

China Power System Transformation

Assessing the benefit of
optimised operations and
advanced flexibility options

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Abstract

China Power System Transformation has a two-fold objective. First, it provides a summary of the state of play of power system transformation (PST) in the People's Republic of China ("China") as well as a comprehensive discussion of PST internationally. This includes a comprehensive review of all possible sources of power system flexibility (power plants, grid infrastructure, storage, and demand-side response) and a detailed discussion of market, policy, and regulatory frameworks to effectively mobilise power system flexibility. Second, it presents findings from a detailed power sector modelling exercise for China in 2035, building on the 2018 *World Energy Outlook* New Policies and Sustainable Development Scenarios. The modelling identifies the establishment of spot markets and trade between provinces as two of the main elements to improve system operation efficiency in China. In order to integrate very high shares of variable renewables consistent with the *WEO* SDS, activating the demand side – especially electric vehicles – and targeted use of electricity storage are found to be crucial for an accelerated transformation of the Chinese power system.

Highlights

- **The rise of low-cost wind and solar power, deployment of distributed energy resources (DER) and increasing digitalisation are accelerating change in power systems around the world, including the People's Republic of China ("China").** With the right framework conditions in place, these trends can combine, leading to a much stronger integration between the demand and supply sides while allowing a more rapid uptake of variable generation resources, notably wind and solar power. "Power system transformation" describes the processes that facilitate and manage changes in the power sector in response to these novel trends.
- **Power system flexibility – a concept that goes beyond power plant flexibility – is the crucial element for a successful transformation of the power system at growing proportions of wind and solar power in China.** Traditionally, flexibility has been associated with the more flexible operation of coal power plants in China. However, the concept of power system flexibility is much broader. Apart from power plants, it can be provided by grid infrastructure, demand-side response, and electricity storage. Changes to market, policy, and regulatory frameworks are crucial for unlocking flexibility.
- **Establishment of spot markets and trade between provinces are two of the main elements to promote power system transformation in China.** Building on the *World Energy Outlook (WEO) New Policies Scenario*, modelling results indicate that if current efforts to implement economic dispatch, boost short-term inter-regional trading and expand transmission interconnectivity succeed, annual power system operational costs in 2035 can be reduced by 15% or USD 63 billion (United States dollars) annually, and power sector CO₂ emissions reduced by up to 750 million tonnes per year.
- **Power system flexibility is the most important cornerstone of a fundamentally transformed Chinese power system which achieves the goals of the Paris Agreement.** Building on the *WEO Sustainable Development Scenario*, modelling results indicate that utilising advanced flexibility measures such as smart electric vehicle charging, demand-side response, and electricity storage can support the reliable integration of extremely high shares of variable generation without any substantial variable renewable energy curtailment in 2035, while simultaneously reducing power system operational costs between 2-11% and reducing the need for fossil generation capacity by up to 30%. Other clean energy technologies such as nuclear power and carbon capture and storage benefit from flexibility in the form of increased utilisation.
- **Accelerated progress on power sector transformation could bring substantial benefits in China and the world.** An accelerated transformation of the Chinese power system could bring significant benefits in the drive to limit climate change in line with the Paris Agreement. China can use the path of power system transformation to make accelerated progress in restructuring its economy towards a pattern of growth in advanced high-quality industrial sectors, while making clean energy technologies affordable for countries around the world – including today's developing countries, which will see a rapid increase in energy demand over the coming years.

Executive summary

China Power System Transformation has a two-fold objective. First, it provides a summary of the state of play of power system transformation (PST) in the People's Republic of ("China") and a comprehensive discussion of PST internationally. Second, it presents findings from a detailed power sector modelling exercise for China in 2035, which explores the impact and value proposition of various public policy and technology deployment options currently under consideration by Chinese policy makers. The report provides a number of insights on possible Chinese PST pathways based on the results of this modelling exercise.

Actions to boost flexibility and investment

Power system transformation requires action to boost power system flexibility and support clean energy investment. Global experience suggests that PST requires the co-ordinated orchestration of actions across the entire value chain of electricity production and consumption to facilitate cleaner, more reliable, more resilient and more affordable power systems. A number of interventions can be made to support PST and promote the increasingly important characteristic of power system flexibility.

Traditionally, flexibility has been associated with the more flexible operation of coal power plants in China. However, it encompasses all resources of the power system that allow for its efficient and reliable operation at growing shares of variability and uncertainty. Apart from power plants, it can be provided by grid infrastructure, demand-side response and electricity storage. In a transformed power system with higher shares of variable renewable energy (VRE), the importance of flexibility options beyond power plants increases sharply. This can open synergies with other developments in the energy sector, such as the deployment of electric vehicles (EVs).

Modelling analyses

Advanced energy modelling exercises explore the value of reform goals and innovative system flexibility measures. The energy modelling analysis presented in this report builds on two International Energy Agency (IEA) *World Energy Outlook 2018* (WEO 2018) energy system scenarios for China for 2035. These scenarios provide the overall energy system setting, including installed power generation capacity. For this report, the power sector is modelled at a much higher level of detail, based on eight regions. In addition, different cases are analysed that represent changes in the way the power system is operated and how much power system flexibility is available.

The New Policies Scenario (NPS) aligns with the achievement of China's Document No. 9 reforms and aims to provide a sense of where today's policy ambitions seem likely to take the energy sector in China. The NPS cases are used to explore the value of currently considered policies, notably the ongoing power market reform that aim to introduce spot markets and increase levels of cross-provincial trade.

The SDS achieves the main energy-related outcomes of the Sustainable Development Goals, including delivering Paris Agreement commitments, achieving universal access to modern energy by 2030 and dramatically reducing negative health outcomes due to energy-related air pollution. Its vision is aligned with the "Beautiful China" initiative proposed at the 19th National

Congress in 2017 as the general blueprint for China's future development. The SDS is used to explore the importance of advanced flexibility options – in particular on the demand side – to support a deeper transformation of the system.

Spot markets and trade

Establishing spot markets and trade between provinces are two of the main elements to improve system operation efficiency in China. China's goal of a transition from fair to economic dispatch would result in significantly lower power system operational costs and improved ability to integrate wind and solar power. Detailed power sector modelling results for the NPS indicate that China's ongoing market reforms to introduce economic dispatch make good financial sense and should strongly benefit the environment. Transferring to economic dispatch could yield an annual operational cost saving of approximately 11% or USD 45 billion (United States dollars) per year in 2035, sharply reducing VRE curtailment and power sector CO₂ emissions by 15%. The implementation of spot markets in China is a crucial element of realising these benefits.

Increasing power trading and further expanding regional transmission interconnectivity will yield substantial economic and environmental benefits, and promote clean energy investment. Boosting power trading has long been considered a national priority in China. While some cross-regional, mid- and long-term trading already occurs, modelling results indicate that if current efforts to implement economic dispatch, boost short-term, inter-regional trading, and expand transmission interconnectivity succeed, annual power system operational costs will reduce even more, and savings will reach 15% or USD 63 billion annually. Power sector CO₂ emissions will reduce by up to 750 million tonnes per year. Notably, VRE curtailment is effectively eliminated when these reform goals are achieved, as greater interconnectivity and competition allow VRE resources to serve a significantly broader market. Thus, the achievement of these reforms would help promote a stable investment environment for clean energy technologies, which is a crucial factor for reaching PST goals. Significant efforts by policy makers will be required to orchestrate and harmonise various markets so that they co-ordinate with one another, while also encouraging broad participation by both state-owned and private generators.

Advanced power system flexibility

Activating the demand side and targeted use of electricity storage are crucial for an accelerated transformation of the Chinese power system. Power system flexibility is the most important cornerstone of a fundamentally transformed Chinese power system that achieves the commitments in the Paris Agreement. In the SDS, which represents an accelerated transformation of the Chinese power system, VRE resources account for 35% of annual electricity generation. Modelling results indicate that utilising advanced flexibility measures enabled by digitalisation – such as smart EV charging, demand-side response, and electricity storage – can support the reliable integration of extremely high shares of variable generation without any substantial VRE curtailment in 2035, while simultaneously reducing power system operational costs by between 2% and 11%. Other clean energy technologies, such as nuclear power and carbon capture and storage, also benefit from the presence of these measures in the form of increased utilisation. Furthermore, the deployment of these measures significantly reduces the need for investment in new fossil capacity by as much as 300 gigawatts, or 30% of the total installed fossil generation capacity in the SDS in 2035. In sum, boosting power system flexibility beyond readily available options (e.g. existing coal-fired power plants) is one of the most important priorities for enabling a rapid transformation of the Chinese power system.

International implications

Accelerated progress on power sector transformation could bring substantial benefits to China and the world. The accelerated transformation of the Chinese power system could bring significant benefits in the drive to limit climate change in line with the Paris Agreement. China is already a global leader in clean technologies. Chinese solar PV manufacturers have played and continue to play a vital role in the rapid decline of solar PV costs. Moreover, the dynamic expansion of electric mobility in China and the associated expansion of the EV value chain have put downward pressure on electric batteries and, ultimately, EV prices. China also has a very well-developed digital communications and software industry, which is an ideal setting to make accelerated progress in the implementation of digitally enabled, demand-side response. China can use the path of PST to accelerate progress in restructuring its economy towards a pattern of growth in advanced high-quality industrial sectors, while making clean energy technologies affordable for countries around the world – including today's developing countries, which will see a rapid increase in energy demand over the coming years.

Findings and recommendations

Report context and objectives

This document summarises the main messages of the *China Power System Transformation* report. The full report has two objectives. First, it provides a summary of the state of play of power system transformation (PST) in the People's Republic of China ("China") and a comprehensive discussion of PST internationally. Second, it presents findings from a detailed power sector modelling exercise for China in 2035, which explores the impact and value proposition of various public policy and technology deployment options currently under consideration by Chinese policy makers. The report provides a number of insights on possible Chinese PST pathways based on the results of this modelling exercise.

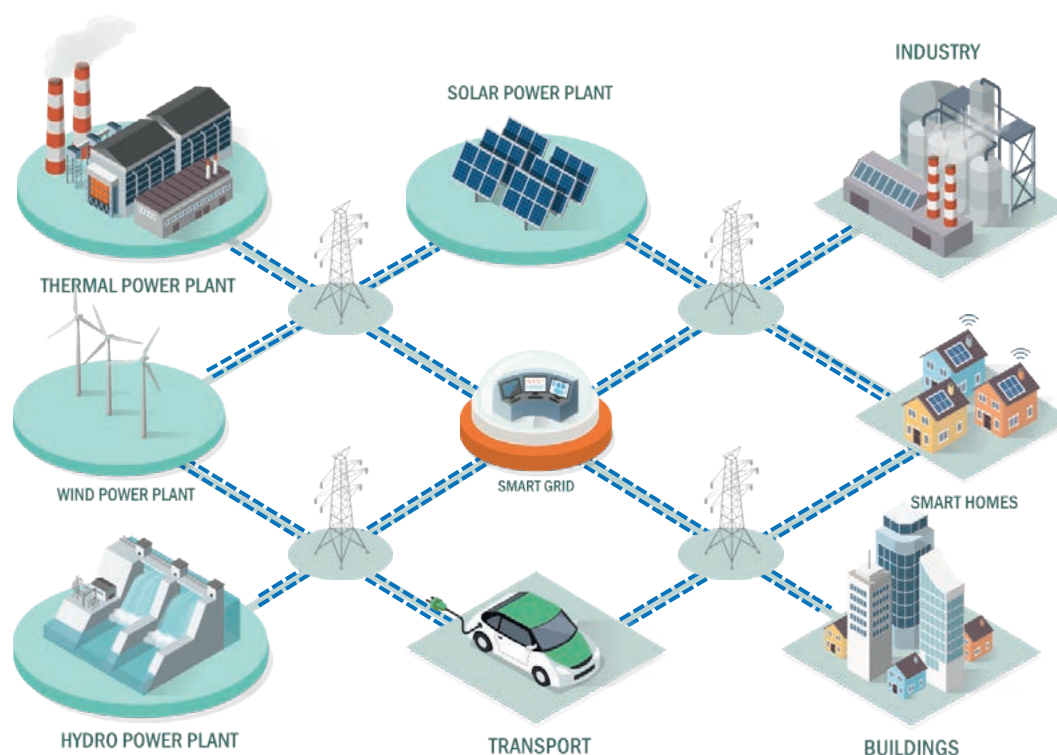
Drivers of change in power systems

The rise of low-cost wind and solar power, deployment of DER and increasing digitalisation are accelerating change in power systems around the world. Throughout the world, power systems are undergoing a period of profound change. The fundamental drivers behind this transformation are threefold. First, renewable energy – in particular wind and solar power – is on track to becoming the cheapest source of new electricity generation in many regions of the world. Wind and solar photovoltaics (PV) can already out-compete new natural gas, and even coal-fired power plants, in areas with high-quality resources and low financing costs. This is leading to transformation on the supply side of electricity.

Second, distributed energy resources (DER) such as electric vehicles (EVs) and rooftop solar PV systems are changing the value chain of electricity. The demand side is poised to play a much more active role in the system, and distributed generation is emerging as a more relevant complement to large-scale generation.

Third, digitalisation of the power sector is expanding from the transmission level – where digital sensors and controls have been used for decades – into medium- and low-voltage networks, all the way to individual devices. This increased connectivity opens up advanced options to more dynamically match demand and supply.

With the right framework conditions in place, these trends can combine to bring more fundamental change to power systems, leading to a much stronger integration between the demand and supply sides while allowing a more rapid uptake of variable generation resources (Figure 1).

Figure 1. Illustration of an interconnected energy system enabled by digitalisation

Source: IEA (2017d), *Digitalisation and Energy*.

Digital technologies enable a multi-directional and highly integrated energy system. Pre-digital energy systems are defined by unidirectional flows and distinct roles.

“Power system transformation” describes the processes that facilitate and manage changes in the power sector in response to these novel trends. It is an active process of creating 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. It is a complex task for policy makers.

Rapid growth of wind and solar PV

Wind and solar power are experiencing rapid growth in China and further cost reductions could accelerate their deployment. China added 44.26 gigawatts (GW) of solar PV in 2018 – this increased total installed capacity by 34% compared to 2017 and accounted for 53% of the global market for the technology. Wind power increased by 20.59 GW and total installed capacity reached 184 GW at the end of 2018. This means that wind and solar accounted for 52.9% of capacity additions in China, demonstrating their position as a mainstream source of electricity. Importantly, generation from wind and solar PV continue to rise, while curtailment levels are falling. Wind generation increased by 20% year on year in 2018, while curtailment fell by 5 percentage points and stood at 7% in 2018. Generation from solar PV grew by 50% over the same period and curtailment fell by 2.8 percentage points and stood at 3% in 2018.

Continued cost reductions could further accelerate wind and solar PV uptake – in China and globally. Wind and solar PV currently receive higher remuneration than coal-fired generation in China. The associated additional costs have been a concern for Chinese policy makers and recent policy changes in China have reduced deployment expectations for solar PV in 2019.

However, if wind and solar PV achieve cost parity with coal-fired generation, they could experience accelerated uptake. Current trends are encouraging in this regard and the Chinese government has announced several pilots for subsidy-free wind and solar PV plants for 2019. This makes it relevant to investigate the ability of the Chinese power system to absorb much higher proportions of variable renewable energy (VRE) in the future.

Very high shares of variable renewables are technically possible. International experience clearly demonstrates that there is no hard technical limit to the uptake of VRE in power systems. In countries where such limits were announced, further investigation showed that limits could be overcome. Technical solutions exist to deal with all issues that may arise from the increased variability and uncertainty inherent in wind and solar PV generation, or from their specific technical design that makes them behave differently on the power system compared to conventional power plants.

Reaching high shares of variable renewables in a cost-effective way calls for a system-wide approach. As experience in a large number of countries demonstrates, traditional approaches to integrating VRE do not take a system-wide perspective. VRE is often treated in isolation from the rest of the system and measures aim to make VRE more similar to conventional generators. However, such an approach becomes increasingly inefficient at growing shares and can lead to unnecessary high costs and/or curtailment. Advanced methods take a systemic approach that aims for a more comprehensive transformation of the power system. The main paradigm of such a transformation is an increase in power system flexibility.

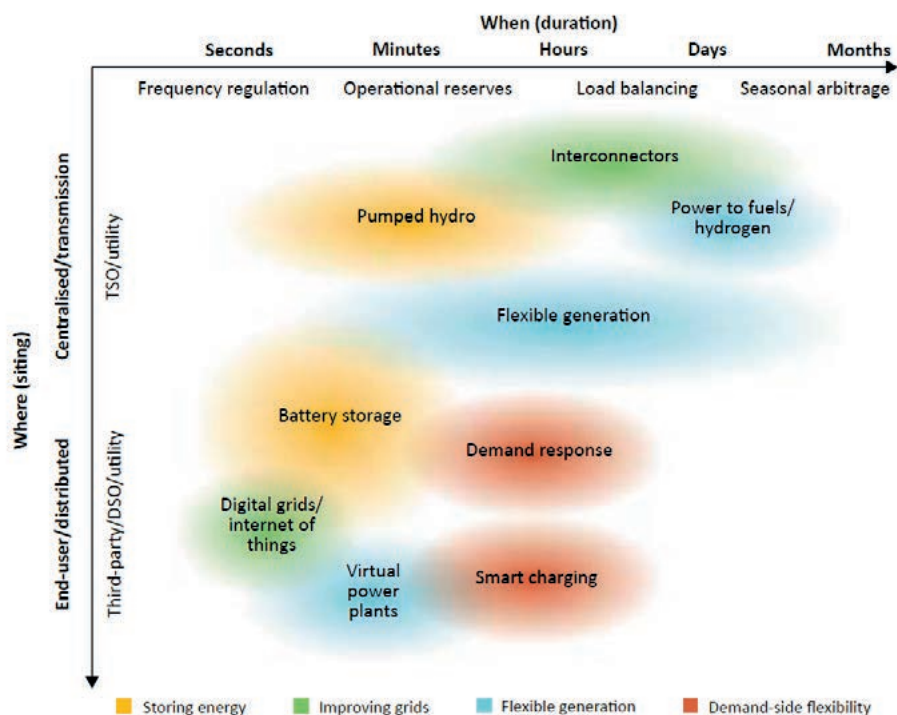
Power system flexibility

Power system flexibility – a concept that goes beyond power plant flexibility – is the crucial element for a successful transformation of the power system at growing proportions of wind and solar power. Driven in many contexts by a higher share of VRE in daily operations, power system flexibility is an increasingly important topic for policy makers and system planners to consider. It is a core aspect of power system transformation, and is crucial for ensuring electricity security in modern power systems.

Power system flexibility is defined as the ability of a power system to reliably and cost-effectively manage the variability and uncertainty of demand and supply across all relevant timescales, from ensuring instantaneous stability of the power system to supporting long-term security of supply. 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.

Importantly, power systems are already designed with the flexibility to manage variability and uncertainty, but requirements may grow and change over time. A number of operational, policy and investment-based interventions are available to make modern systems more flexible, facilitating cleaner, more reliable, more resilient and more affordable power systems.

Power system flexibility is a concept that is much broader than power plant flexibility. Traditionally, flexibility has been associated with the more flexible operation of coal power plants in China. However, the concept of power system flexibility is much broader. Indeed, it encompasses all resources of the power system that allow for its efficient and reliable operation at growing shares of variability and uncertainty. Apart from power plants, it can be provided by grid infrastructure, demand-side response and electricity storage (Figure 2). In a transformed power system with higher shares of VRE, the importance of flexibility options beyond power plants increases sharply. This can open synergies with other developments in the power sector, such as the deployment of EVs.

Figure 2. Overview of different power system flexibility resources

Source: IEA (2018), *World Energy Outlook*.

Notes: DSO = distribution system operator; TSO = transmission system operator.

Expansion of electrification, distributed energy and variable renewables will broaden the need for and range of flexibility options.

Phases of VRE integration

Different levels of VRE penetration require an evolving approach to providing power system flexibility. As VRE penetration increases, ensuring cost-effective and reliable integration may change flexibility requirements. The International Energy Agency (IEA) has developed a phase categorisation to capture changing impacts on the power system and resulting integration issues. This framework can be used to prioritise different measures for power system transformation. The phases are:

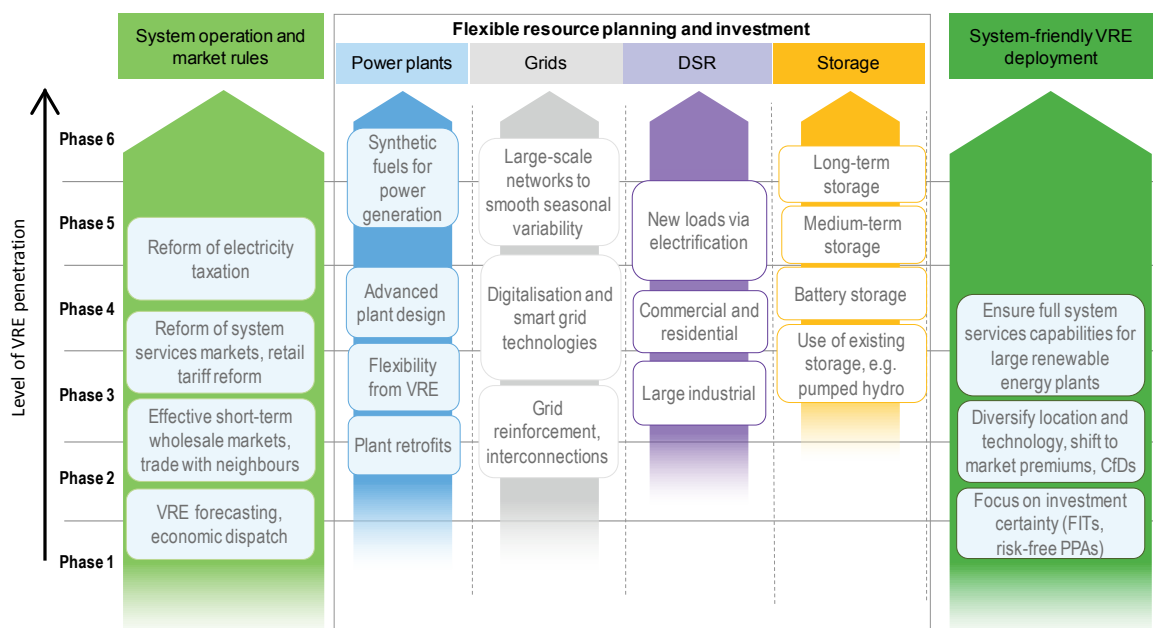
- **Phase 1:** The first set of VRE plants are deployed, but they are essentially insignificant at the system level; integration effects are highly localised, for example at the grid connection point of plants. Korea, the Russian Federation (“Russia”) or South Africa are examples of Phase 1 countries.
- **Phase 2:** As more VRE plants are added, changes between load and net load become noticeable. Upgrades to operating practices and making better use of existing power system flexibility resources are usually sufficient to achieve system integration. On a national level China is currently in Phase 2. Other countries in Phase 2 include India, Japan and the United States.
- **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. Examples of countries in this Phase include

Germany, Italy and the United Kingdom. The Chinese provinces of Xinjiang, Ningxia, Gansu and Qinghai are also considered to be currently in Phase 3.

- **Phase 4:** VRE output is sufficient to provide a large majority of electricity demand during certain periods (e.g. high VRE generation during periods of low demand); this requires changes to both operational and regulatory approaches to preserve power system stability. From the operational perspective, changes may be needed to the way the power system responds immediately following system disturbances. From the regulatory perspective, rule changes may be required to ensure that VRE has to provide frequency response services such as primary and secondary frequency regulation. Only very few countries are in this Phase including Ireland and Denmark.
- **Phase 5:** Without additional power system flexibility measures, adding more VRE plants in this phase may mean that aggregate VRE output frequently exceeds power demand and structural surpluses of VRE appear, leading to an increased risk of curtailment of VRE output. Shifting demand to periods of high VRE output via storage or responsive demand-side resources, and/or creating new demand via electrification, may mitigate this issue. Another possibility is to enhance power trading with neighbouring systems. In this phase it is possible that, in some periods, demand is entirely covered by VRE without any thermal plants on the high-voltage grid. No countries are currently in this phase.
- **Phase 6:** Once this phase is reached, the remaining obstacle to achieving even higher shares of VRE now becomes meeting demand during periods of low wind and sun availability over extended periods (e.g. weeks), as well as supplying uses that cannot be easily electrified. This phase can thus be characterised by the potential need for seasonal storage and use of synthetic fuels such as hydrogen. No countries are currently in this phase.

Priority areas for system transformation

The comprehensive transformation of the power system to achieve high proportions of VRE requires action in three main areas. These are: 1) system operation and market rules, 2) flexible resource planning and 3) investment, system-friendly VRE deployment. A comprehensive set of policy, market and regulatory frameworks is needed to link actions in the three areas effectively (Figure 3). **Importantly, the deployment of these measures has significantly broader benefits than simply promoting VRE integration – rather, they help to boost power system operational efficiencies, reduce environmental impacts, promote investment and competition, and increase reliability and resiliency.**

Figure 3. Three main pillars of system transformation

Notes: CfD = contract for difference; DSR = demand-side response; FIT = feed-in tariff; PPA = power purchase agreement.

Power system transformation for achieving high shares of VRE has three main pillars.

- **First pillar – System operation and market rules:** Improved operating strategies are a powerful tool to maximise the contribution of existing assets to power system transformation. Relevant operating strategies include advanced renewable energy forecasting and enhanced scheduling and dispatch of power plants. In addition, new services for the power system (ancillary services) can become relevant, especially at growing shares of VRE. While markets for ancillary services are a key component, the most important market mechanism for system transformation is a well-functioning short-term (spot) electricity market. This provides a crucial basis for operating the entire power system much more dynamically, reflecting rapidly changing supply/demand patterns. Another important element for improved operations is expanding the geographic area over which demand and supply are balanced. These two fundamental aspects have been investigated in detail in this study.
- **Second pillar – Flexible resource planning and investment:** Deploying a balanced mix of flexible resources is critical for the long-term evolution towards a transformed power system. As explained above, different technical options are available to provide power system flexibility. The most widely used option today is the more flexible use of conventional power plants, combined with increases in grid infrastructure. However, digitalisation and the rise of distributed energy resources and systems open up radically new options to balance supply and demand. Consequently, the detailed modelling for this report investigates DSR and storage as well as EVs as advanced options to provide system flexibility.
- **Third pillar – System-friendly VRE deployment:** Wind and solar PV power plants themselves can also facilitate power system transformation, where policy allows and encourages them to do so. The classical paradigm for wind and solar PV deployment emphasises generating the maximum volume of energy with little consideration for where and when it occurs. However, as wind and solar PV play an increasing role on the system, planning and

procurement strategies must take into account effects on the system. This publication provides a conceptual framework for assessing VRE power plants from a system perspective, referred to as “system value”, and highlights a number of international examples of policies that focus on system value.

Further details on all these actions are provided in the main analysis.

Power system transformation requires co-ordinated changes across the entire value chain of electricity production and consumption. Indeed, it may even necessitate the creation of entirely new roles in the power system, such as aggregators of small-scale power system assets (e.g. smart charging of a fleet of EVs in order to provide grid services).

In practice, this means that it is not sufficient to look only at the technical or economic aspects of system transformation. The institutional setup and the roles and responsibilities of different stakeholders in the system require review and possibly revision. This is particularly relevant for establishing medium- and long-term system plans. Here it is critical for all stakeholders to ensure that planning entities operate in a transparent environment and work to promote fair market access and competition as plans are translated into reality.

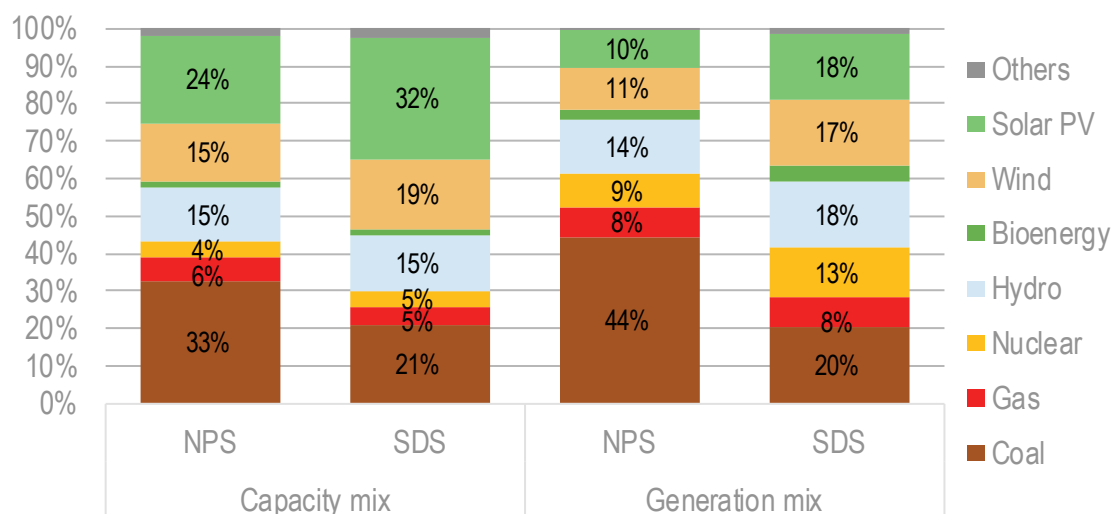
Modelling approach

Advanced energy modelling exercises highlight the possibility of achieving a transformed power system in China by 2035. Two different IEA scenarios describe possible configurations for the Chinese energy system in 2035.¹ This report elaborates on the main scenarios for China from the IEA *World Energy Outlook (WEO)*.² The two key *WEO* scenarios explored for China are the New Policies Scenario (NPS) and the Sustainable Development Scenario (SDS) (Figure 4).

- The NPS aligns with the achievement of China’s Document No. 9 reforms and aims to provide a sense of where today’s policy ambitions seem likely to take the energy sector in China. In the NPS, non-fossil technologies account for 60% of installed capacity and approximately 50% of generation. Wind and solar PV provide 21% of total generation. The NPS assumes a carbon dioxide (CO₂) price of USD 30/tonne. The WEO NPS assumes the implementation of economic dispatch, optimised trading and increased interconnection between provinces.
- The SDS achieves the main energy-related outcomes of the Sustainable Development Goals, including delivering on the Paris Agreement, achieving universal access to modern energy by 2030, and reducing dramatically negative health outcomes due to energy-related air pollution. Its vision is aligned with the “Beautiful China” initiative proposed in the 19th National Congress of 2017 as the general blueprint of China’s future development. Under the SDS, nuclear and renewable technologies have higher levels of installed capacity, particularly wind, solar and hydropower, with less fossil fuel generation. Of the installed fossil fuel capacity, 15% has carbon capture and storage (CCS). Non-fossil technologies account for 74% of installed capacity and 72% of total electricity generation. Wind and solar PV account for 35% of total electricity generation. The SDS assumes a CO₂ price of USD 100/tonne. The WEO SDS assumes sufficient flexible resources to fully integrate VRE into the system.

¹ 2035 is chosen because it is a milestone for the “Beautiful China” initiative. A forthcoming IEA publication will include a focus on the year 2050.

² *WEO* is the IEA flagship publication, widely recognised as one of the most authoritative sources of global energy projections and analysis. It presents medium- to long-term energy market projections and extensive statistics, analysis and advice for both governments and the energy business.

Figure 4. Capacity and generation mix for China in 2035, IEA WEO NPS and SDS

The SDS introduces a greater proportion of renewables and a lower proportion of fossil fuel technologies compared to the NPS.

The modelling analysis presented in this report takes these *WEO* scenarios a step further. Building on a regional model developed for the *WEO 2017*, it features detailed power sector modelling analysis at an unprecedented level of detail to help understand the value of various policy and technology choices in the year 2035. The modelling highlights what aspects of the power system are most crucial in 2035 – this then allows the identification of priority areas for policy options. To achieve this, a regional model has been developed that includes a detailed bottom-up analysis of future demand structures, taking into account anticipated structural shifts in the Chinese economy.

- The NPS is used to explore the value of current and proposed policies, notably the ongoing power market reform that foresees the introduction of spot markets and increased levels of cross-provincial trade. The analysis uses a two-step approach: first, an inflexible version of the NPS is modelled; then different options to make the system more flexible are analysed. The NPS analysis looks specifically at measures to improve system operation and market functioning.
- The SDS is used to explore the importance of advanced flexibility options – in particular on the demand side – to support a deeper transformation of the system. A two-step approach is also used for the SDS: first, an inflexible version is modelled; then different flexibility options are deployed in the system and their impact is analysed. The SDS provides a framework to assess the application of advanced technologies to provide flexibility.

In both scenarios, the modelling finds that steps to increase the flexibility of the power system are crucial for unlocking the full potential of renewable energy for power system transformation.

Spot markets and regional trade

Establishment of spot markets and trade between provinces are two of the main elements to improve market rules and hence system operation in China.

The introduction of market forces in the Chinese power sector is a current policy priority. Dispatching in China currently follows an administratively predetermined “fair dispatch” rule, where generators produce an allocated energy volume, rather than an economically optimised merit order dispatch, which is common in most market-based systems (i.e. “economic dispatch”). Document No. 9 foresees the orderly withdrawal of the administrative allocation system as a crucial next step.

International experience clearly demonstrates that a well-functioning short-term market (spot market) for electricity is a very powerful measure to drive power system transformation. In such an arrangement, the power plant with the lowest generation costs has priority for meeting electricity demand (economic dispatch). In most designs, the cost of the last (most costly) plant that is needed to meet demand sets the price paid to all generators.

Spot markets are particularly useful in fostering power system transformation for the following reasons:

- They solve the issue of needing to allocate the right to generate to different power plants. No explicit regulations are required to determine how much each plant is allowed to generate. Plants can try to increase their generating hours by cutting their operational cost and can optimise their profitability by enhancing their flexibility (in order to generate when prices are high and turn down when prices are low).
- They reveal the actual value of electricity at different times and locations. Spot markets usually have a different electricity price for each hour of the day (in some cases even for every five minutes). They can also be designed to have different prices for each location or zone of the grid. This means that spot prices highlight when and where electricity is most precious or available in abundance. This information is crucial for integrating VRE.
- Their price signals can inform commercial negotiations for longer-term contracts. Spot markets are very useful because they discover an accurate price for electricity. This information can be used to inform long-term pricing of electricity, guide investment in new generation capacity, and help with the establishment of financial markets for electricity.
- They allow for the market entry of new players. A liquid spot market with well-designed market rules can facilitate the participation of new actors, such as demand aggregators and electricity storage.

Combining effective spot markets with better utilisation of interconnections and increased grid investment brings a more efficient power system that can absorb shares of VRE that are much higher than today's. The modelling analysis under the NPS in 2035 indicates that the power system can integrate VRE at over 20% of total generation without any curtailment by improved operations and increased levels of physical interconnections. Hence, accelerating market reform – especially establishment of spot markets and increased provincial trade – is a priority for optimising a system in which VRE accounts for a growing share of generation.

China's goal of transitioning from fair to economic dispatch will result in significantly lower power system operational costs and improved ability to integrate wind and solar power. Ongoing market reforms to introduce economic dispatch make good financial sense and will strongly benefit the environment. Detailed power sector modelling under the NPS compared two different ways to dispatch the system: a fair dispatch approach that allocates guaranteed full-load hours to conventional generation, fixed at 2017 levels; and economic dispatch, i.e. dispatching plants according to lowest operating cost – while still preserving a modest generation allocation for natural gas generators.

Maintaining the current fair dispatch system would lead to major inefficiencies in the capacity mix under the NPS in 2035, including very high levels of curtailment (33% combined for wind

and solar PV at a national level). Improving system dispatch brings operational cost savings of approximately 11% or USD 45 billion per year in 2035. Also, curtailment falls to 5% at a national level. Moreover, power sector CO₂ emissions fall by 15% (650 million tonnes per year). These results clearly demonstrate the importance of introducing economic dispatch in the system.

The swift implementation of spot markets in China is crucial to achieving this. Conversely, failure to introduce economic dispatch or other measures to reduce allocated full-load hours to fossil generators would result in unacceptably high levels of VRE curtailment.

The introduction of economic dispatch is bound to trigger the exit of inefficient coal generators from the market, and this process is likely to need active management by government. Modelling results demonstrate that transitioning the Chinese power system to economic dispatch has significant consequences for fossil fuel generators, which will experience a drop in operating hours, particularly in VRE-rich regions. This issue will require close monitoring and possibly dedicated policy intervention to ensure an orderly transition.

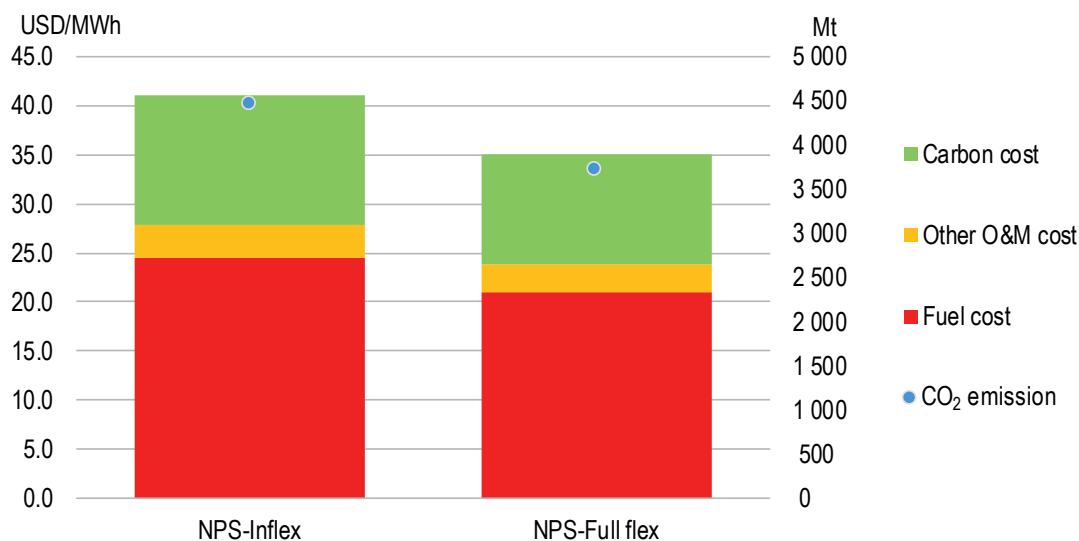
Increasing power trading can substantially boost system efficiency and reliability, but efforts to co-ordinate and harmonise markets are required. Boosting power trading has long been considered a national priority in China. As of today, China already has cross-regional (interprovincial/interregional) mid- and long-term trading, intended to improve the overall efficiency of the power system and make provincial grids more resilient by sharing their energy and backup services. While China has made progress in this area over the past years, this practice is not fully adopted and many barriers still exist. Significant effort by policy makers will be required to orchestrate and harmonise various markets so that they co-ordinate with one another, while also encouraging broad participation by both state-owned and private generators.

Broader regional co-ordination and greater transmission interconnectivity will yield substantial economic benefits. Modelling results show the significant economic benefits of regional co-ordination and power trading in the Chinese power system. Again, two cases were compared: one where utilisation of interregional transmission lines is fixed at 2017 levels, and another where the flows are fully optimised. Assuming a fully optimised use of transmission lines, including those planned to be built by 2022, total operational costs are reduced by an additional 3% (USD 9 billion annually) compared to the case that uses economic dispatch but 2017 utilisation levels. Curtailment levels fall further, from 5% to 3% at a national level. This highlights the importance of increased trade in the system and the large benefit it can bring. Assuming additional interconnections³ further lowers operating costs by USD 8 billion and brings curtailment levels to 0%.

This greater interconnectivity results in a heterogeneous set of regional impacts on power plant generation levels. Regions with more economically favourable power plants experience an increase in generation levels, whereas less competitive regions experience reduced generation levels and purchase cheaper electricity from neighbouring regions. Policy makers should be aware of this expected change in order to carefully and proactively manage the transition.

In summary, the combined impact of improved operations (economic dispatch, regional trade) and additional interconnections is a reduction in operating costs of 15% or USD 63 billion annually. In addition, annual CO₂ emissions are reduced by 750 million tonnes (Figure 5).

³ The analysis assumes an increase from 230 GW to approximately 410 GW of interconnections; see Annex A for details.

Figure 5. Operational costs, inflexible and flexible cases, NPS, 2035

Notes: Mt = million tonnes; MWh = megawatt hour; O&M = operation and maintenance.

The introduction of economic dispatch, higher levels of regional trading and additional grid infrastructure can help to reduce operational costs and CO₂ emissions and brings savings of USD 63 billion annually.

Advanced power system flexibility

Activating the demand side, including EVs, and targeted use of electricity storage are crucial to delivering an accelerated transformation of the power system.

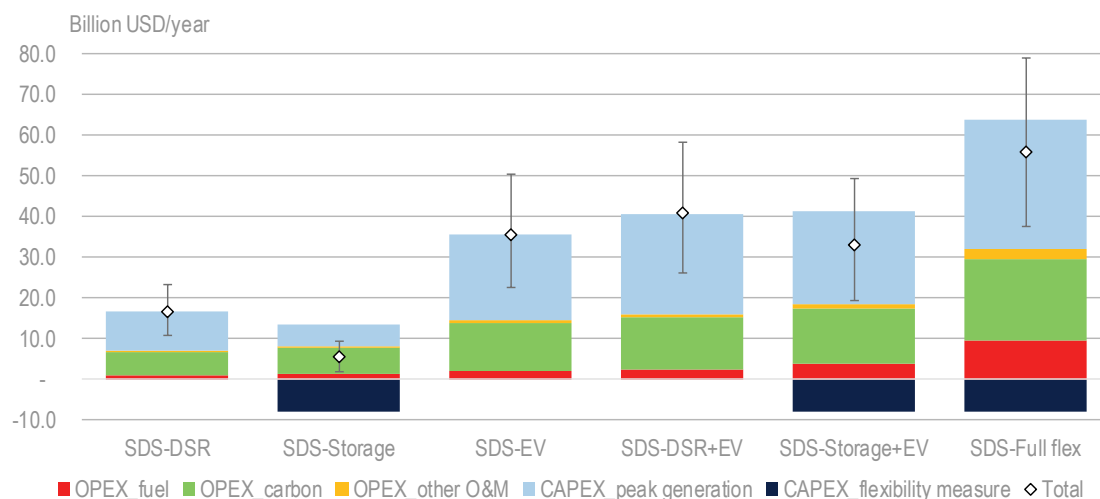
Power system flexibility is the most important cornerstone of a transformed power system with a high share of VRE. In the SDS, VRE resources account for 35% of electricity generation on average. However, in some regions these numbers are much higher. For example, in the Northwest region VRE covers 73% of electricity demand. This requires unprecedented levels of system flexibility, including advanced technologies to ensure system stability. Relying on advanced technologies enabled by digitalisation allows for the reliable integration of very high proportions of variable generation without any excessive curtailment in 2035 under the SDS.

Advanced technologies – enabled by digitalisation – reduce the need to rely on power plants to provide flexibility. The modelling under the SDS combines a broad range of advanced flexibility options. Their impacts have been estimated on the basis of detailed bottom-up modelling of future electricity demand in China, assuming that advanced technologies can unlock the flexibility potential. The assumed flexibility options for this report are:

- Approximately 300 GW of residential, commercial, agricultural and industrial-sector load contributing to DSR programmes are in place in 2035, with enrolled resources spanning space heating and cooling, water heating, refrigeration and cleaning appliances.
- 220 million EVs are made available under smart charging schemes in China in 2035, which corresponds to approximately 250 GW of peak EV charging load and 800 terawatt hours of total annual EV charging load.
- Over 100 GW of pumped storage hydro and over 50 GW of battery energy storage are deployed.

The benefits and costs of the different flexibility options are quantified for this study – in all cases they bring net benefits under the SDS in 2035 (Figure 6).

Figure 6. Benefits and costs of different advanced power system flexibility options, SDS, 2035



Notes: CAPEX = capital expenditure; OPEX = operational expenditure.

Advanced power system flexibility measures can bring substantial benefits for power system transformation.

Working in concert, these options can greatly improve the match between wind and solar PV supply and electricity demand. Indeed, the modelling analysis finds that these options can substantially reduce the need for flexible power generation – by 300 GW, or 30% of the total installed fossil fuel generation capacity under the SDS in 2035.

The use of advanced flexibility options is found to be highly cost-effective compared to the SDS without their presence. Using these options to their maximum potential could lead to total net savings of USD 64 billion annually. This considers both reduced operating costs (including CO₂ emission costs at a price of USD 100/tonne) and avoided capital costs for power plants. This number accounts for the investment required to install advanced flexibility capabilities.

Increasing power system flexibility beyond readily available options, such as coal power plants, is thus one of the most important priorities for facilitating the rapid transformation of the power system towards higher proportions of variable generation.

Investment certainty

A stable investment environment for clean energy technologies remains crucial. The benefits of introducing short-term markets are clearly demonstrated by the modelling carried out for this study. However, the introduction of economic dispatch and spot pricing of electricity could bring new challenges for the system. The investment framework in China after the Document 5 reform provided a high level of certainty for all players. Prices are guaranteed via the regulated on-grid tariff, while operating hours are secured via the fair dispatch system. This arrangement cannot be maintained in the future, due to its contradiction with the efficient operation of the system. This therefore raises the question of how sufficient investment certainty can be ensured for clean energy technologies. This issue is particularly relevant

because clean energy technologies tend to have high up-front costs and low operating costs. This makes the cost of financing a key driver for the cost of delivered electricity. In turn, risk and risk perceptions determine financing costs. As a consequence, this means that mitigating investment risk will become even more important in the future than it has been in the past.

The two most important risks for power generators are price risk and volume risk. Market premium systems and contracts for difference have proven to be effective tools to mitigate price risk while integrating clean energy into spot markets, as examples across Europe demonstrate. As regards volume risk (curtailment risk), a variety of mechanisms are available, including compensation for curtailed energy. In the specific context of China, the quota system currently under consideration could serve this purpose, ensuring sufficient market demand to prioritise clean energy use.

Renewable energy policy

Advanced renewable energy policies that focus on system value can minimise integration challenges. As the share of renewable energy grows in the Chinese power system, the interactions between renewables and the broader electricity system need to be considered in the design of renewable energy policies. This usually becomes evident through the emergence of “hotspots” of VRE deployment, where penetration levels are much higher than the national average and integration challenges become significant. An initial approach to this issue is the geographic and technological diversification of VRE deployment. A variety of measures can achieve this, such as limiting permits for new installations in certain regions, differentiating remuneration levels regionally or by time of production, or giving specific incentives for smaller-scale installations – China has implemented a number of these options in the past years with some success. However, there are additional possibilities to enhance the system integration of renewables by use of deployment policies. The concept of system value (SV) is critical in this regard.

Considering the value of electricity to the overall system opens a new perspective on the challenge of VRE integration and power system transformation. The value of electricity depends on when and where it is generated, particularly in a power system with a high proportion of VRE. During certain times, an abundance of generation can coincide with relatively low demand – in such cases, the value of electricity will be low. Conversely, when little generation is available and demand is high, the value of electricity will be high.

The SV of a power generation technology is defined as the net benefit arising from its addition to the power system. While the conceptual framework applies to all power generation technologies, the focus here is on wind and solar power plants. The SV is determined by the interplay of positive and negative effects arising from the addition. On the positive side are all those factors included in the assessment that lead to cost reductions; these include reduced fuel costs, reduced CO₂ and other pollutant emission costs, reduced need for other generation capacity, reduced water requirements and possibly reduced need for grid usage and associated losses. On the negative side are increases in certain costs, such as higher costs of cycling conventional power plant and for additional grid infrastructure.

Spot markets can be a very useful tool for providing appropriate signals to VRE developers and operators. By exposing VRE plants to the varying prices on the spot market, they can be encouraged to build power plants that generate as much as possible at times and in places where electricity is valuable – and where prices are higher than average. However, such approaches need to strike a balance between creating an incentive for system-friendly deployment while also providing sufficient investment certainty. Advanced market premium

systems such as the current system used in Germany or auction mechanisms that factor in SV such as the Mexican clean energy auctions are examples of how this balance can be achieved.

Market design and planning

A comprehensive change in market design and system planning is needed to accelerate power system transformation.

Wholesale market design

While the presence of competitive wholesale power markets is not a prerequisite for power system transformation, it is an extremely common and highly effective tool for its achievement. Wholesale markets help to open markets to investment, unleash the forces of competition, integrate VRE and reduce system operational costs. While there is no standard design for wholesale electricity markets, several important characteristics are worth noting:

- **Short-term power trading:** Short-term markets are the foundation of all market-based electricity systems, and have been proven to be a valid approach to cost-effective integration of high shares of VRE in Europe and parts of the United States. Short-term markets play a critical role in mobilising the flexibility of the power system, and can support the integration of VRE.
- **Economic dispatch and rapid trading:** Arguably, the shift towards economic dispatch – which enables resources to compete based on their short-run marginal cost – is the single most important market design aspect for supporting the integration of VRE. Because VRE shows large variability across time and has very low short-run cost, rapid trading of electricity, close to real time, is also critical. For example, in Europe trading on intraday markets on the day of delivery is gaining importance for improved integration wind and solar power.
- **Cross-regional trade in electricity:** The benefits of regional power system integration and trading cut across all aspects of the power sector, including: improved security of supply; improved system efficiency; and improved integration of variable renewable resources. These benefits generally derive from the increased optimisation of generator dispatch. For example, the close interconnection and trade with neighbours is the most relevant tool for wind integration in Denmark.
- **Markets for flexibility services:** Reliable operation of the power system critically depends on a number of system services to provide flexibility, which contribute to maintaining system frequency and voltage levels, as well as balancing a power system with increased variability and uncertainty in the supply–demand balance. As the penetration of VRE increases, the need for such services – and hence their economic value – is bound to increase. Establishing market structures to incentivise the provision of flexibility resources and services is an important task for policy makers in the transformation process. For example, Ireland is introducing a comprehensive reform of system services to deal with very high proportions of VRE.
- **Clean energy investment framework:** A crucial aspect of market design is ensuring that clean generation resources have an appropriate investment framework to facilitate their continued growth in line with policy targets. As mentioned, market premium systems in Germany and the Mexican auction design include measures to balance investment certainty with maximising SV.
- **Pricing of externalities:** Price-based instruments aim to internalise the societal costs of environmental degradation, climate change or air pollution – caused by energy production – in the planning and operation of electricity generators according to the

polluter pays principle. Price-based instruments can achieve environmental targets in a cost-effective way. However, they should be part of a coherent policy package. For example, the European emissions trading system has been updated several times to deliver an effective price signal that is well-linked to other policy instruments.

Retail market design

The opportunity of digitalisation and the rise of DER have broad implications for power system transformation in the retail electricity market segment. Relevant dimensions, and examples of them, in the retail market include:

- **Tariff reform to encourage system-friendly investment in and utilisation of DER:** Making time-of-use tariffs accessible to a wider array of consumers may be a useful way of encouraging improved use of DER, including demand response and rooftop solar.
- **Promoting digitalisation and connectivity in various retail customer segments:** One prerequisite for visibility and control across the power system is the availability of appropriate real-time monitoring systems with bidirectional communication across grids, loads and generation. Sweden has implemented a comprehensive roll-out of smart meters in support of power system transformation.
- **Enabling technology neutrality for the provision of power system flexibility:** For a successful transition, a level playing field is crucial to allow advanced DSR and storage to contribute to system services and power system flexibility. System services markets in Europe have been reformed to allow participation of storage and demand response.
- **Establishing procedures for open and secure access to power system data:** Greater monitoring and computing capabilities present a great opportunity for constant improvement of power system operation and the development of new business models for DER in the retail segment. Allowing access both to power sector participants and researchers may assist policy makers in identifying new areas of opportunity to pursue. Denmark has recently established a data hub for better access and availability of smart meter data.

Upgraded planning frameworks

Power sector planning is an inherently complex process due to the long planning horizon and is subject to a range of drivers that are highly uncertain. Traditionally, the primary focus of power sector planning was on expanding supply infrastructure (generation, transmission and distribution networks) to meet projected electricity demand, based on assumptions of economic growth over the next 20 to 30 years. However, with the changing landscape of the power sector, due to increasing deployment of VRE and other new technologies such as DER, as well as increasing consumer participation, planning for a future power system needs to become more sophisticated – it needs to take into account the role and impact of these developments. Several important characteristics of upgraded power system planning frameworks are worth sharing:

- **Integrated generation and network planning exercises:** Historically, generation, transmission and distribution planning processes have been conducted independently in separate processes. However, as the level of VRE deployment increases, there is an increasing need to co-ordinate and integrate generation and network planning exercises in order to avoid transmission congestion in areas with the highest-quality VRE resource, and to plan a system that utilises VRE resources with the highest SV.
- **Incorporation of demand-side resources into planning exercises:** The potential role of the demand-side resources, such as DSR and energy efficiency, is often overlooked in

power sector planning processes. The Integrated System Plan introduced in 2018 in Australia aims to better incorporate these aspects in overall system planning.

- **Integration of planning between the power sector and other economic sectors:** Integrated planning that spans the power sector and other sectors is a growing field, one which promotes broader energy system integration. Historically, planning across different sectors was thought to be relevant only for the electricity and gas sectors, since gas is one of the main fuels for electricity generation in many countries. More recently, continuing innovation in and uptake of demand-side technologies are having an impact on the power system. This is particularly the case for EVs. They can be used with smart charging strategies to support power system flexibility and facilitate VRE integration by recharging during periods of high VRE output and – ultimately – supplying to the grid when output declines. In the European Union, for example, network development plans for electricity and gas infrastructure were better integrated in 2018.
- **Broader interregional planning:** Power system planning was traditionally confined to established single-utility balancing areas. However, with an increasing level of VRE deployment, expanding the size of balancing areas can potentially provide greater flexibility through resource diversification across different geographical regions. In addition, greater geographic diversification of generation sources leads to less variability in supply.
- **Including system flexibility assessments in long-term planning:** 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 the proportion of VRE increases 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*.
- **Incorporation of DER considerations in distribution network planning:** When local grids are expected to integrate considerable amounts of DER, such as VRE, within the planning horizon of a distribution utility, additional and potentially more complicated distribution planning studies typically need to be completed. This is to ensure the continued safe, reliable and cost-effective operation of the interconnected distribution system.

International implications

Accelerated progress on power sector transformation could bring substantial benefits to China and the world. China's power system is the largest national power system in the world; it accounted for one quarter of global electricity consumption in 2017 and its share is expected to rise to around 30% by 2035 in the NPS. Consequently, optimisation of the Chinese power system has immediate global effects, simply because by itself it accounts for such a substantial share.

An accelerated transformation of the Chinese power system could bring significant benefits in the drive to limit climate change in line with the Paris Agreement. As the modelling conducted for this study demonstrates, improved operations and advanced power system flexibility options can deliver substantial emissions savings while reducing overall system costs.

However, there could be further positive effects of an accelerated transformation of the Chinese power system. China is already a global leader in clean technologies. Chinese solar PV manufacturers have played and continue to play a vital role in the rapid decline of solar PV

costs. Moreover, the dynamic expansion of electric mobility in China, and the associated expansion of the EV value chain, has put downward pressure on electric batteries and ultimately EV prices.

China also has a very well-developed digital communications and software industry. So far, these industries have not been combined to their full potential. However, as the scenarios set out in this report demonstrate, an optimised system relying on enhanced digitalisation to unlock load shaping could integrate much larger amounts of clean energy. In turn, this stands to bring substantial economic and environmental benefits.

The accelerated adoption of these solutions in China could make them affordable for countries around the world – including today's developing countries, which will see a rapid increase in energy demand over the coming years. In turn, China can use the path of power system transformation to make accelerated progress in restructuring its economy towards a pattern of growth in advanced high-quality industrial sectors.

Technical analysis

Introduction

Throughout the world, power systems are undergoing profound change. The fundamental drivers behind this transformation are three-fold. First, renewable energy – in particular wind and solar power – is on track to becoming the most cost-effective source of new electricity generation in many regions of the world. Wind and solar photovoltaics (PV) can already out-compete new natural gas, and even coal-fired power plants, in areas with high-quality resources and low financing costs. In addition to meeting energy demands at lower cost and relying primarily on local resource, this trend also makes achieving decarbonisation goals more affordable.

The second driver is digitalisation of the power sector. Digitalisation is expanding from the transmission level – where digital sensors and controls have been used for decades – into medium- and low-voltage networks, all the way to individual devices. And finally, distributed energy resources (DER) such as electric vehicles and rooftop solar PV systems are changing the value chain of electricity. The demand side is poised to play a much more active role in the system through energy efficiency and controllable loads, and distributed generation is emerging as a more relevant complement to large-scale generation.

These trends are not happening independently. In fact, they can be mutually reinforcing. The growing share of variable renewable energy (VRE) requires a more sophisticated approach to system operation and a more active demand side in the power system. The most promising distributed generation technology in both the near and long term in most settings is solar PV. The resulting increase in supply-side variability reinforces the economic case for a more active and responsive demand side. Meanwhile, the increased flexibility of the power system that digitalisation and demand response unlock increases the amount of VRE generation that can be economically accommodated by the power system.

However, as this publication explains in detail, such a virtuous cycle does not happen by itself. Legacy technologies together with traditional policy, market and regulatory frameworks can often impede an accelerated transformation.

“Power system transformation” describes the processes that facilitate and manage changes in the power sector in response to these novel trends. It is an active process of creating 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. It is a complex task for policy makers.

Fundamentally, the triple objective of energy affordability, security and sustainability remains unchanged under power system transformation. However, the emergence of low-cost, clean

energy sources – alongside advanced technologies to facilitate their system integration – presents new opportunities to achieve all three objectives in parallel. Rather than facing sharp trade-offs between the three, the deployment of new technologies, combined with the implementation of appropriate policy, market and regulatory reforms, can deliver a power system that shows improvements along all three dimensions of modern energy policy.

The People's Republic of China ("China") has already embarked on its own path towards power system transformation. In terms of absolute numbers, it is the clear global leader in the deployment of clean energy technologies, from solar PV and wind power to nuclear energy. However, China also faces formidable challenges in the transformation of its power sector. The current largely coal-based system has been remarkably successful at fuelling the country's very rapid economic growth over the past two decades. However, the environmental cost of this system has become a pressing challenge in the form of both the immediate problem of local air quality and the long-term systemic threat of climate change. Also, despite many years of continuous refinement of policy, market and regulatory frameworks, China is still in the process of reforming its power markets and related policies to further improve the performance of the system.

Against this background, this publication has twin objectives. First, it provides a summary of the state of play of power system transformation in China, as well as a comprehensive discussion of power system transformation internationally. Second, it provides a set of detailed power system modelling results for China in 2035, exploring scenarios from the International Energy Agency (IEA) *World Energy Outlook (WEO)* that describe possible configurations for the Chinese power system in the year 2035. The modelling underpinning this document relies on the well-established *WEO* New Policies Scenario (NPS) and Sustainable Development Scenario (SDS). At a high level, these scenarios offer two distinct visions for the evolution of the Chinese power system.

The NPS provides a measured assessment of where today's policy frameworks and ambitions, together with the continued evolution of known technologies, might take the energy sector in the coming decades. The NPS is used to explore the value of current and proposed power sector policies, particularly those specified in Document No. 9 reforms that aim to introduce spot electricity markets and increased levels of cross-provincial power trade.

The SDS starts from selected key outcomes and then works back to the present to see how they might be achieved. The outcomes in question are the main energy-related components of the Sustainable Development Goals, agreed by 193 countries in 2015:

- Delivering on the Paris Agreement. The SDS is fully aligned with the Paris Agreement's goal of holding the increase in the global average temperature to "well below 2°C".
- Achieving universal access to modern energy by 2030.
- Reducing dramatically the number of premature deaths caused by energy-related air pollution.

The SDS is used to explore the importance of innovative power system flexibility measures – in particular those on the demand side – to support a deeper transformation of the Chinese power system. The costs and benefits of these measures are derived from the modelling framework and presented for consideration.

Based on the insights stemming from the modelling work, the publication concludes by providing a set of policy options for making accelerated progress in power system transformation and also discusses possible international implications of such a transformation in China.

The document is structured as six main chapters, including this introduction. Chapter 2 provides an overview of the context and status of power system transformation in China. Chapter 3 discusses power system flexibility and summarises international experiences of transforming power systems from a technical perspective. Chapter 4 reviews policy, market, and regulatory aspects of power system transformation, and similar to Chapter 3, offers a range of international experiences for consideration. Chapter 5 presents results from the power system modelling. Chapter 6 summarises the key messages and insights from the report.

Importantly, the publication integrates analysis from across a range of existing IEA work in order to provide a comprehensive picture of the current state of play of power system transformation. Where sections rely on previous IEA work, this is indicated at the beginning of the section.

Context and status of power system transformation in China

Background

China has made major achievements in its economic development. With its gross domestic product (GDP) rising from USD 7.9 trillion (United States dollars) in 2013 to USD 11.6 trillion in 2017, China has maintained its position as the world's second-largest economy and accounted for more than 30% of global economic growth during that five-year period. China's performance in recent years was highlighted at the 19th National Congress meeting (Xi, 2017):⁴

- Supply-side structural reform has made further headway, bringing a steady improvement in the country's economic structure.
- The development of infrastructure has been promoted and emerging industries such as the digital economy are thriving.
- The level of urbanisation has risen, with more than 80 million people having transferred from rural to urban areas.
- Regional development has become more balanced; several regional development plans have been promoted, including the co-ordinated development of the Beijing-Tianjin-Hebei region, the development of the Yangtze economic belt, the revitalisation of the northeast industrial base, the rejuvenation of middle-China, and the development of China's western provinces.
- More than 60 million people have been lifted out of poverty, and the poverty rate has dropped from 10.2% to less than 4%.

Economically shifting gears

China is the world's second-largest economy and has experienced rapid GDP growth over the past two decades. Even with the recent slowdown, it continues to expand at an impressive speed, with a GDP growth rate of 6.9% in 2017. In recent years the Chinese government has realised that the previous model of resource-intensive economic growth was not sustainable, and therefore proposed a new model of economic growth driven by consumption and the service sector.

To bring about the changes it seeks, the Chinese government proposed a supply-side structural reform plan, with a view to reducing the level of corporate debt and overcapacity in key industrial sectors, including coal and power. Supply-side structural reform has emerged as the main economic policy framework. The pace and depth of this reform will have a major impact on China's economic transition, as well as its energy sector transition (IEA, 2017a).

⁴ The National Congress of the Communist Party of China is a party congress that is held every five years. The National Congress is theoretically the highest body within the Communist Party of China.

Ecological civilisation

China's rapid economic rise has had a major impact on its environment and on public health. Therefore, the government proposed the pursuit of "ecological civilisation" and set targets to 2020, which included the following in relation to the power sector (State Council, 2015a):

- Environmental damage cost recovery will be factored into pricing, and tax policies will reflect the priority of energy conservation, environmental protection and clean energy utilisation.
- Distributed energy resources will be developed to augment centralised power generation; efficient power generation and dispatch is to be promoted; and renewable power generation resources are to be prioritised.
- Energy consumption trading and carbon trading will be promoted.

The rising environmental issues, especially people's concerns about air pollution, alongside China's pledge to the international community on climate change, accelerated the government's progress on preparing a more visionary plan. A "Beautiful China" blueprint was proposed at the 19th National Congress meeting in 2017 (Xi, 2017). Beautiful China is a two-step long-term blueprint proposing that development takes better account of environmental carrying capacities, and promotes a growth pattern that respects planetary ecological boundaries. It targets the preliminary realisation of ecological civilisation and a much better environment by 2035, and the full realisation of ecological civilisation and an environmentally friendly economy and society by 2050.

Power system transformation

China has made optimising the structure of its power supply a top priority since the early 2000s. Its goals were to reduce the share of coal in power generation and increase the use of renewable energy, natural gas and nuclear power. The 13th Five-Year Plan set binding targets to reduce the share of power from coal in total energy consumption to 58% by 2020 and to increase the share of power from non-fossil fuels to 15% by the same date (NDRC, 2016). China continues to set ambitious targets for renewable energy capacity and generation, which have consistently driven impressive acceleration in renewables deployment over the past decade.

China is embarking on a process of power market reform that was initiated in 2015. This reform plans to reduce the involvement of government in several key stages of the power market, while at the same time reinforcing its supervisory and planning roles. The expected key outcomes of this reform are to reduce average electricity costs through competition, and to increase system flexibility and the utilisation of clean energy.

System flexibility is seen as a crucial aspect of power system optimisation.⁵ Increasing the flexibility of coal power has been identified by the government as a near-term step toward overall system flexibility. It committed to retrofitting 133 gigawatts (GW) of co-generation capacity and 86 GW of pure condensing coal-powered plants to enhance their operational flexibility by 2020.⁶ This represents about one-fifth of the installed coal-powered capacity.

⁵ System flexibility is crucial to variable renewable energy (VRE) penetration. Wind and photovoltaic (PV) curtailment rates were 12% and 6% in 2017 respectively. In some regions the curtailment rate exceeded 20%. The high curtailment rate reflects the need for a more flexible power system.

⁶ China has a large co-generation capacity. These units in the winter heating season operate at high loads, therefore exacerbating the curtailment of VRE. Retrofitting co-generation aims to decouple heat and power generation by using electric boilers or heat storage tanks.

Meanwhile, it also plans to develop more flexible generation sources, including gas power and pumped hydropower.

China has already started on its path away from a fully centrally planned approach towards one that offers a stronger role for the market in the power system. The five-year plans have become more about setting policy direction and providing guidance. The government has also placed greater emphasis on a more co-ordinated planning process, meaning better central–provincial co-ordination and fossil fuel–renewables co-ordination (NEA, 2016a).

Development of demand-side response to support power system optimisation is another crucial aspect according to the government (NDRC et al., 2017a). Policy makers in China realise that power demand can be a part of the system that is actively managed, rather than something fixed that just has to be passively accepted. Demand-side response will play a more important role in future to help reduce the curtailment of variable renewables.

Brief introduction to China's power system

Current status of power system in China

General perspective

The impressive speed of China's economic growth has propelled demand for electricity, which has grown from 1 387 terawatt hours (TWh) in 2000 to 6 363 TWh in 2017, making China the world's largest electricity consumer.

China now has the largest installed generation capacity in the world (1 780 GW by 2017), nearly 60% of which is coal powered. However, in the last few years the great expansion in capacity has coincided with a period of slower growth in power demand. The country has therefore experienced overcapacity in the power sector, particularly reflected in a reduction in the capacity factor for coal-fired generators.

Renewable capacity installed in China in the past decade amounted to more than one-fifth of all power capacity installed globally during the same period. The country already leads the world in installed capacity of hydropower, wind and solar power. However, the rapid growth of renewables has created an issue of integration, leading to a high curtailment rate of wind and solar generation. In some regions the curtailment rate has exceeded 40% (CEC, 2017).

China has implemented several rounds of electricity sector reform. In 2015 the government put forward a reform agenda under *Opinions on Further Deepening the Reform of Power System* (Document No. 9), with the aim of increasing reliance on market forces (State Council, 2015b).

How the power system works in China

China's power system was originally designed with the characteristics of a centrally planned system.⁷ With power sector reform, the current system is seen as a combination of the original system with new market-based elements.

The planning and investment cycle in China follows a centrally planned system (NEA, 2016a). The National Development and Reform Commission (NDRC) and National Energy Administration (NEA) are responsible for developing a five-year national plan. This plan includes

⁷ This section follows *Power Sector Reform in China: An International Perspective* (IEA, 2018a).

strict investment and technology deployment objectives for generation, transmission and distribution by province. Provinces are responsible for achieving these targets and are in charge of permitting for many of the projects.

Mid- and long-term contracting⁸ used to contribute a small portion (2-10%) of the total power transactions, and the buyers and sellers were selected administratively before 2015, when Document No. 9 came into effect. China also has cross-regional (interprovincial/interregional) mid- and long-term trading, intended to improve the overall efficiency of the power system and make provincial grids more resilient by sharing their energy and backup services. However, most of the interprovincial/interregional power trading was predetermined by government following a national strategy, such as coal and wind power transmission from the Northeast to the Northern region, hydropower transmission from the Central to the Southern region, and coal power transmission from the Northwest region to the Central or Northern regions.

Since Document No. 9, mid- and long-term contracting is encouraged as the major form of market trading, with multiple timescales (annually, quarterly, monthly, weekly and days-ahead) and multiple forms (bilateral negotiation, listed auction, centralised auction and unbalanced energy trading). It accounted for a larger proportion (26%) of total power transactions in 2017 (EPPEI, 2017).

Responsibility for power dispatch has been assumed by provincial dispatching centres⁹ and still follows an administrative process (NEA, 1994). At the end of each year, the provincial dispatching centres forecast the total power demand for the coming year, and then allocate power generation quotas to each generator within their respective province following a fair dispatch rule. (Annual generation plans made by the dispatching centres need to be approved by the provincial government.) This rule allows each generator in the same category (e.g. coal power) to be allocated the same annual operating hours, with only minor differences in capacity, emissions levels and operating efficiency. Plants are dispatched to meet demand on the basis of target annual full load hours (+/- 1.5%), subject to priority dispatch for nuclear power plants and renewables.

Dispatch centres in China are affiliated to the grid companies and have a multi-level hierarchy, i.e. national, regional, provincial, prefectural and county levels. Provincial dispatching essentially plays the most important role in the system, while national/regional dispatch centres take charge of interregional/interprovincial power transmission, and prefectural/county dispatch centres are mainly responsible for prefectural/county load management (RAP, 2015).

There is currently no spot market, but eight provinces were selected by the NDRC to pilot a spot market and are expected to start trialling by June 2019. Meanwhile, the ancillary services market has been successfully implemented in Northeast China and then extended in five other provinces; the interregional renewable spot market has been adopted for surplus renewables trading, but at a fairly small scale (NDC, 2017).

China has adopted a centrally determined power pricing system, with a benchmarked on-grid price and a benchmarked retail price (IEA, 2006). Owing to the differences in economic development levels, benchmark prices vary between provinces. The benchmarked on-grid price reflects the cost of power plant construction and return expectations. The benchmarked retail price has four pricing categories depending on the type of end user: large-scale industrial;

⁸ Mid- to long-term contracting allows large buyers and newly created independent retail companies to buy power directly from generators, signing monthly or annual bilateral contracts that specify the volume of electricity to be purchased and at what price. These deals are not yet required to schedule their generation to match demand; this is still managed by the grid company. These contracts only govern price and volume.

⁹ Provincial dispatching centres are affiliated to grid companies.

commercial and industrial; agricultural; and residential. Within each pricing category, the retail price varies with voltage level and time of use. They are typically divided into peak, normal and valley prices.

Power system transformation in China is also seen in the growth of renewables in the power mix. The Chinese government has long encouraged the development of renewable energy through pricing incentives. A benchmark feed-in tariff for wind and PV was implemented in 2009. Grid companies pay an on-grid price for wind/PV power benchmarked to coal, and the central government subsidises the difference. Subsidies come from the Renewable Energy Development Fund, resources for which are embedded in the retail electricity price. This means that every consumer in China pays to support renewable energy development (NEA, 2012). The generous subsidy boosts wind and PV capacity, making China the largest wind and PV power operator in the world.

However, the expansion of wind and PV has created a significant deficit in available funds, despite feed-in tariffs having been reduced by central government several times. It is estimated that by the end of 2017 the deficit had reached CNY 100 billion (Chinese Yuan renminbi), and generators claim they have not received payments since 2015. The NEA has therefore designed and revised several times a mandatory quota allocation system, aiming to force either grid companies or other generators to purchase credits up to a certain percentage of their total consumption or generation, the credits being used to pay the outstanding subsidies (NEA, 2018a; NEA, 2018b; NDRC and NEA, 2018a).

Historical evolution

Between the foundation of the country in 1949 and the 1980s, China's power sector followed a vertically integrated model. Central government was in charge of investing in the power sector and operating the system. During the 1980s, the nationwide "reform and opening up" campaign boosted China's economy, but the power shortage at the same time largely hampered economic growth. The Chinese government thus adopted policies aimed at attracting power sector investment and increasing power supply capability.

The first major change in China's power sector was made to the vertically integrated utility structure and ownership in 1984. Third parties outside central government, including provincial governments, local governments, state-owned enterprises, private-sector investors and foreign companies, were allowed to invest in power plants (State Council, 1985). Power plants built in this period were granted a power purchase agreement (PPA) with predetermined utilisation hours and power prices to guarantee the rate of return on investment. Moreover, a so-called "fair dispatch rule" was introduced in 1987 to ensure "transparency, equity and fairness" in dispatch and has been implementing ever since (see previous section "How the power system works in China") (SERC, 2003a). At this time, although power generation was opened up to a diversity of investors, grid assets were still controlled by central government.

The second major change took place in 1998, when most of the assets of the power sector were transferred from the Ministry of Electricity to the newly formed State Power Corporation (SPC) (State Council, 1996). This marked the first step towards separation of government regulatory oversight and market operation. The SPC owned approximately half of China's generation assets and almost all grid assets.

The third major change was the power sector reform of 2002, starting with the release of an official document entitled *Power System Reform Scheme* (Document 5). This largely contributed to the current shape of the sector's structure (State Council, 2002). The intention of this round of reform was to tackle the oversupply of power – after nearly two decades of rapid increase in generation capacity, China no longer suffered from a power shortage. Instead the inertia of

overinvestment in capacity and a reduction in power demand caused by the Asian financial crisis created and exacerbated an oversupply situation. Problems including regional overcapacity, inflexible dispatching and interprovincial trade barriers drew the attention of the highest-level leaders and led to the reform.

The goals of this round of reform, under Document 5, were to break the institutional monopoly and introduce competition, improve overall efficiency, particularly through interprovincial transactions, protect the environment and adopt better regulations. However, the initial idea of transforming the power system to a more energy-efficient and interconnected system was only partly realised for complex reasons (see Box 1).

The crucial changes during the Document 5 round of reform can be summarised as:

- **Unbundling the SPC:** the SPC's assets were disaggregated into five generation companies, two grid companies and four power service companies. The new "big five" generation companies were all state-owned enterprises, including Huaneng, Datang, Huadian, Guodian and China Power Investment Corporation. The two grid companies after unbundling were the State Grid Corporation of China (SGCC) and China Southern Power Grid (CSG). The four power service companies after unbundling were allocated the key power service businesses that had previously been integrated into the SPC.
- **Introducing regulation:** the Chinese government clearly signalled its intention to introduce independent regulation by establishing the State Electricity Regulatory Commission (SERC) in 2003. Priority duties of the SERC were to establish rules for competitive power markets, with authorisation for supervising interprovincial power transmission, policy making and implementation. In general, the SERC had a positive influence on the progress of China's power market transition, but some of its functions overlapped with the NDRC. The SERC merged with the NEA in 2013 (State Council, 2013).
- **Attempts to improve system efficiency:** Several new initiatives to encourage market trading and more efficient dispatch were launched after the release of Document No. 5. However, not all achievements matched expectations. Attempts to improve system efficiency included:
 - Piloting regional wholesale power markets in the Northeast China and East China grids in 2002; however, the pilots were called off in 2006 mainly due to a surge in power demand and vested interests (SERC, 2003b).
 - Implementation of direct power purchasing in 2004, initially between power generators and large industrial consumers selected by the government; this has continued to be crucial in China's market trading since then (SERC, 2009).
 - Promotion of interprovincial and interregional trading, although most of the trade deals have involved government projects such as the large hydropower plants (e.g. Three-Gorges dam) and trade deals between provincial governments (SERC, 2010).
 - Introduction of generation rights trading in 2008, initially intra-provincial, then expanded to interregional/interprovincial trading (SERC, 2008).
 - Piloting energy conservation dispatch as an alternative practice to the fair dispatch rule, although this encountered obstacles and saw limited application (State Council, 2007).

Box 1. Lessons learnt from Document 5 round of reform

The Document 5 round of reform unbundled the vertically integrated power utility, established a regulation authority and attempted to introduce different market-based trading opportunities into the power system. In general, the reform has successfully ensured the rapid development of China's power sector over the past decade; however, it did not realise all its initial objectives. Here are the lessons learnt from this round of reform:

- **Grid monopoly.** Although the SPC was unbundled, the grid companies still had a negative influence on improving system efficiency. They acted as a single transmission and distribution system operator, plus a single buyer on the wholesale side and a single seller on the retail side. In addition, there was no separate transmission and distribution tariff, which made it difficult to know accurate investment and operational costs.
- **Institutional interests.** While a consensus had been reached that cross-regional trading would benefit overall system efficiency, barriers could not be removed because of institutional interests. Resistance from provincial governments made interregional trading difficult, a result of the strong incentive for each province to rely on its own generation rather than import power from other provinces – the incentive was for each province to boost its own GDP growth. In addition, as provincial governments were responsible for power supply stability, the possibility of an uncontrollable blackout also hampered their willingness to accept interregional trading.
- **Market limitations.** A market-based pricing system was important but not easy to implement. The government-determined benchmark pricing system was only seen as a temporary measure before the introduction of competitive markets. However, due to the opposition of provincial governments, generators seeking to maintain high revenues, and grid companies being threatened with losing some of their interests, the wholesale power market was not able to continue. Without a market-based pricing system, more efficient system operation could not be achieved.
- **Planning challenges.** Experience demonstrates a deep-rooted fear of power shortages and the importance of planning. The Document 5 round of reform originated from a severe power oversupply that started in 1997. As a result, central government suspended construction of coal power plants from 1998 to 2000 and underestimated power demand in the 10th Five-Year Plan (2001-05). The dramatic growth in power demand after 2000 rapidly turned oversupply into shortage, resulting in another round of power construction and reform not being a top priority. Fear of power shortages has always been the greatest concern in China's power sector. Therefore, power sector reform should be made with full awareness of this issue, even in an oversupply situation, and the planning process should consider measures to encourage the right levels of investment while avoiding oversupply.

Power sector reform in 2015

After several years of rapid development, China has realised many achievements in its power sector. Although they are remarkable, several remaining problems still need to be resolved to realise a more efficient, environmentally friendly, low-carbon and safe power system, especially under the circumstances of the clean energy transition and demands for environmental protection.

In 2015 the State Council released Document No. 9, symbolising the beginning of China's latest round of power sector reform (State Council, 2015b). The objectives were to: create market-based prices for wholesale and retail supply to stimulate market mechanisms; establish a separate, transparent transmission and distribution tariff; expand interprovincial and interregional transmission; enhance government regulation; and improve power planning.

Key reforms of the pricing system are as follows:

- Creation of separate transmission and distribution tariffs. The cost of transmission and distribution was bundled into the retail price before Document No. 9. It is important to have a separate and transparent transmission and distribution tariff for market transactions. Now the investment and operational costs of the power grid will be made clear, based on authorised costs and a permitted revenue margin.
- Wholesale energy prices to be decided by negotiation or auction between generators and consumers in mid- and long-term electricity markets. Retail prices will be the sum of the wholesale price, transmission and distribution tariff, and government fees.
- Appearance of retail companies for the first time, which means smaller customers have the option to buy power from a retailer. Small and medium-sized enterprises (SMEs) are able to purchase power at the market price, rather than at the benchmark retail price.

Document No. 9 also mentions the importance of planning, as follows:

- Approving power projects remains the responsibility of provincial governments, while planning is the responsibility of central government. This could induce excess investment if co-ordination is not well managed.
- In the long term, all industrial and commercial power demand will be gradually transferred to mid- and long-term contracts. These will not be included in the administrative plan.

Document No. 9 also seeks to redefine the role of grid companies. The major business of grid companies in the future will be investing in power grids, power transmission and distribution, grid system security, ensuring fairness and non-discrimination to all players, and providing grid services. With the opening of the wholesale and retail markets, grid companies will no longer be the single buyer on the wholesale side or the single seller on the retail side. The separate and government-approved transmission and distribution tariff will be the major source of revenue for grid companies.

Responsibility for establishing a separate transmission and distribution tariff, promoting direct contracting, founding power exchange institutions and constructing power markets was handed to provincial governments in this round of reform. The pressure of reducing the cost of power to the real economy is intended to provide a strong incentive to provincial governments to promote power sector reform.

Challenges in China's power sector

Planning

China has already started on its path of moving from a fully centrally planned power system towards one with a stronger role for markets. The ongoing reform under Document No. 9 provides further impetus in this direction. However, challenges remain to be fully resolved on this journey.

The first challenge is the future role of planning and how it co-ordinates with the market (IEA, 2017b). In China's centrally planned approach, the five-year plan directly translates into investment decisions. However, in an electricity system with fully competitive wholesale

markets, the long-term plan does not translate directly into investment in the generation segment of the value chain. Nevertheless, it provides visibility for market participants to inform investment decisions, and the process of establishing the plan is an opportunity to reach consensus on the desired direction of the system. This can then provide the basis for introducing specific policies to ensure the market has appropriate framework conditions. It also gives certainty regarding decisions on new investment for transmission grids.

Data transparency for all market participants will also be a challenge in China, with the growing role of a market-based system. Understanding where new power generation might be feasible requires access to transmission grid data, as well as information on the supply-demand balance of electricity, at a sufficient level of detail.

A further issue is that China is undergoing a transition from a coal-dominated power system to one where renewables play a much stronger role (IEA, 2018a). Therefore, the market is not the only driver of system transformation – the rise of low-cost renewables and decarbonisation, the increased importance of distributed energy resources and electrification, and digitalisation are also positioned to be fundamental drivers. There are concerns that a rapid move to a market system with economic dispatch could put too much strain on the incumbent coal fleets and lead to capacity shortages in the future, reflecting the Chinese power system's historical swings between capacity shortage and surplus. How to conduct planning to secure adequacy investments in a market-based system with high proportion of VRE is a new task for China's policy makers.

Interprovincial and interregional trading

Interprovincial/interregional trading requires grid co-ordination between provinces. There are three challenges to encouraging trade: institutional, economic and technical. Institutionally, each province has its own system with no joint governance. This makes trading difficult to co-ordinate for two provinces connected to one another. Trading between non-adjacent provinces is even more difficult to organise. Economically, provincial governments prefer to use their own generators rather than imports, since self-sufficiency has a large positive influence on the local GDP. Technically, interprovincial links are relatively small, limiting the technical ability of provinces to trade with one another.

Grid companies also pose a challenge. They play a dominant role in interprovincial/interregional trading. Therefore, power generators closely related to grid companies stand a better chance of participating in the trading process, while local and private generators are less likely to participate. A further issue is that while the annual interregional/interprovincial trading plan is intended to be a guideline proposed by national-level grid companies, provincial grid companies usually take it as a mandatory contract, resulting in inflexibility. One example of this occurred in June 2012, when Central China had already imposed hydropower curtailment because of the expectation of rainy weather, but it still had to import 350 gigawatt hours of energy from the Northern China grid, according to the interregional trading plan.

Dispatching order

Dispatching in China follows the administrative fair dispatch rule rather than a merit order. While the fair dispatch rule encourages greater investment, especially in coal power, it overlooks incentives for plants to be efficient or environmentally friendly; for example, all coal power plants were previously granted the same base generation hours. Adjustments to allow differentiated base generation hours took place years later when considering the influence of technologies on efficiency and pollutant emissions. But still, plants with low operational efficiency and high emissions gained significant revenue. The rule created an ingrained belief

among power generators that everyone should receive a nearly equal share of the benefit, no matter how inefficient or environmentally unfriendly their performance.

An alternative energy conservation dispatch rule was piloted in a few provinces (see Box 2), but fair dispatch still dominates most provinces in China. Dispatch reform could encounter resistance from the grid companies as well as generators. For grid companies, the challenge is the difficulty in changing the complex dispatching system to accommodate a new economic dispatch order, and the possibility of losing revenue. For power generators, the challenge is the impact on existing generator contracts, which are based on the expectation of sharing the available operating hours – the financial impact on individual plants of operating hours being reallocated away from them would be substantial.

Box 2. Energy conservation dispatch

Since 2007 a number of provinces have piloted an alternative dispatch method. This so-called energy conservation dispatch is intended to minimise fuel consumption and pollutant emissions by structuring the merit order as follows: 1) renewables that cannot provide a grid service, including wind, PVs and some hydro; 2) renewables that can provide grid services, including some hydro, biomass and geothermal; 3) nuclear; 4) co-generation; 5) gas-fired plants; and 6) coal-fired plants (to be prioritised in order of heat rates).

Energy conservation dispatch has been adopted in a limited number of regions because its promotion is at the expense of certain generators, especially coal-fired power plants with PPA contracts, due to no financial compensation measures being in place. If energy conservation dispatch had been fully implemented, it would ideally have significantly improved clean energy integration and reduced emissions. For example, between 2007 and the end of 2017, 17.66 million tonnes (Mt) of coal-equivalent savings and emissions reductions of 46.98 Mt of carbon dioxide (CO₂) and 0.35 Mt of sulphur oxides (SO_x) were achieved in the Southern Grid region.

Benchmark pricing system

Wholesale and retail electricity prices in China are regulated to ensure overall recovery of costs to build and operate power plants. Provincial governments set and adjust benchmark prices for their own province, according to their costs and economic development level (NDRC, 2005). The adjustment of benchmark prices is reported to central government and approved.

On the wholesale side, one challenge is adjusting the benchmark on-grid price for coal power when the price of coal fluctuates. A mechanism called “price linkage for coal and electricity” was introduced in 2004 (NDRC, 2004). An average change in the coal price of 5% or more triggers an immediate adjustment to the coal power benchmark on-grid price, but the mechanism is unable to adjust the power price in a timely and efficient way since it can only take place after the government review of the coal price every six months. When the coal price rises dramatically, therefore, it may be difficult for generators to remain profitable.

On the transmission and distribution side, no separate tariff existed before the Document No. 9 round of reform. Grid companies took the difference between the regulated retail price and the regulated on-grid price as their revenue. Separate intraprovincial and interprovincial transmission and distribution tariffs were clarified after Document No. 9, which is regarded as a

significant achievement (EPPEI, 2017). However, considering that accurate construction and operating costs are difficult to obtain, achieving cost-reflective tariffs will be a challenge for regulatory authorities.

On the retail side, clarification of cross-subsidies embedded in the retail price is a great challenge (IEA, 2006).¹⁰ Cross-subsidy in China contrasts with retail markets elsewhere, where retail prices are regulated to achieve better efficiency and promote cost-effectiveness. However, it has always been a challenge for the Chinese government to choose between efficiency and fairness. The influence of cross-subsidy on the power price is becoming increasingly important, as the need to lower costs to maintain the advantage of “made in China” keeps growing. Moreover, cross-subsidies have a negative influence on SMEs in the commercial sector, yet these private-sector enterprises are crucial to China’s economic growth and modernisation.

Renewable development and integration

The increasing use of VRE raises the challenge of its integration into China’s current power system. Some power markets around the world provide insufficient economic incentives for other generators to curtail their output during periods of high variable renewable production. Additional challenges arise in China, such as the existing fair dispatch rule for power system operation that may limit the economic use of VRE.

The characteristics of wind and solar generators are contradictory to China’s predetermined planning system. The variability and unpredictability of wind and solar power interact with the inflexibilities of fossil fuel generators, power demand and transmission line constraints.

The integration of renewable energy has drawn resistance from coal power plants, which are experiencing severe overcapacity due to the boost in construction after the shift in authority for administrative approval from central government to provincial governments in 2013. Consequently, newly built coal power plants have been in their debt-servicing period and therefore not wished to see a substantial reduction in their operating hours. The rise in the coal price in recent years has increased the resistance of coal generators to renewables even further.

There is also resistance from grid companies. The current pricing mechanism mandates grid companies to pay wind and solar power the same on-grid price as the benchmark on-grid price for coal power. Therefore grid companies see no profit from integrating more VRE, and only see increased complexity of dispatch to maintain system safety and security.

Interprovincial or interregional renewable energy transmission seems like a feasible way to improve wind and solar integration. However, this is not a good solution in reality, at least for power-importing local governments. The wind and solar on-grid price is fixed to a benchmark, and this price plus the transmission tariff is now higher than the local coal power price. Therefore, local governments tend to use cheaper coal power generated in their own province. Furthermore, allowing local coal power plants to generate more electricity is perceived as being helpful for local GDP growth.

¹⁰ For example, industrial prices are currently higher than residential prices in China due to cross-subsidy, which is different from many other countries.

Emerging trends in system transformation in China

Introducing flexible market operation

Mid- and long-term contracting

Mid- and long-term power trading had been acting as a supplement to the administrative allocation of electricity before Document No. 9, and represented only a small proportion of total power transactions.¹¹ Document No. 9 foresees the orderly withdrawal of the administrative allocation system, with mid- and long-term contracts as a crucial step towards a market-based system (NDRC and NEA, 2016a; NDRC and NEA, 2017a). Because of pressures in the real economy, a request to reduce commercial and industrial retail prices by 10% was announced at the 2018 National Congress Meeting (State Council, 2018). In July 2018, a document was released with the aim of accelerating progress towards the market system, fulfilling the retail price reduction target, requiring power purchasers in the coal, iron and steel, non-ferrous metal, and construction material industries to completely quit administrative planning and fully participate in the mid- and long term market by the end of 2018 (NDRC and NEA, 2018b).

Establishing a separate transmission and distribution tariff is very important to further promoting mid- and long-term power trading (NDRC, 2015a). This fundamental prerequisite was not in place in China, and the transmission and distribution tariff was calculated as the difference between the benchmark retail price and the benchmark on-grid price. Realising that this was a barrier to power reform, the central government decided to make it more transparent. By December 2017, all provinces had published a transmission and distribution tariff.

Each province adopted a different design for its mid- and long-term power market. In general, three types of market operate in China: bilateral negotiation, listed auction and centralised auction.

In 2017 power trading via mid- and long-term contracts (sum of intraprovincial, interprovincial and interregional trading) reached 1630 TWh (26% of total power consumption). Interregional/interprovincial power trading reached 264.5 TWh by the end of Q3 2018 (5.2% of total power consumption), realising a nearly 50% year-on-year increase.

Establishing spot markets

Short-term markets are the foundation of all market-based electricity systems. They have proven to be a valid approach to reducing the cost of electricity supply and promoting cost-effective integration of high shares of the VRE while avoiding curtailment. China has recognised the importance of short-term markets, and in August 2017 the NDRC and the NEA jointly released the "Notice on piloting spot market", selecting Guangdong and seven other provinces to be the first batch of pilots (NDRC and NEA, 2017b). These pilots were expected to start operation by the end of 2018, but because of arguments among stakeholders and a lack of experience in market design, certain pilots continue to lack a preliminary design. In November 2018, each of the eight departments in the NDRC and the NEA involved in power market reform took charge of one or two pilots separately, to provide guidance and accelerate progress in spot market design (NEA, 2018c). The latest timeline for these pilots to start operation is June 2019.

Among all the spot market pilots, Guangdong is processing faster than others, with its design and plan released in August 2018 (NEA, 2018d). The Guangdong spot market is due to be

¹¹ This section follows Power Sector Reform in China: An International Perspective (IEA, 2018a).

further expanded to all provinces within the Southern grid region in the future. If successful, this market design could be the basis for spot markets in the other Chinese provinces. The design incorporates many features that are considered state of the art, including:

- Central optimisation of the commitment and dispatch of units by the system operator, taking generators' bids and security constraints into account.
- A gross pool model, where prices will be defined by the most expensive clearing bid.
- A high granularity of prices, geographically (with different prices for every node in the system) and temporally (with trading intervals of 15 minutes).
- Integration of operations across a large geographical area, which will allow participating provinces to benefit from sharing their resources.
- The capability for demand and supply to bid, although only generators will be able to bid in the first stage of the pilot project.
- Optimisation of all ancillary services.
- Settlement of long- and medium-term contracts through contracts for differences, taking as reference the price in the day-ahead market.
- A centralised system of bonds that will be used to guarantee all the long-, medium- and short-term transactions, meaning that the power exchange will also work as a clearing house.
- Implementation of capacity markets, financial transmission rights and other remaining derivatives after 2020.

The Guangdong spot market takes into consideration the existence of plants not participating in market transactions (type A plants), which will continue with the existing on-grid feed-in price, and those participating in the market (type B plants). The description of the market acknowledges that old rules will coexist with the new market, but defines as an explicit objective the gradual phasing out of the generation defined by administrative authorities in type B plants.

An interregional spot market for surplus renewable generation was established in August 2017, aiming to promote the integration of renewables. Sellers are mainly from provinces with high renewables curtailment rates, such as Gansu, Xinjiang, Ningxia, Qinghai and Sichuan. Buyers can be large consumers, power retail companies or local grid companies. The spot market runs on a small scale due to reliability and stability considerations, allowing only renewable energy unable to integrate after trying all possible methods of participation. The price of the surplus generation tends to be low, which is favourable to the receiving-end provinces in the Central and Eastern regions. In 2017, 6 TWh of renewable generation was traded on the surplus renewable spot market (total power consumption was 6 307 TWh). Gansu Province, the largest trader in the market, sold 2.35 TWh in the first half of 2018.

Incremental distribution grid pilots

Incremental distribution grids are a key part of the Document No. 9 round of reform (NDRC and NEA, 2016b). One reason for promoting distribution grid reform is because, unlike the regional/provincial monopoly on transmission, power distribution can be a local monopoly at the level of the municipality. Therefore, breaking the monopoly on distribution from China's grid companies has the advantage of allowing comparative competition between distribution companies. This, in turn, promotes competition between management teams and in input markets, and increases responsiveness to customer demands for quality of service. An additional reason is that institutional innovation in power distribution could provide support for

a future power system with more VRE and distributed power generation, helping realise the power system transformation.

Incremental distribution grid reform allows more participants to enter the distribution segment. The NDRC and the NEA have identified 320 distribution grid pilot projects in 3 batches. Incremental distribution business, in principle, refers to local power grids of 110 kilovolts (kV) and below, an industrial park of 220 kV and below, or an economic development zone of 330 kV and below.

The progress of these pilots is lagging behind. A survey of distribution grid pilots in 14 provinces was conducted by the NDRC and the NEA in August 2018, showing that only one-tenth of the pilots actually finished construction, with even fewer able to progress to trial operation. The main reasons for the slow progress are resistance from the grid company, which is afraid of losing some of its business, and the lack of a complementary pricing mechanism. However, central government is demonstrating decisiveness on the reform and has mandated deadlines for these pilot projects. SGCC has also taken action to accelerate progress and has issued a dedicated plan in late 2018 to accelerate implementation of incremental distribution grid network pilots.

Unlocking the retail side

Traditionally, grid companies in China acted as the single seller on the retail side. To unlock the retail market, central government decided to introduce market competition in retailing by allowing other players outside grid companies to do retail business (NDRC, 2015b). As a result, consumers – including SMEs, residential and agricultural users – are able to purchase power at the market price rather than at the benchmark retail price issued by government. By 2017, the following progress had been made:

- The number of registered retail power companies had reached 3 500.
- Power trading between generators and retail companies had exceeded 90% of total provincial power trading in Guangdong, Shandong and Anhui provinces.
- Power trading via retail companies had exceeded 30% of total provincial power trading in Shanxi and Yunnan provinces.

Trading centres and regulatory committees have also been established:

- By January 2018, 35 power trading centres had been founded nationwide, comprising 33 at the provincial level, and two at the regional level, namely the Beijing trading centre in the SGCC jurisdiction and Guangzhou trading centre in the CSG jurisdiction.
- Based on power trading centres, 26 regulatory committees have been founded. Members of the regulatory committee consist of delegations from power generation companies, power grid companies, power sales companies, consumers and trading centres.

Power plant flexibility pilots

Increased power plant flexibility has been piloted in Northeast China and proved to be successful in lowering the curtailment rate of variable renewables (NEA, 2016b). Northeast China has excess generation capacity, a large proportion of which is at co-generation plants, alongside a substantial amount of wind power generation. These co-generation units run at a high operating rate during the winter heating season and cause wind curtailment. The ancillary service market was introduced in 2014 to incentivise the flexible operation of coal plants. All plants are required to provide downward regulation, that is, reduce output if called upon at no cost if the plant's output is above a certain threshold (typically 50% of the maximum generation capacity). If the output of the plant, however, is below the threshold while providing downward

regulation, the difference between the threshold and the plant's actual output is reimbursed by those power plants operating above the threshold at the time. Renewables generation in the Northeast region increased by 22% in 2017 compared to 2016, with only a 2% increase in capacity. The experience of the Northeast ancillary service market has been extended to seven other provinces, helping to reduce renewables curtailment in China from 11 TWh in 2016 to about 8 TWh in 2017 (NEA, 2017).

Realising optimised planning

Five-year plan

China adopted a central planning system for its economy upon the foundation of the country, making five-year plans for all critical economic sectors. However, since the nationwide "reform and opening up" campaign in 1978, the economy has gradually changed towards a market-oriented one, and the five-year plans have become more about setting policy direction and providing guidance (IEA, 2017a).

In March 2016 central government released the 13th Five-Year Plan (2016-20) on economic and social development. Based on this, the NDRC and the NEA published the 13th Five-Year Plan on the power sector and its subsectors, including coal, hydro, solar, wind, geothermal and biomass (NDRC and NEA, 2016c; NEA, 2016c; NEA 2016d). It listed the main targets and tasks for the power sector to the year 2020, alongside the supporting policies. Selected key indicators are listed in Table 1.

Table 1. Selected key power sector indicators in China's 13th Five-Year Plan

Indicator	2015	2020
Total electricity consumption (TWh)	5 690	6 800-7 200
Total generation capacity (GW)	1 530	2 000
Electricity consumption per capita (kWh)	4 142	4 860-5 140
Share of electricity in energy consumption (%)	25.8%	27%
Non-fossil fuel generation capacity (GW)	520	770
Non-fossil fuel share of generation capacity (%)	35%	39%
Non-fossil fuel share of energy consumption (%)	12%	15%
Solar generation capacity (GW)	430	110
Solar generation (TWh)	40	150
Wind generation capacity (GW)	131	210
Offshore wind generation capacity (GW)	-	5
Wind generation (TWh)	-	420
Total hydro generation capacity (GW)	297	340
Large and medium-sized hydro capacity (GW)	222	260
Small hydro capacity (GW)	75	80
Pumped storage hydro capacity (GW)	23	40
Normal hydro generation (TWh)	-	1 250
Large and medium-sized hydro generation (TWh)	-	1 000
Small hydro generation (TWh)	-	250
Nuclear generation capacity (GW)	27	58
Coal generation capacity (GW)	900	< 1 100
Gas generation capacity (GW)	66	110
Co-generation capacity (GW)	-	133
EV charging infrastructure	-	Sufficient for 5 million EVs
Transmission from west to east (GW)	140	270

Notes: EV = electric vehicle; kWh = kilowatt hour.

Five-year plans allow for some flexibility, as they can be adjusted in the middle of their duration; for example, the 13th Five-Year Plan starts its evaluation and adjustment process at the end of 2018 (NEA, 2018e).

Long-term strategy

The five-year plan is seen as a medium-term planning instrument. The Chinese government has also started to consider long-term planning for the energy sector. The “Energy Production and Consumption Revolution Strategy” released in 2016 served as broad guidance for all the energy five-year plans and policies (NDRC and NEA, 2016d). The document focused on four areas: energy consumption, supply, technology and institutions, with the latter incorporating the need for international energy co-operation. The overarching aim was to realise a more secure, sustainable, diverse and efficient energy future (IEA, 2017a). There is no long-term strategy document specifically for the power sector, but key targets in the 2016 strategy could provide guidance to the power sector:

- total primary energy consumption to be kept below 6 000 Mt of coal equivalent
- share of non-fossil fuels to reach around 20% in the energy mix
- incremental energy demand to be met mainly by clean energy
- energy intensity to reach current global average levels
- share of non-fossil fuel power generation in total power generation strives to reach 50%
- share of ultra-low-polluting coal-fired power plants to be more than 80% of the fleet
- recall climate change commitments: to lower CO₂ emissions per unit of GDP by 60-65% by 2030 from 2005 levels; CO₂ emissions to peak around 2030 and strive to peak sooner.

Technological innovation and electrification

Distributed energy

It was not until this decade that distributed energy joined the fast lane, especially natural gas, PV and wind power.¹² Since 2010 the NDRC and other governmental departments have issued policies on these three distributed sources and others.

Development of China’s distributed natural gas (DNG) projects dates back to the late 1990s. Since 2003, China began to build distributed energy stations,¹³ including several DNG stations, such as projects for the Beijing Gas building, Shanghai Pudong International Airport and the Central Hospital in Shanghai’s Huangpu district. Over the past ten years the Chinese government has continued to promote the development of distributed energy, with roughly 120 completed DNG projects in China at the end of 2015, having an installed capacity of about 1.4 GW.

Principal users of DNG include industrial parks, commercial complexes, data centres, schools, office buildings, integrated parks and thermal power plants. These users are relatively large and have a continuous demand for cooling, heating and power. Projects that supply energy for these users account for 97% of total installed capacity and account for 72.5% by number. Industrial parks have a relatively high installed capacity, making up 67.7% of the total, with

¹² This section follows Prospects for Distributed Energy Systems in China (IEA, 2017c).

¹³ Distributed energy stations are small-scale energy supply projects specifically applied to commercial buildings, airports, industrial parks, etc. They can provide electricity, heating and cooling.

schools contributing 12.2% and commercial building complexes 6.5%. In China, projects for cooling, heating and power in buildings and district cooling, heating and power each make up approximately half of the DNG projects. Because parks of various kinds and commercial complexes have a stable demand for electricity, cooling and steam, power is mainly provided by gas turbines or by combined-cycle gas turbines. Hospitals, schools, hotels and office buildings have a smaller and less stable demand, so power is mainly supplied by gas turbines and gas microturbines.

Distributed PV capacity is increasing at a faster pace than utility-scale PV (IEA, 2018b). In 2016 newly installed capacity increased by 200% year-on-year. Distributed PV power generation enjoyed very strong growth in the Central and Eastern regions. Provinces that topped the list were Zhejiang, Shandong, Jiangsu, Anhui and Jiangxi. Distributed PV is expected to grow more quickly in the coming years because:

- Newly released policies allow distributed generation owners to use some energy for their own consumption and sell excess generation to on-site consumers. Commercial and industrial projects become economically attractive at high levels of self-consumption, as the retail price is high.
- The administrative hurdles preventing generators from selling power to multiple consumers connected to the same substation were lifted, hence increasing the client base for distributed generators, enabling them to diversify revenues and reduce risk.

Distributed wind power was encouraged in China's 13th Five-Year Plan. Some inland regions have begun to utilise local resources to plan for wind power development, bringing new opportunities for small and medium-sized wind power investment enterprises.

Multi-energy projects, microgrids and "Internet+" smart energy

Recent years have seen the development of China's industrial parks, the popularisation of microgrids and new energy power generation, and the constant upgrading of investment models. While initial efforts focused on technology, finding suitable economic arrangements and business models have more recently been receiving equal attention. In 2016 the NEA started the construction of integrated projects that combine multiple complementary energy sources, as one of the key measures of establishing "Internet+" smart energy systems. In late 2016, the NEA announced the first batch of 23 demonstration projects using "multi-energy" complementary energy sources and integrated optimisation.

Most of the demonstration projects are integrated energy supply systems for end users. Their designs and planning processes are now completed. However, because of programme complexity and other reasons, some are not yet in operation. Notably, demonstration programmes, such as large-scale comprehensive energy stations in cities, had appeared before the concept of integrating different energy sources was even put forward. These projects are also good examples of distributed gas turbine and energy cascade utilisation.

The integration of different energy sources can provide a flexible solution for meeting the energy needs of commercial and industrial complexes. While flexibility within an industrial complex is profitable for enterprises, this flexibility also improves the security and stability of China's energy supply for the wider grid. With the prospect of extensive new energy consumption, this flexibility can decrease the peak load requirement and support the frequency regulation of power grids.

Box 3. Multi-energy complementary project in Gui'an

A project combining complementary energy resources, located in Gui'an city, Guizhou province, provides heating, hot water, cooling and electricity services to a total building area of about 500 000 square metres (m²). The project uses a combination of natural gas with three other energy resources: a water-based heat pump, solar thermal and compressed air energy storage. The project design gives priority to the supply of heating services, and the system usually operates off-grid, but can rely on the grid when needed. The power generation capacity is 2.8 megawatts (MW), cooling capacity is 15 165 kilowatts (kW), and heating capacity is 13 304 kW. Compared with a conventional central air-conditioning system and boiler heating system, the installed capacity for cooling is reduced overall by about 45-55%, and the installed power capacity reduced by about 30 MW. Compared with split system air conditioners, the installed capacity can be reduced by about 70 MW. In the near future, Gui'an city plans to set up ten similar distributed energy stations and a smart energy management centre to meet the energy needs of a 43 square kilometre science park.

Source: People.cn (2017), 贵安新区建设国内首座“1+3”多能互补分布式智慧能源站 [The First Combining Complementary Energy Resource Finished in Gui'an City].

Box 4. Microgrid project in Suzhou

The microgrid project, developed by GCL in Suzhou city, Jiangsu province, is a national renewables-based microgrid demonstration project in China. The microgrid aims to integrate six energy systems based on solar PV, gas-fuelled co-generation, wind energy, low-grade heat supplied by ground source heat pumps, and solar thermal, light-emitting diodes (LEDs), and energy storage. The area of construction of the first phase was 19 515 m².

The energy load of the office buildings from electricity, air conditioning and hot water is estimated to total 1 000 kW, about half that of traditional centralised energy systems. The rooftop solar PV can provide 350 kW of installed electricity capacity, and natural gas 400 kW for electricity and 400 kW for heating and cooling services. The project is also integrated with multiple technologies, including a 100 kW energy storage system, a wind and solar combined system, EVs, microgrid and LEDs. The buildings can achieve more than 50% energy self-sufficiency with more than 30% energy savings. Primary energy is converted in a cost-effective and efficient way to meet end-use needs from lighting, motors, appliances, air conditioners, heating, hot water and steam. This leads to savings in energy investment of 30%, a reduction in energy consumption of 40%, improvement in energy efficiency of 40% and reductions in emissions of more than 50%.

The core benefit of GCL's offering comes from integrating a variety of energy sources with various characteristics to construct a microgrid system. This allows an optimal use of these various energy sources by meeting end-use needs with electricity, cooling, heating, steam and other energy products. This helps improve overall energy efficiency, reduces the total cost of energy consumption, achieves emissions reduction and protects the environment.

Box 5. “Internet+” project in Guangdong

In 2017 CSG built its first smart energy demonstration project in Guangzhou. The project aims to integrate four networks: electricity, Internet, television and telephone. The project district covers a total of 21 buildings with around 1 450 households. The composite low-voltage fibre combines optical and power cables. Integrating four operators’ networks makes the interaction of power flows and information flows feasible, supporting energy data transmission and intelligent home management. Digitalisation of meters for electricity, water and gas is central to the project. With the support of a centralised collection system and the fibre cable, meter reading in a building can be completed remotely in ten seconds. This significantly improves the accuracy and efficiency of metering. At the same time, the system can conduct remote fault diagnosis and control in real time in order to control system losses and ensure intelligent management of electricity, water and gas meters.

The data recording system can provide detailed time series data for household appliances, including lighting, refrigerators, televisions and air conditioners. This will facilitate big-data analysis of consumer demand. Based on four networks and three meters, integrating with distributed energy, charging facilities, intelligent homes and intelligent communities – as well as constructing big data on electricity, water and gas consumption – it is possible to have a better understanding of consumer behaviour and spending. Furthermore, this project can be extended to other smart home applications and also manufacturing applications. It is likely that energy consumption of manufacturing equipment can also be optimised in response to energy structure and production requirements.

Digitalisation

A principal advantage of digitally enabled connectivity-based business models is the ability to collect and analyse large amounts of data and to optimise the use of a vast number of assets accordingly. China is already seeing practical applications of this model.

Box 6. Envision’s platform for the Internet of things

Envision Energy is a large Chinese wind turbine manufacturer that in September 2016 launched a data platform based on the Internet of things called EnOS. It connects and manages various devices related to energy generation, consumption, storage, transmission and distribution through cloud computing and big-data analytics. The objective is to make energy devices operate collaboratively at the level of each household, each community and even each city. Such optimisation can reduce power generation investment, monitor and manage load, and achieve supply-demand balance in response to market dynamics.

The main benefit of this platform is its close integration and optimisation among different components of the entire energy system. It thus allows for the concrete application of the principles of smart distributed energy sources. The platform has already been commercially implemented by utilities and other energy companies.

Source: Envision (2017), “EnOS platform for internet of things”, www.envision-energy.com/energy-os/.

Demand-side management/demand-side response

Demand-side management (DSM) in China is an administrative procedure taken by power generation companies and grid companies. DSM was particularly encouraged during the years 2003 to 2008, when electricity supply experienced a shortage in some regions (CEC, 2018). The three major means of demand response in China are:

- Load shifting: to adjust consumers' energy consumption behaviour by using heat storage and energy storage devices, while applying peak-hour prices and interruptible load compensation.
- Energy saving: to encourage energy-saving bulbs and high-efficiency motors, pumps and transformers.
- Power generation resource replacement: to encourage high-efficiency energy resources.

It was not until recent years that China adopted demand-side response (DSR) projects (Table 2), and initially the process was not smooth. Institutionally, the low level of participation, together with the benchmark pricing system that cannot sufficiently reflect the market balance, limit the DSR resource. Technically, the relatively slow development of an information exchange system makes it difficult to promote smart meters designed for peak–valley power measuring.

Supporting policy was released in 2012 for cities piloting DSR. Pilot cities were allowed to adopt more flexible DSR policies, such as to compensate iron and steel enterprises for interruptible load, and to reduce the power price for DSR demonstration projects. Meanwhile, time-variant power prices and differentiated sectoral power prices were adopted for load shaping so as to create a dynamic power balance.

Table 2. DSR development in pilot cities

	Scale of DSR	Local supporting subsidies	Highlights	Major problem
Beijing	A total of 74 consumers with 17 demand aggregators were organised to implement a DSR event, achieving a maximum load reduction of approximately 72 MW.	CNY 100 million	1) Research promotes green funds, investment and financing models, public-private partnerships and other new financing modes. 2) Adjustments to peak and valley electricity prices and promotion of cross-regional wind power trading. 3) Breakthrough in cool-storage air conditioning technology. 4) Reward for innovation projects.	Some projects, such as cool-storage air conditioning, have a long construction period before DSR can be implemented.
Foshan	Nine demand response events were successfully organised, with the highest number of responding	Locally raised funds up to 11/2015/: CNY 79.79 million	1) Developed and implemented a cool-storage pricing plan. 2) Developed peak pricing and DSR pricing. 3) A well-established DSM platform has been built.	1) Affected by the economic downturn – awareness of energy saving in enterprises declined. 2) Project management process and capital

companies reaching 100, and a load reduction of 94 MW.

declaration process are long, reducing corporate enthusiasm.

3) Peak electricity pricing and interruptible electricity pricing have not been approved yet because of management issues.

Suzhou	One DSR event implemented, with a total of 5 demand aggregators and 28 consumers, and load reduction of more than 380 MW.		1) Created smart electricity demonstration enterprises and communities. 2) Promoted mergers and acquisitions. 3) Drafted the optimisation of the peak and valley electricity price period and the interruptible electricity price scheme.	1) The sluggish economy affected the progress of the pilot project construction. 2) Project review time is long, affecting company enthusiasm.
Tangshan	The first DSR event was carried out in early November 2015, with 4 companies participating, and an estimated peak-time load shift of about 110 MW.	Up to 11/2015: CNY 7.38 million	1) Using advance power indicators for economic operation forecasting and warning. 2) Outreach and internal development of service industry. 3) Developed a DSR mechanism according to local conditions. 4) Adjustment of industrial and commercial electricity prices, peak and valley electricity prices, and valley prices for "double storage" equipment.	1) Restricted by SGCC, the platform has not been fully utilised. 2) Institutional difficulties in the innovation of electricity pricing.

Box 7. DSR trial in Jiangsu (14:00-14:30, 26 July 2016)

Jiangsu province implemented a provincial power DSR trial in summer 2016 for half an hour. Load reduction during this period was 3.52 GW. The number of participants reached 3 154, including industrial consumers and residential consumers. All the extra revenue from the peak-time power consumption was granted to the consumers that participated in the trial, according to a document released by the provincial government.

Electricity storage

After more than a decade of development, China's electricity storage industry has stepped into an important phase of transition from demonstration applications to early commercialisation. At the end of 2016 the operational capacity of China's electricity storage projects totalled 24.3 GW, with the vast majority coming from pumped storage hydro and only 243 MW from battery electricity storage. At the start of 2016, the installed capacity of battery electricity storage projects in operation stood at 101.4 MW, itself a year-on-year rise of 299%. Lithium-ion and lead-acid batteries dominated battery storage; lithium-ion batteries made up the largest share at 59%, increasing by 78% compared with the previous year. The capacity of battery electricity storage projects in planning and under construction in 2016 was approximately 845.6 MW.

As regards the application of electricity storage, capacity in the field of distributed energy storage registered the highest year-on-year increase of 727% in 2016, followed by growth of 523% in applications for renewable energy grid connection. The main storage application is in microgrids. As for regional distribution, new battery electricity storage projects are mostly located in Northwest and East China.

On 22 September 2017, the NDRC, the Ministry of Finance and three other ministries issued *Guidelines for Promoting the Development of Energy Storage Technology and Industry* (NDRC et al., 2017b). The document states that:

"Demand-side distributed energy storage systems should be encouraged. Entry criteria for deploying demand-side energy storage systems should be laid down so as to guide and regulate the establishment of the system. Power companies with rights to manage distribution networks and eligible residential users should be encouraged to install energy storage. Local consumption ratios of distributed energy resources and demand response should be improved so as to lower energy consumption costs. Exploration of relevant business models should be encouraged."

EV development

Transport electrification features as a key development strategy in China's 2030 strategic energy planning. In 2012 China published *Planning for the Development of the Energy-Saving and New Energy Automobile Industry*, proposing that by 2020 China's annual EV and plug-in hybrid EV production capacity would reach 2 million, with an accumulated production and sales volume of over 5 million. In 2017, the Chinese government issued a new energy vehicle (NEV) credit policy that took effect in 2018. The policy sets a minimum requirement for the car industry regarding the production of NEVs,¹⁴ with some flexibility offered through a credit trading mechanism. Annual mandatory minimum requirements for the number of NEV credits that need to be earned are set for car manufacturers. Credits can be earned either through producing or importing NEVs or through the purchase of NEV credits from other manufacturers who have excess credits (IEA, 2018c).

Although EVs have yet to be significant in replacing fossil-fuelled vehicles, with their rapid advance they are expected to play an increasingly vital part in reducing China's dependence on oil imports, thus improving energy security. In the long run, EVs are enabling technologies for the substitution of oil demand. China has also been reported as considering a timetable to ban the production and sales of cars using gasoline and diesel.

¹⁴ Defined as plug-in hybrid electric vehicles (PHEVs), battery electric vehicles (BEVs) and fuel cell electric vehicles (FCEVs).

Box 8. EV subsidy in China

The national Electric Vehicle Subsidy Programme grants subsidies for the purchase of electric cars. The level of subsidy allocated depends on the vehicle range, efficiency and battery pack energy density. In February 2018, the programme was amended, lowering the subsidy level for PHEVs and low-range BEVs, and increasing the levels for long-range BEVs. In addition, the final subsidy received depends on the energy density and efficiency of the car's battery pack, with more credits for battery technologies with higher energy densities and vehicles with higher efficiency. These changes are intended to push original equipment manufacturers to invest in manufacturing electric cars, and the focus on battery performance drives car makers towards battery chemistries with higher energy densities. The changes to the Chinese Electric Vehicle Subsidy Programme entered into effect in June 2018, following a transition period in which electric cars were eligible for 70% of the previous subsidy scheme.

Clean winter heating programme

Tackling the frequent and large-scale smog experienced in Northern China during the winter heating season is a top priority for the Chinese government. In December 2017 central government launched the clean winter heating programme, aiming to phase out the use of decentralised coal and oil for heating (NDRC, 2017).

According to the programme, electric heating is a priority technology. The higher cost of electricity is alleviated by government subsidy or an administrative reduction in the power price. Residents of Beijing adopting the "coal-to-electricity transition" were granted a 10 000 kWh, CNY 0.2/kWh subsidy for the winter of 2017. Hebei province published a power price specifically for the winter heating season, which was substantively lower than the "no-heating" season.

Although electrifying heating is expensive in the current circumstances, it provides a possible pathway towards a cleaner winter, and is likely to be adopted more widely if power market reform proceeds smoothly.

Summary

China has been remarkably successful in achieving very high levels of economic growth over recent decades. This has, in turn, propelled electricity demand, making China's power system the largest in the world.

The unprecedented growth in electricity demand has seen the emphasis placed on the importance of securing sufficient investment, rather than improving environmental performance or system efficiency. Since coal is the only natural resource in which China is self-sufficient, the baseload of the power system has long been dominated by coal power. While in recent years China has decided to diversify its power mix to meet its environmental and economic targets, the shift away from coal in the power system is still likely to be gradual. Conversely, China has installed a great amount of clean energy, and ranks first in the world in terms of installed wind and solar power capacity. This large expansion in capacity has coincided with a period of slowing growth in power demand. As a result, China has found itself with excess coal capacity with low utilisation rates, while the rise of wind and solar power has shone a spotlight on the flexibility limits of the incumbent power system.

To address these challenges, China's power system has embarked on a structural transformation. To improve environmental performance China is putting emphasis on clean energy, with the long-term objective of substantially reducing its reliance on coal. To improve system efficiency, China has launched the Document No. 9 round of reform and has achieved substantial progress: separate tariffs for transmission and distribution have been published; large shares of energy are being traded through energy trading institutions; retail consumer rates are being defined by the market for large customers; and the first pilots on the spot market are being implemented.

Fully realising such a deep transformation is not an easy task. Achieving a cleaner, more efficient power system that can serve the needs of Chinese society in the 21st century requires a number of challenges to be overcome. However, China is not alone in grappling with these issues. While each country has its unique context, understanding the situation in other countries can help accelerate progress. Relevant international experiences are introduced in the subsequent chapters of this report.

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Power system transformation and flexibility

Power systems around the world are undergoing one of the most profound transformations in history (IEA, 2017a; 2017b; 2018a; 2018b). This chapter begins by summarising the main trends behind this transformation: first, the rise of low-cost wind and solar power; second, digitalisation of the power system; and third, the rise of distributed energy resources (DER). It then highlights the importance of system flexibility for power system transformation and discusses its most relevant aspects. Finally, the chapter highlights the consequences of power system transformation for both centralised and distributed power system resources. A diverse number of international examples provide the foundation for this part of the chapter.

Three global trends in power systems

Low-cost wind power and solar photovoltaics

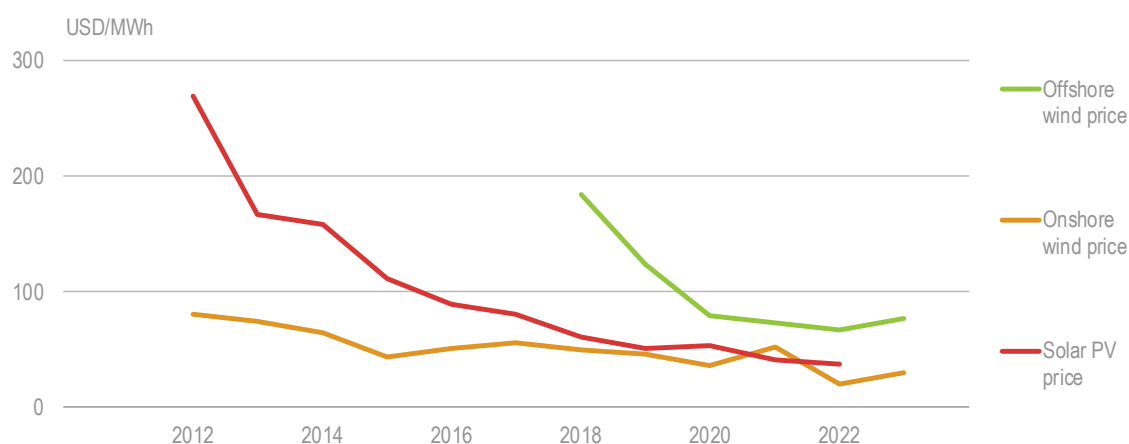
The dramatic reduction in the cost of wind and solar photovoltaic (PV) power – collectively referred to as variable renewable energy (VRE)¹⁵ in this report – is arguably the most radical change for power systems in the past two decades (Figure 7).

The global average levelised cost of electricity (LCOE; see IEA/NEA, 2015; IEA, 2016a) from both technologies has dropped from USD 500 (United States dollars) per megawatt hour (MWh) for solar PV and 94 USD/MWh for onshore wind in 2000 to USD 100 /MWh and USD 71 /MWh, respectively, in 2017 (IEA, 2018c). A combination of technological progress and downward price pressure via well-designed feed-in tariffs (FITs) and competitive auctions has delivered this development (IEA, 2018c). Looking at agreed prices for future projects, even lower costs are emerging. It is important to note that solar PV has seen more rapid reductions than wind power and is on track to become the cheapest source of electricity in sunny areas around the globe. With regard to wind power, the most notable development is the dramatic reduction in the price – and underlying cost – of offshore wind.

Global investment trends reflect these developments: in 2017, renewables accounted for 66% of global investment in power generation, in monetary terms (IEA, 2018d). The International Energy Agency (IEA) forecasts that over the period 2018–23, up to 84% of capacity growth and 46% of generation growth will come from VRE (Figure 8; IEA, 2018c).

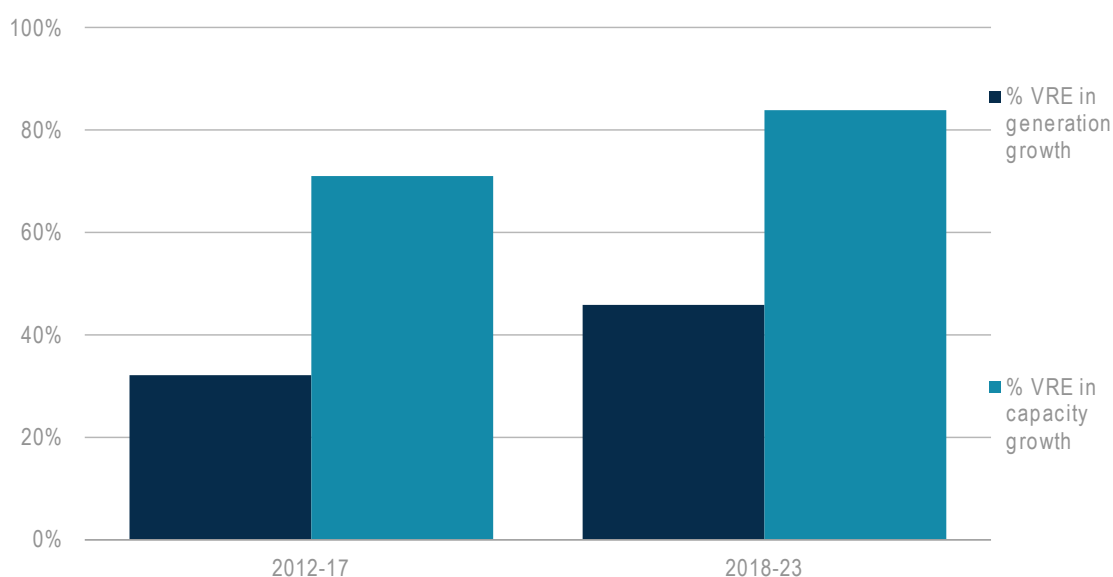
Looking further into the future, IEA scenarios see renewable energy – driven by VRE – becoming the largest source of power generation. In the central scenario of the IEA *World Energy Outlook*, called the New Policies Scenario (see Chapter on “Power system transformation pathways for China to 2035” for details on scenario definitions), renewables become the largest source of power generation by 2030 and VRE makes up 21% of global electricity generation (IEA, 2018b). In the Sustainable Development Scenario, which includes measures to help achieve climate, energy access and local air quality targets, renewables become the largest source before 2025 and VRE alone is the largest source of electricity by 2040, with a share of 35% of global electricity generation.

¹⁵ Strictly speaking, VRE technologies encompass wind, solar PV, wave and tidal power, as well as run-of-river hydropower. Due to the dominance of wind and solar PV in current deployment trends, this report uses VRE to refer to wind and solar PV unless stated otherwise.

Figure 7. Average auction price by project commissioning date for utility-scale wind and solar PV

Source: IEA (2018c), *Renewables 2018*.

Wind and especially solar PV technologies have seen dramatic cost reductions over the past decade. They are on track to becoming the most cost-efficient electricity source in a growing number of countries.

Figure 8. Share of VRE in global capacity growth and power generation growth, 2018–23

Source: IEA (2018c), *Renewables 2018*.

Over the next five years the IEA forecasts VRE to dominate capacity additions and contribute the majority of additional power generation globally.

VRE also contributes to the three other main drivers of change in the power system. First, VRE power plants are digital by design. They use power electronics to connect to the grid (IEA, 2014) and, in modern VRE installations, software can be used to control their behaviour on the grid.

Second, VRE power plants are modular. They can be built as very large-scale plants (such as the mega-bases in the People's Republic of China ["China"]) or in a highly distributed fashion. Solar PV in particular has tremendous potential for distributed deployment, including rooftop deployment on individual houses (IEA, 2017a; 2017c). Finally, due to their technical characteristics – especially weather-driven variability and uncertainty – VRE deployment raises the importance of power system flexibility. These three trends are discussed next.

Digitalisation

One of the most relevant drivers of change in the power sector is digitalisation.¹⁶ While digitalisation is an economy-wide trend, electricity is likely to be the first energy sector to see the impact of its deeper transformation and the one that will ultimately be most affected. Traditionally electricity is generated in large power plants, transferred through transmission and distribution networks and delivered to end-use sectors (residential, commercial, industrial and transport). This model is set to change dramatically.

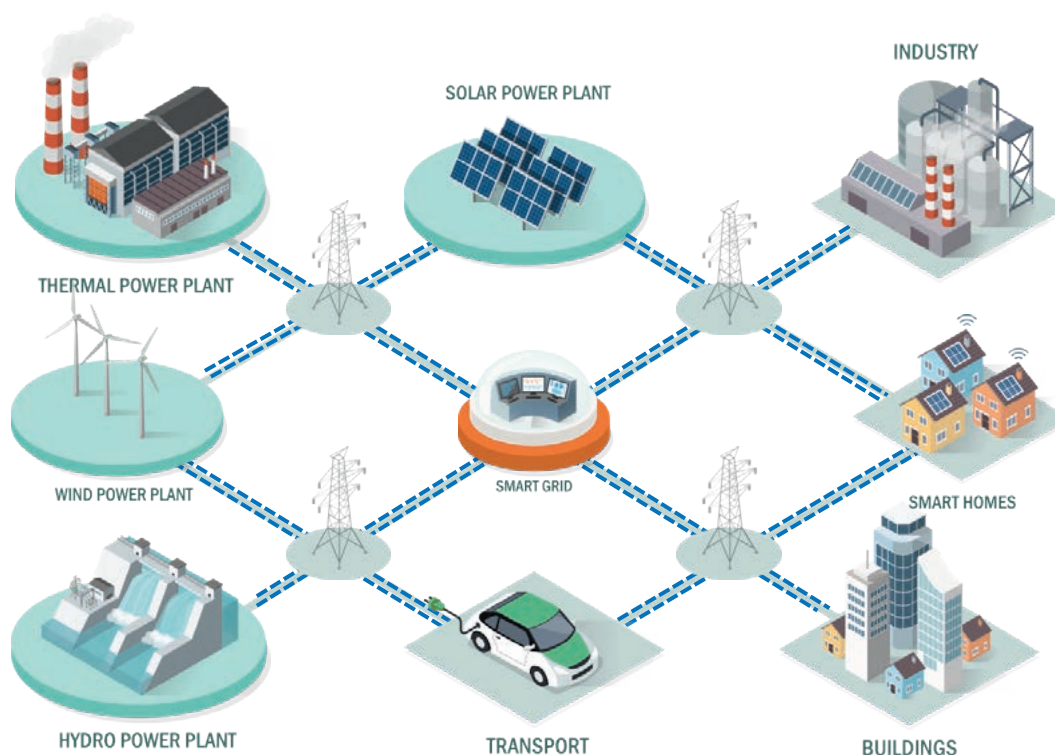
By facilitating a better match between demand and the real-time state of the power system, digitalisation opens up the opportunity for millions of consumers as well as producers to sell electricity, provide valuable services to the grid and benefit from improved consumption patterns. Connectivity is the key factor. It allows the linking, monitoring, aggregation and control of large numbers of individual energy-producing units and pieces of consuming equipment. These assets can be big or small, e.g. a rooftop solar PV system in a home, a boiler on an industrial site, or an electric vehicle (EV).

Increasing availability of advanced metering and communication technology is enabling the deployment of time-variable tariffs and demand response arrangements. Whether implicit – that means customers take individual decisions responding to price signals – or explicit – agreed via a dedicated contractual agreement – demand response is actively reshaping the topology of the power system. In modern power systems, demand will increasingly shift from a passive building block to an active component, contributing to the integration of renewables and meeting the increasingly diverse needs of the power system. From the system planner's perspective, actively engaging demand provides an opportunity to actively shape load and meet the changing needs of the system cost-effectively.

As digitalisation advances, a highly interconnected system can emerge, blurring the distinction between traditional suppliers and consumers with increasing opportunities for more local trade of energy and grid services (Figure 9). In addition, digitalisation allows for the creation of large-scale platforms that integrate and optimise a myriad of interconnected devices across different parts of the energy system (IEA, 2017c).

One of the most visible results of digitalisation is the potential for decentralisation of system operations. This has been driven mostly by increasing penetration of new DER (see next section) and the consequent need to more closely monitor system stability at a local level. Depending on the structure of the market, digitalisation may lead to a shift in responsibilities between stakeholders or even the creation of new roles. The emergence of new roles in the operation and management of power systems is still an open field worldwide. It requires closer examination of the fundamental technical roles in the power system, and how they are currently bundled into different institutional constellations.

¹⁶ The discussion in this section is based on IEA (2017d).

Figure 9. Illustration of an interconnected energy system enabled by digitalisation

Source: IEA (2017d), *Digitalization & Energy*.

Pre-digital energy systems are defined by unidirectional flows and distinct roles; digital technologies enable a multi-directional and highly integrated energy system.

Rise of DER

DER are typically modular or small-scale technologies that empower end users to produce energy locally and adapt the timing of their consumption to the needs of the system. This signifies a break away from the historic top-down supply structure that has characterised electricity systems for more than a century. DER encompass a broad range of technologies, such as distributed generation and storage, and energy efficiency. In addition to well-established DER, such as energy efficiency, three new trends in recent years have been rooftop solar PV, EVs and – to a more limited extent – uptake of next-generation electric clean heating technologies (IEA, 2017a). In all cases, policy support has been crucial for their adoption.

Distributed solar PV

Global installed capacity of residential solar PV grew from 10.6 gigawatts (GW) in 2010 to 51 GW in 2017 (IEA, 2018c). In the same period, commercial and industrial-scale installations increased by over 72 GW to reach 98.6 GW in 2017. Growth in utility-scale projects was 215.7 GW, reaching a total capacity of 224.8 GW in 2017 (IEA, 2018c).

In 2017 the residential and commercial segments combined represented 40% of total installed solar capacity in the United States and 72% in Germany. In 2016 the share of households fitted with rooftop PV was 16% across all of Australia, standing at 26% in South Australia and 25% in Queensland. The share of households with rooftop solar PV systems was 15% in Hawaii, 7% in

Belgium and 4% in Germany (IEA, 2016a). Global installed capacity of residential solar PV is expected to more than double in the next five years to reach 120 GW by 2023.

EVs

Global sales of new electric cars surpassed 1 million units in 2017 – a record volume.¹⁷ This reflected year-on-year growth in new electric car sales of 54% compared with 2016. Electric cars¹⁸ accounted for 39% of new car sales in Norway in 2017 – the world's most advanced market for electric cars by market share. In Iceland and Sweden, the next two most successful markets, electric cars achieved 11.7% and 6.3% market share respectively in 2017. More than half of global sales of electric cars were in the People's Republic of China (hereafter, "China"), where electric cars had a market share of 2.2% in 2017.

The global stock of electric cars surpassed 3 million vehicles in 2017, expanding by 57% compared with 2016. It crossed the 1 million threshold in 2015 and the 2 million mark in 2016 (IEA, 2018e). In 2017 China had the largest stock of electric cars, accounting for approximately 40% of the global total. Electric cars sold in the Chinese market were more than double the amount delivered in the United States, the second-largest electric car market globally.

Electrification of other transport modes is also developing quickly, especially two-wheelers and buses. In 2017 sales of electric buses stood at about 100 000, and sales of two-wheelers were estimated at around 30 million; for both modes, the vast majority were in China.

EV uptake is closely mirrored by the growth in charging infrastructure.¹⁹ In 2017 private chargers at residences and workplaces, estimated to number almost 3 million worldwide, were the most widely used charging installations for electric cars owned by households and fleets. Charging outlets on private property for fleets (primarily buses) numbered some 366 000 units, almost all in China (IEA, 2018e).

Electricity-based clean heating

Heat pumps, which provide space heating, water heating or both, are likely to play a key role in system transformation and cross-sector integration.²⁰ They are among the most cost-effective options to increase the amount of space heating provided by low-carbon energy, and their environmental performance is strengthened by the growth in renewable electricity production. In countries such as Finland, residential heat pumps are already deployed in demand-response systems to augment power system flexibility (IEA, 2018d). Furthermore, heat pumps are also being increasingly used in larger-scale applications in district heating and in industry.

Globally, annual heat pump sales more than doubled from 1.8 million units in 2012 to over 4 million in 2017, with year-on-year growth of 30%; of this growth, 93% was in China (Figure 10).²¹ The market is dominated by air-water systems (97%), followed by ground-source heat pumps (3%), of which sales grew for the first time since 2012. Sales in China made up 72% of the total, followed by those in the European Union (14%), Japan (12%) and the United States (2%). A comparatively smaller market for exhaust air or waste-heat pump technology exists mainly in

¹⁷ The discussion in this section is based on IEA (2018e).

¹⁸ Electric car refers to battery electric vehicles (BEVs) and plug-in hybrid electric vehicle (PHEVs), while it excludes hybrid electric vehicles (HEVs).

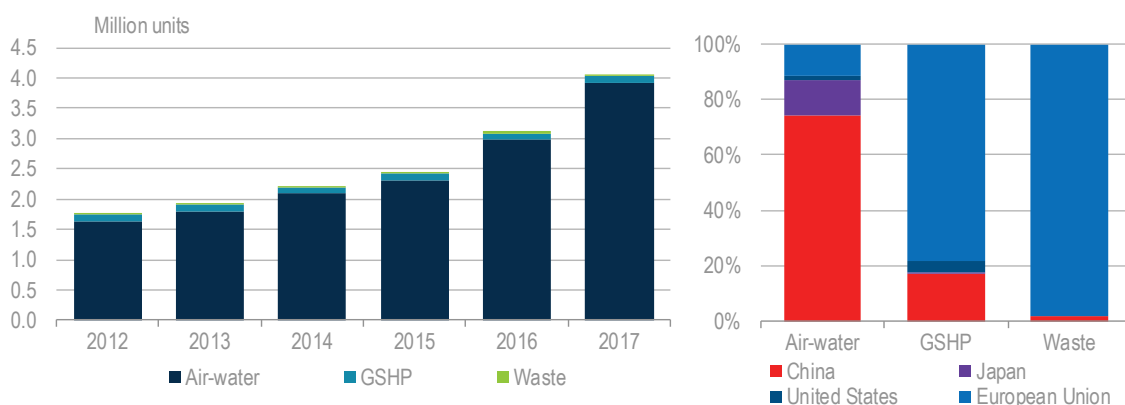
¹⁹ EV supply equipment refers to chargers and charging infrastructure for EVs.

²⁰ The discussion in this section is based on IEA (2018c).

²¹ Global data are based on Building Services Research and Information Association (BSRIA) sources and cover Austria, Belgium, Finland, France, Germany, Ireland, Italy, the Netherlands, Norway, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the Czech Republic, Poland, Slovenia, the United States, China and Japan. The data cover air-water, ground-source and waste-heat pumps, but not air-air heat pumps, which are covered for Europe only.

Europe, in domestic and industrial buildings (30 000 units) (BSRIA, 2018). Global data for reversible air-air pumps used for heating were not available, even though they account for most units sold in Europe. Therefore, while the exact size of the global market is currently unknown, it is larger than shown in Figure 10.

Figure 10. Global heat pump sales by technology, 2012–17 (left) and regional shares in 2017 (right)



Note: GSHP = ground-source heat pump.

Source: BSRIA (2018), *World Renewables: Heat Pump Market*.

Global head pump sales have been increasing over the past years and China is the most important market for air-water heat pumps.

In recent years heat pump deployment has been strongly supported in numerous countries (e.g. China, Japan, the United States and EU countries) through national, subnational and local-level policies, and through building code requirements for new construction and refurbishments.

In China the replacement of coal boilers by heat pumps is mainly driven by air pollution mitigation. In a number of European countries, bans on gas- or oil-fired boilers, as well as stricter energy performance requirements for new construction and refurbishments, are prompting the electrification of heating. In addition, the revised Renewable Energy Directive's heat target for 2030 is likely to drive further heat pump deployment. Incentive schemes (capital grants, tax rebates, tax credits, etc.), building codes and special electricity tariffs for heat-pump heating are likely to reinforce this.

Implications for power systems

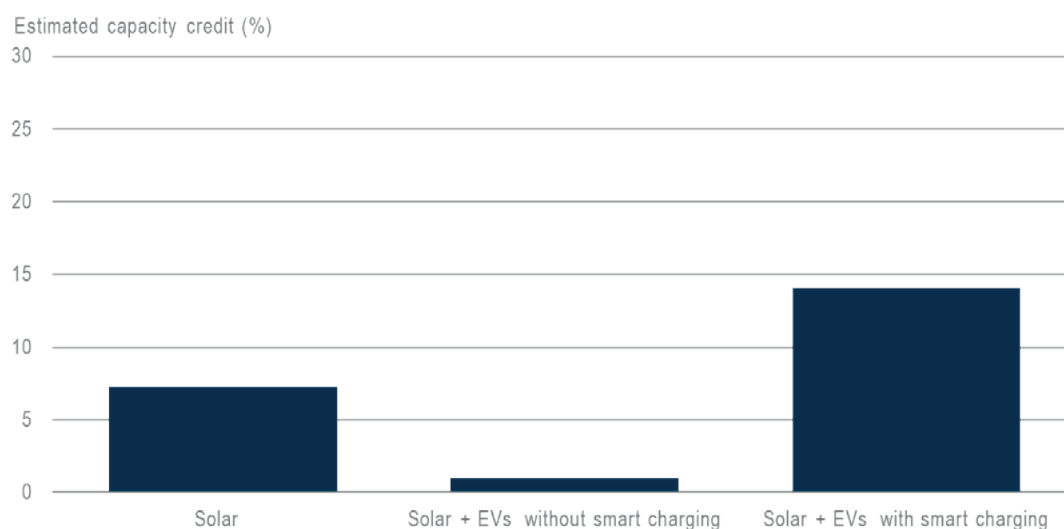
As power system transformation continues, distribution grids may emerge as a central component of a clean, reliable and cost-effective energy system. The following trends could combine to create such an outcome:

- the large-scale adoption of DER, turning these resources into an important part of the power supply
- mass enrolment of demand response, enabled by digitalisation and the effective integration of energy efficiency through intelligent end-use devices
- electrification of transport, heating and industry.

However, co-ordination is required to achieve this. The possible effects of increased electrification of road transport on electricity demand, and consequently on power grids, are a

case in point. If left unchecked, the growth in EVs could have a number of undesirable effects on the power system, such as increases in peak demand, overloading of distribution grids and increased difficulty in integrating VRE. For example, a recent study of grid integration of renewable energy in Thailand (IEA, 2018f) found that unmanaged EV charging could reduce the capacity credit of solar energy, while smart charging would help to improve it (Figure 11). This example also points to the important relationship between EVs and system integration. The key concept in this context is power system flexibility, which is the focus of the next section.

Figure 11. Impact of EVs on capacity credit of solar PV in Thailand, 2036



Note: Scenario assumes 10.87% annual average solar PV penetration, peak demand of 48 GW and a total number of EVs of 1.2 million.

EV charging needs to be managed in order to maximise benefits to the power system.

Flexibility as the core concept of power system transformation

The flexibility of a power system is a measure of its ability to reliably, and cost-effectively, manage the variability and uncertainty of supply and demand across all relevant timescales. The increased relevance of system flexibility is largely due to the rapid deployment of VRE (IEA, 2018a). In order to understand the requirements for power system flexibility, it is useful to consider a number of basic aspects of system integration of VRE. First to consider are the inherent properties of VRE generators, which increase the need for flexibility, followed by their effect on the power system through various deployment phases. Then it is important to understand the different time horizons of flexibility requirements, as well as the deployment framework. Last to be addressed are the associated effects on redefining the roles of system resources.

Properties of VRE generators

VRE generators have five technical properties that differentiate them from more traditional forms of power generation, i.e. large-scale thermal power plants. First, their maximum output fluctuates according to the availability of the underlying resource (e.g. wind and sunlight). Second, the ability to accurately predict fluctuations depends on the lead time, with generally more accurate forecasts possible a few hours ahead than a few days ahead. Third, they connect

to the grid via power converter technology.²² This can be relevant in ensuring the stability of power systems, such as following the unexpected shutdown of a generator. Fourth, they are more modular and are deployed in a much more distributed fashion. Finally, unlike fossil fuels, wind and sunlight cannot be transported, and locations with the best resources are frequently at a distance from load centres. Despite these general similarities, wind and solar PV also show a number of differences (Table 3).

Table 3. Overview of differences between wind power and solar PV

	Wind power	Solar PV
Variability at plant level	Often random at subseasonal timescales; local conditions may yield pattern.	Planetary motion (days, seasons) with statistical overlay (clouds, fog, snow etc.).
Variability when aggregated	Usually with a strong geographical smoothing benefit.	Once “bell shape” is reached, limited benefit.
Uncertainty when aggregated	Shape and timing of generation unknown.	Unknown scaling factor of a known shape.
Ramps	Depends on resource; typically few extreme events.	Frequent, largely deterministic and repetitive, steep.
Modularity	Community and above.	Household and above.
Technology	Non-synchronous grid connection and mechanical power generation.	Non-synchronous grid connection and electronic power generation.
Capacity factor	Approximately 20% to 50%.	Approximately 10% to 25%.

Source: IEA (2017e), *Getting Wind and Sun onto the Grid: A Manual for Policy Makers*.

Phases of system integration

The properties of VRE interact with the broader power system, which gives rise to a number of relevant integration effects. These effects do not appear abruptly, but rather increase over time along with the increase in VRE penetration. The IEA has developed a phase categorisation to capture changing impacts on the power system and resulting integration issues:

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 load²³ 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 system disturbances. 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 such as primary and secondary frequency regulation.

²² With the exception of older wind turbine technologies, which connect directly to the grid.

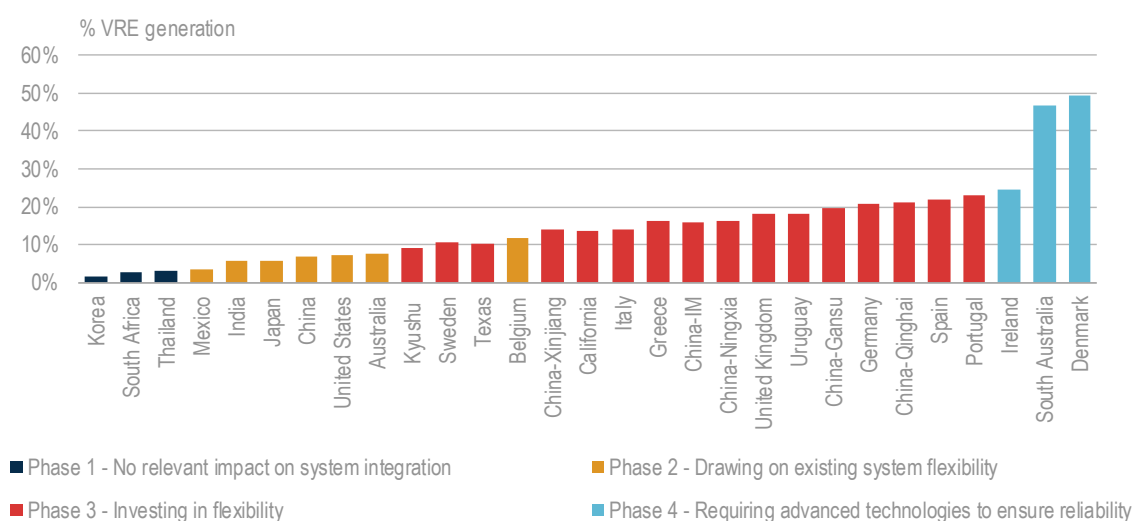
²³ Net load is the difference between forecast load and generation from VRE.

Phase 5: Without additional measures, adding more VRE plants means that their output frequently exceeds power demand and structural surpluses of negative net load 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, demand is entirely covered 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 over extended periods (e.g. weeks), 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.

Most countries around the world are currently in Phases 1 and 2. However, as VRE deployment accelerates over the coming five years, this will shift with more and more countries moving into Phases 3 and 4. It is important to note that a country-wide characterisation – especially for large and diverse countries – can provide only a rough indication. For example, while the overall impact of VRE in China is still moderate on a national scale, there are provinces that already experience issues associated with more advanced phases (Figure 12).

Figure 12. Overview of VRE system integration phases for different countries and selected provinces, 2017



Countries around the world are at different levels of system integration. Regions within one country can be at a higher or lower phase than the national average.

Using this framework for system integration, it is then possible to consider different challenges that need to be addressed for system integration to be successful (Table 4).

Table 4. Summary of impacts associated with Phases 1 to 4 of system integration

	Attributes (incremental with progress through the phases)			
	Phase 1	Phase 2	Phase 3	Phase 4
Characterisation from a system perspective	VRE capacity is not relevant at the all-system level	VRE capacity becomes noticeable to the system operator	Flexibility becomes relevant with greater swings in the supply–demand balance	Stability becomes relevant; VRE capacity covers nearly 100% of demand at certain times
Impacts on the existing generator fleet	No noticeable difference between load and net load	No significant rise in uncertainty and variability of net load, but there are small changes to operating patterns of existing generators to accommodate VRE	Greater variability of net load; major differences in operating patterns; reduction in power plants running continuously	No power plants are running around the clock; all plants adjust output to accommodate VRE
Impacts on the grid	Local grid conditions near points of connection, if any	Very likely to affect local grid conditions; transmission congestion is possible, driven by shifting power flows across the grid	Significant changes in power flow patterns across the grid, driven by weather condition at different locations; increased two-way flows between high- and low-voltage parts of the grid	Requirement for grid-wide reinforcement and improved ability of the grid to recover from disturbances
Challenges depend mainly on	Local conditions in the grid	Match between demand and VRE output	Availability of flexible resources	Ability of system to withstand disturbances

Source: IEA (2017e), *Getting Wind and Sun onto the Grid: A Manual for Policy Makers*.

The impact of VRE on the power system increases gradually from one phase to the next.

Different timescales of system flexibility

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 5).

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.²⁴ 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 investment. 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.

In addition to technical aspects, unlocking flexibility requires action in additional areas as discussed in the next section.

Table 5. 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.

Source: IEA (2018a), *Status of Power System Transformation 2018: Advanced Power Plant Flexibility*.

Layers of system flexibility

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

- technical options available (the hardware and infrastructure, or the “what”)

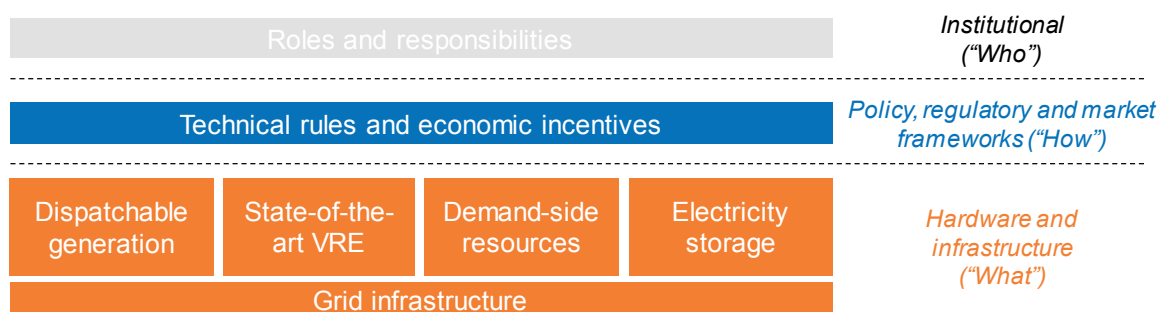
²⁴ Voltage control aspects are not covered in detail.

- 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 13). Addressing each of these in more detail:

- **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.
- **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.
- **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.

Figure 13. Different layers of system flexibility



Source: IEA (2018a), *Status of Power System Transformation 2018: Advanced Power Plant Flexibility*.

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

Redefining the role of system resources

The rising importance of system flexibility has far-reaching consequences for all resources on the power system. This section highlights three main shifts: differentiating the contribution that generation and storage make to the system (energy volume vs energy option), the evolving role of grids, and measures to actively shape demand.

Differentiating energy volume and energy option contributions

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. From a technical standpoint, these plants were designed 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 enters power markets at scale, many existing power plants are being asked to operate with greater flexibility, and in some cases for a reduced number of operating hours.

In order to appreciate this shift, it is useful to consider the role of power plants based on two types of system contribution: (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 open-cycle gas turbines (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 are, it is possible to derive a more general characterisation of power plants. The traditional categories of baseload, mid-merit and peak-load power plants can be captured in this approach.

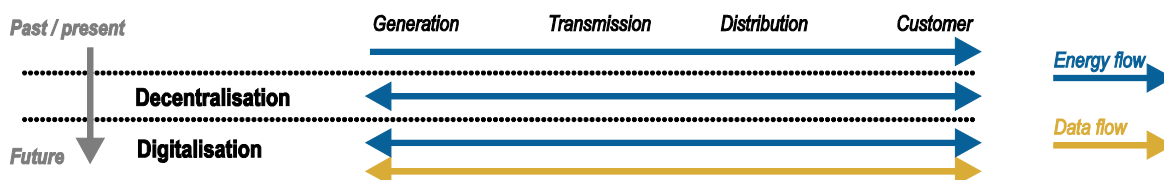
It is worth noting that this approach places power plants according to how they are used in a given power system, rather than what they were technically designed to provide or are theoretically capable of providing. For example, as a result of new operational patterns, it is possible for power plants 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).

An advantage of viewing system resources in terms of their system contribution is that it allows for comparison of alternative resource types. For example, due to their speed of reaction and precision, battery storage may be used for a similar energy option contribution as an OCGT unit.

Evolving grids

Historically, power grids have been designed to transport electricity from centrally operated generators to serve the load. As a result of the rising penetration of DER and the intelligence of all grid components, local grids are able to facilitate bidirectional flows of both electricity and data, giving rise to much richer and more complex interactions between devices on the grid at all levels (Figure 14).

Figure 14. Impact of decentralisation and digitalisation on local power grids



Source: IEA (2017a), *Status of Power System Transformation 2017: System Integration and Local Grids*.

The combination of decentralisation and digitalisation introduces bidirectional power and data flows.

Low- and medium-voltage grids were traditionally designed to passively distribute power from high-voltage networks to end users at lower voltages. Planning standards, which dictated the provision of electric power distribution infrastructure, were based on simplified and often conservative assumptions about future electricity demand. Once in place, there was little need for active management, and hence system operation often amounted to clearing faults and replacing components as and when needed. The demand profile of smaller, residential consumers was reasonably well understood and fairly homogeneous, so it was usually sufficient to read meters once a year or every few months. Demand was generally not actively managed – apart from simple systems that prioritised use at night (e.g. electric space heating, water heaters) (IEA, 2017a).

This picture has begun to change. A number of drivers are aligning to change the way local grids are planned and operated today, including substantial penetration of DER, digitalisation, business model innovation, and cross-sector coupling between electricity, heat and transport. Looking further into the future, these trends may substantially reshape this part of the energy system, increasing its importance as a critical part of a more reliable, cost-effective and clean energy system (IEA, 2017a).

From passive demand to load shaping

In the context of power system transformation, it is useful to consider a generalised concept of demand-side integration, which goes beyond the standard concepts of demand response and management and takes a fresh look at energy efficiency. Essentially, growing shares of VRE can be integrated into power systems by better matching electricity demand to an increasingly variable supply. This is possible not only via dynamic shifts in electricity consumption, but more generally by any intervention that shapes demand to better match available supply. This can be achieved in four different ways:

- Dynamic shifting of load.** This type of load shaping takes into account short-term or real-time information and control signals to adjust consumption. Most importantly, this type of load shaping does not reduce total consumption, but shifts the time when it occurs. For example, an electric water heater with a storage tank may need to be charged for four hours of the day, but these hours can be chosen flexibly. Hence, if there is a spike in wind

production during a number of hours, charging can be adjusted to occur during that time. Similar applications are becoming available for large consumers.

- **Dynamic load curtailment.** In contrast to dynamic load shifting, dynamic load curtailment reduces power demand during critical hours, without recovering this demand later. One example would be a temporary halt of production during times of very high electricity prices. This can be profitable for a consumer if the cost of electricity exceeds the value added of the process for several hours.
- **Structural reductions in electricity demand via energy efficiency.** This can be achieved, for example, by replacement of less efficient lighting in residential buildings with light-emitting diodes (LEDs), which leads to a structural load reduction that is concentrated in hours of low or no sunlight. Hence, such measures naturally improve the match of load with the output profile of solar PV.
- **Structural increases in electricity demand via electrification.** As introduced in the section on phases of system integration, at Phase 5 and beyond structural surpluses of VRE emerge. These are concentrated during the middle of the day for solar PV and during windy weather periods for wind power. In the absence of electricity demand during such periods, VRE output will need to be curtailed and the market price and value of VRE will be very low. Hence, increasing demand through electrification of industry, heating or transport can reduce curtailment, although Power-to-X can also provide viable options for system integration.

After reviewing these general changes in the roles of system resources, the next sections take a more in-depth look, differentiating centralised and distributed resources.

Implications for centralised system resources

The previous sections discussed the main drivers of change in the power system and identified flexibility as a critical enabler for power system transformation. The following sections now take a complementary perspective, highlighting in each case how traditional and new system resources can contribute to system flexibility from a technical perspective, and also identifying the underlying challenges and potential policy options.

Operational regime shifts for thermal assets

With increasing penetration of VRE and a broader range of system resources, conventional power plants may experience 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 utilising available (and cost-effective) flexible resources such as grid infrastructure, demand response and storage resources. However, the remaining power plants that 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 four 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.²⁵ 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. Upward and downward 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.
- **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.

There are numerous options for extracting additional flexibility from existing power plants. These range from simple operational improvements to more comprehensive investments in retrofitting. Updating operational guidelines and providing appropriate price signals are important to strike the right balance with additional costs resulting from increased wear-and-tear or reinvestment. A number of operational improvements and retrofit options for conventional power plants are discussed in IEA (2018a). One example of a lignite-fired plant that has been upgraded to provide increased flexibility in Germany is highlighted below (Box 9).

Box 9. Improving flexibility parameters in legacy coal plants

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 GW commissioned between 1972 and 1975. Retrofits to its fourth and fifth 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 since the retrofit.

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

²⁵ Depending on the plant type and operation regime, there may be further types of minimum stable output, such as economic, emergency and environmental minimum outputs.

Table 6. 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; MW = megawatt.

Matching VRE to system requirements

The output of VRE plants is limited according to the instantaneous availability of their primary resource, wind or sunlight. Consequently, it may appear illogical to consider VRE as a source of flexibility. However, within the boundaries of available wind and sunlight, modern VRE plants can be remarkably flexible. They can be started and stopped almost instantaneously because they do not require heat to be built up for their operation. They can be ramped over a wide range of outputs (up to the limit imposed at any moment by how much wind and sun is available) and this ramping can be carried out very rapidly (IEA, 2016a; REserviceS, 2013a, 2013b). Additionally, in some cases continuous low-magnitude curtailment can be considered as an additional flexibility option, allowing VRE plants to maintain both headroom and foot room in output. This can allow VRE plants to provide operating reserves, which ultimately raises the amount of VRE generation that can be integrated in the system.

However, these capabilities are currently not commonly used by system operators to obtain flexibility, for three main reasons. First, such operation requires direct and automated controllability of the VRE plants, which is not always implemented (yet). Second, VRE forecasting systems need to be established and very well tested in order to make sure that generation levels can be forecasted with sufficient accuracy. Third, regulatory and market arrangements need to allow for VRE participation and this usually requires changes to market design. For example, while it is generally not possible to forecast wind output sufficiently accurately a few days in advance, forecasts are very reliable for a few hours or even shorter horizons. This means that the system operators need to procure flexibility more frequently and closer to real time to unlock the contribution from VRE. Advances in digitalisation are further likely to improve forecasting accuracy.

A growing number of demonstration projects and field tests are validating the feasibility of large-scale VRE plants providing flexibility. Indeed, international experience demonstrates how a more optimised use of VRE plants can help to save costs in the power system (e.g. avoided fuel consumption from redispatching thermal plants) while reducing VRE curtailment (Box 10).

Compared to previous generations of VRE technology, system-friendly VRE can be used to reduce the need for more expensive flexibility assets. For this to happen, it may be necessary to review existing support mechanisms to provide the right incentives. Additionally, ancillary service prequalification requirements and dispatch parameters may have to be amended to allow for fair remuneration of VRE flexibility. The following chapter presents a more detailed discussion of the options available to increase technological diversity in the provision of flexibility.

Box 10. Flexible operation of solar PV

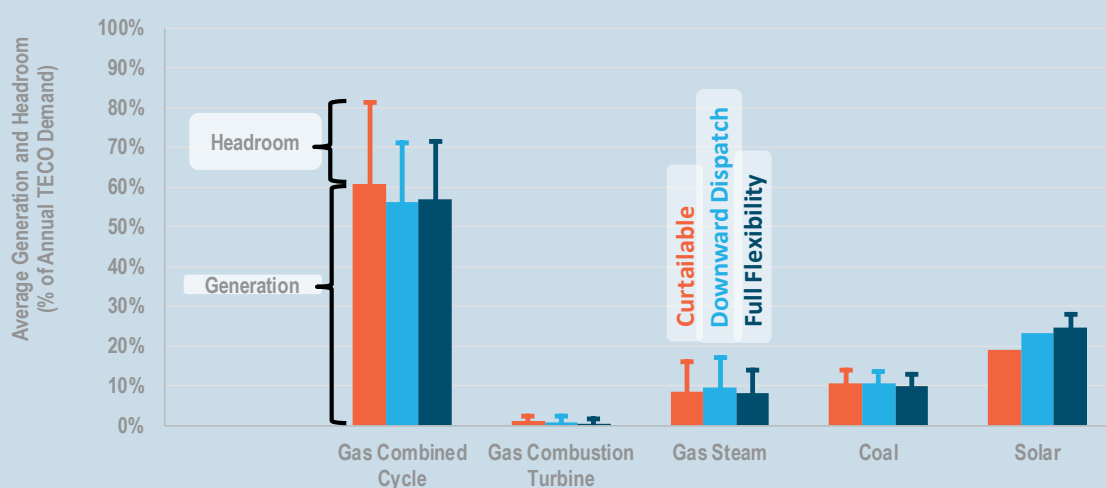
The development of advanced control technologies and operational strategies for VRE technologies is improving the perception amongst utilities that VRE may indeed be part of the solution for system integration. A recent study commissioned by Tampa Electric Company (TECO), sponsored by First Solar and carried out by Energy and Environmental Economics, shows that the operation of PV plants in fully flexible mode can yield substantial operational cost savings, even at annual penetration levels as high as 28%.

The study evaluated four modes of operation:

- Must-take: solar PV generates all of its potential output, with the grid operator meeting the resulting net load through dispatchable resources.
- Curtailable: the option for unscheduled curtailment.
- Downward dispatch: the option for curtailment scheduled in advance.
- Full flexibility: both curtailment and upward dispatch are an option; this is enabled by maintaining constant headroom based on real-time maximum output estimation.

In short, the report shows that enabling a controlled level of de facto curtailment, to ensure headroom, can in fact increase the total average PV share of generation, along with having a positive effect on system savings. An additional finding is that PV in fully flexible mode reduces the operational value of storage (if they are both providing frequency control services). However, there is still a value for storage at high penetrations of PV due to increased balancing requirements, rising solar curtailment and system capacity value of storage.

Average generation and headroom per scenario



Source: Energy and Environmental Economics, Inc. (2018), Investigating the Economic Value of Flexible Solar Power Plant Operation.

From the policy maker's perspective, there are two important considerations: 1) establishing clear guidelines on benchmarking; and 2) the PV operator's incentive to switch to fully flexible mode from a fixed tariff with priority dispatch.

The first point requires regulatory validation of the measuring standard for the maximum potential output, as well as a process to retrospectively validate the actual delivery of the requested downward or upward regulation.

Regarding the incentive to switch to fully flexible mode, this will depend greatly on the revenue risk exposure embedded in the plant's FIT, as well as whether producers receive compensation for curtailed output in instances such as grid constraint. In this particular case, however, it is not a concern as VRE generation does not receive compensation for curtailed output. Furthermore, the installation of automatic control units requires the installation of the right type of inverter and fibre-optic networking to manage operations accurately. Enabling such operations only makes sense for new installations, such that AGC requirements and remuneration that encourages flexibility could be implemented only for new projects.

Source: Energy and Environmental Economics, Inc. (2018), *Investigating the Economic Value of Flexible Solar Power Plant Operation*, www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf.

Increasing need for advanced grid solutions

Grid infrastructure is the only flexible resource that brings a double benefit. First, it reduces flexibility requirements by smoothing VRE output over large geographical areas. Indeed, aggregation of several wind and solar PV plants over large areas effectively eliminates their short-term fluctuations. Second, it links together different flexible resources, allowing them to be pooled more efficiently and effectively. Hence, the cost-optimal amount of grid infrastructure tends to increase with growing shares of VRE on the system.

Expansion of grid infrastructure generally takes longer than constructing new VRE plants. While construction times vary substantially depending on regulatory regimes and public support/opposition, it can take between 5 years and over 20 years to build new transmission lines, while VRE projects can be developed in 3–5 years in the case of complex permitting environments, and only a few months where permitting is streamlined. Hence, grid infrastructure will tend to trail behind VRE generation (although planning tools exist to mitigate this challenge, see section on planning in the following chapter).

Deploying advanced grid solutions

Typically, a transmission line is rated to carry power at a certain capacity. The capacity of a line is usually constrained by line sag, which happens due to current-related temperature increase. The conventional approach to determining the capacity of transmission lines is based on worst-case assumptions (low wind speed, high ambient temperature, high solar radiation) (IEA, 2014). The line capacity determined under this assumption would then be used across a range of actual conditions. However, the actual ability of a line to carry power is influenced by temperature: at lower temperatures, the real capacity of the line is likely to be higher than the rating (IEA, 2017a).

Dynamic line rating (DLR) is one of the tools available to enhance available transmission capacity without the need to construct new lines. DLR calculates the capacity of transmission lines closer to real time by taking into account actual operating and ambient conditions instead of assuming a fixed capacity (IEA, 2017a). With DLR, system operators can make use of additional capacity when available and thus reduce the need for network investment.

At times of high winds and, in some cases, high levels of solar power generation, DLR can be an effective option to alleviate transmission congestion and thus reduce the risk of curtailment. DLR has been implemented to great effect in many systems including, for example, Spain, the

United Kingdom, Ireland, Texas and Australia (Box 11) (US DOE, 2014). The impact of DLR depends on system-specific circumstances (IEA, 2017a).

Box 11. DLR in the Snowy Region, Australia

DLR has been implemented by TransGrid, who is a transmission network service provider in New South Wales, in order to maximise transmission capacity and reduce the risk of congestion. The system utilises weather data that are monitored and recorded in real time by weather stations. These real-time data enable TransGrid to understand the conditions the line is experiencing and therefore manage and operate it more efficiently.

TransGrid expected high levels of wind generation to cause much of the future congestion in the 330 kilovolt (kV) transmission lines between the Snowy Region and Sydney. It is deploying DLR projects to assist in reducing potential congestion by allowing higher thermal limits that result from high wind speed. According to the Australian Energy Market Operator, DLR should make it possible to increase power transfer on the transmission lines by approximately 400 MW.

Source: AEMO (2014), *Independent Planning Review: Attachment A – TransGrid Project Assessment Reports*.

Flexible alternating-current transmission system (FACTS) is another option to improve the use of existing capacities. FACTS devices are high-power electronics-based technologies offering real-time controllability – their main benefit is to enhance transmission efficiency and reliability.²⁶ They are used to enhance controllability of the network, power system stability and increase power transfer capability at key points in the transmission grid. The condition of the network can be controlled by FACTS devices in a fast and flexible manner. In this way, FACTS devices allow for better utilisation of the existing network by enabling transmission lines to be operated closer to capacity without causing disturbances in the system. They can help to address issues of network congestion that may be caused by VRE (IEA, 2017a).

Another option to improve utilisation of existing grids is phase shifters. A phase shifter is used to improve the transfer capacity of existing transmission lines by controlling the direction and magnitude of power flow in specific lines of the network.²⁷ It is considered an economic and reliable approach to managing power flow using existing assets. Phase shifters are important components in alternating-current (AC) transmission networks. They can be used to control active power flow at the interface between two large and solid independent networks, and have increasingly been used to manage power transfers in systems and reduce bottlenecks in the grid caused by VRE power injection (IEA, 2017a).

Multiple deployment opportunities for large-scale storage

Electricity storage describes all technologies that can absorb electrical energy and return it as electrical energy at a later stage. Electricity storage technologies can provide multiple services ranging from fast frequency response to bulk energy storage, which cover timescales from

²⁶ There are two main groups of FACTS device: thyristor-based and voltage source converter-based FACTS. The most common type of FACTS devices are: static VAR compensator (SVC), thyristor-controlled series capacity (TCSC), static synchronous compensator (STATCOM), static synchronous series compensators (SSSC) and unified power flow controllers (UPFC).

²⁷ The basic function of a phase shifter is to control active power by adjusting the phase displacement between the input and the output voltage of a transmission line.

ultra-short- to long-term and which help to accommodate new challenges related to VRE variability. This makes them suited to providing different aspects of the range of services electricity storage can provide (Table 7).

Table 7. Qualitative description of energy storage services in the power system

	Application	Description
Generation	RE integration – Bulk	Time shift RE output to optimise for grid integration and minimise curtailment
	RE integration – Ramp	Optimise short-term RE output to improve power quality and avoid imbalances
Network operation	Frequency control	Maintain supply and demand balance via power increase/decrease with different response patterns
	T&D deferral	Defer upgrades in network infrastructure
	T&D congestion	Avoid re-dispatch or local price differences due to risk of overloading existing infrastructure
	Black start	Restore power plant operations after network outage without external power supply
	Voltage support	Maintain voltage levels across networks via reactive power supply/reduction
Consumption	Peak power supply	Reduce demand supplied by the network during peak hours to reduce network charges
	Back-up power	Provide power during network failure to ensure power quality and availability
	RE self-consumption	Maximise usage of self-generated power and minimise exports to the network
	Bill management	Shift energy consumption from high-tariff to low-tariff periods to reduce energy charges
Market	Energy arbitrage	Purchase power in low and sell in high price periods on wholesale or retail market

Notes: RE = renewable energy; T&D = transmission and distribution.

Arbitrage opportunities have driven storage deployment in the last 40 years, in particular pumped storage hydropower (PSH). 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 in future power systems. Finally, synthetic fuels that can be reconverted to electricity are a possible avenue for seasonal storage.

Optimising the use of PSH

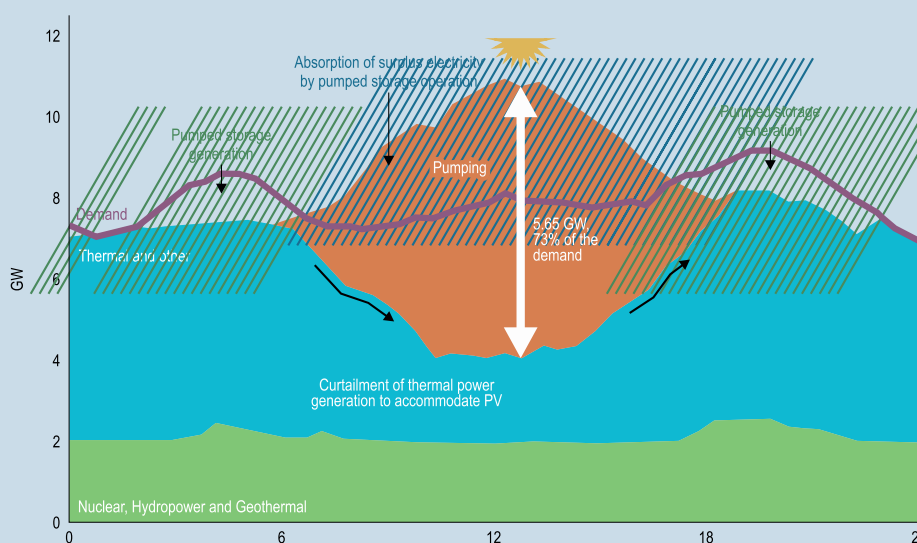
PSH is currently the most mature and widespread technology for electricity storage. Globally, 153 GW of capacity are installed, of which 29 GW are located in China. While future expansion is limited by the availability of suitable sites and public acceptance issues in a number of countries, PSH is expected to increase by 26 GW over the period 2018–23 (IEA, 2018c).

PSH can provide a variety of services to the grid, including all types of short-term and medium-term flexibility services. Due to the technological maturity of this option, future cost reduction potential is limited. However increasing system flexibility needs may bring about new opportunities for deploying PSH, through modernisation and conversion.

Box 12. Innovative use of existing PSH for integrating solar PV in Kyushu, Japan

As a mountainous and fuel-poor country, Japan developed 22 GW of reservoir hydro plants to support its rapid economic growth after World War II. In addition, 27 GW of PSH has been developed since 1960s, and was originally used during the night to absorb surplus generation from nuclear plants. PSH's operational mode has changed in recent years, following the idling of nuclear capacity after the Great East Japan Earthquake and the need to absorb surplus solar PV output during the day.

Portfolio management for VRE curtailment avoidance



Source: Kyushu Electric Power Co., Inc.

Kyushu, the southwestern main island of Japan, has 6 GW of installed PV capacity, 16 GW peak load and 8 GW minimum daytime load. The instantaneous PV penetration in certain periods is higher than 70%. This has motivated the development of cost-effective operational approaches to optimise existing resources, including thermal plants, reservoir hydro and PSH plants. During the daytime, with a lot of low-cost PV generation, PSH plants are operated in pump mode to store water in the upper reservoir, which is then released to generate electricity during the evening peak demand periods when the output of solar PV has diminished. PSH also allows thermal power plants to operate at their minimum stable levels rather than completely shut down during the daytime.

Embracing the versatility of grid-scale batteries

As an inverter-based technology, one advantage of battery storage is its ability to adjust output upwards or downwards very quickly and precisely. Its main constraint is its operating range and duration of response, depending on the state of charge at dispatch. Due to its technical versatility, battery storage can be deployed for a number of system flexibility needs, ranging from rapid ramping in response to sudden peaks in demand, to ultra-short-term flexibility.

No single application requires the entire storage technology's capacity continuously. Therefore, idle capacity can be used to provide additional services, effectively revenue stacking and increasing the likelihood of making electricity storage profitable. To enable revenues to flow from serving various system needs, policy makers need to remove existing barriers, for example

adjusting minimum bidding size in reserve markets, where batteries could be excluded due to small size (Stephan et al., 2016). In the United States, this has been enabled by FERC ruling 841.

Internationally, the deployment of battery storage varies both by size and application. Very large-scale batteries above 5 MW represent a greater share of installed battery capacity in Europe. This is due to a number of reasons. For example, in Northern Germany pilot projects for large batteries have been seen as an alternative to relieve the grid in areas with high wind penetration. Installed in 2014 with an original 5 MW of output, WEMAG's Schwerin battery project was expanded in 2017 by a further 10 MW in order to provide frequency regulation and balance the output of about 800 MW of installed wind generation in the region.

Large battery storage is also relevant in the United Kingdom where, until recently, they were encouraged to participate in the country's capacity market. Owned and operated by Statera Energy, the Pelham battery storage power plant was commissioned in 2017. With an output of 49 MW, it is able to extract revenues from frequency regulation as well as the capacity market.

Outside Europe a number of very large battery storage projects serve very specific needs. With 100 MW, the Hornsdale battery project in Australia is the largest grid-interactive battery storage facility in the world and is further example of revenue stacking, accessing both the wholesale and frequency regulation markets.

Box 13. Reducing the cost of ancillary services in Australia – the Hornsdale battery

Due to its abundant solar and wind resources and favourable policies, South Australia has seen a rapid increase in VRE installation. In 2017 wind accounted for 36% of installed capacity in the state, while rooftop PV accounted for 14%. At times of low demand and abundant VRE resources, wind can reach 143% of maximum incident penetration, while solar can reach up to 41%.²⁸ The speed of ramps is also particularly relevant, as wind output can have a maximum variation of 763 MW/5 min, which increases the need for fast-responding assets to cope with fluctuations in VRE supply.

Built in 2017, the Hornsdale battery project, with 100 MW storage capacity, is operated by Neoen and has been built adjacent to a 315 MW wind farm. By accessing various markets, the battery is able to obtain revenues from both frequency control and wholesale market arbitrage. The project has reserved 70 MW for frequency control, with around 10 minutes of storage capacity for ancillary services, leaving 30 MW with around 4 hours' storage for wholesale market arbitrage.

Due to its speed of response and precision, the project has managed to displace steam turbines, which would have usually been used to balance the grid.

The battery has had a noticeable effect not only in keeping the system in balance, but also on the market for FCAS. Within four months of operation, the Hornsdale battery deployment was associated with a 90% drop in FCAS prices, and within South Australia alone the battery has taken up 55% of the FCAS market. On a national level, demand response and large battery storage now represent 20% of the country's FCAS market.

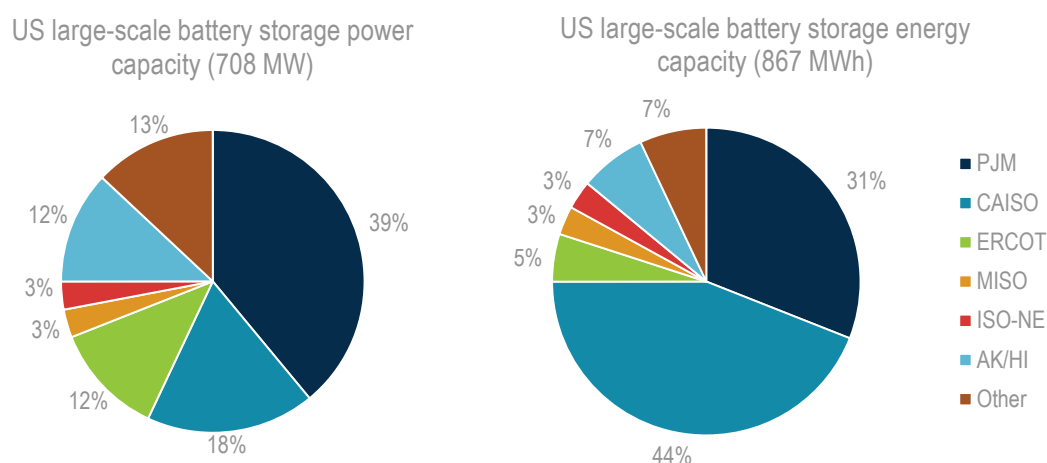
²⁸ Maximum possible instantaneous penetration: the ratio of installed capacity to minimum demand.

However, the advantages of large-scale batteries need to be balanced against the increasing need for flexibility. This is particularly important because, despite the substantial drop in the price of FCAS, the market's volume has continued to increase and, with a potentially saturated market and low prices, it may be difficult to finance similar utility-scale projects.

Source: AEMO (2018), *Initial Operation of the Hornsdale Power Reserve Battery Energy Storage System*, www.aemo.com.au/-/media/Files/Media_Centre/2018/Initial-operation-of-the-Hornsdale-Power-Reserve.pdf.

Until recently, the US market for battery storage was characterised by smaller batteries than in Europe and Asia-Pacific, with the bulk of installations ranging between 1 MW and 5 MW. The diversity in battery storage applications in the United States shows the importance of policy design and prequalification requirements for market development. This is reflected in different capacity-to-energy ratios for different market regions (Figure 15).

Figure 15. Battery storage deployment by market region in the United States, 2017



Notes: AK/HI = Alaska and Hawaii; CAISO = California ISO; ERCOT = Electricity Reliability Council of Texas; MISO = Midcontinent ISO; ISO-NE = ISO New England.

In 2017, PJM and CAISO were the most relevant markets for energy storage in the United States.

The most striking difference in usage can be seen in the PJM and CAISO jurisdictions. In California (CAISO) a significant amount of large battery storage had been procured, mainly for reliability reasons to address constraints in natural gas supply. Thus, large battery storage installations in California tend to have larger energy volume contributions, with an average installed capacity of 5 MW and a four-hour discharge. By contrast, battery storage in PJM on the east coast is typically deployed for frequency regulation, with an average output of 12 MW for large batteries and a discharge time of 45 minutes. The US market for battery storage is set to grow further following the Federal Energy Regulatory Commission's decision to require the participation of energy storage technologies in wholesale markets.

Policy action is needed to make best use of storage. Regulation should allow companies to supply services that cut across multiple independently regulated markets (long-term, short-term, balancing, etc.). A number of studies highlight the importance of establishing pricing

mechanisms that recognise the various benefits that storage can provide to the system (Carbon Trust, 2016; RMI 2017; Stephan et al., 2016). Allowing for revenue stacking and acknowledging each stakeholder's contribution to system services are important steps to maximise the potential of storage deployment.

Synthetic fuels and other long-term storage options

Synthetic fuels do not currently play a relevant role globally in the context of VRE generation and power system transformation. However, this may change in future, but for two very different reasons (Philibert, 2017). In the context of electricity storage, synthetic fuels function via a process that first generates the fuel from electricity and then converts it back to electricity – power to fuel to power. Candidate fuels for this process include hydrogen from electrolysis, which may be further converted to synthetic methane or ammonia to resolve challenges related to hydrogen storage and transport. Studies frequently find that this type of storage is only needed at very high shares of VRE in the energy mix and only if there are seasonal mismatches between VRE supply and electricity demand (Zerrahn and Schill, 2018).

However, there is another driver for the use of hydrogen and its derivatives. Hydrogen is an important feedstock for a number of applications, such as a primary feedstock in the Haber-Bosch synthesis of ammonia and in steel production via the direct iron reduction process, as discussed in the following section (Philibert, 2017).

In addition to long-term chemical energy storage, there are electro-chemical storage options which can be well-suited for seasonal applications such as redox-flow batteries.

Large-scale load shaping

Industrial demand response

Historically, utilities and system operators have engaged large industrial consumers to curtail their consumption at critical times (dynamic load curtailment in the above list). This can be either through interruptible demand contracts agreed bilaterally, auctions for the provision of strategic reserves or through critical peak pricing and use of transmission network charges.

More recently, different types of demand side response in industry have emerged. One example is retrofitting aluminium smelters with a heat management system that allows to increase and decrease production including for longer periods of time (see Box in the chapter on “Power system transformation pathways for China in 2035”).

Efficient industry electrification

Electricity today represents about 20% of final energy demand globally, although its production absorbs about 40% of primary energy demand and is responsible for about the same percentage of energy-related greenhouse gas emissions.

This is set to increase to 25% to 30% of final energy demand by 2040 as the result of demand for improved comfort, an increased share of services in the global economy, and digitalisation (IEA 2018b). Electrification may, however, progress even faster under policies aiming at reducing air pollution and mitigating climate change. In some climate-friendly scenarios electricity represents close to two-thirds of final energy demand by 2050 or 2060 (IEA, 2011; ETC, 2018; CNREC, 2018).

Rather than a challenge, increasing electricity demand in strategic sectors is an opportunity to maximise the utilisation of structural VRE surpluses and links power sector decarbonisation to the wider energy system transition. In this vein, electrification of transport and of heating for

households and services are the most visible (see section on DER). However, there is great potential in a number of energy-intensive industrial processes.

For industrial applications, electric heat pumps and mechanical vapour recompression can produce low-temperature heat and steam in an extremely efficient way. Electric resistances for heating are less efficient, but also less costly. They can bypass the use of fossil fuels at times of excess variable renewables, a benefit that heat storage can extend.

Electro-magnetic technologies offer other options such as induction, and dielectric and infrared heating. Generating heat within the material target, they are more efficient than fossil fuel heating the medium surrounding the material. These technologies also allow for more rapid and more controllable processing, reduce material wastage and improve workers' safety and comfort.

Electric arc and plasma arc furnaces can replace fossil-fuelled furnaces, ovens and kilns, at all temperature levels. Processing cement and other non-metallic minerals in a plasma furnace could considerably reduce energy-related polluting emissions.

It is possible that the production of green hydrogen from renewable electricity could find its way into industry on a much larger scale than for buildings. Considerable CO₂ emissions result from steel making today, from iron ore reduction and coal combustion. Hydrogen could suppress these emissions following the alternative, direct iron reduction route, prior to melting in electric arc furnaces together with scrap steel. Green hydrogen could also replace hydrogen extracted from coal in China or natural gas in other parts of the world in the production of ammonia and methanol, two major feedstocks for chemicals.

Wherever possible, however, direct electrification is likely to be more efficient than hydrogen or hydrogen-rich fuels. The latter would likely find their greatest justification in long-range transport, such as maritime or aviation, or in applications requiring long-duration storage, and in helping harness vast stranded renewable energy resources remote from large consumption centres. In China, for example, this may require the building of long-distance pipelines to ship ammonia, methanol and synthetic liquid hydrocarbon from the western provinces, with their abundant solar and wind power resources, to the rest of the country.

Implications for DER

The continuous improvement of information technology and power electronics have been the main drivers for the emergence of new types of DER as the defining feature of increasingly decentralised power systems. DER encompass a number of technological solutions, namely distributed generation, distributed battery storage and demand response, but also well-established resources such as energy efficiency. The IEA (2017c) presents a comprehensive review of the various approaches and technologies deployed for decentralised solutions. A key feature is the ability to co-ordinate these assets, either to optimise own-consumption in behind-the-meter approaches, or through grid-interactive applications for demand-side integration (DSI). Furthermore, the ability to monitor and control these devices with high degrees of precision enables the development of integrated solutions, often bundling combinations of distributed generation, demand response and distributed storage into distributed energy systems (DES).

System benefits of energy efficiency

Energy efficiency has long been an energy system resource. It can be a highly cost-effective way to reduce the overall costs of the energy system, including investment in new generation, grid

upgrades and improved network operations, in addition to reducing exposure to energy security risks and mitigating environmental impacts (IEA, 2018g). Effective energy efficiency policies applied around the world, including in China, encompass building energy codes, appliance standards, energy efficiency obligations and auctions, and a range of incentive schemes and financing mechanisms to overcome the many market barriers to delivering cost-effective energy efficiency potential.

For example, minimum energy performance standards for air conditioning can substantially reduce the costs and electricity system impacts of rising demand for cooling in China and other countries. The IEA estimates that more ambitious air conditioner standards could save about USD 70 billion of power generation investment in China, halving the average per-capita electricity costs of cooling in 2050. Cooling demand can be further reduced through improved building design measures, such as cool roofs, better insulation and windows, and shading on the building façade (IEA, 2018h).

Energy efficiency obligations are another good example of a policy instrument that directly links energy savings to the energy system. They do this by placing an obligation on energy suppliers or distributors to achieve a certain level of energy savings over time. Today there are around 46 energy efficiency obligations around the globe, including in China. These obligations are cost-effectively delivering the equivalent of 3% of final energy consumption per year in the jurisdictions with the most ambitious targets. Across the globe, these schemes deliver energy savings at a weighted average cost of USD 0.013 per kWh saved over the life of the efficiency measures, which is highly cost-effective from an avoided cost of generation perspective (IEA 2018f).

California has one of the longest-standing energy efficiency programmes in the world, and from an early stage has recognised and incorporated the system value of energy efficiency into its policies and programmes. This focus on energy efficiency has continued as California has increased its ambition to decarbonise the energy system. California first adopted its “loading order” in 2003, which mandates utility procurement of energy resources in the following sequence: cost-effective energy efficiency and demand response first, followed by renewables, and lastly clean-fossil generation (CPUC, 2003). Energy efficiency policies in California are estimated to have saved consumers more than USD 100 billion over the past 40 years, surpassing 70 000 gigawatt hours (GWh) in cumulative electricity savings by 2017.

Energy efficiency obligation schemes also deliver peak demand reductions. For example, in China, State Grid Corporation and Southern Grid Company not only saved 68 GWh, but also reduced peak demand by around 17 GW between 2012 and 2016. Other market-based schemes have effectively targeted reductions in peak load requirements. For example, in the United States the ISO New England Forward Capacity Market captures the capacity value of energy efficiency for meeting future system peak loads. Since 2008 energy efficiency’s participation in the market more than tripled to 2 250 MW (6.3% of the total market). Similarly, energy efficiency resources are bid into the PJM forward capacity market (the Reliability Pricing Model or RPM). The inclusion of demand and energy efficiency resources in the RPM for the 2021/22 delivery year reduced total revenues by 15.7%, saving consumers an estimated USD 1.7 billion.

In summary, power system transformation calls for a continued focus on energy efficiency as a highly cost-effective way to reduce the overall costs of the energy system. Moreover, as the penetration of variable renewable resources increases, energy efficiency measures will need to evolve as part of the broader pool of DER that are responsive to the time and location-specific needs of the system.

Efficiency and flexibility can mutually reinforce one another. The use of ice storage in larger air conditioners can be an effective tool to concentrate electricity demand for air conditioning in

the middle of the day (IEA, 2018h). Cooling demands after sunset are then met by drawing on the cold contained in the stored ice. At first glance, this option is less efficient than an air conditioner that uses only electricity (efficiency losses when making the ice, losses in ice storage etc.). However, this does not mean that efficiency is not crucial for making this option viable: a better-insulated building envelope will minimise the required storage, and a well-insulated storage tank minimises losses and thus allows the use of smaller sized storage, which improves the economic viability of this option.

Mobilising the load through EVs

An additional opportunity and challenge for the application of storage in the power system concerns the deployment of EVs. A high concentration of EV adoption is likely to affect some distribution networks more quickly than others. For example, UK Power Networks is currently exploring the challenges posed by EV adoption in the Greater London area. It is expected that the bulk of this charging infrastructure will be connected to the low-voltage distribution network, in an area that is characterised by high population density and high economic costs associated with service disruptions. This particularly raises the importance of developing smart charging schemes and integrated planning for charging infrastructure in distribution networks.

In other jurisdictions, EVs are increasingly seen as a potential system flexibility resource, with two basic approaches. Smart charging refers to adjusting the timing and speed of charging and is, in principle, unidirectional. By contrast, vehicle-to-grid (V2G) technology allows for bidirectional exchanges between EVs and the grid. So far, smart charging is the most common approach to EV fleet management. In the Netherlands, Next Kraftwerke and Jedlix have partnered to offer the charging flexibility of personal EVs for frequency regulation. On the owner side, participation is encouraged through direct monetary rewards.

Both smart charging and V2G rely not only on the ability of aggregators to participate in providing ancillary services, but also on the presence of a clear picture of the interconnection requirements. This is more challenging for V2G as it requires the matching of the operational parameters of various manufacturers and the specific performance parameters prescribed by system operators. In Germany, Nissan has become the first carmaker to qualify for selling electricity back to the grid. Mobile battery access to ancillary service provision relies on the compatibility between interconnection requirements and the specific charging standard. In the case of Nissan, this is enabled by using the CHAdeMO standard, but competing standards such as Combined Charging System also enable V2G capabilities.

Box 14. V2G for frequency regulation

Operating since 2016, the Parker project in Denmark aims to test the technical ability of, and to identify the regulatory barriers to, EVs in V2G services. It is the world's first fully commercial V2G platform. Energinet, the Danish system operator, is responsible for procuring operating reserves jointly with Svenska Kraftnät, the Swedish system operator, for the ENTSO-E RG Nordic grid. For 2017, Energinet was responsible for providing 23 MW of this reserve, while Svenska Kraftnät's requirement was 230 MW.

The Parker project enables V2G participation in this market, providing normal frequency containment reserve. This is triggered automatically to maintain frequency within ± 0.1 hertz from the nominal 50 hertz frequency. Activated reserves must be delivered within 150 seconds.

On a technical level, the project relies on the deployment of 50 Enel 10 kilowatt charging stations

and enables participation of various car brands, thus increasing the potential for scalability and ease of access. EV batteries are used between 30% and 95% of full charge and fleet dispatch is managed through Nuvve, a platform which aggregates the customers' charging preferences as individually input through a smartphone app. Schedules are developed for customers who do not want to use the app.

At the customer end, the Parker project offers mobility-as-a-service through a monthly fee that provides access to charging and maintenance. The cost of charging is further reduced through frequency regulation revenues.

The project has resulted in a number of interesting findings. Frequency regulation dispatches usually last for extended periods. This means that it is necessary to undersize the EV's availability bid in order to avoid the dispatch exceeding available capacity. Additionally, there is the issue of two-way energy losses, as discharging the battery at a lower level than the rated capacity may result in lower energy efficiency.

From the regulatory standpoint, prequalification rules play an important role in enabling the deployment of V2G. This relates back to the diversity of technical characteristics of different EV brands and the need to account for different charging standards in the prequalification requirements. Added to this is the need to assess the aggregate performance of the fleet, the high cost of settlement meters and the potential for double counting in energy tariffs and taxes.

Source: Everoze (2018), V2G Global Roadtrip: Around the world in 50 projects, <http://everoze.com/v2g-global-roadtrip/>.

Beyond the typical focus on the challenges of personal EV deployment, examples of EV fleet management offer opportunities for better co-ordination of EV charging and location of charging centres respective to the grid. Commercial EV fleets could play a role in offering flexibility services based on the ease of scheduling that results from a fixed time-of-use profile. With regard to long-term planning, network operators, transport operators and planners could co-ordinate schedules for bus route electrification taking into account the state of the distribution infrastructure and the location and type of charging infrastructure.

Targeting energy efficiency for system flexibility

As the share of variable renewable resources on power systems rises, new initiatives are being introduced that fundamentally change the way in which energy efficiency services are being procured and delivered to help ensure a balanced, stable and affordable grid. For example, in California, new requests for energy efficiency services from the state's investor-owned utilities favour performance-based approaches that will deliver energy savings when and where they are most valuable as a load shaping resource – thus enabling the continued growth of renewables and supporting non-wire alternatives to an increasingly decarbonised grid infrastructure. In fact, providing "energy efficiency as a grid resource" is now an explicit requirement of California's energy efficiency portfolio, along with other targeted, cost-effective energy savings and market transformation requirements.

In addition, there are many other examples of how energy efficiency programmes are evolving to address a more dynamic resource mix. These programmes will take advantage of emerging trends, such as connected devices, self-generation and advanced energy management options, to better reflect the central role that consumers will play in the future of the grid. For example, geo-targeting approaches are being employed more often to identify energy users with specific loads with the highest potential for savings at specific times of the year, and in constrained

areas, at specific times of the day. These programmes are becoming more and more common as platforms emerge to match customer usage data with the specific needs of the local distribution system.

Engaging distributed battery storage

Similar to distributed generation, distributed storage systems are connected at the distribution level or sited locally to serve specific needs, for example through collocation with small-scale or remote wind generation.

A growing field in the deployment of battery storage relates to the provision of various grid services. Due to their speed and precision of response, batteries can be deployed for a number of applications, such as frequency regulation. Additionally, depending on the jurisdiction, battery storage may be used for a number of applications such as arbitrage in wholesale markets or for balancing markets. Depending on the frameworks available, it may be possible to deploy existing back-up batteries or even make use of EV fleets.

In all of these cases, the regulatory framework and interconnection requirements play a key role for profitability. In Germany, for example, transmission system operators (TSOs) who are in charge of procuring primary frequency reserves for very short-term flexibility have developed a set of minimum requirements, specifying the secure operating range for primary regulation provision based on the state of charge at the time of dispatch (Regelleistung, 2015).

In the United Kingdom, by contrast, the attractiveness of battery storage participation in the capacity mechanism has reduced substantially due to the introduction of a new de-rating methodology, thus motivating battery operators to seek additional sources of revenue, such as the balancing mechanism. Further to these applications, typically in markets operated by the TSO or independent system operator (ISO), batteries can be deployed at the consumer end to reduce energy bills and potentially to balance the transmission or distribution networks directly. In these cases, the structures of ownership and operation depend heavily on unbundling regulations and the ability to stack revenues from different sources.

Box 15. Battery storage for real-time balancing

Battery storage projects in the United Kingdom have mainly relied on income from participation in frequency regulation services and in the country's capacity market. Revenues from these sources have decreased due to saturation of the frequency regulation market and de-rating provisions in the capacity market.

National Grid operates the balancing mechanism as part of the wholesale market for participants to settle any imbalances close to real time. This market has previously been restricted to generators under 50 MW, as they are exempt from the wholesale market participation licence requirement. Limejump, an independent aggregator, has applied for a special dispensation to enter the wholesale market, aggregating 10 MW of standalone battery storage and a co-located facility of 10 MW PV and 6 MW battery storage.

The project allows sufficient revenue for battery storage, as balancing mechanism prices have been observed to reach up to GBP 2 500 (British pounds) /MWh and are above GBP 100/MWh for a third of the time. An additional aspect to the profitability of such aggregation is the ability to stack revenues from arbitrage in the wholesale market and participation in the balancing mechanism.

One particular area yet to be discussed, which is seeing increasing relevance, is the deployment of battery storage for location-specific flexibility services. For example, ENDESA, one of Spain's largest distribution system operators, is testing the deployment of back-up battery storage from telecommunication base stations for local balancing purposes. Aggregation of flexibility resources for balancing at the local distribution level can limit the extent of bidirectional flows back into the transmission system (Box 16).

Box 16. Battery storage for balancing the distribution network

By using the flexibility available at 20 telecommunication battery sites across the Barcelona distribution network, ENDESA Distribución has tested the feasibility of operating a local market to solve congestion in the distribution network, while maintaining a committed consumption schedule at the border with the transmission network. In practice, such a business model should be expected to facilitate balancing the overall system, although it depends on a number of regulatory and institutional questions. At the institutional level, balancing is currently the responsibility of the transmission system operator, such that ENDESA would actually require a particular agreement with Red Eléctrica de España to recognise and monetise its contribution to keeping the system in balance.

On the regulatory side, as distribution network operators under the European framework, ENDESA is not allowed to own or operate battery storage units, which count as generators. For this reason, ENDESA has established a number of partnerships. For example, the batteries were originally installed to provide back-up supply at Vodafone stations. While ENDESA has visibility over the station's smart meters, it dispatches the batteries via a local flexibility market based on the bids of an aggregator (Our New Energy [ONE]) upon detecting upcoming deviations from the agreed consumption profile.

As with other inverter-based DER, this project supports the deployment of battery storage for real-time balancing due to the speed of response and precision. Nonetheless, any commercial-scale application will depend on the creation of the appropriate co-ordination interface between REE and ENDESA. Moreover, applicability would depend on identifying revenue streams that are sufficient both to incentivise ENDESA, the respective aggregator (ONE) and Vodafone, as the asset's owner, and to prove cost-effective when compared with typical balancing resources.

Source: Madina et. al (2018), "Exploiting flexibility of radio base stations in local DSO markets for congestion management with shared balancing responsibility between TSO and DSO", <https://zenodo.org/record/1445342#.W7XntBMzZTY>.

Distributed generation for system services

Distributed generation includes renewable energy generators and co-generation units connected to the distribution network, or small units connected at the transmission level that are physically close to loads. Due to their technological diversity, distributed generation assets will be able to contribute to flexibility needs differently. This will also depend on the operational and prequalification requirements in place.

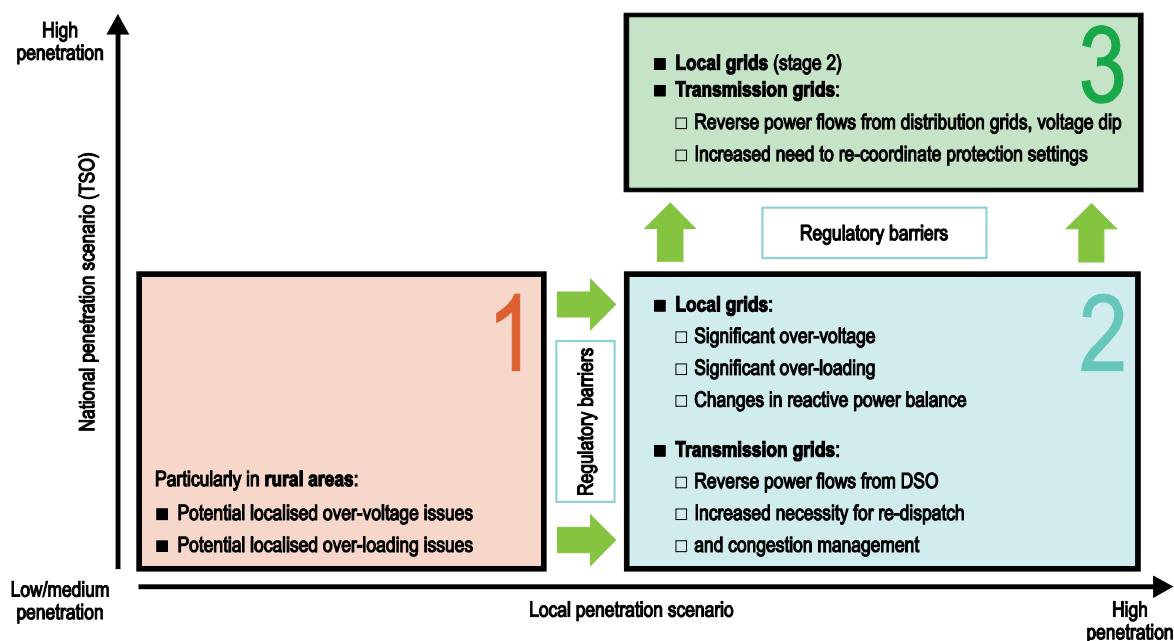
One common case of distributed generation for system flexibility entails the use of back-up generation on site to ensure continuous energy supply for critical energy uses, such as hospitals, banks and data centres. Back-up generators, typically diesel units, are characterised by their rapid start-up times, between 10 and 30 minutes, and short minimum up-times. In recent years back-up generation, primarily from diesel generators, has been used in some American and European markets to serve long-term flexibility needs, and to meet peaks in demand and short-

term balancing through restoration reserves. From the perspective of critical energy users, the deployment of back-up generation for flexibility may be seen both as an additional source of revenue and an additional source of security of supply as the back-up generators are used more regularly. From a policy maker's perspective, deploying otherwise idle back-up generation may be an alternative to kick-starting markets for demand response. However, the long-term viability of this should be balanced against additional concerns, such as increased urban emissions.

Additional distributed generation technologies include dispatchable rooftop PV and co-generation from biomass plants. As explained earlier, distributed PV's ability to contribute to the system depends on the inverter technology available, while for co-generation it may depend on the associated heating demand. While these plants are usually too small to be able to participate in the provision of flexibility at the levels typically required by system operators, it is possible to aggregate and co-ordinate their output through virtual power plants. In Germany and Switzerland a number of pilots and commercial schemes have been established to do this.

Using smart inverter technology, solar PV can provide voltage management capabilities and power system support services, as well as improved communications and interactivity. Adding battery storage improves the provision of these services, and has the important benefit of shifting some or all of the generated power for consumption to times of higher system demand (Figure 16). These services can have value for local grids; at high shares of decentralised solar PV, they can also become relevant to ensuring security of supply.

Figure 16. Technical impacts of rising deployment of distributed solar PV generation



Source: IEA PVPS (2014), Transition from Uni-Directional to Bi-Directional Distribution Grids.

As decentralised solar PV increases, a new set of technical challenges must be overcome.

Aggregation for load shaping

The rise of digitalisation allows for the co-ordinated deployment of many smaller types of system resources at a large scale. So-called aggregators make use of digital platforms to

actively manage distributed energy resources in a way that is beneficial for both the power system and the consumer.

Smaller industrial and large commercial consumers are increasingly engaging in demand response programmes; these are typically operated through aggregators and allow flexibility providers to either obtain an additional source of income or reduce their energy bills. Participation of such end consumers has usually been enabled by the presence of smart metering infrastructure and time-of-use electricity tariffs (dynamic load shifting and curtailment). By engaging a greater number of stakeholders, aggregators can contribute to reduce the cost of balancing the system, but targeted policy or regulatory changes may need to be implemented to allow for their participation in wholesale or ancillary services markets.

Box 17. Pooling industry and battery storage in virtual power plants

In 2018 Belgium faced a tight winter, with extended outages of its nuclear fleet impacting the country's security of supply. The government secured extra capacity from gas-fired power stations, and the TSO introduced a new product to allow additional flexibility to participate in the balancing market. In addition, the Belgian government entered into agreements for cross-border electricity exchanges with its neighbours, France, Germany and the Netherlands. In the previous two years electricity imports and exports across Belgium's borders were severely constrained by network restrictions in the Central Western Europe region, due to grid congestion and unscheduled loop flows.

Belgium is reasonably well positioned among European countries in respect of opening the provision of flexibility services to DER, such as industrial demand response and battery storage. Procuring frequency reserves from a broader range of flexibility resources is seen as a way of reducing the cost of reserve provision and Elia, the country's system operator, has taken an active role in developing products that enable their participation. As of 2018 access for different technologies and market participants was satisfactory. Although in practice some requirements still exclude DER from the market, the cost of procuring reserves has fallen in recent years by opening the balancing markets to additional flexibility from DER.

REstore, part of Centrica, integrates localised distributed energy solutions for businesses around the world, leveraging onsite generation (co-generation, PV and wind), storage and flexible loads (industrial, commercial and residential). As one of Europe's largest aggregators with a portfolio of 2 300 MW, REstore has developed a number of solutions to serve the Belgian balancing markets.

In April 2018 REstore launched the 32 MW Terhills Virtual Power Plant (VPP), located in a former coal mine on the edge of Belgium's National Park. The project took 6 months from inception to operation, including 5 weeks to install the 18.2 MW Tesla Powerpack storage system, composed of 140 batteries. What makes this battery project unique is its inclusion in a larger flexibility portfolio, together with micro-generation, industrial loads and household applications, such as domestic boilers. The VPP provides primary reserve and frequency regulation to the Belgian system operator, instantly charging when frequency is too high and discharging when frequency is too low. The battery can respond incredibly accurately and fast, up to 100 times faster than a fossil fuel power plant.

The European Commission described the Terhills project as a key enabler for the decarbonisation of the European energy system. The VPP supports the grid while reducing the need to ramp up

fossil-fuelled, CO₂-emitting peak plants. Using its patented and proprietary cloud solution, REstore is able to optimise the VPP and co-ordinate the response across all sites. In its first months of operation, the VPP delivered 100% of required power for 99.6% of the time.

Including the battery in a larger flexibility portfolio results in a revenue stream which is up to 1.4 times higher compared to the base case where the battery is monetised on a standalone basis. Complementary technical characteristics of the battery and industrial loads are blended, enabling slower industrial loads to participate in the market, and allowing the battery to remain at a state of charge of 50% or above, while rapidly cycling up and down, increasing its lifetime. Also, value is added by stacking revenues from the provision of primary reserve as well as day-ahead and intraday wholesale markets.

At the operational level, the deployment of a fully automated solution respects the boundary conditions of industrial processes and reduces the impact on the industrial sites' operations. REstore's solution also optimises reporting of the metered demand before, during, and after dispatch, which simplifies settlement processes.

The penetration of DER requires the ability to pool assets, prequalification requirements conducive to the deployment of batteries, and a technology-neutral ancillary service product design, as well as clear and transparent baselining and settlement methodologies.

REstore views the following aspects of product design as helpful to encouraging the participation of DER in all markets on an equal footing with generation. These have the added benefits of improving market liquidity, transparency and social welfare, as well as enabling a clean, secure and cost-efficient energy system:

- Frequency containment reserve (FCR), automatic frequency restoration reserve (aFRR) and manual frequency restoration reserve (mFRR): increase the frequency of tenders to a daily basis instead of a weekly basis.
- FCR and aFRR: procure both products separately.
- aFRR: reduce the minimum bid size, currently set at a still comparably large value of 25 MW, and extend participation to assets connected beyond the medium voltage level.
- aFRR and wholesale markets: extend transfer of energy to aFRR and day-ahead/intraday markets in a timely manner.
- mFRR: review submeter requirements to avoid overly strict accuracy requirements.

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Policy, market and regulatory frameworks for power system transformation

This chapter discusses the basic requirements for policy, market and regulatory frameworks to support the cost-effective and reliable transformation of power systems. It is structured under five main sections. The first uses the six characteristics of variable renewable energy (VRE) introduced in the previous chapter to derive basic principles that system operation and market design need to follow to unlock flexibility. The following sections then discuss the implementation of these principles in three main areas: wholesale markets, retail markets and distributed energy resources, and system planning. A final section presents transition mechanisms for the gradual introduction of innovative frameworks. The objectives are to provide a comprehensive overview of the different areas in which policy, market and regulatory frameworks need to be adapted to facilitate power system transformation, and to provide relevant international experience in these areas.

Basic principles to unlock flexibility

The six basic properties of VRE (low short-run costs, variability, uncertainty, modularity, location constraints, non-synchronous technology) directly imply a number of fundamental principles for appropriate power system operation and market rules (IEA, 2014a):

- **Low short-run marginal cost** – System operation should prioritise generation with low short-run costs in order to minimise fuel costs. Where markets are in place, bids from generators should generally reflect short-run marginal costs. Where such mechanisms are not in place, growing inefficiencies and renewable energy curtailment will result at rising shares of VRE.
- **Variability** – System operation needs to be planned and executed at small time increments. For example, the schedules for interconnectors should be planned at the sub-hourly level. Where markets are in place, this implies a greater importance for high temporal resolution of price signals, i.e. prices are valid only for short time periods. In addition, VRE will cover a varying share of power demand and this share may change rapidly over a few hours (for example, during sunrise). System operation practices need to allow for large changes in operational patterns over shorter periods. Where markets are in place, this implies the increased importance of allowing large differences in prices, i.e. allowing for larger short-term price volatility.
- **Uncertainty** – Available VRE supply is only known with high accuracy a few hours ahead of generation. Hence, system operators need to be able to change planned operations very close to real time. Forecasts need to be matched to relevant timescales in a power system, e.g. the start-up times of power plants. Where markets are in place, this raises the importance of short-term price signals, i.e. prices formed close to real-time that take into account current system status.
- **Location constraints** – Mismatches between supply and demand may occur across large geographic regions (locational constraints). System operations need to efficiently balance supply and demand across large areas, making best use of available infrastructure. Where markets are in place, this increases the importance of enabling efficient trading across large

regions (coupling of markets) and high spatial resolution of price signals, i.e. prices differ from place to place.

- **Modularity** – Local supply may exceed demand and lead to flows from low- to high-voltage levels. System operation needs to better co-ordinate the interface between voltage levels and low-voltage grids need to be more actively managed. Where markets are in place, this implies a greater significance for dynamic price formation in low-voltage grids and the need for close integration with wholesale markets.
- **Non-synchronous technology** – System operation needs to explicitly manage the possibility of new constraints, such as low levels of synchronous inertia. VRE power plants can contribute to managing such issues by providing system services. Where markets are in place, this implies a greater need for system service markets, i.e. prices for products other than bulk power.

Where the policy, market and economic frameworks contradict the above principles, integration of VRE will be more costly and result in lower system reliability. In turn, adoption of these principles can enhance power system efficiency and reliability, even in the absence of VRE. However, substantial effort may be required to adjust legacy designs to more advanced practices. The following sections discuss how the principles can be implemented by means of enhanced power market design, renewable energy policies and system planning.

Wholesale market design

This section provides further detail on how wholesale markets can facilitate power system transformation. The section starts with an introduction to the general setup of wholesale power markets. It then considers international experiences in five areas that are particularly relevant to the current Chinese context: economic dispatch, trade across larger areas, use of system services and medium-term flexibility, procurement of clean generation options, and inclusion of externalities.

General setup

Short-term markets (minutes to hours)

Short-term markets are the foundation of all market-based electricity systems and have been proven to be a valid approach to cost-effective integration of high shares of VRE.²⁹ In most cases they consist of two main markets: the day-ahead market and the real-time market (Figure 17). In the day-ahead market, participants bid for energy and the market clears and sets hourly prices for each hour of the next day. Generating units are committed accordingly. Then, during the day, adjustments have to be made to balance supply and demand, which are continuously updated. This is done either by system operators or by generators. In Europe, participants can also exchange electricity blocks on an intraday market platform before system operators set balancing energy prices that clear the balancing (or real-time) market. In North America, system operators calculate real-time prices in a five-minute market. System operators also procure a number of ancillary services, including operating reserves, to instantaneously restore frequency.

In addition to these short-term markets, medium- and long-term markets enable trading of electricity and forward capacity development, in advance of the day-ahead timeframe. While

²⁹ The discussion in this section follows IEA (2016a).

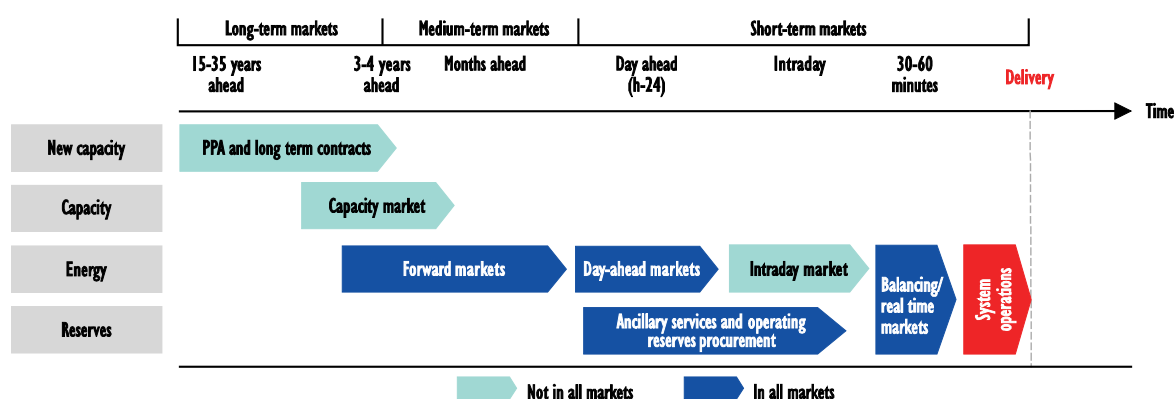
they play a key role in investment decisions (see following sections, Figure 17), it should be remembered that the underlying product of all these markets is the energy traded on short-term markets.

There is no standard design for electricity markets. Broadly, however, existing short-term markets fall into two categories depending on the degree of geographical and temporal resolution of electricity prices (IEA, 2016a):

- **Low-resolution** market designs have been implemented in Europe, where the primary objective was to enable cross-border trade in electricity. Each country had relatively little internal network congestion and a single price by country was considered sufficient. Within each price zone, power exchanges, not system operators, calculate prices as if congestion and network constraints did not exist. System operators handle congestion by redispatching power plants. The primary market is the day-ahead market. Participation is not mandatory.
- The balancing/real-time market is a residual market designed to give market participants the incentive to balance generation and load rather than to reflect the marginal cost of the system.
- **High-resolution** market designs seek to provide an accurate economic representation of the physical reality and operation of power systems. These have become more common in parts of North America, for example in Texas (Alaywan, Wu and Papalexopoulos, 2004). To that end, system operators directly manage the market platform using sophisticated software to perform security-constrained economic dispatch (SCED).
 - The primary market is the real-time market. System operators calculate the locational marginal price for thousands of nodes in order to reflect real-time congestion on the network (Schweppe et al., 1988; Hogan, 1992 and 1999). In order to better reflect economically (in prices) the flexibility needed to accommodate renewables, the time resolution has recently been increased to five minutes in several markets. Day-ahead market prices reflect the best forecast of real-time electricity prices.

High-resolution market design constitutes the benchmark for short-term markets and can reduce overall costs of operating power markets (Green, 2008; Neuhoff and Boyd, 2011). Market design with a high geographic and temporal resolution is better suited to integrating increasing shares of VRE. Existing high-resolution market designs can be further improved if they become more transparent during the intraday time frame, to facilitate the adjustment of power schedules to improving wind and solar forecasts.

Conversely, the geographical resolution of low-resolution markets has to be improved to contribute to the efficient operation of a more diverse set of power plants. However, the contrast between high- and low-resolution market designs reflects the difference in information provided to the market about local and general scarcities in the system. Indeed, the laws of physics are the same everywhere, and even in low-resolution designs, system operators use centralised market platforms with location-specific information to manage congestion and call the power plants needed to balance generation and load in real time. Increasing the transparency of short-term balancing prices by location will become more important with high shares of renewables and would ensure a convergence of market designs (IEA, 2016a).

Figure 17. Overview of different building blocks of electricity markets

Note: PPA = power purchase agreement.

Source: IEA (2016a). *Re-powering Markets*.

A suite of interrelated markets is used to match generation and load in the short, medium and long term.

Short-term markets play a key role in mobilising the flexibility of the power system, and the detail of their design affects the level of integration of renewables that can be reached. These markets are also essential for the integration of power systems over large market areas. The prices constitute the references against which other medium- and long-term prices are set, and they motivate participants both in the short and long run.

Medium-term markets (month to three years)

Medium-term markets allow price risks to be better managed by producers and consumers. In well-functioning markets, most energy is traded before the short-term markets, from a few months in advance up to three or four years. The medium-term market may be a formal, organised market with future and forward standard products traded bilaterally over the counter, or it may be informal, with variable quantities traded by traders or retailers. In liquid European markets, roughly 90% of energy is traded on these medium-term markets. Short-term spot markets play an essential role in settling the deviation between energy contracted on medium-term markets but not consumed, and in allowing energy not contracted in advance to be bought.

Long-term investment market (three years and beyond)

Long-term investment typically involves taking decisions on long-lived assets that will operate well beyond the three years of most forward markets. Beyond these time horizons, investors have to make reasonable long-term assumptions regarding the evolution of demand growth, the capacity mix and fuel prices, and all the other fundamentals of electricity prices.

Long-term contracts for offtake of electricity include PPAs and feed-in tariffs. The contract duration can vary from 10 years up to 35 years for long-lived investments such as nuclear power plants. Such agreements can be bilateral contracts between a utility and an independent power producer. Very often, however, they involve government intervention aimed at promoting new investment, either via an obligation or a regulated price. These long-term contracts can be the result of procurement mechanisms, such as auctions.

The products traded on long-term markets differ from country to country. They can be based purely on megawatt hours (MWh) produced annually (or blocks of several months or years), or

may include more complex product definitions and mechanisms to cover certain aspects of long-term resource adequacy. One example is capacity remuneration mechanisms (CRMs), where generation and other resources (demand-side response, efficiency, storage) are remunerated for their contribution to long-term system reliability. CRMs can be implemented in different forms, ranging from a strategic reserve kept largely outside the regular electricity market to a fully-fledged additional market (see IEA [2016a] for details).

Economic dispatch and rapid trading

Arguably, the shift towards economic dispatch is the single most important market design aspect for enhancing integration of VRE. Because VRE shows large variability across time and has very low short-run cost, rapid trading of electricity, close to real time, is critical.

Technical constraints call for a certain degree of forward planning and scheduling with regard to system operation. In practice, however, many power systems tend to lock in operational decisions far more in advance than technically required, sometimes weeks or even months ahead. For example, long-term contracts between generators and consumers may prevent power plants from providing flexibility. Such a situation is undesirable for least-cost system operation, in particular at high shares of VRE penetration. In regions where the share of VRE is on the rise, steps have been taken to improve the trading arrangements for electricity close to real time.

For example, in Europe a number of steps are being taken to improve the functioning of intraday markets. In Germany the functioning of these markets has been systematically improved over recent years. As a first step, EpeX Spot introduced the ability to trade 15-minute and 60-minute blocks of electricity on the intraday market, a higher level of granularity than the 60-minute contracts on the day-ahead market. This has allowed intraday trade to more accurately reflect the ramping up and down of solar photovoltaic (PV) generation during morning and evening hours. While trading was originally continuous (supply and demand matched as soon as possible), auctions were introduced in 2015 to improve market functioning (supply and demand offers are collected and then matched in groups). As a result, the volumes traded on the intraday market have increased substantially over the past five years (Figure 18).

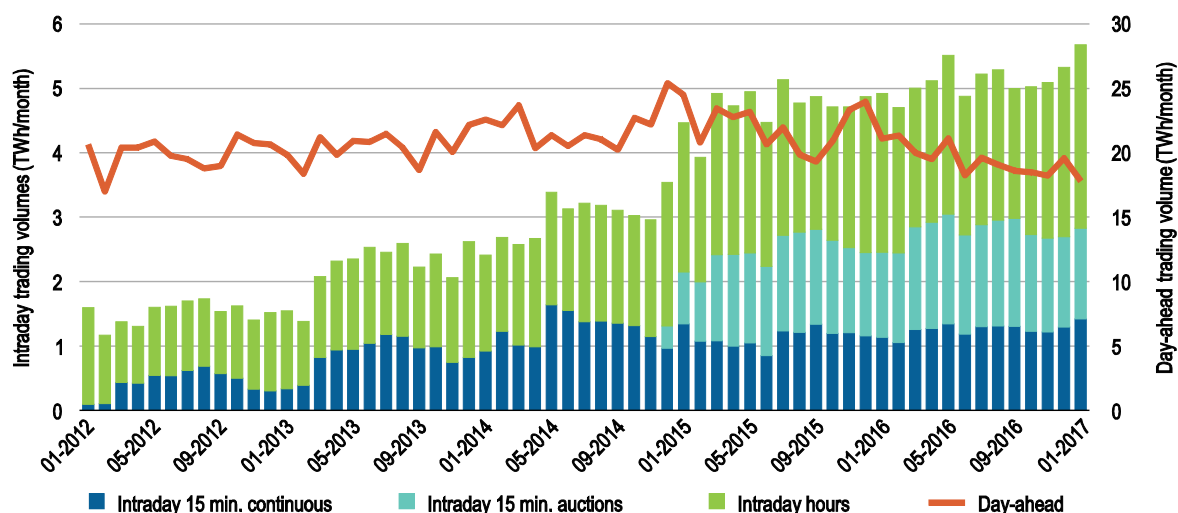
Given that VRE forecasts are more accurate closer to real time, power plant schedules should ideally have the option to be updated accordingly. Otherwise, a power plant that may be technically capable of supplying flexibility may be prevented from doing so due to a binding schedule that is based on outdated information. Where power plant schedules are determined by trade on a power market, the term “gate closure” refers to how close to real time generation schedules can be changed (without changing the plant-specific bids of market participants).

In the United States, the Federal Energy Regulatory Commission (FERC) passed a new rule in June 2016 that aims to improve the trading of electricity closer to real time (FERC, 2016). FERC now requires US independent system operators (ISOs) and regional transmission organisations (RTOs) to settle real-time markets at the same resolution as the dispatch of the system.³⁰ Historically, market participants were sometimes only allowed to submit price offers that were valid for a full hour, while the actual adjustment of power plant operations was performed on a five-minute basis. This meant that it was not possible to update bids according to new information close to real time. The new ruling removes this mismatch, mandating that the length of the settlement period be the same as the dispatch interval. The same principle is

³⁰ These are the California ISO (CAISO), ISO New England (ISO-NE), Midcontinent ISO (MISO), New York ISO (NYISO), PJM and Southwest Power Pool (SPP). FERC does not have jurisdiction over the Electricity Reliability Council of Texas (ERCOT).

applied to operating reserves. The rule will affect those ISOs that have not already adopted these practices (ISO-NE, MISO and PJM).

Figure 18. Monthly trading volumes on the German intraday market, 2012-16



Note: TWh = terawatt hour.

Source: 50Hertz Transmission GmbH (2017), "The transmission perspective".

Germany has systematically developed its intraday market to facilitate trading closer to real time.

Cross-regional trade of electricity

Benefits of regional power system integration

The benefits of regional (or cross-border) power system integration have been discussed in a number of previous International Energy Agency (IEA) studies (see, for example, IEA, 2014b; IEA, 2015a; and IEA, 2016b). These benefits cut across all aspects of the power sector, including: improved security of supply; improved system efficiency; and improved integration of variable renewable resources. Many of the earliest efforts to link power systems were driven by a desire to improve the development and use of resources across larger balancing areas. For example, Norway and Sweden integrated their power systems so that Sweden could take advantage of Norway's low-cost hydroelectric power, and Norway could balance its hydroelectric resources with Sweden's thermal generation.

Many of the benefits of regional integration derive from the increased optimisation of generator dispatch. For example, the western portion of the United States has a regional real-time power market called the Western Energy Imbalance Market (EIM), which started operations in 2014.³¹ According to the most recent estimate of system benefits,³² total (gross) cost savings between November 2014 and September 2018 amount to USD 502 million (United States dollars). This statistic, however, is only part of the story. Membership in the EIM has expanded rapidly, from only two participants in 2014 to eight today (and more expected to join in the next few years). Of the total benefits, USD 214 million (or nearly 43% of the total) accrued in the first three quarters of 2018.

³¹ The organisation and operational structure of the Western EIM is discussed in more detail below.

³² www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

Europe is perhaps the most advanced region in terms of cross-border power system integration. Countries are well interconnected, day-ahead markets are harmonised, and, in some cases, balancing markets are harmonised across borders as well. These efforts have led to measurable benefits. According to the European Network of Transmission System Operators for Electricity (ENTSO-E), day-ahead market integration has led to approximately EUR 1 billion (Euros) in increased social welfare (due to lower wholesale electricity prices) (ENTSO-E, 2017). Regional co-ordination of reserves in the Nordic region, meanwhile, has led to EUR 220 million in annual savings since 2003. ENTSO-E estimates that, if balancing market integration were extended across Europe, the resulting savings could reach EUR 3 billion.

Centralised versus decentralised models of integration

Cross-border power system integration refers to the physical interconnection of power systems across jurisdictional boundaries. These boundaries can be international (such as between the People's Republic of China ["China"] and its neighbours in Southeast Asia) or intranational (such as between provinces within China). In either case, the act of physical interconnection requires increased co-ordination between jurisdictions across many domains, including (but not necessarily limited to) system operations, market organisation and regulation. This co-ordination can be organised under two general models: centralised and decentralised.

Under a centralised model, functions that had previously been distributed among multiple parties become the responsibility of a single, interregional entity. In a decentralised model, each region retains functional control.

It is possible for cross-border integration to include both centralised and decentralised elements. In Europe, for example, power exchanges are organised centrally (for example, Nord Pool in the Nordic region, and Epex Spot in Central Europe) while system operations remain the responsibility of the respective national transmission system operators (TSOs).

The centralised model is functionally simpler than the decentralised model, in that responsibilities are clearly allocated to a single entity that functions across jurisdictional boundaries. However, it is also less flexible, in that common market rules and operational decisions must be developed that can accommodate regions with different generation mixes and energy-related policies, and is potentially less scalable. In the United States, power market organisation and power system operations are both the responsibility of a single, central party: either the vertically integrated utilities (which do not organise markets but do manage system operations) or, in some regions, the ISOs and RTOs, which organise a single regional market and consolidate the operations of multiple utilities, sometimes across multiple states.

The Western EIM, which is organised and operated by CAISO, is another example of a centralised, interregional market. In effect, the Western EIM opens up CAISO's real-time power market to external participants. Participation in the Western EIM is entirely voluntary – that is, participants can enter or leave whenever they want. As discussed above, the benefits of this model are real and measurable. However, they are also relatively limited, both because of the number of participants and also because of the volume of power trade involved. The limited volumes are due to a combination of factors, including the voluntary nature of market participation, and also because real-time power market trades make up only a small fraction of the total volume of trade, with most trading occurring in the day-ahead market.

Market integration in the European Union

Compared to other regions in the world, the European Union has been quite successful at developing harmonised power markets and at encouraging regional power system integration among the various member states. The EU example suggests that more functional

decentralisation, harmonised through the guidance of regional institutions, can lead to better overall results.

The development of the EU Network Codes is a good example of how to strike this balance in practice. The European Union, in its third legislative package ("Third Package"), mandated the development of common European Network Codes and Guidelines (hereafter, "Network Codes").³³ The Network Codes aim to harmonise the technical and commercial rules governing access to energy networks, with the overarching goal of ensuring fair access to all participants and removing barriers to trade between member states. The Network Codes cover a number of areas, including some directly related to cross-border power system integration, namely:

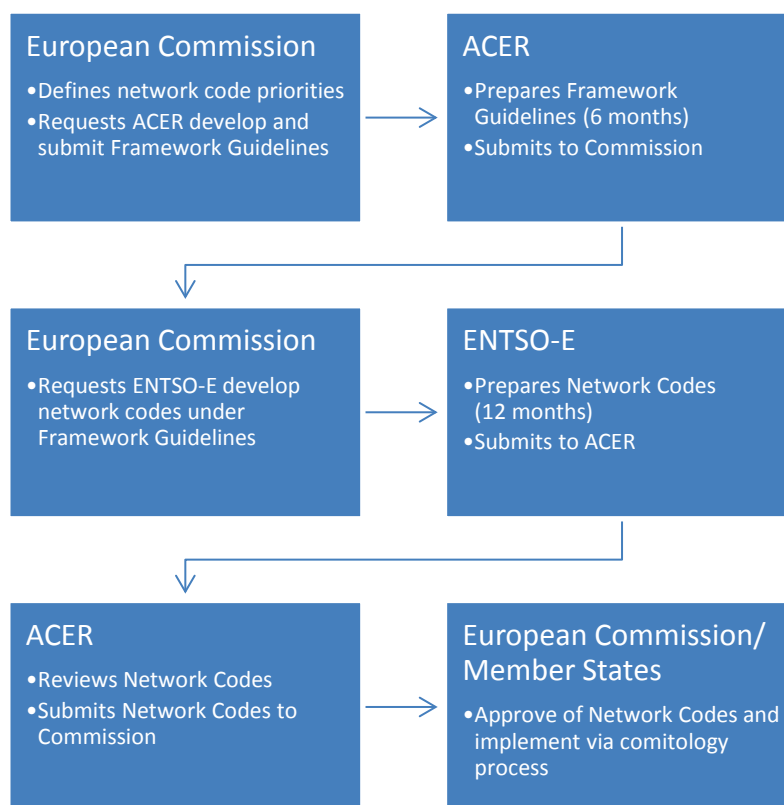
- Capacity allocation and congestion management (CACM), which covers intraday and day-ahead interconnector capacity, and forward capacity allocation (FCA), which covers long-term interconnector capacity.
- Balancing, which includes rules designed to encourage the use of regional balancing resources whenever possible.
- Harmonised tariff structures, including locational signals and inter-transmission system operator compensation.
- High-voltage direct current (HVDC) network codes that set requirements for the integration of HVDC interconnectors into local grids.

Responsibility for developing the Network Codes is divided across a number of different entities. Ultimate responsibility for ensuring their development and implementation rests with the European Commission. However, the Commission does not have the technical capacity to develop the details of the rules, so it allocates responsibility to two entities: the Agency for the Cooperation of Energy Regulators (ACER) and ENTSO-E.

Draft codes are prepared through an iterative process that involves the Commission, ACER and ENTSO-E (Figure 19). The Commission sets overall priorities, which ACER then develops into a set of Framework Guidelines. The Framework Guidelines set the overall scope and direction of each of the Network Codes. ENTSO-E (which is a consortium of TSOs) then develops detailed Network Codes that follow the Framework Guidelines while also respecting local (i.e. national) technical constraints.

The CACM Network Code is of particular importance and so is worth focusing on. Prior to the implementation of CACM, cross-border transmission capacity was either calculated separately by the interconnected TSOs or, in some cases, on a harmonised bi- or multilateral basis. Unilateral calculations led to possible mismatched estimates of the amount of capacity available across a border. Harmonised methodologies improved this, but only on a bilateral or subregional basis. The Network Code on CACM requires, among other things, more formal collaboration and harmonisation of the way in which transmission capacity is calculated across all of Europe.

³³ Network codes and network guidelines are functionally similar and both are legally binding. The main difference is that they are adopted under different provisions of EU regulation on electricity.

Figure 19. Developing the EU network codes

Source: IEA (2016b), *Electricity Security Across Borders: Case Studies on Cross-Border Electricity Security in Europe*.

Europe implemented a systematic process to develop harmonised network codes.

Harmonised calculations of interconnector capacity are crucial both for operations and long-term resource adequacy. Europe's network is meshed, meaning there are multiple pathways through which power may flow. In many cases one country may act as an intermediary for power flows between two or more other countries. Without a common approach to these calculations, it is possible for TSOs to make improper decisions in real time based on assumptions that conflict with other TSOs. Under- or overestimation of available interconnector capacity would also lead to different views on local and regional resource adequacy.

Although CACM harmonises the method for calculating interconnector capacity, responsibility for calculations is not fully decentralised. Rather, responsibility has been given to various Regional Security Coordinators (RSCs). A few RSCs, such as CORESO and TSC, started as a voluntary organisation formed between TSOs in 2008. Under current EU law, however, participation is now mandatory.

Owned by the member TSOs, the RSCs have five primary functions:

- calculation of interconnector capacity between participating regions
- grid security analysis
- development of a common grid model
- development of resource adequacy forecasts

- planning for outages.

Notably, these functions primarily revolve around the harmonisation of information and its dissemination to the participating TSOs. The RSCs have no formal authority with regard to actual system operations, which remain entirely under the control of the respective TSOs.

Market organisation

Market organisation in Europe operates at two scales. First, markets are organised on a national or regional basis through various power exchanges. Second, markets are harmonised between each other through a process known as Price Coupling of Regions.

Nord Pool is perhaps the most advanced example of a regional market in Europe. Its structure follows the same balance between centralisation and decentralisation as the examples discussed above. Nord Pool is a regional entity that organises various wholesale electricity markets across seven member countries.³⁴ Responsibility for system operations, however, remains with the individual TSOs.

The majority of power trading in the Nordic region is done through the Nord Pool Power Exchange: 400 TWh in 2017, or approximately 80% of the total power consumed. The remaining 20% is traded via bilateral agreements outside the Nord Pool market. The Nord Pool model represents one possible allocation between centralised and decentralised power system integration. Within Europe, however, it is also possible to find another model of decentralised integration, namely the Price Coupling of Regions (PCR). Under the PCR model, the various European power exchanges have developed a single methodology for calculating day-ahead electricity prices: the EUPHEMIA algorithm. Each exchange remains responsible for price calculations and co-ordination with the TSOs that operate in their territories. Data is shared among the various exchanges to ensure calculations are consistent and coherent across all exchanges. At present, PCR covers nearly all of Europe.

The implementation of PCR across Europe has been driven in large part by the European Commission, which has encouraged market harmonisation through the legislative package and network code development process detailed above. However, it has also involved a significant amount of work at national and regional (i.e. within Europe) levels. For example, many of the market principles that underpin the PCR process are based on those developed in the Nord Pool region. Other aspects have come from international collaboration through voluntary organisations such as the Pentilateral Energy Forum (PLEF).

The PLEF is made up of seven countries in central-western Europe.³⁵ The PLEF has no formal authority, but instead allows for collaboration among the member countries on a wide range of issues related to electricity sector integration. The basic principles underpinning market coupling, for example, emerged from PLEF working groups. The PLEF has also allowed participating countries to go beyond EU requirements in areas such as electricity security, for example through the development of regional probabilistic resource adequacy assessments and the signing of a regional memorandum of understanding on emergency planning and crisis management (PLEF, 2017).

Market organisation in Europe offers a good example of how decentralisation can support increased regional integration. Allowing different countries (or, more generally, jurisdictions) to

³⁴ Denmark, Estonia, Latvia, Lithuania, Finland, Sweden and Norway. Nord Pool also organises a wholesale market in the United Kingdom. However, at present the United Kingdom is not physically interconnected to the Nordic countries and so operates independently of the other Nord Pool markets.

³⁵ The founding members were Belgium, France, Germany, Luxembourg and the Netherlands. Austria and Switzerland joined later.

retain functional control over their power systems, while at the same time encouraging market, system and regulatory harmonisation at the interregional level, has enabled a flexible yet scalable approach to cross-border power system integration. It is flexible in allowing countries to retain control over system operations and energy policies, yet scalable as demonstrated by the PCR, which now covers a nearly the entire European Union.

System services, short- and medium-term flexibility markets

Reliable operation of the power system critically depends on a number of system services, which contribute to maintaining system frequency and voltage levels. Special capabilities may also be required when restarting the system after a large-scale blackout (so-called black-start capabilities). Different systems may obtain the same service in different ways; for example, some will mandate it in the grid code, while others use a procurement or market mechanism.

As the penetration of VRE increases, the need for such services – and hence their economic value – is bound to change. One reason behind this is that conventional generators have traditionally provided many of these services as a simple by-product of power generation. For example, a conventional generator contributes to voltage and frequency stability with its voltage regulator and governor, including the inertia stored in the rotating mass of its turbine and generator.

Higher levels of VRE also increase variability and uncertainty in the supply-demand balance. Hence, it becomes a priority to mobilise higher levels of flexible resources, such as storage and demand response. Reforming system services markets has a critical role to play, alongside other measures (see section on flexibility below).

Ireland and Northern Ireland are committed to increasing the share of renewable energy in electricity generation to 40% by 2020. In this context, to identify possible operational issues in the power system over the coming years, they have established the DS3 work programme. This programme started a consultation process on a range of new system services products to address and mitigate potential system issues, which had been identified previously by comprehensive technical studies. New products have been proposed to address the challenges associated with frequency control and voltage control in a power system with high levels of variable, non-synchronous generation (Eirgrid/SONI, 2016). The new services identified under the DS3 programme include synchronous inertial response, fast frequency response, fast post-fault active power recovery, and ramping margin. These supplement existing system services products, reflecting new requirements in the specific, Irish context.³⁶

Similarly, the Australian Energy Market Operator (AEMO) launched the Future Power System Security programme in December 2015 (AEMO, 2017). Its objective is to adapt AEMO's functions and processes to deliver ongoing power system security and reliability. The programme targets four high priority areas: frequency control, system strength, management of extreme power system conditions, and visibility of the power system. With regard to frequency control, a fast frequency response mechanism is currently under consideration, supplementing existing frequency control ancillary services. One large generator, AGL, also submitted a rule change in September 2016 to establish an ancillary services market for inertia (AEMC, 2017). These reforms are all ongoing at the time of writing.

³⁶ The issue of low system inertia and rate of change of frequency (RoCoF) is particularly prominent in Ireland and Great Britain, because RoCoF is used to detect islanding on distribution grids (0.5 hertz per second threshold). The issue of islanding on distribution grids is not the case in many other systems, which are thus likely to face inertia-related issues at a later stage.

A further example of an innovative market product for system services is CAISO's flexible ramping product. It is designed to enable procurement of sufficient ramping flexibility from the conventional generator fleet in order to meet ramping needs that arise from more pronounced changes in the supply-demand balance (CAISO, 2014). Other ancillary services, including frequency response and operating reserves, are already integrated into CAISO's day-ahead and real-time energy markets, with generators bidding into the CAISO ancillary services market, which is co-optimised with energy markets.

In jurisdictions where system services markets have historically received less attention, processes are ongoing to establish standard mechanisms or to begin remunerating services that were traditionally a non-compensated requirement. For example, in India the Power System Operation Corporation Ltd has released procedures detailing the implementation of new Reserves Regulation Ancillary Services (POSOCO, 2016). This step marks the introduction of an explicit, financially compensated operating reserves system. In Italy, the Regulatory Authority for Electricity, Gas and Water (AEEG) introduced the option of voluntary participation in the primary frequency regulation service in 2014. Previously, this was a purely mandatory, non-compensated service (Terna, 2017).

The following general principles apply for the design of flexibility markets and their link to short-term wholesale power markets:

- **Establish clear responsibilities for contributions to system stability:** Establishing clear obligations for ensuring system balance and mechanisms for cost allocation may simplify the task of system operation, as well as reduce the cost of reserve procurement. Requirements for cost-saving pass-through may help in ensuring end consumers reap these benefits.
- **Define clear procedures for balancing settlement:** The emergence of new stakeholders and the switching of roles may cause conflicts as new technologies are deployed to serve system needs. Engaging with market participants, system operators, aggregators and grids can help prevent controversies as demand-side integration markets develop.
- **Improve links between short-term flexibility and market timeframes:** Reducing the time between procurement and delivery of wholesale energy and system services, as well as increasing the time resolution of settlement periods across the markets, may reduce the need for rebalancing.
- **Reinforce locational incentives for flexibility:** Identifying localised system constraints and engaging local resources can improve the power system's resilience to increased exposure to weather-induced variability (secondary indicators) and changing patterns in demand.
- **Create fair remuneration streams for flexibility:** This entails appropriate pricing of flexibility requirements such as ramping, operating range, minimum up and down times and response precision.
- **Reduce incentives for inflexible power plant operation:** This can be done by reviewing existing take-or-pay contracts or binding full-load hour schedules to remove obstacles to economic dispatch and facilitate entry of innovative flexibility providers.

Hu et al. (2017) point out a number of key aspects influencing medium-term flexibility in European exchange-based electricity markets:

- **Gate closure and time resolution of trading products:** Typical gate closure at 12:00 in the day-ahead market creates a delivery lead time of up to 36 hours. Generally, longer delivery lead times increase the forecast error, placing VRE generators at a higher risk of imbalance in real time, and increasing demand for balancing resources in the intraday market. In addition, in markets where day-ahead trading products have an hourly resolution, an hourly

spot price becomes a poor indicator of the real conditions of the system due to high sub-hourly variations in VRE and demand.

- **Consistency in settlement period duration across submarkets:** In markets with hourly spot prices and sub-hourly imbalance prices, the low correlation between price signals for the same period in both markets may encourage market participants to under- or over-contract, depending on the cost allocation and their expected position relative to the system-wide imbalance. Additionally, long imbalance settlement periods may enable market actors with a broad portfolio to balance their own position internally, without contributing to balancing the system.
- **Price settlement rule for imbalance settlement:** A number of settlement rules apply across the different submarkets. In balancing services markets, pay-as-clear is seen as more economically efficient in the presence of a liquid and competitive market with perfect information. For imbalance settlement, the use of average pricing, as opposed to marginal pricing, depresses the price signals and provides less incentive for balance responsible parties (BRPs) to strategically maintain a balanced position.³⁷ This can reduce liquidity in the intraday market and increase demand for balancing services.
- **Symmetry in allocation of balancing costs:** This refers to the allocation of imbalance settlement costs to market participants depending on their position. In both one-price and two-price systems, short BRPs pay, while long BRPs get paid. The main difference is that in a one-price system the same price applies to market participants aggravating and alleviating the system imbalance. By contrast, two-price systems differentiate between these two situations. Depending on market conditions, one-price systems may encourage market participants to maintain a strategic imbalance in the intraday market
- **Weak scarcity pricing signals:** Markets with overly stringent, oversized supply reliability standards or with fixed generation schedules may create incentives for keeping inflexible thermal generators online. This limits the occurrence of scarcity prices high enough to encourage investment in new flexible generation or cost-effective deployment of demand-side response. Additionally, limiting energy price caps to well below the value of lost load may present a further obstacle to investment in flexibility resources.
- **Locational signals:** This relates to the difference between the choice of zonal and nodal pricing. Zonal pricing tends to overlook grid constraints and fails to incentivise potential investment in new generation or distributed energy resources to use the existing infrastructure efficiently. Within large zones, the lack of grid consideration may lead to unscheduled power flows, potentially increasing their balancing services demand and imbalance costs.

Attracting investment in low-carbon generation capacity

A crucial aspect of market design is ensuring that clean generation resources have an appropriate investment framework for their continued growth in line with policy targets. At high levels of VRE it is critical that policies seek not only to minimise the generation cost of VRE, but also deploy VRE in a way that is best for the overall system. This type of deployment is closely linked with the concept of system value (SV).

³⁷ In European power markets, BRPs are market participants, or their appointed representatives, who are responsible for maintaining the balance between supply and demand in their assigned balancing area at the end of each settlement period. The function is analogous to the role of Load Serving Entities balancing their control areas in North American regulated markets.

SV as a key concept for renewable and low-carbon energy development

The generation cost of various technology options is most commonly expressed in energy terms and labelled the levelised cost of energy (LCOE), which is a measure of cost for a particular generating technology at the level of a power plant. It is calculated by summing all plant-level costs (investment, fuel, emissions, operation and maintenance, etc.) and dividing them by the amount of electricity the plant will produce. Costs that are incurred at different points in time (e.g. construction costs or operational costs) and electricity generation coming from different years are made comparable by “levelising” them over the economic lifetime of the plant – hence the name.

The LCOEs of wind and solar power have significantly reduced over the past two decades (IEA, 2018a). In a growing number of cases, the LCOEs of wind and solar power are close to, or even below, those of fossil fuel or nuclear options, which is reflected in prices for PPAs. For example, the lowest currently reported contract prices for projects to come online during 2019-23 for onshore wind are under USD 30/MWh (Mexico/Brazil) and below USD 23/MWh for utility-scale solar PV (Mexico, India and Saudi Arabia).

However, as a measure the LCOE is blind to the when, where and how of power generation. “When” refers to the temporal profile of power generation that can be achieved, “where” refers to the location of the power plant and “how” refers to the system implications that the type of generation technology may have. Whenever technologies differ in the when, where and how of their generation, a comparison based on the LCOE is no longer sufficient and can be misleading. A comparison based only on the LCOE implicitly assumes that the electricity generated from different sources has the same value.

The value of electricity depends on when and where it is generated, particularly in a power system with a high share of VRE. During certain times, an abundance of generation can coincide with relatively low demand – in such cases, the value of electricity will be low. Conversely, when little generation is available and demand is high, the value of electricity will be high. Considering the value of electricity for the overall system opens a new perspective on the challenge of VRE integration and power system transformation.

The SV of a power generation technology is defined as the net benefit arising from its addition to the power system. While the conceptual framework applies to all power generation technologies, the focus here is on wind and solar power plants. The SV is determined by the interplay of positive and negative effects arising from the addition. To specifically calculate the SV of a technology, the factors that need to be taken into account first need to be specified. For example, a calculation may or may not include the positive externalities of technologies that do not rely on fuels with significant price fluctuations and associated risks.

On the positive side are all those factors included in the assessment that lead to cost reductions; these include reduced fuel costs, reduced CO₂ and other pollutant emission costs, reduced need for other generation capacity, reduced water requirements and possibly reduced need for grid usage and associated losses. On the negative side are increases in certain costs, such as higher costs of cycling conventional power plant and for additional grid infrastructure.

The SV thus complements the information provided by classical metrics of generation costs, such as the LCOE. It captures the effects that additional generation has on the remaining power system. Simply put, the LCOE shows the cost of a certain technology, while the SV of that technology captures the net costs and benefits on the system (Figure 20).

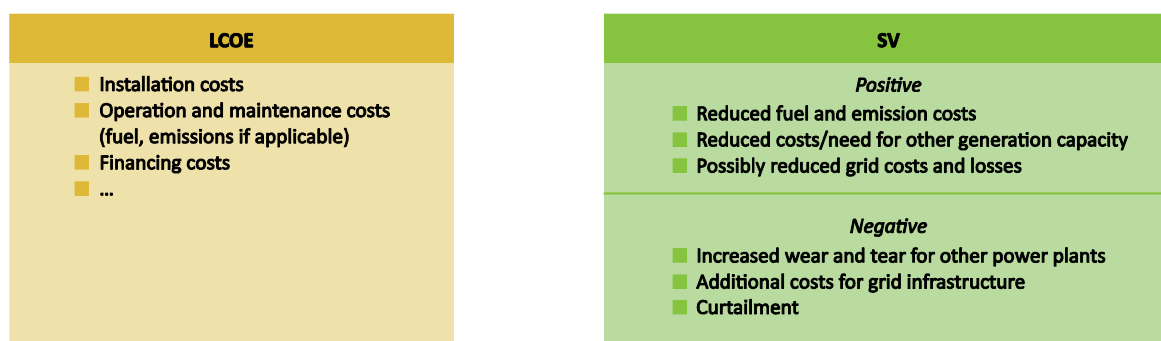
Calculating the SV of a technology requires assumptions to be made regarding, for example, fuel prices or CO₂ prices. It may also require modelling tools that can compare costs between different scenarios. Furthermore, it is possible to estimate certain components of the SV by

analysing actual market data, which is easy to obtain, although this requires careful interpretation of results. Only in the theoretical case that markets accurately price all relevant externalities, remunerate all benefits and charge all costs, do market prices fully reflect the SV. The degree to which this is met in practice depends on many factors. For example, assessing the SV based on spot market revenues may not capture all relevant effects on grid infrastructure if the same price is formed over large geographic regions. However, even partial information on the SV may provide critical insights for policy and market design.

A high SV indicates a good match between what a technology provides and what the power system needs. For example, when a new VRE power plant generates during times of high electricity prices, this favourable situation will be reflected in a high SV of this power plant. In well-designed power markets, a generator will receive an above-average price for the electricity produced during these times.

The SV perspective provides crucial information above and beyond generation costs. Indeed, a comparison between the LCOE and the SV yields critical information for policy makers and other power system stakeholders. Where the SV of the VRE is higher than its generation cost, additional VRE capacity will help to reduce the total cost of the power system.

Figure 20. Illustration of the LCOE and SV



Source: IEA (2015b), *Next Generation Wind and Solar Power*.

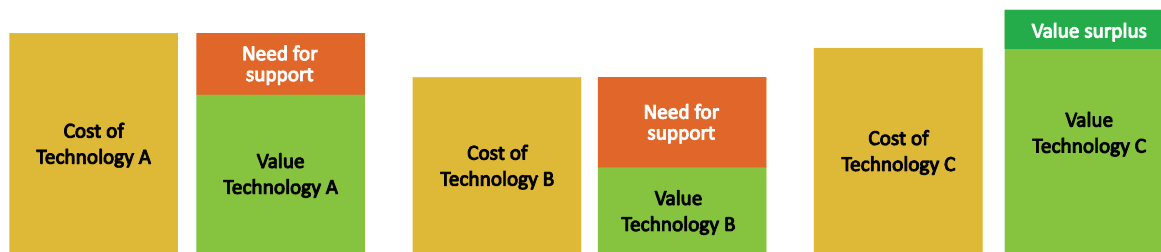
Both cost and value are relevant for assessing VRE.

Comparing the SV values of different technologies – and not just their LCOE values – provides a complete picture and a sound basis for policy design (Figure 21). In the example in the figure, Technology B has the lowest cost, but also has a low value – hence it would require the most support to trigger deployment. By comparison, Technology C has an intermediate cost but a high SV – its deployment would not require any support because an appropriate market design is in place.

A similar metric to SV was developed by the IEA for the 2018 *World Energy Outlook* (IEA, 2018a). The value-adjusted LCOE (VALCOE) is a new competitiveness metric for power generation technologies and was developed by building on the capabilities of the World Energy Model (WEM) hourly power supply model. It is intended to complement the LCOE, which only captures relevant information on costs and does not reflect the differing value propositions of technologies. VALCOE enables comparisons that take account of both cost and value to be made between variable renewables and dispatchable thermal technologies. The VALCOE builds on the foundation of the average LCOE by technology, adding three elements of value: energy, capacity and flexibility. For each technology, the estimated value elements are compared against the system average in order to calculate the adjustment (either up or down) to the

LCOE. After adjustments are applied to all technologies, the VALCOE then provides a basis for evaluating competitiveness, with the technology that has the lowest number being the most competitive (see IEA [2018a] for more details).

Figure 21. Links between the VRE cost, the SV and competitiveness



Source: IEA (2015b), *Next Generation Wind and Solar Power*.

More costly technologies can be optimal from a system perspective, if their SV is particularly high.

System-friendly VRE deployment

Wind and solar power can facilitate their own integration by means of system-friendly deployment strategies. That VRE is often not seen as a tool for its own system integration has historic reasons. Policy priorities during the early days of VRE deployment were simply not focused on system integration. Instead, past priorities could be summarised as maximising deployment as quickly as possible and reducing the LCOE as rapidly as possible. However, this approach is not sufficient for higher shares of the VRE. Innovative approaches are needed to trigger advanced deployment and unlock the contribution of VRE technology to facilitating its own integration.

Reflecting the SV in policy frameworks requires striking a delicate balance. On the one hand, policy makers should seek to guide investment towards the technology with the highest SV compared to its generation costs. On the other hand, calculating the precise SV can be challenging. This is principally because incomplete quantitative information is available to assess all the benefits and negative impacts, but also because the SV is a dynamic indicator that changes over time, implying also that the current and future SVs will differ.

In practice, exposure to short-term market prices can be an effective way to signal the SV of different technologies to investors. This is why the introduction of a functioning spot market in China should be an important priority. However, the current SV of a technology can be a poor reflection of its long-term value. This is due to transitional effects that can be observed in some countries where VRE has reached high shares. For example, in European electricity markets the combined effect of renewable energy deployment, low CO₂ prices, low coal prices and negative/sluggish demand growth (slow economic growth or energy efficiency improvements) led to low wholesale market prices in recent years. These low prices mean that any new type of generation will only bring limited cost savings and will thus have a low short-term SV.

Even where electricity demand is growing more rapidly, investments based purely on expected short-term wholesale power prices face multiple challenges. As wind and solar power are capital intensive, such challenges will directly drive up the cost of their deployment, possibly widening the gap between the SV and generation costs. In addition, current market price signals may be a poor indicator of the SV in the longer term. A similar effect would occur in China in the current context if economic dispatch and spot markets were introduced.

Mechanisms are therefore needed to provide sufficient long-term revenue certainty to investors for clean energy generation capacity. At the same time, such mechanisms need to be designed in a way that accounts for the difference in the SV between generation technologies. Strategies have emerged to achieve this. Two examples are market premium systems, which reward VRE generators that generate higher-than-average value electricity, and advanced auction systems, such as the model recently introduced in Mexico, which selects projects based on their value to the system rather than simply on generation costs.

German market premium system

The German market premium system moves beyond the fixed feed-in tariff system by increasing the exposure of VRE to real-time market conditions, while still providing sufficient revenue certainty. Hence, the system provides an incentive for more system-friendly deployment. The system consists of three components:

- **Reference price per MWh:** This can be determined either by administrative pricing or via a competitive bidding process. Germany moved from the former to the latter as the system evolved. The reference price corresponds to the revenue required for a wind or solar project to be financially viable.
- **Reference market value:** This is determined on a monthly basis as the weighted average of the spot price obtained per energy source, i.e. for wind or solar power. The crucial point is that this reference is calculated for the output of all wind and solar PV plants. Hence, it corresponds to the market revenue of the average plant.
- **Market premium:** This is the top-up that all generators receive; it is determined on a monthly basis as the difference between the reference price and reference market value. For example, if the reference price is EUR 60/MWh and the reference market value is EUR 32/MWh, then the premium is EUR 28/MWh.

The incentive for a more system-friendly development arises from the following: a plant located at a site that allows it to generate during times of higher electricity prices (thus, a plant that has a higher system value) will receive higher market revenues than the reference market value. However, the premium it receives is the same as for all plants of the same technology. Consequently, it can earn a higher profit. Taking the example from above, a plant that receives EUR 35/MWh from the market would receive EUR 63/MWh in total. Investors are now increasingly aware of the difference in value depending on when wind turbines generate. Specialised consultancies provide data on locations where the wind blows during times when the value of electricity is particularly high.

Mexican clean energy and capacity auctions

Mexico has developed an auction system that seeks to minimise the cost of support for low-carbon technologies by focusing on the SV of technologies competing in the auction. In this system, low-carbon technologies eligible for support comprise renewables, nuclear energy, the additional energy created by highly efficient co-generation in industrial process, and carbon capture and storage. These technologies receive a Clean Energy Certificate per MWh generated, which are turned over to the energy retailer that purchases the power. Retailers are then required to present these Clean Energy Certificates to the regulator as proof of compliance with Mexico's clean energy standard.

The Mexican auction system was developed to account for the high revenue uncertainty of renewable energy. It also reflects the fact that while Mexico has a large renewable endowment of wind, solar and geothermal resources, these resources do not each produce the same value for the system. For instance, geothermal and hydro are dispatchable technologies, while wind

and solar PV are not. Solar PV, which was more expensive at the time the first auction was conducted, could produce energy during moments of high demand, avoiding the use of expensive “peaker” plants in the system and providing capacity value in the years following solar PV deployment.

It should be noted that these considerations about value and the LCOE of specific assets will change over time, in an uncertain way. Some technologies can reduce their costs faster than others. Also, the value provided to the system can change as the shape and size of demand evolve, or if too much of one technology is deployed in a single region.

The solution is a technology-neutral auction with a system that incorporates premiums and penalties in the bids, so that different technologies can make comparable bids.

These premiums and penalties are based on the expected value of energy over the next 15 years and are of two kinds:

- Location – the country is divided into 51 power regions, and a penalty or bonus is calculated according to the average difference between the value of the energy in that region and the rest of the country.
- Time of day – a penalty or bonus is included for energy being available at different times of the day.

The following features are incorporated to make the auction as flexible as possible:

- Three different products are sold: energy, Clean Energy Certificates and dispatchable capacity. Generators are not obliged to sell all three, and they can choose to sell only one.
- The auction is held three years in advance of the expected delivery date, although developers can propose different deliverable dates within certain limits.
- Developers can make bids conditional on the acceptance of other bids, which allows for the development of large projects.
- Projects do not have priority on the grid access just because they win the auction. However, in a congested area, those who have completed the interconnection procedures are given priority in the auction.

The auction compares all the bids and a replicable algorithm chooses the bids that minimise the “adjusted” cost to the buyers – including the value that the plants will generate. This allows “expensive” plants (on a cost basis) to be chosen if they produce more value (i.e. they are located in a region with expensive energy, or produce energy at an expensive time of day).

Pricing of externalities

Price-based instruments aim to internalise the societal costs of environmental degradation, climate change or air pollution – caused by energy production – in the planning and operation of electricity generators according to the polluter pays principle. Price-based instruments can achieve environmental targets in a cost-effective way. However, they should be part of a coherent policy package, including a pricing optimisation framework that harmonises incentives. Often this entails removing existing fossil fuel subsidies, which can increase the costs associated with the externalities that are targeted by price-based instruments.

Climate change policy can place a cost on CO₂ emissions. Market-based approaches can be categorised into carbon taxes (direct CO₂ tax; input or output charges) and emissions trading systems (ETSs). When optimally defined, both approaches have the same objective and impact.

However, a carbon tax creates a predictable price of CO₂, whereas an ETS³⁸ puts a cap on emissions and hence creates certainty on the emissions reduction trajectory that is agreed upon in the decision-making process under fluctuating carbon prices.

A carbon tax is easier to implement, but an ETS has the advantage of creating abatement incentives where they are most cost-effective. As emission allowances can be traded for the market price of CO₂, the allowance price sets the threshold below which it is economic for actors to invest in emission reduction options (resource efficiency, low-carbon generation or carbon capture utilisation and storage) (Hood, 2011). In other words, those with a marginal abatement cost below the market price of CO₂ will sell permits (if any) and invest, and those with a marginal abatement cost above the market price of CO₂ will buy permits up to the point that the market price of CO₂ matches their abatement cost (Fan et. al., 2017).

Impact of CO₂ pricing on daily and long-term operations in the power market

Carbon pricing has profound effects on power sector development. It increases the cost differential between low- and high-carbon generation assets by adding a marginal cost to the operation of the latter. In competitive electricity markets with a sufficiently high carbon price, this will incentivise a clean dispatch of the existing generation fleet, accelerated decommissioning of carbon-intensive assets, low-carbon investment, demand-side response and clean-technology innovation (Acworth et al., 2018).

The primary mechanism plays out in the daily (or hourly) dispatch of generation sources: the added marginal cost of CO₂ pushes carbon-intensive generators down the merit order when passing on these costs to consumers. As a result, the capacity factor of high-carbon assets decreases to the benefit of low-carbon generators, who receive more generation hours based on their lower bidding price. The cost of CO₂ pushes the wholesale price up during hours when fossil fuel plants are dispatched, partly offsetting the downward pressure on wholesale prices by low marginal cost (renewable) generation and increasing the returns on low-carbon assets. The immediate effects of carbon pricing are seen in a higher utilisation of low-carbon generation in the existing generation fleet. In the longer term, a deteriorating business case for operating high-carbon assets will accelerate the decommissioning of these generation plants.

Depending on the price level, carbon pricing creates a strong signal for low-carbon investment in the power generation fleet. Fossil-based generators are incentivised to shift production to low-carbon sources when their short-term marginal operating costs surpass the long-term marginal cost of investing in new assets (Guivarch and Hood, 2010). Moreover, new producers might opt to start investing in low-carbon electricity generation directly, especially when the policy framework indicates that the price of CO₂ is going to rise further in the future.

Under an ETS, even with declining emission caps, allocation mechanisms can provide carbon-intensive generators with time to adjust to new market conditions. As allowances are tradeable commodities with a market value, free allocation of allowances provides fossil fuel plants with implicit capacity payments (while ensuring clean dispatch effects due to the cost pass-through in short-term power markets). In the EU ETS, the share of free allocation in the power generation sector has gradually declined and allowances are fully auctioned since the start of Phase III in 2013.³⁹

³⁸ ETSs discussed in this section are limited to cap-and-trade systems. Note that China's national ETS, in its initial phase, differs and is more similar to a tradeable performance standard (TPS).

³⁹ An exception is made for the eight member states who have joined the European Union since 2004, and who can make use of a transitional period until 2019. (European Commission, 2018).

Policy packages and interactions

At moderate levels, carbon prices can lead to shifts towards lower-carbon options in dispatch and a change in fuel inputs. If carbon prices remain moderate, complementary policies are needed to promote the retirement or (carbon capture and storage) retrofit of unabated fossil-fuel generation and guide investment decisions to low-carbon technology development (IEA, 2017b). Policy options include efficiency performance standards, renewable portfolio standards or support measures, and government funding for clean technology research, development and demonstration, parallel with optimising pricing by removing fossil fuel subsidies. These policies can serve multiple functions besides emission reductions, such as increasing competitiveness in certain technologies and decreasing electricity costs in the long term.

Overlapping energy and climate policies have to be addressed in the design of ETSs. In principle, any energy policy that results in emission reductions should be accounted for in the ETS cap setting.

Electricity sector design

The effectiveness of carbon pricing depends heavily on the electricity market design. In general, more heavily regulated electricity sectors constrain the efficient functioning of a carbon price. However, additional regulatory measures can be implemented to imitate the effects a carbon price would have under competitive market circumstances.

In China, administratively set wholesale prices and the fair dispatch rule constrain an effective functioning of a carbon price by limiting cost pass-through and dispatch flexibility. In order to make the carbon price signal visible when market reforms are not feasible in the short term, additional regulatory measures would have to be implemented that have a comparable effect.

Box 18. ETSs in China

Having gained experience with ETSs since 2013 through several pilot programmes in seven regions (five cities: Beijing, Shanghai, Tianjin, Shenzhen and Chongqing; and two provinces: Guangdong and Hubei), China launched its national ETS in late December 2017 (NDRC, 2017). Allowance allocation rules are defined at a national level, will apply identically to all provinces and are currently in a drafting process. They are set to be adopted by 2019. The ETS covers only CO₂ emissions, which make up more than 80% of China's total greenhouse gas emissions.

In Phase I, the ETS covers only firms in the power and heat sectors that use more than 10 000 tonnes of coal equivalent each year (~26 million tonnes of CO₂). According to these rules, roughly 1 700 power plants are obliged to participate in the system, together accounting for an estimated 3.3 gigatonnes of CO₂ (GtCO₂) emissions annually (37% of China's total CO₂ emissions in 2016), making the Chinese system the largest ETS in the world (ICAP, 2018).

During this initial phase, implementation efforts focus on developing the market infrastructure of the ETS (monitoring, reporting, and verification [MRV]). Simulation trading will commence for the electricity sector in Phase II, and a deepening and expansion of the ETS will follow in Phase III (post-2020). In the latter phase, eight sectors are to be included in the system (power and heat, construction, iron and steel, non-ferrous metal processing, petroleum refining, chemicals, pulp and paper, aviation) and emission standards are likely to become more

stringent. With all eight sectors included, the China ETS will cover roughly half of the country's CO₂ emissions, with an estimated 6 000 firms participating (Pizer and Zhang, 2018).

The China ETS follows a different design than that in the European Union and systems used in the United States. Allowance allocation and standard setting are based on output and technology, using sectoral benchmarks, with free allowance allocation in the initial phases. There is no fixed cap in place, with output-based allocation being instrumental in creating extensive data networks for cap setting in later stages. As administratively set prices in China's power sector limit the possibility for cost pass-through, the ETS is also going to include indirect emissions from electricity consumption.

In its current form, the China ETS resembles a tradeable performance standard (TPS) with technology-specific intensity standards. Since subcategorisation creates incentives for intratechnology efficiency improvements, but does not stimulate technology switching, which can lead to less cost-efficient emission reduction outcomes (Pizer and Zhang, 2018), the number of fuel standards will be limited, with higher stringency for coal than for gas-fired power plants. Contrary to a cap-and-trade system, which puts a positive price on all CO₂ emissions, a TPS only prices emissions surpassing benchmark levels, which can result in lower carbon prices. However, in the long term, the objective of China's ETS is to cap national CO₂ emissions and achieve emission reduction targets for all eight sectors in line with China's Ecological Civilisation vision. Low carbon prices and free allocation are likely to be features only in the initial ETS phases in the next few years, with the potential for the TPS to be replaced by a cap-and-trade system after China's emissions have peaked, which it aims to achieve before 2030.

The development of China's ETS is, furthermore, set to follow reforms that are planned for the electricity sector, as alignment between both is critical to an effective functioning of the ETS. Whereas China's ETS policy is nationally determined and applicable to all regions, electricity sector reform is developed and implemented at provincial level. This division in jurisdictional authority can pose added complexities when provinces opt for electricity sector designs that have different outcomes on the incentives for electricity generators (low-carbon and carbon-intensive generation) and consumers under a carbon pricing system. This will be a key area for China to focus effort on once electricity sector reforms are being implemented and the ETS is maturing.

Sources: ICAP (International Carbon Action Partnership) (2018), ICAP ETS Map, <https://icapcarbonaction.com/en/ets-map>. NDRC (2017), 全国碳排放权交易市场建设方案（发电行业） Construction Plan for the National Carbon Emission Trading Market www.ndrc.gov.cn/qzdt/201712/W020171220577386656660.pdf. Pizer and Zhang (2018), "China's new national carbon market", NI WP 18-01, Nicholas Institute, Durham, NC, <https://nicholasinstitute.duke.edu/publications/chinas-new-national-carbon-market>.

Retail markets and distributed energy resources

Retail pricing reform

Driven largely by the many changes described in this report, reforms in retail rate design are being pursued in many jurisdictions (IEA, 2016a).⁴⁰ At the same time, advances in information

⁴⁰ The discussion in this section is taken from IEA (2017a).

and communications technology (ICT) have lowered the transaction cost of communicating prices for energy and other utilities more dynamically, which opens opportunities for introducing more cost-reflective pricing structures with higher levels of granularity.

A growing number of end users now have an alternative to grid supply, and they use retail tariffs as a reference to make investment decisions. As the cost of distributed energy resources (DER) continues to decline, uptake will continue to rise.

At low penetrations, this effect is likely to have marginal impact on retail prices (LBNL, 2017). As DER uptake continues, however, this situation raises questions about distributional fairness among different end users, and may lead to a spiralling uptake of DER as grid supply price increases continue to improve the economics of self-supply.

In addition, sector coupling will link economic signals from other sectors with those of the electricity sector, and make it possible to meet a certain energy service using various sources. For example, customers may choose between using electricity (via efficient heat pumps) or natural gas for heating, or they may choose between electric or internal combustion engine cars. This increases the need for a level playing field between the different resources, whereby energy services are priced similarly and are subject to similar taxes and levies.

Finally, DER may provide system services that are not captured at all in current tariff design. This creates a need not only to consider reform of retail tariffs, but also of valuation frameworks for DER more broadly. Both aspects will be discussed in turn.

When approaching retail pricing reform, a number of relevant trade-offs and distinctions need to be made. End customers – especially residential and small commercial – often do not have the expertise and/or the interest in navigating a complex pricing structure that may expose them to wholesale market risk. However, making it possible for retailers and aggregators to access the differences in value of electricity by time and location can be critical for unlocking the full contribution of DER.

Degrees of granularity for retail tariffs

As DER generation options become cheaper, retail prices should be designed to provide fair and appropriate incentives to both network users and DER (IEA, 2016c). With modern ICT systems and emerging valuation methodologies, it becomes possible to calculate in greater detail the actual value of a given kilowatt hour (kWh) of electricity consumption at a specific time and place. The deployment of smart meters makes it possible to communicate this value to end users and use data measurements at more regular intervals to apply them in the billing process. Price signals that accurately capture the impact on overall system cost give a stronger incentive for demand shaping when and where this is most valuable to the power system.

Retail prices can be refined along three dimensions (Figure 22). First, to indicate the supply-demand balance throughout the day, tariff design may move from a single, flat tariff to various degrees of time dependency. Real-time pricing, the most advanced form of time-based pricing, has been applied in Spain since 2014, although consumers can opt out and subscribe to other supplier or contract structures (IEA, 2016d).

In addition, demand charges can reflect the contribution of an individual customer to overall generation and network costs. The precise characteristics of electricity consumption, such as the timing and magnitude of peak electricity demand, will influence the timing and location of grid planning and reinforcement.

The third dimension relates to the geographical location of consumption. The cost of delivering power to end users depends on transmission and distribution losses, and on the occurrence of congestion and voltage-related network constraints (Schweppe, 1988). The options for

translating this spatial cost granularity into electricity prices range from regional tariff differences to more precise, real-time calculations of locational marginal pricing that reflect how a customer is located relative to the various grid nodes.

Figure 22. Options for retail pricing at different levels of granularity

	Granularity				
Time - Energy	Flat tariff	Seasonal time-of-use (summer/winter)	Daily time-of-use (weekday/weekend)	Intra-daily time-of-use (peak/off-peak hours)	Real-time pricing
Time - Demand	No demand charge	Customer peak	Expected system coincident peak, annual	Expected system coincident peak, monthly	Real-time coincident peak
Location	Single price	Zonal disaggregation	Nodal disaggregation	Locational marginal price (LMP)+Tx losses	LMP +Tx/Dx losses

Notes: Tx = transmission; Dx = distribution; LMP = locational marginal price.

Source: IEA (2017a), *Status of Power System Transformation 2017: System Integration and Local Grids*.

Retail electricity prices can be refined along three main dimensions.

Compensating DER

The methodology for compensating DER, in particular distributed generation, is a strong driver for uptake of these technologies. As far as distributed generation is concerned, setting the right level and structure of remuneration for grid injection is a complex undertaking with important implications. If set too high, a disproportionate amount of money will flow to DER owners; if too low, compensation might be unfair to DER owners. Fixed remuneration (per unit of energy) provides investment certainty, whereas variable pricing can more effectively encourage system-friendly choices that maximise injections during hours of higher system demand.

Pricing and compensation for DER goes beyond generation options and includes incentives for energy efficiency, demand-side response and battery storage. In this report, the focus is on pricing of distributed solar PV, given the novelty of this option in China. However, this does not mean that other options are less relevant and similar principles apply to all DER.

Traditional compensation mechanisms, such as net energy metering, were designed on the supposition that the grid can act as a buffer for the differences in timing of electricity production and consumption of individual households. Household production and consumption are brought together on the final electricity bill. Under net energy metering, localised electricity production is implicitly valued at the rate of the variable component of the retail tariff, as the household can bank production both within and between billing periods (IEA, 2016c).⁴¹

Net billing applies a similar method, whereby injected surplus electricity is deducted from the electricity bill at a predetermined rate. This can be a fixed rate or it can be time and location specific. In jurisdictions where a large proportion of retail tariffs consists of volumetric rates, net energy metering has come under pressure as DER owners are able to disproportionately offset their contribution to network cost. A third compensation mechanism for DER is the feed-in

⁴¹ Under net energy metering, banked kWh credits may eventually expire. When this occurs, they are deemed “net excess generation” and are typically credited to the customer at a predetermined rate, usually set between the avoided utility wholesale energy cost and the retail electricity rate.

tariff. In this arrangement, all electricity injected into the grid is compensated at an administratively determined rate.

Many jurisdictions are shifting to other, value-based methods of compensation for decentralised generation (see IEA, 2017a, Chapter 2). Methods for such value-based compensation for DER generally fall into two categories. The first category involves taking a snapshot of current DER value, and then providing a long-term compensation guarantee based on that.

A value-of-solar (VoS) tariff assigns fixed price tariffs based on an assessment of value components, including energy services, grid support and fuel price hedging, among others (Figure 23). Minnesota became the first US state to adopt a VoS tariff, with a 25-year inflation-indexed tariff that was determined through benefit-cost analysis and an extensive stakeholder consultation process (Farrell, 2014).

The second category of value-based DER compensation involves more granular DER tariffs that reflect market conditions at specific times and locations. Adding price variability based on time and location can contribute to lower system costs by sending appropriate price signals to DER customers.

Figure 23. Value components of local generation

Energy services	Avoided capacity	Grid Support	Financial	Additional benefits
<ul style="list-style-type: none"> ■ Energy ■ Transmission and distribution losses 	<ul style="list-style-type: none"> ■ Generation ■ Transmission and distribution 	<ul style="list-style-type: none"> ■ Reactive power ■ Voltage control ■ Frequency support ■ Operating reserves 	<ul style="list-style-type: none"> ■ Fuel price hedge ■ Market price 	<ul style="list-style-type: none"> ■ Grid security ■ Environmental/carbon emissions ■ Socio-economic development

Note: Depending on deployment scenario, the value components may be negative; for example, if deployment of distributed solar PV leads to grid upgrade requirements, it would contribute to increasing rather than decreasing capacity costs.

Source: IEA (2017a), *Status of Power System Transformation 2017: System Integration and Local Grids*.

Accurately rewarding DER requires a detailed analysis of the various value components.

Implications for general policy design

Recognising temporal and spatial value in the pricing of electricity supply and demand can foster greater flexibility and lower the cost of planning and operating a power system. When implementing more efficient short-run pricing, however, it is important to consider the trade-offs that determine the effectiveness of any new tariff design.

First and foremost, regulatory design needs to balance the costs and benefits of higher granularity. Computation and implementation are the primary cost drivers when adopting higher price granularity. Whereas the pass-through of wholesale prices or LMPs calculated at the interface with high-voltage networks can be achieved by a rollout of advanced metering equipment, the use of more precise LMPs requires additional time and resources as considerable ICT capabilities are needed to verify cost calculations (MIT, 2016).

Moreover, customers, regulators and third parties all benefit from simplicity. If consumers are to adapt their behaviour in line with system needs, they must understand the applicable tariff. Alternatively, an intermediary (aggregator, retailer) can offer a simple tariff to the consumer, while monetising the value to the system as a whole.

The same goes for the granularity of DER compensation, which comes with the cost of advanced metering and billing systems, and can muddle the value proposition for risk-averse DER customers that do not understand energy market dynamics. Again, here aggregators can play a crucial role. In Germany, virtual power plants are used to aggregate many DER systems and sell their cumulative excess power in real-time electricity markets. This improves the overall responsiveness of small-scale DER to market signals, as more of the available flexibility is used. At the same time, the balancing responsibility is shifted away from individual DER customers to aggregators who can better manage this risk on the basis of a portfolio of DER clients.

Regulators also benefit from simplicity, both in the initial rollout of new rules and also in the ability to change them as they learn about the effectiveness of the rules.

Accurate pricing of both supply and consumption will steer operational and investment decisions in the direction that best matches the evolution of local grids. At some point, however, a more comprehensive overhaul of the governance structure will also be needed to enable successful power system transformation across all sectors.

Revisiting roles and responsibilities

The fundamental changes being observed in power systems call for a more systematic revision of the historical institutional structure. The reliable operation of local grids today requires enhanced co-operation between grid operators across voltage levels, on issues including grid congestion management, real-time grid monitoring, prioritisation of operational decision making, balancing and operating reserves, voltage support and improved co-ordination in case of unforeseen system events (ISGAN, 2014).

The DSO-TSO interface

One particularly important aspect in this institutional transition is the definition of the so-called TSO-DSO interface (DSO stands for distribution system operator). One of the main questions dealt within this is the allocation of ancillary service responsibility – for example, whether DSOs should be in charge of balancing their own distribution grid or contracting particular services for local congestion relief and balancing (Madina et al., 2018). An additional point that falls under the TSO-DSO interface discussion relates to data collection and sharing. The widespread adoption of advanced metering infrastructure is leading to a rapidly growing amount of data that can be valuable for system operation and planning, and commercial offerings. Especially in the context of more active management of the distribution level, this data is critical. The question of network visibility is particularly relevant in the face of market-driven adoption of DER, and can be addressed early on through the inclusion of monitoring technology in interconnection requirements and enabling or requiring data sharing between DSOs and TSOs.

It is important for policy makers to enable and co-ordinate the discussion regarding new data collection procedures and responsibilities. In Germany the 2016 Law for the Digitalisation of the Energy Transition was a good example of the broad range of aspects for consideration, including metering requirements, data-sharing processes and security requirements. Denmark provides an additional example of restructuring the TSO-DSO interface. Further to the creation of an electricity system operator (ESO), Denmark has also established a separate “DataHub”, accessible to all power sector participants. In this case, the separate creation of a data hub was seen as a solution to enable competition within the electricity market, particularly by countering information asymmetries between the retail arm of grid companies and independent retailers (Box 19).

Box 19. The role of data exchange platforms in changing power systems

The emergence of a greater number of grid-connected devices and new power system needs is also driving the establishment of data exchange platforms. A recent review by THEMA Consulting (2017) looks at the various models for data exchanges and how they fit in the context of more diverse stakeholder engagement in the power system.

Whether decentralised or centralised, data exchanges are aimed at removing barriers to entry for new actors, such as independent retailers or aggregators, improving efficiency in data management and empowering consumers.

Similar to the role of the system operator, data exchanges should observe full neutrality to ensure non-discriminatory data access and delivery. Here it should be noted that neutrality does not mean full open access to all data, but that actors with a legitimate need and authorisation should have access.

Across Europe, countries such as Denmark, the Netherlands, the United Kingdom, Ireland, Italy and Estonia have established centralised data platforms, while Sweden, Norway, Finland and Spain are in the process of implementing them. Some centralised platforms allow consumers not only to see their data, but also to authorise third parties, such as retailers or aggregators, to access their data. While it is necessary to have clear privacy and data ownership guidelines, this may help third-party providers to develop new service offerings for demand response and energy efficiency.

One key aspect of centralised data exchange platforms relates to the issue of governance, as it requires the sharing of responsibilities between TSOs and DSOs, as well as establishing data-sharing protocols.

Source: THEMA Consulting https://docstore.entsoe.eu/Documents/News/THEMA_Report_2017-03_ES_web.pdf.

Aggregators

One notable change in the evolving landscape of stakeholders involved in the power system is the emergence of aggregators. In unbundled markets, aggregation allows the co-ordination of a number of smaller DER and their participation in balancing, ancillary service and wholesale markets. By jointly operating DER as virtual power plants, aggregators enable both minimum volume requirements and dispatch profile requirements to be side-stepped.

Depending on their nature, aggregators may be able to engage in serving a number of flexibility needs. Commonly small companies using proprietary software, independent aggregators have been a driver in the development of DER markets. On the demand side, their ability to engage a greater variety of low-cost resources can prove to be a cost advantage in the ancillary services market, outcompeting expensive peaking plants in the provision of reserves.

End consumers offering their flexibility through aggregation platforms may see benefits such as substantial reductions in network charges, or a fixed additional revenue source for offering their availability. In this case, the revenues from offering flexibility to aggregators need to offset a range of additional costs, the nature of which will vary depending on the type of resource. Even larger consumers may gain from the benefits mentioned above without increasing operational or administrative burdens.

Retail companies, whether independent or integrated with distribution or generation, may wish to provide aggregation services for a number of uses, such as ancillary service provision and reduction in imbalance costs. In this case, such companies may have easier access to a pre-existing customer base and be able to pass on savings through bill reductions. In liberalised markets, retail companies' access to the wholesale market may also enable them to obtain additional resources for arbitrage. These advantages, however, need to be balanced against the impact this may have on competition or the engagement of a broader pool of resources.

One particularly important point regarding the participation of aggregation in the market relates to the allocation of balancing responsibilities. In markets where balancing responsibility is assigned only to market participants, independent aggregators may be exempt from any imbalances caused during ancillary service dispatch. By contrast, retailers would be responsible for imbalances within their control area. The perception of unfair allocation of additional cost may be a cause of concern for established market participants in the absence of a clear procedure for imbalance settlement. In this case, policy makers and regulators should engage in stakeholder discussions to appropriately gauge the magnitude of such potential imbalances and the potential settlement procedures.

Role of ISOs

The emergence of an ISO is becoming more common outside the liberalised North American markets. In recent years, both the Danish and British power systems have unbundled their TSO into a separate network operator and an ISO, also known as an electricity system operator. This results, in part, from the increasingly active role of the system operation in managing a wider array of flexibility requirements and products for procuring flexibility, in the context of non-discriminatory network access and cost efficiency.

At the distribution level, the most important development entails the emergence of DSOs who, rather than simply owning and maintaining the grid, intend to play an active role in managing the increasing load from DER. As distribution network operators (DNOs) transition to DSOs, they may be able to procure specific ancillary services locally, such as balancing or voltage regulation, either to facilitate wider system operation or to defer the need for local network reinforcements. Distribution network ownership and distribution system operation are soft-linked within the same box as they are typically still bundled within the same company.⁴² This, however, may not necessarily be the case. Similarly, at the transmission level, a TSO that also makes a profit from building new transmission lines may face a conflict of interest when making proposals for planning flexibility enhancements.

Centralised and decentralised platforms for DER engagement

When looking at local markets for flexibility, one very important aspect is the procurement mechanism of choice and how this influences liquidity. As with typical wholesale markets, liquidity is important to ensure that there are enough physical assets, with the appropriate dispatch parameters, to meet the local system's needs cost-effectively.

Centralised, single-buyer flexibility markets take on a variety of shapes. For example, while utilities in New York State rely on directly contracting projects and implicit demand response; in Spain ENDESA's proposed model relies on regular day-ahead auctions, where aggregators and loads bid their capacity to meet the DSO's profile balancing requirements. UK Power Networks offers an additional interesting example of identifying the need for local flexibility and opting

⁴² Note that in some liberalised markets, the function of metering has been recognised as a separate activity from retail and distribution, but is still typically housed within the same company.

for either competitive procurement of DER, bilateral contracting for demand response, or capital investment in new infrastructure depending on the ratio of local DER liquidity to investment costs at their three voltage levels.

Interest is growing in decentralised peer-to-peer exchanges, enabling direct interaction between local producers and consumers of energy. This field has seen increased attention in recent years, driven by technologies such as blockchain, and is often referred to as transactive energy or the “energy Internet of things”. The models vary widely, from optimising and aggregating the consumption of single appliances for demand response to enabling secure decentralised transactions between individuals, while providing critical visibility to grid operators. At their core, many transactive energy systems build on the understanding of standardised data exchanges to provide a common structure to energy exchanges happening throughout the grid and at vastly different scales.

Elements of structural reform

Regulators and policy makers are beginning to grapple with the challenge of capturing the various changes happening as a result of DER and are setting up institutional structures that are fit for purpose. Many stakeholders – from grid operators to aggregators – are arguing that the changing needs and technical possibilities of local grids require the identification and assigning of new roles. Often, however, they do not agree on what form the preferred new arrangements should take.

For example, digitalisation introduces a new role into the structure of electricity markets, related to the ownership and management of data. The creation of a forum for data exchange represents a key challenge for successful power system transformation. If the ownership and management of data flows are centralised, one party would be designated to ensure the provision of a safe depository for metered customer data and data on network operations and constraints. This party ensures that eligible third parties enjoy non-discriminatory access to this data, and facilitates communication of information to end customers about their energy use and production (MIT, 2016).

The assignment of this vital task in future power systems will be a key decision for policy makers in the process of power system transformation. In Denmark, the TSO (Energinet.dk) was designated this role, whereas in the United Kingdom and Australia an accredited third party is responsible for data management. An alternative, decentralised solution could circumvent the need for a single “data hub operator” and instead rely on a network of computers to secure and verify data flows and transactions.

Many reform initiatives focus on evolution of the role of local grid companies. In the European context, regulatory reforms aim to transform local grid operators into neutral facilitators of electricity markets at the local grid level, where DER can offer energy and system services on a level playing field (European Commission, 2017). A similar approach is being taken as part of the “Reforming the Energy Vision” process in the state of New York. Integrating a revised institutional structure for local grids into an overall governance framework for the energy system remains a field of active research.

The scope and depth of such institutional reconfigurations are substantial. The interdependent nature of various elements of reform implies that delays in one area may reverberate throughout the overall transformation process. Indeed, rates of progress on various reform programmes demonstrate the difficulty of aligning the interests of a wide number of stakeholders, while also supporting grid operators and utilities as they evolve towards their projected new roles in future energy systems.

Nonetheless, the rationale for power system transformation in local grids remains. In a process of continuous learning, policy and market reform will continue to unlock the potential of intelligent technologies, innovative business models and increasingly empowered end users that could well drive the decentralisation of electricity supply.

Policy principles for DER

- **Reform tariffs to encourage system-friendly investment in and use of DER:** Making time-of-use tariffs accessible to a wider array of consumers may be a useful way of encouraging improved use of DER. It is critical to balance tariff simplicity and accuracy of the economic signal. Aggregators and retailers have a critical role in helping to achieve this balance. Attention should be paid to limiting the impact of tariff reform on lower-income consumers. Tariff reforms may also free up public finances to engage in targeted programmes to tackle energy poverty.
- **Promote and require digitalisation and connectivity:** One prerequisite for visibility and control across the power system is the availability of appropriate real-time monitoring systems with bidirectional communication across grids, loads and generation. The exact implementation depends on the size of asset or process to be managed and needs to balance the cost of communication infrastructure with achievable benefits.
- **Enable technology neutrality for the provision of flexibility:** Prequalification requirements, such as minimum volume, derating methodologies, minimum response time or aggregation thresholds, may implicitly provide an advantage for existing inefficient assets. System operators, regulators and policy makers should review the match between current requirements and the technical capabilities of new system resources.
- **Establish procedures for open and secure access to power system data:** Greater monitoring and computing capabilities present an excellent opportunity for constant improvement of power system operation and the development of new business cases. Allowing access both to power sector participants and researchers may assist policy makers in identifying new areas of opportunity. In any case, clear security protocols to avoid data breaches should be put in place.
- **Provide regulatory incentives for efficiency, automation and innovation in network management:** The introduction of budget bonuses for the deployment of advanced technologies may assist network owners to modernise the grid infrastructure and improve operations. Such programmes can help extract flexibility from the networks even in a restructured context where grid business is separated from system operation.
- **Co-ordinate synergies with the ICT sector:** Reliable, secure and fast communications are necessary to ensure that increasing integration with ICT meets the reliability and response requirements of the power grid. As such, there may be overlaps in the regulation of telecommunications and the energy sector that need to be managed to ensure cost-effectiveness, security and network access.

Upgraded planning frameworks

Power sector planning is an inherently complex process due to the long planning horizon and is subject to a range of drivers that are highly uncertain. Further complexity results from planning consisting of a number of activities that are undertaken by multiple groups and jurisdictions for a given power system (Cochran et al., 2012).

Traditionally, the primary focus of power sector planning was on expanding supply infrastructure (generation, transmission and distribution networks) to meet projected electricity

demand, based on assumptions of economic growth over the next 20 to 30 years. However, with the changing landscape of the power sector, due to increasing deployment of VRE and other new technologies such as DER, as well as increasing consumer participation, planning for a future power system needs to become more sophisticated by taking into account the role and impact of these developments.

Better integrated and co-ordinated planning frameworks can help identify appropriate options for future power systems. The process should take into account questions of flexibility and reliability, and how different supply- and demand-side resources can play a role in successful integration of VRE, providing a pathway for power system transformation.

Co-ordinated and integrated planning encompasses a number of elements, which can be broadly grouped into the following:

- integrated planning, incorporating demand resources
- integrated generation, transmission and distribution planning
- cross-sectoral planning between electricity sectors and other sectors, particularly heating and cooling and transport
- planning across different regions, jurisdictions and balancing areas.

Integrated planning incorporating demand-side resources

This aspect of integrated planning relates to a planning process that takes into account demand-side resources.

The potential role of the demand side is often overlooked in power sector planning. Demand-side response (DSR) can be considered as part of the suite of DER that can provide valuable services to electricity systems. DER include distributed generation, flexible demand, energy efficiency, storage and other resources.

Appropriate DSR can achieve various benefits, including smoothing the variability of VRE and maintaining system reliability by providing fast response services. It can also play a major role in deferring or avoiding investment in generation and networks. Demand-side management (DSM) options encompass a number of possible interventions, from energy reduction programmes to active load management (IEA, 2014a).

Co-ordinated planning across supply and demand resources can take into consideration the locational value of energy, which helps identify the most advantageous areas for the development of VRE technologies.

Box 20. PacifiCorp's Integrated Resource Plan

PacifiCorp, a utility operating across six states in the Northwest of the United States, has integrated energy efficiency and dispatchable demand-side response programmes into electricity planning under its Integrated Resource Plan (IRP). They are assessed as a supply resource, allowing them to be compared with other supply options in the IRP model.

This has led to cost-saving energy efficiency measures that accounted for a large proportion of electricity supply in the final IRP.

Source: Wilson and Biewald (2013), *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans*.

Integrated generation and network planning

The integrated planning approach optimises resources across an entire network, resulting in a number of benefits from reliability, economic and environmental perspectives. Historically, power system planning, as carried out by vertically integrated regulated monopolies, was typically well co-ordinated, resulting in low levels of congestion.

In jurisdictions with a restructured market, however, co-ordinated planning is typically more difficult (IEA, 2016c). This is often due to generation, transmission and distribution planning being conducted independently in separate processes, since they are managed by different electric utilities. As a result, expansion in generation, transmission and distribution is less likely to align, possibly resulting in ineffective outcomes.

This issue is magnified as the level of VRE deployment increases, since development of VRE projects often outpace changes in other elements of the power system. Geographic concentrations of VRE in areas with the highest-quality resource can place a burden on the local transmission grid and lead to transmission congestion, which ultimately drives up the cost of delivered electricity.

The issue is relevant for both the transmission and distribution networks, where the addition of new VRE may change traditional energy flows and the use of the grid, and connections to local grids may challenge the usual distribution operations. A VRE project can be developed relatively quickly compared to the development of grid infrastructure. This was the case in Brazil, where 300 megawatts (MW) of wind generation capacity was unable to connect to the grid at the end of 2015 due to limited transmission capacity (Epoca, 2016).

Renewable Energy Development Zones (REDZ) are an example of a planning approach that considers generation and transmission expansion. The state of Texas pioneered this approach in 2005 by implementing a systematic process between regulators, renewable energy developers, policy makers and other relevant stakeholders. During the process, a number of preferential development zones are identified that combine good resource quality and developers' interest. These zones are then included in grid planning and cost recovery is ensured for the required grid investment, even before wind power plants have made a request for connection. In turn, this gives certainty to developers that infrastructure will be available in the zones, thus solving the chicken-and-egg problem of transmission only being permitted if there is generation and generation only being built if there is transmission. Developers are then selected for the different locations on the basis of a competitive bidding process (NREL, 2017).

In addition to integrated planning, procurement strategies can provide financial incentives to prospective VRE plants based on location and/or time of production to promote system-friendly deployment.

Integrated planning between the power sector and other sectors

Integrated planning that spans the power and other sectors is a growing field in energy system integration. Historically, planning across different sectors was thought to be relevant only for the electricity and gas sectors, since gas is one of the main fuels for electricity generation in many countries. However, even power and gas planning has been carried out separately in many countries due to a number of challenges, particularly from institutional and regulatory perspectives.

Efforts have been made in many jurisdictions to link the planning of electricity and gas. In the European Union, the European Commission has encouraged electricity planners to work with gas partners in ENTSOG (European Network of Transmission System Operators for Gas) to create a common baseline of assumptions. This involves using the same analytical basis for their

respective ten-year network development plans. These plans can then be used as the basis for the cost-benefit analysis of different electricity and gas network expansion or reinforcement projects.

More recently, continuing innovation in and uptake of demand-side technologies are having an impact on the power system. Demand-side technologies, particularly EVs, have the potential to facilitate a high share of VRE in the power system. Such technology options can be deployed in a way that increases the flexibility of the system. For example, EVs with smart charging can be used to provide flexibility and facilitate VRE integration by charging during periods of high VRE output and – ultimately – supplying to the grid when output declines.

In addition, linking the power and transport sectors can also support the planning and development of EV charging infrastructure, enabling greater uptake of EVs. As EV uptake grows, increasing interaction between the power and transport sectors can be seen. A number of jurisdictions have incorporated cross-sectoral links between planning in the power sector and the transport sector, including Scotland, Japan and the United States (Miller et al., 2015). In Scotland, EVs have contributed to wind integration by absorbing excess wind generation, which prevents curtailment (Miller et al., 2015).

Interregional planning

Power system planning was traditionally confined to established single-utility balancing areas. However, with an increasing share of VRE deployment, expanding the size of balancing areas can potentially provide greater flexibility through resource diversification across different geographical regions. In addition, greater geographic diversification of generation sources leads to less variability in supply. Large and integrated power systems also tend to be more secure, albeit more complex from the perspective of system operation.

Changes to balancing areas and greater amounts of interregional planning have emerged over time from subtle moves toward electricity market integration in certain jurisdictions (Miller et al., 2015). Planning that expands across balancing areas or national jurisdictions can lead to more efficient use of existing generation and transmission resources and minimise the costs of expansion.

Many neighbouring TSOs have now started to co-ordinate power system planning in order to optimise the use of resources and benefit from increased flexibility. Interregional co-ordination is evident in the European Union, South Asia, Association of South East Asian Nations (ASEAN) and the United States (IEA, 2015; IEA, 2016b).

Since 2011, regional transmission planners in the United States have been required to develop regional plans and co-ordinate with their neighbouring transmission planners (FERC, 2016). In South Asia, the power systems of India, Bhutan and Nepal have been interconnected and synchronised since 2013. In 2014, governments signed the South Asian Association for Regional Cooperation (SAARC) framework agreement on energy co-operation, one element of the energy pillar being the development of an interregional electricity market and the further development of interconnections (SAARC, 2017).

Despite the potential benefits of interregional planning, a number of challenges are associated with the institutional and contractual arrangements for multilateral trade. Such cross-border arrangements can be complex and difficult to achieve.

The European Union is a prominent example of regional co-ordination in transmission planning. ENTSO-E was created to co-ordinate transmission network planning and operation across

different jurisdictions (IEA, 2016d). This includes drafting network codes, co-ordination and monitoring of network code implementation and development of long-term regional network plans (Box 21).

Box 21. Co-ordinated transmission network planning in Europe

ENTSO-E publishes an updated Ten-Year Network Development Plan (TYNDP) every 2 years to give an overview of the transmission expansion plans for the next 10-15 years that have been identified as necessary to facilitate EU energy policy goals. The TYNDP is a co-ordinated planning initiative to deliver a pan-European transmission plan within the ENTSO-E region. It is the outcome of a two-year process, starting with the development of scenarios or visions of how the European power system might look in 2040.

For the TYNDP 2018 report, ENTSO-E and ENTSG have for the first time jointly built scenarios that reflect national and European energy policies, are technically accurate and are consistent between the sectors of electricity and gas. The scenarios have been developed based on the recommendations of stakeholders, are more diverse than the previous ones and acknowledge weather conditions. The energy mix of each scenario is modelled under the consideration of a “wet”, a “dry” or a “normal” year. ENTSO-E and ENTSG also focused on improving the prediction of energy consumption for the TYNDP 2018 and developed new approaches to do so.

The target of the report is to identify future transmission and interconnector requirements. The scenarios of TYNDP 2018 – named 2020 Best Estimate, 2025 Best Estimate, 2030–40 Sustainable Transition, 2030–40 Distributed Generation, 2030 EUCO, and 2040 Global Climate Action – consider shares of electricity demand covered by renewable energy sources of between 65% and 81% in 2040. The TYNDP 2018 also identifies further spots on the European grid, in addition to those in the TYNDP 2016 report, where bottlenecks exist or may develop if reinforcement solutions are not implemented. It reviews the state of current projects and identifies main barriers to electricity exchange and interconnection.

The projects that have been identified in the TYNDP will contribute towards meeting EU energy policy goals. Based on the goals, Projects of Common Interest (PCIs) are selected and benefit from accelerated licensing procedures, improved regulatory conditions and some access to financial support.

Source: ENTSO-E (2018), *Ten-Year Network Development Plan 2018*.

Including system flexibility assessments in long-term planning

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 expenditure while ensuring sufficient flexibility on the system for any number of uncertain futures (IEA, 2018a).

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. 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 (see IEA [2018a]).

Planning for distribution grids

When considerable amounts of DER, such as VRE, are expected to be integrated into local grids within the planning horizon of a distribution utility, additional and potentially more complicated planning studies typically need to be completed. This is to ensure the continued safe, reliable and cost-effective operation of the interconnected distribution system (IEA PVPS, 2014). Depending on local circumstances, system operators are likely to pursue a combination of additional planning activities (Table 8).

Table 8. Additional planning activities to integrate DER

Study topic	Purpose
Gross load estimation	Determine circuit load masked by DER generation
Circuit reconfiguration	Ensure that reconfiguration remains possible with DER integration
Power flow	Identify potentially overloaded and/or unidirectional components that may experience reverse power flow
Voltage regulation	Ensure voltage power quality and inform placement and control setting for automatic voltage regulation equipment

Source: Seguin et al. (2016), *High-Penetration PV Integration Handbook for Distribution Engineers*.

Improved screening/study techniques

Local utilities use “screens”⁴³ to assess the impact that DER, such as behind-the-meter solar PV projects, will have on the local network. Screening forms part of distribution planning activities and guides the approval process for DER projects.

The precise distribution of DER on a distribution circuit (e.g. near the start of the circuit or near the end of the line) can strongly determine their impact on the circuit. More accurate grid planning can inform system operators as to which connection requests merit more in-depth analysis, which can be approved without further study, and which projects cannot be connected within the immediate planning horizon without significant circuit modification or upgrade (Box 22).

Many of the grid “screens” in place today were designed in a context of low DER penetration. To improve the accuracy of local grid screening, planning efforts must include future scenarios for DER penetration at a relatively high spatial resolution, such as neighbourhood or even street level. Planning tools could use socio-economic data to determine the likelihood of DER adoption in certain areas (Sigrin et al., 2016). An alternative approach to grid impact assessment assumes random placement of DER (Smith and Rylander, 2012). As such, improved screens require considerable development to account for the rising complexity of the required analysis at high penetration (Rylander et al., 2015).

⁴³ A “screen” is a visualisation used by the local system operator to determine thermal and voltage capacity limits of the local network.

Box 22. Beyond 15% penetration: New technical DER interconnection screens for California

In the past, DER projects in California required a full interconnection study if aggregate DER capacity amounted to 15% of the peak load of the circuit. With the growth of PV deployment, this limit was reached more often, leading to burdensome administrative processes, which slowed down further deployment. Today, a more refined analysis is performed to determine which DER projects are more likely to saturate local circuits and require in-depth analysis by the utility. This has made project assessment less burdensome and more effective, saving time and money for the utility and project developers alike.

After screening, system operators can apply quasi-static time-series (QSTS) analysis, or alternative study methods, to assess PV interconnection requests (NREL, 2014). QSTS analysis incorporates more precise load and solar irradiance models, and allows for a more refined understanding of the expected impacts of DER on combined circuit operation and voltage regulation equipment. However, even with modern-day consumer-grade computing equipment, a comprehensive assessment can take several days to complete. Less time-intensive study methods and tools are needed to enable VRE interconnection. The German local system operators, EWE Netz, is leading efforts to reduce this delay, so that project developers or home owners can receive the outcome of the screening exercise in as little as a few minutes.

Including local flexibility requirements in planning techniques

In addition to basic screening practices, planning processes on the distribution grid increasingly factor in the evolution of local flexibility requirements (Box 23).

Box 23. Planning for local flexibility requirements

In order to accommodate increasing shares of distributed generation, UK Power Networks – the DNO for South East England – is in the process of transitioning to revised status as a DSO. As part of its long-term flexibility roadmap it has identified potential opportunities to defer infrastructure investment through use of DER, with a total potential volume of up to 206 MW by 2023. This potential refers to UK Power Network's high-voltage and extra-high-voltage networks, up to 132 kilovolts, where larger DER such as industrial customers, commercial customers, EV fleets, larger generation and battery storage tend to connect.

Within this market, UK Power Networks has identified four use cases for DER that can be deployed to further support the grid. The table below presents two of these: deferral of grid reinforcement; and management of planned maintenance. For a more detailed discussion of these and the remaining two, refer to UKPN (2018).

UK Power Networks' product development recognises the fact that local flexibility requirements are very location specific and that, while competitive procurement might be advantageous, DSOs should consider alternative procurement strategies in case of limited liquidity.

An additional important point in UK Power Networks' strategy is to first engage with the high- and very-high-voltage sections of its network, while excluding its low- and medium-voltage networks.

This is because there are greater potential savings in replacing high-voltage infrastructure with DER deployment, as opposed to lower-cost reinforcements at lower voltage and the higher transaction costs of engaging smaller consumers.

UK Power Networks product design for DER

	Grid reinforcement deferral	Planned maintenance management
Value driver	Present value of deferring capital expenditure	Managing unplanned interruption risk
2023 flexibility potential	206 MW	Available to eligible DER capacity out of the 206 MW
Required response time of asset	30 minutes maximum	
DER type	Generation, storage and load reduction	Only generation and storage
Procurement type	Competitive tenders or set prices if reduced number of bids	
Time between contract award and delivery	6 months and 18 months ahead	Case-specific; 1-12 months
Payment	Availability-based and utilisation-based	
Contract term	1-4 years	Monthly or seasonal

This last point of appropriately identifying needs and measures will be a defining aspect of the transition from DNO to DSO. For example, the cost-benefit ratio may change with increased EV uptake along with the respective charging infrastructure in highly meshed low-voltage urban networks. With increasing service requirements being expected from the distribution grid, DSOs will have to develop the right combination of non-wire alternatives, infrastructure planning and customer engagement in demand response.

Source: UKPN (2018) <http://futuresmart.ukpowernetworks.co.uk/wp-content/themes/ukpnfuturesmart/assets/pdf/futuresmart-flexibility-roadmap.pdf>.

Policy principles for planning and infrastructure

- **Establish a flexibility roadmap based on the current and expected energy mix:** Institutional market reforms and increased shares of inverter-based generation and DER will affect the system's flexibility needs. Their evolution should be matched through proactive and iterative policy and regulatory reforms.
- **Encourage integration of planning for transport and energy:** Electrification of transport will be a defining feature of power system evolution in the coming years. Policy makers, grid companies and system operators need to engage with transport and urban planning, as well as the transport industry, to recognise shared goals.
- **Establish mechanisms for co-ordination with other sectors:** The power system's increasing exposure to hydrological patterns, wind speed and solar irradiation, as well as the commodity prices underlying back-up generation, will affect the extent to which

different resources contribute to system flexibility. Additionally, competing uses such as irrigation, land use and environmental conservation should be accounted for in long-term planning.

- **Require flexibility in new assets through regulation and network codes:** Requiring the submission of non-wire alternative plans, specific flexibility capabilities for new builds, the installation of monitoring equipment and the inclusion of flexibility in interconnection contracts will help embed flexibility in system transformation.
- **Enable flexibility investments through innovative regulation:** Reviewing cost recovery methodologies, introducing requirements for non-wire alternative proposals in regulated infrastructure expansion plans and partial appropriation of additional savings are some of the options available to TSOs and DSOs to deploy DER.
- **Encourage and co-ordinate the reallocation of institutional roles:** Regardless of the decision to separate system operation from transmission, or to enable distribution system operation, policy makers should facilitate dialogue between various system actors on a level playing field. Depending on context, this may range from providing communication platforms to reviewing the regulated monopolies' organisational and budgetary structures.
- **Improve visibility and bidirectional information sharing:** The shift towards a decentralised power system means that at higher levels of distributed generation, power may start flowing back to the transmission grids. Having an overview of installed DER and expected generation may help system operators reduce costs of redispatch and network reconfiguration.

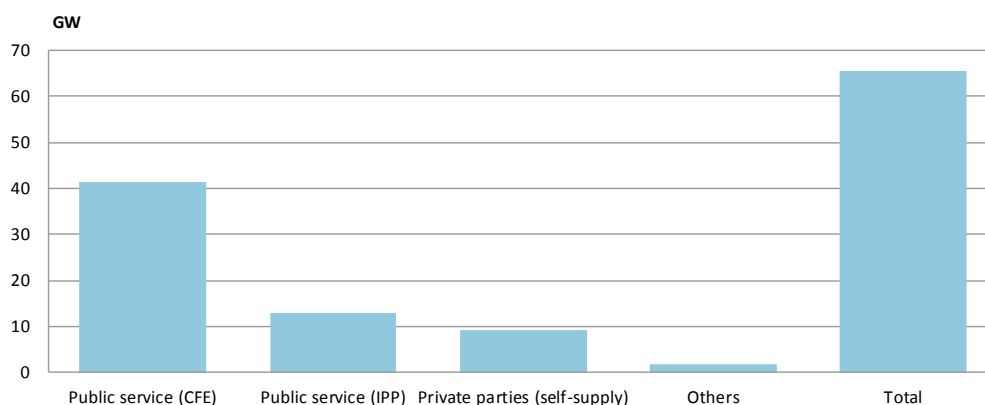
Transition mechanisms to facilitate system reforms

Most transitions from a centrally planned power system to one relying on market mechanisms require consideration of how the old system will be phased out and the new one implemented. A smooth transition requires special instruments and mechanisms. Although there are no two examples with the same transition instruments (because they respond to each country's power sector circumstances), a number of examples that provide interesting insights are given below.

Mexico's legacy contracts for the regulated supplier

Mexico is a good example of transition from a predominantly vertically integrated utility to a competitive wholesale market. Prior to the reform the country's generation was managed through three main legal regimes (as shown in Figure 24 below):

- plants owned and operated by Comisión Federal de Electricidad (CFE), the vertically integrated utility
- independent power producers (IPPs) selling power exclusively to CFE
- an additional regime in place for consumers on self-supply, which allowed for wheeling between different points of the transmission grid.

Figure 24. Power generation by ownership, Mexico prior to reform, 2014

Note: GW = gigawatt.

Source: SENER (2014), Informe Pormenorizado del Desempeño y las Tendencias de la Industria Eléctrica, Detailed Report on Performance and Trends in the Electricity Industry, https://www.gob.mx/cms/uploads/attachment/file/150564/Informe_desempe_o_y_tendencias_de_la_industria_electrica_2014_FINAL_2.pdf.

As of 2014, with 61% of installed capacity owned and operated by CFE, and 18.5% selling exclusively to CFE (IPP), it was crucial to design a transition mechanism that would guarantee revenue certainty and security of supply.

Transition to a competitive market was underpinned by three basic principles:

- protecting end consumers from price increases
- respecting existing legal rights and contractual terms with existing generators
- fostering short- and medium-term efficiency.

Transition from the public service regime

On the demand side prior to reform most consumers, representing 84% of the load, were served through CFE's public electricity service. Following the transition this activity was unbundled into a subsidiary, hereafter called CFE Retail, dedicated exclusively to regulated retail sale of power. In contrast to the previous model, end consumers were now allowed to opt out from the regulated retail service.

In order to ensure low-cost supply for CFE's regulated retail clients in the short term, CFE Retail was assigned a least-cost portfolio of economically efficient IPP- and CFE-owned generators. The selection exercise rewarded plants with positive net present value of their anticipated economic benefit. For this calculation, cash flows were calculated using the margin between the expected local marginal price for the plant and their fixed and variable operational costs. An additional benchmarking step was implemented to ensure cost-effectiveness. This applied to power generation units that had passed the screening based on net present value, but whose contracted payment was above international standards.

In order to account for the three principles mentioned above, specific contracts with particular features were designed for each generator type:

CFE-vesting contracts: These contracts applied to generators owned by CFE, which were unbundled into a number of separate generation subsidiaries. The duration of these contracts was fixed for the number of years in which these plants were expected to be on the money, a shorter time period than each plant's remaining lifetime.

For thermal plants, the contracts were structured as “call” options, giving CFE Retail the right to purchase CFE-vested output when the contract price was below the wholesale price. This reinforced the principle of end-consumer protection.

A number of provisions were included to ensure short- and medium-term efficiency:

- Contracted prices reduce the generator’s incentive to strategically curtail output.
- Contracted prices incentivise generators to further optimise their plants, as they are allowed to keep output beyond the contractual quantity or higher margins resulting from efficiency gains.
- For thermal generators, the contract does not provide any incentive to keep inefficient power generation units, as the contract allows them to replace their units for ones that are more efficient and keep the extra margins.
- CFE Retail is obliged to purchase all the output from renewable technologies. However, VRE plants are free to sell any excess energy output resulting from repowering to any other market participant.⁴⁴

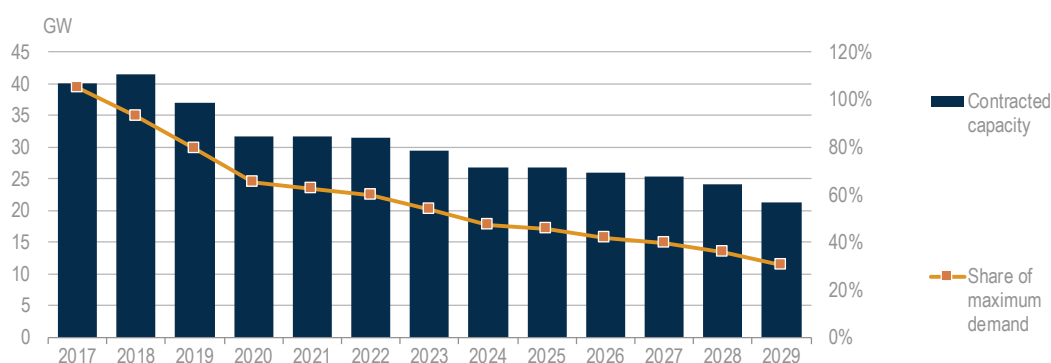
Lastly, one of the key features to ensure a smooth transition was providing a gradual phase-out of vesting contracts to competitive procurement. For this reason, vested contract duration was limited to the year that net present value was maximised, thus phasing out older inefficient plants first. Additionally CFE Retail was now able to fully or partially shed any contracted overcapacity, starting with the oldest CFE-vesting plants in the portfolio, meaning that there is no demand risk for the retailer.

IPP-vesting contracts: The key feature in these was to respect the initial contractual terms and provide revenue certainty for these generators. As part of CFE’s unbundling, a special subsidiary was created to handle their contracts and represent these plants in the market. The main advantage of this was not to create an offtaker risk. The new subsidiary has a similar legal status to its parent company, CFE Holding, a state-owned enterprise with the implicit backing of the Mexican government. This means it cannot go bankrupt except in the case of an explicit government decision.

As most of these IPP contracts concerned combined cycling plants, one particular feature was addressed with the new contracts. Contracted combined-cycle gas turbine IPPs rely on a synthetic output offer curve that covers three feasible discrete output levels. This created issues on both sides: generators were at a disadvantage if they were dispatched at a point where the stylised offer curve fell below actual production costs or at an infeasible output level. CFE, by contrast, could face a loss in the wholesale market if it was purchasing output at a price level above the actual production costs. The new market rules allow for generation compensation that reflects actual production costs.

Under this transition mechanism, any increase in contracted capacity in the future must be procured by CFE Retail through competitive auction processes. The actual and anticipated gradual decline in capacity under legacy contracts, and their share of maximum demand, can be seen in Figure 25.

⁴⁴ In this case, repowering refers to replacing older units with newer ones with better performance.

Figure 25. Installed generation capacity under legacy contracts and share of demand, 2017-29

Gradual phasing out of legacy contracts is expected to ensure a smooth transition to a competitive market without compromising security of supply.

Transition from the private-party regime (self-supply)

Under the restrictive legal framework prior to reform, private parties were allowed to produce energy for self-supply, either at their premises or at remote points, using the CFE transmission grid. Consumers under self-supply and co-generation agreements (that included both load and generation) prior to the new Electricity Industry Act were respected under the reform. In this case the law defined a transition model to allow these generators and consumers to transition, if they found it profitable, to the new regime.

Under the previous regime these societies were able to inject at one point of the grid and withdraw at another, upon the completion of investment in grid reinforcements, paid for by self-suppliers. This restrictive regime created incentives for a very inefficient operational scheme, since self-supply societies were not able to sell energy to CFE (or on the wholesale market after the reform) when they had surplus cheap capacity, or to buy from CFE (or from the wholesale market) when their capacity was more expensive.

The Electricity Industry Act provides incentives for these societies to leave this regime and incorporate into the wholesale market, providing financial transmission rights that hedge the risk due to their location. Leaving their old regime allows these societies to sell and buy electricity in the wholesale market when this is economic.

Treatment of “stranded costs” in the United States

The United States is another example of a country that has had to consider a transitional mechanism in the process of opening the market. As part of its activities to promote wholesale power competition, in 1997 FERC issued Order 888 to explicitly implement the principles to be followed in the open-access system, recognising that there could be transition costs. These costs were labelled “stranded costs”, and were used to identify “capital investments that are unrecoverable because of the transition to competition”.

In the US case, the risks faced by utilities in jurisdictions being opened to competition came from previous commitments made to satisfy expected demand, and the prospect that exiting clients would reduce the revenue base that the utilities relied on to pay for these commitments.

Order 888 treated the opening to competition and the transition as issues to be considered simultaneously. In the final rule, it was decided that utilities could come to the FERC to recover the “legitimate, prudent and verifiable stranded costs”.

Two alternative mechanisms were discussed for recovering these costs:

- an exit fee, paid once, when customers leave the utility
- a wires charge, a fee linked to the transmission service that would be unavoidable for every customer.

Although Order 888 supported the first mechanism as an ideal one, the use of a wires charge has many advantages that could make it the right tool for policy makers in similar circumstances. This is because it makes transition to a competitive market faster as it reduces the costs of switching retailer for exiting customers.

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Power system transformation pathways for China to 2035

This chapter describes a state-of-the-art modelling exercise conducted by the International Energy Agency (IEA), analysing different pathways for the power system of the People's Republic of China ("China"). The analysis relies on two core energy system transformation scenarios for China, which were recently conducted for the IEA *World Energy Outlook (WEO) 2018* – the New Policies Scenario (NPS) and the Sustainable Development Scenario (SDS) (IEA, 2018a). These present the long-term IEA view on the evolution of the global energy system – including China – under different conditions. Using the *WEO 2018* results for national installed generation capacity and demand, the Chinese power system is then simulated in unprecedented operational detail under the NPS and SDS for the year 2035.⁴⁵

The power sector modelling exercise provides insight into various operational, economic and policy-related aspects of a future Chinese power system. It is primarily employed to quantify the annual economic and operational benefits in the year 2035 of various options to optimise the utilisation of the power system and increase its flexibility: 1) introducing economic dispatch, 2) enhancing regional trade, and (3) unlocking innovative sources of power system flexibility.

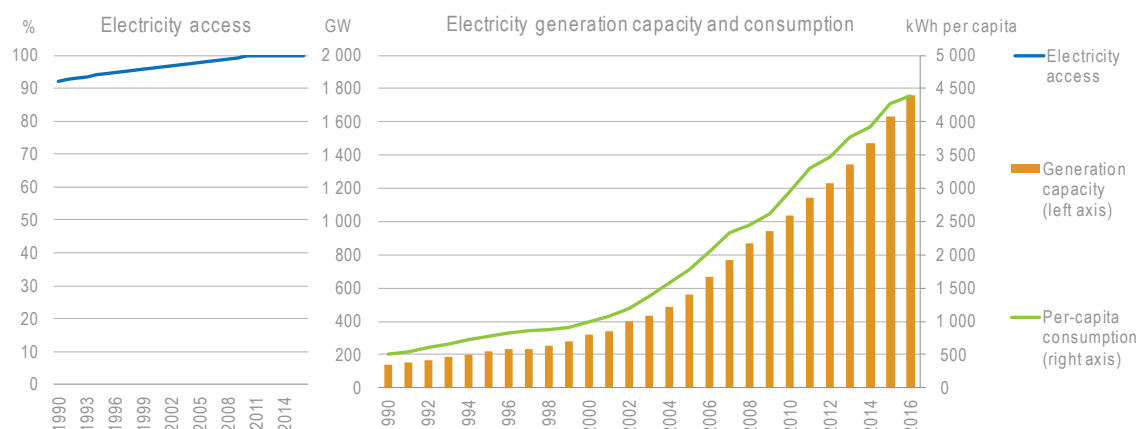
The chapter first summarises particularly important aspects of China's various power system pathways. In a second step, it explains the options that are explored in the power sector modelling exercise. The third section presents modelling results for different cases based on the NPS and SDS.

General trends in China's power system evolution

For many years the dominant narrative on China has emphasised the extraordinary pace of the country's development and its success in lifting hundreds of millions of its citizens out of poverty, including energy poverty. Rapid expansion of the electricity sector in China was a crucial driver for this, making it the world's largest electricity consumer in terms of total national consumption (Figure 26) (IEA, 2018a).

The previously high growth in demand implied the prioritisation of securing sufficient investment. However, as the country has become more prosperous, the Chinese government has increasingly come to focus on the economic and environmental costs of this growth. Indeed, new priorities include improving local air quality, addressing the long-term issues of economic structural transition and also dealing with the systemic threat of climate change.

⁴⁵ Hourly production cost modelling is employed using the PLEXOS® modelling tool to capture a sufficient level of detail for the Chinese power generation fleet, electricity demand, market rules and interregional transmission network.

Figure 26. Energy access, electricity consumption and generation capacity, China, 1990–2016

Notes: GW = gigawatt; kWh = kilowatt hour.

Sources: The World Bank (2018), World Bank Open Data, <https://data.worldbank.org/>; United Nations (2019), UNData, <http://data.un.org/>.

China's power system has experienced rapid expansion over previous decades.

As a result, clean energy, and especially variable renewable energy (VRE), has seen large and rapid expansion. However, this expansion, combined with a very large coal fleet and more modest rates of growth in power demand, has highlighted limitations in the flexibility of China's power system. Although profound achievements have been made in the ongoing Document No. 9 round of reform (see Chapter 2 and IEA [2018b]) as well as in reducing VRE curtailment, a deeper transformation towards a cleaner and fully efficient system has yet to be realised and still requires focus.

Achieving a "Beautiful China"

The transformation of China's power system depends on the outcome of a number of transitions that are underway, supported by policies aimed at achieving a more sustainable development model for future prosperity. The "Beautiful China" initiative is among the most important guiding principles for this transformation. To support the overarching goal of a "Beautiful China", the government is implementing domestic policies addressing regional development and environmental protection.

The "Beautiful China" initiative was proposed at the 19th National Congress in October 2017 as the general blueprint for China's future development (Xi, 2017). The initiative aims to address what the government sees as China's main development challenge: the contradiction between unbalanced development and the people's ever-growing need for a better life. Targets have been articulated for two main years. First, by 2035 the target is to generally realise modernisation, i.e. a more advanced economy, while increasing equality in urban–rural development and in regional development levels, alongside a much better environment and the "ecological civilisation". Second, by 2050 the target is essentially to achieve widescale modernisation in all respects, notably economics and trade, science and technology, military and defence, culture and governance.

Following the general policy framework, the economy is starting to orientate away from a reliance on export-driven, heavy industrial sectors towards domestic consumption, higher

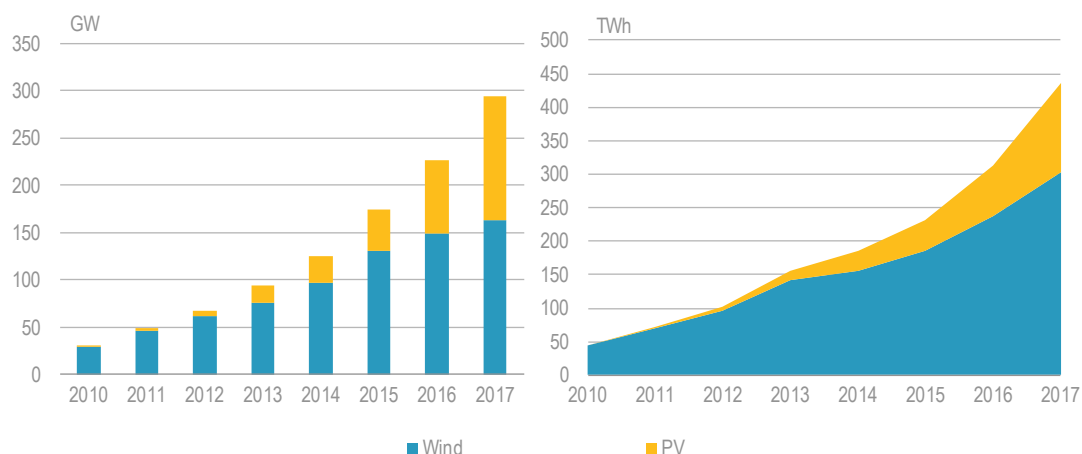
value-added manufacturing and services, which affects regional power consumption. In parallel, more stringent environmental policies have been promulgated to reduce air pollutants and greenhouse gas emissions. The policies include curbing overcapacity in heavily polluting, carbon-intensive industries by closing down the oldest and least-efficient factories. More environmentally friendly electricity sources are expected to see a dramatic increase in capacity. These policies have been considered and included in the modelling exercises presented in this chapter, in particular the regional shift in industrial consumption (more detail can be found in Annex A).

Key variables for system transformation

China is shaping its future power system by continuously focusing on energy efficiency, adopting renewable energy, containing construction of new coal-fired plants and taking steps towards substantially reducing its coal utilisation in the long term. In addition, the desired shift in industrial structure away from heavy industry and towards knowledge-intensive industries and services is anticipated to reduce the energy intensity of China's economy.

In 2017 China's total installed power generation capacity increased by 127 GW. Two-thirds of this growth came from renewables, including rapid growth in wind and solar photovoltaic (PV) (see Figure 27). However, due to the limited flexibility of the power system – a combination of operational, economic and technical factors – China had to curtail over 100 terawatt hours (TWh) of power generated from VRE.

Figure 27. Capacity and generation of wind and solar PV



Source: IEA (2018c), *Renewables 2018*.

Significant increases in wind and solar PV capacity have been achieved in China over the past seven years, and this trend is expected to continue.

In 2015 China launched its Document No. 9 reform programme, which has already achieved substantive progress in improving VRE integration and system efficiency. For example, transmission and distribution tariffs have been published; double-digit percentages of electricity are being traded through energy trading institutions; final customer tariffs are being defined according to the market for large customers; and the first spot market pilots are being implemented (for details see IEA [2018b]).

However, a systemic transformation has yet to be realised, with several crucial issues in need of a good solution. Chapter 2 of this report has given an overview of the basic characteristics of the current Chinese power system and highlighted the objectives of the Document No. 9 round of reform. Chapters 3 and 4 of this report have provided an international perspective on establishing a market-based power system with the application of upgraded system planning and operation and power trading, in the context of global trends in power system evolution and future potential flexibility sources. Simultaneously considering the context of China's power system, international experiences and global trends, three major variables could be crucial for determining the speed and extent to which China can transform its power system:

- **Dispatch order:** the “fair dispatch” methodology has long been adopted together with benchmark pricing to secure power generation investment (see Chapter 2 for a detailed explanation of fair dispatch). However, this dispatching order inherently creates inflexibility, which has become apparent as VRE capacity has increased rapidly. Transitioning to economic dispatch, which is a cost-optimised order of dispatch based on short-run marginal costs of each technology (subject to relevant system constraints), will be necessary to meet the target of both a clean and economically efficient power system in the future.
- **Interregional trading:** due to its large geographical area and climatic diversity, China has a diverse endowment of generation resources and demand patterns. Integration of the power system at a regional level could therefore offer important benefits. As an extension of this, investigating the potential of interregional trading would be an important activity – not only to understand how to unleash the potential of existing and committed interconnectors, but also to examine the necessity of investing in new interconnectors in the future to accommodate demand growth and power sector transformation.
- **Demand-side response (DSR), storage and efficient end-use electrification:** in a future power system with a high share of VRE, system flexibility is a crucial issue to consider. These flexibility options could provide a large amount of flexibility that is complementary to a supply side that is dominated by VRE. Storage options include thermal, electrochemical (batteries) and pumped storage hydropower (PSH), while efficient end-use electrification includes electric vehicles (EVs) and water and space heating.

Given that there is no single pathway for the future of China's power system, this report uses a scenario-based approach to highlight the key policy choices, consequences and contingencies that lie ahead, and to illustrate how the course of the power system in China might be affected by making changes to the crucial variables described above. This approach is underpinned by system-wide modelling that covers all fuels, technologies and regions. As explained in the next section, the main scenarios are based on the IEA *WEO 2018*.

Different power system pathways

This section introduces the pathways which underpin the power sector modelling exercise. The national-level features of the scenarios are based on the IEA *WEO 2018*. *WEO* is the IEA flagship publication, widely recognised as one of the most authoritative sources for global energy projections and analysis. It presents medium- to long-term energy market projections and extensive statistics, analysis and advice for both governments and the energy business. Previous editions of the *WEO* specifically focused on China's energy sector (IEA, 2017) and the future of the global energy sector given the increasingly important role of electricity (IEA, 2018a). Box 24 describes key findings from *WEO* related to China's power sector and global electrification.

Box 24. Key findings in *WEO* related to China's power sector and global electrification

The huge changes underway in China's economy and its electricity sector are having an impact not just within the country, but also on the global energy landscape. Four major trends are identified in *WEO* as shaping the long-term development of China's power sector:

- China is entering a new era of development – the economy is progressively moving away from heavy industry towards domestic consumption, higher value-added manufacturing and services, reshaping future power consumption.
- Energy demand growth is expected to slow more rapidly as economic growth patterns shift away from quantity and towards quality. Electricity accounts for more than half of final energy demand growth to 2040, overtaking coal and oil. Main drivers of this growth are the industrial sector and the buildings sector, particularly the demand for electric motors and cooling.
- China is already the global leader in clean energy investment and continues to make the growth of clean energy a strategic priority.
- The Chinese government has long recognised the extent of its environmental problems and is expected to keep improving air quality and curbing greenhouse gas emissions, further promoting lower but cleaner growth.

Electricity is increasingly important in the modern world. Four major conclusions can be made for the vision of an electrifying future worldwide:

- The rapid growth of electricity brings huge opportunities, but market designs need to deliver both electricity and flexibility to keep the lights on.
- A comprehensive strategy to electrify end uses and decarbonise the power sector is needed to achieve environmental goals.
- There is no single solution to reducing emissions, such as renewables, efficiency or a host of innovative technologies – are all required.

Governments play a decisive role in the future pathway of the energy sector as a whole, as well as in the power sector.

Two main scenarios for 2035

Two *WEO* scenarios underpin the power system modelling exercise: the NPS and the SDS.⁴⁶ While *WEO* generally presents scenario results for 2040, interim results for the year 2035 are used for the power sector modelling exercise. 2035 is an important milestone for the “Beautiful China” initiative as the first step of this two-step blueprint on the way to the middle of the 21st century.

For this study, the scenarios have been disaggregated into eight regions via a detailed bottom-up analysis for each region (see Annex A for additional details on this disaggregation). Disaggregated *WEO* model outputs for 2035 (e.g. power plant fleet characteristics, electricity

⁴⁶ 2017 is the last year for which complete statistics from the China Electricity Council (CEC) are available. The 2018 *WEO* uses 2017 as its formal reference year, i.e. the year from which energy system projections originate.

load) are entered into the PLEXOS® production cost modelling framework for the power sector modelling exercise. For both the NPS and the SDS, the production cost modelling exercise then analyses different **cases**. For each scenario, all cases share the same installed generation capacities and electricity demand. However, the cases differ in several operational and flexibility aspects (see below). This allows the benefits of optimised operations and advanced flexibility strategies to be studied in detail. Importantly, the NPS and SDS provide two very different contexts for carrying out the detailed modelling.

NPS

The NPS aims to provide a sense of where today's policy ambitions are likely to take the energy sector in China. It incorporates not just the policies and measures that government has already put in place, but also the likely effects of announced policies, as expressed in official targets or plans. The IEA reading of the national policy environment is also influenced by policies and targets adopted by subnational authorities, i.e. by provinces, cities and municipalities, in addition to the commitments made by the private sector.

The way that policy intentions are reflected in the NPS depends on the extent to which their realisation is supported by specific policies and implementing measures. Where these are in place, announced targets are assumed to be met or indeed exceeded, where macroeconomic, cost or demand trends point to this. However, given that announced policy intentions are often yet to be fully incorporated into legislation or regulation, the prospects and timing for their full realisation depend on our assessment of the institutional context and relevant political, regulatory, market, infrastructure and financing constraints. With respect to the electricity sector, the NPS represents a power system with the principal targets of Document No. 9 power reform being achieved.

Power sector modelling cases analysed for the NPS

In the NPS, Document No. 9 targets are expected to be met, i.e. the market will play a decisive role, there will be much less administrative intervention and the power system will be efficient and clean with low curtailment of renewables. Applying economic dispatch and removing restrictions on interregional trading are identified as the two most critical factors in this scenario. The original WEO NPS assumes the implementation of economic dispatch, optimised trading and increased interconnection between provinces. For this report, different cases are analysed to assess the benefits of different options.

Various cases are set under this scenario to simulate the power system after unlocking dispatch and cross-regional trading in order to provide deeper insights into the value of adopting these measures. In order to assess their effect it is necessary to construct a baseline case (known as "**NPS-Inflex**") that does not include the measures. In a second modelling step the measures are introduced, allowing benefits to be assessed through comparison.

The first measure considered is the dispatch order. In the NPS-Inflex case the modelling exercise assumes the current practice of a fair dispatch, which allocates fixed full-load hours to each type of technology. Under an optimised dispatch case known as "**NPS-Dispatch**", the modelling assumes an economic dispatch protocol that, on an hourly basis, dynamically allocates utilisation of power plants based on their operational (mainly fuel) costs. In this study the existing government policy of providing gas generators with a generation allocation is preserved – thus, the dispatch protocol modelled is not a pure economic dispatch.

The second measure considered is the trade of electricity between regions. This measure has two different dimensions and is explored in three separate cases. The first dimension influencing trade is the way in which existing transmission lines are utilised. In the NPS-Inflex

case, transmission usage patterns reflect China's current power sector framework that constrains regional trade and permissible utilisation of lines is set to 2017 levels. A more optimised trading approach is implemented in a case known as "**NPS-Flow**", where the use of transmission lines can be optimised freely. However, the use of generation capacity remains constrained to fair dispatch. Under a case named "**NPS-Operations**", both dispatch and trade are used in an optimised fashion.

The second dimension influencing trade is the availability of new interconnection lines. Here, the analysis considers two sets of conditions. Under NPS-Operations, only lines expected to be built by 2022 are made available. Under an "**NPS-Full flex**" case, additional transmission infrastructure investment is made between 2022 and 2035, bringing total interconnection capacity from 230 GW (2022) to around 410 GW (2035), and is accompanied by optimised transmission utilisation and economic dispatch.

The NPS-Full flex case corresponds to the NPS included in the *WEO*. There are minor differences between the NPS in *WEO 2018* and the NPS-Full flex case due to the higher spatial granularity used in the analysis for this report (see Annex A for details). Further details on the installed capacity and the generation mix are presented below, together with the modelling results.

The metrics used to quantify the system benefits of flexibility measures are reductions in the cost of fuel, operation and maintenance (O&M), and carbon dioxide (CO₂) emissions. Other benefits assessed are reductions in VRE curtailment and reductions in other air pollutant emissions. Finally, the utilisation of conventional power plants is also examined to shed light on the operational impacts on different regions. For the NPS-Full flex case, the cost of additional grid investment is also considered.

The different cases are summarised in Table 9.

Table 9. Case settings for the NPS analysis

	NPS-Inflex	NPS-Dispatch	NPS-Flow	NPS-Operations	NPS-Full flex
Dispatch	Current (fair)	Optimised	Current (fair)	Optimised	Optimised
Interregional trade	2017 utilisation	2017 utilisation	Optimised	Optimised	Optimised
Transmission capacity	2022 target	2022 target	2022 target	2022 target	Additional

Four different cases are compared to a baseline scenario in order to assess the benefits of more optimised system operation and additional transmission interconnection.

SDS

The SDS offers an integrated pathway to achieve a range of energy-related goals crucial for sustainable development: climate stabilisation, cleaner air and universal access to modern energy, while also reducing energy security risks. This scenario starts with a certain vision of the energy sector's destination and then works back to the present.

The Sustainable Development Scenario, introduced for the first time in the *WEO-2017*, starts from selected key outcomes and then works back to the present to see how they might be

achieved. The outcomes in question are the main energy-related components of the Sustainable Development Goals, agreed by 193 countries in 2015: (1) Delivering on the Paris Agreement. The Sustainable Development Scenario is fully aligned with the Paris Agreement's goal of holding the increase in the global average temperature to "well below 2 °C". (2) Achieving universal access to modern energy by 2030. (3) Reducing dramatically the premature deaths due to energy-related air pollution.

These three goals are interlinked and can be achieved through an integrated approach. Under the SDS, higher levels of installed capacity are seen from nuclear and renewable technologies, particularly wind, solar and hydropower, with less from fossil fuel generation and 15% of installed fossil fuel capacity having carbon capture and storage (CCS). In addition, this scenario involves a greater role for flexibility options, including storage, demand response, EVs, electrification and energy efficiency. With respect to the electricity sector, the SDS reflects a power system that is consistent with the "Beautiful China" initiative in 2035.

Power sector modelling cases analysed for the SDS

The SDS provides an ideal environment to investigate the benefits and costs of different advanced power system flexibility options. Importantly, all SDS cases assume optimised dispatch, optimised interregional trade and additional transmission investment between 2022 and 2035. This is because the SDS is assumed to build upon progress made through Document No. 9 reform efforts. The original WEO SDS assumes sufficient advanced flexibility to integrate VRE without uneconomic levels of curtailment. For this analysis, different cases are developed and compared to shed light on the value of each flexibility option in more detail.

The first case analysed under the SDS is a baseline case. This case does not include measures included in the original WEO SDS, notably any flexibility measures beyond economically optimised dispatch, interregional trade and increased transmission interconnection. The installed generation capacity and demand structure in this and all other cases are identical with the values specified in the SDS in *WEO 2018*. This case is referred to as "**SDS-Inflex**" and it is used as a reference point for comparison with other cases to quantify the incremental benefits arising from the deployment of advanced flexibility options.

In the next step a number of cases are analysed that only include the addition of a single advanced flexibility measure. These measures are: 1) DSR, 2) electricity storage, and 3) smart EV charging.

DSR is seen as a key measure by Chinese policy makers for enhancing power system flexibility (NDRC, 2017). It can be a crucial resource for a system with high shares of VRE, considering that VRE introduces additional variability and uncertainty into power systems that can require more system flexibility to be properly managed. In cases that include DSR deployment, 300 GW of load shiftable from the residential and service sectors is deployed, comprising space heating and cooling, water heating, refrigeration and cleaning appliances. These loads, depending on their nature, can be shifted within a specific window (either one, five or eight hours), with the ability for the aggregated loads to be controlled between 0% and 200% of the peak load. Depending on power system requirements and usage constraints on flexible load, only a portion of the maximum 300 GW are used in system operation. The case where only DSR resources are deployed is referred to as "**SDS-DSR**". Industrial demand side response is not included in this case, but is explored in a separate analysis (see Box 25).

Electricity storage, especially PSH and electric batteries, is in China's mid- and long-term energy strategies (NEA, 2016; NDRC, 2016). PSH capacity is planned to reach around 40 GW by 2020. Fuel cell, hydrogen and lithium-ion battery technologies and materials are highlighted in the long-term energy strategy. In cases that feature additional storage, deployment of over

50 GW of battery energy storage capacity is assumed, compared to zero deployment in cases without additional storage. The regional distribution of this additional deployment is based on the geographic distribution of VRE resources. For this analysis, a detailed analysis of PSH is included and approximately 70 GW of PSH capacity is also deployed in these cases, bringing the total amount of PSH capacity to over 100 GW. The case where additional electricity storage alone is deployed is referred to as “**SDS-Storage**”.

EV technology is seen to have strategic value in the future transport and power sectors in China. Policies support the development of EVs and both private and publicly accessible charging outlets (NEA, 2017). Fast and smart chargers are encouraged in China because charging duration and cost-competitiveness are more critical in its densely populated cities. Under the *WEO SDS*, 220 million EVs are assumed to be on the road in China in 2035. In cases that include **smart EV charging**, these vehicles are made available under smart charging schemes, which corresponds to approximately 250 GW of peak EV charging load and 800 terawatt hours of total annual EV charging load. The smart charging methodology implemented in the power sector model combines both daytime and overnight charging products, allowing full optimisation across the day in response to broader generation and demand patterns. Universally available EV charging infrastructure is implicitly assumed in all cases under the SDS. The case where smart EV charging protocols alone are rolled out is referred to as “**SDS-EV**”.

Finally, there are several cases that combine multiple flexibility options to investigate interactions between them. Due to the large flexibility potential associated with smart EV charging, the combinations assessed are EVs and DSR (“**SDS-DSR + EV**”), and storage and EVs (“**SDS-Storage + EV**”). In addition, a case combining all flexibility options is investigated (“**SDS-Fully flexible**”).

The analyses employ the same metrics as the NPS to assess the benefits of flexibility measures. However, advanced flexibility options can bring important benefits from reducing peak electricity demand and thus reduce the overall level of generation investment required in the power system. Associated benefits are estimated using the average cost per unit of installed capacity for 2035 generation capacity in the *WEO 2018 SDS* (see Annex A for details). This can be considered a conservative estimate because it does not account for associated cost reductions for grid infrastructure. Because some of the flexibility measures require capital expenditure themselves, associated costs are also estimated and a cost-benefit analysis is performed that examines both investment-related and operational impacts..

Table 10 summarises the power sector modelling cases considered for the SDS in 2035.

The modelling presented in this report explores the efficacy of advanced flexibility options in the Chinese power system at an unprecedented level of detail for IEA analyses. Hence, the detailed operational results, which utilise a separate production cost modelling framework for the year 2035, differ from the *WEO SDS* results in their generation patterns. Installed generation capacity at a national level is in line with the *WEO 2018 SDS*. Further details on the installed capacity and the *WEO 2018* generation mix are presented together with the modelling results in subsequent sections.

Table 10. Case settings for the SDS analysis

	SDS-Inflex	SDS-DSR	SDS-Storage	SDS-EV	SDS-DSR + EV	SDS-Storage + EV	SDS-Full flex
Demand response	No	Yes	No	No	Yes	Yes	Yes*
EVs	No	No	No	Fully flexible	Fully flexible	Fully flexible	Fully flexible
Additional storage	No	No	Yes	No	No	Yes	Yes

Note: A total of 43 GW of PSH capacity is assumed in all scenarios to account for existing and soon-to-be-commissioned capacity.

Three single-option and three multi-option cases are compared to an inflexible scenario in order to assess the benefits of using advanced flexibility options in a largely decarbonised Chinese power system in 2035.

Description of power system model used for analysis

The modelling presented in this study builds on several years of previous developments, including as part of the World Energy Outlook. Since 2017, the World Energy Model has a regional model of China. For this report, a further refinement and additional details in modelling the Chinese power system were implemented.

The PLEXOS® production cost modelling software is used to simulate the operation of the Chinese system for the different NPS and SDS cases in 2035. The production cost model, which represents China as eight different regions, includes supply- and demand-side components in addition to interregional transmission and the relevant constraints thereof. On the supply side, generators are modelled in terms of both technical characteristics (e.g. ramp rates, minimum stable levels, minimum up/down times) and economic characteristics (e.g. fuel prices, O&M costs and carbon costs). In addition, must-run generation, including China's significant co-generation fleet, is represented with specific operating constraints, while hydropower generation includes plants as either run-of-river (both with and without daily pondage), large reservoir or PSH. Seasonality is included for both hydropower availability and must-run constraints on co-generation in district heating regions.

Meanwhile, a representation of regional demand in China in 2035 is also modelled, comprised of different end-use profiles that allow for the modelling of DSR based on the potential of each end use. Operational reserves (spinning and regulatory) are also considered.

The primary outputs from the modelling are system operation profiles of the various power plants, overall system costs and emissions. These are presented in detail for both the NPS and the SDS in the following sections. This model is the most detailed representation of the Chinese power system that the IEA has implemented to date. Further details of the modelling methodology are presented in Annex A.

Power sector modelling results

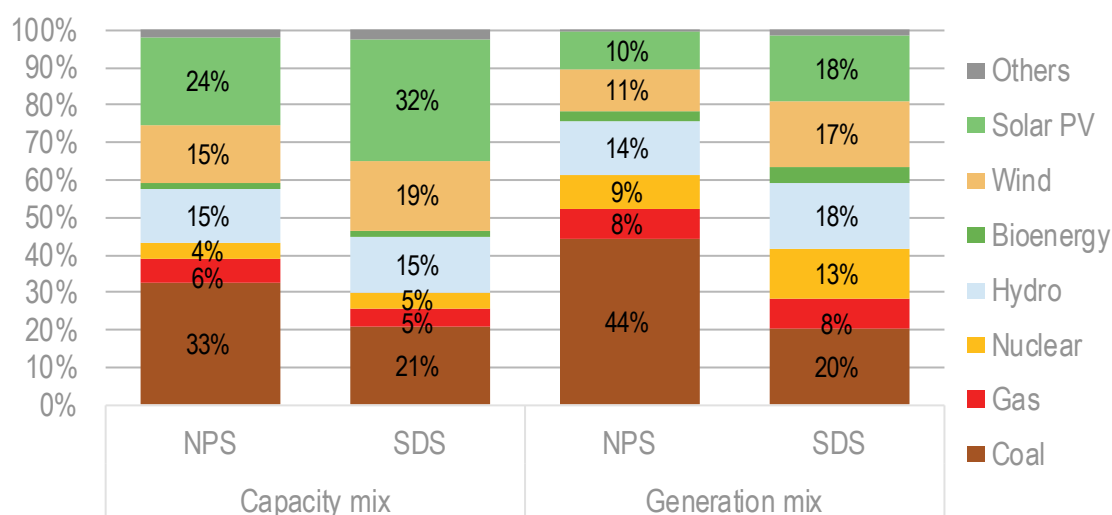
Comparing basic features of the WEO 2018 NPS and SDS results

This section describes basic input assumptions and power sector results from the *WEO 2018* NPS and SDS for China in 2035.

The NPS in 2035 results in total national net electricity generation of 9 835 TWh.⁴⁷ This pathway includes policies to contain electricity demand growth and address environmental challenges. The scenario assumes a moderate carbon price of USD 30 (United States dollars) per tonne (t). Fuel prices vary between USD 63/t and USD 94/t for coal and are fixed at USD 13 per million British thermal units (MMBtu) for natural gas (reflecting transport costs, see Annex A for details). The NPS features a 60% share for non-fossil capacity; 39% is from wind and solar PV. This translates into a generation share of up to 48% for non-fossil energy; 21% is from wind and solar PV.

The SDS exhibits a number of differences compared to the NPS. The SDS employs a mix of low-carbon options to achieve sustainable development objectives, including nuclear power and CCS. Most importantly, the scenario features a much higher share of variable renewable energy. At a national level, total net electricity generation grows to 8 996 TWh in 2035 – this is about 800 TWh less than in the NPS. This pathway includes more ambitious policies to contain electricity demand growth and address environmental challenges relative to the NPS. Compared to the the NPS, it considers additional electricity demand arising from higher levels of electrification of end uses, for example due to larger numbers of EVs.

Figure 28. Capacity mix for China in 2035, NPS and SDS



The SDS introduces a greater share of power from renewables and a lower share from fossil fuel technologies compared to the NPS.

⁴⁷ This figure includes electricity demand and transmission and distribution losses.

The scenario assumes a substantial carbon price of USD 100/t. Fuel prices vary between USD 55/t and USD 80/t for coal, with a price of USD 11.8/MMBtu for natural gas (reflecting transport costs, see Annex A for details). The SDS results in 74% of installed power capacity being non-fossil. Of installed capacity, 51% is wind and solar PV. This translates into a non-fossil generation share of 72%, with 35% of generation from wind and solar PV.

Installed capacity and annual power generation from *WEO 2018* for the two national scenarios are shown in Figure 28 and Table 11.

Table 11. Generation capacity in China, NPS and SDS *WEO* scenarios

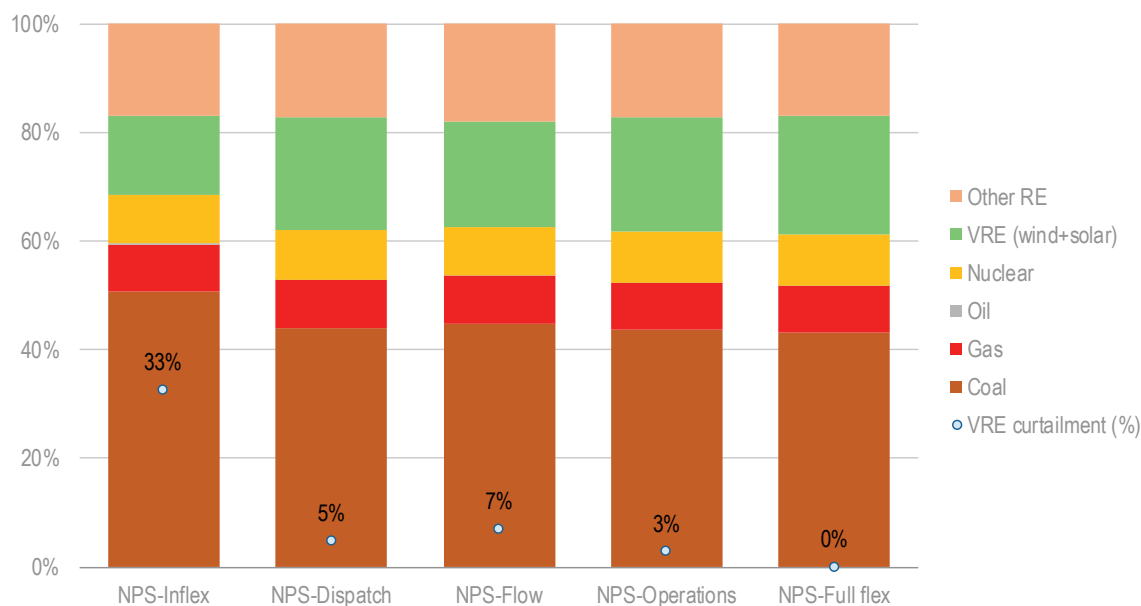
	Power generation capacity (GW)		
	2017	2035 NPS	2035 SDS
Fossil	1 065	1 288	973
Coal	981	1 073	783
Gas	75	208	183
Nuclear	37	136	171
Renewables	653	1 831	2 575
Hydro	344	484	547
Wind	164	508	709
Solar PV	131	776	1213
Total	1 755	3 294	3 772

NPS modelling cases

High-level summary of results

Transitioning to economically optimised power system dispatch and improving regional co-ordination and interconnectivity is shown to dramatically reduce power system operational costs and VRE curtailment. In fact, using a combination of improved dispatch and interregional trade (via better utilisation and additional transmission investments), the modelling results show it is possible to effectively eliminate curtailment of VRE in China (Figure 29) while operating with significant VRE penetration. Although economic dispatch can substantially reduce national levels of VRE curtailment, the levels in some regions remain relatively high. The following sections provide further details on the effects of the different cases.

The different policy options considered – change of dispatch order, expanding interregional trade through full utilisation of existing transmission capacity and additional transmission investment – not only impact the generation mix and VRE curtailment levels, but also bring significant economic and environmental benefits.

Figure 29. Generation mix and curtailment rate in China, 2035, all NPS cases

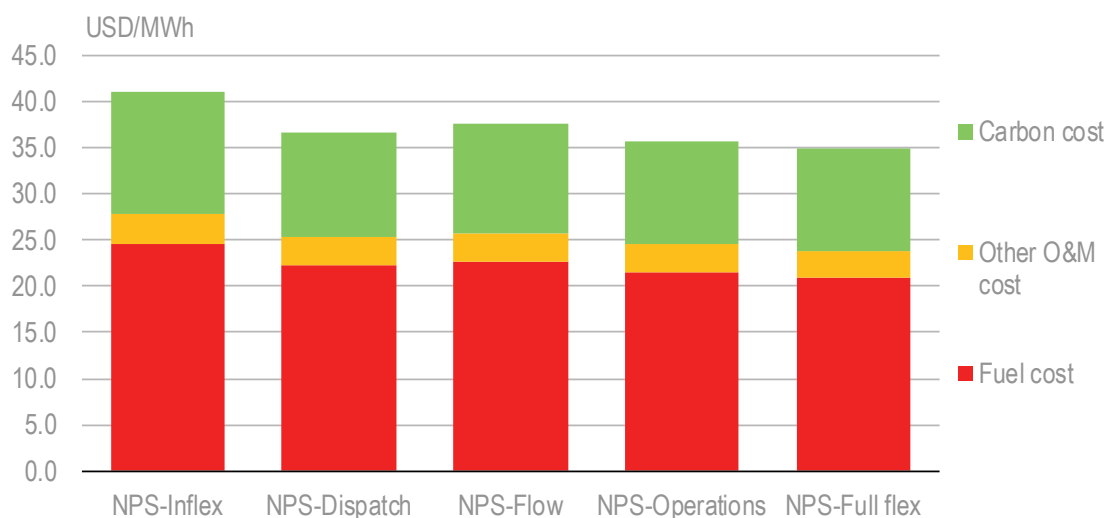
The policy measures explored boost system flexibility and reduce operational costs and VRE curtailment.

In economic terms, moving from fair to economic dispatch leads to considerable reductions in annual power system operational costs. Figure 30 compares major operational costs in each case to identify the contribution of the policy measure. It includes fuel costs, other O&M costs, and carbon emission costs. By changing the dispatch rule from fair to economic dispatch,⁴⁸ operational costs decrease by around 10%, mainly from the reduction in coal consumption.⁴⁹ Expanding interregional trade and additional investment in transmission lines helps further reduce operational costs, largely by reduction of average coal price due to the shift of coal generation to regions where cheaper fuel is available. Total savings from flexibility measures presented in the figure sum up to around USD 6 per megawatt hour, which means that the entire power system could save around USD 60 billion by adapting these measures.

Although a carbon price was assumed at USD 30 per tonne of CO₂ in all NPS cases, it did not lead to switching from coal to gas in the merit order under economic dispatch. The price levels that would lead to a change in the merit order are between USD 70 and USD 110 per tonne of CO₂ depending on coal technology. The change in merit order due to the carbon price is relevant in the SDS cases discussed in the next section.

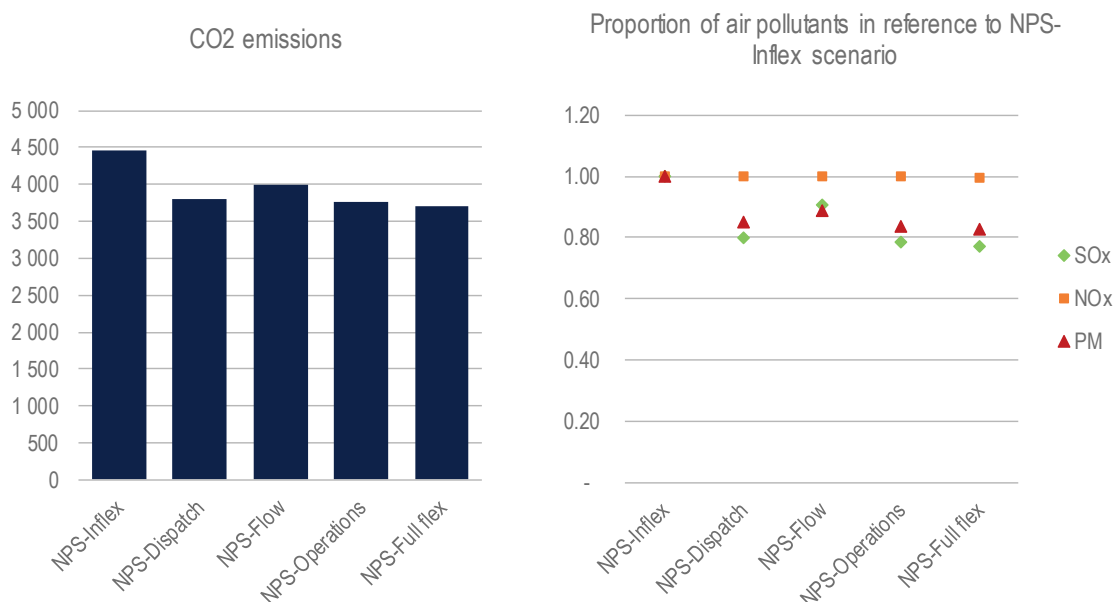
⁴⁸ In NPS cases where economic dispatch is imposed, natural gas generators are nevertheless granted a generation allocation in alignment with government policy.

⁴⁹ Investment-related costs are not considered in production cost modelling exercises.

Figure 30. Annual power system operational costs by cost category, 2035, NPS cases

Economic dispatch and improved trade substantially reduce power system operational costs.

In addition, substantial reductions in CO₂ emissions and air pollutants are observed when these policy measures are adopted (Figure 31). The overall reduction in CO₂ emissions can be as high as around 750 million tonnes, corresponding to 6% of total global power sector emissions in 2017 or the equivalent of the 2017 annual energy-related CO₂ emissions of Germany.

Figure 31. CO₂ emissions and air pollutants, 2035, NPS cases

Note: PM = particulate matter.

The three possible policy measures of economic dispatch, interregional trade and transmission investment can reduce the environmental impacts of the power system.

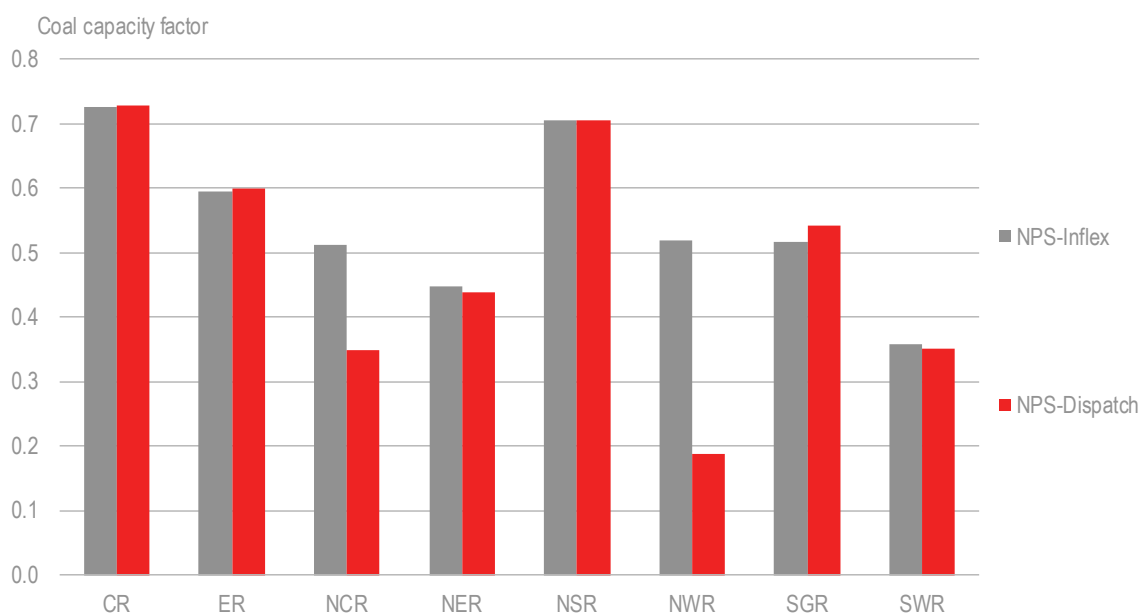
Value of moving from fair dispatch to economic dispatch

Changing the dispatch order leads to a net reduction in annual operational costs of around 11% (USD 45 billion per year) (Figure 30). This is largely driven by reduced coal consumption, which is replaced by electricity generated from VRE, and associated fuel and emission cost savings. This effect offsets the rise in average fuel prices due to the large decrease in coal generation in the Northwest and North Central regions, where the cheapest fuel is available.

In general, the fair dispatch regulation creates a system with major economic inefficiencies. A significant amount of electricity generated by VRE is curtailed in order to meet the target full-load hours of conventional generation. This reaches 30% of available VRE generation in the most restrictive variant, the NPS-Inflex baseline case. This electricity is replaced by more expensive fossil fuels, burned on the basis of allocated generation hours. By changing the dispatching order to one based on economic competitiveness, the power system is able to significantly reduce system costs and integrate more electricity from VRE, while reducing fossil fuel consumption to generate electricity. It is worth noting that natural gas generation retains a guaranteed operating regime under the NPS-Dispatch case.

The detailed hourly modelling confirms the importance of moving to economic dispatch. Even under continued low utilisation of the available transmission capacity and no new construction of transmission lines after 2022, the national curtailment level falls to 5%. However, this number is still above international benchmarks generally deemed economically efficient.

Figure 32. Impact of moving to economic dispatch on coal power plant capacity factor, by region



Notes: CR = Central; ER = East; NCR = North Central; NER = Northeast; NSR = Shandong; NWR = Northwest; SGR = Guangdong; SWR = Southwest.

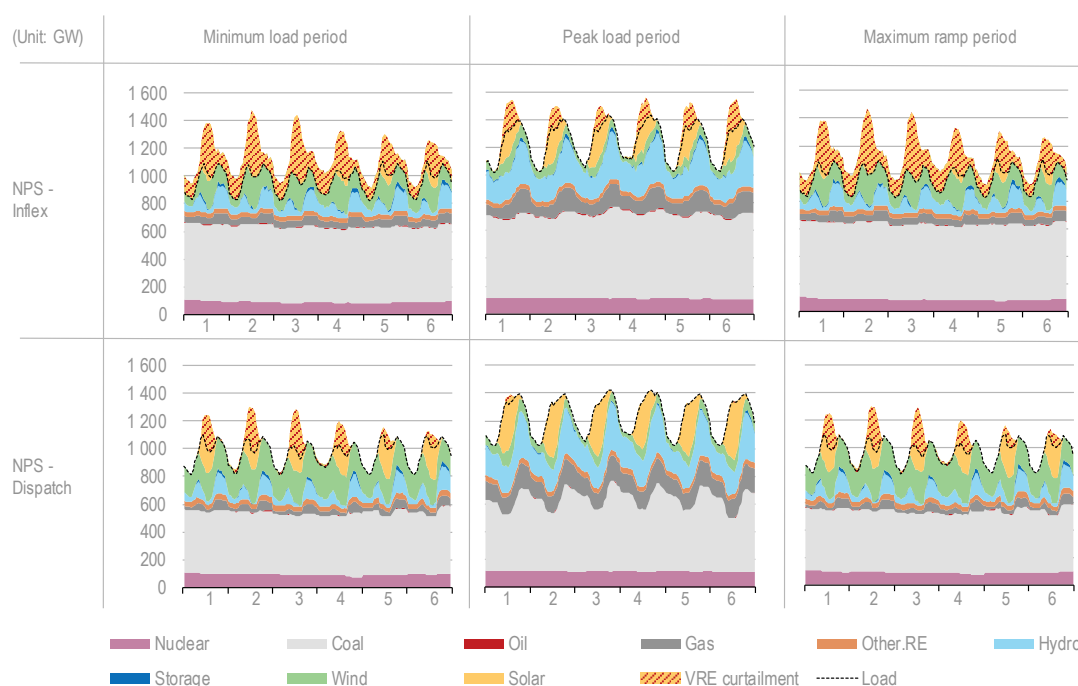
Coal power plants in higher VRE regions experience a reduction in utilisation under economic dispatch.

Moving to economic dispatch has significant consequences for fossil fuel generators, which see a drop in their full-load hours – especially in VRE-rich regions, notably the Northwest and North Central regions (Figure 32). Low utilisation hours indicate possible overcapacity, which can

trigger the market exit of a substantial amount of generation capacity, in the absence of an appropriate economic mechanism. This issue will require close monitoring and possibly dedicated policy intervention to ensure an orderly transition. However, as the following section shows, the opening of electricity trade has a pronounced effect on which coal generators see a reduction in their utilisation.

Increasing penetration of VRE by reducing curtailment is only possible with a changed operational pattern of fossil fuel and dispatchable hydropower plants, as these move to balance a more volatile net load.⁵⁰ This can be observed in particular during periods of very high net load ramps (Figure 33, right panel). However, assuming standard flexibility characteristics of the generation fleet, there is no major issue in balancing supply and demand at a national level.

Figure 33. National level load and generation mix of a typical week, fair and economic dispatch



The Chinese power system can accommodate a larger share of VRE with a mix of flexible generation technologies in the absence of dedicated plants to provide flexibility.

Value of unlocking interregional trading

The value of increased interconnection is explored in a number of different cases with a different emphasis. The first analysis – NPS-Flow – investigates the value of increased trade in the presence of fair dispatch. This allows an assessment of the relative importance of improved regional trade versus improved dispatch. The second analysis – NPS-Operations – combines improved trade and dispatch to investigate trade-offs and synergies between both options. The third analysis – NPS-Full flex – then looks at additional grid investment in a system that already relies on optimised operations.

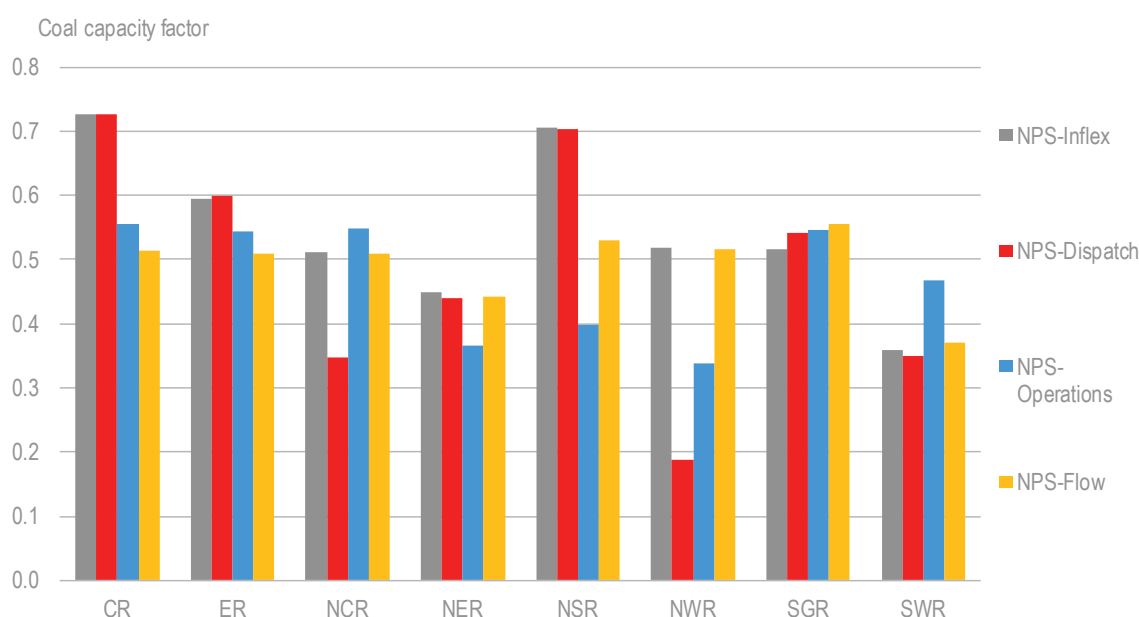
⁵⁰ Net load is the total electricity demand in the system minus wind and solar PV generation. This represents the demand that the power system operator must meet with other dispatchable sources, such as natural gas, hydropower and imported electricity.

The NPS-Flow case results in a reduction of power system operating costs of 9% (USD 36 billion per year). Benefits are somewhat lower compared to the NPS-Dispatch case and the source of benefits is slightly different. First, increased utilisation of interconnections reduces average fuel costs, because plants with lower coal input prices export electricity. In regions with low coal prices, such as the NCR and NWR, the amount of coal-fired generation increases and is exported to other regions (Figure 34). Coal power generation in these regions starts to replace coal power generation in the CR, ER and NSR due to their lower marginal costs of coal generation. Although coal power plant efficiencies are generally lower in NWR and NCR relative to other regions, this is offset by a sizable difference in coal price. (NCR at USD 54/t and NWR at USD 56/t compared to CR at USD 85/t and ER at USD 82/t).

Curtailment of VRE is substantially reduced to 5%, but remains higher than in the NPS-Dispatch case. This is mainly due to a saturation of export capacity from VRE-rich regions, especially the NWR and the binding full-load hours for conventional generation in that region.

Combining improved dispatch and better use of transmission capacity leads to the NPS-Operations case. This case features a reduction in total operational costs of 13% (USD 54 billion per year) and a reduction in curtailment to 3%. This points to additional benefits from combining both measures, but the benefit from the combination (USD 54 billion per year) remains lower than the sum of the individual measures (USD 54 billion for dispatch and USD 36 billion for trade per year). Both measures are still not sufficient to eradicate curtailment completely and national curtailment levels are 3%.

Figure 34. Impact of interregional trading and transmission expansion on coal-fired power plant utilisation, by region



Unlocking interregional power flows allows for cost-optimal levels of coal power generation.

The final case – NPS-Full flex – considers new investment in transmission capacity, bringing total interconnection capacity from 230 GW (2022) to around 410 GW (2035). In this case, operational costs are reduced by 15% (USD 60 billion per year) and curtailment of VRE is brought to 0%. It brings annual savings of USD 6 billion over the NPS-Operations case. This

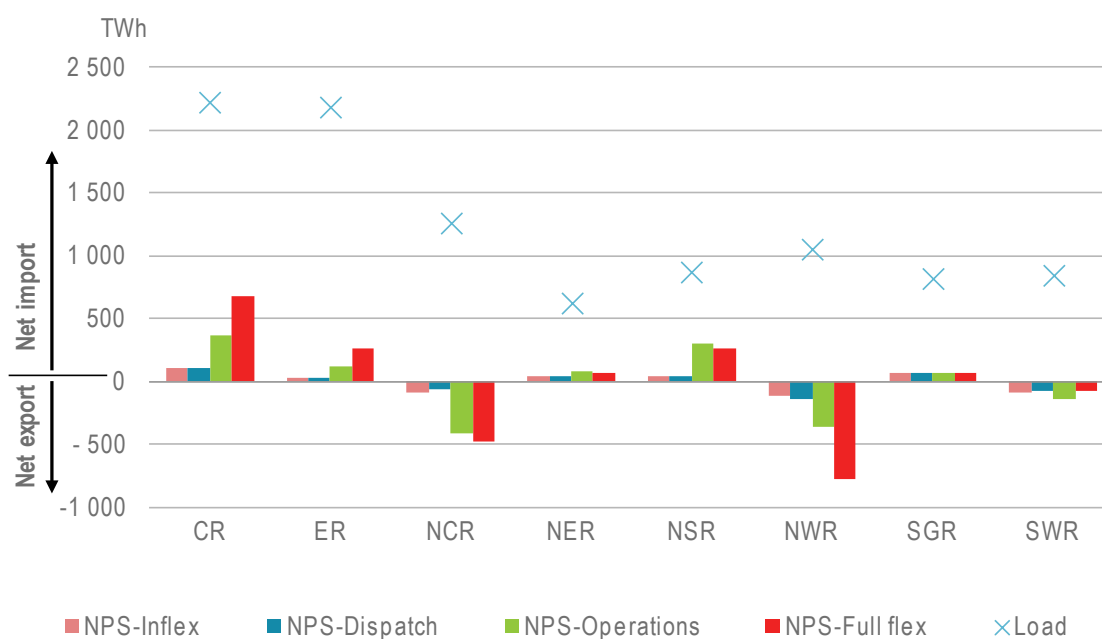
more than offsets the estimated annuitized investment cost for the transmission of around USD 2.3 billion per year.

Fully unlocking the potential of regional trade has a number of effects, which are not linked primarily to VRE integration alone (Figure 35). The most notable effect is the result of the difference in the coal price across China, linked to the cost of transporting and difference in prices for domestic and imported coal.

As the barriers to fully utilising transmission capacity are lifted, there is a change in the way the different regions trade energy. By firstly unlocking interregional trade on the existing transmission network, more power flows from the hydro-rich SWR to the CR, while there is also an increase in the flow of power from the VRE-rich NWR to the CR and ER. NSR also sees a large increase in power imports from the NWR and NCR. The ability for it to import cheaper electricity will be helpful to Shandong's economic structural change (see Annex A).

Following the increase in transmission utilisation, investment in the transmission network in the NPS-Full flex case leads to further development of interregional power trade, mostly characterised by a more than twofold increase in power exports from the NWR and increased power imports into both the CR and ER. The level of power exports from the NWR demonstrates the competitiveness of the low-cost VRE in this region – a fact that could benefit the development of the region's economy.

Figure 35. Load and net import of energy by region, 2035, NPS cases



Increased interconnectivity raises the importance of regions with abundant, low-cost electricity supply to meet national power demand.

A closer look at VRE-rich regions

The implementation of economic dispatch substantially reduces VRE curtailment at a national level. However, considering the size of China, it is necessary also to examine regional levels of curtailment, as some regions with significant VRE capacity might experience high curtailment due to constrained transmission links. Two regions are especially relevant (see Table 12): the NCR and the NWR. These two regions have a curtailment rate of around 50–60% when applying fair dispatch, revealing the shortfall in flexibility of this administrative dispatching order (NCR has capacity of about 100 GW of wind and 100 GW of solar PV, while NWR has about 200 GW of wind and 200 GW of solar PV).

Interestingly, after switching to economic dispatch, the curtailment rates in the both NCR and NWR dramatically drop from 46% to 3% and from 55% to 10% respectively. This significant drop in VRE curtailment is due to the large amount of coal generation capacity in NCR and NWR that receive a generation allocation under fair dispatch protocols in the NPS-Inflex case. When moving from fair to economic dispatch, the amount of coal generation in NCR and NWR is reduced by more than 50%, given the large amount of low-cost VRE generation available.

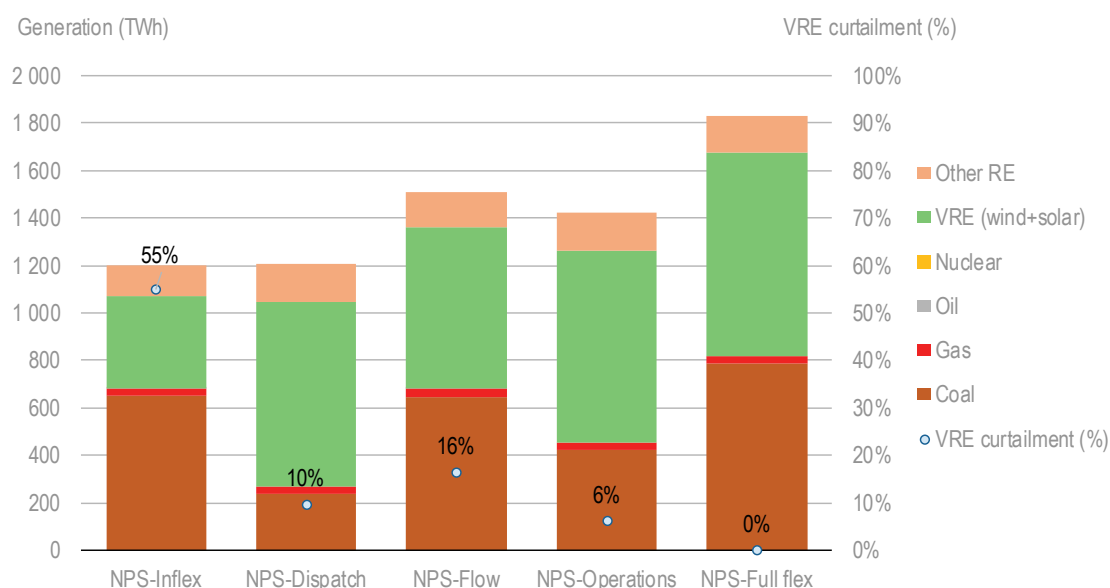
Table 12. VRE curtailment rate by region

	CR	ER	NCR	NER	NSR	NWR	SGR	SWR	China
Fair dispatch (NPS-Inflex)	0%	0%	46%	6%	1%	55%	0%	0%	33%
Economic dispatch (NPS-Dispatch)	0%	0%	3%	4%	0%	10%	0%	0%	5%

VRE curtailment falls significantly after a shift to economic dispatch, but it remains relatively high in certain regions.

Indeed, the NWR hosts one-third of China's solar and wind capacity due to significant potential resources and grid capacity, resulting in its VRE generation capacity far exceeding local demand. Hence, further flexibility enhancements are required to successfully integrate the region's large amount of wind and solar capacity. Interregional trading can be enhanced so that more load from other regions is met by the NWR, helping to consume its large amount of VRE generation.

Current interregional electricity trading in China is mostly administrative and uses only a limited proportion of the transmission capacity. By allowing the full utilisation of existing interregional transmission capacity, interregional trade expands. Energy exports largely remove the VRE surplus in the NWR, leading to a 4 percentage point decrease in VRE curtailment (Figure 36). Additional investment in interregional transmission capacity can further decrease VRE curtailment to below 1% for the NWR. During periods with low VRE output, the system can still operate reliably with the flexibility of interregional trading and transmission capacity.

Figure 36. Generation mix and VRE curtailment rate in the NWR

Due to it having the highest share of VRE and the cheapest fuel price, the NWR experiences the greatest change in generation mix due to implementation of flexibility measures.

SDS modelling cases

Compared to the NPS, the SDS presents a very different 2035 power system in terms of installed capacity. The SDS system reflects a trajectory that emphasises clean energy options in order to reduce environmental impacts, notably air pollution and CO₂ emissions. The SDS employs a mix of low-carbon options to achieve these objectives, including nuclear power and CCS. Most importantly the scenario features a much higher share of VRE relative to the NPS suite of cases. It assumes that power sector reforms have led to the implementation of economic dispatch and the optimal utilisation of transmission capacity for all cases. Due to the paramount importance of power system flexibility in the SDS, the sensitivity analysis presented below explores the value of different innovative measures that can provide flexibility.

High-level summary of the results

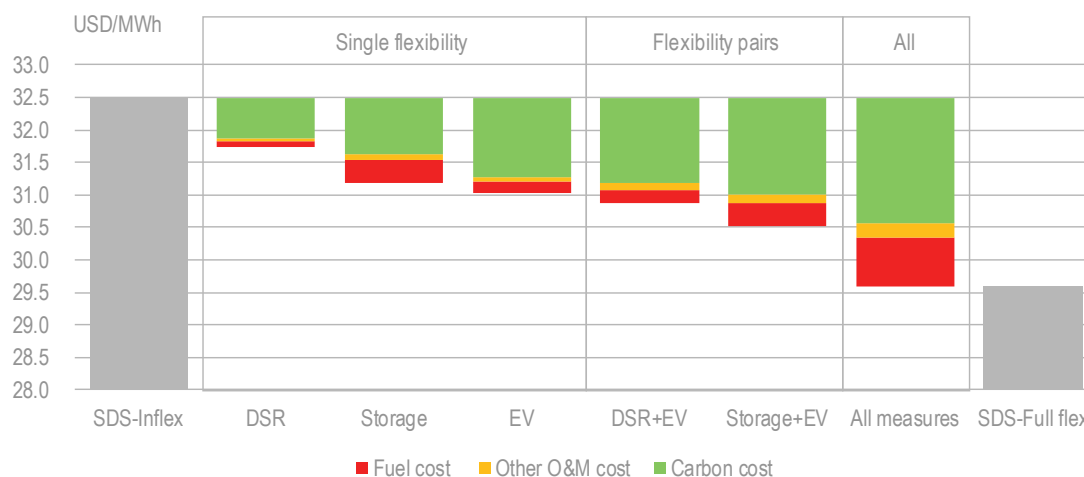
As explained earlier in the chapter, three distinct groups of flexibility options are analysed in the SDS modelling: smart charging of EVs, advanced DSR programmes, and electricity storage deployment. In order to consider the value of these flexibility measures, an inflexible version of the SDS (SDS-Inflex) was established without the presence of these measures, in order to serve as a benchmark for comparison. This allows metrics on cost, benefit and technical impact to be explored for each flexibility measure. Notably, because all flexibility options explored in the NPS are assumed to be implemented – economic dispatch, improved interregional trading and additional investment in transmission infrastructure – the power sector modelling presented in the SDS cases sheds light on the value of more advanced flexibility measures for transforming a power system. In summary, the following advanced power system flexibility options are considered:

- Approximately 300 GW of residential, commercial, agricultural and industrial-sector load contributing to DSR programmes are in place in 2035, with enrolled resources spanning space heating and cooling, water heating, refrigeration and cleaning appliances.
- 220 million EVs are made available under smart charging schemes in China in 2035, which corresponds to approximately 250 GW of peak EV charging load and 800 terawatt hours of total annual EV charging load.
- Over 100 GW of pumped storage hydro and over 50 GW of battery energy storage are deployed.

The investigated flexibility options lead to annual operational cost savings of between 2% and 11% relative to the SDS-Inflex case (Figure 37). Due to a substantial CO₂ price of USD 100/t, CO₂ emission cost savings are an important driver of operational cost savings in the SDS cases. In addition, flexibility options reduce peak net demand and thus bring additional benefit to the system through reduced generation investment requirements. The flexibility measures also provide environmental benefits by reducing annual power sector CO₂ emissions by between 4% and 14% (Figure 39).

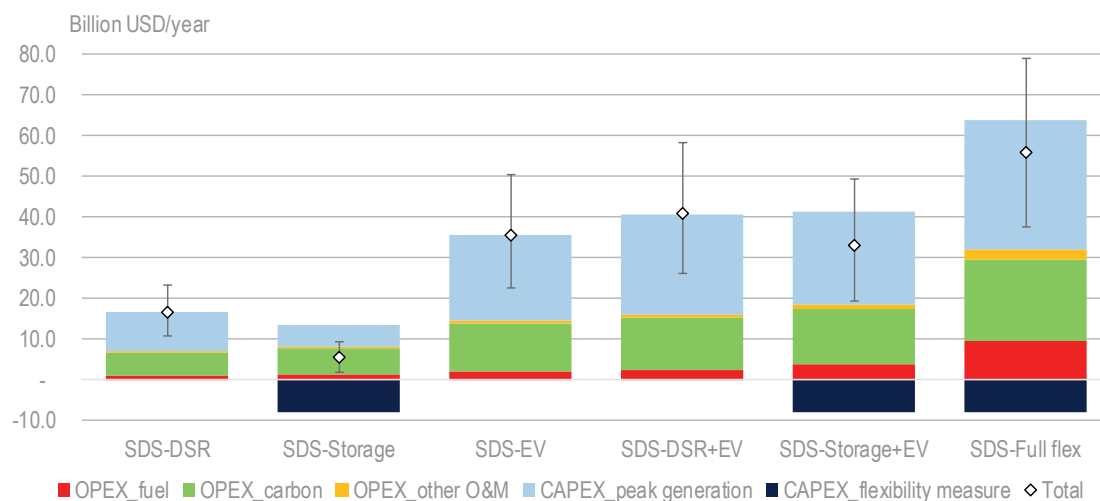
In the case of electricity storage, the flexibility options themselves also require substantial capital investment. In order to assess the full suite of costs and benefits for these measures, the impacts of changed investment requirements have also been included in the analysis by converting capital expenditure (CAPEX) figures into annual payments. This allows comparison of the flexibility options' costs and benefits for the overall power system. In all cases, benefits are higher than costs, although they differ significantly in their cost-benefit ratio (Figure 38). The following sections explore the different cases in more detail.

Figure 37. Annual operational cost savings from different flexibility options, 2035, SDS



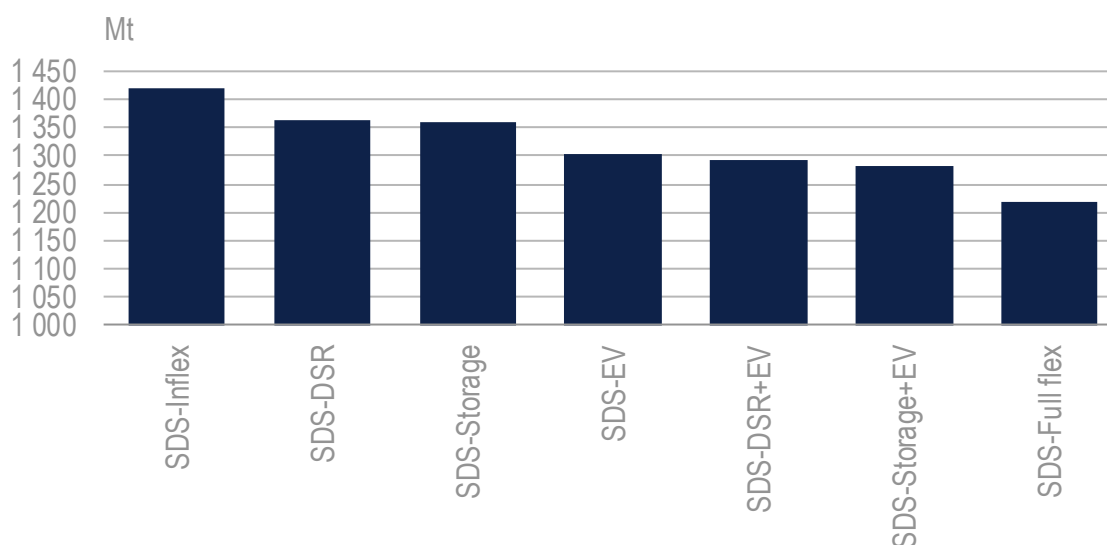
Notes: Y-axis does not begin at 0.0 to enhance reader comprehension of trends; MWh = megawatt hour.

All modelled flexibility options significantly reduce annual power system operational costs.

Figure 38. Annuity net power system cost savings, relative to SDS-Inflex, all SDS cases

Notes: Power system CAPEX required for EV and DSR measures is assumed to be zero – see text for details; OPEX = operational expenditure.

All modelled flexibility options bring net benefit to the system considering each option's total system investment requirement.

Figure 39. Annual CO₂ emissions, 2035, SDS cases

All modelled flexibility options significantly reduce annual power sector carbon emissions.

Understanding an SDS power system without advanced flexibility options: SDS-Inflex

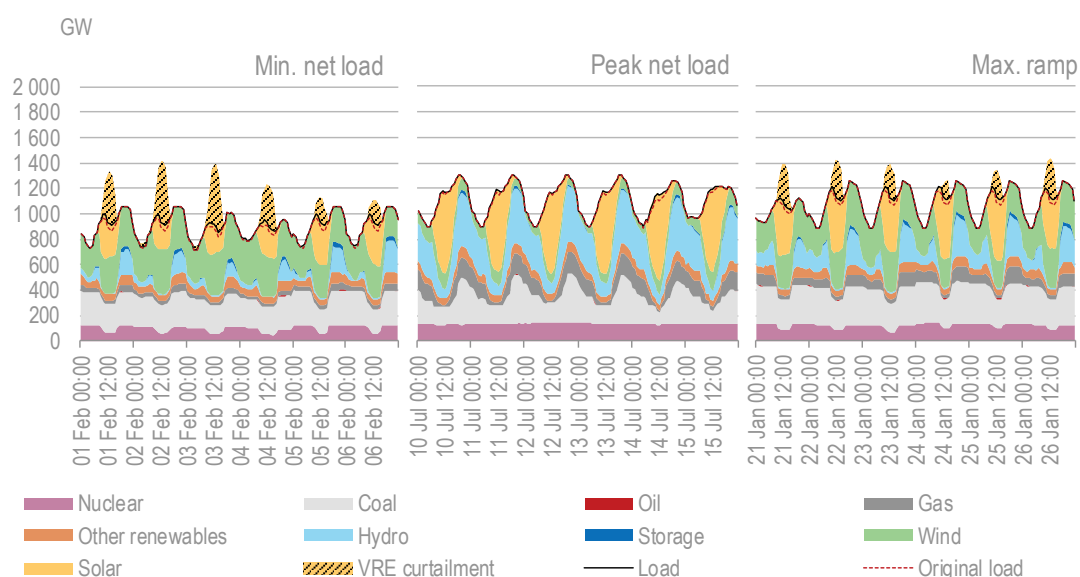
The SDS-Inflex case represents a substantially decarbonised power system that exists largely without the presence of any innovative flexibility options. It only considers existing PSH installations or those that are under construction and expected to come online by 2023. Chiefly, it serves as an analytical baseline against which to compare the impact of flexibility options. In

this baseline case the modelling results show that wind and solar PV contribute around 35% to total power generation, which is significantly higher than the 21% VRE penetration in the NPS. Power system flexibility, already an important characteristic, therefore becomes increasingly critical to the cost-effective operation of the power system and accommodation of VRE.

With limited flexibility options available, annual average curtailment is around 5% nationally, with regional curtailment levels for NCR, NER and NWR reaching between 3% and 15%. Power plants of all technologies, including nuclear, are required to provide a substantial amount of operational flexibility (Figure 40). Importantly, VRE curtailment occurs despite the significant operational flexibility that can be provided by dispatchable generation, improved system operations and greater regional transmission interconnectivity.

In summary, the SDS-Inflex case demonstrates the paramount importance of power system flexibility in a decarbonising Chinese power system in 2035. This case is now used as a basis for comparison of cases in which various flexibility measures are deployed. All reported savings are expressed relative to this baseline.

Figure 40. Generation patterns and the demand profiles during high stress periods with limited flexibility options, SDS-Inflex case



Notes: Max. = maximum; Min. = minimum.

Without additional flexibility options available, the Chinese power system experiences increased VRE curtailment during minimum load and maximum ramp periods.

Assessing individual flexibility options

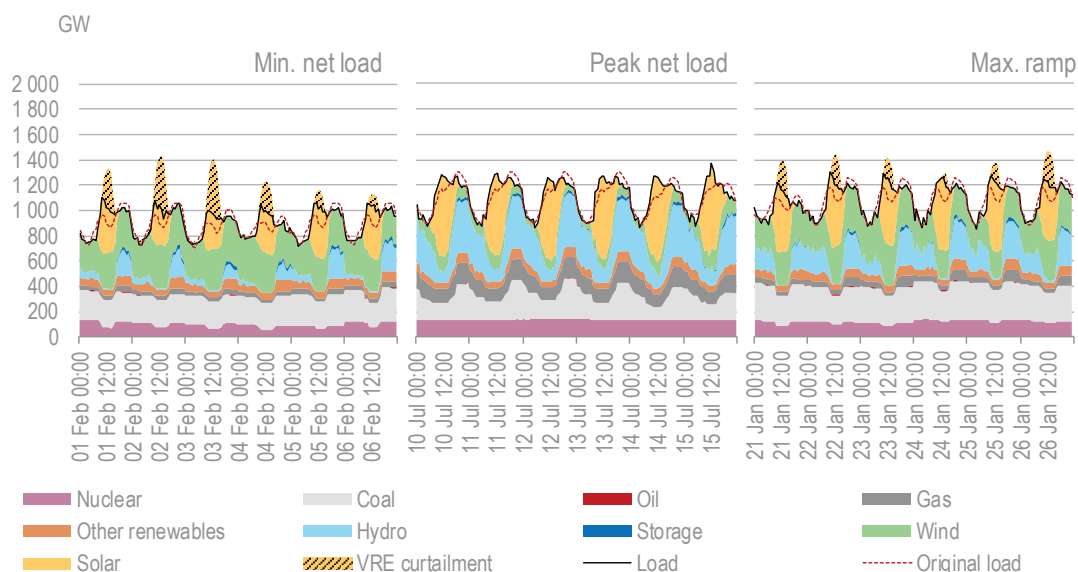
Understanding the value of DSR deployment: SDS-DSR

The SDS-DSR case is used to understand the value of DSR options. It considers 300 GW of residential, commercial, agricultural and industrial load contributing to DSR programmes in 2035, with enrolled resources spanning space heating and cooling, water heating, refrigeration and cleaning appliances. Smart EV charging is assessed in a separate case.

Comparing results from the SDS-DSR case against the SDS-Inflex case is instructive in understanding the costs, benefits and operational impacts of these DSR options in a

decarbonising 2035 Chinese power system. Operational costs in the DSR case are approximately 3% lower, which is equivalent to a saving of approximately USD 7 billion per year. These savings are driven primarily by increased utilisation of VRE enabled by flexibility, which reduces fossil fuel consumption in the system. In addition, DSR leads to a flatter demand profile, which enhances the utilisation of resources with low fuel costs (including nuclear power) at the expense of more costly peaking generation (Figure 41). Total CO₂ emissions in the SDS-DSR case are 4% lower than the SDS-Inflex case.

Figure 41. Generation patterns and demand profiles during high-stress periods, SDS-DSR



DSR measures lead to increased utilisation of low marginal cost resources such as nuclear and VRE, while reducing the stringency of operational requirements during high-stress periods.

Importantly, the modelled flexibility measures also deliver a reduction in peak net demand of 71 GW compared to the SDS-Inflex case, which translates into a potential annualised investment cost saving of approximately USD 9 billion per year (driven by reduced investment in low-utilisation generation infrastructure). Combined savings (OPEX and CAPEX) are USD 16 billion per year.

Enrolling these resources tends to have negligible investment-related cost to the power system, as participating DSR resources (or their aggregators) typically finance the modest infrastructure upgrades to become a DSR resource (e.g. power electronics upgrades, new information and communication systems). They receive compensation based on their participation in the market (and this compensation is captured within the operational modelling framework).

Options are also available that do require additional investment in retrofits. The example of adding flexibility to existing aluminium smelters has been analysed in detail as a separate option in addition to the DSR programmes (Box 25).

Box 25. Boosting the flexibility of aluminium smelters in China

Aluminium production in China accounts for up to 85 GW of demand and 593 TWh (7%) of electricity consumption in 2035. Globally, aluminium smelters account for nearly 5% of electricity consumption. Aluminium plants traditionally require a very stable level of supply to keep the electrochemical process running, as well as to maintain a critical heat balance in the reduction cells (known as “pots”).

Recent innovations in the active temperature management of pots provides smelters with the ability to modulate power consumption both up and down by as much as +/- 30%. This is accomplished by retrofitting pots with an external temperature management system, which allows variations in electricity consumption while maintaining the critical heat balance of the pots and without affecting the electrochemical process in any way.

To increase energy use (which correspondingly produces more metal), additional cooling of the pot is required. The temperature management system achieves such cooling by drawing large volumes of ambient air past the external shell of the pot and into a ducting system, which is (usually) externally vented. The negative pressure to run the system is provided by a large external fan connected to the ducting, which is the only moving part. To achieve a decrease in energy use (which correspondingly produces less metal), the pot needs to be insulated to stop it from cooling. In this situation, the heat exchangers act as an insulating blanket when the fan speed is either reduced or stopped altogether.

An initial analysis of the latent flexibility potential from China’s fleet of aluminium smelters indicates a potential of around 25 GW. Critically, the load-smoothing capacity that modulating aluminium smelters provide is not only from hour to hour and day to day, but from season to season as well. This can help mitigate supply disruption caused through the variability of generation, especially through extended seasonal periods of low generation.

The total cost of retrofitting smelters in China is estimated to be in the order of USD 10 billion, with the cost assumptions provided by industry (approximately USD 50 per kilowatt [kW] for downward flexibility and USD 100 million per smelter for upward) (EnPot, 2019). This compares to operational cost savings of USD 3.5 billion per year compared to the SDS-Inflex option. Assuming a contribution to peak net load reduction of 10 GW, this would imply a simple investment payback period of 1.5 years from a power system perspective, assuming that all retrofits are ratepayer financed.

It is important to note that the flexible use of aluminium smelters for seasonal load shifting will influence the production profile of the plant (while maintaining the same annual output). Costs associated with increased storage requirements for aluminium at the plant have not been taken into account in the analysis. However, the relatively short payback period points to substantial possible savings that merit a more detailed analysis.

Source: Information provided by Energia Potior and available on the website, How EnPot Works, <https://www.energiapotior.com/how-enpot-works/>.

DSR has already been recognised as a key system flexibility measure by Chinese policy makers (NDRC, 2017), and this case demonstrates the significant operational value that DSR programmes can potentially deliver to a largely decarbonised Chinese power system in 2035.

Policy makers can consider a variety of actions to realise the various benefits offered by widescale DSR deployment. First is the commissioning of economy-wide studies of DSR potential to better understand the opportunity and where best to direct efforts. Next, once promising market segments for DSR have been identified, specific government interventions may be necessary to enrol particular larger-scale load resources (e.g. aluminium smelters), including the design of financial incentives for retrofits and/or participation requirements. Once enrolment costs have been well established for specific classes of larger-scale DSR resources, potential estimates and associated costs can be included in long-term planning exercises to provide specific deployment targets and guidance to implementing policy-making agencies.

As increasing amounts of competition are introduced into the power system, upgraded market framework rules can also allow for the participation of demand aggregation entities who have the ability to stack DSR potential across regions, customer classes and devices. The market for small-scale DSR aggregation can be further supported by upgrading device manufacturing standards to encourage or mandate the inclusion of information and communications technology (ICT) systems that streamline secure communication with aggregators and grid operators.

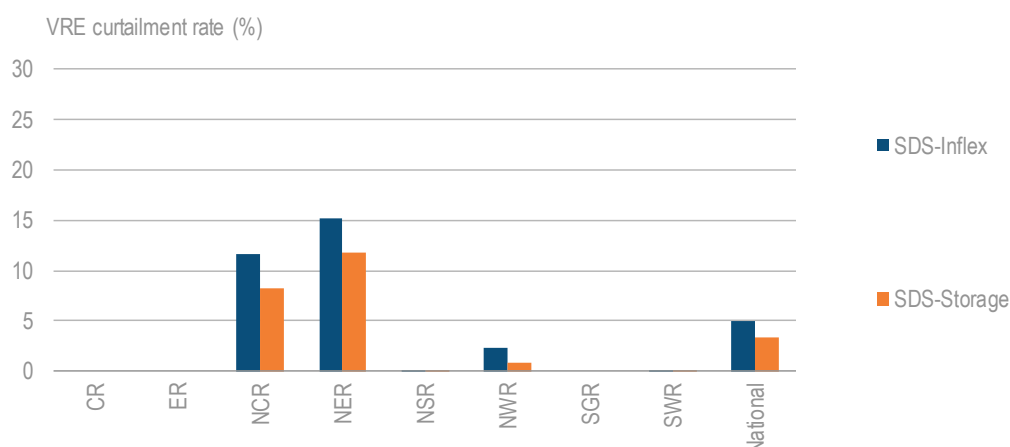
Understanding the value of electricity storage: SDS-Storage

In the SDS-Storage case developed for this report, an additional approx. 70 GW of PSH and over 50 GW of battery energy storage are deployed. The main differences between these two forms of storage, from the standpoint of short-term operational flexibility, lies in the round-trip efficiency of the two technologies (75% for PSH and 81% for lithium-ion batteries) and the size of the storage. PSH resources are assumed to have as many as 10 hours of storage, whereas battery energy storage resources are deployed with an equal split of one-hour and four-hour storage capability.

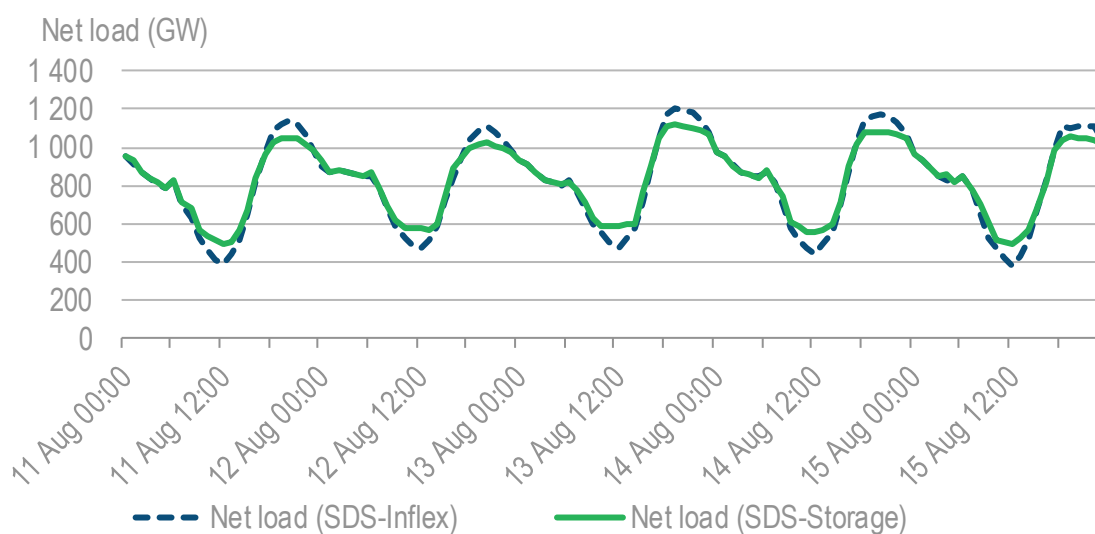
Immediate operational and economic benefits result from adding storage to the SDS power system, as these resources allow pumping/charging loads to be shifted into periods of high VRE output, producing operational cost reductions. The additional storage resources reduce annual operational costs by around 3%, or approximately USD 8 billion per year, which is equivalent to the required annualised investment cost of the storage assets. The storage options bring a further benefit of a peak net demand reduction of 42 GW, which would result in avoided generation investment of USD 6 billion per year.

Storage also reduces VRE curtailment levels in every region compared to the SDS-Inflex case (Figure 42).

Storage options are primarily used during periods of highest and lowest net demand, storing energy during low-demand periods and discharging energy during peak periods. The result is lower peak demand and higher minimum demand (Figure 43). In doing so, storage provides flexibility for the system to reduce reliance on peaking generation while also reducing coal- and gas-fired generation levels, which have relatively high operational costs for fuel and emissions.

Figure 42. VRE curtailment in SDS-Inflex and SDS-Storage cases, by region

PSH and battery energy storage resources help to reduce VRE curtailment.

Figure 43. Net load during peak demand periods in the SDS-Storage and SDS-Inflex cases

Storage resources help to flatten net demand.

Understanding the value of smart EV charging: SDS-EV

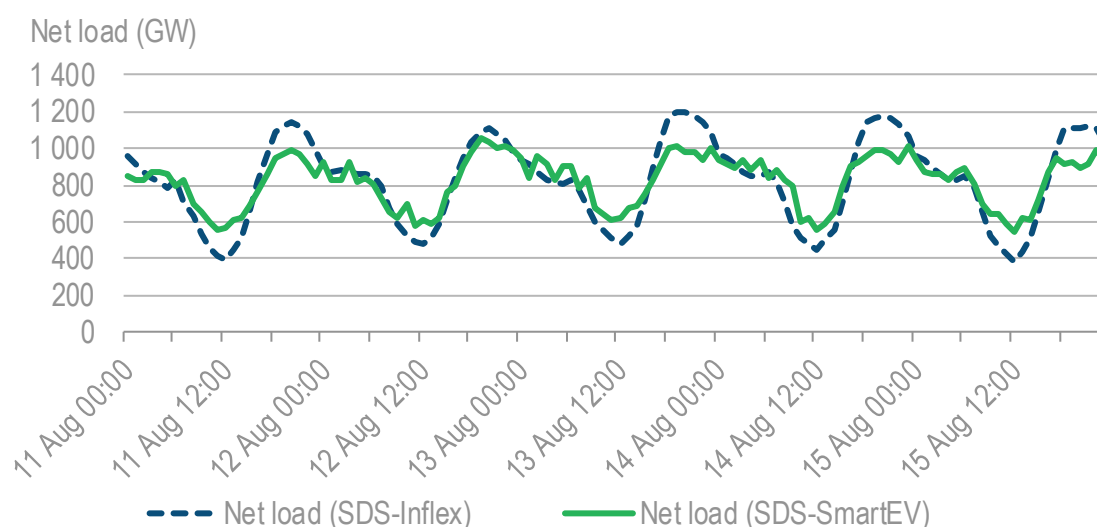
In the SDS-EV case, 220 million EVs are made available under smart charging schemes in China in 2035, which corresponds to approximately 250 GW of peak EV charging load and 800 terawatt hours of total annual EV charging load. This represents a significant shift from the SDS-Inflex case, where the same number of vehicles is allowed to charge in line with currently observed charging patterns and without consideration of power system operations.

The full enrolment of the Chinese EV fleet in grid-optimised smart charging schemes drives down annual power system operational costs by 5% in the year 2035, or approximately USD 15 billion per year, under the SDS-EV case. Power system operational cost savings are primarily driven by increased utilisation of low-cost VRE resources in lieu of coal-fired power

plants, which leads to significant savings of fuel and carbon costs. Minimum generation also increases in this case, which allows for more stable operation of power plants. This is captured in the reduction of operational costs in the modelling.

In addition, the peak net load of the system in 2035 reduces by 160 GW, or approximately 15% (Figure 44). This fall in peak demand reduces the need for additional investment in generation capacity and grid infrastructure, and the associated annualised investment-related benefit of this measure is calculated at approximately USD 21 billion per year.

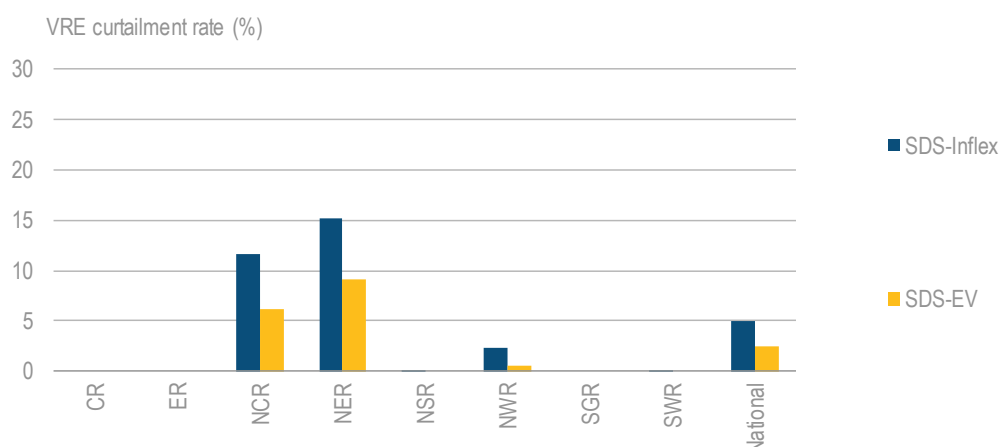
Figure 44. Demand reduction due to smart EV charging during periods of peak demand, SDS-EV case, 2035



Smart EV charging notably reduces peak demand and results in significant investment-related cost savings.

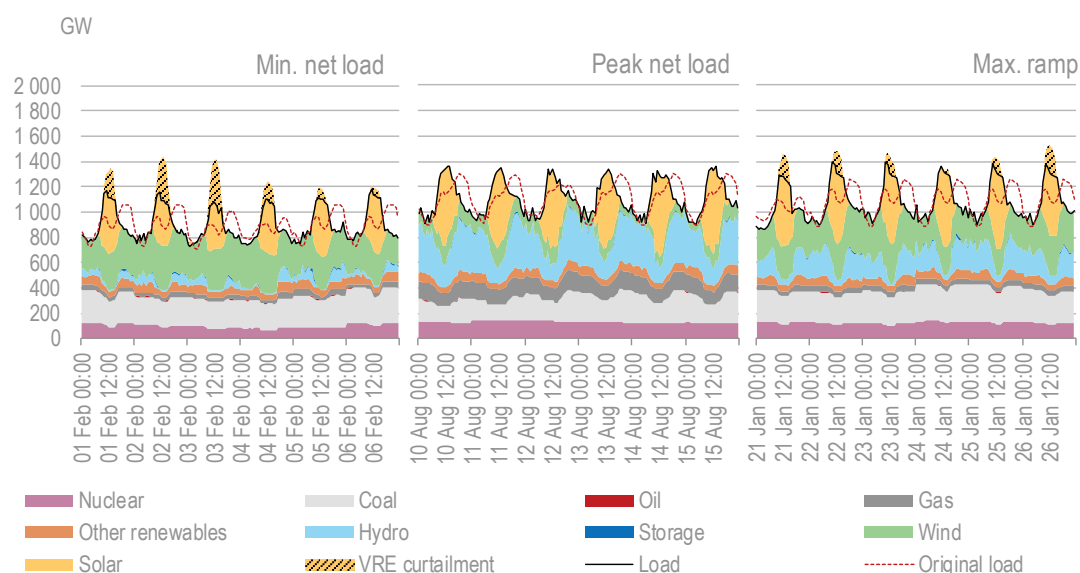
The application of smart EV charging schemes also helps to reduce VRE curtailment in regions with very high VRE penetration, in some cases bringing curtailment levels down to international benchmarks (Figure 45). It is important to note synergy between smart EV charging and transmission infrastructure. Certain regions with very high penetration of VRE (especially the NWR) have a relatively low population and hence a low EV density. Consequently, the presence of strong grid interconnection in these regions is beneficial for linking smart EV charging resources with VRE supply, boosting overall system flexibility and reducing VRE curtailment.

Such reduction in VRE curtailment driven by system flexibility enhancements, particularly in VRE-rich regions where significant deployment is likely to occur, will be an important goal for Chinese policy makers to persevere with. Doing so will help to maintain the investability of the renewable energy sector, ensure that financing is continuously available and possibly reduce the need for government subsidies.

Figure 45. VRE curtailment in SDS-EV and SDS-Inflex cases, by region

Smart EV charging can substantially reduce VRE curtailment levels at a national and regional level, helping to enhance renewable energy sector investability.

With respect to changes in power system operation, the modelling indicates that smart EV charging protocols generally shift EV charging loads to periods of VRE generation, enabling the power system to more easily meet operational requirements, particularly during periods of high stress for the power system (Figure 46).

Figure 46. Generation patterns and demand profiles during high stress periods in SDS-EV case

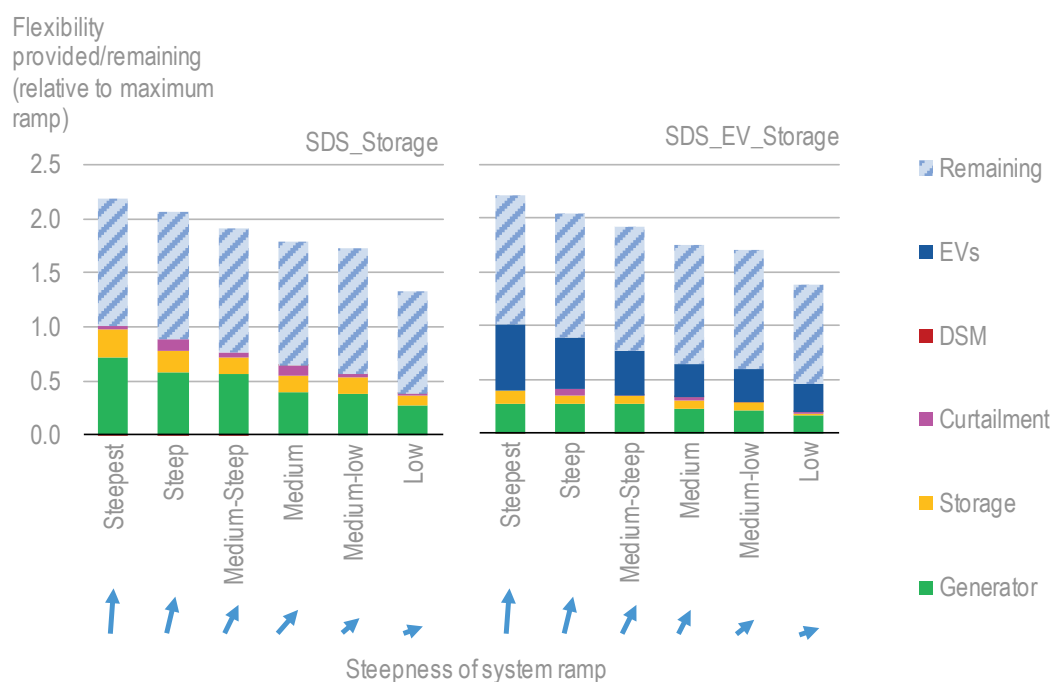
Note: The load shape in the SDS-EV case is distinct from the SDS-Inflex case, as the SDS-EV case allows for optimised EV charging patterns which alter the structure of demand.

Smart EV charging enables more cost-effective management of peak system load and reduces VRE curtailment levels during high-stress periods.

As VRE penetration increases in power systems, the frequency and intensity of high-magnitude ramping events increases, driven by the simultaneous decline in solar generation output and increase in electricity demand in the evening. For the SDS cases – which feature a 35% annual VRE penetration – modelling results indicate that smart EV charging becomes a relevant provider of system flexibility during these high net load ramping periods.

A detailed analysis was carried out in three steps to assess the contribution of EVs to meeting steeper ramps in the power system. First, periods of different magnitudes of net-load ramps were identified in the modelling results. These were binned into six categories depending on the steepness of the ramps in the relevant time period. Second, the contribution of individual flexibility resources to balancing the ramp was assessed. Third, all flexible resources operating on the system during the ramping event, and which could have further increased or decreased their consumption/generation to help balance the power system, were accounted for. The result indicates the degree of flexibility provided by each resource and how much flexibility remains on the system. Figure 47 demonstrates that smart EV charging measures provide a significant share of upward ramping services, which can have large impact on the efficient operation of the system, especially by reducing the need for peaking capacity.

Figure 47. Provision of upward ramping flexibility from different flexibility options before and after the introduction of EV smart charging



Notes: The upward ramps are binned into six groups of ramp severity, with the flexibility provided/remaining presented as a proportion of the maximum observed net load ramp over the modelling horizon; the "Remaining" category includes all flexible resources that are operating on the system during the ramping event that could have further increased or decreased their consumption/generation to help balance the power system.

Smart EV charging makes the most significant contribution to upward ramps, while the power system at large appears to have more than sufficient remaining flexibility from a combination of conventional power plants and storage.

In summary, the SDS-EV case demonstrates – for a decarbonising 2035 Chinese power system – the immense benefit of dynamically incentivising EV users to optimise their charging patterns in alignment with operational requirements of the power system. A future decarbonised system with unoptimised charging patterns has a peak demand that is approximately 15% higher.

Meeting that demand with conventional generation would require significant additional investment in low-utilisation, high marginal cost peaking capacity (and most likely significant distribution grid upgrades too, which are not explicitly considered in this analysis).

Importantly, substantial investment costs are associated with building out EV infrastructure in the first place in order to enable charging of vehicles. However, this investment is considered incurred in the SDS-Inflex case as well and does not necessarily depend on the charging regime – on the contrary, smart charging contributes to reducing required power system investment. The investment costs of enabling smart EV charging itself are comparably very low, and may to some degree ultimately be financed by EV owners and/or EV charging retailers, rather than by the power system via ratepayers; the crucial element is instead the appropriate standardisation of equipment and ICT infrastructure.

In summary, the incremental investment costs associated with enabling this flexibility option are expected to be quite low relative to the potential operational and investment-related savings, though it would be a significant institutional effort to co-ordinate such widespread transport sector integration.

A variety of actions can be considered by policy makers to realise the benefits offered by extensive smart EV charging. First and foremost, linking power sector and transport sector planning exercises can support the smart development and planning of EV charging infrastructure, enabling greater uptake of EVs through increased access to charging infrastructure, reducing distribution system build-out costs, and at the same time supporting broader VRE integration and power system transformation. Next, smart EV charging programmes must offer sufficiently attractive schemes such that EV users enrol in them and adopt smart charging behaviour. While smart charging is likely to be managed through automated processes, EV charging tariffs must nevertheless strike an appropriate balance between dynamic cost reflectivity (i.e. pricing structures that reflect the time-variable cost of power system operation in close to real time) and simplicity (i.e. pricing structures that do not unduly expose retail customers to highly variable, hard-to-understand electricity market dynamics). Finally, the regulatory system may need to allow for ratepayer-financed smart charging infrastructure, particularly at earlier development stages where its deployment may not be commercially attractive to EV charging retailers or individual customers.

Assessing portfolios of flexibility options

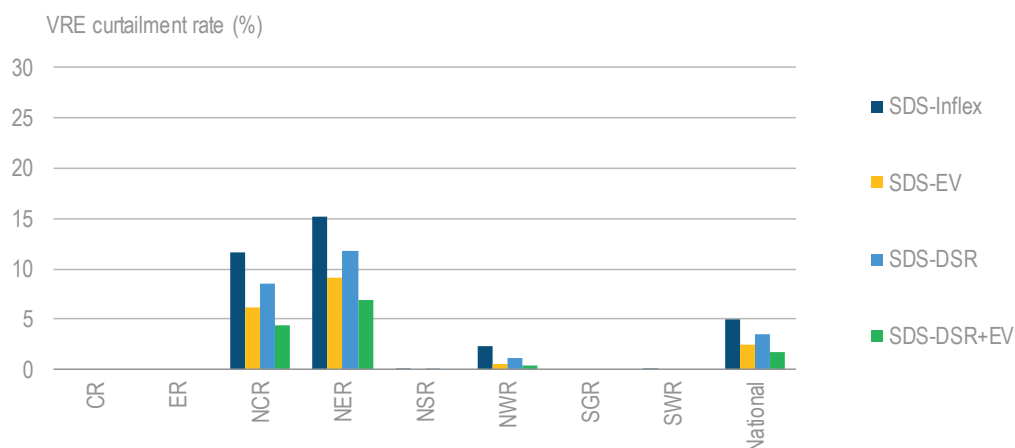
Understanding the value of a portfolio of DSR and EVs: SDS-DSR+EV

The value of both smart EV charging and DSR has been explored separately in previous cases. In a next step, the deployment of both sets of resources in tandem is explored to investigate synergies and trade-offs between both options.

Modelling results indicate that the simultaneous utilisation of both smart EV charging and DSR resources results in a total saving of USD 41 billion from avoided operational costs and capital investment. Summing the savings of the cases individually yields annual savings of USD 52 billion, USD 17 billion in SDS-DSR and USD 35 billion in SDS-EV. While savings are not fully additive, the joint deployment still leads to almost 80% of the summed benefits of each individual option. This indicates that both options only partially substitute each other and deploying both options does bring additional benefits.

Utilising both flexibility resources allows more load to be shifted to periods of excess VRE generation, thus reducing curtailment further (Figure 48), while also reducing and flattening net demand during these periods. This results in a reduction in VRE curtailment from 5% in SDS-Inflex to 1.8% when combining DSR and smart EV charging.

Figure 48. VRE curtailment rate in SDS cases with smart EV charging and DSR, by region



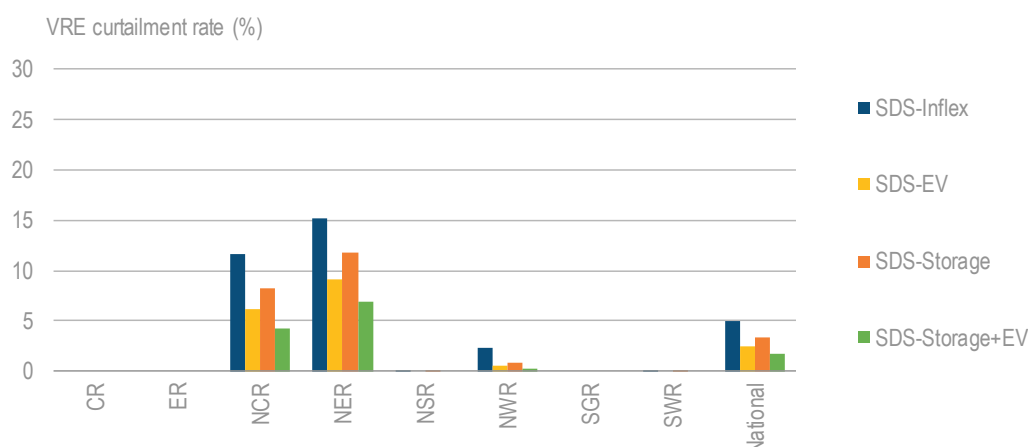
The combination of smart EV charging and DSR further reduces VRE curtailment.

Understanding the value of a portfolio of storage and EVs: SDS-Storage+EV

The combination of additional storage deployment and smart EV charging provides gross annual savings (from avoided operational costs and annualised capital investment) of USD 42 billion. However, due to the required capital expenditure on storage, net savings are USD 33 billion annually. Summing the savings of the individual cases yields annual savings of USD 46 billion. This means that the combination of options reaches only 70% of the combined savings of each option individually. It is worth noting that the SDS-EV case alone brings net savings of USD 41 billion per year. This is actually higher than the combined savings of both options because smart EV charging does not require additional capital expenditure for dedicated storage assets. This result underlines the significant opportunity that smart charging of EVs can bring to the power system.

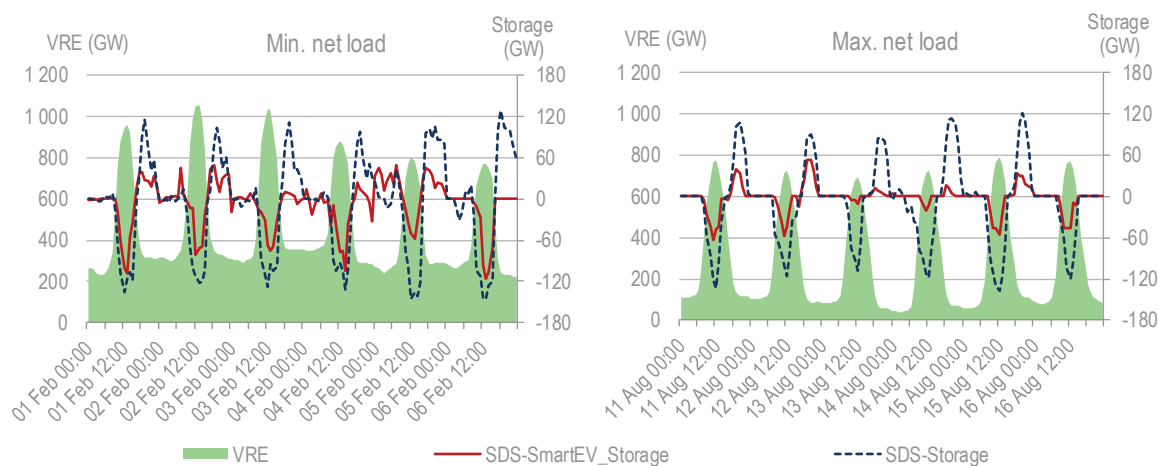
Smart EV charging and storage represent two different solutions that are capable of shifting load to periods of high VRE generation to maximise its utilisation and avoid curtailment. The combination of both options leads to reduced cycling behaviour for nuclear and thermal power plants that operate as baseload and mid-merit plants. The combination of storage and smart EV charging allows for the reduction of VRE curtailment from 5% in the SDS-Inflex case to only 1.7% when the measures are combined (Figure 49).

As regards operation, the combination of smart EV charging and storage diversifies the way that storage is used to benefit the system. Considering storage technologies on their own, their cycling patterns are highly correlated with the availability of excess solar generation prior to the evening peak demand, during which this power can be discharged (Figure 50). Additionally, storage resources exhibit a fairly consistent daily charge–discharge cycle during periods of off-peak and peak net demand.

Figure 49. VRE curtailment rate in SDS cases with EV smart charging and storage, by region

The combination of storage and smart EV charging can further reduce VRE curtailment compared to the level each individual option is capable of providing.

The dual deployment of smart EV charging and storage in the SDS-Storage+EV case reduces the overall utilisation of storage technologies relative to the SDS-Storage case, with cycling of storage resources decreasing by 40% and 75% for batteries and PSH respectively. This is primarily driven by the lower utilisation cost to the system of smart EV charging resources relative to storage technologies, because the former are not associated with any losses.

Figure 50. Charging and discharging of storage alongside VRE generation during the period of minimum and peak net demand, with and without EV smart charging

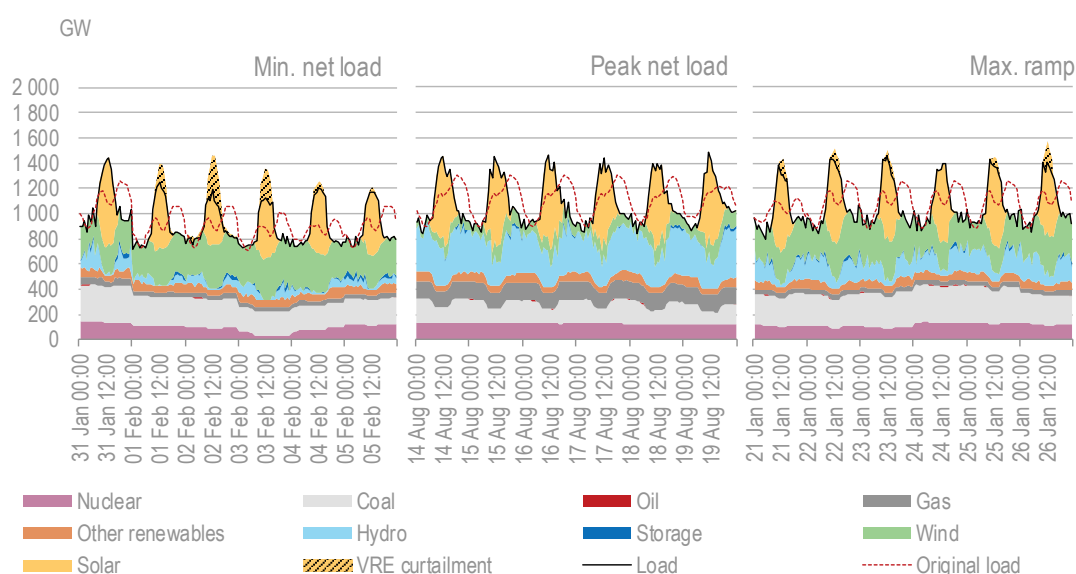
There remains spare storage capacity in the combined storage and smart EV charging case.

Understanding the value of a combined portfolio of smart EV charging, DSR and storage: SDS-Full flex

The SDS-Full flex case is used to understand the combined operational value of a portfolio of EVs, DSR and storage deployment to a decarbonising Chinese power sector in 2035. The options considered are 300 GW of residential and service-sector load contributing to DSR programmes (as detailed in the SDS-DSR case), the smart charging of 220 million EVs representing approximately 250 GW of peak EV charging load and 800 terawatt hours of total annual EV charging load (as detailed in the SDS-EV case), and a total of over 100 GW of pumped storage hydro and over 50 GW of battery energy storage (as detailed in the SDS-Storage case). These lead to the most flexible power system case considered in the analysis – hence the name SDS-Full flex.

Comparing results from the SDS-Full flex case to the SDS-Inflex case is instructive in understanding the costs, benefits and operational impacts of deploying this portfolio of flexibility measures. Operational costs in the SDS-Full flex case are approximately 11% lower than the baseline case, which is equivalent to a saving of approximately USD 32 billion per year. This saving is driven primarily by the broadly enhanced ability of the power system to utilise resources with low marginal costs (including VRE and nuclear power) at the expense of more costly generation resources (Figure 51). Reduction in emission costs is also a major source of operational savings. Total CO₂ emissions in the SDS-Full flex case are 14% lower than in the SDS-Inflex case.

Figure 51. Generation patterns and demand profiles during high-stress periods, SDS-Full flex case

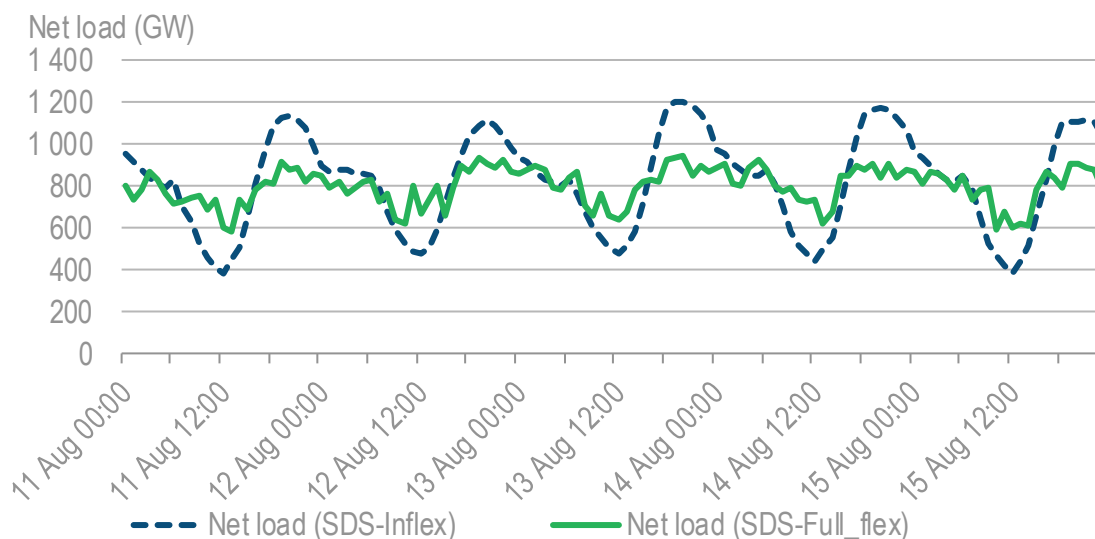


The combined portfolio of flexibility measures enhances the ability of the power system to better utilise resources with low marginal costs, including during periods of high stress.

Peak demand is reduced by approximately 245 GW, a 20% reduction from the baseline SDS-Inflex case (Figure 52). This peak demand reduction translates into a potential annualised investment cost saving (driven by reduced investment in low-utilisation generation infrastructure) of approximately USD 32 billion per year.

This means that total savings (from avoided operational costs and annualised capital investment) stand at USD 56 billion annually. The increased flexibility of the system also brings down curtailment levels to negligible levels (Figure 53).

Figure 52. Demand reduction due to portfolio of flexibility measures during peak demand, 2035, SDS-Full Flex case

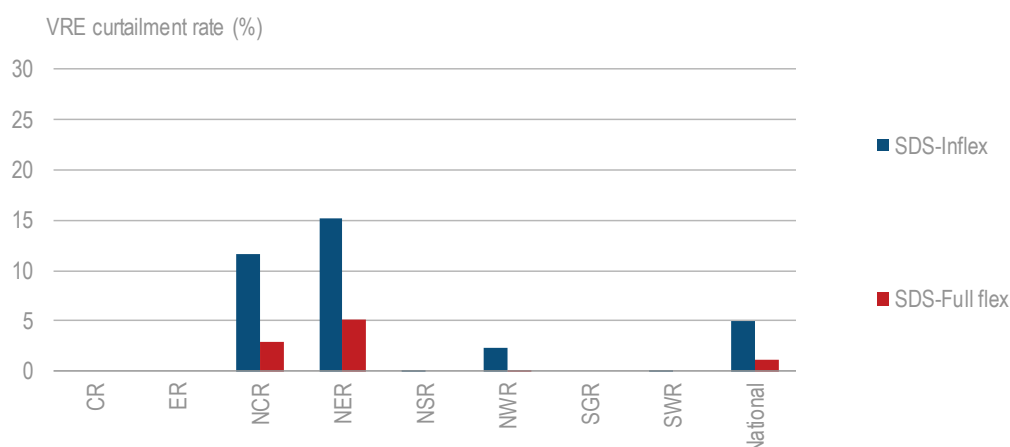


A portfolio of innovative flexibility measures drastically reduces peak demand, flattens demand more broadly and results in significant cost savings relating to generation investment.

The modelling results point to additional flexibility in the system that remains unused during the operational simulations. In the modelling exercise, the utilisation of storage (PSH and battery) during the peak period is less than half of the total storage capacity.

Mobilising this latent flexibility would further reduce requirements for flexibility from other resources such as dispatchable power plants. Assuming that the available storage was fully utilised to offset the need for generation capacity, an additional 60 GW of capacity could be saved; the investment-related benefit corresponds to approximately USD 8 billion, bringing total savings in the SDS-Full flex case to USD 64 billion per year. This is equivalent to 0.5% of China's gross domestic product (GDP) in 2017.

Indeed, additional modelling analysis confirms that the SDS-Full flex case can handle higher shares of VRE generation. Increasing the contribution of VRE to 44% of annual generation was feasible operationally, with curtailment levels at only 1.2% at a national level. It is worth noting that a stronger geographic diversification of VRE sites than assumed in the modelling could eliminate this curtailment.

Figure 53. VRE curtailment by region, 2035, SDS-Inflex and SDS-Full flex

The implementation of a portfolio of innovative power system flexibility measures significantly reduces VRE curtailment at both regional and national levels.

Summary

China's goal of progressing from fair to economic dispatch will result in significantly lower power system operational costs and improved ability to integrate wind and solar power. China's ongoing market reforms, including the introduction of economic dispatch, make good financial sense and will strongly benefit the environment. Detailed power sector modelling under the NPS compared two different ways to dispatch the system: first, using a fair dispatch approach that allocates guaranteed full-load hours to conventional generation, fixed at the level of 2017; and second, using economic dispatch, i.e. dispatching plants according to lowest operating cost while still preserving a modest generation allocation for natural gas generators.

Maintaining the current fair dispatch system would lead to major inefficiencies in the capacity mix under the NPS in 2035, including very high levels of curtailment (33% combined for wind and solar PV at a national level). Improving the dispatch of the system brings operational cost savings of approximately 11% or USD 45 billion per year in the year 2035. Furthermore, curtailment falls to 5% at a national level and power sector CO₂ emissions fall by 15% (650 million tonnes per year). These results clearly demonstrate the importance of introducing economic dispatch in the system.

The swift implementation of spot markets in China is a crucial tool for achieving this. Conversely, failure to introduce economic dispatch or other measures to reduce full-load hours allocated to fossil fuel power generators would result in unacceptably high levels of VRE curtailment.

Broader regional co-ordination and greater transmission interconnectivity will yield substantial economic benefits. Modelling results show the significant economic benefits of regional co-ordination and power trading in the Chinese power system. Again, two cases were compared. First, a case where utilisation of interregional transmission lines is fixed at 2017 levels. Second, a case where the flows are fully optimised. Assuming a fully optimised use of transmission lines, including those planned to be built by 2022, total operational costs are reduced by an additional 3% (USD 9 billion annually) compared to the case that only uses economic dispatch. Curtailment levels fall further from 5% to 3% at a national level. This

highlights the importance of increased trade in the system and the large benefit it can bring. Assuming additional interconnections further lowers operating costs by USD 8 billion and brings curtailment levels to 0%.

The use of advanced flexibility options is found to be highly cost-effective compared to the SDS without the presence of these options. Using these options to their maximum potential could lead to total net savings of USD 64 billion annually. This considers both reduced operating costs (including CO₂ emissions at a price of USD 100/tonne) and avoided capital costs for power plants. This number accounts for the investment required to install advanced flexibility capabilities. Total net reductions correspond to 0.5% of China's GDP in 2017.

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Summary and conclusions

Power system transformation in China

China has already embarked on its own pathway to power system optimisation.

The 19th Party Congress in October 2017 set a number of key guidelines for the medium- and long-term evolution of the Chinese economy and hence also for the power system in the People's Republic of China ("China"). This included the important ambition to realise modernisation, i.e. to develop a more advanced economy while increasing equality between urban and rural areas, reduce disparity between regional development levels, bring about a much better environment and achieve the "Ecological Civilisation" by 2035 – and ultimately a "Beautiful China" in 2050.

Achieving these ambitions implies a fundamental transformation of the power system in China. In 2017, 64.7% of power generation came from unabated coal-fired power plants, corresponding to a total amount of 4 150 terawatt hours (TWh). This was associated with emissions of 4 565 million tonnes (Mt) of carbon dioxide (CO₂), 1.2 Mt of sulphur dioxides (SO₂), 1.14 Mt of nitrogen oxides (NO_x), and 0.26 Mt of particulate matter PM_{2.5}. However, in the same year, China led investment in wind and solar power globally for the fifth year in a row, adding 18 gigawatts (GW) of wind capacity and 53 GW of solar photovoltaics (PV). In addition, China now has 1.2 million electric vehicles (EVs) on its roads, in addition to 249 million electric two- and three-wheelers.

A number of important reform projects are being pushed forward at the national, provincial and local levels, including the reform of the Chinese power market, the introduction of an emissions trading system in the power sector, and the adoption of a more sophisticated renewable energy policy based on auctions and quota obligations.

Integrating variable renewable energy and an orderly reduction of coal power will be the primary challenges for successful power system optimisation.

Two issues stand out with regard to achieving a successful transformation of the Chinese power system by 2035 and 2050. These are the integration of a very large amount of variable renewable energy (VRE) and – connected to this – the orderly reduction of unabated coal-fired generation.

The scenarios assessed in this report feature a share of up to 35% VRE in annual power generation by 2035. As the international experiences in this report demonstrate, achieving such levels of VRE penetration calls for a system-wide approach to integrating renewable energy. While high shares of VRE can be achieved in a cost-effective fashion, the required system adaptations can have profound implications, in particular for the economics of existing power generators.

The projected share of coal generation in 2035 varies from around 45% and approx. 4 500 TWh (New Policies Scenario [NPS]) to 20% and 1 900 TWh (Sustainable Development Scenario [SDS]), compared to 4 150 TWh in 2017. This means an annual average reduction in coal-fired generation of up to over 4 percentage points. The economic challenge associated with this reduction calls for a well-coordinated approach to managing the market exit of unabated coal capacity. Such transition pathways have been implemented successfully in other countries – the

rapid reduction of coal fired generation in the United Kingdom is a recent example. However, the scale of the challenge is much higher for China than for any other country.

Power system flexibility will become the most important attribute of a transformed power system.

Power system flexibility is the key factor that determines success or failure in integrating VRE. Against the background of the critical importance of VRE for system transformation, this means system flexibility is the most important attribute of a transformed power system. Flexibility describes how well a system can cope with variability and uncertainty of electricity demand and supply across all timescales. It can be provided by all power system assets: generation, demand, grids and storage. A lack of power system flexibility can lead to VRE curtailment, increasing the cost of integrating VRE and ultimately undermining power system reliability.

China has already made substantial progress in enhancing the flexibility of its power system, as reflected in falling levels of VRE curtailment. In 2018, a total of 27.7 TWh of wind power (7% of actual production) and 5.5 TWh of solar PV (3% of actual production) were curtailed. Only two years before, these numbers stood at 49.7 TWh of wind power (17% of actual production) and 6.9 TWh of solar PV (10% of actual production). This progress has mainly been achieved through four factors: trading, dispatch, power demand growth and slowing VRE additions.

In respect of trading, the main changes were increased inter-provincial trading, trading of VRE with captive power plants located at industrial customers and increased trading of VRE via spot market mechanisms. As for dispatch, the main contributions were better sharing of balancing resources and operating reserves across provinces, as well as better usage of pumped storage hydro and interconnections. Finally, more dynamic growth of power demand and slower growth of VRE in 2018 compared to 2017 also contributed to the reduction in curtailment.

Looking ahead, the introduction of wholesale energy market structures and the strengthening of regional co-ordination and transmission interconnectivity can help to further unlock latent flexibility in the Chinese power system. Advanced flexibility strategies, including active load shaping and electricity storage, may also be needed to reach sufficient levels of system flexibility. This implies stronger links between different components of the wider energy system (i.e. sector coupling), such as directly linking the transport and electricity system via electrification. It may also be necessary to harness indirect electrification via production of hydrogen and derivative products (e.g. green ammonia, synthetic hydrocarbons) and use these either directly as a feedstock or process agent, or as a transport or power generation fuel.

Different layers of the power system need to be addressed in order to achieve system transformation successfully.

Power system transformation requires co-ordinated changes across the entire value chain of electricity production and consumption. Indeed, it may even necessitate the creation of entirely new roles in the power system, such as aggregators of small-scale power system assets (e.g. smart charging of a fleet of EVs in order to provide grid services).

In practice, this means that it is not sufficient to look only at the technical or economic aspects of system transformation. The institutional setup and the roles and responsibilities of different stakeholders in the system require review and possibly revision. This is particularly relevant for establishing medium- and long-term system plans. Here it is critical for all stakeholders to ensure that planning entities operate in a transparent environment that is free of conflicts of interest, and work to promote fair market access and competition as plans are translated into reality.

The alignment and integration of different policies and measures in the power sector and related sectors are pivotal to long-term success.

Power system transformation affects the entire power system and, ultimately, via sector coupling, has implications for the energy system more broadly. This means that much closer co-ordination between different policies and measures is needed.

Looking only at electricity, the interactions between power market design, renewable energy policy and carbon policy need to be taken into account when designing policies in any of the three areas. Ideally, policies can be designed in a way that mutually reinforces their success. For example, electricity market reform can lower prices for customers and facilitate renewable energy generation. In turn, this can create room to introduce a carbon pricing mechanism. Similarly, a well-designed renewable energy policy can boost the liquidity and efficiency of electricity markets. Finally, a well-designed carbon mechanism can enhance the competitiveness of renewable energy, reducing the need for government support. Going beyond electricity, successful sector coupling calls for much closer co-ordination between electricity-related policies and transport and heating policies.

Options to facilitate implementation of the Document 9 reforms

Optimising the dispatch of power plants is a fundamental prerequisite for reducing power generation costs and preserving VRE investability.

The fair dispatch rule – which guarantees power plants a certain number of full-load hours irrespective of their fuel costs – has been a very effective mechanism to de-risk investment in coal-fired capacity. Moreover, in the context of rapid electricity demand growth, all power plants have historically been needed to meet demand and hence meeting target full-load hours did not imply large economic inefficiencies.

However, in the context of China's ongoing power system transformation, the accelerated deployment of wind and solar power to meet environmental and economic objectives – combined with large investments in coal-fired capacity – has led to an overall excess of capacity. By implementing a more economically optimised dispatch of power plants, VRE generation will in most circumstances be given greater priority, as VRE resources have no fuel costs and near-zero operating costs. The utilisation of more VRE resources in an overcapacity system will inevitably result in reduced generation levels for other sources. This may result in reduced revenues for particular legacy power plants. However, doing so offers the significant benefit of improving the operational efficiency of the power system, leading to lower system-wide energy costs, a reduced environmental footprint, and a more favourable environment for VRE investment.

Creating short-term markets and robust short-term price signals can greatly facilitate power system transformation and reduce system-wide energy prices.

Changing dispatch arrangements can be achieved in different ways, for example by establishing a priority order by which power plants are called upon to generate (e.g. the conservation dispatch that was previously implemented in parts of China). However, such mechanisms can be complex to implement and can inhibit the participation of new actors.

International experience generally demonstrates that a well-functioning short-term market (spot market) for electricity is a very powerful measure to drive power system transformation.

In such an arrangement, the power plant with the lowest generation costs has priority for meeting electricity demand (economic dispatch). In most designs, the cost of the last (most costly) plant that is needed to meet the demand sets the price paid to all generators.

Spot markets are particularly useful in fostering power system transformation for the following reasons:

- They solve the issue of needing to allocate the right to generate to different power plants. No explicit regulations are required to determine how much each plant is allowed to generate. Plants can try to improve their operating time by cutting their operational cost and optimise their profitability by enhancing their flexibility (in order to generate when prices are high and turn down when prices are low).
- They reveal the actual value of electricity at different times and locations. Spot markets usually have a different electricity price for each hour of the day (in some cases even for every five minutes). They can also be designed to have different prices for each location or zone of the grid. This means that spot prices highlight when and where electricity is most precious and most in abundance. This information is crucial for integrating VRE.
- Their price signals can inform commercial negotiations for longer-term contracts. Spot markets are very useful because they discover an accurate price for electricity. This information can be used to inform long-term pricing of electricity, guide investment in new generation capacity, and help with the establishment of financial markets for electricity, as explained in this report.
- They allow for the market entry of new players. A liquid spot market with well-designed market rules can facilitate the participation of new actors, such as demand aggregators or electricity storage.

The modelling carried out for this report shows that transitioning from fair dispatch to economic dispatch can bring substantial benefits. In the 2035 'NPS Dispatch' case, annual operational costs are around 11% (USD 45 billion [United States dollars] per year)

The optimised use of existing and soon-to-be-built transmission lines can substantially reduce renewable energy curtailment and integrate additional wind and solar capacity.

Grid infrastructure is a crucial source of power system flexibility; it brings a double benefit of smoothing VRE output across large geographical regions and linking together many diverse flexible resources (generation, demand shaping, and storage).

China has very successfully established an advanced electricity grid, including 13 ultra-high-voltage direct-current (UHVDC) links (as of 2018). Barriers to trade between provinces, alongside a number of technical challenges, have translated into the sometimes low utilisation of these assets. According to the China Electricity Council, the average utilisation of interconnectors was 37% in 2017, ranging from 3% to 64%.

The modelling carried out for this report demonstrates that relying only on existing grid infrastructure and lines that are planned for commissioning by 2022 can achieve large-scale integration of much higher levels of VRE generation. In the 'NPS Operations' case, moving from 2017 utilisation patterns (average of 17%) to a fully optimised use of lines (bringing utilisation to 50%) can bring substantial benefits in 2035, lowering total operational costs by 13% (USD 54 billion per year).

It should be emphasised that no new lines beyond those planned for 2022 are assumed in this analysis. Hence, the existing grid provides ample flexibility to absorb more VRE. However, there are regions that would face insufficient export capacity in this case: in Northwest China

curtailment would rise to 6%. Adding a further approx. 200 GW of transmission lines to the existing 230 GW assumed brings this number down to 0% in the Northwest region.

Optimising power system operation is bound to trigger the market exit of inefficient coal generators; this process is likely to need active management.

Moving from the fair dispatch system to economic dispatch, combined with more optimised trade of electricity, would lead to a substantial shift in the operating pattern of coal-fired power plants.

International experience shows that prices based on economic dispatch, in the context of rising shares of VRE, can lead to insufficient remuneration for conventional generation. In the Chinese context, less-efficient coal-fired power plants may face reduced operating hours and a smaller share of the market as a result of increased renewable electricity production and more competitive conventional generation. International experience suggests that such plants may be at risk of closure. In order to ensure reliable service is maintained, it is critical that a mechanism is in place to retain any such plants that might still be needed for reliability and/or resiliency purposes.

Furthermore, the modelling analysis in this report demonstrates that if economic dispatch were implemented in concert with additional transmission infrastructure buildout, significant interregional shifts in generation would occur, with some regions becoming major exporters and others major importers. There are important social and economic implications of such changes, and a smooth transition is needed to allow for the necessary socio-economic adjustment, particularly in areas that may experience a reduction in economic activity as a result of lower coal-fired generation levels.

The issue of power plant retention for reliability purposes can be addressed via capacity remuneration mechanisms (CRMs). Well-designed CRMs help to provide more revenue certainty to plants deemed necessary to maintain reliability, ideally allowing a range of generation and demand-side resources to compete in a market-based system that secures such payments. Using a market-based (i.e. competitive) system for determining the appropriate allocation and level of CRM payments can help to reduce system costs and ensure that the most efficient resources are being utilised to provide reliability services.

The issue of socio-economic adjustments can be addressed by a variety of transition mechanisms. Their design is fundamentally a political choice and depends on how quickly regions are being transitioned toward economic dispatch, and what socio-economic impact (if any) that change may ultimately result in. This report contains a number of examples of transition mechanisms that have been implemented internationally to smooth transition challenges associated with adopting economic dispatch.

Innovative options to further accelerate progress towards a “Beautiful China”

Optimised use of demand-shaping techniques is critical to unlock very high shares of renewable energy cost-effectively.

The SDS features a VRE share of 49%, ranging from 12% in Guangdong to 74% in the Northwest region. These shares imply a much higher level of supply-side variability and uncertainty. Consequently, shaping electricity demand to better match variable supply can bring substantial benefits to the system.

Load shaping can be achieved with three basic mechanisms:

- electrification, which creates new demand when and where there is VRE supply (e.g. electrification of transport using smart charging)
- shedding of load during times of low supply (e.g. reducing consumption in certain industrial processes)
- shifting load from times of low supply to times of high supply (e.g. shifting the time of heating water in electric water heaters).

In practice, these effects can be achieved through “implicit” and “explicit” load-shaping practices. While explicit practices directly control the load shape, implicit practices attempt to more indirectly influence its shape through economic signals. Time-of-use retail electricity tariffs are an example of an implicit practice, where customers are presented with a time-variable tariff which sends an economic signal to reduce or increase their demand throughout the day or week. More direct utility-led demand response programmes are an example of an explicit load-shaping practice, where the utility is given more direct control over certain aspects of their customers’ load in exchange for bill reductions. Such utility-led programmes may also incorporate energy efficiency measures for load shaping.

Optimising demand for electricity also requires reducing wasteful use of energy. China has made substantial progress in improving energy efficiency through programmes such as the Top 1 000 Programme, energy performance contracting and the Energy Efficiency Obligation. Without energy efficiency improvements made since 2000, China would have used 12% more energy in 2017, emitting an additional 1.2 gigatonnes of CO₂ equivalent. China’s energy efficiency policies should continue to achieve energy savings, reducing the absolute volume of resources needed while at the same time delivering economic, environmental and social benefits.

In addition to strong policies in support of energy efficiency, comprehensive strategies for load shaping are an emerging trend in China, as well as globally in countries with growing proportions of VRE. China has a substantial opportunity to develop and implement advanced solutions for load shaping, which could also help boost long-term industrial development.

Electric mobility has great potential for integrating renewable energy, but only if charging patterns are optimised.

China is a global leader in electric mobility. In 2017, China accounted for 5 out of every 10 EVs sold, and 99% of battery electric buses are in China. This trend is likely to continue thanks to a mix of policy support, technology improvement and cost reductions. The SDS projects there to be 220 million EVs in China in 2035, with an aggregate peak charging capacity of 250 GW, or almost 20% of peak demand.

Dynamically matching the times when EVs are charging to the availability of VRE can help balance supply and demand from a few seconds up to several hours. However, EVs do not automatically result in a benefit to the power system. Indeed, unmanaged charging of EVs can increase peak demand and worsen the match between VRE supply and demand. For example, it makes a great difference if charging is concentrated in the evening when people return home or during the day when people are at work or conducting daily activities. In the case of unmanaged home charging in the evening, EV charging will show a very poor match with solar PV availability. Conversely, daytime charging leads to a much better match. In addition, unmanaged charging of EVs may result in the need for additional distribution grid upgrades, particularly in congested urban areas. To move forward, the integration of transport planning

and distribution grid planning will be an important task to contain such costs and promote VRE integration.

The modelling conducted for this report underlines the point. In the SDS, smart charging of EVs helps to achieve USD 2 billion in fuel cost savings, 79 TWh of reduced VRE curtailment (reducing curtailment from 5% to 3%), and avoided emissions totalling 115 Mt of CO₂, 0.4 Mt of SO_x, 2 898 Mt of NO_x and 196 272 Mt of PM_{2.5}.

However, these benefits require policy makers to take action to be realised. For example, daytime charging is only possible if chargers are indeed available at work or at shopping centres. Moreover, the regulatory system needs to allow for the implementation of smart charging and pass on (part of) the benefits of smart charging to make it commercially attractive.

Applying digital technologies to the distribution grid and at the customer level can unlock additional flexibility and is an opportunity for economic development.

China is a global leader in the use of digital technologies and innovative software products. These technologies have the potential to play a substantial role in shaping electricity demand dynamically to better match consumption with available supply. They also hold the promise of improving service offerings to consumers via improved analysis and automated control of electricity consumption.

The analysis conducted for this report shows the benefits that advanced digital sensors and controls bring to the power system by unlocking demand-side response, especially in the commercial and residential sectors. All of the 300 GW of demand contributing to response capacity present in the SDS is enabled via digital technologies.

Unlocking this potential in practice requires action along technical, economic and institutional dimensions. Technically, agreed standards need to ensure the smooth interoperability of technical solutions. Economically, reform of retail electricity prices and allowing distributed resources access to wholesale market trading are the most important factors. Institutionally, measures to promote independent actors and establishment of effective short-term markets are the most important priorities to unlock these resources, along with addressing cyber security considerations.

Additional considerations for markets, policies, regulation and planning

Advanced renewable energy policies can minimise integration challenges.

Traditionally, policies to support renewable energy do so by providing appropriate investment conditions, such as sufficiently high and certain remuneration alongside streamlined planning and approval procedures. However, as the share of renewable energy grows on the system, the interactions between renewables and the broader electricity systems need to be considered in the design of renewable energy policies. This usually becomes evident via the emergence of “hotspots” of VRE deployment, where penetration levels are much higher than the national average and integration challenges become significant.

An initial approach to this issue is the geographic and technological diversification of VRE deployment. A variety of measures can achieve this, such as limiting permits for new installations in certain regions, differentiating remuneration levels regionally or by time of production, or giving specific incentives for smaller-scale installations – China has implemented

a number of these options in the past years. However, there are additional possibilities to enhance the system integration of renewables by use of deployment policies. As explained in detail in this report, the fundamental idea behind such approaches is to maximise the value of VRE for the power system.

Electricity has more or less economic value depending on where, when and how it is produced. It is most valuable at times when demand levels approach the limits of available generation and (depending on the exact conditions on the grid) when it is generated close to demand. In addition, if a power plant can provide system services, it will also be more valuable compared to a plant that cannot provide such services. Of course, VRE generators cannot influence how much wind and sunshine is available at given times and places. However, it is possible to build VRE plants in different locations and optimise their design to maximise the value of the VRE fleet. Price signals can play a decisive role in incentivising VRE generators to design and operate plants in a more system-friendly way.

Spot markets can be a very useful tool for providing appropriate signals to VRE developers and operators. By exposing VRE plants to the varying prices on the spot market, they can be encouraged to build power plants that generate as much as possible at times and in places where electricity is valuable – and where prices are higher than average. However, such approaches need to strike a balance between creating such an incentive for system-friendly deployment while also providing sufficient investment certainty. Different forms of financial hedging arrangements and/or market premiums can achieve this objective.

Advanced design of wholesale markets, including markets for system services, is an important tool to accelerate power system transformation.

Establishing a basic spot market that allows for short-term trade across large geographic regions is a fundamental tool for co-ordinating the operation of diverse power system assets, both renewable and conventional. Many countries have further refined and enhanced such markets to optimise the operation of their power system. Measures focus on moving gate closure closer to production times (e.g. via shorter trading windows in intraday markets), improving markets for system services and establishing capacity remuneration mechanisms.

Growing shares of VRE increase the importance of tools to balance supply and demand at short timescales. These include measures to balance forecast errors a few hours before real-time operation, large changes in output that occur over a few hours to minutes and rapid fluctuations from minutes to seconds. In addition, new measures can be required to ensure system stability to withstand disturbances such as the loss of a large generator or transmission line. In some cases, new services may need to be defined and remunerated, such as the ability to respond very quickly to frequency changes (fast frequency response).

Reforms are also crucial for unlocking the participation of new providers of such system services, notably demand-side response and storage providers. They usually include changing prequalification requirements (allowing smaller units to participate, reducing the minimum time that resources need to guarantee the service and procuring resources closer to real time). In addition, changing product definitions can lead to optimised outcomes. For example, separating downward and upward reserve provision can help the entry of new players: demand response can often reduce demand most easily at short notice (providing upward reserves) and VRE can more easily and economically provide downward reserves (by reducing its output).

Changes to electricity tariffs could help optimise the deployment and use of distributed energy resources (DER).

As DER become more relevant in the power system, individual customers (industrial, commercial and residential) increasingly have a choice between either obtaining electricity from the grid or relying on various self-supply options. While this trend is only emerging today, it will greatly increase the importance of accurate retail electricity tariffs, as the profitability of a distributed energy resource often critically depends on the tariff system. In addition, unlocking flexibility from these sources is only possible if there is an economic signal to make a more dynamic operating pattern profitable.

Standard tariff systems do not usually differentiate prices depending on time of use and do not capture a customer's contribution to peak electricity demand explicitly at a lower voltage level. Such a tariff environment provides little to no commercial incentive to invest in and operate DER or demand response in a system-optimal manner. As detailed in this report, a shift to more advanced tariffs that differentiate prices by time of day will unlock optimal contributions from DER.

Integrated long-term planning that includes demand shaping and advanced options for energy storage is a crucial foundation for a successful transformation of the power system.

Power system transformation substantially increases the complexity of system planning. Simply put, traditional power sector planning usually focuses on finding a suitable plan for adding large-scale generation capacity to meet expected load growth. Based on this, transmission system planning determines the need for grid expansion and reinforcement.

By contrast, a system featuring a large share of VRE (both large-scale and distributed) and DER (EVs, batteries), and much smarter demand, provides many more options for the future evolution of the system. For example, ultimately a mix of VRE, demand-shaping options and storage may be more cost-effective than building new large-scale generation capacity. Moreover, VRE impacts the power system at all timescales, which means that planning studies also need to examine operational aspects and system stability in a much more sophisticated way than in the past. Finally, the coupling of the electricity system with other parts of the energy system can reduce overall energy system costs while meeting environmental and reliability objectives. Capturing such synergies in planning requires the appropriate inclusion of these sectors in power system planning.

International implications

Accelerated progress on power sector optimisation could bring substantial benefits for China and the world.

China's power system is the largest national power system in the world; it accounted for 25% of global electricity consumption in 2017 and its share is expected to rise to 28% by 2035 in the NPS. Consequently, optimisation of the Chinese power system has immediate global effects, simply because by itself it accounts for such a substantial share.

The accelerated transformation of the Chinese power system could make a significant contribution to limiting climate change in line with the Paris Agreement. As the modelling conducted for this study demonstrates, improved operations and advanced power system flexibility options can deliver substantial emissions savings while reducing overall system costs.

However, there could be further positive effects of an accelerated transformation of the Chinese power system. China is already a global leader in clean technologies. Chinese solar PV manufacturers have played and continue to play a vital role in the rapid decline of solar PV costs. Moreover, the dynamic expansion of electric mobility in China, and the associated expansion of the EV value chain, has put downward pressure on electric batteries and ultimately EV prices.

China also has a very well-developed digital communications and software industry. So far, these industries have not been combined to their full potential. However, as the scenarios set out in this report demonstrate, an optimised system relying on enhanced digitalisation to unlock load shaping could integrate much larger amounts of clean energy. In turn, this stands to bring substantial economic and environmental benefits.

The accelerated adoption of these solutions in China could make them affordable for countries around the world – including today's developing countries, which will see a rapid increase in energy demand over the coming years. In turn, China can use the path of power system transformation to make accelerated progress in restructuring its economy towards a pattern of growth in advanced high-quality industrial sectors.

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Annexes

Annex A. Spatial disaggregation of national demand and supply

Modelling regions and interconnections

The International Energy Agency *World Energy Outlook* (WEO) model creates national results for both supply and demand. For this study, those results were further spatially disaggregated into eight regions for the detailed power system modelling. This disaggregation is a further refinement compared to previous WEO analyses (which feature six regions for China). It is also the first time that the Sustainable Development Scenario (SDS) has been spatially disaggregated. This refinement required three main analytical steps: 1) defining the modelling regions and setting regional transmission interconnection levels; 2) creating hourly load profiles for each region; and 3) allocating generation capacity regionally. These power system characteristics were then fed into the production cost model.

Defining modelling regions and regional interconnections

China's power grid topology needs to be considered for the purpose of modelling the country's power sector on a regional basis. Generally speaking, China has six major grid regions, i.e. Northeast, North Central, Northwest, East, Central and Southwest. Each region includes several provinces.

Reflecting the size and diversity of the country, major differences in resource availability, economic development, industrial structure and energy use are evident. These differences are not only present between the six power grid regions. Indeed, some of the provinces within one region show very large differences. Based on this fact, two regions were further disaggregated by separating one province from each. Firstly, Guangdong was separated from the rest of the Southwest region. Secondly, Shandong was separated from the North Central region.

Shandong in the north and Guangdong in the south have been separated as standalone regions in the modelling. The reasons for separating Guangdong from the Southwest region are:

- The power generation mix has a high portion of coal power in Guangdong, while other provinces in the Southwest region are hydropower dominated.
- Guangdong has a high percentage of power imports from other provinces, raising the importance of explicitly modelling the interconnections of the province.
- Guangdong is likely to be the first province to have a spot market.
- Guangdong is the most developed province in China, and its economy is more advanced than the other five provinces in the Southwest region.
- Guangdong has a national-level strategy to change its economic structure, which will influence its power consumption.

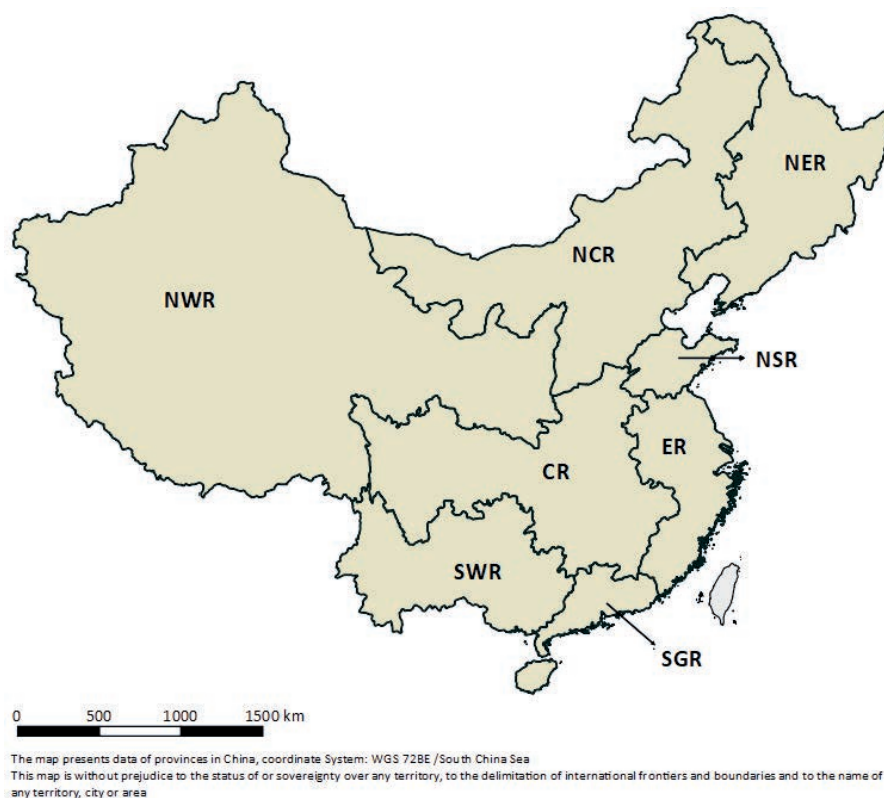
The reasons for separating Shandong from the North Central region are:

- The power generation mix is dominated by coal power, in contrast to the rest of the region.
- Shandong has receiving terminals for several ultra-high-voltage lines to import energy from the Northwest, Inner Mongolia and Northeast.

- Shandong is also one of the spot market pilot provinces.
- Shandong is a crucial province in respect of alleviating air pollution and curbing overcapacity.
- Shandong is one of the most developed provinces in China.
- Shandong has a national-level strategy to shift from heavy industry to light industry, which will influence its power consumption.

The eight regions are shown in Figure 54. Their constituent provinces and acronyms in the modelling are shown in Table 13.

Figure 54. Modelling regions



The different regions are also crucial for setting transmission capacity levels. Under the current administrative planning arrangements for interregional transmission (see Chapter 2 for more detailed information), cross-regional transmission capacity has not been fully utilised – some are substantively underutilised. Therefore, enhancing transmission has two layers: increasing the utilisation rate of existing transmission capacity by eliminating the barriers to regional trading; and investing more in transmission capacity in the future.

In terms of utilisation, the modelling scenarios feature two different settings. Under a constrained utilisation, the utilisation level of transmission lines corresponds to the level reported by the China Electricity Council (CEC) for 2017. This constraint is lifted in some cases, allowing for the optimised use of transmission capacity.

Table 13. Division of eight regions

Region	Acronym	Constituent provinces
Northwest	NWR	Gansu, Shaanxi, Tibet, Ningxia, Xinjiang, Qinghai
North Central	NCR	Beijing, Hebei, Inner Mongolia, Shanxi, Tianjin
Shandong	NSR	Shandong
Northeast	NER	Heilongjiang, Jilin, Liaoning
Central	CR	Henan, Hubei, Jiangxi, Chongqing, Hunan, Sichuan
Eastern	ER	Anhui, Jiangsu, Shanghai, Fujian, Zhejiang
Southwest	SWR	Guangxi, Guizhou, Hainan, Yunnan
Guangdong	SGR	Guangdong

In terms of investment, existing transmission capacity includes incumbent interconnectors and the newly planned ultra-high-voltage transmission lines, which are due to finish construction by 2022 and hence to be treated as existing lines by the target year 2035 (State Council, 2018a; see Table 14). Additional investments to 2035 are based on a possible build-out trajectory of about 200 GW of transmission capacity in total, particularly in the corridors from the regions with high VRE capacity; the numbers presented represent estimates.

Table 14. Transmission capacity (MW): existing and future assumed capacity

Region	CR	ER	NCR	NER	NSR	NWR	SGR	SWR
CR		41 000	11 000	5 000**		26 000 115 000**	5 000	17 500
ER			12 000	8 000**	7 500	6 000 112 000**		
NCR				24 500	41 500	12 500		
NER						7 000**		
NSR						31 000		
NWR								
SGR								37 000
SWR								

** Numbers show sum of existing, planned and assumed future expansion transmission capacity.

Note: MW = megawatt.

Creating regional electricity demand profiles

Electricity demand in China in 2035 has been estimated using the World Energy Model (WEM). On the demand side, the model covers the residential, services, agricultural, industrial and transport sectors, and can estimate yearly electricity demand and hourly load curve by end use (IEA, 2017). National electricity demand for 2035 and underlying assumptions are consistent with *WEO 2018* analysis for both the New Policies Scenario (NPS) and the SDS (IEA, 2018). For this report, additional input variables were collected and analysis was conducted to be able to break down electricity demand for the eight modelled regions. This was achieved by disaggregating detailed load profiles for each end use.

Generating hourly load profiles for each region

In order to capture regional differences, regional projections carefully consider key drivers of each end use, factoring in regional trends, policies and other conditions. For example, future geographical shifts of industry were considered explicitly, particularly the shift of centres of energy-intensive industry, by considering annual retirement of the existing manufacturing capacity and the required additional capacity in a specific year to meet product demand. The future production of each good is projected on the basis of the capacity of a region after allocating additions and depending on five relevant criteria: gross domestic product per capita, environmental restrictions, resource availability, infrastructure and policy support (Box 26).

Box 26. Disaggregation of China's electricity demand based on future regional development and environmental strategies

The disaggregation of national-level electricity demand into the eight modelling regions was performed taking into account two main factors: regional development strategies and measures to reduce negative environmental impacts.

Regional development strategies

A national-level strategy was released in 2018 with targets for reaching a more uniform regional development level by 2035 (State Council, 2018b). This strategy highlights the latest regional strategies, including the "Beijing-Tianjin-Hebei integrated economic region", "Along-Yangtze-River regional development", the "West Development" strategy for the West, the "Revitalisation of the old industrial base" for the Northeast, the "Rise of the Central region", and the "Leading development" for the East (Beijing, 2018; State Council, 2014; State Council, 2013; State Council, 2016a; State Council, 2016b).

Alongside the large regional development strategies, central government also issues national-level strategies for key provinces in respect of their economic structural transition, aimed at leveraging regional development by first unleashing the economic potential of the leading provinces. The "Guangdong-Hong Kong-Macau development plan" aims to transform Guangdong from "world factory" to "world-class economic platform", by accelerating the development of innovation and technology industries (Deloitte, 2018); Shandong was chosen to be the "Momentum shifting pilot zone" for shifting its economic structure from heavy industries to one dominated by light industry and services (State Council, 2018c). These plans have been taken into account when allocating different types of electricity demand across the eight regions in 2035.

Environmental strategies

The Chinese government has emphasised the importance and urgency of curbing air pollution. The 13th Five-Year Plan (2016–20) set a must-meet air quality standard for the 338 largest cities by 2020 (State Council, 2016c). The State Council further released the *Three-Year Action Plan on Blue Sky War* in July 2018, setting targets for emission reductions as well as listing the critical cities, most of which were in the Beijing-Tianjin-Hebei area, Shandong, the Yangtze River Delta and the Pearl River Delta (State Council, 2018d). These government documents detailed not only the reduction of pollutants, but also optimisation of regional industrial structures,

restricting development of industries with high energy intensity and high pollution levels, cutting overcapacity and developing environmentally friendly industries.

China specifies a number of policies and measures to achieve these objectives, notably in relation to energy efficiency improvements, the mandatory closure of small power plants and the emissions trading system (ETS). These plans have also been taken into account when allocating different types of electricity demand across the eight regions in 2035.

Sources: Beijing Government (2018), 推进京津冀协同发展2018-2020年行动计划 [Action Plan on Integrated Development of Beijing-Tianjin-Hebei Region (2018-20)], <http://finance.chinanews.com/cj/2018/07-30/8583198.shtml>; Deloitte (2018), 打造“中国模式”粤港澳大湾区将成为下一个世界级顶级湾区 [Shaping the Guangdong-Hong Kong-Macau to World-Class Bay Area], www2.deloitte.com/cn/zh/pages/about-deloitte/articles/pr-greater-bay-area-whitepaper.html; State Council (2018b), 关于实施乡村振兴战略的意见 [Opinions on Revitalization of Rural Areas], http://district.ce.cn/newarea/roll/201802/05/t20180205_28052212.shtml; State Council (2018c), 关于山东新旧动能转换综合试验区建设总体方案的批复 [Reply on Plan for Shifting Momentum in Shandong Province], www.gov.cn/zhengce/content/2018-01/10/content_5255214.htm; State Council (2018d), 打赢蓝天保卫战三年行动计划 [Three Year Action Plan on Blue Sky War], www.gov.cn/zhengce/content/2018-07/03/content_5303158.htm; State Council (2016a), 促进中部地区崛起规划 (2016至2025年) [Plan on Middle China Rejuvenation (2016-25)], www.scio.gov.cn/34473/34515/Document/1535229/1535229.htm; State Council (2016b), 关于深入推进实施新一轮东北振兴战略加快推动东北地区经济企稳向好若干重要举措的意见 [Opinions on Deepening A New Round of Northeast China Revitalization Strategy], www.gov.cn/zhengce/content/2016-11/16/content_5133102.htm; State Council, (2016c), 十三五“生态环境保护规划” [13th Five-Year Plan on Ecological and Environmental Protection], www.gov.cn/zhengce/content/2016-12/05/content_5143290.htm; State Council (2014), 关于依托黄金水道推动长江经济带发展的指导意见 [Opinions on Yangtze River Economical Belt Development], www.gov.cn/zhengce/content/2014-09/25/content_9092.htm; State Council (2013), 关于深入实施西部大开发战略情况的报告 [Report on Implementation of the Western China Development Strategy Report], www.npc.gov.cn/npc/zxbg/gwygyssxbdkfzlqkdbg/node_21794.htm.

To determine electricity demand for road transport, the number of electric vehicles (EVs) per region was used as an activity driver. The regional EV stock was estimated by assuming the share of EVs in car sales in a specific year and then taking into account the difference in the speed of EV uptake between regions.

Allocating generation capacity between regions

Projections of installed capacity in 2035 were also based on *WEO 2018* projections at the national level. These were broken down for each of the eight regions for all fuels and technologies, based on several criteria. All power plants installed in 2017 and not scheduled to be retired or reach the end of their technical lifetime were assumed to be available in 2035. All plants currently under construction were included in the 2035 installed capacity projections for each region, plus a share of the planned power plants, which varies by region and by scenario.

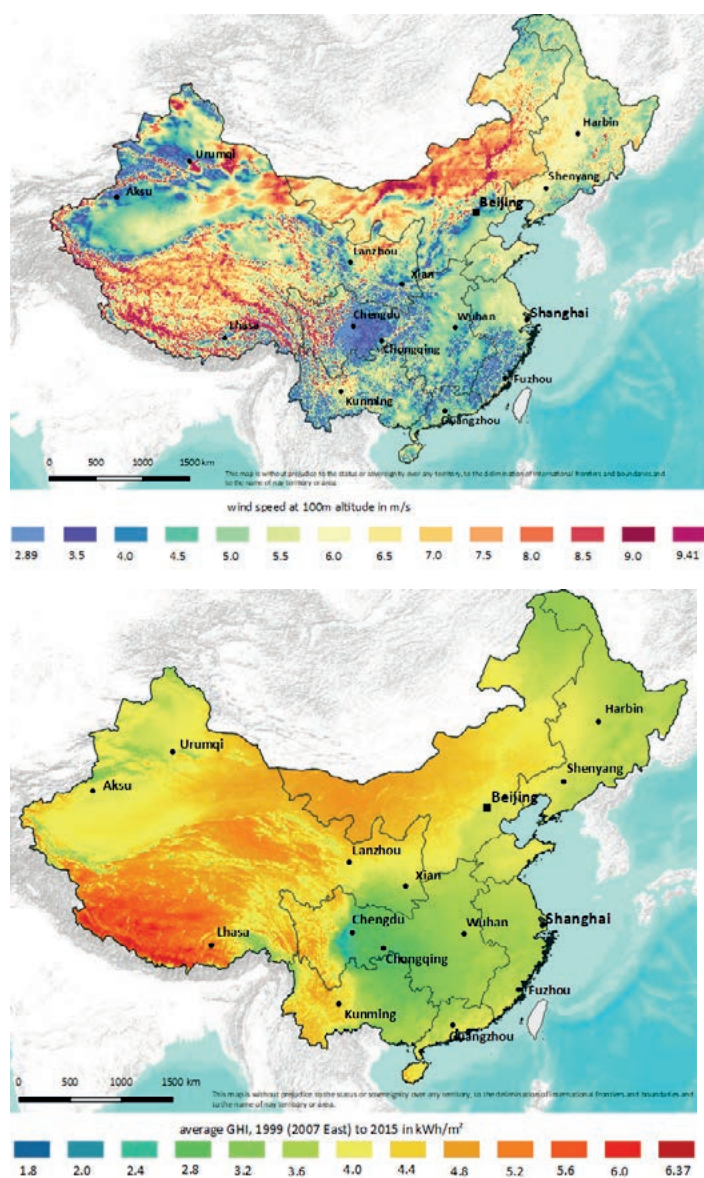
For the deployment of coal plants, a particular role is played by co-generation plants following the changing heat demand resulting from the shift of heavy industry towards the northern regions, and in particular towards the Northwest. Co-generation plants are broadly divided into industrial steam and district heating operations, and a seasonal pattern was applied to the district heating plants. Gas-fired plants are developed in each region considering the evolution of the gas supply infrastructure. New nuclear reactors are deployed reflecting planned and proposed sites.

Wind (on- and offshore) and solar photovoltaic (PV) (utility-scale and rooftop PV) capacity are allocated on the basis of over 4 000 representative sites considering several factors, such as potentials, population density, distance from power grids and policies in place. Hourly wind and solar generation have been simulated from the selected wind and solar sites across China. Site selection was based on three criteria:

- resource potential, i.e. wind speed for wind sites and global horizontal irradiance for solar sites
- distance to the transmission grid
- distance to load based on population density.

Exclusion factors, such as environmentally protected areas, land use/land coverage, altitude, slope and infrastructure, were also applied to exclude unsuitable sites.

Figure 55. Wind and solar potential in China



Note: These maps are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Hydro capacity has been broken down in each region into four main types: run-of-river, run-of-river with small storage, reservoir and pumped hydro storage. Different types of seasonal inflow have been considered for each of these types.

The expansion of the remaining renewables technologies (bioenergy, concentrating solar power, geothermal and marine) was based on resources and capacity requirements across the different regions.

Fuel prices for both NPS and SDS were derived from WEO 2018, and for steam coal prices, the price differences between eight regions were estimated considering current market trends and transport costs.

Method used for calculating CAPEX savings

In this study, a longer term system benefit of load shaping driven by a reduced need for generation infrastructure investment is estimated based on the magnitude of peak net-load reduction effect and an average investment cost for dispatchable technologies which are assumed to be necessary if the effect is not in place. The average investment cost, 131 USD/kW, is calculated by assuming capital cost of each dispatchable plant (see IEA, 2018a) annuitized with lifetime and a discount rate of 8%, and weighted with installed capacity. This is associated with an uncertainty range, calculated with different capital cost assumptions among dispatchable technologies.

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Acronyms

AC	Alternating current
ACER	Agency for the Cooperation of Energy Regulators
AEMO	Australian Energy Market Operator
AGC	Automatic generation control
ASEAN	Association of South East Asian Nations
BEV	Battery electric vehicle
BRP	Balance responsible parties
CACM	Capacity allocation and congestion management
CAISO	California Independent System Operator
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CEC	China Electricity Council
CFE	Comisión Federal de Electricidad
CGE	Computable general equilibrium
CHAdEMO	CHARge de MOve charging standard
CR	Central region
CRM	Capacity remuneration mechanisms
CSG	China Southern Power Grid
DER	Distributed energy resources
DES	Distributed energy systems
DLR	Dynamic line rating
DNG	Distributed natural gas
DNO	Distribution network operators
DSI	Demand-side integration
DSM	Demand-side management
DSO	Distribution system operator
DSR	Demand-side response
ED	Economic dispatch
EIM	Energy Imbalance Market
ENTSO	European Network of Transmission System Operators for Gas
ER	East region
ESO	Electricity system operator

ETS	Emissions trading system
EUPHEMIA	Pan-European hybrid electricity market integration algorithm
EV	Electric vehicle
FACTS	Flexible alternating-current transmission system
FCA	Forward capacity allocation
FCAS	Frequency control ancillary services
FCR	Frequency containment reserve
FERC	Federal Energy Regulatory Commission
FIT	Feed-in tariffs
GCL	Golden Concord Group Limited
GDP	Gross domestic product
GW	Gigawatts
HVDC	High-voltage direct current
ICT	Information and communications technology
IEA	International Energy Agency
IPP	Independent power producers
IRP	Integrated resource plan
ISO	Independent system operator
LCOE	Levelised cost of electricity
LED	Light-emitting diodes
LMP	Locational marginal price
MRC	Multi-regional coupling
MW	Megawatt
NARUC	National Association of Regulatory Utility Commissioners
NCR	North central region
NDRC	National Development and Reform Commission
NEA	National Energy Administration
NEV	New energy vehicle
NPS	New Policies Scenario
NSR	Shandong region
NWR	Northwest region
O&M	Operation and maintenance
OCGT	Open-cycle gas turbines
OPEX	Operational expenditure
PCI	Projects of Common Interest

PCR	Price coupling of regions
PHEV	Plug-in hybrid electric vehicle
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PLEF	Pentalateral Energy Forum
PPA	Power purchase agreement
PSH	Pumped storage hydropower
PV	Photovoltaics
PVPS	Photovoltaic power systems
QSTS	Quasi-static time-series
REDZ	Renewable energy development zones
REE	Red Eléctrica de España
RPM	Reliability pricing model
RSC	Regional security coordinators
RTO	Regional transmission organisations
SAARC	South Asian Association for Regional Cooperation
SCED	Security-constrained economic dispatch
SDS	Sustainable Development Scenario
SERC	State Electricity Regulatory Commission
SGCC	State Grid Corporation of China
SME	Small and medium-sized enterprises
SPC	State Power Corporation
SV	System value
SWR	Southwest region
TECO	Tampa Electric Company
TPS	Tradeable performance standard
TSO	Transmission system operators
TYNDP	Ten-Year Network Development Plan
UC	Unit commitment
UHVDC	Ultra-high-voltage direct-current
VALCOE	Value-adjusted levelised cost of energy
VoS	Value-of-solar
VPP	Virtual Power Plant
VRE	Variable renewable energy
WEM	World Energy Model
WEO	World Energy Outlook

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Table of contents

China Power System Transformation Assessing the benefit of optimised operations and advanced flexibility options	1
Abstract	1
Highlights	2
Executive summary	3
Findings and recommendations	6
Report context and objectives	6
Technical analysis	23
Introduction	23
Context and status of power system transformation in China	26
Background	26
Brief introduction to China's power system	28
Emerging trends in system transformation in China	37
Summary	48
References	49
Power system transformation and flexibility	54
Three global trends in power systems	54
Flexibility as the core concept of power system transformation	60
Implications for centralised system resources	68
Implications for DER	79
References	87
Policy, market and regulatory frameworks for power system transformation	90
Basic principles to unlock flexibility	90
Wholesale market design	91
Retail markets and distributed energy resources	110
Upgraded planning frameworks	118
Transition mechanisms to facilitate system reforms	126
References	130
Power system transformation pathways for China to 2035	134
General trends in China's power system evolution	134
Achieving a "Beautiful China"	135
Key variables for system transformation	136
Different power system pathways	137
Two main scenarios for 2035	138
Power sector modelling results	144
Comparing basic features of the WEO 2018 NPS and SDS results	144
NPS modelling cases	145
SDS modelling cases	153
References	170
Summary and conclusions	171
Power system transformation in China	171
Options to facilitate implementation of the Document 9 reforms	173
Innovative options to further accelerate progress towards a "Beautiful China"	175
Additional considerations for markets, policies, regulation and planning	177
International implications	179
References	180
Annexes	181
Annex A Spatial disaggregation of national demand and supply	181
Generating hourly load profiles for each region	184
Allocating generation capacity between regions	185
Method used for calculating CAPEX savings	187
References	187

Acronyms	189
Acknowledgements, contributors and credits	192
Table of contents	194

List of figures

Figure 1.	Illustration of an interconnected energy system enabled by digitalisation	7
Figure 2.	Overview of different power system flexibility resources	9
Figure 3.	Three main pillars of system transformation	11
Figure 4.	Capacity and generation mix for China in 2035, IEA WEO NPS and SDS	13
Figure 5.	Operational costs, inflexible and flexible cases, NPS, 2035	16
Figure 6.	Benefits and costs of different advanced power system flexibility options, SDS, 2035	17
Figure 7.	Average auction price by project commissioning date for utility-scale wind and solar PV	55
Figure 8.	Share of VRE in global capacity growth and power generation growth, 2018–23	55
Figure 9.	Illustration of an interconnected energy system enabled by digitalisation	57
Figure 10.	Global heat pump sales by technology, 2012–17 (left) and regional shares in 2017 (right)	59
Figure 11.	Impact of EVs on capacity credit of solar PV in Thailand, 2036	60
Figure 12.	Overview of VRE system integration phases for different countries and selected provinces, 2017	62
Figure 13.	Different layers of system flexibility	65
Figure 14.	Impact of decentralisation and digitalisation on local power grids	67
Figure 15.	Battery storage deployment by market region in the United States, 2017	77
Figure 16.	Technical impacts of rising deployment of distributed solar PV generation	85
Figure 17.	Overview of different building blocks of electricity markets	93
Figure 18.	Monthly trading volumes on the German intraday market, 2012–16	95
Figure 19.	Developing the EU network codes	98
Figure 20.	Illustration of the LCOE and SV	104
Figure 21.	Links between the VRE cost, the SV and competitiveness	105
Figure 22.	Options for retail pricing at different levels of granularity	112
Figure 23.	Value components of local generation	113
Figure 24.	Power generation by ownership, Mexico prior to reform, 2014	127
Figure 25.	Installed generation capacity under legacy contracts and share of demand, 2017–29	129
Figure 26.	Energy access, electricity consumption and generation capacity, China, 1990–2016	135
Figure 27.	Capacity and generation of wind and solar PV	136
Figure 28.	Capacity mix for China in 2035, NPS and SDS	144
Figure 29.	Generation mix and curtailment rate in China, 2035, all NPS cases	146
Figure 30.	Annual power system operational costs by cost category, 2035, NPS cases	147
Figure 31.	CO ₂ emissions and air pollutants, 2035, NPS cases	147
Figure 32.	Impact of moving to economic dispatch on coal power plant capacity factor, by region	148
Figure 33.	National level load and generation mix of a typical week, fair and economic dispatch	149
Figure 34.	Impact of interregional trading and transmission expansion on coal-fired power plant utilisation, by region	150
Figure 35.	Load and net import of energy by region, 2035, NPS cases	151
Figure 36.	Generation mix and VRE curtailment rate in the NWR	153
Figure 37.	Annual operational cost savings from different flexibility options, 2035, SDS	154
Figure 38.	Annuitised net power system cost savings, relative to SDS-Inflex, all SDS cases	155
Figure 39.	Annual CO ₂ emissions, 2035, SDS cases	155
Figure 40.	Generation patterns and the demand profiles during high stress periods with limited flexibility options, SDS-Inflex case	156
Figure 41.	Generation patterns and demand profiles during high-stress periods, SDS-DSR	157
Figure 42.	VRE curtailment in SDS-Inflex and SDS-Storage cases, by region	160
Figure 43.	Net load during peak demand periods in the SDS-Storage and SDS-Inflex cases	160
Figure 44.	Demand reduction due to smart EV charging during periods of peak demand, SDS-EV case, 2035	161
Figure 45.	VRE curtailment in SDS-EV and SDS-Inflex cases, by region	162
Figure 46.	Generation patterns and demand profiles during high stress periods in SDS-EV case	162
Figure 47.	Provision of upward ramping flexibility from different flexibility options before and after the introduction of EV smart charging	163
Figure 48.	VRE curtailment rate in SDS cases with smart EV charging and DSR, by region	165
Figure 49.	VRE curtailment rate in SDS cases with EV smart charging and storage, by region	166
Figure 50.	Charging and discharging of storage alongside VRE generation during the period of minimum and peak net demand, with and without EV smart charging	166

Figure 51.	Generation patterns and demand profiles during high-stress periods, SDS-Full flex case.....	167
Figure 52.	Demand reduction due to portfolio of flexibility measures during peak demand, 2035, SDS-Full Flex case	168
Figure 53.	VRE curtailment by region, 2035, SDS-Inflex and SDS-Full flex.....	169
Figure 54.	Modelling regions.....	182
Figure 55.	Wind and solar potential in China.....	186

List of boxes

Box 1.	Lessons learnt from Document 5 round of reform	32
Box 2.	Energy conservation dispatch	35
Box 3.	Multi-energy complementary project in Gui'an	43
Box 4.	Microgrid project in Suzhou	43
Box 5.	"Internet+" project in Guangdong.....	44
Box 6.	Envision's platform for the Internet of things	44
Box 7.	DSR trial in Jiangsu (14:00-14:30, 26 July 2016)	46
Box 8.	EV subsidy in China.....	48
Box 9.	Improving flexibility parameters in legacy coal plants	69
Box 10.	Flexible operation of solar PV	71
Box 11.	DLR in the Snowy Region, Australia.....	73
Box 12.	Innovative use of existing PSH for integrating solar PV in Kyushu, Japan.....	75
Box 13.	Reducing the cost of ancillary services in Australia – the Hornsdale battery.....	76
Box 14.	V2G for frequency regulation.....	81
Box 15.	Battery storage for real-time balancing	83
Box 16.	Battery storage for balancing the distribution network	84
Box 17.	Pooling industry and battery storage in virtual power plants	86
Box 18.	ETSS in China.....	109
Box 19.	The role of data exchange platforms in changing power systems	115
Box 20.	PacifiCorp's Integrated Resource Plan	119
Box 21.	Co-ordinated transmission network planning in Europe	122
Box 22.	Beyond 15% penetration: New technical DER interconnection screens for California.....	124
Box 23.	Planning for local flexibility requirements	124
Box 24.	Key findings in <i>WEO</i> related to China's power sector and global electrification.....	138
Box 25.	Boosting the flexibility of aluminium smelters in China	158
Box 26.	Disaggregation of China's electricity demand based on future regional development and environmental strategies	184

List of tables

Table 1.	Selected key power sector indicators in China's 13th Five-Year Plan.....	40
Table 2.	DSR development in pilot cities	45
Table 3.	Overview of differences between wind power and solar PV	61
Table 4.	Summary of impacts associated with Phases 1 to 4 of system integration	63
Table 5.	Different timescales of power system flexibility	64
Table 6.	Performance parameters per unit	70
Table 7.	Qualitative description of energy storage services in the power system	74
Table 8.	Additional planning activities to integrate DER	123
Table 9.	Case settings for the NPS analysis	140
Table 10.	Case settings for the SDS analysis.....	143
Table 11.	Generation capacity in China, NPS and SDS <i>WEO</i> scenarios	145
Table 12.	VRE curtailment rate by region	152
Table 13.	Division of eight regions	183
Table 14.	Transmission capacity (MW): existing and future assumed capacity	183

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