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Status of Power System Transformation 2018

Advanced Power Plant Flexibility

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Executive summary

Power systems are undergoing a rapid transformation

Across the world, change is accelerating in power systems. Three main factors are driving this transformation. First, the advent of abundant, low-cost variable wind and solar energy resources. Second, the deployment of decentralised energy resources, including rooftop solar and smart loads such as electric vehicles and smart appliances. And third, the spread of digitalization, which is reaching across entire power systems to uncover new opportunities to reduce costs and improve resiliency, from generation all the way to customers.

These changes are driving a structural shift in the way power systems are best planned and operated. They also have systemic implications for ensuring energy security, especially security of electricity supply. Hence, they require a co-ordinated and proactive response by policy makers and relevant stakeholders in the power sector, encapsulated by the term power system transformation (PST). The task of PST is to create appropriate policy, market and regulatory environments to manage the impacts of change, and in doing so achieve the upgrading of power system operational and planning practices. PST helps accelerate investment, innovation and the use of smart, efficient, resilient and environmentally sound technologies. PST is crucial for ensuring electricity security in modern power systems (21CPP, 2015a/b; IEA, 2017).

Power system flexibility has become a global priority

Enhancing power system flexibility is often an important objective of PST. This report defines power system flexibility as all relevant characteristics of a power system that facilitates the reliable and cost-effective management of variability and uncertainty in both supply and demand. Driven in many contexts by the integration of variable renewable energy (VRE) in daily operations and a growing intensity and frequency of high-impact events, power system flexibility is an increasingly important topic for policy makers and system planners to consider. A lack of system flexibility can reduce the resilience of power systems, or lead to the loss of substantial amounts of clean electricity through curtailment of VRE.

Keeping the lights on requires the continuous balancing of supply and demand across all timescales, from moments to years – it is thus useful to consider flexibility across these timescales. To help understand different flexibility needs, as well as the different mechanisms for meeting them, this report groups flexibility requirements on the basis of timescales, ranging from short-term (subseconds to hours) to medium-term (hours to days) and long-term (days to years) (Table ES.1).

Importantly, power systems are already designed with the flexibility to manage variability and uncertainty. Historically this has been needed in particular to meet variable electricity demand or the sudden loss of a large generator or transmission line. Requirements for flexibility may grow and change over time, particularly as VRE shares increase. Power system flexibility is also important in modern power systems for managing outages and extreme weather events, promoting resiliency, and other important purposes. A number of different investments and operational and policy changes can be made to increase flexibility in modern systems, and the realisation of additional flexibility can result in cleaner, more secure, more resilient and more affordable power systems.

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Table ES.1 • The timescales of issues addressed by power system flexibility

	Short-term flexibility			Medium-term flexibility	Long-term flexibility	
Timescale	Subseconds to seconds	Seconds to minutes	Minutes to hours	Hours to days	Days to months	Months to years
Issue	Address system stability, i.e. withstanding large disturbances such as losing a large power plant.	Address fluctuations in the balance of demand and supply, such as random fluctuations in power demand.	Manage ramps in the balance of supply and demand, e.g. increasing electricity demand following sunrise or rising net load at sunset.	Decide how many thermal plants should remain connected to and running on the system.	Manage scheduled maintenance of power plants and larger periods of surplus or deficit of energy, e.g. hydropower availability during wet/dry season.	Balance seasonal and inter-annual availability of variable generation (often influenced by weather) and electricity demand.

Key point • System flexibility addresses a set of issues that span a wide range of timescales, from subseconds to years.

Power plants play a critical role in enhancing system flexibility

Based on a wealth of real-life case studies and data, this report provides a comprehensive overview of how power plants can contribute to making power systems more flexible, while enhancing electricity security. It summarises the findings of the Advanced Power Plant Flexibility (APPF) campaign of the Clean Energy Ministerial (CEM). The work of the campaign seeks to build strong momentum and commitment from governments and industry to implement solutions that make power generation more flexible.[1] The solutions presented in this study have been collected in close collaboration with industry stakeholders, including manufacturers, expert consultancies, system operators and plant operators.

The report showcases technical options and examples of successful flexibility retrofits to existing power plants. It provides guidance on how the contribution of power plants to overall system flexibility can be analysed. It also provides examples of the policy, market and regulatory instruments available to unlock power plant flexibility. It shows that conventional power plants – including coal- and natural gas-fired units – can assist in the rapid uptake of clean energy technologies and accelerate PST. Depending on the specific system context, a number of low-cost measures are readily available to make existing power plants better suited to complement the fluctuating output of wind and solar, and ensure security of supply at all times in a reliable and cost-effective manner.

The role of power plants in power systems is changing

Historically, baseload, intermediate and peaking plants helped meet specific segments of electricity demand at least cost by providing the appropriate mixture of energy and capacity. These plants were designed, from a technical standpoint, with these specific operating conditions in mind. From an economic standpoint, the plants were financed under the expectation of a certain number of operating hours. Today, as a new generation of technologies with distinct cost structures and technical characteristics enter power markets at

[1] See http://cleanenergyministerial.org/campaign-clean-energy-ministerial/advanced-power-plant-flexibility for more information.

scale, many existing power plants are being asked to operate with greater flexibility, and in some cases for a reduced number of operating hours.

For example, in response to significant VRE curtailment in certain regions of China, the China National Energy Administration requested that the Electric Power Planning & Engineering Institute (EPPEI) conduct research on the pathways for enhancing power system flexibility in the period 2016-20 (NDRC, 2016). The study found that nearly 220 gigawatts (GW) of thermal power plants could be retrofitted by replacing old equipment or improving operations in order to increase flexibility and significantly reduce VRE curtailment rates. The goal of retrofitting some or all of this 220 GW of capacity was codified into China's 13th Five-Year Plan for the power sector. Similarly, a recent study for India demonstrates that a large, coal-dominated power system can accommodate over 20% wind and solar generation (GTG, 2017). Reducing the minimum generation levels of coal plants significantly reduces VRE curtailment. Together with other operational changes, the Indian power system can operate more flexibly, enabling greater VRE integration at lower operating costs.

A diverse range of strategies can make existing plants more flexible

This report discusses a diversity of strategies to make existing power plants more flexible, ranging from modifications to how existing plants are operated to adding new generators to the grid that provide additional, system-appropriate flexibility capabilities. These strategies include:

- **Changes to operational practices for existing plants.** Significant new capital investments are not necessarily required to operate power plants more flexibly. Changes to certain plant operational practices – often enabled by improved data collection and real-time monitoring – can be used to unlock latent flexibility at existing plants. For example, better monitoring and control equipment can allow plants to start faster and ramp output more dynamically without compromising reliability.
- **Flexibility retrofit investments for existing plants.** Depending on the plant technology, a range of retrofit options may be available to improve various flexibility parameters of power plants (e.g. ramp rates, start-up times, minimum economic or technical generation levels). This report details specific retrofit opportunities across various power generation technologies, including coal, combined-cycle gas turbine (CCGT) co-generation, carbon capture and storage (CCS), nuclear, bioenergy and hydropower
- **New flexible generation opportunities.** Many state-of-the-art flexible power plant technologies can be deployed in power systems; several of these technologies are described in this report. Good long-term planning practices can ensure new flexible power plant investments are risk-hardened against a range of uncertain futures.

Countries such as Denmark, Germany and Italy, and also most recently countries such as China and India, have deployed a number of strategies to improve flexibility, particularly for their coal-fired and, where prevalent, CCGT power plants. For example, the thermal power plant fleet in Germany has upgraded its operational performance substantially in response to higher flexibility requirements. Power plants that were initially designed to run around the clock and were built over 40 years ago have been upgraded to start and stop twice a day, while also providing a range of additional services to the system.

Options for country-wide roll-out

The flexibility of a power system is determined by the hardware and infrastructure available (the "what"), the policy, regulatory and market frameworks (the "how"), and the institutional roles

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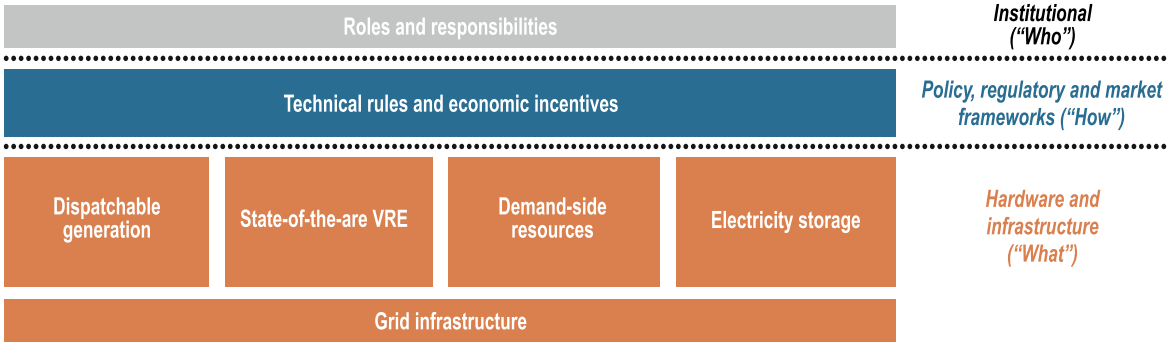
and responsibilities of entities providing flexibility (the "who"). All three aspects must work in concert to support system flexibility (Figure ES.1).

Consequently, not only technical factors will determine system flexibility. For example, the Thai power system includes features that make it relatively flexible from a technical standpoint, such as strong transmission grids and fairly high shares of hydropower and CCGT generation. However, from an economic standpoint many of the generators are inflexible, operating under take-or-pay power purchase agreements and fuel supply agreements. A recent analysis found that the relaxation of take-or-pay contracts could reasonably cut operational costs if natural gas procurement arrangements and power purchase contracts were made more flexible in the long term (IEA, forthcoming).

Figure ES.1 • Relevant dimensions for unlocking system flexibility



Key point • Technical, economic and institutional policy layers mutually influence each other and have to be addressed in a consistent way to enhance power system flexibility.

At a system level, creating a suitable flexibility strategy to roll out various flexibility measures requires consideration of current and future system needs, taking into account the existing generation fleet, market conditions, status of the transmission network, and potential for innovative flexibility solutions.

Enhancing system-wide flexibility

Enhancing system-wide flexibility can mitigate the need for additional flexibility provision from power plants. For example, improving communication and co-ordination among neighbouring balancing areas can eliminate the need for new power plant flexibility measures. For the transmission network, innovative approaches to control and monitoring – such as dynamic line rating and targeted investments in high-voltage transmission lines and equipment – can reduce the need for additional plant flexibility requirements that would otherwise arise due to grid congestion.

Unlocking existing power plant flexibility

Making use of existing generation assets can be cost-effective, but may require regulatory modifications and the introduction of certain economic incentives. Regulatory approaches include measures such as allowing for VRE participation in reserve provision, reviewing must-run requirements on existing power plants, enabling faster scheduling and dispatch intervals, and certain types of performance-based regulatory approaches. As for economic incentives, providing policy support for reviewing inflexible contract terms and creating new revenue streams for flexibility services can encourage plant owners to operate more flexibly.

Incentivising additional power plant flexibility investments

Both regulated and market-based power systems can ensure appropriate investment in additional power plant flexibility measures by identifying the value of specific flexibility services and ensuring fair compensation for them. This can be accomplished in market-based power systems by improving energy pricing schemes, especially close to the moment of delivery (intra-day markets) and during times of scarcity. Implementing well-designed market mechanisms that accurately reward generators for the system value of their flexibility can also incentivise increased flexibility. These remuneration mechanisms may be structured around specific services, such as ramping or start-up time, and could provide a complementary source of income for power plants that are necessary to the system but unable to maintain business-as-usual profitability due to reduced utilisation. In regulated contexts, power plant flexibility investments can be secured by allowing for cost recovery of flexibility retrofits, as well as by offering financial incentives for developers to utilise highly flexible technical components.

Policy approaches for long-term flexibility planning

Policy actions to accommodate future flexibility needs will be beneficial even in systems without an urgent flexibility deficit. Measures to prepare the system include requiring technical flexibility assessments in periodic adequacy assessments, facilitating the creation of a power system flexibility inventory, requesting the consideration of operational flexibility in long-term planning exercises, and requesting the use of start-of-the-art decision support tools used in long-term planning exercises.

Policy guidelines for advanced power plant flexibility

The strategy adopted and the prioritisation criteria formulated will depend largely on the local power system's conditions; however, a set of general policy guidelines can be identified to ensure sufficient system flexibility and safeguard electricity security. Policy makers should:

1. ASSESS – Commission assessments of system-wide flexibility requirements, opportunities and barriers, including the role of power plant flexibility, and periodically refresh these assessments to inform both near- and long-term decision-making and planning processes.
2. ENGAGE – Engage with stakeholder communities to strengthen technical, policy and institutional capabilities to enhance power system and power plant flexibility, and engage with international communities to share best practices.
3. ENHANCE – Enhance the use of available power system flexibility by adapting a range of market, regulatory and operational best practices at the system level.
4. UNLOCK – Update regulations, policies and practices that govern power system operation to unlock latent flexibility. These options include more flexible power purchase agreements with independent power producers and fuel supply contracts for thermal generators.
5. INCENTIVISE – Facilitate the opportunity to seek fair and appropriate remuneration for all assets that can provide flexibility to the power system, through changes to policy, regulatory and market frameworks.
6. ROADMAP – Enhance planning procedures to incorporate future expectations of system flexibility requirements; ensure consideration of all possible flexibility options to mitigate the long-term costs and operational impacts of PST.

Future work

In the context of the CEM, the work of the IEA and 21CPP on enhancing electricity security through power system flexibility will continue. Notably, the CEM campaign will be relaunched at CEM9 with a broader scope as the *Power System Flexibility Campaign*, covering concepts and experiences around power plants, grids, demand-side resources and storage over the next 12 months. This relaunched campaign will complement the efforts of the 21CPP Initiative of the CEM, which will continue to advance state-of-the-art solutions and provide a platform for in-depth capacity building, working closely with all related CEM campaigns and complementary initiatives.

In its analysis and advice to governments, the IEA continues to prioritise PST and its role in bolstering energy security.

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1. Introduction

Many power systems around the globe are undergoing a period of rapid change. The perennial desire for affordable and reliable power systems is now accompanied by a variety of developments, including:

- A desire to reduce environmental impacts (including local air pollution, carbon emissions and water use).
- Rapid cost reductions in new supply- and demand-side technologies (e.g. low-cost wind and solar power, electric vehicles).
- Increasing digitalization and automation of end uses.
- An increasing focus on promoting resiliency within power systems, which covers system security from technical and economic perspectives.
- Expansion of energy access using innovative technology and market solutions.

Responding to these changes requires innovative approaches across the entire power system, spanning both institutional reforms and technical adaptations. In addition to new business models driven by the private sector, this may include a need for governments to change policy, market and regulatory frameworks. It may also require enhanced power system planning and operation. This report groups such innovative approaches, which both facilitate and manage the requisite changes in the power sector, under the term “power system transformation” (PST).

PST, in the context of this report, can be defined as:

> The active process of creating the policy, market and regulatory environments, as well as establishing operational and planning practices, that accelerate investment, innovation and the use of smart, efficient, resilient and environmentally sound technology options.

PST, by definition, is a system-wide task. As such, it is difficult to isolate a particular element for a narrow and focused discussion. At the same time, a clear topical focus can help to provide deeper analysis and insight on a specific topic. In that context, this report focuses specifically on power plant flexibility, considering technical as well as policy, market and regulatory aspects.

The report builds upon the joint 21st Century Power Partnership (21CPP) and International Energy Agency (IEA) report entitled “Status of Power System Transformation 2017 – System Integration of Renewables and the Future of Local Grids”, which was presented at the 8th Clean Energy Ministerial (CEM) in Beijing, China, in June 2017, and the 21CPP report entitled “Status Report on Power System Transformation”, which was presented at the 6th Clean Energy Ministerial in Mérida, Mexico, in May 2015 (IEA, 2017; 21CPP, 2015).

Advanced Power Plant Flexibility Campaign

This report summarises the findings of the Advanced Power Plant Flexibility (APPF) Campaign, which was launched at the 8th CEM in Beijing in June 2017. The campaign seeks to build strong momentum and commitment from governments and industry to implement solutions that make power generation more flexible, in order to accommodate increasing shares of variable renewable energy (VRE) and promote PST more generally. It is a joint initiative of the CEM Multilateral Wind and Solar Working Group and the 21CPP, with IEA acting as the main

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technical partner. It is co-led by the governments of the People's Republic of China (hereafter referred to as China), Denmark and Germany and brings together 11 additional CEM members – Brazil, Canada, the European Commission, India, Indonesia, Italy, Japan, Mexico, Saudi Arabia, South Africa and the United Arab Emirates – as well 13 industry and non-governmental partners. The APPF Campaign's main objectives are to highlight current success stories of power plant flexibility, unlock latent flexibility potential, optimise the utilisation of generation assets, and facilitate VRE integration.

The APPF campaign consisted of a series of expert technology and policy workshops, technical study tours and high-level policy forums hosted by its co-leads. The findings and lessons collected through a continuous process of stakeholder engagement throughout the campaign form the main basis of this report. This CEM campaign will continue with a broader scope on power system flexibility, covering concepts and experiences around power plants, grids, demand side resources and storage over the next 12 months.

Objectives, scope and structure of the report

This report provides a comprehensive overview of how power plants can contribute to making power systems more flexible, as well as offering a range of guidance on strategies to promote cost-effective and system-appropriate power plant flexibility measures. Based on a wealth of real-life case studies and data, it provides a reference source for the technical capabilities of power plants in a diverse set of country contexts. In particular, it showcases a number of technical options and examples of how retrofits to existing power plants have been a cost-effective tool for enhancing system flexibility. In addition, it provides examples of policy, market and regulatory instruments available to unlock power plant flexibility, and discusses how these instruments can be combined into a comprehensive roll-out strategy.

The report is aimed at policy makers and regulators who are not experts in engineering, but who need to understand power plant flexibility in order to enhance system planning and upgrade policy, market and regulatory frameworks. The detailed technical annexes[2] provide an opportunity to dig deeper into the subject and will also be of interest to a more technical audience, including system and market operators, power plant operators and engineers, as well as system planners. Last but not least, the report contains a broad set of parameters and measures, both technical and economic, which can be applied to appropriately reflect power plant flexibility in power system models that are used to inform decision-making. It provides examples from a number of countries.

Chapter 2 presents an updated definition and discussion of power system flexibility. Chapter 3 focuses on flexibility at the power plant level and discusses constraints on more flexible operations and how these can be overcome. Chapter 4 takes a system perspective, presenting a conceptual framework for policy makers to approach decision-making on measures to increase power plant flexibility; it also discusses the role of decision support tools to help inform both near-term decisions and longer-term strategies. Chapter 5 synthesises the results and provides guidelines for how an increase in power plant flexibility can be organised at the country level.

[2] The technical annexes are available on line at https://webstore.iea.org/status-of-power-system-transformation-2018-technical-annexes. It is not included in the print version.

References

21CPP (21st Century Power Partnership) (2015), *Status Report on Power System Transformation: A 21st Century Power Partnership Report*, NREL, Golden, CO, www.nrel.gov/docs/fy15osti/63366.pdf.

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2. Overview of power system flexibility

HIGHLIGHTS

- Power system flexibility is one aspect of power system transformation (PST). It is the ability of a power system to reliably and cost-effectively manage the variability and uncertainty of supply and demand across all relevant timescales.
- With increased penetration of variable renewable energy (VRE), power system flexibility becomes highly relevant for effective VRE integration.
- Six relevant timescales can be applied to flexibility, ranging from subseconds all the way to seasons and years.
- In the short term, these flexibility needs are driven by technical power system characteristics, which are essential to system stability. Longer-term flexibility needs are related to the availability of appropriate capacity and resources.
- Sources of power system flexibility can be categorised into three main layers: the technical options available (the hardware and infrastructure, or the "what"); the technical rules and economic incentives (the policy, regulatory and market frameworks, or the "how"), and the roles and responsibilities that various entities have in providing flexibility (the institutional, or the "who").

Definition and role of power system flexibility

Relationship between power system transformation and flexibility

Power system flexibility, in its broadest sense, encompasses all the attributes of a power system that are conducive to the reliable and cost-effective management of the variability and uncertainty of supply and demand. Power system flexibility has always been important for meeting variable electricity demand and responding to the sudden losses of large generators and transmission lines. More recently, it has become increasingly relevant for the integration of VRE. By contrast, the concept of PST, as introduced in the previous chapter, describes a broad range of trends that are collectively reshaping the electricity sector across the globe. From the viewpoint of PST, increasing system flexibility is one relevant objective, but not the only one.

This report focuses on power system flexibility with a specific emphasis on the flexibility contribution from conventional power plants. It thus examines one aspect of PST. To the extent that it touches on other drivers of PST – for example the increased uptake of digital monitoring and control equipment – it does so through the lens of power system flexibility.

Defining flexibility

The term and concept of power system flexibility has evolved over time to reflect the way technology and power markets have evolved and was first introduced in IEA (2008) as:

> "…The ability to operate reliably with significant shares of variable renewable electricity."

A more specific definition was put forward in IEA (2011):

> "Flexibility expresses the extent to which a power system can modify electricity production or consumption in response to variability, expected or otherwise."

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IEA (2012) differentiates between stability, balancing and adequacy for flexibility based on time horizons, but focuses the discussion on the balancing timeframe. 21CPP (2014) and NREL (2015) also focused on balancing timeframes, broadly defining "operational flexibility" as the ability of a power system to respond to change in demand and supply, a characteristic present in all power systems.

IEA (2014) introduced a distinction between a broader concept of flexibility and a narrower concept of ramping flexibility:

> "In a narrower sense, the flexibility of a power system refers to the extent to which generation or demand can be increased or reduced over a timescale ranging from a few minutes to several hours."

NREL (2016), IEA-RETD (2016), and EPRI (2016) also highlight the concept of flexibility as applying across timescales, ranging from investment-related horizons (i.e. years), to operational planning timescales (i.e. from days to months), to actual operation itself (i.e. from subseconds to days). In recent years, a number of other definitions can be found in the literature; see IRENA (2017, p. 37) for a review.

While system flexibility is a characteristic that has existed in power systems from well before the advent of low-cost VRE, the evolution of its definitions has undoubtedly been driven by the increase of VRE, reflecting an evolving understanding of the relevant properties of VRE as well as the response strategies for its integration. Wind and solar power have a number of unique characteristics, which differ from conventional generation resources (IEA, 2014; IEA, 2017a). Most importantly, their output is constrained by the instantaneous availability of wind and sun. This makes them both variable and uncertain: variable because the available output varies over time, for example because there is no sunlight during the night; and uncertain as the available output cannot be predicted perfectly, for example because cloud coverage can only be predicted accurately a few hours ahead. These two properties were most prominently addressed in earlier definitions of flexibility given that they were the main areas of concern for wind and solar integration.

However, the understanding of system integration has continued to evolve. Issues related both to shorter timescales and longer time horizons have received increasing attention. As far as short timescales are concerned, another important property of VRE is the way it connects to the power grid. VRE sources use software-controlled power electronics to connect to the grid and are commonly referred to as non-synchronous generators. By contrast, most conventional generators are directly coupled to the power grid electro-mechanically and are recognised as synchronous generators. The fact that VRE is a non-synchronous generation source requires new approaches to ensuring the stability of power systems, which refers to very short-term effects of a few seconds and below – *inertia* is a key word often heard in this context. However, in the short term VRE can also improve the extent and frequency of supply-demand balancing. VRE has a high ramping capability and faster response than conventional technologies. From this perspective, VRE can possibly increase the inherent flexibility of the system (part-loaded generation), while if VRE provides frequency control it can also improve system regulation.

Regarding longer time horizons, planning exercises are increasingly incorporating system flexibility requirements and constraints into planning practices for power systems with a greater share of VRE. Furthermore, the electrification of end-use sectors – especially transport and thermal applications – is growing in prominence as an important tool to support the system integration of renewables.

Consequently, it is timely to elaborte on the concept of flexibility and to provide a comprehensive and differentiated account of different relevant timescales of flexibility.

Flexibility on different time-scales

Six relevant timescales can be applied to flexibility (Table 2.1, Box 2.1). As regards the short term, these flexibility needs are driven by technical power system characteristics relating to voltage and frequency management, which are essential to system stability. Longer-term flexibility needs come from weather system and seasonal drivers and are related to the availability of appropriate capacity and resources.

For the short timescales in this report, the focus is on system frequency, while the voltage aspect is not covered in detail. Any imbalance between supply and demand results in frequency deviation, denoting either supply surplus or deficit. System frequency is one of the critical considerations in determining appropriate technical and regulatory options, particularly as the share of VRE increases.

For longer-term flexibility, the issue of uncertainty in the future resource mix is also relevant since it is related to ongoing investments. One important consideration is that the non-VRE mix should be sufficiently robust to accommodate an uncertain VRE penetration rate, which may differ from the plan. The task of promoting adequate power system flexibility grows increasingly complex as levels of VRE increase.

Table 2.1 • Different timescales of power system flexibility

Flexibility type	Ultra-short-term flexibility/ stability	Very short-term flexibility	Short-term flexibility	Medium-term flexibility	Long-term flexibility	Very long-term flexibility
Timescale	Subseconds to seconds	Seconds to minutes	Minutes to hours	Hours to days	Days to months	Months to years
Issue	Ensuring system stability (voltage, and frequency stability) at high shares of non-synchronous generation	Ensuring short-term frequency control at high shares of variable generation	Meeting more frequent, rapid and less predictable changes in the supply/ demand balance, system regulation	Determining operation schedule of the available generation resources to meet system conditions in hour- and day-ahead time frame	Addressing longer periods of surplus or deficit of variable generation, mainly driven by presence of a specific weather system	Balancing seasonal and inter-annual availability of variable generation with power demand
Has relevance for following areas of system operation and planning	Dynamic stability (inertia response, grid strength)	Primary and secondary frequency response, which include AGC	AGC, ED, balancing real time market, regulation	ED for hour-ahead, UC for day-ahead time frame	UC, scheduling, adequacy	Hydro-thermal co-ordination, adequacy, power system planning

Notes: AGC = automatic generation control; ED = economic dispatch; UC = unit commitment.

Box 2.1 • Deriving different flexibility timescales

Fundamentally, flexibility needs cover a continuous time spectrum from the nearly instantaneous to years. However, to help understand the basis of these needs, as well as the different mechanisms for meeting them, it is helpful to group flexibility requirements on the basis of timescale ranges. In this report, six separate timescale categories are considered, although categorisations with both fewer and more divisions can easily be applied.

Ultra-short-term flexibility/stability covers timescales from subseconds to seconds and focuses on arresting immediate frequency deviations during the transition to frequency nadir. In other words, this refers to limiting the rate at which the frequency deviates from its standard operating range. Ultra-short-term flexibility is the

time period before the frequency nadir (Figure 2.1). The key source of ultra-short-term flexibility is the inertia provided by synchronous generators, where the physical spinning mass of the generator resists changes in power system frequency.

Very short-term flexibility then covers timescales from seconds to minutes in order to return frequency to its standard operating range (Figure 2.1). This includes the response on the scale of seconds from generator governors, where frequency is detected locally and generation output can be autonomously adjusted without external input (for example, droop response), and also includes processes that involve an external control signal, such as AGC.

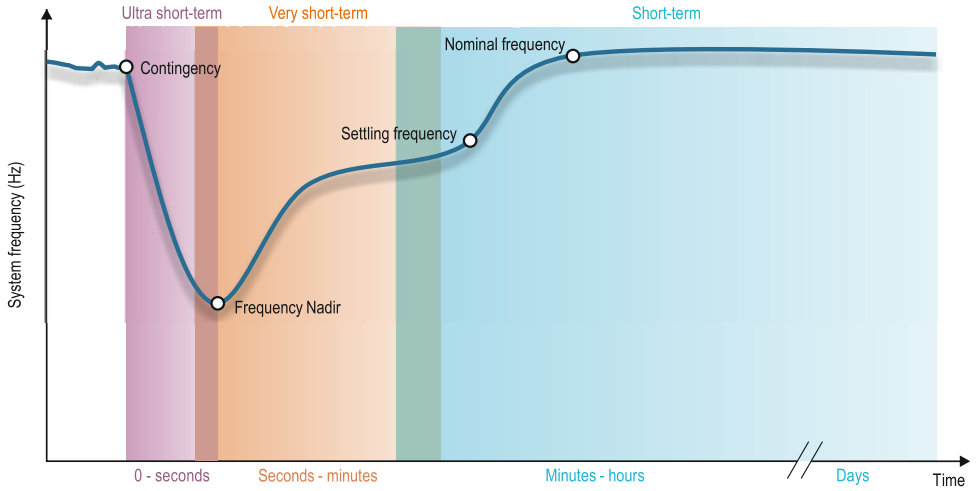
Short-term flexibility covers periods from several minutes to hours, from the fastest market-based adjustments up to typical ED horizons (Figure 2.1). AGC is applicable in the timescale of several minutes. ED is also applicable from minutes to hours, depending on the structure of the market. On these timescales, increased VRE can increase the extent and frequency of changes in the supply-demand balance, and also has implications for the predictability of these changes. This is driven by both predictable patterns in VRE output (high solar output in the middle of the day, stronger wind resources in the evening and at night) and by the partial unpredictability of VRE output due to weather forecast uncertainty.

Medium-term flexibility ranges from the timescale of hours to days, which involve both ED and UC. ED is applicable to the hour timescale while UC mostly covers the day timescale, but can also touch upon the hour timescale. In this medium term, the operation schedule is determined on the basis of the reliability and economics to meet the expected system conditions in the hour- and day-ahead schedule. With increased VRE penetration, ED and UC play an important role in accessing the physical capability of power plants in order to enhance system flexibility.

Long-term flexibility covers the timescale of days to months where weather system patterns become a driver for flexibility needs. Particular weather conditions often persist for several days, with impacts on both electricity demand and supply, due to weather-driven heating and cooling needs and impacts on VRE output. UC is still applicable in this timescale, particularly from day to week.

Very long-term flexibility extends a similar principle to monthly and yearly timescales. Both electricity demand and VRE output can have strong seasonal patterns. Increasing VRE penetration results in flexibility requirements to balance supply and demand on a seasonal basis where, for example, there may be a mismatch between the time of the year with the strongest VRE output and the highest system demand. Beyond this, interannual flexibility is also an important consideration, with VRE and hydropower resources often showing significant interannual variations (e.g. via the El Niño phenomenon). Long-term flexibility issues are often considered and designed out during power system planning processes.

Figure 2.1 • Contributions of ultra-short-term, very short-term and short-term flexibility services



Note: Hz = hertz.

Key point • Ultra-short-, very short- and short-term flexibility services are important for maintaining system frequency.

Phases of VRE integration and system flexibility

Flexibility has historically been an important requirement for power systems to balance supply and demand, including following unexpected contingencies such as plant and transmission outages. Securing the provision of system flexibility has become increasingly important for policy makers as the share of VRE generation increases. Previous IEA analysis has identified different phases of VRE integration (IEA, 2017b). They are characterised not by a specific penetration level of VRE, but rather by the main integration issues that are experienced. It is important to note that a variety of system specific factors will influence how much an increase in VRE will affect the overall flexibility requirement of the system.

The six phases outlined below cover all the main issues that are experienced up to the point where the power system can meet all of its electricity based on generation from VRE.

- **Phase 1:** The first set of VRE plants are deployed, but they are basically insignificant at the system level; effects are very localised, for example at the grid connection point of plants.
- **Phase 2:** As more VRE plants are added, changes between load and net load[3] become noticeable. Upgrades to operating practices and making better use of existing system resources are usually sufficient to achieve system integration.
- **Phase 3:** Greater swings in the supply-demand balance prompt the need for a systematic increase in power system flexibility that goes beyond what can be fairly easily supplied by existing assets and operational practice.
- **Phase 4:** VRE output is sufficient to provide a large majority of electricity demand during certain periods (high VRE generation during times of low demand); this requires changes in both operational and regulatory approaches. From the operational perspective, it is related to the way the power system responds immediately following unexpected disruptions in supply or demand. This phase thus concerns power system stability. From the regulatory perspective, it may involve rule changes so that VRE has to provide frequency response services.
- **Phase 5:** Without additional measures, adding more VRE plants will mean that their output frequently exceeds power demand and structural surpluses of negative net load would appear, leading to an increased risk of curtailment of VRE output. Shifting demand to periods of high VRE output and creating new demand via electrification can mitigate this issue. Another possibility is to enhance interchange with neighbouring systems. In this phase, it is possible that in some periods the demand is entirely supplied by VRE without any thermal plants on the high-voltage grid.
- **Phase 6:** The main obstacle to achieving even higher shares of VRE now becomes meeting demand during periods of low wind and sun availability, as well as supplying uses that cannot be easily electrified. This phase thus can be characterised by the potential need for seasonal storage and use of synthetic fuels such as hydrogen.

Countries can be categorised according to their VRE deployment phase. Today, even the most advanced countries are primarily dealing with issues related to Phase 4 and the vast majority of countries in the world are in Phases 1 or 2. The phase categorisation is context-specific, depending not only on the share of VRE, but also on other characteristics of the system. It is possible for a larger system to be in a lower phase, while a certain region or subsystem has already reached a higher phase. For example, despite the generally low share of VRE in Australia – and correspondingly moderate challenges – South Australia has a very high penetration and

[3] Net load is the difference between forecast load and generation from VRE.

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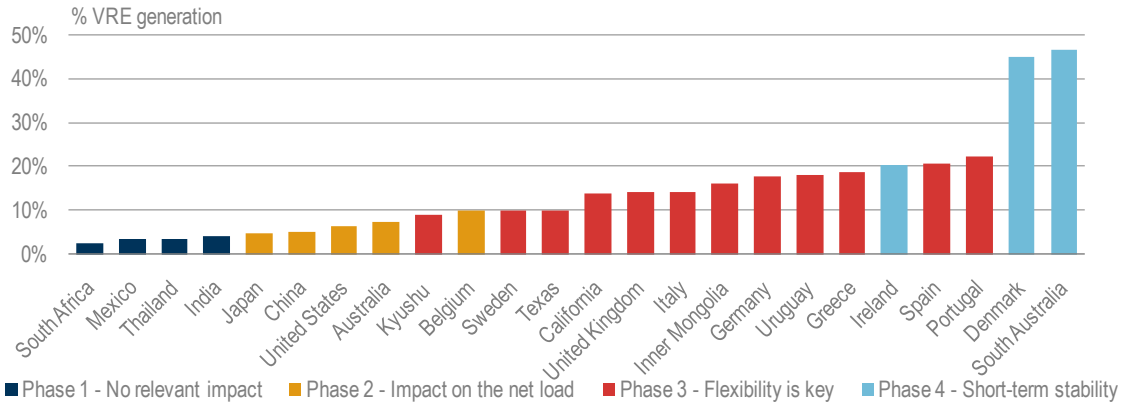
faces Phase 4 issues (Figure 2.2). Moreover, all else being equal, smaller systems will tend to fall into a higher phase than large systems, e.g. Ireland is in Phase 4 while it has a lower annual share than Spain, which is in Phase 3.

Figure 2.2 • Selected country by phase, 2016



Note: Kyushu is a large island located in southwest Japan.

Source: Adapted from IEA (2017c), *Renewables 2017: Analysis and forecasts to 2022*.

Key point • While most countries of the world are in Phases 1 or 2 of system integration, a variety of power system jurisdictions are experiencing later phases.

It is possible to combine the different phases of system integration with the more differentiated definition of flexibility based on the timescales presented above. Table 2.2 identifies the phases of VRE integration and what timescales of flexibility typically are a main priority. Importantly, the linkages presented are intended to capture general power system trends and not to rigidly encompass all possible circumstances.

Table 2.2 • Indicative links between VRE integration phase and different timescales of power system flexibility

Phase	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Phase 6
Becomes a main priority	Typically no system flexibility issues	Short-term flexibility	Short-term flexibility Medium-term flexibility	Ultra-short-term flexibility Medium-term flexibility Long-term flexibility	Long-term flexibility Very long-term flexibility	Very long-term flexibility

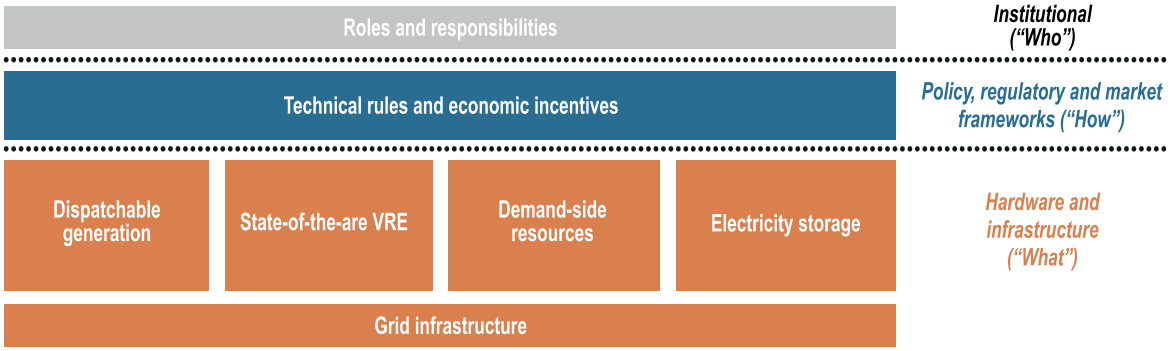
Layers of system flexibility

The flexibility of a power system can be determined based on three different aspects (adapted from IRENA, IEA and REN21, 2018):

- technical options available (the hardware and infrastructure, or the “what”)
- economic incentives and other constructs that entities experience when utilising those technical solutions (the policy, regulatory and market frameworks, or the “how”)
- roles and responsibilities that various entities have in providing flexibility (the institutional, or the “who”).

For example, in order to make the demand side more flexible, one may need special devices for the remote control of loads (hardware and infrastructure); electricity prices may need to vary across time in a market design that supports flexibility and gives the right economic incentives (policy, regulatory and market frameworks); and possibly a new player, such as a flexibility aggregator, needs to be allowed to participate (institutional). All three aspects must work in concert to support system flexibility (Figure 2.3).

Figure 2.3 • Different layers of system flexibility



Key point • Technical, economic and institutional policy layers mutually influence each other and have to be addressed in consistent way to enhance power system flexibility .

Hardware and infrastructure: The "what" of system flexibility

Hardware and infrastructure encompass the technical resources that provide physical power system flexibility – both the physical equipment itself and the flexibility services the equipment provides. It is the "what" of power system flexibility. A detailed description of costs, challenges and capabilities of flexible resources can be found in IEA (2014).

The five categories of hardware and infrastructure for system flexibility are: dispatchable generation, state-of-the-art VRE, demand-side resources, electricity storage and network infrastructure.

Dispatchable generation is currently the dominant source of system flexibility in all power systems, accommodating the variability of demand and VRE output. Dispatchable generators provide flexibility by reducing power output or shutting down completely when VRE output is plentiful or when demand is low. Similarly, they ramp up or start up rapidly to cover periods of low VRE availability or rapid increases in demand. They also provide a range of short-term and ultra-short-term flexibility services throughout the day. Retrofits and retirement/replacement of power plants may be required to improve fleet flexibility.

State-of-the-art VRE refers to a range of advanced technical capabilities that VRE can provide to help manage the variability and uncertainty of supply and demand. For ultra-short-term and very short-term flexibility, state-of-the-art VRE uses software-controlled power electronics to connect to the grid and can use these technologies to provide multiple services, ranging from fast frequency response to up/down ramping and operating reserves. For longer timescales, using the right mix of state-of-the-art wind and solar PV in strategically well-chosen locations can reduce long-term variability and uncertainty. Such an approach to VRE deployment that seeks to optimise overall outcomes for the system is known as "system-friendly" VRE deployment (IEA, 2017a).

Demand-side resources have the potential to cost-effectively balance supply and demand, offer back-up power during system contingencies, facilitate the integration of VRE, and provide a range

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of other system services. A range of technologies are suitable for demand response purposes. Their common property is the ability to shift or adjust power consumption for a certain amount of time, or interrupt electricity consumption in exceptional circumstances at short notice. These resources are typically more useful for very short-term and short-term flexibility. Another form of demand-side resource is the implicit use of price signals to change consumers' behaviour and load profile.

Electricity storage describes all technologies that can absorb electrical energy and return it as electrical energy at a later stage. Arbitrage opportunities have driven storage deployment in the last 40 years, in particular pumped storage hydro (PSH). Electricity storage technologies can provide multiple services ranging from fast frequency response to bulk energy storage, which cover timescales from ultra-short- to long-term and which help to accommodate new challenges related to VRE variability. Recently, battery storage technologies have seen rapid cost declines, and although not suitable for seasonal storage, could play a greater flexibility role in the short-term timescale in future power systems.

Grid infrastructure encompasses all assets that connect generation to demand: high-voltage (HV) and ultra-high-voltage (UHV) transmission lines for both alternating current (AC) and direct current (DC), distribution network lines, protection schemes, additional devices such as transformers, and sophisticated HV/UHV and distribution network components. Larger and meshed networks, as well as digitalization of the grid, can help to integrate VRE generation. Aggregating distant VRE plants and flexible resources smooths overall VRE output and allows cost-effective utilisation of flexibility options.

The different categories of flexible resources described can provide flexibility services across all of the flexibility timescales. However, specific technologies and approaches are most suited to the different flexibility timescales. It is thus possible to map the technical options in more detail (Table 2.3).

Table 2.3 • Specific hardware and infrastructure options (equipment and services) organised into technical flexibility resource categories for different timescales of system flexibility

Flexibility timescale / Flexibility resource	**Ultra-short term** (subseconds to seconds)	**Very short term** (seconds to minutes)	**Short term** (minutes to hours)	**Medium term** (hours to days)	**Long term** (days to months)	**Very long term** (months to years)
State-of-the-art VRE	Controller to enable synthetic inertia; very fast frequency response	Synthetic governor response; AGC	Downward/ upward reserves; AGC; ED of plants including VRE	ED tools; UC tools; VRE forecasting systems	UC tools; VRE forecasting systems	VRE forecasting systems; power system planning tools
Demand-side resources	Power electronics to enable load shedding	Demand-side options including electric water heaters, electric vehicle chargers, large water pumps and electric heaters; variable-speed electric loads	Air conditioners with cold storage and heat pumps; most equipment listed under very-short-term flexibility	Smart meters for time-dependent retail pricing	Demand forecasting equipment	Demand forecasting equipment; power-to-gas
Storage	Supercapacitors ; flywheels; battery storage; PSH ternary units	Battery storage	Battery storage; CAES; PSH	PSH	PSH	PSH; hydrogen production; ammonia or other power-to-gas/liquid

Conventional plants	Mechanical inertia; generation shedding schemes	Governor droop; AGC	Cycling; ramping; AGC	Cycling; quick-start; medium-start	Changes in power plant operation criteria	Retrofit plants; flexible power plants; keeping existing generators as reserve
Grid infrastructure	Synchronous condensers and other FACTS devices	SPS; network protection relays	Internodal power transfers; cross-border transmission lines	Internodal power transfers; cross-border transmission lines	Control and communication systems to enable dynamic transmission line ratings; WAM; HV components such as SVC	Transmission lines or transmission reinforcement

Notes: AGC = Automatic Generation Control; CAES = compressed air energy storage; FACTS = flexible alternative current transmission system; SPS = special protection schemes; SVC = static var compensator; WAM = wide area monitoring system.

When assessing hardware's role as a source of flexibility, it is useful to address the notable limitations still prevalent in the existing power system. One major element is likely to be the physical limitations of hardware during normal operating conditions, such as the minimum stable level of a coal-fired power plant, where each generating unit is unable to reduce its continuous output below a certain value (e.g. 50% of its capacity) due to boiler pressure constraints or combustion stability. However, global experience suggests such limitations can be mitigated, and the minimum stable level can be significantly reduced to around 10-35% of capacity. This is achieved with some cost-effective combination of technical solutions including unit master control, feed-water and boiler controls, and/or turbine enhancement retrofits (see Chapter 3).

Additionally, limitations are imposed by the feasible commitment cycle constraints of different power plants, whereby prevailing physical conditions prohibit units from immediately shutting down or restarting until a minimum time has elapsed following a change in operating state. An example of this constraint, commonly referred to as minimum up- or downtime respectively, is applicable to a number of thermal generation technologies, including nuclear power plants. In the case of certain nuclear power plants, reactors are unable to restart immediately after the tripping of the plant due to a phenomenon called Xenon build-up.

Hardware inflexibility also extends to transmission network constraints, whereby the balancing of supply and demand between neighbouring regions/balancing areas is limited by the interzonal transmission connectivity.

Policy, regulatory and market frameworks – the "how" of system flexibility

Policy, regulatory and market frameworks provide signals that power system stakeholders experience to influence investment in, and operation, of hardware and infrastructure to achieve flexibility targets. These frameworks influence the deployment and operation of system flexibility hardware and infrastructure in a number of ways:

- technical rules and standards influencing hardware and power system operation
- economic incentives influencing operation of hardware and infrastructure
- economic incentives and planning protocols influencing investment in new hardware and infrastructure.

Each of these is now discussed in turn.

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Technical rules and standards influencing hardware and power system operation

What regulatory requirements exist for hardware and infrastructure to provide flexibility services? At a high level, a range of regulatory requirements influence 1) what technical capabilities hardware must have to provide flexibility, and 2) how the power system is operated to utilise hardware and infrastructure flexibly. Key examples of technical rules and standards are listed below. Importantly, many of the regulatory requirements have strong economic implications, but are categorised under this section to enhance understanding.

Grid codes specify the performance standards and capabilities normally required of all power system hardware. With respect to generation hardware, the grid code dictates what services various pieces of power generation equipment must be able to provide. For instance, Germany has recently undertaken a reform of its Application Guide for the Connection of Distributed Generators to Low-Voltage Networks (VDE-AR-N 4105) in order to require greater grid support capabilities from increasing numbers of very small-scale systems (VDE, 2011). For the transmission system, grid codes can influence how flexibly it can be operated by specifying whether certain flexibility strategies are used (e.g. dynamic line rating, active network management).

System operational standards are created by power system operators to ensure the security and stability of the power system. These standards generally focus on the system frequency, voltage and reserve margin of the system; performance subsequent to a disturbance is also typically specified. By imposing specific rules about how the power system operates (e.g. specifying how much regulating reserve capacity must be available at any given moment), they strongly influence how hardware is operated – and, by implication, how *flexibly* hardware is operated.

Rules for balancing area co-ordination are highly intertwined with system operational standards, specifying the guidelines under which power can be transferred between neighbouring systems. The presence or absence of these rules can greatly influence how power system hardware is operated. There are also significant economic implications to these arrangements.

VRE forecasting practices are closely related to system operational standards. The relative accuracy of VRE forecasts, as well as how effectively forecasts are integrated into system operation decisions, can influence how much power plant capacity is ultimately held in reserves. More accurate and well-integrated VRE forecasting practices can lead to a reduced amount of power plant capacity being held in reserves, and thus able to operate flexibly.

Environmental regulations governing aspects such as carbon dioxide emissions, local air quality or water use can greatly influence how power plants operate. For instance, environmental regulations for river systems may impose constraints on hydropower generators, influencing their ability to operate flexibly at all times.

Economic incentives influencing operation of hardware and infrastructure

What constructs do owners of hardware participate in to seek remuneration for providing flexibility services? In practice, a range of economic incentives in the power system influence how hardware is operated, the most important of which are listed below.

Contract terms between power sector stakeholders can be highly influential on the ability of power system hardware and infrastructure to operate flexibly. These relate to both economic and operational dimensions. For instance, “take-or-pay” stipulations are very common in power purchase agreements and power plant fuel procurement contracts. These stipulations can serve as a useful risk mitigation measure, but may lock power plants into specific operational modes and economically restrict the ability to access latent flexibility in a power plant. Similarly, power plant maintenance contract terms can influence the economic incentives of a power plant to

operate flexibly. Maintenance fees typically depend on the numbers of start-ups and shutdowns, and as such may reduce the incentive to turn off a power plant when it is otherwise economic for the power system to do so. In certain instances, it may be economically efficient to offer additional incentives for power plants to turn off. For transmission lines, contract terms with power plants can potentially influence the extent to which flexible grid management approaches are required, such as dynamic line rating schemes to increase the capacity of transmission lines.

Market rules determine how various hardware resources are prioritised, dispatched and remunerated based on market settlement or out-of-market payments for services such as voltage support or reserves. For wholesale electricity markets, market rules determine which specific system services (e.g. energy, capacity, reserves) are remunerated, and how. They also specify relevant dispatch periods and gate closure times for market operations, the geographic granularity of prices, and other technical aspects that influence operational behaviour. In more advanced power markets, the development and introduction of products that incentivise flexibility help to remunerate actors for operating hardware flexibly, in alignment with the requirements of the system. The presence of various remuneration schemes within market rules can also influence investment in new hardware (see next subsection).

Tariff structures can also influence many aspects on the demand side. In some contexts, wholesale energy tariffs are offered to distributors/retailers by a single-buyer utility (e.g. South Africa, Thailand). In these settings, the extent to which the tariff structure changes with time (e.g. flat, seasonal, peak vs. off-peak, hourly pricing) or has non-energy components (e.g. peak demand-based charges) can send economic signals to distributors and end users to reduce demand during periods when the grid is under stress conditions, and more broadly to consider "flexibilising" aspects of their demand to reduce energy procurement costs. To that end, the implementation of time-variable retail electricity tariffs or other alternative tariff structures, such critical peak pricing, can influence end-user consumption behaviour in retail, commercial and industrial sectors; these strategies typically require the roll-out of additional smart metering and information and communications technology infrastructure.

Economic incentives and planning protocols influencing investment in new hardware and infrastructure

What economic incentives or planning protocols influence new investment in power system flexibility hardware and infrastructure? The economic incentives for flexible operation discussed in the previous subsection can be highly influential in fostering an attractive investment environment for new flexibility hardware and infrastructure. However, other policy, regulatory and market aspects pertaining directly to new hardware and infrastructure investment are also worth elucidating.

Long-term planning practices can, to varying extents, inform the scope and nature of new flexibility hardware and infrastructure investments. In regulated contexts with centralised planning processes (e.g. an integrated resource plan), long-term planning exercises can directly influence the type, location and scale of flexibility hardware investments being made. Systems with less centralised planning processes may rely more on market signals to ensure adequate generation hardware is available on the system to balance supply and demand. In these cases, long-term planning practices may identify certain flexibility requirements that necessitate the creation of new market-based remuneration mechanisms.

Regulated paradigms for cost recovery can – for segments of the power market under traditional regulation – be highly influential in determining whether and what kind of new hardware and infrastructure investments are made. On the demand side, the cost recovery terms, such as regulation of retail tariffs, offered by a regulator can potentially encourage or discourage a

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regulated utility to pursue a demand response programme. For transmission investments, cost recovery may be tied to performance, including the ability of the transmission system owner to operate the line in support of system flexibility needs. For the generation segment, the extent to which flexibility retrofit investment at regulated plants can be passed through to ratepayers will strongly influence whether investments are made.

For a more detailed discussion of policy, regulatory and market strategies, see for example IEA (2017a) and 21CPP (2015).

Institutional: The "who" of system flexibility

The institutional layer encompasses the roles and responsibilities of various actors and stakeholders that can participate in providing system flexibility, relating to power system operation and planning. Important relevant actors include policy makers, utilities, system operators, power plant operators, demand-side resources, regulatory bodies and investors in the energy sector. The institutional aspect is also closely linked to the rules that govern actors and stakeholders.

Key categories of institutional issues include the following:

- **Participation of actors**: Do participation rules prevent the involvement of actors who would otherwise be able to contribute to system flexibility? For example, who is allowed to own and/or operate flexibility hardware? Are VRE generators allowed to provide flexibility services and receive compensation for them? Are other new actors (e.g. distributed energy resource aggregators, storage operators, end users) allowed to participate and monetise the range of flexibility services they are able to provide?
- **Roles and responsibilities**: Which actors are responsible for grid codes and interconnection requirements, system operations, market administration (if relevant) and planning? Are there any conflicts of interest among these actors? Is a neutral and technically competent body responsible for the grid code? Are certain responsible actors motivated to impede participation by other actors?
- **Co-ordination among actors**: How are co-ordination and communication conducted between various planners and operators in neighbouring balancing areas? How is the co-ordination managed between transmission and distribution layers within the same context? Does a lack of co-ordination between responsible entities within and between balancing areas restrict the implementation of certain flexibility options?

Inflexibility within power system institutional arrangements may be driven by unclear roles and responsibilities in the operation of power systems. More specifically, this is the inability of market participants, who are technically capable of providing flexibility, to do so due to the absence of a suitable market framework and/or constrained market rules.

Institutional issues can lead to certain technologies being overlooked for their ability to provide flexibility services to the power system due to a lack of an appropriate participation mechanism. They are one of the primary causes of inflexibility that is prevalent in existing, liberalised power systems. This is perhaps best illustrated by the barriers to demand-side participation present in many power systems, where demand response aggregators are unable to secure a licence to participate in energy and ancillary service markets.

Another common form of institutional inflexibility surrounds electricity storage projects; often these projects are contracted to provide a specific grid function (e.g. dynamic reactive support of the transmission network), but are contractually constrained from serving other functions (e.g. economic load balancing or energy arbitrage activities). This lack of opportunity to monetise

multiple revenue streams from energy storage may limit the economic viability of projects that would otherwise be valuable to the system for flexibility services over various timeframes. Similarly, VRE power plants may also be restricted from bidding into reserve markets, despite a physical ability to provide reserves through energy-constrained operation.

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3. Flexibility at the power plant level

HIGHLIGHTS

- Power plants can provide flexibility across all relevant timescales. However, depending on cost structure (fixed costs vs variable costs), fuel type and plant design, power plants show large differences in their flexibility performance. Experience and examples reported in this report highlight that many, if not all generating assets can operate flexibly, across different timescales.
- The role of existing thermal power plants is transitioning in many modern power systems toward more flexible modes of operation. While these plants can offer increasingly important services to the system, concomitant reductions in energy sales raise issues related to plant financial viability and the need for reevaluation of remuneration constructs in many markets**.**
- New technical and economic requirements, often driven by greater penetration of wind and solar, can influence how existing power plants are best operated or new ones are designed. In particular, at high shares of variable generation, adjusting the output of all power plants – even those designed to run around the clock at maximum output – in response to market conditions can contribute to least-cost electricity supply.
- Generators that were initially designed and operated as "inflexible" have been successfully changed into highly flexible assets. Power plants can be retrofitted to enhance their flexibility. This includes measures to reduce the time needed to start and stop the plant, lower the minimum operation level of plants and increase the speed at which plants can change their output.
- The cost implications of retrofits vary across a wide range. The most cost-effective options aim at unlocking flexibility via changes to operating procedures and adding improved monitoring and control equipment. More substantial retrofits require additional capital investment and may involve structural changes to plants.
- Increasing the flexibility of a power plant is best accomplished via a comprehensive approach, starting with raising awareness of plant flexibility across all relevant stakeholders. Understanding current capabilities, executing test runs and improving information technology (IT) capabilities are also general priorities.
- Variable renewable energy (VRE) plants can also provide various system flexibility services, if regulation and market rules permit.

The previous chapter introduced flexibility, its multiple aspects and the instruments that are available to unlock it. This chapter takes a more in-depth look at power plants and their role in providing flexibility.

All power plants share the fundamental property that they convert other forms of energy into electricity. Plant characteristics vary significantly depending on input energy and design. For example, a coal-fired co-generation plant is significantly different from a back-up diesel engine. The former is more expensive to build, but inexpensive to run. For the latter, it is the other way around: inexpensive to build, but costly to use. Consequently, the plants with low fuel costs are designed to run most of the time while the ones with expensive fuel will only run occasionally. These different operating modes are also related to the technical design of power plants, including (*inter alia*) how much advance notice is needed ahead of starting operations, or how rapidly and to what extent plants are able to change their output.

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This diversity of power plant types is exploited by combining different plants on the grid. This portfolio approach allows the overall cost of electricity supply to be minimised, while also ensuring reliable electricity is available at all times. Historically, the most important driver for this mix was the structure of electricity demand (see section below for details). Nearly all power plants operated by producing electricity from stored energy – fossil or nuclear fuels, biomass, geothermal energy, potential energy of water in a reservoir[4] – all with a distinct capacity to provide flexibility services.

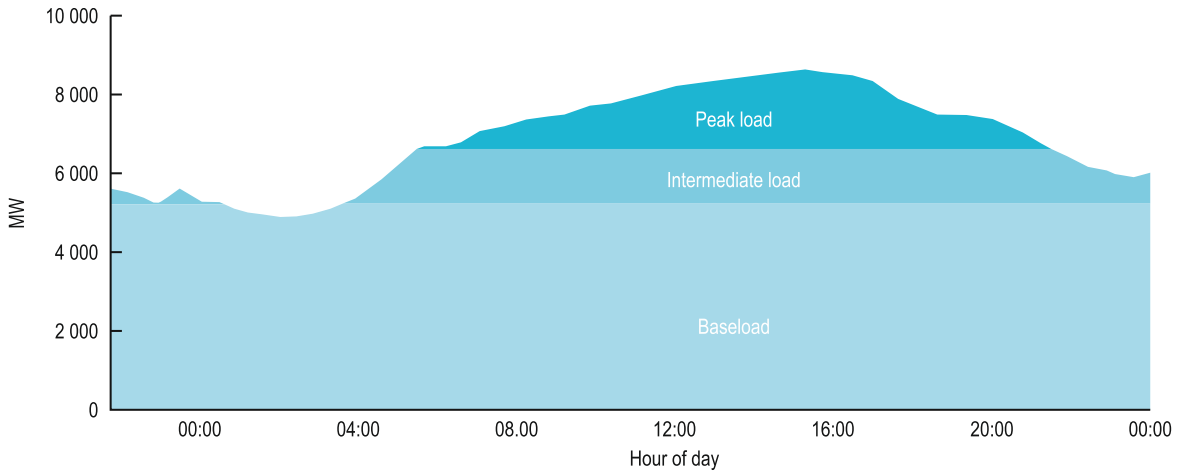
As new generation technologies with distinct cost structures and technical characteristics enter power systems at scale – especially wind and solar photovoltaic (PV) power plants – the mix of power plants which constitutes least-cost changes. Furthermore, new technical requirements emerge, which may influence how existing plants are best operated or new ones are designed. Finally, the way power plants are categorised may need to change as well, especially in order to accommodate new technologies such as VRE, within a general framework.

This chapter reviews the traditional framework for categorising power plants, introduces a framework to characterise power plants in modern power systems, and shows how power plants can provide each type of flexibility (as introduced in Chapter 2). Building on this, the flexibility of different technologies (organised by type of fuel input) is discussed in more detail. Options to increase flexibility are also highlighted, including via selected case studies.

Historic power plant categorisation

Power systems have always needed flexibility to cope with the varying demand for electricity, by time of day, by weekday versus weekend, and by season. Although the details vary by power system, power system planners have found it useful to classify demand for electricity into three categories: baseload, intermediate, and peak load (Figure 3.1).

Figure 3.1 • Traditional categorisation of electricity demand



Note: MW = megawatt.

Key message • Power demand has been traditionally segmented into different categories: baseload, intermediate and peak, which is the basis for which power plant roles have historically been categorised.

[4] Run-of-river hydropower and backpressure co-generation plants are perhaps the most notable exceptions.

The lowest section of the demand profile is the baseload. This is the minimum amount of electricity that needs to be provided at all times, regardless of short-term changes in behaviour. The next segment can be identified as intermediate load. This part varies constantly throughout the day depending on activity levels across households, businesses and industry. Peak load is the highest segment of demand for the day (or other time periods under consideration) and refers to a small number of hours with the highest energy demand. The highest level of peak demand in a year is known as the system peak, which is often driven by seasonal needs for heating or cooling.

This historic classification of demand is strongly linked with how power systems have been planned, regulated, financed and conceptualised. In turn, this has influenced the design and optimisation of power plants over past decades. In a nutshell, the design and operation of power plants has been optimised to match the different requirements of each demand category.

Power plants designed and operated to meet baseload

Baseload plants run most of the time at stable levels of output. This operational mode is a result of a cost structure that can allow for high capital costs, as long as operational costs are low. Such technologies include, for example, coal, nuclear plants and some run-of-the-river hydropower plants. Under conventional operation, these have been the least flexible from both a technical and economic standpoint; however, their traditional use as baseload resources has not required much flexibility. With long start-up times, high minimum stable generation levels and constraints on the speed with which they can change output, they provide little ramping flexibility.

Plants designed to serve the baseload usually have a small number of cycles (starts and stops) throughout their lifetime; once they have been committed and synchronised to the grid, they tend to run without interruption for very long periods of time. Because of their high capital costs, they need to maximise running hours to remain economic, hence their contribution to medium-term and long-term flexibility can also be limited.[5] Because these plants were designed to be on the grid most of the time and are synchronous generators, some of these plants can also contribute to ultra-short-term and very short-term flexibility.[6] Some reservoir hydropower plants are designed to operate as baseload plants, and many of them can provide flexibility services in short timeframes without incurring significant expense.

Power plants designed and operated to meet intermediate load

Plants that are optimised to serve intermediate demand are designed to adjust their output upwards and downwards to accommodate changes in demand throughout the day. Often referred to as mid-merit plants,[7] they are also designed to start and stop frequently, sometimes twice a day. They have lower minimum stable output levels than baseload plants and can ramp output relatively quickly. Some examples of such plants are combined-cycle gas turbine (CCGT) plants and hard-coal plants optimised for this type of application.[8] Many reservoir hydropower plants also fall into this category, depending on the size of the reservoir and water inflow patterns. Except for hydro plants which can start very rapidly, their start-up times are shorter

[5] One exception is the timing of scheduled maintenance and plant revisions. These are usually planned during seasons with lower electricity demand.

[6] Many baseload plants are designed to allow for small fluctuations around maximum output in order to provide operating reserves and frequency support.

[7] The merit order of power plants ranks plants according to their short-run marginal costs. It primarily reflects fuel costs. Mid-merit plants have fuel costs that are higher than baseload plants but lower than peaking plants. Hence, they are positioned in the middle of the merit order, which explains their name.

[8] Some CCGTs are not designed to be flexible.

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than for baseload plants, but they may require a couple of hours' notice before being able to deliver power to the grid. Such plants are typically designed to have a significantly higher number of cycles throughout their lifetime but require appropriate scheduling to accommodate for the delay in start-up time. Hence, mid-merit plants can provide substantial short-term and medium-term flexibility. They also contribute to long- and very-long-term flexibility. Once operating, they can also provide ultra-short-term and very short-term flexibility services.

Power plants designed and operated to meet peak load

Peaking plants cover periods of very high demand, which either do not last long enough, or do not occur often enough, to justify starting a mid-merit power plant. Peaking plants can also come on line in a matter of minutes following unexpected events, such as plant outages or forecast errors. To meet this role, peaking plants have very low start-up times and high ramping speeds. Their cost structure requires fixed costs to be minimised, while allowing for higher operating costs. Open-cycle gas turbines (OCGTs), banks of reciprocating engines and certain types of hydropower plants are traditionally designed to operate as peaking plants. Peaking plants have superior ramping flexibility and are well-suited to provide short- to medium-term flexibility services. Providing long-term flexibility may become uneconomic if this implies a large number of operating hours. Peaking plants have historically played a less important role in providing ultra-short- and very short-term flexibility, as lower demand variability resulted in limited operating hours.

Link between cost structure and flexibility attributes

As explained, a desire to serve the different load categories economically has led to differentiations in power plant design. These differentiations have economic and technical dimensions. From an economic perspective, plants to meet the baseload are designed to be cost-optimal when running around the clock and during most of the year. This allows for a higher investment cost as long as running costs are low. For peaking plants it is the opposite: high fuel costs are not a problem, as long as fixed costs are low enough. Technically, a plant that is intended to run all the time naturally will not be designed for many starts and stops or steep changes in output. Conversely, for a plant that needs to come on line rapidly and only for a limited time, quick start and steep ramping capabilities are key.

Not all plants of a given fuel are designed to provide the same level of flexibility. Therefore, some CCGTs may be flexible, whereas others are not. As explained in more detail below, it is possible to enhance the technical flexibility of power plants. However, the cost structure of a plant remains fundamental. Even if it is technically possible for a power plant to provide short-term flexibility, its cost structure will affect the economics of more flexible operation.

Updated characterisation of power plants

In modern power systems with growing shares of VRE, demand side management and distributed energy resources, the classical categorisation of power plants based on the type of load they are meant to serve is no longer sufficient to capture all relevant aspects. The first reason for this is that the roles of existing power plants – and the types of load they serve – are changing. This is driven in many cases by the need for more flexible operation due to increasing shares of VRE. The second reason is that modern resources such as VRE plants are not captured by the above categorisation. They are very capital intensive – making them similar to baseload plants – but their capacity factor is closer to that of mid-merit or peaking generation. When operating, they can provide short-term, very short-term and in some cases ultra-short-term flexibility. However,

they show a fundamental difference to most conventional plants: their primary fuel is not storable and their availability varies according to geography, climate and weather.

This chapter addresses these issues in a two-step approach. Firstly, the traditional baseload, mid-merit and peaking categorisation is linked to a more general approach that distinguishes the "energy volume contribution" and "energy option contribution" of power plants. Secondly, different types of power plants are then matched to the flexibility contribution they can make. Notably, in modern power systems these roles are not necessarily fixed, since a power plant's contribution to the system will also be influenced by the presence of other system resources including demand response and storage.

The role of power plants based on system contribution: Energy volume and energy option contributions

Currently, electricity cannot generally be stored cost-effectively for long periods of time, and power demand cannot be easily shifted in time.[9] Given the limited number of options for large-scale cost-effective storage, meeting electricity demand reliably and at a reasonable cost currently requires two distinct services from power plants. First, they need to generate enough cost-effective electricity overall during a period, say one year, to meet demand. Second, the combined output of all plants has to match demand at each moment.[10]

It is useful to consider the role of power plants based on two types of system contributions: *(1) energy volume contribution* and *(2) energy option contribution*.

Energy volume contribution is an indicator of the extent to which a power plant provides low-cost, bulk energy to satisfy demand over a given time period. As a way of comparison with the traditional plant categorisation, a plant with a high energy volume contribution would be comparable to a baseload coal or nuclear power plant running near maximum output in a system with low VRE generation and dominated by thermal generation technologies. In modern power systems with least-cost dispatch, VRE plants at very high shares have an essentially pure energy volume contribution. They are dispatched at full capacity whenever the wind or solar resource is available and the system can accommodate them, due to their near-zero operating costs.

Energy option contribution is an indicator of the extent to which a power plant is *available* to satisfy demand for energy and other critical system services over a given time period. Thus, a plant can be characterised as having a higher energy option contribution role if it is consistently available to commence production when needed. Under the traditional power system categorisation, peaking plants such as OCGTs could be seen as predominantly contributing to the system via a high energy option contribution. Despite running few hours during the year and at infrequent intervals, they contribute to the system by allowing system operators the option to call on them whenever required, providing important value to the system.

Building on the notion of how important the energy volume and energy option contributions of a generation resource is, it is possible to derive a more general characterisation of power plants (Figure 3.2). The traditional categories of baseload, mid-merit and peak-load power plants can be captured in this approach.

[9] Note that fuel, however, can generally be stored, as can water behind a dam, though both have their own set of constraints.

[10] In systems with substantial amounts of electricity storage, this requirement is less strict, but the general principle also applies.

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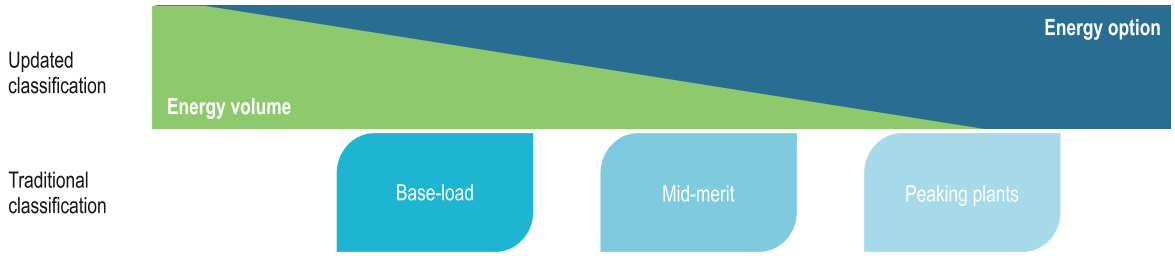
It is worth noting that this approach places power plants according to how they are used in a given power system, rather than what they were technically designed to provide or are theoretically capable of providing. For example, as a result of new operational patterns required from power plants at increasing shares of VRE, it is possible for power plants to shift from an energy volume-focused contribution (e.g. a coal-fired plant in traditional baseload operation) towards a more energy option-focused contribution, which implies greater flexibility (e.g. a traditionally baseload coal-fired plant providing balanced energy volume and value contributions). The ability of an existing power plant to successfully fulfil its new role with different energy volume or option contributions will determine its ability to remain "in the market". **Importantly, many of the power plant retrofit options presented in this chapter aim to make this shift in operational patterns technically feasible and economically attractive.**

Figure 3.2 • Characterisation of power plants according to energy volume and energy option contribution



Key message • The role of power plants differs by their contribution of energy volume and energy option to the power system.

Potential changes to conventional power plant operations

Power systems undergoing PST may increasingly begin utilizing VRE resources, energy efficiency, demand side management, storage and other modern technologies. With increasing penetrations of VRE in particular, conventional power plants may experiences changes in their operational conditions. With their very low cost of operation, it is generally most economic for the power system to accept all VRE output when available, while turning off conventional plants with higher running costs and utilizing available (and cost-effective) flexible resources such as grid infrastructure, demand response and storage resources. However, the remaining power plants which are still running need to be able to accommodate wind and solar PV generation to maintain the reliability of the system. In order to do this cost effectively and reliably, conventional power plants need to possess the ability to operate flexibly, while also being available to cover periods of low VRE availability. Under these new operating conditions, it is possible that the operating hours and energy output of these conventional power plants may be reduced.

The flexibility of power plants is determined by five main parameters:

- **Stable operating range**: This refers to possible generation levels that can be chosen, given a long lead time. The **minimum stable output** of the power plant is the lower bound of the stable operating range, while the maximum output is the upward constraint. The larger the stable operating range, the more operationally flexible the power plant.
- **Ramp rate**: This is the speed at which output can be adjusted upwards or downwards within the stable operating range. Upwards and downwards ramping rates vary depending on the plant's technical characteristics and the technical attributes of the control system.
- **Minimum up and down times**: These are the time constraints within which generating units have to a) remain on line once they have been synchronised onto the system (minimum up

time) or b) remain off line once they have been decommitted (minimum down time). These constraints are due to the technical limits as well as economic factors of conventional thermal generation technologies. For example, if a conventional power plant has been dispatched to start and is followed by an unexpected decrease in demand or increase in VRE output that eliminates the need for the plant some hours later, limited flexibility is available since the conventional plant has to be operated at the specified minimum up time.

- **Start-up time**: This is the required advance notice to make generation available, i.e. the time necessary to reach the minimum stable output level. The start-up time can be further categorised into cold, warm and hot start-up, which is based on the operational status of power plants at the time. These relate to the temperature of the plant and depend on the time between operation cycles (a thermal plant will remain hot for several hours after shutdown). Cold start-ups take the most time, while hot start-ups can be significantly shorter. During the start-up period a plant is not available to provide services. For example, a coal-fired plant with an 8-hour minimum downtime, an 8-hour start-up time, and an 8-hour minimum uptime, is operationally constrained for these 24 hours.

These different components combine to shape the flexibility of a plant.

Importantly, power plants originally designed to meet baseload that now operate in a more flexible power system with higher shares of VRE may need to provide greater flexibility, including via improving minimum stable output levels, ramping capabilities, start-up times and minimum up/down times as described. Because the classical term of baseload power plant suggests continuous operation around the clock, this name can be misleading in modern power systems. Thus, the new approach to characterise contributions from power plants may be appropriate in modern power systems with higher shares of VRE.

Matching power plant type and flexibility requirements

Chapter 2 introduced different types of flexibility across various timescales. These can be paired with the power plant framework introduced above to analyse how different power plant types are positioned to provide flexibility (Figure 3.3). The exact capabilities of a power plant will depend on the system it was designed for and how its role changes depending on changes to the generation fleet. For example, a coal-fired plant on the energy volume side of the spectrum may be able to provide ultra-short-term flexibility through inertia, or long-term flexibility by adjusting output and ensuring additional fuel availability in advance. By contrast, short-term flexibility may be provided either by a plant with a balanced energy volume/energy option contribution, such as a mid-merit plant that is already on line and able to ramp up quickly, or by a gas turbine dedicated to providing capacity quickly and at short notice. The relationship between the technical requirements for each flexibility horizon and the capability of different power plants will be discussed in detail below. It should be noted that the extent to which different technologies can take part in this, or are encouraged to, will depend greatly on the prevailing institutional arrangements.

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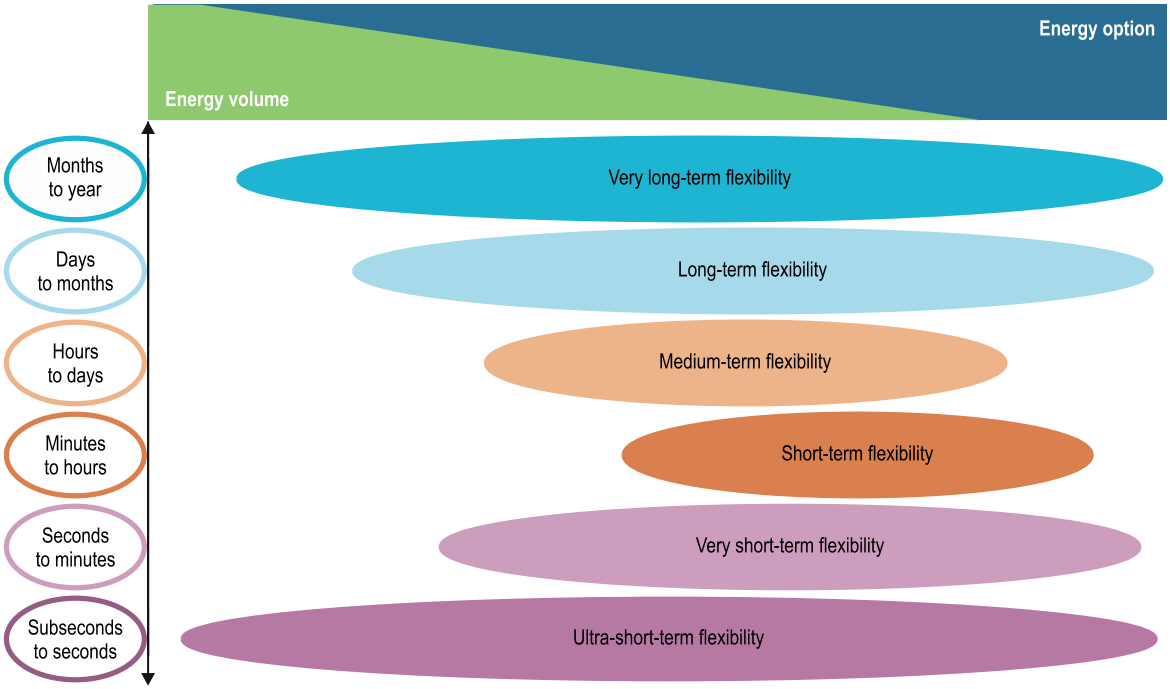
Figure 3.3 • Relationship of power plant type to typical flexibility contribution



Key message • Power plants can provide all forms of flexibility to the system.

Ultra-short-term flexibility from power plants

Ultra-short-term flexibility refers to timescales of subseconds to seconds. These timescales are relevant for the stability of the power system and include responses such as inertia, which are faster than the speed of governor response.[11]

Power generation technologies based on synchronous generators automatically contribute to ultra-short-term flexibility, as long as they are synchronised to the grid. Essentially, all larger (several MW) thermal plants and most hydropower plants use synchronous generators. One important aspect of this contribution is inertia. Other important aspects relate to the provision of short-circuit current, a highly technical issue beyond the scope of this report.

A VRE plant, which is an inverter-based power generation technology, does not contribute to ultra-short-term flexibility *by default*. However, widely available technical options exist which can allow wind turbines to provide inertia-based fast frequency response (GE, 2017). Solar PV plants require battery storage to provide similar functionalities.

An important constraint of the vast majority of existing generators is that they can only provide this ultra-short-term flexibility if they are also feeding electricity into the grid. It is possible to decouple these two features by disconnecting the synchronous generator from the turbine(s) of the power plant. This can either be done permanently in decommissioned power plants or dynamically via a clutch. For example, in the small isolated power system of Tasmania, there are several gas turbine generators (CCGT, OCGT and reciprocating) and hydro turbines that can be operated as synchronous condensers – meaning that they produce inertia without injecting energy into the system (Hydro Tasmania, 2016).

[11] Governor response relates to the fastest automatic control response in thermal power plants.

Ultra-short-term flexibility has historically been a welcome by-product of electricity generation. For power systems in transition, it is likely to become more valuable. As it becomes an increasingly scarce good in some settings, market arrangements need to be adjusted to value this service and provide it according to the system's needs. For example, in 2015 in the United Kingdom the system operator, National Grid, introduced a frequency response product to provide ultra-short-term flexibility called Enhanced Frequency Response (EFR). At the time of writing National Grid is also defining a new product for dynamic frequency-sensitive demand response to provide for both frequency containment and balancing with fast response times (IEA, 2017a; National Grid, 2016; National Grid, 2018).

Very short-term flexibility from power plants

Very short-term flexibility covers the timescales of seconds to minutes and often refers to frequency control needs that are so short term in nature that only power plants already operating can provide them. Part of these services (especially frequency response, see Box 3.2) has been historically provided by baseload power plants. These are often designed to allow rapid fluctuations in output within a narrow band around their nameplate capacity. These reserves are also known as regulation reserves in many systems. Another relevant type of very short-term flexibility often comes in the form of frequency restoration reserves, an essential service required to bring system frequency back to desired levels over the course of a few minutes following a grid disturbance. Power plants can provide these by operating at an intermediate level of output, leaving enough margin to increase or decrease output more substantially and at short notice. An automatic generation control (AGC) system is typically used to automatically control power plants for frequency regulation for the minutes timescale.

Box 3.1 • Retrofit for a legacy lignite coal plant: Unlocking flexibility

RWE's Neurath power plant in Grevenbroich, Germany, was designed as a baseload lignite-fuelled plant, with five units totalling a gross capacity of 2.2 gigawatts commissioned between 1972 and 1975. Retrofits to its 4th and 5th units were completed in August 2012 by Siemens to fulfil the requirement for increased flexibility coming from higher shares of VRE in Germany and Europe more widely. The retrofit aimed to increase their (very) short-term flexibility characteristics (primary and secondary frequency control). This was implemented via advanced monitoring and control techniques (so-called advanced state-space unit control) and other technical interventions (condensate throttling, partial deactivation of heat pump preheaters and optimisation of the feedwater, aid and fuel controls). The plant's technical capabilities have been significantly improved after the retrofit (Table 3.1).

Table 3.1 • Performance parameters per unit

Parameters		Performance before intervention	Performance after intervention
Minimum stable load	MW	440	270
Maximum ramp-up	MW/min	5	15
Maximum ramp-down	MW/min	5	15
Primary frequency control (within 30 s)	MW	18	45
Secondary frequency control (within 5 min)	MW	0	100

Notes: min = minute; s = second.
Source: Case study information provided by Siemens, March 2018; Siemens (ND), "Continued operation even during low load demand: Minimum load at Neurath Power Plant reduced to approx. 40 %".

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Power plants originally designed to provide baseload have been successfully retrofitted to improve this capability. Similar to ultra-short-term flexibility, the provision of this flexibility service can face trade-offs with other types of flexibility. For example, providing very short-term downward flexibility from a power plant is only possible if it is generating above its minimum stable output level. Hence, very short-term flexibility can induce a must-run requirement for power plants. In turn, this will reduce the ability to provide short-term flexibility, the next category (discussed below). This means that other technology options for the provision of very short-term flexibility sources may become more relevant. These can include demand-side or battery electricity storage options or sourcing downward reserve from wind and solar PV plants.

Short-term flexibility from power plants

Short-term flexibility covers periods from several minutes to hours. System operators face two related short-term optimisation decisions: economic dispatch (ED) and unit commitment (UC).

- ED is deciding the individual power output of the scheduled generating units at each point in time, the timeframe varying between systems, but usually being hourly or half-hourly periods on the long end of the spectrum and 5 minutes in more advanced systems.
- UC involves deciding which generating units at each power station to start up and shut down, and when. It usually relates to a time period of several hours or longer, dictated by the time required to start and stop power plants and the operational procedures of the power system.

Operators manage ED and UC to optimise the short-term operation of power generation. AGC is also still relevant for the dispatch of power plant in the minutes timescale.

Box 3.2 • Operating reserves for flexibility in all three short-term timescales

Operating reserves are the amount of capacity that system operators call upon to meet supply-demand mismatches within a short timeframe. These can be identified through deviations from the power system's nominal frequency. Terminology varies across countries and power systems, but different categories and response times can be identified.

Inertial response

This refers to an initial response whereby generators with rotating masses compensate for immediate mismatches between supply and demand. This response comes from the stored energy in the rotating mass of the synchronous generator. The objective of this response is to limit the speed at which frequency changes, in order for the other reserves to have time to react (fully).

Frequency containment reserves

Frequency containment reserves are provided by governor control of synchronous generators and by frequency responsive loads. This response is automatic from each resource and does not require central operator action. The objective of these reserves is to contain system frequency within a defined range following an imbalance in supply and demand.

Frequency restoration reserves

Frequency restoration reserves are automatic, usually provided by by resources under AGC. The response is slower than primary response, but still may occur within seconds to minutes. The objective of these reserves is to restore frequency to its target level and free up frequency containment reserves.

Replacement reserves

Replacement reserves, usually activated manually, are required to free up faster-acting reserves. They have longer activation times and its duration ranges from minutes to hours.

Flexibility requirements on this timescale tend to increase with rising shares of VRE, but this flexibility is required even in the absence of VRE. Hence, all power systems will to some extent already have a certain degree of short-term flexibility available. **Crucially, the available flexibility can be enhanced by moving both ED and UC decisions closer to real time and allowing frequent revisions to previous operating schedules.**

A wide range of power plant technology options are available for providing short-term flexibility. These include VRE, reservoir hydropower plants, coal plants and CCGTs or banks of reciprocating gas engines.

For short-term flexibility, plants are likely to be required to follow steeper and less certain ramps. Enabling the provision of short-term flexibility from existing power plants requires retrofits in order to limit the negative impact of operational changes on plant lifetime.

Co-generation can be a highly restrictive constraint on short-term flexibility: if power production is determined by heat requirements, power plants may be designated as must-run. Decoupling heat and electricity provision via the introduction of heat storage or electric boilers can be used to overcome this. In some cases, for example the supply of district heating, the heat capacity of the network and connected buildings may be sufficient to ensure some heat and electricity decoupling.

Medium-term flexibility in power plants

As outlined in Chapter 2, this timescale spans hours to days. UC is a typical method for scheduling power plants based on hours to a few days ahead, depending on the markets. The provision of medium-term flexibility requires plants to start and stop operations, in some cases daily or multiple times per day, depending on the plant category as previously described. The ED of power plants is still applicable in the hour timescale in some markets, but **maximising medium-term flexibility critically depends on the ability to turn power plants on and off as and when needed**. This may include changing the decision to start a plant before the start is executed. For example, a day-ahead unit commitment may foresee many conventional power plants operating. But if wind and/or solar availability increases on the following day, it can help minimise system costs to not turn on a plant, i.e. change the UC.

Power plants can have substantial start-up times of several hours. Retrofits are available to reduce the time needed to start a plant and bring it up to full capacity. New designs include options to allow a very rapid start of part of the plant, and thereafter a gradual ramp-up of the remainder of the plant to full capacity. These options, combined with appropriate policy, regulatory and market frameworks, are crucial to unlock medium-term flexibility.

Long-term flexibility in power plants

The timescale covered by long-term flexibility is from days to months, which typically involves UC and system planning on a weekly and monthly basis to determine available capacity and a generation schedule that accommodates anticipated VRE generation and demand in the most reliable and cost-effective manner.

In many parts of the world, weather conditions change over a period of several days. This affects both the supply of and demand for electricity. On the supply side in systems with considerable penetration of VRE, higher or lower availability of wind and sunlight can bring abundance or scarcity of generation, respectively. Forecasting VRE is applicable in this timescale, although accuracy is much lower than in the short-term timescale. On the demand side, a period of exceptionally high or low temperatures can lead to peaks in power demand for cooling or heating, respectively.

Dealing with such conditions requires the ability for plants to achieve and sustain higher than normal outputs for several days, potentially followed by periods of low generation. Traditionally, this type of flexibility was typically provided by mid-merit generation, such as CCGT and certain coal plants.

Absolute peak demand of power systems is usually driven by weather events – cold or hot spells. On the supply side, the longest shortfall of wind and solar PV output also tends to be associated with specific weather conditions. These may be correlated with peak demand weather conditions. If this is the case, it is possible that the system's peak load will occur at a time with reduced availability of wind and solar resources. Providing flexibility for these particular circumstances will require the presence of generation capacity that is only needed infrequently.

In this timescale, flexibility in the fuel supply chain can also be critical for the performance of power plants. For example, the natural gas grid may experience stark differences in gas consumption only a few days apart as a result of changes in weather systems. In addition, the natural gas grid or basins could be unavailable due to maintenance or forced outages.

In this flexibility timescale, reservoir hydropower plants are very well placed to adjust their output in response to periods of high or low VRE generation. Already today, hydro plant operators in many countries forecast VRE generation several days ahead and adjust water management strategies accordingly.

In addition, power plant maintenance schedules and unexpected outages are also important factors. Seasonal variation also needs to be taking into account during the system planning and scheduling of power plants, relevant for long-term and very long-term flexibility.

Very long-term flexibility in power plants

Very long-term flexibility covers the timescale from months to several years, which also involves seasonal and yearly variations. Seasonal flexibility has typically been provided by asset management strategies, such as keeping plants available only during certain periods, including by conducting plant maintenance during low demand seasons. Power demand can show strong seasonal patterns, especially where heating and cooling loads are substantial. On the supply side, water availability is a major driver of seasonal availability in hydro-dominated systems. Biomass generation based on some agricultural residue fuels can also show seasonality linked to harvesting periods; this is evident in Brazil, for example, with co-generation from sugar cane bagasse. On the wind and solar side, seasonal patterns are common. These can be the result of latitude (solar and, to a more limited degree, wind) or climate patterns.

Options for improving power plant flexibility

Enabling flexibility through improved operation and management

While the previous section has shed light on the technical potential related to each type of flexibility requirement, it is important to acknowledge that the successful deployment of flexibility depends greatly on operational practices and management culture. Instigating changes might entail a comparatively long implementation period but should also have lower costs. Potential areas for enabling flexibility include improving operations through better monitoring and engaging the industry's human capital (21CPP, 2013).

Monitoring and operation

Data and monitoring

In order to have up-to-date perspectives on the current operational status of the fleet, the specification of each unit and easily achievable options for increasing flexibility, it is useful to have detailed plant-level technical and operational data over an extended period of time. A feature of the Danish system that enabled power plant operators to respond to increasing flexibility needs caused by VRE was their tradition of collecting reliable operational data, at high resolution. The case of Denmark is quite particular, as most of its generation fleet has historically been coupled with co-generation heat provision and has required operational flexibility over a long period in order to meet both heat and power demand. Overall, the availability of data and the relatively consistent evaluation of those data enable the development of optimisation software for power plants across an operator's portfolio.

This is particularly important in plants with steam systems. Monitoring procedures to control temperature ramp rates as feedwater enters the boiler and steam is generated help minimise thermal fatigue caused by temperature gradients in thick-walled components. Such measures are relevant for coal-fired, biomass-fired, nuclear and CCGT plants.

For wind and solar plants, the ability to measure current output conditions, as well as controlling output remotely, leads to better management of the plants' contribution to the system. In the case of wind power plants, pilots for real-time output measurement can be used to study their potential contribution to system flexibility needs.

Altogether, systematic data collection is instrumental in improving forecasting techniques for all types of generation as well as developing optimisation software for power plant portfolios. The resulting findings can be used to inform regulators and policy makers on the actual need for different flexibility types.

Mobilising the data

High-energy piping inspections

High-energy piping systems in thermal power plants operate at elevated temperatures and pressures and are critical for plant and personnel safety. Inspection programmes to identify potential failures – for both major and smaller components – address how inspections should occur, what failures can be expected, how degradation occurs and how failures can be repaired (21CPP, 2013). Collectively, rigorous inspections help ensure that the plant operators systematically check for and identify potential failures and can quickly make necessary repairs.

Power plant operational optimisation

Operational optimisation can be done through remote control of VRE plants or through the continuous improvement of ramping and output management procedures in large plants shifting from energy to capacity contributions. Locally available data can provide plant operators with a better idea of the state and capabilities of the equipment they operate. This wealth of information can also enable portfolio managers to co-ordinate the provision of flexibility across different asset types.

Other changes to procedures

Procedures for boiler cooling and plant layup that employ established best practices for the plant will minimise corrosion and fatigue failures (21CPP, 2013). Controlling temperature changes and

water chemistry can reduce corrosion and protect surfaces that oxidise. Programmes that monitor each pressure component can establish procedures for identifying potential degradation and failure. Monitoring temperature changes at the turbines can minimise thermal fatigue and friction dust.

Box 3.3 • Advanced monitoring for turbine replacement optimisation

At Tokyo Electric Power Company's Futtsu power plant, General Electric (GE) carried out a flange-to-flange upgrade. This method entails the full replacement of an existing gas turbine within the footprint of the existing unit, with minimum disruption to the plant's auxiliary systems such as transformers, inverters and supporting structures. Options such as this can be up to 75% cheaper than a new build and can reduce time from 12-20 months down to 2 months, particularly when scheduled during planned maintenance outages. The intervention was carried out in order to ensure that the plant was able to meet the increasing ramping and start/stop requirements of the system. Once installed at the Futtsu power plant, the unit underwent validation testing. During this process, more than 1 000 pieces of instrumentation were used to collect data and optimise the machine.

So-called tip-rub deterioration is one of the main limiting factors for plants operating in conditions with faster ramps and quick start-ups. This refers to the clearances between rotating and stationary parts. Data collection has played a very important role in understanding the clearances in newer turbine models. Here engines are instrumented with clearance probes to validate design and predict clearances with regard to the thermal transient response of the turbine. Data collection is also used to analyse material deterioration. The use of advanced monitoring is particularly important to help remove fleet variability in clearances, such that the whole portfolio can be operated reliably in flexible conditions.

Source: Case study information provided by GE Power, March 2018; additional information available in GE (2018), Powering the Future with Gas Power Systems – Product Catalog, www.gepower.com/content/dam/gepower-pgdp/global/en_US/documents/product/2018-gps-product-catalog.pdf.

Engaging human capital

Addressing workforce inflexibility

Workforce inflexibility has many dimensions that influence the flexibility of a plant's operations. Power generation has historically been a significant employer, particularly in vertically integrated state-owned monopolies. Having a greater personnel base also implies higher fixed costs, which need to be offset by higher operational levels. This may become unsustainable in the long run, forcing power plants out of the market, which could have otherwise been technically capable of providing flexibility services. The transition towards leaner utilities in a liberalised context may ultimately be constrained in pace by the remaining duration of legacy employment arrangements. On the other hand, building up the necessary base of skilled technicians and professionals to operate plants flexibly and manage generation portfolios accordingly requires time.

Continuous training and capacity build up

One of the critical success factors in the successful deployment of power plant flexibility relates to the engagement of all personnel levels in power production. Beyond the deployment of advanced technical solutions, it is necessary to bring together control engineering staff and system planners. While planners understand the bigger picture of what is possible for the power

system, plant operators will be better positioned to know the exact operational flexibility constraints and potentials facing the equipment in their daily workplace. This can enable a constant exchange of information aimed not only at continuous improvement of operational practices, but also the embedding of detailed flexibility considerations into long-term planning. While many plants have long had such type of procedures in place, following them becomes more critical when the plant cycles frequently. "Continuous training programs reinforce the importance of these procedures and ensure that these procedures do not fall dormant" (21CPP, 2013).

Capacity building in a changing power system relates to the notion of being able to adapt to technological and regulatory changes. Plant operators need to know how to adapt dispatch strategies to new safety, environmental or economic regulations. Pursuing constant improvement in the workforce skill level can lead to leaner, more efficient operating regimes.

Within the framework of its comprehensive energy reform, Mexico has also launched a number of initiatives to build up a qualified personnel base at all levels. This includes two funds for postgraduate scholarships in energy sustainability and hydrocarbon technologies, a competence certification programme for PV installation and commercialisation, and a special programme for women in energy.

Flexibility potential by technology

With an updated framework of power plant types and how they fit the different system needs for flexibility, it is possible to go down into the detail, technology by technology. This will provide a clearer picture of both the challenges for existing plants facing new roles in the power system and the opportunities for new plant designs in each technology group. The terms energy volume contribution and energy option contribution, as used in the following discussion, refer to the power plant roles presented above. Technical details of each technology presented below are provided in the technical annexes.[12]

Coal-fired power plants

Most coal-fired power plants are based on pulverised coal (PC) technology. They produce electricity through steam turbines running with high-pressure and high-temperature steam. These can be subcritical, supercritical and ultra-supercritical depending on the steam conditions and represent the highest share of installed capacity globally (Gonzalez-Salazar et al., 2018). A few, advanced plants rely on integrated gasification combined-cycle (IGCC) technology. These plants use a combination of gas- and steam-driven turbines to generate electricity. As the largest source of electricity today, increasing the flexibility of PC coal plants to facilitate the integration of renewables will be of particular importance in many systems.

PC plants are the main technology for electricity production from coal and have historically been designed as plants leaning more towards a higher energy volume contribution. However, designs vary and plants can be optimised to run around the clock while others are specifically designed to provide short- and medium-term (ramping) flexibility. IGCC plants operate similarly, with the difference of increased fuel efficiency due to the combined-cycle process, and require a high number of operating hours to be economic.

For existing PC plants, flexible operation can be enabled through retrofits, depending on original plant design, to increase the boiler efficiency as well as water and steam pressure in both the

[12] The technical annexes are available on line at https://webstore.iea.org/status-of-power-system-transformation-2018-technical-annexes. It is not included in the print version.

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boiler and steam turbine. Boiler retrofits can improve ramp rates by up to 33%, reduce the minimum stable level by between 33% and 50% and improve start-up/shutdown times by between 33% and 100% depending on the measure taken (21CPP, 2013).

Flexibility considerations are relevant for coal plants in the planning and construction stages and should be incorporated early on in the plant design. Incorporating new specifications into the planning stage can reduce costs and allows for optimising the plant design to meet the required flexibility parameters.

Box 3.4 • Retrofits in an ultra-supercritical coal plant

Nordjylland Unit 3 is an ultra-supercritical coal-fired co-generation unit in Denmark. It was commissioned in 1998, designed for 30 years of operation and was at that time the most efficient coal-fired unit in the world, with a net electric efficiency of 47%. The unit can produce both power in condensing mode and district heating by extraction of steam before the low-pressure turbine. It can produce up to 380 MW of power in condensing mode and 420 megajoules per second (MJ/s) of heat via steam extraction. The district heating system includes a heat accumulator, allowing flexibility in the production of heat and thereby in the production of power.

The unit at the time of commissioning operated primarily in baseload mode, at full load for the entirety of the year. Nevertheless, it was designed to operate with large ramping gradients (~4%/min) and a relatively low minimum load (25%). Also, the plant could operate over its rated capacity by bypassing feed water heaters, but this required complete bypassing of the heaters and installing an additional coal pulveriser. Due to the unit's high efficiency and flexibility, it has almost always been on line. Therefore, the retrofit focused on optimising the start-up.

The substantial increase in VRE over the last two decades in Denmark has forced the unit to operate differently, responding to changing market conditions with large variations in electricity prices and new requests for minimum load, maximum load, ramping and automatic regulation.

The retrofit intervention was designed to improve the operational flexibility of the plant; the initiative had several key components. First, all the plant's coal pulverisers were refurbished in order to uprate their output. For this, certain internal parts for the pulverisers as well as the rotating classifier were redesigned. Second, plant operations were optimised to continuously ramp from normal load to overload with only three pulverisers (as opposed to the previously required four), ramping at an increased rate between 40% boiler load and 110% boiler load while eliminating the need to put an additional pulveriser into operation during ramping (Figure 3.4).

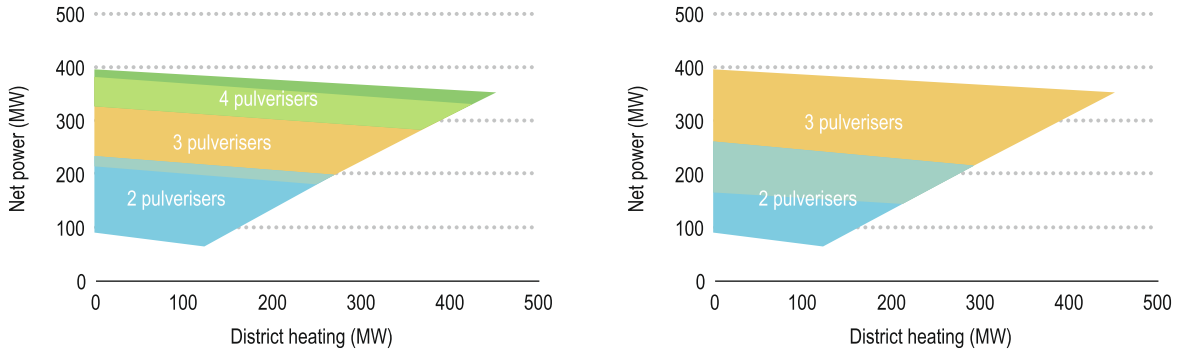
The retrofit also entailed the installation of an improved valve for bypassing the feed water preheater. Finally, several software updates to the plant's master controller were made, to further increase the ramping and the ability of the plant to provide fast regulating capacity. As a result of the software update, the unit could then:

- Provide automated frequency control by stopping the intermediate condensate pumps. This results in a lower steam extraction for the condensate preheaters, thus increasing electricity production briefly. The opposite is also possible for decreasing load.
- Utilise a fully automated use of the district heating accumulator to either increase or decrease heating load.

The interventions have been performed in an ongoing plant optimisation process to maximise plant revenues from the power market, and have not required major investment.

Source: Case study information provided by COWI, March 2018.

Figure 3.4 • Plant operations before (left) and after (right) the refurbishment of the pulverisers



Note: The load ranges are indicative.

Source: Case study information provided by COWI, March 2018.

Key point • After the refurbishment, the plant was able to operate between 40% boiler load and 110% boiler load with three pulverisers in continuous operation; this eliminated the need to put an additional pulveriser into operation during ramping.

Box 3.5 • MoorFlex: Flexible coal and co-generation in Hamburg

Moorburg Power Plant in Hamburg was built as a co-generation power plant with two 827 MW electricity generation units. It was built to supply heat to the city's district heating system as well as supplying steam to industrial facilities. Due to increasing VRE feed-in, the plant was unable to obtain sufficient returns from baseload operation, which caused it to introduce new strategies for increased flexibility in operations.

The MoorFlex project (Applying Flexibility to Moorburg) took three key measures to increase the plant's flexibility. First, the minimum stable load was reduced from 35% to 26% to reduce the number of start-up and shut-downs. Second, control systems and operation modes were optimised to increase the ramp rate between partial and full load. Third, the plant was retrofitted with flue gas dampers to regulate the cooling of the plant after a shutdown, which can reduce start-up time at a later stage. The project involved the modification of the steam generators provided by Mitsubishi Hitachi Power Systems.

The main outcomes from the optimisation were:

- Decrease in minimum stable output: This was reduced from 40% to 20% of maximum load. This was aimed at reducing financial losses as well as the number of plant start-ups and shutdowns.
- Increase in ramping rate: The plant is now able to change output at 48 megawatts per minute (MW/min) and up to 90 MW/min in special load ranges, with both units in operation.
- Quicker start-up times: The installation of valves in the air and flue gas pipes allows for heat to be maintained during long shutdown periods. Warm-cold start times are now 20% faster, warm starts between 42% and 50% faster, and hot starts between 40% and 46% faster.

Source: Case study provided by MHPS, March 2018. Further information available in MHPS (2014), Power Performance: At Home in Energy Plant Engineering. www.eu.mhps.com/media/files/broschueren/technologie/GB_Prsp_PowerfulPerformance_05-2014_SCREEN.pdf and Vattenfall (2016), *Kraftwerk Moorburg – flexible Antwort auf die Energiewende* [German]. https://blog.vattenfall.de/kraftwerk-moorburg-flexible-antwort-auf-die-energiewende/.

With respect to CO_2 capture and storage (CCS), the global portfolio of these projects is expanding and the technology has the potential to play a vital role in reducing emissions across the global

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energy system (IEA, 2017b). CCS enables the decarbonisation of fossil fuel-based power plants or negative net emissions with biomass power plants. Most information on this topic stems from experiments with pilot plants, global R&D programmes and literature (Box 3.6).

Box 3.6 • Impact of carbon capture and storage on thermal power plant flexibility

Carbon capture and storage (CCS) is a technology that enables the decarbonisation of coal- and gas-fired power plants and allows for CO_2 removal from the atmosphere when coupled with biomass-fired power plants. Retrofitting thermal power plants with one of the three main carbon capture routes – post-, pre- and oxyfuel combustion – appears to have a small to negligible impact on the operational flexibility of thermal power plants, provided that the capture systems are designed properly. In fact, post- and precombustion capture applications could potentially increase the ramp rate and lower the minimum stable operating load if the capture system and power block are operated independently. Oxyfuel combustion applications, however, may impose additional constraints on the power plant's flexibility, due to the inertia of the oxygen production plant required for the capture process.

Today, there are two large-scale, integrated power-CCS projects in operation around the world, although these are operating as baseload capacity. As a result, there is limited experience with flexible operation of large scale systems. Both CCUS projects are related to post-combustion capture technology applied to coal-fired power plants: the Boundary Dam project in Saskatchewan, Canada, and the Petra Nova Carbon Capture project in Texas, U.S., with annual capture capacities of 1.0 $MtCO_2$ and 1.4 $MtCO_2$, respectively.

There are several techniques to enhance flexibility. Oxyfuel power plants could temporarily switch back to conventional air-firing mode, while power plants equipped with post- or precombustion systems could (partly) bypass the capture units. These options can help to temporarily boost power output as less or no energy is required for the capture process, although CO_2 would be vented to the atmosphere. Other flexibility options involve storage of oxygen (oxyfuel combustion), hydrogen (precombustion) or solvents (post-combustion), which enable the carbon capture process to continue during transient operation. While storage may entail slightly higher capital and operational costs, enhanced flexibility capabilities can also increase electricity sale revenues by boosting power output when electricity prices are high (arbitrage). More technical information on CCS flexibility can be found in the technical annexes.[13]

Source: Brouwer et al. (2013), "The flexibility requirements for power plants with CCS in a future energy system with large share of intermittent renewable energy sources", *Energy Procedia*, Vol. 37, pp. 2657-64.

Gas-fired power plants

A wide range of natural-gas electricity generation technologies are available, designed for diverse power system needs. OCGT, CCGT and reciprocating engine plants are the main types of gas power plant in operation today.

In an OCGT plant, combustion air is compressed and natural gas is injected and burned to heat up the air. The compressed air then expands in the turbine and drives a generator to produce

[13] The technical annexes are available on line at https://webstore.iea.org/status-of-power-system-transformation-2018-technical-annexes. It is not included in the print version.

electric power. OCGT plants have been used for peaking applications for many years because they can be started quickly and ramped up and down rapidly.

CCGT plants combine two processes in a series whereby the exhaust heat from a gas turbine is fed into a steam cycle. The latter, also referred to as a bottoming cycle, produces additional power without requiring additional fuel input, thus increasing the plant's efficiency. CCGT plants are less flexible than OCGT turbines due to constraints related to the steam cycle. While conventional single-unit CCGT are designed to operate around the clock and have a minimum stable output typically of 50% (Siemens, 2010), advanced CCGT plants have to be more flexible to meet the increasing demand for very short-term and short-term flexibility, particularly ramping and minimum stable output.

The priority for increasing gas-fired power plant flexibility lies in particular with CCGT plants. New large CCGT offerings from major manufacturers reflect this, and show a shift away from prioritising greater full-load efficiency towards flexible operation at the maximum possible efficiency. In these flexible designs, efficiency penalties during part-load are modest while capital costs remain roughly identical. Combined-cycle power plants have different avenues for improvement in operational flexibility. These include changes to the design of the heat recovery steam generator (HRSG), steam turbine and the balance of plant. Newer combined-cycle plants can also be operated flexibly, either through a gas bypass – from the gas turbine exhaust to the stack – or through a steam bypass –from the HRSG to the condenser. This makes it possible for a CCGT to run in OCGT mode during fast start-up transients.

Box 3.7 • The Hot Start on the Fly (HoF) procedure

The increasing market share of renewable energy and relatively higher fuel prices in Europe have changed the operational profile of CCGT power plants. Faced with fewer operating hours than expected in their original business plans, some CCGTs now need to cope with the new operational scenarios. The Mainz Wiesbaden CCGT plant was originally built in 2000 for baseload operation; it has been successfully retrofitted to operate in a more flexible cycling mode.

The plant is equipped with a gas turbine in a multi-shaft configuration. This feeds three pressure stage drum boilers, which supply steam to a steam turbine with steam extraction to supply district heating and process steam. The owner, Kraftwerke Mainz Wiesbaden AG (KMW AG), upgraded the plant multiple times. In August 2014 the plant was upgraded with the Hot Start on the Fly (HoF) procedure. The HoF procedure utilises an improved start-up concept, which allows the parallel start-up of both gas turbine and steam turbine in hot start conditions (Figure 3.5).

The HoF process has proven to be an extremely fast and efficient start-up method with only moderate reduction in plant lifetime. Since its implementation, the HoF procedure has been in frequent use for hot starts on weekdays, demonstrating consistent availability and reliability with great accuracy in start-up times. The successful implementation of the HoF procedure has reduced the start-up time from approximately 67 to 27 minutes.

KMW AG and Siemens performed additional tests during the commissioning of the HoF procedure. Concepts for an even more advanced HoF procedure (HoF+) and the highly integrated shutdown of gas and steam turbine were tested successfully. It was found that an evacuated high-pressure turbine at the beginning of the steam turbine start-up process provided the potential for a further reduction in hot start-up time of approximately 4 minutes. The shutdown time was shortened by approximately 6 minutes, bringing plant shutdown from base to no load in just 20 minutes.

Source: Case study information provided by Siemens, March 2018, further information available from Siemens (2011), Fast cycling and rapid start-up: new generation of plants achieves impressive results, www.energy.siemens.com/hq/pool/hq/energy-topics/technical-papers/Fast%20cycling%20and%20rapid%20start-up.pdf.

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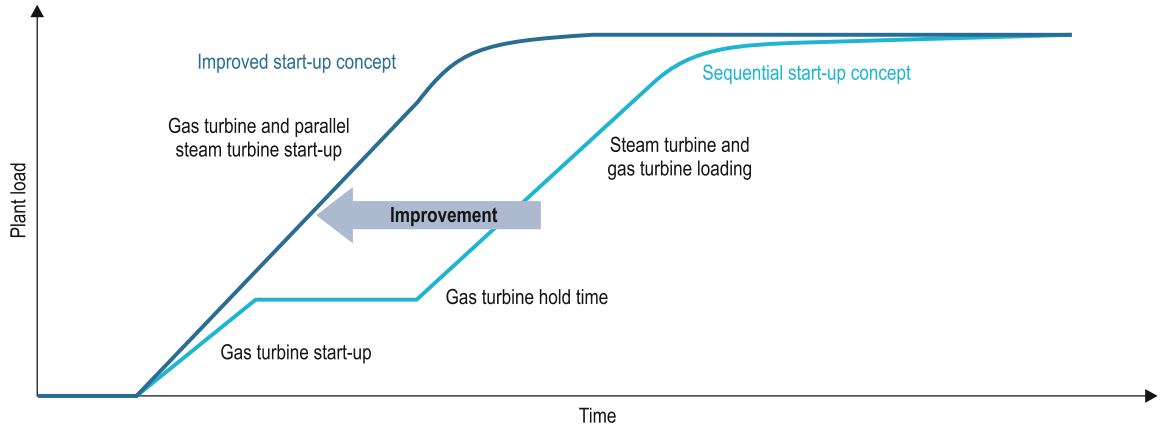
Figure 3.5 • The HoF start-up concept



Source: Case study information provided by Siemens, March 2018;

Key point • Hot Start on the Fly procedure reduces start-up time of CCGT for hot start condition.

Box 3.8 • Flexible operation of CCGT through refurbishment and optimisation in Italy

La Casella power plant was originally built in the 1970s as an oil-fired power plant for baseload operation, with four 320 MW units. It is located 50 kilometres south of Milan. From 2000 to 2003 the plant was progressively converted into a CCGT plant with four 370 MW units, becoming the largest CCGT power plant in Italy (1 480 MW). For this, HRSGs were installed in the steel structures of the old boilers, allowing for a very compact design since the existing steam turbines were reutilised and modified in the high-pressure section.

The main drivers for this "brownfield" flexibilisation programme at the beginning of the 2000s were low capital expenditure and short time to market. Satisfying these criteria required the reutilisation of both the main equipment (steam turbines and generators) and the auxiliary systems of the power plant (auxiliary boilers, water treatment, etc.). These were not fully automated and had not been designed for the original power plant.

The request for flexibility with frequent warm/cold start-ups was the driver for the first "flexibilisation" programme. In addition, updated environmental legislation required the optimisation of emissions at operation close to the minimum stable level.

The first flexibilisation programme consisted of three main streams:

- Exploration of the plant's real limits and constraints.
- Modernisation of the main equipment (steam turbine controls, gas turbine upgrades), partial process automation and the redesign of specific systems such as drains, vents, pumps and steam lines.
- Update of operational procedures.

The outcome of these actions was the substantial reduction of start-up time (about 20% cold and about 50% warm), improvement of the operational range by reducing the minimum stable load from 230 MW to 170 MW and the increase in ramp rate for both the gas turbine (improved to more than 80%) and the complete CCGT unit.

Since 2008, the increase in competition, decrease in demand and increasing shares of VRE led to reconsideration of the plant's role. A second flexibilisation programme was launched in 2014 in response to these new market requests, in particular deprovision of reserves.

This programme focused on minimum load and ramp rate optimisation and included the following measures:

- Optimisation of combustion behaviour at low loads, which relied on the combined expertise of ENEL and the original equipment manufacturer. Air and gas flows were optimised to ensure flame stability at part load and during ramps. This also allowed for compliance with environmental regulations.
- Study of the actual limits of some components of the plant when subject to significant stress increase, in particular the HRSG's behaviour. The drain and vent system, which had already been redesigned during the first flexibilisation programme, was subject to a new design validation given the new operating conditions.
- Measurement and redesign of the turbines to understand increased stress to rotors during faster start-ups.
- The experiences learnt from La Casella plant have been implemented across ENEL's generation portfolio.

Source: Case study provided by ENEL, March 2018.

Co-generation

Co-generation refers to making use of excess heat from power stations or industrial processes which would otherwise be lost through cooling. Heat output can be delivered to adjacent industrial processes or, as is most common in power generation, to district heating networks. Co-generation can be fired by coal, gas or biomass.

The local heat requirements for (gas) co-generation plants restrict the amount of flexibility the plant can provide. Heat requirements are set by the attached industrial processes or district heating networks. Moreover, the ability to operate flexibly will depend on whether it is a backpressure plant with fixed power-heat ratios or an extraction unit with variable power-heat ratios. Decoupling heat and power outputs can help improve flexibility. Key measures for this include heat storage and electric boilers. Reconfiguring the plant to allow for partial bypassing can also improve the degree of flexibility in the power-heat ratio.

Box 3.9 • Reciprocating gas engines for combined heat and power provision

In 2015 Stadtwerke Kiel set out to replace a 50-year-old hard coal-fired co-generation plant in Kiel Germany. The original plant, with 323 MW of electrical output, was also able to provide 295 MJ/s of thermal energy to Kiel's district heating network. The new installation comprised the provision of 190 MW of gas-fired co-generation and was split into two phases.

A 30 000 cubic metre hot water storage facility, with 1 500 MWh capacity, a 35 MW electrode and a pump house to be connected to Kiel's district network were built during the first phase. During the second phase twenty 9.5 MW Jenbacher gas engines were installed.

The main requirement of the new plant is to provide a secure power supply option in a system with high VRE share. Deploying gas-fired plants in co-generation mode allows for high fuel utilisation and flexible operation to balance out VRE intermittency. The number of engines operating at any one time will depend on demand, so the individual units will always run at full load, and therefore with high efficiency. The multiple unit concept allows the new coastal power plant to run at maximum 45% electrical and 91% total efficiency even if the plant is providing just 5% of the nominal 190 MW output. The plant also offers the flexibility to provide electric power without heat in peaking periods (Table 3.2).

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Table 3.2 • The K.I.E.L. power plant replacement project

Parameters		Performance at intervention	Performance after intervention
Electrical output	MW	323	190
Heat output	MW	295	192
Fuel utilisation rate	%	>50	91
Minimum stable load	MW	na	4
Maximum ramp-up	MW/min	na	~40
Maximum ramp-down	MW/min	na	~120
Start-up time	Hot, in min	na	<5
	Warm, in min	na	8
Electrical efficiency at minimum stable load	%	na	45
Electrical efficiency at full- and part-load operation	40%	na	45
	100%	~40	45
Lifetime	years	~50	>25
Minimum down time	min	na	~5

Note: na = not applicable.
Source: Stadtwerke Kiel (2016), Küstenkraftwerk K.I.E.L. [German], www.stadtwerke-kiel.de/swk/media/pdf/unternehmen_1/unternehmensbroschueren_1/stadtwerke-kiel-unternehmensbroschueren-kuestenkraftwerk-kiel.pdf.

A main driver and enabling factor for co-generation power plant investment in Germany are incentives for emissions reduction through fuel co-generation and fuel switching. With the last revision of the German co-generation law in 2016, a Kiel-type gas-fired co-generation plant of more than 50 MW can receive incentives of EUR 34 for every MWh of electricity produced. If the new co-generation plant is replacing a coal-fired plant, then a bonus of an additional EUR 6 for every MWh of electricity produced will be paid. That total will be paid to the plant operator for the first 30 000 operating hours the plant is running in co-generation operating mode. Today, Germany has an energy-only market, with renewables having priority dispatch. Coal power plants are the main source for balancing out renewable power generation, and therefore the merit order rule is leading to some low electricity prices. That makes it difficult for all gas-fired power plants to run, even for co-generation power plants with additional revenues from heat sales. The higher renewable share and alternative heat supply technologies such as power-to-heat are reducing the annual operating hours of gas-fired power plants, which results in further challenges for them. Therefore, the co-generation incentives are essential for new gas-fired co-generation power plants that run with a 91% fuel utilisation rate.

Because of the switch to gas fuel at Kiel, and the ability to provide high operating flexibility, the new gas engine-powered co-generation facility will reduce Kiel's annual carbon dioxide (CO_2) emissions by about 70%.

Source: Stadtwerke Kiel (2016), Küstenkraftwerk K.I.E.L. [German], www.stadtwerke-kiel.de/swk/media/pdf/unternehmen_1/unternehmensbroschueren_1/stadtwerke-kiel-unternehmensbroschueren-kuestenkraftwerk-kiel.pdf.

Nuclear

Nuclear power has typically been used to cover baseload. Its high capital intensity and low running costs upon achieving its minimum stable level lend themselves to operational modes with dominant load coverage in the system. The extent to which nuclear has been able to provide ramping or short-term flexibility varies according to the specific system. In countries such as France, the prevalence of nuclear energy in the generation fleet led to an early need to incorporate ramping flexibility requirements in plant design to account for variability in demand. At present reactors in France and Germany can offer regulation services up to 5% of nominal capacity while current regulations for new reactor sales require at least 10% of nominal capacity to be offered for regulation (Jenkins et al., 2018).

The shift to a new operational mode with an enhanced provision of capacity services is technically possible but may prove more difficult to implement in old power plants designed for energy provision at stable levels. The provision of ramping flexibility and short-term flexibility is constrained by the timeframe in the fuel cycle, with a significant scope for upwards and downwards flexibility at early stages and close to no potential as the nuclear fuel passes 80% of its cycle. By contrast, reactors with continuous refuelling, such as CANDU designs,[14] are not faced with this restriction as they do not require plant shutdown before refuelling. Moreover, in new builds it might be possible to improve the operating range by making the reactor's structure more resilient to corrosion and wear and tear, and by reducing minimum stable levels. This, however, should be considered in close connection with concerns regarding social acceptance of new projects and security of operations.

Hydropower

Hydropower's role in addressing system flexibility needs varies greatly, a reflection of plant characteristics varying according to location and the additional services provided. Overall, hydropower has great potential for providing flexibility, with rapid ramping potential and very low minimum operating levels. Three main technologies can be distinguished that can provide flexibility: reservoir hydro, pumped storage hydro and run-of-river hydro.

Large hydropower plants with a reservoir often provide an amount of constant generation, while also being able to provide ramping and short-term flexibility. Pumped storage plants can be used for arbitrage and provide ramping flexibility. This, however, depends on the type of pumped storage plant, as variable-speed pumped storage plants can provide a greater degree of flexibility than fixed-speed plants (IEA, 2017c). Run-of-river hydro has very limited storage but excellent ramping capability. Some plants in Norway can go up from 0 to 1 200 MW within 4-5 minutes and from 50 MW to 1 000 MW (and vice versa) within seconds (Eurelectric, 2011). One of the main limitations of hydro may come in serving seasonal flexibility due to potential variations in rainfall within and between years. One additional consideration regarding flexibility from hydropower is the specific system need served by the individual hydropower portfolio. Changing system needs may shift the role of specific hydropower plants, often requiring retrofits, particularly with older plants. Retrofitting plants to shift them from an energy volume contribution role to an energy option contribution operation can enable older plants to provide a greater amount of ramping flexibility.

[14] CANDU stands for Canada Deuterium Uranium.

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Bioenergy

Bioenergy comprises a wide range of different technologies that are able to operate flexibly to different extents. In this paper the primary focus is on solid biomass, biogas from anaerobic digestion and biomethanation. The capital investment required for bioenergy technologies often means they are operated to prioritise energy volume rather than focusing on energy option provision. Bioenergy can mainly provide seasonal flexibility, but in some systems, like in the United Kingdom, they can operate within the balancing mechanism on an hourly basis. Nevertheless, increased variability in power supply has created momentum for developing operational modes that enable lower full-load hours and shorter response times.

Regarding solid biomass plants, the potential for ramping generation up and down is similar to those of a typical coal-fired plant and primarily relate to the operational limits of the boiler turn-down ratio. It should be noted that for biomass co-generation units connected to district heating, heat requirements can become a lower limit on output reduction, particularly in cases where units are operated according to heat demand.

Anaerobic digestion biogas plants, on the other hand, have flexibility potentials similar to those of gas-fired plants. Here, however, the flexibility limits are imposed by the organic processes used in the production of gas and the ability to store gas on site. While it is possible to adapt the rate of gas production, the plant as a whole is constrained to the stable limits of the biodigestion process. While it is technically possible to increase on-site gas storage, this can be limited by economic constraints and relates specifically to the type of flexibility to be provided.

For some categories of biogas, storage is relatively simple and could match short-term flexibility requirements. However, it should be taken into account that there might be no incentive for short-term output reduction in systems with fixed remuneration, such as feed-in tariffs. The provision of long-term flexibility, by contrast, will require larger and more complex storage facilities. This should also be taken into account when designing appropriate regulatory frameworks and remuneration schemes. An alternative option is upgrading biogas, also referred to as biomethanation. This allows for storage in the gas distribution network for later use by local gas-fired power plants, and may be an alternative for the provision of indirect flexibility in specific cases. In this case it should be noted that biogas from biomethanation can also be used in heating and transport such that using it to balance the power system will depend on the financial attractiveness compared to alternative uses. Lastly, the deployment of virtual power plants through aggregators make it possible to aggregate smaller dispersed bioenergy plants.

Box 3.10 • Improved biomass and co-generation flexibility

Fyn Unit 8, located in Odense, Denmark, is a biomass-fired unit designed for firing straw and was commissioned in 2009. The backpressure unit delivers power to the Nordic power market and district heating to the local community. It can produce up to 35 MW of power and 120 MJ/s of heat at 100% output. The plant was commissioned when wind power was already a significant factor in the Danish power system. The production of wind power with a low marginal production cost put great pressure on the spot market price for electricity. The daily fluctuations in wind power have also led to more variable market prices and increased the demand and price for regulating capacity.

In this context, Fyn Unit 8 was designed to operate flexibly, in particular through the inclusion of a full turbine bypass, a flue gas condenser bypass and a heat accumulator tank containing district heating water. The full turbine bypass allows the plant to produce only district heating when electricity prices are low. The turbine bypass can regulate continuously, allowing for a partial or

full bypass. In full bypass mode, the auxiliary consumption of the plant is purchased from the grid, i.e. the plant has a negative net electric output in this case. In situations when it is desirable to increase electricity production as much as possible, the flue gas condenser can be bypassed, which reduces the auxiliary consumption and increases the plant net electric output by approximately 1%. The heat accumulator allows stable heat supply to the district heating network, while operating the unit's heat and power production flexibly. These features in combination allow a power production range from negative to overload with a very high gradient of 8% per minute.

The fuel for the plant is straw delivered by local farmers. Occasionally, weather conditions have led to the straw being too wet or a supply shortage, leading to the plant being unable to operate for several months until the following harvesting season. The flexibility challenge for this unit has therefore mainly been that of fuel flexibility. Consequently, the plant has been retrofitted with a system to co-fire wood chips with the straw, at a ratio of approximately a 50:50. The retrofit has ensured that the unit can operate even in years with limited availability of straw. The economics of the biomass plant are supported by a tax exemption on biomass-based heat production.

Source: Case study information provided by COWI, March 2018.

Wind

Wind power plants rely on variable wind resources to produce electricity. They are generally operated at the maximum possible output in power systems with priority least-cost and priority dispatch for VRE, due to their zero fuel costs and low operating costs. Given that their capacity cannot be called upon on request, they have typically operated as plants with a dominant energy contribution to the system though it should be noted that their technical ability to deliver an energy option contribution is increasingly being enabled through new regulations and revenue streams in systems such as Ireland, Spain and Texas. Wind power plants have the potential to provide short-term, very short-term and ultra-short-term flexibility. At very high shares of VRE, this can be more cost-effective than procuring flexibility from plants with higher operating costs.

Wind has typically been limited to providing downward short-term flexibility by curtailing output upon request. Output curtailment is enabled through remote pitch control. This response needs to be managed within the wind park, as curtailing wind from one turbine causes downstream wind speed behind the turbine to increase, which may increase output in turbines behind it. Wind turbines are also able to increase output as long as they are operating at less than full load. Moreover, it is possible to momentarily increase output beyond full load if the wind turbines are enabled to provide synthetic inertia. An important highlight concerning flexibility from wind is the technology's very quick response times, allowing it to ramp faster than most thermal generation.

Only a few jurisdictions allow flexibility services from wind turbines; it requires appropriate training for operators, as well as the introduction of economic incentives and/or regulatory requirements. This can be through participation in balancing services, which should be adequately remunerated via market-based mechanisms and allow for separate bidding of upward and downward reserves. Additional measures to enable the participation of wind include the reduction of minimum reserve bid sizes, shorter lead times and shorter product lengths. The latter refers to the time window during which generators have to guarantee that their capacity is able to deliver the contracted capacity.

On the technical side, participation of wind in flexibility provision can be achieved through the introduction of remote controlling equipment along with improvements in monitoring and

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forecasting. In the United States, measures such as the deployment of AGC and allowing the participation of wind generation in primary regulation have demonstrated the potential for flexibility provision from wind.

Altogether, the feasibility of delivering flexibility from wind, and the mechanism of choice to do so, depend on the specific system conditions. There are a number of technically possible choices, such as continuous derating for upward and downward flexibility, exclusive provision of downward regulation with respect to an output baseline, and wind farm output management by reducing the output of selected turbines. These strategies have varying effects both in terms of the type of system flexibility needs they address, and how they impact wind plant revenues (see technical annexes[15] for further detail).

Solar PV

Solar PV, as for wind, depends on the availability of the resource to generate electricity and is typically dispatched at full load due to low operating costs. Output is limited to daylight hours and is influenced by a range of factors such as time of the year, material accumulation and cloud cover. In this case, output adjustment, both upwards and downwards, relies on advanced power electronics and is enabled by the introduction of the appropriate price signals. Similar to wind, PV systems have historically been operated as pure energy contribution plants, while the short-term provision or reduction of available capacity has become more relevant most recently. Solar PV is increasingly being coupled with electricity storage as an emerging technology solution to help serve peak demand and balance supply and demand.

Advanced power controllers make use of power electronics to regulate the output of PV systems. In Puerto Rico, equipment has been tested that can adjust the PV system's output in real time in relation to the system frequency. The test also assessed the potential for the provision of fast frequency response, droop response and automatic generator controls. While technically possible, the plant's economic incentives result in operation at full load whenever possible, limiting the incentive of the plant to demonstrate upward regulation potential (Gevorgian and O'Neill, 2016). Measures to shift economic incentives for this are discussed further in Chapter 5.

Concentrated solar power

Like PV, concentrated solar power (CSP) depends on the availability of sunlight. However, the ability to store thermal energy gives it a more important role in the provision of ramping flexibility as its capacity and energy contributions to the system are more balanced than PV's. Under sunnier conditions, solar CSP's main limitation comes from the start-up processes related to the heat transfer fluids. In parabolic trough designs this involves bringing the synthetic oils to the appropriate temperature. For CSP designs with a central receiver plant, the start-up time relies on the molten salts' heat requirements. In comparison to PV, CSP may offer greater capacity for load shifting, while also having a longer start-up time. There is a diversity of CSP design configurations that can provide a range of flexibility services, but the potential varies according to the maturity of different technologies. Parabolic troughs date back to the 1980s and their performance improvement potentials have been documented extensively. By contrast, central receiver plants have become commercially available relatively recently and it is expected that they will offer greater scope for flexibility due to lower thermal inertia as they become more mature.

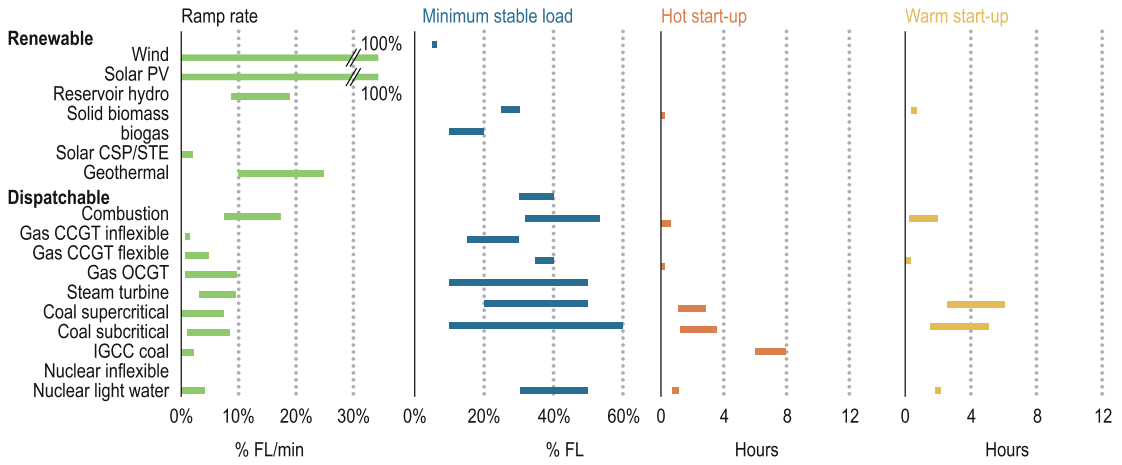
[15] The technical annexes are available on line at https://webstore.iea.org/status-of-power-system-transformation-2018-technical-annexes. It is not included in the print version.

Summary of flexibility parameters

In summary, the flexibility of power plants of every technology can be categoreised and assessed according to the timescale from real-time power system operation to long-term planning. For the three short-term timescales that have been described, the important dimensions of power plant flexibility depend largely on ramp rate, minimum stable load and start-up time (Figure 3.6). This is because provision of flexibility at these time scales require power plants to be operational (or to become operational quickly) and have sufficient capability to modify output.[16]

The range of these technical parameters varies not only between different technologies, but also for the same technology. This is due to a number of factors that are related to the hardware, policy and regulatory as well as institutional aspects as described in Chapter 2.

Figure 3.6 • Assessment of flexible generation according to dimensions of flexibility



Note: FL = full load.

Source: IEA (2017b), *Energy Technology Perspectives 2017.*

Key message • Power plants show large differences in their technical flexibility.

Options for enhanced flexibility in conventional power generation

A wealth of options can be implemented to enhance the technical flexibility of thermal generation plants. They are all accordingly highly technical in nature, as they relat to improving the operational characteristics of power plant, including quicker start-up times, reduced minimum stable levels and faster ramp rates. Details of technical considerations and options to improve the operational characteristics of power plants can be found in the technical annexes of this report, both in general and for specific generation technologies.[17]

In summary, two broad classes of interventions can be identified. First are measures that primarily aim to enhance the performance of existing hardware. These measures target operating protocols, as well as monitoring and control equipment. The overall cost impact of these measures is very low, but they can help to substantially increase flexibility. One reason for this is that plants

[16] It is important to note that a technological assessment of ultra-short-term and very short-term flexibility parameters was not conducted as part of this effort. Thus, flexibility parameters for these timescales are not included in Figure 3.6.

[17] The technical annexes are available on line at https://webstore.iea.org/status-of-power-system-transformation-2018-technical-annexes. It is not included in the print version.

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are often operated without clear knowledge of a plant's true capabilities and operators often make a conservative judgement on what is possible. A second group of interventions requires changes to the hardware. Cost implications can vary in a wide range, all the way to a full refurbishment of plants, where enhanced flexibility is one measure considered for an overall lifetime extension of the plant. A set of common guidelines can be identified to enhance power plant flexibility (VGB, 2018):

- **Raise the awareness of flexibility:** While plant operators will certainly notice changes in their plant's operational regime and revenues, they might not be aware of flexibility as a potential avenue for performance and revenue improvement. Raising awareness across different actors in the power sector, such as plant operators, utilities and regulators, is important for framing the discussion. Ministries or system operators can take the first steps in providing this information. In raising awareness, it is necessary to provide background information about the need for flexibility, explain the necessity and impact on the O&M of the plant, and initiate training programmes. Additionally, raising awareness may enable information sharing across power plant operators facing similar challenges.

- **Check the status of the plant:** The ability of a power plant to change its operational regime and the extent to which this will result in more rapid deterioration are highly plant-specific factors. While referring to the experience of retrofits and performance improvements in similar plants might be a useful, it is necessary to look at the current status of the power plant in order to avoid greater integrity risks from flexible operation. Moreover, taking stock of the current state of the plant and its remaining useful life will provide information about the scope for carrying out retrofits. Once this has been done, it is necessary to identify bottlenecks and limitations with respect to flexible operation:
  - Consult with original equipment manufacturers to assess the influences of low load operation and temperature and pressure gradients on main components and equipment. In many cases, they will also be able to provide specialised solutions for specific plant types, thus improving the chances that a targeted retrofit will improve plant performance without the need to undergo substantial equipment replacement.
  - Ensure that all plant controllers are functioning smoothly at all operational levels, including at the original operational mode and current system requirements. This will provide an indication of any underlying control system failures that need to be addressed in upgrading the plant's performance.

- **Plan and execute test runs** to evaluate the plant's flexibility potential. This allows a clear picture of the plant's performance parameters and the exact procedures required in changing the plant's operation with the current equipment.
  - Create transparency about the plant's performance with respect to minimal load, start-up and cycling behaviour in the current setup. Consolidating a clear picture of this information will be helpful at many levels: involving operators in plant improvement, illustrating potential benefits from performance improvements to portfolio managers, and documenting technical performance parameters for regulators.
  - Identifying constraints and improvement potentials should provide the foundations for further investment in retrofits or participation in grid service provision. This information can also be used when applying for rate increases in the case of regulated utilities, or when applying for financial support mechanisms.

- **Optimise the IT system:** Having better data visibility over the current plant performance is one of the most important aspects for improving operations. The actions in this field may range from updating management software to renewing and expanding the system monitoring infrastructure. This is also the most cost-effective way to enhance the flexibility of the plant. Improving data and control capabilities can be of particular use when improving complex processes such as start-ups through automation.
  - Making use of distributed control mechanisms will be essential in co-ordinating the timing, speed and precision of processes throughout the power plant.

- **Implement mitigation measures** to manage the consequences of flexible/cycling operation. It is important to carry out a substantial review of the current processes across the plant. This includes a reassessment of all O&M procedures, with a special focus on water and steam quality, preservation and layup procedures as well as on maintenance strategies. If these processes are not updated along with the plant's operations, they may lead to increased deterioration and reduced plant efficiency. The use of appropriate condition monitoring systems is essential, particularly when handling water and steam systems under variable plant operations.

- **Optimise combustion:** Stable combustion is the key aspect to ensuring minimum load operation. Thermal plants operating at their minimum load will be less efficient but also less reliable. Carefully understanding and tailoring solutions for improving the fuel combustion process is a key step for flexible operations. Considerations in this regard are as follows:
  - Reliable flame detection for each individual burner: This involves understanding flame behaviour in each specific plant and the effect of operation with lower fuel feed-in levels.
  - Transparency on the fuel quality and composition: Ensuring consistent fuel quality is key to maintaining combustion processes. In the case of coal, this can be achieved through blending and washing as well as online coal analysis. For gas, unexpected variations in fuel composition can result in substantial variations from the plant's nominal operational values due to combustion stability problems. These have been typically managed through changes to the plant's operations and are expected to become more common as plants are operated more flexibly. A potential solution for this is the development of fuel-flexible combustors.
  - Optimised air flow management: This aspect is important in maintaining combustion stability but also to understand the dynamics between varying power production and system efficiency.
  - Operation with a reduced number of mills: Strategic use of the mills is important in adjusting the speed of fuel input into the combustion process. In this regard it is useful to assess the impact that full mill utilisation or part loading might have on the power plant's power output.
  - Adaptation of the boiler protection system to low load operation: As mentioned earlier, ramping and faster start-ups will increase the boiler's exposure to corrosion and deterioration due to thermal stress. One way to avoid costly replacement is to improve its resilience to more extreme operating conditions.
  - Real-time combustion monitoring: This requires advanced sensors, e.g. optical sensors, and new indicators for the identification and prevention of combustion instability. This is particularly important in the context of rapid load changes and unexpected variations in fuel composition.

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- **Optimise start-up procedures**: In order to ensure a fast and efficient start-up, plant operators should check start-up-related procedures and the associated temperature measurements, and consider optimisation or replacement. Together with automated start-up procedures, this is a prerequisite to assessing admissible temperature limitations and to operating with less conservative set points.

- **Improve the plant efficiency at part load** and the **dynamic behaviour of the plant**: This refers to measures using the potential of the water-steam cycle. For steam plants, this will involve the installation of pumps and water management systems to account for decreases in pressure and aeriation due to lower load. For co-generation plants, this will involve the installation of steam bypassing valves to shift between productive processes.

- **Consider storage options** to enhance the overall flexibility performance of the plant. Storage can be implemented at different levels of the power system. Particularly in the case of power plants with complex generation processes, storage can offer the advantage of decoupling processes. For example, in gasification plants, syngas storage can allow for varying power outputs while keeping syngas production constant. For co-generation plants, there might be value in the deployment of thermal storage, while CCGT, OCGT, coal-fired power plants and VRE plants might profit from the installation of battery storage. The benefit of including storage technologies into the plant depends heavily on the market design.

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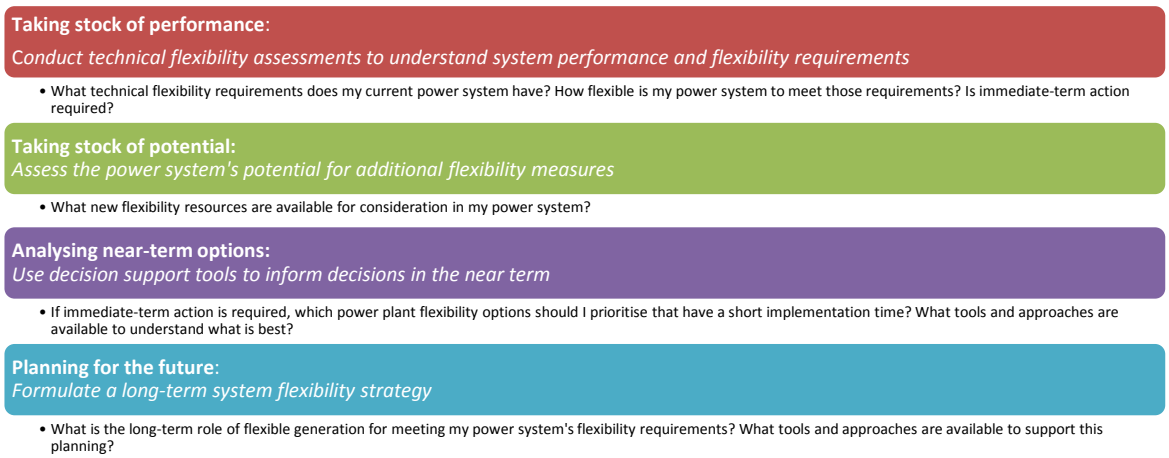
4. Approaching power plant flexibility at the system level

HIGHLIGHTS

- When considering power plant flexibility measures, adopting a holistic system perspective is critical for ensuring a reliable and affordable 21st-century power system.
- Technical flexibility assessments are a critical first step for characterising the current flexibility requirements of the power system and helping to understand the capacity of the power system to meet those requirements.
- Formulating a detailed inventory of potential power plant flexibility measures is an important exercise for informing both near- and long-term decision making.
- Many capital-light, quick-to-deploy power plant flexibility measures may be available for consideration; decisions to use these resources are best informed by production cost modelling exercises.
- The emergence of variable renewable energy (VRE) in 21st-century power systems requires more careful consideration of power system flexibility in planning exercises. Recent experience has shown that it is good practice to accompany longer-term power system transformation goals, including VRE targets, with a long-term system flexibility strategy.

Examining power plant flexibility from the perspective of the system as a whole is critical to making informed, value-driven investment decisions to ensure a reliable and affordable 21st-century power system. This section presents a framework for policy makers to approach decision making on power plant flexibility measures, and also discusses the use of decision support tools to help inform near-term decisions and long-term strategies (Figure 4.1). Note that this section does not address the influence of power sector organisation or regulatory and market frameworks on power plant flexibility – these issues are addressed in Chapter 5.

Figure 4.1 • Power plant flexibility from a system perspective



Key point • Four key steps can be taken to holistically examine power plant flexibility from the system perspective.

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Taking stock of performance: Conduct technical flexibility assessments to understand system performance and flexibility requirements

A first step in understanding the role of power plant flexibility from the system perspective is to assess current performance. **Technical flexibility assessments** are analytical exercises designed to do just this, quantifying the current flexibility requirements of the system and understanding the capacity of the current power system to meet those requirements. Various tools exist that can be used to conduct technical flexibility assessments; these tools examine real or modelled power system dispatch data for a given analysis period (typically one year of operation) to:

- Identify the required type, magnitude, frequency and duration of operational flexibility parameters (e.g. quick start, fast ramping, lower turndowns), and under what broader power system conditions (e.g. high wind periods in winter months) this flexibility may be needed.
- Understand how much flexibility is available from the existing power generation fleet.
- Identify periods of stress for grid flexibility (e.g. the magnitude and length of the steepest ramp each day) and/or periods of "flexibility deficit" where the system has insufficient ramping capability to balance supply and demand. Curtailment of VRE can be a useful indicator for this.

Importantly, these technical assessments do not need to consider economic factors. Rather, they analyse and dissect real power system data or modelled data, which originate from production cost modelling tools and endogenously consider economics. Technical flexibility assessments may be particularly useful to serve as a check on long-term power system plans, examining simulated dispatch data for future years to understand if the capacity and generation mixes being selected by a long-term planning tool will lead to a sufficiently flexible power system in real life.

Taking stock of potential: Assess the power system's potential for additional flexibility measures

What options are available today or in the future to increase power system flexibility? To answer this question, policy makers, system operators and utility planners can undertake a research process to create a detailed inventory of available options to access or deploy additional power system flexibility, ideally characterising both technical and institutional options and their associated costs. While it is important to take an inventory across all available options for power system flexibility, the focus of this subsection is on options for additional *power plant* flexibility.

At a high level, taking an inventory of potential power plant flexibility measures requires:

1. Surveying the potential physical flexibility of each existing power plant in the system.
2. Surveying how much flexibility from existing power plants can be harnessed through current operational practices or power plant-relevant market rules, regulations or policies.
3. Surveying the potential for increasing access to the latent flexibility of power plants through changes in market rules, regulations or policies.
4. Characterising the landscape of available technology for deploying new flexible power generation infrastructure or retrofit projects, including plant repowering.

Importantly, creating an inventory of power plant flexibility measures is not only a technical survey; ideally, the inventory reflects a range of financial information on the capital and operational cost implications associated with implementation.

Current physical flexibility of existing plants.[18] Surveying the existing fleet's ability to operate flexibly is a foundational step in creating an inventory of power plant flexibility measures. This step involves collecting data on various power plant flexibility parameters (e.g. minimum stable level, ramp rates, start-up times, part-load efficiencies), the operation and maintenance (O&M) costs associated with various modes of operating, and the remaining technical lifetime of the plant.

Potential to access physical flexibility from existing plants. Developing a survey of institutional and operational measures that can enable power plants to operate more flexibly requires a thorough understanding of existing operational practices and market rules. The extent to which power plants provide system flexibility can be significantly determined by the operational and settlement rules of electricity markets, procedures for generation scheduling and dispatch, government subsidies and/or generation quotas, and contractual obligations. Thus, one particularly important aspect of a flexibility survey is to characterise the historic operation and environment of each plant, understanding if existing operational practices, contractual arrangements, public policies, market structure, or system reliability constraints result in plants being run less flexibly than they are technically capable of.

Potential for power plant retrofits to enhance physical flexibility. Creating an inventory of potential plant retrofit opportunities requires collecting a variety of information, including: expected improvements to various operational flexibility metrics, capital costs, construction lead time, plant downtime during plant modification, expected changes to O&M costs, and others. Multiple retrofit options will almost certainly be available for each individual power plant – all with distinct costs and performance implications. Not all of these retrofit options will necessarily be essential or appropriate for the power system. Thus, during the research process it is critical to interact with individual plant owners as well as the original equipment manufacturer (OEM) of each power plant's technology, to understand the landscape of likely potential options and to ensure that enhanced flexibility will be accessible to the system operator.

Potential for new flexible power plants. Creating an inventory of cost and performance assumptions for potential new-build flexible power plants is an important activity to support long-term planning processes. This can be conducted by interacting with plant OEMs and utilities and/or issuing formal requests for information (RFIs) to solicit interest from power plant developers. RFIs can also be used to understand the expected operational environment, remuneration structures, or other contractual terms that developers would expect in order to consider building a project. One particularly important dimension of data to understand is the lead time for construction and commissioning of new power plants – as policy makers begin formulating longer-term strategies, this information is critical for understanding procurement timelines and ensuring sufficient flexibility is available to the system in the future.

[18] It is necessary to collect these data in advance of a technical flexibility assessment (see previous step). However, this requirement is being presented in this section alongside other power plant flexibility data categories to enhance understanding.

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Box 4.1 • Chinese efforts to characterise the flexibility potential of thermal power plant

The rapid growth of renewable energy in the People's Republic of China ("China") has led to significant VRE curtailment in some of the regions with the highest penetration levels. In 2016, the wind and solar curtailment rate reached 17% and 10%, respectively. Regions in China with the highest share of VRE are also endowed with abundant coal resources, such that coal-fired capacity is the backbone of power systems in these regions. At the request of the China National Energy Administration, the Electric Power Planning & Engineering Institute (EPPEI) carried out research in 2015 on the pathways for enhancing power system flexibility in the period 2016-20 (NDRC, 2016). According to EPPEI, about 220 gigawatts (GW) of thermal power plants, including about 130 GW of co-generation units and 86 GW of condensing power-only units, could be retrofitted by replacing old equipment or improving operations in order to significantly reduce curtailment rates. The goal of retrofitting some or all of this 220 GW of capacity is also written and codified into China's 13th 5 year plan for the power sector, which was jointly released by the National Energy Administration and the National Development and Reform Commission in 2016.

For more information, see Case Study subsection: China.
Source: NDRC (2016), China 13th Renewable Energy Development Five-Year Plan (2016-2020).

Analysing near-term options: Using production cost models to inform investment decisions in the near term

Once a clear picture of both system flexibility requirements and prospective options has been established, it is possible to address the question: *What power plant flexibility options should be prioritised in the near term?*

Near-term options (i.e. 1-4 years) are likely to be capital-light in nature and not to involve significant development of new infrastructure.[19] These options include: modification of plant operational procedures; power plant retrofits; and shifts in policy or operational practices to unlock flexibility in existing plants. Because of the longer lead time associated with investments in new flexible power plant, discussion of those options is reserved for long-term planning in the later subsection on planning for the future.

It is certainly possible that the technical flexibility assessment of a power system may indicate that no near-term actions are required. However, this subsection may still be useful for policy makers in those contexts to understand the role of production cost models in helping to quantify the system value of longer-term power plant flexibility measures, as well as the role of other power system flexibility measures.

Overview: Production cost models and power plant flexibility

Production cost models (PCMs) offer an important, integrated look into prospective changes to power plant flexibility, considering both the technical and economic implications of a particular change for the system at large. While technical flexibility assessments examine plant dispatch data *ex-post* (see the previous subsection on taking stock for performance),

[19] Excluding combustion turbine (CT) gas plants that can be constructed within 2-4 years.

PCMs simulate the least-cost economic dispatch of the power system subject to physical constraints of generators and the transmission network.[20]

In order to assess needs and opportunities for power plant flexibility, including costs and benefits, production cost modelling can be conducted to understand the system-level economic value of potential flexibility investments.[21] Such analyses can help us understand:

- What is the operational value of a particular flexibility measure relative to a business-as-usual scenario, or relative to other prospective flexibility measures?
- What is the relative operational value of a flexibility measure across a range of future scenarios (e.g. a scenario with lower demand, or higher VRE)?
- How will power plant generation behaviour be impacted by broader changes to the system that encourage greater flexibility?

PCMs generally examine power system flexibility questions at timescales from the very short-term flexibility timescale (minutes) to the very long-term flexibility timescale (months to years). While they do not capture the full range of power system flexibility requirements and power plant flexibility services, they tend to be used in both near- and long-term planning exercises because of their comprehensive view of technical and economic constraints at these timescales.

Asking "What if" questions using PCMs

PCMs can be employed to ask "What if?" questions about the costs and benefits of a particular flexibility measure to both the system and individual power plants. They can also be used to compare and contrast the impact of individual elements of multiple flexibility measures, or to understand the benefits of multiple flexibility measures in concert. The "What if?" questions can extend to a variety of future scenarios with diverse power system conditions (e.g. changes to demand, VRE deployment, fuel prices). The process can be divided into four steps (Figure 4.2) described below.

Step 1: The current power system can be characterised within the PCM framework. This involves locating and/or developing a variety of detailed data sets, including: descriptions of the power plant fleet (including operational flexibility parameters and constraints) and transmission system; hourly (or sub-hourly) demand data; a characterisation of wind and solar resources; O&M and fuel costs; and a variety of other factors that affect dispatch decisions.

Step 2: Next, the power system must be extended forward in time to the near-term test year (typically 1-5 years ahead of current day) where the flexibility measure will be evaluated. This might be a year when a particular plant retires, or when a VRE deployment target is expected to be hit. To create data sets for a near-term future power system, analysts tend to rely on policy targets, industry knowledge and stakeholder input. For longer-term timeframes, moving from Step 1 to Step 2 is typically informed by capacity expansion models (CExMs) that simulate the least-cost build out of the power system – this is a more time- and resource-intensive process that will be discussed in further detail in the subsection on planning for the future.

Step 3: Once the near-term future power system is constructed, a "Reference" or "business-as-usual" scenario is created to establish a baseline for how the power system is expected to operate without any new flexibility measures put in place.

[20] A production cost model considers variable production costs (e.g. fuel cost, variable O&M cost), but does not consider fixed (capital) costs. Evaluation that optimises investments based on fixed costs will be addressed in the next section on capacity expansion models.

[21] These assessments also yield significant technical insights.

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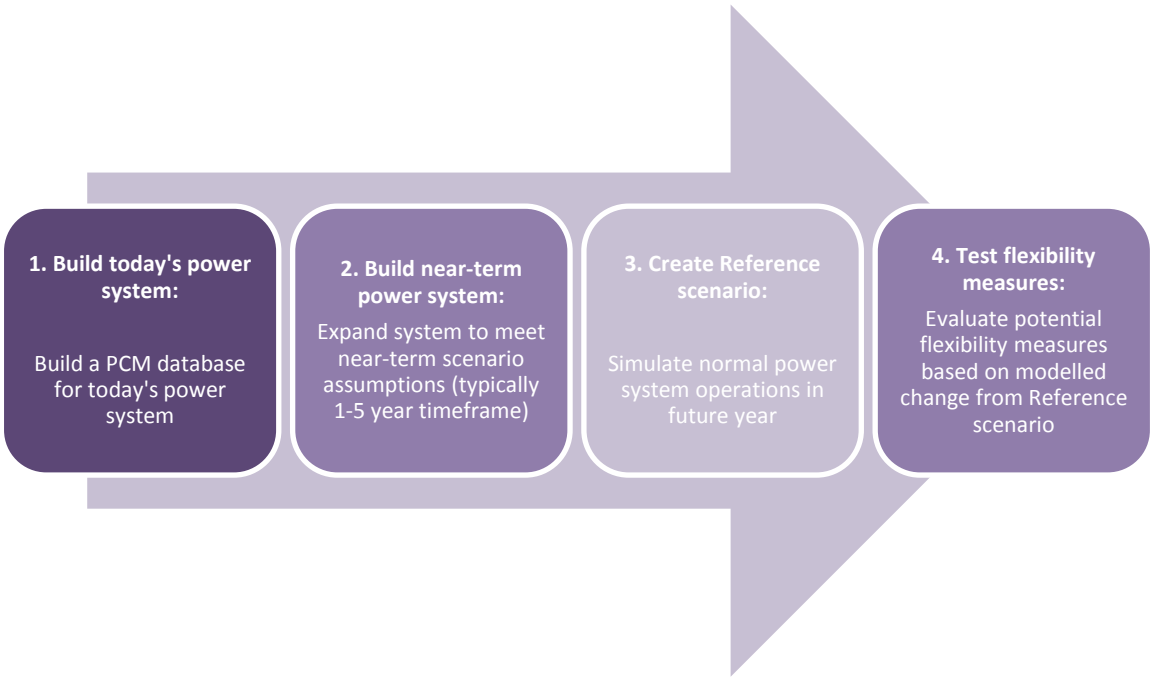
Step 4: Finally, new scenarios are modelled that simulate the implementation of various flexibility measures (e.g. a plant retrofit) and/or changes to market conditions (e.g. more VRE deployment, closure of thermal plants). These scenarios are compared with the Reference scenario to understand what impact the measures have on overall system operational costs, ability to meet supply and demand, and a variety of other metrics. System operation cost savings can also be compared against any available capital cost estimates (if relevant) associated with prospective flexibility measures.

Figure 4.2 • Production cost modelling for flexibility valuation



Key point • Production cost modelling exercises can be employed to characterise the operational value of various flexibility measures.

Importantly, this fundamental process can be employed to ask a variety of questions about power plant flexibility measures of all types, and for testing the efficacy of longer-term planning scenarios as well. PCMs have a number of the key high-level uses to understand the value of power plant flexibility measures (Table 4.1).

Table 4.1 • Uses of PCMs to understand the value of power plant flexibility

Assess system-level value	
Quantify system-wide production cost impact of new power plant flexibility measure(s)	By comparing a new PCM scenario where a power plant flexibility measure is installed to a business-as-usual scenario, a PCM can quantify the positive or negative change in system-wide production costs. This reveals how much operational value the measure would have from a system standpoint. Multiple plant size and location options can be tested.[22]

[22] The ability to test the value of a power plant flexibility measure across a range of plant sizes and locations holds true across applications listed in the table.

Understand the technical and economic value of various flexibility measures	By comparing changes in production costs for a range of flexibility measures, a PCM can help planners and policy makers understand which specific flexibility measures would be of the highest relative system value.
Test the value of a new power plant flexibility measure in a range of future power system conditions	By comparing changes in production costs for a single flexibility measure across a range of uncertain future power system conditions (e.g. electricity demand, VRE penetration, fuel costs), a PCM can help planners and policy makers understand the future conditions under which a particular measure may be valuable, and to what extent its relative value is impacted by specific market conditions.
Assess plant-level value	
Understand the expected operational environment of a new flexible power plant investment	By adding prospective flexible power plants to the fleet of a PCM scenario, planners and policy makers can understand how – under economic dispatch – the generation fleet would operate, including hours of operation, patterns of operation (e.g. frequency of ramping and cycling), changes to O&M costs, and expected revenue from sales.
Understand plant-level changes in operational environment for flexibility retrofit investment	By comparing a new scenario where power plant retrofits are completed against a business-as-usual scenario, a PCM can quantify the extent to which operating hours, patterns of operation, changes to O&M costs, and expected revenue from sales would change if the retrofits are installed.

What specific costs and benefits do PCMs consider in evaluating more flexible power plant operation?

From a system standpoint, as VRE penetrations increase it is likely that the remaining generation fleet will need to operate more flexibly. Dispatchable power plants may be required to ramp faster, start and stop more frequently, and/or turn down to their minimum generation levels more frequently (and stay at those levels longer). This can lead to additional wear-and-tear costs and changes to emissions. On the other hand, the addition of flexibility can reduce overall system operational costs and increase the system value of VRE. PCMs can help assess such cost-benefit trade-offs and provide insights to policy makers and planners on transformation pathways.[23] It should be noted, however, that while differences in system operation costs can be obtained from PCM models, increases in wear-and-tear cost parameters are external inputs and require information to be obtained directly from plant operators.[24]

[23] PCMs do not endogenously consider wear-and-tear costs. However, these costs can be captured through modification to plant O&M parameters.

[24] See Troy et al. (2012) for a detailed discussion about methods, challenges and limitations of representing cycling costs in production cost models, http://ieeexplore.ieee.org/document/6189770/.

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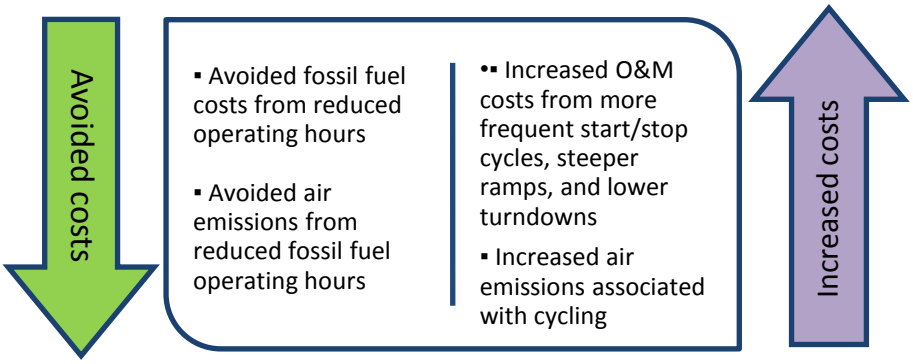
Figure 4.3 • Key system costs and benefits captured by PCM



Key point • PCMs capture several operational costs and benefits of power plant flexibility measures.

Recent studies demonstrate a clear trend: from a system operational standpoint, fuel cost savings from more flexible operation tend to far outweigh cycling costs associated with more flexible operation of the thermal fleet (see for example: GTG, 2017; NREL, 2016; NREL, 2013).The US National Renewable Energy Laboratory's *Western Wind and Solar Integration Study: Phase 2* contains one of the more detailed assessments of the costs of increased power plant cycling and additional transmission associated with increased VRE deployment, analysing scenarios for the western interconnection of the United States (Figure 4.4) (NREL, 2013).

Figure 4.4 • Key results from NREL *Western Wind and Solar Integration Study: Phase 2*, 33% VRE Scenario

	Emission reduction due to renewables	Cycling impact
CO_2	260-300 billion pounds 29%-34%	Negligible impact
NO_x	170-230 million pounds 16%-22%	3-4 million pounds
SO_2	80-140 million pounds 14%-24%	3-4 million pounds

*High wind and solar scenarios. Capital costs are not reflected

Notes: CO_2 = carbon dioxide; NOx = nitrogen oxides; SO_2 = sulphur dioxide.

Source: NREL (2013), *Western Wind and Solar Integration Study: Phase 2*, www.nrel.gov/docs/fy13osti/55588.pdf.

Key point • Detailed production cost modelling exercises indicate that the operational benefits of increased VRE penetration in the western United States far outweigh the increased costs associated with additional power plant cycling.

The study found that increased cycling to integrate higher levels of VRE increased operating costs by between 2% and 5% for the average fossil-fuelled plant, and that avoided fuel costs far outweighed the increased cost of cycling. Importantly, this PCM analysis did not consider the capital costs associated with new VRE generation and transmission.

When might a new power plant flexibility measure have economic merit?

Importantly, PCMs can examine net *operational cost* savings resulting from changes to technology deployment and system, operational and institutional changes in a power system. Importantly, they do not consider the *capital costs* to the system associated with new flexibility measures.[25] Thus, in order to have a complete system perspective on the costs and benefits of a power plant flexibility measure, any production cost savings associated with the measure must be put into the context of the costs that the new measure would incur to the system.

Complicating matters further, the individual power plant in question, whether a new investment or a retrofitted plant, would need to have sufficient operating hours and revenues in its expected operating environment to be economically viable for its owners. When a plant is deemed technically necessary but financially unviable, public policy can be an important tool to "bridge the gap" and provide a return that is more reflective of the value the plant brings to the system.

Table 4.2 summarises the conditions under which a power plant flexibility measure may have economic merit from the perspective of the system and the individual power plant.

Table 4.2 • When might a new power plant flexibility measure have economic merit?

Plant owned by vertically integrated utility	
Perspective: System	**Perspective: Power plant**
If the annual savings on system production costs (compared to a business-as-usual scenario) are higher than the annual revenue requirement (i.e. compensation) the utility receives for the power plant flexibility measure, the investment may have economic merit from a system perspective.	The new power plant flexibility measure is a regulated investment, and the utility owner typically receives compensation via an electricity tariff increase. If the plant receives a fixed revenue regardless of operational patterns, the investment should theoretically always have economic merit from the power plant perspective. If the plant receives revenue based on electricity sales, the investment may have economic merit if the expected sales revenue is larger than the plant's fixed costs.
Plant owned by IPP with PPA to electricity distributor	
Perspective: System	**Perspective: Power plant**
If the annual savings on system production costs (compared to a business-as-usual scenario) are more than the annual cost to ratepayers of the PPA, the investment may have economic merit from a system perspective.	If the NPV of the new power plant flexibility measure is positive – based on the terms stated in the utility PPA and the expected operating hours – the investment may have economic merit from the IPP owner's perspective.
Merchant IPP on competitive wholesale market	
Perspective: System	**Perspective: Power plant**
If the annual savings on system production costs (compared to a business-as-usual scenario) are positive, the investment may have economic merit from a system perspective. The system only pays the merchant IPP for energy and/or ancillary services sales, the cost of which is already included in the estimate of system production cost savings.	If the NPV of the new power plant flexibility measure is positive – based on expectations of generation behaviour, spot and day-ahead market prices, contract prices and other factors – the investment may have economic merit from the IPP owner's perspective.

Notes: IPP = independent power producer; NPV = net present value.

[25] In some cases, capital costs are not relevant from the system perspective, such as when a new flexible power plant is privately owned and participating in the wholesale market or a power purchase agreement (PPA).

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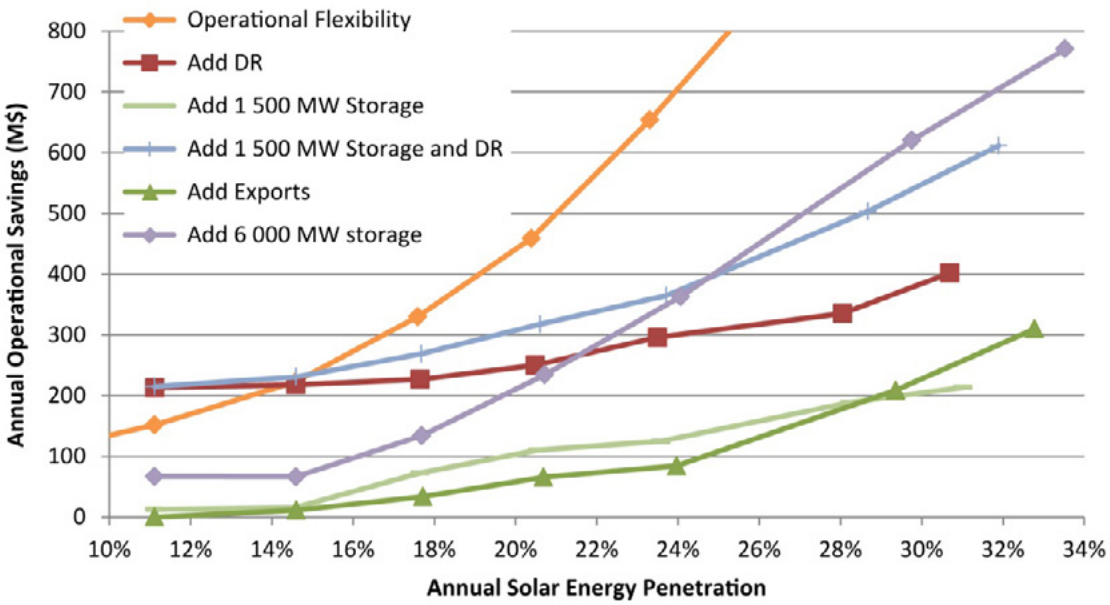
Considering multiple flexibility options using PCMs

While the focus of this report is on power plant flexibility, it is important to note that good investment planning practice can use PCMs to examine a *broader set of flexibility options* for the power system, such as aggregating and dispatching distributed resources, utilising storage, developing the transmission system, co-ordinating neighbouring balancing areas, and/or co-optimising a portfolio of flexibility resources. Ultimately, the appropriate group of flexibility measures for a given power system is specific to the system in question and depends on a variety of factors that influence the net system value of each measure.

Denholm et al. (2016) offer case studies for three relatively distinct power systems where the value of multiple flexibility options is compared. The study employs PLEXOS® – a commercial production cost modelling tool – to perform grid simulations for scenarios over a range of wind and solar penetrations, and to understand the efficacy of various flexibility options. The scenarios are analysed to understand how implementing various flexibility measures may impact annual system production costs, economic carrying capacity,[26] VRE curtailment and other metrics. The flexibility options considered include, *inter alia*: demand response; storage; removal of certain operational flexibility constraints (e.g. removal of local generation requirements, raising instantaneous VRE penetration limits); allowing VRE to contribute to reserves; and increasing import/export capacity (i.e. transmission) of the balancing area (Figure 4.5).[27]

Figure 4.5 • System operational cost savings from flexibility and storage



Note: DR = demand response; MW = megawatt.

Source: Denholm et al. (2016), *Impact of Flexibility Options on Grid Economic Carrying Capacity of Solar and Wind: Three Case Studies.*, www.nrel.gov/docs/fy17osti/66854.pdf.

Key point • The operational value of flexibility measures tends to increase as VRE penetrations increase.

[26] Economic carrying capacity is defined as the level of VRE penetration at which the costs to the system of the VRE outweigh the benefits, and further VRE deployment may not be economically desirable.

[27] Importantly, this figure presents system operational cost savings associated with various flexibility measures. The study also considered capital costs of the measures to understand implementation costs, and also the total value (i.e. sum of operational savings and capital costs) of various flexibility measures. However, because the study chose to quantify total value as the "impact on the value of PV" (rather than a total system cost impact metric), this figure is presented here in order to avoid confusion.

Overall, the study found that the value of all flexibility options increases with VRE penetration through decreased operational and capacity costs, and that while all flexibility options can add value, not all of their benefits are additive when deployed simultaneously.

Another method to assess the value of different flexibility options is to use VRE curtailment as an indicator of system performance. Using this method, different flexibility options are compared based on their contribution to reducing VRE curtailment, both on an average annual basis and during periods of system stress (i.e. periods of coincident low demand and high VRE generation).

Planning for the future: Formulating a long-term system flexibility strategy

While traditional approaches to power system planning have ensured that sufficient flexibility is available on the system to balance supply and demand, the emergence of VRE in 21st-century power systems requires more careful consideration of power system flexibility in planning exercises. As VRE shares grow in many markets and government deployment targets continue to evolve, recent experience has shown that it is good practice to accompany longer-term power system transformation goals with a *long-term system flexibility strategy*. Such strategies examine a range of measures to increase power system flexibility over 5- to 25-year periods, seeking to minimise combined capital and operational expenditures while ensuring sufficient flexibility on the system for any number of uncertain futures.

A robust system flexibility strategy relies, to a large extent, on multiple decision support tools working in concert to provide insights into least-cost flexibility pathways, using a flexibility inventory that identifies potential options – and associated implementation costs – for enhancing system flexibility.[28] A system flexibility strategy should identify the steps necessary to create an environment that facilitates investment in flexibility; this may take the form of centralised procurement strategies for new infrastructure, increased co-ordination across balancing areas, creation of new market products, or a range of other near- or long-term policy options. These options are discussed in more detail in Chapter 5, whereas this subsection focuses on the role of decision support tools.

Review of relevant decision support tools for creating long-term system flexibility strategies

As previously discussed, increased cycling costs and operational cost savings are the dominant components of the costs and benefits of flexibility measures in the near term; these can be examined within a PCM framework. However, when examining longer time periods, equally relevant questions emerge: what additional flexibility measures may be required as the system evolves over time, and what additional capital costs (and system-wide benefits) are associated with these measures relative to other options? Hence, decision support tools that specialise in long-term investment planning, but also consider flexibility parameters and constraints, are similarly important for informing system flexibility strategies (Table 4.3).

CExMs optimise new generation investment decisions to achieve a least-cost, reliable power system over multi-year periods (i.e. 5-25+ years). They tend to take a relatively detailed approach to capital expenditure (CAPEX) in the system, but provide only an approximate understanding of operational expenditure (OPEX) at timescales relevant to power system operation. This means

[28] See the section: 'Coupling CExMs and PCMs to assemble a long-term flexibility strategy'

that they may not be able to capture certain changes in system flexibility that are relevant at operational timescales, and may not account for the real-life impact of chronological decision making on power system operation. In theory, these models can also include a coarse representation of the transmission system constraints and power flows, and even provide insights for transmission expansion decisions. However, when transmission expansion decisions are treated as variables in a capacity expansion optimisation, models often become computationally intractable due to the complexity of the problem. Furthermore, because these models do not consider detailed technical considerations of the transmission network, results are of limited use to transmission planners when considered in isolation.

Box 4.2 • Including operational flexibility parameters and constraints in CExMs

From a long-term planning perspective, assumptions about minimum generation levels of existing and new power plants can have a significant impact on expected levels of VRE curtailment and the general feasibility of deploying large amounts of otherwise economical VRE. As a first step, system planners can incorporate operational flexibility parameters and constraints (e.g. ramp rates, minimum generation levels) into planning models (Denholm et al., 2018; Panos and Lehtilä, 2016). For more information on incorporating flexibility considerations into planning models, see e.g. IRENA (2017).

Sources: Denholm et al. (2016) Impact of Flexibility Options on Grid Economic Carrying Capacity of Solar and Wind: Three Case Studies, www.nrel.gov/docs/fy17osti/66854.pdf; IRENA (2017), Planning for the Renewable Future: Long-term Modelling and Tools to Expand Variable Renewable Power in Emerging Economies; Panos and Lehtilä (2016), "Dispatching and unit commitment features in TIMES", http://iea-etsap.org/docs/TIMES_Dispatching_Documentation.pdf.

Transmission planning models (TPMs) explicitly consider the topology and technical characteristics of the transmission network, power flows through the network, and interactions with power plants' ability to support grid stability. In this context, they tend to examine ultra-short-term and very short-term flexibility issues. They are employed – often in an iterative fashion – to understand the technical performance of current or future transmission networks, considering the location and time-varying characteristics of supply and demand (often obtained from CExMs). TPMs can help to identify specific needs for new transmission investment (e.g. grid reinforcements, new transmission lines) and test the technical feasibility of proposed transmission projects. They can also test the usefulness of particular measures (e.g. storage, new generation) in deferring the need for new transmission infrastructure. Importantly, most TPMs do not endogenously create cost estimates of transmission projects; this is done separately by grid engineers and other experts.

PCMs optimise the operation of the power system on an economic basis, given a fleet of generators, transmission system topology and load profile. These models simulate the operation of the power system, taking into account all relevant physical and operational constraints, either using current or future system specifications. The results from these models can be examined so that the level of flexibility, or flexibility shortfalls, can be identified. When this is done, specific types of flexibility constraint can be identified, such as ramping or minimum stable generation. This "root cause" analysis can then form the basis of improvements to the system. The modelling results inform flexibility in time scales from the short term (minutes to days) to the long term (months to years), and can be used to ensure that power system infrastructure plans proposed by CExMs and TPMs will result in a reliable power system with reasonable operational costs. Importantly, these models do not endogenously consider CAPEX associated with power plants, but do have a highly detailed consideration of OPEX.

Box 4.3 • Managing uncertainty of VRE deployment levels in long-term planning exercises

Whether a power system has a government-mandated VRE target or not, system planners may in reality face substantial uncertainty over how much VRE is ultimately deployed on their power system. This uncertainty has significant implications for the level of system flexibility that is required across all timescales, and in turn, the nature of long-term power system investment plans.

Countries with specific VRE targets may, at first glance, appear to exhibit a relative certainty around near- and long-term expectations of VRE deployment. However, global experience suggests that in reality these targets can be easily increased, driven by inter alia improving VRE cost characteristics, stronger climate change commitments, and/or a desire to promote more local manufacturing following earlier successes. Targets can also be decreased or go only partially achieved, perhaps due to the inability of a procurement process to motivate investment. Furthermore, as VRE deployment in many major markets is increasingly motivated by economics alone, there may be less certainty from a system planning standpoint, as planning exercises may not be able to capture the investment behaviour of IPPs, and/or utilities may actually push "ahead of schedule" on government targets when the economics merit it.

In the absence of certainty, the question of the robustness of power system plans can be raised: "Is the proposed long-term power system investment plan sufficiently robust against different potential levels of VRE deployment?" One strategy to address issues of uncertainty during planning exercises is to perform sensitivity analysis using various levels of VRE deployment. This is also a useful approach to address a range of other uncertain factors that may influence the buildout of the power system, such as future fuel prices, technology costs and policy scenarios.

The India Greening the Grid Study (GTG, 2017), for example, performed detailed production cost modelling for a range of likely 2022 VRE deployment scenarios, including scenarios where government VRE targets are both under- and overachieved. Through systematic sensitivity analysis around VRE deployment, the study found that the current system has sufficient flexibility to accommodate the VRE target.

Source: GTG (2017), "Pathways to integrate 175 GW of renewable energy into India's electric grid", www.nrel.gov/analysis/india-renewable-integration-study.html.

Table 4.3 • Modelling tool scope

	Purpose	Scope
Capacity expansion model (CExM)	*Creates optimal power generation fleet to meet long-term timeframes.*	Detailed economic consideration of CAPEX over multi-year timeframes; coarse treatment of power system operational costs.
Transmission planning model (TPM)	*Simulates detailed power flow and network performance of a power system.*	Detailed technical consideration of short-term and ultra-short-term grid operations; no endogenous consideration of costs.
Production cost model (PCM)	*Simulates least-cost economic dispatch of a power system.*	Detailed technical and economic consideration of power system operations for a single year of operation; no consideration of CAPEX for infrastructure.

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Because this report is focused on power plant flexibility, the subsequent sections focus on the coupled use of CExMs and PCMs. However, it is important to note that the deployment of both VRE and new flexibility measures can have important cost implications for grid investment, and in many cases grid investments themselves can be a direct substitute for additional power generation.

Box 4.4 • Evaluation of flexibility measures in Thailand's renewable grid integration analysis

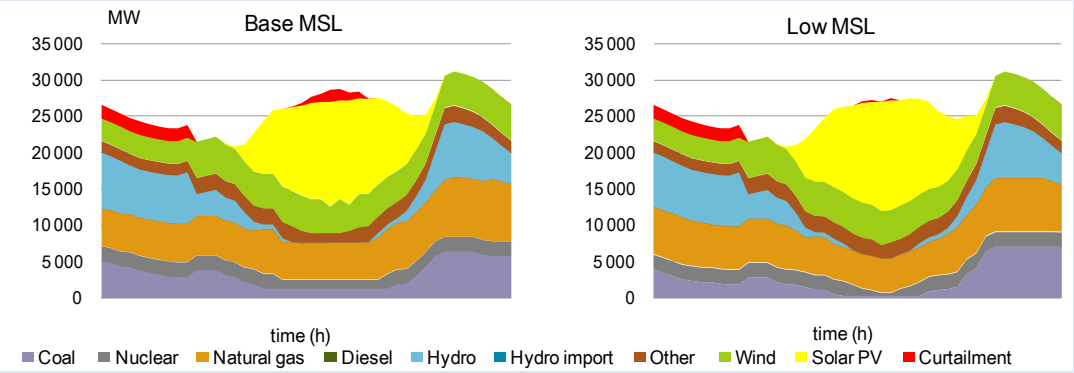
As an input into the Power Development Plan process in Thailand, the International Energy Agency (IEA) performed a grid integration study to assess the impact of existing VRE targets on the Thai power system, while also considering the impact of higher levels of VRE in 2036. A key component of the assessment is detailed production cost modelling examining the operation of the Thai power system under different VRE scenarios in 2036, with assessment of flexibility options. Three main scenarios for VRE deployment are considered in the study, called Base, RE1 and RE2, with annual VRE penetrations of 6%, 12% and 15% respectively.

The current Thai power system includes features that make it relatively flexible from a technical standpoint, such as strong transmission grids and fairly high shares of hydropower and combined-cycle gas turbine (CCGT) generation. However, from an economic standpoint, many of these generators have reduced flexibility, as they operate under take-or-pay PPAs and fuel supply agreements. Examination of data on power plant operational parameters suggests that the flexibility of the system could be enhanced through measures that decrease the minimum stable level (MSL) of generating plants. For example, the average MSL for coal- and gas-fired steam turbines is around 55% and nearly 60% for CCGT capacity.

The renewable grid integration analysis considers various flexibility options for 2036 scenarios, including increasing contract flexibility (e.g. removing take-or-pay contract stipulations for hydropower and CCGT plants), a demand-side management (DSM) scheme, and measures to reduce the MSL of conventional generation. All modelled flexibility interventions, called cases, resulted in an operational cost saving to the system, primarily driven by the displacement of high-cost fossil fuel generation with VRE. Annual operational cost savings for the Base and RE2 scenarios are presented for different flexibility measures. Thesystem cost reduction occurred under the contract flexibility case across all scenarios. The savings from the lower MSL case were also from avoided fuel costs andreduction in start-up costs (IEA, forthcoming).

The impact of lower MSLs can also be observed in the dispatch during a low net-load period (Figure 4.6). Reduced MSLs allow conventional generating units, particularly coal and gas, to further reduce their outputs. This enables a larger amount of renewables to be dispatched during the time of lowest net load while keeping conventional power plants on line to meet higher demand later in the day. This translates into reduced VRE curtailment (particularly during the day) and decreased plant start-up costs.

Figure 4.6 • Impact of reduced minimum generation (right) in the RE2 scenario relative to the reference RE2 scenario (left) in the period of lowest net load



Note: h = hour. RE2 = For a definition of the scenarios please refer to text above.
Source: IEA (forthcoming), *Thailand Grid Renewable Integration Assessment Report*.

Key point • Reducing the MSL requirements of conventional power plants in Thailand may be a useful strategy to allow greater integration of VRE and reduce curtailment.

Coupling CExMs and PCMs to assemble a long-term flexibility strategy

While near-term decision making can be informed by PCMs that rely on policy targets and stakeholder input to formulate a future power system, long-term system planning requires the additional step of employing a CExM to create assumptions about the future power system.

Step 1: As a first step in long-term planning, a CExM should be assembled that contains all relevant information about the current power system, as well as future expectations for electricity demand, plant retirements, technology cost and performance assumptions, evolutions in public policy, and a variety of other input assumptions.

Step 2: Next, analysts can create a reference case scenario using the CExM which relies on reasonable, middle-of-the-road predictions of future technology and market conditions. This reference scenario will ultimately serve as a point of comparison with scenarios that include additional flexibility considerations, but first must undergo an iterative validation process using a PCM (see Step 3).

Step 3: CExMs create least-cost power generation portfolios in future years with detailed considerations of CAPEX but an incomplete picture of power system operations (and thus, OPEX). Operational constraints are represented in a simplified form, commonly resulting in proposed fleets that – when examined in PCMs – ultimately have some form of flexibility shortfall or redundant flexible capacity. This results in a system that is more expensive to operate, despite being "CAPEX-optimised" from a CExM standpoint. Thus, once the initial reference case has been created in Step 2, the proposed fleet from this scenario can be examined with significant operational detail using a PCM. By creating this "soft link" between the CExM and the PCM, planners can iteratively discover what an optimised scenario might look like, considering both CAPEX and OPEX (i.e. total expenditure [TOTEX]) together.

For this approach, PCMs can first be used to understand if the proposed power system has any kind of flexibility shortfall or surplus. This operational feedback can then be incorporated back into the CExM, typically by augmenting certain CExM input parameters (e.g. modifying reserve margins, retiring operationally redundant power plants). In theory, this should result in a new

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CAPEX-optimised power system that has lower operational costs than the previous iteration. This new CExM scenario can again be tested in the PCM to yield further operational insights and inform further changes in the next iteration, continuing until planners are satisfied with the level of TOTEX cost optimality they have achieved. At a high level, this iterative process helps to assemble a more complete picture of the required CAPEX and OPEX of future power systems, and also helps to create more cost-optimal systems.

Importantly, CExMs normally create *yearly* generation and capacity mixes, starting in the current day and ending in the final year of the model simulation (typically 30 years in the future or later). Thus, one additional nuance in this step is selecting an appropriate year to test the proposed power generation fleet in the PCM. Examining operational performance in a single year can be a useful exercise to inform long-term target-setting activities (e.g. formulation of VRE deployment goals). On the other hand, using a PCM to test the cost-effectiveness of a proposed fleet as it evolves over the years (e.g. in intermediate steps every 5 years) is a more complex process, but is perhaps a more useful exercise for understanding pathways toward meeting longer-term policy targets.

Step 4: As a next step, the capital cost implications of various flexibility measures can be tested. These may be investments in new flexible power plants, rollout of a new policy, or any number of possible measures. A new measure can be incorporated into the CExM framework as an input condition, and thereafter the model can formulate a long-term investment plan. One important nuance is around the *time of implementation* of the flexibility measure. Since CExMs examine the buildout of the power system from present day to a certain future year, an important input condition is the year (or years, if assessing a progressively evolving policy) during which the flexibility measure will be implemented.

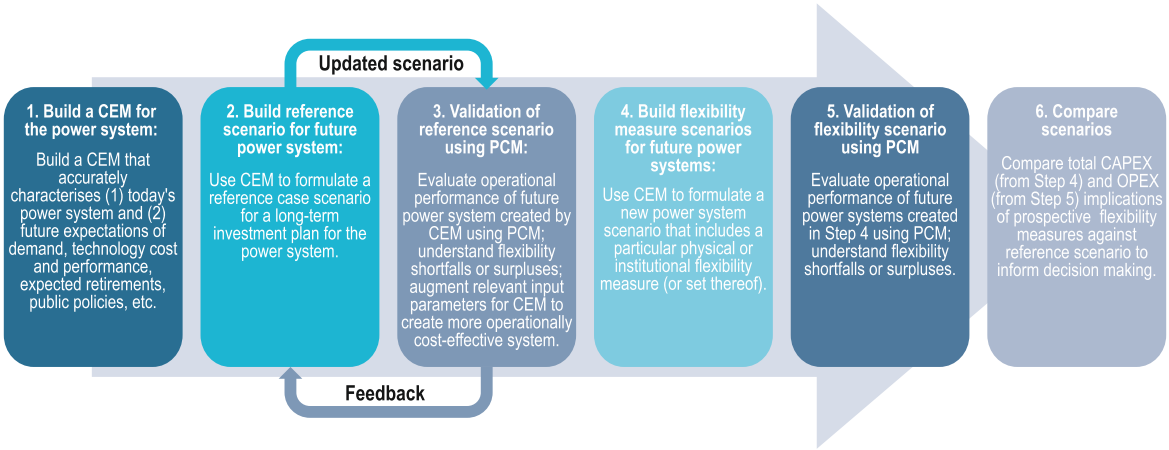
Step 5: Next, a PCM analysis is used to evaluate operational costs and/or savings of the flexibility measures in question. The new PCM results are benchmarked against the reference PCM scenario established in Step 3. This step enables analysts to precisely evaluate how the new measures would impact system flexibility and operational costs, and to identify flexibility surpluses or shortfalls that can be addressed by modifying input conditions of the CExM in the previous step.[29]

Step 6: At this stage, the CAPEX and OPEX implications of various flexibility measures be compared and contrasted with the reference scenario (and relative to one another) to inform long-term planning pathways.

This overall process is depicted below in Figure 4.77.

[29] Because CExMs have coarser temporal resolution, they may yield less accurate estimates of plant operating hours, VRE curtailment, and other important operational metrics when checked against PCM results. Modifying CExM input parameters with PCM results can help to promote more realistic and convergent power system investment plans. See, for example, Aunedi et al. (2017), Diakov et al. (2015), and IRENA (2017) for additional background. These approaches, as well as the broader topic of CExM-PCM model hybridisation, are formidable and actively researched technical topic areas; however, they are outside the scope of this policy maker-oriented report.

Figure 4.7 • Multi-step iteration for the evaluation of power plant flexibility measures with PCM



Key point • Considering power plant flexibility measures in the long-term may require an iterative approach using both CExMs and PCMs.

Box 5 • Challenges associated with representing hydropower resources in power system models

Hydropower resources represent an important potential source of flexibility in power systems. However, they also experience a relatively unique set of operational constraints compared to other power generation technologies, as their usage in power generation is inherently intertwined with water resource management. In some countries, the challenges introduced by integrated power and water management at hydropower facilities create operational constraints that can limit hydropower flexibility due to higher priorities placed on water uses, such as irrigation, flood control, residential, commercial and industrial needs, navigation, environmental preservation, and even recreation. These can be broadly categorised into operational, environmental and regulatory constraints. Incorporating these wide-ranging issues into an integrated energy and water system planning framework is extremely difficult. Nevertheless, as system flexibility needs become more prominent in 21st-century power systems, understanding and incorporating these constraints into power system planning exercises is important.

Effective hydropower modelling acknowledges the complexity of hydropower system operation with a concerted effort to incorporate hydropower operating details into analytical tools to the extent possible, with this effort proportional to the current or potential future influence of hydropower on power system operation. As many hydropower issues are site-specific, dependent on local and time-dependent behaviours, it is not often reasonable to account for all issues within a given power system planning approach. However, models and tools with higher spatial and temporal resolution are more amenable for integrating site-specific hydropower constraints. Flexible frameworks for representing constraints as costs can also yield some insight into integrated hydropower operations.

Nevertheless, power sector analysis tools can remain limited in their ability to account for the myriad issues influencing hydropower planning and operation. Another approach to hydropower modelling thus incorporates specialised water resource management tools that have explicit representations of stream flows and hydropower operational, environmental and regulatory constraints. These tools can be used to inform, or be integrated with, power sector planning models for a more complete analysis exercise.

Either approach (modifying power sector models or integrating electricity and water models) must be informed by good data. Depending on the management and oversight of hydropower facilities

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along with the local data-gathering infrastructure, it could be challenging to model hydropower systems even with a detailed analytical framework. To enable effective hydropower modelling for power system planning, the following information is important, both for existing facilities and candidate sites for new hydropower systems:

- Hydropower resource data: power capacity and energy potential at the highest resolution possible, including historical data for existing facilities.
- Cost data: capital and operating costs, both for new construction and continued maintenance.
- Environmental attributes: local ecological conditions that could influence construction and operation.
- Regulatory structures: laws and requirements influencing construction and operation.
- Hydrological data: current and projected hydrological conditions; characterisation of drought, flood and normal hydrological conditions over a substantial time horizon (i.e. 20-50 years) for sensitivity analysis.
- Equipment characteristics: technical performance and constraints.

Gathering the necessary data and integrating them into a power system planning approach requires thorough stakeholder engagement and communication. If successful, the resulting planning tools can enable more informed and effective energy-water sector planning with a detailed understanding of how hydropower can fit into 21st-century power systems.

For more information on challenges in hydropower modelling, see: Stoll et al. (2017).

Source: Stoll et al. (2017), *Hydropower Modelling Challenges*, www.nrel.gov/docs/fy17osti/68231.pdf.

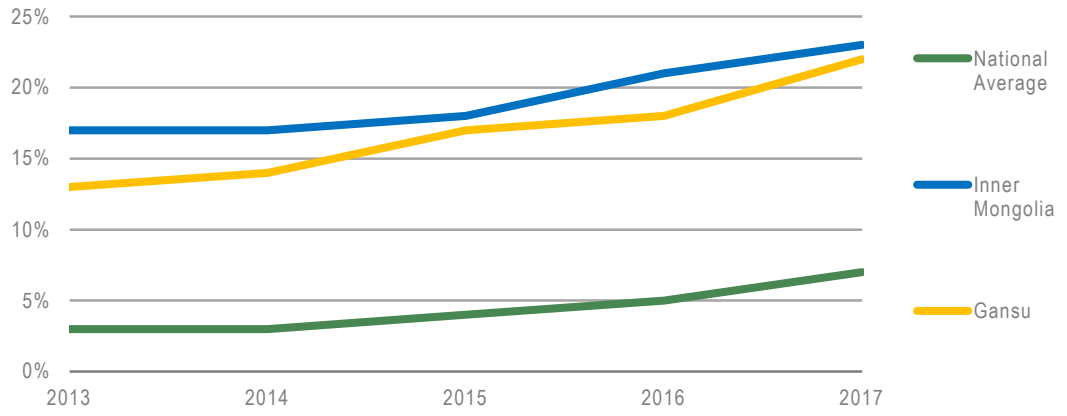
Country case study: People's Republic of China

Background and context

As of the end of 2017, the installed capacity of wind power and solar PV in the People's Republic of China ("China") reached 163 GW and 130 GW, respectively. VRE produced about 7% of the total annual electricity consumption in China, compared to 3% in 2013 (Figure 4.88). About two-thirds of VRE generation in China is located in its northern and western regions, with annual penetration of VRE in many of these provinces surpassing 20%. For instance, on 16 April 2017 the daily VRE penetration level reached approximately 33% for the Western Inner Mongolia Grid, one of the provincial grids with the highest VRE penetration rates. In May of the same year, the same grid experienced a record instantaneous VRE penetration of 47%.

The rapid growth of renewable energy in China has also led to significant VRE curtailment in some of the regions with the highest penetration levels. In 2016, the wind and solar curtailment rate reached 17% and 10%, respectively.

Figure 4.8 • Wind and solar generation shares in China



Source: China National Energy Administration 2018.

Key point • Annual VRE penetrations in China have been steadily increasing in recent years.

Regions in China with the highest share of VRE are also endowed with abundant coal resources, and therefore power systems in these areas have substantial coal-fired power plant capacity. The share of coal power plants in the three northern regions (where about two-thirds of China's VRE capacity is installed) is expected to remain above 60% out to 2020. Conventional flexible power generation, i.e. hydropower stations with reservoirs and pumped storage capability, as well as peaking natural gas turbines, account for less than 5% of installed capacity. In the future, coal-fired power plants are expected to be the primary candidates for providing flexibility to the power system.

The flexibilisation of co-generation units is mainly proposed through heat-power decoupling strategies using thermal storage or an electric boiler. Power-only units typically need a more systematic retrofitting of both boiler and turbine parts. With reasonable retrofitting, coal power units could deliver extra regulation capability of at least 20% of their rated capacity.

Barriers to flexibility

The technical barriers to coal-fired power plants becoming more flexible are numerous. First, it is important to note that maintaining a reliable and adequate supply of heat tends to be the first priority for co-generation power plants in China and elsewhere. High heat demand for district heating in China results in high minimum capacity factors for the power generation equipment within co-generation units. The dispatchable minimum generation level is usually above 60% in the winter season. Next, all of the power-only coal units were initially designed to operate as baseload generators. As a result, their technical minimum load – with automatic generation control on line – is usually above 50%. Finally, the lack of a wholesale spot market or ancillary services market makes it uneconomic to retrofit thermal power plants. The price of generation in China is also typically fixed over long time periods. Thus, more flexible operation creates an opportunity cost which cannot be recouped under current market arrangements.

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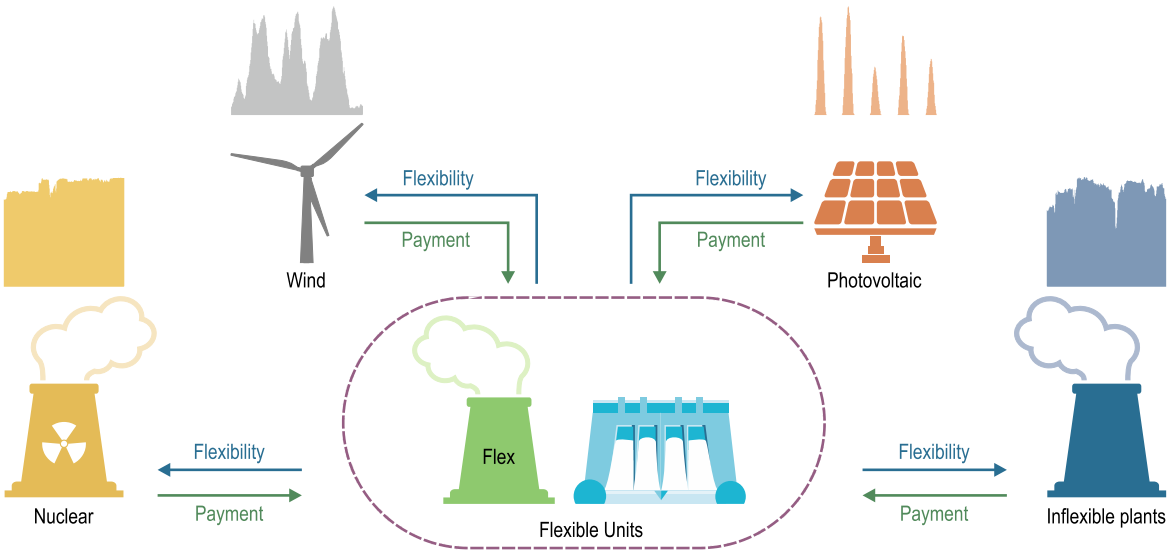
Scope of the reform/intervention

Figure 4.9 • Down-regulation market in China



Source: Provided by Electric Power and Planning Institute (2018).

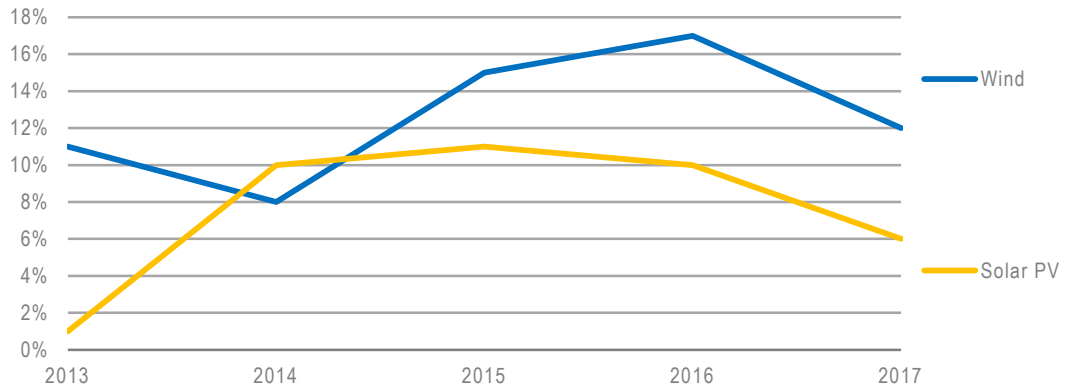
Key point • The down-regulation ancillary service market pilot in China facilitated an exchange of revenue between plants operating below and above a set output, rewarding power plants for their ability to provide flexibility.

In 2014, the Northeast region of China launched a demonstration project for a down-regulation ancillary services market. This aimed to incentivise thermal power plants to lower their minimum load; at the time, thermal power plants did not experience an economic incentive to do so, despite it being an otherwise efficient outcome for the market at certain times.

In the market demonstration project, providing downward regulation above a certain baseline was obligatory, and further downward regulation below 50-55% output was deemed as providing an ancillary service to the system. These down-regulation services were reimbursed by those power plants which operated above the baseline at the same time. The mechanism offered a new financial incentive to reduce output and increase flexibility while somewhat reducing the financial impact of reduced operating hours.

The down-regulation market mechanism has largely been considered a success and has been introduced into another five provinces in China. The implementation of the mechanism has significantly boosted the flexibility of coal power units. According to the Northeast Bureau of the NEA, about 3 000 MW of down-regulation capability was released in 2017. The curtailment of VRE energy reduced from about 11 terawatt hours (TWh) in 2016 to 7.7 TWh in 2017. With only a 2% increase in new capacity, VRE in the Northeast region generated 22% more electricity in 2017 than in 2016 (Figure 4.10).

Figure 4.10 • Annual percentage VRE curtailment in China



Source: China National Energy Administration 2018.

Key point • Wind and solar curtailment in China has been decreasing in recent years due to market reforms.

Meanwhile, China also launched a new round of spot-market demonstration projects in eight provinces. Increasing flexibility in the system has become one of the major goals of these demonstration projects, and the eight provinces are expected to have a wholesale spot market in operation by late 2018 or early 2019.

Country case study: Denmark

The share of electricity produced from wind and solar has been continuously increasing over the past 15-20 years in Denmark. In 2017, the share of the gross domestic electricity consumption covered by domestic VRE sources reached 45.8%, of which 43.5% was wind and 2.3% was from solar power. In the western part of Denmark, the number of hours where VRE production covered more than 90% of gross consumption has been between 1 600 and 2 100 in each of the last four years (i.e. around 20% of the time). Despite the high share of wind power in Denmark, forced curtailment of wind and solar power has been extremely low, while the power system's security of supply ranks among the best in the European Union.

As VRE penetration has increased, two other main trends have also taken place: first, Danish interconnector capacity with neighbouring countries has been increasing significantly over the past ten years (Figure 4.11). The high level of interconnection allows for a larger geographic balancing area, benefitting from both different mixes of production technologies and consumption profiles across the area. Second, Danish thermal capacity has been consistently declining at the same time as VRE capacity has been increasing (Figure 4.11). The regularly utilised thermal power plant fleet in Denmark consists almost exclusively of co-generation. As the share of VRE has increased, the role of co-generation plants has undergone a transition from primarily one of heat provision to becoming a key source of system flexibility.

The successful integration of VRE in Denmark relies on market-based least-cost dispatch with clear and reliable price signals for market participants to react to. This is supported by high levels of interconnection and close market integration with neighbouring countries, as well as pro-active planning and forecasting by the transmission system operator (TSO) and a highly flexible thermal generation fleet. The establishment of a common power market (Nordpool) about 20 years ago and, through this, the close integration of markets in the Nordic countries, have been key in facilitating the cost-efficient integration of VRE.

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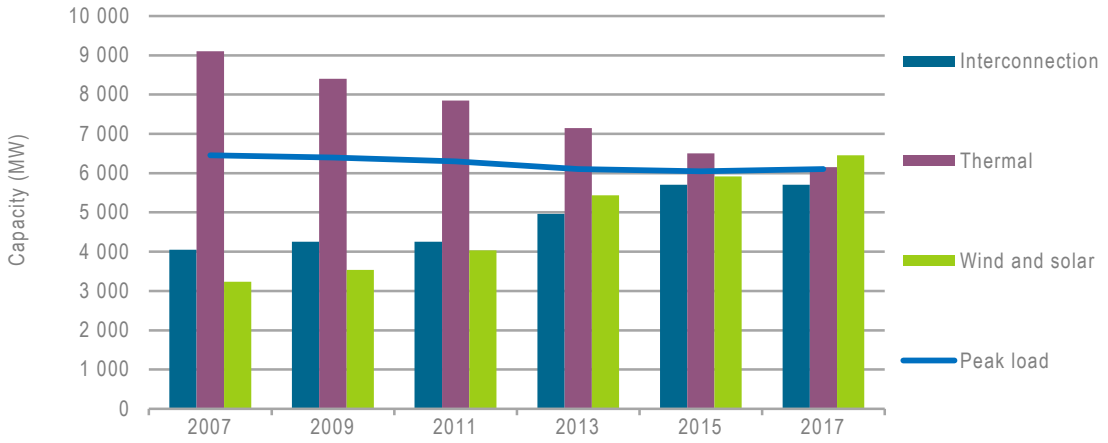
Figure 4.11 • Historic development of Danish capacity and peak consumption



Source: IEA (2017), *Energy Policies of IEA Countries: Denmark – 2017 Review*, www.iea.org/publications/freepublications/publication/EnergyPoliciesofIEACountriesDenmark2017Review.pdf.

Key point • Danish thermal capacity has been declining in recent years as wind, solar and international interconnection capacity have grown.

The market-based least-cost dispatch in Nordpool ensures a closely connected Nordic area with electricity always flowing towards high-price areas. Further, the development of a common Nordic balancing energy market allows Swedish and Norwegian reservoir hydropower to provide cheap short-term flexibility to the entire Nordic system and reduce the cost of imbalances caused by VRE. The coupling of European day-ahead markets and increasing interconnection with the Central Western European power system are likely to be fundamental steps for the continued, cost-efficient market integration of Denmark's high share of renewable energy production.

In recent years Denmark's TSO has agreed with the Dutch and British TSOs, respectively, to invest in 700 MW (Denmark–Netherlands) and 1 400 MW (Denmark–Great Britain) interconnectors, which will further increase the balancing area and improve the ability to balance the system with higher shares of VRE. The hourly price changes and volatility in the day-ahead market driven by an increasing share of VRE production have incentivised Denmark's thermal plants to become more flexible over time. By being able to produce power independently of demand for heat, but also by improving the plants' ability to operate at low load and with steeper ramps, Danish co-generation plants have been able to benefit from the new demand for flexible generation in the market. Heat storage tanks can be found in essentially all power plants and, increasingly, electric boilers allow for better adjustment to power market prices without affecting heat delivery to the local district heating system. Today, Danish co-generation power plants are among the most flexible in the world – a development that was undertaken by the sector itself through clear economic incentives in the market.

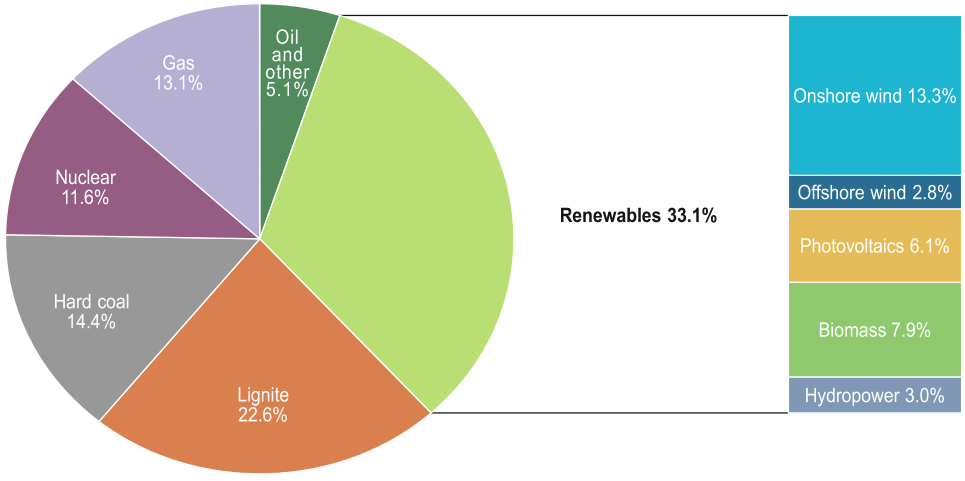
With a declining share of thermal power plants that have traditionally provided ancillary services to the system, the ability to maintain system stability in the future is a concern. Technological developments, for example system-friendly wind turbines and the automated grid, as well as developing market models for ancillary services, are important solutions to these challenges. For example, newer models of wind turbine are now able to participate in the balancing market, because they are able to adjust their rotor angle to limit production to benefit system operation, such as during hours of negative prices.

Denmark has set a goal of 50% wind power in 2020 and independence from fossil fuels in 2050. Thus, the share of VRE in Denmark will continue to increase and so will the need for cost-efficient integration of VRE into the system. Interconnector capacity to neighbouring countries is foreseen to increase by at least 40% within the next decade, including the new connections to Great Britain and the Netherlands. Further development of short-term power markets is currently under discussion. These include a finer time resolution (shifting to 15-minute dispatch intervals from 1-hour) and a gate closure closer to real time, which will improve the ability to balance VRE. In addition, by the end of 2018, intraday markets will be coupled across large parts of Europe, and within a few years cross-border trade of balancing electricity will become a reality not only in the Nordic countries, but in all of Europe. Lastly, the coupling of different energy sectors, such as heat, electricity, fuels and transport, are opening up for the possibility that variations in a single sector might be absorbed, or to some degree mitigated, through this sectoral coupling, given the right market structures and incentives. The Danish government, for instance, has recently decided to reduce the taxes on power-based heat production in order to support electrification, for example more extensive use of heat pumps.

Country case study: Germany

In 2017, wind and solar PV commanded a share of 22.2% of total electricity production in Germany (Figure 4.12), up from 18% in 2016. The instantaneous maximum penetration of wind and solar reached 75.3% of total demand on 30 April 2017. Throughout recent years, the German electricity system has remained reliable – the average duration of supply interruption[30] has remained below 15 minutes per customer for several years, making the German power system one of the most reliable power systems in the world.[31]

Figure 4.12 • Electricity mix in Germany in 2017



Source: Agora (2018a), *Die Energiewende im Stromsektor: Stand der Dinge 2017*, www.agora-energiewende.de/fileadmin/Projekte/2018/Jahresauswertung_2017/ Agora_Jahresauswertung-2017.pdf.

Key point • In 2017 VRE and Hydro represented 33.1% of the electricity mix in Germany.

[30] As measured by the System Average Interruption Duration Index (SAIDI). SAIDI is the average outage duration for each customer served.

[31] No single indicator exists for measuring system reliability (or power quality). However, SAIDI, the average annual power interruption for grid customers, provides a useful perspective on system reliability for technical and non-technical audiences alike. No SAIDI was available in respect of 2017 at the time this report was published, but since 2014 the index has remained below 13 minutes.

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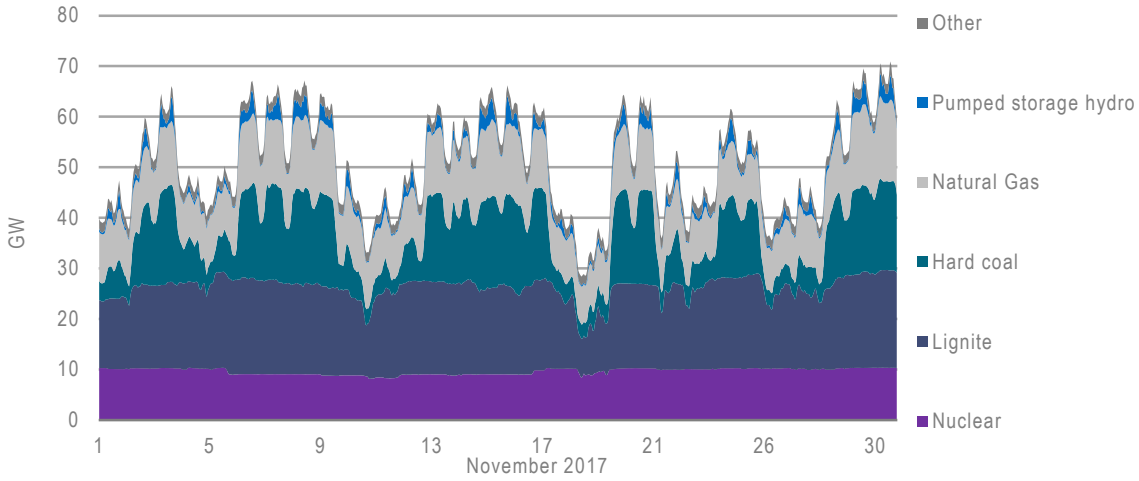
Three main reasons can be identified to explain the ability of the German power system to maintain reliability while increasing the share of VRE:

1. The German power system maintains sufficient dispatchable capacity. At the end of 2017, a total of 103 GW of conventional capacity was available (nuclear, lignite, hard coal, gas and pumped hydro), plus 9.0 GW of bioenergy and 5.5 GW of run-off-river hydropower. Load peaked at 80.6 GW on 12 January 2017 at 11 a.m.
2. The transmission grid is increasingly used for regional balancing. The amount of traded power increased to 133.6 TWh in 2017, with a significant surplus of 60.2 TWh exported, enabled by co-operative neighbouring countries. Furthermore, system operators have enhanced the technical abilities of the grid, for instance by implementing smart technologies and building a small number of additional lines.
3. On the supply side, flexibility is mainly provided by conventional generation. In particular, hard-coal units are increasingly operated in a load-following mode (Figure 4.13). However, a significant amount of gas-fired capacity rests idle as it is largely unable to compete with hard coal. The potential of demand response has yet to be exploited.

Figure 4.13 • Conventional electricity generation in Germany in November 2017



Source: Agora (2018b), *Die Energiewende im Stromsektor: Stand der Dinge 2017*, www.agora-energiewende.de/fileadmin/Projekte/2018/Jahresauswertung_2017/ Agora_Jahresauswertung-2017.pdf.

Key point • The significant share of relatively inflexible generation coupled with high VRE variability make flexibility a priority for the operation of Germany's power system.

Several trends show a further need to increase flexibility in the system. Costs for redispatch and curtailment have risen for several years and currently amount to 2-3% of total electricity supply costs. Negative prices on the day-ahead market, another indicator of a lack of flexibility, occurred in 146 hours in 2017 with an average rate of EUR -26.47 per megawatt hour.

Several reasons for these developments can be identified: firstly, insufficient grid capacity, especially in the northern region of Schleswig-Holstein, which is responsible for roughly 70% of redispatch and curtailment costs; secondly, the German power system still contains significant shares of relatively inflexible baseload power in the form of nuclear, lignite and gas in heat-led co-generation plants; and finally, demand-side management plays a negligible role, despite its significant technical potential.

The government acknowledges the need for further flexibility. Public-sector interventions are primarily focused on expanding the transmission grid and improving the flexibility of short-term markets. In fact, wholesale market flexibility is increasing both in the day-ahead and the intraday market. In the coming years, the nuclear phase out (9.5 GW remain) and the transition of 2.7 GW lignite assets (from 21.3 GW currently) into a strategic reserve ("stand-by mode for back-up purposes") will reduce the amount of inflexible baseload capacity.

However, the flexibility measures that are applied in Germany secure a significant market share for carbon-intensive technologies, i.e. lignite and hard coal, and prevent further reduction of CO_2 emissions in the power sector.

Country case study: India

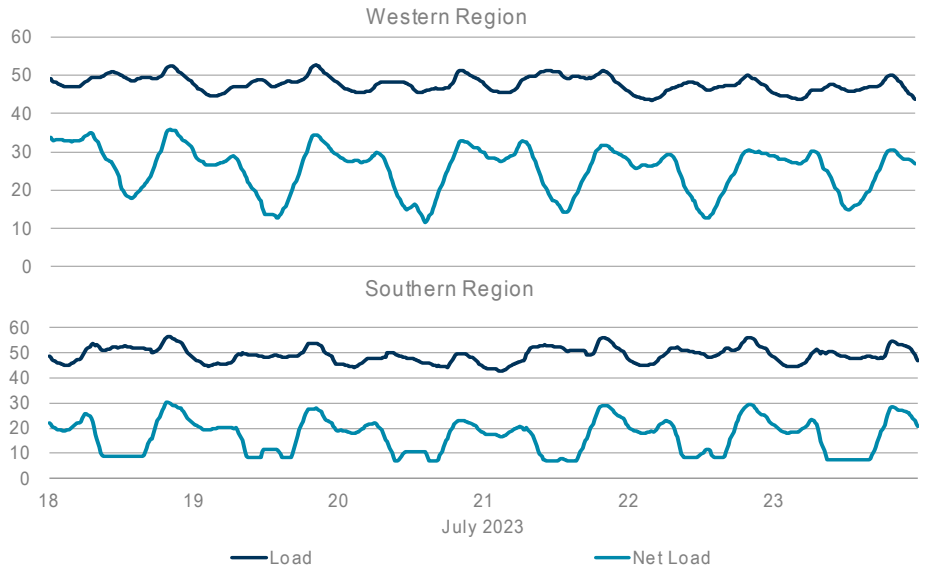
India's power sector is undergoing rapid transition to include larger quantities of wind and solar capacity. As of January 2018, India had 32.8 GW of wind and 17.1 GW of installed solar capacity (CEA, 2018). By 2022, India has a target to integrate 60 GW of wind and 100 GW of solar capacity, representing roughly 17% year-over-year growth in total VRE capacity. Multiple government departments are pursuing efforts to facilitate this transition by evaluating and promoting potential system flexibility options. Due to India's large thermal generation fleet, existing power plants have been identified as significant potential sources of system flexibility to be explored. This case study examines one effort by the government to better understand the role of power plant flexibility in the future Indian power system.

Rapid growth in VRE on the grid may require more flexible operation from existing power plants and more electricity transmission between India's regions. To understand potential operational challenges associated with these high levels of VRE capacity, India's Ministry of Power recently undertook a joint initiative with the United States Agency for International Development (USAID) to conduct a comprehensive analysis of power system operations under high penetrations of VRE on India's grid. This is known as the Greening the Grid Study (GTG, 2017).

An important indicator of flexibility requirements for integrating larger shares of VRE is the net (residual) load. The Greening the Grid Study sheds light on potential benefits from various operational changes, including increased power plant flexibility. The graphs in Figure 4.14 depict hourly load and net load with 160 GW VRE capacity for 18-23 July 2022 in the Southern (top) and Western (bottom) regions of India.

This period includes the highest penetration of wind and solar nationally in the modelled 2022 scenario. When compared with the projected load curve, the net (residual) load curve experiences steeper ramps (upward and downward), shorter peaks and larger variation between peaks and valleys. A more variable net (residual) load curve requires flexible operations from across the power system, including from coal-fired power plants.

Figure 4.14 • Expected VRE incidence of net load at 160 GW of VRE in India

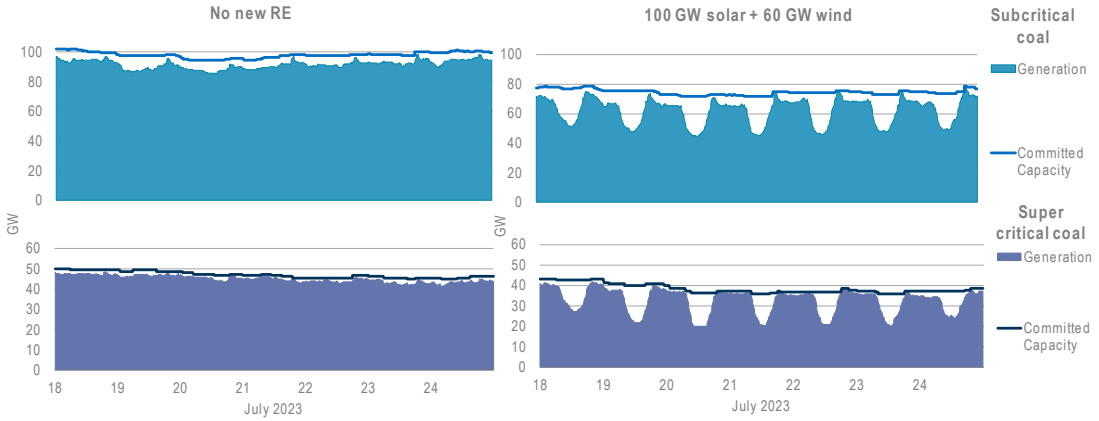


Source: GTG (2017*), Pathways to Integrate 175 GW of Renewable Energy into India's Electric Grid,* www.nrel.gov/analysis/india-renewable-integration-study.html.

Key point • The distinct profile of net load due to increased VRE requires more flexible operations from across the power system.

The Greening the Grid Study provides a good example of how the PCM framework can be used to identify potential flexibility constraints, and the study indicates the extent to which coal-fired power plants will be an important source of flexibility on India's grid in the future. It used detailed generator-specific information about ramping capabilities, minimum generation level, minimum up/down time, and other important factors to characterise the physical ability of power plants to provide system flexibility. Figure 4.15 below depicts how coal-fired power plants will provide flexibility in the modelled 2022 scenario with 160 GW of wind and solar.

Figure 4.15 • Expected flexibility provision from coal plants in 2036 in India



Notes: "100S-60W" refers to the India national target scenario with 100 GW of solar and 60 GW of installed wind capacity; "Sub-Coal" refers to subcritical coal-fired power plants; "Super-Coal" refers to supercritical coal-fired power plants.

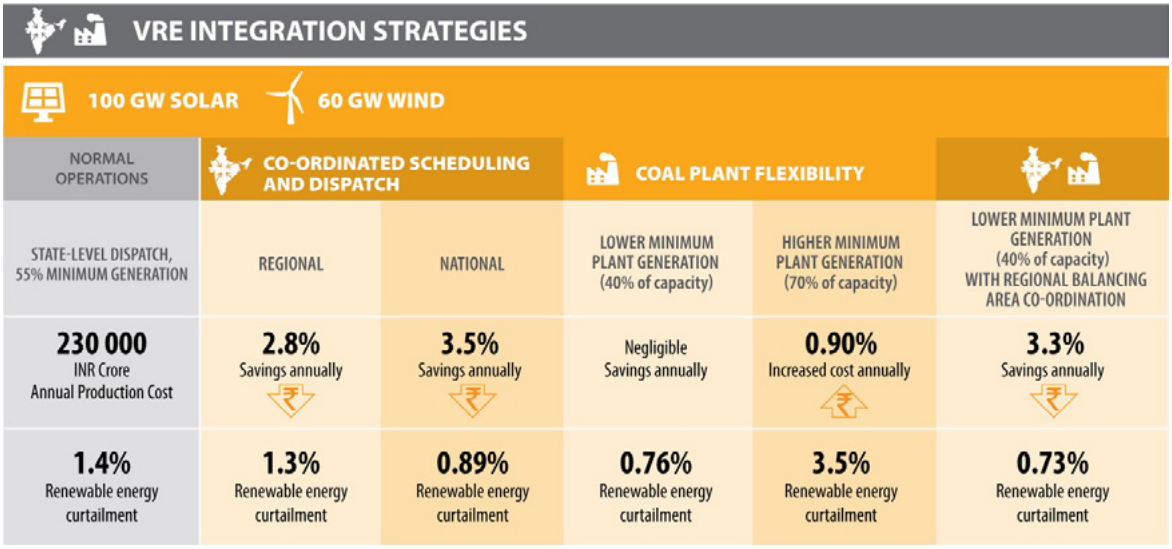
Source: GTG (2017), *Pathways to Integrate 175 GW of Renewable Energy into India's Electric Grid,* www.nrel.gov/analysis/india-renewable-integration-study.html.

Key point • Coal-fired power plants are expected to operate more flexibly in a power system with 160 GW of VRE.

Overall, the PCM analysis explored the system-level costs and benefits of more co-ordinated dispatch, changes to minimum plant generation levels for the coal fleet, and several other flexibility options for a scenario where India meets its 2022 renewable energy deployment target (as well as a range of other VRE deployment scenarios). In the context of power plant flexibility, the ability of coal-fired power plants to provide flexibility was shown to be an important factor that affects both VRE curtailment and total production costs. The minimum plant generation, or the lowest amount that a plant can generate when it is turned on, has the largest impact. Lowering coal plant minimum generation levels from 55% (current mandate for centrally operated plants) to 40% would nearly halve system-wide VRE curtailment, an important indicator of bankability for VRE projects.

Further, it found that if this minimum generation policy shift were pursued in combination with expanded co-ordination among balancing areas, additional savings would be achieved. Specifically, transitioning from state-level balancing and co-ordination to regional schemes would result in system-level savings of approximately 3.3% (around USD 1 billion annually) compared to current operations (Figure 4.16). These results demonstrated not only the potential cost savings from a specific policy change and shift in market operations, but also the complementary and additive nature of multiple flexibility measures working in concert.

Figure 4.16 • Impact of flexibility measures for 2022 Indian power system at 160 GW of VRE



Notes: crore = 10 million; RE = renewable energy; INR = Indian rupee (mid-2018 INR 65 ~ 1 USD).

Source: GTG (2017), *Pathways to Integrate 175 GW of Renewable Energy into India's Electric Grid,* www.nrel.gov/analysis/india-renewable-integration-study.html.

Key point • Comparison of the value of power system flexibility measures is an important step for informing decision making.

The India study demonstrates that a coal-dominated power system can integrate high levels of VRE, with coal flexibility playing a central role. In light of this, India has recently taken steps to increase flexibility in the coal fleet, which comprises most of the installed capacity in the country. In 2016 the Central Electricity Regulatory Commission (CERC) introduced a regulation requiring that units of a central generating station or interstate generation station be able to run at 55% of their maximum capacity, down from the previous regulation of 70% technical minimum.[32] These

[32] www.cercind.gov.in/2016/regulation/124_1.pdf.

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units represent roughly one-third of the thermal fleet in India. Ensuring more flexible operations in the rest of the fleet, which is comprised of state-owned plants and IPPs, requires separate regulations from each state regulatory commission.

Certain operational procedures also limit access to physical flexibility in the system. First, states have limited options to update interstate transmission schedules in response to load and VRE forecasts, which occur closer to real time. Revising schedules and dispatch closer to real time would increase the ability for other plants to react to changes in the system. Second, there is currently no efficient mechanism for accessing operating reserves at the state or regional level. Optimising reserves could allow for increased access to faster ramping or lower turndown units.

The Central Electricity Authority (CEA) of India is considering implementing AGC at all coal-fired power plants, and recently began an AGC pilot project at the NTPC Dadri Stage-II power plant.[33, 34] AGC technology, which is widely implemented in European and North American power markets, helps optimise short-term changes and extract fast-response capabilities from power plants that provide operating reserves.

Additional analysis is currently under way. Various interstate reserve markets have been proposed by CERC and analysis of their potential is being conducted. Also, in addition to CEA and USAID, the IEA, the German Gesellschaft für Internationale Zusammenarbeit (GIZ), and the UK Department for International Development (DFID) are partnering with the Indian Ministry of Power to analyse and identify opportunities for enhancing coal fleet flexibility.

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[33] www.cercind.gov.in/2017/orders/79_rc.pdf.

[34] The Power System Operation Corporation of India also has plans to develop an AGC pilot project at a regionally dispatched generation plant. This may pave the way for more cost-effective use of generation reserves, and it will provide a new revenue stream for these individual power plants.

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5. Policy options for country-wide roll-out

HIGHLIGHTS

- An appropriate roll-out policy and strategy for power plant flexibility depends on a number of factors, including the flexibility of the current power system, desired pathway for transformation and institutional structure of the sector.
- Thoughtful and deliberate engagement – both at domestic and international level – can help build political, institutional and technical momentum in the transition towards more flexible and modernised power systems.
- Policy options that increase system-wide flexibility can help to mitigate the need for additional power plant flexibility measures. Obstacles to overcome include limited access to neighbouring power systems, inefficient market rules, out-of-date operational methods, network congestion, limited storage capacity and large forecasting errors.
- If required, the flexibility in existing power plants can be enhanced through regulatory interventions and economic incentives that are not capital-intensive to encourage more flexible power plant operation.
- Policy options that remunerate new power plants with greater operating flexibility can provide fair compensation for the provision of flexibility services. The remuneration schemes depend on the context of the market (i.e. wholesale or regulated utility).
- Long-term planning procedures for the power system need to incorporate future expectations for system flexibility requirements, with a pathway to accommodate flexibility from all possible options to mitigate the long-term costs and operational impacts of power system transformation (PST).

As discussed in the previous chapters, requirements for system flexibility and the appropriate way to fulfil them are highly system-specific. Creating a suitable flexibility strategy requires consideration of current and future system needs, taking into account the generation fleet, network, market conditions and the potential for innovative options such as demand response and storage, as well as the expected pace of VRE deployment.

Chapter 4 discussed the role of decision support tools in assessing current and future flexibility needs, and identifying cost-effective options to improve system flexibility, especially power plant flexibility. The detailed results and analysis from these models will have identified the key flexibility constraints – and in some cases potential solutions – but not necessarily pathways to implementation.

In that context, this section offers a more policy-focused perspective for implementation purposes that builds on the rigorous modelling and analysis. It first presents a set of key questions to help understand the extent to which power plant flexibility should be prioritised. It then highlights the importance of stakeholder engagement and dialogue for implementing flexibility enhancements. Next, it identifies common policy approaches that may be useful for reducing the need for additional power plant flexibility measures by enhancing overall system flexibility. Thereafter, the chapter outlines policy approaches for unlocking latent power plant flexibility that exists on this system (i.e. capital-light, near-term measures), followed by a discussion of instruments to enable more capital-intensive measures (e.g. major retrofits and new flexible power plants). Finally, this chapter discusses specific actions that policy makers can take to enhance long-term planning processes so that they consider system flexibility (Figure 5.1).

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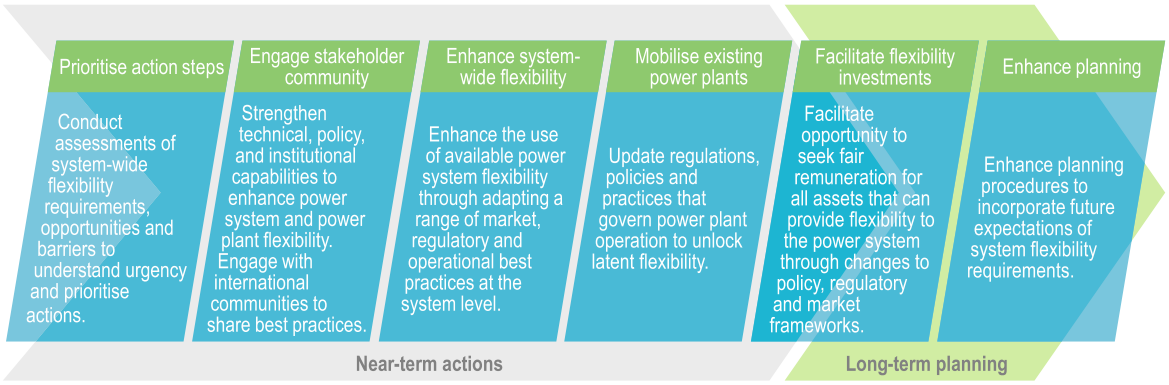
Figure 5.1 • Policy priorities for flexibility deployment



Key point • Policy options to roll-out flexibility can categorised based on the timescale which cover the operation, investment and planning aspects.

Where relevant, the chapter highlights differences in policy approach between more regulated, vertically integrated market structures and liberalised, unbundled market structures. It should be noted that the options presented here – mitigating the need for flexibility, improving flexibility through operational changes, and providing additional flexibility through new investments – should be assessed against each other for their effectiveness. In this respect, policy makers can employ the tools described in the previous chapter to evaluate the system's need for flexibility and appropriate measures and policies to ensure cost-effective and reliable provision.

Utilise assessments to prioritise actions steps for country roll-out

An appropriate roll-out strategy for power plant flexibility depends on a variety of factors. First and foremost is the question of timing: how urgent is the need to address power plant flexibility, and how quickly might challenges emerge relative to other power system policy priorities? To this end, assessments that characterise system flexibility requirements, opportunities and barriers can be utilised to prioritise actions and inform these questions.

While Chapter 4 discusses the role of technical flexibility assessments and production cost modelling exercises to gain a detailed quantitative understanding of flexibility requirements, this chapter aims to provide policy makers with a more qualitative understanding of when additional power plant flexibility measures might be needed. To this end, a list of questions is provided that may help uncover high-level system conditions that are indicative of the need for policy action to secure additional power plant flexibility.[35]

Does the current power system have difficulty balancing supply and demand? Systems that regularly experience reliability/power quality issues or excessive deviations from schedules may already operate power plants at their physical limits, making more flexible power plant operation less likely.

What proportion of the current power generation fleet cannot be operated flexibly? Systems with large proportions of traditionally inflexible generation sources, such as nuclear power or run-of-river hydropower, may require more flexible operation from other generators such as

[35] While this chapter focuses on power plant flexibility measures, it is important again to note that a variety of strategies are available to policy makers to promote/obtain system flexibility. These strategies, however, are outside the scope of this report.

fossil-fuelled power plants or VRE plants.[36] Equally, systems with large contributions from hydropower facilities that are operationally limited by water management constraints (e.g. irrigation, navigation, flood control), or fossil-fuelled power plants constrained by local air emissions limits, may need to rely on additional power plant flexibility. At a high level, plants may not be able to operate flexibly because of technical constraints, operational practices and/or economic incentives – all of these factors can be considered when evaluating this question.

How rapidly is the generation and capacity mix expected to change, and is the system operating efficiently now? Systems experiencing a rapid increase in system flexibility requirements may especially benefit from power plant flexibility to accommodate increased variability. This may be due to rising shares of VRE in the generation mix but also due to changes in demand patterns. High levels of VRE curtailment are often an indicator of the need for additional power plant flexibility.

How quickly or slowly is electricity demand growing? In systems with rapidly growing demand, existing and planned power plants may be sufficiently flexible if the flexibility of prospective power plants is emphasised during planning. In systems with low/stagnant demand growth and increasing VRE, traditionally baseload units may be pushed into more flexible mid-merit operations, resulting in a reduced number of operating hours and the potential for increased operation and maintenance (O&M) costs.[37]

How does VRE generation match the demand profile today and in the future? The relationship between VRE generation and the hourly, daily and seasonal demand profile can indicate how quickly additional flexibility will be needed.

How robust is the portfolio of options to enhance system flexibility? System flexibility can be achieved in numerous ways (see Section 2). Having a clear picture of existing options offers a solid baseline to assess options for enhancing system wide flexibility and can be indicative of how urgently action may be required.

How are VRE resources geographically distributed across the system? Large concentrations of VRE capacity in a single or nearby geographic area may be more susceptible to localised weather patterns (clouds, wind gusts) that can induce high levels of variability in the system.[38] Additionally, highly concentrated VRE capacity poses higher risk of grid congestion and possible curtailment of VRE output.

Engaging domestic and international stakeholder communities

Thoughtful and deliberate engagement – both at domestic and international level – can help build political, institutional and technical momentum in the transition towards more flexible and modernised power systems. Policy makers can consider a variety of actions for engagement on power system flexibility that fit their specific goals, priorities and available resources. Options include:

[36] While some later-generation nuclear plants can be operated more flexibly, historically nuclear energy has been considered an inflexible resource. See Chapter 3 and the Annex B of this report for a more detailed discussion of nuclear power plant flexibility.

[37] Furthermore, some mid-merit plants already operating for a relatively low number of hours could experience declines of operating hours and revenue and become at risk of financial insolvency. At a system level, this trend can cause concerns about flexible power plant retirements and may require policy interventions to ensure that sufficient power plant flexibility is available.

Embrace engagement in global learning environments for flexibility. International engagement in established forums – such as the Advanced Power Plant Flexibility Campaign and the 21st Century Power Partnership – can help policy makers quickly understand the issues, prioritise solutions, and effectively implement decisions.

Disseminate assessment results and data widely to ensure that power system stakeholders understand near- and long-term flexibility needs. Dissemination of accurate and high-quality data facilitates investment decisions and helps maintain sound analysis capabilities among a broader community including potential investors, academia, research organizations and other advisors to government decision makers.

Facilitate domestic capacity-building through international learning and exchange. Many global best practices are emerging vis-à-vis policy solutions, planning practices, and decision support tools – supporting international engagement for ministry, regulatory and utility staff can enhance human capacity and ensure that domestic stakeholders are working cohesively.

Promote domestic analysis through facilitating data sharing and issuing public grants for clean energy research on system flexibility. Policy makers can issue calls for proposals for the research and analysis community to directly answer the questions they have about moving forward on system flexibility. Analysis activities will not only serve to strengthen human, technical and institutional capacity, but also help inform policy priorities and next steps for policy making.

Convene and participate in domestic and international workshops to share information and discuss power system flexibility issues and opportunities. Workshops can help raise awareness of system flexibility issues, review analysis and assessment results, advance dialogues around the evolution of market structures, build local capacity, and help enhance investment environments.

Engage directly with power plant operators and original equipment manufacturers (OEMs) to discuss the future flexibility requirements of the power system. Such dialogues can help communicate policy objectives and power system transformation goals to plant owners, highlight power plant flexibility as a potential avenue for performance and revenue improvement, help policy makers understand the requirements of plant operators, and inspire power plant flexibility retrofit concepts from OEMs.

Policy options to mitigate the need for additional power plant flexibility measures

As discussed earlier in this report, power plant flexibility is one among several factors that contribute to system-wide flexibility. In practice, different system-wide flexibility options are evaluated and compared via system-specific planning and operational studies. In general, interventions that enhance system-wide flexibility (e.g. balancing area co-operation, transmission network development) can reduce the need for power plants to operate more flexibly and thus the need for additional power plant flexibility measures.

A non-exhaustive list of approaches that may help enhance system-wide flexibility in relation to system conditions is presented in Table 5.1. The left column lists system-wide conditions that may require power plants to operate more flexibly. The right column lists policy options that can enhance system-wide flexibility, which in turn may mitigate the need for additional power plant flexibility measures.

Table 5.1 • Approaches to increasing system-wide flexibility

Sources of system-wide inflexibility that may require more flexibility from power plants	Policy options to reduce the need for additional power plant flexibility
Limited access to flexible resources in neighbouring power systems	**Increase communication and co-ordination among neighbouring balancing areas**, potentially through joint operations of day-ahead and real-time energy markets. Access to diverse generation resources over a wider geographic area can reduce the flexibility required from individual power plants. This can be achieved both through increased institutional co-operation and building additional interconnection infrastructure. Although the latter, is likely to be more costly, it can increase the reliability of power systems.
Frequent transmission network congestion – when transmission lines operate at or near their rated capacity	**Introduce regulatory instruments to enable the adoption of advanced strategies to increase available grid capacity** (e.g. dynamic line rating, line switching). Targeted investment in high-voltage transmission lines, distribution networks, protection schemes and other high-voltage network components, as well as digital control mechanisms.
Limited storage capacity and lack of demand that can be shifted, such as certain large industrial electricity users, or residential and commercial heating demand	**Incentivise adoption of technologies that enable demand shifting** and create market rules that encourage participation of demand-side resources in electricity systems and markets. Introduce instruments that reflect the system value of electricity storage deployment.
Large forecast errors for VRE plants	**Introduce among system operators centralised VRE forecasting systems** that integrate forecasts from third-party vendors, meteorological research institutions and individual VRE generators. Control centre operators may require additional training on VRE plant models and new decision support tools for integrating VRE forecasts into scheduling and dispatch decisions.

For a more exhaustive discussion of policy and operational approaches to increase system-wide flexibility, see, for example, 21CPP (2014), IEA (2014) and IEA (2017a).

Policy options to unlock flexibility in existing power plants

The section above outlines several strategies for reducing the need for additional power plant flexibility measures. However, depending on system context, measures to unlock power plant flexibility may still be required over and above pursuing those strategies. Policy makers play a central role in promoting power plant flexibility in power systems. The menu of policy options below offers potential strategies that can mobilise latent flexibility in existing power plants and contribute to least-cost operations in the overall system. These capital-light interventions can be encouraged through a range of regulatory and economic instruments. Policy solutions are organised into two categories:

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- Regulatory interventions that encourage more flexible operation of existing plants.
- Economic incentives that encourage more flexible operation of existing plants.

Interventions and incentives, whether part of a market structure or a regulatory scheme, should be carefully constructed and analysed so that potential unintended consequences can be identified and eliminated.

Regulatory interventions for more flexible power plant operation

Review "must-run" requirements

In some jurisdictions, power plants are granted minimum generation quotas (e.g. People's Republic of China) or fall under government regulations that require plants to operate above a prescribed minimum load factor (e.g. India). While these plants may be able to provide a limited amount of flexibility, relaxing certain must-run constraints can increase the flexibility of the power system. In other jurisdictions, generators may be designated as "must-run" for more localised reliability reasons and are not required to respond to market price signals or provide flexibility to the power system. In general, policy makers can review must-run designations to identify the potential benefits of increased flexibility and compare these benefits with the cost of alternative strategies for maintaining reliability (e.g. increased local transmission capacity). The system-level benefits of relaxing such requirements can also be weighed against economic impacts on individual plants.

Promulgate rules that allow state-of-the-art VRE to provide reserves

Spinning reserve requirements generally increase with higher shares of VRE. Using existing thermal power plants to provide this additional reserve can reduce the potential flexibility of the thermal generation fleet and limit the amount of VRE that can be integrated. However, as noted previously, state-of-the-art VRE capacity can provide some of these services and reduce requirements on the thermal generators. Enabling the provision of reserves from wind and photovoltaic generation can allow thermal generation levels to be reduced to minimum stable levels, which in turn can reduce VRE curtailment while allowing power plants to have a wider operating range. While this requires VRE generators to be run below full load to provide regulation, it is possible that allowing a small amount of VRE to be dispatched as needed (and when it is economic to do so) can help to prevent longer periods of scheduled VRE curtailment. Moreover, new strategies such as the introduction of asymmetric reserve products, which allow VRE to provide only downward regulation, or managing the output of wind farms through selected units, provide a greater balance between flexibility provision and output curtailment. The feasibility of such measures can be assessed through production cost models (PCMs) and may require the introduction of incentives to compensate for production losses.

In a well-developed wholesale electricity market, this problem is often already solved by arrangements for frequency regulation. This is because regulation services, which can be provided by hydro or thermal resources, have prices that do not disincentivise the resource from selling regulation vs. selling energy. Thus the price of regulation will never be less than the price of energy, and is usually higher. If this market construct operates in a country that is considering obtaining frequency from VRE, then the only concern would be to find a policy solution to compensate VRE for lost energy if it is dispatched downward.[39]

[39] For example, wind power plants in Ireland equipped with inertia emulation can be used to provide ultra-fast services for fast frequency response and primary operating response. Using such technology for the provision of these services removes

Encourage market and system operators to implement strategies for "faster" grids

Existing power plant flexibility can be more efficiently accessed by implementing faster scheduling and dispatch intervals (e.g. 5 or 15 minutes) and shorter gate closure periods. By dispatching the system at shorter intervals, the amount of conventional generation required to balance the system (i.e. regulation services) can be reduced. This is because the resources subject to economic dispatch are generally not allowed to alter their output for the hour, stranding whatever capability these plants may have to respond to flexibility needs within that hour. This effect is also driven by lower forecast errors (for both demand and VRE generation) as the time interval of scheduling, dispatch and gate closure is shortened.

Ultimately, this reduces the amount of conventional generation that must be held in reserve and improves the economics of running the power system. These reductions can thus free up power plant capacity for providing energy and other ancillary services. In general, faster markets and dispatch intervals can lead to a more cost-efficient power system (both in market and non-market structures), while financially encouraging more flexible power plant operations. Sub-hourly markets have been shown to provide price signals that incentivise higher-cost generators to provide intra-hour flexibility.[40]

Box 5.1 • Portfolio co-ordination at high shares of VRE. Case study by Kyushu Electric Power Co.

With 6 GW installed PV capacity, 16 GW peak load and 8 GW minimum daytime load, Japan's southern-most island, Kyushu has the highest VRE penetration in Japan. This has motivated the development of sophisticated operation strategies to optimise the capabilities of the existing thermal, reservoir hydropower and pumped storage hydropower plants.

To accommodate today's levels of variability and uncertainty, Kyushu Electric Power Co currently applies six power system dispatch rules developed by the Japanese Organization for Cross-regional Coordination of Transmission Operators:

- Avoid generation from reservoir and pumped storage hydropower plants during daytime.
- Prioritise absorption of surplus electricity by pumped hydropower storage plants.
- Reduce the output of thermal generation plants to minimum stable levels.
- Export surplus electricity through cross-regional system's interconnection lines.
- Reduce the output of biomass power plants.
- Curtail solar PV and wind power as a last resort.

Example implementation of priority dispatch rules during sunny day

On 30 April 2016, PV output peaked at 13:00 peaked at 5.65 GW, or 73% of demand in Kyushu. According to the priority dispatch rules, pumped storage plants absorbed part of this generation, as they had spare storage capacity after releasing energy to cover the morning peak. As shown in

the need for the wind power plant to run below full load and can avoid incurring the associated production and revenue losses (EirGrid, 2017).

[40] See *Market Characteristics for Efficient Integration of Variable Generation in the Western Interconnection* by Michael Milligan and Brendan Kirby; www.nrel.gov/docs/fy10osti/48192.pdf.

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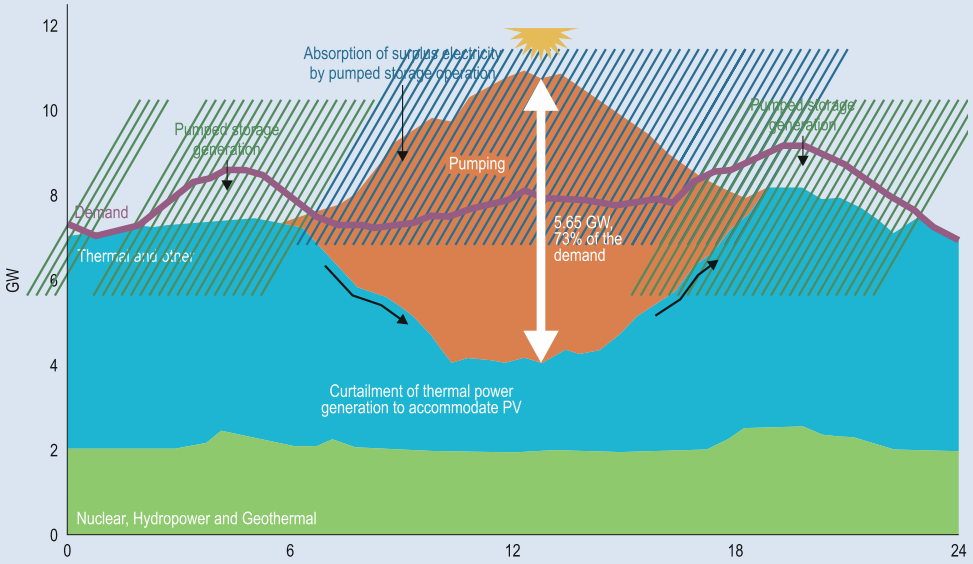
Figure 5.2 below, thermal capacity ramped down toward their minimum stable levels, with hydro pumping helping to avoid complete plant shutdown. Pumped storage also helped cover the evening demand peak with stored PV electricity. Avoiding thermal generation shutdown is an important priority in Kyushu, as the start-time for steam generators is currently up to 8 hours and 2 hours for CCGT units.

Figure 5.2 • Portfolio management for VRE curtailment avoidance



Source: Kyushu Electric Power Co. Ltd.

Key point • Portfolio management approaches can increase system flexibility, reduce operational costs and avoid VRE curtailment.

On this day, Kyushu's power system was close to the portfolio's current flexibility limit before requiring cross-regional exports or VRE curtailment. As PV output decreased at 1.3 GW/hour due to lower irradiation in the afternoon, thermal power plants were dispatched to increase their output while the pumping was stopped to accommodate the reduction in PV output.

Example of balancing solar PV forecast errors

PV forecast errors have also been one of the main issues, which can drive requirements for flexibility. On 5 May 2016, peak PV output was 2 GW greater than the intraday forecast. The day-ahead PV output forecast was modified at 04:00 am due to lower than expected PV output, resulting in an unexpected additional generation of 2 GW. In this case, pumped storage plants were able to supply additional energy in the morning and store available solar generation in the afternoon.

Economic incentives for more flexible power plant operation

Creation of new revenue streams to reward flexibility

As mentioned in Chapter 3, many legacy power plants that operate in today's power system were deployed with a specific expectation of generation behaviour in mind (e.g. a coal-fired power

plant built to operate at near-maximum output to serve baseload); this expectation influenced the technical design of plants and also the operating conditions that the plant requires to maintain financial viability. With VRE penetrations increasing in power systems, however, the operating conditions of many power plants are shifting to a need for more flexible modes of operation. Thermal plants, in particular, must be increasingly available to rapidly up- and down-ramp to provide energy, but in order to do so may require reduced output and/or operating hours relative to their legacy behaviour, leading to a reduction in revenue. In these cases, new revenue streams may be necessary to appropriately reward power plants for the value they provide the system by being available to provide flexibility services. The exact nature of this value can be identified through PCM exercises, as mentioned in Chapter 4. Discussion of specific measures and approaches is offered in the subsequent chapter section, "Policy options to facilitate investment in additional power plant flexibility".

Oversee review of electricity and fuel contracts and propel changes that would enhance flexibility

Power plants may be under contract structures that restrict their ability to operate flexibly. Take-or-pay fuel contracts are common in gas-fired generation or for ensuring fuel supply availability during the life of generating plants. Other types of generation, such as hydropower, can also be under take-or-pay contracts. For example, most of Thailand's hydropower generation purchased from neighbouring Lao People's Democratic Republic depends on some form of take-or-pay contract to ensure the delivery of non-energy services. However, take-or-pay contracts can also be specified as a minimum energy purchase volume in power purchase arrangements, fixed remuneration schemes for VRE generation, and fixed heat delivery contracts for co-generation plants.

Contractual inflexibility is also relevant in vertically integrated systems, as system operators may also be subject to power purchase arrangements. Contract reviews are done by the involved parties, but the introduction of flexibility provisions can be overseen by regulators while communicating results to policy makers. Regulators can also introduce requirements to ensure flexibility in both the ongoing contract negotiation and future contract revisions, but likely require a mandate from policy makers to do so. The scope for direct action from policy makers may be greater for specific technology support schemes, for example the introduction of variable tariffs for VRE generation or ensuring payment for a specific amount of energy delivered. Reviewing contract terms can be a particularly useful approach for unlocking power plant flexibility that is technically available but economically disincentivised. However, such efforts must be approached with significant caution and sensitivity to perceptions among the power sector investment community, given the sensitivities surrounding offtakers honouring financial contracts.

Encourage power plant participation in competitive energy markets

Energy markets provide price signals that indicate the value of electricity generation in different locations and at different times. Encouraging power plants to participate in energy markets can help to extract flexibility from existing resources by more accurately valuing energy production at different times of the day and throughout the year. Price signals can, for example, incentivise co-generation plants to increase heat storage capacity, enabling more flexible delivery of electricity at different times of the day.[41] In certain cases, a shift to direct market participation,

[41] Short-term heat storage for co-generation plants is widely implemented in Denmark, where nearly 70% of all private homes are connected to district heating systems. Further reading: https://ens.dk/sites/ens.dk/files/Globalcooperation/regulation_and_planning_of_district_heating_in_denmark.pdf.

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away from bilateral energy contracts or policy-prescribed energy quotas, can lead to negative economic impacts for individual power plants. These costs can be weighed against system-level benefits of increased flexibility and market competition. The system-level benefits of market participation can also be used as a benchmark for the design of a fair compensation scheme to maintain the economic viability of existing power plants, as described in the section above, "Creation of new revenue streams to reward flexibility".

Policy options to incentivse investment in additional power plant flexibility

It is considered good practice to evaluate multiple potential investment pathways in order to establish a cost-effective flexibility strategy; this can be done using the methods outlined in Chapter 4. Once an investment plan has been formulated, it may be appropriate to introduce remuneration mechanisms for new power plants, including market-based mechanisms and other options that are applicable to a regulated structure. Such remuneration measures can be designed to recognise the increasing need for (and system value of) new investment in power plant flexibility, and to provide fair compensation for the flexibility services the plants will provide while also taking into account the expected operational behaviour. Approaches to new power plant remuneration tend to be relatively distinct, based on the type of power system (i.e. from wholesale market to regulated utility).

Options to unlock investment in power plant flexibility – wholesale market systems

Improve pricing approaches in short-term energy markets

Short-term energy markets, also referred to as spot markets, play a crucial role in incentivising flexibility, including recovering capital costs for flexibility investments. The more flexible a power plant is, the more dynamically it can respond to rapidly changing market conditions. Hence, designing markets that are capable of forming robust prices frequently and close to real time are a critical building block for incentivising flexibility.

For example, the spot market in Europe consists of a day-ahead and intraday market. As the name suggests, the intra-day market allows for trading on the day of delivery, up to 45 minutes before real-time operations. Under such an arrangement, a sudden surge in market prices – for example because of the unexpected failure of a large power plant or a VRE forecast error – will provide a strong incentive for power plants to respond quickly and increase their output or start up operation. Conversly, in case there is an unexpected oversupply of power, market prices may turn negative and provide a strong economic signal to reduce output. This mechanism – together with the opportunities coming from system services markets (see below) have been a primary economic driver for retrofitting power plants in Europe. Developing a robust and liquid intra-day market requires a number of facilitating steps, including measures to incentivise accurate demand and supply forecasts by all market participants.

Establish advanced markets for system services

Shifting flexibility requirements in transforming power systems may call for new types of market products or other economic constructs that provide appropriate remuneration for critical system services. This can take the form of competitive procurement form system operators or the establishment of new products that can be traded directly.

The provision of system services (such as frequency response) can be a lucrative revenue stream for power plants, provided that they are sufficiently flexible to meet required specifications. The provision of system services generally requires power plants to respond rapidly and reliably to unexpected system conditions. The main difference between regular wholesale energy markets and system services markets is that system operators act as the single-buyer in such markets. Exact product definitions and remuneration systems vary from one country to the next.

Implement mechanisms to value flexibility in liberalised markets

Market mechanisms can be implemented to remunerate power plants (and, if appropriately designed, flexible demand and other resources) for their ability to provide capacity, flexibility and other system services, serving as a supplement to the payments they receive from selling energy. These payments may reward resources for their *availability* to provide services, or provide a volumetric payment for the quantity of services received, or both. In any case, they can incentivise investment in new flexible power generation, especially in cases where a "premium" payment is provided to power plants complying with specific flexibility requirements, including quick-start capability, faster ramp rates, or ramp rate control capabilities. The exact level of payment a plant may receive can be determined through competitive procurement (e.g. auctions), but other administrative mechanisms exist as well. Moreover, they can help mitigate the financial impact of reduced operating hours that some flexible power generation units experience over time, including when VRE penetration increases. Under these conditions, certain flexible power plants may be necessary to the system from a technical standpoint, but are unable to maintain financial solvency due to a low number of operating hours and/or insufficient energy prices. In general, such instruments should be designed in a way that minimises distortions on wholesale electricity markets and promotes market entry of innovative solutions.

Options to unlock investment in power plant flexibility – regulated systems

Allow cost recovery for retrofit investments in regulated power plants

If a proposed retrofit project for a regulated power plant is considered cost-effective and appropriate for the system, regulators can consider allowing retrofit costs to be passed through to ratepayers. Ideally, such regulatory decisions are informed by cost-benefit analyses conducted with production cost modelling techniques that evaluate multiple flexibility measures. A variety of cost-benefit analysis methods can be used to determine whether a retrofit project is cost-effective and appropriate. Ultimately, the specific techniques used to determine cost-effectiveness are highly dependent on the local regulatory context.

Provide financial incentives that encourage new fossil-fuelled power plants to utilise high-flexibility technical components

In some cases it may be appropriate to offer direct financial incentives to encourage new power plant investors to use high-flexibility technical components. Paying an incremental incentive amount upfront may obviate the need for more expensive power plant flexibility investments in the future. In financial terms, spending additional ratepayer or taxpayer funds upfront to ensure highly flexible technologies are utilised may be considered a hedge against a range of uncertain futures with flexibility needs and costs.

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Policy approaches to enhance long-term planning processes

Even in a scenario where no immediate-term flexibility shortfall exists, policy makers can help influence how effectively future flexibility requirements are planned for. As mentioned in Chapter 4, it is good practice to accompany longer-term PST goals with a long-term system flexibility strategy. In practice this means modifying how system planning is done, both with respect to the decision support tools and methods employed, and the specific questions asked during planning processes. This long-term strategy may also include the alternative risks of developing too much, or too little, flexibility, allowing for the treatment of uncertainty in the process. Characterising future expectations of system flexibility requirements, and charting a path toward addressing them, are important steps in mitigating the long-term costs and operational impacts of PST.

Require technical flexibility assessments during regularly planned system adequacy assessments

It is normal practice for utilities and system operators to regularly assess the reliability and adequacy of their power systems – these assessments often happen at predetermined intervals (e.g. annually) and are often performed in response to specific regulatory requirements.[42] Creating a regulatory requirement mandating that these exercises also include a technical flexibility assessment would help to ensure that system flexibility insights can be used to inform long-term planning exercises.

Request the creation of a comprehensive system-wide flexibility inventory

System flexibility can be sourced from a number of alternatives, such as power plants, transmission and distribution investment, electric storage, and demand-side management (see Chapter 2 for a discussion of system flexibility measures). Assembling a clear picture of options to increase system flexibility – including power plant flexibility measures – helps to ensure that planning exercises are informed by the best possible data on options for the future. To that end, policy makers and regulators can consider requiring the creation (and periodic updating) of system-wide flexibility inventories. This process is discussed in Chapter 4 in the context of power plant flexibility measures.

Encourage including operational flexibility parameters in long-term planning tools

Long-term resource planning tools (e.g. capacity expansion models) tend to incorporate a relatively approximate representation of power system operations and many common system flexibility considerations (e.g. ramping flexibility requirements). However, with a more comprehensive perspective of available flexibility resources and constraints, it is nevertheless possible to incorporate coarse flexibility considerations into these long-term planning tools. By including certain flexibility parameters and constraints, resource planning tools can provide incrementally improved insights into long-term system flexibility needs to identify the most cost-effective investment pathways.

[42] For example, the South African grid code imposed by the National Energy Regulator of South Africa requires that Eskom (the vertically integrated utility and system operator) publishes a "Medium-Term System Adequacy Outlook" annually (Eskom, 2017), which provides a five-year outlook of the ability of the generation fleet to reliably meet demand.

Encourage including production cost modelling methods in long-term planning exercises

Traditional resource planning techniques may not consider aspects of flexibility with sufficient temporal and spatial granularity to consistently propose an adequately flexible and reliable least-cost power system. Incorporating production cost modelling (and/or technical flexibility assessments) into long-term planning exercises can help identify more optimal investment plans and uncover specific power plant flexibility characteristics that may be required for the power system in the coming decades (this is discussed in more detail in Chapter 4). To the extent required, policy makers and regulators can consider requesting that utilities and system operators use PCM exercises more holistically during planning exercises to evaluate the costs and benefits of potential flexibility measures (as well as other technical elements). To best facilitate PCM exercises, it may also be important for policy makers to specify an institutional home and collection mechanism for all the data required by the PCM. In reality, this is an ongoing process, as power system data are continuously evolving and PCM exercises are typically performed annually or every six months to ensure that systems are adapting appropriately for the entire long-term planning period.

Encourage cost-benefit assessment of local and regional transmission and distribution investment

Among the numerous flexibility measures that can be considered during a planning exercise, enhancing the ability of the transmission and distribution system to deliver flexibility is considered a central strategy for promoting cost-effective PST pathways. Production cost modelling assessments of costs and benefits can help inform the extent to which new transmission and distribution infrastructure will yield system flexibility and reduce operational costs, and perhaps at a higher level whether such projects would be appropriate to pass through to ratepayers. While transmission and distribution investments are already considered during most system planning exercises, they are often considered separately from generation investment exercises. Policy makers and regulators can help ensure that transmission and distribution planning processes are better integrated with generation planning,[43] particularly as the latter begins to include a more holistic consideration of system flexibility.[44] This process is often referred to as integrated resource planning, which also takes into account the demand-side options.

For example, Mexico has recently changed its long-term planning practice by adopting the new long-term integrated planning procedure, the National Power Sector Development Programme (PRODESEN), which takes into account generation additions/retirements, transmission expansion and distribution expansion programmes. This change not only modified the expected technology mix, but also the likely location of new generation investments and thus long-term transmission expansions. From this planning method it became clear that wind and solar photovoltaic technologies would play a vital role in achieving the country's objective of 35% of its power supply to be sourced from clean energy in 2024 (SENER, 2016).

[43] The integration of generation and transmission planning has a number of benefits not discussed in this report. See, for example, IEA (2017b)

[44] A more difficult to quantify, yet important benefit of regional transmission is the increased reliability that results. Reserve activation during a contingency event can be enhanced because of greater resource availability. In the long term, a stronger transmission system coupled with co-ordinated system operation over a larger footprint can also reduce the need for investment in new resources. NREL (2012) shows this in an extreme case of "perfect" transmission and operational co-ordination. In reality, the reduction in installed capacity would be less.

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Encourage cost-benefit asssement of demand-side resources and electricity storage options

As specified in Chapter 2, demand-side resources (DSR) and electricity storage options are also key hardware and infrastructure components for providing system flexibility and accommodating the integration of VRE. Importantly, DSR and storage options can have an impact on the requirement for power plant flexibility. In the long-term planning process, the costs and benefits of DSR and storage options should be taken into consideration due to their potential flexibility potential.

For DSR, a number of potential options can be included in the long-term planning procedure. These options include energy efficiency options, demand response programmes that depend on possible tariff structures (e.g. real-time pricing, critical peak pricing, direct load control) and system conditions (e.g. event-based and non-event-based). These DSR options have different impacts on the system and their associated costs also vary according to type.

As described in previous chapters, electricity storage options consist of many technology types, including pumped hydropower and battery storage. These technologies can have notable impact on system flexibility, particularly in a system with a high penetration of VRE (i.e. from Phase 3 of VRE integration). Long-term planning processes can also effectively analyse the costs and benefits of storage options, particularly their potential to reduce possible VRE curtailment (IEA, 2016).

Summary of policy priorities

The six areas discussed above can be summarised with specific action priorities for policy makers.

1: ASSESS – Commission assessments of system-wide flexibility requirements, opportunities and barriers, including the role of power plant flexibility. Peridiodically refresh these assessments to inform both near- and long-term decision-making and planning processes.

2: ENGAGE – Engage with stakeholder communities to strengthen technical, policy, and institutional capabilities to enhance power system and power plant flexibility. Engage with international communities to share best practices.

3: ENHANCE – Enhance the use of available power system flexibility through adapting a range of market, regulatory, and operational best practices at the system level.

4: UNLOCK – Update regulations**,** policies and practices that govern power system operation to unlock latent flexibility. These options include more flexible power purchase agreements with independent power producers and and fuel supply contracts for thermal generators.

5: INCENTIVISE – Facilitate opportunity to seek fair and appropriate remuneration for all assets that can provide flexibility to the power system through changes to policy, regulatory and market frameworks.

6: ROADMAP – Enhance planning procedures to incorporate future expectations of system flexibility requirements; ensure consideration of all possible flexibility options to mitigate the long-term costs and operational impacts of power system transformation.

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Abbreviations and acronyms

AC	alternating current
AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
APPF	Advanced Power Plant Flexibility
CAES	compressed air energy storage
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CEA	Central Electricity Authority (India)
CEM	Clean Energy Ministerial
CExM	capacity expansion model
CERC	Central Electricity Regulatory Commission (India)
CSP	concentrated solar power
CT	combustion turbine
DC	direct current
DFID	Department for International Development (United Kingdom)
DR	demand response
DSM	demand side management
ED	economic dispatch
EFR	enhanced frequency response
EPPEI	Electric Power Planning and Engineering Institute (China)
FACTS	flexible alternative current transmission system
FL	full load
GE	General Electric
GIZ	Gesellschaft für Internationale Zusammenarbeit (Germany)
GHG	greenhouse gas
HDGT	heavy duty gas turbines
HoF	Hot Start on the Fly
HRSG	Heat recovery steam generators
HSCPS	hydraulic short-circuit pumped storage
HV	high-voltage
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IPP	Independent Power Producer
IT	information technology
KMW	Kraftwerke Mainz Wiesbaden
LCOE	Levelised cost of energy
LoLP	loss of load probability
MSL	minimum stable level
NDRC	National Development and Reform Commission (China)
NEA	National Energy Administration (China)
NPP	nuclear power plants
NPV	net present value
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
OCGT	open-cycle gas turbine
OEM	original equipment manufacturer
OPEX	operational expenditure
ORDC	operating reserve demand curves

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PC	Pulverised coal
PCMs	production cost model
PPA	power purchase agreements
PSH	pumped storage hydro
PV	photovoltaic
PWR	pressurised water reactors
RE	renewable energy
SAIDI	System Average Interruption Duration Index
SPS	special protection scheme
SVC	static var compensator
TOTEX	total expenditure (CAPEX + OPEX)
TPM	transmission planning model
TSO	Transmission system operator
UC	unit commitment
UHV	ultra-high-voltage
USAID	United States Agency for International Development
USC	ultra-supercritical
VoLL	value of lost load
VRE	variable renewable energy
WAM	wide area monitoring system

Units of measure

EJ	esajoule
GW	gigawatt
h	hour
Hz	hertz
kV	kilovolt
kW	kilowatt
min	minute
MJ/s	megajoules per second
MVA	megavolt ampere
MW	megawatt
MWh	megawatt hour
MW/min	megawatts per minute
s	second
TWh	terawatt hour

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