Integrating Solar and Wind

Global experience and emerging challenges

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Abstract

Solar photovoltaics (PV) and wind power have been growing at an accelerated pace, more than doubling in installed capacity and nearly doubling their share of global electricity generation from 2018 to 2023. This report underscores the urgent need for timely integration of solar PV and wind capacity to achieve global decarbonisation goals, as these technologies are projected to contribute significantly to meet growing demands for electricity by 2030. However, should countries fail to implement integration measures in line with a scenario where they achieve their climate and energy pledges, the global power sector could jeopardise up to 15% of solar PV and wind energy or variable renewable energy (VRE) generation in 2030. If this gap is compensated for with continued reliance on fossil fuels, it could lead to significantly less CO_2 emissions reductions.

A key aspect of this report is a first-ever global stocktake of VRE integration measures across 50 power systems, which account for nearly 90% of global solar PV and wind power generation. This analysis identifies proven measures for facilitating VRE integration, particularly in systems at early phases of adoption. This report also updates IEA's phases of VRE integration framework to reflect emerging challenges at higher levels of VRE penetration and provides an overview of solutions to address them that are already beginning to be implemented in several countries. This report emphasises that while systems at early phases of VRE integration can accelerate deployment with relatively low system impact, those in high phases face more complex challenges related to stability and flexibility, which call for a transformation of how power systems are operated, planned and financed.

This report calls for strategic government action, enhanced infrastructure, and regulatory reforms to ensure the successful large-scale integration of solar PV and wind in order to meet global energy transition targets. Robust data, stakeholder collaboration and government prioritisation of integration measures are essential for overcoming these challenges and achieving a sustainable energy future.

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Executive summary

Timely integration is essential for widespread uptake of solar PV and wind

Realising the full potential of expanding solar PV and wind requires proactive integration strategies. Between 2018 and 2023, solar PV and wind capacity more than doubled, while their share of electricity generation almost doubled. Governments are positioning these sources as key pillars for decarbonising the energy sector, and capacity is expected to continue expanding at speed towards 2030, driven by a supportive policy environment and recent cost reductions in solar PV and wind. The COP28 pledge to triple global renewable capacity by 2030 suggests growth could accelerate even more than anticipated, requiring intensified efforts and investments to meet this ambitious target.

Maximising the benefits from increased solar PV and wind capacity requires effective integration into power systems. While power systems have always managed demand variability, variable renewable energy (VRE) such as wind and solar PV introduces supply variability depending on the weather. This variability will require increasing the flexibility of the entire power system, by leveraging dispatchable generation, grid enhancements, increased storage and demand response. Successful integration maximises the amount of energy that can be sourced securely and affordably, minimises costly system stability measures, and reduces dependency on fossil fuels.

Delaying the implementation of measures to support integration could jeopardise up to 15% of solar PV and wind power generation in 2030 and would likely result in up to a 20% smaller reduction of carbon dioxide (CO_2) emissions in the power sector. Should integration measures fail to be implemented in line with a scenario aligned with national climate targets, up to 2 000 terawatt-hours (TWh) of global VRE generation would be at risk by 2030, endangering achieving national energy and climate pledges. This potential loss – equivalent to the combined VRE output of China and the United States in 2023 – stems from possible increases in technical and economic curtailment, as well as potential project connection delays. Consequently, the share of solar PV and wind in the global electricity mix in 2030 would reach 30%, lower than the 35% in the case where integration measures are implemented on time. If this decrease is compensated by increased reliance on fossil fuels, it could lead to up to a 20% smaller reduction of carbon dioxide (CO_2) emissions in the power sector.

Governments must strategically support targeted integration measures, but guidance is needed on which to prioritise at different stages. Integration of VRE has been a key research focus for many years in leading markets, resulting in the proposal of numerous technological, policy and operational measures. Despite this extensive research, identifying specific priority measures for implementation remains challenging. This report aims to support policy makers on this issue by presenting an update of the IEA's phases of VRE integration framework, originally developed in 2017 and subsequently refined with the Clean Energy Ministerial Initiative, 21st Century Power Partnership.

This framework identifies six phases of increasing system impacts from solar PV and wind generation, each with corresponding challenges and solutions. By mapping a system to its current phase, the framework helps identify priority integration measures and facilitates the sharing of experiences across systems in similar circumstances. A definition of each phase can be found at the end of this executive summary.

The IEA's stocktake reveals proven strategies and concrete measures for successful VRE integration. This report presents a first-ever comprehensive stocktake of integration measures implemented across 50 power systems worldwide, covering nearly 90% of global solar PV and wind generation. The analysis identifies a core set of measures universally adopted by systems in Phase 2 of VRE integration and higher. These serve as a guide for governments to identify and implement proven, effective integration approaches. Additionally, the stocktake provides insight into the measures adopted in systems at the forefront of VRE integration, offering a guide for creating forward-looking strategies.

Well-known and tested measures can be used to integrate the majority of new VRE

Most of the growth in VRE generation will occur in systems at low phases of VRE integration (Phases 1 to 3). In a scenario in which countries meet their climate and energy commitments in full and on time, nearly two-thirds of additional solar PV and wind generation in 2030 compared to 2022 is projected to occur in systems at low phases of VRE integration. These systems are primarily located in emerging market and developing economies (EMDEs), including India and Brazil, along with others in the Middle East, Asia, Africa and Latin America. The remaining third of VRE generation growth would take place in energy systems at high phases of integration, many of which are in advanced economies.

Measures based on progressive and targeted adjustments can integrate most new capacity in low-phase systems. Systems in early integration phases experience relatively low impacts as solar PV and wind generation increase, with most challenges addressable through straightforward modifications to existing assets or operational improvements that increase flexibility. Our stocktake, which identified core integration measures implemented in all of the 40 systems in Phase 2 or higher, revealed a common characteristic: they could be implemented in a targeted and progressive manner. These measures include optimising dispatch processes and improved forecasting, soliciting higher flexibility and system services from both conventional and VRE power plants, enabling industrial demand response and enhancing grid infrastructure. The key advantage of these measures lies in their adaptability, as they do not require complete implementation or sweeping transformations of the power system, regulatory frameworks or market structures. Instead, they provide a flexible approach that can be tailored to address specific challenges as they arise, facilitating a cost-effective and scalable integration process that evolves alongside the changing needs of the power system.

Integration challenges should not be seen as a significant barrier for expanding VRE capacity in systems at low phases of integration. The relatively low system-level impacts of VRE in low-phase systems, coupled with the availability of cost-effective, progressively implementable integration measures, should alleviate concerns about integration challenges for countries with low VRE penetration. By implementing the core integration measures we identified in tandem with VRE deployment, systems with currently limited VRE capacity can significantly accelerate their clean energy ambitions. This strategic approach is crucial for maximising the benefits of VRE technologies, including their positive impacts on decarbonisation, delivering affordable energy to consumers and reducing dependency on fossil fuels.

Frontrunner systems show that effective integration of high VRE shares is possible today

Some frontrunner power systems today are effectively managing high levels of variable renewable energy. Systems such as those in Denmark, Ireland, South Australia and Spain have reached Phase 4 or higher, integrating from 35 up to 75% of VRE in their annual generation, depending on the system. At these penetration levels, challenges in stability and flexibility across all timeframes become more acute. These systems often see VRE cover most of their generation for over a day, necessitating innovative solutions in terms of operating, planning, and financing their power system. Their experiences provide valuable insights for other systems around the world aiming to accelerate VRE integration.

Existing technologies are successfully helping to tackle the challenges associated with integrating high shares of VRE. Most technological solutions addressing emerging challenges – namely, a higher focus on stability and a growing need for flexibility across all timeframes – are either mature or commercially available. The key to their successful rollout often lies in appropriate policy and regulatory action rather than new technological breakthroughs. For many systems, reaching Phase 4 or even 5 depends mainly on effective deployment of existing technologies rather than developing new ones. While for Phase 6, viable technologies exist but their implementation at a large scale remains limited, requiring additional testing or economic incentives for deployment.

Achieving this level of integration requires a paradigm shift in system operation, planning, and financing. Integrating high shares of VRE requires rethinking the traditional way in which power systems are operated, planned, and financed. Essential elements include modernising system operation practices, improved strategic planning, and overhauling regulatory frameworks. Market design must evolve as well to accommodate the unique characteristics of solar and wind-dominated grids, new technologies, and the new role of conventional generation as the provider of essential system services rather than energy. This includes developing new methods for procuring and rewarding necessary system services, ensuring they are maintained and evolved as needed.

While significant progress has been made by frontrunner systems, not all answers exist today for future very high VRE penetration levels. The continued and accelerated VRE growth in the coming decade will likely unveil new integration challenges. These may come from frontrunner systems reaching unprecedented levels of VRE or from systems with unique local conditions that require innovative solutions. Many additional systems – including those in Australia, Japan, Italy and Brazil – are expected to reach Phase 4 or higher by 2030. For these systems, an ongoing focus on developing integration measures – coupled with global sharing of effective policies, regulatory frameworks, and market design elements – will be crucial in supporting a secure energy transition.

Some key issues for power systems with very high VRE penetration remain unresolved. These topics include addressing seasonal variability concerns, operating systems with very high levels of converter-based resources, ensuring the profitability of new investments amid increasing price volatility, and appropriately remunerating assets that provide flexibility for their system value. Resolving these challenges will require continued innovation, collaboration and commitment from policy makers, technology leaders and researchers worldwide.

Six phases of variable renewable energy integration

Phase 1: VRE has no significant impact at the system level

Phase 2: VRE has a minor to moderate impact on the system

Phase 3: VRE determines the operation pattern of the power system

Low phases

Phase 4: VRE meets almost all demand at times

Phase 5: Significant volumes of surplus VRE across the year

Phase 6: Secure electricity supply almost exclusively from VRE

High phases

Introduction

The global energy landscape is witnessing unprecedented expansion of variable renewable energy (VRE) sources,[1] particularly solar PV and wind power. These technologies consistently break records for annual installation, driven by rapidly declining costs and increasingly ambitious government and multilateral policies, and are set to grow at an increasing pace. The COP28 pledge to triple global renewable capacity by 2030 exemplifies the commitment to accelerate this growth, setting the stage for the continuing transformation of the power sector worldwide.

VRE sources are not only crucial for power sector decarbonisation, but also offer benefits that extend far beyond environmental concerns. By reducing reliance on fossil fuels, renewables can enhance energy security and improve affordability, providing a hedge against volatile fuel markets. However, realising these multifaceted benefits requires more than simply installing renewable capacity; it needs the effective integration of VRE into existing power systems. This integration ensures that renewable electricity can be reliably delivered when and where it is needed, maximising its value to the grid and consumers alike.

The system integration of solar PV and wind involves the technical, institutional, policy, and market adjustments necessary to ensure their secure and cost-effective incorporation into the power grid. Achieving this requires enhancing system flexibility and strengthening the supporting infrastructure. Successful integration maximises the use of renewable energy, minimises the need for costly interventions to maintain system stability, and reduces reliance on fossil fuels.

Despite the global trend towards VRE, growth has been uneven across regions and countries. While some nations, particularly among advanced economies, are achieving high levels of solar and wind penetration, many others lag behind. This disparity is especially pronounced when compared with emerging market and developing economies (EMDEs), where significant renewable energy potential often remains untapped. Many of these countries can deploy renewables faster, but integration concerns hinder progress. Addressing this VRE deployment and integration disparity between regions is crucial for meeting global climate goals and ensuring equitable access to clean energy benefits.

There is now a wealth of global experience in integrating VRE into power systems with low to moderate shares. Early adopters of VRE have developed and refined a wide array of integration measures spanning technological solutions, operational

[1] In this report, VRE refers to solar PV and wind unless explicitly stated otherwise. Similarly, solar and wind refers to solar PV and wind unless explicitly stated otherwise.

practices, market designs and policy frameworks. This accumulated knowledge provides a solid foundation for countries at early stages of their VRE deployment journey, offering proven strategies to overcome initial integration challenges.

Simultaneously, a growing number of power systems are pushing the boundaries of VRE integration, successfully managing very high shares of variable renewables. These frontrunner systems are developing innovative approaches to address the unique challenges that arise when VRE becomes a dominant electricity source. Their experiences offer insights into highly renewable power systems and guidance for countries progressing towards higher VRE penetration.

Policy action will be key to maximising the contribution of solar and wind to the system

This report aims to put a spotlight on the measures used to integrate VRE, particularly those beyond grid expansion. As most technological solutions for VRE integration are operationally proven or commercially available, their sufficient deployment in many cases will be directly tied to decisions by policy makers in co-ordination with regulators, system operators, utilities, and consumers. In this report, we present a first-ever detailed stocktake of VRE integration measures from 50 power systems representing nearly 90% of global VRE generation.

Our analysis shows that countries with a lower penetration of VRE can integrate vastly higher amounts of VRE, relying on gradual adjustments to their systems based on ample global experience. Even systems with higher levels of VRE penetration, which will require an increasingly transformative way of operating, planning and financing the system, can learn from successful early experience of frontrunners that are already dealing with emerging integration challenges.

This report also provides an update of the IEA's phases of VRE integration assessment framework, reflecting an improved understanding that builds on more than a decade of global experience. We use this framework to classify and describe the challenges and solutions typically experienced when integrating VRE at different penetration levels. We also provide a first-of-its-kind analysis showing that 64% of the global growth in VRE generation between 2022 and the IEA's 2030 Announced Pledges Scenario (APS) is set to occur in systems at low phases of VRE integration, mostly found among EMDEs.

Additionally, we introduce the Integration Delay Case, a variation of the APS that explores the impacts of insufficient deployment of integration measures by the end of this decade. This special case allows us to highlight that significant increases in VRE generation can be realised by 2030 by implementing a set of VRE integration measures progressively, particularly at lower levels of VRE penetration. However, at the same time, the full value of new VRE capacity additions will only be unlocked if the necessary VRE integration measures are deployed on time. Our Integration Delay Case estimates that about 15% of total solar PV and wind generation in the APS in 2030 could be jeopardised if the implementation of VRE integration measures is delayed.

The report is structured in four chapters as follows:

In **Chapter 1, From installing to integrating solar PV and wind,** we give an overview of the evolving role of VRE in power systems worldwide, in the context of market developments and national and multilateral pledges. We then highlight specific challenges relating to VRE integration and explore how several regions are already addressing them successfully, making VRE central in operation of their power systems. We also look at the growing need for further grid development and power system flexibility. Finally, we present the updated phases of VRE integration framework, and give an updated assessment of several systems in terms of their current phase of VRE integration and its evolution to 2030.

In **Chapter 2, Global experience,** we describe in more detail the updated IEA's phases of VRE integration assessment framework and the typical challenges at each phase. Based on an analysis of 50 power systems globally, we show through historical experience how various countries and regions have addressed these challenges and draw out common measures. We also offer insights based on the prioritised measures according to system archetypes. These are the grouping together of systems sharing similar characteristics that affect their ability to deal with the challenges at each phase of VRE integration.

In **Chapter 3, Emerging challenges and solutions at high VRE shares,** we focus on two challenges that become more acute and widespread at higher levels of VRE penetration: a higher need for stability and flexibility. We discuss how most of the technological solutions needed to address these challenges are either already or nearly commercially available, with the key factor for a successful rollout in many cases being policy and regulatory action. We discuss and present examples of several approaches that have been taken by various frontrunner systems to address the need for more stability and flexibility, including new system services, updated operating practices, and market mechanisms.

In **Chapter 4, Policy action,** we highlight the relevance of policy action and highlight key focus areas for policy makers. Based on a first-of-its-kind analysis, we show how most of the VRE growth out to 2030 – in a scenario where countries meet their climate and energy pledges – happens in systems at low phases of VRE integration. Further, we explore the global impacts of delaying the introduction of necessary integration measures. We then provide cross-cutting recommendations on topics such as infrastructure development and market design and operation, and how to accelerate VRE uptake in systems at low and high phases of VRE integration.

Chapter 1. From installing to integrating solar PV and wind

Electricity systems are undergoing a significant transformation as part of the global clean energy transition, led by the installation of solar and wind generation capacity. The widespread adoption of solar (largely PV) and wind generation technologies are increasingly leading to changes in how electricity systems are operated and planned. VRE deployment is set to accelerate in the coming years due to market trends and political commitments, which include national and regional decarbonisation commitments and the COP28 pledge to triple global renewable capacity by 2030. To better integrate existing and new VRE capacity into electricity systems across the world, it is essential to understand the outlook for their deployment, which integration measures are currently implemented, and what could be the main challenges to address to ensure that they provide the best value to consumers.

In this chapter we present an overview of the status and challenges of VRE integration. We discuss how several domestic and multilateral energy pledges, alongside market trends, are set to push solar and wind deployment to new heights in the coming years. After briefly discussing some of the characteristics of VRE that require adjustments to power system operation and planning, we highlight how concerns about integration challenges are already impacting the power sector. Despite these concerns, record levels of VRE penetration are being reached by frontrunner systems, which shows how effective many countries are being at integrating growing shares of VRE.

We then point out how greater power system flexibility and expanded grids will be crucial to integrating more VRE. Our analysis shows that global supply of short-term power system flexibility and grid investment need to double by 2030 to stay on track with a scenario where countries achieve their climate and energy goals (the IEA's Announced Pledges Scenario).

We present an update of our phases of VRE integration assessment, which builds on more than a decade of integration experience to classify and describe the challenges and potential solutions associated with increasing system impacts of VRE. By applying the IEA's phases of VRE integration classification, we find that out of 50 systems we assessed, about 80% of them are currently in low phases of VRE integration (Phases 1 to 3) and 20% are currently in high phases (Phases 4 to 6). Based on the future evolution expectations, we project many additional systems to be in high phase by 2030. Frontrunner systems are mostly found within advanced economies, even though there are systems in EMDEs with remarkable resource potential that could be leveraged to deploy and integrate solar and wind faster. Historical experience with successful VRE integration across various regions shows that there is a good understanding on how to navigate lower VRE penetration in different system and institutional contexts. At the same time, based on the outlook for 2030 and beyond, there is a clear need to continue developing solutions to integrate VRE securely at high phases of VRE integration, some of which are already being introduced successfully by frontrunner systems in many regions.

Upcoming growth in renewable energy

The installed capacity of renewables has more than doubled in the past decade, with almost all the growth coming from solar and wind power. In the coming decade growth is set to continue at pace, with global commitments such as the pledge to triple renewable power capacity by 2030 requiring additional acceleration. According to IEA analysis, in a scenario where this pledge is achieved, two-thirds of new renewable capacity out to 2030 comes from solar PV and a quarter from wind. The generation capacity of other low-emissions technologies, such as nuclear and hydro, are also expected to increase by about 25% and 30%, respectively. This contrasts with the trajectory of generation capacity from fossil fuels (coal, natural gas and oil), which is expected to decrease by almost 25% out to 2030 in the same scenario.

Market trends supported by government pledges indicate that accelerated growth of solar and wind is coming

Since the Paris Agreement was adopted by 195 parties in 2015, a growing number of decarbonisation pledges have been made across the globe to keep the 1.5 °C target within reach. As of November 2023 a group of 145 countries accounting for almost 90% of energy-related CO_2 emissions had adopted net zero pledges. Further, recognising the major contribution of coal to greenhouse gas emissions from the power sector, by the end of 2023 at least 84 countries had agreed to phase out (unabated) coal, accounting for 30% of coal-fired generation at the time. In the European Union, in the context of its REPowerEU plan, renewable electricity would reach a share of 69% by 2030,[2] with large contributions from solar and wind. Moreover, G7 countries pledged to achieve predominantly decarbonised electricity systems by 2035.

[2] Based on the RES-E indicator. This document by the European Commission provides an explanation of its definition.

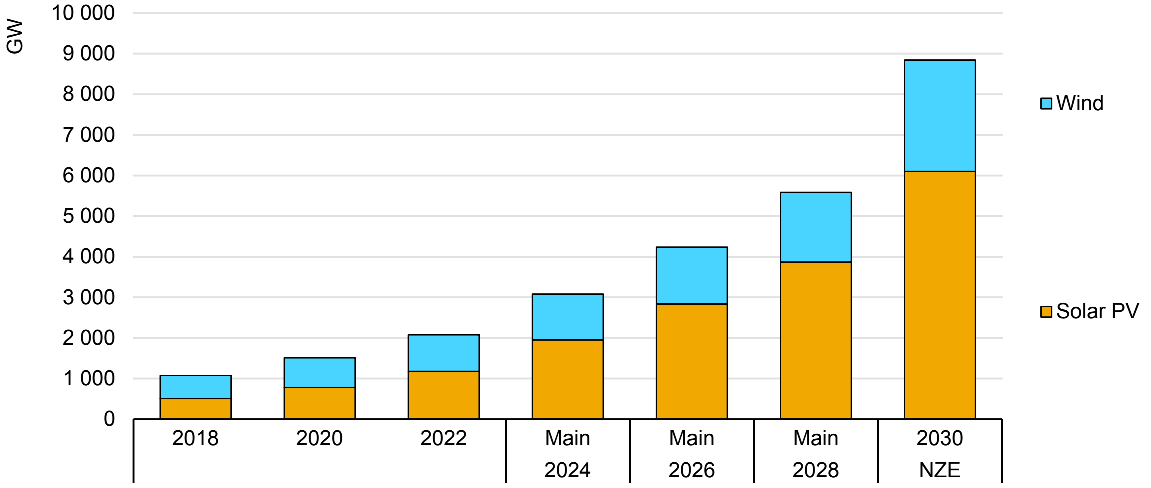
Multilateral power sector goals are complemented by domestic ambitions supporting the deployment of renewables. As part of the Paris Agreement, countries submit nationally determined contributions (NDCs) in which they outline the targets and actions they will take to reduce their emissions. As of October 2023 more than 110 signatories had established 2030 renewable energy targets for the power sector, with 63 commitments specifying percentages, including countries beyond Europe and North America such as Kenya, Australia, Chile and Brazil. Among these, 24 parties have pledged a renewable share ranging from 25% to 59%, 14 have set targets between 60% and 89%, and 12 aim for a share between 90% and 100%.

In this context, COP28 in 2023 saw 132 countries and the European Union pledge to triple global renewable power capacity by 2030, recognising the major role that renewables will play in reducing power sector emissions in an affordable manner. To reach the tripling goal, global installed renewable capacity should reach at least 11 000 GW by 2030 (up from about 3 600 GW in 2022), keeping the 1.5 °C target within reach. The pledged scale-up includes investment in various renewable technologies; however, in a scenario where the tripling goal is achieved, solar PV and wind represent 92% of the increase in total renewable capacity by 2030. These sources already account for most generation capacity additions, in part thanks to reductions in the average levelised cost of electricity (LCOE) for utility-scale solar and onshore wind of about 89% and 67%, respectively, between 2010 and 2022.[3]

Given the current policy setting and market conditions, VRE generation capacity by 2028 is set to reach 2.7 times that of 2022, with solar accounting for about three-quarters of that growth. Despite this significant expected VRE growth, more efforts are needed to reach the goal of tripling the generation capacity of all renewables by 2030.

[3] The LCOE combines into a single metric all the cost elements directly associated with a given power technology. This includes construction, financing, fuel, maintenance, and costs associated with a carbon price. It does not include network integration or other indirect costs. It is normally presented in terms of USD/MWh.

Historical and future cumulative solar PV and wind power capacity in the Renewables 2023 main case (2024-2028) and Net Zero by 2050 Scenario, 2018-2030



Notes: Main = Renewables 2023 main case; NZE = Net Zero Emissions by 2050 Scenario.
Sources: IEA (2024), Renewables 2023; IEA (2023), World Energy Outlook 2023.

Integrating variable renewable energy

VRE integration is key to ensuring that the potential benefits offered by capacity additions are maximised. Integration is the process of incorporating solar and wind power into electricity systems in a secure and cost-effective way. It is important to do this in a timely manner, in synch with the solar and wind capacity additions, so that investments in VRE deliver the intended benefits.

Concerns over integration challenges, such as grid connection queues and congestion management, are deterring investment in solar and wind, as reported by various industry players. These issues cause delay and uncertainty, making it difficult for projects to get approved and connected, and negatively impacting their business case. In 2023 more than 3 000 GW of renewable power projects were reported to be in connection queues, and congestion management volumes and costs are rising in places such as Europe and the United States. These signal potential delays in the buildout of VRE projects, and when they are built, in the delivery of the generated energy, affecting cost recovery in line with business plans. The risk of delay affects investor appetite, which can slow growth in renewable energy projects despite the increasing demand for clean energy.

Integrating high shares of VRE requires operating the power system in a different way to that of operating a grid designed with conventional generators in mind, where power flows from fewer large units mainly in one direction towards consumers. This is because VRE plants have characteristics that are more pronounced than or inherently different from conventional units, such as variability and uncertainty, locational mismatch, decentralisation and their non-synchronous interface with the grid.

The variability and uncertainty of the outputs of solar and wind power plants are caused by changing weather conditions, which can be difficult to predict accurately. Wind power output fluctuates with wind speed and direction, while solar power output varies with the intensity of the sunlight, which is affected by clouds and fog. These aspects can change rapidly and are localised, making them difficult to anticipate. While existing power systems' operational decisions are already designed to deal with some level of demand variability and uncertainty, the characteristics of solar and wind bring larger swings in supply and wider ranges of uncertainty, affecting the ability to manage power systems using traditional methods. These impacts can be seen in timeframes ranging from less than a minute to months or seasons.

Areas with an abundance of solar and wind resources are typically far from those where electricity consumption is concentrated, needing them to be connected by the grid – this is what we refer to as locational mismatch. In particular, utility-scale VRE plants tend to be situated far from urban and industrial centres. To deliver the generated electricity from one location to another, transmission capacity needs to be created or enhanced, which typically involves long lead times due to planning and funding requirements.

Furthermore, in contrast with conventional generation, which is typically large power plants, the rollout of VRE often tends to be decentralised. For example, rooftop solar power systems are small and numerous, and even utility-scale renewable power plants are on average smaller than conventional power plants. The large volume of power-producing units with various sizes, configurations and ownership makes it difficult to have a comprehensive overview of or influence over their behaviour. This can particularly be the case on distribution grids, where many of these power plants are being connected.

Lastly, solar and wind power plants are connected to the grid as non-synchronous generation, without relying on the rotating machinery of synchronous generators used in conventional plants such as hydro, coal, nuclear and gas-fired power units. Instead, these technologies typically use electronic power converters, which do not provide by default the same grid-stabilising properties such as inertia (although, as discussed in Chapter 3, connecting them via grid-forming converters could support grid stability further). The lack of synchronous generation can lead to challenges in maintaining grid stability, particularly for frequency control and voltage support, if system management is not adapted for these conditions.

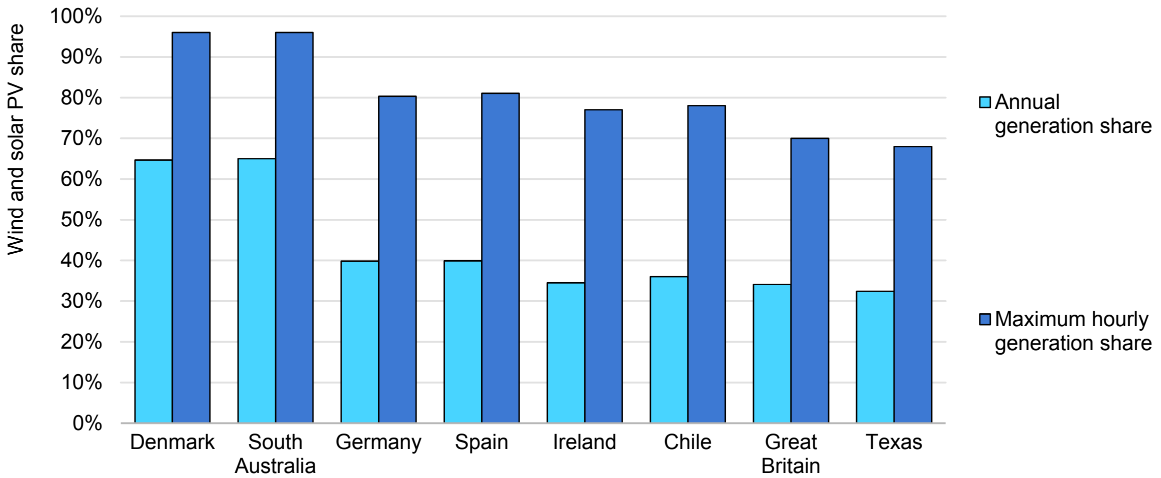
Several regions are successfully integrating high shares of VRE in their power system operation

More than a decade ago many power systems around the world were just beginning to deploy VRE and facing some of these integration challenges – challenges which were, at the time, new. However, there are now numerous power systems around the world that have successfully integrated VRE, with some of these achieving shares that were previously considered impossible.

Reaching high levels of solar and wind penetration in the power sector is no longer a hypothetical case – they are a reality in many countries. Denmark, Texas, South Australia, Ireland, Spain and Chile are among the countries and regions where solar and wind already contributed over 30% of annual generation in 2023. These and other systems are also achieving record highs of hourly penetration, when VRE meets the majority (or practically all) of their power needs for several hours during the year.

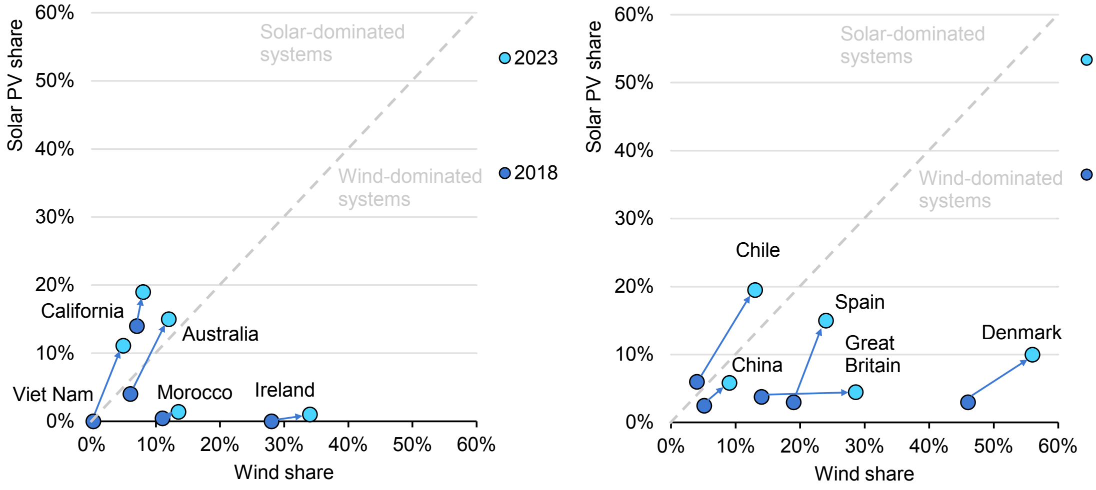
This growth in VRE integration is taking place across power systems with varied renewable energy resource endowments. For example, Denmark, Ireland, Great Britain, Morocco have increased their VRE generation predominantly relying on wind power, while VRE generation in the People's Republic of China (hereafter "China") and Spain is slightly dominated by wind power. In contrast, Chile, California, Viet Nam and, to a lesser extent, Australia, have adopted solar as their predominant source. This shows that systems have managed to integrate higher shares of VRE with different mixes of solar and wind, depending on which resource is more competitive in their area.

Annual and maximum hourly solar PV and wind generation shares, selected countries and systems, 2023



Sources: IEA (2024), World Energy Statistics; hourly data collected using the IEA's Real-Time Electricity Tracker.

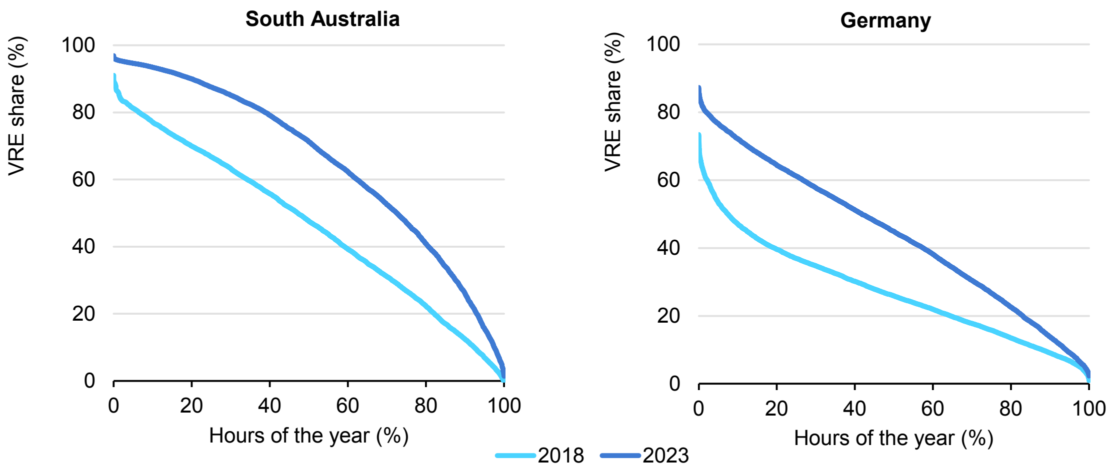
Annual solar and wind generation shares, selected countries and systems, 2018-2023



Note: The countries shown were selected to achieve a sample with geographical and solar and wind resource diversity.
Sources: IEA (2024), World Energy Statistics; operational data collected using the IEA's Real-Time Electricity Tracker.

VRE is becoming central to the operation of power systems in many countries and regions. In South Australia, while in 2018 VRE provided less than 50% of total generation in roughly half of the year, by 2023 VRE generation provided at least 70% of the region's total generation during half of the year. In another example, Germany's power grid operated with hourly VRE shares below 30% for most of 2018. By 2023 almost 70% of the year saw a VRE share above 30%. Many other systems around the world have seen similar transitions.

Cumulative distribution of hourly solar PV and wind generation shares, South Australia and Germany, 2018 and 2023



Note: VRE = variable renewable energy. The presented data is based on operational data at the transmission level, which may not include behind-the-meter generation at the distribution level such as from rooftop solar PV panels.
Source: IEA analysis based on operational data collected via the IEA's Real-Time Electricity Tracker.

Keeping up the pace of integration will require more grid development and additional supply of flexibility

Successfully integrating higher levels of solar and wind energy into the grid will increasingly rely on having adequate measures in place. In this context, two critical requirements are electricity grids (including expansion, modernisation and upgrades) and procuring flexibility from a broad range of assets.

Grid development needs

Electricity grid expansion, modernisation and upgrades are crucial to allow solar and wind energy to serve growing demand. Grids need to grow and be strengthened to connect the new solar and wind power plants, to transport the generated electricity to consumers, and to balance electricity supply and demand securely. Additionally, grids support solar and wind integration by facilitating geographical smoothing of their generation profiles, improving the power system's flexibility. IEA analysis shows that global annual grid investment needs to double by 2030 to stay on track to meet country pledges on energy and climate goals.

Power systems globally are already seeing the consequences of delayed grid investment, as concerns over issues such as grid connection queues, congestion management costs and electricity security have risen in recent years. Between 2010 and 2023 global investment in renewables almost doubled, while from 2015 grid investment stagnated at USD 300 billion annually until 2024 when it rose to USD 400 billion. As a result of insufficient grid investment, at least 1 500 GW of solar and wind projects at an advanced stage were waiting for grid connection as of mid-2023. Further, many countries are facing grid congestion issues, which are expensive to address due to the high cost of dispatching power plants to overcome immediate issues and because of the large amount of investment necessary to overcome congestion in the future. In the United States, for example, congestion management costs rose from USD 6 billion in 2019 to almost USD 21 billion in 2022, the latter equalling more than USD 4 per MWh consumed. Similarly high multi-billion annual costs have been seen in other countries such as Germany and Great Britain, which have resulted in a cost of approximately USD 8 per MWh consumed. Furthermore, delayed grid development also increases the risk of power outages, which already cost the world at least USD 100 billion a year (0.1% of global GDP).

It is crucial for countries to accelerate grid expansion and upgrades, as it enables benefits beyond solely integrating VRE, such as improved electricity access and supporting overall demand growth. However, as grid development takes a long time to materialise, complementary solutions with shorter lead times must be deployed when needed to improve the integration of solar and wind. This is why we focus on VRE integration measures beyond grid expansion in this report.

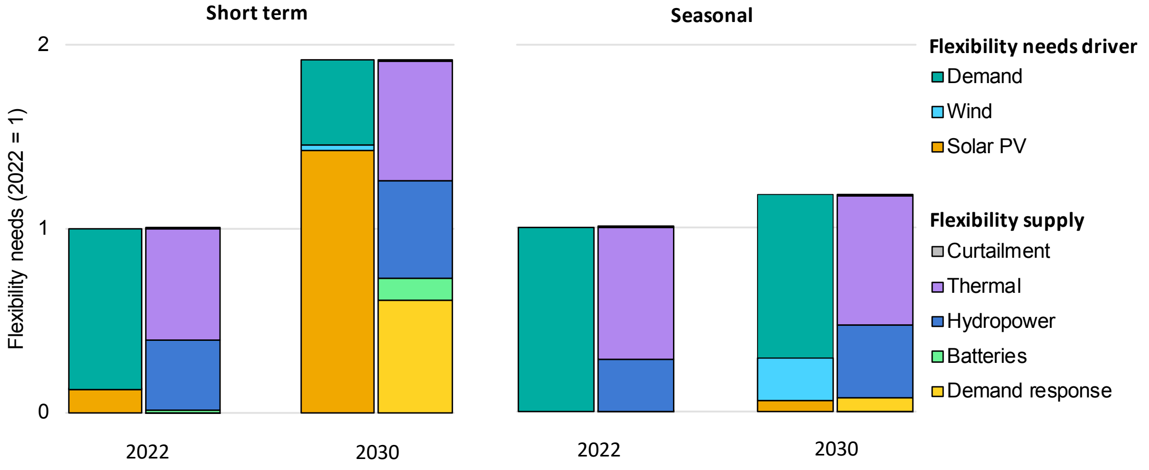
Growth in the need for flexibility

Power system flexibility is key in dealing with many of the impacts of variability and uncertainty. It 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. Maintaining the supply-demand balance is achieved by adjusting electricity generation and demand. Flexibility can extend across several timescales, for example managing hourly changes in the supply-demand balance, up to dealing with extended periods of lower resource availability, for example in the case of droughts affecting hydropower.

In a scenario where countries reach their announced climate and energy goals (the Announced Pledges Scenario), global average flexibility needs increase by 2030 and even more so in later years. At one end of the timescale spectrum, short-term flexibility needs (i.e. hourly changes within a day) are on average almost twice those of today by 2030, with solar PV becoming a key driver of these flexibility requirements. Most of these needs would be met by solutions that are already in use, such as batteries, demand response and, to a smaller extent, curtailment. At the other end of the timescale spectrum, global seasonal flexibility needs increase less sharply by 2030. However, countries with higher VRE penetration and/or power demand from end uses such as heating and cooling could also see greater seasonal flexibility needs as an emerging challenge. For example, in its 2024 Summer Reliability Assessment, the North American Electric Reliability Corporation (NERC) gave several regions the ”Elevated Risk” classification, some of them because of expectations of high demand related to high temperatures.

The sources of flexibility differ across regions, shaped by natural resources, historical development, and the specific characteristics of each system. One region may rely heavily on hydropower, while another might depend on a mix of gas-fired plants and demand response. Flexibility also extends beyond conventional generators, encompassing storage, new electricity-based end uses, and grid infrastructure, all of which vary regionally.

Global power system flexibility needs and supply in the Announced Pledges Scenario, 2022-2030



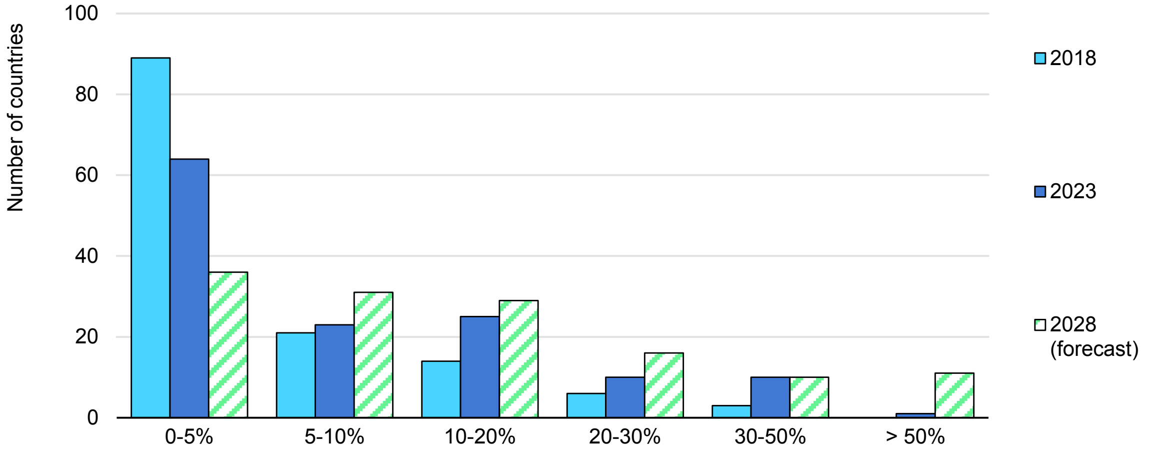
Notes: Flexibility needs are computed for 2030 taking into account changes in electricity supply and demand and weather variability over 30 historical years. Demand response includes the flexible operation of electrolysers. The figure represents the global average and therefore does not include the contribution of imports or exports. Short-term flexibility is calculated based on hourly changes in net demand (i.e. total demand minus wind and solar PV generation) within a day, and seasonal flexibility based on weekly changes in net demand within a year. More details on the calculation methodology can be found in IEA (2024), Managing the Seasonal Variability of Electricity Demand and Supply.

Source: IEA (2023), World Energy Outlook 2023.

Integration is crucial as even more systems will depend on solar and wind in the coming years

Power systems around the world have done rapid progress on VRE uptake, and expected capacity additions are set to continue driving the contribution of VRE to new heights. From a sample of 133 countries covering 99% of global electricity generation, in 2018 only around 15 countries had an annual VRE generation share of 10% or higher – that amount of countries nearly doubled in 2023. By 2028 almost 70 countries are set to have a VRE generation share of at least 10%, whereas those with VRE shares above 30% will grow from only four in 2018 to more than 20 in 2028. This shows that higher levels of VRE penetration will not only be a reality for a select group of frontrunner systems, but a common trend for a large group of systems around the world. This highlights the speed of the transformation that electricity systems are experiencing around the world, with solar PV and wind playing a key role in this transition.

Number of countries per range of annual VRE generation share, 2018-2028



Note: The analysis includes 133 countries and territories, representing about 99% of global electricity generation in 2023.
Sources: IEA analysis based on data from IEA (2024), Renewables 2023; IEA (2024), Electricity 2024.

This report presents an updated version of the IEA's phases of VRE integration framework as a basis to discuss integration challenges and measures. We originally developed this framework in 2017 and updated it in 2018 and 2019 in partnership with the 21st Century Power Partnership. It consists of six distinct phases of VRE integration that describe typical challenges and examples of how various countries have addressed them. The updates made to the assessment framework, which relate to Phases 4 to 6, are described in more detail in Chapter 2.

The framework identifies system-level challenges rather than isolated local incidents, focusing on net load characteristics. Local conditions taken into account include not only VRE penetration, but also the technology mix, degree of interconnection and size of the system. There are no generic thresholds to denote that a country is in a particular phase. While the annual share of VRE is an indicator used to identify a system's phase, its short-term variability and system balance are also taken into account.[4] Using this assessment framework, we also present typical solutions implemented at various phases.

[4] This evaluation is based on several criteria, including but not limited to: hourly and sub-hourly (when available) profiles of demand, generation by technology and required system ramp rates (how fast it can change its output). It is also based on annual statistics, such as generation by technology and total energy consumption.

Six phases of
Variable Renewables Integration

Updated IEA framework

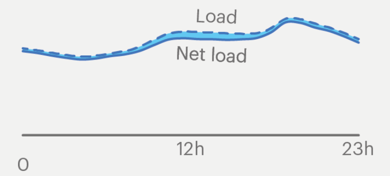
Phase 1

VRE has no significant impact at the system level

The first set of VRE plants are deployed, but their impact is **largely insignificant at the system level** and the typical operating parameters of the system remain unchanged. Any effects are very **localised**, for example at the grid connection point of plants.

Load versus net load

The difference between load and net load is **minimal**



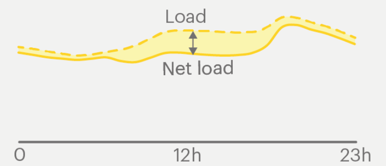
Phase 2

VRE has a minor to moderate impact on the system

As more VRE plants are added, changes between load and net load become more noticeable with a minor to moderate impact on the system such as **faster and more frequent ramping of generators**. Upgrades to operating practices such as integrating forecasting into dispatch and making better use of existing system resources are usually sufficient to achieve system integration.

Load versus net load

The difference between load and net load becomes **noticeable**



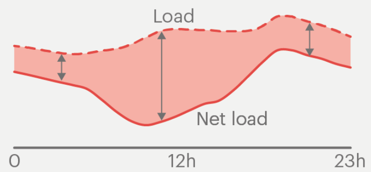
Phase 3

VRE determines the operation pattern of the power system

VRE determines the operation pattern of the power system and **increases the uncertainty and variability of net load**. Greater swings in the supply-demand balance prompt the need for a **systematic increase in flexible operation** of the power system that often goes beyond what can be readily supplied by existing assets and operational practice.

Load versus net load

The **"duck"** curve starts emerging, suggesting that more pronounced and longer ramps are required



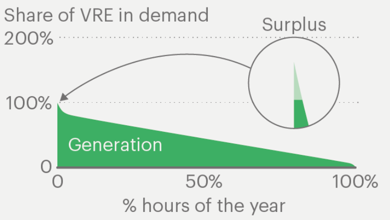
Phase 4

VRE meets almost all demand at times

VRE output is sufficient to meet a large majority of electricity during certain periods, which may impact power system stability. A key operational challenge is related to the way the power system responds to **maintain stability immediately following disruptions** in supply or demand, which may involve advanced operational solutions and changes in regulatory approaches.

Percentage of hours covered by VRE

During a few hours of the year, almost all demand is covered by VRE



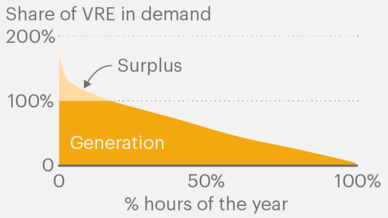
Phase 5

Significant volumes of surplus VRE across the year

Rising shares of VRE mean that without additional measures VRE availability will exceed demand during many hours and be in **overall surplus for periods of a day or more**. Achieving such shares under decarbonisation goals in an **economic and secure manner** requires increased measures to support VRE utilisation, such as large deployment of demand response, energy storage and grids, and more extensive solutions to ensure stability at low levels of conventional supply.

Percentage of hours covered by VRE

VRE generation can be higher than 100% of the local demand: surplus energy must be managed



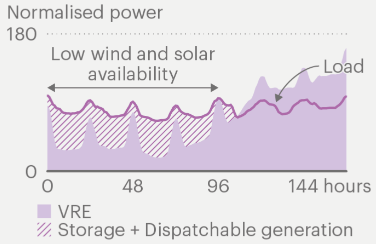
Phase 6

Secure electricity supply almost exclusively from VRE

Phase 6 applies to regions looking to meet extremely high shares of annual electricity demand with VRE. The main challenges in this phase include **operating a system largely dependent on converter-connected resources** and **meeting demand during extended periods of low wind and sun availability**. Addressing flexibility needs can involve long-duration energy storage or extensive electricity trade with other regions.

Electricity generation and load profiles

Prolonged periods of low VRE availability need to be compensated for by storage and dispatchable generation



Variable renewable energy (VRE): wind and solar PV
Load: total electricity demand in a system
Net load: system load minus the output from VRE generators

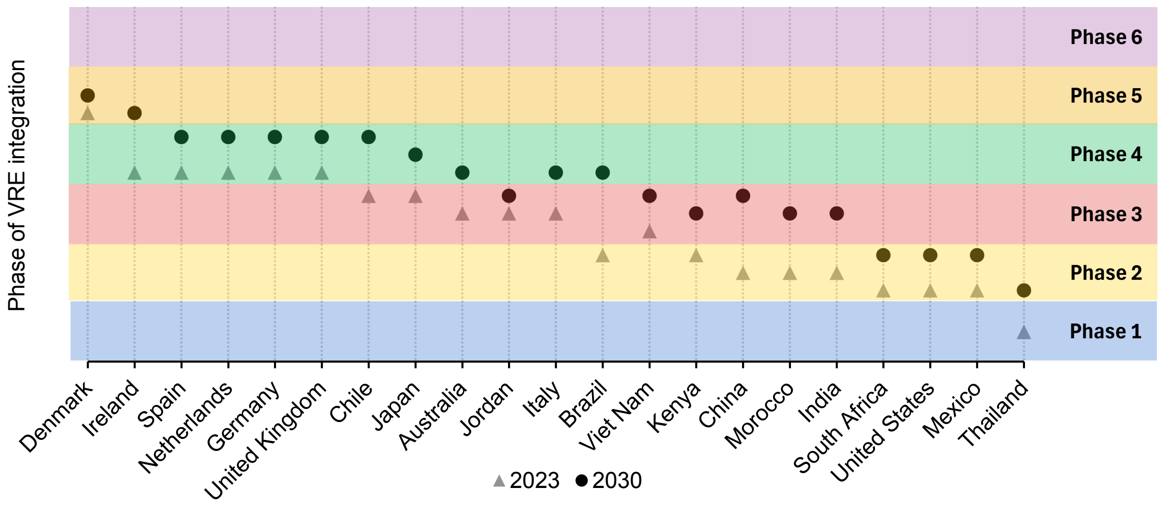
According to our assessment, most systems in the world are currently in Phases 1 or 2. Of the 50 systems we analysed, 25 are in Phases 1 or 2, representing around 60% of global electricity generation. These countries can leverage learnings from a wealth of global experience to manage the challenges in low phases (1-3), as several systems have already reached Phase 3 – the end of the low-phase spectrum. In 2023, several countries with different geographies and levels of economic development reached Phase 3, including Japan, Viet Nam, Italy, Australia, and Kenya. These and other countries have reached Phase 3 by focusing mainly on policies that accelerate deployment on VRE capacity and addressing integration challenges as they arise, in a targeted and progressive manner.

There are already several examples of countries entering the high phases (4-6), where integration measures that transform system operation, planning and financing are needed. Where such measures are developed in parallel with the rollout of VRE, the systems successfully enter and navigate the high phases. At a country level, only a few European countries are classified as being in Phase 4 or above in 2023. At a subnational level, however, systems such as Kyushu in Japan are also classified as being in Phase 4, while South Australia's system is classified as Phase 5.

Certain large countries are classified at a phase of VRE integration that may differ with subnational systems. For example, countries such as China, India and Brazil are categorised as being in Phase 2 at a national level in 2023 but may have subnational areas at higher phases. This is because the natural endowment of VRE resources in specific regions has spurred geographically concentrated development. Subnational-level incentives that support accelerated development of solar and wind may also have had an impact.

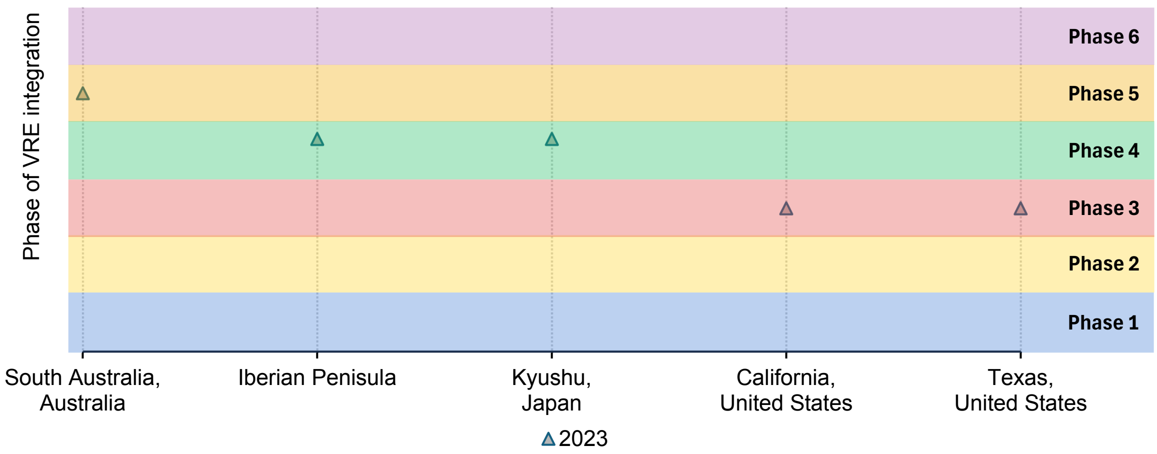
Based on the projected growth of VRE and load, we expect even more countries to reach the high phases of VRE integration in the coming years. By 2028 the main case of our renewables forecast shows that a range of countries, such as the United Kingdom, Spain, Chile, Germany and Denmark, reach unprecedented annual shares of generation originating from wind and solar power plants – some above 65%. This development calls for a better understanding of how this could affect electricity systems even further, and what measures can be taken on several fronts to ensure that those higher levels of VRE are integrated in an affordable and secure manner. The main emerging challenges we see that need to be addressed to successfully navigate the high phases of VRE integration are a focus on system stability and a higher need for flexibility across all timescales. In Chapter 3, we focus on these emerging challenges and on solutions that various countries are already implementing to address them.

Selected countries in phases of variable renewable integration, 2023-2030



Note: The phase assessments for 2030 are based, among other factors, on VRE forecasts that will be presented in the upcoming Renewables 2024 report.

Selected regions in phases of variable renewable integration, 2023



Chapter 2. Global experience

Over the last decade, various countries at different stages of deploying variable renewable energy (VRE) have addressed integration challenges with a wide range of policy, regulatory, and technical measures. These experiences provide valuable insights that can be used to guide other systems[5] trying to understand which integration measures to prioritise at their respective levels of VRE deployment.

VRE integration into power systems has become a prominent issue and research focus for utilities, private companies and international organisations. Numerous reports, studies, guides and toolkits from entities such as the Global PST Consortium, the Energy System Integration Group, Cigre, IEEE Power Energy & Society, the National Renewable Energy Laboratory, the International Renewable Energy Agency, the Electric Power Research Institute and the World Bank Energy Sector Management Assistance Program, among others. These efforts highlight the challenges of integrating solar and wind power into power systems in various contexts, and the numerous measures that can be implemented.

Despite the extensive research, policy makers often struggle to prioritise the most cost-efficient, rapid measures for integrating VRE. The broad range of measures and the need for local adaptation can make it hard to identify which should be considered in the short term, while simultaneously preparing for future VRE growth. Policy makers often view systems at high phases such as Denmark, South Australia[6], Ireland and California as benchmarks, and lead to misguided attempts to emulate their latest solutions. Instead, a more effective approach would be to look at the measures these systems implemented during earlier phases of VRE integration, comparable to its present situation. Advanced measures being taken by these frontrunner systems are typically not the most cost-effective way of integrating VRE in a country beginning its VRE deployment. Instead, countries benefit from analysing systems with similar conditions and developmental stages to inform their own integration strategies.

This chapter offers guidance on how systems worldwide have prioritised and implemented measures to integrate VRE into their power systems. It provides a

[5] A system may be the power system of a country such as Denmark of Kenya, or a subregion of a country such as the Electric Reliability Council of Texas system in the United States, or the NEM in Australia.
[6] South Australia is a subsystem of the National Electricity Market (NEM) of Australia, where the NEM is The Australian National Electricity Market (NEM), interconnecting five regional market jurisdictions – Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania. Western Australia and the Northern Territory are not connected to the NEM.

stocktake of 50 power systems from various countries,[7] representing almost 90% of the global solar and wind generation in 2023, using the phases of VRE integration assessment framework. This structured approach offers a comprehensive overview of the strategies used globally to integrate VRE, helping policy makers and utility practitioners to identify which measures to prioritise at different stages of VRE growth. The chapter serves as a valuable resource for understanding the global experience in VRE integration.

Phases of VRE integration

Chapter 1 reintroduced the IEA's phases of VRE integration framework, outlining six phases of increasing solar PV and wind impacts on the power system. Each phase presents new challenges requiring targeted measures to enable the secure and cost-effective uptake of VRE. Phases 1 to 3, considered low phases of VRE integration, experience relatively low impacts, with most challenges addressable through straightforward modifications to existing assets or operational improvements. Phases 4 to 6 are considered high phases and mark increasing influence of VRE in shaping system operations, requiring a fundamental transformation of the power system.

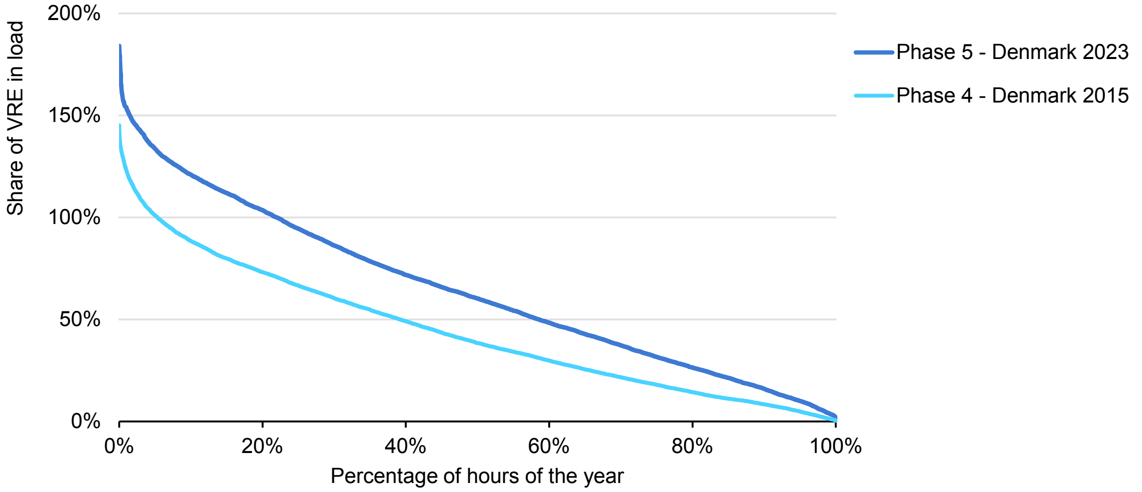
The rapid global growth of VRE has significantly increased the number of systems reaching Phase 4 and above since our last update in 2019. This growth has provided us with increased evidence of the typical emerging challenges faced by systems in high phases and the measures being introduced to address them. Drawing on these experiences, we have revised the definitions of Phases 4 to 6 to better reflect this growing body of knowledge.

Refining the descriptions of Phases 4 to 6

Systems such as Germany, Ireland, Spain and Kyushu in Japan have reached Phase 4. This phase is characterised by periods when VRE meets almost all demand. The main challenge in this phase is managing system stability during moments of high VRE penetration. Systems in this phase also tend to experience pervasive grid congestion, given the speed at which VRE has grown and its varied geographical spread. These challenges need system-wide solutions to be developed to enhance responses to steep ramps and low inertia, as well as addressing increased grid congestion.

[7] Argentina, Australia, Austria, Belgium, Brazil, Canada, Chile, China, Colombia, Denmark, Egypt, Ethiopia, France, Germany, Greece, India, Indonesia, Islamic Republic of Iran, Ireland, Israel, Italy, Japan, Jordan, Kenya, Korea, Mexico, Morocco, Namibia, Netherlands, Nigeria, Pakistan, Philippines, Poland, Portugal, Saudi Arabia, Senegal, Spain, South Africa, Sweden, United Republic of Tanzania, Thailand, Republic of Türkiye, Ukraine, United Kingdom, United States, Uruguay and Viet Nam.

Duration curves of variable renewable energy share of load at Phase 4 and Phase 5, Denmark, 2015 and 2023



Source: IEA analysis based on operational data collected via the IEA's Real-Time Electricity Tracker.

Denmark became the first country to be classified as Phase 5 of VRE integration in 2022, offering new insights into managing high levels of VRE. The primary challenge in this phase involves efficiently handling extended periods of both low and high shares of VRE that can last from days to months – due to daily fluctuations, weather events such as "dunkelflaute"[8] (dark doldrums) and seasonal variations – which introduce new technical and economic challenges. Over the years, Denmark has implemented various integration measures as it has progressed across phases. Currently, it manages Phase 5 challenges primarily through extensive interconnections with neighbouring power systems, while also exploring further developments such as storage, sector coupling, as well as installing more solar PV to take advantage of its complementarities with wind power.

Power systems with less interconnection than Denmark that reach Phase 5 might need to address these challenges differently. To manage longer VRE deficits, these systems will need to rely on a combination of electricity trade (where possible), various duration storage solutions and dispatchable generation sources. In the context of power system decarbonisation, there are low-emission generation sources available, such as nuclear power and synthetic fuels.

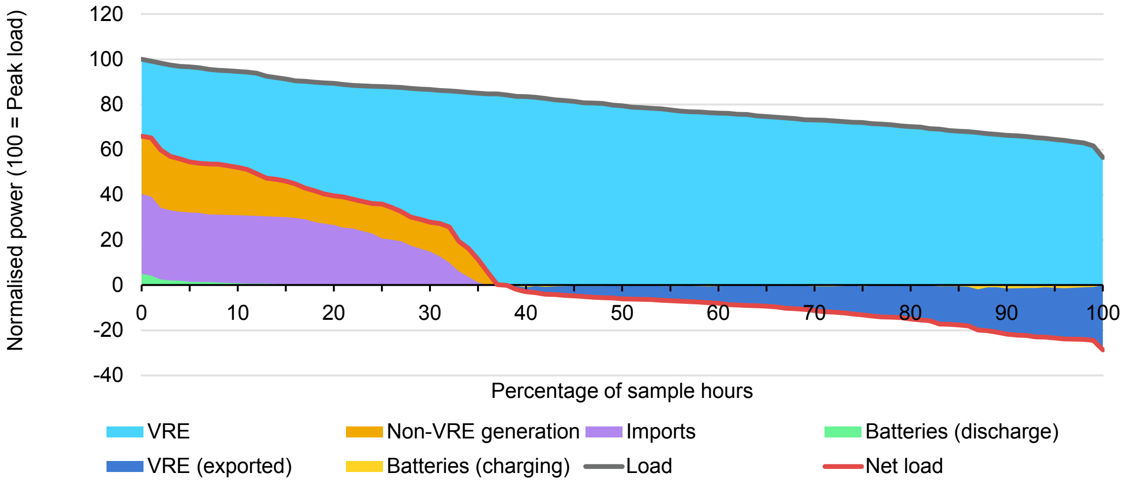
One example of this is South Australia, which has for the first time been classified as Phase 5. In contrast to the case of Denmark, South Australia has limited interconnections with its neighbours, and the impact of solar PV on the net load is

[8] In the renewable energy sector, a "dunkelflaute" is a period of time in which little or no energy can be generated with wind or solar power, because there is neither wind nor sunlight.

more visible. High VRE periods resulting in surplus generation are managed by a combination of measures including energy exports via interconnection to the neighbouring state, storage with battery energy storage systems (BESS), demand response and curtailment. High ramps at sunrise and sunset hours resulting from solar PV generation are managed predominantly by fast-acting gas turbines and the BESS, as well as accessible resources in the rest of the NEM through the interconnector.

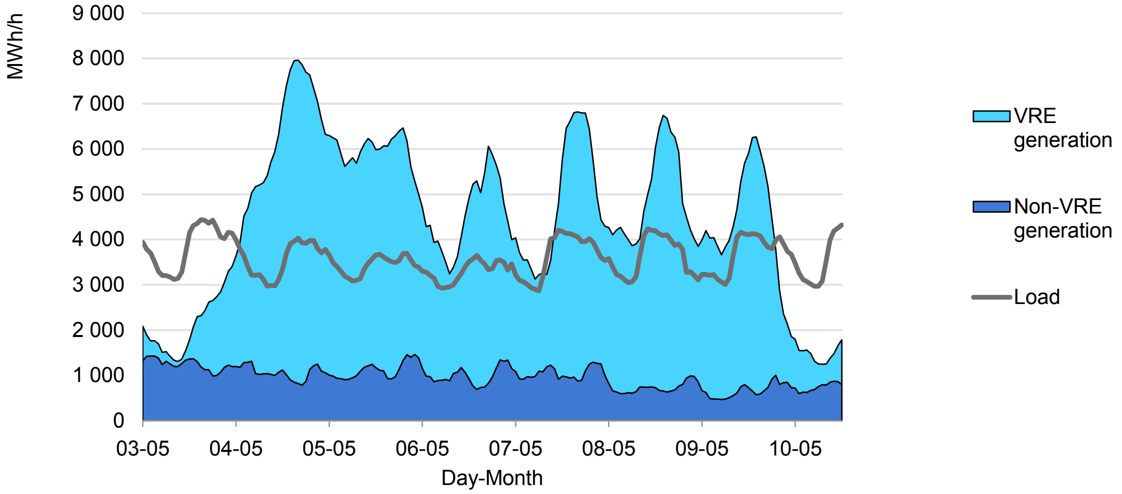
In general, dealing with VRE surpluses presents primarily an economic challenge rather than a technical one, introducing a new dimension to look at for systems reaching Phase 5. The surplus energy can significantly reduce electricity prices in periods of abundant VRE generation, potentially undermining the business case for new VRE projects, requiring innovative approaches to maintain their viability. Systems with limited interconnection capacity will be more exposed to this effect and will need to consider a variety of strategies to address this. These include converting excess energy into low-emissions fuels, using energy storage of various durations, and implementing sector coupling through the electrification of transport, heating and cooling. Additionally, overbuilding VRE capacity – that is, building capacity expected to be curtailed in some seasons – may be considered if it proves economically viable.

Load and net load duration curve of a week showing how surplus and deficit hours are managed, South Australia, 2023



Note: The duration curve was created using 1 week of operation data with 30-minute resolution from winter 2024.
Source: IEA analysis based on data from OpenNEM.

Generation and load in the week with the highest solar PV and wind surplus, Denmark, 2023



Note: The shown data correspond to hourly values.
Source: IEA analysis based on Energinet data collected through the IEA's Real-Time Electricity Tracker.

Finally, Phase 6 represents systems where almost all electricity demand is met by solar PV and wind. Presently, no major systems around the world are classified in this phase. In such systems, strategies to manage extended periods of VRE surplus and deficit become even more important, while dealing with the need for system services becomes critical.

It is important to note that in a context of achieving net zero emissions, we do not see Phase 6 systems as the target to aim for to decarbonise the power system, but a niche phase for smaller systems (such as some island systems) with extremely high or absolute uptake of VRE.

Stocktake of measures

In this section we present the findings of the global stocktake of VRE integration measures. The stocktake is based on research of 50 systems from countries worldwide, covering almost 90% of global solar PV and wind generation in 2023.

The six phases of VRE integration framework provide a structured approach to understand which integration measures to prioritise at each phase. For each of the systems, we mapped the technical and regulatory measures that have been implemented, and then created an overview highlighting how common each measure is across systems at a specific phase. Since each phase includes multiple systems, the table shows the combined outcomes for all systems in that phase. Indicators in the table show how commonly a measure is applied by systems in a particular phase.

Our assessment identified several key findings about VRE integration measures:

1. Common practices exist across systems. These involve straightforward modifications to existing assets or operational arrangements that increase flexibility. All 40 systems in Phase 2 and above transversally apply these measures.

2. Measures do not need to be implemented completely to be effective. Implementation can be targeted and gradual, and measures can address specific challenges as they emerge.

3. Implementation depth varies by phase. Complete overhauls are not necessary for systems in Phases 1 to 3, while those in Phases 4 and 5 implement almost all, indicating a full system transformation.

4. Measure prioritisation depends on specific challenges and existing resources. To better understand application patterns, we grouped systems with similar characteristics into "system archetypes."

This approach allows for a more nuanced understanding of how different systems integrate VRE effectively.

Measures taken by systems in Phases 1-5 of VRE integration

Measure to integrate VRE	Phase of VRE integration				
	1	2	3	4	5
Enhance power plant capability					
Retrofit conventional power plants	Limited	Common	Common	Widespread	Widespread
Flexible offtake and upstream fuel contracts	Limited	Limited	Common	Widespread	Widespread
Increase VRE technical requirements	Common	Widespread	Widespread	Widespread	Widespread
Forecasting					
VRE generation	Common	Widespread	Widespread	Widespread	Widespread
Net load	Limited	Common	Common	Widespread	Widespread
Power flows	Limited	Common	Common	Common	Common
Demand-side measures					
Industrial demand response	Common	Widespread	Widespread	Widespread	Widespread
Commercial demand response	Limited	Common	Widespread	Widespread	Widespread
Residential demand response	Limited	Limited	Common	Common	Widespread
Steer location of new demand	Limited	Limited	Limited	Common	Common
Modify system operation rules					
Allow VRE curtailment	Limited	Common	Common	Common	Widespread
High granularity/closer to real time	Limited	Common	Common	Widespread	Widespread
Least-cost dispatch	Common	Widespread	Widespread	Widespread	Widespread
Capacity mechanism	Limited	Common	Common	Common	Common
Establish balancing market	Limited	Common	Common	Widespread	Widespread
Establish ancillary service market	Limited	Common	Common	Common	Widespread
Enhance use of interconnection	Limited	Common	Common	Widespread	Widespread
Enhance grid capacity and use					
Install stability support devices (STATCOMs, SYNCONs)	Common	Common	Common	Common	Widespread
Interconnection/redundancy/mesh	Widespread	Widespread	Widespread	Widespread	Widespread
Reinforcement	Common	Widespread	Widespread	Widespread	Widespread
Allow VRE curtailment	Common	Widespread	Widespread	Widespread	Widespread
Power flow control	Limited	Common	Widespread	Widespread	Widespread
Steer location of new VRE	Limited	Common	Common	Widespread	Widespread
Storage					
Pumped hydro	Common	Widespread	Common	Common	Widespread
Battery energy storage	Limited	Common	Common	Widespread	Widespread
Long-duration storage	Limited	Limited	Limited	Limited	Common

Implementation of measure Limited Common Widespread

Notes: Green = > 80% of systems in the phase have implemented the measure. Yellow = 50-80% of systems in the phase have implemented the measure. Red = < 50% of systems in the phase have implemented the measure. No information could be gathered for Phase 6 as there are no power systems in this phase. Steer location of new VRE = establish dedicated zones for solar PV and wind development, e.g. by applying location network charges, bidding zones or competitive renewable energy zones. Steer location of new demand = e.g. green industrial clusters. There are two reasons for curtailment of wind and solar energy: localised grid reasons (where only a subset of wind/solar generators can contribute to alleviating the problem); and system-wide reasons (where the reduction of any or all wind/solar generators would alleviate the problem).

A common set of integration measures can be implemented gradually

Our analysis found that implementing VRE integration measures using progressive, targeted adjustments enables integrating most new solar and wind capacity in low-phase systems. These systems face relatively low impacts, with challenges addressed through straightforward modifications to existing assets or operational arrangements to increase flexibility. Our stocktake of 40 systems in Phase 2 and above identified common measures implementable in a targeted, progressive manner. These include optimising dispatch, improving forecasting, increasing flexibility from conventional and VRE plants, enabling industrial demand response, and enhancing grid infrastructure. The key advantage of these is adaptability – measures don't require complete implementation or sweeping transformations. Instead, they offer a flexible approach tailored to specific challenges, facilitating a cost-effective, scalable integration process that evolves with the power system's changing needs.

While it is difficult to draw out common benchmarks for systems in high phases, as there are yet fewer examples, our analysis shows that integrating high shares of VRE requires a sweeping transformation, as all types of measures need to be implemented. Solutions to address challenges at high phases of VRE integration go beyond simple operation measures, increasingly requiring a deeper transformation. We take a separate view of emerging challenges and how frontrunner systems are addressing them in our analysis in Chapter 3.

Enhancement of power plant capability to provide flexibility and system services

At the onset of VRE integration, conventional hydro and thermal power plants are often the assets that are used first to provide flexibility and system services, as they are already installed and familiar. However, solar PV and wind power plants are also capable of providing some flexibility and system services, given the right set of technologies, regulations and contracts. Enhancing power plant capability to provide flexibility and system services includes improving the ability of conventional power plants to provide these services, while also taking advantage of the capabilities of new VRE generators.

Conventional power plants have historically been designed to deal with the variability of demand and maintain grid stability, which makes them convenient as the main source of flexibility and system services, and therefore natural candidates for sourcing the additional flexibility needed due to increased VRE generation.

The ability of conventional power plants to provide this flexibility can be enhanced by both technical and contractual improvements.

Technical improvements increase the physical capability of power plants to provide more flexibility, by improving characteristics such as their ramping rates or their minimum stable level. This might require updating operational practices, retrofitting the generator with equipment to enhance their performance, or even improving the quality of the fuel being used.

Contractual improvements refer to removing contractual barriers that might limit a power plant from providing the flexibility their technical capabilities allow. This might require renegotiating the conditions of upstream fuel and offtake contracts to free them from contractual obligations regarding how power is produced. Despite their importance, a significant number of countries around the world still maintain contractual structures that limit the possibility of generators to provide flexibility.

Our analysis shows that over 80% of systems at Phase 2 or above enhanced conventional power plant flexibility via technical retrofit programmes, while only around 50% have introduced improvements to some upstream fuel and offtake contracts to be more flexible.

Beyond flexibility, many countries have increased the provision of system services by requiring specific technical capabilities from VRE plants. For example, many countries demand active and reactive power controls and fault ride-through capabilities, which can be ad hoc requirements or set by system-wide grid codes. Our stocktake reveals that 90% of the Phase 2 or higher systems impose technical requirements on VRE aimed at improving their provision of system services.

As systems change, the provision of flexibility and system services can no longer be taken for granted and needs to be more clearly defined. To ensure that these services are still provided, clear definitions of system services are necessary. This ensures that power plant operators can refine their operational strategies and enhance their capabilities to better provide what is valuable to the system.

System-friendly VRE

System-friendly VRE refers to planning, operating or contracting solar and wind power plants in a way that supports the overall outcomes for the system.

For example, it could be the deployment of solar and wind together to leverage their complementarity, the installation of solar panels at various orientations to generate more on the shoulders of the midday peak, collocating generation with demand in a way to reduce grid congestion, or grid code-related aspects that mean that VRE does not exacerbate issues when faults or frequency issues arise.

Source: IEA (2018), Status of Power System Transformation; IEA (2017), Status of Power System Transformation.

Improvement of forecast accuracy for reliable system operation

Forecasting demand and generation is key for system operation and plays a crucial role in scheduling, dispatching and allocating operating reserves. Accurate and precise VRE forecasting reduces the need for reserve capacity and enables more flexible operation. Improving short-term forecasts is also increasingly relevant for intraday and day-ahead trading, in systems where this is possible.

Introducing high-quality forecasts, even in systems at low phases of VRE integration, is highly recommended to avoid significant operational difficulties. At high phases, accurate forecasting becomes essential to maintain energy security. Improved forecasting is required for both the supply side, where VRE introduces unpredictability, and the demand side, where (in addition to the natural variability of demand) increased ownership of electric devices creates new load patterns that system operators need to manage.

Forecasting power flows and grid congestion is also being implemented in different systems, with recent practices becoming higher in temporal resolution, more frequently updated and more detailed at lower voltage levels. All analysed systems at Phase 2 or above have implemented VRE forecasting, with 80% also using net load forecasting and around 65% considering power flow forecasting in dispatch decisions.

Enhancing forecasting accuracy can involve combining weather models with different spatial resolutions, incorporating real-time measurements from VRE plants and frequent updates of the weather model. Big data technologies, machine learning algorithms and predictive analytics have notably improved forecasting accuracy, extending beyond weather-related data. Access to large datasets, including from smart meters and home energy management systems, is key for implementing these methods. Probabilistic forecasting is also an emerging practice in high VRE systems, to account for weather-related uncertainties.

Finally, an important point is that the distribution of forecasting responsibilities can impact the forecast quality. A centralised approach, where a central entity performs the forecast, generally ensures greater reliability and consistency. Around 80% of transmission system operators worldwide use this method, including the most developed power markets. Centralised forecasting is preferred for systems with large amounts of distributed VRE generation, as it is challenging for small generators to provide high-quality power forecasts. Establishing a national register of VRE plants is key to producing centralised forecasts for all installed capacity, including smaller units.

Mobilisation of large volumes of flexibility through industrial demand response

Demand response is a key provider of flexibility as it can contribute to reducing electricity consumption peaks and thus to the integration of more solar and wind. Industrial users are particularly effective at implementing demand response due to their significant and concentrated energy use. All reviewed systems at Phase 2 or higher have implemented industrial demand response, with almost 90% and 55% employing commercial and residential schemes, respectively, too.

Demand response activation can be explicit or implicit. Explicit demand response programmes provide direct payments to consumers who reduce demand during periods of tight supply via markets such as capacity and balancing markets – incurring costs for producers and system operators. For instance, Spain contracted 609 MW of industrial capacity through active demand response services in 2024. Explicit programmes are increasingly used to manage fluctuating VRE outputs, for example through the EU regulations on aggregators.

Implicit demand response, driven by price signals, encourages consumers to adjust consumption to match power system needs. Industries with flexible production processes, such as food, steel and paper, can respond to price signals and reduce peak demand by 20% to 40%. Even high load factor industries such as aluminium can adjust electricity consumption without disrupting production. These flexible production processes can take advantage of low prices at times of surplus VRE production, soaking up this excess supply, while reducing consumption at times of low supply, contributing to managing the variability of solar and wind. However, activating implicit demand response remains challenging due to the high prices needed to activate industrial flexibility, insufficient investment incentives and counterproductive tariff structures.

When regulators design demand response programmes or incentives, three elements that impact their effectiveness need to be considered: shiftability, controllability and acceptability. Shiftability indicates the technical potential to reduce or shift load. Controllability refers to the technical capabilities of current equipment and communication technologies, which can be enhanced through further electrification and digitalisation. Acceptability involves users' willingness to accept reduced service levels in exchange for financial incentives, balancing production commitments with benefits from time-of-use tariffs and other incentives.

Making dispatch cost-efficient and conducive to flexibility

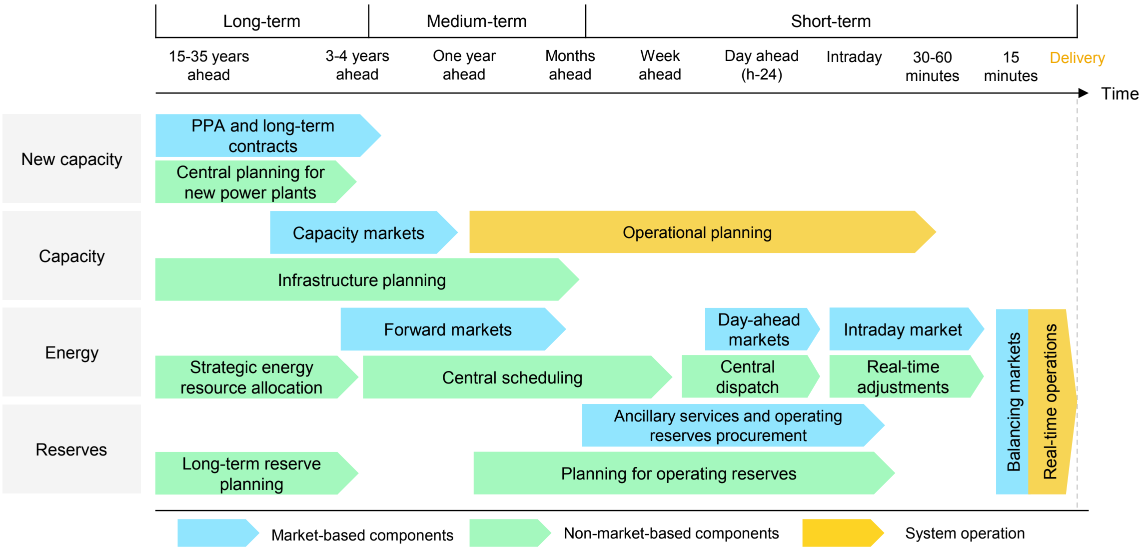
Dispatch involves choosing which power plants to use to meet electricity demand at any moment. Dispatching the cheapest generators first – called least-cost dispatch or economic dispatch – ensures that demand is met in an economically efficient manner, minimising electricity costs regardless of the generation mix. As VRE sources generate electricity without using fuel, they have near-zero marginal costs, meaning that under economic dispatch they are among the first technologies to be used to supply demand. In our analysis, while more than 80% of systems at Phase 2 or above implement least-cost dispatch in some form, additional elements often distort dispatch compared to the optimal choice at the system level.

Subsidies and contractual constraints can distort the outcome of economic dispatch by creating artificial costs and inefficiencies. Contractual conditions that commit the power plant to produce regardless of the economic merit order, or subsidies such as feed-in tariffs, production tax credits, capacity payments and fossil fuel subsidies, along with fixed-price and long-term contracts, can create inflexibilities in the way these plants respond to system needs. This can happen in both regulated and deregulated power markets. By removing or minimising such distortions, dispatch will better reflect the true cost of generation, enabling an efficient use of resources and lowering total system costs. Furthermore, clear and undistorted market signals and accurate pricing can incentivise investment in VRE, demand-side management and other flexibility solutions such as storage. To do this, it might be necessary to consider removing price caps and allowing negative prices (in the markets linked to dispatch).

Beyond minimising distortions from the dispatching process, improvements in the design of the dispatching mechanism can allow better management of variability, for example by allowing smaller commitment sizes and shorter durations of time for dispatching. In the process of deciding which power plants to use to match supply with demand, allowing small plants connected to distribution grids to participate in the process, and also allowing participation by the demand side, can unlock a large pool of resources to respond to system variability.

These principles can be implemented in systems with either regulated or deregulated power markets. What is important is to set up a method to explicitly quantify and communicate the status of and expected need for flexibility and place a value on providing it. This enables valuation of the flexibility and the design of vendor-agnostic procurement mechanisms. Globally, there is a trend towards improving the resolution of dispatching mechanisms, with over 60% of systems at Phase 2 or above having introduced higher granularity decision points in the dispatch process and having set up balancing and ancillary service markets.

Overview of the different decision points for dispatch



Note: PPA = power purchase agreement.

Enhancement of grid capacity and use

Grid capacity is essential, transporting power securely from where it is produced to where it is consumed. This needs building grid connections for new demand and new generation and reinforcing parts of the grid to handle new and increased power flows. Efficiency can also be tapped from the existing grid, in the way it is determined how much capacity can be safely used, how the available capacity is used, and how to leverage wide-area diversity by interconnecting different areas.

Our analysis shows that all surveyed systems at Phase 2 or above have implemented some form of grid reinforcement and congestion management mechanisms. Moreover, 90% of them have adopted power flow control measures, and 90% have enhanced interconnection, highlighting the widespread adoption of measures to enhance grid capacity and utilisation to integrate solar PV and wind.

Furthermore, steering the deployment of new assets can facilitate faster connection and integration of both VRE and demand for clean electricity. We highlight three examples of mechanisms to do so. First, competitive and efficient renewable energy zones can be set up, as they have been in Australia, Texas and the Philippines. Second, dispatch settlement prices can be made to reflect the locational value of generation, for example by creating bidding zones and using locational marginal pricing. Third, system operators can steer their choices with connection permits or network charges that vary also depending on the connection location. Of systems at Phase 2 or higher, 75% implement a measure to steer the location of new VRE development. This approach could also support demand development in areas where grid congestion is less severe, when needed.

Priority integration measures vary by system archetype

In this part of the analysis, we first categorised power systems based on key differentiating factors that influence their ability to manage VRE integration challenges. These factors include system size (large/small), interconnectedness (high/low), technology availability and suitability for VRE integration, spatial concentration of VRE resources (concentrated/dispersed), and the formality of market structures used to induce efficiency through competition.

By applying these criteria, we identified various "system archetypes" - groups of power systems sharing similar traits. However, our comprehensive study revealed that only three pairs of these archetypes demonstrated particularly strong relevance and contrasting approaches to VRE integration.

The contrasting pairs of archetypes in terms of applied measures were: island or quasi-island systems (denoted “I” in the overview table) versus large interconnected systems (denoted “X”), meshed systems (denoted “M”) versus sparsely connected systems (denoted “S”), and systems with more utility-scale VRE (mainly wind, denoted “U”) versus distributed VRE (mainly solar PV, denoted “D”). In this section, for each archetype we describe the main drivers across these dimensions.

Measures taken by systems of different archetypes

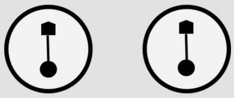
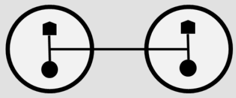
Measure to integrate VRE	System archetype					
	I	X	M	S	U	D
Enhance power plant capability						
Retrofit conventional power plants	Widespread	Widespread	Widespread	Common	Widespread	Widespread
Flexible offtake and upstream fuel contracts	Common	Common	Common	Limited	Common	Common
Increase VRE technical requirements	Widespread	Widespread	Widespread	Widespread	Widespread	Common
Forecasting						
VRE generation	Widespread	Widespread	Widespread	Widespread	Widespread	Widespread
Net load	Widespread	Common	Widespread	Common	Widespread	Common
Power flows	Common	Common	Widespread	Common	Common	Common
Demand-side measures						
Industrial demand response	Widespread	Widespread	Widespread	Widespread	Widespread	Widespread
Commercial demand response	Widespread	Widespread	Widespread	Common	Widespread	Common
Residential demand response	Widespread	Common	Limited	Common	Common	Limited
Steer location of new demand	Limited	Common	Limited	Limited	Limited	Limited
Modify system operation rules						
Allow VRE curtailment	Common	Common	Common	Widespread	Common	Limited
High granularity/closer to real time	Common	Common	Widespread	Limited	Common	Common
Least-cost dispatch	Widespread	Widespread	Widespread	Common	Widespread	Common
Capacity mechanism	Widespread	Common	Common	Common	Common	Common
Establish balancing market	Common	Widespread	Widespread	Limited	Common	Common
Establish ancillary service market	Common	Common	Widespread	Limited	Common	Limited
Enhance use of interconnection	Common	Widespread	Widespread	Common	Common	Common
Enhance grid capacity and use						
Install stability support devices (STATCOMs, SYNCONs)	Common	Common	Common	Common	Common	Common
Interconnection/redundancy/mesh	Widespread	Widespread	Widespread	Common	Widespread	Widespread
Reinforcement	Widespread	Widespread	Widespread	Widespread	Widespread	Widespread
Allow VRE curtailment	Widespread	Widespread	Widespread	Widespread	Widespread	Widespread
Power flow control	Widespread	Widespread	Widespread	Widespread	Widespread	Widespread
Steer location of new VRE	Common	Common	Widespread	Common	Common	Common
Storage						
Pumped hydro	Widespread	Common	Common	Widespread	Common	Common
Battery energy storage	Widespread	Widespread	Widespread	Common	Widespread	Widespread
Long-duration storage	Limited	Limited	Limited	Limited	Limited	Limited

Implementation of measure Limited Common Widespread

Notes: Green = > 80% of systems in the phase have implemented the measure. Yellow = 50-80% of systems in the phase have implemented the measure. Red = < 50% of systems in the phase have implemented the measure.
I = Island and quasi-island systems
X = Large interconnected systems
M = Meshed systems
S = Sparsely connected systems
U = Utility-scale VRE-dominated systems
D = Distributed VRE-dominated systems

Island vs interconnected systems

Descriptions of island and quasi-island systems and large interconnected systems

Island and quasi-island vs large interconnected systems	
Island or quasi-island system	**Large interconnected system**
	
Island and quasi-island systems are power systems with no or limited interconnection with their neighbours, respectively. Examples of island systems are the islands of Indonesia, South Korea, the islands of Hawaii in the United States, and Western Australia. Examples of quasi-island systems are the Iberian Peninsula, Texas in the United States, and South Australia.	Large, interconnected power systems have transmission and sub-transmission lines between different countries in a region or between different regions within a large country. Examples are continental Europe, China, India and Brazil.

Island and quasi-island systems have more limited resources to ensure short-term supply-demand balance and to maintain sufficient inertia for frequency stability, as they have restricted diversity and volume of flexibility and system services resources. Our stocktake analysis shows that measures to increase flexibility and system services have been prioritised, such as enhancing conventional power plants to change their outputs faster and ensuring they stay in service by setting up capacity mechanisms, increasing technical standards for VRE power plants, extending demand response programmes to commercial and residential customers and using the fast-acting capabilities of technologies such as battery energy storage systems (BESS). Efforts are also being made to limit the additional flexibility needs caused by VRE output uncertainty by improving VRE power plant and net load forecasting.

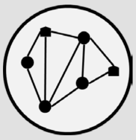
Large interconnected systems, conversely, can leverage a diverse array of solutions to manage variability and stability. Therefore, in addition to measures that increase the sources of flexibility, emphasis is also placed on measures that promote broader access to these resources, for example by increasing interconnection, enhancing its use and co-ordinating procurement of flexibility across the region. Efficiency is derived from effectively utilising a large and diverse pool of resources available across interconnected systems.

Meshed vs sparsely connected systems

Descriptions of meshed and sparsely connected systems

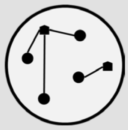
Meshed vs sparsely connected systems

Meshed system



Meshed systems are characterised by a high level of redundancy, meaning that they have multiple pathways between two points on the grid.
Examples are Germany, France, Great Britain, China, South Korea and the PJM system in the United States.

Sparsely connected system



Sparsely connected systems are power systems where the power grids are large because they stretch across long distances, but do not have a high level of redundancy.
Examples are Chile, Australia, Morocco and Viet Nam.

In meshed power systems, there are multiple routes for power to flow from one point to another. This means that it is easier to utilise resources in different parts of the network without overloading the grid, as well as being able to redirect the power flow through less congested areas in case there is a risk of overloading parts of the system. This is why we found in our analysis that forecasting is developed even for power flows in these systems. Because a wide range of assets can easily be accessed, these systems prioritise implementing measures that extract flexibility from a range of assets. Our stocktake analysis found that these include conventional and VRE power plants, industrial and commercial demand response, and BESS. They often introduce competition in the procurement of flexibility from these sources to boost efficiency, paving the way for market-based procurement of flexibility. Many systems in this category have set up shortened dispatch intervals in intraday trading, balancing or frequency regulation and ancillary services markets.

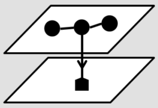
In contrast, sparsely connected systems have less redundancy, and the unavailability of a single line can have significant consequences if there is no alternative path to deliver the electricity. Where there is less redundancy, incidences of structural congestion are more obvious. Drawing a new circuit over a long distance can be costly, limiting cheap options for congestion relief. The stocktake analysis found that these systems allow curtailment of VRE to avoid grid congestion but transfer capacity can be enhanced by uprating or using dynamic line rating (DLR) as well. Supplementary system services might be needed, with auxiliary devices such as voltage support devices or synchronous condensers, where increases in VRE are happening at the same time as a dwindling of conventional power plants.

Utility-scale VRE vs distributed VRE-dominated systems

Descriptions of utility-scale and distributed VRE-dominated systems

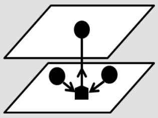
Utility-scale vs distributed VRE systems

Utility-scale VRE domination



Utility-scale VRE-dominated systems include Denmark, Spain, Canada, China, France, Mexico, Morocco and Chile.

Distributed VRE domination



Examples of distributed VRE-dominated systems include the power systems in the south of the United States, Japan, Viet Nam and in the Middle East.

Systems dominated by utility-scale VRE are characterised by having large solar PV or wind power plants connected to the transmission grid. Typically, these are at locations far away from demand centres. Our stocktake analysis found that grid reinforcement and enhancing interconnection redundancy, as well as power flow control, are often implemented to manage congestion in these systems to avoid the VRE facing curtailment. Their large scale makes the power plants ideal candidates for providing system services, such as fault ride-through, voltage support and active power management.

Systems dominated by distributed VRE are characterised by large numbers of small solar PV or wind power plants dispersed throughout the power system. More typically these are solar power plants collocated with demand, such as a rooftop solar PV system to power a home. The large volume of power-producing units of various sizes and configurations makes it difficult to have a comprehensive overview and control of the operation of these power plants. This justifies the findings from the stocktake analysis: to manage the impacts of distributed VRE, it is typical to look to the system side to provide flexible solutions rather than solicit flexibility from the distributed solar power plants. Prioritised measures include the development of ramping capability at conventional power plants, energy storage to complement diurnal cycles, and distribution grid reinforcement.

Special focus on solar PV and wind curtailment

VRE curtailment has gained attention in recent years due to the potential economic impacts that reduced revenues can have on new and existing solar PV and wind projects. In this section we discuss what needs to be considered when deciding how to deal with curtailment, depending on factors such as underlying system conditions and the level of VRE penetration in the system.

In the context of power systems, two types of curtailment can be distinguished. On the one hand, technical curtailment is implemented by system operators for technical reasons – such as grid congestion or voltage control issues – aimed at preserving the security of electricity supply. On the other hand, economic curtailment is applied by generators when generation is reduced due to price signals. In this context, VRE curtailment is an important option and one of the many[9] that are utilised to maintain the balance of supply and demand and to ensure system security.

High levels of VRE curtailment could represent significant unused amounts of clean energy and can lead to sizeable losses of revenue for generators. Another consequence is higher CO_2 emissions from power generation if redispatching fossil-fuel-fired plants, notably to solve technical constraints. Together, these two consequences could affect countries as they seek to reach their decarbonisation targets: if the business case for new VRE is worsened, the deployment of new VRE capacity could slow down; and if their systems are not able to displace fossil-fired generation, CO_2-free generation from VRE sources could be limited.

Historically, curtailment has been understood as a measure of how inflexible a system is, interpreted as "throwing away" clean energy because of a lack of flexibility or inadequate grid infrastructure. This can still be the case for systems with low and medium levels of VRE penetration, where in many cases there remains a need to explore how to unlock cost-effective system flexibility from grids, generation, storage and demand. However, in systems with high or very high levels of VRE penetration, particularly under conditions of structural oversupply at times such as midday solar PV peaks, keeping curtailment close to zero as a policy decision can compromise the cost-effectiveness of running the system. When assessing how to address VRE curtailment in these systems, it is key to understand its context and underlying factors, such as VRE penetration, transmission capacity, demand structure and available flexibility, and whether reducing it would lead to lower system costs.

[9] Other measures include adjusting the grid topology, utilising energy storage, activating demand response measures and redispatching other generation units.

Unlocking power system flexibility is key to managing curtailment

As wind and solar PV penetration has grown in recent years, several countries around the world have begun reporting VRE curtailment to take stock of the utilisation rates of assets and to identify potential integration issues. Higher technical curtailment is normally found in specific regions where investment in grid infrastructure has not kept pace with the growth of wind and/or solar PV and where local electricity demand is rather low compared to the VRE resources available. Systems that report VRE curtailment are generally not curtailing more than 5-10% of their VRE generation per year due to grid constraints or other technical reasons. However, a subgroup of systems with an accelerated deployment of VRE and more than 30% VRE share at the national or subnational level has seen higher curtailment rates than other countries. This subgroup includes Ireland, Chile and, in the past, China.[10] Similarly, regions such as northern Germany, Scotland in Great Britain and Kyushu in Japan have experienced higher curtailment due to these infrastructure and demand imbalances.

High levels of technical VRE curtailment can lead to higher power system costs and financial hurdles for wind and solar project developers. A regular need for a system operator to curtail VRE generation due to technical constraints can be driven by factors such as delayed grid development, contractual inflexibilities of traditional generators and lack of technical supply flexibility. On the system side, this can lead to the introduction of measures such as redispatch, which, over time, could end up being more expensive than addressing the root factors that are causing the issue. On the developer side, regular reductions in their output can make it challenging for them to fulfil their contractual obligations or to earn enough revenues in the market. Additionally, this can raise the perceived risk of developing new projects, which may lead to higher financing costs and, ultimately, increased overall development expenses.

To avoid undermining much-needed VRE investment, several operational measures can be explored. For example, IEA analysis shows that VRE curtailment can be significantly reduced by improving the flexibility of generation, storage and the demand side. Further, the Spanish transmission system operator, Red Eléctrica, introduced in 2022 the Automatic Power Reduction System (SRAP). This voluntary scheme is designed to solve congestion constraints by monitoring the conditions closer to and in real time. If a contingency causing congestion occurs, the power output of participating plants can be automatically reduced to 0 MW. This approach avoids relying solely on preventive redispatching based on potential contingencies that may never happen. As of September 2024, this has

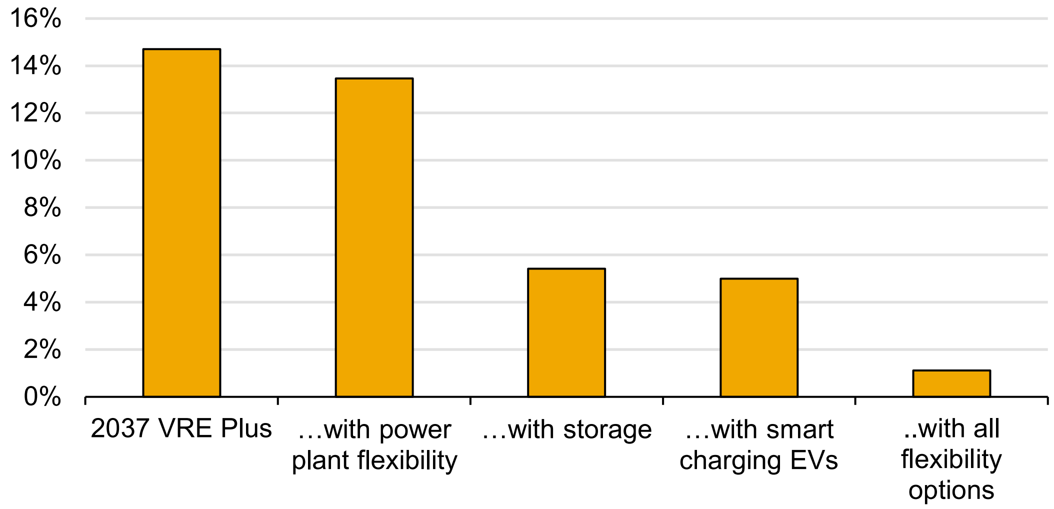
[10] China reached VRE curtailment levels of more than 10% in the early 2010s, which decreased significantly after the country successfully deployed targeted grid investment.

allowed them to reduce system costs by avoiding the curtailment of more than 3.4 TWh that would have been curtailed if only a preventive redispatch approach had been used. This system has contributed to maintain the monthly renewable technical curtailment generally under 2% for the peninsular system with nearly 40% of VRE generation in 2023.

Additionally, countries can explore introducing alternative revenue streams or compensation schemes for managing VRE curtailment under certain conditions. Curtailment compensation schemes can act as a transitional measure to address underlying systemic causes such as a lack of grid or flexibility development. These transitional measures can reduce hurdles for additional VRE growth while systemic issues are being addressed.

For example, the European Union has introduced curtailment compensation mechanisms, which help compensate for real-time deviations from the dispatch programme caused by technical restrictions not reflected in the zonal pricing scheme. In Germany, the Energy Act was amended in November 2023 to introduce the Use Instead of Curtail mechanism. This scheme incentivises consumers near VRE plants to use excess VRE supply by offering a fixed discount on wholesale electricity prices and an incentive in the form of no network charges or taxes. At the same time, this scheme ensures economic efficiency by capping compensation at the cost of alternative redispatching solutions.

Curtailment rate in Thailand under the VRE Plus scenario in 2037 with various combinations of additional flexibility measures



Note: EV = electric vehicle.
Source: IEA (2023), Thailand's Clean Electricity Transition.

Additionally, non-firm connection contracts can increase how much VRE capacity the system can host and at the same time mitigate the impacts of curtailment by offering benefits to developers. For example, from April 2025 system operators in the Netherlands will be allowed to offer contracts to large electricity consumers where these end users will benefit from lower tariffs at the cost of not being able to use the grid at all at certain times of system stress.

Enabling VRE plant owners to access additional revenue streams beyond the energy market, such as through ancillary services or capacity markets, helps to support their investments by remunerating value they provide to the system beyond energy generation, thus mitigating the impacts of curtailment and other.

At very high levels of VRE penetration, aiming for zero curtailment may prove costly

While having high levels of VRE curtailment typically points to a lack of flexibility, aiming for zero (or near zero) curtailment could be technically challenging and costly in systems with very high shares of VRE. This can particularly be the case when curtailment is reflecting increasingly structural conditions of oversupply at certain times, which could most notably be expected in systems with a very strong preponderance of solar PV. If there is no additional economically competitive use for that excess energy, for example storage, hydrogen production from electrolysis or electrified end uses, VRE curtailment can serve as an economically efficient tool (from a system cost perspective) to balance supply and demand.

Operating high VRE power systems with some curtailment can be a cost-effective outcome. In that context, the optimal curtailment levels for each system need further analysis, and how to manage them requires considering how to safeguard cost efficiency and the speed of VRE deployment. The optimal curtailment level depends on factors such as the system's characteristics, the abundance and competitiveness of VRE resources, operating practices and market design (if there is a market), and the technical level of flexibility available and its cost.

Various studies show that non-negligible VRE curtailment levels could be optimal with high levels of VRE, particularly as wind and solar PV generation costs decrease. For example, curtailment can enhance grid stability and provide operational flexibility, sometimes being more economical than measures such as increasing the cycling of other generation units. Additionally, a recent study showed that, even when unlocking other flexibility solutions such as storage and reducing minimum generation constraints in thermal generators, curtailing VRE to some extent can be a cost-efficient outcome at higher solar PV generation shares.

Special focus on grid interconnection queues

In 2023, IEA analysis identified over 1 500 GW of renewable energy capacity at advanced development stages waiting in connection queues globally. Interest in developing renewable energy has grown thanks to policy support and competitive technology prices, leading more projects to enter connection queues, which has in some cases led to higher project lead times. To manage the increase in both projects and wait times, and thus help to integrating more VRE into the grid, markets have taken various approaches to address market-specific challenges.

New federal and regional rules address US grid connection delays

In the United States, policy incentives have driven VRE growth, with further increases expected under the Inflation Reduction Act. The decentralised power grid of the country leads to varying connection queue practices across system operators. The increase in new capacity has increased connection queues and project lead times, resulting in the Federal Energy Regulatory Committee (FERC) and individual system operators introducing new rules to ease project connection.

At the federal level, FERC issued a new rule in 2023 to revise the connection process across regions, impacting both system operators and developers. Developers now have additional requirements aimed at reducing project speculation, requiring site control and readiness and increasing financial requirements and penalties. System operators' new requirements include producing grid availability maps, which may enable developers to understand where to best connect. In addition, FERC requires system operators to implement a "first-ready, first-served" process, reviewing projects in batches (cluster studies) rather than individually. Finally, the rule allows multiple projects to share a connection point and, thus, a connection request, while also setting strict review timelines and cost allocation of studies and potential system upgrades proportionally across projects. In addition, two additional rules issued by FERC in 2024 (nos. 1920 and 1977) highlight the importance of grids, as they aim to improve transmission planning, build and cost allocation, potentially impacting future transmission availability.

Regionally, in the northeastern United States, PJM has paused new project connections until 2026 to reform its process, which had led to a five-year backlog. PJM is moving from a first-come, first-served model to a first-ready, first-served model, which is expected to reduce waiting times. In addition, PJM will perform cluster studies instead of assessing each project individually. This transition has already had an impact, with over 18.5 GW of renewable energy projects being reviewed in the first transition cycle. In addition, 306 energy projects have been selected for expedited review, with connection agreements expected by 2024.

Australia's Renewable Energy Zones address connection delays

By 2050 Australia aims to have 127 GW of utility-scale wind and solar PV capacity. Currently, projects face connection and commissioning delays, impacting project economics. To ease the integration of energy resources in the long term, Australia has established Renewable Energy Zones (REZs) where large clusters of renewable energy projects can be developed with capacity and transmission infrastructure planned in co-ordination. The REZs aim to speed connection, reduce and share costs, and increase reliability and energy security.

The development of the REZs considers new generation capacity and transmission expansion forecasts and limitations, among other factors. The plan is for REZs to have greatly increased transmission capacity to accommodate more renewables. For example, the Central-West Orana REZ near Sydney aims to boost network capacity from 900 MW to 4 500 MW. Co-ordinating planning for demand, transmission capacity and VRE deployment could ease connection concerns as these projects are built to meet these specific requirements.

Brazil boosts renewable energy connections with policy reforms and new transmission projects

Thanks to policy and regulatory actions such as new energy auctions and market deregulation, many new energy projects in Brazil are expected to connect by 2030. The resulting boom in project interest has led to larger connection queues and project wait times, especially in areas of high resource potential.

Brazil has tackled the growing renewable capacity queues in two ways. In the short term, the projects that would not materialise but remained in the connection queue were allowed to leave it without penalty in 2023 on the “Day of Forgiveness”. This resulted in reducing capacity awaiting connection by around 10 GW.[11] This has helped free up connection availability, especially in the resource-rich northeast.

To address grid congestion and enable more connections in the long term, Brazil held tenders for new transmission infrastructure in 2023 and 2024. These tenders are aimed at building transmission between the northeast and central-south regions, as the latter have high power demand. The projects target completion between 2026 and 2028, significantly boosting transmission availability and, therefore, the capacity to connect new resources.

[11] Amnesty, or allowing projects to withdraw from a connection queue without penalty, has also occurred in other markets, with the United Kingdom’s Ofgem allowing 8 GW of capacity to leave the connection queue without a cancellation charge.

Chapter 3. Emerging challenges and solutions at high VRE shares

A growing number of systems are reaching high phases of VRE integration (Phase 4 and higher), with VRE meeting most of the demand at times or even experiencing significant surplus generation. Experiences from these frontrunner systems provide insight into emerging challenges and possible solutions at these phases and give us evidence of how power systems can securely operate with high shares of VRE.

As power systems reach (or surpass) Phase 4 of VRE integration they not only face the same issues from previous phases on a more widespread basis, but also encounter new technical and economic challenges. From a technical perspective, the structural role of VRE in system operations creates the need for a greater focus on aspects such as grid stability and enhanced flexibility. These challenges require solutions that go beyond simple operational measures, which were fundamental at low phases. Instead, they demand a deeper transformation in system operation, planning and financing within this new paradigm.

On the economic front, a key symptom of these challenges is the increased frequency and duration of negative price periods in markets that allow them. Excessive occurrence of negative prices can undermine the bankability of new renewables projects and often indicates insufficient system flexibility, though a nuanced understanding of their specific causes within each system context is crucial.

Addressing these technical and economic challenges requires a multifaceted approach, simultaneously deploying technological solutions and making improvements to market design and regulation. This holistic strategy is essential for maintaining the momentum of renewable energy growth and achieving climate objectives in high phases of VRE integration.

Technologies with high promise, such as various sector coupling solutions, grid-forming converters, and bidirectional smart charging (vehicle-to-grid) of EVs, could play a significant role in integrating these higher shares of VRE, but are yet to reach market maturity and may need support to do so. However, most of the technological solutions for integrating high shares of VRE have already reached market maturity. This means that their effective deployment does not hinge on significant additional R&D, but on implementing effective regulatory and policy actions.

Emerging challenges: increased focus on stability and on higher flexibility needs

From the perspective of system performance and resilience, the main emerging challenges to successfully integrate VRE at high phases are a greater need to focus on safeguarding system stability and on meeting growing flexibility needs across all timescales. Both stability and flexibility have historically been ensured by large hydro and thermal generators but require alternative solutions as unabated fossil-fuel-fired plants are phased out.

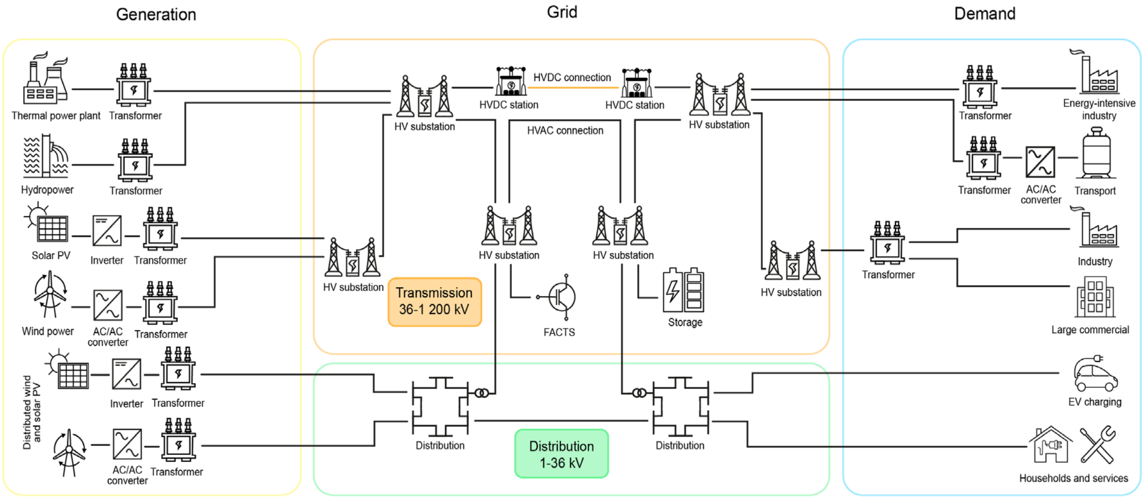
Stability refers to the ability of the system to return to a state of equilibrium after a disturbance – for example, by keeping frequency and voltage within acceptable ranges after an asset outage. The large rotating masses of traditional generators support system stability by slowing down the impacts of a disturbance. As large generators are giving way to VRE, it is necessary to procure the needed stability from a wider range of sources, be that dedicated equipment or assets such as batteries or VRE plants themselves. At the same time, operating practices need to adapt to ensure the system can continue responding to disturbances.

In Phases 1 to 3 the flexibility challenges are mostly related to ramping up or down dispatchable resources in the minutes-to-hours timeframe. In Phases 4 and above, the flexibility needs in this timeframe may increase further. In addition, new flexibility needs arise in the timeframe of days, weeks and longer, to manage periods where wind and solar PV are not available, as well as periods of oversupply. Addressing this increasing need for flexibility across all timescales requires contributions from existing and new resources, such as power plants, batteries, VRE generators themselves, and demand, complemented by strong electricity grids and sector coupling.

The displacement of large synchronous generators can affect system stability

The stability of large power systems requires three essential characteristics, collectively called system strength: physical inertia, a stiff voltage waveform and high fault currents. These characteristics have traditionally been supplied by synchronous generators, requiring the system to procure them from different assets as VRE grows. Rather than connecting directly to the grid, VRE generators (as well as storage and HVDC interconnectors) do so through a converter. These converters can deliver a wide range of system services such as voltage regulation, frequency regulation and tailored response to system events, as well as improved use of the grid. Despite their versatility, converter-connected resources do not inherently provide system strength, and therefore as VRE resources replace traditional units, challenges can arise across all aspects of system strength.

Key components of electricity grids

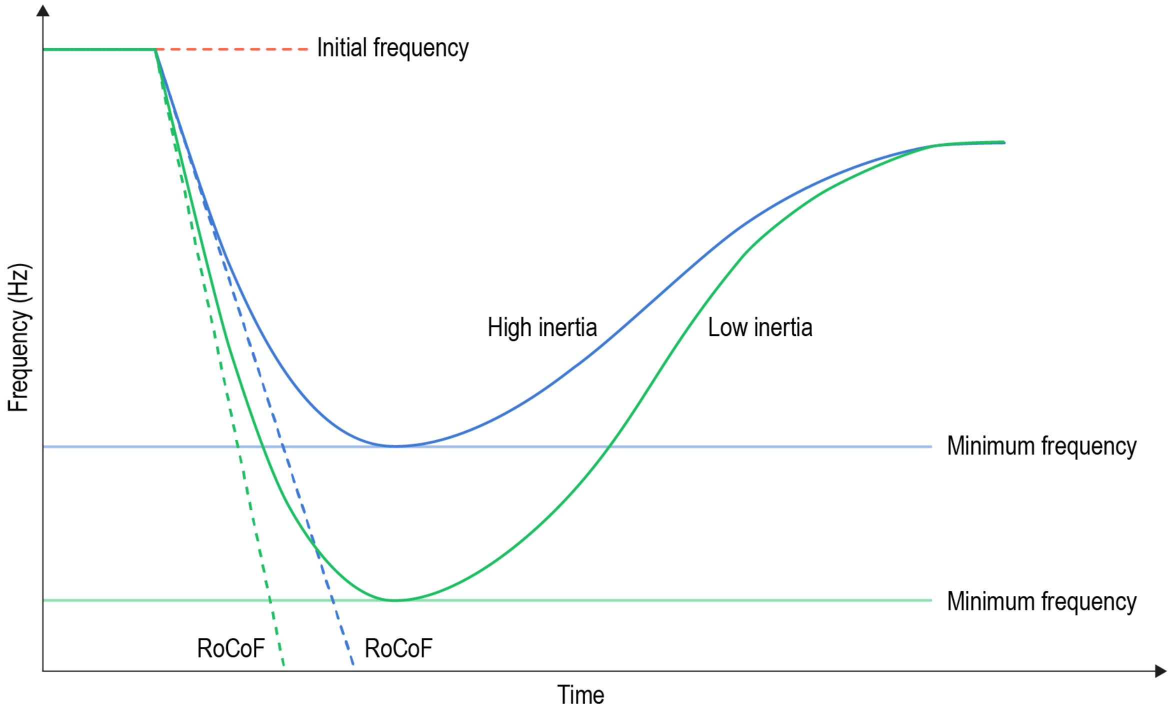


IEA. CC BY 4.0.

Notes: FACTS = flexible alternating current transmission system; HVAC = high-voltage alternating current; HVDC = high-voltage direct current.
Source: IEA (2023), Energy Technology Perspectives 2023.

The first possible challenge is related to a decrease in inertia, which determines the speed at which the frequency varies following a disturbance (called rate of change of frequency, or RoCoF). The kinetic energy stored in the spinning parts of synchronous generators (e.g. thermal power plants) is the system's inertia. Inertia slows down the change in system frequency in case of an imbalance, and it plays a key role in system operations, as too large a frequency deviation can lead to consequences such as equipment damage and widespread outages. Converters do not inherently provide inertia, as they isolate the rotating part (if any) of the connected resource from the electrical grid. Therefore, if the number of synchronous generators online decreases, an imbalance in the system will produce more abrupt changes in frequency. Issues due to lower inertia tend to appear earlier in smaller systems (for example Ireland), although many other factors play a role, in particular the speed at which resources in the system detect and respond to imbalances.

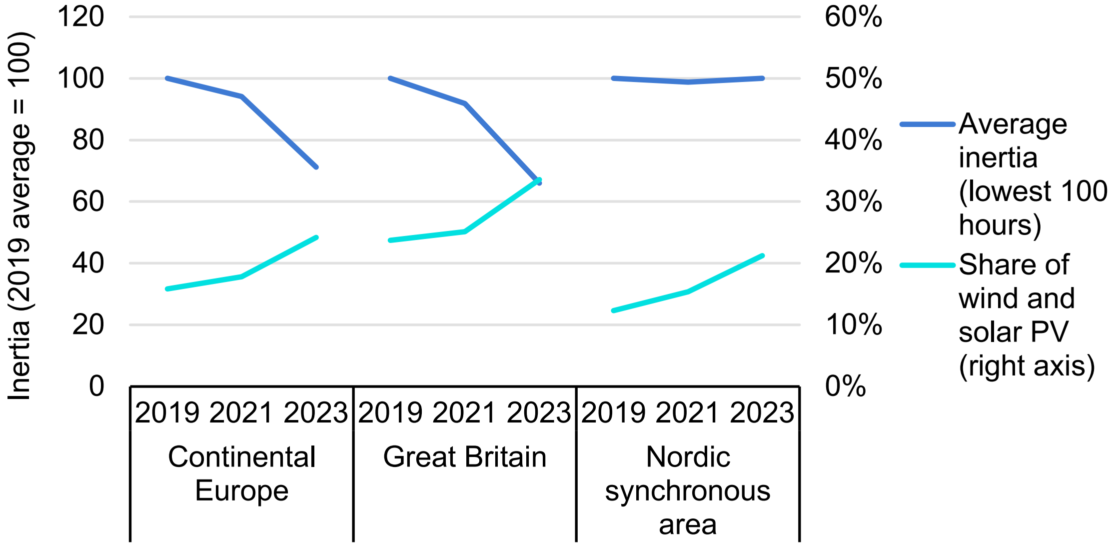
Frequency response of a power system with high and low inertia



Source: Fingrid (2024), [Inertia of the Nordic power system](), as modified by the IEA.

An increasing share of VRE does not necessarily lead to lower system inertia. Synchronous generators provide their full inertia when they are online even when they are operating at partial output levels. The inertia in the system drops only when synchronous generators are taken offline, which in the context of growing VRE can happen either seasonally during low demand periods, or structurally as VRE sources increase faster than demand. This has been observed over the last five years in the synchronous systems of continental Europe and Great Britain, where the average inertia over the 100 hours with lowest inertia of the year – used as an indicator of potential periods of system stress – decreased by around 30% as the share of VRE in their annual generation mix increased by about 10 percentage points. In contrast, inertia levels in the hydropower-dominated Nordic system remained mostly unaltered over the same period, supported by hydro and nuclear power plants.

Annual generation share of wind and solar PV and indexed average inertia (100 lowest hours of each year) in selected systems, 2019-2023



Note: The inertia for continental Europe was estimated with the methodology and inertia constant values presented by ENTSO-E (2020) in Inertia and Rate of Change of Frequency (RoCoF).

Sources: IEA analysis based on data from Energy Charts (2024), Electricity Production; National Grid ESO (2024), System Inertia; Fingrid (2024), Inertia of the Nordic power system.

A second major stability challenge is the weakening of the voltage waveform in the system, which provides a voltage and frequency reference for the control systems of most grid-connected resources. Synchronous generators can generate their own voltage waveform and synchronise independently from other electricity sources: they are naturally "grid-forming". In contrast, converters are typically grid-following, needing this reference waveform to synchronise to the grid. The absence of a stiff voltage waveform leads to wider voltage fluctuations and more disconnections of grid-following resources due to malfunctioning of controllers, among other issues. In contrast to inertia, voltage issues tend to be local and related to the sparsity of grid-forming resources, rather than the system size.

The third consequence of the displacement of synchronous generators is a reduction in the current supplied during short circuits – also called fault current. This allows detecting, locating and isolating faults and supports the voltage level immediately after. When a fault occurs, nearby synchronous generators respond by instantaneously injecting high levels of current (many times their normal operation level), which allows the system to detect the fault and respond to it. In contrast, converters are limited to the design current because of their fragile semiconductor components, limiting their ability to respond to such faults, and therefore allowing fault currents to drop. Protecting grids and users' equipment when fault currents decrease requires an adjustment of the protection systems.

System strength challenges can be addressed through various strategies. One approach is maintaining synchronous generators online at low output, supported by additional revenue streams, while allowing some curtailing of renewable energy during excess supply. However, as countries commit to decarbonisation, adapting to reduced system strength may prove more cost-effective than keeping numerous thermal generators operational.

Assets can also be deployed with the specific purpose of increasing system strength, such as installing synchronous condensers, but it can also be possible to require new VRE assets to contribute to system strength. Thanks to the versatility of power electronics, a battery or a VRE plant can also emulate inertia and behave as grid-forming. A portfolio of solutions exists, but each solution needs to be studied in the context of the needs and costs in each system.

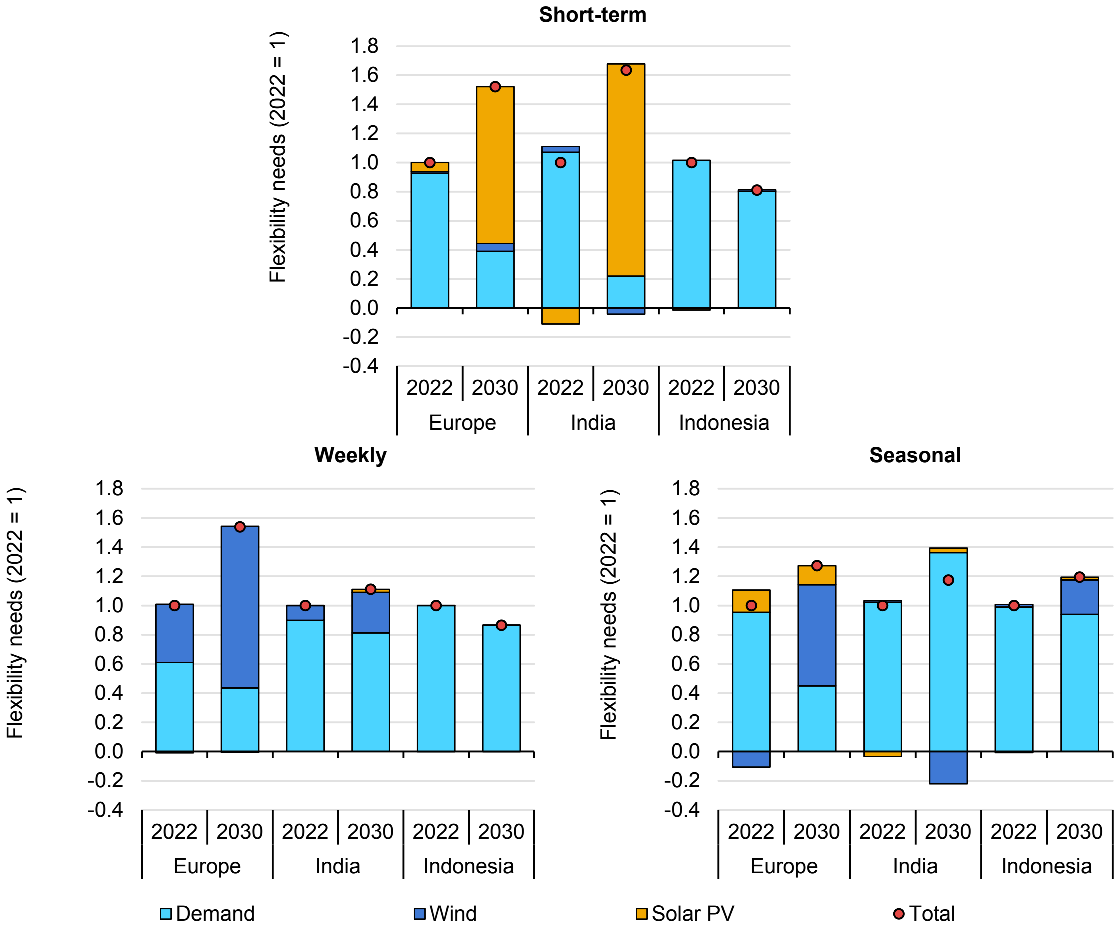
Growth of VRE contributes to increased flexibility needs across all timescales

Demand has historically been the main source of variability in power systems, but its structure is changing. Electrification of major end uses (such as space heating and cooling or transport) could induce larger swings in electricity demand. Combined with climate change, this could increase evening demand peaks and also amplify weather-dependent (seasonal) demand for heating and cooling, particularly in hot regions such as Southeast Asia and India.

With higher shares of solar PV and wind, supply uncertainty and variability also increase and periods where there is a mismatch between generation and demand may occur more often and last longer. For instance, another challenge is related to managing periods of low VRE generation, such as the “dark doldrums” (also referred to as “dunkelflaute” in German) already experienced in Europe and Japan during winter when VRE generation is low. At higher penetrations of VRE, the inherent variability of solar and wind resources contributes to the increased need for flexibility over periods longer than a few hours or a couple of days, not simply in shorter periods. These flexibility needs over longer timeframes are less pronounced in systems at low phases of integration.

Very different variability patterns can emerge in various regions depending on their mix of resources and demand, but flexibility needs across all timeframes – for example, in hours within a day, in weeks and in seasons – are set to increase faster than demand in most regions in the Announced Pledges Scenario (APS). In that scenario, short-term (i.e. of hours within a day) flexibility requirements increase by at least 50% in Europe and India out to 2030, with solar PV becoming the main driver for flexibility requirements in that timeframe. On the other hand, weekly flexibility needs also grow by at least 50% by 2030 in a region such as Europe in the APS, with its higher penetration of wind being a key driver. Finally, average seasonal flexibility requirements increase by at least 15% from 2022 to 2030 in Europe, India and Indonesia. In India and Indonesia, the largest driver of seasonal flexibility needs in the APS continues to be demand, particularly as a larger share of their populations gain access to air conditioning.

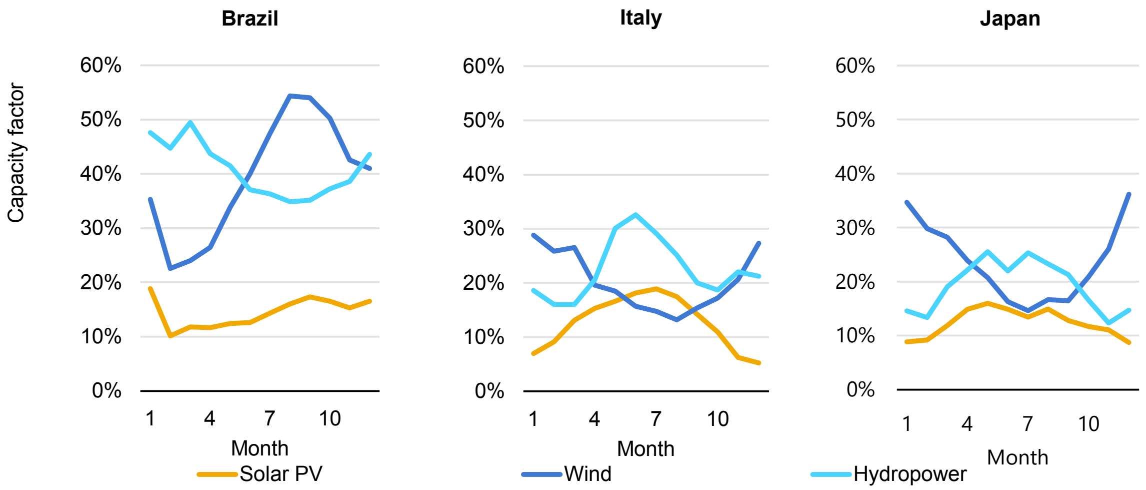
Evolution of flexibility needs and their drivers in selected regions in the Announced Pledges Scenario, 2022-2030



Notes: Flexibility needs are computed for 2030 taking into account changes in electricity supply and demand and weather variability over 30 historical years. Short-term flexibility needs are calculated based on hourly changes in net demand (i.e. total demand minus wind and solar PV generation) within a day. Weekly flexibility needs are calculated based on daily changes within a week. Seasonal flexibility needs are calculated based on weekly changes in net demand within a year. More details on the calculation methodology can be found in IEA (2024), Managing the Seasonal Variability of Electricity Demand and Supply.
Source: Adapted from IEA (2024), Managing the Seasonal Variability of Electricity Demand and Supply.

While renewable technologies such as VRE and hydro can increase flexibility needs, deploying a mix of them can leverage their complementarities. In periods of deficit of one of the renewable technologies, this approach can reduce reliance on fossil fuels to meet flexibility needs, which can help to avoid emitting carbon dioxide and incurring significant additional operational expenditures. For example, in Brazil the average capacity factor of wind and solar reaches high points in the third quarter of the year, when hydropower is usually at its lowest. Similar complementarities in capacity factors can be seen in Italy and Japan, where summertime high solar and hydropower match lower average wind speeds. These higher-capacity factors can also coincide with higher seasonal demand, for example in summer due to air conditioning, which they can contribute to meeting.

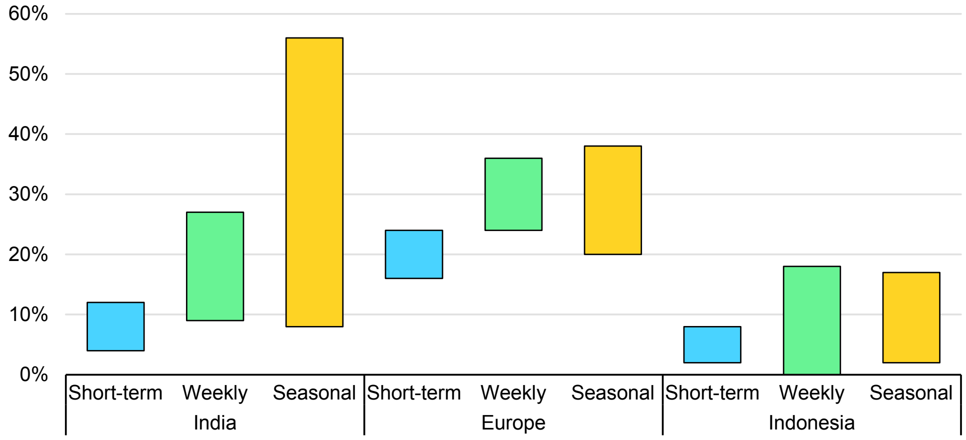
Average monthly renewable capacity factors for selected countries, 2018-2023



Sources: IEA analysis based on IEA (2024), Renewables 2023; IEA (2024), Monthly Electricity Statistics; ONS (2024), Geração e Fator de Capacidade Médios Mensais.

Another way of addressing power system flexibility needs is with interconnectors. Interconnectors between countries or regions can contribute greatly to mitigating power system flexibility needs in general, which also includes longer timeframes. For example, Denmark already benefits from its major interconnections with the rest of Europe to raise its power imports significantly during summertime, when its average wind capacity factor is about half that of winter. In the APS, assuming no interconnections across country borders (or between subnational regions) in the period from 2022 to 2050, India, Europe and Indonesia face weekly flexibility needs that are up to 35% higher and seasonal needs up to 55% higher.

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



Source: IEA (2024), Managing the Seasonal Variability of Electricity Demand and Supply.

Technological solutions to enable high solar PV and wind penetration

Addressing the stability and flexibility challenges at high phases of VRE integration requires more than simple operational measures. Dedicated assets may need to be deployed to contribute to stability and flexibility, while ensuring that resources on the supply and demand side contribute to system needs and VRE integration. Among these technological solutions, while most are commercially mature, others are yet to achieve maturity.

A portfolio of technologies is available to contribute to stability

While maintaining stability has usually relied on thermal generators, which used to deliver the bulk of frequency controls, contributions from the demand side are growing. Demand has contributed to stability in Texas for over a decade, now meeting up to 60% of the total volume available to contain frequency deviations. Denmark's DK1 market prequalified 56 MW of electric boilers in industry and the district heating sector to be eligible to contribute to the frequency containment reserve in 2023, making up about 85% of the new prequalified capacity.

The disconnection of demand or the use of advanced controls to reduce consumption both contribute to normalising frequency following imbalances in the system. For example, during the unintended separation of the continental European system on 8 January 2021, the contractual disconnection of 1 700 MW of industrial demand in France and Italy allowed system operators to arrest the frequency drop, avoiding an emergency situation where the frequency reaches the thresholds for shedding demand.

Traditionally, contributions to stability from demand response were limited to large commercial and industrial loads, as it is more cost-effective to install the necessary equipment at these sites, but home energy management systems and the electrification of transport are unlocking the possibility of residential demand as well. For example, in Norway, Statnett implemented a demonstration programme providing a guaranteed fast frequency response (FFR) reserve of at least 80-90 EVs – which corresponds to a guaranteed delivery of 0.25 MW – with a response time of two seconds.

To maintain system strength and stability without interfering in the power market and increasing VRE curtailment, system operators started to deploy assets such as synchronous condensers and static synchronous compensators (STATCOMs) at least a decade ago. A synchronous condenser is a synchronous machine without prime mover (the part that converts the primary source of energy into a rotating movement, such as a turbine or engine and does not inject active power into the grid but contributes to inertia,[12] voltage control and short-circuit current. A STATCOM uses a large coil of wire, known as a reactor, behind a converter that provides essential voltage control.[13]

Synchronous condensers have been installed in many systems, such as Great Britain, Denmark, Australia and Texas where six additional devices have been recently approved for deployment. It is also feasible to repurpose existing or retired generators as synchronous condensers, as operated with coal plants in Ohio or with nuclear plants in California, which could be cheaper than deploying new assets altogether. STATCOMs have been installed in several countries including Spain, Nigeria and Germany.

Modern converters can strengthen grid stability, with plans for deployment in large-scale systems

Deploying modern converter controls can enable higher VRE uptake by supporting grid stability.[14] Traditional, grid-following converters need a stiff voltage waveform at the connection point to feed power into the grid. State-of-the-art grid-forming (GFM) converters, on the other hand, are able to create their own voltage

[12] The inertia of the synchronous condenser is lower than the original generator, due to the absence of the prime mover and shaft connecting it to the electrical machine. This can be compensated through the addition of a flywheel as at the hybrid grid stabilisation and battery storage plant at Shannonbridge in Ireland.
[13] STATCOMs also contribute to damping electromechanical oscillations, another stability phenomenon that arises from adverse interaction between voltage controllers in the system.
[14] Beside system strength, grid-forming converters are expected to contribute positively to the system performance in other ways such as: countering harmonics and voltage imbalances, and contributing to system restoration.

waveform, supporting grid voltage and increasing the ability of converter-connected sources to operate in grids with low system strength.

The additional investment cost for making a converter GFM remains limited when considering its impact on the total project cost, as it mainly requires a software upgrade for the converter controls. When considering a project to build a battery storage or VRE asset, the converter accounts for about 10% of the total project cost. However, there are also cost implications to maintain headroom to respond and increase current injection at all times. This may have significant implications for the business case of a converter-connected asset, which can be particularly penalising for VRE. Long-term contracts for system services, if they exist, may compensate for the lost electricity sales.

As a consequence, in contrast to the use case of GFM with batteries and HVDC interconnectors, GFM for VRE plants is further away from market uptake, as it requires substantial changes to the plant controls, moving away from maximising output for given wind/solar conditions, or adding hardware such as energy storage behind the converter to have enough headroom to provide the GFM service.

GFM converters are already a mature technology for small and isolated systems, but deployment at large-scale grids requires high levels of co-ordination among contributing converters, underpinned by very fast and reliable communication and computing. The technology has already been demonstrated in at least five countries around the world, although there is still a need for further developments to be able to reliably operate a large-scale power system with a large number of grid-forming converters. For example, the 30 MW/8 MWh Dalrymple battery project in South Australia provides frequency control plus inertia and fault current, and part of the 100 MW/200 MWh battery project by CHN Energy in Ningdong, China, is designed to emulate a synchronous generator. In Germany, the deployment of large-scale 300 MVAr grid-forming STATCOM has started. In Great Britain, 5 projects of battery storage with grid-forming capability were procured under the Phase 2 of the Stability Pathfinder programme.

The path to large-scale deployment will require the industry to define grid code requirements for GFM converters, including testing and verification procedures, advanced modelling capabilities and protocols to operate systems with GFM converters. Currently, even though there is a global interest to define what are grid-forming capabilities, there is no harmonised definition across regions. At the European level, the Connection Network Codes are being amended to consider GFM capabilities, and the system stability roadmap in Germany expects GFM converters to be at the demonstration phase by 2027 and to have a significant contribution to system stability by 2030. With GFM converters, VRE and batteries can also contribute to other services such as black start, which is needed to restart the power grid after a large-scale outage.

Transitioning towards a highly decarbonised system does not mean that all converters will need to have grid-forming capabilities. A few GFM converters may suffice to ensure system stability of a grid area, although specific studies are needed to estimate the adequate ratio for each particular system, depending on the system characteristics, potential disturbances to withstand, among other factors.

Selected technological solutions for improving power system stability

Solution	Stability services provided	Technology readiness level	Typical deployment time	Country/state examples
Pumped-hydro storage	Energy storage, inherently grid-forming, inertia, fault current	Mature (TRL 11)	4-10 years	Switzerland, China, United States, Japan, Spain
Synchronous condensers	Inherently grid-forming, inertia, fault current	Market uptake (TRL 9-10)	18-24 months	Australia, Texas, Great Britain, Denmark, Germany, Ireland
STATCOMs*	Voltage waveform stiffness, voltage control and oscillations damping	Market uptake (TRL 9-10)	18-24 months	Nigeria, India, United States, Spain, Ireland, Germany
BESS with grid-forming	Energy storage, voltage waveform stiffness, voltage control and inertia	Market uptake (TRL 9)	6-12 months	Australia, China, Great Britain, United States
VRE with grid-forming**	Voltage waveform stiffness, voltage control and inertia	Demonstration (TRL 7-8)	12-24 months	Great Britain, Denmark, Saudi Arabia, China, Scotland

* Other equipment such as supercapacitors and flywheels can be added to provide inertia.

** Grid-forming services in a VRE plant can only be provided for a few milliseconds unless there is an additional storage resource to sustain the provision of these services.

Notes: TRL = Technology readiness level; STATCOM = static synchronous compensator; BESS = battery energy storage system. The solutions and country/state examples included are for reference purposes only and do not necessarily represent a comprehensive list.

The technology readiness levels, and deployment times of the solutions correspond to grid-scale applications and the ability of these applications to provide stability services. The typical project deployment time is considered from the moment that the system operator or utility decides to procure the solution until the solution is deployed, including the necessary intermediate steps following local regulations.

For grid-forming solutions, the country/state examples include grid-connected and laboratory assets. The technology readiness labels presented for grid-forming solutions refers to the operation of one (or a few) grid-forming assets, as the operation of a large number of grid-forming converters in a large-scale power system still requires more development.

Sources: IEEE Power and Energy Magazine (2024), Inverter-Based Resources: Status, Opportunities and Challenges; ENTSO-E (2024), Technopedia; IEA (2024), Clean Energy Technology Guide.

Most technological solutions for providing flexibility are already or nearly available in the market

Currently, almost all flexibility over all timeframes comes from dispatchable generation (thermal and hydropower plants) and grids (including interconnections). Industrial demand response is also used in some regions for short-term flexibility needs. Up to 2030 this remains the case in several regions in the APS, but by 2050 the transition away from unabated fossil fuels reduces the overall role of thermal power in power system flexibility. Instead, demand response becomes a more significant short-term flexibility provider, driven by EV smart charging and flexible industrial demand. On the other hand, electrolysers and other sources serve as alternatives to conventional generation for flexibility over longer timeframes, particularly if the reliance on fossil-fuel-fired power is reduced.

In the APS in 2030, around 60-80% of the short-term flexibility needs in Europe, India and Indonesia are covered with technological solutions including hydropower, thermal power plants, and battery storage. These technologies are currently already mature or commercially available in the market for providing flexibility. In the APS in 2050, demand-side solutions such as demand response and flexible operation of electrolysers play a larger role in meeting short-term flexibility needs. Many of these solutions may soon offer a fully viable business case, enabled by the right improvements in market design and regulation.

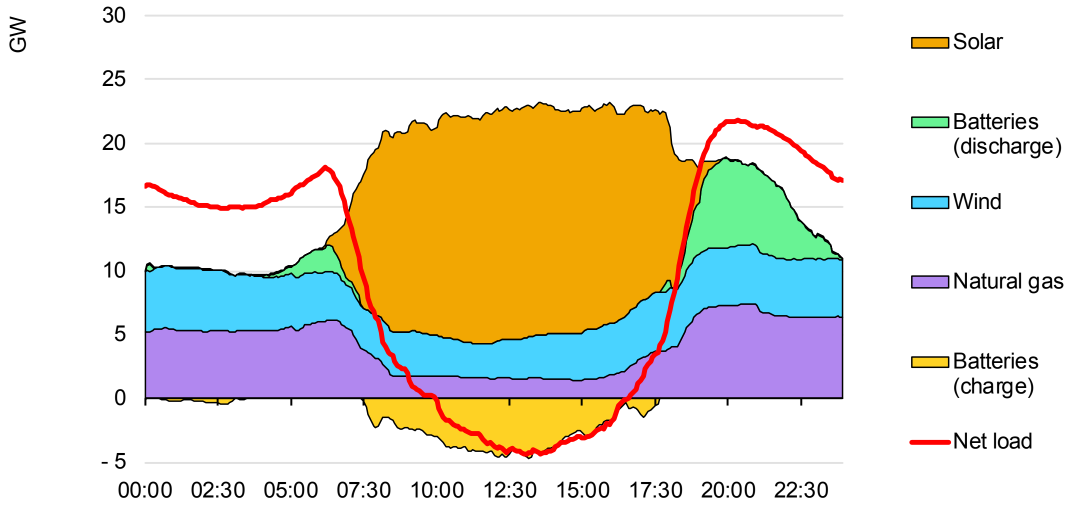
Technological solutions for addressing longer-term flexibility, on the other hand, vary more in their maturity. In India and Indonesia, thermal and hydropower plants, combined with other nearly mature technologies, can cover up to 80% of the weekly and seasonal flexibility needs in 2030 in the APS. However, these solutions only address 40-50% of longer-term flexibility needs in decarbonised systems such as Europe by 2050 in the APS, as flexibility sources such as electrolysers cover part of the needs that are currently met by conventional generators.

Residential demand response programmes with wide deployment of smart meters, in particular, are emerging as a viable option for providing short-term flexibility. In 2022 the number of smart meters worldwide exceeded 1 billion, a tenfold increase since 2010. The potential response will increase further with heat pumps and smart appliances reaching market uptake levels. Active control systems and home management systems are currently in the demonstration phase but could further enhance flexibility as they scale.

Another prominent flexibility tool are battery storage systems. Due to their ability to ramp up and down very quickly, batteries are well-suited to compensate for the variability of VRE. Lithium-ion batteries are technologically mature and, with costs falling, commercial deployment is picking up with year-on-year deployment rates doubling in 2023. Other battery technologies, such as redox-flow and metal-air batteries, are at lower readiness levels, but have the potential to provide longer-duration storage from hours to days. Beside short-term flexibility, batteries can deliver a wide range of system services and contribute to system stability and grid congestion management. The world is likely at the tipping point of exponential growth in battery stationary storage as it is currently an extremely profitable sector.

Several countries already have battery storage or plan to have in the coming years. In California, batteries reached a record power discharge of 7 GW on 30 April 2024, meeting about 33% of net load peak, contributing significantly on top of imports and natural gas. In Italy, the National Climate and Energy Plan relies on batteries to meet decarbonisation targets for 2030. While batteries accounted for 2.3 GW in 2023, these were spread across 300 000 installations. Italy aims for 15 GW of battery capacity by 2030, with 11 GW of utility-scale installations.

Generation profile in California (CAISO) for selected technologies, 30 April 2024



Note: Net load refers to the difference between total electricity demand and generation by wind and solar. Negative generation refers to batteries charging at times of excess supply, mainly driven by solar generation.
Source: IEA based on data from Gridstatus.io (2024).

EVs are increasingly contributing to flexibility as well, relying on smart charging technologies that are currently being deployed at scale. VRE generators themselves can also contribute to balancing services. For example, in Spain, more than 60% of installed wind capacity and about a quarter of installed PV capacity participate in frequency regulation services in the minutes timeframe, accounting for more than 35% of the energy allocated in these balancing markets.

Sector coupling has the potential to play a key future role in long-duration flexibility and making best use of VRE. Hydrogen production is an alternative that contributes to that regard. While the flexible operation of electrolysers as part of integrated energy systems does not yet present a fully viable business case, their proven ability to operate with varying loads highlights their potential to provide long-duration flexibility. Storing the excess hydrogen in pressure vessels or salt caverns is already technically feasible. In Europe in the APS, by 2050 the flexible operation of electrolysers fulfils about 20-30% of weekly and seasonal flexibility needs, if significant volumes of hydrogen storage are available. Hydrogen-fired (or co-fired) power plants could run on this stored hydrogen and provide flexibility. Despite the technological and economic challenges, Germany is planning the construction of 12.5 GW of hydrogen or hydrogen-ready gas plants that are planned to switch to hydrogen in a phased approach. The first phase includes 7 GW of new or retrofitted hydrogen-ready gas plants that must switch to hydrogen after 8 years, while 500 MW of hydrogen capacity is expected to be auctioned by late 2024 or early 2025. Heat storage also shows promise for flexibility across short and long timescales, linked to district heating networks as in Finland, or through a variety of thermal energy storage techniques linked to the electrification of industrial heat.

Selected technological solutions for increasing power system flexibility

Solution	Flexibility duration	Technology readiness level	Typical deployment time	Country examples
Pumped-hydro storage	Seconds to months	Mature (TRL 11)	4-10 years	Norway, China, Japan, United States
Interconnection	Sub-seconds to years	Mature (TRL 11)	15 years	Denmark, Germany, India Brazil
BESS	Sub-seconds to days	Market uptake (TRL 9)	6-12 months	Italy, California
Electrolysis	Minutes to months	Market uptake (TRL 9)	2 years	European Union, China, United States
Other smart appliances e.g. heat pumps	Seconds to hours	Demonstration (TRL 7-8)	Weeks-months	Ireland, Italy, Great Britain
100% hydrogen-fired power plants	Seconds to months	Demonstration (TRL 7)	4 years	Germany
Smart charging (vehicle-to-grid)	Seconds to hours	Demonstration (TRL 7)	1-2 years	Great Britain

Notes: TRL = Technology readiness level, BESS = battery energy storage systems. The typical project deployment time is considered from the moment that the system operator, utility or consumer decides to procure the solution until the solution is deployed, including the necessary intermediate steps following local regulations. Grid connection queues are not included. For each solution, several sub-technologies may exist, but the table refers to the most mature, as well as the technology's ability to provide flexibility services.

Sources: IEA (2024), Batteries and Secure Energy Transitions; IEA (2024), Clean Energy Technology Guide; IEA (2024), Global EV Outlook 2024; IEA (2023), Global Hydrogen Review 2023; IEA (2023), Electricity Grids and Secure Energy Transitions; IEA (2022), The Future of Heat Pumps; IEA (2019), Average power generation construction time; Shenling (n.d.), How long does it take to install a heat pump; International Council on Clean Transportation (2020), Assessment of Hydrogen Production Cost from Electrolysis: United States and Europe.

The transformation that systems need: rules, remuneration and planning

The solutions to address challenges at high phases of VRE integration go beyond simple operational measures, increasingly requiring a deeper transformation of how to plan, finance and operate the system, and simultaneously deploying technologies and introducing improvements in market design and regulation. Several countries are also updating their grid codes and operating protocols to facilitate the integration of high shares of VRE while safeguarding electricity security. They are being complemented by out-of-market and market-based mechanisms to ensure that the resources needed for a flexible and stable system are deployed and available. These are underpinned by modern planning approaches required to address the higher complexity and uncertainty of the long-term planning horizons.

New rules, protocols and services are needed to maintain stability cost-effectively

System operators have adopted pragmatic approaches when faced with the challenge of properly modelling the behaviour of converter-connected resources and their interactions, allowing higher levels of these resources in a step-wise approach. To maintain stability, system operators concerned by system strength have initially set operational constraints and limits such as keeping online a minimum number of synchronous generators. In the face of the costs of these measures and the barriers that they impose on adding VRE, operators are progressively lifting the limits after trials, thanks also to advanced simulation studies.[15] In parallel, they are adapting grid codes and deploying new assets and services to make best use of existing assets. Combining these changes allows operators to maintain stability at a lower cost than keeping thermal generators online.

Grid codes and operating protocols

Grid operators are adapting grid codes to support the smooth operation of the system, amending connection requirements to ensure grid users remain connected in a wider range of conditions and resources can contribute to essential system services. Since the early stages of VRE deployment, grid codes have been adapted, initially to ensure VRE resources remain online in a wide range of conditions and avoiding imbalances in the system if simultaneous disconnections

[15] In a system dominated by synchronous generators, EMT (electromagnetic transients) simulations were only performed at the local level to ensure power quality. With high shares of converter-connected resources, the scope of EMT needs to expand and address interactions between remote converters.

take place during disturbances. Ensuring compliance with the requirements is as important as the requirements themselves. Connection requirements need to be reasonable, avoiding requiring excess features while being forward-looking enough to cover a large part of the lifetime of connected assets – since retrofitting existing assets can be very expensive.

As system strength reduces, it could also be an option to extend the system's range of nominal operation. For example, as part of the roadmap to enable up to 95% instantaneous non-synchronous power supply by 2030, in 2023 the Irish TSOs EirGrid and SONI (System Operator for Northern Ireland) raised the RoCoF (rate of change of frequency) requirement from 0.5 Hz/s to 1 Hz/s for all grid-connected assets, following a three-year trial, to accommodate lower inertia.

Grid operators are also creating new protocols to operate systems with high shares of inverter-based resources, such as must-run requirements for resources providing system services. Inertia floors (minimum levels of inertia) have been in place in Ireland, Australia (at the regional level) and Texas, and are updated downwards in steps as TSOs trial operating the system with lower inertia levels and deploy new services to further stabilise the frequency.

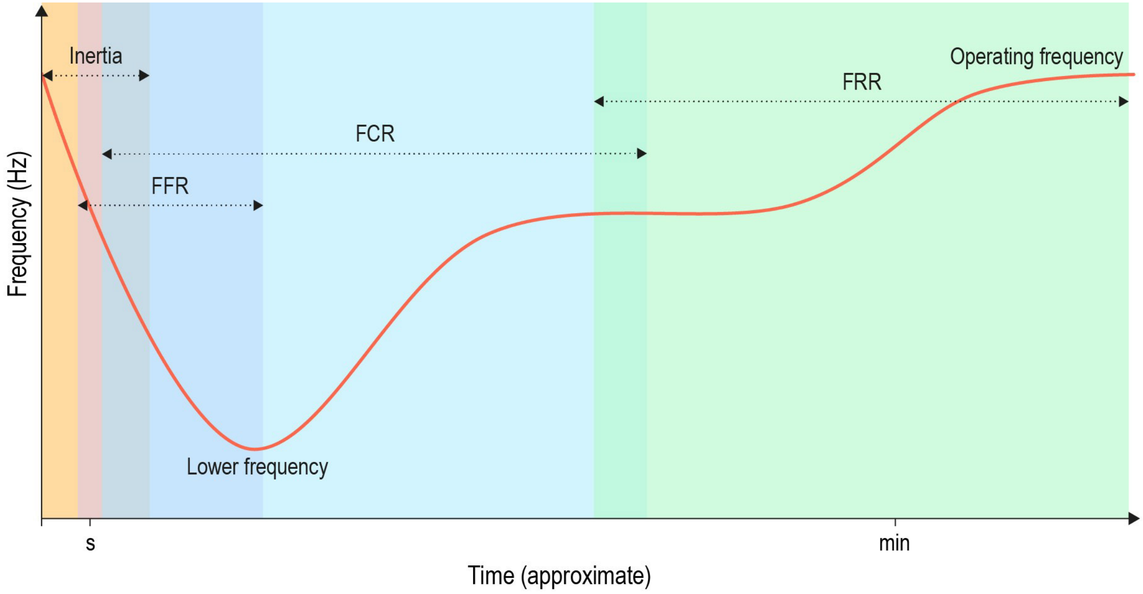
New products for system stability services

As thermal generators retire and VRE penetration increases, new services are designed that can be delivered by converter-based resources, demand-side resources and dedicated assets to maintain stability. Achieving stability at a reasonable cost requires finding a balance between strengthening grid code requirements for all resources of a selected type and deploying competitive market mechanisms to procure services to fulfil the needs.

At least 9 electricity markets[16] have started procuring fast frequency response (FFR) services in recent years, to compensate for the expected drop in inertia. Situated in the timeframe between inertial service and the traditional frequency containment reserve service, FFR enables system operators to activate assets in a timeframe of up to a couple of seconds, reducing the need for inertia and helping stabilise frequency after an excursion event. For example, in the Nordic power grid, an FFR service was introduced in 2020. In this system, FFR volume needs are assessed at the system level, but each country procures its own share according to a distribution key. A major feature of FFR is that it can be readily supplied from battery storage and demand response through fast disconnection of load.

[16] PJM (United States), ERCOT (United States), Great Britain, Ireland and Northern Ireland, Nordic power grid, HQT (Canada), AESO (Canada), New Zealand, NEM (Australia).

Inertial response and activation of different frequency control services after a disturbance



Notes: FFR = fast frequency response; FCR = frequency containment reserve; FRR = frequency restoration reserve.

System operators around the world have organised targeted auctions to ensure the provision of stability services. National Grid ESO, the system operator of Great Britain, auctioned stability services under its Stability Pathfinder programme, which resulted in about 12 synchronous condensers being brought online in 2020 for its first phase, adding 12.5 GVA.s (GVA seconds) of inertia to the grid, along with the deployment of 870 MW of batteries in its second phase. In Chile, the national system operator Coordinador Eléctrico Nacional organised an auction for the provision of voltage control services. This has led to an investment of around USD 500 million for the deployment of five synchronous condensers with a total capacity of about 1 GVA, which are set to be operational by 2027.

Beyond targeted auctions, there is already an example of a more widespread stability market. National Grid ESO observed in recent years an upward trend in the volumes and costs of measures required to manage system stability. In that context, and as a follow-up to the Stability Pathfinder programme, in 2023 it announced plans to introduce a stability market. This scheme is designed to procure contributions to stability requirements such as inertia and short-circuit level more efficiently, and will be split into different timescales, including a day-ahead market, a year-ahead mid-term market, and a four-year-ahead long-term market. The mid-term market was the first of the three to be introduced, as the tender process for 7 GW.s (GW seconds) of inertia to be delivered for a year starting October 2025 is already in its final stages. The final results are set to be published in October 2024.

Higher flexibility can be achieved by leveraging market mechanisms, contracts and demand-side resources

To meet the system flexibility needs identified across all relevant timescales, system operators can resort to assets that already have the necessary capabilities, assets that need retrofitting, and the deployment of new assets. A broad set of solutions exists to facilitate that the power system flexibility needs are met, ranging from mechanisms to ensure that enough flexible capacity is available when needed, to system-friendly contracts and support schemes for VRE, and demand-side solutions. The design of these mechanisms, though, needs to avoid inhibiting flexibility provision from the benefiting resources and limit market distortions. A variety of assets can contribute to the needed flexibility, such as power plants and storage, but demand-side resources have the highest untapped potential.

Mechanisms to ensure that flexible capacity is available

Mechanisms can be deployed when market revenues are not sufficient to maintain a sufficient pool of flexible, dispatchable resources. The revenues of dispatchable resources mainly come from the sale of energy and are complemented in most markets by paid-for system services, such as frequency and voltage regulation. As wind and solar penetration increases, price volatility increases and dispatchable assets tend to operate at lower output levels. This means that energy sales and system services[17] may fail to generate sufficient predictable revenues to encourage adequate investment in new flexible generation and to keep necessary existing assets operational. These issues are commonly referred to as the "missing money problem" of power markets, which may affect the ability of the system to reliably manage flexibility needs across various timescales and ensure system adequacy.

Various approaches can tackle the missing money problem and ensure that enough capacity is available to act when needed. These include regulated procurement, in which the amount and/or the price of capacity are determined by a regulatory body, energy price adders, and direct payment to resources to be available when needed. Energy price adders,[18] such as scarcity pricing, allow for higher prices than the market clearing price when the system operator becomes short of the desired level of generation needed to support energy and reserves. This provides incentives for resources to be available during periods of supply scarcity and has been used in Texas and Australia.

[17] In addition, competition to provide paid-for system services is on the rise as system operators redefine system services so that products and batteries, demand-side management and VRE are eligible to participate.

[18] Energy price adders are typically used in energy-only markets to cover the investment costs of assets that run very rarely (a few hours a year) but are still needed to meet peak demand or maintain adequate reserves.

Capacity remuneration mechanisms are a further option and can vary significantly across different jurisdictions, but their design can support cost-efficient integration of VRE. At least 20 markets[19] around the world have introduced them in some form to directly reward capacity. They are tailored to ensure system reliability in the specific context of each system. In Germany, the strategic reserve mechanism (Kapazitätsreserve) operates outside the market. It consists of contracting specific plants to remain on standby, to be activated only when additional power is needed to cover specific periods where procurement via standard market mechanisms may not be enough. In the PJM and ISO New England regions of the United States and in Germany, payments are based on having capacity available throughout the whole year, while in Great Britain, Belgium and France, although the contracts require the capacity to be prepared throughout the year, the capacity payments depend on availability during specific periods of system stress.

Regardless of the choice of capacity remuneration mechanism, key principles emerge for designing these mechanisms. When doing so, policy makers must achieve a fine balance between market intervention to correct shortcomings and taking steps that create market distortion. Except in cases where a specific technology needs to be boosted to achieve maturity or faster deployment (such as storage technologies in Italy), focusing on the services needed instead of on the technologies that provide them is key. Further, keeping costs down for consumers is highly desirable, such as via determining capacity requirements efficiently and proceeding through auctions.

System-friendly contracts and support schemes for VRE

Support schemes, such as feed-in tariffs, feed-in premiums and contracts for difference (CfDs), and long-term contracts or power purchase agreements (PPAs) can play a key role in the deployment of VRE by reducing the revenue risk to developers. Moreover, they can be designed in ways that ensure assets are operated in a system-friendly way. Considering the renewable targets that many countries have committed to achieve, a portfolio of contracts and support schemes is set to continue being used to incentivise the buildout of VRE and meet the demand for low-emissions electricity. This justifies the attention given by the European Commission to these mechanisms in its electricity market design reform. Ideally, contractual agreements used to hedge price risk would do so without distorting the dispatch of assets according to the economic merit order, and without adding barriers to the participation of flexibility resources in providing system services.

[19] Japan, Korea, United States (PJM, California, ISO New England, NYISO), Canada (Ontario), Brazil, Chile, Colombia, Australia, Belgium, Bulgaria, Croatia, Finland, France, Germany, Greece, Ireland, Italy, Lithuania, Poland, Portugal, Spain, Sweden, Great Britain.

While a lack of incentives for system-friendly operation may be imperceptible when VRE penetration is low, the inflexibilities and distortions unintentionally created by contracts and support schemes can end up resulting in significant costs for the power system when VRE penetration increases. For example, a must-run clause or a high payment guarantee can lead to inflexibilities in a contractual arrangement, due to the inability of the system operator to reduce the output of a specific plant or the high cost of doing so, even if it would be best for the system's operational efficiency or security.

Various forms of subsidy have been adopted to replace feed-in tariffs, which offered a stable revenue per megawatt-hour injected into the grid and have been the most common mechanism to support the deployment of small and medium-sized VRE plants. The motivation behind this replacement was to control costs and remove the incentive to maximise output regardless of the system conditions, including when prices are negative.

Originating in the United Kingdom to support offshore wind investments, two-sided CfDs[20] gained traction during the global energy crisis that started in 2022, thanks to their clawback mechanism that prevents windfall profits. This government-backed scheme is already in use in at least 10 countries in Europe, including the United Kingdom and 9 EU member states, and at least a third of Europe's offshore wind capacity has been developed via this arrangement. The United Kingdom expects over 50% of its renewable capacity to be under a CfD scheme by 2035.

CfDs can be designed in many ways and design choices can have material implications for system operations and the functioning of power markets. Depending on their design, production-based CfDs can be a missed opportunity if they reward output maximisation at the expense of system-friendly behaviour, as is often the case with production-based CfDs with an hourly settlement period. In this context, system-friendly behaviour means that power plants aim to be available at times with above-average market prices and reduce generation during low, zero or negative price hours. Developers can make system-friendly decisions at the project stage, deploying wind turbines able to run at low wind speeds or solar panels oriented westwards, and make system-friendly operational decisions by scheduling plant maintenances at times of low demand. Schemes that decouple subsidy payments from actual generation volumes contribute to addressing these points. In addition, the choice of the reference (or strike) price in CfDs requires careful attention, as it could distort short-term power markets.

[20] A two-sided CfD is a mechanism based on a defined strike price. If the reference market price is below the strike price, the producer receives the difference and if the reference market price is above the strike price, the producer pays back the difference. While feed-in tariffs only offer risk mitigation for the investor/producer, CfDs also offer risk mitigation for the system/consumer by limiting excess remuneration.

Support schemes such as net metering, while promoting distributed solar PV, can introduce system inflexibilities. Net metering allows households to offset their electricity consumption with their own solar generation, significantly reducing bills. However, as these assets scale up, their lack of visibility and controllability by system operators can increase grid congestion. Moreover, allocating grid costs according to net consumption shifts the burden to non-generating users, often lower-income households. Recognising these distributional effects and grid challenges, the Netherlands plans to phase out net metering by 2027.

How corporations procure electricity and the design of the contracts they use can also affect system operations. While companies can procure clean electricity in many ways, direct PPAs are experiencing significant growth: a record 46 GW of solar and wind contracts were signed in 2023. PPAs are tailor-made contracts typically signed for durations lasting between five years and the lifetime of the assets. Corporations seeking to match their demand with clean generation may be tempted to purchase power from the cheapest resources (often solar PV generation) regardless of the temporal alignment with their demand and the availability of grids. Compared to yearly matching, shorter matching periods can deliver a more diverse clean energy portfolio, bringing wind, batteries and clean dispatchable capacities online in addition to cheaper solar PV.

For support schemes and private contracts alike, design choices can be made to incentivise deployment of system-friendly VRE and support VRE integration efforts, to complement electricity market arrangements. To this end, the main desirable features in the design of these mechanisms is to ensure they maintain (or introduce) price signals representing system needs, do not interfere with the merit order and do not remove assets from the pool of flexibility providers. Of course, the design of these contracts and the effectiveness of different approaches to incentivising system-friendly behaviour will depend on the particular market framework they are implemented in.

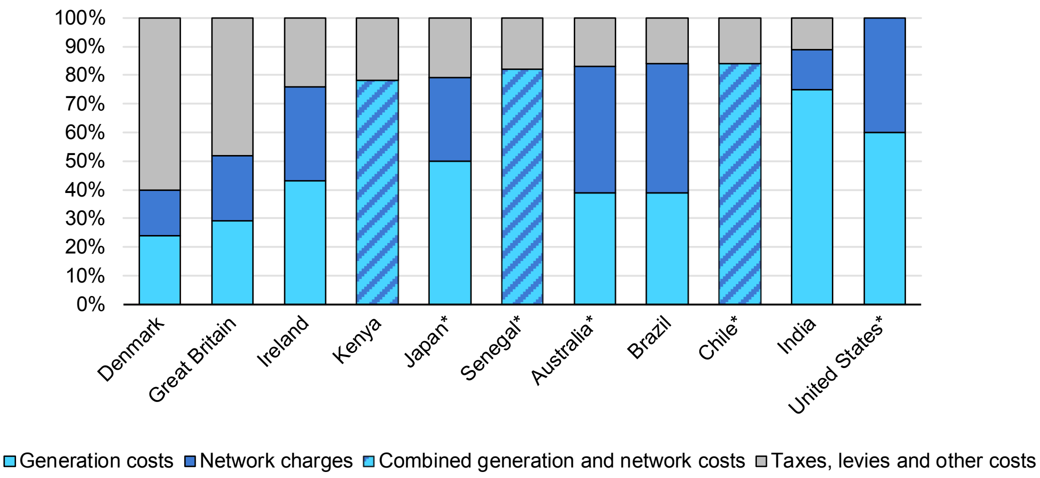
Unlocking the demand response potential of small-scale resources

Leveraging more flexibility from a broader range of demand-side resources will be essential to integrate high shares of VRE. Although less than 2% of the global potential of demand response is being utilised today, mainly from industry, IEA analysis expects demand flexibility to provide a quarter of daily ramping needs by 2030 in a scenario where countries achieve their climate and energy targets. Broader participation can be facilitated by more transparent price signals, digital tools and variable network charges.

The key to unlocking demand response across a broader range of electricity users lies in time-varying rates and enabling technologies. Instead of charging customers a flat rate per kWh, time-varying rates change throughout the day to reflect system conditions and incentivise shifting consumption to align with system needs, for example to better synchronise with VRE generation or reduce local grid congestion. Customers subscribed to time-varying rates can reduce peak demand by up to 20%, although currently large volumes of demand response are held back by limited information and manual activation. Responding to this barrier, technologies can roughly double the peak demand reduction induced by price signals and enable demand response participation from additional sources. Smart EV charging stands out as it can provide flexibility across time and space, with a potential peak load reduction estimated between 7% and 21% by 2035 in Europe.

Expanding time-varying rates to network charges provides additional incentives for consumers to respond to changing system conditions, especially where network costs constitute a significant part of electricity bills. Typically, energy regulators determine distribution and transmission charges and can choose to vary them according to available grid capacity, such as in Australia, which contributes to optimising grid upgrades. This can be a powerful driver of flexibility in high-phase systems by, for example, increasing the incentive for self-consumption or the viability of storage in solar-dominated systems. Variable network charges already exist in many European countries such as Austria, Norway and Spain. Overall, when designing rates, it is key to consider potential distributional effects and impacts on affordability.

Residential electricity bill components in selected countries, 2021



* Data for Australia, Chile and the United States are for 2020, for Senegal are for 2019, and for Japan are for 2016.
Sources: IEA (2023), Electricity Grids and Secure Energy Transitions; Solar Run (2020), Electricity Cost Comparison and Analysis; Ofgem (2021), Breakdown of an Electricity Bill; US Energy Information Administration (2022), Annual Energy Outlook 2022; ANEEL (2022), Tarifas e Informações Econômico-Financeiras; Biblioteca del Congreso Nacional de Chile (2020), Componentes y determinación de la tarifa eléctrica para los clientes regulados; Shas, S. (2024), Electricity Costs in Kenya; GET.Invest (n.d.), Senegal; Japanese Cabinet Office (2016), Transition of Electricity Tariff and Grid Tariff Comparison of Japan and Overseas.

Planners can adopt proactive and robust approaches to deal with uncertainties

As the energy system transforms, the scale and pace of investment in both resources and transmission and distribution grids will need to step up. To provide confidence to investors, the transformation must be supported by a vision of the new future and transparent plans to achieve it. To lay out investment needs, system planners conduct studies every one to five years to identify system needs typically around ten years into the future, or more. To enable the integration of high shares of VRE, studies should be based on national energy and climate goals, and anticipatory investments in grids should be made.

Integrated and co-ordinated planning

An overarching challenge of planning decades into the future is the need to account for how various aspects may evolve. These include many factors such as the cost of resources and technologies, demand for goods and services, and environmental and geopolitical realities.

New planning practices are required to deliver a robust plan under these uncertainties, leaving some flexibility but updating it periodically to adjust to new realities. Not to be confused with central planning, integrated and co-ordinated planning is a collaborative framework bringing together the strengths and resources of many stakeholders in the power sector and from other sectors to feed into the plan. A prime example is Australia's Integrated System Plan, performed over a two-year cycle by the Australian Energy Market Operator.

Key features of effective integrated planning are considering the power system as a whole (including integration with other sectors), incentivising all solutions that contribute to policy goals, being transparent and engaging stakeholders, and aiming for robustness with a broad range of futures and uncertainties (including, for example, extreme weather events).

To achieve these results despite the large uncertainties, the tools currently used by planners include scenario-based planning, sensitivity analysis and stochastic approaches.

Developing scenarios that cover a broad range of outcomes allows planners to identify different challenges to the system that need to be addressed. Sensitivity analysis observes how variations in the key parameters affect the outcome. Sensitivities are often used to complement scenario-based planning, to test their robustness against specific assumptions.

Demand has always been central to planning, but its complexity is growing. Expanding historical demand profiles no longer holds, as the structure of demand evolves with end-use electrification. Improved assumptions are required on how energy efficiency performs, the pace of electrification of new uses and, most importantly, the representation of how demand response can contribute to system flexibility.

Explicitly considering controllable demand-side resources as part of the portfolio of measures in power system planning can help reduce the investment needs. For example, one of the scenarios in Australia's latest Integrated System Plan considers that by 2050 at least 40 GW of capacity will come from consumer-side storage and EVs, which combined account for about 15% of total installed capacity in that year. It also includes the contribution of non-EV demand-side participation.

A significant change in planning from the growth of VRE is the incorporation of short- to mid-term variability and the uncertainty of VRE resources. Traditional approaches fail to consider the contribution of wind and solar to system adequacy, which is not null but also not at a constant level.

Stochastic methods for system adequacy

One area of power system planning with significant potential for innovation is adequacy, which ensures the system can reliably balance supply and demand under stable operating conditions. Traditionally, this has been assessed by analysing the impact of outages during critical periods of tightness, such as peak and minimum demand. The conventional method, known as the reserve margin approach,[21] focuses on how much spare capacity from generation, grid infrastructure, and demand response is expected to be available during these key moments.

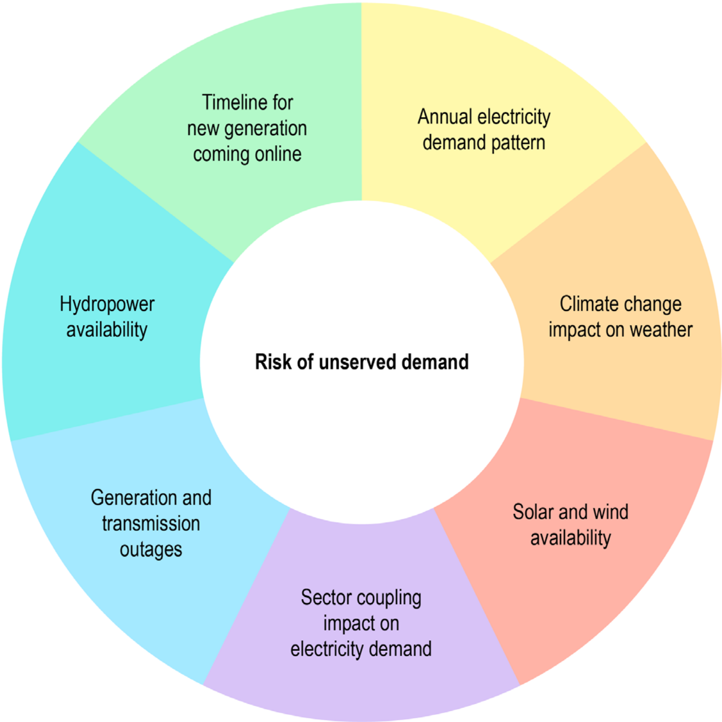
Over the last decade, many systems have moved to probabilistic models to size their operating reserves, where the randomness of events (unit outages and the variability of VRE and demand) are each represented by probability distributions. These are built from time series of past events, allowing planners to estimate the expected reliability of the system.[22] In parallel, the underlying time series have also extended to represent multiple weather years.

However, the growing complexity and interactions between generation, grid and demand-side assets make the case for stochastic adequacy assessments, which consider a wider range of uncertainties when studying a system that may look very different from that of today. To that end, regions such as Australia, Belgium and Europe (via ENTSO-E) are using Monte Carlo simulation techniques to represent

[21] System operators normally set a target for the reserve margin of around 10-20% to safeguard the adequacy of their power systems.
[22] The calculation involves the convolution of the various probability distributions for the various sources of uncertainty and variability. The typical metrics are then a loss of load probability or an expected energy not served.

uncertainties on fronts such as resource availability, grid outages and demand patterns. Simulations using novel artificial intelligence (AI) models can also help address the uncertainties associated with planning. Fully simulating system dispatch under different conditions provides a better understanding of the frequency and duration of demand response activation and risks of unserved demand.

Key aspects of uncertainty that stochastic assessments can capture



Source: IEA (2022), Energy Transitions Require Innovation in Power System Planning.

Chapter 4. Policy action

Successfully integrating solar PV and wind requires policy makers' leadership and guidance on several fronts. These include implementing policies for government action, and introducing measures enabling other power sector stakeholders, such as industry players and other public institutions, to implement integration measures within their own domain of responsibility.

There is extensive experience of integrating VRE at different phases of VRE integration around the world, as well as numerous comprehensive reports and studies on technical and institutional solutions. Nonetheless, it is not always clear how to prioritise the implementation of these solutions with policy action. In this chapter, we provide recommendations for policy action on three fronts:

First, a set of measures that can bring benefits regardless of the level of solar PV and wind penetration in the power system.

Second, a set of measures that are key to navigating the low phases of VRE integration (Phases 1-3), of particular importance for ensuring the rapid and cost-efficient deployment of VRE.

And third, recommendations for achieving higher shares of VRE successfully (Phase 4 and higher), measures that need more careful consideration as they require a deeper transformation of the way power systems are operated, planned, and financed.

Countries can already make significant progress by deploying more solar PV and wind capacity, especially at lower levels of VRE penetration. The necessary integration measures tend to be straightforward modifications to existing assets or operational processes, which can be implemented in a targeted and progressive manner as challenges arise. At higher levels of VRE penetration, even though capacity additions will be the main driver of VRE uptake, integration measures will play a more important role in ensuring that the output and value of new capacity are maximised.

Without the implementation of necessary integration measures, VRE uptake could be delayed, resulting in inefficient rollout of solar PV and wind capacity. Clean electricity that could have been utilised by consumers may be wasted because the power system is not ready to integrate it effectively. This would act to deter further investment, endangering the achievement of national and multilateral renewable electricity goals, and thus the decarbonisation efforts to which many countries have committed.

To avoid delaying VRE uptake, it is imperative to promptly assess the current context of each system and identify the measures that are critical to implement. Policy makers can leverage the phases of VRE integration framework to understand the main challenges that their power system is currently facing, anticipate which challenges it could be expected to face in the near future, and decide which solutions and strategies to prioritise, taking advantage of global experience. Simple, tried-and-tested measures should be promptly implemented, as they bring benefits to the power system regardless of integrating more solar PV and wind. If they are not already implemented, policy makers can lead the way for the power sector to make progress. Transformational measures need strategic vision and commitment, which is where strong government leadership and co-ordinated effort across all stakeholders will be required.

Variable renewable energy integration outlook to 2030 and integration risks

Solar PV and wind generation capacity additions and implemented VRE integration measures will define how much VRE countries will be able to integrate on their path to achieving their committed climate and energy goals. In that context, it is essential for policy makers to understand what kind of impact the VRE will have on their system and what measures are effective in addressing them at different levels of VRE integration. This will enable policy makers to define appropriate areas of action, adequate for their specific system context, which will enable them to make the most out of VRE and to stay on track with their ambitions.

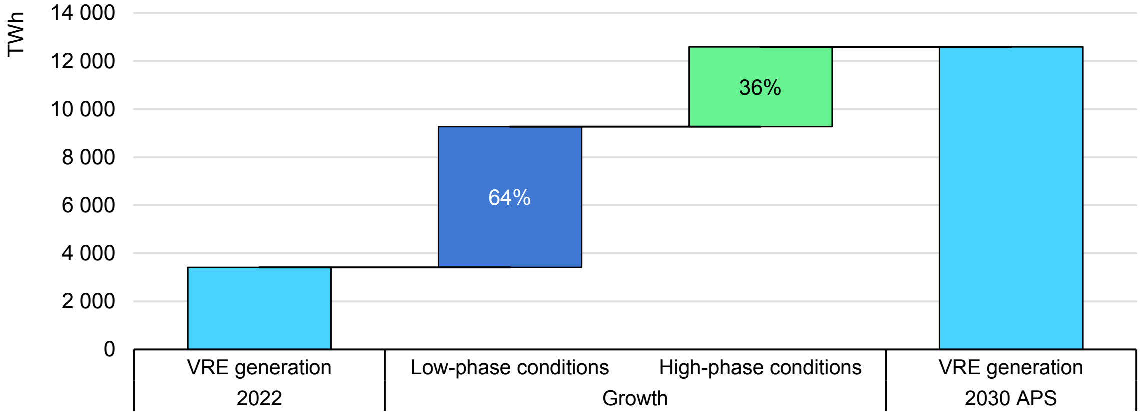
Most new solar and wind generation out to 2030 will be integrated into systems with low penetration of VRE

Solar PV and wind capacity is being built in countries across all phases of VRE integration, with distinct challenges for systems in low and high phases. Ensuring that this new capacity contributes to decarbonisation to the maximum extent possible calls for countries to tackle the relevant roadblocks at each step of the way. Integrating VRE in systems at low phases can be addressed in a targeted and progressive manner to address challenges as they arise, whereas systems at high phases need measures that have only more recently started to be developed and introduced.

Acknowledging this difference, we quantify how much additional VRE generation required to stay on track with countries' pledges for 2030 needs to be integrated in low- or high-phase system conditions. Our approach is based on the Announced Pledges Scenario (APS), which reflects a scenario in which countries fulfil their energy and climate targets on time and in full. Our quantification of how much additional VRE is integrated in low- or high-phase conditions is based on current and projected phases of VRE integration in countries and subsystems, current and projected VRE shares (including for some subregions of large countries), and the level of interconnection with neighbouring power systems, among other technical and operational criteria used in our phase assessment framework.

We find that most VRE generation growth out to 2030 in the APS takes place in low-phase systems. Approximately 64% of the new VRE generation that needs to be integrated by 2030 to stay on track with countries' climate and energy pledges must do so in conditions associated with low-phase systems.

Global solar PV and wind generation growth in conditions of low and high phases of VRE integration in the Announced Pledges Scenario, 2022-2030



Notes: VRE = variable renewable energy; APS = Announced Pledges Scenario.
Source: IEA analysis based on IEA (2023), World Energy Outlook 2023.

While there are some exceptions, low-phase systems are found predominantly in EMDEs. In the Announced Pledges Scenario, 55% of the global growth in VRE generation out to 2030 is set to happen in EMDEs, including India and Brazil, and others in the Middle East, Asia, Africa and Latin America. Decarbonisation in EMDEs is crucial for these countries to stay on track with their energy and climate pledges. Additionally, this finding offers encouraging prospects for global power sector decarbonisation, as this significant share of the global VRE generation growth out to 2030 in the APS can be unlocked by implementing tried-and-tested integration measures progressively. For this, EMDEs with low-phase systems can build on the extensive experience from other countries as they moved through the low phases.

Insufficient integration measures may put a significant amount of new clean energy at risk

New energy in the form of VRE out to 2030 is exposed to different levels of risk due a lack of sufficient integration measures. This risk depends on the readiness of systems to deal with the challenges they are facing. While new generation sources coming online in systems at a lower phase may be accommodated with relatively simple and tested integration measures that can be implemented progressively, additional generation in high-phase systems may be at greater risk if the necessary measures are not developed and deployed in time.

For this report, we introduce the Integration Delay Case. This case is derived from the Announced Pledges Scenario, and it explores a situation in which countries fail to implement sufficient VRE integration measures, resulting in a lower ability of power systems worldwide to integrate energy from new VRE developments. Building on our analysis of VRE integration in systems at low and high phases, this case explores the specific consequences of insufficient integration measures for VRE integration in these two system classifications.

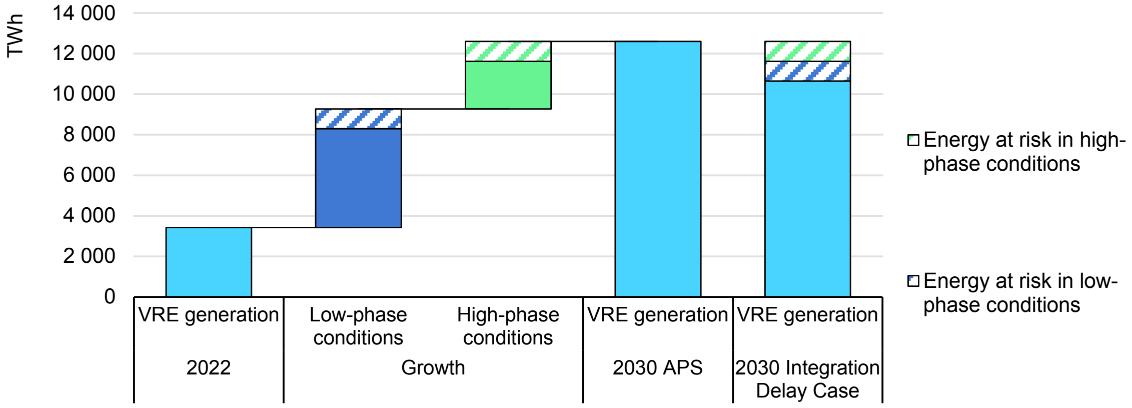
The Integration Delay Case is based on our comprehensive stocktake of integration measures for 50 power systems accounting for nearly 90% of global VRE generation. To build this case, we analysed the current state of power systems globally, including their current VRE integration measures, and their present and projected levels of VRE deployment. In addition, the case integrates insights from previous IEA country and regional modelling studies on VRE integration to understand which future challenges these jurisdictions could face and how a lack of integration measures would impact effective VRE uptake.

In this special case, we represent a situation where integration measures deployed by 2030 are not significantly different from those already introduced or being deployed today. Leveraging projected VRE shares, current and expected future integration measures, and prior IEA integration studies, we employ a comparative approach to estimate which regions could have more or less VRE generation at risk.

Delays in introducing necessary VRE integration measures can derail countries significantly from achieving their announced energy and climate pledges. In our Integration Delay Case, which reflects a situation where countries fail to implement integration measures in line with a scenario aligned with national climate targets, 15% of global VRE generation is put at risk by 2030. This is equivalent to jeopardising 2 000 TWh from VRE, equivalent to the VRE generation of China and Europe combined in 2023. This loss is stemming from potential increases in VRE curtailment (technical and economical) and potential project connection delays.

Where renewables capacity is tripled by 2030 but integration measures that create enabling conditions, such as grid development and enhanced power system flexibility, are underdeveloped, IEA analysis[23] suggests that curtailment and technical losses could be significantly higher than in the Announced Pledges Scenario. This would put the world off track for net zero emissions by 2050.

Global solar PV and wind generation in the Integration Delay Case and the Announced Pledges Scenario, 2022-2030



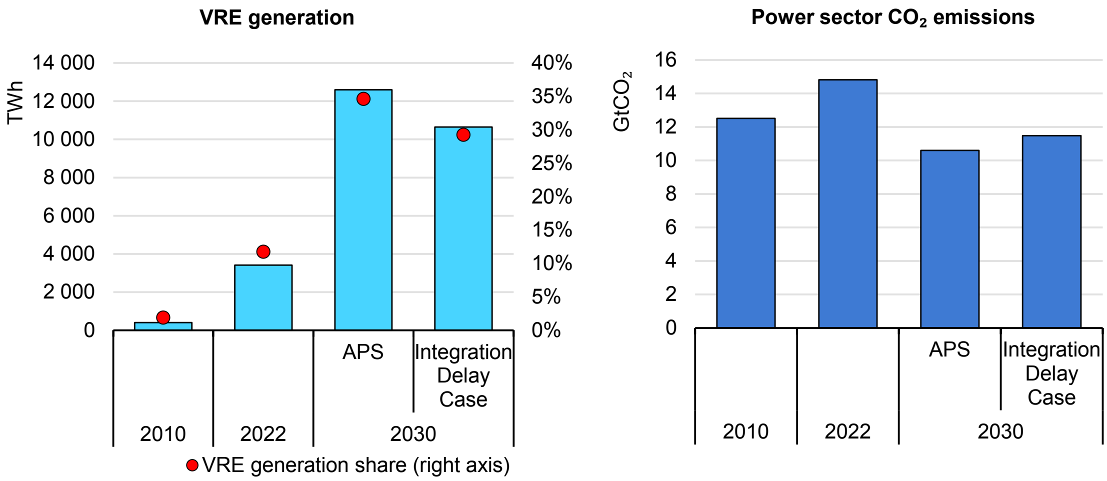
Notes: VRE = variable renewable energy; APS = Announced Pledges Scenario.
Source: IEA analysis based on IEA (2023), World Energy Outlook 2023.

Delays in deploying VRE integration measures can also lead to higher emissions due to a higher emission intensity of the resulting generation mix. In the Integration Delay Case, the VRE share in the global electricity mix reaches 30% by 2030, lower than the 35% reached in the APS. In turn, if this gap is compensated for with higher reliance on fossil fuels, the reductions in global power sector CO_2 emissions could be up to 20% smaller. This can also result in other consequences such as higher fossil fuel imports, which could impact electricity affordability, and higher pollution for communities around fossil-fuel-fired plants.

The Integration Delay Case highlights that progress in VRE uptake can be made across all phases of VRE integration by deploying additional capacity. However, delays in introducing sufficient integration measures put more energy at risk in high-phase systems, as a more transformational set of solutions is needed to integrate high shares of VRE. For low-phase systems, where a simpler and progressively implemented approach is needed, we estimate that 15% of VRE generation in 2030 is at risk. On the other hand, in high-phase systems, almost 30% of the VRE generation is at risk in 2030.

[23] This analysis will be published in a forthcoming IEA report on implementing COP28 energy goals.

Global solar PV and wind generation and carbon dioxide emissions in the Integration Delay Case and the Announced Pledges Scenario, 2010-2030



Notes: VRE = variable renewable energy. The additional CO_2 emissions stemming from the VRE generation gap in the Integration Delay Case are estimated using countries' 2022 power sector CO_2 emission factors (gCO_2/kWh).
Source: IEA analysis derived from IEA (2023), World Energy Outlook 2023.

This demonstrates that most countries can deploy more solar PV and wind capacity while progressively implementing integration measures. While these measures are key to unlocking the full potential of VRE, countries need not wait to have a complete set of advanced measures in place before expanding their VRE capacity.

Focus areas for policy action

Policy makers need to prioritise the implementation of VRE integration measures that are both relevant to and effective for their present and anticipated challenges. The phases of VRE integration provide a valuable framework for gaining a general understanding of these challenges, while a thorough analysis of the system's unique characteristics and capabilities highlights the most acute issues. By combining these insights, policy makers can identify the solutions that should be strategically deployed in their systems for effective VRE integration.

Our analysis reveals a common aspect to the set of measures applied by systems in Phase 2 and above: they can be implemented in a targeted and progressive manner. The key advantage of these measures lies in their adaptability, as they provide a flexible approach that can be tailored to address specific challenges as they arise, facilitating a cost-effective and scalable integration process that evolves alongside the changing needs of the power system. The implementation and advancement of this core set of measures should be universally prioritised, as it unlocks significant global progress in VRE integration by being an essential enabler of system-wide VRE integration in low-phase systems. This is particularly important as nearly two-thirds of new VRE generation by 2030, in a scenario where countries meet their climate and energy pledges on time and in full, will occur in low-phase conditions. The remaining one-third, in high-phase conditions, will require advanced frameworks and solutions. In Phase 4 and beyond, integration demands measures that transform the power system towards a VRE-dominated paradigm.

The role of policy makers is evolving

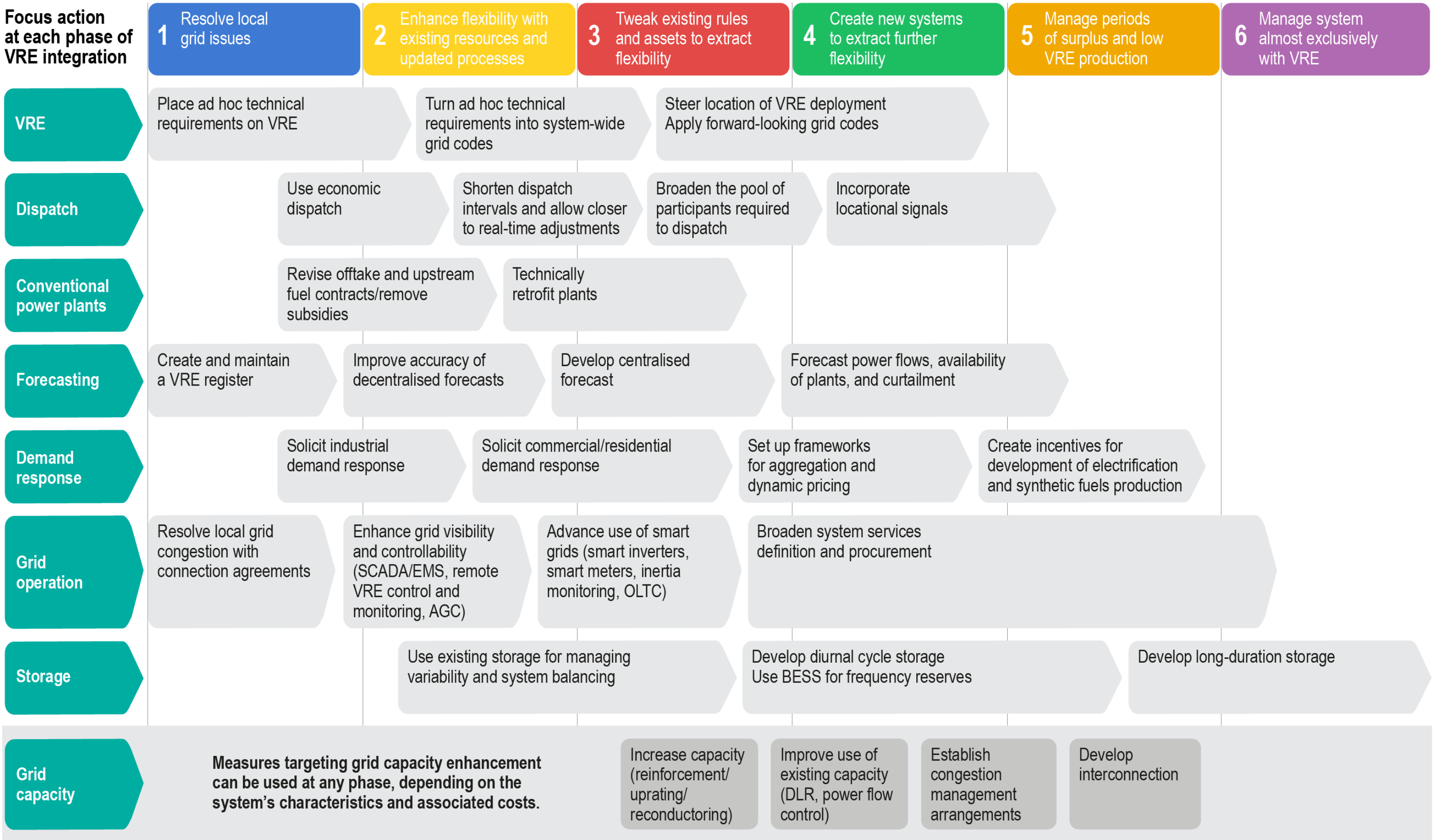
As global experiences have shown, the integration of VRE into power systems is a non-linear process. Initially, the impact of VRE on system operation is limited, allowing policy makers to focus on accelerating deployment of VRE generation capacity through supportive policies and targets. As VRE generation capacity increases, incremental improvements, such as better forecasting and minor grid investments, help integrate more VRE. Essentially, until Phase 3, the system is operated very similarly to how it has traditionally been operated, with conventional power plants still providing the bulk of electricity, while at the same time ensuring system stability.

However, in high phases, where VRE becomes a significant part of the system, system operation requires a fundamental shift. This implies moving away from the traditional paradigm of "baseload" power plants to a new paradigm of “VRE as baseload”, requiring a more flexible, dynamic and responsive power system. It involves a new approach to policy and regulation to ensure that the rules and planning for system operation are aligned with the needs of a high VRE power system. Extensive adoption of already proven technologies, such as energy storage, demand response and smart grids, requires policy and regulation that create an enabling environment incentivising their wide-scale deployment.

Policy makers' roles evolve together with the system’s needs, becoming more complex, requiring collaboration between stakeholders to address both technical and institutional challenges. Integration measures must consider all power system elements – many of which are under the direct responsibility of policy makers – including those related to generation, transmission, distribution, storage and demand. Policy makers should also consider the interdependencies between these elements, ensuring a co-ordinated and comprehensive approach to a high VRE future.

Based on our analysis of different measures implemented in several power systems around the world, we provide a set of recommendations for policy makers to accelerate the integration of VRE in a secure and affordable manner.

Focus area of measures by asset or process, by phase of VRE integration



Notes: The proposed set of focus actions by phase represents a timeline of priorities, though specific system contexts may require adjustments to address their particular challenges. AGC = automatic generation control; DLR = dynamic line rating; EMS = energy management systems; OLTC = on-load tap changers; SCADA = supervisory control and data acquisition; VRE = variable renewable energy.

Modernise infrastructure and prepare resources for VRE integration

The first set of recommendations relate to measures that make sense to apply to all systems regardless of the phase of VRE integration in which they find themselves. These essential actions include improving system understanding, modernising grid infrastructure, establishing robust data foundations, creating effective incentives, and developing the necessary workforce skills.

Prepare for VRE integration by improving the understanding of the power system's characteristics and available resources. Understanding the impact of VRE variability and uncertainty on system operation and security is crucial. Any major outages that can be traced back to renewables could also have a negative impact on the accelerated deployment of VRE. This is why the monitoring of systems and assets, developing metrics, and proactive analysis are important to prepare for future needs. While there is a need to accelerate VRE deployment, and there are many examples that increase confidence in doing this, every system is different and policy makers must base their plans on data-based intelligence. For example, Korea's system operator used the phases of VRE integration framework as an input to focus on targeted integration measures. NREL has studied several systems and has suggested pathways for power sector transitions that account for each of their particular conditions. States, countries and regions should prepare for VRE integration in their system by conducting such studies and deepening their understanding of the effective measures available to them, to overcome anticipated challenges of VRE integration.

Ensure sufficient funding and timely deployment of power grid infrastructure. Grids are not only a key source of flexibility across all timeframes, but also an enabler of economic growth and access to energy services. Governments need to ensure sufficient funding is available and accessible for modernising, digitising and improving the resilience of grids. Regulators need to allow investment and the rollout of grid projects in an anticipatory manner while incentivising efficient use of infrastructure. Modern power systems are increasingly being defined by an increase in more modular and decentralised generation assets, as well as higher electrification of new end uses at both the transmission and distribution level. Higher-capacity transformers and lines will be needed to handle the power flows to serve the electrification of end uses such as transport and heating and cooling, in addition to emerging consumers such as data centres and aggregators of flexibility from distributed energy resources. Due to the longer lead times and supply chain constraints of grid infrastructure relative to generation assets and distributed energy resources, system planners should consider these investments in a co-ordinated and timely manner to ensure that projects are not delayed due to the lack of grid capacity. Grid-enhancing technologies, such as dynamic line rating, are increasingly being deployed and should also be considered.

Build structured data foundations that enable secure and efficient operation of future power systems. Governments and regulators can take the initiative in setting requirements and standards for data reporting and sharing. Future power systems will require robust data foundations to ensure different actors in the system provide efficient and reliable operations. Key data include real-time monitoring of grid infrastructure and connected generation and storage assets, high-resolution demand data, and commercial transaction data. High-resolution real-time and advanced meteorological forecasts are also important for accurate generation and consumption forecasting, as well as assessing vulnerabilities to extreme weather and preparing for the associated risks. A probabilistic rather than deterministic approach to forecasting can likewise prepare system operators for a range of possible outcomes. Additionally, data for cybersecurity monitoring and regulatory information are essential. These data foundations support improved forecasting, grid stability, optimised operations, modelling, incentive design and alignment with regulatory goals, facilitating a seamless transition to a sustainable energy future.

Create clear signals that indicate where and when the deployment and utilisation of assets is needed. For the sake of efficiency of investment and system operation towards an affordable energy transition, the power system needs incentives that accurately reflect its requirements for the deployment of new resources – where and when they are most needed. Incentives include locational grid tariffs and specifying development zones. This promotes the best utilisation of the existing grid such that new assets can be put online more quickly and grid infrastructure investment is kept at reasonable levels. Generation dispatch, whether via a market or by central dispatch, should also be strongly aligned with system operations in aspects such as temporal and spatial granularity. The impact of efficient system design on system requirements should not be overlooked, whereby changes such as shortening dispatch intervals can reduce the system's requirements for certain balancing and frequency control services.

Build a skilled workforce to manage and operate changing requirements of modern power systems. It is essential to create a pipeline of talent to manage the complexity of transforming the power system. There is a significant shortfall in expertise, particularly in digitalisation and power electronics. Companies in the energy sector need to cultivate a digitally proficient workforce, while policy makers should consider integrating energy transition modules into training programmes, and championing capacity building in relevant public institutions, to support implementing long-term climate and energy targets. Reskilling and on-the-job training should be available to the existing workers to adapt to the changing power sector landscape and technological advancements.

Implement the common set of measures gradually at low phases of VRE integration

Several systems around the world have managed to integrate increasing shares of VRE in power systems originally powered exclusively by conventional generation. Integration challenges should not be seen as a significant barrier to expanding VRE capacity in systems at low phases of VRE integration. The relatively low system-level impacts of VRE in early-phase systems, combined with the availability of cost-effective, progressively implementable integration measures, should alleviate concerns for countries with low VRE penetration. By implementing core integration measures alongside VRE deployment, systems currently in the early phases can significantly accelerate their clean energy transition.

This subsection highlights a set of measures that have been successfully implemented in power systems around the world, supporting the integration of VRE in the early phases and therefore suitable for systems currently at the beginning of their journey. It is important to highlight that these measures do not require the sudden transformation of the power system – they can be applied progressively and step by step to address challenges as they arise. Additionally, many of these measures do not require additional large-scale investments, but rely on improving operational, regulatory and market frameworks to advance cost-efficient integration of VRE.

Improve forecasting accuracy to optimise system operation. Due to the variable nature of wind and solar PV generation, improved forecasting can support the secure and efficient operation of the power system and minimise the need for balancing actions. Forecasts need to be carried out at different timescales and with sufficient geographical resolution. Forecasting requirements can form part of the conditions for connection, so that each plant is responsible for sharing its production forecasts. Regulators should require the registration of VRE plant data so that when the time comes to develop centralised forecasting, fundamental data that are necessary for forecasting are available. Probabilistic rather than deterministic forecast approaches, particularly for demand and the weather, can better prepare system operators to respond to changing conditions between forecasts and real time. Machine learning and other developing technology can improve forecast accuracy, where appropriate. At the same time, it is important for these forecasts to be made available to and understood by all relevant power system participants. This can include not only the publication of centralised VRE forecasts by system operators, but also training on how to integrate the data into decision-making processes. Irrespective of the choice of a decentralised or centralised forecasting system, the accuracy of the forecasts can be enhanced by designing proper incentives.

Make VRE data available to improve asset visibility and controllability. The ability of system operators to maintain security of supply in a cost-effective manner will depend on the visibility and controllability of the power system. Making sure that operational data are gathered and made available to the system operator in real time, for example through supervisory control and data acquisition (SCADA) systems, will allow it to take appropriate least-cost actions to ensure the security of the system, which will also facilitate its ability to integrate VRE. Governments should ensure that the system operator is granted the right to monitor third-party operational data (from generators, demand and storage) so that they can monitor and flag any danger. It is also important that they have agreements in place with third-party owners of assets so that they can take action (such as disconnect or curtail) in case of grid security issues. Further, phasing out mechanisms that do not introduce incentives for system-friendly operation due to a lack of visibility and controllability, such as net metering, will be key.

Introduce grid codes that clarify the role and technical requirements for VRE and ensure compliance through monitoring and enforcement mechanisms. Regulators need to ensure that grid codes are updated so that new VRE generation, typically connected through converters, will not negatively affect the resilience or security of the power system. Ensuring that grid codes define minimum standards on how this generation needs to react to disturbances on the system will minimise its impact on security. Grid codes need to be revised as VRE shares increase and compliance needs to be monitored and enforced across new and existing assets. Regulators can formalise the process of periodic reassessment and updates, as well as checking compliance with grid codes.

Improve dispatching practices to benefit from near-zero marginal costs of VRE. VRE plants can produce electricity at very low marginal cost, meaning that once the initial investment is made, the energy is generated with minimal additional cost. Updating dispatching practices is critical for the economic operation of the system. This can be done, for example, by improving the geographical and time resolutions of the decisions as to which generation to dispatch, and removing the distortions that come from subsidies and contractual constraints (either for electricity generation or for upstream fuels). Considering priority dispatch temporarily would maximise the benefits obtained from renewable energy capacity. Furthermore, clear and undistorted market signals and accurate pricing that allows negative prices (in the markets linked to dispatch) and reflects carbon prices can incentivise investment in renewables, demand-side management and other flexibility solutions like storage. Significant efficiencies can be gained by allowing the principles of economic merit to be reflected in dispatch without distortion. Where there are markets, regulators can step in to modify rules, while in a central dispatch system government may need to negotiate with the dispatching authority on how to change their decision-making processes. Furthermore, subsidy design may need revision if it is impeding efficient dispatch.

Begin leveraging demand response by mobilising industrial demand as a source of flexibility. Some industry sectors exhibit large and predictable power consumption patterns. This allows system operators to trigger major demand changes by sending signals to a single facility, facilitating management and implementation of demand response programmes. To create (or expand) industrial demand response schemes, policy makers and regulators need to address three main barriers: creating economic incentives, setting a conducive regulatory environment and market rules, and establishing rate structures such as time-varying tariffs and grid charge amendments that give the appropriate signals to industrial consumers. Having sufficient digital infrastructure will also be a key enabler.

Consider the retrofit of thermal power plants to allow for more flexible operation. Soliciting greater flexibility from existing thermal power plants can support the integration of VRE as it continues to grow. By reducing minimum load levels, increasing ramping capability and reducing start-up times, they can be ready to adapt their generation profile to the increasing amount of VRE, reducing emissions and fuel costs. It is therefore important for governments to consider whether broad retrofit programmes are beneficial, and if so, how it can support the wide implementation of technical retrofits.

Strategic transformation of energy systems is required at high phases of VRE integration

As power systems reach higher phases of VRE integration, challenges emerge that require a new approach. The challenges typically observed in systems that reach Phase 4 and above require to be addressed with a modern and transformational approach.

In practice, this means that a transformational change in the way that power systems are operated, planned, and financed is needed. Integration of VRE at these phases no longer depends exclusively on introducing improvements progressively, but will require deployment of new technologies, modernised approaches to planning and regulation, better co-ordination between transmission and distribution operators and an overhaul of existing remuneration mechanisms for different power system assets.

Deploy and scale up VRE integration technologies with strong regulatory support. The technologies and solutions to integrate VRE are mostly available in the market, but stakeholders must focus on deploying and scaling them up. Market participants need support to develop new business models that use technological solutions and co-ordinated market processes, ensuring the optimal operation of the entire power system. Regulation and policy frameworks are key in driving the wide adoption of these technological solutions and innovative business models.

Design remuneration schemes and mechanisms to properly compensate technologies according to the value they provide to the system. Several technologies can provide services beyond energy – for example, synchronous condensers can provide inertia and voltage regulation, while batteries and VRE can help regulate the system's frequency and manage grid congestion. With grid-forming converters, VRE plants can provide even more services such as voltage formation. A focus on market design is key, for example to have mechanisms that create revenue streams for the providers of these services, and to ensure that remuneration schemes for grid operators account for these contributions. Remuneration models are currently not widely equipped to value and remunerate system services, especially not for a variety of different providers.

Ensure that corporate procurement of power contributes positively to the transition. Companies can better support the integration of VRE by adopting corporate power purchase agreements that include flexible and innovative designs. These agreements should ensure long-term commitment, thus providing financial stability for renewable projects. Additionally, PPAs can incorporate time-of-use pricing, incentivising energy consumption when renewable generation is high, and include clauses that prioritise grid stability and reliability. Companies should also engage in collaborative efforts with grid operators and policy makers to streamline processes and advocate regulatory frameworks that facilitate VRE integration. By doing so, corporations not only meet their sustainability goals, but also contribute to a more resilient and efficient power system.

Focus on the services that are needed, not on specific technologies to provide them. As we transition to a future with diverse flexibility providers, procurement methods must evolve. Traditionally, conventional power plants have provided most system services without explicit compensation. However, in a system where distributed energy resources, demand, storage and auxiliary devices can offer these services as well, clear definitions of what services are required, when and where. In addition, we must understand the value these services bring to the overall system. Communicating these needs and benefits transparently will create a level playing field for the various service providers, and ensure that the system can rely on the provision of the necessary services. For emerging technologies crucial to specific services, targeted support schemes may be necessary to accelerate deployment, enabling innovation and diversifying the pool of providers of system services.

Plan and regulate the power system with a holistic perspective to adapt to the changing landscape. Traditionally, power system planning has focused on the expansion of generation and transmission to meet peak demand growth. However, the ongoing transformation of electricity supply and demand will need targeted improvements in planning and regulation. Policy makers and regulators need to consider ways to allow a broad range of stakeholders to be included as part of planning. This encompasses not only independent power producers and owners of distributed energy resources, but also those of demand-side resources, anticipated by electrification and sector coupling. Moreover, greater co-ordination between transmission and distribution system operators and the owners of these energy resources needs to be encouraged, as that will be key to maximising the benefits from distributed resources. Finally, co-ordination across the power, hydrogen, transport and heating sectors can bring an optimal all-energy system.

Adapt adequacy assessments to fit the stochastic and regional nature of power systems. By considering the inherent contribution of a diverse range of assets to adequacy, the same level of adequacy can be achieved more efficiently and put less financial burden on society when integrating VRE. In systems with a high penetration of VRE and distributed energy resources, higher variability in power generation, storage and demand means that traditional adequacy assessments will typically result in overbuilding conventional power plants, which may not be the most cost-optimal way to ensure adequacy. Introducing stochastic assessments that study different scenarios of system stress, and consider how each generation and demand-side measure can contribute to adequacy, will be key to ensure that planning exercises lead to a more efficient investment plan. The contribution of imports via interconnectors with neighbouring jurisdictions should also be incorporated, considering that renewable resource complementarities are normally higher across greater distances.

Promote the scale-up of demonstration projects and regulatory sandboxes to accelerate innovation. Co-ordinated R&D efforts and demonstration projects can help proven technologies to reach the market at scale. Regulatory sandboxes can help regulators and policy makers understand how a market reacts to new regulations such as incentives. This allows them to refine the technical standards, requirements or grid codes and define market rules in such a way that large-scale deployment does not cause unintended problems. Additionally, sharing best practices for regulatory approaches to the adoption of VRE – as done through the Regulatory Energy Transition Accelerator (RETA) – can accelerate solar PV and wind integration.

Accelerate demand-side response programmes beyond the industry sector, while maintaining access to affordable energy. Price reductions in distributed resources such as EVs and heat pumps, together with the rollout of smart meters and time-varying rates, can make these programmes accessible and financially attractive to residential and commercial consumers. This would make government initiatives that promote the deployment of technologies allowing consumer electronics to participate in demand response programmes more effective. Further advancements in digitalisation, through IoT-ready appliances, smart charging and buildings energy management systems, can unlock the full range of demand response by households and small and medium-sized enterprises. Furthermore, aggregators can play a crucial role by connecting households and businesses with grid operators. When designing demand response programmes, it is key to consider their impacts on affordability and their distributional effects.

Enhancing international knowledge exchange on emerging challenges and solutions is key to foster global innovation in VRE integration. While technical collaboration through platforms such as CIGRE, IEEE Power Energy & Society, Global PST Consortium and the Energy Systems Integration Group has accelerated the adoption of best practices and technologies, there is a need for greater focus on sharing insights related to regulation, market design, and policy frameworks. Lessons learned from systems at different stages of VRE integration and diverse local contexts have proven invaluable. To ensure the effective implementation of VRE integration measures, a more holistic approach to knowledge sharing is required – one that extends beyond technical aspects to include regulatory structures, market frameworks, and financing models. This comprehensive exchange will help overcome common barriers and facilitate faster, more efficient integration of VRE globally.

Annex

Abbreviations and acronyms

AI	artificial intelligence
AC	alternating current
APS	Announced Pledges Scenario
ASEAN	Association of Southeast Asian Nations
BESS	battery energy storage systems
CAISO	California Independent System Operator
CAPEX	capital expenditure
CfD	contracts for difference
CIGRE	International Council on Large Electric Systems
CO_2	carbon dioxide
COP	conference of parties
DLR	dynamic line rating
DSO	distribution system operator
EMDEs	emerging markets and developing economies
EMS	energy management system
ENTSO-E	European Network of Transmission System Operators
ERCOT	Electric Reliability Council of Texas
EU	European Union
EV	electric vehicle
FACTS	Flexible AC Transmission Systems
FCR	frequency containment reserve
FERC	Federal Energy Regulatory Committee
FFR	fast frequency response
FRR	frequency restoration reserve
GDP	Gross Domestic Product
GFM	grid-forming
G-PST	Global Power System Transformation Consortium
G7	Group of Seven
HVDC	high-voltage direct current
IEEE	Institute of Electrical and Electronics Engineers
ISO	independent system operator
LCOE	levelised cost of electricity
NDCs	nationally determined contributions
NEM	National Electricity Market (Australia)
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
OLTC	on-load tap changers
PPA	power purchase agreement
PV	photovoltaic

RETA	Regulatory Energy Transition Accelerator
REZs	Renewable Energy Zones
RoCoF	rate of change of frequency
R&D	research & development
SCADA	Supervisory Control and Data Acquisition
SNSP	System Non-Synchronous Penetration
SONI	System Operator Northern Ireland
SRAP	Automatic Power Reduction System (Spain)
STATCOM	static synchronous compensator
SYNCON	synchronous condenser
TSO	transmission system operator
VRE	variable renewable energy
21CPP	21st Century Power Partnership

Glossary

°C	degree Celsius
gCO_2/kWh	grams of carbon dioxide per kilowatt hour
GW	gigawatt
GWh	gigawatt hour
GW.s	gigawatt-seconds
GW/h	gigawatt per hour
GVA	gigavolt-ampere
GVA.s	gigavolt-ampere-seconds
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
MVAr	megavolt-ampere reactive
MW	megawatt
MWh	megawatt-hour
TWh	terawatt-hour

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