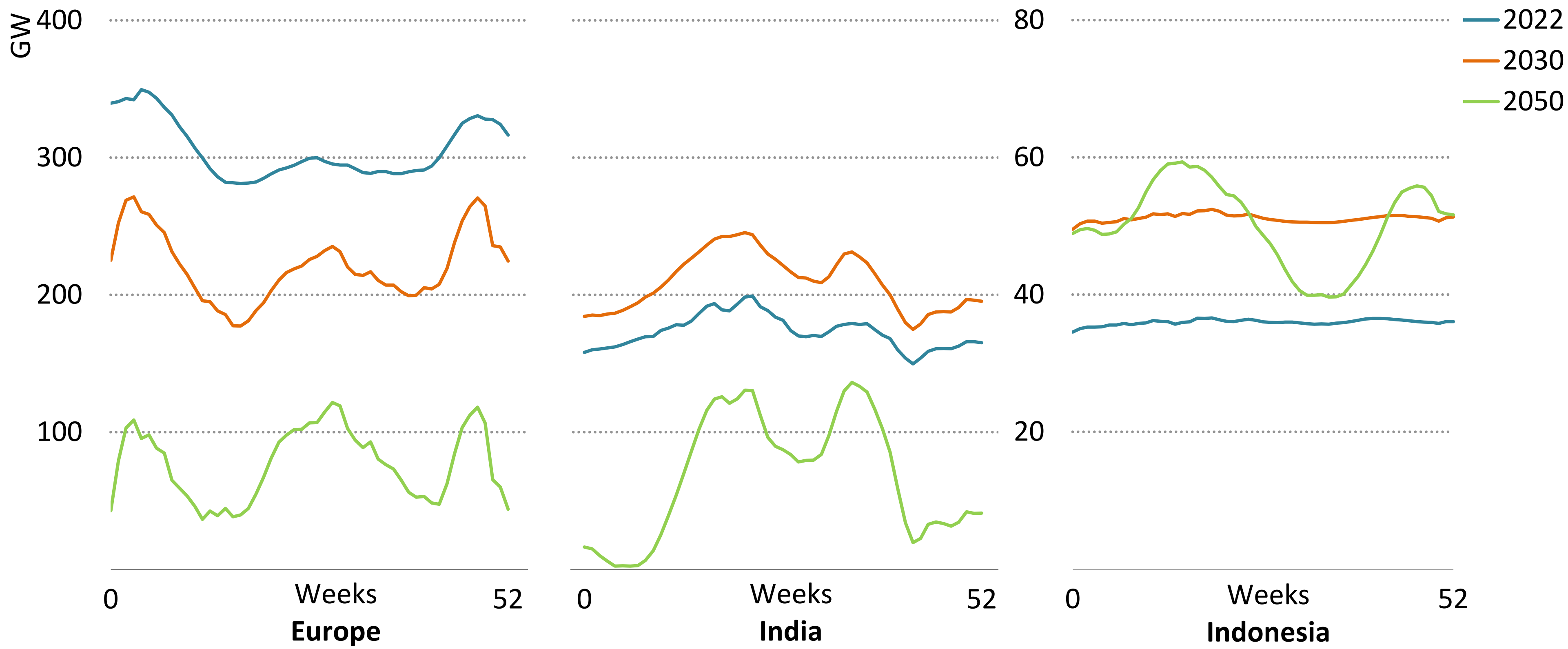


Notes: GW = gigawatt. The values correspond to the weekly average for one specific weather year for the analysis of Europe.

Key findings

Seasonal variability in electricity systems

Figure 3. Weekly net load, Announced Pledges Scenario, 2022-2050



Note: The net load is defined as the difference between electricity demand (excluding battery charging, pumped storage pumping, electricity consumption by electrolysers and net exports) and variable renewable generation (solar PV, wind and run-of-river hydro). It can also be referred to as the residual load.

Impact of seasonal variability on electricity system operations

The seasonal variability of the net load increases in all three power systems – Europe, India and Indonesia – analysed for this report, and significantly changes system operations in the long run. Their locations in different climatic zones, with a broadly temperate climate in Europe, a hot monsoonal climate in India and a tropical climate in Indonesia, impacts the renewables and temperature patterns and reflects on the net load (Figure 3). The systems also differ in their composition: the relative contribution of wind and solar PV, hydro and dispatchable thermal power plants, the electricity demand distribution across sectors and end-uses, and the availability of storage and demand response. In general, the overall decrease of the annual average of the net load reflects a decline in the need for baseload generating capacity, while the stronger seasonality reflects the increasing need for seasonal balancing.

With the increasing penetration of variable wind and solar PV and rising temperature-sensitive demand from air conditioning and electric heating, the seasonal variability of the net load increases in all three systems, significantly changing system operations in the long run and amplifying seasonal flexibility needs. The net load shape also evolves over shorter timescales, especially within the course of a day. Short-term flexibility needs increase in all power systems, mostly due to the rising importance of solar PV in electricity systems. On the demand side, the rising uptake of electromobility is the main contributor to daily load variations, and drives up the need for flexibility.

Today, both seasonal and short-term flexibility are mostly provided by hydro and thermal dispatchable power plants. They both remain important providers of seasonal flexibility in the future. With the decarbonisation of electricity generation and the transition away from fossil fuels in the power sector, grid-connected electrolysers and hydrogen storage emerge as important providers of seasonal flexibility, especially around 2050. The curtailment of some of the renewable surpluses during periods of lower net load is also shown to be a cost-effective solution to balance the residual load on a seasonal timescale. Batteries and demand response emerge as key technologies to address short-term variability. Providing proper access to markets and secure revenue streams for storage assets is key to ensure that they will be available to cope with the increasing short-term flexibility needs. Demand response mechanisms can easily be unlocked with tariff incentives without compromising customers' services.

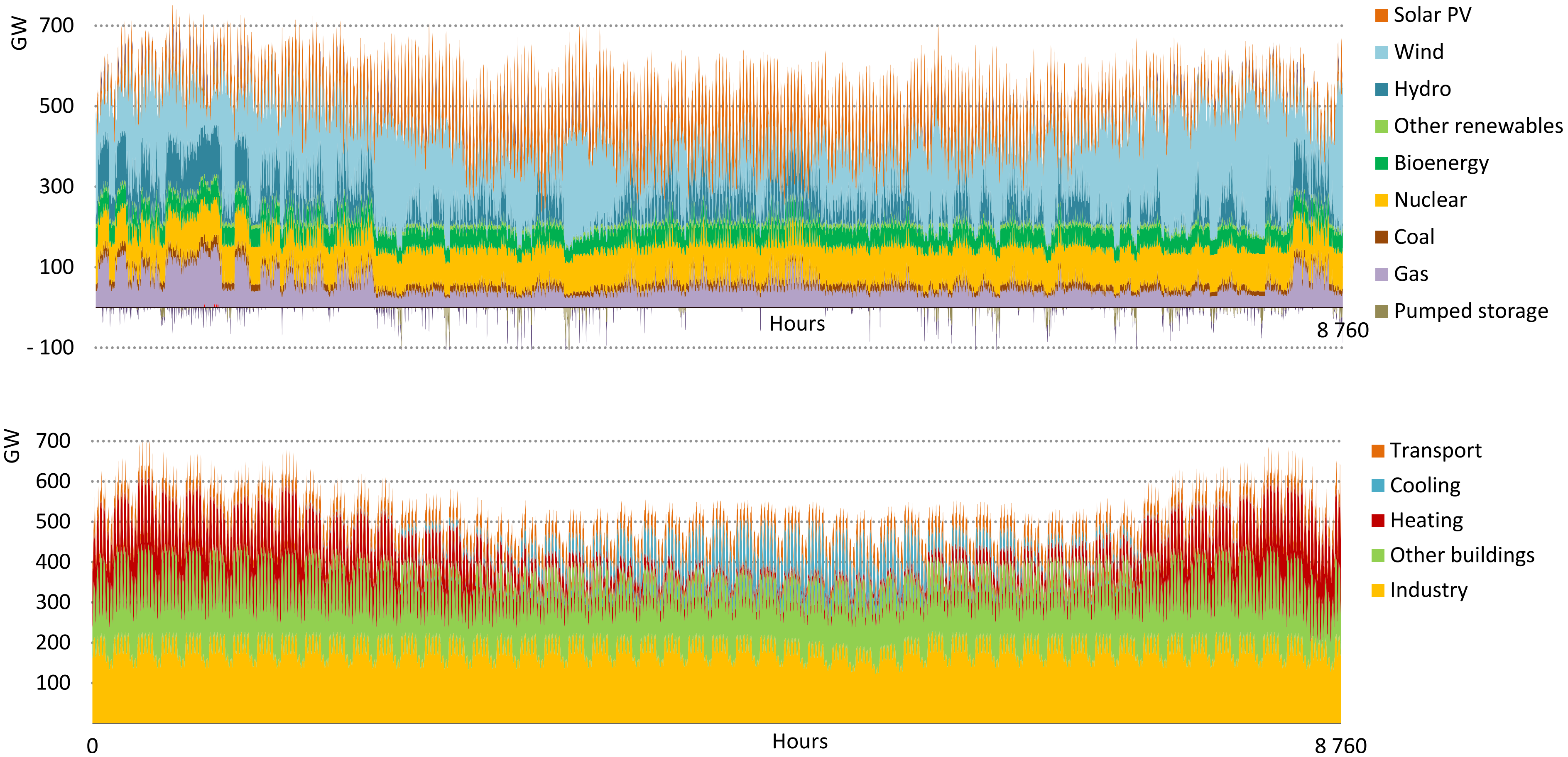
The contribution of the different sources of supply in critical hours of high system stress, which is when high demand coincides with low levels of generation from variable renewables, changes considerably between 2022 and 2050. While battery energy storage systems emerge as important sources of supply during peak hours – especially in solar PV-based systems – dispatchable thermal power plants remain key providers of secure capacity. Across the year as a whole, their average capacity factors decline significantly as the share of variable renewables increases, but in periods of great system stress, much of the installed capacity is used to maintain security of supply. In a low-emissions electricity system, these dispatchable sources will have to be decarbonised with the use of low-emissions fuels or carbon capture and storage. It is therefore essential to ensure that sufficient dispatchable capacity is maintained in the long run by putting mechanisms or considerations in place that adequately value the critical services these generators provide to the system, even when they operate very infrequently over the course of a year.

Average solar insolation, wind speeds, temperatures and rainfall can vary significantly across weather years. Interannual weather variability impacts power system operations and thus operating costs across years. Total power system costs per unit of electricity are anticipated to decline across three systems due to the shift towards low-emissions technologies, particularly wind and solar PV. The increasing share of low-marginal-cost generation is expected to reduce the share of the operating costs (mainly fuel costs) from about two-thirds today to 30% or less by 2050. Despite an expected rise in weather-induced variability in operating costs, the overall impact on total system costs is projected to be relatively small as most of these costs are fixed.

While the analysis provides valuable insights into understanding the impact of seasonal variability on electricity system operation and security of supply, it is important to highlight that it does not represent a detailed assessment of system adequacy for the three regions. A true adequacy assessment would require much more granular modelling of each region’s power plant fleet and transmission system, as grid congestion could potentially raise the need for flexible capacity in certain locations, forcing the use of a greater proportion of the remaining capacity margin. However, the study does demonstrate that it will be possible to cost-effectively maintain security of supply in future power systems with high shares of weather-dependent variable renewables provided crucial elements, such as sufficient amounts of flexible capacity and a robust grid infrastructure, are in place. The study also demonstrates that such low-emissions power systems are cost-effective and have the potential to lower costs for consumers in the long run.

Variability of electricity demand and supply

Figure 4. Hourly electricity generation by source (top) and hourly demand by end-use (bottom) in Europe, Announced Pledges Scenario, 2030



Notes: Announced Pledges Scenario (WEO 2022). The weather patterns shown are those of the year 2001.

Regional insights

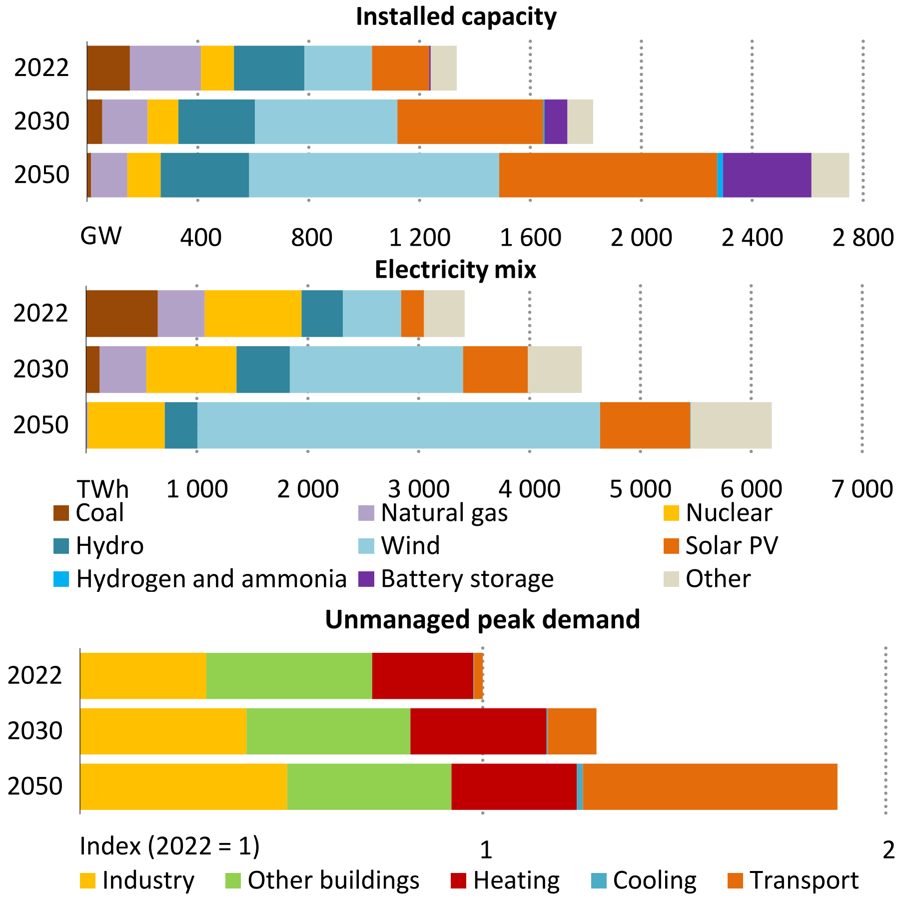
Europe

Evolution of the electricity system

In Europe, thermal power plants using coal or natural gas produced 43% of the electricity consumed in 2021, with nuclear and hydro accounting for 25% and 18%, respectively. Wind and solar PV together already make up nearly 20% of the region's electricity production. An emphasis on energy security and reducing reliance on imported natural gas is expected to speed up the deployment of renewables, with rapid capacity growth in the near and medium terms, bringing the share of wind and solar in total electricity generation to 45% by 2030. In the long run, the region moves towards an electricity system dominated by onshore and offshore wind, with both accounting for 47% of generation in the APS in 2050 (Figure 5). The role of thermal shifts from bulk generation to flexibility provision and to ensure security of supply at peak demand.

Driven by ambitious energy and climate policies across the region, energy end-uses in Europe are increasingly electrified. The share of electricity in total final energy consumption in 2030 is nearly 30% in the APS, compared with 22% in 2022. More than 400 GW of heat pumps are deployed by 2030. Electric vehicles (EVs) are estimated to account for 45% of electricity demand growth until 2050: there are 350 million EVs on the road by 2050, compared with around 9 million today, and EVs make up 80% of the vehicle fleet. Changing patterns of consumption as electricity use increases have a significant impact on peak electricity demand over the year. Unmanaged peak demand increases by 88% to 2050, with two-thirds of the increase coming from EV charging.

Figure 5. Evolution of installed capacity, generation mix and unmanaged peak demand, 2022-2050



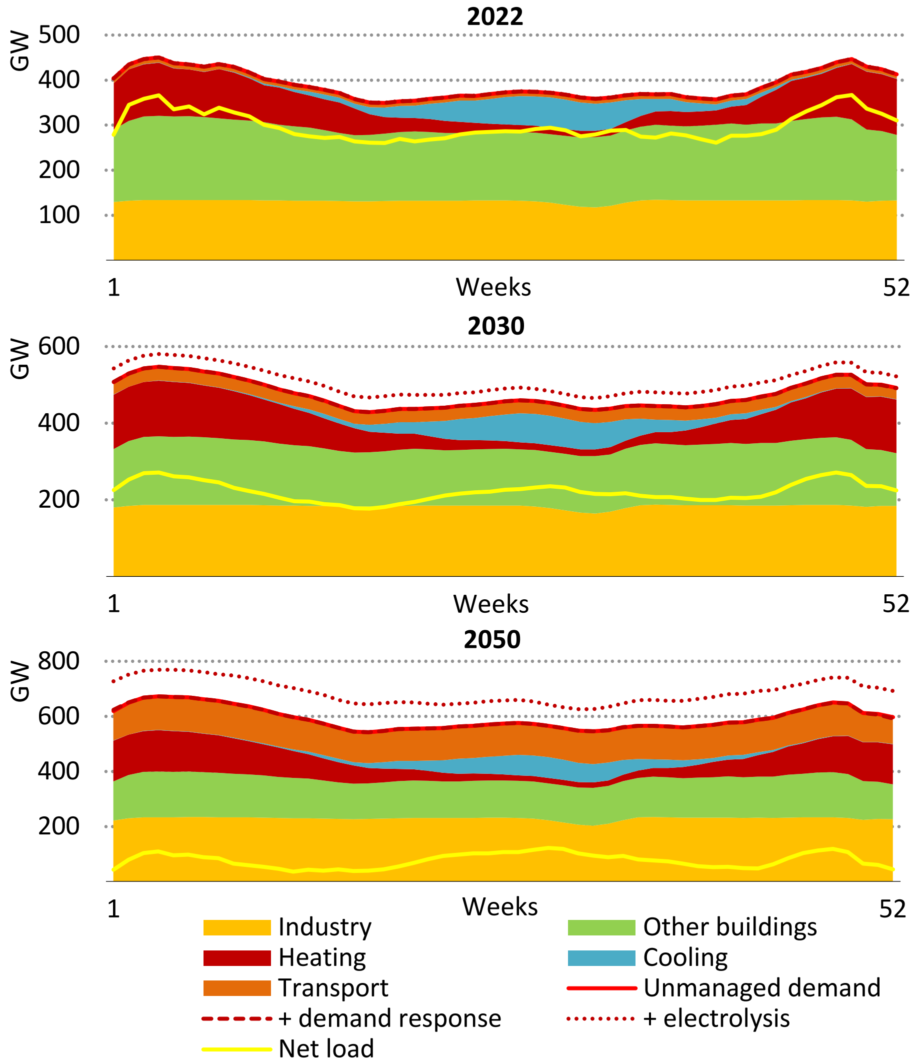
Notes: TWh = terawatt-hours. Other includes bioenergy, waste, geothermal, concentrating solar power, marine and oil. Unmanaged peak demand is the average of the 500 highest load hours of the year, before activation of demand response. Heating includes space and water heating. Other buildings includes lighting, cooking and appliances. Europe includes the European Union, the United Kingdom, Norway, Serbia and Ukraine.

Seasonal variability of demand and supply

The variability of the net load across seasons changes until 2050, driven mainly by the increasing penetration of wind and rising shares of electric space heating and cooling.

Europe's mid-latitude climate features four distinct seasons, with colder temperatures in winter and hotter temperatures in summer, the magnitude of which depends on the country. Today the seasonality of electricity demand is mostly due to electric space heating and space cooling, which directly respond to the variations in outdoor temperatures (Figure 6). Other end-uses and sectors feature a rather flat demand over the year, except during summer when industrial activity slightly slows down, and during the Christmas holidays. On average over Europe as a whole, demand is higher in the winter months (November to March). The seasonality of individual countries' load profiles may differ significantly depending on their location and climate, with countries around the Mediterranean typically exhibiting a cooling-related summer peak, while countries located farther to the north in the continents' temperate and continental climatic zones experience a winter peak driven by electric heating. Across Europe as a whole, space cooling and space heating can reduce the seasonal variability of the aggregate load, with the former raising demand across the summer months and the latter across the winter, although whether that translates into a reduction in overall flexibility needs depends mainly on the availability of sufficient transmission capacity to help balance load fluctuations among different countries and regions.

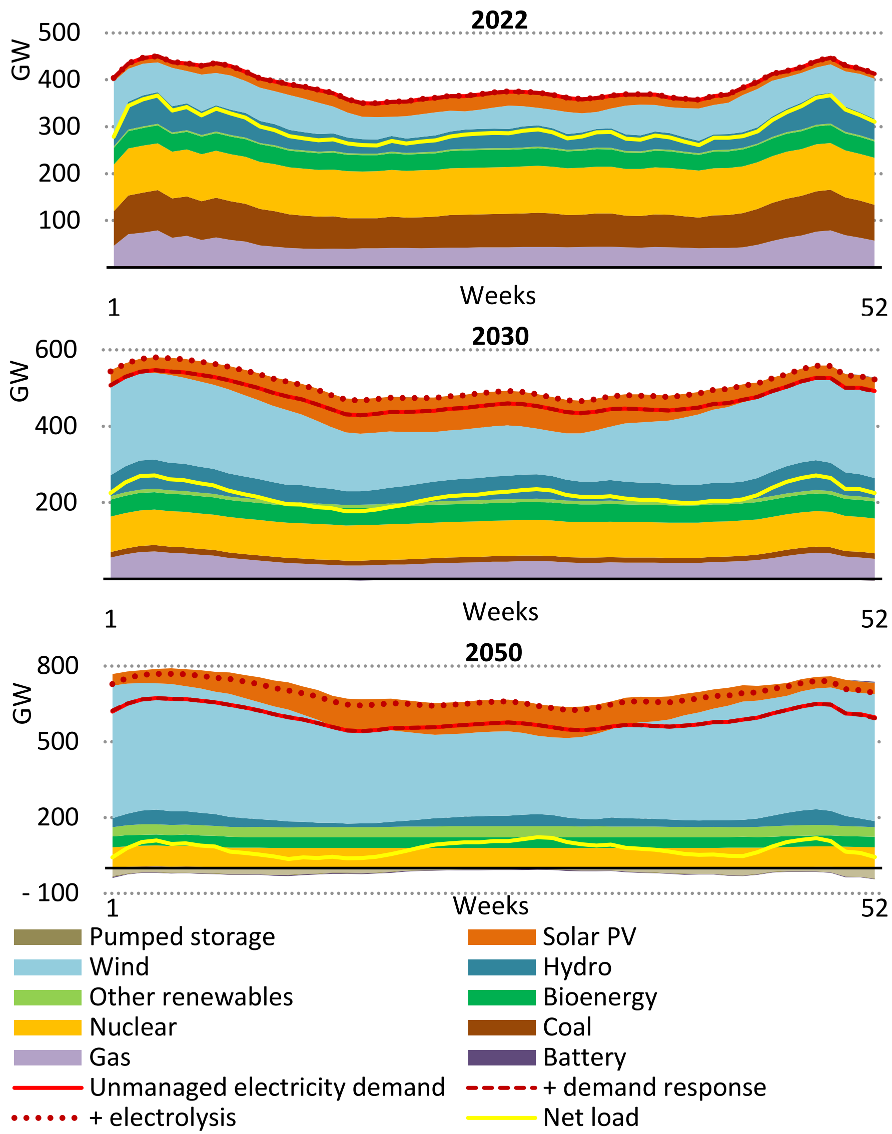
Figure 6. Average annual load curve by end-use, 2022-2050



The uptake of electromobility in Europe has no significant impact on seasonality given the relatively flat demand on average over the year, in contrast to the daily-level impact where transport is a major driver of load variations. By 2050, temperature-sensitive end-uses add little to the seasonality, as energy-efficient heat pumps limit the increase in space heating demand to 25% and efficient air conditioners limit the increase in cooling demand to 10%. Additional baseload demand from industry and transport reduces the relative share of temperature-sensitive end-uses in total electricity demand.

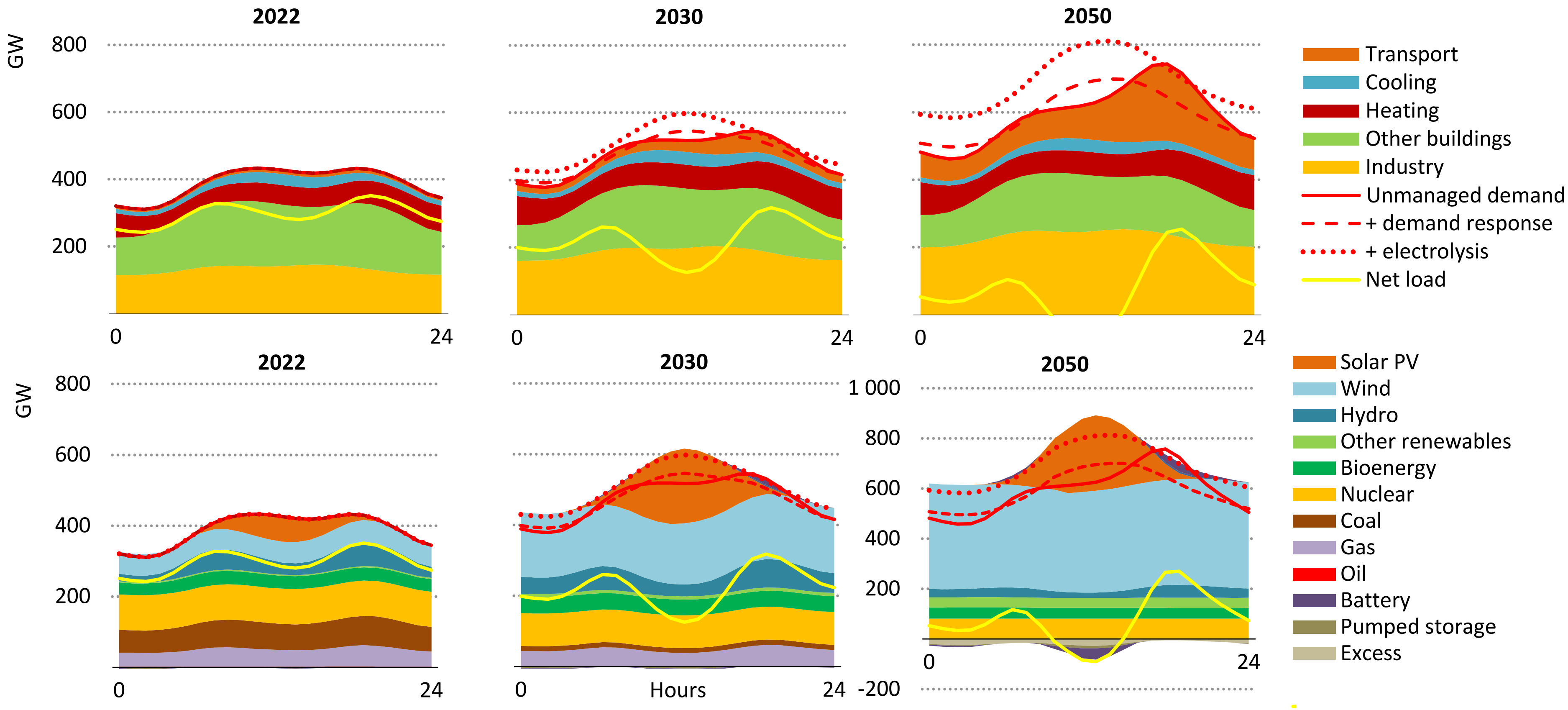
On the supply side today, the seasonality of electricity demand is met largely by adjusting the output of thermal and hydropower plants. As wind and solar PV become predominant in the electricity mix, the residual load is increasingly shaped by the seasonality of wind and solar PV, with generally stronger winds in the winter months and higher solar PV output over the summer (June to September). By 2050 in the APS, unabated fossil fuel generation has almost been phased out in Europe, except for specific periods, such as cloudy low-wind periods in the late autumn or winter (also known as *Dunkelflaute*), which feature low wind and solar PV generation along with high demand. The average annual capacity factor of thermal power plants declines to less than 10% in 2050 compared with 60% on average in 2022, with these plants increasingly acting as providers of back-up capacity for when the system is short, instead of as suppliers of bulk energy (Figure 7).

Figure 7. Average annual electricity supply by source, 2022-2050



Daily variability of demand and supply

Figure 8. Average daily load curve and average daily electricity supply by source in Europe in the Announced Pledges Scenario, 2022-2050



Notes: Europe includes the European Union, the United Kingdom, Norway, Serbia and Ukraine. Other renewables includes geothermal, concentrating solar power, and marine; Electricity demand is represented in three different states: without the effect of demand response nor electrolysers ("unmanaged demand"); with the addition of the activation of demand response ("+ demand response"); and with the addition of electrolysers ("+ electrolysis").

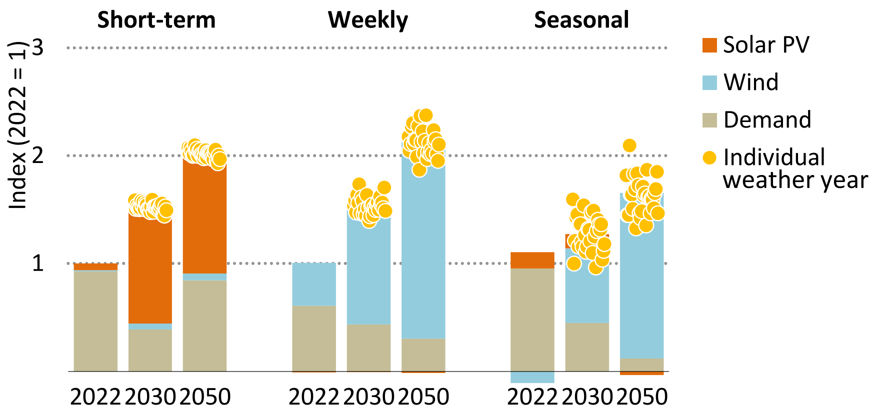
In Europe, the daily variability of electricity supply and load is growing, with the rise of electromobility reshaping the daily consumption profile and the rising share of solar PV in particular increasing variability on the supply side.

The load curve reflects daily electricity consumption patterns across Europe, shaped by human activity, industrial operations and societal habits. Its profile varies across countries and regions and over the year, as differences in temperatures are reflected in the consumption patterns. The typical electricity usage trend shows morning and evening peaks, driven by people's daily routines, business operations, and residential activities such as cooking and lighting (Figure 8). Winter profiles exhibit a stronger evening peak, primarily attributed to the increased demand for heating in households. Consumption from air conditioners, by contrast, is highest in daytime when temperatures reach their maximum, shifting the peak towards the afternoon. Until 2050, baseload consumption increases as industrial applications are increasingly electrified. However, more energy-efficient appliances blunt the rise in household electricity consumption associated with increasing ownership, including of air conditioners and electric heat pumps. The massive uptake of electric vehicles creates new challenges for the electricity system, especially as unmanaged EV charging concentrates in the evening when people return home. Demand response, mostly through smart charging, optimised heating and cooling, and smart appliances, will therefore play a key role in mitigating the impact of these developments, shifting this evening peak to midday, taking advantage of solar PV feed-in during the day.

On the supply side, today, most of Europe’s electricity is produced from conventional sources such as nuclear, natural gas and coal, although wind and solar PV already account for significant shares of the supply mix in many countries. Flexible generation by large hydropower plants helps meet the morning and evening peaks. Until 2030, the share of unabated fossil fuels declines sharply, with renewables accounting for 70% of the electricity supply. By 2050 Europe’s electricity system is projected to be dominated by variable wind and solar PV. Such systems are shaped by the dynamics of the residual load. While the typical net load peak is projected to remain in the evening, the midday net load dips below zero on a regular basis as the share of solar PV in the mix increases, meaning that renewable generation surpasses electricity demand during these hours. To make the best use of the daytime renewable surplus, demand response (notably through the smart charging of electric vehicles) shifts consumption from the evening peak to periods with surplus generation. Similarly, batteries and pumped storage hydro, engaging in arbitrage by charging during off-peak hours and discharging at peak hours, shift electricity from midday to the evening peak.

Flexibility needs

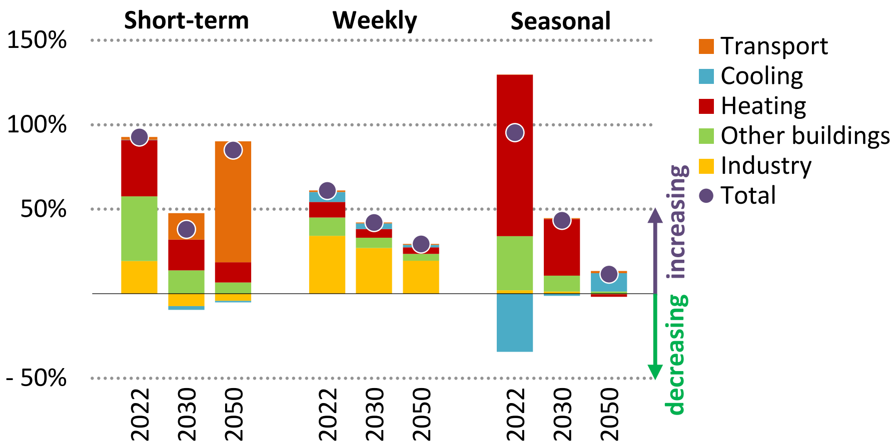
Figure 9. Evolution of flexibility needs and their drivers, 2022-2050



IEA. CC BY 4.0.

Note: Yellow dots represent the total needs for each individual weather year.

Figure 10. Contribution to flexibility needs by end-use, 2022-2050



IEA. CC BY 4.0.

In Europe, short-term and weekly flexibility needs rise by about 50% by 2030 and double by 2050. The increase in seasonal flexibility needs is less pronounced by 2030, but they increase by about two-thirds by 2050.

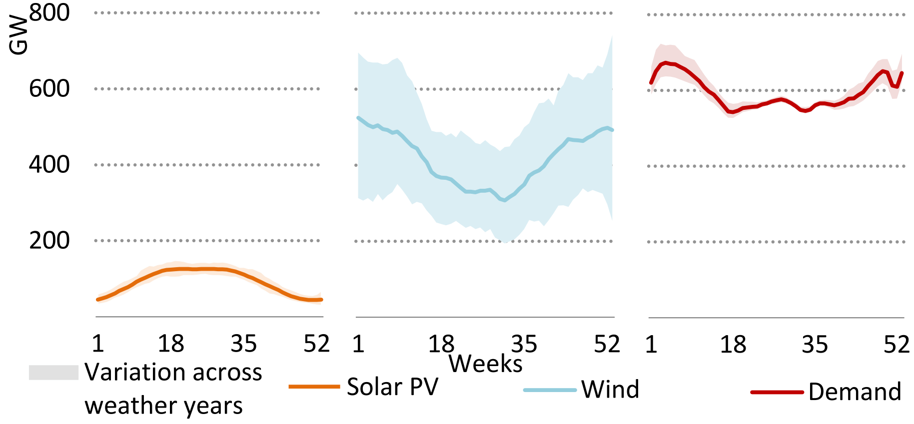
Today, despite the growing penetration of wind and solar PV in the European electricity mix, variations in demand are still the main driver of flexibility needs across all timescales. By 2030, the share of wind- and solar PV-based electricity generation has grown enough that they significantly increase the need for additional flexibility. Solar PV is responsible for most of the increase in short-term flexibility needs until 2050 (Figure 9). It is characterised by its distinct daily cycle and increases the variability of the residual load over the course of a day.

Over longer timescales, flexibility requirements are driven by phenomena exhibiting longer cycles than solar PV output, such as wind and electricity demand patterns. Weekly flexibility needs are generally driven by the differences in electricity demand between weekdays and weekends. However, they also reflect the variability of wind across multiple days, which can be significant in Europe as weather systems move across the continent. Variations in electricity demand driven by higher heating loads in winter and greater cooling needs in summer are the primary drivers of seasonal flexibility needs today. However, by 2030, wind, with its share in the electricity mix increasing from 15% today to 40% in 2030, becomes the main driver of seasonal flexibility needs as wind typically generates more in the winter than in summer in Europe. In 2050, the seasonal variability of wind is responsible for nearly all the seasonal flexibility requirements.

Today, short-term flexibility requirements are determined largely by the daily increase of electricity demand in the morning, mainly from industry, appliances and space heating (Figure 10). In 2050, the biggest upward increase in net electricity demand tends to shift to the evening, when people return from work and charge their EVs. On the weekly scale, flexibility needs are driven by variations in demand between weekdays and weekends, most notably in industry. These variations over the week tend to fade as industry is more electrified, hence reducing the overall demand contribution to weekly flexibility needs. Each end-use's share in seasonal flexibility needs reflects the alignment of its profile with the net load. In 2022, temperature-sensitive end-uses increase net load in winter and summer; the winter peak drives the flexibility needs given its larger size. As a smaller and complementary peak, cooling flattens the net load over the year and mitigates the increase in seasonal needs. In 2050, the seasonality of the net load is driven mostly by renewables rather than electricity demand.

The overall magnitude of short-term flexibility needs varies little from one weather year to the next. After 2030, the variability of weekly and seasonal flexibility needs in Europe is driven primarily by the variability of wind generation. Weekly flexibility needs in 2030 and 2050 can vary by up to 13% from weather year to weather year, and seasonal flexibility needs can vary by up to 30%.

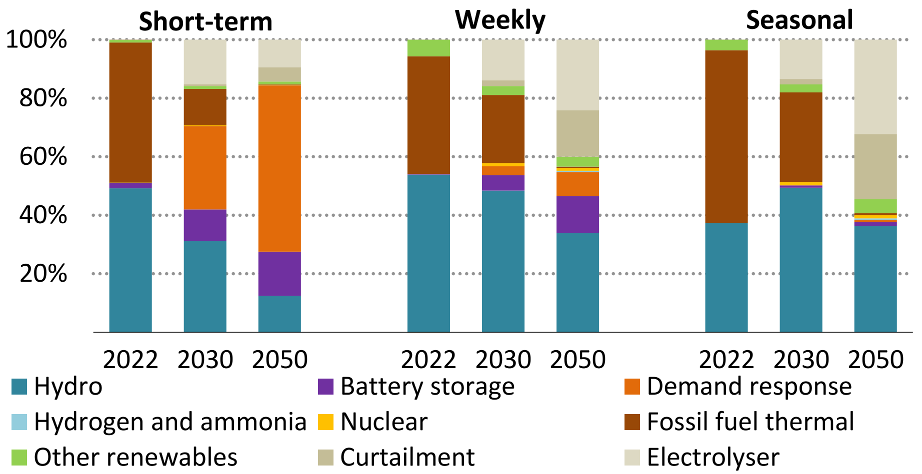
Figure 11. Variability across weather years in the Announced Pledges Scenario, 2050



In Europe, solar PV shows a clear seasonal trend with higher monthly capacity factors in summer than in winter (Figure 11). Solar PV has a pronounced daily cycle, but weekly average generation varies little across weather years. Conversely, wind generation demonstrates both a strong seasonality and a substantial variability across weather years as some years are on average much windier than others. The most extreme weather years result in a roughly 40% upward and 30% downward variation in weekly average electricity generation compared with an average weather year in both the summer and winter. Electricity demand tends to be higher in winter, mainly due to electric heating. As a result, variations in temperatures between weather years lead to significant interannual variability in winter demand in particular.

Flexibility supply

Figure 12. Flexibility supply by source, 2022-2050



In 2022, flexibility across all the relevant timescales in Europe is provided mainly by thermal generators (mostly coal- and gas-fired power plants) and hydro reservoirs. By 2030, thermal power plants are increasingly complemented by alternative sources of flexibility, with batteries and demand response in particular emerging as important suppliers of short-term flexibility. In 2050, demand response, including the flexible operation of electrolysers to produce hydrogen, provides nearly two-thirds of the short-term flexibility needed, with the remainder supplied mostly by battery storage and hydro (Figure 12).

For weekly and seasonal flexibility needs, which span over days, weeks and months, the mix of solutions differs from the short term. Thermal power plants remain important providers of seasonal flexibility after 2030. However, the capacity factor of thermal assets decreases and by 2050, these plants are mostly used to cope with the infrequent periods when generation by renewables, especially wind, is low for extended periods of time. In 2050, the flexible operation of electrolysers complements hydro to address seasonal variations. As Europe's electricity system is characterised by high shares of variable renewable generation, curtailing some of the excess wind and solar generation can also be an efficient solution to balance the residual load and thus to provide flexibility.

Demand response includes both the response of individual electricity consumers to variable prices and bulk flexibility provided through aggregators. Pricing strategies can either be static, such as time-of-use tariffs that are defined ahead of actual market outcomes, or dynamic, such as peak and dynamic pricing. Demand response is well suited to respond to short-term flexibility needs thanks to its high degree of responsiveness. However, the potential is more limited over longer time frames as shifting durations are limited to a few hours in most cases, or up to a day for electromobility (see Annex). In 2030, 10% of electricity demand is assumed to feature some form of demand response; this share increases to 28% by 2050.

In Europe, demand-side response plays an increasingly important role in the provision of short-term flexibility, as it meets 30% of the short-term flexibility needs by 2030 and more than half by 2050. End-uses with the longest shifting durations and highest shares in electricity demand contribute the most. In 2030, one-third of the demand response contribution is from the smart charging of electric vehicles. This increases to 60% by 2050. The remainder is mostly shifting space and water heating, accounting for 56% of the contribution by 2030 and 31% by 2050.

To a lesser degree, demand response also contributes to the weekly flexibility supply by shifting electricity consumption over the night and when feasible, from the first and last weekdays to the weekend. By 2050, EV charging and water heating make up more than 75% of the demand response contribution to addressing weekly flexibility needs.

The flexible operation of electrolysers represents an important source of flexibility as well. While they play only a marginal role in 2030, they meet 24% of the weekly needs and 32% of the seasonal needs by 2050. Flexible hydrogen production allows for the best use of electricity surpluses, especially in summer where peak daily PV generation may be much higher than what the final demand can absorb, even considering the demand response potential. Enabling flexible operation comes at the cost of oversizing electrolyser capacities but allows electrolysers to operate when electricity is the cheapest. The electrolyser load factor is a key parameter to size the capacity and minimise the total hydrogen production cost. Electrolysers can operate flexibly over long durations only if hydrogen storage is available. In Europe, there is significant potential for underground hydrogen storage in salt caverns. The model assumes that part of the hydrogen produced by on-site electrolysers co-located with iron and steel plants and refineries is consumed directly, without going through underground storage. However, even in this case, storage tanks will permit the flexible operation of on-site electrolysers across a day.

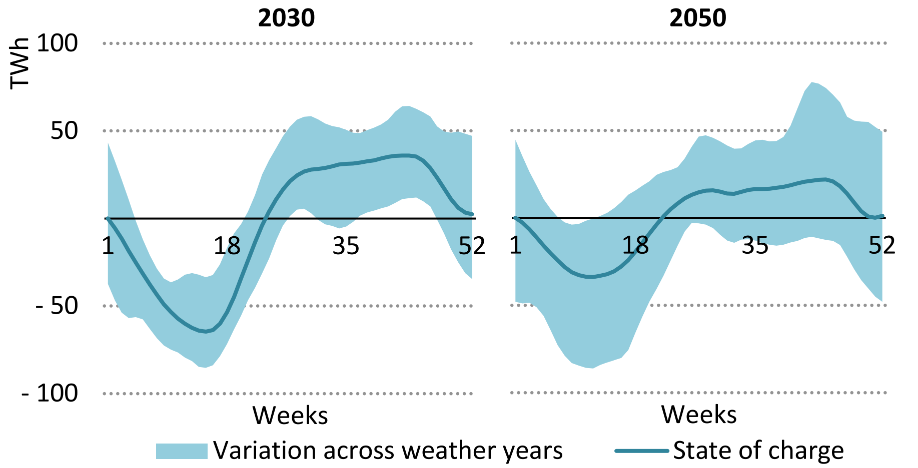
Battery energy storage systems emerge as a key technology for the balancing of short-term flexibility needs. Batteries complement the daily cycle of solar PV output, enabling the integration of solar PV by reducing potential curtailment during periods of surplus, while reducing the need for dispatchable thermal assets to compensate during periods solar PV is not available.

Our analysis shows that due to their low marginal cost and the flexibility provided by other elements of the electricity system, nuclear power plants tend to continue to operate at high capacity factors over the course of a year, thus providing relatively little flexibility by themselves. However, this does not mean that nuclear power plants are inherently inflexible. Examples of nuclear being an important provider of flexibility across all timescales exist: the scheduling of planned maintenance or refuelling during periods of low net demand is one way for nuclear to provide seasonal flexibility. Nuclear power plants also have the ability to provide short-term flexibility if necessary. The output of the French nuclear fleet, for example, can vary significantly in response to changes in the net load, with reactors able to ramp up from 20% to 100% of their nominal capacity within 30 minutes twice a day.

Hydropower plants are key assets to manage flexibility across all timescales. As of today, pumped storage hydro represents the most efficient and cost-effective way of storing electricity over extended periods of time. It is used to respond to short-term variations of the residual load, reducing ramping needs and enabling conventional generators to operate at their optimal efficiency. Together with the flexible operation of hydro reservoirs, which store water over multiple weeks, they account for nearly half of the flexibility provided across all timescales. However, the potential expansion of hydro reservoirs is limited in the future depending on the region, and with the growing needs for flexibility, their share in the overall supply of flexibility decreases. Their share in the short-term flexibility supply mix will decline more sharply since batteries and demand response supply most of the additional flexibility required. However, hydro reservoirs and pumped storage hydro remain key providers of seasonal flexibility until 2050, retaining a 40% share.

Hydro inflows are seasonal and depend on rainfall and snowmelt. Inflows are larger in spring (April to June). Hydro reservoirs can optimise their operations by saving water for times when the system is short, with their optimal dispatch depending on the evolution of electricity prices and water inflows over the course of the year. In Europe, at the beginning of the year, when temperatures are low and electricity demand is higher because of heating needs, hydro reservoirs are mostly discharging to provide additional electricity. When spring arrives, inflows from rainfall and snowmelt start to fill up the reservoirs. They tend to start discharging once again at the end of autumn when electricity demand increases.

Figure 13. Variability of hydro seasonal storage across weather years, 2030 and 2050



Note: The figure displays the amount of electrical energy stored in hydro reservoirs, relative to the storage level on 1 January, for years 2030 and 2050.

As shown in Figure 13 in the projections for 2030, hydro storage levels are inversely correlated to the residual load, which is lower in summer and higher in winter. Conversely, water levels decline in late autumn and winter and reservoirs fill up in spring and over the summer months. In 2050, hydro storage operations follow a similar pattern, yet with more limited variations over the year. This is mostly due to the competition with flexible hydrogen generation for surplus renewable electricity.

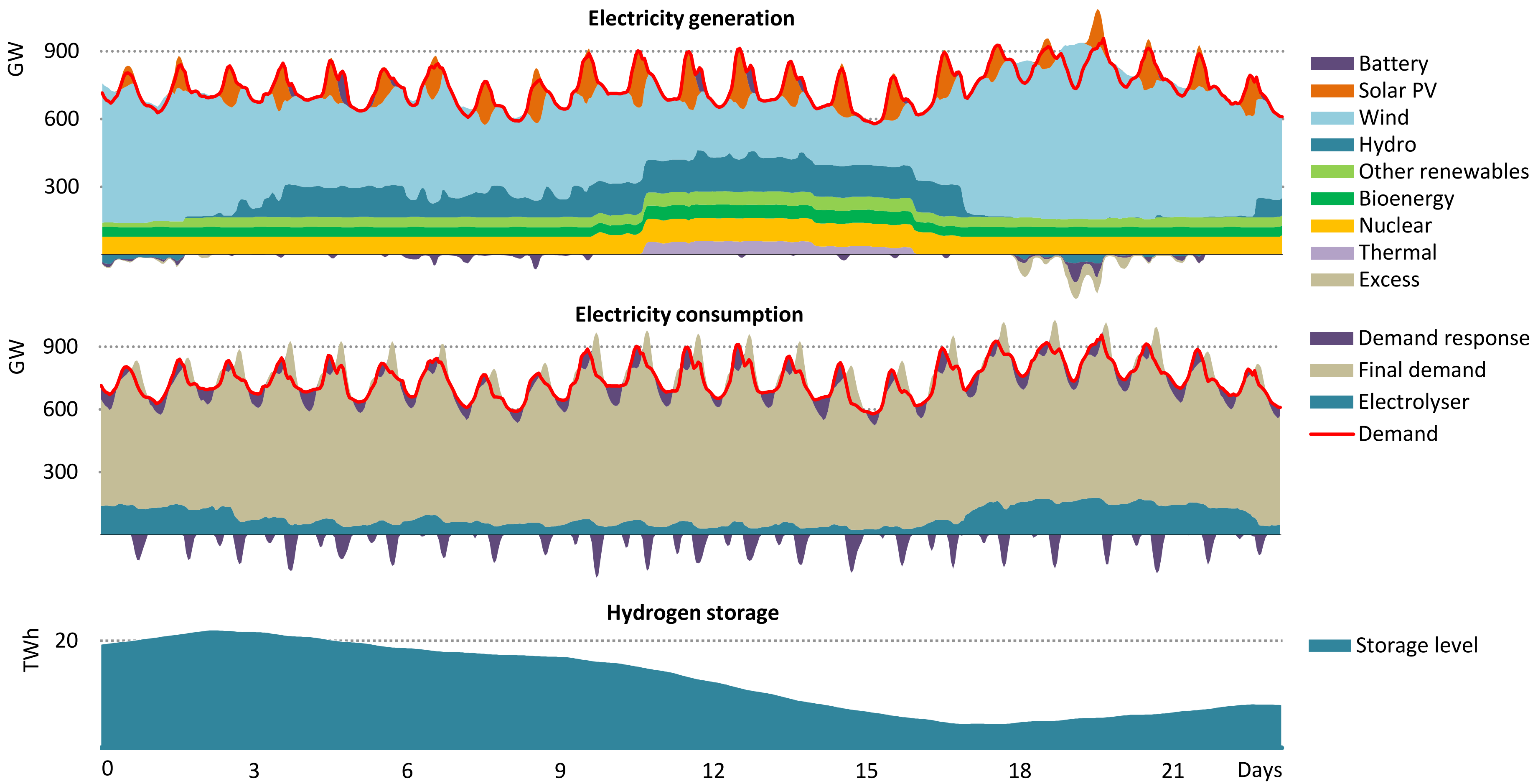
However, hydro is key to accommodate variations between weather years – as noted earlier, wind, solar PV and demand are not distributed evenly among the months, and some months might be windier in a given weather year than another. As shown before, wind is the key driver of interannual variability. With higher capacity in 2050 and a share of 10-20% in the electricity supply, hydro supports more variability between weather years and arbitrage might be more difficult, as one weather year can look very different from another.

Zooming in on the periods in a year with cold weather and low renewable electricity generation (dark doldrums or *Dunkelflaute*) shows that hydro and the flexibility offered by the hydrogen system are both key to meet seasonal flexibility needs (Figure 14). At the beginning of such periods, hydro ramps up first, followed by thermal generation. Other dispatchable generators maximise their output. Demand response adjusts to make the best use of the remaining wind and solar generation, with EVs charging around midday and at night. Flexible hydrogen electrolysers power down and reduce their electricity consumption. However, some electrolysers still run for industries and refineries that require a steady supply of hydrogen. While their storage tanks allow for some flexibility, on-site storage typically lasts no longer than a day. Other end-uses that consume hydrogen draw from the underground hydrogen storage.

This snapshot highlights the importance of sector coupling (which links hydrogen and electricity systems) and system integration (with the integration of end-uses through demand response an essential element) to manage seasonal variability and ensure security of supply.

The role of sector coupling in managing seasonal variability

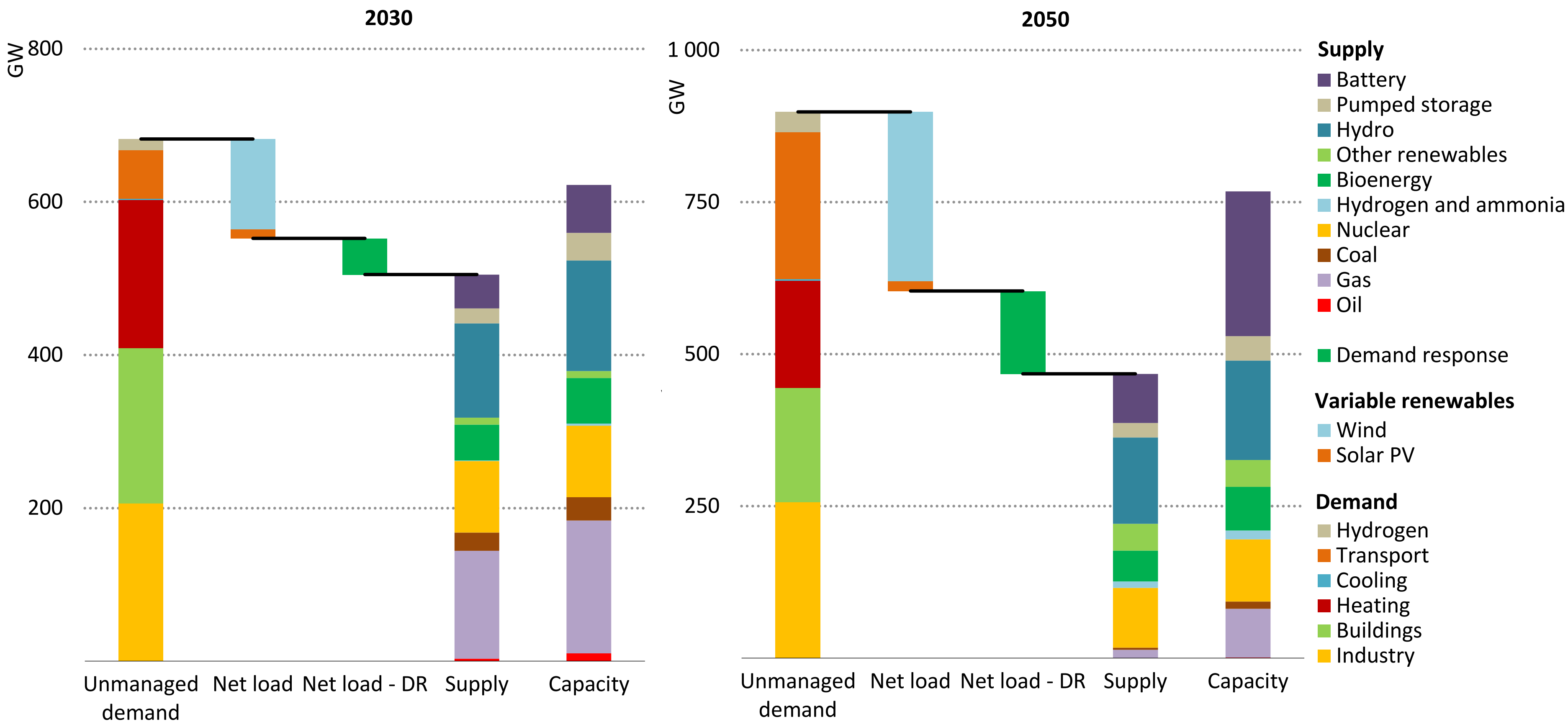
Figure 14. Illustration of the role of sector coupling to provide flexibility for the power system, Europe, Announced Pledges Scenario, 2050



Note: Other renewables includes geothermal, concentrating solar power, and marine.

Electricity demand and supply and capacity margin at peak net load

Figure 15. Electricity demand and supply during the highest net load peak over 30 weather years in Europe in the Announced Pledges Scenario, 2030 and 2050



Notes: DR = demand response. Unmanaged demand represents electricity demand before activation of demand response. Other renewables includes geothermal, concentrating solar power, and marine. Peak net load is computed as the top 100 hours over the year. The capacity represents the available capacity during these peak hours.

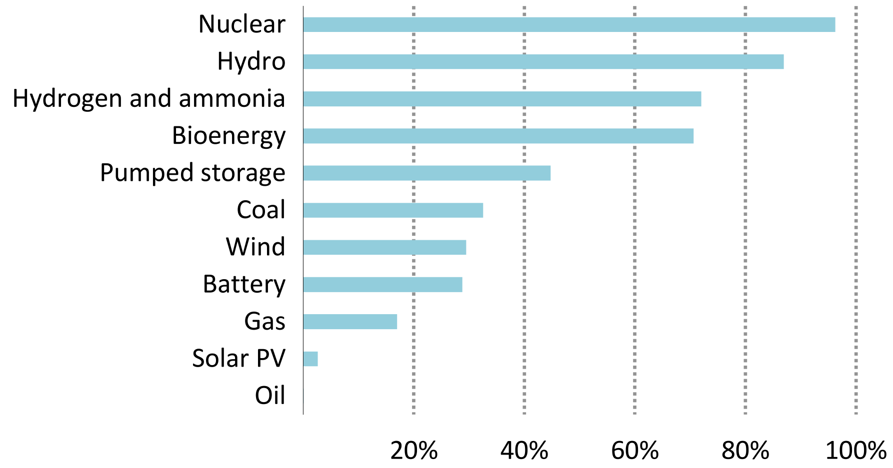
Enhancing power system flexibility is essential not only to integrate rising shares of solar PV and wind, but also to ensure electricity security of supply. Historically, the key metric to assess the tightness of power systems was the peak demand. However, in systems characterised by high shares of variable renewables, the situations in which the system is short on supply are the peak hours of the net load, when electricity demand is high and the availability of variable renewables is low. Figure 15 above displays the electricity demand, split by end-use and the electricity supply by technology during peak net load in Europe (computed as the top 100 hours over the year), in the weather year with the highest observed peak net load.

In these critical hours, demand is driven primarily by EV charging and heating. Notably, the end-use contribution during the peak net load period in Europe is quite similar to that in the peak demand period, which means that even with demand response and variable renewables, peak demand matters for system sizing.

Even at periods of peak net load, the system typically still sees significant wind generation (corresponding to 28% of average load factor over the year for onshore wind and 47% for offshore wind), while solar PV makes almost no contribution at these times.

Already by 2030, demand response supports the system by shifting about 42 GW of demand. It is distributed first across end-uses with significant shifting durations with 20% provided by EVs, 60% by heating and 7% by appliances. This corresponds to shifting about 15% of the total EV charging and heating demand. In addition, 5 GW of industrial demand is curtailed given the high electricity price levels in these hours. By 2050, almost 140 GW of demand can be shifted, with 60% EV charging and 36% heating. This corresponds to 30% of EV charging and heating demand shifted out of those hours. Both in 2030 and 2050, only 60% of the total demand response potential is activated – it cannot be tapped fully as it is constrained by shifting durations (especially if the peak has a long duration). This emphasises the importance of smart charging of EVs that is going to be crucial for net peak demand management: by 2050 this enables the shift of 84 GW of peak demand, the equivalent of two-thirds of the installed nuclear capacity in Europe.

Figure 16. Share of available capacity used during net demand peak, Europe, Announced Pledge Scenario, 2050



Note: The available capacity is considered as the net capacity available during net demand peak hours.

In 2030 during net demand peak hours, natural gas and hydropower plants are the primary sources, together accounting for 50% of the net load peak. Coal power plants still cover a portion of the peak with 80% of the available capacity used during these critical hours. However, the role of unabated fossil fuels declines over the years and by 2050, both natural gas and coal are replaced entirely by battery energy storage and hydro as the main contributors at peak demand. Despite their low share relative to other sources during the net load peak hours, dispatchable low-emissions thermal capacity such as hydrogen turbines has a high utilisation rate, with more than 70% of the available capacity operating in these critical hours (Figure 16). Indeed, dispatchable thermal capacity has an important role to play for the security of supply at peak, even though it operates for only for a few critical hours per year. Providing revenue streams for this important resource of flexibility at times of peak hours is important to secure the supply of electricity at all times.

As with demand response, the full installed capacity of batteries is not available during the net load peak, as its duration may extend beyond typical battery discharge times. The remaining supply is bioenergy and nuclear (running at full available capacity). However, in 2050, the European electricity system still has significant margins as less than 20% of the natural gas-based capacity is used.

While these results highlight that in 2050 in the APS, it should be possible to match electricity supply and demand during periods of extreme system stress, it should be noted that this analysis does not constitute a comprehensive security-of-supply assessment of the pan-European grid. As an aggregate assessment based on a model with a limited number of grid nodes, it potentially underestimates local peaks and grid congestion within nodes that could require the remaining margin to be used to ensure security of supply.

Box 1. The role of energy efficiency in reducing flexibility needs

Energy efficiency is the first lever in mitigating rising electricity demand and is at the centre of the global agenda with the COP28 pledge on doubling energy efficiency improvement rates by 2030. As fluctuations in net load increase, reducing overall electricity consumption not only addresses immediate challenges but also minimises flexibility needs.

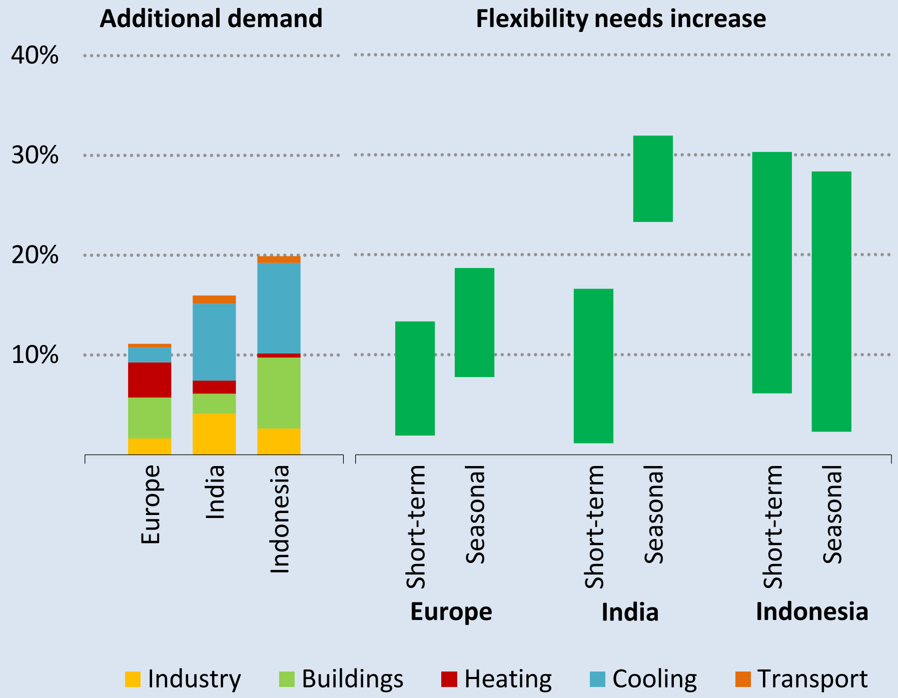
Meeting decarbonisation pledges while failing on energy efficiency improvements would require additional renewables development to compensate for higher demand. Solar PV and wind would further add to the variability of the net load and increase flexibility needs, making energy efficiency a dual remedy, both curbing demand increase and mitigating flexibility needs.

If energy efficiency does not improve beyond current policies, electricity demand would surge by 20%, with most of the increase on thermo-sensitive end-uses because of lower thermal insulation for buildings and limited technological improvements for air conditioning and heat pumps. This increase extends to short-term and seasonal flexibility requirements, potentially reaching 30%, contingent on variable renewable energy penetration (Figure 17).

India stands out with the most significant seasonal needs surge, driven by higher cooling needs and increasing net load seasonality. In Europe, reduced insulation drives net load upwards in winter.

Indonesia faces notable implications on both short-term and seasonal, with additional PV generation intensifying daily net load variations.

Figure 17. Additional electricity demand and additional flexibility needs in a low-energy-efficiency scenario in 2050



Note: Energy efficiency improvements from the Stated Policies Scenario (STEPS) are assumed. The range depends on the renewable mix to meet the additional demand.

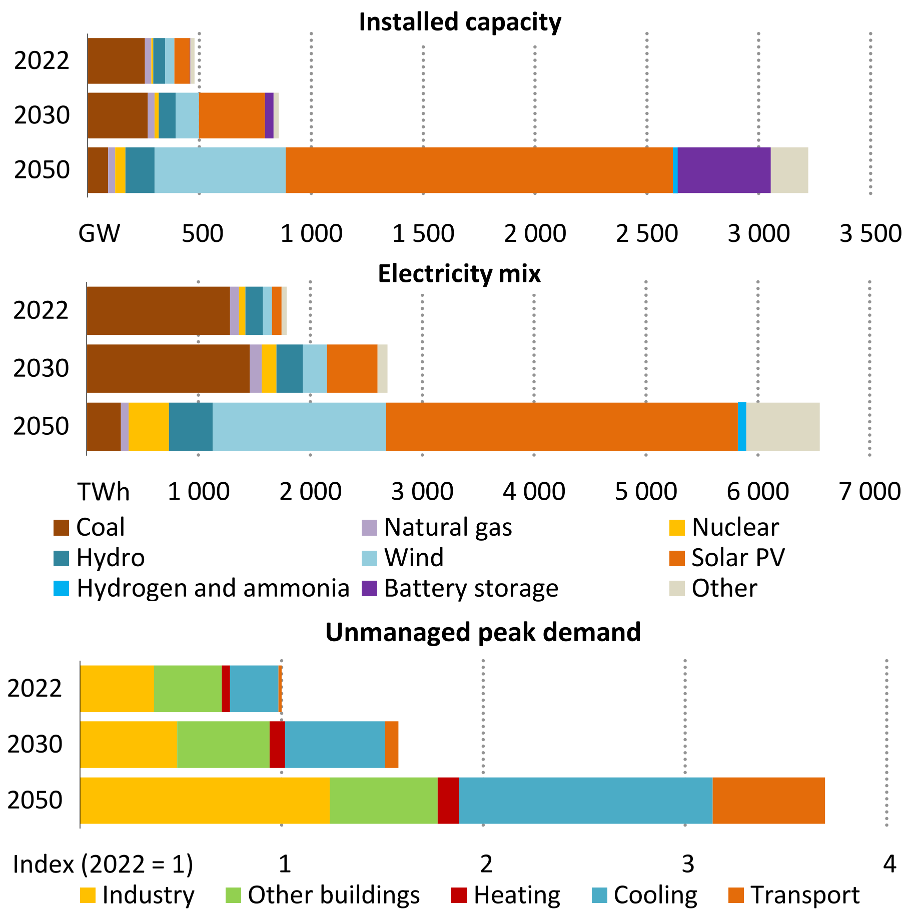
India

Evolution of the electricity system

In India, coal provides close to 75% of electricity today. The APS shows that meeting current pledges in full calls for a dramatic transformation of India's power system, from one which is dominated by coal to one in which solar PV and wind combined account for around 70% of total electricity generation by 2050. In the APS, coal generation is projected to continue to rise in absolute terms in India, peaking around 2030, though its share of electricity generation declines (Figure 18). Expanding renewables is the central means of meeting demand growth and limiting coal use, with solar PV leading the way. Flexible coal generation will play a major role in the penetration of solar PV generation to avoid curtailment.

Although India's population growth is slowing down, its urban population is projected to increase by another 74% and per capita income triples by 2050. Industrial activity expands rapidly, resulting in a tripling of output of iron and steel, and a doubling of cement production. Air-conditioner ownership in India has been rising steadily with growing incomes, tripling since 2010 to reach 24 units per 100 households. Air-conditioner ownership is estimated to expand ten-fold by 2050, outpacing the growth of every other major household appliance. Residential electricity demand from cooling is contained to a fivefold increase by 2050 because of an increased use of energy-efficient air conditioners and better insulation for buildings. In the APS, peak electricity demand rises by around 60% from the 2022 level by 2030 and cooling accounts for nearly half of this increase. By 2050, peak demand more than triples.

Figure 18. Evolution of installed capacity, generation mix, and unmanaged peak demand, 2022-2050



Notes: Other includes bioenergy, waste, geothermal, concentrating solar power, marine and oil. Unmanaged peak demand is the average of the 500 highest load hours of the year, before activation of demand response. Heating includes space and water heating. Other buildings includes lighting, cooking and appliances.

Seasonal variability of demand and supply

The seasonality of the net load in India is increasing mainly because of the expansion of solar PV in the electricity mix and higher electricity demand for cooling due to a rising adoption of air conditioners.

Electricity demand shows seasonality driven by the increased cooling needs during summer months (April to June), with temperatures exceeding 40°C in many regions, and the monsoon season (June to September) when moisture from the Indian Ocean brings heavy rainfall (Figure 19). During the monsoon, there is a significant increase in humidity levels, a drop in temperatures, a decrease in solar PV output, higher hydro availability and stronger winds. After the monsoon, the wind decreases in many parts of the country, and temperatures start to decline.

The monsoon shapes agricultural activities, leading to interannual fluctuations in electricity demand, as drier years increase the need for groundwater irrigation, which relies heavily on electricity. In 2023, for example, limited rainfall generated a surge in electricity demand in August and September, and electricity demand reached an all-time high driven by irrigation needs peaking around midday.

With increasing cooling needs and the overall increase in electricity demand, the seasonality of the net load in India is projected to increase in the decades to come

Figure 19. Average annual load curve by end-use, 2022-2050

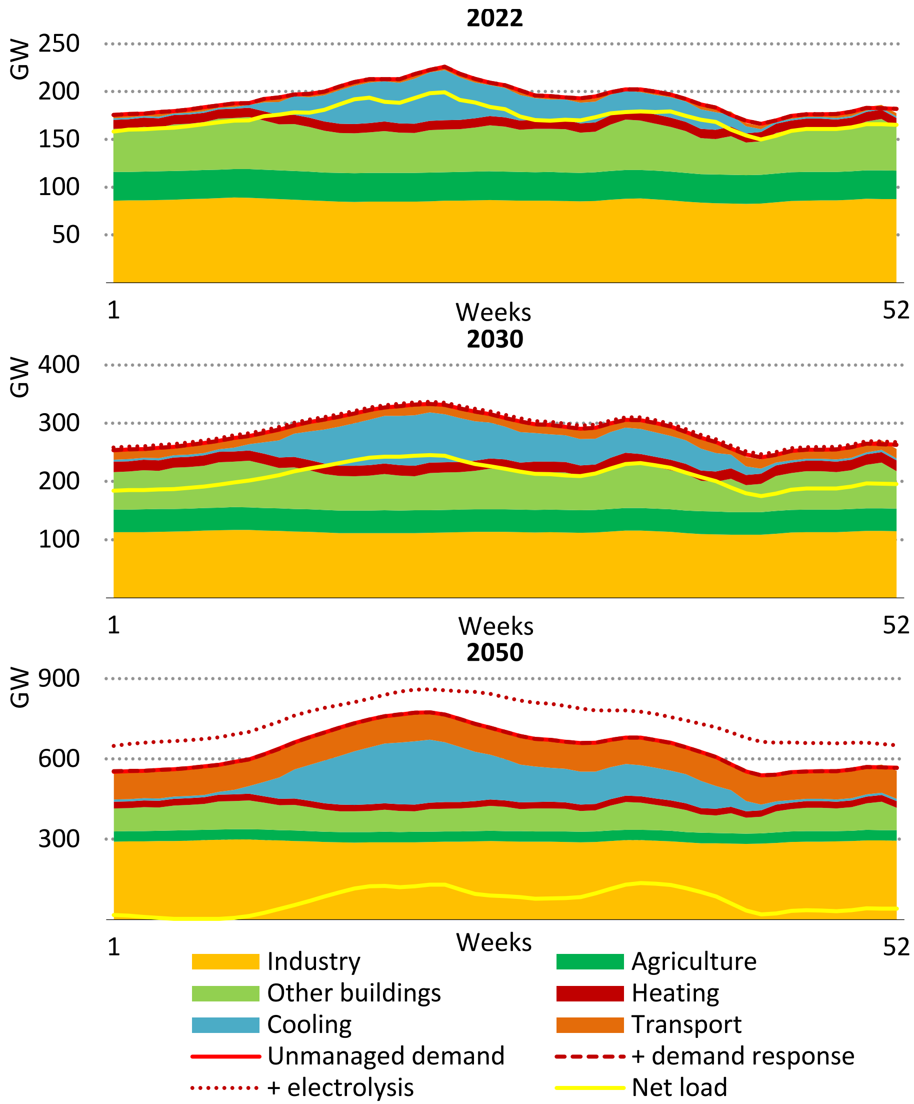
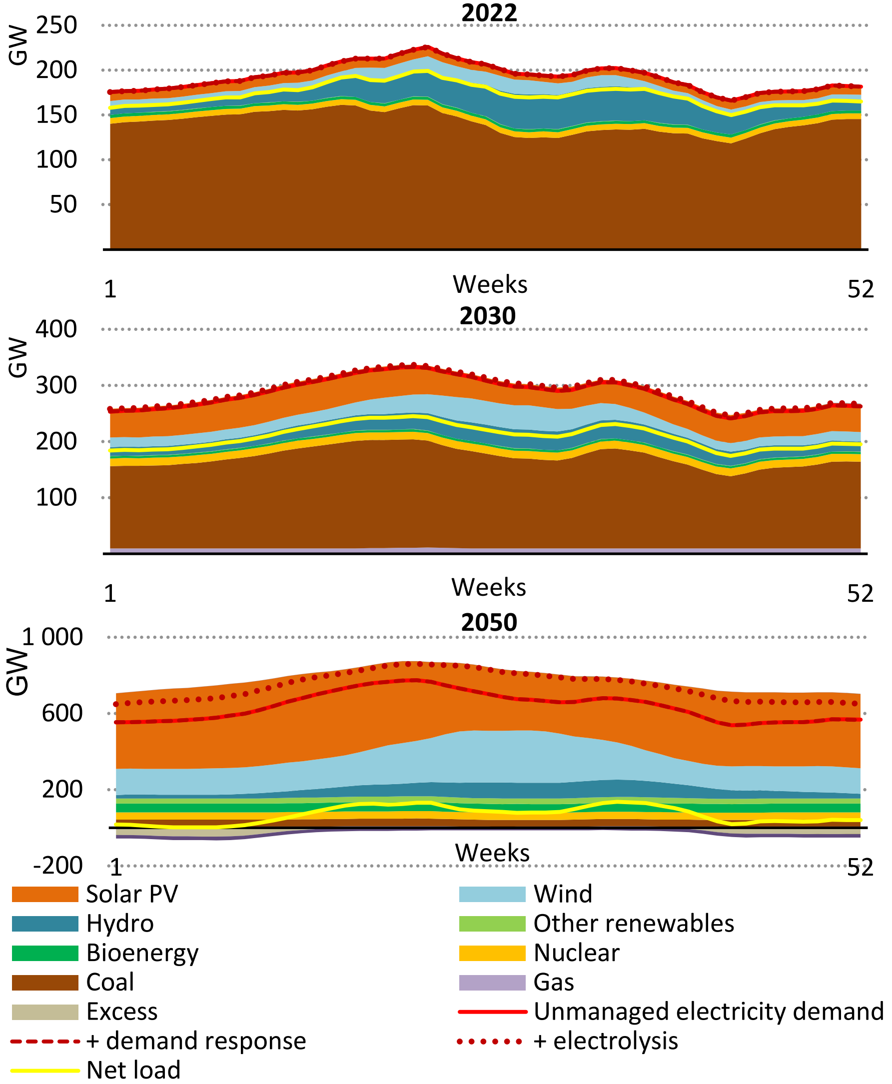


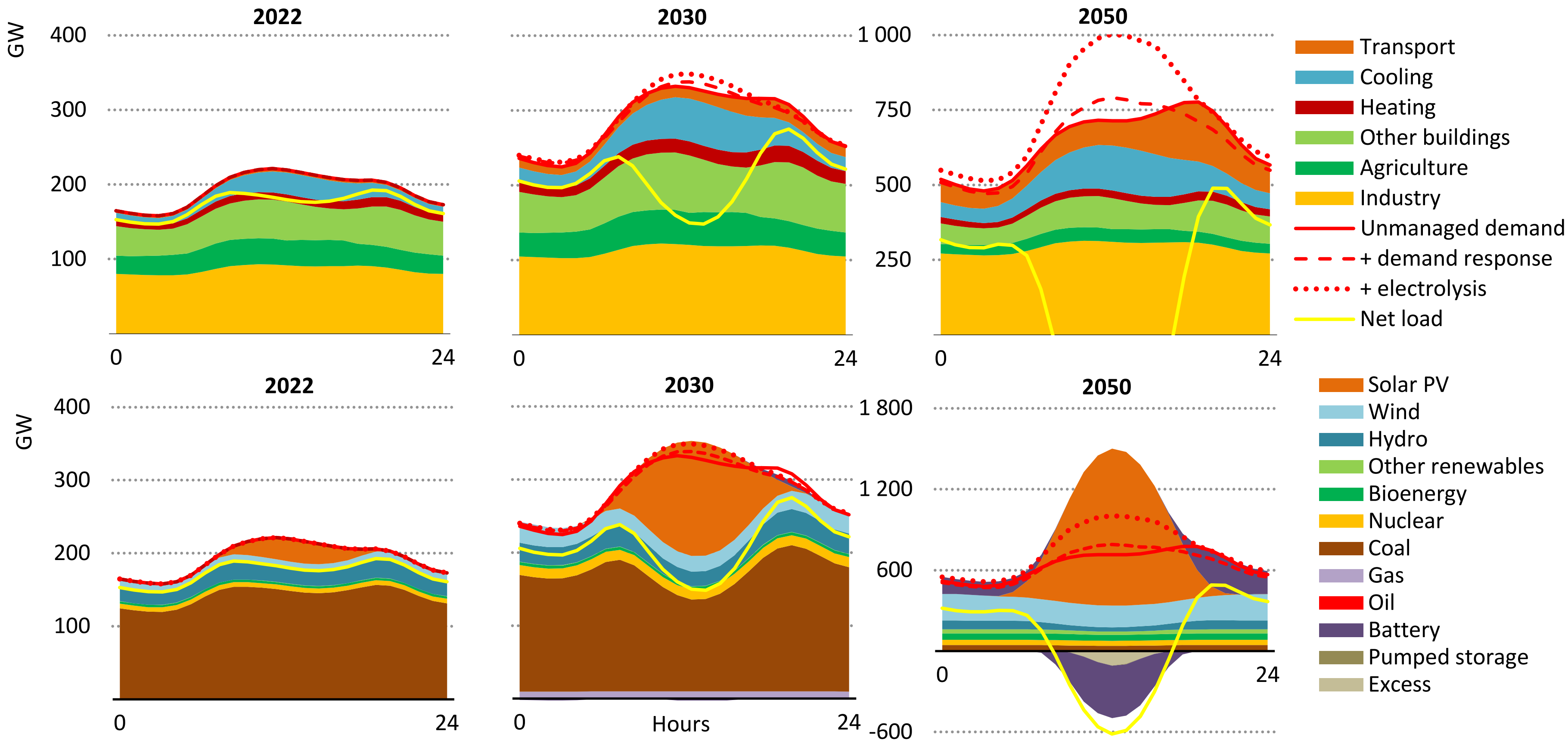
Figure 20. Average annual electricity supply curve by source, 2022-2050



Currently, coal is the primary source of electricity in India. Heavy rainfall between July and September increases inflows, allowing for higher levels of hydro generation during this period. The average weekly residual load closely mirrors the evolution of the average weekly electricity demand since wind and solar PV generation has not yet reached a level significant enough to reshape the net load. Between 2030 and 2050, wind and solar PV capacity grow significantly. By 2050 the system is dominated by variable renewables, most importantly solar PV. The seasonality of solar PV, wind and hydro drives the seasonality of the net load. Two distinct peak periods emerge: one during summer with important cooling needs, and another post-monsoon when average wind speeds sharply decrease, and solar PV has not yet reached its annual peak (Figure 20).

Daily variability of demand and supply

Figure 21. Average daily load curve and average daily electricity supply by source in India in the Announced Pledges Scenario, 2022-2050



Notes: Other renewables includes geothermal, concentrating solar power, and marine. Electricity demand is represented in three different states: without the effect of demand response or electrolysers ("unmanaged demand"); with the addition of the activation of demand response ("+ demand response"); and with the addition of electrolysers ("+ electrolysis").

In India, the increasing demand for daytime cooling and electromobility, along with widespread adoption of solar PV, are shaping the daily variations of electricity supply and demand.

The electricity load curve is characterised by a two-peak profile that shifts significantly over the year. During the winter months, the daily load curve tends to follow a relatively stable pattern. There is steady demand throughout the day with peak loads occurring in the morning and evening. The pre-monsoon summer months witness a distinctive shift in the daily load curve. High temperatures drive a substantial increase in the use of air conditioning, leading to a prominent afternoon peak in demand. Demand for electricity remains high throughout the evening and the night due to little diurnal variation in temperature and continued cooling demand. During the monsoon season, cooler temperatures curb demand, but electricity demand for agriculture may influence energy usage patterns and potentially increase the midday peak because of the increase in water pumping needs, dependent on rainfall (Figure 21).

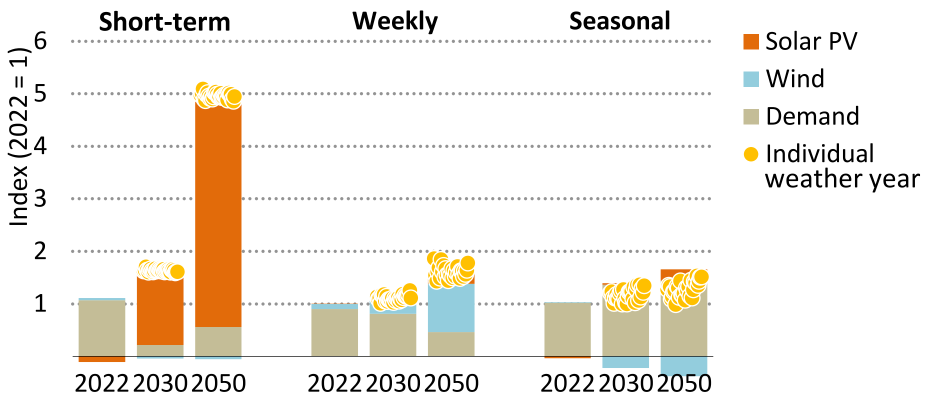
Consumption patterns shift significantly until 2050, with surging cooling demand adding to the midday peak by 2030, and the uptake of electromobility to the evening peak after 2030. Demand response supports PV integration by shifting electricity consumption to midday, with significant contributions from EV charging, the pre-cooling of buildings where feasible and smart appliances. Flexible electrolyser electricity consumption also peaks at midday to make the best use of renewables surpluses.

Today, coal is the dominant source of electricity in India, and it continues to be beyond 2030. Renewables provide less than a quarter of total electricity generation, with almost half of renewables generation coming from hydro. Thermal power plants respond to daily variations in electricity demand, adjusting their output accordingly. By 2030, the growing share of solar PV reshapes the daily net load profile. Thermal power plants need to cycle more to accommodate the midday peak in solar generation. Increasing the flexibility of the coal fleet will be crucial to cope with the rising solar PV penetration and enable the integration of progressively greater shares of variable renewables. By 2050, solar PV dominates the electricity mix in India, accounting for about 50% of total generation, with more than 1 700 GW of installed capacity. As a result, the net load is often negative during the daytime.

This calls for a transformation away from a baseload paradigm in which thermal power plants produce most of the electricity and manage variability, towards a system predominantly powered by variable renewables, especially solar PV, resulting in substantial daily fluctuations. Battery energy storage systems are essential to manage these variations and shift surplus electricity into the evening and night.

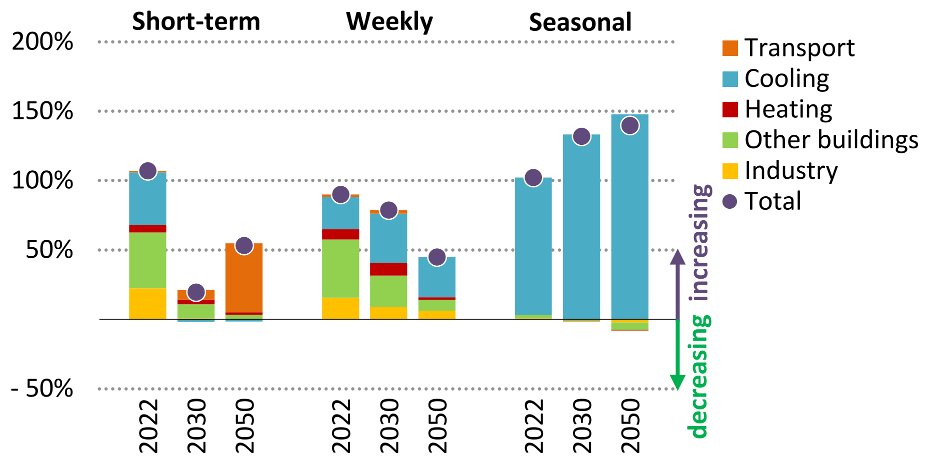
Flexibility needs

Figure 22. Evolution of flexibility needs and their drivers, 2022-2050



Note: Yellow dots represent the total needs for each individual weather year.

Figure 23. Contribution to flexibility needs by end-use, 2022-2050



In India, short-term flexibility needs are projected to increase fivefold until 2050, primarily due to the strong increase in solar PV. Seasonal flexibility needs rise by 30% to 2050, driven largely by stronger seasonality in the net load.

Today, flexibility needs on all timescales are almost entirely driven by variations in electricity demand. The strong uptake of solar PV is the key factor increasing short-term flexibility requirements until 2030 and 2050. The contribution of demand to short-term flexibility needs declines until 2030, as the net load is increasingly shaped by solar PV. After 2030, the rising share of EVs and EV charging needs increase the net load in the evening, hence contributing to a rise in short-term flexibility needs (Figure 22).

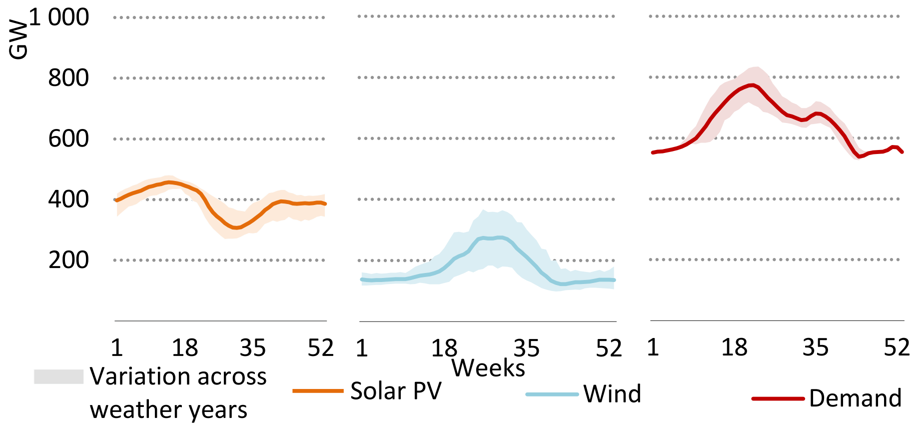
Weekly flexibility needs rise partly due to the increase in electricity demand and the differences in demand between weekdays and weekends, but it is the variability of wind generation within a week that becomes the main driver in the long run.

The increase in seasonal flexibility needs in India between 2022 and 2050 is driven primarily by the increasing seasonal variability of electricity demand, which is mostly related to space cooling (Figure 23). Rising levels of air-conditioner ownership and rising temperatures due to climate change push the pre-monsoon demand to new heights. Depending on the weather year, limited rainfall may increase groundwater pumping for irrigation, and add to pre-monsoon electricity demand. A decrease in PV generation during the cloudy but hot and humid monsoon period, which also features higher-than-average cooling demand, also drives the need for seasonal flexibility. Wind, on the other hand, helps reduce the need for seasonal flexibility given its seasonality is somewhat aligned with the seasonal variations of net load.

Flexibility needs can vary significantly from one weather year to the next. Where short-term needs are relatively constant across weather years, weekly and seasonal flexibility needs are more volatile on an interannual basis. In 2050, weekly flexibility needs can vary by around 10% and seasonal flexibility needs by 25% compared with their 30-weather-year-average. The higher volatility of seasonal flexibility needs is the result of the seasonality of temperature, solar insolation and wind varying more from one weather year to the next than daily or weekly variations.

Solar PV in India exhibits lower capacity factors during the monsoon season between July and September. Capacity factors are slightly higher in summer than in winter, but in regions with very high temperatures in the summer, the performance of solar PV panels can deteriorate, thus summer and winter capacity factors there are relatively similar. The comparison of 30 weather years shows that on an interannual basis, PV output varies mostly during the monsoon season, with some years having stronger monsoons with more cloud cover than others (Figure 24).

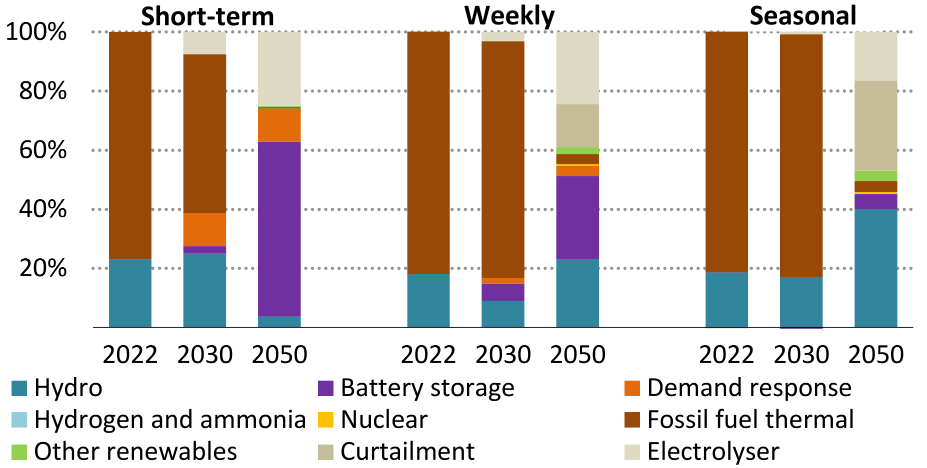
Figure 24. Variation across weather years in the Announced Pledges Scenario, 2050



The seasonality of wind generation in India is also related to the monsoon. Wind resources are unevenly distributed between the regions, with the coastline benefiting from more consistent wind while the continental eastern part of the country has lower capacity factors. Overall winds are stronger during the monsoon, which can compensate for the seasonal dip in solar PV output. The comparison of 30 weather years shows that in some years, the monsoon period is much windier than in others, while in all years, winds blow relatively consistently during the dry season. The seasonality of electricity demand is due to space cooling, which drives the increase of electricity demand during both summer and the monsoon, in the latter case because of higher humidity. Differences in average temperatures and temperature profiles between weather years mean that some years have higher cooling-related electricity demand than others.

Flexibility supply

Figure 25. Flexibility supply by source, 2022-2050



IEA. CC BY 4.0.

In India, fossil fuel thermal generation currently accounts for 80% or more of the flexibility supply across all timescales. Hydro provides the remaining 20% (Figure 25).

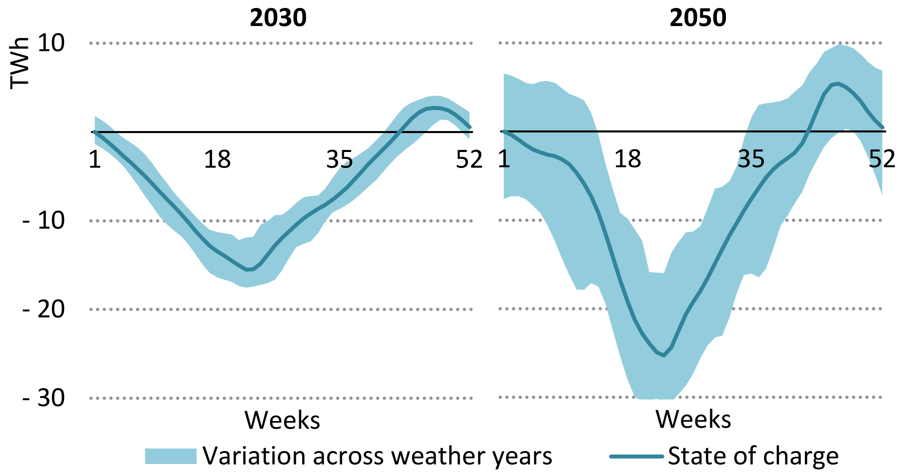
With batteries and demand response, alternative solutions emerge by 2030 to cope with the rising flexibility needs. In 2050, most of the short-term flexibility is provided by battery storage (60%) and flexible electrolysers (20%), with other types of demand response and hydro covering the remainder. Battery storage becomes a key flexibility provider in India due to its complementarity with solar PV production. However, by 2050, high-capacity batteries with about eight hours of storage are necessary to make best use of the daily solar PV surplus at midday and cover most of the demand during the evening and at night. Flexible electrolysers are the second-most-important source of short-term flexibility by 2050. Similarly to batteries, they take advantage of surplus solar PV production and reduce potential curtailment. However, lifting this flexibility potential will require raising the share of electrolysers that is grid-connected (as opposed to powered by off-grid dedicated renewables), as this determines how much flexibility they can provide to the system.

Demand response plays a more limited role in India. While there is large flexibility potential from space cooling, shifting durations are limited by the low thermal inertia of buildings. Cold water storage and better insulation could further extend the load shifting potential.

When considering seasonal flexibility needs, the mix of flexibility solutions diverges from the short-term perspective, with a more significant role for hydro and electrolysers. Thermal power plants remain the mainstay of the seasonal flexibility supply until well after 2030, and it is only by 2050 that their contribution declines to very low levels as the electricity system is mostly decarbonised. In 2030, hydro accounts for 20% of the seasonal flexibility supply, a figure that doubles to 40% by 2050. Grid-connected electrolysers, in combination with large-scale hydrogen storage in salt caverns or depleted gas fields, also provide significant flexibility on a seasonal basis as hydrogen production is adjusted in response to seasonal variations in the availability of low-cost renewable electricity.

The most significant transformation of the electricity mix in India by 2050 is the gradual phase-down of coal in favour of solar PV, with an additional 1 400 GW of solar PV installed between 2030 and 2050. The evolution of the flexibility portfolio follows a similar path, as the share of thermal technologies decreases and alternative solutions such as batteries and electrolysers that can help enhance the integration of solar PV become more relevant. The deployment of short- to medium-duration storage technologies such as battery storage or hydro pumped storage thus becomes crucial in countries such as India that will be strongly dependent on solar PV.

Figure 26. Variability of hydro seasonal storage across weather years, 2030 and 2050



Note: The figure displays the amount of electrical energy stored in hydro reservoirs, relative to the storage level on 1 January, for years 2030 and 2050.

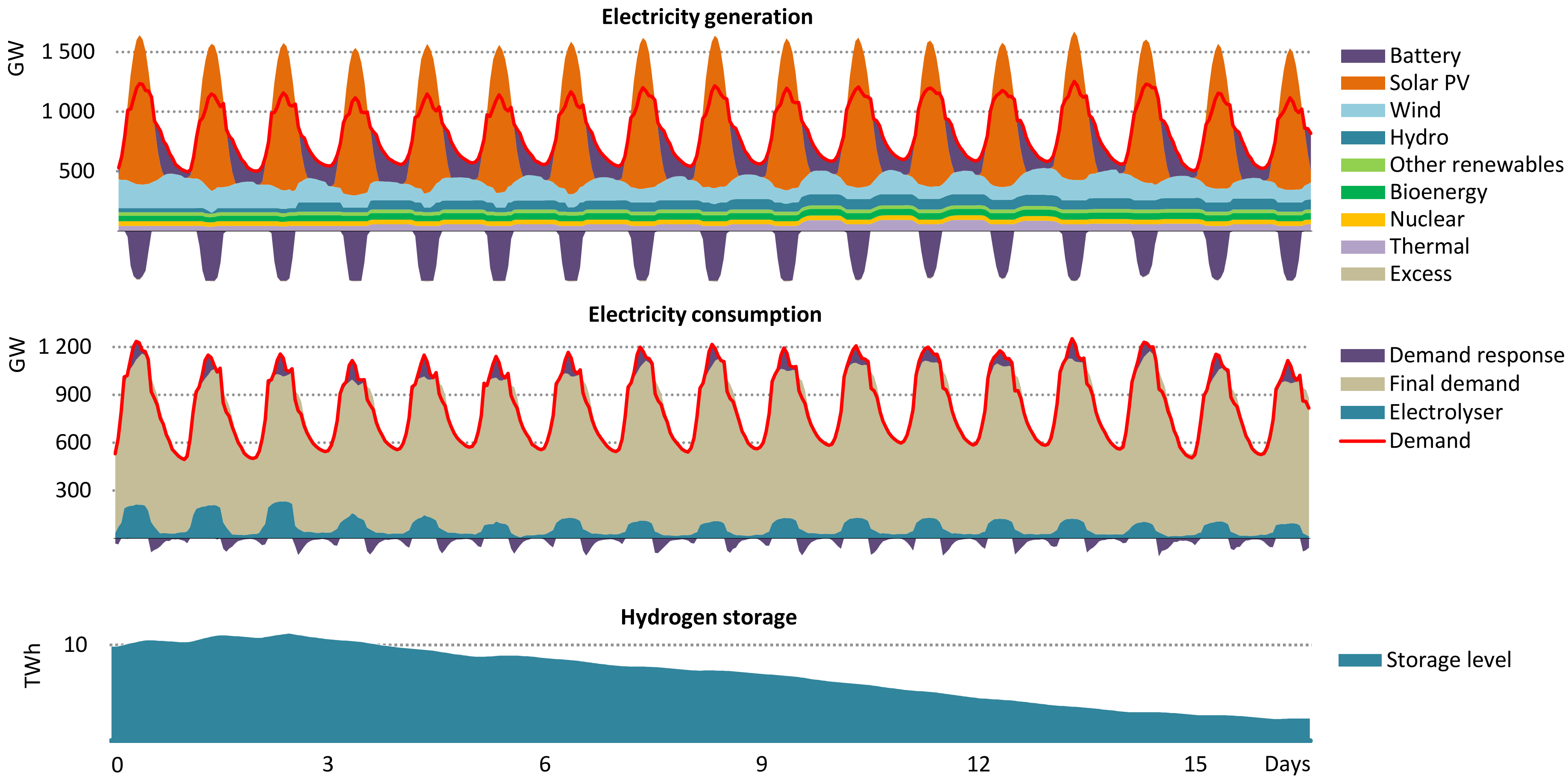
Reservoir hydro capacity is projected to further increase in India from 2030 to 2050. The seasonality and the availability of hydro generation in India is linked to the monsoon rains, which account for most of the available water inflow. Hydro reservoirs act as long-duration electricity storage and can store water for many weeks. For these reasons they are key assets for seasonal balancing. When electricity demand is on average higher in summer because of the increase in cooling, hydro reservoirs are discharging and provide additional electricity supply. Years with lower-than-average rainfall constitute a double challenge, as irrigation needs tend to increase electricity demand, and inflows into hydro reservoirs are reduced. The simulations show that the utilisation rate of hydro storage has a higher volatility in 2050 compared with 2030, which reflects the potential increase of the uncertainty on hydro operation. However, the magnitude of this variability is limited and does not significantly impact the global guide curve for hydro operation to manage interannual variability (Figure 26).

Figure 27 showcases the operation of the power system in a critical period, when it is facing an increase in electricity demand, and at the same time, a decrease in the availability of solar PV. In response, hydropower plants increase their output. Batteries shift surplus solar electricity from the daytime into the night. Simultaneously, hydrogen electrolysers reduce their output and draw less electricity from the grid as they respond to higher electricity prices. To supply industrial consumers with the steady stream of hydrogen they require, long-duration hydrogen storage is tapped instead, helping to reduce the strain on the electricity system.

This example illustrates that the coupling of electrolysers with hydrogen storage and the main electricity grid will be an important source of flexibility that can help mitigate shortfalls caused by variations in the availability of renewables and electricity demand in a future low-emissions power system in India.

The role of sector coupling in managing seasonal variability

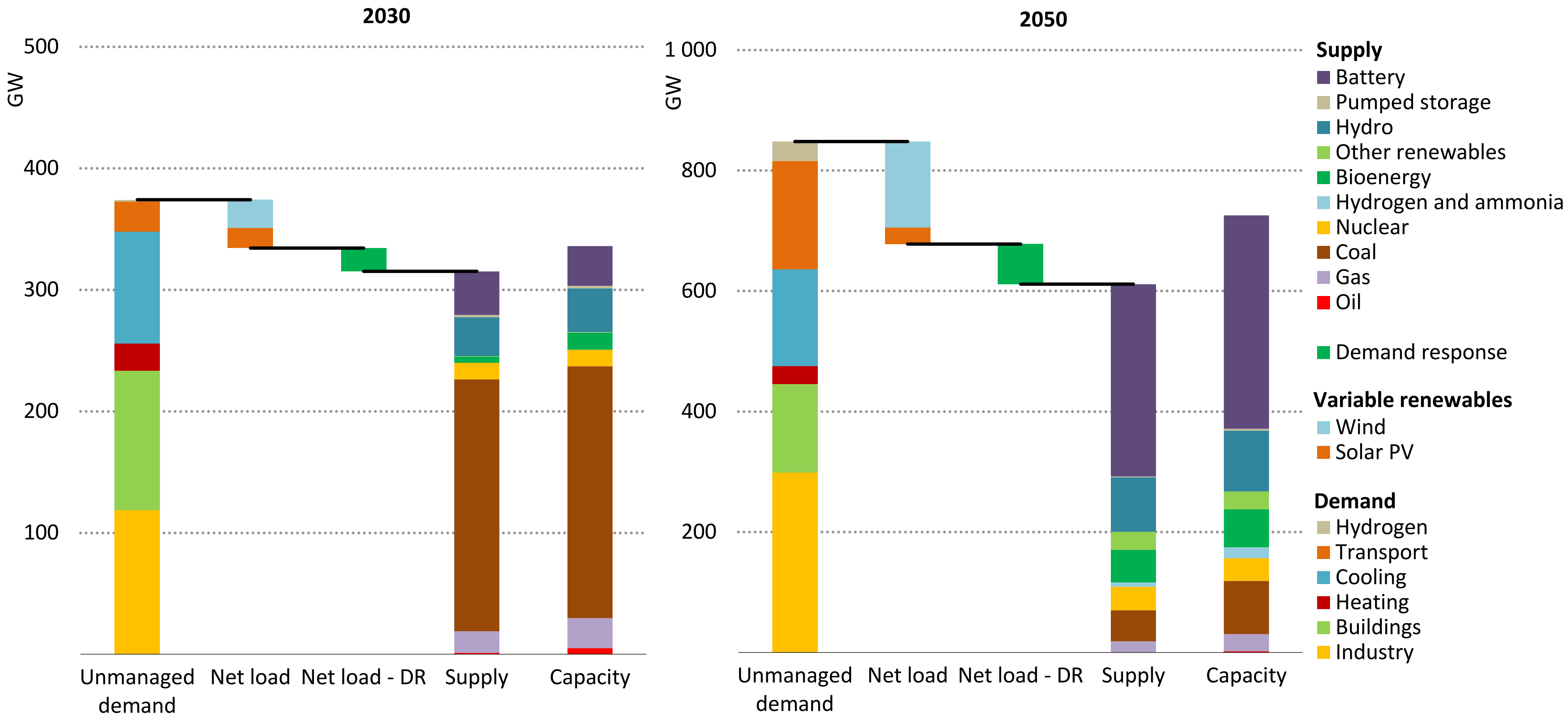
Figure 27. Illustration of the role of sector coupling to provide flexibility for the power system, India, Announced Pledges Scenario, 2050



Note: Other renewables includes geothermal, concentrating solar power, and marine.

Electricity demand and supply and capacity margin at peak net load

Figure 28. Electricity demand and supply during the highest net load peak over 30 weather years in India in the Announced Pledges Scenario, 2030 and 2050



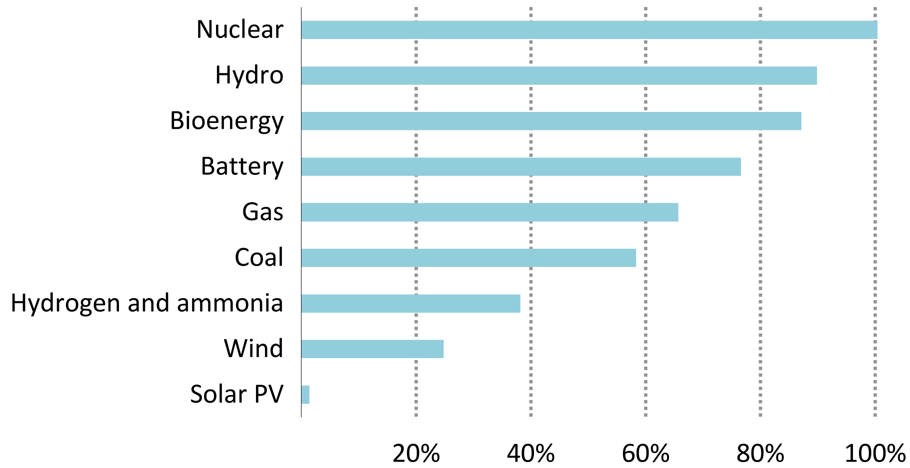
Note: DR = demand response. Unmanaged demand represents electricity demand before activation of demand response. Other renewables includes geothermal, concentrating solar power, and marine. Peak net load is computed as the top 100 hours over the year. The capacity represents the available capacity during these peak hours.

As highlighted in the previous section, the key metric to assess the tightness of the system is the net load during peak hours, when the system is facing either low renewable availability or potentially high electricity demand, or a combination of both. Figure 28 displays the electricity demand, split by end-use, and the electricity supply by technology during peak net load (computed as the top 100 hours over the year). The weather year with the highest peak net load has been selected.

In 2030, peak net load is driven by electricity demand for industry and buildings, especially space cooling, which accounts for almost 100 GW. The capacity credit of wind and solar PV during these critical hours is above zero. In 2030, 10% of the peak is covered by wind and solar PV. Demand response helps reduce the size of the peak by shifting about 20 GW of demand to off-peak hours, with half from space cooling and 15% from water heating. This corresponds to around 10% of cooling demand being shifted in those hours. Around 75% of the total demand response potential is activated. In 2030, most of the electricity supplied in those peak hours comes from coal-fired power stations. They cover 55% of the peak net load, followed by hydro and battery storage discharge. The system maintains a ratio of 1:1 between the peak of the net load and the dispatchable available capacity.

In 2050, the system has undergone important transformations: most of the coal capacity has been phased out, and solar PV represents 50% of the total generation. Electricity demand from EVs rises thirty-fold between 2030 and 2050, and space cooling demand fivefold over the same period of time. The peak almost doubled compared with 2030 to reach more than 800 GW. During these critical hours, wind is five times higher than solar PV, and helps to reduce the peak by more than 100 GW.

Figure 29. Share of available capacity used during net demand peak, India, Announced Pledges Scenario, 2050



Note: The available capacity is considered as the net capacity available during net demand peak hours.

Demand response shifts almost 70 GW off-peak, with half from EV charging and 40% from cooling. This corresponds to less than 20% of each end-use's demand shifted in those hours. Only one-third of the total demand response potential is activated. Demand response cannot be fully tapped because limited shifting durations in industry and cooling constrain its activation, especially if the peak net load period is longer than several hours.

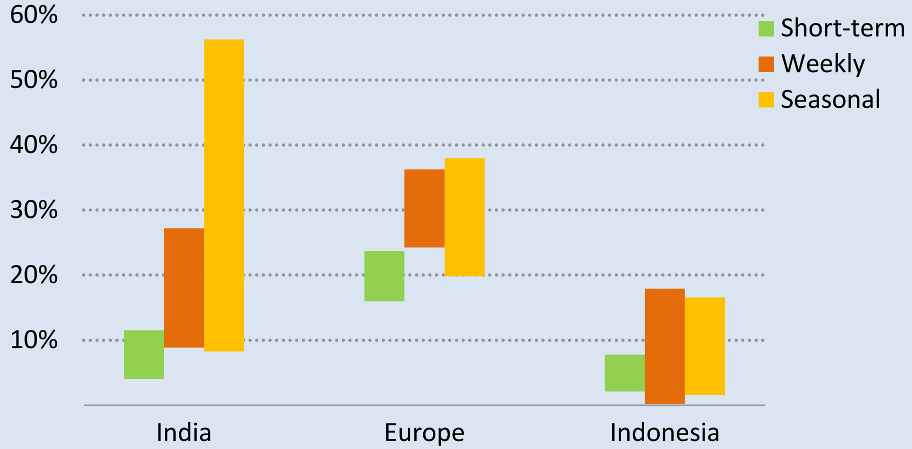
In 2050, thermal capacity provides only 10% of the net load peak, or 80 GW. The bulk of the electricity supply comes from battery storage discharge, which accounts for 40% of the peak. Hydro comes in second, with 10%, followed by bioenergy, nuclear and other renewables. Compared with 2030, the system in 2050 has more margin, notably from thermal power plants – only half of their available capacity is used (Figure 29).

Box 2. The role of transmission in reducing flexibility needs

Grids are one of the key enablers of the energy transition. Insufficient grids and delays in the expansion and reinforcement of grids are becoming the main bottleneck for the integration of higher shares of variable renewables in power systems around the world. This bottleneck could result in a significant slowdown in achieving emissions reduction targets. Enhancing grids and interconnections is an important solution to balance supply and demand over wider geographical areas and facilitate the integration of variable renewables. Delaying or under-sizing interconnections between countries or regions could lead to an increase of flexibility needs.

In the context of Europe, the development of interconnections and cross-border trade can unlock significant flexibility potentials, allowing the system to harness the abundant wind resources of northern Europe alongside the substantial solar potential in the southern Europe. This co-ordinated approach not only enhances the overall efficiency of the energy system but also contributes to a more resilient and sustainable power grid. The development of grid infrastructure can offset the need for the development of local flexibility solutions that may not always be cost-effective for the entire system. Conversely, a lack of co-operation could result in an increase in fossil fuel capacity used as backup and delay the integration of renewable generation.

Figure 30. Increase of flexibility needs without interconnections or cross-border trade in the Announced Pledges Scenario, 2022-2050



Our calculations show that a more limited development of transmission of interconnections between regions can result in a substantial increase of flexibility needs, especially on the seasonal time frame (Figure 30). In India, for example, seasonal flexibility needs are up to 55% higher in a scenario in which each region balances supply and demand on its own and electricity is not exchanged. Under-sizing transmission infrastructure, including cross-border interconnectors, might require significant additional investments in flexible capacity to ensure electricity security of supply within a country, region or state.

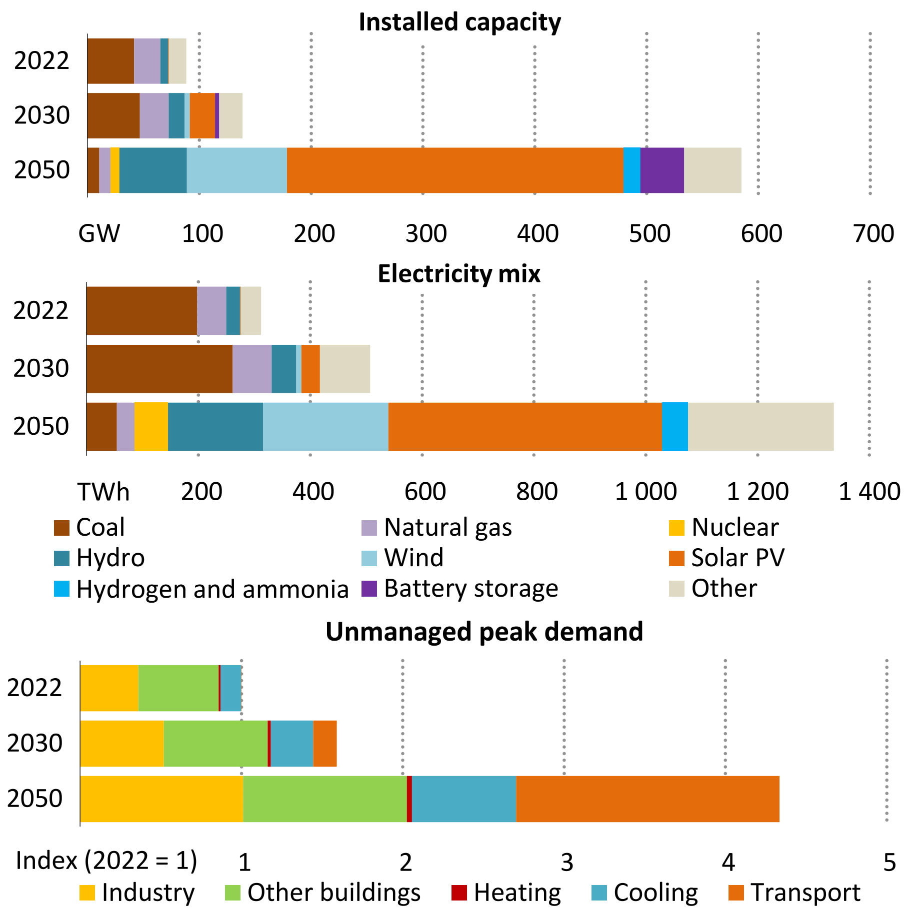
Indonesia

Evolution of the electricity system

Indonesia's electricity generation mix undergoes a major transition in the APS. Today's high share of unabated fossil fuels – 80% of generation in 2021 – is progressively reduced in favour of low-emissions generation sources. Displaced by renewables, unabated fossil fuels are two-thirds of total generation in 2030 and only a few percent in 2050 (Figure 31). Solar PV and onshore wind are the most significant renewables contributors in the long term. In 2050, they account for more than 50% of total generation. They are complemented by significant volumes of dispatchable renewables (hydropower, bioenergy and geothermal), which together account for another 30% of total generation. Other low-emissions sources such as nuclear, coal and gas equipped with carbon capture, utilisation and storage (CCUS), and small amounts of ammonia- and hydrogen-fired generation also play an important role, putting the electricity sector well on the way towards achieving net zero emissions by 2060.

Indonesia's electricity demand increases 3.5-fold until 2050, driven by an increasing population, rising standards of living and rapid urbanisation. Indonesia has set up multiple policies to support EV use, such as reduced value-added tax and subsidies. It also strengthens its industrial production of clean energy technology manufacturing, joining the ranks of exporters of equipment such as solar PV modules. Overall Indonesia sees a fourfold increase in peak electricity demand by 2050 because of expanding electrification, increased use of air conditioners and EV charging.

Figure 31. Evolution of installed capacity, generation mix and unmanaged peak demand, 2022-2050



Notes: Other includes bioenergy, waste, geothermal, concentrating solar power, marine and oil. Unmanaged peak demand is the average of the 500 highest load hours of the year, before activation of demand response. Heating includes space and water heating. Other buildings includes lighting, cooking and appliances.

Seasonal variability of demand and supply

The seasonal variability of the net load in Indonesia is projected to increase until 2050, driven almost exclusively by the rising share of wind and solar PV in the electricity mix.

Indonesia's climate is characterised by wet and dry seasons determined by the movement of the tropical rain belt associated with the Australian-Asian monsoon. Rainfall tends to peak between October and March in most of the country, while drier conditions prevail during the rest of the year.

Due to Indonesia's tropical climate with only small variations in average temperatures across the year, there is little seasonal variation in the average load. Unlike in India, where electricity demand for space cooling increases significantly in the hot pre-monsoon period, it remains mostly flat across the year in Indonesia (Figure 32).

The progressive electrification of road transport means that transport sector electricity consumption increases considerably, with its share rising to about a quarter of total electricity demand by 2050. While this introduces significant additional variability over the course of a day, it remains mostly flat over the course of the year, as is electricity demand from buildings and industry that is not related to space cooling.

Figure 32. Average annual load curve by end-use, 2022-2050

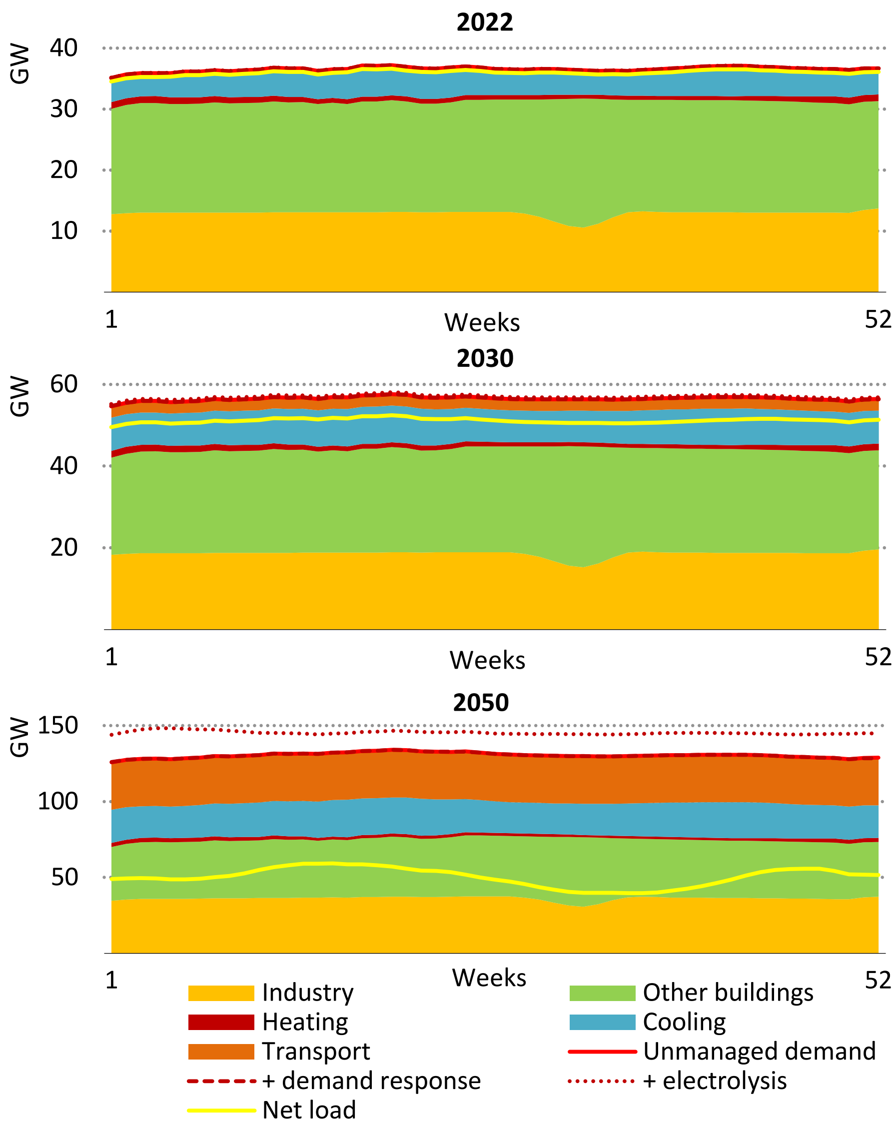
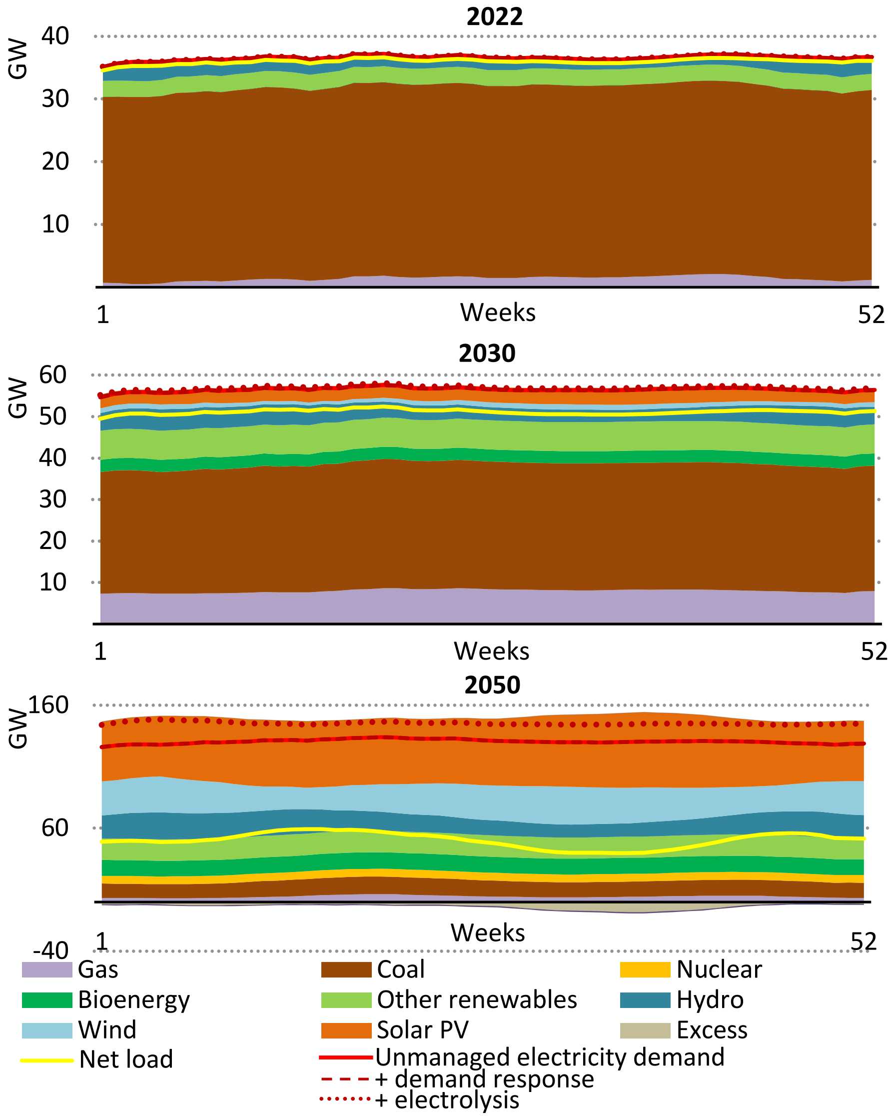


Figure 33. Average annual electricity supply curve by source, 2022-2050



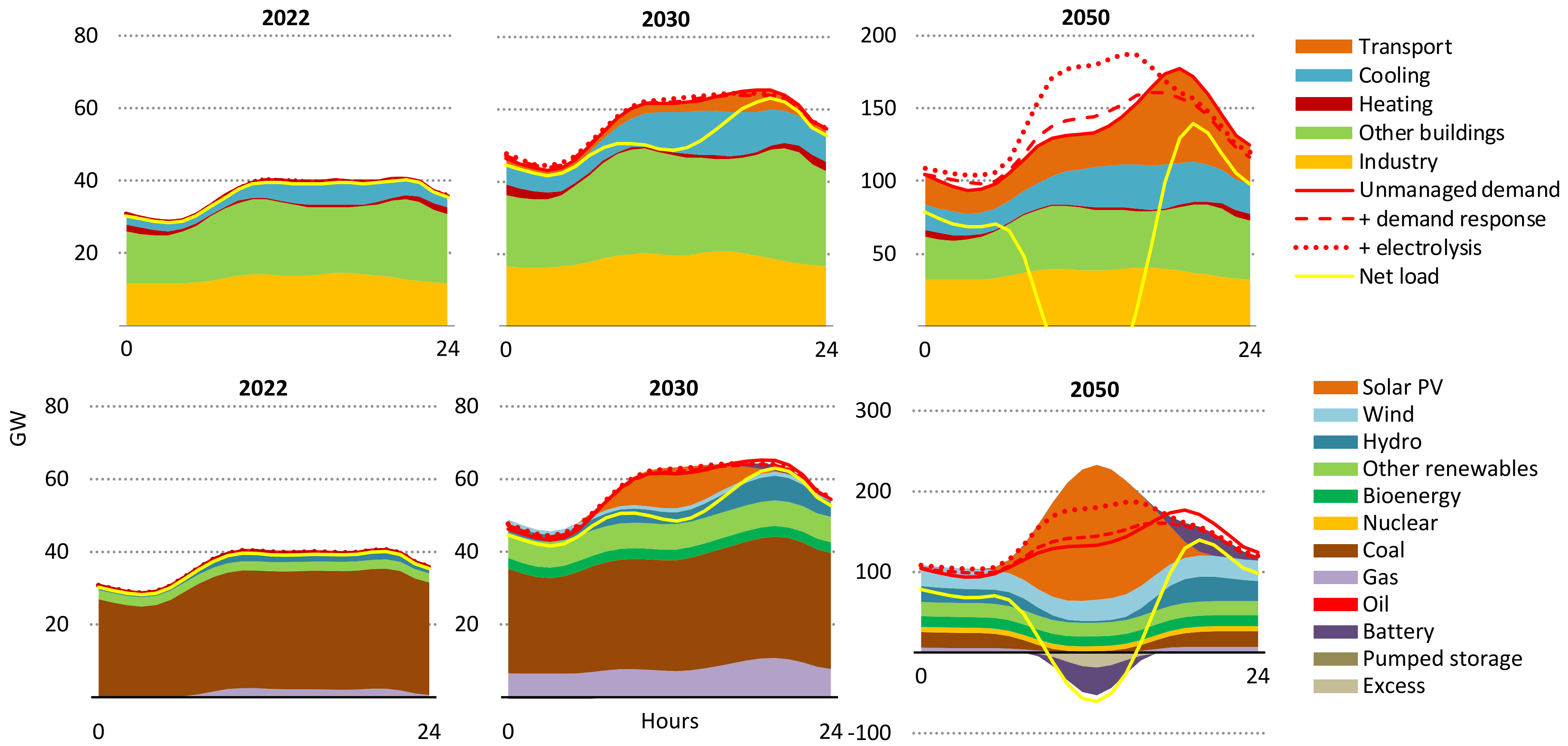
The upshot is that the increase in the seasonal variability of the net load projected for Indonesia is driven almost entirely by the rising share of wind and solar PV on the supply side.

The average annual electricity supply curve shows that today, seasonal variation is induced mostly by hydro, which produces less electricity in the dry season. This is largely balanced by gas-fired power plants, while the output of Indonesia's large coal fleet remains constant over the course of the year (Figure 33).

The rising share of wind and PV in the electricity mix introduces additional seasonal variability, especially after 2030. Higher-than-average wind speeds and greater solar insolation mean that both sources tend to produce more electricity in the dry season. While this seasonal pattern complements hydro, wind and solar PV electricity generation is projected to significantly exceed that of hydro in the long run, leading to a marked surplus of electricity in the dry season. Consequently, there is a substantial increase in the seasonality of the net load until 2050, with two distinct peaks at the beginning and the end of the rainy season. In 2050, gas-fired power plants still play an important role in load balancing, even though their contribution to overall electricity generation is relatively small.

Daily variability of electricity demand and supply

Figure 34. Average daily load curve and average daily electricity supply by source in Indonesia in the Announced Pledges Scenario, 2022-2050



Notes: Other renewables includes geothermal, concentrating solar power, and marine. Electricity demand is represented in three different states: without the effect of demand response nor electrolysers (“unmanaged demand”); with the addition of the activation of demand response (“+ demand response”); and with the addition of electrolysers (“+ electrolysis”).

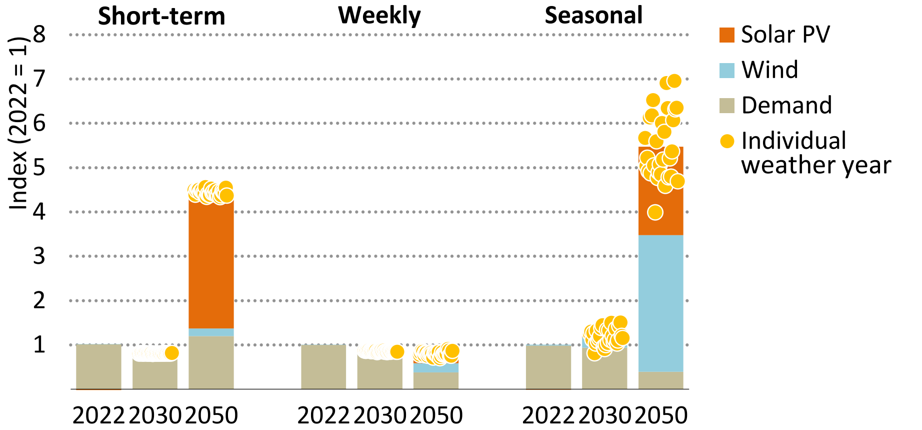
In Indonesia, the daily variability of electricity supply and load will increase substantially until 2050, driven mostly by overall electrification, rising solar PV generation and growing electricity demand from electric vehicles (Figure 34).

Currently, Indonesia's electricity mix is dominated by coal, with natural gas and hydro providing additional electricity during the peak hours. The low share of wind and solar PV means that these sources have very little impact on the day-to-day variation of the net load, which is driven almost exclusively by the demand side, most notably by daily patterns in residential electricity consumption and space cooling. By 2030, the rising share of solar PV-based generation will have a measurable effect on the shape of the net load, causing it to dip around midday, shifting the peak into the evening. It is becoming more variable, requiring the rest of the power plant fleet, including the still-large coal fleet, to operate more flexibly over the course of a day.

In 2050, coal is almost entirely phased out, while renewables dominate the electricity mix. The net load is highly variable: driven largely by solar PV, the daytime peak in generation from renewables exceeds demand. Hydro, including pumped storage hydro, batteries, electrolysers and other types of demand response, such as smart charging of EVs, are essential to smooth out this daily variation, with batteries and pumped storage hydro storing electricity during the day and discharging it to meet the evening peak. Furthermore, the remaining coal-fired power plants need to operate much more flexibly than the coal fleet today.

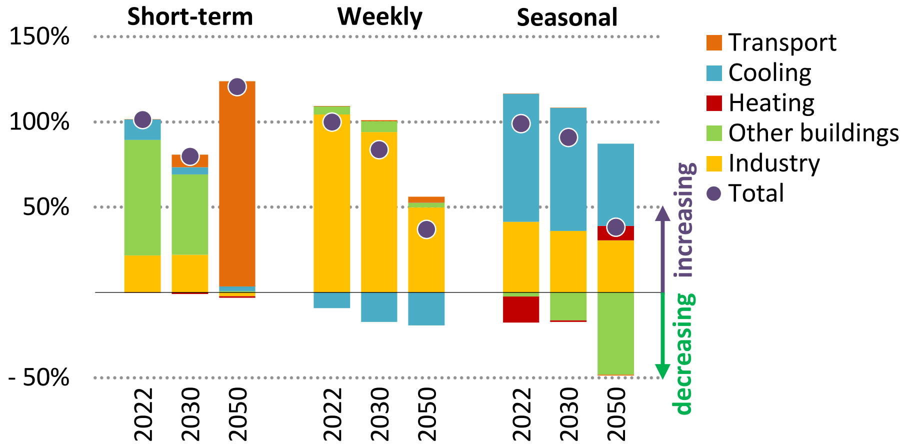
Flexibility needs

Figure 35. Evolution of flexibility needs and their drivers, 2022-2050



Note: Yellow dots represent the total needs for each individual weather year.

Figure 36. Contribution to flexibility needs by end-use, 2022-2050



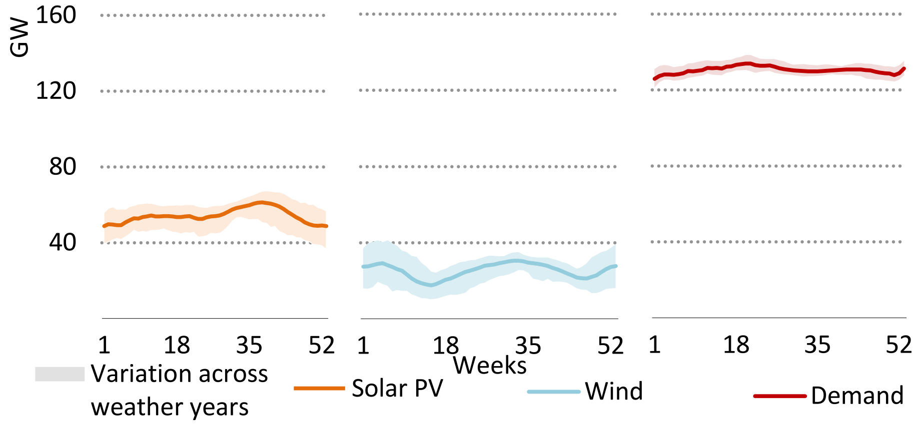
Both short-term and seasonal flexibility needs rise significantly in Indonesia until 2050, driven mainly by the growing share of variable wind and solar PV in the electricity mix. While Indonesia's power system currently shows relatively low seasonality, this changes with the rising penetration of variable renewables.

Due to the low share of variable wind and solar PV in the electricity mix today, power system flexibility needs across all timescales in Indonesia are almost entirely driven by variations in electricity demand. It is after 2030 that wind and solar PV emerge as significant drivers of flexibility needs, with solar PV responsible for the lion's share of the increase in short-term flexibility needs until 2050, and wind playing an important role in driving the need for additional seasonal flexibility. Overall, short-term flexibility needs rise on average nearly 4.5-fold until 2050, while seasonal needs increase 5.5-fold. Whereas short-term needs vary little from weather year to weather year, there are significant differences in the availability of wind and solar PV among the 30 weather years studied, leading to a substantial variation in seasonal flexibility across different sample years. Weekly flexibility needs notably do not increase between today and 2050. However, while the difference in load between weekdays and weekends plays a smaller role than it does today in driving flexibility needs across this timescale, variations in wind and solar PV output emerge as additional drivers (Figure 35).

Although the simulations show that the demand side as a whole does not contribute to a rise in both short- and longer-term flexibility needs between now and 2030 in Indonesia, the electrification of road transport becomes an increasingly important driver of short-term flexibility needs after 2030. On the scale of a week, industry, which sees higher consumption during the working week and lower on the weekends, remains the primary driver of weekly flexibility needs, while across seasons, it is mainly the variations in cooling demand across the year which raise the need for flexibility (Figure 36).

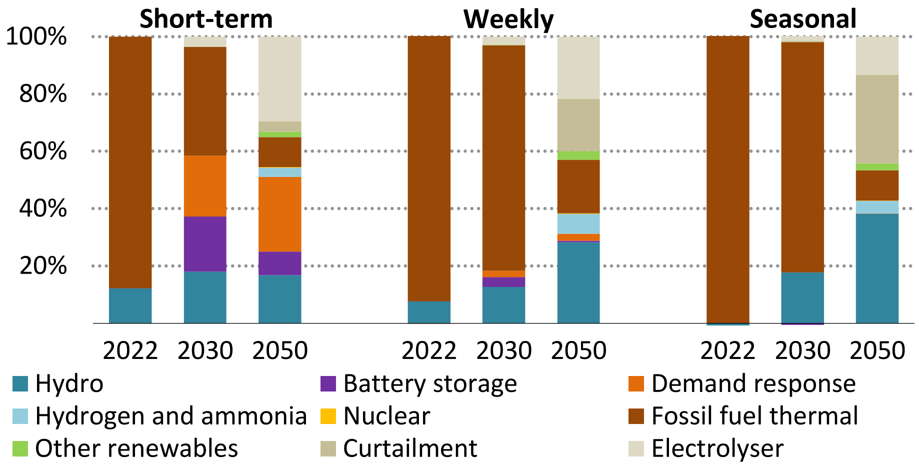
As shown by Figure 37, solar PV and wind generation exhibit distinct seasonal patterns, with solar PV generation peaking towards the end of the dry season, while wind peaks at both the height of the rainy season and the height of the dry season. The monsoon has an impact on wind speeds, which peak in the middle of the two monsoon periods, between November and March, and between May and September. Indonesia's wind patterns are complex and can vary significantly between different islands and regions. In addition to that, as indicated by the range, wind and solar output varies significantly from weather year to weather year, leading to the high variation in seasonal flexibility needs between weather years. Demand, by contrast, varies much less between weather years, owing to the stable tropical temperature regime, which results in stable cooling needs across the year.

Figure 37. Variation across weather years in the Announced Pledges Scenario, 2050



Flexibility supply

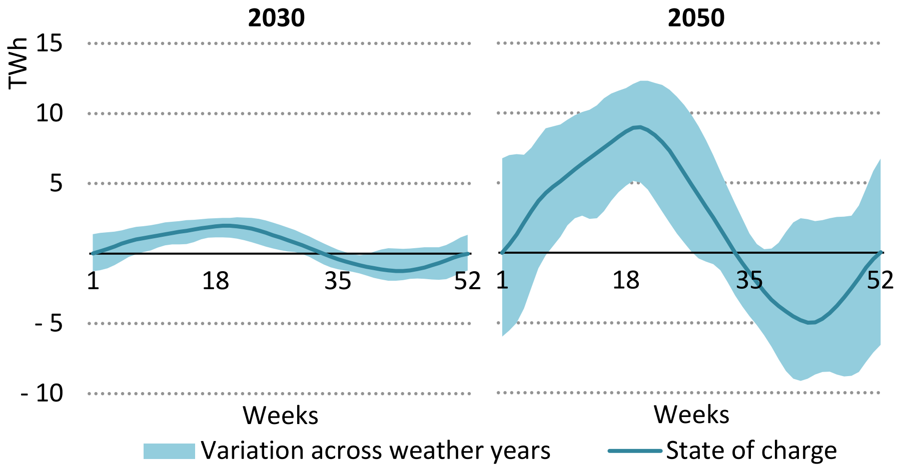
Figure 38. Flexibility supply by source, 2022-2050



Currently, thermal power plants provide almost 90% of the short-term flexibility and all the seasonal flexibility required in the Indonesian electricity system, with the remainder provided by hydropower plants. Until 2030, battery energy storage and demand response emerge as important additional sources of short-term flexibility, with batteries able to take advantage of the daily pattern of PV electricity generation, shifting electricity from the daytime into the evening. The smart operation of water heaters and air conditioners in buildings represents more than half of the demand response potential. In 2050, electrolysers and coal plants co-firing ammonia are crucial providers of short-term flexibility as well. Electric vehicles now make the bulk of demand response contribution by shifting charging to the daytime and thus attenuating the sharp increase in electricity demand in the evening. Across the week and across seasons, thermal power plants, most notably coal, remain the most important source of flexibility until well after 2030. By 2050, they are mostly displaced in that role by additional hydro, co-fired ammonia and the flexible operation of grid-connected electrolysers. The simulations also show that the curtailment of surplus wind or solar PV electricity generation becomes an increasingly important tool to manage longer-term weekly or seasonal variations and balance the system in a cost-effective manner. Curtailment accounts for nearly a third of the seasonal flexibility provided to the Indonesian electricity system in 2050 (Figure 38).

Reservoir hydro capacity is projected to further increase in Indonesia from 2030 to 2050. The seasonal variability in reservoir storage levels is related to the inflow of rainwater, which is higher during the rainy season. Storage levels peak towards the end of the rainy season, and discharge during the dry season leads to a fall in water levels. While there is some variability between weather years, it is lower than in Europe and India due to Indonesia experiencing more consistent rainfall on an interannual basis (Figure 39).

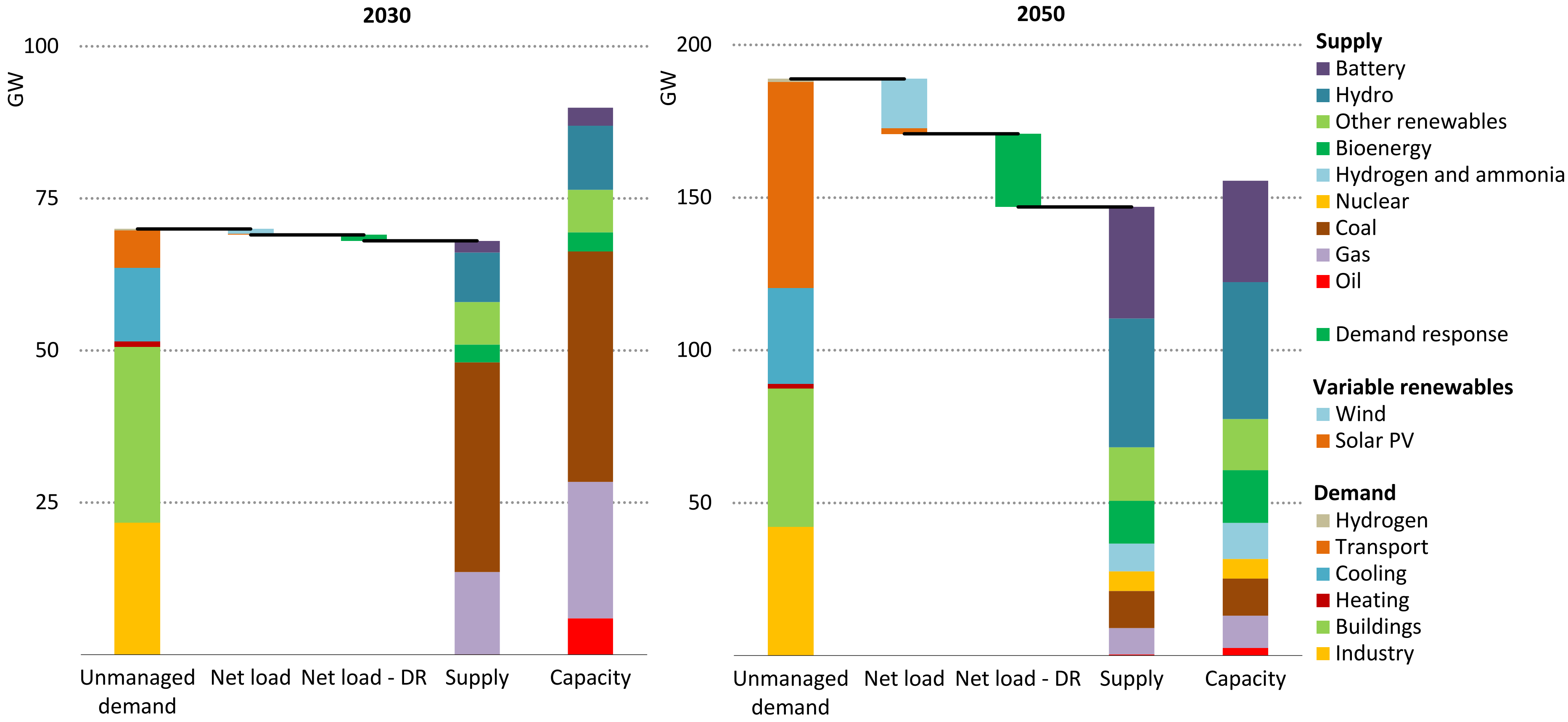
Figure 39. Variability of hydro seasonal storage across weather years, 2030 and 2050



Note: The figure displays the amount of electrical energy stored in hydro reservoirs, relative to the storage level on 1 January, for years 2030 and 2050.

Electricity demand and supply and capacity margin at peak net load

Figure 40. Electricity demand and supply during the highest net load peak over 30 weather years in Indonesia in the Announced Pledges Scenario, 2030 and 2050



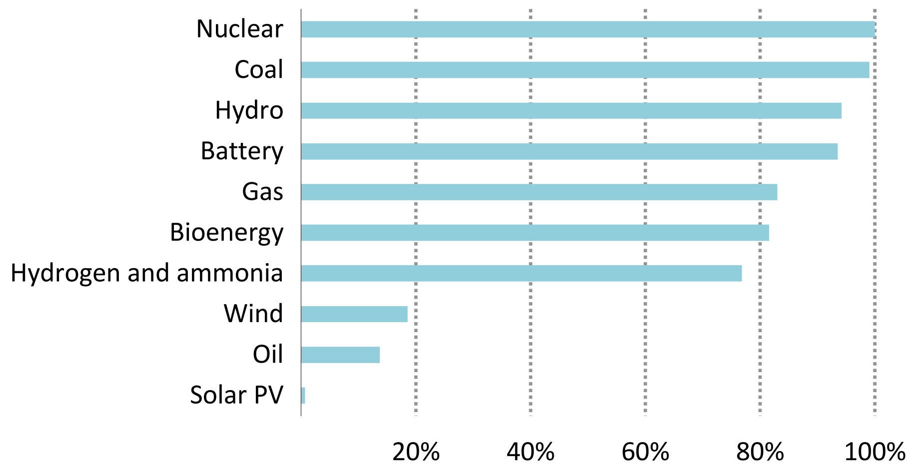
Notes: DR = demand response. Unmanaged demand represents electricity demand before activation of demand response. Other renewables includes geothermal, concentrating solar power, and marine. Peak net load is computed as the top 100 hours over the year. The capacity represents the available capacity during these peak hours.

As highlighted in the previous sections, the key metric to assess the tightness of the system is the net load. Figure 40 above displays the electricity demand, split by end-use, and the electricity supply by technology during peak net load (computed as the top 100 hours over the year). The weather year with the highest peak net load has been selected. Peak net load occurs when the system is facing either low renewable availability or potentially high electricity demand or a combination of both.

Indonesia's electricity system changes considerably between 2030 and 2050, with the substantial increase in variable wind and solar PV electricity generation and the additional electricity consumption from EVs and air conditioners leading to a shift in how system adequacy is maintained in critical periods.

In 2030, peak net load is driven largely by electricity consumption in industry and in buildings, including for space cooling, resulting in a peak demand of about 70 GW. The charging of electric vehicles plays a small but growing role. The capacity credit of wind and solar PV during those hours is not zero. However, the installed wind and solar capacity is still relatively low, meaning that its contribution at these times is very small. Demand response activation is limited to 1 GW, two-thirds coming from transport and cooling. Almost all electricity is provided by thermal power plants and hydro.

Figure 41. Share of available capacity used during net demand peak, Indonesia, Announced Pledges Scenario, 2050



Note: The available capacity is considered as the net capacity available during net demand peak hours.

This changes significantly by 2050. Peak demand rises to nearly 200 GW, in large part due to a surge in demand from the transport sector, rising space cooling needs and elevated industrial electricity consumption due to economic growth and the progressive electrification of additional industrial processes. At the same time, the strong growth in wind capacity ensures that it provides some electricity even at periods of high system stress, characterised by low-wind conditions. Demand response helps reduce overall demand in these peak hours by shifting 25 GW of electricity consumption, 70% of which is from smart charging of EVs, bringing the net load down to below 150 GW on average. Cooling makes the remainder of demand response contribution by shifting 18% of its demand. On the supply side, more than half of this load is met by hydro and batteries, with the remainder provided by thermal power plants, bioenergy and nuclear. Thermal dispatchable capacity is largely used at peak demand: coal power plants are almost used to 100% of their available capacity, and natural gas power plants run at 80% (Figure 41). The development of low-emissions fuels in thermal generation also has an important role at peak demand, with more than 75% of hydrogen and ammonia co-fired total capacity running.

The system margin – the amount of available capacity compared with the size of the peak – declines from about 130% in 2030 to 80% in 2050, which means that the system increasingly relies more on demand response to help reduce the net load during peak hours.

Spotlight: Korea

The context for Korea's clean energy transition

Electricity generation in Korea today relies heavily on fossil fuels, which accounted for 65% of total electricity generation in 2020, consisting primarily of coal (38%) and gas (27%); nuclear power accounted for 29%, while wind and solar combined to account for less than 4% of total generation. As a result, total emissions were the sixth-highest in the world and emissions intensity is higher than that in peer countries.

In October 2020, Korea's government pledged to reach net zero emissions by 2050. Decarbonising the power sector (37% of total emissions) will be at the heart of Korea's clean energy transition. This will require reducing fossil fuel-based generation and electrifying the buildings, transport and industrial sectors, increasing the demand for low-emissions electricity.

Wind and solar will meet most of this new demand for low-emissions electricity due to low and declining costs of construction, widespread availability, and policy support. But Korea's power system faces unique pressures to integrate wind and solar, particularly at the seasonal timescale. Korea has no electricity interconnections with other countries, and thus lacks the option to increase load and resource diversity by connecting with different climatic regions. It is limited by its geography, with high population density, average solar and wind potential, and lack of suitable sites to expand hydropower production. Thermal power plants will be needed to supply the bulk of seasonal flexibility needs, but reducing emissions towards net zero will require that coal and gas plants eventually convert to using low-emissions fuels or equip their units with carbon capture.

Nuclear power, as a dispatchable and low-emissions generation source with low operating costs, can reduce both the demand for and the uncertainty associated with other sources of flexibility by increasing the amount of baseload energy in the system. Korea currently has 26 reactors in operation, suppling about 30% of total electricity. It has developed significant domestic technical expertise, building its own reactor designs since 1989, and is now building the Generation III APR-1400, with four units completed since 2016 and two units currently under construction. Korea's construction costs for nuclear plants are estimated to be the lowest in the world, at around USD 2 000 per kilowatt (overnight cost in 2020 dollars).

Despite the favourable cost of domestic nuclear power, and lack of alternative sources of low-emissions generation, the government in place in 2017 announced a policy to phase out nuclear power. This was reflected in its 9th Basic Plan for Long-Term Electricity Supply and Demand (BPLE), released in 2020, in which no nuclear capacity would be built, and no lifetime extensions of nuclear power plants would be granted. Instead, additional wind and solar would be needed to meet decarbonisation goals. The next government, elected to office in March 2022, reversed plans to phase out nuclear power, setting a goal to increase capacity from 24 GW today to 35 GW (35% of total generation) by 2036 in the 10th BPLE, released in January 2023. This spotlight on Korea focuses on this policy shift on the pathway to decarbonisation by comparing two scenarios – first, the APS, including policies supported by the current government in the 10th BPLE, which see an increased role for nuclear power and a moderation in its proposed uptake of wind and solar, and second, a Nuclear Fade case, including the nuclear phase-out policies of the previous government in the 9th BPLE. It assesses the changes in the shape of net load, the amount of flexibility required at various timescales, including seasonally, and the operation and economics of various sources of flexibility that will be needed to maintain secure power system operation. We find that the shift to higher shares of nuclear will reduce the total amount of system capacity in general, and the specific amount needed to address seasonal variability of renewables.

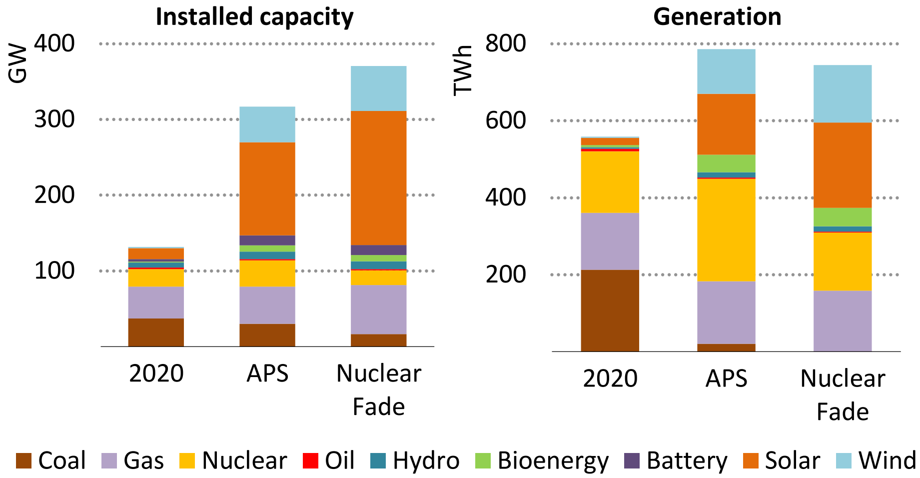
Pathways to net zero electricity

We have modelled a net zero compatible power sector pathway for the medium term (2035) using the APS, which is consistent with the Korean economy achieving net zero by 2050. The APS and Nuclear Fade case, and the investments reflected in each, are then adjusted to meet the emissions reductions milestones associated with the APS. We note that the APS should be viewed as only one of multiple pathways that the Korean power system can take to meet its net zero objectives.

in the APS, total installed capacity reaches 317 GW in 2035, with wind and solar accounting for 170 GW (Figure 42). The share of variable renewables grows from 4% today to 35% by 2035, while nuclear power increases from 29% to 33%. These measures see a reduction in emissions intensity from around 485 tonnes (t) of CO_2/ per megawatt-hour (MWh) today to 75 t CO_2/MWh by 2035, despite strong electricity demand growth.

In the Nuclear Fade case, total installed capacity reaches 369 GW in 2035, a 52 GW (17%) increase from the APS, with wind and solar accounting for 236 GW, an increase of 28% from the APS. The share of generation from variable renewables grows faster, to 50% by 2035, but the share of nuclear declines to 20%. As the share of total low-emissions generation remains constant, there is a comparable drop in emissions intensity in both the APS and Nuclear Fade case.

Figure 42. Installed capacity (left) and generation (right) by technology in Korea, in the Announced Pledges Scenario and Nuclear Fade case, 2020-2035

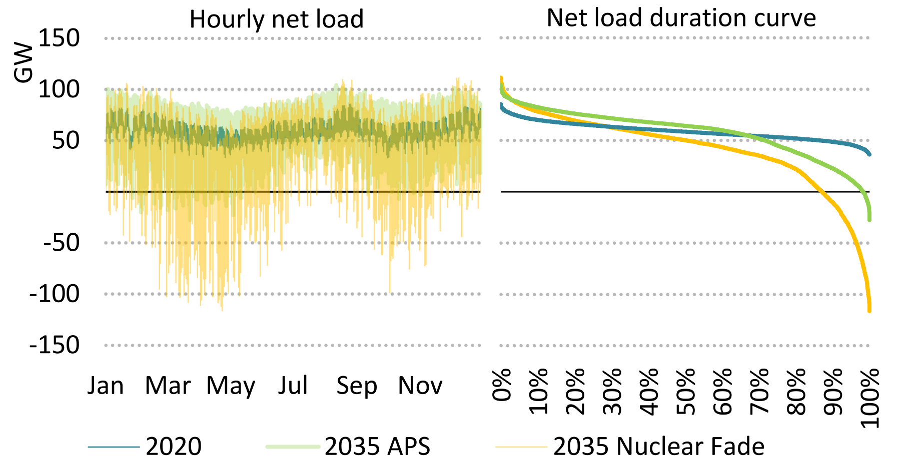


Renewable variability in Korea

The increase in the shares of variable renewables, from 4% in 2020 to 35% in the APS and 50% in the Nuclear Fade case in 2035, increases variability over all timescales and leads to significant changes in net load profiles due to factors on both the demand and supply sides (Figure 43). In 2020, peak demand of 89 GW was roughly 28 GW higher than average demand throughout the year, with nuclear, coal and gas making up most of the energy supply. Through 2035, peak demand is expected to grow faster than average demand, and development of new demand, such as EVs and electrolysers, will affect the load shape. In the IEA Korea Regional Power System Model APS 2035, 30% of EV load is assumed to be flexible as well as all grid-connected electrolyser demand, allowing a proportion of demand to be shifted into the middle of the day to accommodate high solar output.

As a result, by 2035 in Korea, net peak hourly demand rises from 85 GW in 2020 to 104 GW in the APS and 111 GW in the Nuclear Fade case. Minimum net hourly demand falls from 33 GW in 2020 to -28 GW in the APS and -116 GW in the Nuclear Fade case.

Figure 43. Hourly net load and load duration curve, 2020 and 2035

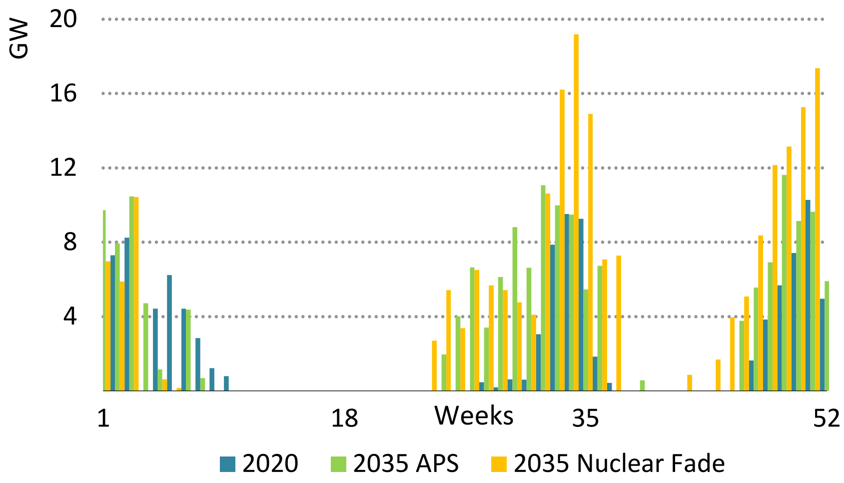


The APS includes a 5% share of hours with excess variable renewables, which rises to 13% in the Nuclear Fade case. The range of the net load thus increases to between 2.5 and 4 times higher in 2035 than in 2020. The system will thus experience higher hourly and sub-hourly ramps, and larger differences between minimum and maximum daily demand in 2035 in both the APS and Nuclear Fade case.

Seasonal flexibility needs

In 2020, which includes a 4% share of variable renewables, the need for seasonal flexibility is driven primarily by changes in load, with peak load periods in summer and winter months, reaching a maximum in December at 10 GW of capacity (Figure 44). By 2035, in the APS we see a slight increase in the maximum seasonal imbalance to nearly 12 GW, but in the Nuclear Fade case, with its larger share of variable renewables, the maximum seasonal imbalance increases to 19 GW.

Figure 44. Seasonal flexibility needs in Korea by week in the Announced Pledges Scenario and Nuclear Fade case, 2020-2035



Note: Seasonal flexibility need is calculated as the difference between the annual and weekly average net load.

The role of nuclear power

The increase in seasonal flexibility needs from the APS to the Nuclear Fade case highlights the stabilising role that firm, low-emissions sources, in particularly nuclear power, can play in future low-emissions power systems. Because nuclear is dispatchable and has low operating costs, it runs as baseload, only reducing output during refuelling and forced outages, resulting in capacity factors above 85% in Korea. Nuclear refuelling, which typically occurs every 18 months and lasts around 45 days, can also be timed to coincide with periods of low demand while remaining fully available during high demand periods.

Nuclear capacity can thus replace greater quantities of other sources of energy that run at lower capacity factors or whose output does not correlate with peak energy demand. In Korea, the capacity factor of wind has historically ranged from 18-25% and solar from 12-15%. The increase in nuclear capacity from the Nuclear Fade case to the APS, by 15 GW, leads to a reduction in total portfolio capacity by 52 GW, reducing solar PV by 54 GW and wind by 13 GW. The sharp increase in seasonal flexibility needs in the Nuclear Fade case suggests that some form of clean baseload generation is likely necessary for certain regions, such as Korea, that lack high potential for variable renewables and load and resource diversity through interconnection, to reach very high levels of decarbonisation at both technical and economic levels. Globally, we calculate that nuclear generation can replace 3.5 to 4 times the alternative capacity needed to serve the same level of demand in highly decarbonised power systems. Also, the alternative capacity must include significant flexible and dispatchable capacity, including batteries, low-emissions fuels, and units with carbon capture, utilisation and storage. Nuclear thus not only reduces the capacity needed for the energy transition but also the reliance on pre-commercial technologies. Nuclear generation additionally reduces demand for transmission and distribution expansion compared with scenarios with higher variable renewables. Transmission is a key risk to the energy transition due to high costs, local opposition and regulatory delays.

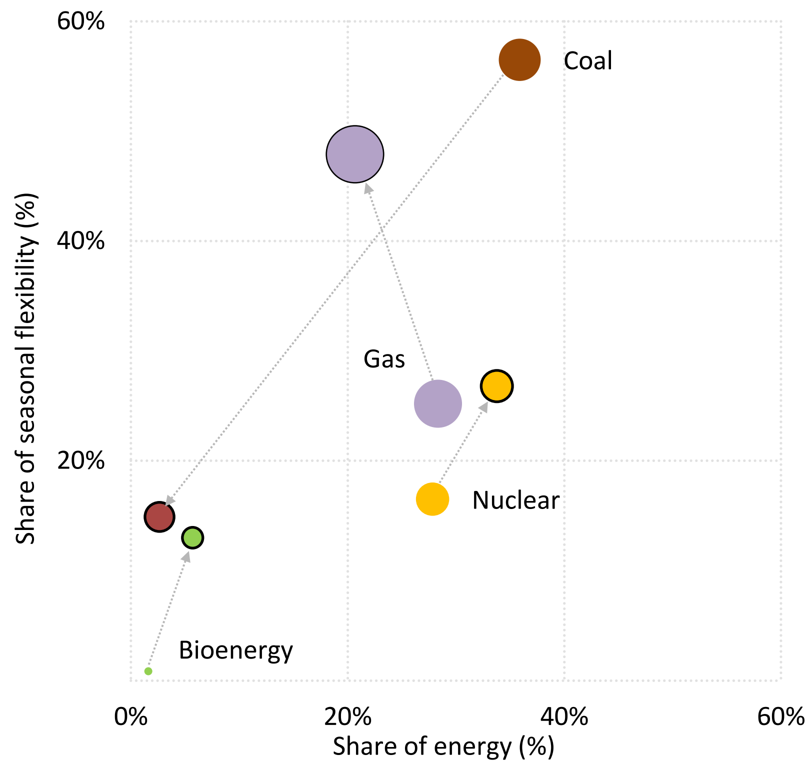
The role of coal- and gas-fired plants

Emissions reduction goals will push coal and gas units down the merit order, reducing their supply of electricity. We estimate that the coal fleet is reduced from 30 GW in 2020 to 20 GW in 2035, with the remaining capacity lowering its capacity factor from 60% to 8%, reducing the share of coal in total generation from 36% to 3%.

The capacity factor of gas-fired generation remains stable at around 38% in the APS, while the fleet grows from 44 GW to 49 GW, with the share of gas in total generation falling from 28% to 21%. This includes the expectation that some hydrogen is blended into the natural gas system and co-fired in gas power plants, reducing its emissions intensity. To reduce emissions further and get closer to net zero, an even greater share of coal- and gas-fired generation will need to transition to low-emissions fuels.

Gas, nuclear and bioenergy increase their quantity and share of seasonal flexibility supply between 2020 and 2035. Gas becomes the largest supplier of seasonal flexibility at 48%, while the share of nuclear increases from 17% to 27% of the total and bioenergy's share increases from 1% to 13% (Figure 45).

Figure 44. Share of energy and seasonal flexibility by source, Korea, Announced Pledges Scenario, 2020 and 2035



Contribution to energy services

Multiple services, in addition to bulk energy supply, are required to operate the power system securely. Adequate capacity is required to cover net peak load, flexibility is needed to follow load and supply variations over short and long timescales, and stability is needed to operate the system smoothly during and after disturbances. Power systems have traditionally relied on conventional power plants such as coal, gas, nuclear and hydropower to provide these services, such that the services were bundled with the energy provided.

The transition to variable renewables changes the picture – they can supply electricity but do not contribute equally to the supply of all the services needed for secure power system operation. Emerging technologies can also provide specific services. For example, batteries are an increasingly cost-effective source of flexibility and capacity. As a result, the cost-effective pathway to net zero includes a diverse set of power technologies providing different services.

Adequacy

Adequacy is the ability of the electricity system to always meet electricity demand within an area under normal operating conditions. Adequacy is a critical element of power system flexibility as it allows the system to constantly balance supply and demand using system resources with the right capabilities to satisfy the load.

Systems with higher variable renewables will continue to need thermal power plants to provide dispatchable capacity to contribute to system adequacy, despite a decline in their share of total energy.

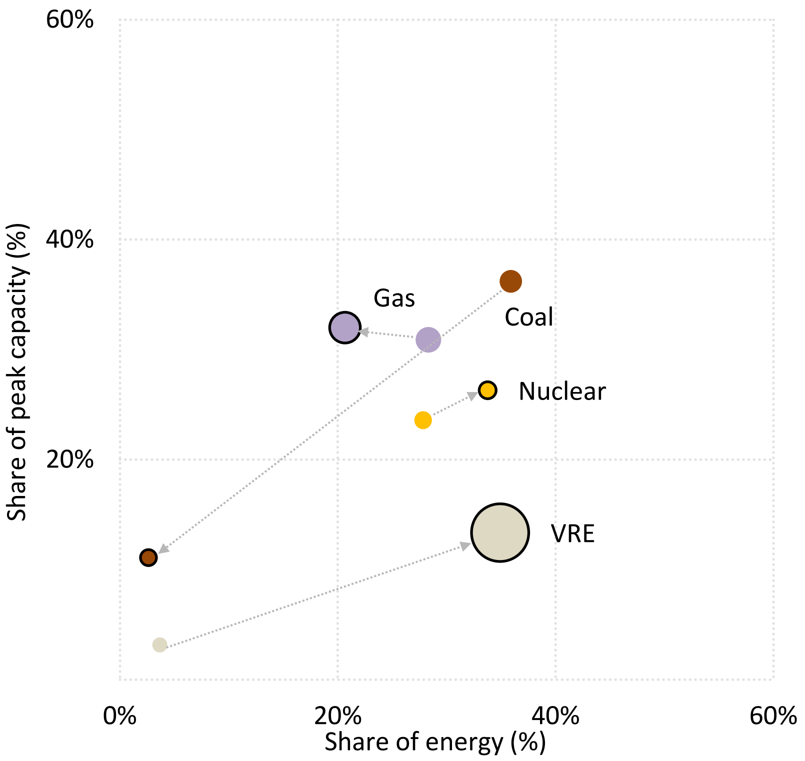
In Korea, the total share of energy provided by coal and gas plants declines from 63% in 2020 to 24% in 2035 in the APS (Figure 46). However, the share of peak capacity, defined as generation provided during the 100 hours of the year with highest load, declines by only 24 percentage points, from 67% to 43%. In fact, the share of peak capacity provided by gas plants stays stable around 30% in this period even though its energy share declines by 7 percentage points. Coal provides 11% of peak capacity, despite its energy share falling to 3%. Nuclear's share of peak capacity increases from 24% to 26%, in line with its increase in the share of energy.

Short-term flexibility

The need for short-term flexibility will increase with the share of variable renewables, which is highlighted by changes in Korea's net load profile. For example, the maximum upward change in load over a three-hour period is expected to increase from 21 GW in 2019 to 35 GW in 2035, which equals 50% of system load. This share is moderate compared with power systems such as California and India, which can see requirements as high as 60-70%.

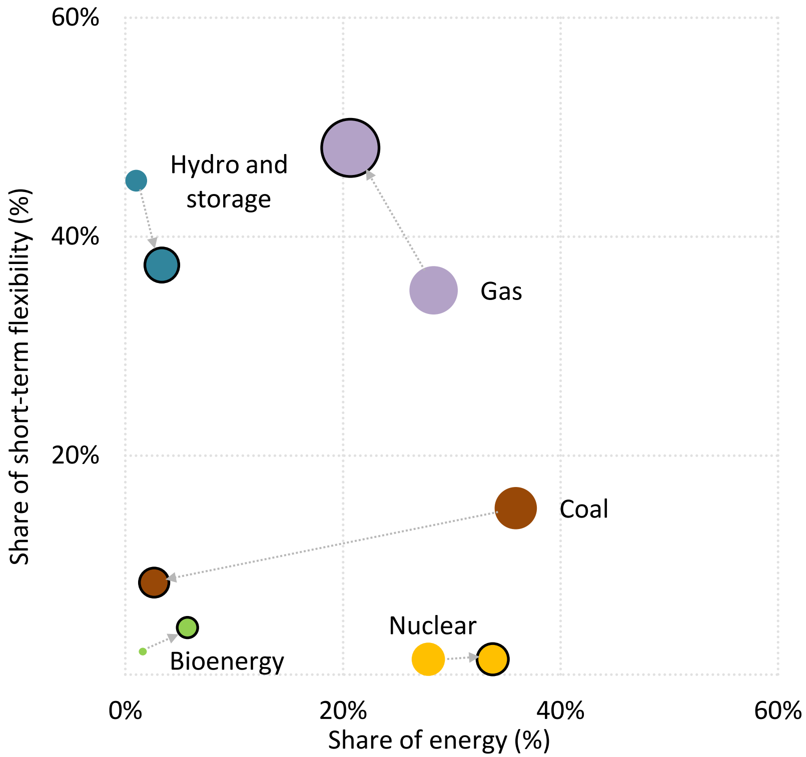
Thermal power plants will continue to provide short-term flexibility even while their share of energy declines. Gas plants will provide 48% of short-term flexibility in 2035, an increase from 35% in 2020. Coal will still provide 8% of short-term flexibility in 2035, down from 15% in 2020, even though its share of energy falls from 36% to 3% (Figure 47).

Figure 45. Share of energy and peak capacity by source, Korea, Announced Pledges Scenario, 2020 and 2035



Notes: Bubble size indicates installed capacity. Peak load is computed as the top 100 hours over the year.

Figure 46. Share of energy and short-term flexibility by source, Korea, Announced Pledges Scenario, 2020 and 2035



Note: Bubble size indicates installed capacity.

Implications for power plant operations and costs

Impact on power plant operations

The variability of demand and wind and solar PV output between different weather years can result in significant year-to-year variations in the operation of high-marginal-cost thermal power plants, which, together with demand response and storage assets, balance the system to ensure demand is always met reliably. The higher the variable renewable share in the electricity mix, the lower the capacity factor for thermal power plants, which switch from bulk generation to balancing and adequacy services. For power systems with seasonal flexibility needs showing a strong volatility across weather years, this directly translates to strong volatility in thermal power plant operations.

In Europe in 2030, the total annual generation of the fleet of dispatchable thermal power plants varies from weather year to weather year, with total generation of more than 700 TWh per year in the most extreme years, in contrast to about 500 TWh in more typical years (Figure 48). The high wind share in Europe's power mix means that most of the variation in thermal power plant operations between weather years comes from the first and last quarter of a year, as in Europe, wind typically blows stronger during the winter and the impact of interannual variation in wind is thus most strongly felt then.

In the case of India in 2050, when the power system is dominated by solar PV and battery storage, the variability of thermal plants is less significant, with total generation in excess of 800 TWh in the most extreme weather year in contrast to 700 TWh on average (Figure 49).

Figure 47. Thermal power plant generation by quarter in Europe, 2030

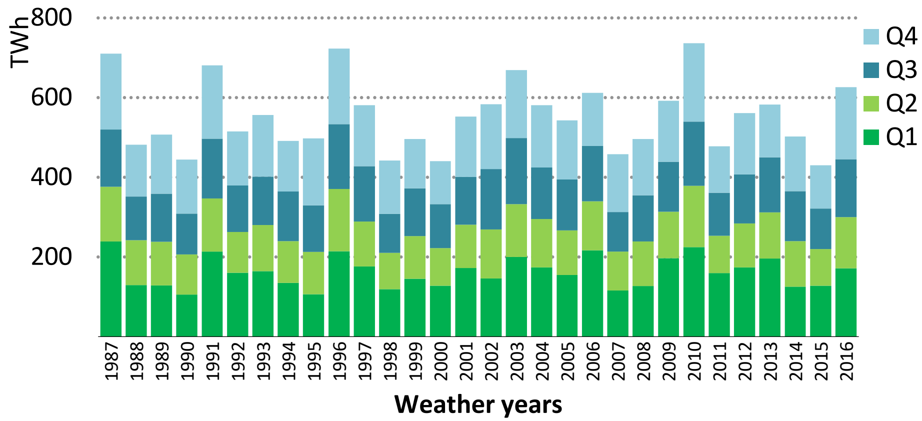
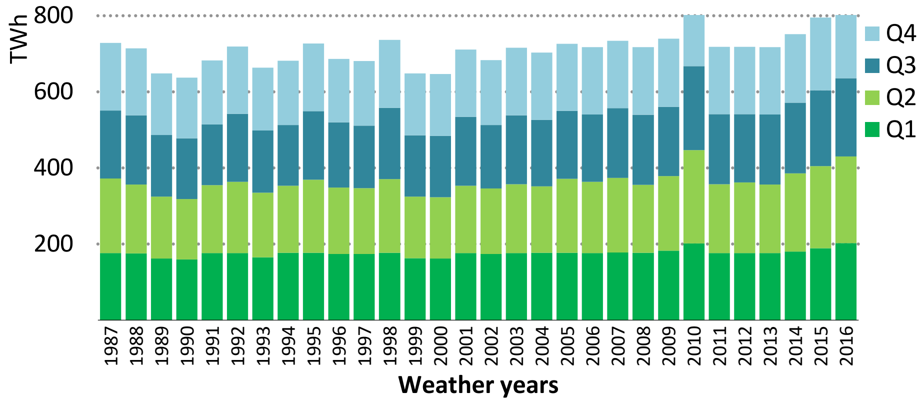
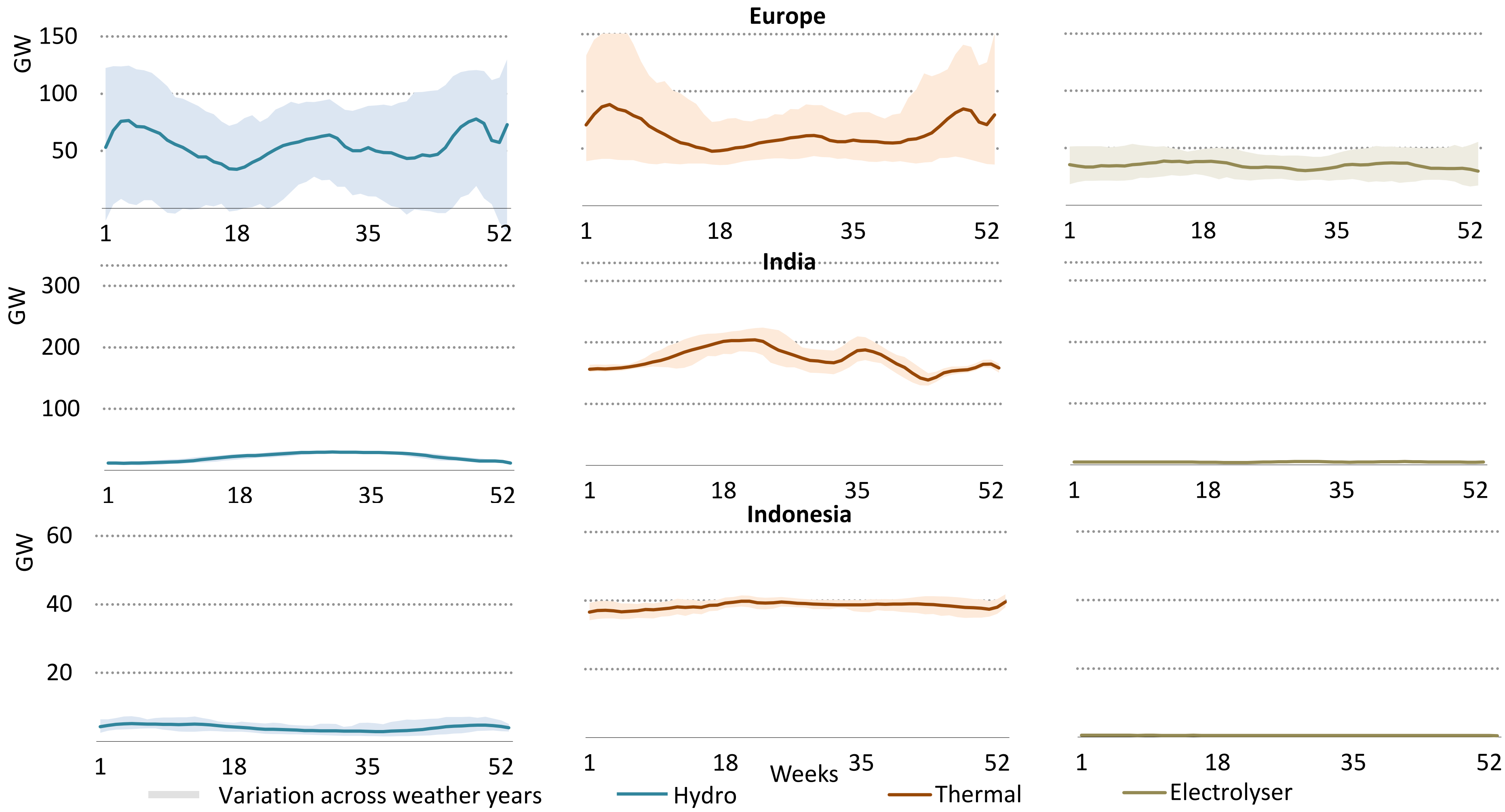


Figure 48. Thermal power plant generation by quarter in India, 2050



Seasonal and interannual variability of hydro, thermal generation, and electrolyser output

Figure 49. Variability across weather years, 2030



In India's 2050 solar PV-dominated power system, the seasonal and interannual variability of the net load is much lower than in Europe, translating to a much more predictable operating environment for dispatchable thermal power plants on a seasonal and interannual basis.

Seasonal flexibility supply in the power system comes from four key sources: hydro, thermal, electrolysers and curtailment. Hydro generation, being cost-effective and well suited for meeting seasonal variations, aligns its production profile with the net load. However, its availability depends on its own seasonality and on available inflows (coming from rainfall and snowmelt), which can vary significantly from one year to the next. A recent example are the repeated drought episodes in the People's Republic of China, which have required thermal power plants to run harder to compensate.

Figure 50 compares the seasonal and interannual variability of hydropower generation, generation by thermal power plants and the operation of flexible electrolysers between the three regions. The variability of hydro across the 30 tested weather years for 2030 is highest in Europe, which, compared with India and Indonesia, experiences greater interannual variability in seasonal flexibility needs.

Dispatchable thermal power plants have more freedom to adjust their output in accordance with the fluctuations of the net load, and are thus an important provider of seasonal flexibility. Their average production profile is in line with the average net load, and the variability across weather years matches the most stressful periods for the systems (winter peaks in Europe, and monsoon in India). In 2030, unabated coal and gas generation varies between +40% and -25% around its 30-weather-year average in Europe, with stronger volatility in the dispatch observed during winter months. In India, coal generation varies by at most 5% compared with an average weather year, and Indonesia has an even more stable variation of 3% of coal and gas generation. Until 2050 the variability of thermal generation increases in all three systems, reaching ranges of between +75% and -30% in Europe; +20% and -15% in India; and +20% and -10% in Indonesia.

Electrolysers can provide significant seasonal flexibility provided they are grid-connected to absorb the renewable surpluses, and significant volumes of hydrogen can be stored in large-scale underground storage facilities. However, by 2030, in our scenario, this would be the case only in Europe. Electrolysers operate more during the shoulder seasons, when the net load in Europe is lower than its annual average. The flexibility provided by electrolysers for the electricity system can be a source of uncertainty depending on the operational constraints and regulatory framework.

Impact of weather variations on power system costs

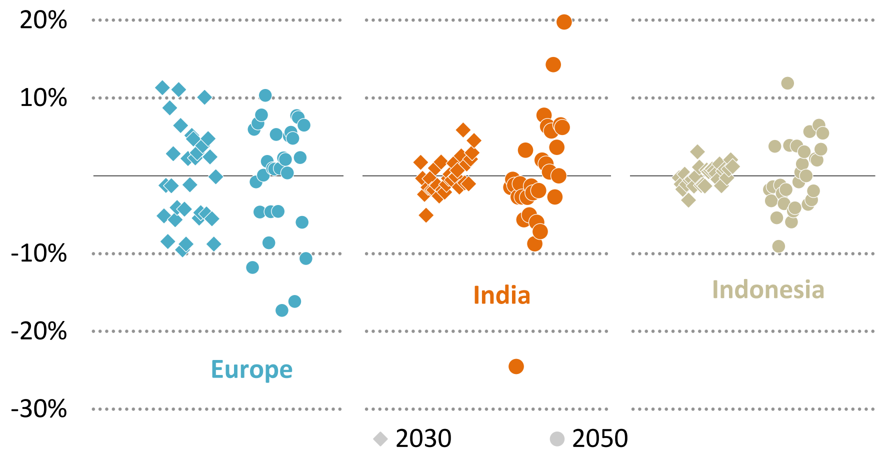
The variation in the utilisation of high-marginal-cost thermal power plants between different weather years highlighted in the previous section can result in substantial variations in total operating costs across weather years in all three systems. In 2030, the most extreme weather years can include a 10% upward or downward variation in operating costs in Europe, about 5% in India and around 4% in Indonesia (Figure 51).

Due to the rising shares of low-marginal-cost variable renewables and falling load factors of the remaining fleet of thermal power plants, the variability in operating costs increases to 2050, even as they decrease significantly in absolute terms compared with 2030.

In 2050 in Europe and India, system operating costs can vary by up to 20% compared with an average weather year in the most extreme cases. In Indonesia, more consistent interannual weather patterns mean that operating costs vary slightly less, by about 10% in either direction in the most extreme weather years.

Total power system costs (per unit of electricity) are projected to decline in all three systems because of the transition to low-emissions technologies, in particular wind and solar PV, which are already among the cheapest forms of electricity in many markets today.

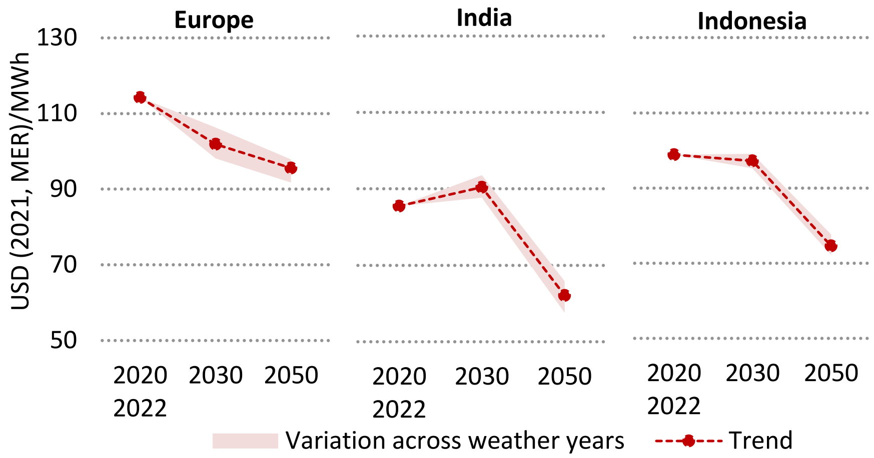
Figure 50. Variability of operating costs across weather years and systems in the Announced Pledges Scenario, 2030-2050



Note: the variability in percentage is the difference with an average weather year.

As a result of the rising share of near-zero marginal cost generation, the contribution of the variable costs (most notably fuel costs) to the total system costs will decrease over time, from about two-thirds today to 30% or less by 2050, depending on the system (Figure 52). While the weather-induced variability of the operating cost component is projected to increase, most of the total system costs are fixed, which means that the weather-related variability of the total system cost as a whole is fairly small.

Figure 51. Variability of total power system costs across weather years and systems in the Announced Pledges Scenario, 2020-2050



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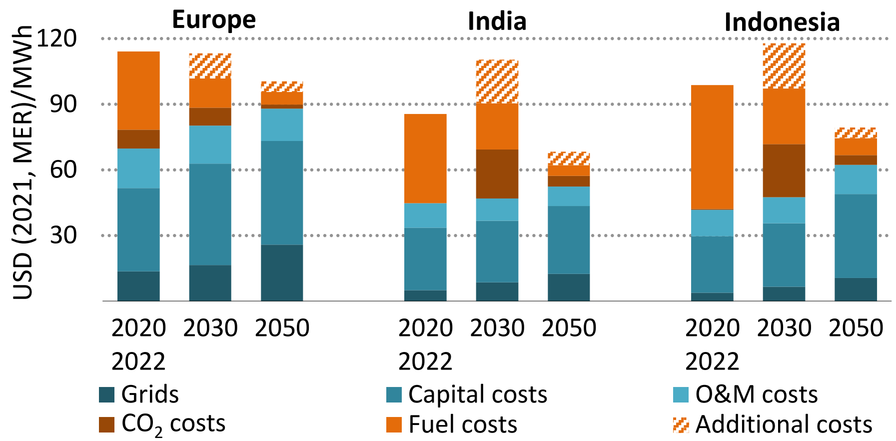
Fuel cost uncertainty on the other hand, has a much greater impact, with higher fuel prices greatly increasing the total system costs. However, the falling share of variable costs means that the impact of fuel price shocks on the total system cost will be smaller than it is today. Figure 53 illustrates the cost impact of a doubling of fuel costs compared with the reference case in 2030 and 2050. In Europe it would result in a 10% increase over the reference case in 2030, and less than 5% increase in 2050, despite the important role of thermal generation in the region – and particularly natural gas power plants – providing seasonal flexibility. In India and Indonesia, where power systems are much more dependent on coal power plants in 2030, the impact of a doubling of fuel prices would result in a 20% increase in total power system costs. In 2050 this impact becomes less significant as all systems have reduced their reliance on fossil fuels.

The variability of total power system costs results not only from weather fluctuations introducing variability in thermal generation. Another source of uncertainty lies in the availability of substitute flexibility sources. As previously stated, hydro can be an important source of flexibility, but is subject to uncertainty around water inflows. Electrolysers linking the power and hydrogen systems also offer flexibility, assuming that sufficient electrolyser and hydrogen storage capacity is available to cope with potentially extended periods when the electricity system is short, but their availability depends on several crucial assumptions, ranging from the overall level of grid-connected electrolyser capacity to the availability of large-scale hydrogen storage sites.

Figure 52. Impact of doubling fuel prices on total power system costs in the Announced Pledges Scenario, 2020-2050



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Note: O&M = Operation and maintenance.

Power system planning and market design to increase flexibility

Managing the seasonal and interannual variability of electricity demand and supply through sound planning practice is a critical area to address as electricity systems enter higher phases of system integration of renewables. Traditional methods of planning that were appropriate for largely thermal-based power systems, which focused on ensuring a reserve margin of installed capacity over the expected peak load, need to be updated to include probabilistic assessments of weather's impact on demand and generation output, randomised and weather-dependent generation and transmission outages, demand flexibility, and the interactions between them. Measuring the uncertainties associated with all of these factors will help to better calibrate the amount of flexible capacity needed to reach a desired level of reliability.

Decarbonising electricity generation and maintaining system reliability at all times requires dealing with intrinsic seasonality and short-term variability of different elements of the system, and making sure that appropriate solutions are economically viable to provide flexibility. In the near to medium term, an important consideration is increasing the flexibility of existing thermal assets to cope with rising short-term variability and prepare them for more responsive, flexible operations at lower capacity factors, in particular in countries with relatively young fleets of baseload coal plants, such as India and Indonesia. Repurposing power plants for flexibility may require equipment upgrades that enable faster ramping, a lower stable minimum load or faster start-ups, changes in plant operations, updating markets to better reflect the needs of the system, and updating to long-term power supply contracts.

Encouraging electricity consumers to use demand response methods by offering appropriate incentives to adjust their consumption (without affecting service quality), leveraging digitalisation and strategies such as time-of-use or dynamic tariffs, will be crucial for smoothly incorporating new technologies such as EVs or heat pumps without jeopardising security of supply. Batteries have a crucial role to play as providers of short-term flexibility. Once hydrogen production ramps up, encouraging the flexible operation of hydrogen electrolysers will also be essential as they can potentially be a major source of flexibility for the electricity system. To encourage the effective deployment of demand response and storage solutions, it is vital to remove regulatory barriers and expand their access to flexibility and electricity markets.

This analysis also highlights the essential role of hydro reservoirs and long-term energy storage in the form of hydrogen to manage seasonal variability and ensure security of supply. However, seasonal flexibility needs can vary significantly from one year to the next. In light of this uncertainty, it is essential to provide operators of long-duration energy storage with the right incentives to engage in long-duration energy shifting and hold sufficient energy in reserve for critical periods.

Managing seasonal variability and ensuring electricity security at all times critically depends on well-developed grid infrastructure. Grids help reduce flexibility needs by aggregating consumers and variable renewables over greater areas, smoothing out variations. They also help connect additional sources of flexibility to the system. New grid infrastructure is capital-intensive and often takes between 5 and 15 years to plan, permit and complete, compared with 1 to 5 years for new renewables projects. Planning for transmission and distribution grids needs to be further aligned and integrated with broad long-term planning processes by governments, and sufficient investments need to be directed into the sector.

Planning is also relevant for sectors that are part of a country's strategy to increase its energy security or promote industrial activity. Clean energy technologies, including nuclear power, fall into this category. The decision to promote the development of these technologies has a significant impact on the investment and operation of other aspects of the power sector, from transmission and distribution to generation. As a result, the role of clean energy investments, including nuclear power and other low-emissions dispatchable sources of electricity, should be made clear at very early stages of planning to send the correct signal to the buildout of other generation sources, in particular renewables, to avoid inefficiencies in the level and type of investments. For example, substantial renewables investment in parallel and uncoordinated with nuclear power could create a risk of chronic overproduction during certain periods, which decreases the value of both assets.

In systems with high shares of variable renewables, it will be necessary to accommodate resources that provide essential system services, while at the same time reducing their contribution to total energy supply. As observed, most of the thermal dispatchable fleet sees lower utilisation rates in the future; however, the services provided to the system for security of supply or for seasonal balancing are still important and should be financially rewarded to ensure their economic profitability. In market-based systems, this will require reforms that ensure that these sources have access to adequate levels of remuneration that are not tied to the generation and sale of electricity. Markets should be designed to establish efficient price signals to procure these needed services at lowest cost. There are various ways in which markets can move toward more efficient outcomes, by more closely reflecting the technical and economic constraints of the electricity system. The ability to generate or consume electricity has different values to different system actors depending on time and location, and this should be reflected in market prices.

Capacity remuneration mechanisms are an option to ensure that sufficient generation capacity will remain available if needed. While their implementation is slightly different from market to market, they generally provide a fixed payment to generators in exchange for the obligation to provide energy during discrete times of system need.

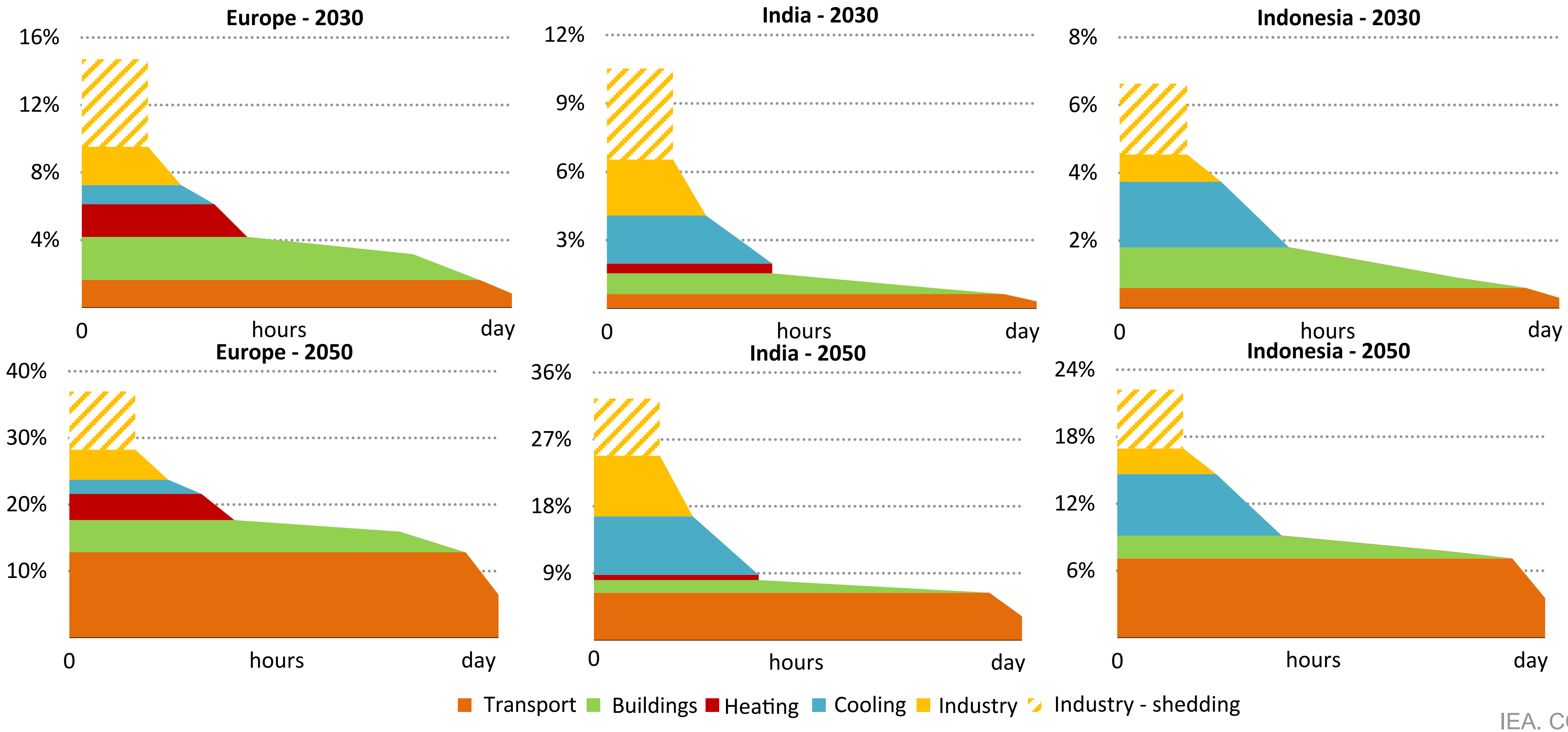
The use of energy price adders, which allow prices to rise to the full economic value of energy and reserves at times of system stress, can provide additional incentives to invest in firm and flexible solutions to address system security. Also, services such as ramping and stability should be valued, with prices reflecting their contribution to secure operation. However, this will also require robust market oversight to ensure that firms do not abuse any market power that may arise in shortage conditions.

Furthermore, guarantees of origin to promote the use of renewable electricity with a premium wholesale price for customers should be consistent with the variable nature of electricity, and should cover only short periods of time to incentivise the use of flexible sources to compensate for the variability of the production. Similarly, they should only cover a well-defined market zone to account for potential grid congestion and geographical constraints that exist in real systems.

Annex

Demand response potential

Figure 53. Demand response potential by end-use as a share of average demand against typical shifting duration



Notes: These graphs illustrate demand response as the shifting potential (as a share of demand) against the shifting duration, by end-use. In Europe in 2050, EVs can shift up to 14% of demand, over durations that reach up to a day. Buildings add 5% via appliances (such as washing machines, dishwashers, dryers), whose cycles can be shifted within the day. Heating, cooling, industry offer less significant potential; durations are limited to few hours because of thermal inertia or planning constraints. Overall, on average, 30% of demand can be shifted, and needs to be recovered within different time frames, offering various flexibility services. On top of that, 10% of demand can be curtailed via reduced industrial production (which comes at a very high cost).

Flexibility needs

Short-term flexibility needs are computed as follows:

$$Ramp(t) = ResidualLoad(t) - ResidualLoad(t - 1h)$$

$$FlexibilityNeeds_{year,short-term} = \frac{\frac{\sum_{t \in \{t_1,t_2 \ldots t_{100}\}\ with\ Ramp(t_i) \geq Ramp(t_{i+1})} Ramp(t)}{100}}{\frac{AnnualElectricityDemand_{year}}{8760}}$$

Weekly flexibility needs are computed as follows:

$$FlexibilityNeeds_{year,weekly} = \frac{\sum_{t \in year} |ResidualLoadDailyAvg(t) - ResidualLoadWeeklyAvg(t)|}{AnnualElectricityDemand_{year}}$$

Seasonal flexibility needs are computed as follows:

$$FlexibilityNeeds_{year,seasonal} = \frac{\sum_{t \in year} |ResidualLoadWeeklyAvg(t) - ResidualLoadAnnualAvg(t)|}{AnnualElectricityDemand_{year}}$$

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Abbreviations and acronyms

APS	Announced Pledges Scenario
BPLE	Basic Plan for Long-Term Electricity Supply and Demand
CCUS	carbon capture, utilisation and storage
CO2	carbon dioxide
ECMF	European Centre for Medium-Range Weather Forecasts
EV	electric vehicle
GEC	Global Energy and Climate model
IEA	International Energy Agency
PV	photovoltaic
PyPSA	Python for Power System Analysis
STEPS	Stated Policies Scenario
USD	United States Dollar
WEO	World Energy Outlook

Units of measure

GW	gigawatt
MWh	megawatt-hour
TWh	terawatt-hour
t	tonne

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