Managing Seasonal and Interannual Variability of Renewables

International Energy Agency

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Abstract

Renewables are growing rapidly in the electricity systems around the world as countries seek to improve their energy security, meet emission reduction targets and take advantage of cheaper electricity sources. Thanks to successful use of flexibility resources – from stronger grids and interconnections to demand-side measures, affordable storage and dispatchable power supply – many countries have already securely and efficiently integrated significant shares of variable renewables (VRE) in their electricity generation.

As wind and solar continue to grow as a proportion of generation, system level surpluses and periods of lower generation will eventually expand beyond hour-to-hour or daily variations to seasonal timescales. Addressing seasonal variability of renewables means that flexibility resources will be needed to varying extents throughout the year, even on a week-to-week or month-to-month basis.

The present study, produced in support of Japan's G7 Presidency, explores the integration of VRE beyond 70% share of annual generation in future power systems, focussing on four different climatic regions: Temperate with hot summer, Tropical, cold Arid and Continental with warm summer. The study confirms that a mix of flexibility resources is needed to manage variability across all timescales and seasons. In particular, systems with very high level of VRE require seasonal flexibility services, which can be provided from existing thermal power capacities and from hydropower plants. Eventually, as energy systems transition towards net zero emissions, all flexibility services will need to be fully decarbonised.

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The work benefitted from strategic guidance by Keisuke Sadamori, Director of Energy Markets and Security. The lead authors of the report were Ilkka Hannula, Ana Alcalde Báscones, and Keith Everhart. Brent Wanner and Julie Dallard contributed to the report design and flexibility analysis. The model development and simulation results were provided by external consultants Tomi J. Lindroos, Juha Kiviluoma and Jussi Ikäheimo from VTT Technical Research Centre of Finland.

Other IEA colleagues who contributed to this work include (in alphabetical order): Sara Budinis, Carlos Fernández Álvarez, Craig Hart, Zoe Hungerford, Rena Kuwahata, Brian Motherway, Yu Nagatomi, Amalia Pizarro, Isaac Portugal, Uwe Remme.

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Executive summary

Renewables are rapidly transforming power systems worldwide

An additional 2400 GW of renewables power capacity is forecast to be installed by 2027, equal to renewables growth over the last 20 years or to the total current installed capacity of China, as countries seek to improve their energy security, meet emission reduction targets and take advantage of cheaper electricity sources. Renewables are set to account for over 90% of global power capacity expansion between now and 2027.

Renewables become the largest source of global electricity generation by 2025, surpassing coal. Their share of annual electricity generation is forecast to increase by 10 percentage points worldwide, reaching 38% in 2027. Over the period to 2030, renewables outpace overall electricity demand growth, and in the longer term are set to become the dominant source of electricity worldwide.

Electricity from wind and solar PV more than doubles in the next five years, together providing almost 20% of global power generation in 2027. These variable renewables (VRE) will account for 80% of the increase in global renewable generation over the next five years, changing how power systems operate.

Secure and cost-effective integration of renewables is the cornerstone of clean energy transitions

The IEA has long-standing experience in power systems and has developed a framework for secure and cost-effective integration of wind and solar PV, which calls for significant increases in all forms of flexibility, from stronger grids and interconnections to demand side measures, affordable storage and dispatchable power supply.

Already today, thanks to successful use of flexibility resources, many countries have been able to securely and efficiently surpass double digit shares of variable renewables in annual electricity generation. As of the end of 2021, Denmark surpassed 50% – also thanks to good interconnections – and four other countries – Germany, Ireland, Spain and United Kingdom – have integrated above 25% VRE, meaning that during certain periods of the year variable renewables have supplied up to almost all generation.

In the coming years, an expanding group of countries are expected to reach even higher shares of VRE, thereby experiencing a growing number of weeks with electricity surplus, as well as longer periods with relatively lower wind and solar conditions when other sources will continue to be needed. Such variations will eventually extend beyond hour-to-hour or daily fluctuations to monthly and seasonal timescales.

A mix of flexibility resources is needed to manage variability across all timescales

The importance of using a full range of flexibility resources is confirmed by the present study, which explores the integration of VRE beyond a 70% share of annual generation. The study was carried out as a parametric analysis using a model that optimises investments in wind, solar PV and flexibility resources to minimise overall system costs under given cost and performance assumptions, taking into account legacy infrastructure. Over 700 model runs with technical sensitivity analyses were carried out in four different climatic regions: Temperate (hot summer), Tropical, Arid (cold) and Continental (warm summer). The model shows that different mixes of flexibility resources are required to manage variability across timescale and climatic regions.

In the future high-VRE electricity systems modelled in this study, short-duration flexibility resources play a critical role in balancing the hourly and daily variation of renewables. For example, in the Tropical and Arid systems – characterised by high levels of solar radiation – batteries provide around 40% of the total annual short-duration flexibility requirements, playing a key role in balancing daily variation in solar PV electricity supply. In the Temperate and Continental systems, demand-side measures – smart charging of electric vehicles and industrial demand response – provide 30%-35% of these short-duration flexibility needs.

Systems with very high levels of variable renewables require seasonal flexibility services

As the penetration of wind and solar increases, periods of system level surpluses and lower generation become longer, eventually reaching seasonal and even interannual timescales. Addressing seasonal variability means that other electricity or flexibility resources will be needed to varying extents throughout the year, even on a week-to-week or month-to-month basis.

The interactions between electricity demand, hydro availability, and the amount and complementarity of wind and solar resources set the basic conditions for integrating high levels of variable renewables on a seasonal timescale. There are a number of conditions that can ease the integration of variable renewables, including limited seasonality in electricity demand patterns, moderate to low peak demand, high availability of dispatchable renewables including hydropower, and a high degree of complementarity among patterns of solar PV, wind and hydro availability.

For example, seasonal variability is relatively easier to manage in a Continental (warm summer) system where solar PV and wind show good complementarity on a seasonal scale, with wind peaking in the winter and solar in the summer. The combined monthly generation from wind and PV never falls below 85% of their peak.

An Arid (cold) system has a relatively flat seasonal electricity demand with a minimum monthly level of only 88% of the peak. Monthly solar PV potential is also very flat over the year, but monthly wind generation experiences a significant slump during a short period of rainfall in the beginning of the year, when it dips to just 57% of the peak.

Seasonal variability is more complex in a Temperate system (with hot summer) that is characterised by peak electricity demand in the summer driven by demand for cooling, and a smaller peak in the winter driven by demand for heating. Winter sees higher average winds that help to meet the demand peak, while solar is generally available at high levels during summer complemented with a good availability of hydropower.

A Tropical system has also relatively flat seasonal electricity demand but is exposed to a strong seasonal wind pattern, which leads to large surpluses during the dry season and periods of lower generation during the rainy season, that is only partly compensated by hydropower.

Existing thermal power capacities help to manage seasonal variability requirements

In the future high-VRE systems we analysed, legacy thermal power plants provide only 5%-15% of total annual electricity, but they are the main source of seasonal flexibility. Depending on the system, half to two-thirds of seasonal flexibility needs are supplied from thermal power plants during critical periods of the year.

The current stock of legacy thermal capacity is sufficient to meet the seasonal flexibility requirements of the modelled high-VRE systems. However, the use of these assets is very different than today, as the thermal plants are used on average just between 500 and 2000 hours per year, depending on the climate, significantly lower than the 4000 hours of global average utilisation today. Successful management of this transition from bulk electricity generation to flexibility supply is needed to ensure an orderly transition to secure, clean and affordable power systems.

Hydropower is a key provider of seasonal flexibility but is exposed to interannual variations

Hydropower is the second most important seasonal flexibility resource after thermal power plants, providing one-third to half of total seasonal flexibility demand. Many hydropower plants can be modified and upgraded to provide more balancing and integration services. However, due to fluctuating precipitation and snowmelt from year to year, hydropower is exposed to significant interannual variations, including the possibility of consecutive years with higher or lower-than-average generation. Possible multi-year deficits in hydropower availability cannot be fully offset by reservoir withdrawals leading to shortfalls in power generation if the variability aspects of hydropower are not properly addressed as part of energy infrastructure planning.

There is enough legacy fossil, nuclear and biomass power capacity in the modelled systems to maintain a secure supply of energy. However, the use of thermal assets may significantly vary across the years: a significant amount of thermal capacity is needed in some years to secure electricity supply and cover peak demand, while in other years some plants may remain unused.

Moving towards zero-emission seasonal flexibility services

Annual grid emissions in the modelled high-VRE systems range from 15 gCO_2/kWh (Continental) to 50 gCO_2/kWh (Tropical). Achieving these levels would represent a 90-97% reduction from current global average grid emissions of 460 gCO_2/kWh. However, as energy systems transition towards net zero emissions, services from unabated fossil fuel power plants must eventually be replaced by other forms of flexibility that do not emit CO_2.

The use of low-emission fuels such as hydrogen and ammonia can provide decarbonised long-duration flexibility resources, while simultaneously maintaining all services of the existing fleet. However, the current high cost of low-emission hydrogen and ammonia as a fuel remains a critical barrier to their wider use. While countries are starting to build relevant infrastructure, investments in fuel transport, storage and supply assets need also to significantly accelerate.

Meanwhile, synergy opportunities with other sectors exist, for example in terms of shared infrastructure costs. Low-emission fuels have several potential applications and can play an important role in decarbonising industry and maritime transport. Increasing demand for hydrogen and hydrogen-derived fuels can therefore reduce costs, thanks to scale benefits, technology learning and shared infrastructure.

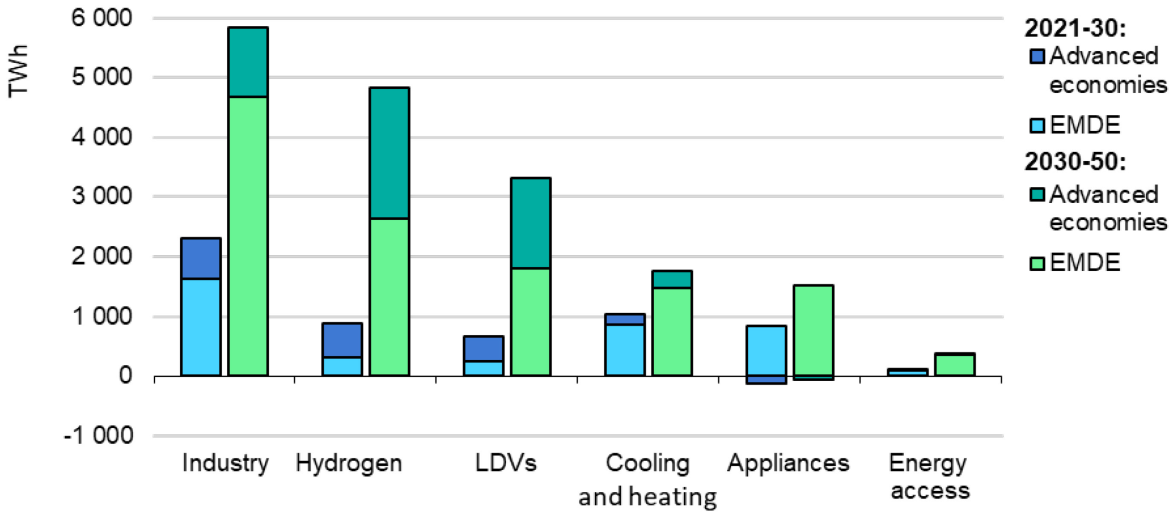
Chapter 1. Introduction

Electricity plays a fundamental and growing role in our economy, supporting many aspects of daily life. While electricity currently accounts for about 20% of total final consumption, this share increases sharply in the scenarios presented in the 2022 IEA World Energy Outlook – from 25% in the Stated Policies Scenario (STEPS) to 40% in the Announced Pledges Scenario (APS) and 50% in the Net Zero Emission (NZE) Scenario by 2050. The rising share of electricity in final consumption is central to clean energy transitions and puts electricity security concerns even closer to the heart of energy security.

The factors behind rising energy demand

Two major factors drive the increase in electricity demand in these scenarios. First, emerging market and developing economies (EMDE) increase their consumption in line with strong economic growth. Electricity demand in EMDEs grows by 60% from 2021 to 2030 in the APS, versus roughly 20% growth in advanced economies.

Figure 1.1 Drivers of electricity demand growth in the Announced Policies Scenario, 2021-2050



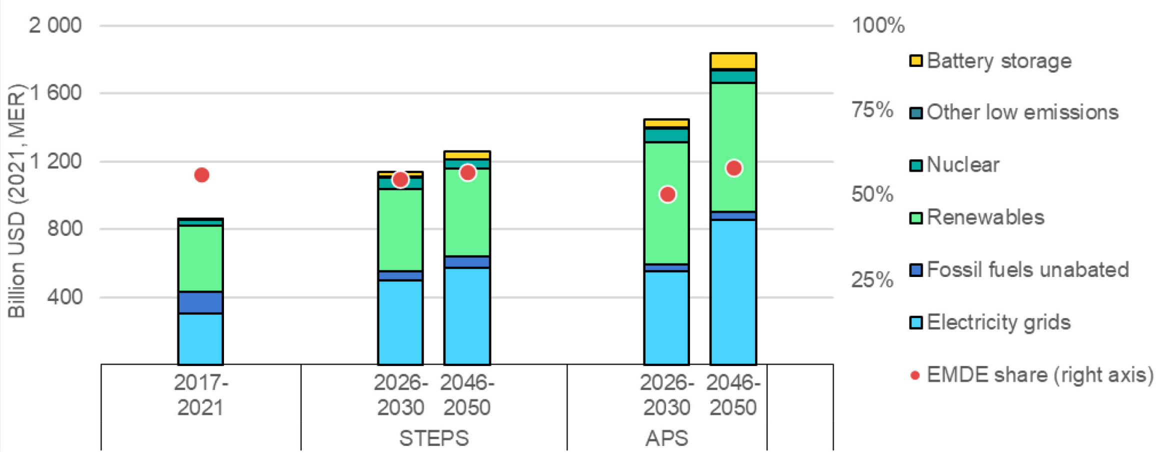
Note: LDVs = light duty vehicles; EMDE = emerging market and developing economies.
Source: International Energy Agency (2022), World Energy Outlook 2022.

Secondly, end uses that are currently served directly by fossil fuels are increasingly electrified. Industries are the biggest drivers of electricity demand growth in the APS, followed by hydrogen production and light duty vehicles (LDVs). In the transport sector, global electricity demand expands more than three-fold in the next decade under the APS.

Investments in renewables increase to meet demand

The policy reaction to Russia's invasion of Ukraine has driven renewables into an accelerated growth phase as countries seek to capitalise on both their economic and energy security benefits. Over the next five years, the world is set to add as much renewable power capacity as it did in the previous two decades. By 2025, renewables are expected to overtake coal as the largest energy source for electricity generation.

Figure 1.2 Average annual investment in the power sector by type and scenario, 2017-2050

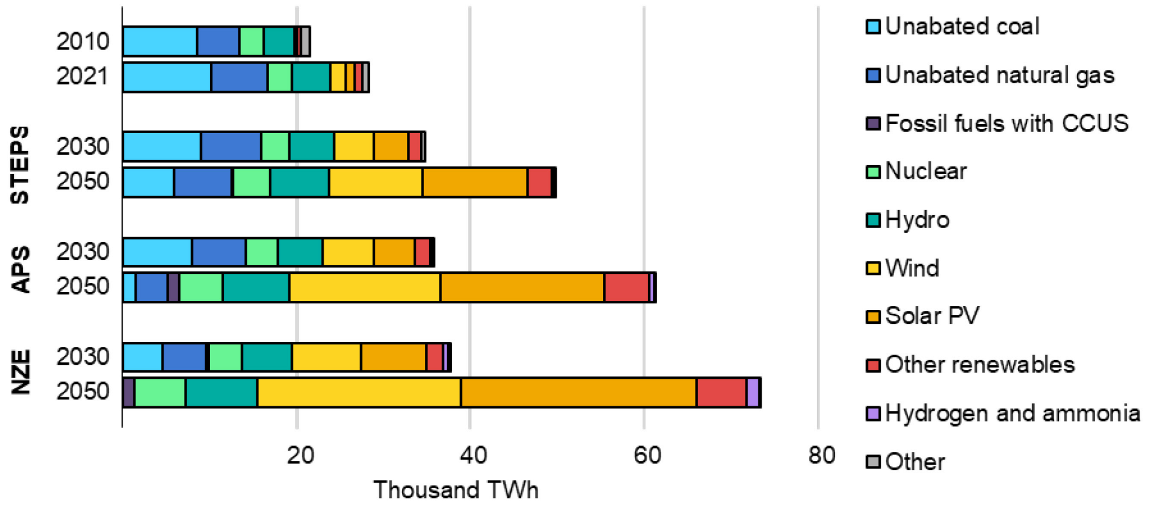


Notes: MER= Market Exchange Rates; EMDE = emerging market and developing economies.
Source: IEA (2022), World Energy Outlook 2022.

Renewable energy technologies such as onshore wind and solar photovoltaic (PV) remain the cheapest option for new electricity generation in most countries – even without considering the exceptionally high prices seen in 2022 for coal and gas. There is also further scope for cost declines in wind and solar production due to economies of scale and improvements in the technology and manufacturing process. In the APS, the levelised cost of electricity for solar falls from USD 50/MWh in 2021 to USD 30/MWh in 2030 and USD 25/MWh in 2050 in the United States. Accordingly, these technologies attract a large share of new investments, which for renewables amount to around USD 630 billion per year under the APS. At the same time, the scenario sees investment in unabated fossil fuels declining from around USD 120 billion in the 2017-2021 period to around USD 40 billion in 2026-2030.

This leads to renewables becoming the dominant source of electricity worldwide in the long term. In 2021, renewables – including wind, solar PV, hydro, bioenergy, concentrated solar power, geothermal and marine – accounted for around 28% of global electricity generation. Under the APS, this share rises to around 49% by 2030 before reaching 80% in 2050.

Figure 1.3 Global electricity generation by source and scenario, 2010-2050



Notes: Other renewables include bioenergy and renewable waste, geothermal, concentrating solar power and marine power. CCUS = carbon capture, utilisation and storage. PV = photovoltaic.
Source: IEA (2022), World Energy Outlook 2022.

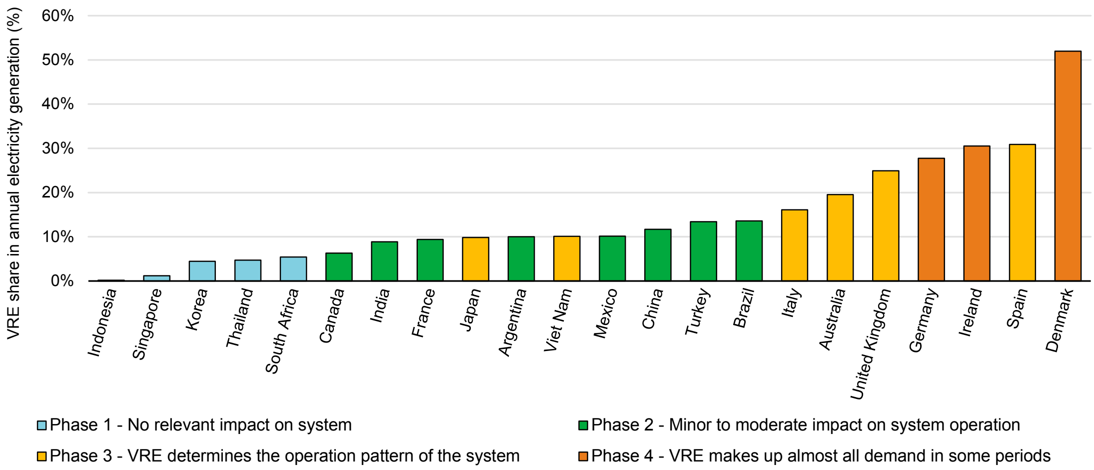
Flexibility needs will change as a result of higher shares of renewables

The rapid growth in the penetration of wind and solar PV in electricity systems requires careful consideration of the effects of the variability and uncertainty of their output to ensure cost-effective and secure integration. No two systems are the same in terms of size, legacy infrastructure, solar and wind potential, or flexibility resources, and there are no simple rules that link a certain annual share of variable renewables (VRE) with specific integration actions or costs. However, the potential impacts of variable renewables on system operation can be categorised according to the characteristics just described, as well as operational practices and standards, demand patterns and market and regulatory design.

The IEA uses a framework that classifies VRE integration into six specific phases that cover the main issues that are experienced as penetration of wind and solar PV increase. The phases are conceptual and intended to help set the order of priority for institutional, market and technical activities. For example, issues related to flexibility will emerge gradually in Phase 2 before becoming the hallmark of Phase 3. Two countries may be in different phases even though they share a similar annual VRE share of electricity generation.

Thanks to the use of various flexibility resources, countries have been able to successfully integrate variable renewables into their electricity systems. Many systems are still in Phases 1 and 2 with less than 15% shares of VRE in annual electricity production, including large systems like Korea, France, India, China and Brazil. Japan has recently moved from Phase 2 to Phase 3. A few European countries are already in Phase 4, where VRE can meet almost all demand in a given period. These include Germany, Ireland, and Denmark.

Figure 1.4 Tracking progress on variable renewables integration by country, 2021



Note: Phase assessments are based on the load curve and the availability of renewables generation and are influenced by factors such as load shape, interconnection and wind and solar shares. Regions within one country can be at a higher or lower phase than the national phase. Annual variable renewables generation shares for whole countries are based on 2021 estimates from Renewables 2022, Electricity Market Report 2023 and Monthly Electricity Statistics.

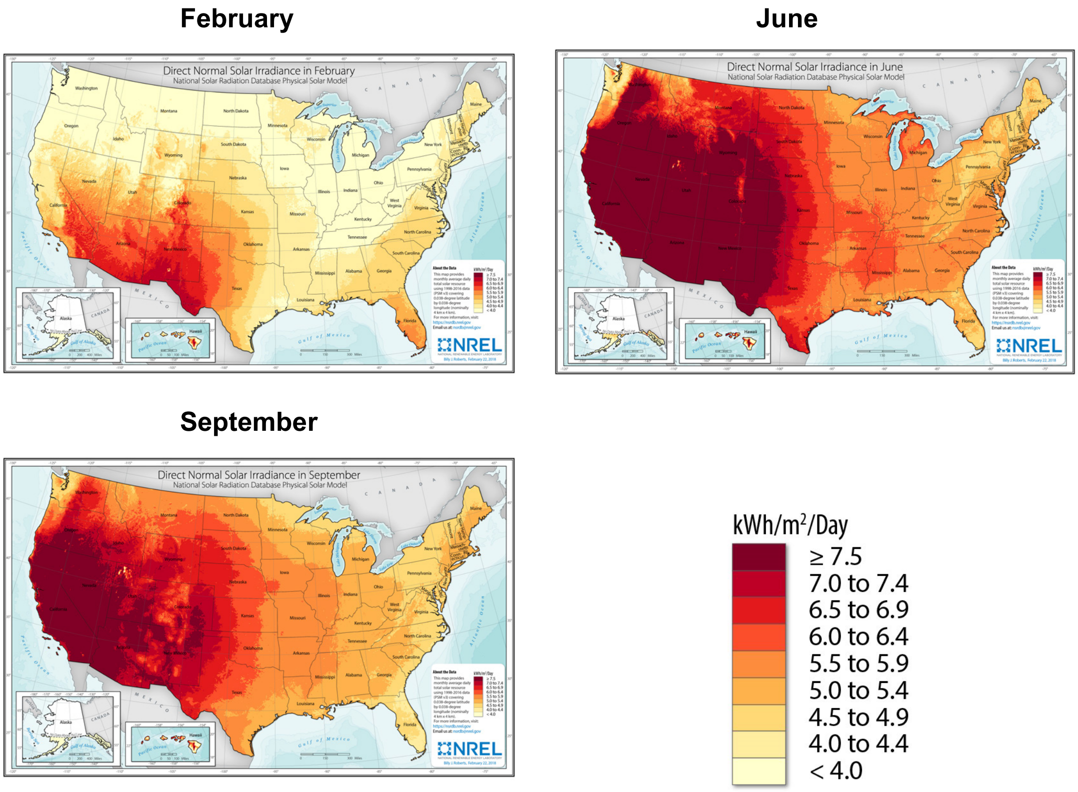
Integration issues experienced in Phases 5 and 6 are mainly associated with increasingly longer periods of surplus or periods of low electricity production from variable renewables extending from days to months and beyond.

Variability on a seasonal timescale

Climatic conditions, or weather averages over decades, greatly affect the production of renewable generation across all timescales, including seasonally. Climate is more predictable than weather. For example, in many California desert locations, the wind blows more frequently between April and October as the extreme heat of the Mojave Desert causes the hot air to rise and be replaced by cooler, denser air above the

Pacific Ocean. Solar insolation – the amount of solar radiation received on a given surface – is greatly affected by seasonal weather patterns.

Figure 1.5 Solar resource maps by month, United States



Source: NREL (2022)

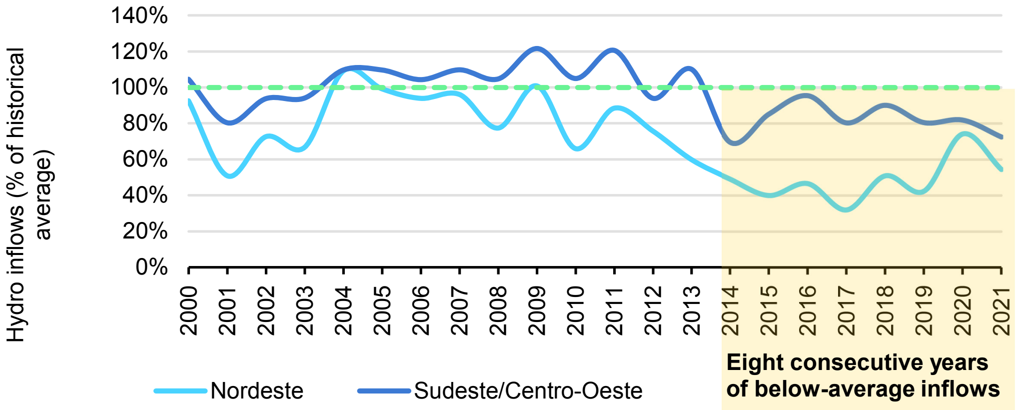
Besides seasonal variation, some weather patterns cause variation to extend to multi-year timescales. The amount of solar radiation that reaches the surface varies widely from year to year at some locations, due to variations in cloud cover and atmospheric aerosol loading. For wind resources, the monthly and annual changes respond to large-scale atmospheric circulation patterns, such as the El Niño-Southern Oscillation (ENSO) or the North Atlantic Oscillation (NAO). Wind resources are also subject to anomalies, such as the record-low-wind conditions experienced by vast swaths of the United States in 2015, which have been linked to an unusual ocean warming event in the northeast Pacific. During this roughly 6-month "wind drought," wind speeds over much of the US slowed to between 6% and 20% of their long-term average – eclipsing any previous event since 1979 in terms of both longevity and geographic breadth. A similar event occurred in 2021, when parts of Northwest Europe – particularly the United Kingdom and Ireland – experienced their lowest annual average wind speeds since at least 1979.

A global analysis of wind and solar resources found that, between 1980 and 2016, the monthly mean of solar radiation varied by as much as 11%, while wind speed varied by as much as 8%. While average variability was lower over land than over oceans during this period, those countries and regions that are currently investing heavily in solar and wind energy generation (e.g. India, China, Western Europe and the US) were the ones that experienced above-average variability. On land, solar variability was found to be lowest in the middle latitudes compared to high and low latitudes, while wind variability peaked at high latitudes. Since solar radiation has a linear relationship with solar generation, variation in generation closely resembles fluctuations in radiation. However, wind speed has a cubic relationship with wind generation, so variability in wind generation can be expected to be larger than that of wind speed.

Hydropower generation is dependent on precipitation – either from rain or runoff from snowmelt that is released into river systems – which can vary widely from year to year, affecting the generation potential of renewables. In most climate models, variability in precipitation also increases over a majority of the global land area in response to warming. Hydropower plants – including reservoir, run-of-river and pumped-storage – provide flexible generation for intervals ranging from less than a second to months. They also provide long-term energy storage.

Despite its value as a flexible resource on a wide range of timescales, hydropower can experience significant interannual variability due to changes in inflow caused by variation in precipitation and also temperature that alters the pattern of snowmelt runoff. In 2021, hydroelectric power generation in the Pacific Northwest and California dropped below the 10-year (2011-2020) average by 14% and 48%, respectively. Multi-year climate phenomena can also lead to persistent shortfalls. In Brazil, hydroelectric inflows have been below average for the last eight years, falling to as low as 30% of normal in 2017 in the Nordeste region.

Figure 1.6 Hydro inflows in Brazil by region



Source: Empresa de Pesquisa Energética (2022).

Reservoirs can help to balance generation between wet and dry years, but only to a certain degree. The total volume of storage is limited by geological factors, as well as other competing uses like irrigation, navigation, flood control, recreation and fish and wildlife protection. For example, on the Columbia River System in the US Pacific Northwest, the total water storage volume is equal to 30% of an average year's runoff. However, critical events include typically three or more consecutive years with lower-than-average generation.

Choosing the right mix of flexibility options that address the needs across all timescales will be critical to avoid the negative impacts of seasonal and interannual variability. This will become an increasingly higher priority for power system planning and operations as systems reach higher stages of renewables integration.

Chapter 2. Technology review

Electricity grids today operate very much like they did at their inception, more than 100 years ago. Grid operators need to maintain instantaneous balance between supply and demand to ensure system stability, measured by frequency. This includes managing uncertainties like changes in overall demand levels in response to variables like weather conditions, the time of day and the day of the week, as well as contingencies like a sudden loss of a large transmission or generation facility. In extreme cases, lack of frequency control can lead to cascading system blackouts, when facilities intentionally disconnect from the grid to avoid damage caused by under- or over-frequency. However, maintaining electricity security as power systems transition to more variable energy sources calls for new tools and approaches to help manage this variability and uncertainty.

There are four main sources of power system flexibility: power plants, grids, demand-side response and energy storage. Thermal power plants provide key flexibility and other system services (e.g. inertia and ramping) that contribute to the security of electricity supply. In countries where they are present, nuclear power plants or hydropower also provide critical flexibility services. Reinforced power grids – including additional alternating current (AC) and long-distance High Voltage Direct Current (HVDC) interconnections – diversify the portfolio of supply options. Battery storage helps to balance the daily variation of solar PV and provide other system services. New forms of energy storage are also being developed, including thermal and gravity-based solutions. The expansion of electricity to new uses will reshape demand patterns and has the potential to increase the variability of demand, although new sources of flexibility are also emerging in the form of demand response, especially for short-term flexibility. Demand response will benefit both from technological developments and from behavioural changes. Energy efficiency and sector coupling will also play a role in synchronising demand patterns with supply.

As energy systems transition towards net zero emissions, flexibility services from unabated fossil fuel power plants need to be replaced with sources that produce fewer carbon emissions. Possible candidates for replacing long-duration flexibility services include low-emission thermal generation and long-duration energy storage technologies, which will be discussed in this chapter. The role of demand response will also be highlighted. (Detailed discussions of the roles played by grid interconnections and smart grids appear in separate IEA publications.)

Decarbonisation options for fossil fuel power plants

Dispatchable generation, particularly from thermal power plants, is currently the dominant source of system flexibility for both short- and long-duration timescales. Dispatchable generation can be cycled up and down to manage variability and uncertainty in supply and demand. This can take the form of "peaker plants" that operate only during periods of high net demand for electricity – either dedicated new facilities that respond quickly to changing demand, or older plants that run less efficiently but are maintained as providers of emergency capacity. Legacy power plants that will be used as peakers do not require the capital investment of new plants, but their maintenance and staffing costs still must be accounted for despite their low rates of utilisation.

The ability to combust high shares of low-emission hydrogen and ammonia in fossil fuel power plants provides countries with an additional tool for decarbonising the power sector, while simultaneously maintaining all services of the existing thermal power fleet. Technologies are progressing rapidly. Co-firing up to 100% of ammonia and more than 90% of hydrogen in mixes with natural gas has taken place successfully at small scale, and larger-scale demonstration projects are under development. Biogases, especially biomethane, are drop-in solutions for turbines, while solid biomass feedstocks are already used to decarbonise coal power plants at industrial scale.

Low-emission fuels for gas turbines

Low-emission **hydrogen** can be produced from fossil fuels with carbon capture, utilisation and storage (CCUS) or via electrolysis of water using low-emission electricity. Other hydrogen-derivative fuels are also considered low-emission fuels when produced from low-emission hydrogen.

Electricity generation from hydrogen is technically available today in co-firing operation. Some current designs of reciprocating gas engines are capable of operating on hydrogen-rich gases up to 70% on volumetric basis. Various manufacturers are developing new engines using 100% hydrogen, and existing engines are being tested to increase their hydrogen blending capacity.

Gas turbines have been operating on industrial hydrogen-rich off-gases for many years in steel-making factories and oil refineries. State-of-the-art turbines control their emissions using dry low nitrogen oxides (DLN) burners, which allow for mixtures with natural gas in the range of 30% to 60% by volume depending on the turbine model. A key challenge of mixtures that are rich in hydrogen is flame temperatures, that are almost 300°C higher than for methane and may lead to modification requirements in the combustion chamber. Apart from the combustion system, the introduction of hydrogen as a fuel requires modifications in piping, valves, control systems and fuel storage, and more strict ventilation and enclosure systems due to safety requirements. Hydrogen leakages need to be closely monitored, as hydrogen has a higher tendency to leak through pores, fittings or seals than methane, and has an indirect warming effect on climate.

Gas turbine manufacturers are developing new models and integration accessories as well as carrying out tests to retrofit and increase the capacity to use hydrogen in existing facilities (see Table 2.1). Tests in small equipment have already proved 100% hydrogen combustion, while use in existing industrial equipment, such as in combined cycles, is expected to be possible by 2025.

Some companies have published strategic plans to run their power plants with hydrogen. In early 2023, the German company RWE announced plans to build new gas power plants in Germany and run them initially on a mix of half hydrogen and half methane, ramping up to 100% hydrogen by the mid-2030s. The hydrogen would be produced by Equinor – initially from natural gas reforming, coupled with carbon capture and storage, and later as renewable hydrogen – and transported by pipeline from Norway.

Another alternative for electricity production from hydrogen is to use stationary fuel cells. They have the advantages of higher electrical efficiency (50% to 60%), good performance in part-load operation, and being faster to ramp up and down. Hydrogen fuel cells, however, represent a tiny share of stationary fuel cells today, with only around 90 megawatts of global installed capacity, and would require significant investment in new plants. Fuel cells also require high-purity hydrogen.

Table 2.1 Development status and industrial tests of hydrogen co-firing in large-scale gas turbines

Project	Description	Status	Location
FLEXnCONFU	European consortium developing power to fuel to power solutions	Ongoing	Five testing sites in Europe
Hydrogen to Magnum	Aims to convert 440 MW gas turbine to 100% H_2 by 2025	Announced	Netherlands
GE	25 gas turbines operated on fuels with at least 50% (by volume) hydrogen	In operation	Various locations
EnergyAustralia	Over 300 MW gas turbine plants with blending of H_2 by 2024	Announced	Australia
HyFlexPower	Modification of a 12 MWe CHP unit for hydrogen firing	Ongoing at pilot scale	France

Project	Description	Status	Location
Long Ridge Energy Terminal	Transition of 485 MW combined-cycle power plant to co-firing 5% hydrogen with intention to reach 100% over next decade	First phase completed	United States
Hydrogen Power South Australia	The Hydrogen Jobs Plan announced by the government includes construction of 200 MW power plant running on H_2, plus electrolysers and H_2 storage	Announced, expected to operate by 2025	Australia

Due to hydrogen's low volumetric density – and therefore high transport and storage costs – more easily transportable derivatives like **ammonia** are being developed. Ammonia is a well-known commodity that can be transported and stored using commercially available technologies, and when it is produced from low-emission hydrogen, it is also itself a low-emission fuel. Although ammonia can be re-converted back into hydrogen and nitrogen before end-use, it can also be burned directly in gas turbines or reciprocating engines. Direct combustion of ammonia avoids efficiency losses associated with its reconversion back to hydrogen (around 20%), but can lead to a significant increase in nitrogen oxides (NOx) emissions if not properly addressed. Partial cracking of ammonia to hydrogen represents an intermediate approach that offers some advantages in combustion applications. As hydrogen flammability is greater than that of methane, and ammonia's is lower, the cracked mixture of ammonia, hydrogen and nitrogen has better combustion characteristics for gas turbines than pure ammonia, with a lower risk of high NOx emissions. A new development by Mitsubishi Heavy Industries is looking at integrating ammonia cracking upstream of the gas turbine, using heat from the turbine exhaust gases. The resulting hydrogen-rich mix would then be combusted in the gas turbine.

Tests to demonstrate ammonia direct co-firing in gas turbines at a commercial scale, without an upstream cracking to hydrogen, are also being conducted. Japanese IHI demonstrated direct ammonia co- and mono-firing in a 2-megawatt natural gas turbine in 2022. In this configuration, liquid ammonia is directly sprayed, which allows for reduced energy consumption compared to using previously vaporised ammonia. A new combustor was developed to allow co-firing ratios above 70%. Ammonia does not contain carbon and thus does not emit CO_2 when combusted. However, at concentrations above 70% there is a high possibility for N_2O formation that needs to be controlled to a very low level (Nitrous oxide has a global warming potential 273 times that of CO_2 for a 100-year timescale). Further optimisation regarding additional reductions of NOx is underway. Other tests in bigger machines are being conducted, and Mitsubishi is expected to test mono-firing by 2025 in a 40 MW turbine. Ammonia can also be used in reciprocating engines. Some examples of ongoing development work are compiled in Table 2.2.

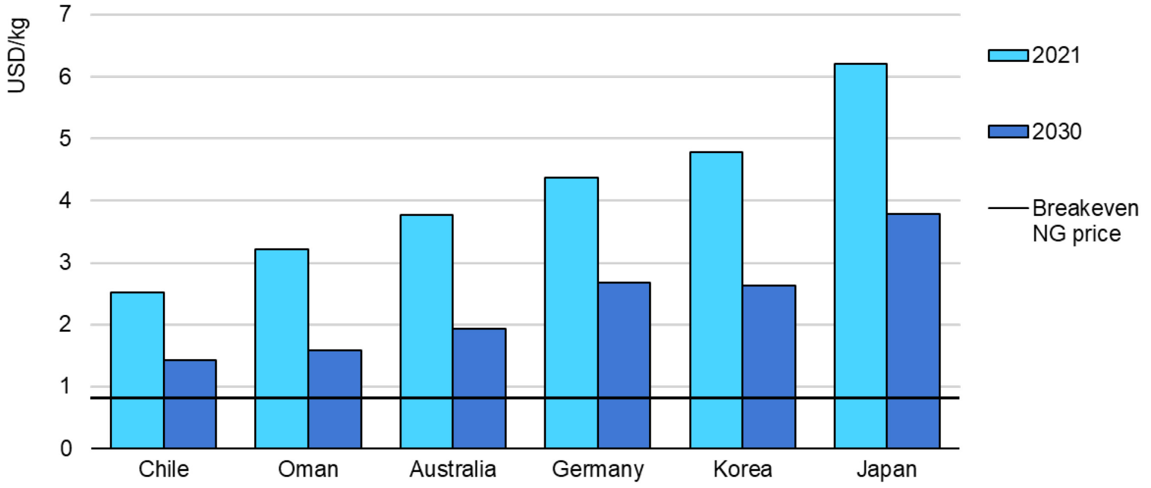
Table 2.2 Development status and industrial tests of ammonia co-firing in large-scale gas equipment

Project	Description	Status	Location
IHI Yokohama	Test to increase ammonia ratio in 2 MW gas turbine	70% co-firing ratio achieved in 2021 and 100% in 2022	Japan
Mitsubishi Heavy Industries	Tests in 40 MW gas turbine	100% by 2025 in small and medium models	Jurong Port, Singapore
Mitsubishi Heavy Industries	Developing NH_3-fired gas turbine by 2024, and NH_3 cracking to H_2 with turbine exhaust heat by 2025	Announced	Japan
Wärtsilä	Reciprocating engines	70% co-firing ratio achieved in 2021	Finland

Natural gas power plants can also use biogases as alternative fuels. Biomethane can be used as a drop-in fuel with existing infrastructures and equipment. There is also commercial equipment available for combusting biogas without upgrade to biomethane. Other biofuels that are being used or considered for power generation are ethanol or methanol. Since 2010, Petrobras operates an 87 MW power plant in the Brazilian state of Minas Gerais using sugarcane ethanol. The conversion of the natural gas fired technology was supported by General Electric.

Very few countries have set explicit targets for the use of hydrogen or hydrogen-derived fuels in the power sector. Japan is one of the few exceptions: it is aiming to reach 1 gigawatt (GW) of power capacity based on hydrogen by 2030, which corresponds to an annual hydrogen consumption of 0.3 metric tonnes (MT). Over the longer term, the goal is to increase capacity by 15 to 30 GW, which corresponds to annual hydrogen use of 5 to 10 MT. In its hydrogen roadmap, Korea has set a target of 1.5 GW installed fuel cell capacity in the power sector by 2022, and 15 GW by 2040. Meanwhile, several countries have recognised the potential of hydrogen as a low-emission option for power generation, e.g. to provide flexibility for an energy system with high shares of VRE.

Figure 2.1 Production cost estimates for electrolytic hydrogen from wind and solar PV in selected countries in 2021 and 2030



Note: Results for electrolytic hydrogen are based on a dynamic optimisation of the wind/PV mix for the electrolyser. The following key assumptions were used: WACC 3.5%-4.7% depending on the country, electrolyser efficiency (LHV): 65% (2021), 69% (2030), electrolyser CAPEX: USD 1500/kW$_e$ (2021), USD 320/kW$_e$ (2030), electrolyser OPEX 3% of CAPEX, technical lifetime 25 years. Levelised cost of hydrogen includes compression but does not include storage or transport to the final use point. Breakeven NG price is the hydrogen-equivalent cost of natural gas at USD 4/GJ and USD 50/t CO_2 carbon price.

Low-emission hydrogen can be produced from low-emission electricity via electrolysis, from fossil fuels with CCUS and from sustainable biomass. Natural gas with CCUS is currently the lowest-cost production route, but significant increases in the price of natural gas in 2021 and 2022 have also affected the cost of hydrogen.

Production costs for the electrolytic route are decreasing rapidly due to continuing reductions in the installed cost of renewable electricity and economies of scale in electrolyser manufacturing. Different countries and regions can have different production costs depending on the quality of their renewable resources. The cost of electrolytic hydrogen from wind and solar PV ranges today from USD 3 to USD 6/kg depending on the location. By 2030, costs are estimated to decline to USD 1.5 to USD 4/kg. Despite expected cost reductions, low-emission hydrogen in 2030 will remain significantly more expensive than the projected cost of natural gas, even with a moderate carbon price (see Figure 2.1).

Low-emission fuels for coal power plants

Existing coal power plants can use several alternative fuels: Solid biomass, ammonia, and methanol have all been successfully used with coal, for example.

Co-firing of **sustainable biomass** with coal has been developed and practised for more than 20 years, first in Western Europe and North America and now in Asia.

The most common types of biomass that have been co-fired with coal are wood, agricultural residues, grasses and energy crops. Since relatively high co-firing shares can be achieved with biomass, it provides a quick way to reduce the use of fossil fuels at existing large-scale power plants at capital costs that are much lower than investment in a new thermal power plant.

Key technical options for the conversion of large, pulverised coal (PC) boilers to the firing and co-firing of biomass have been successfully demonstrated and remains the most popular method for co-firing in countries such as Japan and South Korea. In China, meanwhile, co-firing via gasification has been preferred.

Waste materials, agricultural residues and cereal straws are relatively inexpensive feedstock options, but tend to have higher ash content and more problematic ash compositions. They can therefore be used at only modest co-firing ratios. Feedstocks based on clean wood tend to have lower ash content and can be used at higher co-firing ratios. For 100% direct biomass firing, only the higher grade and more expensive wood materials are currently suitable. Solid biomass pellets are usually the preferred form of solid biomass for this application. With additional investment, higher rates of various types of biomass co-firing are possible. Higher co-firing shares usually require more expensive modifications, such as better handling systems, dedicated mills and biomass burners, boilers with improved corrosion resistant alloys and larger spacing sections, or biomass gasifier pretreatments.

The conversion of coal power plants to 100% biomass firing can be carried out either in a relatively short period of time, or gradually over the course of many years. Drax power station in the United Kingdom is an example of converting a large-scale coal-fired power plant to 100% biomass firing through several intermediate stages.

In December 2022, India's largest power utility company, NTPC Limited, signed a memorandum of understanding with GE Power India to develop technologies for gradually replacing coal with alternative fuels. A first goal is to co-fire biomass pellets above a 20% ratio and continue up to 100%. The agreement will also explore co-firing of methanol and ammonia.

Ammonia can be co-fired directly in pulverised coal boilers. As in co-firing with natural gas, one of the main technical challenges is related to keeping NOx formation at very low levels. NOx emission levels are regulated for environmental and health reasons. NOx emissions need to be effectively minimised also due to their high global warming potential. Research is ongoing on this subject. For example, tests performed by the Japanese company IHI showed that ammonia injected into specific combustion zones could help reduce NOx formation, and 20% ammonia co-firing would lead to the same or lower NOx emissions than in the case of 100% coal firing.

Some coal power plants have announced their intention to explore co-firing with ammonia. For example, the Indian company Adani Power Ltd. and the Japanese firms Kowa and IHI signed a memorandum of understanding in 2022 to start 20% ammonia co-firing with coal, with a view to transitioning towards 100% ammonia firing.

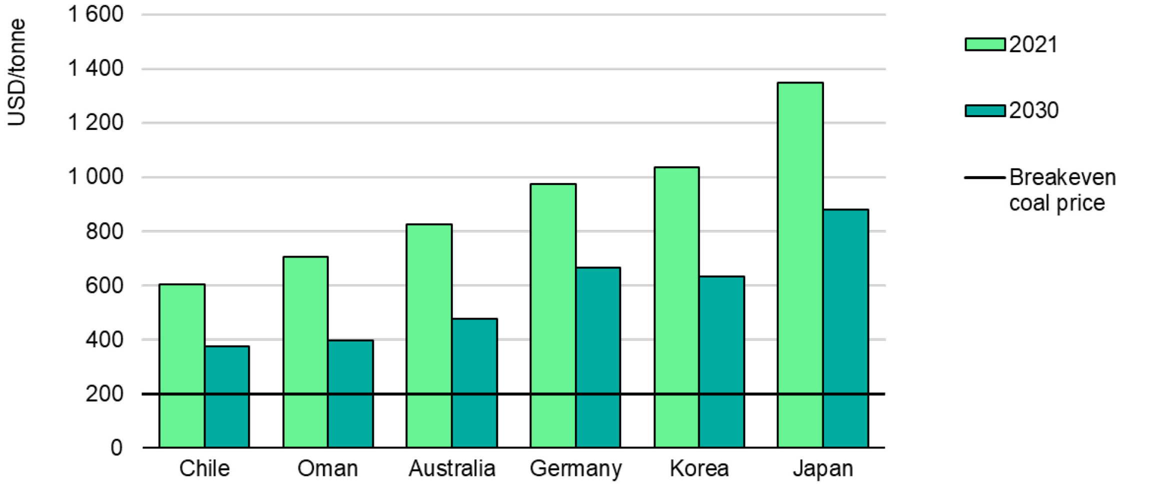
Table 2.3 Development status and industrial tests of ammonia co-firing in coal plants

Project	Description	Status	Location
JERA Hekinan thermal plant, collaboration with IHI	Large-scale testing on 1 GW plant for 20% of NH_3 co-firing	Tests to start 2023. Burners, tank and pipes already installed	Japan
Mitsubishi collaboration with JERA	Develop a new burner for coal boilers	Demonstrate 50% co-firing burners by 2028 and 100% in the future	Japan
Guacolda power plant, Mitsubishi Heavy Industry technology	MoU to conduct feasibility study and start tests on 30% NH_3 in the 758 MW plant	Tests expected to start in 2026	Chile

Ammonia is usually produced from reformed natural gas hydrogen by reacting it with air using the well-known Haber-Bosch process. In the case of using renewable hydrogen, an additional air separation unit is needed to produce nitrogen for the reaction. Reductions in the cost of hydrogen will also reduce the cost of ammonia, although on an energy-basis ammonia will remain more expensive due to the additional investments needed for its production and to the efficiency losses that incur during the conversion.

The cost of electrolytic ammonia from renewables ranges today from USD 600 to USD 1 300/tonne depending on the location. By 2030, costs are estimated to decline to USD 400 to USD 900/tonne. Despite cost reductions, the cost of low-emission ammonia in 2030 will remain significantly higher than the projected cost of coal, even with moderate carbon price (see Figure 2.2).

Figure 2.2 Production cost estimates for electrolytic ammonia from wind and solar PV by selected country in 2021 and 2030



Note: Results for electrolytic ammonia are based on a dynamic optimisation of the wind/PV mix for the electrolyser. The following assumptions were used for the ammonia production from hydrogen: Haber-Bosch synthesis CAPEX USD 41/GJ/yr, OPEX 3% of CAPEX, synthesis efficiency 86% (LHV). Levelised cost of ammonia cost does not include storage or transport to the final use point. Breakeven coal price is the ammonia-equivalent cost of coal at USD 150/tonne and USD50/tCO_2 carbon price.

Transport and storage of hydrogen and ammonia

A broader global use of hydrogen and ammonia, including a potential future use in thermal peaker plants, will require a development of the hydrogen supply chain, with main challenges in transport and storage steps. For distances shorter than 2 500 km, onshore and offshore pipelines are expected to be the most efficient and least costly solution. Repurposing existing natural gas pipelines for hydrogen can lower investment costs by 50% to 80% relative to new builds. Several plans to build new pipelines have also been announced, such as the Mediterranean hydrogen pipeline project, that will link renewable hydrogen production from Portugal and Spain to the rest of Europe or the pipeline to connect Norway and Germany.

For greater distances, it will be essential to develop ships and associated port infrastructure. Hydrogen can be transported either in the form of liquid hydrogen, ammonia or as a liquid organic hydrogen carrier (LOHC). Liquid hydrogen tankers are not yet commercial, although their design could benefit from existing experience with LNG tankers. Marine transport of compressed hydrogen is also being studied.

In contrast to hydrogen, the transport and storage of ammonia is commercially available due to its widespread use as feedstock for fertilisers. Ammonia is shipped in refrigerated, non-pressurised tankers, similar to the ones that carry liquified petroleum gas (LPG). Pipeline transport is widely used in some regions.

Ammonia can be stored in a liquid state at -33°C or under pressure at 8.6 bar. Currently, the largest refrigerated tank is in Qatar and has a capacity of 50 kt. Hydrogen storage presents more challenges due to its low volumetric density and low boiling point of -253°C. Today hydrogen is mostly produced onsite for direct use. For large-scale and long-duration storage, salt caverns could present a low-cost solution and several examples are in operation. Depleted natural gas fields are also being studied for hydrogen use, but their higher porosity presents a challenge. Lined rock caverns are also being tested for large-scale hydrogen storage.

Retrofitting with CCUS

Retrofitting power plants with CO_2 capture equipment can enable their continued operation in a low-emission energy system, as well as the operation of associated existing infrastructure and supply chains, but with significantly reduced emissions (85% to 99% lower than unabated power plants). In addition to adding capture equipment at the power plant, CO_2 transport and storage infrastructure needs to be built to handle and geologically store the captured emissions.

To date, CCUS[1] has been applied to four commercial power plants: Petra Nova in the US state of Texas, Boundary Dam in Canada and Energy Guohua Power Jinjie in China (all coal-fired, retrofitted plants) and Mikawa Power Plant in Japan, a biomass-fired retrofitted facility. This involves adding a capture unit to separate CO_2 from the flue gases to avoid it being released to the atmosphere. The most cost-effective approach today is absorption of CO_2 by amine-based solvents that are regenerated by heating, which liberates the absorbed CO_2 so it can then be compressed for transport and storage. To avoid contamination of the solvent, the flue gas needs first to undergo flue gas desulphurisation (FGD).

The cost of a CCUS retrofit depends greatly on the individual plant. Detailed engineering studies show that retrofitting a coal-fired power plant today could have a cost for the capture step of around USD 45/t CO_2. There are now plans to equip more than 75 power plants with capture equipment globally. With further R&D and growing practical experience, there is considerable potential to further reduce energy needs and costs.

Captured CO_2 needs to be transported to suitable locations for use or permanent geological storage. Transport of large volumes of CO_2 in pipelines (average pipeline capacity range is between 3 and 30 $MtCO_2$/year) is a known and mature technology, with significant experience from more than 8 000 km of CO_2 pipelines

[1] Carbon capture and storage (CCS) includes applications where the CO_2 is captured and permanently stored. Carbon capture and utilisation (CCU) includes applications where CO_2 is used, for example in the production of fuels and chemicals. Carbon capture, utilisation and storage (CCUS) includes CCS and/or CCU.

in North America – mostly in the United States. For example, carbon dioxide is transported 66 km from the Boundary Dam plant in Saskatchewan, Canada. There is also experience, albeit limited, with transport of CO_2 using offshore pipelines, for instance at the Snøhvit project in northern Norway. In addition, CO_2 can be transported by barge, train and truck, but in small quantities and generally at a higher cost.

Long-duration energy storage

Energy storage can reduce imbalances between supply and demand by storing energy for later use. Long-duration energy storage (LDES) encompasses a range of technologies that can store energy for prolonged periods and is currently subject to extensive R&D activity.

Energy storage is considered long duration when it can store energy for more than 10 hours. This section reviews the status of different technologies that address long-duration storage, focusing especially on those that allow seasonal and interannual storage – that is, storage that lasts for weeks, months or years.

Pumped-storage hydropower (PSH)

Pumped-storage hydroelectricity is the main commercially available energy storage technology that can provide low-cost, long-duration and grid-scale storage today. PSH also provides short-term flexibility to the grid, and has more than 8 500 GWh of installed storage capacity, representing 96% of current global storage capacity. PSH can store energy by pumping water from a lower reservoir to an upper reservoir and then release it when needed by passing water through a turbine that generates electricity. The installation of PSH is expected to increase in the coming years, with an installed capacity of 11 700 GWh by 2026.

PSH can provide storage capacity for days or months, with long discharge times (from a few hours to a full week) and high discharge rates. (The biggest such facility, Fegning Pumped Storage Power Plant in China, has 3.6 GW power capacity and 40 GWh energy storage capacity, for example.) Construction costs for PSH are high, but they are compensated by very long operational life. Traditional PSH is limited geographically, however, due to specific site and environmental requirements.

Although pumped-storage hydro can currently only be used in certain locations, there is potential to increase PSH capacity by adding new units to existing reservoirs or non-powered dams. In countries with large reservoirs at different altitudes, this represents tens of gigawatts in potential capacity without the need to extend dams in current use. Other proposed configurations feature seawater reservoirs using the height difference in cliffs, existing underground reservoirs such as abandoned mines or oil and gas wells, or decentralised systems that use existing small water reservoirs and networks. Other innovative configurations propose pumping high-density liquids instead of water.

Compressed air energy storage

Compressed air energy storage (CAES) is another technology with potential for providing significant capacities, making it suitable for seasonal balancing if sufficient underground repositories are available.

CAES stores energy by compressing air, which can later be decompressed, generating electricity as it is discharged. Compressed air can be stored in fixed-volume reservoirs – e.g. empty salt caverns or vessels – or in variable-volume reservoirs, akin to underwater "balloons." Variable-volume vessels keep air at a constant pressure, which presents benefits for the rotating machinery, but are more expensive. Salt caverns are currently the most competitive place to store compressed air. If heat released during compression can be stored and used later during decompression, the so-called adiabatic CAES has the potential to achieve round-trip efficiencies up to 70%.

There are currently two large-scale CAES plants in operation: Huntorf, in Germany, (290 MW) started operations in 1978 and McIntosh, in the US state of Alabama, (110 MW) in 1991. Both use diabatic CAES, providing heat by burning natural gas. The new Jiangsu Jintan Salt Cavern plant (60 MW) in China, inaugurated in mid-2022, is designed with heat storage.

Other storage technologies under development

Gravitational energy storage (GES) is based on potential energy, in a similar way to pumped hydro energy. In this case, solid masses are generally used. Lifted Weight Storage (LWS) uses excess electricity to lift solid blocks vertically. When electricity is needed, a controlled decline of the weight produces electricity in a generator. Construction of a first commercial-scale plant designed by Energy Vault began in March 2022, in Shanghai, China. The plant will have a generation capacity of 25 MW and 100 MWh of storage in its first phase. In the future, the plant capacity can be increased by adding new modules without topological constraints.

Liquid air energy storage (LAES) uses electricity to cool down air until it liquefies at -196ºC, and stores it in a vessel under atmospheric pressure. Storing air in liquid form takes up only 1/1000th of the volume of air under atmospheric conditions. The storage is discharged by heating up the liquid and expanding it through a turbine to produce electricity. Either sensible heat from ambient air or waste heat from an external source can be used as a heat source. Cold generated during evaporation can be captured – for example in a large gravel bed – and using it in the next liquefying cycle can increase efficiency to around 50%. If waste heat is available at high temperature (e.g.115ºC), round-trip efficiency can reach up to 70%. LAES systems do not require specific location characteristics, but will benefit from existing sources of waste heat or unused cold (such us an LNG regasification plant). The UK company Highview Power is planning to build the first commercial-scale LAES plant, expected to come online in 2024 with 30 MW generation capacity and 300 MWh of storage.

Thermal energy storage (TES) is largely used for short-term energy storage. Although typical capacities are not as large as in other technologies, TES has the potential to retain heat for weeks or months, depending on the technology and the insulation. The most common storage media are solid beds, made of materials such as rocks, pebbles or ceramics, hot water tanks or molten salts (used for high-temperature storage, for example with concentrating solar power plants). Heat storage can reach temperatures as high as 1 500ºC and be used to produce high-temperature heat and steam.

Configurations that can store heat at a high temperature can produce electricity again when it is economically attractive. One interesting variant for storing and producing electricity is TES coupled with heat pumps. Such a system uses two tanks where the storage medium is kept at two different temperatures. At a time of high electricity prices, the cycle can operate in a reverse mode, producing electricity and sending it back to the grid. The overall system can produce electricity with very high round-trip efficiency, around 70% to 80%.

Other TES solutions, especially lower-temperature storage, have a low round-trip efficiency back to electricity, but are useful for electrifying heat demand and decoupling it from electricity supply. Using TES, the storage medium can be charged when electricity prices are low, and used to supply heat when needed, operating as a demand-response mechanism.

Comparison of LDES technologies

Realising the potential of long-duration energy storage hinges on innovation – to support both continued cost reductions and improved performance in commercially available technologies, as well as to ensure that the next generation of LDES technologies (now at the demonstration stage) reach timely commercialisation. Pumped hydro is commercially available, while the first large-scale demonstrators of adiabatic CAES are being built. Most other technologies are still in the R&D phase.

In 2020, the US Department of Energy (DOE) inaugurated the Energy Storage Grand Challenge. Its goal is to accelerate the development, commercialisation and utilisation of next-generation energy storage technologies. Key parameters of different LDES technologies are shown in Table 2.4. For comparison, chemical storage of electricity in the form of hydrogen or ammonia is also included in the table, considering the full power-to-fuel-to-power cycle from these fuels.

Table 2.4 Key parameters for long-duration electricity storage technologies

Technology	Power range	Storage capacity	Typical round-trip efficiency	TRL[2]
Pumped hydro	10 MW - 5 GW	0.2 - 0.5 GWh	70-85%	11
Compressed air (underground storage)	5 MW - 300 MW	0.2 - 1 GWh	41-75%	9
Thermal storage – low temperature	1 kW - 300 MW	n.a.	30-50%	8-9
Thermal storage – high temperature	1 - 60 MW	n.a.	80%	5-7
Gravitational	1 kW - 25 MW	100 MWh	80%	7
Electrolytic H_2 and gas turbine (GT) in combined cycle	Hundreds of MW	Unlimited	21%-27%	9*
Electrolytic ammonia and direct combustion in GT-combined cycle	Hundreds of MW	Unlimited	22%-24%	9*
Electrolytic H_2 and fuel cell	0.3 - 50 MW	Unlimited	30-50%	7-9

* In co-firing mode.

Demand-side response

Demand-side response can be used to reduce electricity use during times when supply is not enough to meet the demand. Demand response can contribute to grid stability and reduce the need for investment in energy storage. The progressive electrification of end-uses offers new opportunities for load shifting, with electric vehicles (EVs) and electric heating playing a major part. Under the STEPS and APS scenarios, demand-side response provides roughly a quarter of power system flexibility in 2050. In the NZE scenario, contribution from demand response rises to 500 GW in 2030, a tenfold increase from 2020 levels. Demand response is expected to come mainly from buildings, electrolytic hydrogen production, electric vehicles and industry.

As electrification of energy uses advances, the quantity and variety of electrical equipment that can adjust demand also increases. Meanwhile, the number of distributed-energy resources such as rooftop solar panels, small-scale wind generators or behind-the-meter battery storage also continues to grow. While this adds an extra level of complexity, it can also create new opportunities.

[2] Technology readiness levels (TRL) reference scale: concept development 1-2-3, small prototype 4, large prototype 5-6, demonstration plant 7-8, early adoption 9-10, mature technology 11.

Virtual Power Plants (VPP) are networks of aggregated, decentralised small- and medium-sized power generation units, flexible power consumers and storage systems. By aggregating, a VPP can provide services to the grid and also participate in the trade market in the same way that large power plants do. VPP can also serve as a source of flexibility for the system.

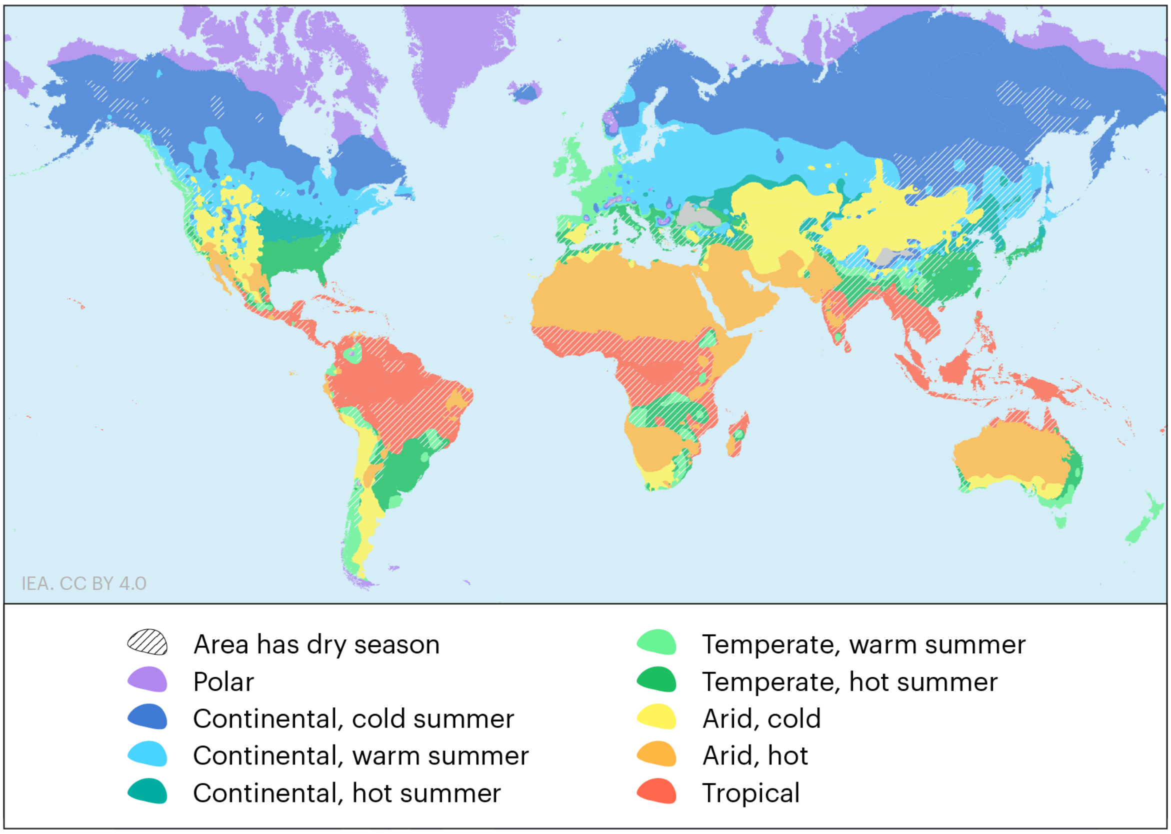
There are several examples of aggregated management of electrical equipment that can play a role in future energy systems. Electric vehicles connected to the grid with a vehicle-to-grid (V2G) technology can be controlled to selectively change the rate at which each individual vehicle is charging or even deliver electricity to the grid. In a similar way, aggregated heat pumps, air conditioners or electric water heaters can be selectively turned on and off to shift their demand.

Although demand response plays an important role in providing short-duration flexibility, its contribution to long-duration flexibility will be significantly lower. However, when coupled with long-term energy storage its services can extend to longer timescales.

Chapter 3. Seasonal variability

Climate is defined as the average weather over a long period of time, typically 30 years or more. Different climates can be grouped into zones based on threshold values and the seasonality of monthly air temperatures and precipitation. Such regimes are largely governed by latitude and therefore occur mainly along the east-west direction around the Earth. However, local conditions can be significantly altered by variables like terrain, altitude, land use and proximity to water bodies and ocean currents.

Figure 3.1 World climate classification map



Source: Beck, H., Zimmermann, N., McVicar, T. *et al.* (2018) "Present and future Köppen-Geiger climate classification maps at 1-km resolution", *Sci Data,* 5, https://doi.org/10.1038/sdata.2018.214

Climates can be classified by zone

The Köppen-Geiger classification recognises five main climate zones, which are temperate, tropical, arid, continental, and polar. These primary zones are further divided into 30 sub-types depending on temperature and seasonal precipitation (see Figure 3.1). In total, 40% of the world's population lives within the temperate zone, 30% in tropical, 20% in arid, and 10% in the continental zone. Average population density varies from 150 people/km^2 in the temperate zone, to 30 people/km^2 in the continental climate zone.

Climate sets the basic conditions for human societies and impacts regional energy systems in three major ways:

Temperature governs the size and seasonal profile of the energy demand through heating and cooling needs.

Precipitation governs the potential for hydropower generation through rain seasons and spring floods.

Wind strength and **solar radiation** patterns govern the availability of wind and solar resources.

The interactions between energy demand, hydro inflow, and the availability of wind and solar resources set the basic conditions for integrating renewables on a seasonal timescale. Integration is relatively easy in the seasonal context when the monthly energy demand is flat, the ratio of peak load to base load is small, there are sufficient reservoir hydro resources, and the aggregate amount of power generated from solar PV, wind and hydro helps to smooth out each other's variation.

In practice, most energy systems around the world extend across more than one climate zone. This is likely to increase the diversity of load and resource patterns within the system's area, leading to easier management of seasonal variability – so long as the grid is robust enough to enable transfers across regions. Population density and the size of energy-intensive industries is also an important boundary condition, as it directly influences the level of energy demand. At higher population densities, the average amount of renewables available per person is also lower, although the actual availability is highly dependent on local geography and overall conditions.

Modelling approach

Simplified "example energy systems" have been created to study seasonal variability in different climatic conditions and under a large range of technological parameters. The objective is to understand which flexibility sources are relevant in the different climatic zones when dealing with long-duration variability. The following climate zones are simulated: Temperate (sub-type: hot summer), Tropical, Arid (sub-type: cold), and Continental (sub-type: warm summer), and the main seasonal characteristics of these systems are summarised in Table 3.1.

Representative weather years for the example systems were compiled by collecting times series data for hydro, solar, wind resource availability, as well as electricity demand, from geographical areas that map to the desired climate regions. The model minimises the total cost of the system, including annualised investment costs. For more information on the model, data collection, technology parameters and cost assumptions, see Annex.

Table 3.1 Key seasonal attributes of examined example systems

Example system	Time series based on	Seasonal attributes			
		Demand profile	Peak load size	Hydro availability	Complementarity of wind and PV
Temperate, sub-type hot summer	Japan (Kansai province)		|||	■ ■	+
Temperate, sub-type dry season/arid*	Spain		||	■	+
Tropical	Costa Rica		|	■ ■ ■	–
Arid, sub-type cold	Peru (Coastal arid area)		|	■	–
Continental, sub-type warm summers	Poland		||	■ ■ ■	+

*Temperate (sub-type dry season/arid) example system is only discussed in the context of interannual variability in Chapter 4.

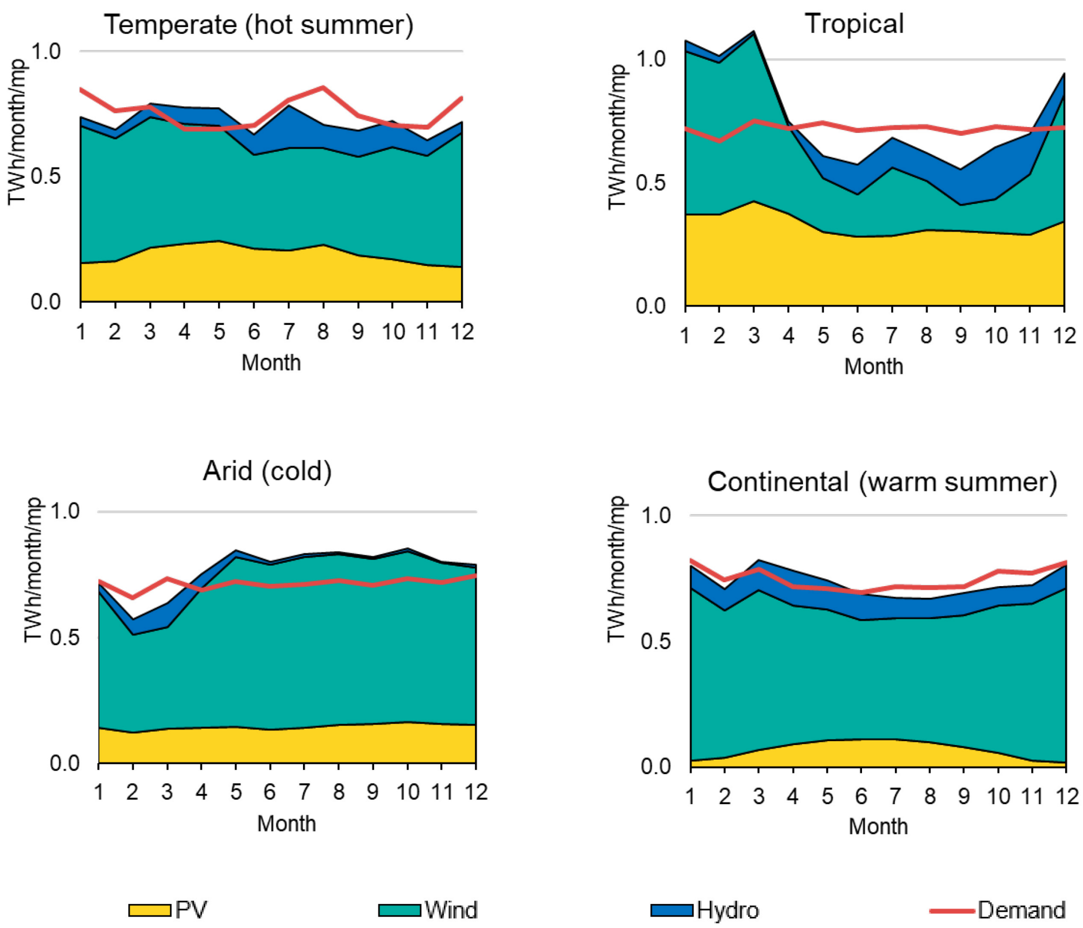
Results

Under the main assumptions, the share of variable renewables ranges from 70% to 90% of annual generation across all systems. The remaining electricity demand is supplied from hydropower and legacy thermal power plants, while various resources are used to provide flexibility services, depending on the system. At longer timescales, the role of thermal and hydro power plants in flexibility supply increases. The main results are discussed in detail in the following subsections.

Seasonal variability depends on climatic conditions

The evolution of the monthly electricity demand and generation potential from renewables are shown in Figure 3.2 separately for the four example systems. The results are normalised to TWh per month per million people (TWh/month/mp) to facilitate easy comparison across systems. When the combined supply potential from solar PV, wind and hydro exceeds the demand, the excess will need to be curtailed. When their potential is not enough to meet the demand (white area under the demand curve), thermal generation is needed to meet the remaining demand. This also happens during shorter periods that are not visible in the monthly averages. However, analysing the monthly timing of supply and demand helps illustrate seasonal variability patterns and to pinpoint periods of interest for the example systems.

Figure 3.2 Monthly demand and generation potential from renewables based on an hourly optimisation model



Note: The vertical axis is TWh/month/million people. The naming of the systems follows the Köppen-Geiger climate classification. The shape of the demand curve is based on time series and does not reflect changes that might occur through electrification of heating in buildings. However, increases in use of electric vehicles and electrolytic hydrogen for industry are assumed. White area under the demand curve is supplied with thermal generation. The results are based on ideal systems that do not account for energy taxes and tariffs, political targets, and other constraints that can shape the generation mix of real systems. For detailed technology and costs assumptions, see Annex.

The **Temperate (hot summer)** example system is characterised by peak energy demand in the summer, driven by demand for cooling. There is also a smaller peak in demand during the winter, driven by demand for heating. On the supply side, winter sees higher average winds, while solar PV peaks in spring and is generally available at high levels during summer. Summer is also the wettest season, while monthly hydro availability is at 50% to 60% of the peak level over the winter months.

The **Tropical** example system has relatively flat seasonal electricity demand (minimum monthly level is 89% of peak demand) with a small peak in spring. Monthly hydro availability is concentrated around the rainy season (peaking in October), and then falls to only 6% of the peak level during the dry season. Wind and solar PV do not complement each other much on a seasonal level, as generation from both drops during the rainy season. The monthly generation from PV drops to between 66% and 72% of the peak, while from wind it falls to between 16% and 36% of the peak.

The **Arid (cold)** example system also has a relatively flat seasonal electricity demand, being at minimum 88% of the peak. However, there is a small peak driven by cooling needs during the hot season. Monthly solar PV potential is also very flat over the year, being at minimum 75% of peak generation. In this example system, there is a long dry period from July to November, when monthly hydropower generation is below 10% of the peak. Wind generation meets most of the load, although there is a significant slump in the beginning of the year, when generation dips to just 57% of the peak.

In the **Continental (warm summer)** example system, peak demand is reached in the winter, driven by heating needs. During those months, power generation – supplied mainly from wind – also peaks, before dropping to around 70% of the peak in summer. Inversely, most of the solar PV potential occurs in the summer and falls to quite low levels in winter, reaching only 15% to 25% of peak generation. Thus, solar PV and wind show good complementarity on a seasonal scale, with wind generation peaking in the winter and solar in the summer. The combined monthly generation from wind and PV never falls below 85% of their peak. The highest hydro inflows occur in the spring when snow melts. It is during these weeks that it is most difficult to match hydropower generation with demand since hydro plants are typically operating at or near capacity – which means that they must often spill part of the water inflow. For the rest of the year, monthly generation from hydro ranges between 55% and 65% of the peak.

Defining short-duration and seasonal flexibility

Flexibility can be defined as the ability of a power system to reliably and cost-effectively manage the variability and uncertainty of supply and demand across all relevant timescales.[3] As electricity supply and demand need to be balanced at all times, flexibility needs represent a way to quantify these efforts to keep the system in balance.

Since variability and uncertainty occur across vastly different timescales (ranging from milliseconds to years), a system's flexibility requirements also need to be defined using similar time intervals. Apart from very short timeframes (variations that last less than a second, or from minute to minute), it is possible to address flexibility needs by analysing the residual load, which is calculated by taking the difference between hourly electricity demand and variable renewable generation. The residual load represents the instantaneous demand that must be supplied by flexibility sources within the system. Flexibility needs capture how much the system needs to adapt to the variations in the residual load to make the best use of available variable renewables.[4]

To account for specific temporal variations of the system, short-duration and seasonal flexibility needs are defined for the following timescales:

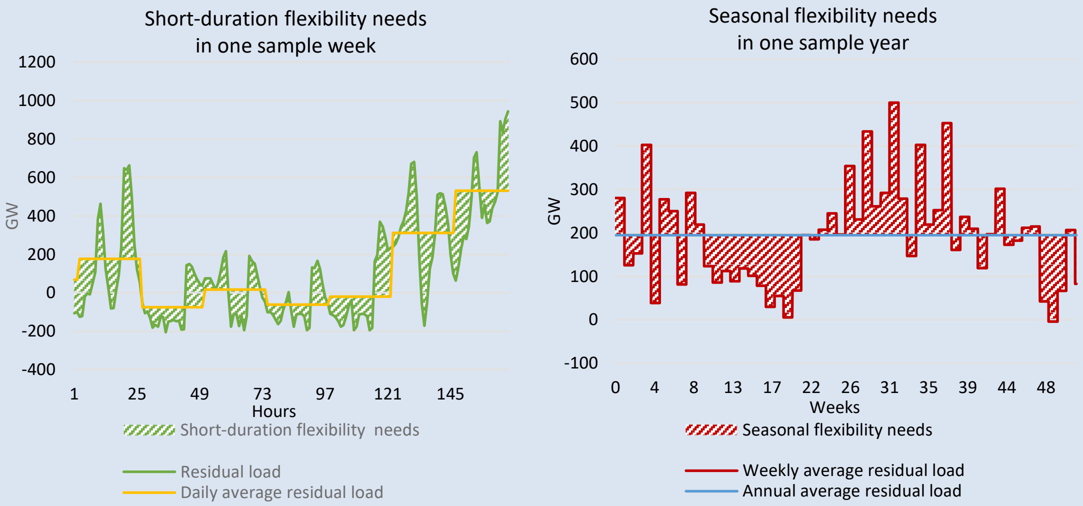
- **Hours-to-days flexibility** (short-duration), which measures the hourly variations of the residual load compared to its daily average.
- **Weeks-to-year flexibility** (seasonal), which measures variations in the weekly averages of the residual load, as compared to its annual average.

The figure below illustrates the difference between short-duration and seasonal flexibility needs using the Temperate (hot summer) climate zone as an example. Short-duration flexibility needs (left graph) are directly influenced by daily patterns of electricity demand and renewables supply, while seasonal flexibility needs (right graph) are influenced by long-term patterns in climatic conditions.

[3] IEA (2018), Status of Power System Transformation,

[4] This metric of flexibility needs is introduced in the "Study on energy storage – Contribution to the security of the electricity supply in Europe," European Commission 2020.

Flexibility needs across different timescales in the Temperate (hot summer) example system

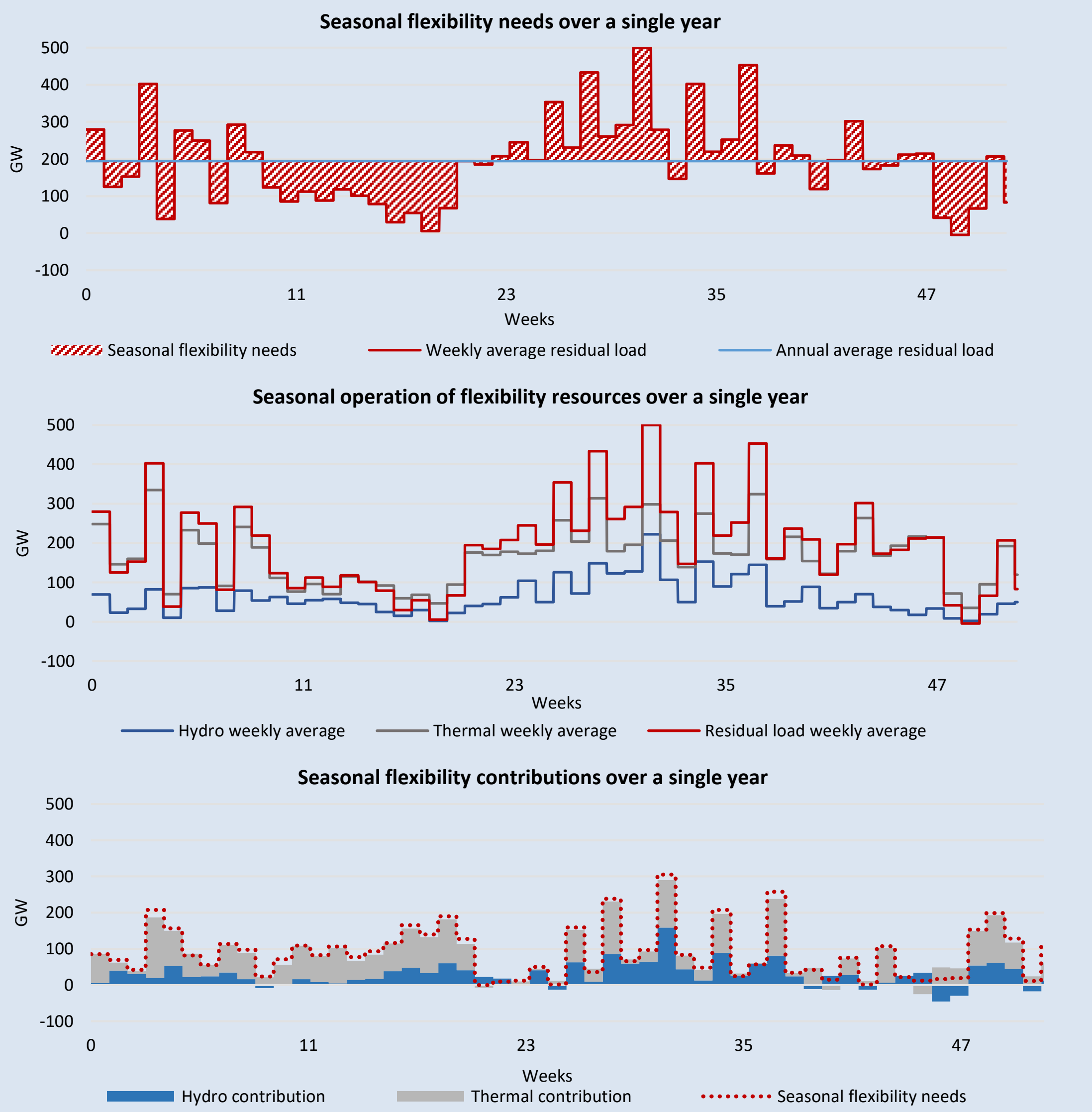


IEA. CC BY 4.0.

The contribution of different resources to the overall flexibility supply is measured as a percentage of the system's flexibility requirements. **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 long-duration energy imbalances (e.g. weekly). Seasonal flexibility requires scheduling to anticipate the availability of resources across the year.

A resource contributes positively to seasonal flexibility supply when its average weekly supply is synchronised with the average weekly evolution of the residual load compared to annual averages. In the figure below, the top graph shows the evolution of the weekly residual load compared to the annual average. The middle graph shows how weekly average generation from hydro and thermal power plants is synchronised with the evolution of the residual load over the year. Finally, the bottom graph shows how these resources contribute to the seasonal flexibility supply, as their weekly average operations respond to the seasonal variations of the residual load. A given resource may also increase the need for flexibility from other resources (shown as a negative value in the figure) when other constraints – such as reduced hydro inflows or scheduled maintenance – restrict their ability to respond to variations in the residual load.

Illustration of hydro and thermal contributions to seasonal flexibility needs

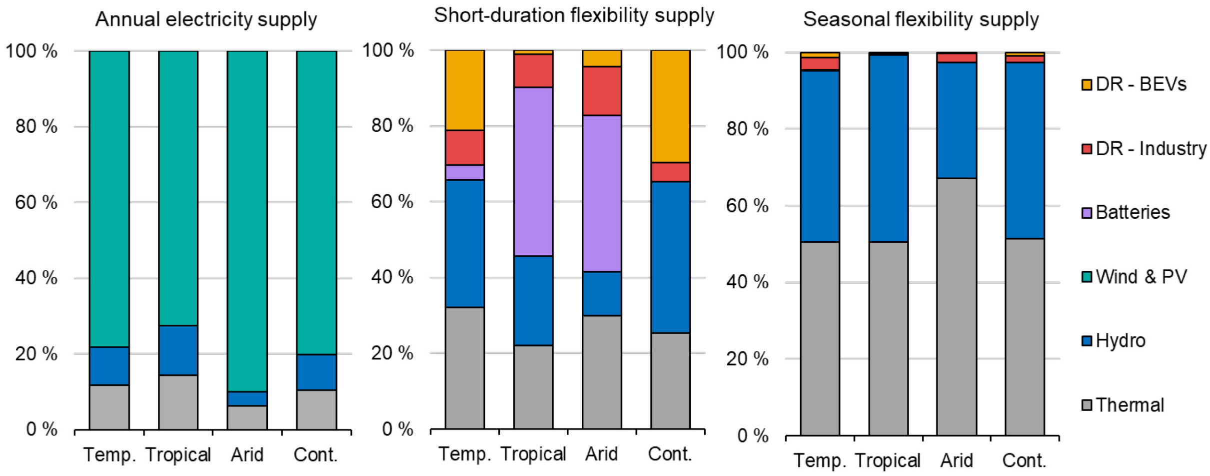


Thermal and hydropower fleets are the main sources of seasonal flexibility in high-VRE systems

In all the examined systems, the share of variable renewables varies from 70% to 90%. As a result, thermal generation represents only 5% to 15% of annual generation, despite the large size of the legacy thermal fleets. Figure 3.3 shows how annual electricity supply, and the use of different flexibility resources vary across systems due to different climatic conditions.

The share of VRE in **annual electricity supply** (shown in the left graph) is highest in the Arid system thanks to its good solar PV and wind resources, and lowest in the Tropical example system that is characterised by long periods of low-wind conditions, making investments less attractive. The Tropical system sees the highest amount of hydropower as well as thermal generation that compensate for long periods of low wind.

Figure 3.3 Energy and flexibility supply by technology in the example systems



Note: Electrolytic hydrogen provides both demand response (during production via electrolysis) and flexible supply (when used in thermal power plants). DR = Demand Response. BEVs = Battery Electric Vehicles.

Despite their small role in electricity supply, legacy thermal capacity and reservoir hydro resources supply 42% to 66% of the **short-duration flexibility** services for the example systems (center graph). In addition, new investments are made also to other flexibility resources. Battery energy storage systems (BESS) are most profitable in grids that have high shares of PV and where daily demand peaks in the evening. Under these conditions, batteries provide a valuable service by absorbing excess generation during the day and extending PV generation to evening hours. The largest BESS investments are made in the Tropical and Arid systems, where they provide 45% and 41% of the short-duration flexibility supply, respectively.

In addition to grid-level energy storage, battery electric vehicles (BEVs) can also provide system flexibility through demand-side management. In the example systems, BEVs are not supplying stored electricity back to the grid, but they enable load shifting through smart charging. The amount of flexibility provided by BEVs depends on the share of electric vehicles in the transport fleet (see Annex). In the Temperate system, they provide 21% of the short-duration flexibility needs, while in the Continental system they supply 30%. In the Tropical and Arid systems, the contribution of BEVs is just 1% and 4%, respectively.

The production and use of low-emission hydrogen and ammonia provide both demand- and supply-side services. Demand-side management is provided through flexible production of these fuels via electrolysis, while the produced fuel can be stored and used to provide low-emission, dispatchable energy via co-firing in existing fossil fuel power plants. The overall short-duration flexibility contribution from electrolytic H_2/NH_3 is labelled in the figure as “DR - Industry” and ranges from 5% to 13%.

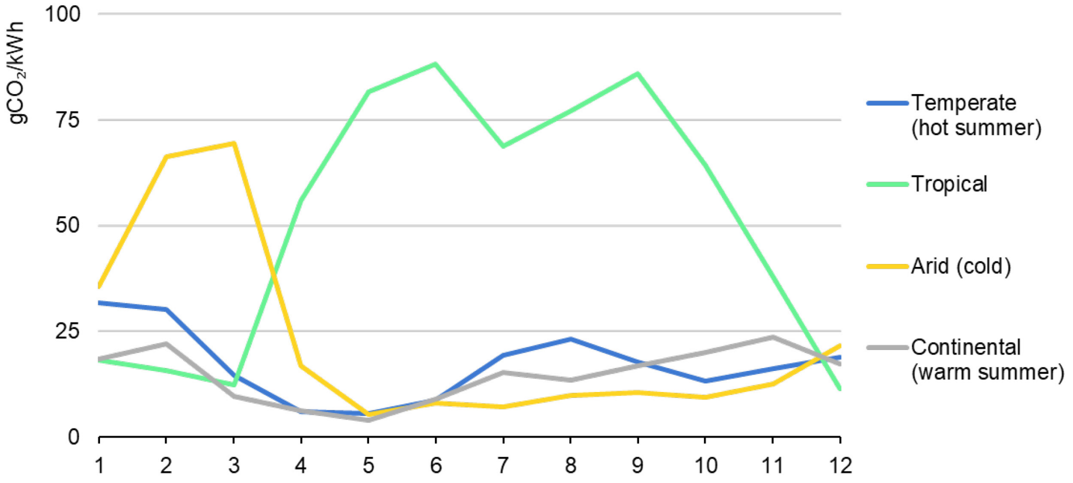
The role of legacy thermal assets along with hydropower is further increased when considering **seasonal flexibility supply** (right graph). Thermal fleets provide 51% to 67% of the seasonal flexibility supply, while reservoir hydro delivers most of the remaining needs (30% to 49%). Other flexibility resources that are extremely relevant for short-duration flexibility supply have a lower importance on the seasonal timescale.

Despite the large role of thermal capacity in seasonal flexibility supply, annual carbon intensities remain low

Variation in the supply potential of renewables has direct impact on the variability of carbon emissions in the example systems as residual load is met to a large extent by thermal plants. The thermal fleet is a mix of fossil fuel (coal, gas and oil), biomass and nuclear power plants (see Annex for details) and is unique for each example system. As a result, the use of thermal assets has a system-specific impact on carbon emissions.

Annual carbon intensity of electricity supply ranges from 15 gCO_2/kWh (Continental) to 51 gCO_2/kWh (Tropical). Achieving these levels would represent around 89-97% reduction from the current global average grid emissions of 460 gCO_2/kWh.

Figure 3.4 Monthly average carbon intensity of electricity in the example systems



The variation (see Figure 3.4) is fairly limited in the Temperate and Continental example systems, where monthly carbon intensity remains mostly below 25 gCO_2/kWh. The Arid system experiences a sharp peak in carbon intensity in the beginning of the year. The Tropical system has the highest overall emissions, partly due to the long rainy season – when residual load is met by thermal generation – and partly because it has a high share of coal power plants in the legacy fleet.

Sensitivity analyses

In addition to climatic conditions, the example systems are sensitive to several assumptions that govern the cost and performance of technologies. These sensitivities are examined in the following subsections.

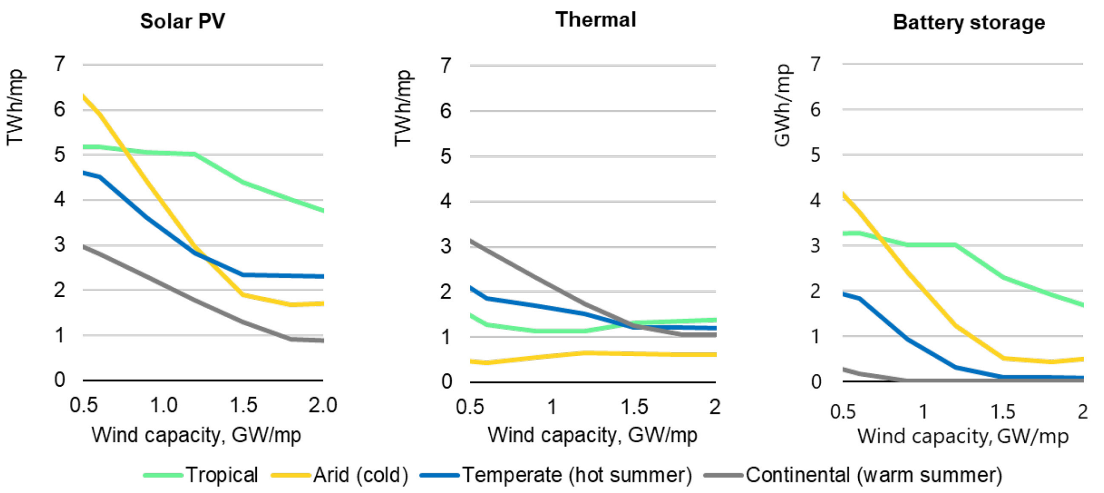
The role of wind capacity limits

As a result of economic optimisation, investments in wind power range from 1.5 to 2 GW per million people (GW/mp) in the example systems. While such an amount is feasible in less densely populated regions, it might not be attainable everywhere due to space limitations, competition over land with other uses, unsuitable terrain for wind power development, or public opposition. The impact of limited wind power potential is shown in Figure 3.5.

Limiting the maximum available wind power capacity leads to an increase in solar PV generation in all example systems. The Arid system is the most sensitive to changes in wind, with an increase of more than 4.2 TWh/mp in solar generation, while impact remains at around 2 TWh/mp in the other systems. Thermal generation is sensitive to wind power limitations only in the Temperate and

Continental systems. The nearly 2 TWh/mp increase in thermal generation is driven by the strong seasonality of solar PV in the Continental system, where solar struggles to meet the winter demand peak.

Figure 3.5 Impact of wind power capacity limitations on battery storage and generation from solar PV and thermal power plants in the example systems



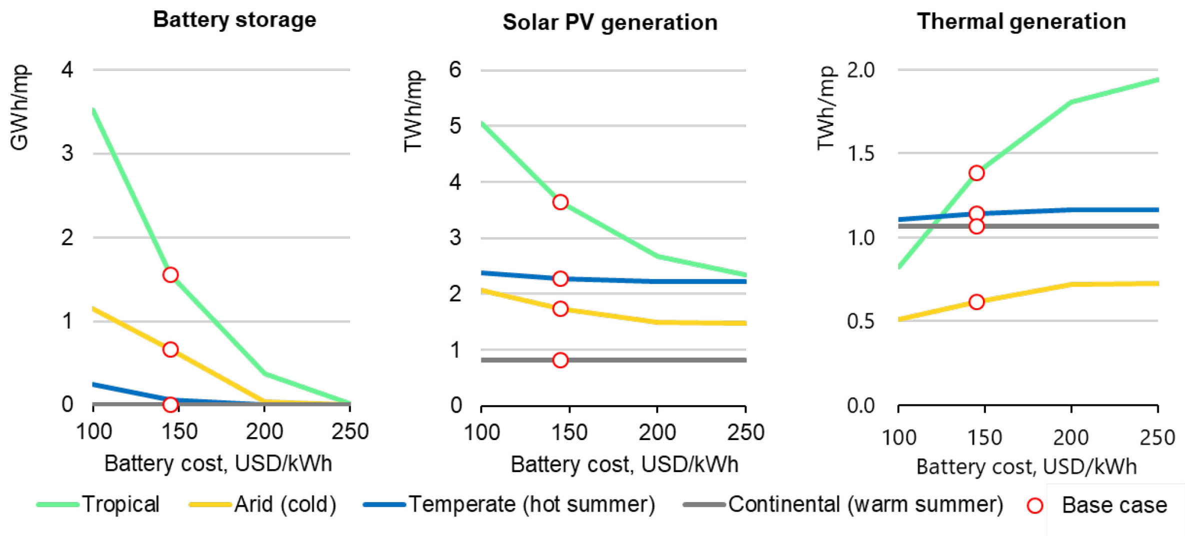
Note: In the main results, wind capacity is not constrained.

Investments in short-term battery storage closely track changes in solar PV generation, given the need to balance daily variations. Battery capacity increases by more than 3 GWh/mp in the Arid system, and by around 2 GWh/mp in the Temperate and Tropical systems. Even when solar PV generation is tripled, the Continental system only sees a 0.2 GWh/mp increase in battery storage, since it is competing against a relatively large reservoir hydro capacity that also provides short-term services.

The role of battery storage costs

The impact of battery storage costs on the level of battery investments and on solar PV and thermal power generation are shown in Figure 3.6, across a price range of USD 100 to USD 250 per kilowatt hour. Lower battery costs generally lead to an increase in storage and solar PV, as well as a reduction in thermal generation. The Tropical and Arid systems are most sensitive to battery prices, while these costs have little to no impact in the Temperate and Continental systems.

Figure 3.6 Impact of battery energy storage cost on battery investments and annual electricity generation from solar PV and thermal power plants in the example systems



Note: In the main results, the central assumption for battery cost is USD 145/kWh.

Lower battery costs drive up both solar PV and battery usage, in a similar way to limitations on wind capacity. Although batteries cannot replace thermal plants as a source of seasonal flexibility, they reduce generation from these plants by decreasing the number of available operational hours.

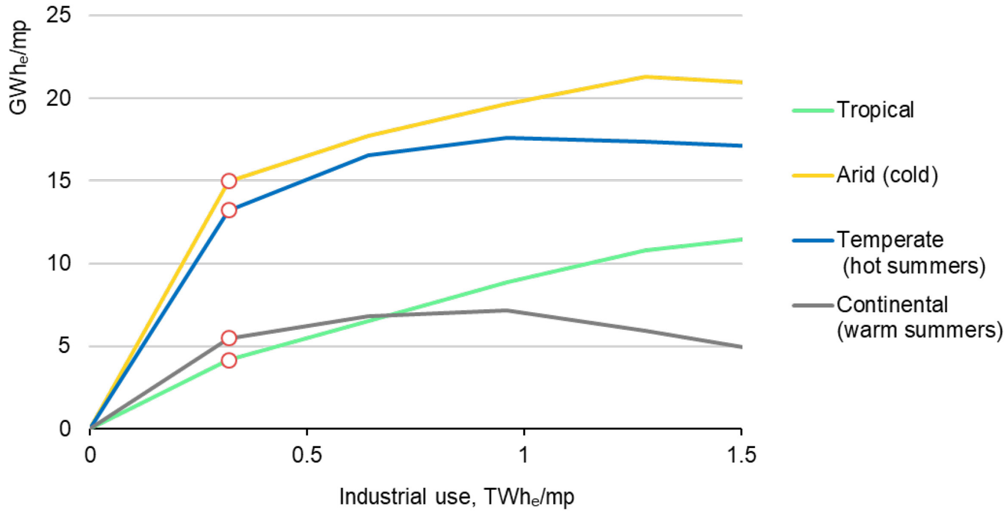
The Tropical system is the most sensitive to battery costs, its storage capacity increases by 3.5 GWh/mp, solar PV generation doubles to 5 TWh/mp and thermal generation falls by more than 50% across the studied range. In contrast, the Continental example system is much less sensitive to battery costs due to its large reservoir hydro capacity, which provides a similar service. In addition, a very low amount of PV is available during the Continental winter season, which reduces the number of annual cycles for batteries and makes storage relatively more expensive than in systems with more flat seasonal solar profile.

The role of electrolytic hydrogen demand from industry

Hydrogen is a widely used chemical feedstock that can also be used as an energy vector for multiple purposes, including transport fuel, providing high-temperature heat and electricity generation. The amount of hydrogen co-firing in the example systems is highly sensitive to the level of industrial demand for these fuels, as seen in Figure 3.7.

The increasing industrial demand for electrolytic hydrogen – either for fuel or feedstock purposes – stimulates production significantly compared to a situation where power generation represents the only source of demand. The continuous demand enabled by industrial use drives up full-load hours of the electrolysers, thereby reducing production costs and making fuels more affordable for other uses as well. Industrial use also requires investments in supply infrastructure and buffer storage – which can be co-used for low-emission and dispatchable power generation. By sharing infrastructure and storage investments, users can realise greater cost savings than through co-firing alone.

Figure 3.7 Impact of industrial use of electrolytic hydrogen on co-firing with hydrogen in thermal power plants



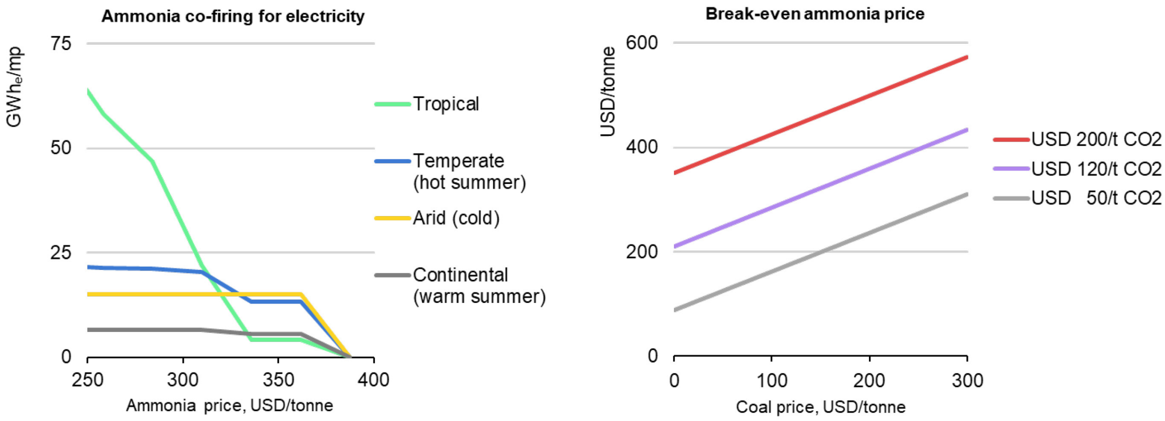
Note: The scale of industrial hydrogen use is measured in terms of the energy content, even though the actual use could be for feedstock purposes. In the main results, the central assumption for electricity use in hydrogen production is 0.3 TWh$_e$/mp.

Electrolytic hydrogen is not used for co-firing in the absence of industrial demand. However, even at low levels of industrial demand, low-emission hydrogen starts to provide services for the power sector – mostly through demand-side management via flexible operation of electrolysers, but also through co-firing in thermal power plants at a level of 5 to 15 GWh$_e$/mp. At high levels of industrial demand, co-firing increases up to 20 GWh$_e$/mp in the Tropical and Temperate example systems. Eventually, the amount of co-firing begins to saturate as demand increases.

The role of import prices for low-emission ammonia

There is a large pipeline of projects around the world that aim to export low-cost, low-emission hydrogen mainly in the form of ammonia. The emergence of an international market for low-emission hydrogen and ammonia would help to connect regions that have low-cost renewable resources with regions where such fuels have high value. This could significantly reduce the cost of low-emission ammonia for end-users. The impact of ammonia import costs on the level of ammonia co-firing in the different example systems is shown in Figure 3.8.

Figure 3.8 Impact of import cost on the use of low-emission ammonia for power generation by example system



Note: Ammonia imports are not modelled in the main results.

All regions supplement their own low-emission fuel production with imports when the price is low enough. For ammonia, the break-even price is generally observed to be around USD 350/tonne – although the exact price depends on the prices for fossil fuels, carbon emissions, and other energy-related taxes and fees. The right-hand side of the figure makes it possible to estimate the break-even price of ammonia based on different assumptions for coal and carbon prices. For instance, at a coal price of USD 50/tonne and a carbon price of USD 200/tCO_2, the break-even price for low-emission ammonia is USD 400/tonne.

Once the break-even price has been reached, a significant increase can be seen in ammonia co-firing (up to 70 GWh_e/mp within the studied range) for the Tropical example system. The increase is driven in this system by large seasonal variations in wind generation, as well as significant existing coal capacity. For other systems, the amount of electricity produced from ammonia remains below 25 GWh_e/mp across the studied range.

Chapter 4. Interannual variability

In the studied systems, the variability extends also beyond seasonal timescales. The impact of such interannual variability (IAV) cannot be captured with single-year time series or average meteorological conditions, since these do not capture years with smaller or higher than average annual renewables generation.

To analyse IAV in the example systems, multi-year datasets were compiled using time series for hydro, wind and solar, as well as demand. The data used were from the same years to maintain temporal correlations. The objective is to understand which flexibility sources are most relevant in the different climatic zones, when dealing with multi-year variability. The datasets used range from seven consecutive years for the Tropical system to 17 years for the Temperate (hot summers) system. The length of the datasets was limited by data availability. Analysing multi-year time series makes it possible to track storage levels and changes to storage states over time, as well as how such variations affect a system's flexibility requirements. That said, these multi-year datasets can be considered relatively short compared to standard hydropower analysis, which typically draws on at least 30 years of hydrological records (though sometimes, only modelled time series are available). Given this limitation, the analysis here cannot be considered definititive. However, it is still useful for illustrating the role of interannual variability in a high-VRE energy system.

Interannual variability in the example systems

The size of interannual variation in the example systems is estimated using the mean coefficient of variation (CV) over the multi-year datasets (see Table 4.1). Across all systems, the IAV falls between 6% and 17% for PV generation, while for wind it ranges from 4% to 9%. These values are roughly in line with the 10% interannual variability of wind and solar globally. Variability is much higher for hydropower, ranging from 26% to 61%. However, the scale of these fluctuations is moderated by hydropower's relatively small energy contribution compared to wind and solar PV in the example systems. The share of hydro is highest (20% of annual generation) in the Tropical system where the IAV is the smallest, and lowest (4% of annual generation) in the Arid system where IAV is 40%. (Note: since these results are based on relatively short time periods from hydropower analysis perspective – seven to 17 years, depending on the system – the results are especially dependent on the utilised set of years.)

The greatest interannual variability is observed for hydro in the Continental example system. Hydropower represents 14% of annual generation and has an IAV of 62%. Hydropower in this system also has a very notable multi-year pattern, as highlighted in Figure 4.1. The average level of monthly hydropower generation over the 12-year period is 95 GWh/mp, and the first three years show a particularly high level of generation: as much as 170 GWh/mp above the long-term average.

Table 4.1 Interannual variability in renewables generation by example system

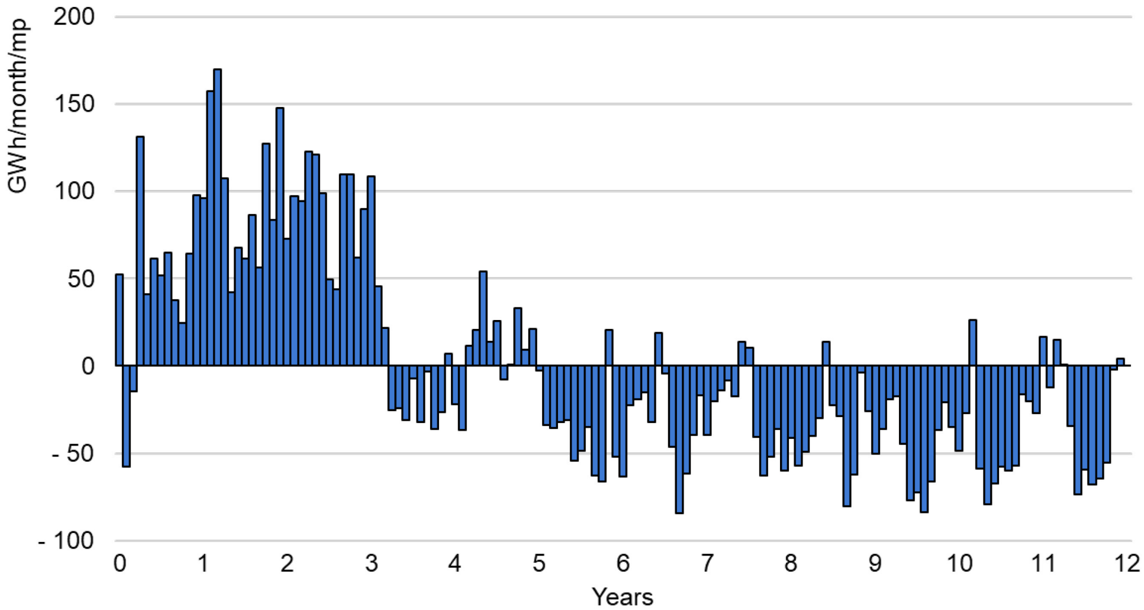
	Solar PV	Wind	Hydro
Temperate (hot summer)	9%	9%	41%
Temperate (dry season)	7%	4%	33%
Tropical	17%	6%	26%
Arid (cold)	6%	3%	40%
Continental (warm summer)	14%	9%	62%

Note: The higher the coefficient of variation, the greater the level of dispersion in energy generation around the average value.

Generation levels subsequently return to average levels for the next two years, however, and the remaining dataset reveals seven consecutive years of lower-than-average production. At minimum, the monthly generation is 84 GWh/mp below average over the 12-year period. This interannual pattern in hydro generation has significant implications for the Continental system as shown in Figure 4.1.

In the **Continental** system, short-duration flexibility is provided with demand response (BEVs and industrial hydrogen use), hydropower and thermal generation. Long-duration flexibility is supplied almost exclusively with hydropower and fossil fuels. During the first years of the simulation, hydropower complements wind and solar PV generation to meet demand, leading to a very low requirement for the thermal fleet as well as a high level of curtailment for wind and solar PV. The maximum monthly curtailment during this 12-year period is 420 GWh/mp (compared to an average of 190 GWh/mp over the first three years). During this time, the system dispatches thermal capacity only during the winter months. However, due to the low levels of hydro generation in the last seven years of the simulation, the system dispatches its legacy thermal fleet every month of the year to meet the residual load. This leads to significant variability in the annual carbon emissions of the system. In addition, generation from wind increases during these years due to lower levels of curtailment.

Figure 4.1 Monthly difference of hydropower generation in the Continental (warm summer) example system compared to a 12-year average



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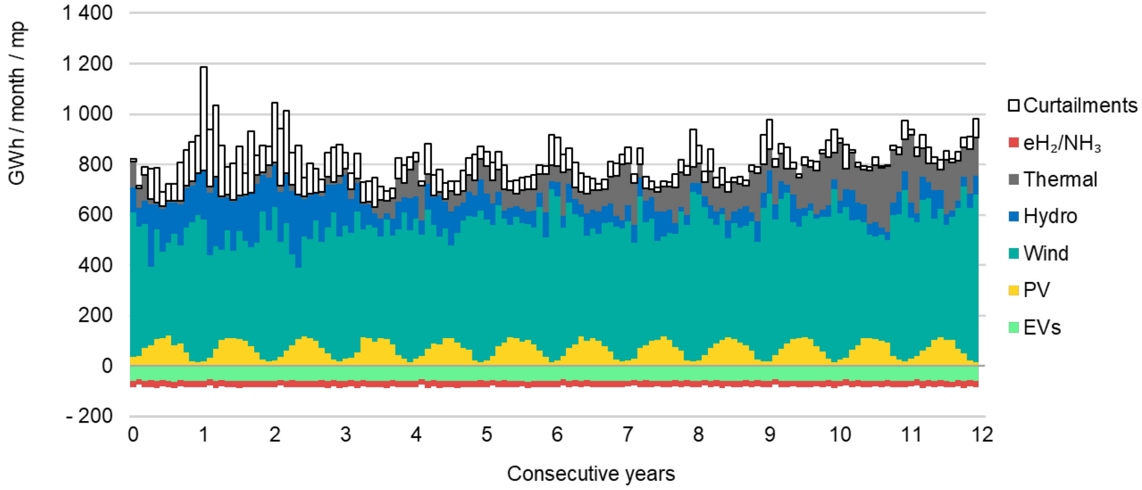
The impact of interannual variability on the other example systems is analysed similarly in Figure 4.2. The systems have been simulated for the full length of the compiled time series, which is different for each system and limited by data availability (see Annex). For the multi-year analyses, a new system – the "Temperate (dry season)" – has also been modelled, to enable the study of IAV in a system with a dry season and facilitate understanding of how this affects the flexibility provided by hydropower.

The **Tropical** system receives important short-term flexibility from battery energy storage. Combined with a relatively flat seasonal availability of solar PV, batteries go through 267 full cycles per year on average. Despite the flat seasonal profile, the Tropical system has the highest IAV of solar with 17% variability in monthly average generation across different years. The strong seasonal cycles in wind and hydropower generation are easily recognisable since the annual slump in wind generation during the rainy season is similar for each year. Curtailments are strongly concentrated around the winter season and reach their annual minimum during the rainy season. The IAV of wind is only 6%, while for hydro generation it varies by 26% – the smallest variation for hydro in all the systems studied.

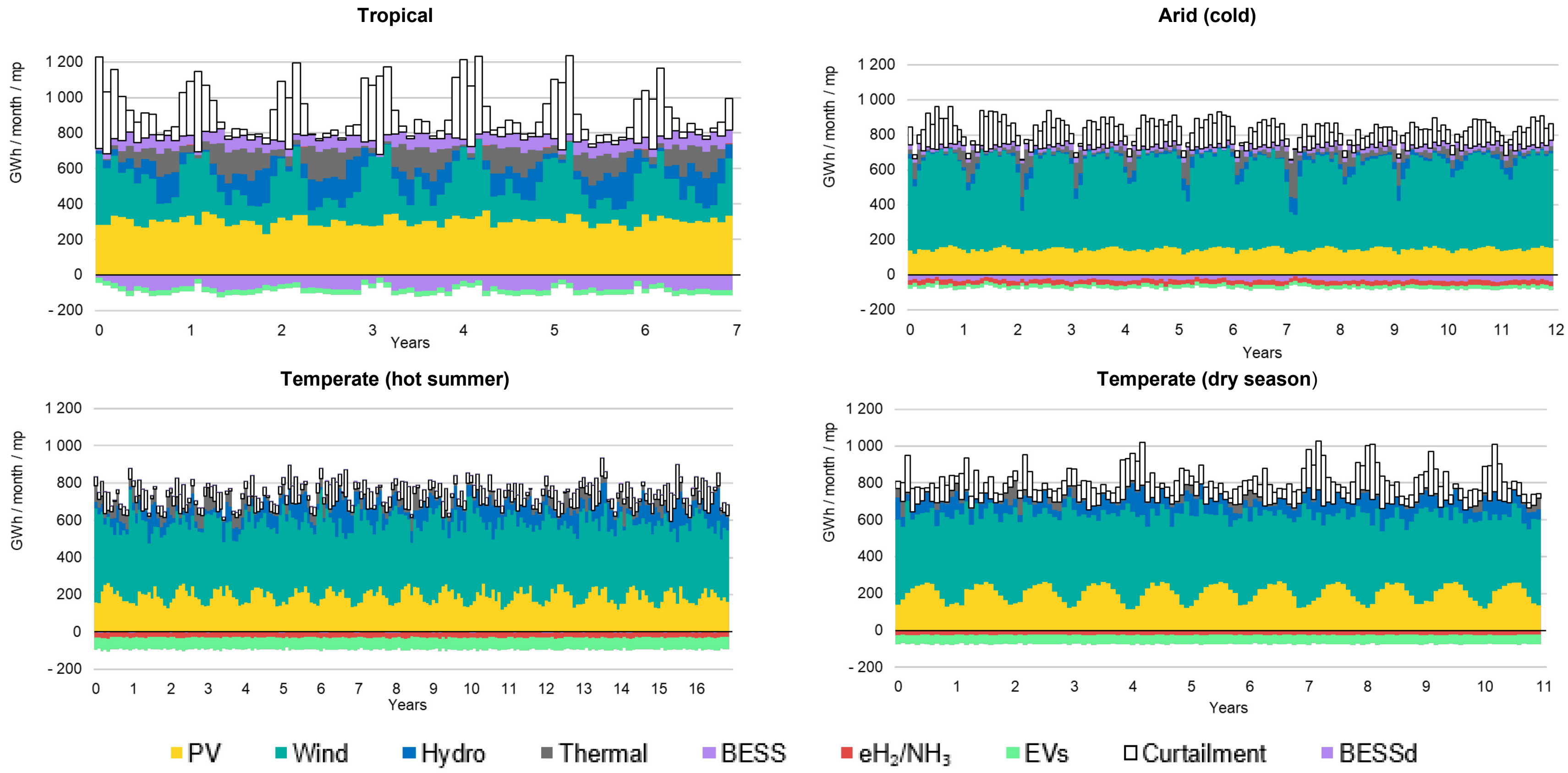
Figure 4.2 Monthly generation by technology across a 12-year simulation of the Continental (warm summer) example system



Note: Time series are based on ENTSO-E data for Poland for years 2005 to 2016.

The **Arid (cold)** system has the lowest interannual variability of both wind and solar PV. The monthly average wind generation varies by only 3% across the years, while the IAV of solar is 6%. There is a consistent slump in wind generation during the winter when the system must dispatch thermal plants to meet the residual load. Hydro has a relatively high IAV of 40% across the years. The flat seasonal availability of solar improves the feasibility of batteries as a short-term flexibility resource with 271 annual cycles on average. Monthly curtailments are spread across the year fairly evenly around the winter slump in VRE generation.

Figure 4.3 Monthly generation by technology across multi-year simulations in the example systems



Note: BESS refers to charging of a Battery Energy Storage System, BESSd refers to discharging of the battery system, eH_2/NH_3 refers to production of electrolytic hydrogen or ammonia.

The **Temperate (hot summer)** example system is characterised by an average level of interannual variability among the studied systems. The monthly average wind and solar PV generation both vary by 9% across the 17-year period. Short-duration balancing is provided by a mix of demand response from electric vehicles and industry, as well as a small contribution from BESS, which is limited by the seasonality of solar PV. As in other systems, seasonal flexibility is provided by hydro and thermal generation. The interannual variability of hydropower is 41%, the second highest among the studied systems. Legacy thermal power plants are dispatched throughout the year and across the entire period to meet the residual load. Curtailments are also distributed between seasons fairly evenly.

The **Temperate (dry season)** example system is characterised by relatively flat seasonal electricity demand varying from -7% to 9% on an annual basis. Solar PV has significant seasonality and almost twice the variability of wind. In general, wind and solar PV complement each other well on a seasonal scale since solar PV peaks in the summer and wind generation is on a generally higher level during the winter. Due to this high degree of complementarity, curtailments are distributed evenly across the year. Wind and solar remain very stable across the multi-year period, with only 4% and 7% IAV, respectively. Generation from hydropower has interannual variability of 33%, an average value among the studied systems.

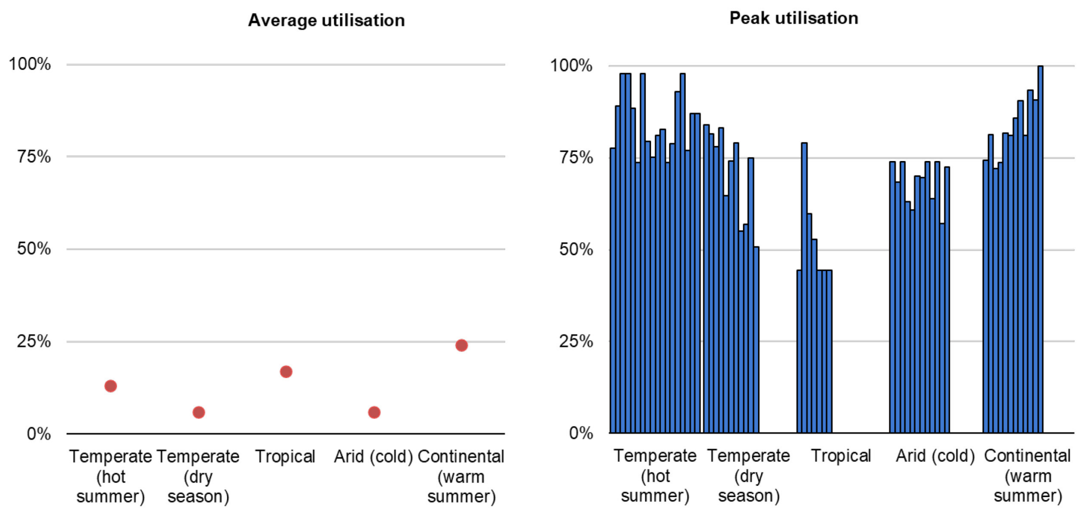
The role of thermal assets in managing interannual variability

Legacy thermal assets and hydropower are the main resources for managing seasonal variability in the studied systems (Chapter 3). Hydropower helps to meet the residual load in all systems, although it is an especially helpful resource in the Tropical and Continental (warm summer) systems that are characterised by high seasonal variations in wind (Tropical) or solar PV (Continental) generation. However, when the analysis is extended to multi-year timescales, the variability patterns change in important ways: wind and solar PV become more stable, while variation in hydropower increases.

The interannual variability of solar PV ranges between 6% and 17%, while for wind it is only between 3% and 9%. Hydropower is clearly the largest driver of interannual variability in the studied systems, with average monthly variability ranging from 26% to 62% across the years. In addition, hydropower is exposed to the possibility of several consecutive years with higher or lower-than-average generation (see Figure 4.1), with important implications for integration.

Given the strong interannual variability of hydropower, thermal plants and their fuel storage capacity clearly become the main source of flexibility for the longest of timescales. The existence of legacy thermal capacity has a decisive impact on how the examined systems behave, as there is no need to invest in backup or reserve capacity, and investments in energy storage are much less profitable than they would be in the absence of thermal generation.

Figure 4.4 Average (left) and peak (right) utilisation of legacy capacity in multi-year simulations



Due to the relatively large amount of legacy capacity in the form of fossil, biomass and nuclear power plants, there is enough thermal generation available in all systems to always secure the supply of energy and capacity (see Figure 4.4). However, peak contribution from these plants varies significantly from year to year. Variation is smallest in the Arid (cold) example system, where peak utilisation varies between 57% and 74%. The largest variation was observed in the Tropical system, where peak utilisation was 44%-79% across the period. The variation in peak dispatch is much higher than the average 10% IAV of wind and solar and means that a significant amount of thermal capacity needed in some years to cover the peak demand, but the same plants can remain unused in other years.

The legacy fleets see low average utilisation: just 24% in the Continental system, 17% in Tropical, 13% in Temperate (hot summers), and only 6% in both Arid (cold) and Temperate (dry seasons). But thermal generation is still needed to meet residual peak demand and to supply flexibility over very short periods. Lower utilisation can mean lower profitability if markets do not appropriately remunerate the flexibility and other services that they provide, and can lead to decommissioning of plants that could otherwise help to maintain system security at lowest cost.

Towards low-emission flexibility

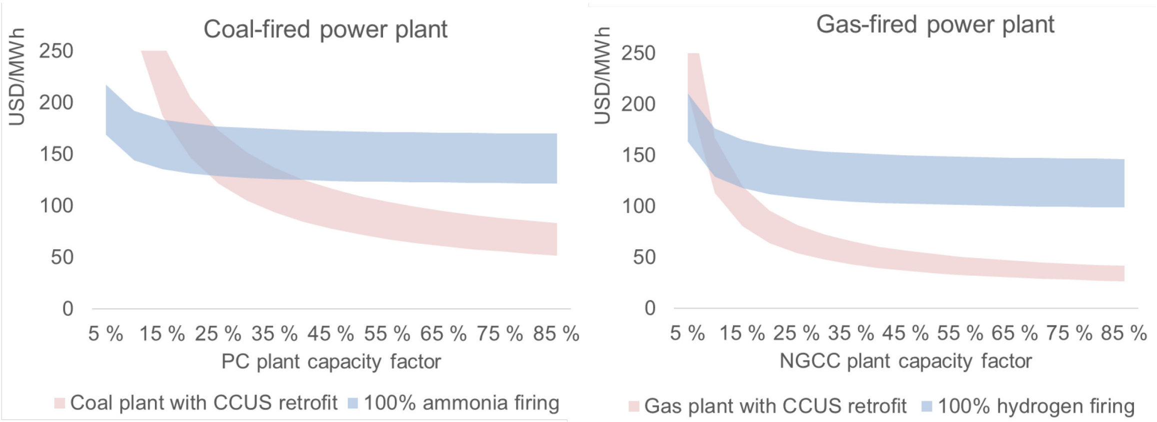
Energy transitions are characterised by the addition of new clean energy infrastructure while reducing the reliance on existing carbon-emitting infrastructure. Managing the co-existence of these systems during the transition is essential. Wind and solar PV are the cheapest forms of electricity generation in large parts of the world and the role of thermal generation must adapt to the increase in variable renewables. As a result, the main task of thermal plants becomes the provision of flexibility rather than baseload generation.

As transitions progress toward net zero emissions, services from unabated fossil fuel power plants must eventually be replaced by other forms of flexibility that do not result in carbon emissions. The ability to combust high shares of low-emission hydrogen and ammonia in fossil fuel power plants represents an important tool for decarbonising the power sector while simultaneously maintaining all services of the existing fleet. However, low-emission hydrogen and ammonia need to become significantly cheaper.

The use of low-emission fuels can be most directly compared to retrofitting power plants with CCUS, as each can provide output with comparable characteristics (low in emissions, dispatchable and flexible) although their cost profiles are quite different. CCUS retrofits involve higher upfront capital costs, but their operating costs are lower than plants that have been modified for co-firing with low-emission fuels. As a result, both will have a distinct role in power system operation. Plants converted to CCUS will likely operate at higher capacity factors when compared to plants that use low-emission fuels, if both options are feasible in a given location (see Figure 4.5).

The co-firing of ammonia in a coal power plant is cheaper than CCUS at low-capacity factors. It is also competitive with retrofitted CCUS in load-following mode but is more expensive as a baseload option. Co-firing hydrogen in gas turbines is of interest mainly for peak power operation. The inflection point at which one technology becomes cheaper than the other will depend on local system conditions, the method of fuel transport, and the cost and availability of CO_2 storage.

Figure 4.5 Comparing the additional cost of CCUS retrofitting and modification for low-emission fuel use of an existing thermal power plant



Source: IEA (2021), The role of low-emission fuels in the clean energy transitions of the power sector.

Another option for further reducing emissions from unabated fossil fuel plants is to increase the capacity of variable renewables. Oversizing will increase the level of generation from renewables, thereby reducing the residual load and the need for unabated fossil fuels. However, this will lead to increased curtailments during peak VRE generation. Over time, demand patterns can adjust to better absorb periods of oversupply, although to what extent depends on local system conditions. Energy efficiency policies should also consider this question and help accommodate renewables supply over the long term.

Emissions from the use of unabated fossil fuels in thermal plants can also be offset by application of bioenergy with carbon capture and storage (BECCS) and direct air capture with storage (DACS). Biomass-based CO_2 can be captured from power plants, but also from other bioenergy conversion processes such as biofuel plants, biomass heat boilers, as well as industrial kilns and furnaces delivering high temperature heat.

Currently, the only large-scale BECCS facility is the Illinois Industrial CCS plant that annually captures up to 1 Mt of CO_2 from the fermentation of corn ethanol and injects it into geological storage beneath the facility. In addition, four smaller ethanol plants have been operated as BECCS facilities using most of the captured CO_2 for enhanced oil recovery (EOR). In Europe, projects are currently ongoing to apply BECCS in large-scale power generation and in district heat production.

Chapter 5. Conclusions

A mix of flexibility resources is needed to manage variability across all timescales

This study explores the integration of variable renewables (VRE) beyond 70% share of annual generation. Four different climatic regions – Temperate (hot summer), Tropical, Arid (cold) and Continental (warm summer) – were studied using a model that in addition to legacy infrastructure optimises investments in wind, solar PV and flexibility resources to minimise overall system costs under given cost and performance assumptions. The results show that different mixes of flexibility resources – including grids, interconnections, demand response, energy storage, and dispatchable power plants – are required to manage variability across timescales and climatic regions.

Short-duration flexibility services play a critical role in balancing the hourly and daily variation of renewables. Battery storage pairs well with systems that have high levels of solar radiation throughout the year that enables large amount of storage cycles in balancing the daily variation in solar PV supply. For example, in the Tropical and Arid systems, batteries provide around 40% of the short-duration flexibility requirements. In the Temperate and Continental systems, demand response provides 30%-35% of these requirements.

Systems with very high level of variable renewables require seasonal flexibility services

As the penetration of wind and solar increases, system level surpluses and periods of lower generation extend to longer periods, eventually reaching seasonal and even interannual timescales. The interactions between electricity demand, hydro availability, and the amount and complementarity of wind and solar resources set the basic conditions for integrating renewables on a seasonal timescale.

There are a number of conditions that can make the integration of variable renewables easier, including limited seasonality in electricity demand patterns, moderate to low peak demand, high availability of dispatchable renewables including hydropower, and a high degree of complementarity among patterns of solar PV, wind and hydro availability.

Different climatic zones are exposed to different types of seasonal variability

In a Continental (warm summer) system solar PV and wind show good complementarity on a seasonal scale, with wind peaking in the winter and solar in the summer. The combined monthly generation from wind and PV never falls below 85% of their peak.

An Arid (cold) system has a relatively flat seasonal electricity demand with a minimum monthly level of only 88% of the peak. Monthly solar PV potential is also very flat over the year, but monthly wind generation experiences a significant slump during a short period of rainfall in the beginning of the year when it dips to just 57% of the peak.

A Temperate system (with hot summer) is characterised by peak electricity demand in the summer driven by demand for cooling, and a smaller peak in the winter driven by demand for heating. Winter sees higher average winds that help to meet the demand peak, while solar is generally available at high levels during summer complemented with a good availability of hydropower.

A Tropical system has also relatively flat seasonal electricity demand with minimum level being 89% of peak demand. However, the system is exposed to a strong seasonal pattern of wind, which leads to large surpluses during the dry season and periods of low renewables supply during the rainy season, when generation from wind falls to 16%-36% of the peak, which is only partly compensated by hydropower.

Fossil fuel use is significantly reduced in high-VRE systems but need for thermal capacity remains

In the modelled systems, legacy thermal power plants provide only 5%-15% of total annual electricity, but they are the main source of seasonal flexibility supply. Depending on the system, half to two-thirds of seasonal flexibility services are supplied from thermal power plants during critical periods of the year.

The current stock of legacy thermal capacity is sufficient to meet the seasonal flexibility needs of the modelled high-VRE systems. However, the use of these assets is very different than today, as the average utilisation of thermal plants is just between 500 and 2 000 hours per year, depending on the climate. Successful management of this shift from bulk electricity generation to flexibility supply is needed to ensure an orderly transition to secure, clean and affordable power systems.

Hydropower is a key provider of seasonal flexibility but is exposed to interannual variations

Hydropower is the second most important seasonal flexibility resource after thermal power plants, providing 30%-50% of total seasonal flexibility demand. However, due to changes in precipitation and snowmelt from year to year, hydropower is exposed to significant interannual variations, including the possibility of consecutive years with higher or lower-than-average generation. Possible multi-year periods of low hydropower availability cannot be fully offset by reservoir withdrawals, leading to potential shortfalls in power generation if the variability aspects of hydropower are not properly addressed as part of energy infrastructure planning.

Moving towards zero-emission seasonal flexibility services

Annual grid emissions range in the modelled high-VRE systems range from 15 gCO_2/kWh (Continental) to 50 gCO_2/kWh (Tropical). Achieving these levels would represent 90-97% reduction from current global average grid emissions of 460 gCO_2/kWh. However, as energy transitions progress towards net zero emissions, services from unabated fossil fuel power plants must eventually be replaced by other forms of flexibility that do not emit CO_2.

The ability to combust high shares of low-emission hydrogen and ammonia in fossil fuel power plants provides a tool for decarbonising long duration flexibility services. However, the current high cost of low-emission hydrogen and ammonia remains a critical barrier to their wider use. For this option to be viable, these resources need to become significantly cheaper than they are today.

The cost of low-emission fuels can be reduced through trade and by exploiting synergies with industrial users

Regions where fuel ammonia has a high value for system flexibility do not necessarily have suitable resources to produce low-emission ammonia at a low cost. An international market for ammonia can connect regions with low-cost renewable resources to others where low-emission fuels have high value. The commercial viability of low-emission fuels is closely connected to fossil fuel and carbon prices. In the example systems studied, ammonia imports start to become viable once prices drop below USD 350/tonne.

Meanwhile, synergy opportunities with other sectors exist, for example in terms of shared infrastructure costs. Low-emission fuels have several potential applications and can play an important role in decarbonising industry and maritime transport. Increasing demand for hydrogen and hydrogen-derived fuels can therefore contribute to reduced costs, driven by scale benefits, technology learning and shared infrastructure.

Annex

Modelling methods and assumptions

Example systems (or “reference systems") have been modelled using the Backbone energy system model, an open-source energy model developed by VTT Technical Research Centre of Finland. Backbone is a linear optimisation model that minimises overall system (investment and operational) costs, with constraints on parameters such as generation capacities, electricity demand, unit operation, time series and emission prices. Helistö et al (2019)[5] have published a full documentation of the model. Model introduction, download section, and demo models can be found from https://gitlab.vtt.fi/backbone/backbone/-/wikis/home.

The level of detail in the analysed systems was kept intentionally low to keep the exercise tractable and to facilitate a high number of simulations – more than 700 – in the course of the work. Modelling real systems, with full system detail, would have made the results more applicable to those systems, but would have also constituted a much larger and computationally demanding effort, due to the large number of scenarios analysed. Each area was modelled as a single node without depicting transmission constraints, which in general makes the variability easier to manage.

The model was used in investment planning mode, which means that issues like short-term uncertainty could not be captured. Such factors typically have a minor impact on planning decisions, although they could adversely affect the value of extremely short-duration storage. A 15% capacity margin was used, however, which forces the model to have sufficient spare capacity to cope with operational issues like reserves.

The reference systems represent different climate zones with different renewable resources (such as hydropower and wind power) as well as demand profiles due to differences in heating and cooling demands. Different climates also have their distinct seasonal and multi-year weather patterns.

[5] Helistö N, Kiviluoma J, Ikäheimo J, Rasku T, Rinne E, O’Dwyer C, Li R, Flynn D. Backbone: An Adaptable Energy Systems Modelling Framework. Energies. 2019; 12(17):3388. https://doi.org/10.3390/en12173388

Representativeness of each climate zone measured by population and land area

Climate zone	Land area Mkm²	Population billion	Population share	Population person/km²
Continental	37	1.0	14%	28.4
Temperate	20	2.9	38%	145.8
Arid	44	1.5	20%	34.5
Tropical	28	2.2	29%	80.2

We use the Köppen-Geiger climate classification of climate zones (Geiger, 1954[6]). In total, 40% of the world's population lives in temperate climate zones (Lloyd et al, 2017[7]). We also subdivide the temperate climate zone into two reference systems: one representing regions with dry periods and other regions with hot summers.

In this study, we link the reference systems to the IEA's Announced Pledges Scenario (APS) by aligning certain assumptions to the scenario results for 2040. In addition, each system is scaled to 1 million people to improve comparability across systems.

The assumed annual electricity demand of each system varies between 8.7 and 9.1 TWh/1 million people. The electricity demand of electric vehicles is based on the WEO APS scenario, but the industrial H_2 demand was aligned between the regions. Other electricity demand roughly corresponds to the current electricity demand, and we used an average value as it varies widely between actual countries.

[6] Geiger, Rudolf (1954). "Klassifikation der Klimate nach W. Köppen" [Classification of climates after W. Köppen]. Landolt-Börnstein – Zahlenwerte und Funktionen aus Physik, Chemie, Astronomie, Geophysik und Technik, alte Serie. Berlin: Springer. Vol. 3. pp. 603–607.

[7] Lloyd, C., Sorichetta, A. & Tatem, A. High resolution global gridded data for use in population studies. Sci Data 4, 170001 (2017). https://www.nature.com/articles/sdata20171

Average annual electricity demands of different reference systems

Example system	Electricity demand for EVs TWh / 1 million people	Electricity demand for industrial H_2 TWh / 1 million people	Other electricity demand TWh / 1 million people
Tropical	0.4	0.3	8.0
Arid	0.3	0.3	8.0
Temperate with dry season	0.7	0.3	8.0
Temperate with hot summers	0.8	0.3	8.0
Continental	0.7	0.3	8.0

Actual demand depends on the modelled year. Whenever possible, time series from the same historical years are used. For the Tropical, Continental, and Temperate (dry seasons) models, the electricity demand time series are also from the same years, except for the Temperate (hot summers) and Arid (cold) regions. The Temperate (hot summers) system features observed data from 2016 to 2021 and constructed demand data from 2005 to 2015. For the Arid (cold) model, only one year of electricity demand data was available, and it was used for all weather years.

The load shapes were not modified from the historical profiles to account for possible future electrification of heating, and this will have impacted the results. However, part of the electrified heat can be flexible and should be modelled in a manner that recognises this potential flexibility, as well as the impact on the shape of inflexible demand.

Time series are collected from the following data sources: For Temperate with dry seasons, all hourly data is from ENTSO-E data for Spain.[8] For Continental, all hourly data is from ENTSO-E data for Poland. For the remaining regions, solar, wind, and hydropower hourly data has been derived using Atlite.[9] Data for the Tropical region is from Costa Rica, for the Arid region, it is from Peru, and for the Temperate with hot summers, it is from Japan's Kansai province. Electricity demand data comes from the IEA.

[8] ENTSO-E. Input Data for Mid-term Adequacy Forecast 2019. https://www.entsoe.eu/outlooks/midterm
[9] Atlite: A Lightweight Python Package for Calculating Renewable Power Potentials and Time Series. https://github.com/PyPSA/atlite

Modelled time series years and annual averages of time series

Example system	Modelled weather years	Hydro inflow (TWh)	Wind onshore (capacity factor)	Wind offshore (capacity factor)	Solar PV (capacity factor)
Tropical	2015-2021	1.1	0.34	0.37	0.16
Arid	2010-2021	0.40	0.45	0.62	0.20
Temperate with dry season	2006-2016	0.86	0.39	0.50	0.22
Temperate with hot summers	2005-2021	0.88	0.36	0.56	0.15
Continental	2006-2017	1.1	0.40	0.53	0.12

Note: Available data varies between regions, but allows modelling of at least seven consecutive years for the selected regions.

For each region, the annual sum of hydro inflow is scaled to WEO APS 2040, and the wind power capacity factor time series are scaled 40% higher, based on current trends of increasing capacity due to increasing turbine sizes.[10]

Modelled non-VRE capacities given as MW per 1 million people (MW/mp)

Example system	Coal MW/mp	NGCC MW/mp	Oil MW/mp	Nuclear MW/mp	Bioenergy MW/mp	Hydro MW/mp
Tropical	371	331	102	10	41	445
Arid	144	825	160	33	8	130
Temperate with dry season	526	322	30	63	23	336
Temperate with hot summers	465	301	17	117	41	358
Continental	256	500	11	142	25	442

Modelled non-VRE capacities are based on WEO APS 2040, but scaled down to match a system of 1 million inhabitants. Wind and solar power capacity are not assumed, but instead optimised by the model investment run and can vary, depending on assumptions and sensitivity studies.

Technology parameters and prices are derived from the IEA APS 2040 scenario, along with typical regional capacity mixes for thermal power plants (coal, natural gas, oil, biomass and nuclear), hydropower and the share of battery electric vehicles in the transport fleet. The model invests in wind and solar PV capacity and flexibility resources to minimise overall system costs at representative a

[10] Wind energy in Europe: 2021 Statistics and the outlook for 2022-2026.

carbon price of USD 120/tCO_2. Each example system is modelled separately using an hourly optimisation model, which considers the following technology options:

- Solar PV and wind (onshore and offshore) units
- Fossil, nuclear and biomass units
- Reservoir hydro
- VRE curtailment
- Battery energy storage
- Pumped hydro storage
- EV flexible charging
- H_2 storage with industrial demand side management
- Fuel cells
- H_2 co-firing in NGCC units
- Ammonia storage
- Ammonia co-firing with coal
- 100% ammonia combined cycle units.

Technology costs and efficiencies are based on techno-economic inputs of WEO APS 2040.[11] The following tables contain the main parameters of assumed existing units, and units that the model can invest in.

[11] https://www.iea.org/reports/global-energy-and-climate-model/techno-economic-inputs

Electricity generation units and H_2 production units

Technology	Investment cost		Fixed O&M	Efficiency	Variable O&M	Additional info
	USD / kW_elec	USD / kWh_elec	% of capex	%	USD / MWh_elec	
Bio	2560	-	3%	36%	3.9	
Coal	2000	-	3%	46%	2.8	NH_3 co-firing with coal, up to 60% (energy)
Diesel	600	-	5%	35%	6.0	
NGCC	1000	-	3%	55%	1.7	H_2 co-firing with NG, up to 50% (energy)
Gas engine	600	-	5%	35%	2.7	
Nuclear	5760	-	3%	33%	9.0	
PV	400	-	2%	100%	0.1	
Wind, onshore	1000	-	2%	100%	2.7	
Wind, offshore	1600	-	2%	100%	1.4	
Batteries	-	145	2%	86%	3.6	
PHS	1000	100	3%	76%	1.0	
PEM electrolyser	485	-	3%	71%	1.5	
Fuel cell	60	-	4%	54%	2.0	
CCGT Ammonia	1300	-	3%	44%	1.7	100% NH_3

H_2 storage assumptions

Technology	Investment cost		Fixed O&M	Efficiency	Variable O&M	Additional info
	USD / kW_H_2	USD / kWh_H_2	% of capex	%	USD / MWh_H_2	
H_2 storage	100	1	4%	95%	0	

NH_3 generation and storage assumptions

Technology	Investment cost		Fixed O&M	Efficiency	Variable O&M	Additional info
	USD / kW_NH_3	USD / kWh_NH_3	% of capex	%	USD / MWh_NH_3	
Haber-bosch + air separation unit	750	-	2%	74%	0	Efficiency calculated from H_2 and electricity inputs
NH_3 storage	10	0.1	-	100%	0	

Fuel prices are from WEO APS 2040, but the different coal and oil types were simplified for this study.

Fuel prices and CO_2 content of fuels

		Biomass	Coal	Natural gas	Oil
All regions	Price (USD/MWh)	22	22	37	50
All regions	CO_2 content (tCO_2/MWh)	0	0.340	0.200	0.265

Other central assumptions include an interest rate of 5% for wind and solar investments and an 8% interest rate for all other investments, as well as an economic lifetime of 20 years. We assume that in any given hour, 100% of generation can come from VRE, such as wind or solar. This assumes additional capabilities from the modelled grids and VRE technologies compared to today's standards – but many grid and VRE technology solutions are emerging that could eventually enable very high momentary contributions from VRE. Our investment modelling also assumes a 15% capacity margin (additional capacity beyond the highest actual level of demand) to ensure the necessary back-up capacity for every hour. This assumption is because we do not model reserves and intra-hour balancing.

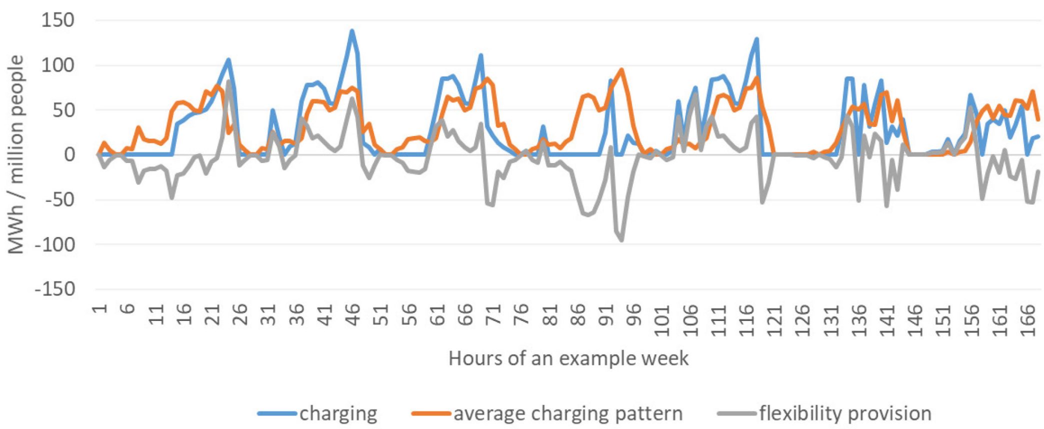
The model can provide required flexibility through dispatchable units (e.g. coal or hydropower), storage, as well as demand-side management. In the simulations, both electric vehicles and industrial electricity demand for H_2 generation can provide this kind of demand-side management.

Other central assumptions

Parameter		
Investments	Interest rate for wind and solar	5%
	Interest rate for all other investments	8%
	Economic lifetime (years)	20
Grid parameters	Maximum hourly VRE share	100%
	Capacity margin	15%
Other	CO_2 price (USD/tonne)	120

In the case of industry, we assume a constant demand for hydrogen, but the model may adjust the production of hydrogen in the case of new investment in hydrogen storage (see technological details above). Even relatively small additions to storage capacity can enable increased hydrogen production when there is excess electricity available, for example. Hydrogen can also be discharged from storage when there is less wind or solar available.

Example of EV charging patterns in the Arid example system



EVs have different demand patterns on weekdays than on weekends. These demand patterns, as well as the type of local electricity generation technologies available, produce a typical weekly charging pattern, that can vary from month to month. The figure above illustrates an average charging pattern of an example week from the Arid reference system. Actual hourly charging, and flexibility provisions are calculated as a difference between these two.

Abbreviations and acronyms

BECCS	Bioenergy with carbon capture and storage
BESS	Battery energy storage system
BEV	Battery electric vehicle
CAES	compressed air energy storage
CAPEX	capital expenditure
CCGT	combined-cycle gas turbine
CCUS	carbon capture, utilisation and storage
CO_2	carbon dioxide
DAC	direct air capture
DACS	DAC with storage
EMDE	Emerging market and developing economies
H_2	hydrogen
LDES	long-duration energy storage
NH_3	ammonia

Glossary

bbl	barrel
bbl/d	barrels per day
bcm	billion cubic metres
bcm/yr	billion cubic metres per year
cm/s	centimetres per second
g CO_2	gram of carbon dioxide
g CO_2/kWh	grams of carbon dioxide per kilowatt hour
GJ	gigajoule
Gt/yr	gigatonnes per year
Gt CO_2	gigatonne of carbon dioxide
Gt CO_2/yr	gigatonnes of carbon dioxide per year
GW	gigawatt
GWh	gigawatt hour

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