Steering Electricity Markets Towards a Rapid Decarbonisation

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Abstract

Achieving net zero emissions by 2050 will require a significant reduction in electricity sector emissions, with around half of these coming from systems that currently have liberalised electricity markets. In order to support a rapid decarbonisation of power systems, the design of these markets will need to evolve to ensure that they maximise the value delivered by existing and new low-carbon technologies. When policymakers design electricity markets, they need to consider the interactions between all parts of the market including wholesale, retail and capacity markets. At the same time, it is essential to ensure synergies with low-carbon investment frameworks and other decarbonisation policies.

This report identifies key principles for designing different parts of the market-based on evidence from electricity markets globally and provides actionable guidelines to help policy makers match decarbonisation pledges with actions. With short-term wholesale markets as the starting point for generating efficient price signals, the report systematically considers the different parts of electricity markets, perspectives for integrating technologies such as distributed resources and storage, and how the design process fits with other decarbonisation policies and system planning. The principles derived from this analysis provide policy makers with market design tools in the context of new technologies and low-carbon transitions.

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Table of contents

Executive summary

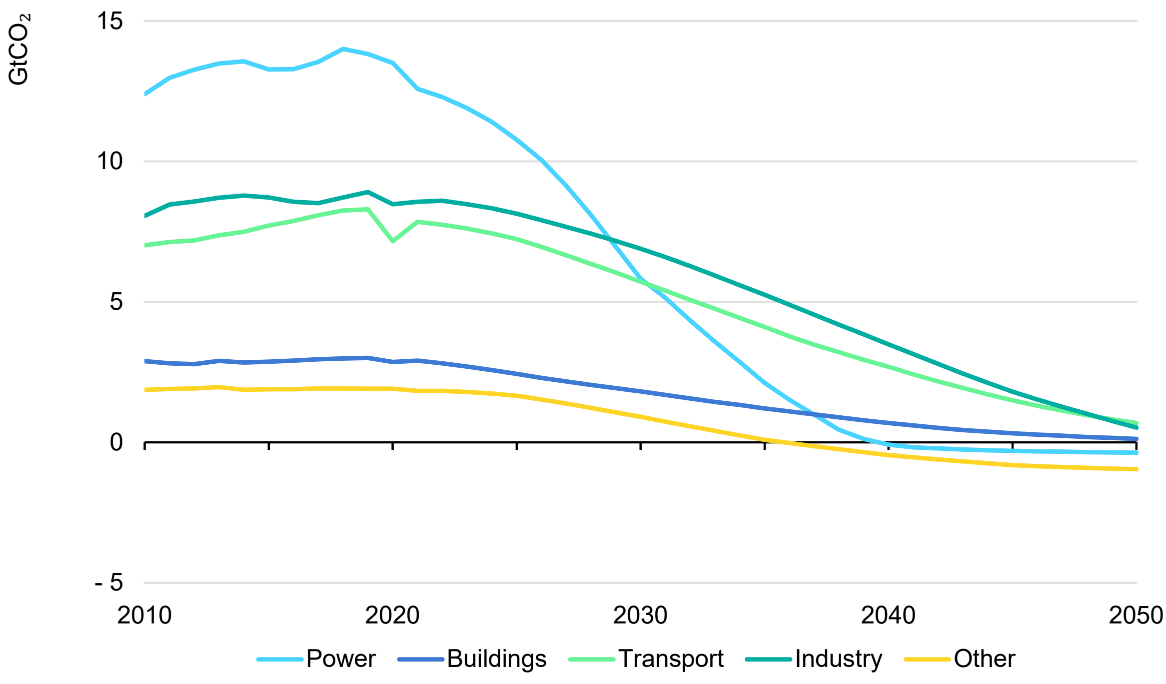
Electricity plays a vital role in achieving net zero emissions by 2050

The electricity sector has grown to be one of the most important sources of energy. In 2020, global electricity demand was 23 230 TWh, 20% of total final energy consumption and its generation produced 40% of total energy-related CO_2 emissions globally, making it the single largest source of such emissions.

By 2050, as sectors that currently rely on fossil fuels become electrified, demand is expected to more than double to 60 000 TWh. In light of stated global climate change goals, decarbonising the electricity sector is central to achieving net zero emissions by 2050.

In the IEA's Net Zero Emissions by 2050 Scenario, emissions from electricity generation fall to zero (in aggregate) in advanced economies in the 2030s, with emerging market and developing economies achieving this goal around 2040. Making this scenario a reality requires accelerated decarbonisation of the sector.

Total CO_2 emissions per sector, Net Zero Emissions Scenario, 2010-2050



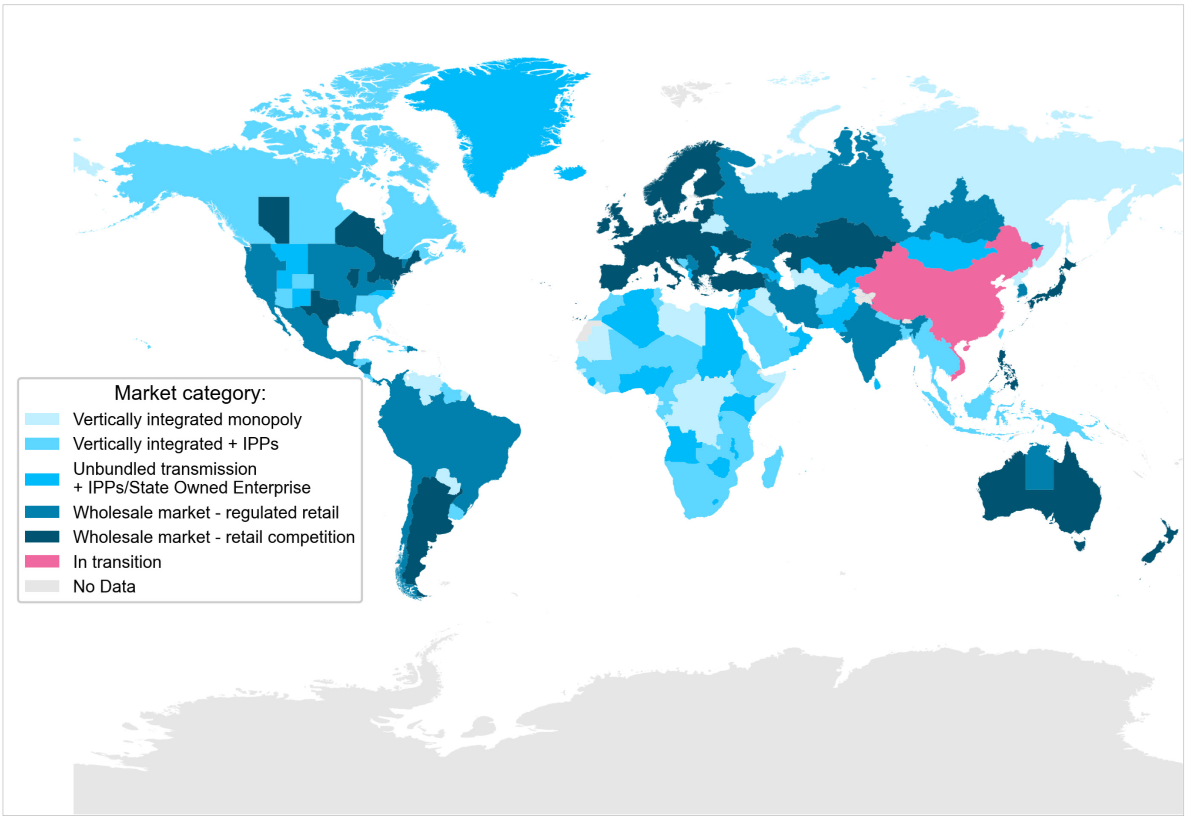
Source: IEA (2021), Net Zero by 2050.

Expansion of generation from renewables is expected to contribute the most to decarbonisation of electricity, output from these sources almost tripling by 2030 and growing eightfold by 2050 – driven mostly by significant deployment of variable renewable energy (VRE) such as solar photovoltaics (PV) and wind. Other low-carbon generation (such as nuclear and hydrogen) and flexibility-providing technologies (e.g. battery storage systems and demand response) will also play lead roles in the path towards net zero emissions.

Electricity markets are central to decarbonising the sector

At present, around 50% of electricity in the world is generated in power systems relying on liberalised markets; this will increase to approximately 76% once the People's Republic of China ("China" hereafter) completes implementing power markets. As such, much of the accelerated decarbonisation will have to be stimulated in the short and medium term in systems that rely on electricity markets to minimise operation costs and – to varying degrees – to attract investments.

Status of electricity markets around the world in 2022



Market forces can support decarbonisation of the power sector when guided and complemented by the implementation of policies designed to match net zero ambition, including effective investment frameworks, carbon pricing and other decarbonisation instruments.

As in any other market, a socially optimal equilibrium can only be achieved if all participants are made responsible for all costs and benefits arising from their actions. This is the mechanism by which markets can provide price signals that function as incentives (or disincentives) to guide the decisions of market actors. In the context of decarbonisation, such price signals are not yet optimally aligned. In most power systems in the world, whether co-ordinated by electricity markets or by vertically integrated utilities, externalities due to CO_2 emissions are not completely included as part of power sector costs.

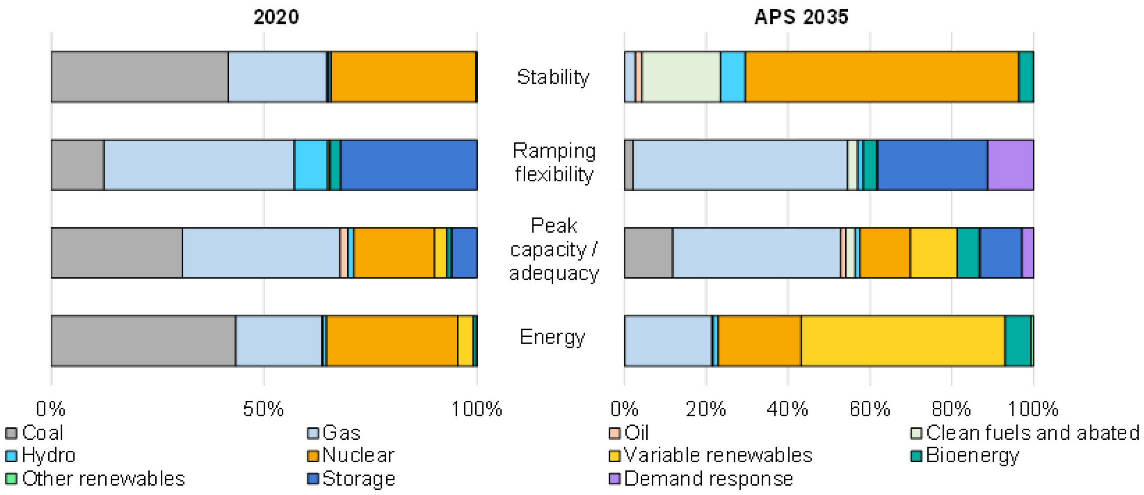
This creates substantially distorted price signals that make investments in and operation of carbon-intensive technologies more profitable than they should be, and do not properly recognise the value of low-carbon technologies.

Market design needs to be able to adapt to changing landscapes

Over the past several decades, liberalisation of electricity markets has been used as a mechanism to ensure efficient dispatching of resources in line with demand and to obtain benefits from competition in system operation and investment. Since the creation of the first liberalised electricity market – in 1982 in Chile – the design of markets has continuously evolved and matured. This does not mean electricity market design has been solved or that any solution could be static in nature. Ongoing changes in policy and technology require that markets be designed to adapt to new landscapes. This is particularly true in the context of short- and medium-term acceleration of decarbonisation of the electricity sector.

Procurement of system services is an example of this change. As electricity systems transition away from fossil fuel generation to higher shares of VRE, ensuring secure system operation will need to be based on a different configuration of different components. The fundamental services of energy, flexibility, peak capacity and stability will have to be procured to sufficient levels by using all available technologies. In turn, the assets needed and their respective value to systems will evolve. VRE for instance, can provide substantial volumes of clean, low-cost energy but contributes much less to firm capacity. In contrast, despite not providing a net-positive energy contribution, energy storage can contribute to ramping flexibility and adequacy.

Power system services in highly decarbonised scenarios, Korea announced pledges scenario, 2020 and 2035



Note: Stability is represented by system inertia.
Source: IEA (2021), Reforming Korea's Electricity Market for Net Zero.

Experience shows how electricity market design can be changed to help decarbonisation

Although there is no perfect market, several experiences indicate the main elements of market design that can bring the power sector on track to achieve net zero emissions.

- Redesign of short-term wholesale markets to integrate large shares of VRE and open opportunities for modern technologies to provide flexibility.
- Creation or redesign of investment frameworks and policy instruments to enable deploying larger amounts of low-carbon electricity generation and to enable new technologies to participate in the markets.
- Introduction of carbon pricing to correct distortions due to the lack of recognition of the costs created by greenhouse gas (GHG) externalities. In most systems, this signal is still very low compared to estimates of the actual social costs created by GHGs.
- Strengthen adequacy mechanisms, providing incentives to all resources capable of delivering energy in times of distress of the system

This report collects evidence from electricity markets around the world to identify several innovations in market design and investment frameworks that provide policy makers with immediate actionable ideas to support a transition to a flexible, decarbonised and affordable power sector. It also draws attention to approaches that synergise with decarbonisation in other sectors. These experiences represent examples of one or more of the previously mentioned fundamental elements. Individually and collectively, they provide powerful tools that will hopefully empower policy makers to match pledges with actions.

Provided that all governments strengthen their energy and climate policies to meet climate ambitions, electricity markets could function as a tool to significantly support decarbonisation pathways, particularly when synergised with a broader portfolio of policies and regulations.

Market design will need to keep evolving and to be revised to stay on the path towards net zero emissions by 2050. We hope that the experiences presented here will serve as the building blocks for rapid decarbonisation of electricity systems.

Short-term wholesale market design is first step towards establishing efficient price signals

Wholesale markets enable the trading of energy between market players at different time scales; as such, they are the cornerstone of successful market design. Well-designed, short-term wholesale markets are fundamental to being able to leverage the advantages of competition in electricity production and consumption while synergising with and supporting accelerated decarbonisation of the sector.

Establishing efficient price signals can provide incentives to market actors to align their decisions with the needs of the system. The overarching aim is to ensure that price signals represent the reality of the system and that they reward services that provide value to it. These price signals are essential to highlight the needs of the system. Examples of particular value to system decarbonisation include generation at times of high demand, lower carbon emissions and flexibility to modify levels of generation or consumption in response to system needs. As technology evolves and the needs of the system change, it is necessary to adapt the design of the wholesale market to ensure that price signals continue to correctly represent the needs of the system and reward the value provided by different assets.

Wholesale markets should be designed such that price signals ensure improved representation of the time and geographical value of energy. This can be achieved through increased time resolution, moving gate closure times closer to the hour of delivery, and applying a market model that correctly represents the underlying physical infrastructure. Additionally, to ensure efficient system operation, it is important to make sure long-term contracts support risk hedging and investments, but do not impede optimal dispatch on short-term wholesale markets.

Embedding decarbonisation instruments in competitive markets

Among decarbonisation technologies, wind and solar PV have become the most cost-competitive. Current electricity markets and regulations, however, have not managed to stimulate sufficient investment. To accelerate deployment of low-carbon electricity, it is necessary to close the investment gap by reflecting the cost of negative externalities and introducing additional decarbonisation mechanisms that are compatible with both wholesale market signals and other policy instruments.

Several decarbonisation instruments facilitate integration with competitive wholesale market revenues while reducing the overall cost burden that gets passed on to consumers. To implement these decarbonisation mechanisms correctly and efficiently, market design needs to balance providing revenue certainty through long-term signals while encouraging efficient integration in day-to-day power system operations.

In the coming years, as VRE comes to account for the majority share in generation, it will be important to introduce market-based instruments to ensure sufficient investment in dispatchable low-carbon assets. To achieve this, policy makers will need to introduce instruments that reward the provision of services such as flexibility and adequacy while maintaining the efficiency of the wholesale market.

Maximising the value of distributed energy resources requires changing current market structures

The diversification and accelerated deployment of distributed energy resources (DER) worldwide is shifting electricity systems. The past model of centralised, large generators connected to transmission networks with little demand-side control is no longer reflective of how modern systems function. The emergence of decentralised systems, with many distributed resources that are smaller and interconnected, allows both end use devices (e.g. appliances) and consumers to have more active roles.

If deployed efficiently, DER offer large potential to support the integration of VRE, increase system resilience and reduce the need for grid upgrade. In addition to providing demand-side response, some DER assets can supply ancillary services as sources of flexibility, black start services and non-wire alternatives. To maximise the benefits of DER, it is necessary to adapt markets to reward their true value. Indeed, under current market structures in which system operators often lack visibility of DER, its deployment can create issues and incentivise inefficient behaviours by asset operators, particularly considering the increased electrification that results in higher peak loads and congestions of distribution grids.

Ensuring electricity markets are ready to let DER play their role is therefore highly recommended. To make DER visible to system operators, digitalisation should be encouraged. This implies deployment of connected appliances and smart metering infrastructure, supported by effective data exchange structures and appropriate data privacy measures. Digital infrastructure will facilitate the design of electricity tariffs that reflect the locational and time-variant value of electricity and ensure a fair repartition of grid costs, thereby ensuring optimal use of DER. In addition, policy makers should review connection schemes and participation rules and acknowledge the role of aggregators while facilitating their involvement. Lastly, co-operation protocols among stakeholders (particularly transmission and distribution system operators [TSOs and DSOs]) and grid operation processes have to be adapted to the DER-induced shift from the transmission to the distribution system.

Market design must recognise the unique role of storage to leverage its advantages

Cost reductions in energy storage technologies, especially battery storage, have resulted in increased uptake in various domains of the power system. To support its further deployment and ensure the system value of storage is maximised to support decarbonisation, market design changes must consider its unique role and technological advantages.

Storage is unique in its ability to provide flexibility through both load and generation, across a broad range of timescales. As it cannot decarbonise the power system on its own, storage must be part of a package of measures that aims to align market incentives and the generation mix towards decarbonisation to avoid worse emissions outcomes. Taxation and network tariffs must also be adapted to appropriately recognise its role as a flexibility provider, ensuring it is not charged twice as a consumer and as a generator. Finally, specifications for market participation must evolve away from the properties of conventional technologies towards technologically neutral ones that use (and appropriately remunerate) the system services of storage.

Design changes to reward technological advantages of storage could focus on fast-response time and geographic flexibility. Remunerating fast response could be achieved through shorter time periods or new markets focusing on fast frequency regulation. Remunerating geographic flexibility could be achieved through more granular locational signals or new markets for localised system services.

Ensuring system adequacy requires additional measures

Policy makers have the duty to set the desired reliability standard for electricity systems and ensure mechanisms are in place to meet it. If they do not properly value all system services, wholesale markets may not sufficiently provide incentives for the assets needed for secure system operation. Even if restrictions on prices (e.g. price caps) were relaxed in the wholesale market, if the quantity of reserves that needs to be procured is not properly valued, the problem of “missing money” arises and can result in underinvestment.

Three policy instruments can help solve the missing money problem: energy price adders, capacity-based payments and regulated procurement. These instruments can be used in combination – use of one does not exclude use of the others. Energy price adders embed the cost of procuring reserves into the wholesale market by allowing prices to exceed variable costs during periods of reserves shortages (which indicate system stress). Rewarding capacity that directly contributes to security in these periods creates incentive for investment in the types of capacity that can be available when actually needed. Capacity payments directly reward capacity through a long-term payment for their availability, providing a predictable stream of revenue that can encourage some capacity to enter or remain in the market. These payments also effectively reduce the volatility that can occur when energy markets do become stressed. It is important that these payments be designed to ensure performance of the asset when needed. Regulated procurement, under which utilities are mandated to contract in advance enough energy to supply a share of their forecasted demand, can also play a significant role in supporting capacity adequacy by providing longer term incentives.

Retail markets need to encourage efficient behaviour while protecting consumers

Well-functioning retail markets are crucial to ensure that the benefits of liberalised wholesale markets are passed on to final consumers. Given that most retail customers prefer not to interact directly with the price of energy in their daily consumption, retailers serve a critical function in the power sector – i.e. managing and allocating risk on behalf of their clients. New developments are changing the types of risks that retailers face in power markets. Recent events, including the spike in the price of natural gas (which sets the electricity price in many markets), and extreme weather events are leaving consumers and retailers alike exposed to the resulting high prices of electricity.

Retail markets can serve the desire to reduce system costs while also protecting consumers. Innovative tariffs, such as capacity subscriptions, can protect the truly critical portion of a customer's consumption while also leveraging technologies to manage demand during times of stress. These measures can be almost imperceptible to customer comfort, such as smart charging of electric vehicles or activation of appliances. But customers who prefer to completely avoid being exposed to market fluctuations should be able to choose fixed tariffs from financially stable suppliers for this service.

System planning lays the foundation for power markets

Transforming electricity systems is key to a clean energy transition. To meet stated climate goals, systems will need more grids, along with more and better integrated low-carbon resources (including demand-side participation). Developing a vision that sets out clear objectives, provides a realistic view of how systems may evolve and sets a plan for deploying the assets needed to meet the policy objectives is helpful to framing the role of markets. Power sector planning provides information on system needs in the long term and, as such, serves as a guide for competitive investments. Planning also supports policy making as it helps identify necessary enhancements to market design.

Planning is a complex process that requires taking account of a large number of uncertainties; the longer the time horizon, the number and scope of uncertainties tends to increase. Traditional practices were centralised and highly technical; new approaches have evolved to engage (early and often) a wide range of stakeholders in the mission of designing the future system.

Integrated and co-ordinated planning (an emerging practice that must not be confused with central planning) is a collaborative framework bringing together the strengths and information from many stakeholders within the power sector and from other sectors to feed into the plan. It helps ensure robustness in planning and stability in the rules over the long term, thereby supporting decarbonisation of the power system. Key features of effective integrated planning are to consider the power system as a whole (including integration with other sectors); to incentivise all solutions that contribute to policy goals; to be transparent and engage stakeholders; and to aim for robustness with respect to a broad range of futures and uncertainties (including, for example, extreme weather events).

Finally, mechanisms should exist to ensure formalised feedback between planning, policy making and market design (with a clear process for adapting rules over time) so that planning supports increasing ambitions for decarbonisation.

Chapter 1. Optimising wholesale markets

Short-term wholesale markets reveal the system value of resources through price signals

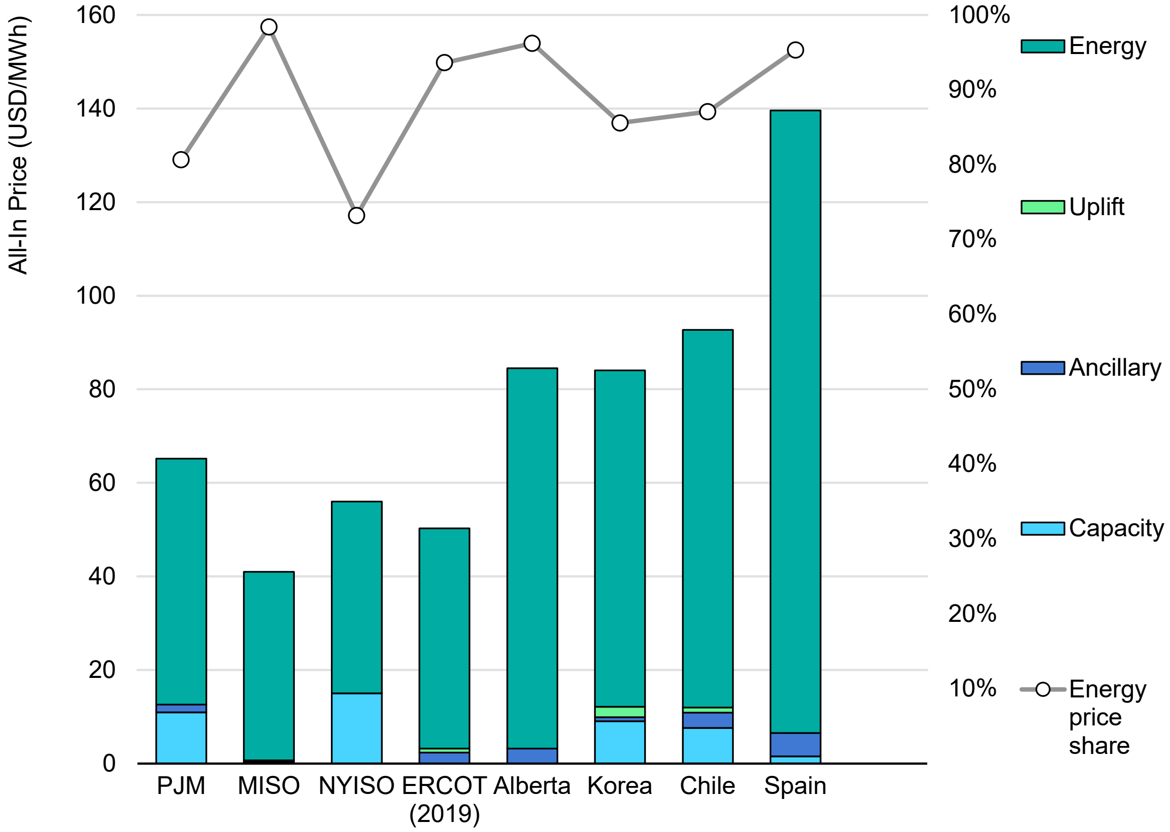
Wholesale markets enable the trading of energy from electricity among market players. A key feature is that trading occurs at different time scales, with activity and pricing changing as more information becomes available to support the precise, real-time balance between demand and supply. Wholesale markets provide a transparent way to select the most efficient resources to dispatch in order to balance the system such that all stakeholders, including society broadly, benefit from the advantages of competition in electricity production and consumption.

The sale of energy in short-term wholesale markets is the main source of income for generators, providing close to 80% of their revenues. For this reason, the short-term wholesale market is a cornerstone of successful market design. Not surprisingly, the way these markets are designed influences system operation and investment decisions regarding assets.

In a liberalised electricity market, price signals that arise through market design and actual trading will provide the information market actors need to make decisions (operational or investment) that align with the needs of the system. The aim of market design is to ensure that price signals represent the reality of system needs and appropriately reward services that provide value to it. For example, in periods of high demand, price signals should incentivise increased generation or reduced consumption. Price signals should also incentivise sources of flexibility to modify the level of production or consumption in response to the system needs. As such, price signals should be reflective of the actual costs of different actions and technologies.

In the context of a clean energy transition, an emerging challenge is to design markets to enable efficient use of low-carbon sources and technologies while also minimising system costs.

Sources of revenue for generators in selected competitive markets in USD per MWh, 2016



One example of how effective market design can reduce emissions while delivering substantial cost savings can be found in the China Power System Transformation, according to an analysis published by the IEA in 2019. Modelling of the shift from the current dispatch mode in China to a fully economic dispatch through a two-settlement system shows that use of short-term wholesale markets could reduce annual operational cost by 11%, equating to roughly USD 45 billion per year in 2035. The short-term markets also sharply reduce curtailment of variable renewables (VRE), thereby helping to lower carbon dioxide (CO_2) emissions by 15%.

As technology evolves and the needs of systems change, it is necessary to adjust market design to ensure that price signals provided by the wholesale markets continue to support efficient operations and necessary investments. Some low-carbon technologies, such as nuclear, are better suited to wholesale markets designed primarily for trading of fossil fuel generation. Other technologies and actions that are playing larger roles – such as VRE, new storage technologies or demand response – have characteristics that offer value to systems that are not fully captured under current market design.

As countries decarbonise their power systems by increasing the share of VRE and integrating other emerging technologies and actions, it will be necessary to adjust the design of wholesale markets. An overarching challenge is finding ways to harness the full potential of technologies characterised by uncertainty and variability in their generation, in both location and in time.

Market design must balance planning and adaptability

As different technologies have different characteristics in terms of key functions (e.g. start-up times, minimum loads and ramping rates), ensuring these constraints are respected during operation requires planning in advance the expected schedule of the assets. The uncertain nature of VRE generation and of expected demand, however, makes it impossible to pre-plan system operation with complete certainty. As the hour of delivery approaches and the accuracy of forecasts improves, system operators usually need to modify previously made schedules.

To support this need for both advance planning and real-time matching of demand and supply, electricity wholesale markets typically combine a series of markets that operate consecutively across time. Generally, these markets use either two-settlement systems, with trades occurring in the "day-ahead" market and in real time (the "balancing market"), or three-settlement systems, in which case an "intraday" market is injected between the two others. These markets operate together, allowing operators to plan a in advance what resources they will call on to balance the system while providing flexibility to adapt operations in real time if generation or demand are higher or lower than anticipated.

Originally, markets were designed when large, dispatchable thermal power plants provided the majority of generation and system operators knew which physical assets would be available at a given time and location, their level of capacity and any technical constraints linked to generating or modifying operations. Normally, the only deviations from the day-ahead schedule in such a system would be small adjustments due to errors in demand forecast or to compensate for unplanned outages.

As the share of VRE increases, new challenges arise linked to their intrinsic uncertainty. The volume of electricity generated by solar or wind, for example, can change from one minute to the next; as such, uncertainty on expected generation increases over forecasts with longer timeframes. Additionally, new technologies, such as DER, can introduce characteristics for which current market designs are not yet well adapted. Yet, if the market design is fit for capturing their value, these technologies can significantly reduce system emissions to support a clean energy transition.

Following more detailed descriptions of the main elements of market design and some key features that influence system operation, this chapter offers broad recommendations for consideration. The chapter does not precisely cover all elements or possible designs but aims to demonstrate a set of guiding principles.

Day-ahead market: enables planning the operation of assets

The day-ahead market serves the function of providing both market actors and the system operator with an initial expectation of how system operations will play out on the following day. Producers participating directly in the market will give offers for generation they can provide (sell); consumers (including retailers) will, in turn, provide bids for electricity they want to consume (buy). Based on the offers and bids received, the market operator will match supply and demand in a way that minimises costs of operating the system, thereby ensuring the lowest cost to the system. A given market will divide a day into multiple periods (typically 24, 48 or even more) and this process will be repeated for each, with offers and bids being received until the day-ahead gate closure time, typically around noon of the day before delivery.

Day-ahead markets are usually based on the principle of marginal pricing (also called pay-as-cleared). This means that once the market has determined which bids and offers are accepted, the price of electricity for a given period is set by the most expensive offer that comes into play. This price is called the clearing price and determines who is "in" or "out" of the market, referred to as clearing the market. All producers with offers below the clearing price will be scheduled to generate; all consumers that bid to buy at or above the clearing price will be scheduled to consume (in the absence of physical transmission constraints, which will be further discussed later). An essential aspect is that all producers "cleared" in the market will receive the same clearing price, even if they offered lower prices. In turn, all consumers cleared will pay this price, even if they were willing to pay more.

Broad consensus exists that this mechanism for setting the price of electricity provides the most efficient way of matching production and consumption, based on all available resources and information at a given time. In addition to reflecting the actual cost of clearing the market, marginal pricing provides other important cues. By revealing moments when clearing the market depends on high-cost actions and/or technologies, it acts as a thermometer for the needs of the system. It also creates strong incentives for generators to look for ways to lower their costs, as being able to bid below competitors allows them to capture higher benefits. In efforts to decarbonise, it has another role: as wind and solar have no fuel costs – and thus low marginal costs, they are consistently able to offer below thermal generators (who need to pay for fuel). This means they clear the market first and capture profits even if their marginal cost is close to zero, which supports them in recovering their fixed costs.

Ultimately, market clearing enables the creation of detailed schedules for individual generators and consumers while also giving market players a clear expectation of operation for the following day.

The day-ahead market is the main market that defines system operation and reflects the costs of operating it through price signals. As such, it is often considered the main market to which other markets refer. Long-term contracts, for example, are typically settled against the day-ahead market price.

Intraday market: a tool to refine schedules

As it became clear that rising shares of VRE introduce high levels of uncertainty on generation schedules, markets in places such as Europe introduced intraday markets. The intraday market facilitates adjustment of the day-ahead schedule by allowing market participants to trade any expected imbalances in demand and supply after the day-ahead market has closed, but before the hour of delivery. This provides a means to update schedules closer to the hour of delivery, as forecasts for generation from VRE become more accurate.

Trading on the intraday market begins after the closure of the day-ahead market and will continue until the intraday gate closure time. Different intraday markets have different gate closure times, ranging from 60 minutes before delivery time on the Nordic market down to just five minutes in places such as Belgium and the Netherlands. As shorter time horizons give market players more time to update their positions based on the evolving reality of the system, most countries in Europe are moving in this direction.

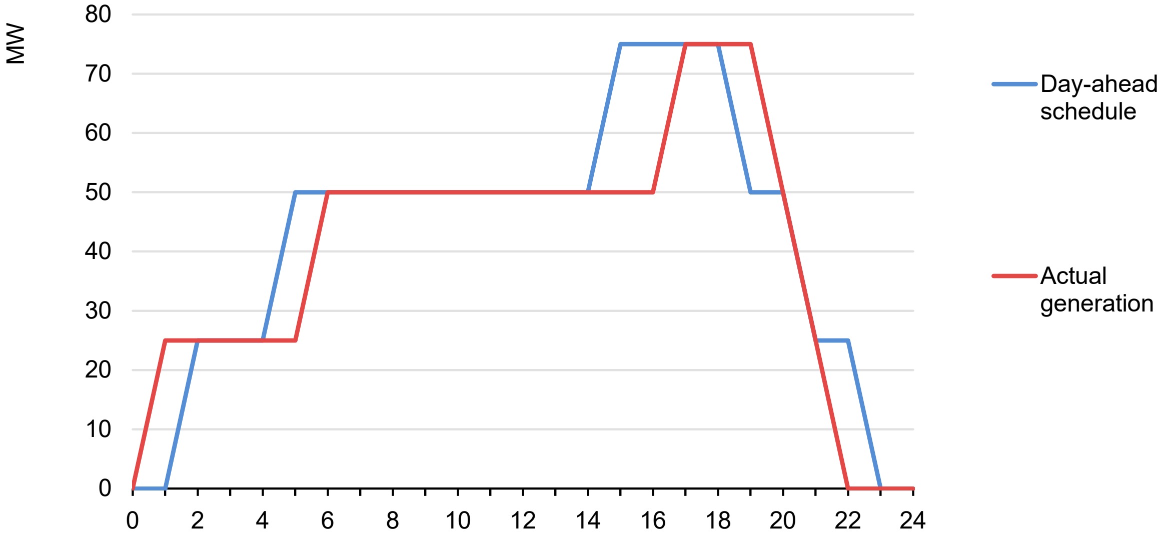
In Europe, the intraday market follows the model of single intraday coupling (SIDC), based on cross-border continuous trading with bids and offers matched on a pay-as-bid basis. In contrast to the market clearing and single price of the day-ahead market, pay-as-bid means that bids and offers are matched in pairs, and each transaction occurs at a different price. It should be noted that if traded volumes are sufficient, it is possible to combine this type of continuous trading with auctions that provide a clearing price during the intraday market.

Balancing market: A tool for efficient delivery in real time

The balancing market is where actual physical match of generation (supply) and consumption (demand) is carried out in real time, managed by the system operator, who takes over as a single buyer, acquiring and activating reserves as needed. Typically, the system operator will buy reserves in advance and activate them in real time as needed to maintain the balance between supply and demand.

A hypothetical mapping of scheduled generation based on the day-ahead market and actual hourly generation at the moment of delivery demonstrates the potential for mismatch. In some moments, a fictional generator produced more than it was scheduled to; in other moments, it produced less, creating imbalances between the planned generation and the actual generation. Any deviation from the schedules created in the day-ahead and intraday markets is settled in the balancing market.

Schematic of mismatch between hypothetical day-ahead schedule and actual generation



As there is always some risk that a producer or consumer may deviate from the planned schedule during the hour of delivery, the system operator needs to have a way to ensure system stability. Having pre-established contracts for different kinds of reserves, the operator can activate the necessary resources in real time to keep the system in balance in a cost-effective manner. The actual cost of drawing on these resources will be settled afterwards between the party responsible for the imbalance and the relevant reserve provider, typically through a central clearing party.

The potential of having to pay when responsible for imbalances creates incentives for being able to follow the planned schedule – and has been a significant driver for improving forecasting for VRE generation. In turn, the potential to be contracted for either supply or demand within the balancing market provides a new revenue stream for technologies that can modify generation or consumption in the direction needed by the system.

Designing markets to capture value from low-carbon technologies

Refining time resolution unlocks flexibility of diverse technologies

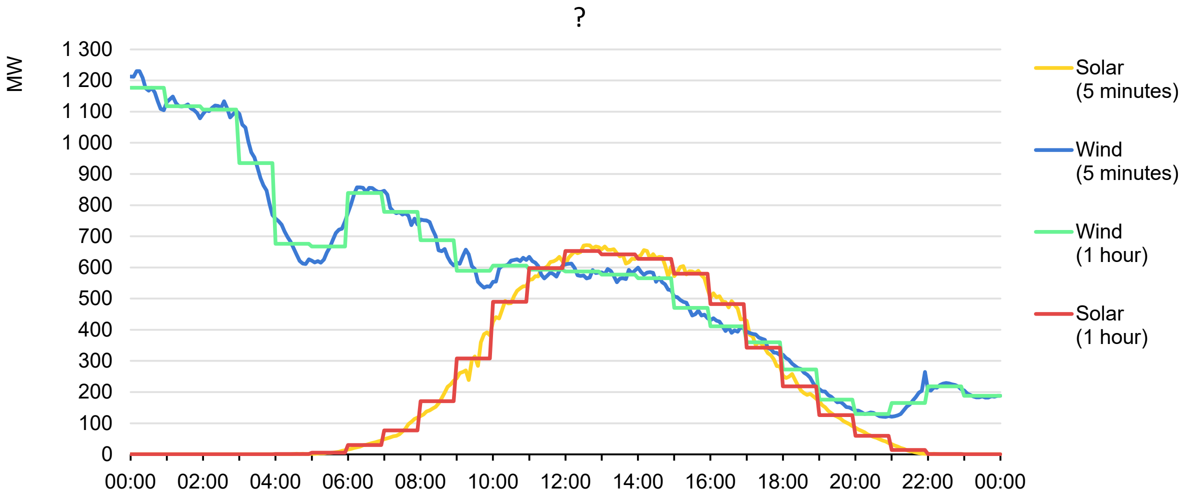
As alluded to above, the time resolution of the market is an essential aspect of being able to use market prices as incentives for flexibility. In fact, resolution refers to two features: the granularity of the dispatch period for electricity traded on the markets (the market time unit); and the minimum period of time during which the system operator will consider imbalances between scheduled and actual generation and consumption (the imbalance settlement period). Refining the time resolution of the market would mean reducing the span of both of these elements.

With higher resolution of the market, it is possible to provide market players with more detailed price signals that better reflect the status and needs of the system at a particular point in time and, in turn, to improve the scheduling of system assets.

Higher market resolution is particularly important for systems with high shares of VRE, as their intrinsic variability is relevant over both short (less than one hour) and long time frames. As shown below, the generation profiles of wind and solar change significantly when considering a resolution of five minutes versus one hour. If forced to rely on a 1-hour resolution, it would be necessary to net out a significant imbalance between expected and actual generation. As higher resolution can reduce the volume of energy imbalances that need to be netted out, it can also provide incentives for flexibility and high quality forecasting of VRE. Finally, higher resolutions can enable deployment of new providers of flexibility (e.g. battery storage technology) and better capture the flexibility of existing loads. Altogether, this increases the efficiency of use of existing flexibility assets and provides incentives to remunerate market actors that can provide the short-term flexibility the system needs.

In 2017, the European Commission introduced the Electricity Balancing Guideline, which calls for harmonising the imbalance settlement period at 15 minutes across the European Union. A subsequent cost-benefit analysis commissioned by the transmission system operators (TSOs) in the Nordic region (Energinet, Fingrid, Statnett and Svenska kraftnät) found that reducing the imbalance settlement period to 15 minutes would provide better investment signals for flexibility and improved frequency quality, thereby triggering improved use of interconnector capacity. In 2021, the Australian Energy Market Commission (AEMC) shortened the settlement period from 30 minutes to five minutes.

Average generation of wind and solar energy at 5-minute and 1-hour resolutions in MW in DK1, 13 July 2021



Source: IEA analysis based on energidataservice.dk, (2022).

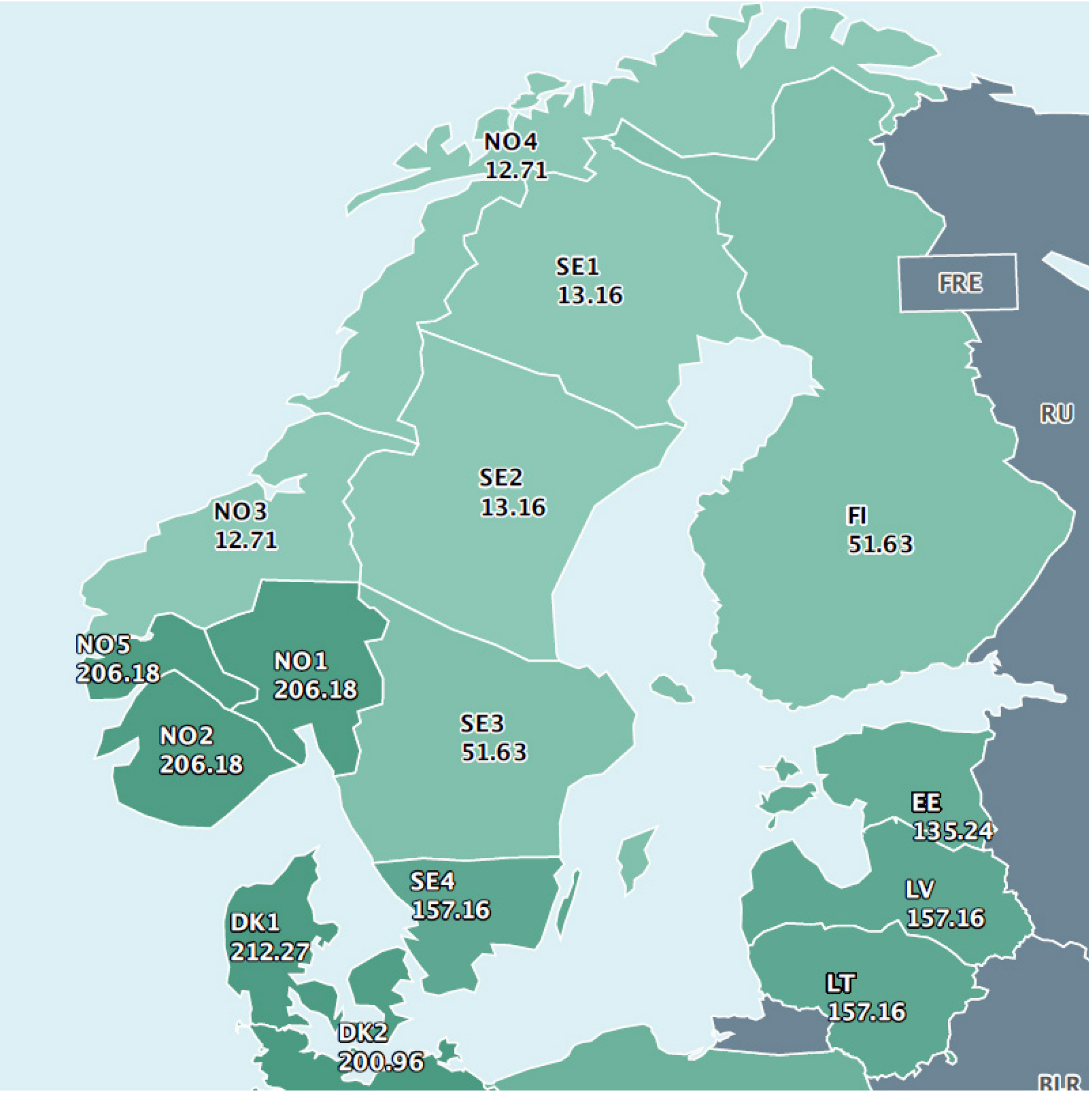
Locational price signals provide geography-aware value

The representation of the underlying geography of an electricity system also plays a strong role in matching the physics and the market. At present, two main approaches exist: a zonal representation splits the market into different simplified price zones (as done in Europe); and a nodal representation reflects the physical layout of the underlying transmission infrastructure (used, for example, in some systems in the United States).

In a zonal design, different zones can have different prices. Within the zones, the market assumes that there are no congestions and power can move freely, irrespective of any physical congestions that may arise within the zone in real life. Between zones, power flow is limited by available transmission capacity, which is represented in the market model. If transmission capacity inside a zone does not limit the flow of electricity as scheduled by the market, prices will be consistent across neighbouring zones. If the transmission capacity is insufficient, prices will diverge to reflect the congestion. A high price within a given zone indicates either a lack of generation or excessive demand and thus provides incentives for market players to participate by increasing generation or lowering consumption. A low price, in contrast, indicates excess generation and provides incentives for increased consumption and/or diminished generation. In this way, price signals provide incentives to align with the needs of the system.

An example of congestion can cause prices to diverge across price zones can be seen in the Nordic countries, each of which has multiple price zones: Denmark (2), Norway (5) and Sweden (4). The price variations indicate there is not enough transmission capacity to transport electricity from low-priced zones towards those with higher prices. If it were possible to transmit available supply, prices would average out across the entire region.

Day-ahead prices in the Nordic region in EUR/MWh on 2 May 2022

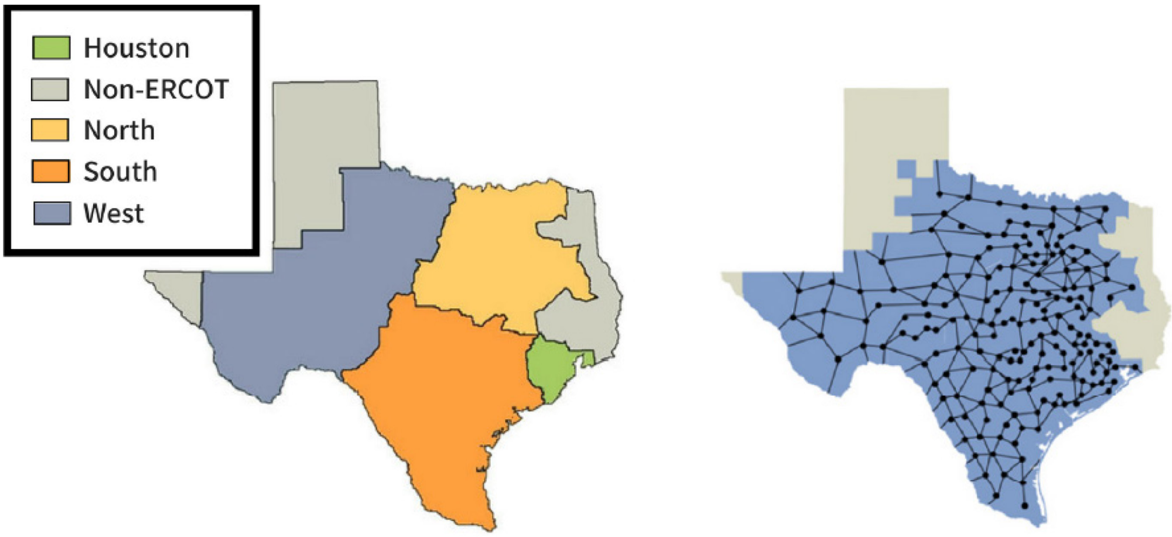


Note: This map included is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.
Source: IEA analysis based on Nord Pool Group, (2022).

Nodal pricing, which accounts for individual network bus bars in the market model, offers greater granularity than zonal pricing. Since all transmission lines are considered, there are no assumptions of infinite capacity in an area. Under this market structure, when transmission capacity between nodes is not fully utilised, prices will converge while congestion will result in different prices in different nodes. This allows for better representation of congestion in the system and of the locational value of energy. The increased granularity of nodal zones also produces a significantly higher number of price points in the system.

In December 2010, the Electric Reliability Council of Texas (ERCOT), the independent system operator (ISO) in Texas, switched from a zonal to a nodal market, which significantly increased the number of potential individual prices in the state. Mapping the two systems provides a good illustration of the difference between how zonal and nodal pricing options represent the underlying grid in the dispatch.

ERCOT market design transition from zonal (left) to nodal (right) prices



Source: IEA analysis based on ERCOT data (2021) https://www.ercot.com/news/mediakit/maps

Both types of market design have merits and drawbacks, which continue to trigger debate about which is best. What matters most is that chosen market model accurately reflects all physical grid congestions. If the chosen market model does not reflect physics, the system operator will have to take actions to modify the market result after it has cleared. This can involve having to request specific assets to reschedule, with some being asked to produce less (or not at all) and others asked to produce even though they were not selected to run in the market clearing. Such rescheduling ensures system stability when taking into account congestions that were not reflected in the market design, but results in a loss of efficiency in market operation, with the final effect of increasing prices in locations with abundance of energy and depressing them in those facing scarcity, reducing the incentives for load and generators to choose the best locations from a system perspective

An example of the need for rescheduling due to congestion after market clearing can be found in Germany, which is represented as one pricing zone in the European market. In theory, if that accurately represents the German grid, it indicates that Germany has no significant internal physical congestions. In reality, however, frequent internal grid congestions exist in Germany, driven by three interrelated factors: insufficient transmission capacity to transport the high volumes of renewable generation from the north towards consumption centres in the south; the closure of nuclear plants in the south; and the policy decision to establish a single price zone.

This means that the market representation does not reflect the underlying reality of the German grid. As a result, German system operators have incurred very high costs to ensure grid stability. In 2020 alone, redispatching carried a cost of EUR 981.7 million in Germany, with redispatch measures costing EUR 221 million while roughly EUR 761 million went to compensating wind turbines that were curtailed after having been cleared by the market.

If the market model more accurately represented the underlying physical system, such constraints would be calculated when assets were cleared in the market. The original market clearing would define, for example, the participation of wind assets taking into account the available transmission capacity. This would eliminate the need to modify market clearing afterwards and, in turn, provide adequate price signals and reduce the cost of compensation. Since dispatching would be based on price signals and consider transmission constraints from the beginning, it would also eliminate costs associated with compensating generators that have to be redispatched out of the market.

Additionally, if markets are coupled across system operators (as in Europe), dispatch can account for all of the assets across the interconnected system, whereas redispatching is usually managed by a single system operator and only with assets under its authority, which reduces the efficiency of the resulting redispatch. In short, a design that better represents the system geography could avoid a significant share of redispatching costs.

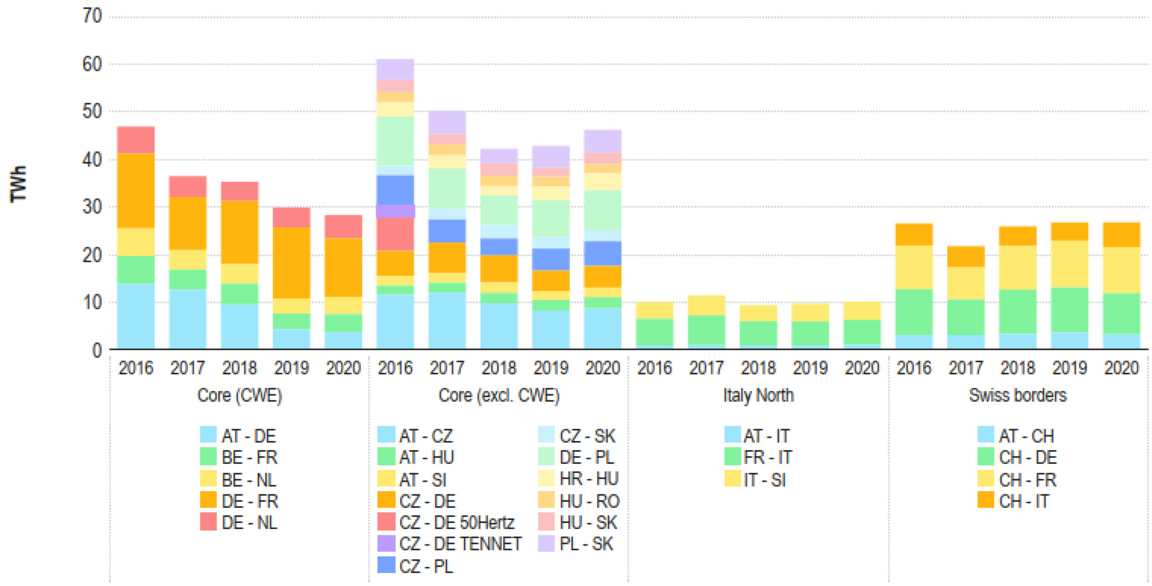
To resolve this disconnect, policy-driven plans aim to expand transmission capacity between the northern and southern parts of Germany, thereby supporting future better alignment between the chosen market design and the physical grid.

Another consequence of the mismatch between the market representation and system physics is increased creation of unscheduled flows. These are unplanned flows of electricity across parts of the system due to the physical execution of the market clearing, which were not expected due to the price model chosen for the market. Unscheduled power flows consume interconnection capacity between bidding zones, making it more difficult to operate the system according to the market clearing. They also make it harder for system operators to ensure security and reduce overall system efficiency.

In the case, for example, of a trade between a generator in the north of Germany and a load in the south, internal congestion in the German price zone may force the power to flow through other price zones (e.g. Poland, Austria or the Netherlands), even though the zonal design assumes no congestions inside the German zone. If the market model better represented these congestions, the dispatch could choose and provide visibility to the most efficient path for power flow and provide price signals that accurately represent the status of the system.

Although measures are being implemented to reduce them, unscheduled power flows remain an issue in Europe. As they stem from incorrect representation of the physical constraints of the meshed A/C grid, improving representation of power system topology in the market model is one direct way to reduce such flows.

Unscheduled power flows within central Europe in TWh, 2016-2020



Source: IEA analysis based on ACER (2020), Electricity Market Monitoring Report.

Settling contracts key to balancing long-term signals with real-time dispatching

Many consumers and producers seek to hedge the price risk of the electricity market, aiming to reduce uncertainty on the future price of electricity they will buy or sell, and therefore also reducing investment risk. Long-term trading and contracts for the exchange of electricity – such as futures, forwards or power purchase agreements (PPAs) – are instruments that allow market participants to manage their risk exposure in competitive electricity markets. By making explicit the cost of managing risk, these long-term contracts support investments through improved risk management, increase competition by lowering barriers to entry and provide transparent price discovery. A study carried out by Sapere Research Group shows that developing an electricity futures market in Australia triggered downward price pressure, reducing the retail electricity price by AUD 8 to 10/MWh (approximately USD 6 to 7/MWh).

Different horizons for long-term contracts exist and fulfil different objectives. Shorter long-term contracts, with horizons between one to five years, are typically used to hedge price risk from an operational perspective. While those with a horizon of more than five years, typically aim to reduce income uncertainty as a means of stimulating investments. Since long-term contracts are linked to risk management (and should not define actual system operation), they tend to have low granularity. Rather than representing specific hours as in the short-term markets, long-term contracts are often linked to peak- and base-load periods across the day.

In markets that are transitioning from regulated to liberalised systems (e.g. India and Mexico), the different wholesale markets will often need to co-exist with long-term point-to-point physical contracts. In these contracts, the volume of electricity purchased needs to be delivered specifically by the contracted generator, even if at the time of delivery, it would be more efficient to use other assets, possibly belonging to other generating companies. This reflects a market context in which individual generating companies optimise their own portfolio but there is no incentive to optimise the overall system.

Having long-term contracts settled financially means that while the price is hedged, the actual trading of electricity is based on the short-term wholesale markets. This ensures least-cost dispatch and maximises the economic surplus, supporting optimisation of total system costs while still providing hedging possibilities through long-term trading.

While the possibility to hedge price risk in the long term is useful, to ensure adequate price signals are created to maintain cost-efficient dispatch, design must ensure that long-term markets do not impede adequate volume of trading in short-term markets. A high enough volume in short-term markets is essential to ensure the clearing price reflects the equilibrium cost of the system itself while also limiting the possibilities to exercise market power. If the markets are effectively integrated, financial long-term contracts do not impede participation in short-term markets. Additionally, arbitrage possibilities create incentives for participating in the markets with timelines closer to the hour of delivery, motivated by the low granularity of typical financial long-term contracts.

Physical long-term contracts create risk of efficiency losses

A hypothetical case demonstrates how long-term contracts can undermine efficiency. Company A has three generators (A1, A2 and A3) of 100 MW each. Company B has two generators (B1 and B2) of 50 MW. The marginal costs for these generators are presented below.

Characteristics of hypothetical generators

Generator	Price per MWh	Capacity	Owner
Generator A1	USD 20	100 MW	Company A
Generator A2	USD 25	100 MW	Company A
Generator A3	USD 30	100 MW	Company A
Generator B1	USD 27	50 MW	Company B
Generator B2	USD 35	50 MW	Company B

In the hypothetical case, long-term contracts oblige Company A to dispatch 250 MW and Company B to dispatch 70 MW. If the contracts are physical in nature, to deliver the contracted 250 MW, Company A would schedule all of generator A1 and A2 plus 50 MW from A3. In turn, Company B would schedule all of B1 and 20 MW of B2.

While such a schedule fulfils the contractual requirements of each company and minimises their own costs, it is not the most efficient outcome from a system perspective. Scheduling that aims to optimise the entire system would, at market clearing, dispatch A3 – which has lower costs – instead of B2.

In contrast, if the long-term contracts were settled financially, both companies would be paid for electricity sold in the long term, while electricity is dispatched in the short-term market under least-cost conditions.

It is important to note that fuel contracts can affect the possibilities generators have to optimise generation by procuring cheaper energy from the short-term market. If the contract for supply of fuel is inflexible (e.g. because of “take-or-pay” obligations), the marginal cost of fuel for the contracted generator is zero, leaving no incentive to procure cheaper electricity. Assessing upstream and downstream contract conditions is vital to enable flexible cost-effective dispatching.

Final recommendations

As the cornerstone of electricity markets, there are several design aspects that are recommended to implement as a way to facilitate and accelerate the cost-efficient integration of low-carbon sources:

- **Refine time resolution and improve gate closure times**: enable creation of price signals that better represent the value of electricity and flexibility across time and improve the adaptability of schedules to respond to uncertain supply and demand.
- **Ensure price signals represent locational value**: ensuring the market model matches the underlying physical reality of the system allows price signals to differentiate the geographical needs of the system and reward actors that provide value to the system in this dimension.
- **Ensure long-term contracts do not impede optimal dispatch**: separating price hedging and long-term signals from the physical dispatch of assets enables optimal short-term dispatching without compromising long-term contracts.

Chapter 2. Market instruments to accelerate decarbonisation

Leveraging wholesale markets and support policies is key to accelerate decarbonisation

In many electricity systems around the world, low-carbon technologies (such as wind, solar PV, nuclear, biomass and geothermal) have become the most cost-competitive generation sources relative to thermal generation. Often, this reflects decades of policies designed to spur technological advances.

To date, however, a range of market designs and regulatory frameworks have fallen short of stimulating sufficient investment in low-carbon technologies due mainly to two overarching factors: lack of acknowledgement of the value of low-carbon technologies and long-term uncertainty about their revenues.

In competitive power systems, the wholesale market is the main instrument to achieve three interrelated goals: ensure efficient system operation; minimise the cost of generation; and stimulate investment in the technologies needed for the first two (see detailed discussion in Chapter 2). Price signals play the central role to achieve these goals; as such, it is crucial that they are complete and provide a level playing field for all generation technologies based on their attributes and the value that they bring to the power system, for example by generating electricity from low-carbon sources or contributing to the security of the system.

To enable efficient competition between all generators that provides enough revenues for low-carbon technologies, it is important to account for the full cost to society of fossil-fired technologies – i.e. their negative externalities. A key mechanism to achieve this is to reflect the cost of carbon dioxide (CO_2) emissions in wholesale market design, such that the use of fossil fuel-based technologies reflects the real negative impact to society, shifting the operational pattern to enable more low-carbon generation and that these technologies are appropriately valued. In fact, failing to account for negative externalities prematurely erodes the value created by low-carbon technologies.

However, even after ensuring a level playing field, market revenues may still fall short of encouraging sufficient investment in low-carbon generation. This may reflect various reasons such as long-term uncertainty over revenues or low or insufficient carbon pricing. Support policies, and increasingly, market-based instruments can contribute by providing additional revenue certainty, to close the gap between the investment levels encouraged by the wholesale market and the desired policy objective.

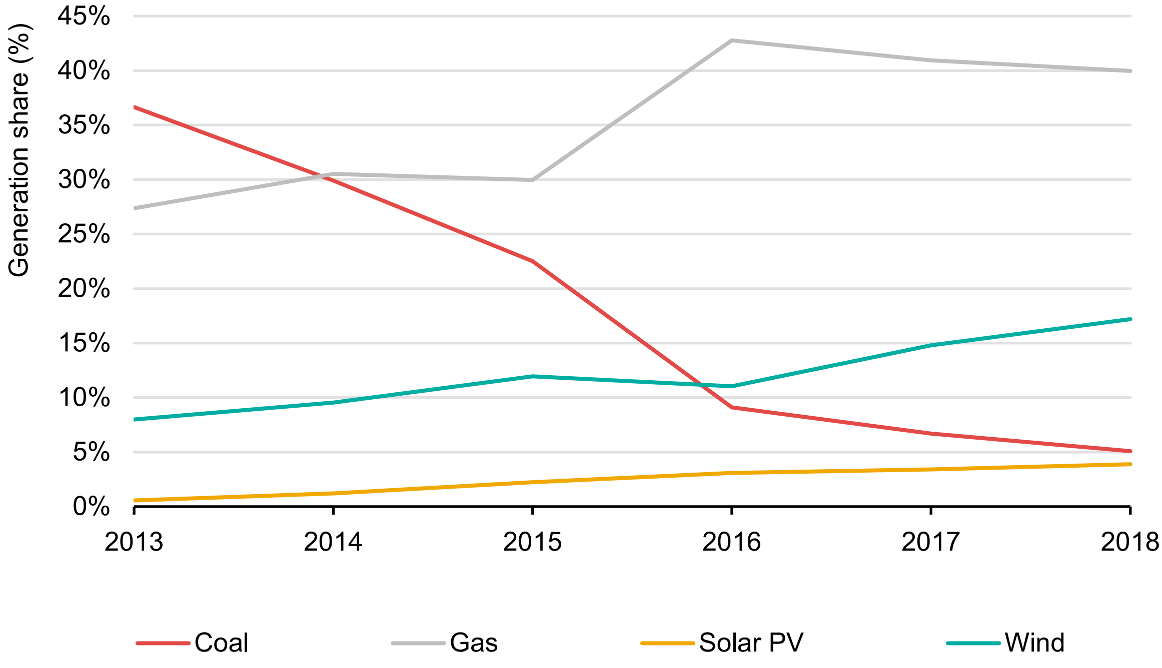
This chapter explores options to design market-based support instruments for clean energy investment that ensure system integration and reduce the share of support policy costs that are ultimately socialised to end consumers.

Carbon pricing is key to valuing low-carbon technologies

In several power markets, introducing carbon pricing has partially levelled competition by making it more cost-efficient to dispatch low-carbon technologies (VREs, hydropower or nuclear) or plants fired with natural gas ahead of those that rely on coal. The carbon tax has effectively shifted the merit order of supply. In the United Kingdom, strategic application of several policy instruments triggered a sharp decline in the share of coal-fired generation – from 37% in 2003 to 5% in 2018 – while spurring a rapid increase in the share of VRE generation – from 9% to 21%.

Stimulating such a shift was a key aim of the UK government when it implemented a UK-specific tax, which was added onto the price of carbon in the EU Emissions Trading System (EU ETS). First introduced in 2013, this tax was one of a set of policies that helped incentivise a stronger shift from coal to gas than was likely with the EU ETS alone. Most notably, introducing a set of dedicated instruments, such as contracts for differences (CfDs) and auctions, contributed to the share of coal-fired generation declining from 37% in 2013 to 5% in 2018, while the share of VRE generation grew from 9% to 21% over the same period.

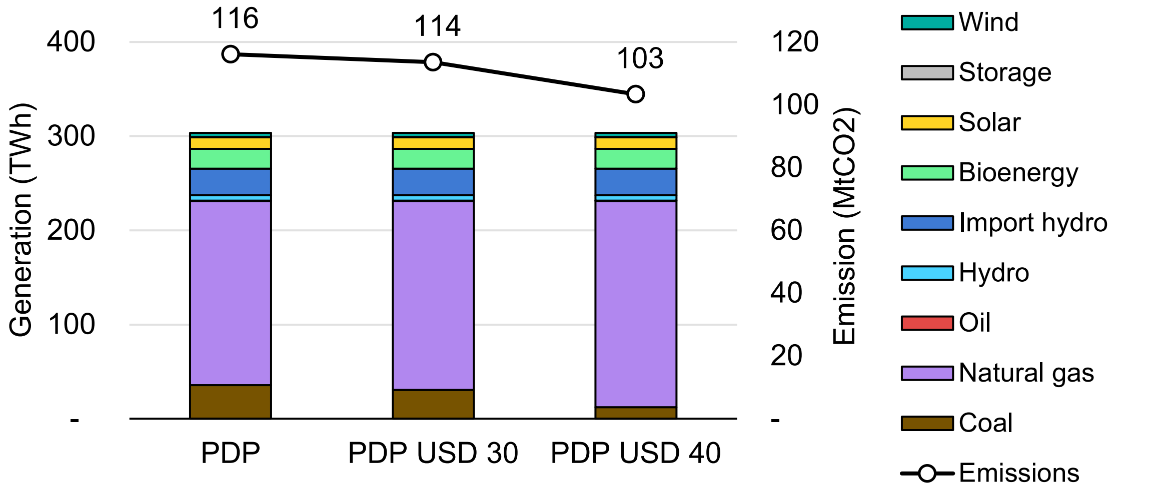
Decline in share of coal generation in the United Kingdom after introduction of carbon pricing



Source: IEA (2020), World Energy Balances.

A recent IEA study assessed the potential to reduce emissions in Thailand by introducing of carbon pricing. Using the country's main planning document, the Power Development Plan (PDP), as a base scenario, analysis showed that a carbon price of USD 30/tCO_2 could incentivise a five TWh generation shift from coal to natural gas and reduce emissions by two MtCO_2 by 2030. Pushing the carbon price to USD 40/tCO_2 could incentivise more than 23 TWh of coal to gas shifting and deliver 13 MtCO_2 of emissions reduction. The latter case represents an 11% reduction from the PDP scenario.

Impacts of different carbon price levels on generation mix and emissions in Thailand's power sector in the PDP scenario, 2030



Source: IEA (2021) The Potential Role of Carbon Pricing in Thailand's Power Sector.

In many cases, governments introduce a staggered tax to give market players time to adjust. Initially, it may not account for the cost of all negative externalities, so additional policy support may be needed to ensure that every investment advances in the desired direction. In other cases, even though significant carbon pricing improves price signals in wholesale markets, additional policy support may be needed to bridge the gap between current and desired levels of investment in decarbonisation technologies. Without adjusting for the effects of other policies, instruments can also become less effective over time: carbon pricing or carbon credits, for example, may lose some of their efficacy as more renewables come online and boost the supply of low-carbon energy.

As such, governments need to build complementarity among different policies and be prepared to adapt targets as the system develops to prevent issues such as an oversupply of carbon credits if renewables expand more quickly than anticipated.

It can also be the case that the effectiveness of instruments is impacted by early retirement or due to the time required for them to gain social acceptance. Australia introduced a carbon tax in 2011, then retired it in 2014, due to political controversy surrounding its impact on costs to end consumers, despite it being regarded as effective for reducing emissions. By contrast, the EU ETS got off to a slow start but as the mechanism matured, improving the price signal, it has contributed to create long-term visibility for investors. Overall, for support mechanisms to be effective, providing certainty in the long run is key to establish credibility and secure investment in low-carbon technologies.

VRE support schemes need to encourage long-term certainty and system integration

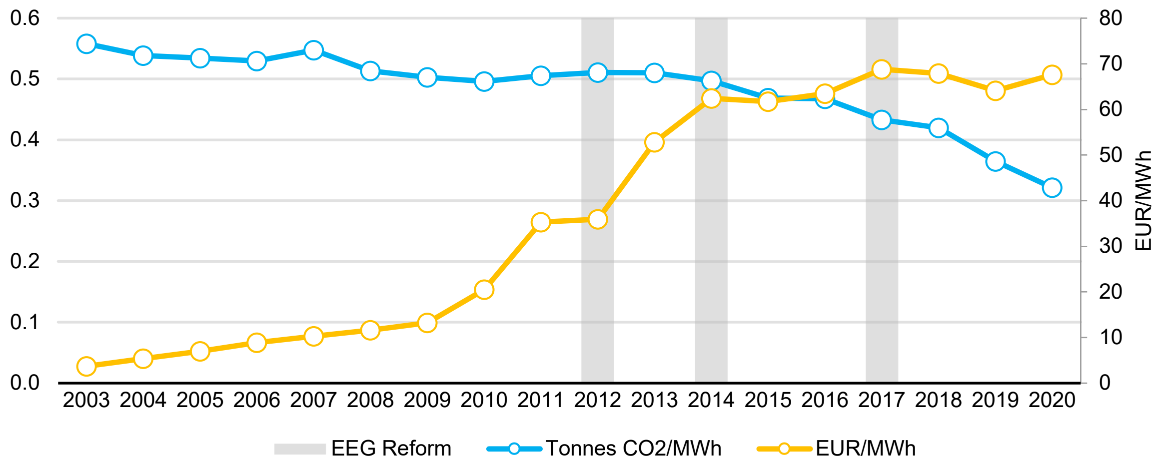
In their bid to de-risk investment and accelerate deployment of low-carbon technologies, policy makers have implemented a variety of renewable energy policy instruments. To ensure return on investments, one of the earliest were feed-in-tariffs (FiTs), which guaranteed revenues for each unit of power output over the lifetime of a given plant. More recent instruments focus more on enabling actors to have direct interaction with the wholesale market (e.g. market-based premiums, contracts for difference [CfDs] and auctions). The merits and shortcomings of each are discussed below.

By providing long-term revenue certainty, FiTs (whether for large-scale generation or distributed solar PV) were an effective choice in the initial stages of policy intervention as they supported development of new technologies and associated industries. As these technologies matured, it became necessary to limit rising policy support costs and system integration costs that were passed directly onto consumers (through energy bills). In turn, these instruments were adapted to encourage system integration of VRE generation technologies that had reached a degree of maturity.

Monitoring increases in policy costs in terms of the desired policy outcome and being ready to adapt support mechanisms are essential for all policy instruments. For example, in Germany, the challenge of complementarity among instruments became evident. While the first generation of policy support mechanisms boosted installed capacity of VRE, overall power sector emissions remained relatively stable and the public protested against rising consumer bills. The limited impact of VRE support on emissions reduction needs to be evaluated in the broader policy context – including policies to phase out nuclear and coal generation. Moreover, the rapid build-out of renewable energy in Germany had the unexpected effect of reducing the price of certificates in the EU ETS.

Within its main instrument for renewable energy support, the Renewable Energy Law (EEG), Germany subsequently shifted to more market-driven policies. Even this law has been reformed several times to reduce policy support costs, driven by recognition that modifying FiTs administratively was not enough to account for the rapid drop in technology costs. In 2012, following the rapid build-out of VRE capacity, the German government reformed the EEG to remove the guarantee of purchase by the system operator and gave generators the option to sell their output directly to other participants in the wholesale market, earning a market-based premium (i.e. a feed-in premium or FiP). To slow the rise in policy support costs, a 2014 reform introduced technology-specific corridors and maximum ceilings for installed capacity per technology. This reform also included the obligation for all new large generators to sell their output directly on the market (under the FiP model), further limiting the impact capacity increases would have on end consumer bills. In 2017, Germany introduced a system of renewable capacity auctions, which allowed developers to bid for their required level of support informed by price signals, marking a shift from administratively determined levels of support. Most recently, on 1 July 2022, the EEG surcharge on end consumer bills was phased out and the policy support costs will now be covered through dedicated state funds for energy and climate.

Power sector emission intensity vs EEG costs to end consumers in Germany



Sources: IEA World Energy Statistics 2021 edition, IEA Renewables Information 2021 final edition

Other governments have developed different policies to support deployment of renewable energy in connection with market revenues. Across much of the United States, building complementarity between federal and state-level action has been important. Introduction of Federal Production Tax Credits (FPTCs) has provided long-term revenue certainty to address the capital-intensity of renewables. Parallel roll-out, by states, of renewable portfolio standards (RPS) and their associated green certificates has encouraged wholesale market integration. In Europe, a shift towards CfDs has proven effective for enabling both long-term revenue certainty and a better degree market integration than the previous FIT-based schemes for large generation technologies.

The overarching challenge in designing policy support instruments is four-fold. Policy makers must ensure instruments for decarbonisation: meet the policy objective cost-efficiently; provide sufficient long-term visibility; can be adapted to reflect changes in the power system; and are compatible with other instruments that address other policy objectives in the broader policy context. In the United States, this multifaceted challenge has motivated discussion of a shift from remunerating solar PV based on the levelised cost of energy to applying methodologies such as the "value of solar", which accounts for the energy value as well as other contributions or impacts on system costs. In Germany, following the announcement of coal phase-outs by 2030, experience from the first roll-out of VRE capacity on the price of EU ETS certificates has been taken into account and is expected to be reflected in the withdrawal of certificates from the EU ETS markets to ensure the mechanism remains effective.

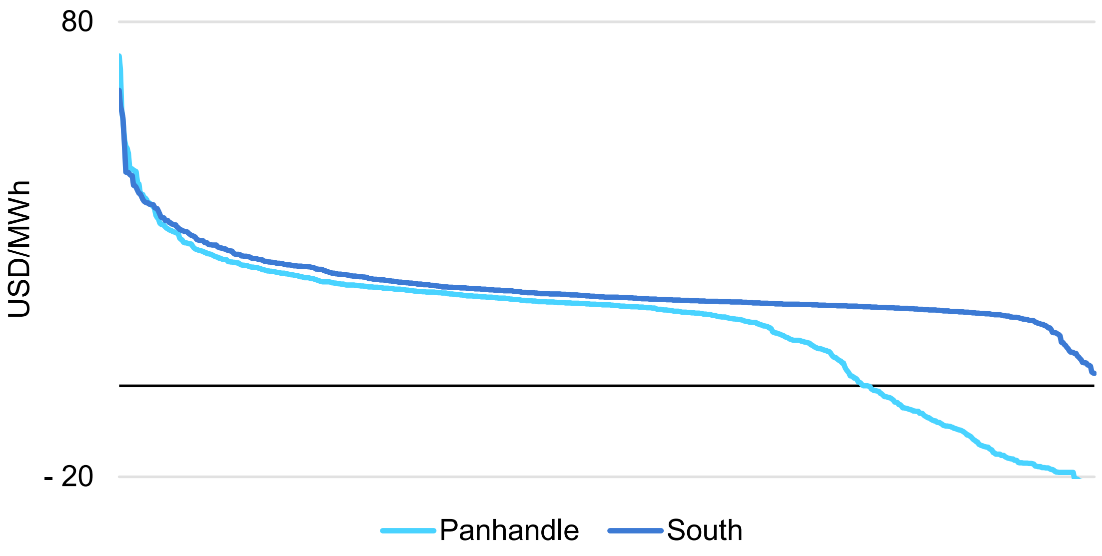
Decarbonisation instruments should encourage investments of highest value to power systems

Introduction of FPTCs has bolstered much of the renewable capacity build-out in Texas, with the federal support making such projects viable. In addition, in states where RPS schemes have been introduced, utilities or load-serving entities are meant to cover a certain part of their load through renewable generation. By providing additional revenues on top of energy only wholesale revenues, the sale of renewable energy certificates (RECs) through RPS helps developers to cover their costs, in part by passing such costs on to end consumers .

Together, these instruments help reveal geographic areas where investments would bring most value to the system and reduce the share of additional cost that gets passed to consumers. The case of wind power is interesting in that planning investment in the areas that can deliver greatest value may not align with a strategy that is based solely on the potential for generation in areas with very high wind. In Texas, while the region with the highest with resources is in the north of the state (the so-called Panhandle region), a significant amount of investment has gone to the south and coastal regions. This reflects that the lack of interconnection in the Panhandle means prices will often go below zero whereas, despite having lower capacity factors, the south and coastal regions have consistently higher prices because of their proximity to large load centres. As the cost of acquiring RECs is socialised among each utilities' consumers, investments in areas that deliver higher market prices yield a better deal for end consumers.

Texas market-based support mechanisms have been instrumental in directing generation investments to where they bring the greatest value to the system as shown in the image below depicting day-ahead price duration curves in the ERCOT. In general, this initial approach is beneficial in terms of reducing the cost of policy support that needs to be socialised and in limiting the need for grid expansion.

ERCOT day-ahead prices duration curve per hub in January 2021



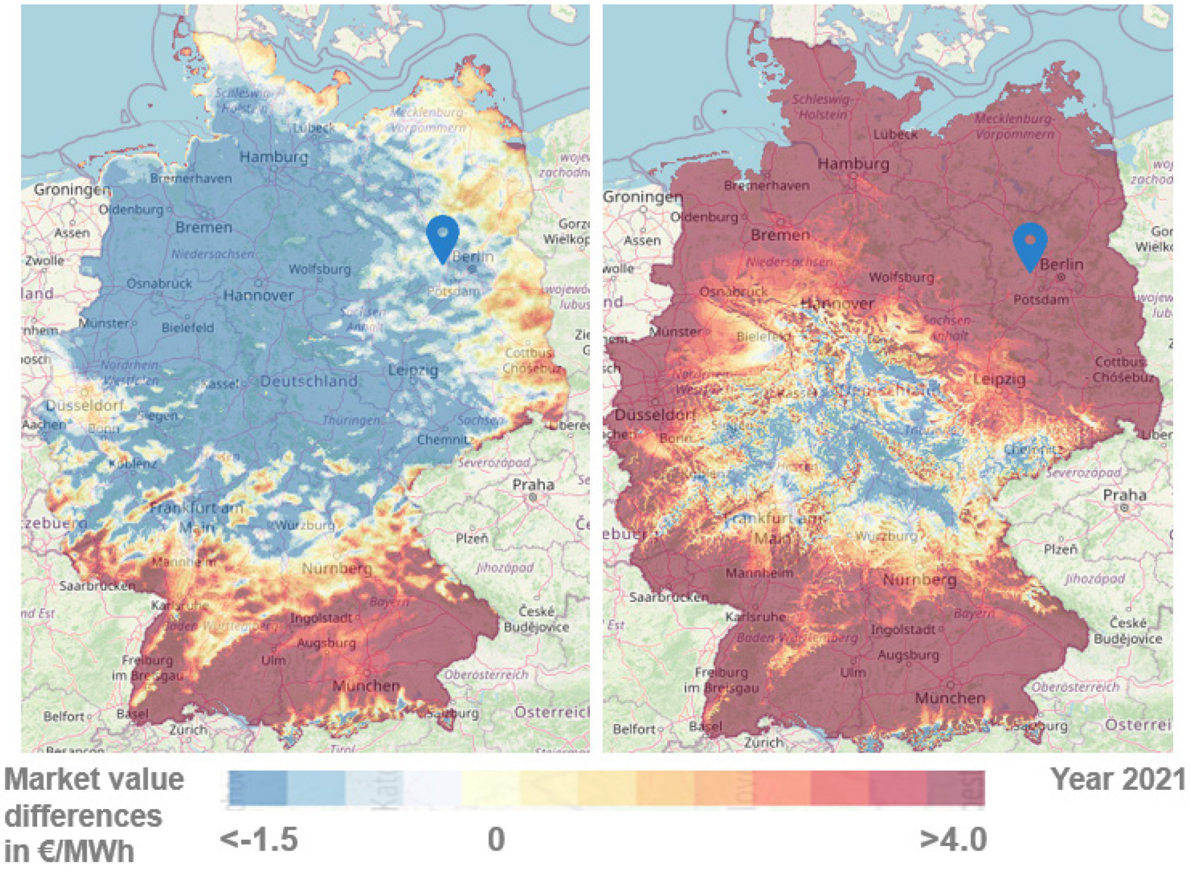
Source: ERCOT (2021), [Market prices.]

Similarly, Germany's introduction of FiPs (in 2014) encouraged investors to select the technologies and locations in which VRE technologies generate the most when demand is higher, thereby incentivising investment in the right technologies, while maximising value for the system. Rather than a fixed amount on top of market revenues, Germany uses a sliding premium system that compensates the difference between the average value of electricity generated per technology and the per MWh revenue that generators in that technology class would require to recover their costs. Premiums are determined as the difference between the weighted monthly average electricity price obtained by all generators using the same technology – for example, wind – and their required strike prices. This means new generators sited such that they generate at times when wholesale prices are highest can make additional profits.

As shown in the figure below, Germany's sliding premium system encourages developers to place their plants according to when they provide the highest value for the system. For example, newer, larger wind generators are optimised for lower wind speeds while older versions require higher wind speeds, which typically correlate with the hours in which the wholesale price is lower. In 2021, it became clear that being sited in more diversified locations, new wind generators were able to capture better revenues while the market value of older wind generators was lower in part because of the amount of previously installed capacity that generates during times of low prices.

Overall, encouraging deployment of new generation where it adds the most value – i.e. targeting locations where grid capacity is available – improves the integration of renewables and reduces the cost of grid expansion.

Market value of different locations for old, smaller wind turbines (left) and new, larger wind turbines (right) in 2021



Source: Evervis/Anemos (2021), Market value atlas.

Long-term auctions provide revenue certainty and allow generators to reveal required level of support

Auction mechanisms have proven an effective means to incentivise decarbonisation of the power system while helping co-ordinate the pace of grid development. In contrast to other instruments, auctions provide private actors an incentive to competitively declare their required level of support, while the government or auction organiser has the task of identifying how much capacity is needed or how much budget is available. For example, Germany's pay-as-bid premium auctions encourage developers to compete among themselves to identify who needs the least support to invest in new generation. Developers that place plants in locations where they will produce most in times of high demand can still capture extra revenues while also delivering more value to the system. The auctions' pay-as-bid nature and selection of the cheapest bidders minimises the total cost of the support to these technologies.

Under the United Kingdom's CfD scheme, which operates as a long-term auction, generators bid for a specific strike price that would allow them to recover their costs across the plant's lifetime. They subsequently receive the difference between their declared price and the obtained market price. While this system provides a great deal of certainty to developers, it also limits the risk of spiralling policy support costs as it caps earnings at the developer's declared strike price. In contrast to many other market mechanisms, CfDs have a clawback mechanism to avoid windfall profits over the investment period, which acts as a hedge in times when the wholesale price is very high.

In France, CfDs for wind and solar PV are expected to contribute approximately EUR 14.4 billion to public finances in 2021 and 2022, according to the French Association for Wind Energy. This stems from the fact that the CfDs were established in previous years when average wholesale prices were EUR 50/MWh and the CfD strike price was set at around EUR 60/MWh. For numerous reasons, the average wholesale price in 2021 was around EUR 108/MWh, and spiked to EUR 231/MWh in the first trimester of 2022. The estimated sum of EUR 14.4 billion includes EUR 3.3 billion in excess profits in 2021 that solar and wind producers will need to pay back, EUR 5.1 billion of CfD support that will not need to be paid out in 2022 and an estimated EUR six billion that producers will need to transfer back due to excess revenues in 2022.

Technology-specific and neutral mechanisms deliver different outcomes in terms of cost and innovation

When developing instruments, and choosing among options that are technology-neutral or technology-specific, it is important to consider the different outcomes each leads to. Technology-neutral options tend to lead to lower-cost renewable deployment in the short term as mature technologies are likely to win the bids. By contrast, technology-specific options may be best suited if the objective is to stimulate development of nascent technologies and encourage innovation within specific technologies. Striking a strategic balance between these two instruments, such that they encourage the right mix of technologies and leverage complementarities, requires that policy decisions be informed by long-term system planning exercises.

In recent years, the Netherlands, Mexico and Chile have introduced technology-neutral auctions with the aim of reducing the cost of policy support while tasking developers with identifying both the locations and technologies that will bring the greatest value in different parts of the grid. The Netherlands' technology-neutral auction is similar to the German sliding premium system in that it allows for surplus revenues; however, it also includes a floor price, which essentially precludes the payment of subsidy in negative hours. An additional contrast to other auction designs is that the amount of support awarded is based on available budget rather than on procured capacity. To date, use of this approach to technology-neutral auctions in Germany and the Netherlands has typically favoured solar PV projects, which without other technologies to balance the mix can lead to particular grid integration problems (e.g. increasing congestion at the distribution network level).

In contrast, by incorporating locational elements through zonal pricing, technology-neutral auctions in Mexico and Chile have attracted a variety of renewable energy technologies. In Mexico, load-serving entities and large, qualified market participants were allowed to bid for a variety of bundled products such as energy, firm capacity and renewable energy credits. Moreover, the long-term auctions built on the strengths of the recently introduced local marginal pricing system, which accounts for energy, congestion and losses. This multifaceted approach encourages investors to locate new generation in areas that lower the cost to the grid. Overall, adding locational adjustment components for new renewable projects encouraged development of solar PV in areas with greater grid availability while the introduction of a firm capacity component has incentivised dispatchable geothermal projects. Across Latin America, the introduction of technology-neutral auctions has stimulated rapid expansion of renewables capacity while keeping policy support costs low.

Ultimately, triggering diversified investments in technologies and at locations that provide value is linked to provision of specifications (e.g. auctioning certain demand blocks or introducing locational pricing and firm capacity elements).

Market-based mechanisms can provide a better picture of what technologies bring most value to the system

Another approach to stimulating investment is to push the burden of assessing which technologies provide the highest economic net value to the private sector as opposed to conventional auctions, which generally rely on a central actor setting the pathway for capacity expansion and organising subsequent rounds. This comes with the advantage of allowing industry and business players, who may have better information than a central planner, to assess the most efficient level of additional support.

In Australia, introduction of the large-scale renewable energy target together with an RPS and large-scale generation certificates (LGCs) has fostered a dynamic market that drives investment and tasks retailers with selecting and contracting the most cost-effective clean energy sources. This approach introduces an additional measure of flexibility in that the ideal contract and support duration for the purchase of LGCs is defined by market actors (rather than a central administrator). As the industry develops, the actors and investors build up expertise and knowledge of the most efficient duration. Between 2001 and 2020, the target and certificates supported the achievement (by 2021) of 33 000 GWh of renewable energy. It should be noted that this target had been retroactively scaled back from the original target of 41 000 GWh defined in 2015. Beyond 2022, the yearly target for generation from renewable sources will remain constant at 33 000 GWh. The experience in Australia shows that while RPS targets may be useful in prompting private actors to identify the best value projects to cover their certificates, they still depend on policy and political decisions such as the reduction or limitation of a target. And that policy changes affect the long-term visibility investors need to make efficient decisions.

Market instrument design should reflect policy objectives

Policy support mechanisms should be designed with the explicit aim of stimulating action to achieve a specific policy objective. Many of the mechanisms mentioned above set targets based on installed capacity or share in generation of renewable energy technologies rather than for emissions reduction. Ultimately, this tips support in favour of technologies that will lead to a majority share of generation being provided by zero-cost VREs while limiting the participation of other technologies – particularly hydropower and nuclear – that are vital to reducing emissions and are dispatchable. As these zero-cost technologies take over the majority share of generation, additional instruments may be required to address emerging needs for adequacy and stability support and to trigger deployment of other necessary dispatchable low-carbon technologies.

For example, the auction system creates incentives for developers to offer the most competitive technology to serve specific requirements (e.g. energy demand, firm capacity or clean energy). The bigger challenge for policy makers is to ensure that across all instruments (auctions, market premiums, etc.), the conditions for awarding support ensure smooth integration with the power system and avoid shifting the cost burden (typically towards consumers) or shifting the merit order (e.g. such that it rewards coal-fired generation instead of lower-emissions dispatchable technologies such as hydropower, nuclear or natural gas).

In systems that deploy renewables solely on short-term wholesale market revenues, policy instruments should support technologies that enable improved forecasting, balancing and siting. The absence of clear guidelines can lead to either additional back-up costs that need to be socialised or additional grid constraints.

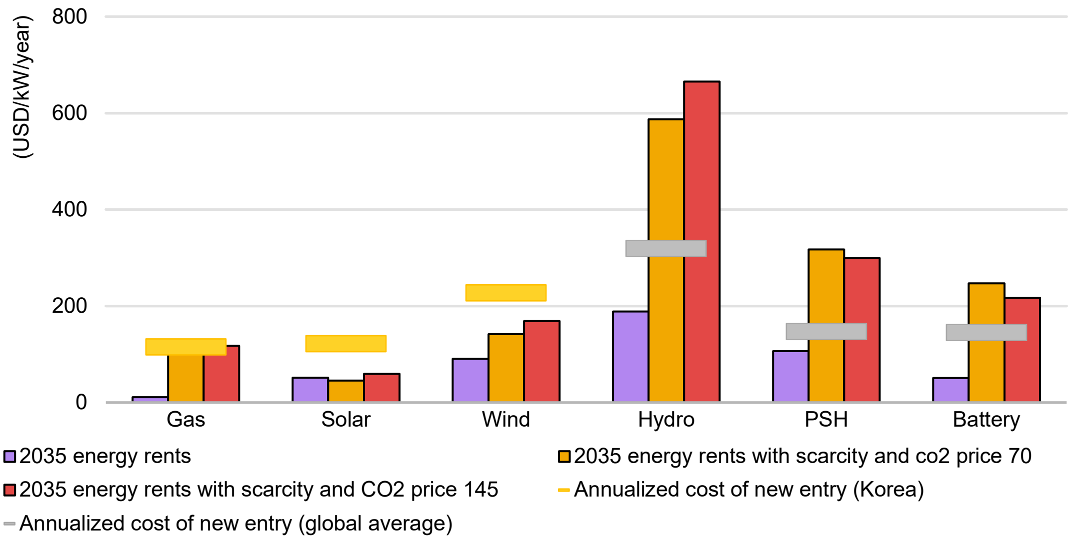
Adapting market instruments will be essential to ensure investment in low-carbon dispatchable technologies

In the coming decade, the acceleration of power system decarbonisation through greater VRE deployment will fundamentally change how wholesale markets work and how assets recover their costs. The suite of support mechanisms presented so far, particularly those focused on energy-based earnings and technology neutrality, tend to implicitly reward technologies such as solar and wind. By contrast, the example of Mexico remunerating energy and firm capacity shows the potential to adapt these mechanisms to also encourage deployment of other low-carbon dispatchable generation (such as geothermal or hydropower).

In systems with majority shares of wind and solar PV, continued operation and new investment in dispatchable low-carbon technologies is becoming increasingly difficult. To ensure availability of sufficient dispatchable capacity at critical hours, support mechanisms will have to be adjusted to value attributes such as ramping capacity and the contribution to system stability. In specific power system regions (such as Kyushu, Japan), integrating large, local shares of solar PV generation has required adapting the operational patterns of local pumped storage hydropower (PSH). Unless policy makers change how these assets are remunerated for ramping services and acknowledge their contribution to capacity provisions, operators will find it increasingly difficult to keep such assets online.

Instruments designed to promote continued operation and new investment in dispatchable low-carbon generation should, as with earlier recommendations for VRE support mechanisms, maximise compatibility with wholesale market signals. This will require effectively remunerating their value contribution to adequacy and decarbonisation. Recent IEA analysis of efforts to decarbonise the Korean power system shows that introducing scarcity and carbon pricing can improve investment prospects in dispatchable low-carbon assets such as hydropower, PSH and in flexibility technologies such as battery storage.

Projected energy rents for new investment in low-carbon generation in 2035 in the Korean power system relative to the annualised cost of new entry



Notes: Comparison of energy rents to fixed O&M and annualised capital cost, WACC = 7%. Using system reference marginal price (SRMC) with no carbon price and USD 145 per tonne carbon price.
Source: IEA (2021) Reforming Korea's Electricity Market for Net Zero https://www.iea.org/reports/reforming-koreas-electricity-market-for-net-zero.

Improving wholesale market signals and correctly identifying the specific policy objectives that need to be met, policy makers can introduce additional support instruments that are compatible with – and even strengthen (rather than distort) – market signals. Basing support on criteria such as performance, availability and contribution to the most critical system conditions will be crucial to ensure build-out of sufficient dispatchable low-carbon capacity to guarantee system security.

Final recommendations

To create a level playing field for low-carbon technologies, policy instruments should ensure that wholesale electricity markets appropriately account for both the negative externalities of CO_2 emissions and the value that these technologies add to the system. In instances where market revenues do not stimulate enough investment, support instruments are essential to close the gap and meet policy objectives.

- **Balance long-term revenue certainty with market integration:** this will ensure that decarbonisation instruments will support efficient deployment of low-carbon technologies.
- **Integrate decarbonisation mechanisms with competitive price signals:** helps reduce the policy support cost burden that must be passed on to end consumers.

- **Enable value based on location and time:** decarbonisation instruments design should enable market participants to maximise the contribution of locational, time-of-generation value to the system through new clean technology investments.
- **Improve price signals and market-based decarbonisation mechanisms:** as variable technologies take the majority share of generation in electricity markets, refining price signals and market-based decarbonisation mechanisms can contribute to ensure sufficient investment low-carbon dispatchable generation.

Chapter 3. Distributed energy resources

DER reshape the structure and operation of electricity markets

While DER existed in the past, their deployment in electricity systems is rapidly increasing. To date, their capacity to support both decarbonisation and efficient system operation is typically not properly valued in electricity markets. To ensure DER are deployed and operated in manners that benefit the system, these shortcomings need to be adequately addressed in system planning and market design.

Generally, DER are classified in three categories. **Distributed generation** includes fuels or technologies that supply power, such as biomass, small hydro, solar photovoltaic (PV), small wind power or diesel generators. **Demand response** refers to a number of actions by which consumers participate actively in system operation (e.g. through end use energy efficiency to reduce overall demand or by "shifting" loads to reduce pressure on the system). **Storage,** in the form of devices that temporarily "hold" energy for release on demand (e.g. electric water heaters or batteries), provides an additional mechanism by which system operators can balance electricity demand and supply in real time.

DER can interact with the grid in three main ways. Some DER (e.g. solar PV) can only inject electricity, while some only consume electricity (e.g. traditional appliances). Some can do both, which gives them the capacity to serve as storage options. Depending on such characteristics, DER can participate in energy, capacity and ancillary services to support power system decarbonisation by displacing traditional, fossil fuel-based providers of these services.

The emergence of DER as active players in electricity systems is closely linked to rapidly declining cost of supply technologies (e.g. solar PV) and accelerated digitalisation of the power system. In turn, DER allow end users to participate more actively: instead of being passive consumers of electricity, they can also participate in its production and in system balancing.

With DER accounting for growing shares of electricity systems, three key factors come into play. First, in contrast to large, centralised power plants that feed into the transmission grid, DER are connected to and interact with the distribution grid. Second, DER represent millions of small devices spread over wide geographic regions (although some tend to be concentrated in specific areas, such as rooftop PV in urban zones). Finally, their presence influences the operations of – and interactions between – transmission system operators (TSOs) and distribution system operators (DSOs), giving the latter a more active role than in the past.

While a single DER has minimal impact in system operation (and thus minimal value), the growing number of devices increases their potential impacts. If aggregated, co-ordinated and effectively managed, DER can help integrate VRE, reduce the need for grid upgrades and contribute to power system resilience.

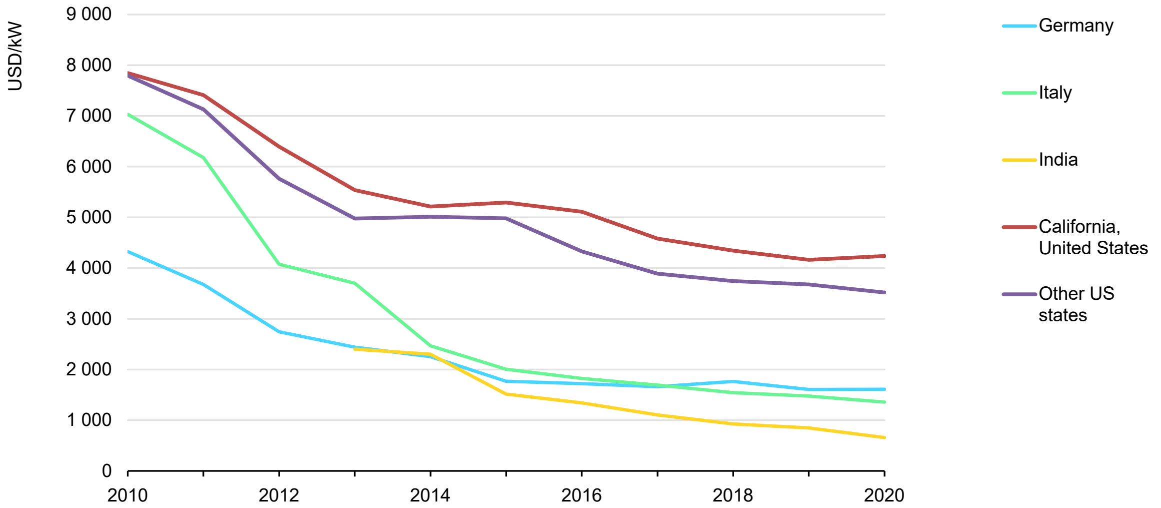
By 2050, an estimated 83% of European Union households could become active through DER by generating and/or storing electricity and providing flexibility. Capturing this value will require changes in electricity market design, which currently reflects characteristics needed for centralised control at the transmission grid level. Going forward, maximising DER benefits requires finding ways to overcome challenges that are emerging with broad electrification and the increased importance of the distribution grid level. While increased demand (due to electrification of end uses) could lead to higher peak loads and grid congestions, DER can provide solutions to alleviate these issues. To overcome key challenges, market design needs to give operators (both TSOs and DSOs) greater visibility of distributed loads and distributed resources, beginning by encouraging digitalisation. In turn, it will be necessary to adapt tariff design to incentivise the penetration of DER and enable their participation where and when they can bring value. As described in more detail below, facilitating interaction between DER, system operators and aggregators, in tandem with adapting and streamlining roles and processes, is crucial to ensure optimal deployment of DER.

Rapid DER deployment induces a shift towards the distribution grid

The first motivations to deploy DER were for large industrial or commercial consumers to increase their security of supply and provide grid services such as peak load "shaving" or emergency demand response. Recent changes both in power systems (e.g. the increase of small-scale PV) and end uses (e.g. electrification of vehicle transport and uptake of many connected appliances and devices) led to deployment of a more varied range of DER, with a wider application scope.

Scaling up of these technological changes, prompted in part by implicit and explicit incentives built into regulatory frameworks, has triggered strong cost reductions, especially for solar PV (both rooftop and utility scale) and batteries. In turn, a trend to stronger investment in these newer types of DER has emerged, with expectations for financing to increase by a further 75%, reaching close to USD one trillion by 2030.

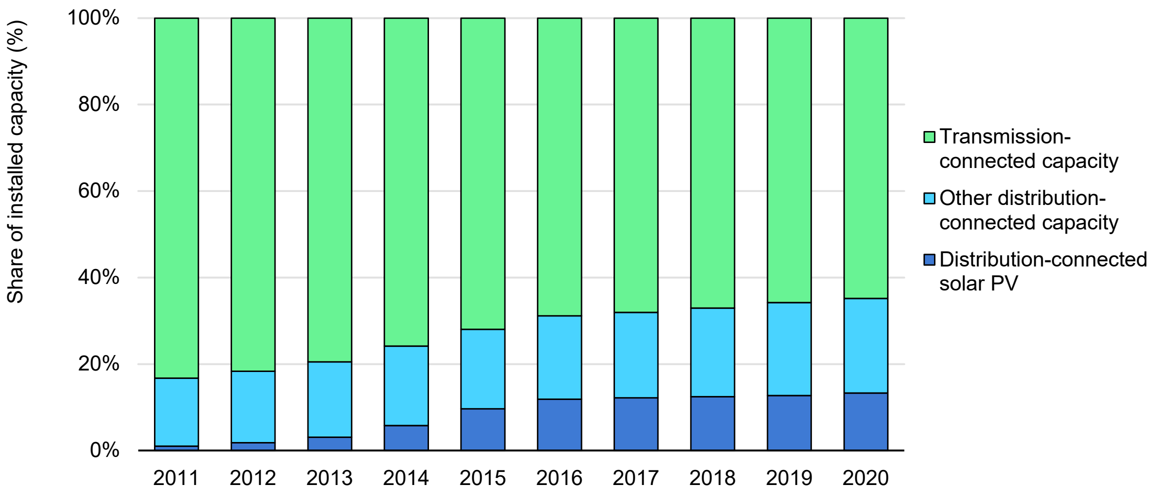
Residential solar PV total installed costs, 2010-2020



Note: Data for India is available from 2013.
Source: Adapted with permission from IRENA (2021), Renewable Cost Database, accessed May 2022.

This increased deployment of DER is now shifting the balancing point of electricity systems away from transmission towards the distribution level. In the United Kingdom, for example, the share of capacity installed at the distribution level rose from 17% in 2011 to 35% in 2020 and is expected to continue increasing.

Share of transmission-connected versus distribution-connected installed capacity in the United Kingdom, 2011-2020



Note: Other distribution-connected capacity includes coal, oil, gas, hydro, wind, wave and tidal, bioenergy, and other fuels.
Source: IEA analyses based on data adapted with permission from UK National Statistics (2020), Digest of UK Energy Statistics: electricity, accessed April 2022.

This shift creates both short- and long-term challenges for system operation and development. Because consumers tend to follow similar routines and use appliances in the same time periods, electrification of end uses can cause sharp increases in demand at certain times. As system operators often lack visibility on these distributed loads, higher peak loads could suggest the need for grid upgrades.

Distributed generation can offer a means to meet geographically concentrated demand spikes. But if deployed without the right siting signals, DER can create local imbalances, leading to more frequent grid congestion in some areas or excess generation in others. These impacts require stronger management of distributed networks and resources by system operators, but in most systems today, loads behind the meter are invisible to operators. They lack the information they need to tap into DER to fine-tune their control.

Advances in digitalisation give operators new means to increase the visibility of these resources and to co-ordinate their generation or consumption to provide flexibility.

Capturing the value DER services bring to the grid

As noted above, DER technologies offer several benefits of critical importance to electricity decarbonisation efforts in that they can support the integration of VRE, reduce grid upgrade costs and contribute to higher system resilience.

In relation to helping **integrate high shares of VRE** into the system, DER offer new capacities that become a strong source of flexibility. Indeed, as VRE generation varies depending on resource availability, and as electricity demand changes over the course of a day – and indeed from minute to minute – flexibility from DER can be used to balance supply and demand.

DER can **reduce the need for grid upgrades** that can become necessary when broad electrification increases overall demand and exacerbates peak loads, as well as in certain cases to support electric vehicles (EV) charging infrastructure. Deploying DER as non-wire alternatives (NWA) can reduce peak demand and thus the volume of electricity that must be transmitted, effectively decreasing the need for additional grid infrastructure and lowering grid operation costs.

Lastly, DER can contribute to **improving power system resilience,** which is the ability of the system to react to changes and recover from disruptions. Able to provide both back-up power and black start services, DER can play an active role in boosting system security.

Connected DER are a strong source of flexibility

Diverse DER can provide flexibility (and hence participate in frequency regulation) in different ways: upwards, by quickly injecting more power as needed or by consuming less, or downwards, by consuming more or injecting less. DER that can draw electricity from the grid and store it for later re-injection support load shifting, which has significant value in the current context of increased peak loads as electrification pushes up overall demand. A common enabler for all types of flexibility are time-of-use (TOU) tariffs, in which pricing varies throughout the day in relation to demand and supply, thereby providing the adequate signals to market participants.

Thanks to digital technologies, DER that can be triggered to consume less when needed become an important contributor to flexibility via demand response. When made "smart" and "connected" through digital technologies, three important things change for devices, users and the system overall. First, the use of such devices and associated electricity consumption can be closely monitored by users and by system operators. Second, they can be controlled remotely (again by both parties). Most importantly, they can be "pooled" such that millions of small devices can act collectively in ways that benefit both users and the system.

With anticipated temperature increases, the expected rise in use of air-conditioning (A/C) units provides an excellent example of the enormous potential of demand-side response. Traditionally, during hot weather, A/C units in workspaces operate most of the day to maintain cool temperatures. As people return home in late afternoon, they switch on home units, creating a sudden increase in demand in peak periods, which strains the electricity system overall, often forcing operators to call on power plants that rely on fossil fuels.

If heating, ventilation and A/C (HVAC) units (and other types of devices) are connected and controlled through a centralised digital platform, co-ordinating their operation can shave peak demand. Provided that incentivising tariffs exist, owners and users can benefit by reducing consumption during peak tariff times – e.g. by leveraging occupancy-based thermostats to reduce operations where relevant. Such measures have been shown to save 5-10% of HVAC energy costs.

Water heaters are an example of a flexibility tool in transition. Traditionally, water heaters have provided balancing services to the grid in two ways. During limited periods of high demand, curtailing their output contributes to peak shaving. They can also serve as a type of thermal storage that absorbs excess electricity when advantageous for the system (i.e. in off-peak periods).

Smart metering has led to new developments in the visibility and controllability of residential hot water heating, thereby unlocking significant new value for the provision of flexibility. Grid-interactive water heaters (GIWHs) are fitted with a bidirectional control that can increase or decrease their power or shut it on and off, repeatedly. A Brattle Group report found that the combination of peak shaving and peak to off-peak arbitrage (where cheaper heat is stored for use in higher-price times), provided the necessary fast response for frequency control service while also avoiding distribution costs, delivering benefits to both the grid and the customer. The net benefits from installing a GIWH can be up to USD 200 per participating unit per year.

Increased electrification of road transport carries similar load challenges and opportunities for millions of devices to play a role in demand response. In 2021, EVs made up 9% of global car sales; as this figure increases, EVs will become one of the main distributed loads. By 2030, EVs could account for 4% of global annual electricity demand. However, as their use will be heavily concentrated in daytime hours and people will seek to recharge upon returning home, they could be responsible for four to 10% of total peak power demand. Left unmanaged, their charging sessions could strongly increase the need for grid upgrades.

Using smart charging systems, which control the time, rate and duration of charging sessions, can avoid higher peak loads and help achieve the broader decarbonisation potential of EVs. Programming EVs to recharge during periods of low demand typically coincides with the use of low-emission sources and can make use of electricity that might otherwise not find a “buyer”. The combination of advanced metering infrastructure, smart chargers and strategic electricity tariff design can ensure that EVs charge with the cleanest, lowest-cost electricity available while avoiding curtailment of renewable electricity sources because of lack of demand. TOU tariffs can shift 60% of power generation capacity needs for EVs to off-peak times, significantly reducing peak demand while also supporting VRE integration.

As grid operators cannot control each vehicle individually, to optimise smart charging overall, aggregator platforms co-ordinate their users such that each vehicle charges at the most optimal time.

As will be discussed in Chapter 5 on Storage, when adequately integrated and incentivised by adequate pricing structures, battery energy storage systems can provide flexibility by storing excess generation in times of high availability and low demand and discharging into the grid in times of peak demand. Vehicle-to-grid-enabled EVs, in which the battery can both draw electricity from the grid and inject into the grid, will be able to provide similar services.

Deploying DER can reduce the need for grid upgrades

Facilities that can be installed in areas of local distribution or transmission constraints provide significant value to the system. DER can provide non-wire alternatives (NWA), a type of asset developed to minimise system costs by considering not only energy generation but also the need to invest in grid upgrades. The Brooklyn Queens Demand Management Program, initiated in 2014 and extended after its first three-year period, is a successful example in which energy efficiency measures and distributed generation allowed deferral of distribution grid upgrades.

For distribution level NWAs, highlighting the locational value of a DER is essential, as it varies significantly. For example, developing solar PV in an area of high demand can lower the need to increase the capacity of the transmission grid, and be an extremely valuable investment, even if the available solar resource is lower than in other areas. A study by Brown & O'Sullivan found that the value of PV varies by as much as 50% between low- and high-cost nodes within each United States regional transmission organisation (RTO). NWA projects will become attractive if market design allows the DER owner to capture some of this value.

To capture this locational value, the Reforming the Energy Vision (REV) programme in New York has replaced net metering tariffs for new DER customers by a Value Stack. The stack includes six different values to reward specific benefits, of which two target spatial benefits for local congestion or grid upgrade needs: the locational system relief value (LSRV), which is available in specific, utility-designated locations to reward siting DER in locations they can bring additional value to, and the demand reduction value (DRV), which is calculated based on the project's capacity to reduce future grid upgrade needs.

DER can contribute to power system resilience

Traditionally, diesel generators have been used as back-up generators for resilience. Other options are increasingly considered, such as onsite renewable generation together with energy storage or the development of a microgrid. In some army bases of the United States for example, a combination of diverse DER – solar PV, storage and connected controls – Is being used to provide back-up.

Black start is the process of restoring power supply after a complete outage in the system. This service has traditionally been provided by large, centralised thermal plants that are high voltage and connected to the transmission grid. In effect, restarting these plants would create "power islands" with enough inertia to energise the system, gradually reconnecting other plants.

An ongoing project in the United Kingdom is testing distributed restart processes to see if leveraging digital technologies to co-ordinate a vast array of very diverse resources (natural gas turbines, biomass generators, embedded hydropower stations, wind turbines and solar panels) – distributed across the power system – can energise the power system. In May 2022, live testing in south west Scotland successfully established a power island with a hydro-plant anchor generator and intermittent wind power. Compared to a traditional black start, the project analysts expect potential cumulative emissions reduction of 0.81 Mt CO_2 and financial savings of GBP 115 million savings by 2050.

In electricity systems with increasing shares of distributed generation, the value of DER taking on this role is high as it has potential to decrease service costs while decarbonising the system. It requires, however, that processes be updated as using DER for distributed restart would require more and smaller power islands, potentially operating at varying voltage levels within the distribution system.

Recommendations for DER-optimised market design

The potential for DER to provide valuable services to system operation is clear. Current wholesale and retail markets, as well as regulatory frameworks, however, are often not adapted to capture the benefits of DER. Under current structures, deployment of DER without the right incentives runs the risk of leading to increased costs for grid upgrades, curtailment of renewable energy, higher balancing costs, out-of-market interventions from operators and reduced reliability.

Integrating DER strategically requires uptake of the right technologies and adaptation of markets and regulatory frameworks. Building on digitalisation and the deployment of smart technologies are essential preconditions to optimal integration of DER; design of market structures and tariffs is essential to success. As it is crucial for DER to be able to participate in electricity and ancillary services markets, institutional procedures and frameworks need to facilitate their participation, including by clarifying roles and participation rules.

Case study: DER in Hawaii

DER are at the heart of decarbonisation and grid support strategies in Hawaii, where over 20% of the households have rooftop solar PV. As DER heavily influence decisions on electricity market design, this island state offers a good example of the transformations needed to facilitate large penetration of DER.

Hawaii's renewable electricity targets and solar power potential, combined with the upcoming retirement (September 2022) of a coal power plant in Oahu, led Hawaiian Electric (the largest electricity supplier) to devise an ambitious DER-led strategy that aims to increase DER penetration and maximise its contribution to grid services.

In recent years, the Hawaii Public Utilities Commission discontinued net-metering tariffs, which it found did not incentivise users to inject electricity at grid-valued times, replacing them with TOU tariffs and specific incentive programmes. The Battery Bonus programme, for example, provides funding for owners of rooftop PV systems to install a battery, if they commit to inject electricity into the grid every day at peak times (18:00-20:30). To further promote installation of rooftop PV, Hawaiian Electric rolled out a fast-track approval, called Quick Connect, that is applicable only for areas in which there is 30% or more hosting capacity. The hosting capacity can be visualised using Hawaiian Electric's locational value maps. This condition allows Hawaiian Electric to ensure a more detailed review for those areas that do not fit the requirement and are therefore at risk of saturation.

Additionally, new structures and interaction platforms have been developed to enable the participation of DER to grid services. Hawaiian Electric's Grid Services Purchase Agreement (GSPA) is technology-neutral in that it awards contracts to aggregators that have GIWHs, rooftop solar and battery storage among their portfolios. In March 2022, the utility partnered with a virtual power plant (VPP) provider that uses heat pump water heaters for load shifting, taking advantage of excess solar power generation in times of lower demand. The utility is also looking into using DER for NWA, including such resources in their integrated grid planning processes.

Encourage digitalisation to improve visibility

To create load forecasts, system operators use established criteria such as weather conditions, time of day, and day of week (for short term) and macroeconomic factors such as population and industry trends (for long term). With growing shares of DER, which system operators often lack visibility on, these forecasts start to lose predictive power. Rooftop PV offers a good example. This DER is usually connected with the load but it only becomes visible to system operators when clouds block the sun and the device suddenly becomes a demand point. In cases where a large number of "invisible" DER suddenly start drawing power, system operators may have to use out-of-market operations to maintain sufficient reliability.

Digitalisation of the electricity system is key to giving operators the visibility needed to avoid inefficient operations. DER need to be equipped with monitoring devices to measure and collect generation and demand data separately, and connected (e.g. through Wi-Fi) such that they can provide and receive real-time data. Having access to such data (which operators can acquire by installing monitoring devices, co-ordinating with or purchasing from third-parties, or modelling missing data) allows system operators to get visibility over DER.

On the supply-side, these digital technologies support the interconnection of several power production units (usually smaller units at the distribution level) and connected end users into VPPs. Equipped with a central control system that exchanges and aggregates information from the different units, VPPs can draw on the various capabilities of connected units to provide grid services in a very similar way to traditional plants.

Advanced metering infrastructure (AMI) and smart meters are key enablers of DER. AMI makes it possible to measure customer demand more precisely in terms of location and time and could be used to help distribution companies and retailers offer more granular and cost-reflective tariffs to end users.

Having a high frequency of communication (as often as every 15 minutes), smart meters can allow DER to exchange information, which makes such resources more visible to operators. Over the past decade, several economies have rolled out large smart meter deployment programmes; as with other technologies now active in energy systems, wider deployment is triggering cost declines.

An overarching challenge in this area is the need to ensure that data access and exchange are effectively regulated to balance two potentially conflicting aims: a) ensuring that operators and aggregators have a good overview of the system needs and connected resources; and b) that data privacy of individuals is respected and protected. The Australian Energy Market Operator (AEMO) took a positive step in this direction by creating a DER register to gather data on DER characteristics, thereby enabling higher visibility of their potential.

Strategic tariff design crucial to optimal DER deployment

The growing shares of DER in electricity systems require rethinking the design of tariffs. Tariffs need to ensure that the market rewards services that provide value to the system, and that the investment into necessary assets, as well as the operation of existing ones, is incentivised. Increasing price granularity – which is possible thanks to advances in digital technologies – allows tariffs to reflect accurately the time- and location-dependent value of demand and supply, thereby providing signals for a cost-efficient allocation of resources.

An overarching challenge is that increased penetration of DER can lead to a decoupling of energy costs from grid operation costs. In essence, in reducing consumption of electricity from the grid, DER also lowers revenues to system operators who still have to keep sufficient supply at the ready to immediately meet peak demand. This means lower revenues while grid operation costs remain the same. This disconnect is directly linked to historic pricing structures, which are largely based on volumetric retail tariffs – i.e. a tariff that charges the customer a flat price for each kilowatt hour of energy consumed during the billing period.

To incentivise efficient DER deployment and ensure costs are recovered fairly, the different factors that influence demand and supply need to be taken into account. With increased granularity of more types of data (e.g. capacity-based, time-variant, locational), the market can be designed to tailor tariffs to different users. With higher shares of VRE, for example, tariff design should include incentives that trigger consumption in times of high generation of clean energy. It should also discourage consumption during peak demand, when operators often have to rely on fossil fuel-based generation.

Structuring tariffs to incorporate time and geographical resolution will also incentivise owners of connected DER to participate in grid-friendly behaviour. For this reason, retail customers with DER should be able to access information that shows how siting and operation of such resources is expected to benefit the system overall.

To date in many countries, distributed solar PV generation has been developed based on net metering schemes in which the generator receives energy credits for generation beyond what it consumes (excess generation) that can be fed into the grid. Such schemes, especially when the credits are awarded over long time periods such as a year, often lead to a mismatch between the value of the electricity generated and the electricity consumed. In countries with evening peak, for example, credits earned from excess PV generation during the day are of lower value than the cost of electricity needed during peak demand. In the absence of time or locational differentiation in net metering schemes, the value of electricity fed into the grid does not incentivise consumption in times of excess PV generation. As an additional example, EV owners should be rewarded for charging at times of high low-carbon electricity availability and discouraged from charging in peak times during which peaking plants – often fossil fuel-based – are needed.

Implementing TOU rates is one way to align actual operating costs with tariffs to end users. Numerous cases show that, compared with flat volumetric charges, TOU supports more efficient system operations while ensuring predictability in the retail rate structure. In 2016, the California Public Utility Commission (CPUC) adopted Net Metering 2.0, which required all new customer-generators (representing DER) connected to the three investor-owned utilities within the state to take service under a TOU rate. In the PG&E service area in Northern California, the TOU rate (“E-TOU-C”) for peak demand in summer (between 16:00 and 21:00) is USD 0.42/kWh versus USD 0.34/kWh in non-peak hours. The tariff changes also included a one-time interconnection fee of between USD 75 and USD 145. In parallel, PG&E changed the netting on volumetric non-bypassable charges from annual to hourly. This increased the quantity of kilowatt hours subject to these charges that apply to all electricity imported from the grid, regardless of the export of excess generation. A lookback study released in 2021 demonstrated that while this new scheme was cost-effective to participants, costs increased for nonparticipating customers and grid operation costs were not fully recovered. In an ongoing review of the plan, Net Metering 3.0, CPUC proposed a reform that would increase TOU tariffs for consumption in peak times and add a grid participation charge of USD 8/kW of installed solar capacity, aiming to address equity concerns with the allocation of grid operation costs. This proposed reform is under discussion as it has been criticised for potentially deterring investment into rooftop solar.

For end consumers, continuing flat volumetric-based tariffs in the context of increased DER can lead to unjust allocation of operational costs. As fewer customers draw on the grid when DER is generating, overall compensation for grid operation declines. In turn, to recoup costs, grid operators have to spread related charges among the consumers who do not have access to DER generation, creating an unfair cost burden considering that DER generators do still rely on the grid at certain times.

To avoid the situation described above, the European Commission recommends that infrastructure costs be shared by grid users based on the degree to which their demand contributes to peak load. In the United Kingdom, the practice of cost shifting – in which large commercial and industrial consumers seek to reduce network costs by dispatching their back-up, distributed units to reduce grid consumption during the Triad hours (the three hours of the year with the highest demand and hence the highest cost) – led Ofgem (the regulator) to review its network charges. Ofgem found that existing network charges created a situation in which large customers were incentivised to exit (i.e. dispatch their back-up units or reduce consumption) in order to avoid high network costs. However, as the lower demand did not reduce overall operation costs, it instead triggered a strong transmission charge cost to consumers who could not exit. As such, the benefit of cost shifting to individual customers exceeded the system benefit from reduced demand, indicating the need to modify tariffs for fairer allocation of costs.

Ensuring grid operation remains funded in ways that are fair to both operators and consumers is crucial. Experience to date show this can be achieved by introducing a tariff component that is based on capacity instead of on energy flows.

Enable DER participation in markets

As shown above, DER participation can add value in energy markets – when associated regulatory frameworks and other factors facilitate their participation. Currently, many jurisdictions miss the opportunity to capture this value by imposing burdensome requirements. The PJM, for example, requires that any resource wishing to participate as a generator in its markets enter its normal queue process, which includes a two-phase impact study and may also involve installing a second utility service line and additional measurement and verification equipment. As demand for DER connections increased, this process led to significant queues and delays, ultimately prompting PJM to start (at the end of 2020) a consultation to explore changes to the interconnection process and to the planning committee endorsing (February 2022) a transition plan.

System operators should design streamlined processes by which smaller DER can gain access to these markets. While accelerating approval of interconnection requests may come with trade-offs in terms of accuracy (e.g. less time for detailed interconnection studies), linking eligibility for fast-track screens to facility size should limit expected system impacts. Some regions, such as Singapore and Western Australia, have implemented simplified interconnection schemes to facilitate DER participation with positive outcomes.

As system operators, even with the necessary visibility, cannot manage all individual DER, they also need to facilitate participation of aggregators – i.e. entities that connect DER through platforms to create a resource of sufficient size and controllability to provide system services. Whether independent third parties or local electricity retailers, aggregators have to be able to compete in the market in a transparent and fair way.

The United States Federal Energy Regulatory Commission, for example, has opened (in Order 2222) the right to DER to aggregate and participate in wholesale markets. In its DER roadmap, Western Australia defines aggregators as "a party which facilitates the grouping of DER to act as a single entity when engaging in markets (both wholesale and retail) or selling services to the DSO (network operator)". The roadmap suggests a new structure for the region, in which distributed customers enter into relations with an aggregator, thereby gaining the ability to participate in markets and system services. The aggregator passes information from the DER within its network to the DSO, which can analyse and use this information to ensure the reliability and balancing of the power system.

As power system roles evolve, facilitate transparent interaction and adapt processes

Increased penetration of DER will continue to influence how energy systems need to opeate in the context of the just, clean energy transition. No doubt, existing roles will evolve and new ones will emerge.

As mentioned above, as connections to the distribution grid increase, the balancing point shifts away from the transmission grid towards the distribution grid. This will make the role of DSOs more important and require their engagement in areas such as forecasting and scheduling of local resources, integrating DER into bulk markets, optimising of a two-way grid, and co-ordinating with TSOs.

As interactions between DSOs and TSOs need to be well co-ordinated, existing protocols need to be updated to reflect these evolutions – and those still to come. In particular, as TSOs and DSOs will have to collaborate closely on balancing needs and emergencies, they need clear protocols and division of responsibilities. In the spring of 2020, when increased DER penetration and lower-than-expected demand during the Covid-19 pandemic (20% below predicted values) led to worries that high DER infeed would destabilise power supply, the lack of such clarity in protocols prompted the UK National Grid to request an emergency grid code update. The temporary measure clarified that National Grid could instruct DSOs to disconnect distributed generation as a last-resort to secure supply, with clear allocation of responsibilities. Having proved effective, it was replaced by an enduring solution (Measure GC0147) in 2021.

Distributed system platforms (DSP) – essentially exchanges that create markets for diverse energy, capacity and ancillary services at the distribution level – are one way to facilitate the evolving roles of DSOs. Importantly, DSPs can facilitate market participation by small resources in a transparent and neutral manner, with the DSOs playing a role similar to that of the ISO or RTO at the wholesale level. By co-ordinating among all available supply and demand options at the distribution system level, DSPs ensure efficient operation and investment. If they act as the aggregator, DSPs provide an additional layer of optimisation that brings additional value to the system.

Such platforms will become increasingly important with higher shares of DER in the system, as centralised command of system operation at the transmission level would risk unacceptable erosion of the value of DER investments or a cascade of system imbalances if DER were implemented incorrectly. In energy systems of the future, control will have to be predominantly local, at the distributed level. Transactive energy models, involving peer-to-peer exchange of energy services among producers and consumers at the distribution level – and facilitated by a neutral DSP that can take full advantage of new information and communications technology – show strong potential to address issues that are emerging as the clean energy transition rolls out.

Final recommendations

To ensure DER contribute positively to decarbonisation efforts, the following considerations should be taken into account for system planning and market design:

- **Make DER visible to system operators by encouraging digitalisation**: deploy connected appliances and smart metering infrastructure to ensure operators can efficiently engage and control DER. Ensure transparent data exchange, while protecting data privacy.

- **Design electricity tariffs to ensure optimal use of DER**: review volumetric pricing structures to ensure a fair cost allocation. Develop pricing structures that incentivise the use of low-carbon electricity and leverage data to introduce granular pricing that reflects the varying value of locations or periods.
- **Facilitate DER participation in electricity markets**: streamline and revise connection schemes to ease integration of smaller size of DER. Recognise the role of aggregators as providers of grid services and enable their participation in markets.
- **Adapt protocols and processes to support increased penetration of DER**: acknowledge the increased importance of DSOs by revising protocols to encourage increased co-operation with TSOs. Consider creating DSPs to increase control at local, distributed level.

Chapter 4. Storage in decarbonising power systems

Taking advantage of storage for decarbonisation

An increasingly broad range of energy storage technologies are bringing unique capabilities to power systems and, importantly, are becoming more cost-effective. Battery storage options, in particular, are mature enough to be deployed at different scales and in multiple locations while responding in more refined time periods. Within the range of technologies that can contribute to maximising the use of low-carbon electricity, storage offers the ability to consume and re-inject electricity when needed, thereby increasing system flexibility to achieve decarbonisation.

Deploying storage in today's electricity markets is complex, particularly as several regulatory frameworks and market arrangements are still based on key features of older technologies. Storage, in general, still faces barriers such as double taxation and, under existing arrangements, new storage technologies face low visibility of temporal and locational signals as well as high participation requirements in various power system services. Moreover, known market imperfections linked to decarbonisation need to be addressed to reduce the risk that the flexibility storage provides could lead to worse emissions outcomes.

Several measures could make the various services storage offers more cost-effective, thereby stimulating their uptake in power markets geared towards decarbonisation. Removing features such as double taxation is one example of ways to improve the efficiency of storage operations. Price signals that prompt storage to charge when generation emissions are low and discharge when emissions are higher is another. More broadly, facilitating different models of participation can open up more revenue streams for storage assets. This could be done by adjusting minimum size and discharge duration requirements, appropriately remunerating fast response (at shorter time periods) in wholesale markets or in frequency regulation products, or increasing the visibility of locational signals through spatial granularity or location-specific tenders to incentivise provision of network capacity.

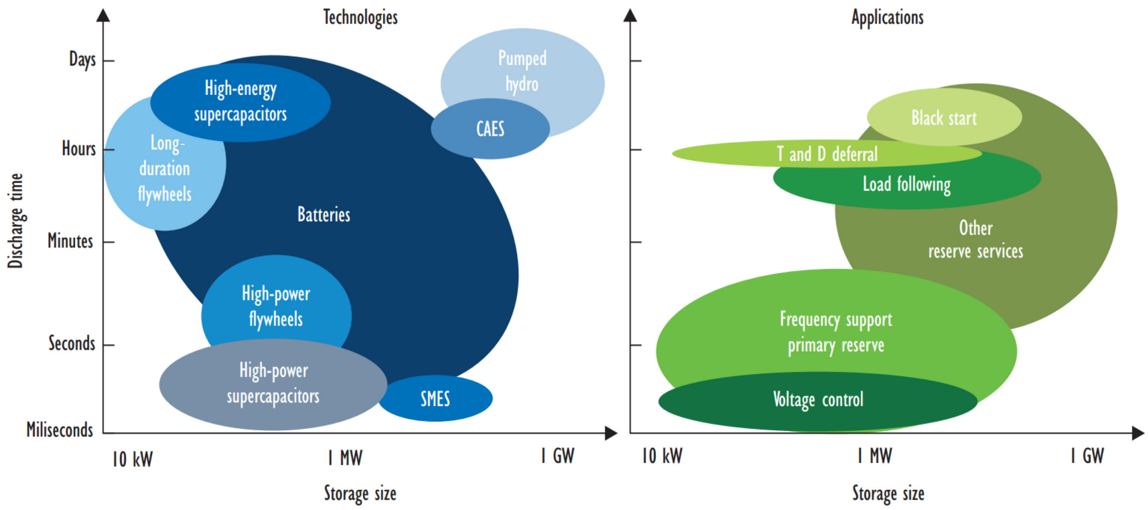
Value of storage and trends in deployment

Storage provides multiple values to decarbonising power systems

To date, in their bid to decarbonise electricity systems, most countries focus on increasing VRE technologies. This is pushing up demand for flexibility assets and services, in turn opening new possibilities for energy storage, which can provide different services at varying speeds and discharge duration periods.

Capacitors, flywheels and batteries can perform split-second discharge cycles to support voltage and frequency regulation. Depending on their size, batteries – when paired with VRE generation – can help reduce grid integration costs. Large storage options, such as compressed air energy storage (CAES), PSH or large batteries, offer discharge cycles of longer duration that can help in wholesale price arbitrage. Storage technologies can even support deferral of network investments, especially when periods of exceptional peak occur for only a few hours annually. In helping reduce system costs, storage can lower the average cost passed on to consumers.

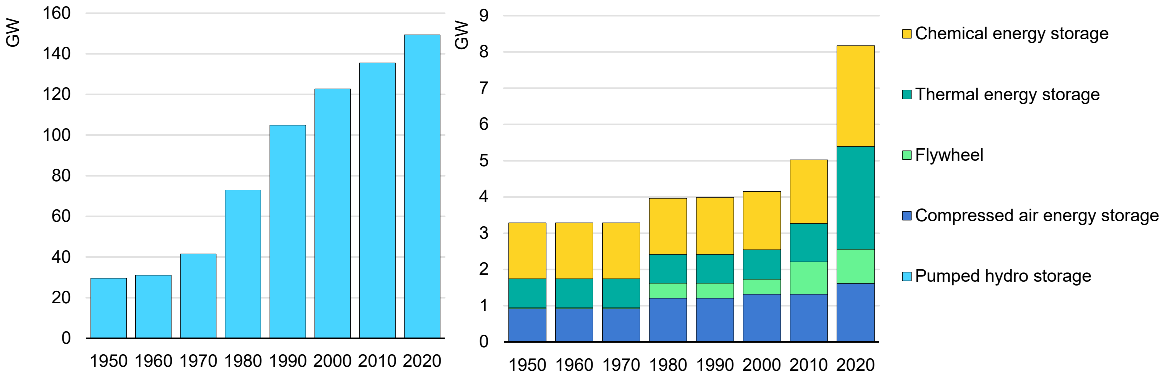
Storage technologies and potential power system applications based on size and discharge times



Notes: T and D = transmission and distribution; CAES = compressed air energy storage; SMES = superconducting magnetic energy storage.
Source: IEA (2014), The Power of Transformation: Wind, Sun and the Economics of Flexible Power Systems.

Globally, PSH currently accounts for more than 90% of total storage capacity. As its use of large turbines makes PSH similar to generation technologies, most market arrangements value (and remunerate) storage based on conventional characteristics of large volumes and long-duration discharge. This fails to capture the multiple values that new storage technologies can deliver to modern electricity markets, particularly as they mature and become more cost-effective.

Historical deployment of storage by technology type, 1950-2020



Source: IEA analysis based on DOE Global Energy Storage Database.

Recent developments create opportunity to expand the role of storage

Among different storage technologies, batteries have followed the technology path of innovation, development and deployment leading to massive cost reductions. Most notably, lithium-ion batteries show a 97% cost decline between 1991 and 2021, thanks to innovations in both battery materials and chemistry. Better performance for lower cost warrants fresh investigation of areas where storage can bring value to today's electricity systems.

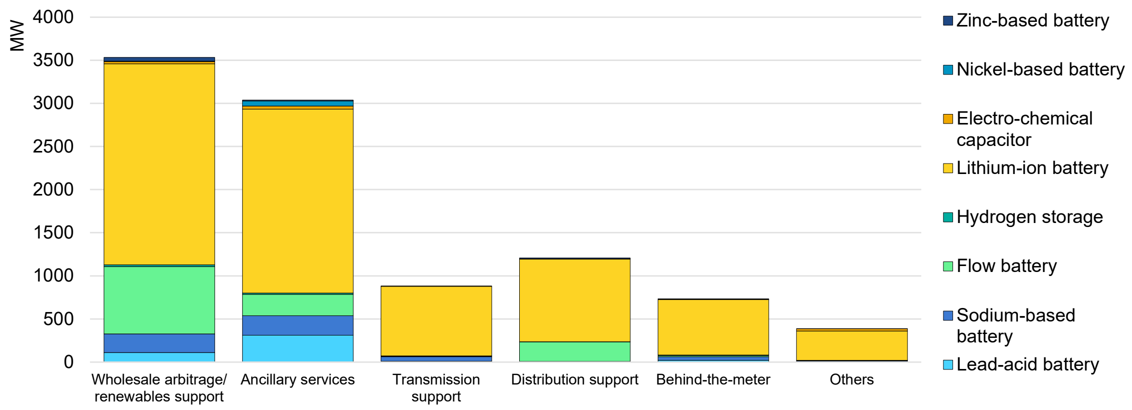
The modularity of batteries allows assets to be deployed in different locations and at different levels, from behind the meter (BTM) to transmission and distribution levels. In turn, batteries can be stacked based on their optimal size for specific functions in the grid, thereby ensuring cost-effective application for a wider range of flexibility services.

Precision and speed of response are other properties of battery storage that allow it to provide fast frequency regulation or voltage support in a very precise manner. These properties are shared with other inverter-based power system resources such as solar PV and wind generation.

In parallel, digital asset optimisation systems have become more common. By using advanced software to forecast prices for different services, along with data that reveal battery health and progression of charge and discharge cycles, operators could optimise micro-transactions and maximise revenues, helping bring battery storage technologies into the market.

To date, battery storage has been mostly deployed as hybrids or in providing frequency regulation support. In the United States alone, around 4.6 GW of hybrid capacity has already been installed, with 14.6 GW in the immediate pipeline and 69 GW in select interconnection queues. In South Australia, a 150 MW/193.5 MWh battery collocated with wind farm provides energy arbitrage and frequency regulation services. In the European Union, frequency regulation has been the main driver for early installations of battery storage.

Deployment of battery storage technologies in different value streams, 1987-2020



Note: Each value stream shows the maximum installed storage capacity. Where an asset performs across multiple value streams, its capacity is counted in each.
Source: IEA analysis based on DOE Global Energy Storage Database.

Despite this progress, more effort is needed to increase deployment of battery storage. According to the IEA's Net Zero by 2050 Scenario, to support a generation mix that can achieve net zero emissions by that time, global storage would need to be around 600 GW of capacity by 2030 – a massive expansion from the current installed capacity of around 20 GW. At present, different jurisdictions are providing direct incentives to increase battery storage uptake. Subsidies for grid-connected and PV-connected battery have been put in place, for example, by the Australian Capital Territory, Berlin and Bavaria.

Financial incentives must be considered in the context of broader system objectives, however. If geared towards BTM storage, incentives may encourage uptake without responding to actual system needs and may internalise the benefits only to the end user. This rest of chapter focuses on encouraging uptake of storage through the market, by designing features that reflect the system needs.

Considering that a significant amount of storage has already been installed BTM and for distribution level, associated opportunities and challenges for these applications are covered in Chapter 3 Distributed Energy Resources. Analysis and recommendations in this chapter focus primarily on the transmission domain or distribution level storage participating in this domain.

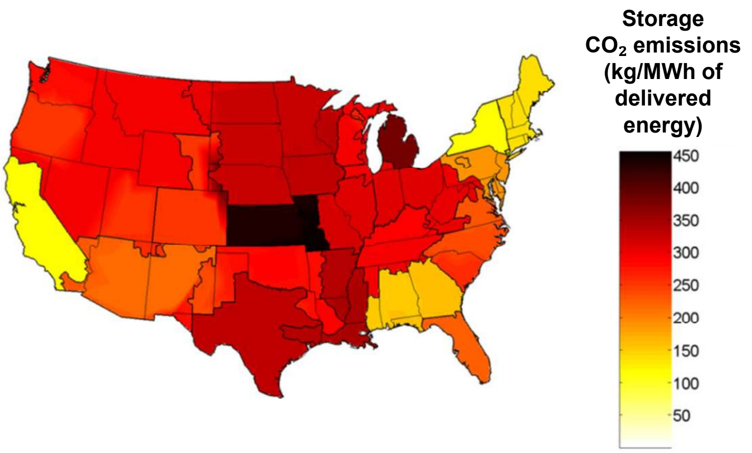
Market design for cost-effective storage deployment

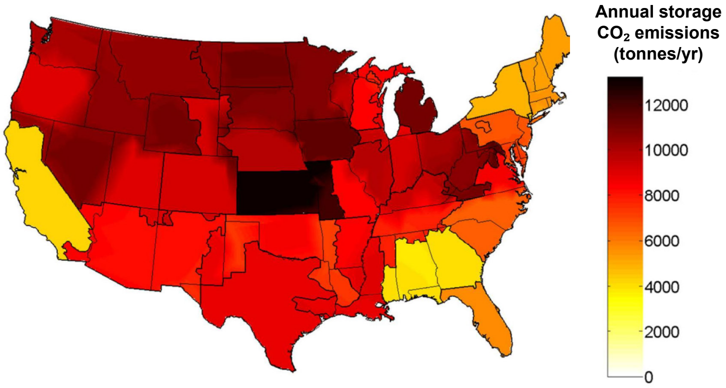
Leverage storage through decarbonisation instruments

The benefits of storage come with an inherent challenge: because of losses in the charging cycle, overall storage increases electricity consumption. In turn, depending on the generation mix feeding into storage, the charge cycle can push up emissions. Under current market conditions for certain countries, its price arbitrage operation would likely trigger charging when the electricity price is low but emissions are high and discharging when the price is high but emissions are low. Without strategic decarbonisation measures, market incentives stimulate storage operations that work against emissions reduction targets.

In a power generation fleet composed mostly of coal and gas, for example, charging would likely be triggered when cheap but carbon-intensive coal is dominant while storage resources would be called upon to discharge during peak periods when they would push out less carbon-intensive but more expensive natural gas. In the United States, diverse generation mixes in different locations could result in storage operations having average emissions of up to 450 kg CO_2/MWh of electricity stored and more than 12 kt CO_2 emissions per year. For scale, this is equal to around 60% of total emissions for the state of Kansas in 2020.

Estimated induced carbon emissions of stored electricity in the United States per kilowatt hour and per year, 2017





Source: IEA analysis based on and adapted from Hittinger E. and Azevedo I. (2017), Estimating the Quantity of Wind and Solar Required to Displace Storage-Induced Emissions. Copyright © 2017 American Chemical Society.

Governments need to implement policies that will leverage the flexibility benefit of storage without the emissions cost undermining long-term goals. Carbon pricing is one mechanism to decarbonise the power system while maintaining market efficiency as described in Chapter 3 on Policy Instruments. Other instruments, such as RPS, auctions or capacity payments, can help by bringing in low-carbon technologies that may have high capital costs but low or zero fuel costs and low emissions. Such policy instruments can help ensure that arbitrage operations help optimise the consumption of low emissions electricity.

To meet both aims for high shares of VRE and stricter emissions standards, California made flexibility a priority while imposing costs on using natural gas. In southern California, retrofitting gas turbines with battery storage – which can respond to frequency regulation and spinning reserves – helped minimise the use of turbines and reduce emissions. When gas turbines are deployed, the storage acts as reserve capacity such that more efficient units dispatch up to full load instead of more turbines running at lower capacity. This approach also leaves space for spinning reserves.

Address outdated participation features to level the playing field

Some features of services that keep electricity systems running smoothly still reflect operation protocols linked to conventional generation technologies – and may pose barriers to emerging technologies. Prior to market restructuring, for example, frequency regulation was an operational requirement for generators. As markets were liberalised, the need to define ancillary services became clear and several aspects of service provision (e.g. minimum size) were anchored to the features of large generating assets. Storage is among the emerging technologies that make it necessary to reassess these features to facilitate market participation of all assets that can bring value.

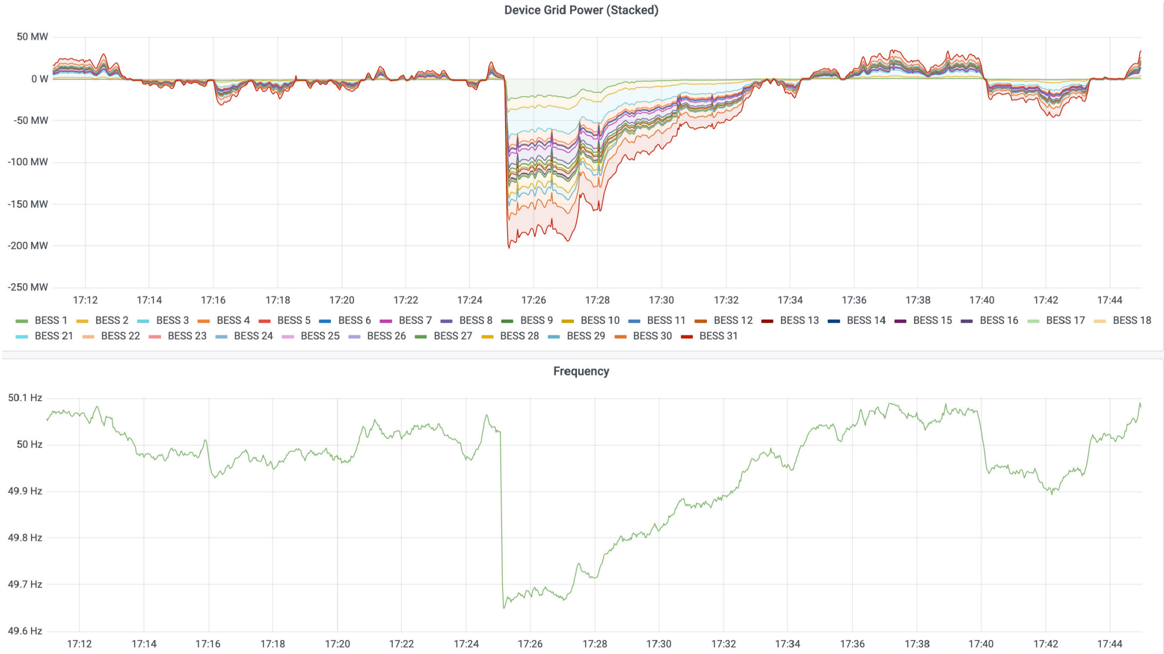
In 2020, the United States Federal Energy Regulatory Commission (FERC) issued Order 841, mandating regional system operators to remove market participation barriers. By targeting areas such as minimum thresholds, participation models, de-rating and bidding parameters, the order makes it easier for storage assets to bid into energy and ancillary services markets. This stimulates their deployment without setting specific procurement targets. The key in specifying market services is to ensure technology neutrality and readiness to adapt to technology changes that can bring more cost-effective solutions.

One approach to address barriers of market features is to create arrangements around minimum thresholds. For example, in 2018, PJM initially required 10 hrs of minimum discharge duration to qualify for capacity payments. Given that current battery technologies often become less cost-effective beyond the 4-hr duration, this requirement reduced their participation. PJM has since changed this rule and adopted an effective load-carrying capability (ELCC) scheme and adjusted payments to reflect the service that assets are able to provide to the system annually. Now that the market supports participation, for its 2024 rating, a 4-hr storage asset would receive 82% of the payment made to a 10-hr storage asset for its services.

Allowing aggregation of distribution level assets to overcome minimum volume or dispatch duration limitations, or reconsidering power export restrictions for BTM assets are other options. Leveraging the excess capacity of battery storage assets deployed as BTM or in the distribution grid could help address flexibility requirements. For example, in 2019, the United Kingdom opened wider access for participation in the balancing mechanism to aggregators acting as “virtual lead parties” (VLP) that co-ordinate the responses of DER, including smaller-scale storage assets.

Such instruments support a wider range of participation of flexible technologies such as storage and also leverage various sources of investment from different actors in the system. Opening these markets to diverse participation models also helps concretise the idea of revenue stacking, which can incentivise storage uptake.

Aggregated battery storage response to a frequency drop in 26 April 2022



Source: IEA analysis based on from Johnson C. (2022) KrakenFlex, with permission from author.

Rationalise the costs of storage operation

Currently, storage assets participating mainly in wholesale energy arbitrage often face a systemic disadvantage: storage may be taxed as a load when it charges and again as a generator at when it discharges. Removing such double taxation helps reduce the costs of charge and discharge cycles and improve business case of storage. As storage is a flexibility provider, rather than an actual final consumer, reforming taxation to align with its role leads to fairer remuneration. Recently, the United Kingdom abolished regulations that led to double taxation as did the Netherlands.

Policy makers need to also adapt and rationalise tariff components to reflect the unique role of storage. Network tariffs sometimes have components that include demand charges associated with the use of transmission and distribution, as well as components to recover the costs for balancing the system.

In the United Kingdom, the costs associated with the balancing service use of system (BSUoS) component of the network tariff will now be charged just once – when the storage asset exports electricity back to the system. As BSUoS is considered as a cost recovery component, charging it during electricity import and export would be an undue burden on storage.

Individually and collectively, such measures would contribute to create a level playing field for such technologies and create a more equitable business case.

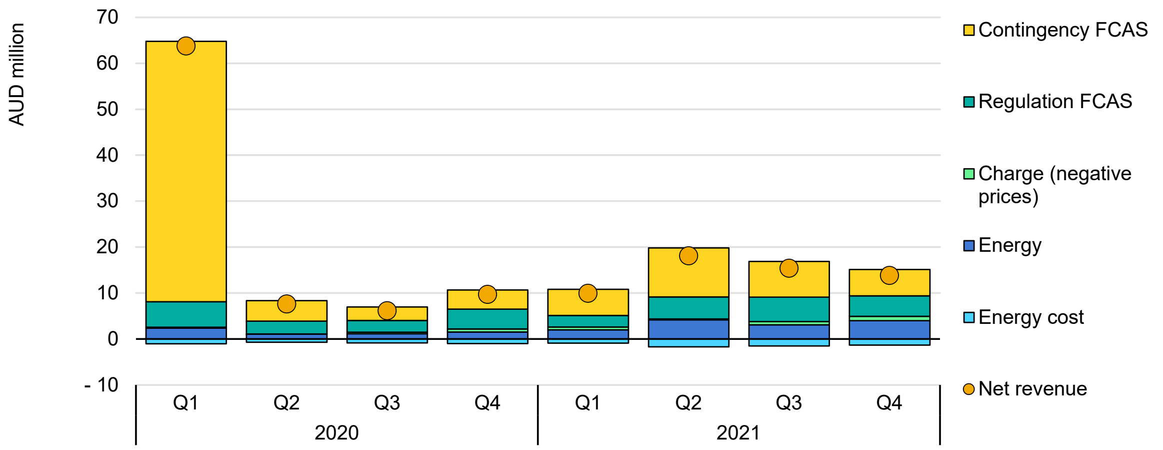
Compensate fast-response time where applicable

A key value of storage technologies such as flywheels and battery storage systems is their ability to react at split-second rates. Market design that appropriately remunerates this value – in both the wholesale market and for frequency regulation – supports their own market deployment and enables integration of higher levels of VRE.

Increase temporal granularity

Refining price signals by shortening time periods can encourage higher uptake of fast-response flexible assets such as battery storage, as discussed in the Chapter 2 on Wholesale Markets. While some markets have already set dispatch periods as short as five minutes, aligning financial settlement to the same period would help attract additional investment for fast response. Without such alignment, price spikes occurring for a few minutes are averaged out with the lower prices within a settlement period, resulting in lower remuneration. To address this, markets such as PJM and the Australian National Electricity Market (NEM), recently aligned their settlement periods to five minutes. In Australia, the alignment led battery storage operators to accrue higher revenues from energy arbitrage since 2021.

Quarterly revenue streams of battery storage in the Australian NEM, Q1 2020 to Q4 2021



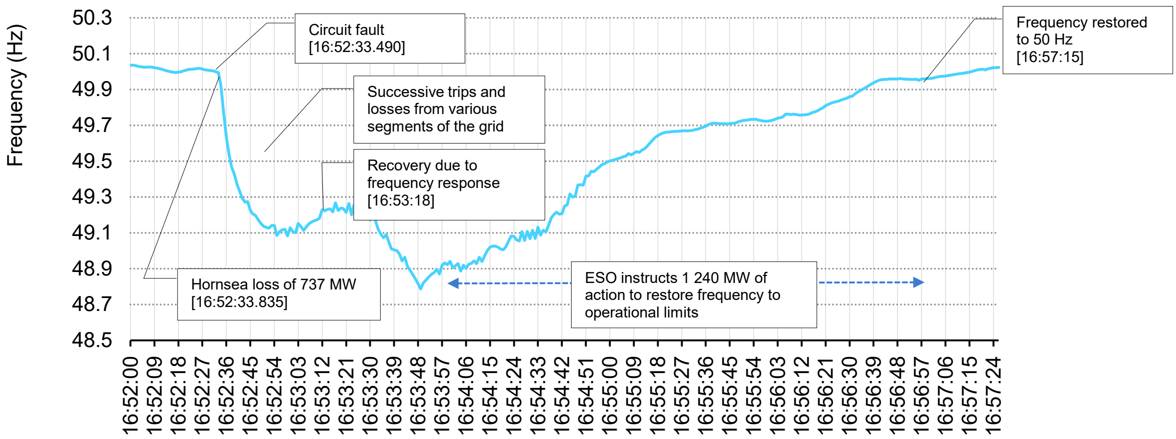
Note: FCAS = frequency control ancillary services.
Source: IEA analysis based on AEMO (2021), Quarterly Energy Dynamics.

Open faster frequency regulation services

Adapting regulation to open up a market for participation of fast-response storage for faster frequency is another means to compensate this important service. Such instantaneous services could support higher VRE in power systems needing grid stability.

When the United Kingdom initially launched (in 2016) the Enhanced Frequency Response (EFR) mechanism, under which full delivery is expected in one second, the majority of bids received came from batteries. When, on 09 August 2019, successive trips and losses – including that of 737 MW of power from the Hornsea plant – threatened grid operations, successful action revealed the huge value storage to the system service market. The immediate response of batteries was key to restoring the system, with Firm Frequency Response (FFR) contributing 44% for the primary response and EFR contributing 37% for secondary response. In 2021, Dynamic Frequency Response replaced the EFR scheme, with batteries still constituting the majority of bids.

Frequency response during a fault in the United Kingdom power system, 9 August 2019



Source: IEA analysis based on data from the National Grid ESO (2019), Technical Report on the events of 9 August 2019; (2019) System Frequency [database].

Compensate geographic flexibility

Storage technologies such as batteries have a key advantage in that, unlike PSH, they are not geographically constrained. They can be deployed to specific locations to substitute for transmission and distribution (T&D) lines or for use as capacity to address issues such as congestion. In some cases, storage is also more cost-effective. In the United States, the Midcontinent Independent System Operator (MISO) selected a battery option to address outage issues on a transmission line in need of redundancy, saving USD 0.8 million compared to a new circuit.

As storage straddles the traditional line between grid and generation assets, remunerating its contribution to the grid requires clear rules in operation and ownership to prevent conflicts of interest and undue market advantage. In the European Union, TSOs and DSOs are prohibited from owning and operating storage assets except if they are fully integrated network components (FINCs) or if the market could not cost-effectively satisfy a system operator's needs through an open tender. Clear, visible and granular locational signals – through granular prices or localised flexibility markets – can help maintain this regulatory separation while expanding the range of grid contribution by storage.

Where storage is needed to function both as both grid and market assets, governments will need to establish clear guidelines to identify when, where and how each function operates and is remunerated for the value it contributes.

Ensure visibility of locational signals through spatial granularity or localised flexibility services

Price signals that reflect the actual conditions of different points of the network encourage investment for local flexibility, as discussed in more detail in Chapter 2 on Wholesale Markets. Establishing a nodal pricing system is a common way to create a transparent signal. Likewise, increasing the number of zones in a zonal market can reveal diverse flexibility needs of different locations.

Where large zonal markets persist, network operators are best placed to identify opportunities for local system services. Open tenders for local flexibility within zonal markets can increase the visibility of the location in need of service while ensuring a satisfactory level of market competition among technologies and service providers.

In France, the TSO is preparing a call for tender for local flexibility based on a pilot study for transmission-level storage approved by the national regulator. Several other instruments or tools are emerging to facilitate participation of storage in geographically-specific flexibility that is remunerated by system operators. DSO-level flexibility market platforms (such as in the United Kingdom), TSO-DSO-level information platforms (such as in the Netherlands) and several similar pilot platforms offer innovative models.

Consider guidelines for dual use if necessary

The opportunity to "stack" different revenue streams is a key opportunity for storage operators to boost both utilisation and profitability. In certain cases, to tap the potential benefits of storage as a cost-effective grid asset while improving its utilisation through market participation, power system stakeholders may collectively decide to allow storage to receive a portion of regulated remuneration for the grid capacity it provides while also participating in the market to maximise its utilisation. For such situations, additional rules could be considered to maintain competition in electricity markets and encourage efficient investment of regulated assets.

For example, the Australian Energy Regulator's (AER) shared asset guideline allows network service providers to utilise regulated assets for unregulated activities where the revenue for the latter would be used to reduce the regulated revenue, eventually benefitting the consumers through lower grid tariffs. Considering a storage asset providing network services, maximising utilisation through this guideline could entail participation in frequency control services. However, in recognising operational issues surrounding potential conflicts of interest and cross-subsidies, distribution network service providers (DNSPs) were limited to using storage for network services only through procurement from third-party providers or ring-fenced DNSP affiliates. This limits direct ownership and control, while allowing the asset to participate in competitive markets when needed.

Where necessary, policy makers could consider guidelines on dual usage based on experiences from the California Independent System Operator (CAISO) and MISO to help determine when and how a storage asset could participate in a market, and where and how it recovers its cost:

- For fair remuneration of regulated rates, the storage asset's capacity component must be available when needed – similar to any other regulated network asset. As such, stakeholders could define market participation windows based on the time or state of charge of the storage asset, or its ability to be recalled from the market, with actual utilisation left to the system operator.
- To avoid market abuse, policy should define how storage participates on the market. Specific asset definitions could establish transmission arrangements, similar to information on dispatchability and responsiveness. Corrections for cost inequities (e.g. avoided interconnection costs) could be included to avoid situations of dual-use storage underbidding in the wholesale market. Definitions for control could also be set to ensure appropriate transition to the system operator when needed. Finally, a life-cycle management protocol would be needed to avoid overly aggressive market participation that could degrade the asset and lead to an earlier refurbishment compared with a reasonable lifespan expected from a typical network asset.
- Policy makers should also strike a balance between providing regulated remuneration and the level of market revenue that the storage asset could accrue. The aim is to fairly balance savings that accrue to grid users from more cost-effective network alternatives with sufficient incentives for developers to invest in storage.

Final recommendations

To capture the full value of storage to power systems, policy makers should take the following points into consideration:

- **Storage must be paired with decarbonisation policies**: market incentives linked to storage operation should be geared towards decarbonisation. Carbon prices or other means to increase the share of low-carbon generation with low marginal costs help optimise storage operation towards decarbonisation.
- **Facilitate market entry and rationalise costs based on the role of storage**: removing current operational and market barriers is critical and implies the need to review minimum size thresholds, discharge duration requirements, bidding parameters or other specifications that might reduce (explicitly or implicitly) the participation of new storage technologies. It is also necessary to review taxation and network tariffs that might unfairly charge storage as both consumer and generator, and thereby reflect its true role as a flexibility provider at different timescales.
- **Compensate fast-response time**: increase the temporal granularity of dispatch and settlement periods in the wholesale market and set up fast frequency regulation to increase incentives for fast-response batteries and to build a strong foundation for higher VRE uptake.
- **Compensate geographic flexibility**: increase spatial granularity of prices and/or open location-specific system services to ensure visibility of locational signals.

Chapter 5. Adequacy mechanisms

Ensuring system security

The trend of shifting away from government-run, centrally planned electricity systems towards an approach based on liberalised energy markets has aimed to improve efficiency of the systems, in part by spreading both rewards and risks among the full range of actors involved. Under this structure, the role of government is removed from day-to-day operations while maintaining responsibility for setting up the parameters that incentivise actors to operate in a secure, cost-efficient manner. The overarching argument is that liberalised power systems can produce better outcomes because incentives are more aligned with the needs of all stakeholders.

Setting the rules for wholesale markets is the mechanism by which governments create incentives for efficient operations in liberalised power systems. If well designed, the market will, in turn, offer sufficient revenues to cover both operating and capital costs of various system functions, thereby stimulating investments needed to provide a secure system at lowest cost.

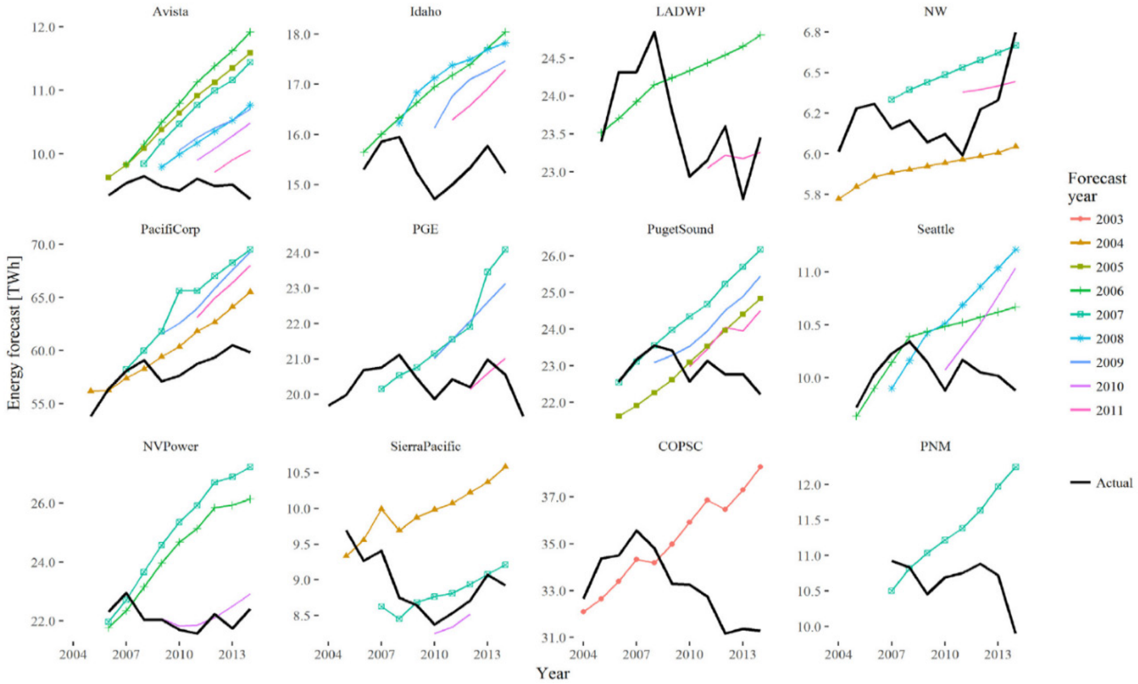
In the liberalisation process, two major issues have arisen in competitive markets that, left unaddressed, could result in inadequate investment. The first is the need to ensure that markets fully value all of the services required for secure system operation. Beyond the generation of electricity, this includes ancillary services that support its transmission and distribution, such as reserves that allow the system to respond to adverse events such as outages. The second is the need to create frameworks that allow the market to evolve as technologies and operations change. This second challenge is particularly important considering the very large investments needed for some capacity, for which costs are normally recouped over several decades of revenue.

In the bid to decarbonise the electricity system, past operations and market policy decision can create the risk that some assets become used less or accrue lower revenue than the financial model on which original investments were made. In effect, they may become “stranded” as the context and policy change. In reality, market instruments to allocate these risks over the life of the investment are missing or incomplete in many places, both geographically and across the range of technologies and services involved in system security. For governments, this raises a difficult question. Should they let market forces play out, trusting that opportunity to generate sufficient revenue will attract the investments needed, even in long-lived power sector assets? Or should they implement market instruments to encourage investments needed to ensure security of supply is maintained? A fine balance must be achieved between market intervention to correct shortcomings and taking steps that create market distortion.

Drawbacks of central planning

Historically, centrally planned power systems have been able to secure investments based on calculations of future demand and strategies to supply it – to the degree that over-investment is a common problem. In many jurisdictions, this problem arises because incentives set out by the institutional framework for the power sector give planners the responsibility of deciding how much firm capacity is needed. As planners are also responsible for ensuring the power sector supports the well-being of any country or region, they tend to err on the side of caution, overestimating both peak demand and the capacity needed to minimise the risk of outages. Recent analysis of integrated resource planning in the western United States shows that total energy demand is consistently overestimated, with only one of 12 utilities having forecasted less load than actually occurred over a period of 10 years.

Comparison of total electricity consumption forecast versus actual in western United States integrated utilities, 2004-2015



Note: LADWP = Los Angeles Department of Water and Power (California). NW = North Western (Montana). PGE = Portland General Electric (Oregon). PugetSound = Puget Sound Energy (Washington). NVPower = Nevada Power. SierraPacific = Sierra Pacific Power (Nevada). COPSC = Colorado Public Service Corporation. PNM = Public Service Company of New Mexico.

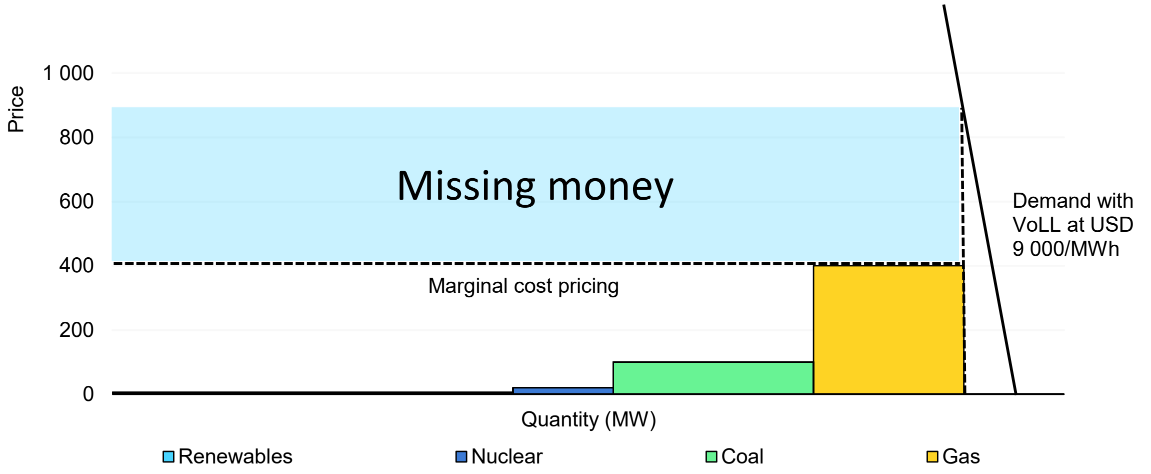
Source: IEA analysis based on Carvalho et al (2018), Long term load forecasting accuracy in electric utility integrated resource planning.

Central planners must also choose among different sources of energy that will support efficient supply in the short term and 10 to 15 years into the future, knowing there is a risk that variable factors (e.g. fuel prices or innovations in generating technologies) can change the equation such that very large investments become uncompetitive. This requires, unrealistically, that planners have good foresight of the future costs of technologies (such as VRE and storage) that are rapidly evolving. A base argument for liberalisation is that private actors are better placed to collect such knowledge and use it to calculate investment decisions. A fundamental difference between centrally planned and liberalised systems is that, under the latter, most of the risks are borne by investors rather than by taxpayers or ratepayers, who do not decide on investments but pay them back over time through energy tariffs.

Shifting risks to investors: the "missing money" problem

Electricity markets that have decided to shift some of these risks to private actors have typically used energy pricing as an explicit incentive to attract necessary investments. Under liberalisation, however, even if the wholesale market sufficiently remunerated the locational and spatial value of energy, marginal cost pricing of generation alone can be insufficient incentive for secure operation and investment. In short, the marginal cost of generation does not reflect the full economic value of energy and reserves at times of system stress or the value of lost load (VoLL). This problem is known as "missing money", referring to the gap between potential remuneration and the economic value of electricity to consumers, leading to underinvestment and a level of reliability below the desired one.

Marginal pricing and missing money



Ways to address the missing money problem

Conceptually, policymakers can apply three different approaches to tackle the missing money problem, which can be used together in complementary ways:

- **Energy price adders**, which allow for higher prices when the system operator becomes short of the desired level of generation needed to support energy and reserves.
- **Capacity remuneration mechanisms**, which are a payment given for generation or demand-side resources to be available when needed.
- **Regulated procurement**, in which the amount and/or the price of capacity are determined by a regulatory body.

Energy price adders reward availability in real time

To secure extra revenues needed to cover the fixed costs of the generation fleet, markets are often designed to allow prices to exceed variable costs during certain periods (e.g. in peak demand or moments of stress to the system). Essentially, such “energy price adders” acknowledge the fact that, to secure supply in periods of distress, additional capacity needs to be available – and remunerates owners of for their ability to provide such assets if needed.

Reliability payments prove effective in Argentina

The liberalised power system in Argentina has two main payment schemes. Energy payments for supply delivered provide revenue certainty for investors while capacity payments remunerate for generator availability during the most critical hours.

In turn, the capacity mechanism also includes two types of payments, one for capacity and one for reserve capacity. The first rewards available capacity on working days during so-called non-valley hours (i.e. between 6:00 and 23:00). It set at USD 10/MW/hour, corresponding roughly to the annuity costs of an open cycle gas turbine. This payment is awarded to both the non-contracted capacity of dispatched generators and to generators scheduled in the day-ahead but not dispatched, based on their declared availability. The scheme also remunerates non-rotating reserves based on the day’s marginal reserve price.

To reward scarcity, Argentina’s market design includes a second payment associated with the loss of load probability. This top-up to the wholesale market price is calculated in two ways. The ISO uses power market simulations to identify critical weeks for supply, based on probability bands for loss of load. In these weeks, the ISO sets a weekly premium for loss of load risk, calculated as the difference between the marginal price between peak hours and the associated VoLL. Generators operating during critical hours are eligible for these payments.

For the remaining weeks, in which the ISO expects to serve all load, the operator carries out probabilistic simulations (using daily peaks, load, generation and congestion risks) to determine an average premium for the rest of the season's peak periods.

Inspired by the original model of the electricity market in the United Kingdom, this system has allowed Argentina to maintain investment without auctions or long-term contracting – since the beginning of the market operation in 1992.

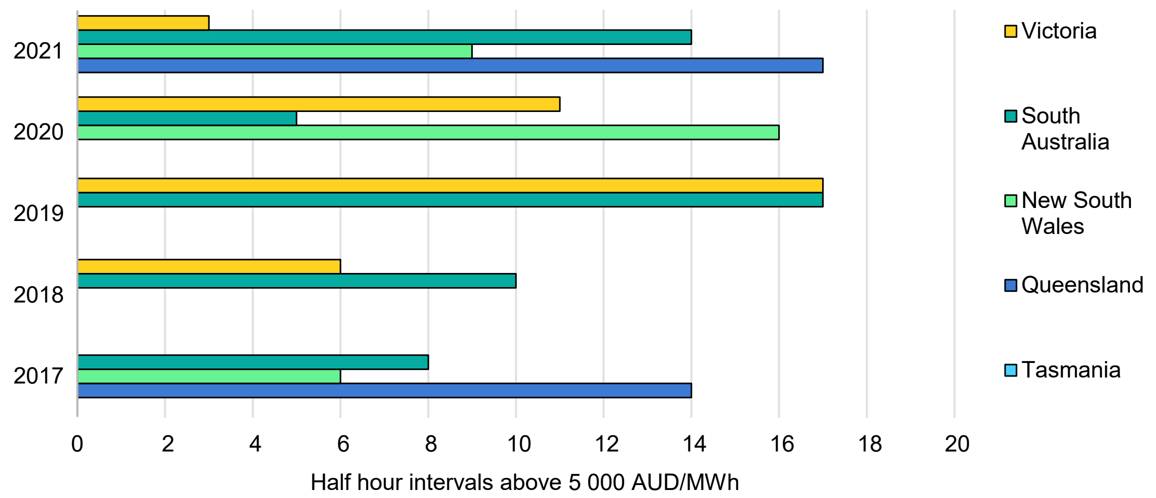
Adequacy payments in Australia

The National Electricity Market (NEM) in Australia has an adequacy mechanism that allows generators to receive revenues above the variable cost of energy through two means:

- Generators can make bids above their variable costs; in times of peak demand, since there is no available capacity to out-compete them, these bids can be cleared in the market.
- A fixed at the price cap, of AUD 15 000/MWh, comes into play when the system operator does not procure enough reserves to maintain system security in case of a contingency. This approximates the VoLL in case of demand shedding.

To avoid excessive profits, rules of the Australian NEM foresee reducing the price cap once a net margin of AUD 224 600/MW has been reached in a given year. When this threshold is reached for more than a week, or about 7.50 full hours of scarcity pricing, this mechanism requires the system operator to enter a scheme of administered prices.

Scarcity episodes in Australia

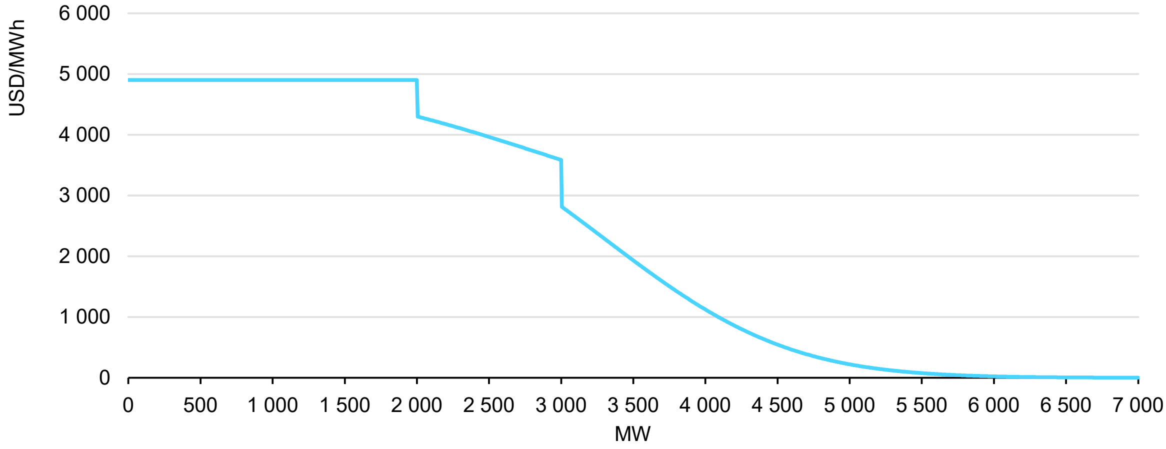


Source: IEA analysis based on AEMO.

Energy adder use by the Electric Reliability Council of Texas (ERCOT)

In the ERCOT market, which comprises most of the Texas power system, when the system becomes short of reserves, the market incorporates energy adders to prices that reflect the VoLL. As a complement, ERCOT implemented an operating reserves demand curve that permits prices to exceed the variable cost of the marginal source; the compensation level increases with the likelihood of a lost load event when reserves are in short supply. This mechanism emulates how markets of other products react to scarcity in reality: i.e. the lack of spare production capacity triggers an increase in price as demand increases.

Operating reserves demand curve in ERCOT



Source: IEA analysis based from ERCOT,(2022), Operating reserves demand curve.

In short, markets with energy price adders use high prices to reward availability during periods of distress. The period in which these prices apply differs in that it can be forecasted (as in Argentina) or occur in real time (as in Australia and Texas). In the latter case, various market participants help the system operator maintain electricity security according to their own interests: in the case of generators, it is in their interest to be available; in the case of retailers, to activate the reduction of flexible demand.

Capacity remuneration mechanisms (CRMs)

To secure enough investments to satisfy peak demand, many power systems have opted to use capacity remuneration schemes (CRMs) to directly reward the capacity of technologies. Experience in the application of CRMs is extensive, with many designs having been tested around the world.

In many markets, capacity markets complement the incentives provided by energy adders. In any commodity market, it is expected that the per-unit price will, over time, provide a sufficient signal to repay the investment needed to satisfy demand. Adding a capacity payment implies paying for an input that is separate from the energy and ancillary services needed to balance demand and supply. In many markets, legitimate reasons justify the potential to earn revenue by providing this capacity. CRMs play this role in energy markets (going beyond energy adders to fulfil a different role).

Conservative reliability standards

In sharp contrast to most markets, electricity demand does not represent the preference of consumers in real time. This feature makes electricity demand very “inelastic” and not reflective of the real value of the energy consumed. As a substitute, regulators set reliability standards based upon the number of hours or amount of “unserved energy” that are acceptable over a given period.

Traditionally, electricity systems have set reliability standards based on engineering criteria, such as a “1 outage event in 10 years”. This is much more conservative than standards based on economic criteria (e.g. three outage hours per year) or the amount of unserved energy. In such systems, policy makers have the responsibility of assessing the tolerance of populations to supply interruptions, which may justify conservative reliability standards. However, conservative reliability standards could require larger additional amounts of firm capacity – beyond what can be sustained by energy only markets. In this case, CRMs provide a mechanism to sustain the reserve margins required to comply with such reliability standards.

Low price caps

In cases where electricity supply is concentrated across a small number of firms, the lack of demand elasticity in real time exposes the market to manipulation. Price caps, which can change the shape of cost-based bids and pricing, are regulatory measures to prevent such abuse. The downside is that a low price cap might preclude the marginal generator from recovering its fixed costs through the energy market. In this case, the capacity market serves as a mandated, centralised purchase of an option to buy energy at the price cap.

Regulatory uncertainty

Lack of clarity on policy and regulation regarding future polices of the power sector, such as the speed and manner of decarbonisation of the power sector or the future of the nuclear or coal fleets in many markets may increase the perception of risk for new and existing assets. Where significant, unforeseen government interventions could erode the profitability of new investments, the concept of a minimum revenue source could reduce the perceived risk. This is particularly important for dispatchable sources.

Optimising CRMs for the energy transition

As a concept, CRMs are relatively simple; in practice, they have always been complex to implement, particularly as they are supposed to compensate for the missing money. The energy transition creates additional pressure to reform these mechanisms to make them fit for the purpose of ensuring security of supply at the lowest cost.

Even in the context of liberalisation, many capacity markets face similar problems as central planning in that planners (often the system operators) forecast more capacity than is required to satisfy system needs. Many CRMs provide incentives to overestimate demand or underestimate the contribution to adequacy from resources that are harder to measure, such as demand-side response, energy storage or VRE.

CRMs, at least historically, often paid for capacity-based on a measure of expected availability; in turn, penalties for lack of performance during critical periods were low or non-existent. This provides insufficient incentive for generators to participate in times of system stress. With more VRE and an increasing number of extreme weather events, the predictability of critical periods of the year is likely to decline. Systems will need to evolve and develop new incentives to guarantee that the product – i.e. security of supply – is delivered by the resources being paid to provide it.

CRMs were conceived at a time when most technologies were “dispatchable”, including hydro, geothermal, nuclear or fossil fuel-based thermal plants. In today’s context, many of these mechanisms are ill-suited to properly operate and remunerate the contribution to adequacy sources (e.g. demand-side response and VREs) and energy-constrained resources with short duration (e.g. batteries).

This range of factors makes the redesign of CRMs one of the most vital topics of reform for mature electricity markets.

Designing adequacy mechanisms for the future

Years of trial and error in testing different mechanisms to stimulate investment in and appropriate compensation of CRMs for the power sector have created a wealth of experiences – and greater knowledge of the characteristics needed.

Through different designs, policy makers vary in whether they assign certain decisions to planners or leave them to market participants, as shown in a summary of diverse adequacy remuneration frameworks. The following table provides an overview of different decisions that are taken by planners or regulators within various adequacy regimes.

Characteristics of adequacy mechanisms

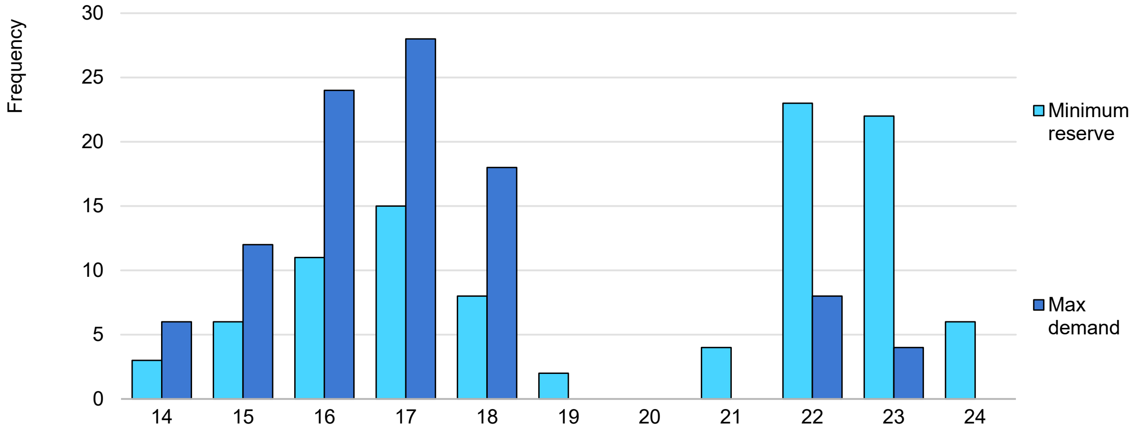
Administrative/ regulatory decision	Centrally planned	Energy + centralised capacity market	Energy + decentralised capacity market	Energy only
Reliability standard	●	●	●	●
Energy prices in periods of stress		●	●	●
Level of operating reserves	●	●	●	●
Peak demand forecast	●	●		
Defining technologies capable of deliver the product	●	●	●	
Product definition	●	●	●	
Amount of capacity to be procured /Capacity demand curve	●	●		
Technology/ fuel	●			
Location	●			
Size	●			

Source: IEA (2021), Secure Energy Transitions in the Power Sector.

Availability should be focused on critical periods, not peak demand

For planning purposes, peak demand is a normal metric used to determine adequate capacity. In practice, the periods when contingencies arise do not necessarily coincide with peak demand. In Mexico, the capacity market defines the product based on hours in which system reserves are lowest. In fact, while peak demand typically occurs during summer peaks, half of the critical periods occur during the night – not coinciding with the hour of peak demand. A strong logic exists, in such cases, for redefining capacity products to better reflect actual scarcity periods in systems.

Critical hours of the day in Mexico



Source: IEA analysis based on data from CENACE (2022), 100 horas críticas.

Decarbonisation boosts need for technology neutrality

Technological innovation and changes in how the power sector functions have led to a much richer set of capacity sources with very different capabilities. Defining *ex ante* the technologies that can or cannot provide a capacity product inevitably leads to misrepresentation of the supply and demand of the product.

Across the European power spot exchange (EPEX), suppliers can participate in auctions or make bilateral trades to obtain certificates at numerous intervals, both before and during the delivery year. France has developed a mechanism that taps into this opportunity. The French system operator, RTE, certifies the requirements for obligated parties (suppliers) and capacities for operators by informing these parties of selected performance dates (called PP1 periods). This is done one day in advance, up to 15 days per year during the months of November through March. On these days, between 07:00 and 15:00 and from 18:00 to 20:00, RTE calculates the consumption of the load assigned to each supplier and the output of operators. At the end of the delivery year, the supplier must hold certificates in the amount of their consumption during the PP1 periods. If short of certificates, the supplier pays a penalty rate.

France's mechanism provides an economic incentive for suppliers to tailor offers to customers that reflect their consumption during PP1 periods, in effect driving demand response participation. It also prompts capacity operators to avoid outages during times of expected stress as a means to obtain certificates that can be sold to suppliers. Operators of VRE receive certificates that match their actual contribution to security of supply, instead of an *ex ante* calculated contribution.

Class ratings

To assess the ability of resources to deliver during times of expected shortage, system operators also need to determine capacity ratings for resources. These can be assessed by type (e.g. gas, coal, wind and solar) and/or by location. The type rating is particularly important for intermittent resources (e.g. wind and solar) and energy-limited resources (e.g. batteries) as the rating, and as a result, the potential payment can vary dramatically across different assessment methods. The location rating is especially crucial to assess in large, geographically diverse systems.

As PJM is the largest power market in the United States and one of the largest interconnections in the world, these factors lead to very different conditions of supply and demand within its footprint. In 2021, PJM implemented an accreditation process using the effective load-carrying capability (ELCC) method, which maps future expected outputs of a resource against expected load shapes. The capacity rating is a result of this modelling exercise and equals the quantity of load estimated to be able to be served when adding a new resource of that type.

Effective load-carrying capability effect on type rating, PJM (2023-2024)

Resource	Status quo rating (%)	New rating (%)	Change
Onshore wind	14.7	13	-1.7
Solar fixed	38	29	-9
Solar tracking	60	54	-6
4-hr storage	40	79	+39
8-hr storage	80	95	+15
Hydro intermittent	100	44	-56
Landfill gas	100	62	-38

Source: IEA analysis based on PJM (2021), How effective load-carrying capability ("ELCC") accreditation works.

PJM adjusts these values annually, based on changes to the resource mix and load shape. The hours in which shortages are expected to occur (load shape), for example, are most likely near or after sunset or in winter – i.e. when solar cannot produce at high-capacity factors. Thus, with greater penetration, solar fixed becomes less able to supply during times of distress and its capacity rating is reduced. Current estimates suggest it will be lowered from 29% in 2023 to 18% in 2028.

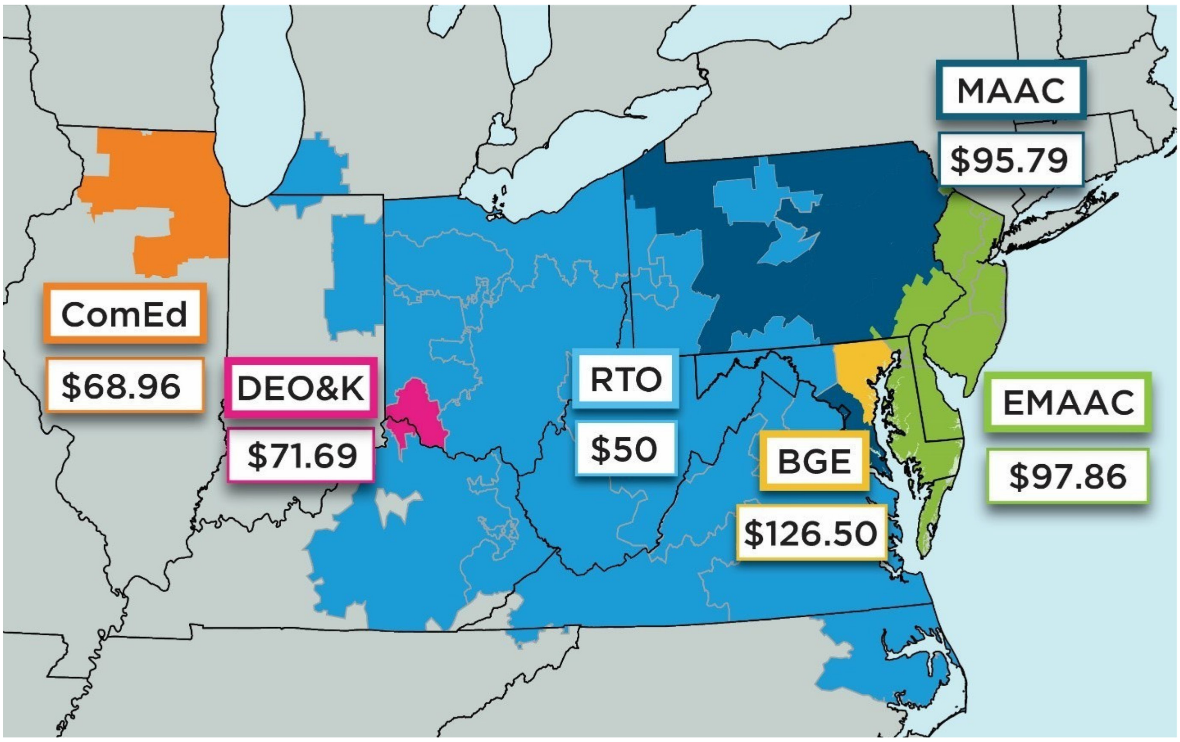
This approach has significantly shifted the capacity ratings of several generating classes. The sharpest drop was in intermittent hydro (56%) and landfill gas (38%), with less severe declines in solar fixed (9%) and tracking (6%). In contrast, storage ratings increased substantially for both pumped hydro and battery, from 40 to 79% for 4-hour duration and 80 to 95% for 8-hour duration.

Locational prices

In additional to the rating of a particular resource at a particular location, the price of a resource should also vary according to market conditions. PJM uses two additional mechanisms (beyond nodal prices in the spot market) to account for this geographical diversity and provide incentive for generators to locate where needed:

- **Capacity zones:** PJM is divided into up to 19 zones or delivery areas, depending on transmission capabilities between different regions. Capacity prices vary, depending on the supply-demand balance of each region.
- **Average price adjustment:** the level of the capacity payment is determined by auction, after which they may be adjusted by subtracting the average energy rents of the wholesale market. This means that plants located in zones with high prices will earn higher revenues than those in zones with low prices. This price signal will become more relevant as the market share of VRE increases.

Capacity prices by zone in the PJM for 2022/2023 delivery year (USD/MW per day)



Note: ComEd = Commonwealth Edison. DEOK&K = Duke Energy Ohio and Kentucky. RTO = PJM Market (excluding the delivery areas mentioned). BGE = Baltimore Gas and Electric. EMAAC = Eastern Mid-Atlantic Region. MAAC = Mid-Atlantic Region.
Source: PJM.

Regulated procurement of peak capacity

Generally, electricity markets were introduced with the primary aim of minimising the costs of everyday operations. The underlying mechanism is to allow diverse entities – mainly generators and retailers – to exchange energy produced through assets they own or have contracted in advance.

In electricity markets in which "load-serving entities" procure capacity, it is often utilities in charge of distribution and retail activities that must comply with a regulatory obligation to contract – in advance – sufficient capacity for their demand forecast. A good example of this type of adequacy mechanism is applied in the state of California, where the CPUC imposes the obligation to the load-serving entities, which must contract in advance with different generators.

Final recommendations

To ensure that a sufficient level of resources needed to ensure secure power systems can recover fixed costs and encourage further investments in line with decarbonisation policy objectives, policymakers should:

- **Use price adders in wholesale markets to create incentives for capacity to be available in times of distress.** Create strong price signals in the energy market by embedding the cost of reserves within the market price. Strong price signals provide incentives for all resources- both on the demand and supply-side- to contribute to system security in times of distress, and steers investments towards the technologies and locations providing the highest value to the system.
- **Supplement energy market price signals with CRMs to achieve the desired level of reliability**: Use CRMs to complement the price signals given by the energy market. There is not a need to choose between them, in particular if mechanisms to avoid double payments are implemented.
- **Define capacity to compensate resources for their contribution to system adequacy:** Design CRMs in a technological neutral manner, such that the contribution of all technologies towards a secure power system, including VRE, battery storage, and demand-side resources, is properly acknowledged.

Chapter 6. Retail market regulation

Protecting consumers while encouraging innovation

In liberalised electricity systems, the ways in which wholesale and retail markets interact ultimately has impacts on final consumers, whether large, energy-intense industries, mid-size companies or individual households. Behind the actual trading, the policy instruments that governments use to allocate risks and rewards play a crucial role in determining whether the benefits of liberalised wholesale markets reach final consumers or the scale tips more towards the costs linked to risk becoming an extra burden.

For end consumers, electricity is like many other commodities in that they do not participate directly in wholesale markets but engage with retailers – i.e. intermediaries that purchase the product (in this case, power) and re-sell it. Ideally, the sale price (or tariff) allows customers to satisfy their demand for electricity, while also providing a sufficient profit margin to the retailer.

In the market liberalisation process, many policies transferred the role of managing and allocating risk on behalf of customers to retailers. As such, retailers serve a critical function in the power sector. The clean energy transition is changing the types of risks retailers face, how they must be managed and ultimately, what prices they need to charge. Bringing more variable renewables (VREs) and non-dispatchable resources onto the grid means that some of the new resource is located BTM – i.e. away from the point where retailers are able to track customer consumption.

Recent spikes in electricity prices highlight how they much they are linked to the price of natural gas, and how the current system leaves both retailers and consumers exposed to price volatility on global markets. The energy crisis arising in late 2021 was exacerbated by the sean Federation's ("Russia" hereafter) invasion of Ukraine in early 2022. Both brought more public attention to how the market functions, including its strengths and weak points.

The need to re-examine existing retail regulation is crucial on two levels. Because electricity access is a necessity of modern life, policies should protect consumers who would like to avoid excess exposure to complicated market risks. As well, policies should also encourage system-friendly behaviours that engage customers in ways that can drastically lower their bills. The potential of digitalisation to empower customers to directly participate in balancing the grid (e.g. through smart metering and home devices such as electric vehicle [EV] charging), for example, is promoted as opening up new opportunities but often met with scepticism.

In turn, in light of the large number of retailers that were forced into bankruptcy by recent events, regulation also needs to consider how to support a competitive retail market while not burdening the taxpayers. The delicate and complex balance across these areas is the focus of this chapter.

Why electricity is unique

For most goods, the combination of the choice of multiple suppliers and well-informed consumers is sufficient to ensure a competitive market outcome – i.e. one in which consumers can select a product or service that meets their needs (or preferences) and fits their budgets while retailers earn sufficient profit to keep operating. While both parties may make trade-offs in terms of what they offer or buy at what price, a policy role exists in setting basic standards for quality.

In the case of electricity, several factors complicate the process of establishing clear regulations to ensure consumers have access to choices that fit their preferences while retailers can maintain viable businesses:

- **Storage is expensive:** until recently, electricity storage was limited mostly to hydropower reservoirs. As a result, retailers had to contract with suppliers such that power would be available at exactly the moment of customer demand. While the real-time nature of the system still exists, technologies are being developed that provide storage capacity which can "absorb" excess electricity and release it on demand, lowering the risk of a system imbalance. While prices are declining, storage is a relatively costly commodity that retailers need to reflect in the price they charge to consumers.
- **Volatility**: energy prices vary in relation to expected demand and available supply. In electricity markets, wholesale prices mainly reflect the cost of the most expensive unit needed to instantaneously match grid demand. This price of fuel and the efficiency of the price-setting unit can vary widely in the short run, as fast as five to 15 minutes, and even further in the long term, driving large changes in the market price. Continued reliance on geopolitically strategic natural gas as the price-setting fuel in many markets could lead to even more pronounced electricity price volatility in the future.
- **Lack of real-time response**: in contrast to most markets, where people take an immediate decision to buy or not depending on the product offer and its price, there are few practical ways for consumers to react in real time to wholesale electricity market prices. Typically, they are unaware of wholesale prices and only pay retail bills days or weeks after consuming the product. This creates situations in which consumers may find they consumed electricity at times when the cost to deliver the service may have exceeded the value they feel they derived. Digitalisation, through devices such as smart meters, theoretically increase the

ability of consumers to respond to electricity prices in real time. Some technologies will automate this function in ways that are imperceptible to customers (e.g. smart charging of EVs or programming thermostats and dishwashers to run when prices are lowest).

- **Complex market dynamics**: the above characteristics of electricity create multiple risks that retailers need to hedge against, which requires a certain level of knowledge and skill.

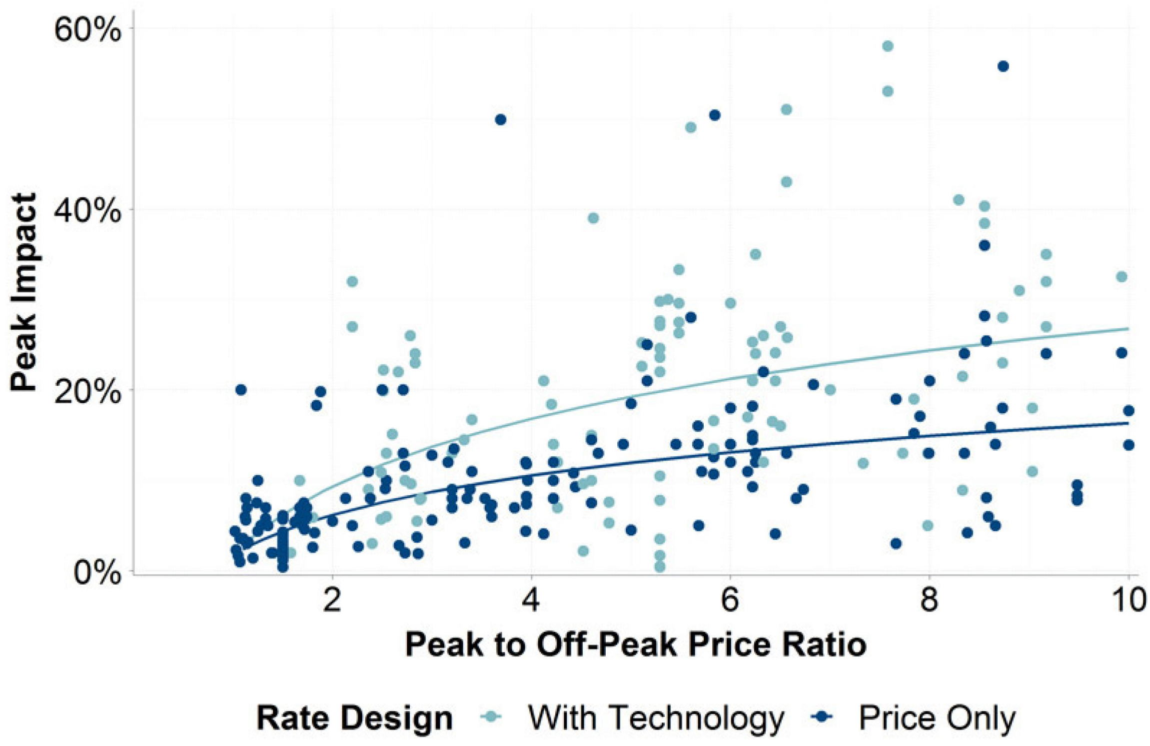
With these factors in mind, policy makers and energy regulators should constantly assess how well current retail market design responds to consumer preferences, including their aversion to risk and willingness to accept price volatility, while effectively using price signals at the margin to encourage behaviours that benefit the system.

Time-varying rates can lower bills and increase system efficiency

There is clear economic rationale behind time-varying rates, which occur in many different forms[1] and have been implemented in jurisdictions including France, the United Kingdom, Italy, Spain, Ontario, Arizona, California and Michigan. Studies show that these multiple pricing options, which in some way raise the price of peak energy relative to other periods, can clearly reduce peak loads – and overall system costs, as a result. The impact has been shown to relate to the ratio between peak and off-peak price, with as much as a 25% expected reduction in peak demand when peak prices are 10 times higher than off-peak.

[1] These include demand charges, time of use rates, critical peak pricing, variable peak pricing and real-time pricing.

Price responsiveness of time-varying rates with and without enabling technology



Source: IEA analysis based on Faruqui Sergici and Warner (2020), Arcturus 2.0: A meta-analysis of time varying rates for electricity.

Capacity subscriptions are another innovative way to introduce real-time price responsiveness while protecting consumers. They are currently under consideration in Norway. Under such schemes, during high demand periods, customers pay a regular energy charge for consumption up to volume defined in their subscription; any additional consumption is charged at a much higher rate. This can be particularly helpful during emergency situations when rationing of electricity might be required. It ensures that all customers can draw upon a basic level of service for critical loads but adds a price penalty for those who over-consume during a time of system stress.

But retail markets should also protect consumers

Retail choice

Allowing consumers to choose their electricity supplier is a fundamental element of liberalised electricity markets. In most markets, large consumers typically benefit from having access to tailored rates that reflect the volume and characteristics of their demand. This might include TOU and seasonal rates adapted to their consumption profile, reduced price variability and consideration of their demand response capabilities. To keep the market competitive and fair, various price (e.g. price caps) and service regulations establish parameters within which suppliers can make these offers.

The efficacy of relying solely on retail choice to enable small consumers to benefit from competition is less clear. Although the entrance of more suppliers has been implemented in many jurisdictions; retail choice has often prompted slow rates of supplier switching. Although this is not by itself a sign of lack of competition, it can take sometimes years for entrant retailers to capture significant market shares from incumbents.

Basic service or default retailers

Within many retail markets, the sub-group of basic service (or default) retailers plays a specific role. Rather than being determined through wholesale markets, their rates (prices) are fixed by regulators. This reflects, in part, that they are usually established to supply certain classes of consumers (e.g. those below a certain consumption threshold).

Regulators need to be deeply engaged to set appropriate rates and address key questions:

- To what degree should basic service retailers be exposed to spot prices?
- What contract duration is needed to protect the basic service retailer from spot prices?
- Should the basic service retailer hedge on fuels linked to electricity spot prices?
- What happens if large gaps arise (either in quantity or value) between demand and the hedging contracts?

In practice, many jurisdictions have hybrid retail electricity systems with a range of regulations. Large consumers, for instance, may be obliged to buy from a competitive retailer while mid-sized consumers have the option to choose their retailer – but are not obliged to. Often, households and small businesses have no choice and are obligated to take supply from a regulated retailer.

For customers that do not choose a third-party retail supplier, the state of New Jersey (United States) offers basic generation service through an innovative auction in which retailers compete on price to serve those customers. This service requires potential suppliers to offer a fixed rate for the generation portion (including energy, capacity and ancillary services) of the customer’s electricity tariff. In the 2023 delivery period, the New Jersey State Board of Utilities offered 54 equal tranches of residential load across the four electricity delivery companies. The auction led to 10 different suppliers winning tranches. In this way, the auction allows small customers to benefit from competition while maintaining the price certainty of fixed rates. To date, the level of uptake in third-party suppliers varies widely by customer type: only 8% of residential load has chosen a tariff from a third-party supplier, compared with 46% of small and 85% of large commercial and industrial customers.

Recent events prompt a re-think of retail market policies in many countries

In 2021, the price of natural gas in Europe (including embedded emissions costs) rose to six times what it was before the COVID-19 pandemic wreaked havoc on economies and energy markets. With gas-fired units being essential for balancing electricity systems across the continent – and generally playing the role of the price-setting producer – rising gas prices triggered higher wholesale electricity prices (even in countries where gas is only a minor share of the electricity mix). In the fourth quarter (Q4) of 2021, wholesale electricity prices in France, Germany, Spain and the United Kingdom exceeded Q4 averages over 2016-2020 period by three to more than four times.

Such increases in fuel and production costs have to be covered across the market system, typically by increasing prices to retailers – who then pass them on to customers – or by building them into charges to taxpayers.

In the recent energy crisis, much of the increase has been passed on to final consumers. From December 2020 to December 2021, electricity prices charged to European households rose by 31% on average. The extent to which these increases have immediately affected households reflects how existing regulations govern retail price setting and whether and how governments intervened to manage the crisis. Household electricity prices in France, where nuclear supplies roughly 70% of generation, rose by less than 10%. In Belgium, Greece and the United Kingdom, household prices increased by over 75%. In the Netherlands, households bills surged by 127%.

As the situation continues to evolve in mid-2022 (at time of publication), it brings to the fore many challenges for regulators not only across Europe but globally. As well as some valuable lessons.

Prudential regulation for retailers

The current crisis has also hit retailers hard. In Germany alone, between the summer of 2021 and 21 January 2022, 38 retailers declared bankruptcy. Since the start of 2021, 30 suppliers in the United Kingdom have done the same. While seeing firms that cannot compete (i.e. deliver goods or services in a cost-efficient manner) exit a market is a feature of effective competition, such a large wave of failures in the electricity supplier market suggests imperfections in the regulatory framework.

Lack of a legal framework to ensure the financial safety and stability of retailers (known as a prudential regulation) has created a context in which retailers can entice consumers with low price offers that are not backed by sound risk management practices. When retailers failed – in the middle of the crisis – their consumers were passed on to a default retailer; with little or no choice in their contracts, these consumers lost their ability to participate in the market and were usually given no compensation. This set of circumstances is a significant consumer protection issue.

When extreme prices get passed on to consumer bills

In February 2021, a record-breaking winter storm hit Texas and other states in the mid-west and southern United States. Historically cold temperatures and high winds hovered over several states for five days straight. Across the natural gas and power infrastructures, energy demand spiked to the degree that it caused outages, hampering supply in a significant portion of the system. In Texas, more than five million people (about 30% of system load) were left without power for up to four days. The unmet electricity consumption caused direct cost to consumers of around USD four billion and total economic cost of at least USD 100 billion. Tragically, the combination of the storm and the energy crisis have been linked to an estimated 700 deaths.

The physical shock across these systems revealed several weaknesses in the regulation of retail markets. As the storm was approaching, the ERCOT, the market operator) anticipated the supply shortage and called on customers to conserve energy (reduce energy demand). The call was only voluntary, not part a formal demand response programme that would involve payments to compensate customers for the value to the system that lower demand would represent. As shortages started to occur and grow deeper, ERCOT was unable to maintain service to critical loads (such as hospitals) on some feeders without entirely cutting off service to other feeders. In turn, it had not included some natural gas facilities as critical loads, which lead to their electricity service being turned off, further reducing the overall capacity to produce electricity. A domino effect ensued, leaving up to five million customers without heat and/or electricity. Lacking any concrete incentive, post-event analysis found the reduction in demand to be negligible.

In parallel, the imbalance between demand and available supply caused the Texas wholesale market to hit the price cap of USD 9 000/MWh, which is typically reached for only a few minutes per year. ERCOT maintained that price for four days, even though the pricing model was outputting lower prices.

While Texas has retail choice, which allows many different types of offers with variable exposure to prices, in this extreme example, some consumers ended up paying a heavy cost for their choice. About 30 000 customers were supplied by Griddy Energy, which offered a tariff consisting entirely of the wholesale spot price (plus a fixed monthly fee of around USD 10). When bills arrived after the storm, they reflected the price cap (USD 9 000/MWh) having been in place for up to four days – and obliged consumers to pay bills that were between 150 and 300 times the average rate.

Final recommendations

Retail market design should fulfil the dual role of encouraging more efficient use of system assets while also protecting consumers – particularly the most vulnerable – from exposure to risk. Various instruments can be applied under three main measures:

- **Develop innovative tariffs to encourage demand-side participation:** significant efficiencies can be gained by creating tariffs (e.g. capacity subscriptions) that involve some exposure to spot market prices but do not create excessive risk.
- **Prudential regulation should be stablished to protect consumers**: Regulation should guarantee that retailers are able to fulfil their contracts with final consumers, in particular when the tariff is meant to provide some rate stability.
- **Enable the use of technology to manage consumption:** policy makers should allocate the responsibility to educate customers on ways to use smart technologies to manage their consumption and be transparent regarding the use of technologies (e.g. grid-friendly EV charging and smart activation of appliances) that operate in ways that are imperceptible to consumers.
- **Protect basic service**: consumers who “opt-out” of the choice to actively manage their consumption should be able to choose fixed tariffs from financially stable suppliers. This can be combined with a mechanism that introduces some form of competition to serve small customers at lowest cost.

Chapter 7. Electricity system planning

Planning creates the framework within which markets operate

Achieving a clean energy transition requires large-scale electrification of many activities that currently rely on fossil fuels. In IEA's Net Zero by 2050 Scenario, electricity demand nearly triples globally and doubles in advanced economies, where it was stable over the last decade. As demand increases rapidly and diversifies, the electricity system will need to adapt. This implies deploying a wider array of clean electricity resources and building out sufficient T&D networks to ensure the system remains in balance efficiently. Both of these need to happen at a scale and pace that is unprecedented in the electricity sector. In short, it requires a massive transformation of electricity systems, led by a vision of a new future and plans to achieve it. Planning must therefore convince market players that sufficient value is available to warrant investment.

Power sector planning is the process by which a selected entity (typically, the system operator) outlines feasible options to meet the future needs for electricity – effectively and efficiently – while working towards stated policy goals for climate and energy. An overarching challenge is that planning must be done looking decades into the future and accounting for how various aspects may evolve. Adequacy studies, for example, seek to determine what resources of what type and located where could be needed to meet system needs a decade (at least) into the future. Transmission planning aims to ensure the grid will be capable of delivering electricity generated by these resources in locations and at times where they create value for consumers, electricity companies and society as a whole.

Planning practices evolve along with reforms in the power sector. In recent decades, in jurisdictions that have decided to liberalise generation and supply, markets and investment frameworks will guide competitive investments. A key role of planning is to provide the framework under which the markets operate. With the clean energy transition now a global goal, the planning process must also ensure that markets design will support policy goals – and identify necessary enhancements to their design.

Traditional energy systems assets are big, have long lifespans and require large investments. This creates several big challenges in a time of transition. First, change tends to happen slowly, in part because it is not technically easy to rapidly change how systems operate and in part because incumbent stakeholders need to recoup past investments.

Second, planning into the future in 2020 is fundamentally different than it has been for past decades. While planners are used to specific types of uncertainty – and indeed to the certainty of errors – with new technologies that operate in different ways and in the context of climate change, the future holds many more sources of potentially greater uncertainty. And the further forward one looks, the greater the uncertainty. Today's planners need to take into account uncertainty in relation to more key features such as the cost of resources and technologies; demand for goods and services; and environmental and geopolitical realities. Even stated policies change as new priorities arise for governments, as illustrated by the recent adoption of an assertive, global decarbonisation agenda.

This chapter examines good practices being developed to execute system planning that takes account of the changing landscape of the power sector and the growing number of uncertainties.

1Planning sets the path for markets and policies

In the past, system planning was largely a technical exercise carried out by a central entity which had a strong, monopolistic position over the power sector. In the current context of an expanding range of resources and assets – and a stronger political agenda to reduce the impacts energy systems have on the environment and climate change – the planning process requires multi-disciplinary expertise. It must take into account a vast number of inputs, with various levels of uncertainty.

While policy objectives and the current market design are the essential inputs to system planning, the desired outputs are a list of the system needs for new resources and flexibility, a plan for grid, and a roadmap to meet these needs. Often, planning maps out several possible future trajectories that could achieve the same end goals.

Planning provides different stakeholders with crucial information that supports their different aims. Market players will base their own planning decisions (for example, to invest) on the system plan, as it informs them about ways to realise profits. Policy makers will assess possible trajectories against their vision of the future system, adjusting or correcting policies and regulations as needed.

Planning is a strategic tool to meet policy objectives

Planning helps decision makers shape the power sector to meet, effectively and efficiently, stated policy goals. Policy goals often span several dimensions that need to be addressed simultaneously, such as expectations of reliability, affordability and climate-related requirements. Ultimately, some choices are strongly driven by long-term policy choices (such as investing in nuclear know-how, developing offshore grids to harness wind resources or mapping out a hydrogen strategy).

Setting policy and system planning is an iterative process: policy goals are key inputs to planning; in turn, the planning exercise provides essential information on options and corresponding costs to meet the policy objectives. Planning provides policy makers with valuable information to adjust policies and possibly increase the ambition of their objectives for the next planning cycle. Experience shows the value of a formalised feedback process between planning, real life operations and policy making.

A recent IEA analysis of the Korean power sector reveals how planning can inform more detailed modelling assessments, allowing policy makers to identify adjustments required to meet the long-term objectives of decarbonisation and security. Under the current framework, wholesale market price signals appear insufficient to attract investment into new dispatchable low-carbon generation. By 2035, Korea's power system will require increased capacity of low-carbon, flexible generation, such as hydropower and batteries, to replace the ageing and decommissioned fleets of coal and nuclear generation and ensure electricity security. The assessment, using long-term scenarios as a base, showed that enhancing wholesale market price signals to account for scarcity pricing and carbon pricing, would align markets and emission goals, thereby creating favourable conditions to enable clean energy technologies to enter the market.

Planning informs market players regarding system needs

For market participants, planning provides critical information needed to assess investment opportunities and risks. This might include data on demand forecasts and the available infrastructure or visibility on policy choices that fundamentally influence the power sector over the long term (e.g. whether to include nuclear in the mix).

In turn, markets support the system through their ability to find efficient solutions to address uncertainties. While the system planner may not be the best qualified to project future costs of technologies, markets can define the value of resources at various moments in time. To this end, the final plan may include options for grid expansion that help capture a wide variety of resources without imposing a specific choice.

Planning supports an evolving set of rules

Planning helps find a balance between the two conflicting objectives of stability and flexibility in the rules governing energy systems. To some degree, it is an exercise in mapping trajectories towards a moving target as many things (technologies, policies, demand, etc.) can change rapidly. Policy makers and regulators have the key role of monitoring such changes and, as necessary, intervening to correct or adjust rules when it becomes clear that the current market design will not deliver the policy objectives.

Markets can be extremely sensitive to policy adjustments, as these may increase risks for investors, so changes must be brought with care. For this reason, it is critical to have governance structures that define the overarching rules of the sector in terms of high-level roles and responsibilities, and explicitly set out the process for adapting rules (including how such changes can be initiated and designed). If processes for reforming rules are too complex, it creates a risk that market design will not be adapted, which may result in barriers that block the entry for new innovations and make system operations more difficult. In turn, this heightens the risk of making the energy transition more costly or even making it impossible for systems to adapt to exogenous changes such as climate change.

Building in mechanisms so that plans can be adapted as circumstances change is vital; that said, enacting reforms too often and too quickly can erode private sector confidence and risks negative outcomes that undermine necessary support. Planners need to manage a fine balance between regulatory certainty and adaptable governance. The engagement of all stakeholders is key to the process for changing rules.

The evolving context is challenging traditional planning approaches …

Uncertainties are growing

Past system planning practices focused on ensuring adequacy of electricity supply to meet demand, which was inherently variable and uncertain to a degree but largely followed well-known, long-term trends. With greater deployment of variable renewables (VRE), digital technologies and distributed resources, the paradigm is shifting. In contrast to traditional operations in which dispatchable generation followed variable load, generation itself has become more variable and uncertain while demand has become more dispatchable. Today, electrification of new end uses and integration of electricity with other sectors (e.g. heating, mobility) expand the scope of the power sector and offer new opportunities. The role of grids continues to evolve, to facilitate competition and allow markets to harness the resources that deliver the greatest value.

The transition needs to accelerate while remaining affordable

The climate agenda has triggered a sense of urgency for decarbonising the power sector, in turn, prompting acceleration in the deployment of low-carbon sources, mainly VRE. Although the cost of VRE technologies has dropped, the pace of deployment depends heavily on grid availability.

Several features of VRE trigger the need to adapt planning practices. For example, locations where wind and solar potential are highest may be remote from load centres. As such, a compromise may need to be made between the value of harnessing wind and solar potential and the cost of developing the transmission grid to deliver it. The absence of a locational signal has prompted China to make huge investments in developing massive infrastructure to bring power from resource-rich areas in the north and west to the cities concentrated on the east coast. Another feature is that VRE plants can be deployed in a few months, much quicker than centralised power plants. In contrast, large transmission projects tend to be slow, mainly because of permitting issues.

… but several good practices are emerging

With power sectors around the world facing similar challenges, several good practices are emerging. When taken together, these recommended practices support development of electricity systems that deliver with a good confidence on policy objectives and at the best value-cost ratio for the whole system, in co-ordination with a wide range of stakeholders and across sectors.

Grid planning should favour investment in locations that deliver best long-term value

In a perfect market, resources compete with each other on a level playing field. In reality, electricity systems will always be limited by physical constraints. Therefore, locational signals play an essential role in identifying the best locations for resources. While markets can provide daily to seasonal locational signals, the volatility of these signals can lead to underinvestment.

Locational signals on a longer term, which should help investors identify the best locations to invest, depend on the transmission system. Indeed, the transmission system is an essential enabler of markets and can be a substitute to building new resources. Policy makers and regulators can use various mechanisms to incentivise efficiency in the choices made to deploy grids and resources. Among others, the approach to transmission charges (the way transmission costs are recovered and allocated among users) can be important.

The push for electrification is, indeed, creating the need for more grids. The roadmap to net zero by 2050 requires – in the decade 2020-30 – multiplying by three the annual investment in T&D grids. Holistic and pro-active grid planning helps assess the full system value of transmission projects over the long term and ensure enough grids are built.

Multi-value, portfolio planning recognises that every grid expansion project may have multiple benefits and seeks to optimise a portfolio of investments across the complete range of needs. Individual projects are selected so that they collectively contribute to increased reliability, satisfy economic and public policy requirements, reduce seams between markets, and enable interconnection of low-carbon resources. This approach brings cost-efficiency and accelerates transmission grid development.

Efficient grid development can anticipate the best way to meet future system needs, rather than reactively responding to a list of interconnection requests from stakeholders. The creation of renewable energy development zones (REDZ) is an example of pro-active, portfolio planning. REDZ are geographical areas with high quality VRE resources where developing clusters of large-scale renewable generation can deliver economies of scale. By developing networks to connect several generation sources at different locations (instead of proceeding project by project), REDZ enable efficient connection of renewables. REDZ also have potential to promote development of locations of high system value – i.e. a set of locations that experience high wind speeds or solar insolation when the system most needs additional generation (e.g. during system peaks). REDZ are being used in several jurisdictions to boost uptake of renewable energy including: the Competitive Renewable Energy Zones (CREZ) in Texas; the Australian Energy Market Operator's (AEMO) integrated system plan in Australia; the Renewable Energy Development Zones (REDZ) initiative in South Africa; and the *Schémas régionaux de raccordement au réseau des énergies renouvelables* (S3REnR) in France. This approach can be applied to both onshore and offshore developments: the ambitious plans of Europe for offshore wind cannot be met without strong co-ordination and the creation of a dedicated offshore grid.

Planners should adopt robust approaches, designed to deal with uncertainties

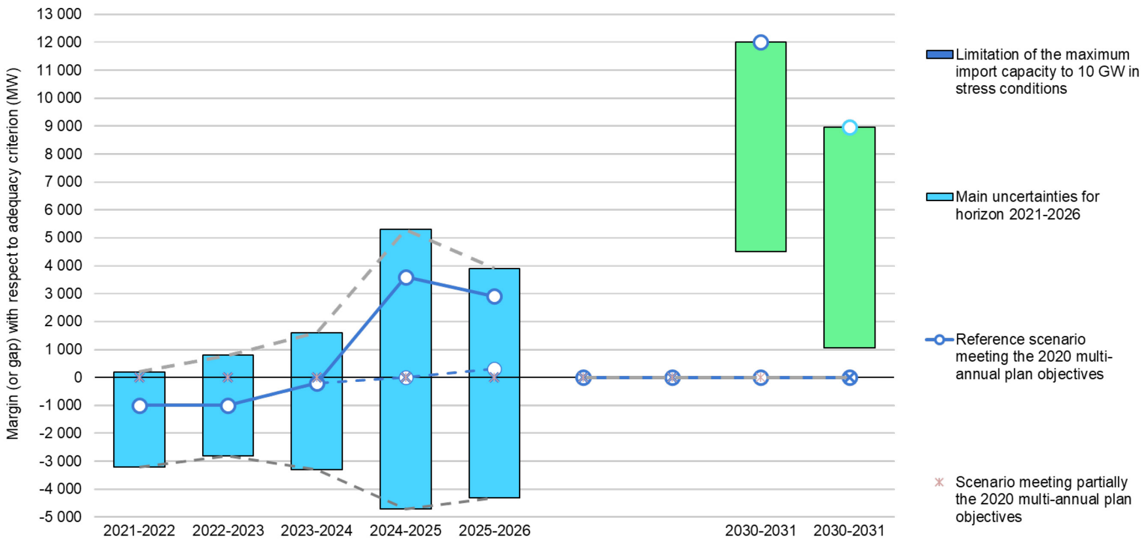
Planners face many uncertainties. Markets, if provided with the necessary framework and information, can help find efficient solutions to address them. The planning process needs recognise both the uncertainties and elements that cannot be fully controlled (e.g. future demand and cost of technologies and resources) and adopt a risk management mindset. Engaging stakeholders early in the process is helpful to understand which uncertainties are relevant. Three tools can then help planners take into account these uncertainties: scenario-based planning, sensitivity analysis and stochastic approaches.

Scenario-based planning uses modelling to consider a broad range of possible long-term futures and real-world conditions. The key benefit of scenario analysis is the ability to capture a plausible range of contrasting, possible futures and identify different challenges to the system inherent in each that need to be addressed. Scenarios can compare among many system attributes, for example contrasting a future with large, centralised renewable plants against one with distributed resources, or assessing the role of a specific technology (such as nuclear or large-scale battery storage). Ranking scenarios according to their likelihood or desirability can further inform decision making.

Sensitivity analysis can be used separately or to complement scenario-based planning. Sensitivities to key parameters (or sets of parameters) are applied to observe how variations to these parameters affect outcomes. Often, they are used to test robustness against specific assumptions. Out of the possible scenarios that meet policy objectives, sensitivity analysis can help identify those deemed robust with respect to the key assumptions that should thus be retained. It also reveals which scenarios should be discarded, for example, if costs or societal consequences become unacceptable outside of a limited domain for the main parameters that are not under control. Typical parameters used in sensitivity analysis include: fuels and carbon prices; the long-term societal cost of emissions; the cost of capital; climate year; load (how energy efficiency performs and the pace of electrification of new uses); phase in/out of specific technologies; and timing of new generation and retiring units (as well as impacts of delays). South Africa, for example, incorporated in its integrated resource plan the productivity of thermal power plants and the consequences of not meeting expected targets.

Stochastic or probabilistic adequacy assessments give more insights for modern power systems as they allow planners to evaluate many uncertainties together. Past planning practices tended to be deterministic. Continuing to use these approaches today would lead to inefficient, conservative outcomes. Stochastic approaches make it possible to determine more accurately the contribution of VRE to the system and to consider rare events with potential large consequences (“tail risks”), such as extreme weather events (e.g. a week of cold weather combined with the absence of wind and sun) or failures due to the growing threat of cyber-attacks. In its long-term adequacy study, RTE (the French transmission system operator [TSO]) considers a range of scenarios and sensitivities with respect to several uncertain parameters and applies a stress test under extreme but realistic weather conditions.

Assessment of French system adequacy for various scenarios, taking into account the main uncertainties



Note: The graph shows the margin (when positive) or gap (when negative) with respect to the probabilistic criterion for meeting system adequacy with market-based mechanisms. The assessment considers several scenarios articulated around the reference scenario issued by authorities in their 2020 multi-annual plan (PPE), as well as sensitivities to address the main uncertainties.

Source: RTE (2021), French long-term adequacy study.

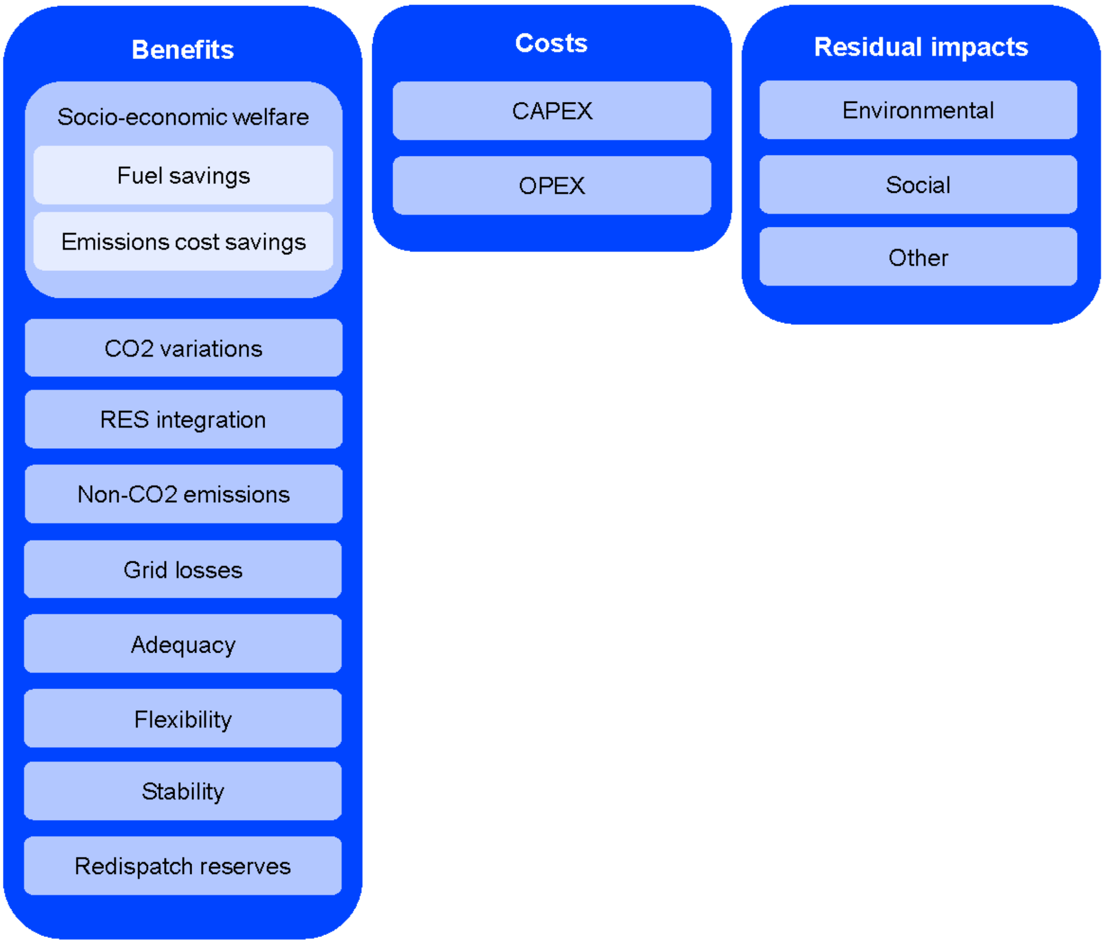
Cost-benefit analysis should promote all cost-effective solutions

As power systems evolve, planning plays a role in promoting all cost-effective solutions. This implies assessing and comparing the value of all investments and resources: grids, energy storage and new central generation, as well as distributed resources (which may include BTM storage), demand response and energy efficiency. In California, the effective load-carrying capacity approach makes it possible to compare the contribution of various resources to system reliability and at which cost.

Cost-benefit analyses (CBA) can ensure optimal economic value of power systems over the long term. It should be noted that project costs are typically independent from scenarios while benefits are strongly related to scenario-specific assumptions. Traditional CBA methodologies or alternative approaches are now being adapted to value all solutions, not only supply-side resources. In particular, it must be possible to compare investments that reduce operating costs and solutions that defer new investments at the expense of slightly higher operating costs. Emerging solutions that fit into the latter category include grid-enhancing technologies, dynamic line rating and flows optimisation software, as do new practices such as ad hoc modulations in VRE generation to avoid building infrastructure that would remain unused for most of the time. A full assessment of benefits must consider many indicators. While economic quantification (or monetisation) can be done in a straightforward manner for some indicators; it relies on strong assumptions for others. The benefit of monetising all indicators is to compare scenarios through a single, financial indicator. Using separate indicators, however, allows policy makers to examine scenarios and solutions according to various perspectives (not necessarily financial) and identify priorities for policies and regulatory initiatives.

The assessment framework for grid development projects used by the European Network of Transmission System Operators for Electricity (ENTSO-E) comprises three main categories: costs, benefits and residual impacts. Within each category, it assesses a number of simple and robust indicators according to a methodology consistent with European policy objectives. In adopting a combined cost-benefit and multi-criteria matrix to assess projects, this methodology ensures a consistent assessment of trans-national transmission and storage projects in Europe.

The ENTSO-E framework for grid development project assessment



Note: Residual impacts refers to the impacts of investments that are not addressed by any of the identified mitigation measures contained within the cost category. This ensures that all measurable costs associated with projects or investments are taken into account and that no double accounting occurs between any of the indicators.
Source: ENTSO-E (2021), 3rd Guideline for cost benefit analysis of grid development projects.

Mandate transparency and stakeholder engagement, as both benefit the planning process and competitive investments

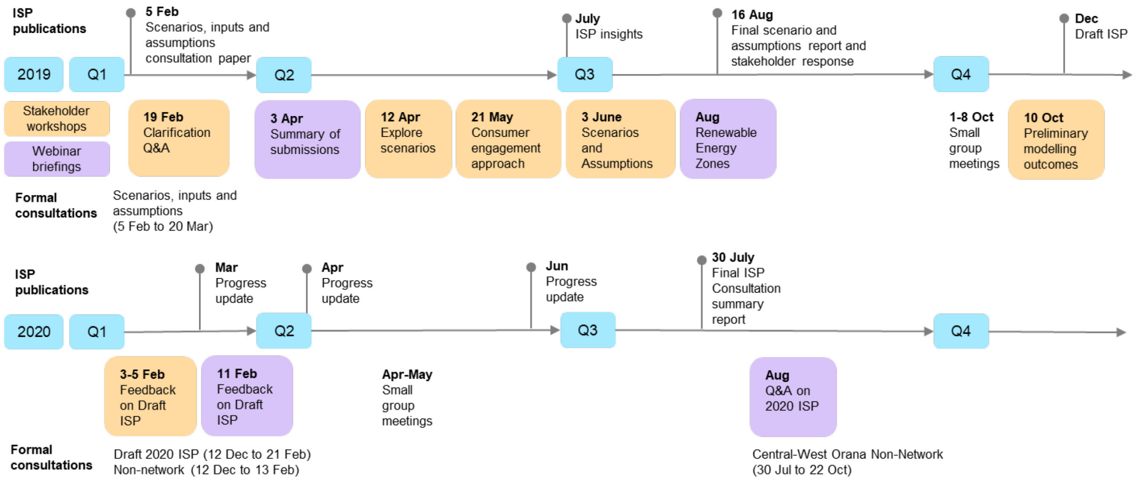
Public and stakeholder consultations – in conjunction with consultation of relevant authorities – allow the interests of all interested parties to be considered, thereby improving the quality of the planning process. In gathering a wider range of expertise, such consultations increase transparency, minimise conflicts of interest for the party leading the process and increase buy-in of the outcome. This is increasingly important as the transformation of electricity systems that will drive the energy transition needs to be centred around people.

The Argentinian electricity reform of 1992 (Law 24065) was one of the first policies to involve grid users (at the time, generators, distribution companies and large consumers) in a project of grid expansion planning to connect a group of remote generators to load centres located hundreds of kilometres away. Innovative at the time, the public contest approach stimulated economic awareness and enabled more efficient decision making. Under this approach, the system operator identified beneficiaries of transmission projects and distributed costs according to the "beneficiary pays" principle. In turn, the operator assigned voting rights to major grid users in proportion to each of their proposed participation costs. Expansion projects were approved only if at least 30% of votes were in favour and no more than 30% of votes were opposed. The stakeholder engagement was successful, and criticism of the process focused mainly on the method of identifying project beneficiaries.

As power systems become more complex, larger and more diversified, it becomes impossible for a single entity to perform the planning work or design markets in isolation. The process now requires the support and scrutiny of many stakeholders with different perspectives. In this complex environment, stakeholder engagement is beneficial across the complete planning cycle. Generally, stakeholder engagement is well received but organisers must take care to use efficiently the time and expertise of participants. Diverse formats and platforms may facilitate participation from a large audience. Opportunity to provide feedback on the process is necessary (for example, commenting on the periodicity of information webinars, duration of formal consultations) to improve for the next exercise, as illustrated by the evaluation mandated by the Public Utility Commission in California.

Planners should be mandated to engage with stakeholders, with consultations from early stages (e.g. the proposed policy objectives and targets) and at key moments such as the collection of inputs, definition of planning scenarios, preparation of key methodologies (e.g. CBA), and interpretation of results. In Europe, to support implementation of main legal requirements, the energy law requires TSOs to co-host with the regulatory agencies a range of stakeholder committees with periodic meetings. In Australia, in preparing the integrated system plan (ISP), the AEMO must follow a stakeholder engagement programme that includes multiple public stakeholder workshops, webinars and two formal written consultations.

Comprehensive stakeholder engagement programme of AEMO for its 2020 integrated system plan



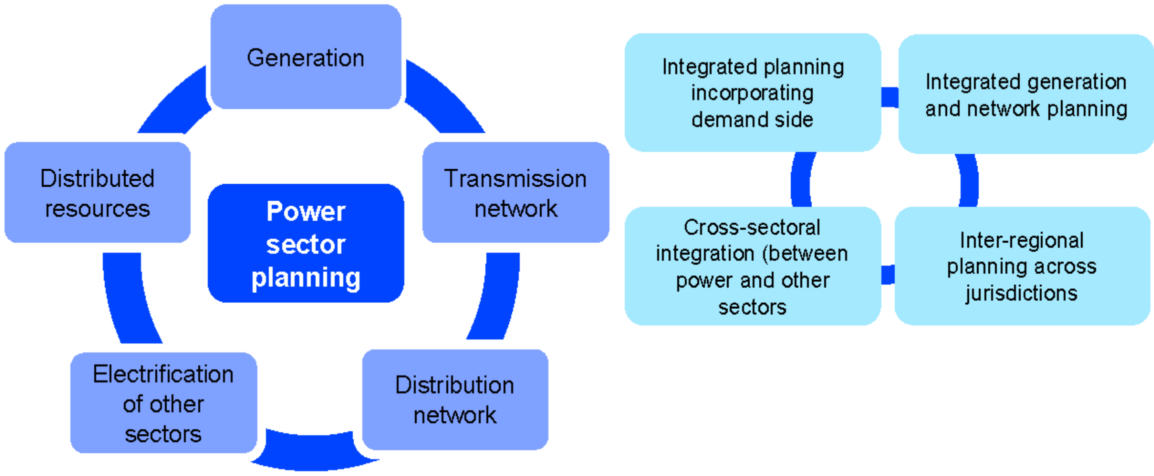
Source: AEMO (2020), Integrated System Plan – stakeholder engagement.

Integrated and co-ordinated planning should be central to designing future energy systems

In unbundled power systems, regulated T&D networks are typically managed by utilities that are separate from entities participating in competitive activities (generation, aggregation, trade and supply). As they have distinct yet interdependent activities, lack of alignment between these separated entities may lead to sub-optimal planning.

In order to identify appropriate options for future power systems and maximise their economic value for consumers, integrated and co-ordinated planning frameworks address together the functions of generation, T&D networks, demand-side and electrification of other sectors. Such frameworks aim to harness the benefits of both competition and co-optimisation of grids and resources (including, in a broad sense, demand). With the aim of breaking silos within the sector and between sectors, integrated and co-ordinated planning can take several forms, but all share the ability to consider a wider range of solutions to meet future needs for system flexibility.

Major components of power sector planning and various forms of co-ordinated and integrated planning approaches



Source: IEA (2017), Status of power system transformation and IEA (2018), Thailand renewable grid integration assessment.

The first, obvious form of integration and co-ordination is to plan and co-optimise generation and transmission, as illustrated by REDZ. The next step is to consider demand as integral to the plan rather than as an input. The Integrated Resource Plan in California is a good example in that it assesses the cost of reaching a specific emissions level while considering demand and BTM resources as active system components. As distribution grids host a growing share of generation and play a more active role, co-ordination of T&D planning takes into account the variety of flow patterns and the potential of demand-side management to defer or avoid investment in generation and networks. In Europe, a pan-European DSO entity was recently launched, with one of its main tasks being to promote co-ordinated planning of DSO/TSO networks.

Electrification of end uses, such as mobility and heating, increases demand for electricity but also offers new opportunities. Cross-sectoral planning across electricity sectors and other sectors enables the emergence of new solutions to secure the needed future system flexibility. EVs with smart charging can, for example, be used to provide flexibility and facilitate VRE integration – by charging during periods of high VRE output and supplying to the grid when output declines. In light of dependency on natural gas supplies, Europe's Ten-year Network Development Plan (TYNDP) has, since 2018, been published jointly by ENTSO-E and European Network of Transmission System Operators for Gas (ENTSOG) (respectively, the associations of TSOs for electricity and natural gas networks).

Finally, planning across different regions, jurisdictions and balancing areas is critical to optimising the use of resources – and is particularly beneficial with the increasing share of VRE. Europe's TYNDP is a prominent example of regional co-ordination in transmission planning in that it assesses all large-scale storage and transmission projects across Europe. Projects of Common Interest (PCIs) are selected according to their contribution to European policy goals and will benefit from accelerated licensing procedures, improved regulatory conditions and some access to financial support. Interregional planning in the United States and among the Association of Southeast Asian Nations (ASEAN) are other examples.

Integrated and co-ordinated planning must not be confused with central planning

While different and distinct from central planning, integrated and co-ordinated planning retains the benefits of planning the whole system, rather than planning grids separately. In central planning, a single entity elaborates and executes the plan while an authority (a ministry or an independent regulator) approves the plan and develops a strategy for recovery of costs – often through tariffs applied to energy consumers. In contrast, integrated and co-ordinated planning is a collaborative framework that involves a large number of stakeholders ranging from traditional energy sector actors to independent businesses and civil society groups. The entity leading the process is given a mandate by authorities to collect data, perform calculations, organise stakeholder consultations and deliver results to the public and policy makers. Ultimately, the leading entity's main role is to present cost-efficient pathways that meet the policy goals and provide clear signals to stakeholders as to where investments are needed and valuable.

Comparison of two holistic system planning approaches

	Central power sector planning	Integrated and co-ordinated system planning
Leader	A company that owns the assets	A selected entity with a neutral role, ideally with no conflict of interest
Inputs sources	Own data/models, complemented with data collection from selected stakeholders with essential inputs to the process	Virtually unlimited, from a broad range of sources (whoever wishes to contribute) that may have conflicting interests
Objectives	Meet legal requirements (reliability, sustainability) and balance sheet constraints or shareholders return	Meet climate and energy policy objectives and maximise overall market benefits at reasonable risk

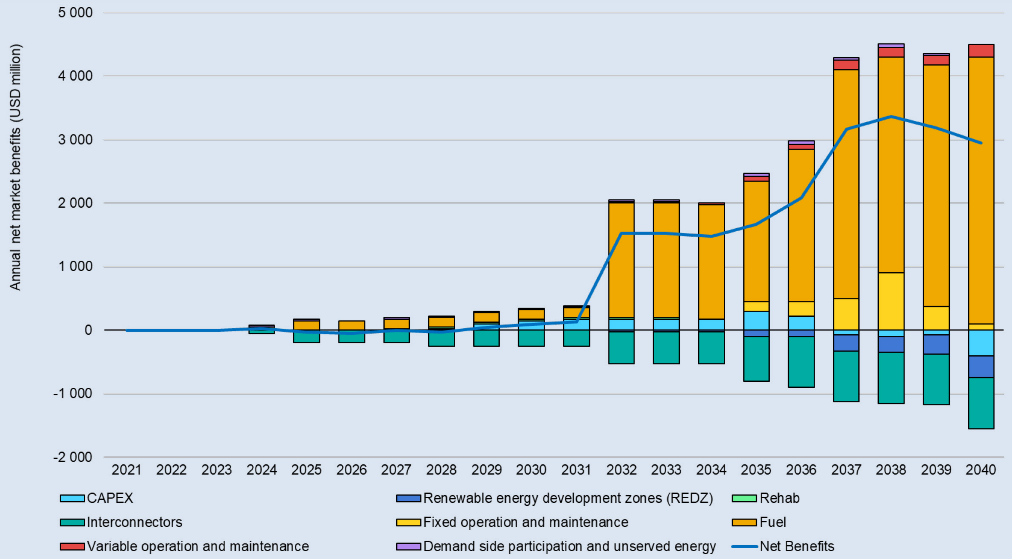
	Central power sector planning	Integrated and co-ordinated system planning
Outputs	A plan focused on investments	Several outputs to guide decisions of policy makers and market players
Transparency	Assumptions and details may be restricted, with only headlines made public	Stakeholder consultations to develop scenarios, select sensitivities and challenge assumptions; results made public and open to debate

AEMO's integrated system plan (ISP)

With the express aim of maximising value to end consumers, the AEMO in Australia has put into practice its ISP that seeks to design the lowest cost, secure and reliable energy system capable of meeting any emissions trajectory determined by policy makers at an acceptable level of risk. This approach serves the regulatory purpose of identifying actionable and future projects, as well as the broader purpose of informing market participants, investors, policy decision makers and consumers. It provides a transparent, dynamic roadmap over a planning horizon of at least the next two decades, optimising net market benefits while managing the risks associated with change. The AEMO published the inaugural ISP in 2018 and it is updated every two years.

Many alternative investment decisions may be able to meet future system requirements. The AEMO assesses all options, using CBA to identify the least-cost development path for each scenario. To optimise the economic value of the power system, the net present values (NPV) of all candidate developments are compared to a baseline and to each other over the full planning horizon. Finally, the ISP delivers a roadmap with pre-established decision milestones (or signposts) to confirm the need and timing of considered major transmission projects according to circumstances that may change in the meantime.

Assessment of the NPV of a selected trajectory



Note: The green line represents the net benefits of the proposed development path. FOM: fixed operation and maintenance cost, VOM variable operation and maintenance cost, DSP+USE: demand-side participation and cost of unserved energy, REZ: estimated cost of increasing hosting capacity of future renewable energy zones.
Source: AEMO (2020), Integrated system plan – cost benefit analysis.

Final recommendations

Within market-based power systems, planning plays a key role in providing information for decision making by policy makers and stakeholders. As decarbonisation of energy systems must accelerate, planning practices are evolving towards more holistic approaches that aim to engage all stakeholders, creating a framework within which markets operate to attract private investments and deliver efficiencies.

For planning to serve its purpose of supporting effective and efficient decision making, the following key recommendations should be considered:

- **Apply a holistic approach:** planning should strategically consider the whole power system and how all assets – generation, T&D, and demand – need to work together and interact with other sectors.
- **Carry out detailed cost-benefit analysis:** taking account of the costs and values of all technologies and options facilitates comparison – on equal grounds – of all cost-effective solutions.
- **Identify and address all uncertainties:** by using multiple scenarios, assessing sensitivities to key assumptions and adopting stochastic approaches, planners can adopt a risk-based mindset that appropriately considers the many

uncertainties of future systems, including exogenous risks such as extreme weather events.

- **Consult all stakeholders, early and often:** the complete planning process should be transparent and include extensive stakeholder engagement to capture the many benefits diverse expertise and experience brings to planning and markets.
- **Establish governance structures with adaptation in mind:** planning frameworks should include a formalised feedback mechanism that covers planning, policy making and market design and a clear process for adapting rules as needed to meet decarbonisation goals

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