Korea Electricity Security Review

A joint report with the Korea Energy Economics Institute

International Energy Agency

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Abstract

This report, commissioned by the Korean Ministry of Trade Industry and Energy and written jointly by the International Energy Agency and the Korea Energy Economics Institute, examines current conditions and future opportunities to ensure electricity security and system flexibility with higher shares of variable renewable energy in Korea. The report examines the objectives from the 9th Basic Plan for Long-term Electricity (BPLE) in terms of energy demand and variable renewable energy deployment, and provides options to maintain the country's current high level of electricity security, while integrating increasing shares of solar PV and wind. Taking into consideration the existing institutional and market structure, the analysis first looks into how flexibility needs may evolve in Korea's power system and suggests technical options to satisfy these requirements making use of flexible generation, storage, demand-side flexibility and grids. The report then looks at key aspects of operational security and long-term planning, both recognising current progress in terms of grid and market code updates as well as suggesting improvements to the long-term planning process, through for example integrated resource planning. The report suggests market design improvements that can be implemented within the current framework, considering price formation mechanisms and integration with the existing emissions trading scheme. Finally, the report examines key aspects of climate and cyber resilience, suggesting improvements that can be integrated into long-term planning to ensure resilience across the whole value chain.

Acknowledgements

This report was jointly prepared by the International Energy Agency and the Korea Energy Economics Institute at the request of Korea's Ministry of Trade Industry and Energy. It includes findings based on the objectives set out in the 9th Basic Plan for Long-term Electricity (BPLE), international experiences and policy options to improve system flexibility for higher shares of VRE.

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Executive summary

Around the world energy transitions are driving up the participation of renewable energy in electricity systems and increasing electricity's share of total final energy consumption. According to the IEA Sustainable Development Scenario, the share of electricity in total final energy consumption is projected to increase from around 20% today to more than 30% by 2040. Objectives for greater deployment of hydrogen in energy systems will also rely on additional electricity demand.

These developments require policy makers to think about electricity security, which is the power system's capability to ensure uninterrupted availability of electricity by withstanding and recovering from disturbances. The IEA looks at electricity security from three angles: adequacy, operational security and resilience. These three building blocks underpin each section of this report.

Jointly written by the IEA and the Korean Energy Economics Institute (KEEI), at the request of the Ministry of Trade, Industry and Energy, this report looks at electricity security in Korea's power system in light of the ambitious goals set out in the 9th Basic Plan for Long-term Electricity (BPLE) and, more recently, the New Green Deal. These include an increase in the share of new and renewable energy (NRE) generation from 7.4% today to 20% in 2030 and 30-35% in 2040. NRE includes hydro, oceanic, biogas, landfill gas, fuel cell and IGCC energy sources, in addition to solar PV and wind.

Furthermore, the 8th and 9th BPLEs foresee a reduction in the share of nuclear power in power generation between 2020 and 2034 and a ban on new coal-fired generation. Given Korea's history of a diversified and secure electric system, this report addresses the main considerations for ensuring electricity security through the following components: future flexibility requirements, operational security, long-term planning, market improvements, and cyber and climate resilience.

Flexibility

The first outcome foreseen from the country's long-term objectives is a shift from dispatchable to non-dispatchable generation. Between 2019 and 2030 the share of dispatchable generation is expected to fall from 94% to 79%. This shift in the energy supply accompanies a sustained increase in electricity demand of 0.6% per year, and a 1.1% yearly increase in peak load. The increase in NRE generation, of which the variable sources solar PV and wind comprise 70%, will significantly alter the generation matrix. Moreover, attaining the annual share of variable renewable energy (VRE) planned in the 9th BPLE will bring about significant changes to the power system's operation, notably from more frequent and much higher levels of instantaneous penetration of VRE generation. By 2030, based on an initial analysis, it could reach around 70% of the system load, similar to the current maximum penetration levels in Texas, Spain and the United Kingdom.

According to initial analysis of the objectives of the 9th BPLE, by 2030 Korea's power system will see an increase in its flexibility requirements. This can be appreciated from the evolution of the system's net load and changes in the three-hour and one-hour ramping requirements. For example, the maximum upward daily three-hour ramp is expected to increase from 20 718 MW in 2019 to 35 435 MW in 2030. The maximum three-hour downward ramp increases from 12 941 MW to 25 483 MW over the same period. Overall, the maximum ramping requirement is expected to be around 50% of the system load. This is moderate compared to power systems like California and India, which can see ramps as high as 60-70%, but these systems have more interconnections with neighbouring systems than Korea.

A number of options are available to meet Korea's increasing flexibility requirements; they include making use of the latent flexibility in existing assets as well as deploying new technologies. For example, operational guidelines and market rules – including enhanced compensation for reserves and other balancing services like ramping capability – could be updated to enable the flexible operation of coal and nuclear plants. Taking advantage of the existing technical capabilities of Korea's thermal fleet may require regulatory and market updates to provide better signals.

Different storage technologies could contribute to meeting Korea's increased flexibility requirements. For storage to be effective, it is important to understand the connection between the technologies' ability to provide flexibility and the value to the system of various storage durations. For example, battery storage currently has a better case for very short-term to short-term flexibility, pumped storage hydro (PSH) can cover hourly to daily requirements, and power-to-gas technologies can serve the country's longer-term flexibility requirements. Improvements in remuneration mechanisms are needed so that the full value to the system, and not simply the avoided fuel costs, is recognised.

Demand-side flexibility is also expected to play a key role in serving the system's flexibility needs. While some industrial capacity already takes part in specific voluntary and mandatory load reduction programmes, widening participation to smaller customers will be important. Electric vehicles (EVs) could make a significant contribution, but to ensure participation it will be critical to improve the price signal provided to users through retail rates.

Operational security

System-friendly deployment of variable renewables will be essential to ensure the operational security of Korea's power system. This involves considering the technology mix between different VRE resources, managing their geographical spread and enabling their participation in the provision of system services (from frequency regulation to voltage, etc.). One option is to co-ordinate network development and VRE deployment, as done with renewable energy zones (REZs), particularly given the plans for offshore wind deployment and current grid constraints.

Improving the visibility of VRE generators and the quality of generation forecasts is important for maintaining operational security and mitigating the cost of VRE integration. Improving the grid code is fundamental to ensuring that all assets, from VRE to distributed energy resources, are correctly equipped and all market participants share their forecasts and real-time data with the system operator on time. Korea has already taken significant steps to update its grid code, but it is important to continuously review and update it to account for both technological change and emerging system requirements.

Decreasing system inertia may start to become a challenge at higher shares of VRE or in specific regions with high concentrations of VRE. The solutions range from the most technically mature, such as maintaining a minimum of conventional generation or installing synchronous condensers, to introducing mechanisms to enable synthetic inertia from VRE or developing grid-forming converters. There is a growing body of experience globally on technical solutions to strengthen systems with a high penetration of converter-based assets. Deployment strategies should consider the technical and economic implications.

Long-term planning

Better long-term planning will be needed to ensure adequacy and operational security with higher shares of renewables. For example, assuming that load patterns remain consistent, VRE deployment is expected to shift the system peak later into the evening as well as increase it by around 10 GW by 2034. Additionally, while Korea has already introduced probabilistic planning to some extent, it may be helpful to introduce more detailed analysis of more diversified scenarios that account for, among other factors, climate-related extreme events and VRE or load variability.

One of the main developments enhancing electricity system planning is making use of multiple reliability indicators rather than a single indicator. It is important to account for all dimensions of outage risk, such as average frequency, volume of energy not served and frequency of extreme events. This approach is vital to understand extreme as opposed to average events.

Developing an understanding of the economic impact of outages – across consumer groups, regions and times of the year – will be an important step to guide investment in the system once a set of reliability targets is defined. For policy makers this can provide an indication of the options that might be worthwhile, ranging from new programmes for demand-side flexibility to investments in flexible system resources.

Integrated resource planning will become an increasingly important tool for co-ordinating the development of the power system. While there is currently a degree of integration, better outcomes can be achieved by combining traditional generation and transmission planning with more sophisticated models that account for different scenarios of distributed energy resource deployment, distribution network development and electrification of new end uses. Such plans can be carried out in an indicative way, such that they allow for market dynamics while improving system efficiency in the long term and providing certainty to investors.

Market improvements

Improving market design will be an important element of maintaining and enhancing Korea's high level of electricity security. This requires effective regulatory oversight to ensure competitive markets that are transparent, fair and flexible enough to adapt to a changing energy landscape. Such developments should account for both technological progress and changes in consumer preferences.

High-level improvements to market design include: strengthening mechanisms to ensure that market participants share data; enhancing price formation mechanisms so they reflect not only technical constraints, but also the value of scarcity; and improving the link between the existing emissions trading scheme (ETS) mechanism and price formation in the wholesale market.

Cyber and climate resilience

On power system resilience, Korea has taken good first steps both in respect of climate resilience and cybersecurity. For example, on climate resilience the power system's long-term energy plans have strong proposals for infrastructure to mitigate future impacts, but it is important to embed climate adaptation measures in power system planning. Accounting for the greater incidence of harsher extreme weather events, such as heatwaves, extreme rainfall and more frequent typhoons, will be essential to safeguard the continuity of electricity supply in Korea.

On cybersecurity, it is important to build on existing mechanisms to protect national security and critical infrastructure, and reinforce mechanisms that apply specifically to the power sector and secure the whole value chain. While significant steps have been taken at the bulk power system level, it is important to introduce practicable security guidelines at the grid edge and for connected IoT devices. Finally, policy makers need to strike the right balance between prescriptive and more flexible regulatory requirements, recognising both the rapid evolution of technological development and potential threats, as well as the international nature of cybersecurity threats.

Chapter 1 – Electricity security developments in Korea and globally

Electricity security in a changing landscape

Korea has built a diverse and reliable electricity system largely based on thermal generation, both from nuclear and fossil fuels. The current long-term energy goals set a path towards a more diversified energy matrix, but also one that is increasingly decarbonised and decentralised. Diversification of the generation matrix can contribute to improving energy security, but also requires changes to the way the system is operated and planned, particularly in the context of greater shares of VRE such as solar PV and wind. Additionally, changes on the demand side, in overall electricity demand growth, electrification of energy demand – such as transport and heating – and increasing interconnectivity, add new possibilities to ensure electricity security.

In the long term this presents a paradigm shift, from matching electricity supply to a set energy demand projection, to co-ordinating all system resources – generation, grids and load – as part of the process of power system transformation.

This, however, raises the question: how can the system continue to be operated reliably and cost-effectively in the future with greater decentralisation, decarbonisation and digitalisation? Policy makers have an active role to play in striking the right balance between reliability and cost-effectiveness when they legislate for electricity security, and need to take into account the social and economic impacts of electricity supply interruptions.

In addition to a changing electricity mix, policy also needs to address potential cyberattacks and the implications of climate change. These may require changes to market design, institutional roles and technology requirements. Drawing on experience from other jurisdictions, this report provides guidance to policy makers on the changes that may be needed to manage the transition in Korea's power system.

Electricity security: What do we mean?

Electricity security is the electricity system's capability to ensure uninterrupted availability of electricity by withstanding and recovering from disturbances and contingencies. It can be understood through three main properties:

1. **Adequacy** is the ability of the electricity system to supply the aggregate electrical demand within an area at all times under normal operating conditions. Power system flexibility is a critical element of adequacy as it allows the system to constantly balance supply and demand using system resources with the right capabilities to satisfy the load. This report discusses a number of planning and market instruments that can achieve flexibility and therefore adequacy.
2. **Operational security** is the ability of the electricity system to retain a normal state or to return to a normal state after any type of event as soon as possible. An important consideration here is balancing or frequency reserves. These are closely linked to forecasting, visibility and reserve requirements. Another dimension is system stability and strength from the more conventional perspective of physical resilience. This report addresses current practices in operational security and how they may be improved as part of the transition in Korea's power system.
3. **Resilience** is the ability of the system and its component parts to absorb, accommodate and recover from both short-term shocks and long-term changes. In this report, we particularly look at a new set of challenges for system security stemming from cyber and climate security.

Energy transitions around the world

A decarbonised power system will require a much greater contribution from VRE

Over the past decade, global awareness of the need to mitigate climate change and greenhouse gas (GHG) emissions has increased, gaining momentum with the adoption of the Paris Agreement in 2015. A combination of technological advancement, the falling costs of clean energy technology (particularly solar PV and wind) and policy support have created favourable conditions for a low-carbon energy transition.

Between 2010 and 2019 the global installed capacity of solar PV increased significantly from 40 GW to 603 GW, and wind capacity grew from 181 GW to 623 GW (IEA, 2020a). However, energy demand is expected to keep growing. The IEA Stated Policies Scenario (STEPS) projects a 9% growth in total energy demand between 2019 and 2030. Within this, electricity demand is expected to outpace growth in all other fuels, reaching 21% of final energy demand in 2030 in the STEPS and close to 35% according to the Sustainable Development Scenario. By 2030 renewable energy sources – including solar, wind, hydro, biomass and marine energy – are expected to meet 40% of the world's electricity demand according to the STEPS. However, keeping track with the SDS projection, renewables' share of electricity generation is expected to reach 80%, with solar and wind alone delivering 50% (IEA, 2020b).

At the same time advanced economies will see one-third of their coal-fired capacity and one-fifth of their nuclear fleet being retired in the next decade under the STEPS, reducing the amount of dispatchable capacity available in their systems (IEA, 2019). These retirements will be partially compensated for by additional gas plants as a flexible resource that can be dispatched in relatively short time frames and with a lower carbon footprint compared to coal and oil alternatives.

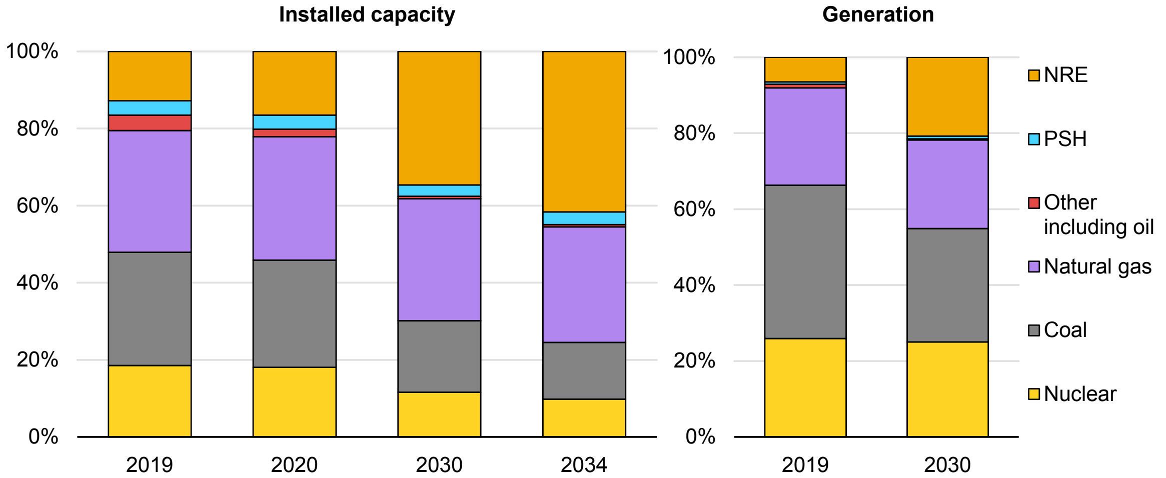
A large increase in distributed energy resources is another important aspect of the energy transition with implications for electricity security. One element of this is the growth in distributed generation, especially distributed solar PV, which has an effect on both the power system as a whole and at the distribution level in particular. In addition, the growing "smartness" of loads resulting from electrification (for example EVs) creates an important opportunity for the demand side to actively provide system services that help to maintain electricity security. Distributed energy resources such as batteries can be deployed as grid assets.

In many regions system operators have sought interconnection with neighbouring systems to increase security and eventually bring down overall system costs. Larger interconnected electricity systems allow for the smoothing out of variability in demand and generation from solar PV and wind.

Korea's electricity objectives

Korea has set a target of reaching carbon neutrality by 2050 by substantially increasing the share of renewable energy sources in its electricity supply, gradually phasing out coal, significantly improving energy efficiency and fostering the country's nascent hydrogen industry.

Figure 1.1 Evolution of installed capacity and generation according to 9th BPLE



Note: Korea uses new and renewable energy (NRE) for the classification of energy sources and national targets, which includes solar PV, wind, hydro, oceanic, bio/landfill gas, by-product, fuel cell and integrated gasification combined cycle energy sources. Solar PV and wind are the most prominent technologies in this group.

As renewable generation increases, the share of dispatchable generation is expected to decrease from 94% in 2019 to 79% in 2030.

The growth in variable renewables is spurred by the government's ambitious plan to increase renewables in power generation to a 20% share by 2030, leading to a 30-35% target in 2040. The country's 9th Basic Plan for Long-term Electricity Supply and Demand (BPLE) foresees an increase in the share of renewable capacity from 15.8% in 2020 to 40.5% in 2034. Korea's long-term energy targets relate to new and renewable energy (NRE), a category bringing together many technologies. However, solar PV and wind are the most prominent technologies in this group. This energy transition requires the rapid uptake of VRE from 16.1 GW today to 51.7 GW in 2030 and 70.5 GW by 2034.

While coal-fired generation has maintained a share of over 40% in electricity generation in Korea in recent years, increased awareness of GHG emissions and local air pollution have led the government to pursue a policy of reducing coal-fired generation. Installed coal-fired capacity is expected to decrease from 35.8 GW to 29 GW by 2034. The 9th BPLE also includes the conversion of 24 coal-fired plants to natural gas, significantly increasing gas-fired capacity by 16.8 GW in the next 15 years.

The rise in the share of renewables comes partly as a result of the plans to gradually phase out nuclear generation, as laid out in the 2017 Energy Transition Roadmap. The government decided not to extend the life of existing reactors beyond their initial design lifetime and to add no further installations beyond the plants currently under construction. According to the schedule for retirement and addition of new nuclear plants, as stated in the 9th BPLE, between 2020 and 2034 installed nuclear capacity is expected to decrease by almost 17% from 23.3 GW in 2020 to 19.4 GW by 2034.

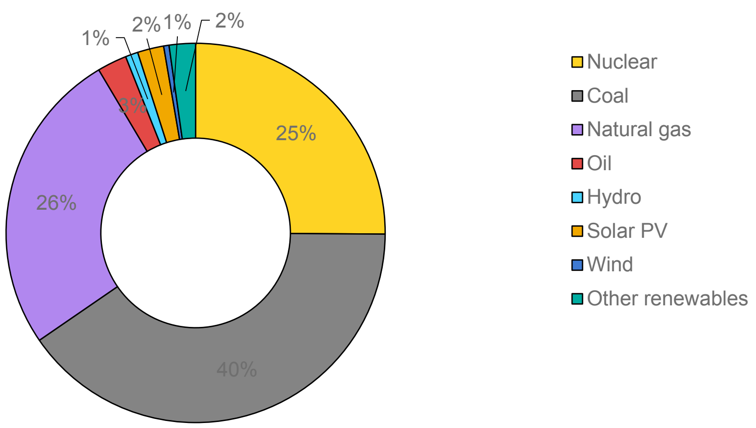
Looking ahead, electricity demand is expected to grow at an annual average rate of 0.6%, with peak demand growing by 1.1% according to the 9th BPLE. The growth rates are the result of demand-side management objectives covering improvements in energy efficiency, demand response and emerging technologies such as smart charging of EVs. Demand-side management is projected to lower peak demand by 12.6% from the business-as-usual level, leading to peak demand of 102.5 GW by 2034.

Overview of Korea's electricity sector

Current generation mix

Korea's total electricity generation amounted to 581 TWh in 2019. Korea currently relies mainly on fossil fuels and nuclear power for electricity generation. Coal is the largest source with a 40% share, followed by 26% from natural gas and 25% from nuclear power (Figure 1.2). By contrast, NRE accounted for 6% of annual generation, with solar PV and wind supplying around half of that amount. The growth in generation from solar PV and wind has accelerated in the past five years, especially solar PV generation, which has grown fivefold since 2014 (IEA, 2020c). In the coming years solar PV and wind capacity is projected to rise from 11.8 GW and 1.5 GW respectively today to 28 GW and 7 GW by 2024 (KEA, 2020a; MOTIE, 2020). This is substantial in the context of Korea's overall generation fleet today of about 129 GW.

Figure 1.2 Share of electricity generation by source, Korea, 2019



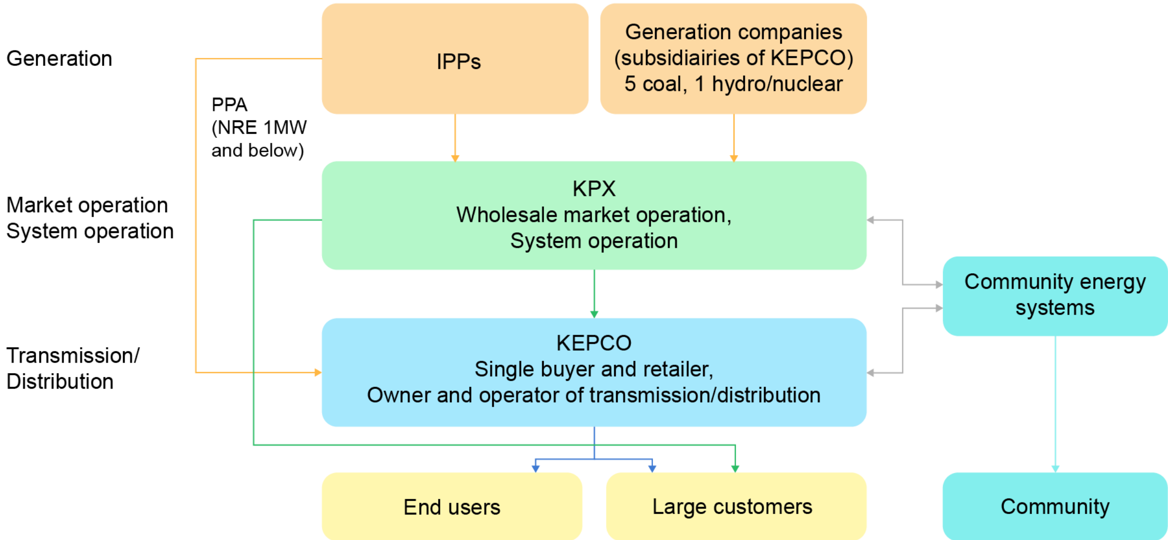
Source: IEA (2020c), *Electricity Information 2020* (database), https://www.iea.org/data-and-statistics/data-tables?country=KOREA&energy=Electricity&year=2019.

Fossil fuels currently account for the majority of electricity generation in Korea

Current market structure

The Korean electricity market is characterised by a day-ahead wholesale market run by Korea Power Exchange (KPX), and a regulated monopoly, Korea Electric Power Corporation (KEPCO), controlling the transmission, distribution and retail of electricity to end consumers. Korea's electricity is generated by independent power producers (IPPs) and subsidiaries of KEPCO.

Figure 1.3 Korea's electricity market structure



Source: KEPCO (2013), Structure of Korea's electric power industry, https://home.kepco.co.kr/kepco/EN/B/htmlView/ENBAHP001.do?menuCd=EN020101, (accessed 29 January 2021).

Korea's electricity market is characterised by 6 KEPCO generation subsidiaries, IPPs and KEPCO as the single buyer.

KPX operates the wholesale electricity market, the power system and real-time dispatch in Korea. In the day-ahead wholesale market, KPX carries out daily demand forecasts for the next day on an hourly basis according to generators' declared availability. The market is structured as a cost-based pool. Scheduling is done on an hourly basis and KPX is in charge of settling any imbalances in real time.

Generators comprise six wholly owned subsidiaries of KEPCO and numerous IPPs. Of KEPCO's generating subsidiaries, five own most of Korea's coal and natural gas plants and one, Korea Hydro & Nuclear Power, runs all the country's hydro and nuclear plants. In 2019 power plants with a capacity of 121 GW participated in the wholesale market, with KEPCO's six generation companies operating 69% of the registered capacity in the market. Among IPPs, 20 companies operate 21 GW of installed capacity and 3 442 producers of renewable energy registered 5 GW (KPX, 2020). Below is the breakdown of capacity traded in the wholesale market by fuel type.

KEPCO owns and operates the transmission and distribution system. As the de facto single wholesale buyer and only retailer in the country, KEPCO buys electricity from KPX and supplies it to end users. While it is possible for large businesses to buy directly from the wholesale market, there are no actual cases of this, reflecting the price advantage when buying from KEPCO.[1] In some selected cases, large consumers are able to diversify their supply by installing own generation on site.

Certain IPPs have long-term power purchase agreements (PPAs) exclusively with KEPCO. There are currently two PPA contract types: NRE producers with installed capacities below 1 MW, and conventional generation from combined-cycle gas turbine (CCGT) or co-generation plants. It should be noted that large thermal IPPs have not been allowed to enter new PPAs since 2001 and are expected to leave the market eventually. Regarding remuneration and market participation, PPA units are not settled against the wholesale market price, but rather against the prices set in bilateral agreements with KEPCO. In 2019, 9 274 MW of capacity was traded through PPAs.

Table 1.1 Installed capacity by contract type in 2019

<table>
<tr><th rowspan="2"></th><th colspan="2">Wholesale market</th><th colspan="2">PPAs</th></tr>
<tr><th>Type</th><th>Capacity (MW)</th><th>Type</th><th>Capacity (MW)</th></tr>
<tr><td rowspan="6">Conventional technology</td><td>Nuclear</td><td>23 250</td><td rowspan="3">CCGT</td><td rowspan="3">1 476</td></tr>
<tr><td>Coal</td><td>37 456</td></tr>
<tr><td>Natural gas</td><td>38 875</td></tr>
<tr><td>Oil</td><td>3 479</td><td rowspan="3">Co-generation (community energy system)</td><td rowspan="3">325</td></tr>
<tr><td>PSH</td><td>4 700</td></tr>
<tr><td>Other</td><td>4 623</td></tr>
<tr><td rowspan="4">Renewables</td><td>Solar PV</td><td>3 411</td><td>Solar PV</td><td>7 446</td></tr>
<tr><td>Wind</td><td>1 562</td><td rowspan="3">Wind, small hydro and other renewables</td><td rowspan="3">26</td></tr>
<tr><td>Hydro</td><td>1 795</td></tr>
<tr><td>Other renewables</td><td>1 972</td></tr>
<tr><td></td><td>Total</td><td>121 123</td><td>Total</td><td>9 273</td></tr>
</table>

Sources: KPX (2020), *Electricity Market Statistics 2019*, http://epsis.kpx.or.kr/epsisnew/selectEkifBoardList.do?menuId=080401&boardId=040100; KEPCO (2020), Electricity Statistics (2019.12) https://home.kepco.co.kr/kepco/KO/ntcob/ntcobView.do?pageIndex=2&boardSeq=21046002&boardCd=BRD_000097&menuCd=FN05030101&parnScrpSeq=0&categoryCdGroup=&regDateGroup1=.

[1] Large consumers buying directly from the market need to pay the system marginal price (SMP) plus capacity payment, ancillary services and transmission fee, whereas KEPCO is able to buy baseload generation at prices below SMP due to the adjustment coefficient.

Current policy support for variable renewables

Under the Electric Utility Act, renewables in Korea enjoy guaranteed purchase and priority dispatch, with KEPCO being the main off-taker for VRE output. Small-scale VRE installations – under 1 MW – can participate via PPAs, selling directly to KEPCO. Indeed, 61% of solar PV capacity in Korea is under PPA contracts. While renewables in the wholesale market are paid the hourly system marginal price (SMP) for their hourly generation, renewables under PPAs are remunerated ex-post on a monthly basis according to weighted average SMPs.

Aside from PPAs, small-scale VRE sources can sell directly to KEPCO through net-metering arrangements for installations dedicated to self-consumption. For solar PV this is available for installations under 1 MW, whereas the threshold is 10 kW for other renewable sources. KEPCO's net-metering scheme is structured as either a cash payment, based on the average annual SMP, or a rolling energy credit, which is remunerated on an annual basis. Additional schemes for small-scale solar PV generation include 20-year feed-in tariff contracts for individual generators under 30 kW and for special producer types such in agriculture, fisheries, livestock or co-operatives under 100 kW.

Renewables are able to obtain additional income through the country's Renewable Energy Certificate (REC) scheme, which awards RECs on a per-MWh basis. Under the Renewable Portfolio Standard, RECs can be traded on the spot market, or through long-term auctions that combine both an REC price and an agreed SMP strike-price. The current Renewable Portfolio Standard scheme requires power producers with an installed capacity greater than 500 MW to increase their share of renewable generation to 10% by 2022, to be proven by the presentation of RECs. Companies can either generate renewable energy themselves and receive RECs, or buy RECs from other renewable producers. In the first half of 2020 the total amount of RECs auctioned under long-term contracts was around 1 207 MW, which was 49% of the additional investment in renewable capacity in the same period (KEA, 2010; 2020b).

Korea's REC mechanism assigns different weighting factors to different technologies and installation types to ensure the balanced development of renewables. Up until 2020 the highest REC weighting factor of 4.0 was applied to hybrid energy storage systems with solar PV or wind generation in order to limit network impacts. This scheme will be gradually phased out starting in 2021. By contrast, rooftop solar PV under 3 MW is given a weighting factor of 1.5 for every MWh of generation.

Table 1.2 Current REC weighting scheme in Korea

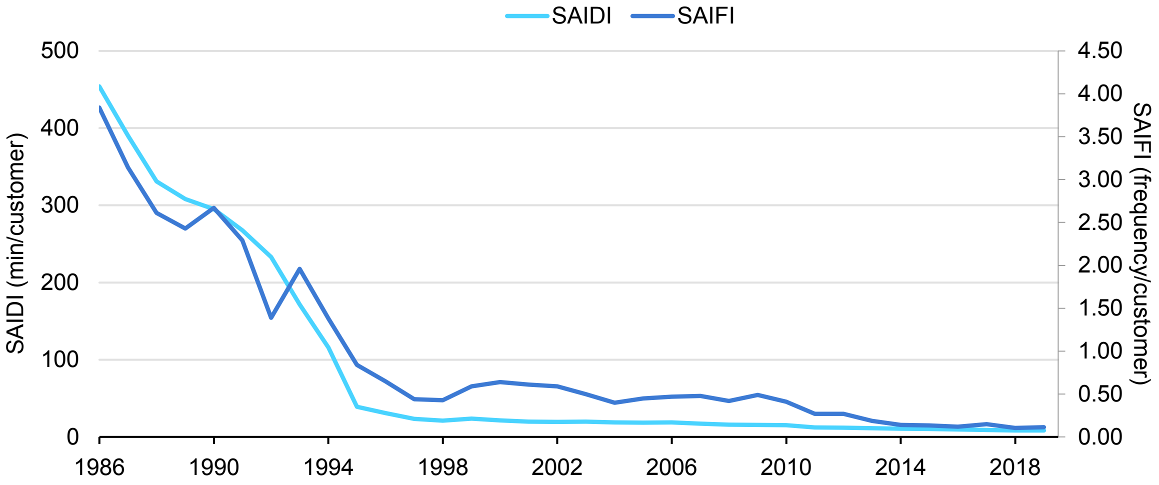
Category	REC weighting factor	Installation type	Other criteria
Solar PV	1.2	Installed on general site	Less than 100 kW
	1.0		More than 100 kW
	0.7		More than 3 000 kW
	0.7	Installed on forest land	–
	1.5	Installed on existing buildings	Less than 3 000 kW
	1.0		More than 3 000 kW
	1.5	Floating on the water	
	1.0	Self-consumption PPA solar PV	–
	5.0	ESS connected to solar PV	2018–June 2020
	4.0		July–December 2020
Wind	1.0	Onshore wind	–
	2.0	Offshore wind	Grid connection within 5 km
	2.5		5–10 km
	3.0		10–15 km
	3.5		More than 15 km
	4.5	ESS connected to wind	2018–June 2020
	4.0		July–December 2020

Note: ESS = energy storage system.
Source: KEA (2010), *Renewable Portfolio Standard* (in Korean), https://www.knrec.or.kr/business/rps_guide.aspx, (accessed 29 January 2021).

History of reliability

Korea enjoys one of the most reliable electricity supplies in the world. The power system indicators – SAIFI (system average interruption frequency index, frequency/customer) and SAIDI (system average interruption duration index, minutes/customer) – illustrate how Korea has continuously improved the reliability of its power system. KEPCO has been responsible for managing SAIFI and SAIDI and other indexes representing the level of power quality since 1980 and has strived to improve the reliability of supply. Its efforts included reinforcing old facilities, establishing a predictive maintenance system and deploying high-efficiency equipment. In particular, the deployment of a distribution automation system since 1997 has helped reduce outages significantly through automatic fault location, isolation and restoration (KEPCO, 2019).

Figure 1.4 Historical trend of SAIFI and SAIDI in Korea, 1987-2019



Source: Information provided by KEPCO.

The quality of supply in Korea is one of the highest across OECD countries, with the system average indicators for the duration (SAIDI) and frequency (SAIFI) of interruptions improving continuously since the 1990s.

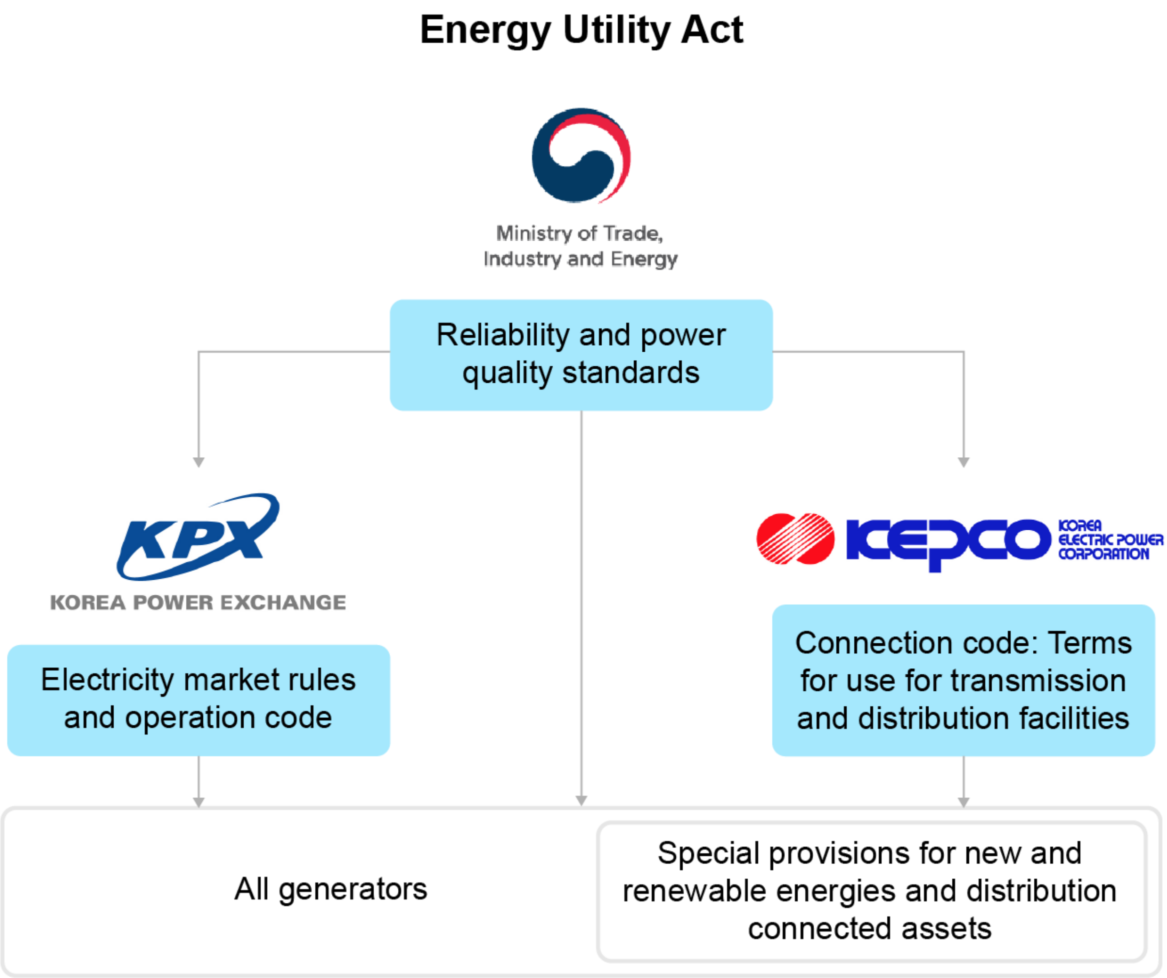
Institutional framework of Korea's electricity sector

In Korea the Electric Utility Act is the basic foundation that governs the responsibilities for electricity security. Under this law, the Ministry of Trade, Industry and Energy (MOTIE) is in charge of setting long-term energy targets through the BPLE. The process involves defining reliability requirements such as the capacity reserve rate, defined as a percentage of installed capacity, to ensure stable supply at times of peak demand.

The short-term reliability requirements are defined in the grid code, and multiple actors control different aspects of supply security. MOTIE is responsible for setting reliability standards that apply to all actors in the power system by issuing legal notices. KPX has market rules in place that regulate the wholesale electricity market. As KPX is also responsible for system operation and real-time dispatch, an operational code (i.e. minimum levels of operational reserves) is written in as part of the market rules. KEPCO controls the connection code and sets reliability requirements for power plants' connection to the transmission and distribution lines. When KPX and KEPCO want to make changes to their grid codes, they have to propose them to MOTIE for approval. Review processes must be completed before the approval of the minister is granted: the Electricity Regulatory

Commission (KOREC) reviews every reform proposal, and if necessary, the Council for Power System Reliability organised by MOTIE reviews it before KOREC conducts its review.

Figure 1.5 Legal and regulatory framework for Korea's power sector



Source: Information provided by KEPCO.

Governance of Korea's power sector is governed by the Energy Utility Act, through MOTIE, with additional market rules, grid codes and connection codes implemented by either KPX or KEPCO

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Chapter 2 – Evolving system flexibility requirements

Power system flexibility is crucial for ensuring electricity security in modern power systems and for a successful clean energy transition; it represents the key characteristics for handling variability and uncertainty on the system. Driven in many regions by a higher share of VRE in electricity generation, power system flexibility is becoming increasingly important for policy makers and system planners to consider.

The flexibility of a power system is its ability to modify or buffer electricity production or consumption in response to variability, expected or otherwise. Flexibility can refer to the system's capacity to change power supply and demand as a whole or within a particular unit. In the energy sector, resources that can provide power system flexibility include generation (both conventional and VRE), electricity grids, storage assets, demand-side management and sector coupling. There are various types of system flexibility needs that vary either on a time dimension or on a geographical dimension.

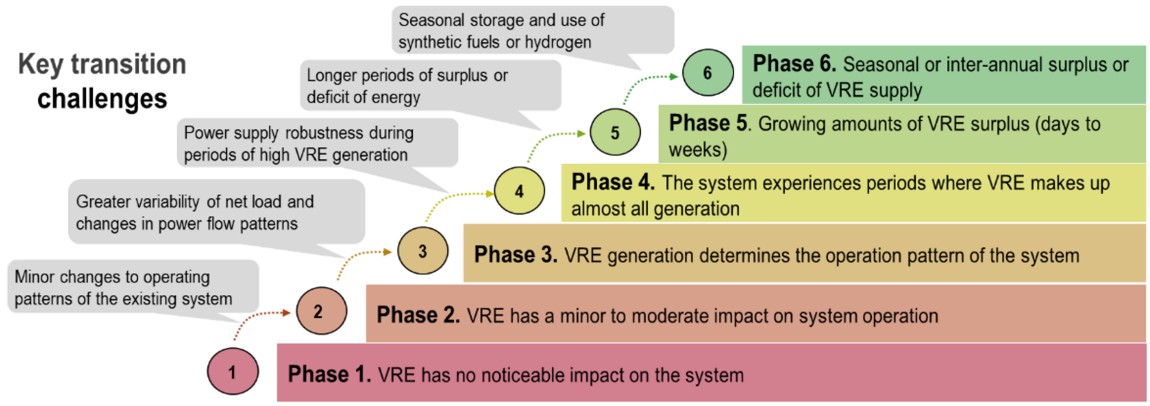
Local flexibility requirements are becoming increasingly pronounced in areas seeing significant penetration of renewables or new electrified loads such as electric heating or EVs. Time wise the power system's flexibility needs vary from very short term to very long term. While these needs have always been a feature of power systems, they are evolving and increasing with changes in the generation mix, patterns of electricity consumption and the power system's exposure to weather variability.

Different phases of VRE integration

Because there are a number of aspects involved in determining the system's flexibility needs, beyond simply the share of variable renewables, the IEA has developed a phase assessment framework to understand the typical sequence of challenges as they appear and how they can be addressed in order to allow for greater shares of VRE. The integration of VRE can be classified into six phases. The usefulness of this simple categorisation comes from the fact that the possible integration challenges can be segmented. While a system will not transition sharply from one phase to the next, the phased categorisation framework can help to prioritise institutional, market and technical measures.

During the first three phases of renewables integration, where the share of VRE are still relatively low to moderate, it is likely that the system can be operated reliably by implementing changes to operational practices at existing power system assets. Issues related to flexibility will emerge gradually in Phase 2 before becoming the hallmark of Phase 3. Beyond Phase 3, VRE output represents the majority of electricity demand in certain time periods, which requires grid-wide reinforcement to improve the ability of the grid to cope with short-term disruptions that affect system stability.

Figure 2.1 VRE integration phase assessment



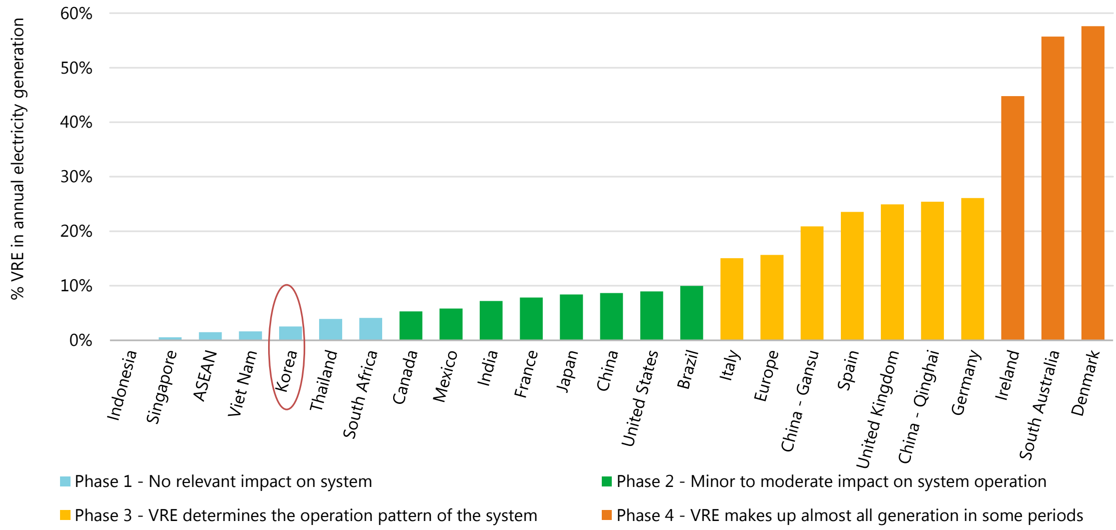
Source: IEA (2019a), Status of Power System Transformation 2019: Power System Flexibility, https://www.iea.org/reports/status-of-power-system-transformation-2019.

There are various phases of VRE integration, each of which comes with different flexibility challenges. They depend on the share of VRE and also its match with the load profile and the degree of interconnection.

Most systems are still in Phases 1 to 3 and have up to 10-20% share of VRE in annual electricity production. The general trend is clear that higher phases of system integration are forthcoming in most countries. Many countries are expected to enter Phase 4 in the coming years. Some steps that need to be taken are operational in nature, particularly from Phase 4 as the system faces multiple periods with high levels of VRE generation. Isolated systems, such as that in Korea, face greater challenges in integrating VRE compared to countries that are well interconnected with neighbouring systems. While any system has its unique characteristics and legacy, exchange of best practices can support progress in many regions.

The annual share of VRE provides a general picture of a country's VRE integration phase. The share of VRE in Korea in 2019 was around 3%, and VRE generation has only started to become noticeable to the system operator in Phase 1. Further flexibility requirement analysis is presented in the next section.

Figure 2.2 Annual VRE share and corresponding system integration phase in selected countries/regions, 2019



Korea is currently in Phase 1 of VRE integration, but understanding the experiences of countries at higher integration phases, and evaluating their applicability, will help achieve the country's energy transition targets.

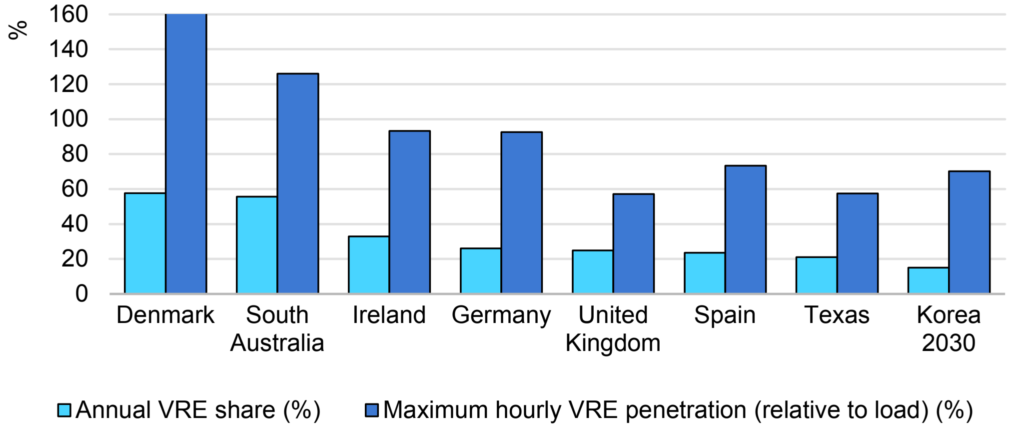
Korea's flexibility requirements towards 2030

Higher penetrations of VRE will have an impact on the combined variability and uncertainty that the entire power system needs to cope with. As system-wide variability needs to be actively balanced, and VRE is not typically dispatchable, VRE output is often subtracted from the demand profile to form what is known as a net load curve.

With VRE penetration anticipated to be around 15% by 2030, Korea is expected to experience a significant change in the variability of net load, with both the profile shape and magnitude changing as a result of the increasing number of hours with high instantaneous penetration of VRE. Hourly VRE penetration in Korea may increase to a maximum of 70%, with greater variability of the net load profile.[1]

[1] For this section the current VRE profiles were scaled up using 2019 data from KPX, based on the projected increase in installed capacity from 2019 to 2030. Capacity assumptions for solar PV and wind for 2030 have been taken from the 9th BPLE (33 981 MW and 17 679 MW respectively). To align VRE output with the 2030 target in the 9th BPLE, 1 GW of onshore wind and 11.2 GW of offshore wind have been simulated using the weather data in selected locations. Load forecast for 2030

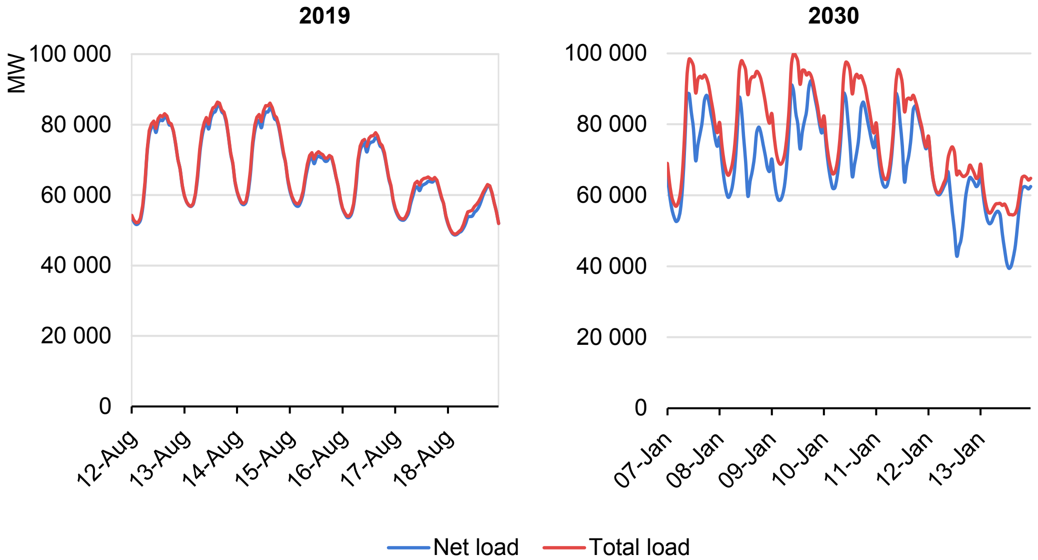
Figure 2.3 Annual and maximum hourly VRE penetration in Korea (2030) and selected countries (2020)



Sources: Based on data from ENTSO-E (2020), ENTSO-E Transparency Platform; EIA (2020), EIA Independent Statistics and Analysis; AEMO (2020), Market Data NEMWEB.

Simplified analysis reveals that reaching the country's VRE deployment objective by 2030 can lead to maximum instantaneous penetration of VRE of up to 70% of load.

Figure 2.4 Load and net load profiles during peak demand periods in Korea, 2019 and 2030



Note: The load profiles in 2019 and 2030 represent different periods of the year. It should be noted that in 2019 peak demand occurred on 13 August, while the load projection in 2030 has a winter peak according to the assumptions in the 9th BPLE.
Source: IEA analysis based on KPX data.

has been performed by Plexos, taking load growth assumptions from the 9th BPLE (0.6% load growth per year during 2020-2034 and 1.1% peak load growth per year in the same period). Further assumptions related to the current generation of solar PV under PPAs or limitations on the estimation of wind capacity factors, in the context of a simplified simulation, explain the difference between the simulated numbers and those expressed in the 9th BPLE.

Looking at net load ramps is a useful way to understand the variability in the system and corresponding flexibility requirements. Other important indicators include minimum net load and the gap between minimum system load and peak load. With increasing variability of net load, the power system will have greater ramping requirements across different timescales (from sub-hourly to multi-hourly). In 2019 the highest hourly upward ramp in Korea occurred during the morning at around 9 200 MW (equivalent to 153 MW/minute), which accounted for just 11% of the daily peak demand. The peak hourly ramp is expected to increase to 16 500 MW (275 MW/min) in 2030, or 18% of the daily peak demand. The increase is also expected in maximum 3-hour ramping requirements, especially the ramp down requirement in 2030, which accounts for 51% of the daily peak. Reduced load growth, such as slower demand recovery following the Covid-19 pandemic, could also imply even higher renewables shares and increased ramps.

Such ramping requirements are still relatively moderate and can be managed by making effective use of all system resources. By comparison, in systems such as India and California, 3-hour ramp rates can be as high as 60-70% of the daily peak demand due to the increasing penetration of solar PV in the system. However, more detailed analysis may be required to understand the exact implications of such ramping requirements given that Korea's power system is smaller, less meshed and less interconnected than power systems like those in India or California.

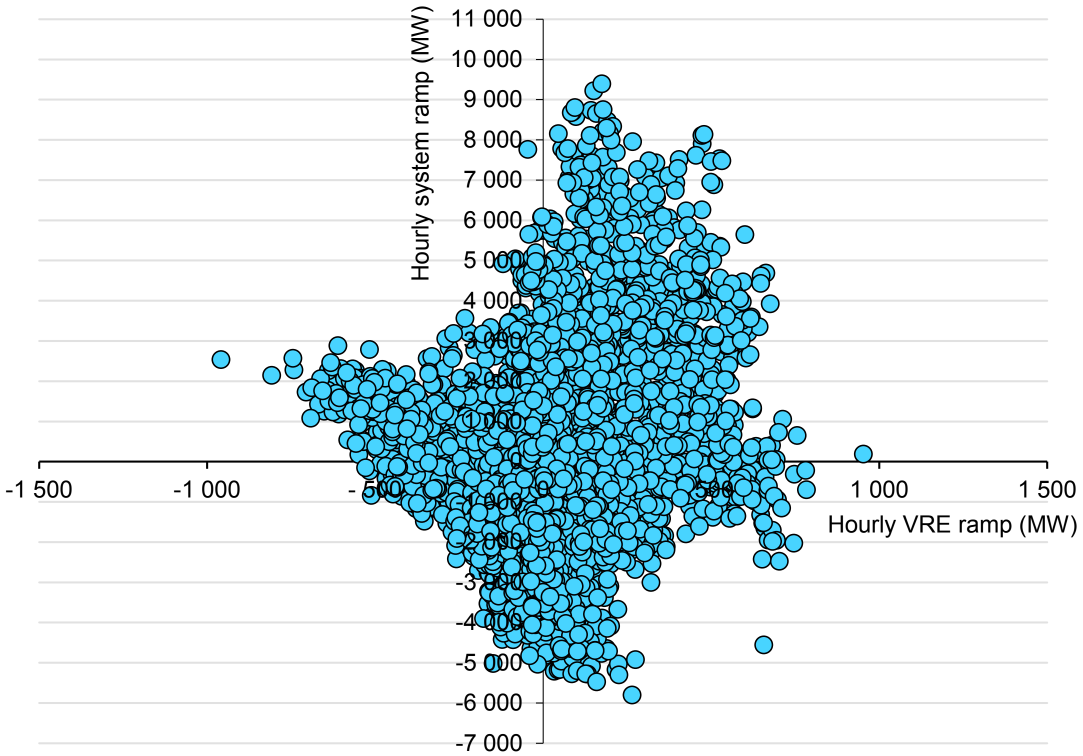
Table 2.1 Ramping requirements in 2019 and 2030

	2019		2030	
	1 hour	3 hour	1 hour	3 hour
Max daily ramp up (MW)	9 223 MW	20 718 MW	16 492 MW	35 345 MW
Season	Summer	Summer	Winter	Winter
Time	Weekday 8-9 am	Weekday 7-10 am	Weekday 8-9 am	Weekday 6-9 am
Period (%) of daily peak	11%	25%	18%	39%
Max daily ramp down (MW)	-6 058 MW	-12 941 MW	-12 076MW	-25 483 MW
Season	Winter	Summer	Winter	Winter
Time	Weekday 12-1 pm	Weekday 10 pm-1 am	Holiday 9-10 am	Holiday 8-11 am
Period (%) of daily peak	8%	15%	24%	51%

The correlation between the timing of VRE outputs and demand patterns is a key factor that influences the integration of VRE into the system, particularly at high shares of VRE and in an island power system, such as Korea's, which cannot rely on interconnection capacity.

Taking 2019 as a basis, output from Korea's current VRE generation increased with load in 56% of hours. By contrast VRE output decreased as load increased in 23% of hours. These particular hours are the ones that will be most critical for integration at high shares of VRE. In the future it will be important to understand geographically where VRE is most likely to develop and how the generation profile in these areas correlates with the load.

Figure 2.5 Scatterplot of hourly ramps of VRE output (x-axis) and system load ramps (y-axis)



Note: Each blue dot represents the intersection of the load ramp and the VRE ramp in each specific hour.
Source: IEA analysis based on KPX data.

Currently load and VRE ramp in the same direction in 56% of hours, whereas VRE output ramps down with upward load in 23% of hours. Managing these latter hours will become more critical at higher shares of VRE.

With the growing amount of VRE in the power system, conventional power plants, which are the main source flexibility, will need to provide more flexibility to system. However, battery storage and demand response are emerging as critical sources of flexibility (discussed in a later section).

Existing and potential flexibility resources to facilitate VRE integration

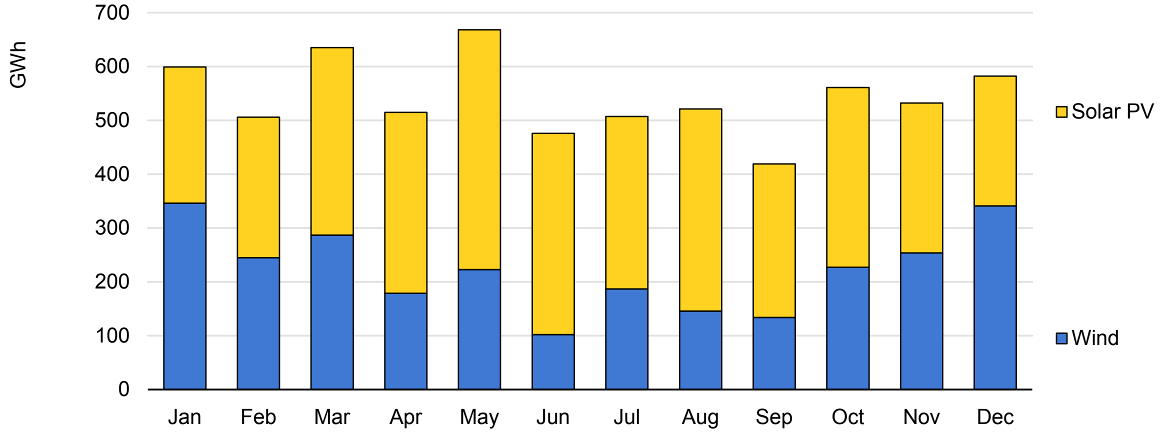
System-friendly deployment of VRE

System-friendly deployment is a key component of cost-effective and reliable integration of variable renewables. The measures that make the deployment of VRE more accommodating from a system perspective (or “system friendly”) are related to the VRE **technology mix**, **geographical spread** of VRE and **location** of VRE plants. The optimal strategy will depend on country-specific circumstances.

The portfolio effect of aggregating different renewable generation technologies can lead to a lower need for overall system flexibility due to their different but complementary profiles. Solar and wind generation patterns are often negatively correlated, hence the rate of export to the grid of either technology will be higher or lower at different times of the day and vary across seasons. This means that simply summing their rated generation capacity may result in an overestimation of the grid hosting capacity needed to accommodate a mix of wind and solar power plants. While it may be logical in the case of conventional power plants with very high capacity factors (such as coal and nuclear), it is less so with VRE plants whose output depends on weather conditions and is, on average, lower than their rated maximum output. Here, however it is important to study the specific seasonality, or day-night variation patterns, in each specific power system to understand the extent to which solar PV and wind may be complementary.

In Korea the overall solar PV and wind output appear to be complementary across the year (Figure 2.6). For example, during winter when there is low solar output, wind plants tend to generate more compared to other seasons. Such portfolio effect is not limited to just wind and solar, but takes advantage of the diversity of the system and ensures that the variability of one plant, be it thermal or renewable, is less prominent in the system.

Figure 2.6 Monthly generation of solar PV and wind power output in Korea, 2019



Source: IEA analysis using KPX data.

Solar PV and wind generation in Korea show seasonal complementarity, with wind generation being greater in winter months and solar PV output greater in summer months.

With the growing share of VRE, the geographical spread of renewable energy plants is another important element to smooth the aggregated output of VRE plants, since different parts of the systems are likely to experience different weather conditions at the same time. When more renewables are added at different locations, the portfolio effects will smooth the overall output variability of VRE plants collectively and potentially lower total forecasting errors (further discussed in the next chapter).

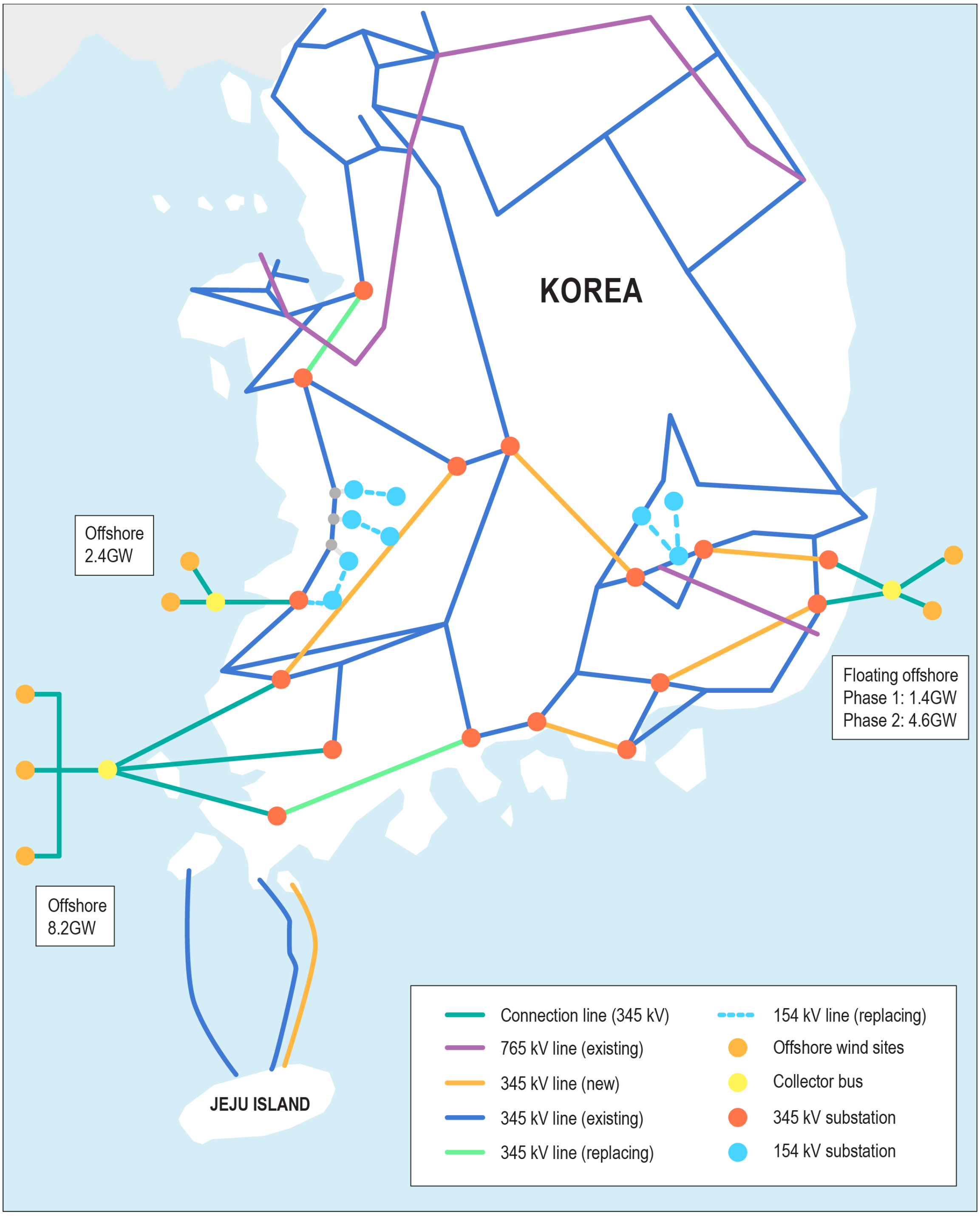
With the significant benefits of spreading VRE deployment geographically and selecting a range of VRE technologies, it is prudent to consider steering VRE deployment towards available grid capacity, while in parallel planning and implementing grid reinforcement to allow VRE deployment in areas with high resource potential but a weaker grid.

A large amount of offshore wind plants is planned along the west coast of Korea given its wind resource potential. Without adequate grid expansion, this will add to current grid congestion from power flows northwards and from a concentration of generation in coastal areas that needs to be delivered to load centres. In this regard, the grid planning process needs to consider the options for expansion of the transmission system together with innovative grid operation practices that can help to increase access to high-quality VRE resources and avoid grid congestion. A renewable energy zone (REZ) approach has been adopted in many countries, which customises transmission planning and the development of VRE projects.

REZs are geographical areas that are characterised by high-quality VRE resources, suitable topology and strong developer interest.

The process of establishing REZs consists of assessing the geographic VRE resource potential, selecting candidate zones, developing transmission modelling scenarios to assess the value of various options, and ultimately, selecting transmission scenarios (i.e. projects) to be developed. Countries and jurisdictions that have adopted the REZ approach include South Africa, the Electric Reliability Council of Texas (ERCOT) and most recently the Australian National Electricity Market (NEM). South Africa is a relevant example for Korea given that their electricity sectors both still have a vertically integrated structure. The South Africa Renewable Energy Development Zone process was established and approved in 2016, and the state-owned utility Eskom now considers renewable resources holistically in its transmission planning exercises. REZs are part of the integrated planning framework, which is discussed in more detail in Chapter 4.

Figure 2.7 Planned sites for offshore wind and expected grid reinforcement, Korea



This map is without prejudice to the status of or sovereignty over any terrotory, to the delimitation of international frontiers and boundaries and to the name of any territory, city, or area.

Source: MOTIE(2020), Offshore wind power generation plan, http://www.motie.go.kr/motie/gov3.0/gov_openinfo/sajun/bbs/bbsView.do?bbs_seq_n=163153&bbs_cd_n=81

Significant expansion of offshore wind generation capacity is planned for Korea's west coast. This will require network reinforcement to prevent further grid congestion from northward power flows.

Currently, while the process of approval for renewables up to 3 MW and their construction is governed by local government, grid connection needs to be secured to actually operate a plant. The grid connection of renewables is prioritised in Korea, especially for small-scale renewables. KEPCO bears the cost of reinforcement or expansion of the network if the contracted renewable power plant is less than 1 MW. As of January 2019, out of 56 657 applicants for grid connection (equal to 12.2 GW), around half (6.23 GW) were on hold (MOTIE, 2019a). One of the reasons for the delay in grid connection is that small-scale renewable development has rapidly become concentrated in the southern provinces of the country, which have relatively favourable solar resources and lower land availability constraints. The 9th BPLE set out plans to connect the 3.93 GW of capacity remaining as of October 2020 and to perform regional projections of renewables capacity with capacity lower than 40 MW, which will enable grid expansion planning in advance.

Box 2.1 Flexibility requirements on Jeju Island: A glimpse into the future?

Located 64 km south of the Korean Peninsula, Jeju Island is one of Korea's nine provinces, with a population of about 700 000 people and 15 million tourists visiting annually. In 2019 Jeju's total electricity demand was about 15 TWh and its peak load was 965 MW during summer. An islanded system with a local source of generation from oil-fired thermal plants (250 MW), Jeju has historically relied on two HVDC submarine cables with a total capacity of 700 MW connected to the mainland. These have long allowed the island to complement its lack of supply with access to cheap electricity from Korea's nuclear fleets.

Since 2012 Jeju has promoted the deployment of renewables by setting ambitious objectives to become a "carbon-free island" by 2030. By the end of 2019 renewable capacity had grown to 934 MW, which was almost two-thirds of all locally installed generation capacity. From the 285 MW of solar PV and 291 MW of wind capacity installed in Jeju, the share of VRE generation reached 14.3% in 2019 (Jeju Special Self-Governing Province, 2019). VRE covered as much as 50.9% of the hourly system load at midday, when solar penetration is at its peak. This required the more flexible daily operation of the HVDC connectors, adjusting their load between 100 MW and 300 MW to accommodate steep ramps at the beginning and the end of the day.

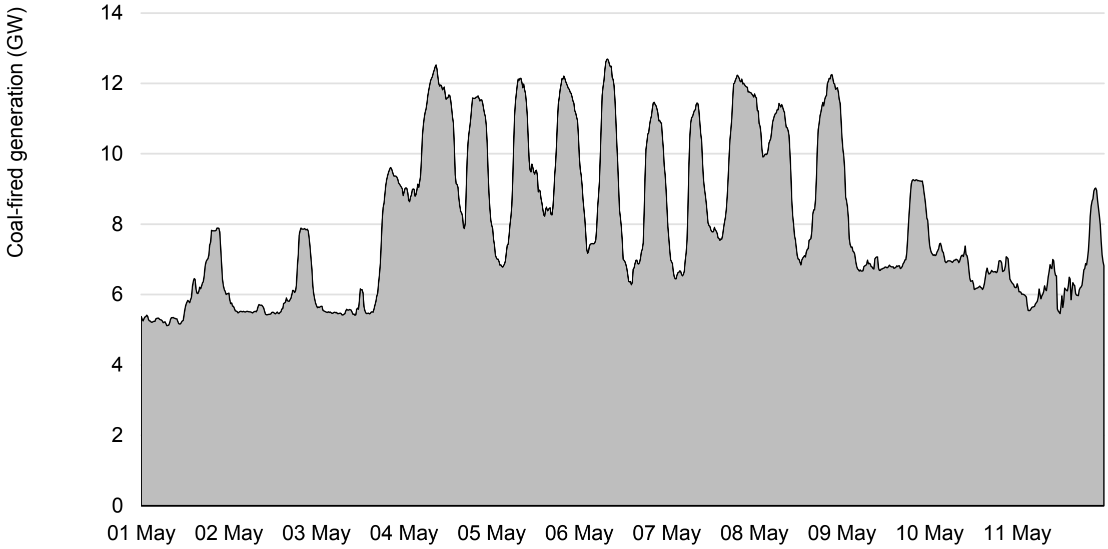
Most importantly, with the accelerated deployment of VRE since 2015, the Jeju branch of KPX has started to curtail wind generation. The amount and frequency of wind curtailment increased to 9 223 MWh on 46 occasions in 2019 (1.7% of total wind generation). The current grid code does not include compensation for VRE curtailment, even when surplus generation is partly a result of the continued operation of thermal generation or the inability to control other resources. Thermal plants are operated as must-run units at a steady level of around 200 MW to maintain frequency levels in the power system, and most small-scale solar PV generators do not have an output control system. Any excess amount of wind is therefore curtailed due to a combination of seasonally low demand, the daily peak in solar generation and an inflexible baseload.

Several measures have been explored to reduce curtailment; for instance, the Korean government proposed introducing a new demand response programme (Plus DR) to incentivise the use of electricity, such as charging EVs, when electricity demand is low. KEPCO plans to install 400 MW of battery energy storage systems (BESS) in the area and is further exploring the technical feasibility of sending surplus VRE generation to the mainland by utilising the HVDC lines, with a third line expected to come online by 2022. Sharing resources between the mainland and Jeju systems through bidirectional transfers can help accommodate increasing shares of VRE. Most recently KPX announced that it will start including solar PV in the curtailment, as the amount of wind it can curtail does not satisfy KPX curtailment requirements at critical hours.

Improving flexibility from thermal generation

Another enabler of the integration of VRE could be to improve the technical ability of the conventional generating plants in the system – especially coal-fired and nuclear power plants – to deliver greater flexibility. This includes improving ramping capabilities and reducing minimum stable output levels, minimum up/down times and start-up times. In many countries with rising shares of VRE, such as Denmark, Germany, India and the People’s Republic of China, thermal power plans have adapted their operational patterns to integrate VRE output. In Germany alone, a series of refurbishment and operational improvements has allowed previously baseload coal-fired plants to significantly adjust their output during the day in order to accommodate VRE generation. In China around 20% of its coal-fired capacity is planned to be retrofitted to increase its flexibility. Pilot projects to improve the flexibility of thermal plants in India are being implemented. Retrofitting thermal power plants that were initially designed to operate as baseload can be a very cost-effective way of enhancing their flexibility, given the appropriate financial incentives.

Figure 2.8 Coal-fired generation pattern in Germany, 2020



Sources: Based on data from ENTSO-E (2020), *ENTSO-E Transparency Platform*, https://transparency.entsoe.eu/.

It is useful to compare the current parameters of typical generators in Korea with best-in-class plants. The 9th BPLE envisages the conversion of coal-fired generation to LNG. Of the coal plants over 30 years old, 30 are already approaching the age of retirement, but 24 of these (12.7 GW) are expected to be replaced by new CCGT plants. CCGT plants are relatively more flexible than coal plants; nonetheless, the experiences mentioned above suggest that it would be useful to operate the remaining coal plants more flexibly up until their retirement.

The principal operating characteristics of typical power plant technologies in Korea (nuclear, coal, CCGT and hydropower) generally demonstrate less flexibility compared with typical international averages for the same technology, particularly nuclear and coal power plants. The inflexible operating patterns of thermal generation in Korea are not solely due to the plants' technical characteristics, but are mainly driven by current grid code specifications and the remuneration mechanism. These could limit the contribution of coal and nuclear plants to the flexibility requirements at a higher share of VRE.

Depending on its compatibility with any existing phase-out programmes, power plant retrofit is one of the options to enhance technical flexibility, including faster ramp rates, lower minimum operating levels and faster start-up times. In China, for example, about 220 GW of thermal power plants – including co-generation and condensing power-only units – could be retrofitted to improve their flexibility by replacing old equipment or improving operations. Based on experiences in China, Denmark, Germany and the United States, retrofit costs to enhance the flexibility of fossil plants vary significantly. Significant investment in new equipment or retrofits, however, may not necessarily be required to operate power plants more flexibly. Flexibility improvements may also be achieved by updating the software and monitoring and control mechanisms.

Table 2.2 Average operating parameters of different technologies in Korea compared with typical international average

Technology	Minimum operating level (% of capacity)			Ramp rate (MW/minute)			Warm start-up time (hours)		
	Korea	International	Retrofit	Korea	International	Retrofit	Korea	International	Retrofit
Nuclear	67%	50%	-	0	10	-	76	72	-
Coal	44%	37%	20%	9	21	60	7	6	2.6
CCGT	49%	45%	30%	18	21	56	4	1.6	0.5
Hydro	27%	15%	-	135	60	-	-	-	-

Sources: IEA (2017), *Energy Technology Perspectives 2017 – Catalysing Energy Technology Transformations*; NREL (2012), *Power Plant Cycling Cost*; Gonzalez-Salazar et al. (2018), "Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables"; Siemens (2017), *Flexibility of Coal- and Gas-Fired Power Plants*; Agora Energiewende (2017), *Flexibility in Thermal Power Plants – With a Focus On Existing Coal-Fired Power Plants*; NEA (2011), *Technical and Economic Aspects of Load Following with Nuclear Power Plants*.

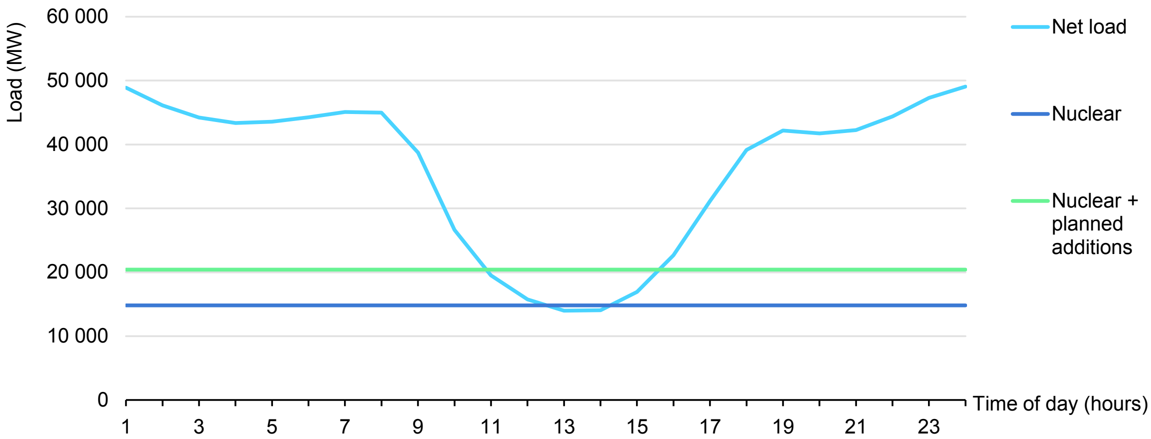
Analysing opportunities for flexible nuclear

Similar to most countries, nuclear power plants in Korea are used to cover baseload. Their high capital intensity and low running costs upon achieving their minimum stable level lend themselves to operational modes with dominant load coverage in the system. Nuclear plants were utilised for over 90% of their total installed capacity until 2012, although this has fallen to 65-85% in recent years due to increased maintenance. Nuclear power plants in Korea are generally not required to adjust their production according to variations in electricity demand or supply, or to participate in balancing or frequency control. The only exceptions occurred this year on two national holidays when the demand level was expected to be significantly lower than usual. The system operator required two nuclear plants to operate at a reduced load of 80% for a maximum of 124 hours. However, this may become necessary in the lead up to 2030 if the system's net load reaches the point where it is below installed nuclear capacity in operation.

In a number of OECD countries nuclear reactors are operating in load-following modes. These flexibility capabilities typically include ramp rates of up to 5% per minute and continuous operations between 50% and 100% of rated power. They have traditionally been implemented when a high share of nuclear power in the national electricity mix or the seasonal and inter-annual variability of hydroelectric production requires operators to implement or improve the manoeuvrability of nuclear units. More recently, the integration of VRE is another driver for implementing load following.

The extent to which nuclear has been able to provide ramping or short-term flexibility varies according to the specific system. In countries such as France, the prevalence of nuclear energy in the generation fleet led to an early need to incorporate ramping flexibility requirements in plant design to account for variability in demand (Box 2.2). In recent years, several other countries have also implemented load-following and frequency control capabilities in their existing nuclear reactors. This may be an option for Korea to improve VRE integration in a situation there the system's net load begins to systematically fall below the minimum stable output of the country's nuclear capacity, as shown in the figure below. New regulatory approval may be required, but changes to the plants operating procedures would not entail significant additional costs and would benefit from the international experience in several countries with similar reactor designs.

Figure 2.9 Minimum net load relative to nuclear installed capacity in Korea, 2030



Source: IEA analysis using BPLE installed capacity figures in 2030.

Simplified analysis shows that operating nuclear flexibly may be an option if the net load evolves to reach levels below installed nuclear capacity. This will require the updating of operational guidelines.

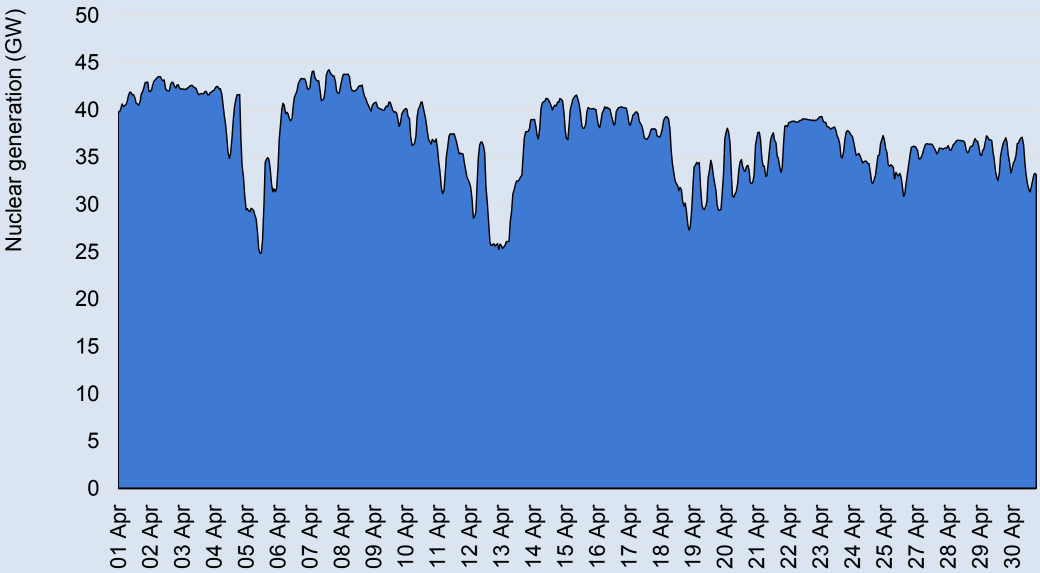
Box 2.2 France's flexible nuclear fleet

The nuclear reactors in operation in France are primarily designed to provide baseload capacity, although they also have a substantial amount of flexibility built in. Proven experiences in France show how nuclear power plants can provide flexibility at various timescales.

Certain types of French reactors, by design, are able to reduce output to 20% of rated capacity twice a day within 30 minutes, for example via a gradual ramp down of 30-40 MW per minute. This modulation of electrical output is performed using special rods that absorb fewer neutrons than the usual rods. These flexibility capabilities have played a significant role in maintaining the reliability of the French power system during the Covid-19 crisis. During the last weekend of March 2020, the nuclear fleet was able to adjust its output by up to 14 GW (out of 40 GW of available nuclear capacity at that time), primarily in response to the variability of solar PV and wind power in France and its neighbouring countries. During that period, nuclear power was the first source of flexibility in the country.

In addition to short-term flexibility, French nuclear plants can also adjust their output on a yearly basis by optimising planned outages for refuelling and maintenance. More than 15 reactors are scheduled to shut down for refuelling at the same time in the summer period when load is lowest.

Hourly nuclear generation pattern in France, April 2020



Source: Based on data from ENTSO-E (2020), *ENTSO-E Transparency Platform*, https://transparency.entsoe.eu/.

Role of storage at high shares of VRE

Energy storage can play a vital role in improving the flexibility of electricity systems as they transition to higher shares of renewables, by allowing the storage of cheap or surplus energy from wind and solar PV at times of low net demand and then its use at times of peak demand. While pumped storage hydro (PSH) is still the most widely deployed utility-scale storage option, accounting for over 90% of global energy storage capacity (equivalent to 160 GW of capacity in 2019), a rapid decline in technology costs is creating an important opportunity for battery energy storage systems (BESS) to play a larger role in providing power system flexibility. BESS offer notably fast and accurate responses to dispatch signals from system operators, and their modularity enables a wide range of installation sizes and potential locations for deployment. This is in comparison to PSH, which is constrained by geographical limitations of suitable pumped storage sites.

Perspective on PSH

Korea Hydro & Nuclear Power, a subsidiary of KEPCO, owns all PSH plants in Korea. They have an installed capacity of 4.7 GW and are all closed-loop PSH. While 2.3 GW of the PSH plants were built before 2001 as part of a regulated base, since the wholesale market was introduced in 2001 all revenues for these plants are market-based. Korea has plans for another 1.8 GW to be installed by 2034 as per the 9th BPLE.

The switch to market-based revenues has severely challenged the business model of these plants. The market role for PSH plants in Korea is energy arbitrage, whereby they pump during off-peak periods (at night and on the weekend) when electricity prices are low and generate during peak periods when prices are high. The storage volume of the reservoirs at existing PSH plants in Korea is such that the plants can conduct energy arbitrage over multiple days in a week. To enable these plants to provide peaking capacity throughout the week (from Monday morning through to Friday evening) the typical operation is to fill their reservoirs to their maximum level over the weekend. However a limitation in the business model of PSH (and other storage) is that the more they are utilised, the lower their potential revenues during the peak periods when they generate, as they effectively flatten prices.

As systems move towards more VRE, the role of PSH is expected to change. In particular, the cycling of storage should begin to move from a weekly to a daily basis, especially with the rise in deployment of solar PV (both utility scale and distributed), which will lead to valuable opportunities to pump during periods of peak solar output (and minimum net load). The ability of PSH to quickly and more accurately follow changes in wind and solar profiles will become increasingly important for its business case, as will the ability to provide system services. Considering the decreasing costs of BESS, the value proposition of PSH to the Korean system will also need to be well understood, to allow markets to both incentivise and reward the specific flexibility they provide.

The way PSH adapts to this changing environment in Korea and globally can be enabled with a number of novel approaches to both technology and design. While PSH is a flexible resource, capable of fast balancing both in terms of its ramping capability and start-up time, most plants are still limited in their operation. Traditional PSH is limited to fixed-speed operation in pumping mode, meaning that it can only pump at full load, limiting its ability to closely follow the variability of wind and solar PV generation profiles. However, advanced pumped hydro technologies that include variable-speed pump turbines and ternary units (comprised of separate units for pumping and generating) are now being considered in both greenfield projects and retrofits to allow access to additional flexibility.

Variable-speed turbines are able to follow the variability of wind and solar more closely. Having separate pumping and generating units allows for simultaneous pumping and generating modes, otherwise known as hydraulic short-circuit operation, and provides enhanced flexibility for switching between modes and providing a broader range for balancing and other system services. Ternary units also allow for a more optimal design for pumping efficiency. While traditional PSH plants have a typical efficiency of ~75%, ternary units may achieve closer to 80%, taking the technology much closer to the round-trip efficiency of BESS installations, which have a typical efficiency of 91%.

An example of the deployment of flexible PSH is ongoing in Europe with the XFLEX Hydro project, which will demonstrate how flexible hydropower assets, including PSH specifically, can help countries meet their renewable energy targets (XFLEX Hydro, 2021). The PSH demonstrations consist of a new plant in Portugal and three retrofitted plants, one in each of France, Portugal and Switzerland. These projects are seeking to improve understanding of the value proposition of a combination of variable-speed turbines, hydraulic short-circuit operation and/or modern electronics and advanced control systems, through their ability to provide a range of system services such as balancing, voltage support and fast frequency response. It is expected that the 1.8 GW of new PSH due to be installed by 2034 in Korea will all at least have variable-speed turbines.

The cost competitiveness of closed-loop PSH plants in their current configuration, with storage sized for weekly cycling, may also decrease as cycling becomes based on the daily swings in net demand balance as opposed to weekly cycling driven by off-peak demand at the weekend. Currently, the daily peak in demand occurs in the afternoon (1 pm–5 pm) in the summer and around midday (10 am–2 pm) in the winter. However, the increased deployment of solar PV will see new net demand peaks in the morning and evening, with storage cycling driven by the daily swing in net demand. As peak periods generally last for 4 hours, this will result in a significant amount of the storage duration of existing plants being underutilised. This may present an opportunity to expand capacity on existing reservoirs, to increase the capacity for peak shaving through energy arbitrage and to increase the cost-competitiveness of new installations.

The value of PSH to future electricity systems may also be increased by making the reservoirs even larger to allow seasonal storage. For example, seasonal pumped storage hydro (SPSH) has been deployed in hydro-thermal systems such as Switzerland and Austria in order to better regulate seasonal variations in hydro flow (e.g. the rainy or ice-melting seasons). This offers an alternative to conventional reservoir dams, which have both higher land use and evaporation losses compared to SPSH (Hunt et al., 2018). As more VRE is deployed, the case for SPSH to address longer periods of surplus and deficit in wind and solar PV generation (as described in Phases 5 and 6 of VRE integration) may become stronger. However, the business case for such plants would be very difficult as a non-regulated asset due to the high upfront capital costs and great uncertainty in revenues.

The benefit of PSH also extends far beyond just energy arbitrage and peak shaving. Due to its flexible operation (fast start-up time and ramping), it should be able to provide valuable system services such as frequency control. However, it is currently limited to providing tertiary regulation that is scheduled on a weekly basis. Furthermore, the ability for certain designs of PSH plants to be run in synchronous condenser operation mode can allow for providing inertia and system strength to systems that are in transition to higher shares of VRE. As higher shares of VRE are deployed, there will begin to be periods where VRE makes up almost all the generation in specific parts of the grid (Phase 4 of VRE integration). Additionally, PSH can make valuable contributions towards other system services that are currently either undervalued or not valued at all by the Korean wholesale market, including voltage support and black-start services.

Perspective on battery storage

Unlike PSH, which is generally deployed for energy arbitrage using large storage capacity that is capable of shifting demand over a number of days, the design of BESS is more flexible for a number of applications.

BESS are well suited to short-duration storage that involves charging and discharging over a span of hours or days. This makes them a good partner for variable renewables, and there is a growing trend for battery storage to be co-located with solar PV and wind. From a renewable energy developer's point of view, BESS may be co-located with renewable projects in order to shift generation from periods of plentiful supply (and low market value) to peak periods when generation is more valuable.

Similarly, they may also be deployed as standalone projects to provide peak shaving through energy arbitrage, whereby price signals lead to charging in periods of low demand and discharging in periods of peak demand, thereby offering an alternative to other peaking capacity such as gas turbines. In both of these applications, it would require BESS with sufficient storage volume to provide capacity over the peak period, which would usually mean a storage duration of approximately 4 hours. An example of this is a recently completed tender for 1 200 MW of renewable projects with storage in India, which will lead to the installation of 600 MW of battery storage with 6 hours storage duration to provide firm supply to the Indian system (Barman, 2020).

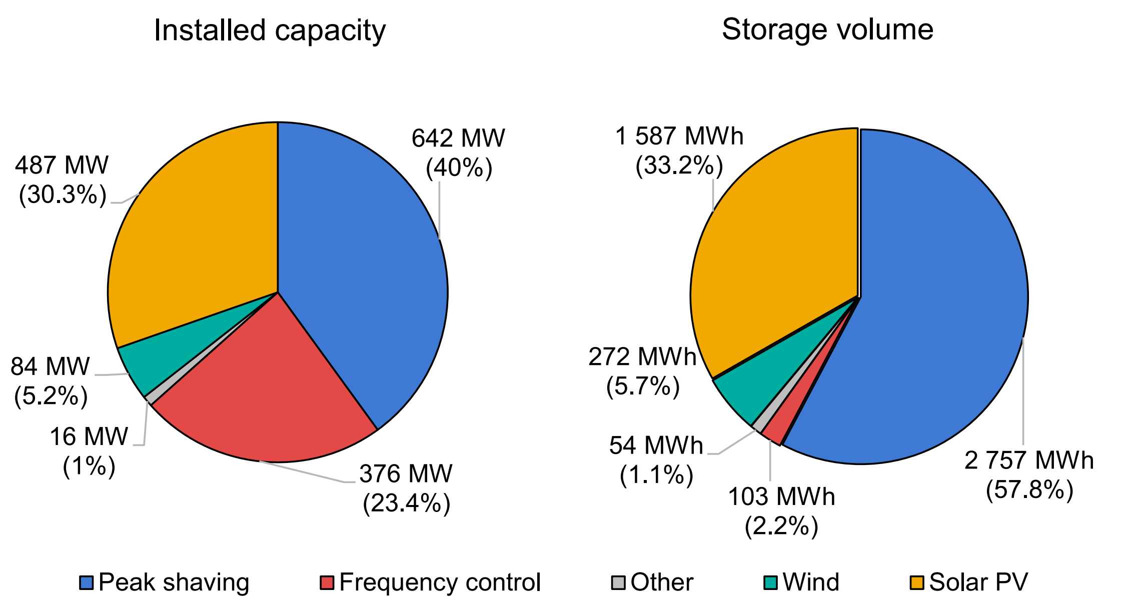
However, BESS installations need not be sized only according to their ability to provide peak shaving. The ability of batteries, which are interfaced to the grid via inverters, to respond quickly to control signals and adjust their output more accurately than conventional generators makes them competitive for the provision of faster ancillary service products, especially newer products such as fast frequency response. Unlike conventional generation technologies, including PSH, BESS also do not have minimum generation constraints and other "no-run" zones of operation. This has led to the deployment of BESS with lower storage duration (typically 1 hour, though sometimes even shorter) and higher capacity in order to provide important ancillary services to the grid.

While battery costs have declined considerably,[2] in most contexts BESS are not yet a fully cost-competitive flexibility resource. Further reducing costs and improving the technology's performance characteristics will remain important;

[2] A 2019 report by Bloomberg New Energy Finance suggests that the levelised cost of electricity from lithium-ion battery storage has dropped by 76% since 2012. See: https://about.bnef.com/blog/battery-powers-latest-plunge-costs-threatens-coal-gas/.

however, it is equally important to ensure that policy, market and regulatory frameworks allow BESS to participate fairly within the power sector, and offer the full range of services they are technically capable of providing. The relevant frameworks will therefore have a strong influence on both the design and operation of BESS. This is particularly evident in Korea, where a number of enabling policies have led to the roll-out of BESS with different storage volumes, ownership and applications.

Figure 2.10 Installed capacity and storage volume of BESS in Korea by application, 2019



Sources: MOTIE (2019b), *Announcement of investigation on causes of ESS incidents and measures to enhance safety* (in Korean), http://www.motie.go.kr/motiee/presse/press2/bbs/bbsView.do?bbs_seq_n=161771&bbs_cd_n=81; Yu. J. (2020), *Problems and Improvement Tasks of the Energy Storage System Supply Policy* (in Korean), National Assembly Research Service, https://www.nars.go.kr/eng/report/view.do?page=2&cmsCode=CM0136&categoryId=b3&searchType=TITLE&searchKeyword=&brdSeq=29667.

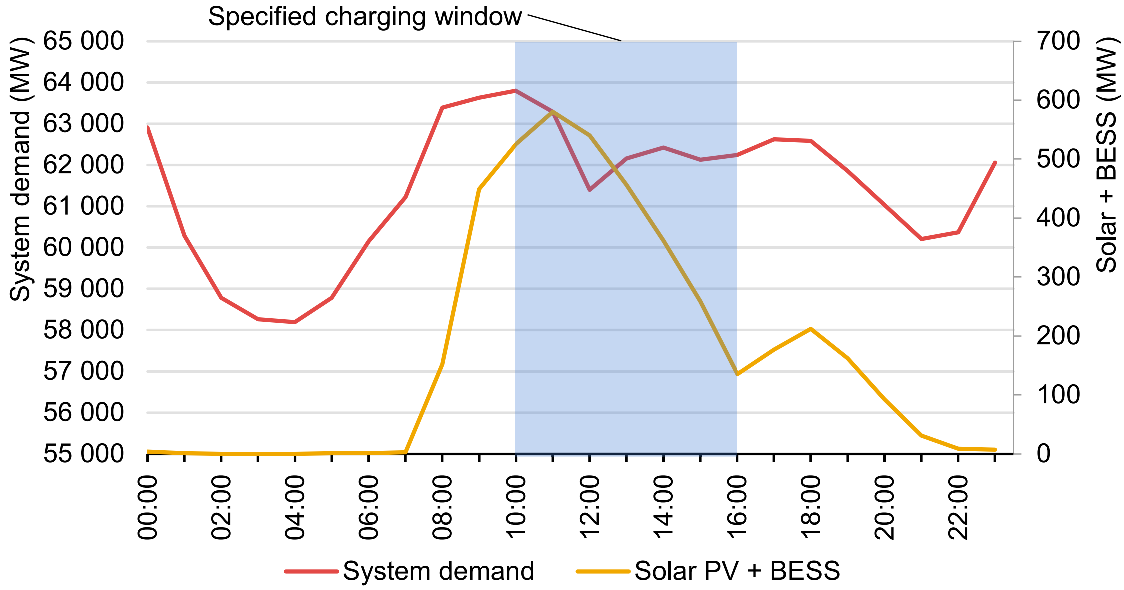
Currently most installed BESS capacity is used for peak shaving. Remuneration schemes that enable the provision of the various services BESS can offer will be important to fully realise their system value.

The deployment of BESS installations in Korea began to accelerate after the introduction in September 2016 of a higher REC weighting for BESS co-located with wind or solar PV (see Chapter 1). This means a VRE plant co-located with BESS leads to four times the REC allowance compared to standalone VRE generation. This REC weighting is gradually being phased out for new installations. As of 2019, BESS co-located with VRE accounted for 35.5% of the installed BESS capacity in Korea.

However, charging and discharging criteria are applied to the award of this weighted REC. To qualify for the REC for solar PV, BESS have to charge between 10 am and 4 pm, while they must discharge after 4 pm. For wind, the charging time is not set, but they have a predetermined discharging time according to the seasons (9 am–12 noon in winter and spring, 1 pm–5pm in the summer and 6 pm–9 pm in the autumn).

The current pattern of co-located BESS usage, especially for solar PV, is leading to periods where solar PV is charging in periods of high load and discharging when demand is low, resulting in less than optimal use of the storage from a system operations perspective. For VRE-connected BESS, MOTIE has announced plans to change the operational requirements from predetermined hours to allowing flexible operation of BESS charge and discharge according to VRE output and demand levels.

Figure 2.11 Hourly system demand and solar generation in Korea on 21 December 2019



Source: IEA analysis based on KPX data.

The most prominent type of BESS installation by installed capacity (40%) is behind-the-meter (BTM) installation at industrial and commercial customers, which accounted for 57.8% of the storage volume in 2019. In Korea, a time-of-use electricity rate is applied to industrial and commercial consumers; it consists of a base tariff according to their peak monthly usage (KRW/kW/month) and a usage tariff according to the electricity they consume (KRW/kWh), which is differentiated by peak and off-peak hours. Initial deployment of BTM BESS was incentivised by tariff discounts to support peak shaving and energy arbitrage, lowering the base tariff according to the reduction in the customer's peak monthly usage and providing a 10% discount on the usage tariff for charging electricity during specific off-peak hours (11 pm–9 am).

Moreover, since 2017 a special tariff scheme has allowed customers with BESS to receive a base tariff discount for electricity provided back to the grid for shaving the peak load. This discount in the base tariff was based on the average net power provided towards peak reduction multiplied by a factor of three. The discount for charging BESS in off-peak hours was also increased from 10% to 50% at the same time. With this special tariff scheme, consumers were able to shorten the payback period for their BESS installations from 10 years to 4.6 years, which resulted in the rapid construction of BTM BESS in Korea (Hwang and Jung, 2020). From 2021 the base tariff discount for contribution towards peak reduction will no longer be multiplied by a factor of three, but instead by just one.

The last major application of BESS in Korea is for frequency control, which accounts for 23% of installed capacity. However, due to its design for ancillary services, this application only accounts for 2.2% of the storage volume of BESS installations in Korea. While all BESS can technically provide frequency control, the participation of BESS (and other storage types) in real-time balancing has been limited as the remuneration scheme for reserves was based on generators' avoided fuel costs, and therefore offered no revenue stream for BESS. As a result, only KEPCO-owned BESS has been participating in providing frequency control. KPX is conducting ongoing reforms to the remuneration scheme to provide payment to storage used in reserves, further allowing privately owned storage to participate in providing flexibility.

Finally, a small amount of BESS (16 MW or 1.6%) has been deployed for a number of other reasons, including an obligation on public entities that consume large amounts of power (>= 1 000 kW) to install BESS in their buildings.

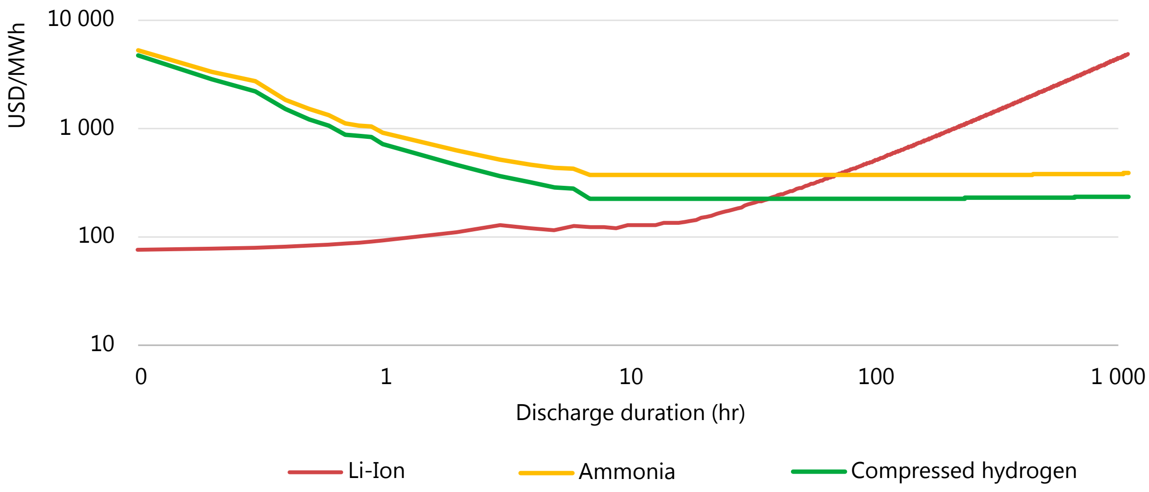
According to the 9th BPLE, of the 70.5 GW of VRE capacity in the 2034 target, 970 MW will be backed up by BESS. Meanwhile, the government also has a target of 1 658 MW peak shaving by 2034 through BTM BESS as part of its demand-side management plan, a significant increase from 105 MW today. This will also take place with a backdrop of several out-of-market incentives being phased out, and is therefore likely to require the ability for BESS to combine multiple revenue streams, driven by the broad range of services they can provide.

Examples of this can be found in markets such as Australia, the United States and Europe, where the ability of BESS to bid into ancillary service markets can make them suitably attractive. This can challenge existing policy, market and regulatory frameworks, because it may be difficult for one single economic actor to access all possible value streams for a storage asset. Of course, if owned and operated by a transmission system operator, several benefits can be realised without markets providing revenue streams. An example of this in South Australia, where the 30 MW ECRIS-SA BESS facility is owned by ElectraNet, the distribution system operator, but is leased to AGL, a large generation company in Australia. As a result, the facility is able to provide regulated services such as reduced unserved energy and fast frequency response (for which no market currently exists in Australia), while AGL is able earn revenue through energy arbitrage and providing ancillary services in competitive markets (ElectraNet, 2021).

Long-term flexibility requirements and the role of synthetic fuels

Given Korea's ambitious VRE deployment targets and the present lack of interconnection to other countries, it will be important to consider resources that can provide long-term flexibility, that is from weeks to seasonal and inter-annual periods. While BESS and PSH can contribute to satisfying the power system's short-duration flexibility needs, typically they are not cost-effective options for longer-duration storage. Depending on the costs of electricity and infrastructure development, synthetic fuels, like ammonia or hydrogen, which can be stored and used later for power generation, can represent a more cost-effective opportunity for long-term storage.

Figure 2.12 Comparison of cost of storage across technologies



Source: IEA (2019b), *The Future of Hydrogen*.

Depending on the cost of electricity and the capacity factor, synthetic fuels can become a cost-effective alternative for longer-duration storage.

These technologies may be cost-effective a source of long-term flexibility in the future by using renewable energy surpluses and operating at a high load factor. While still at the advanced large-scale demonstration stage, a number of manufacturers around the world are developing turbines that can be co-fired or fired exclusively with hydrogen-rich fuels. At present most existing commercial gas turbine designs can handle a hydrogen mix of 3-5%, with the most advanced handling shares up to 30%. As the technology develops and with low electricity prices, hydrogen-fired CCGT could become a competitive option against other flexible power generation options (IEA, 2019b).

The role of demand-side flexibility

Aggregators can play a role in providing demand-side flexibility by participating in the wholesale market, effectively facilitating demand response resources. While Korea's power market is highly concentrated, with 6 KEPCO subsidiaries and a few IPPs selling to KEPCO as a single buyer, there are also currently 28 aggregators bringing together 4 168 participants, which add up to 4.3 GW (MOTIE, 2019c). While their participation in the two national demand response programmes – voluntary and mandatory – has been limited so far, the government is currently in the process of introducing new schemes that are more closely connected to the electricity market and provide better participation incentives. The 9th BPLE has a target of 7.1 GW of demand response by 2034.

Currently, deployment of demand response resource is scheduled day-ahead, so they are in fact not contributing to real-time balancing. The government operates mandatory demand response at times of emergency (when reserve capacity is under 5 500 MW) and has recently expanded its participation in the market. It is currently reviewing the participation of fast demand response in providing balancing services, mainly for large industrial consumers.

Under the current scheme for economic demand response, resources are only dispatched if their bid cost is lower than the fuel cost for marginal generation. As with other flexibility resources, this fails to recognise the demand response's full value to the system. At the wholesale level, increasing the participation of demand-side flexibility in either the wholesale market or for ancillary services will require enhancing the price signal to encourage and ensure participation.

Moreover, broadening participation in demand-side flexibility schemes beyond large industrial consumers is closely linked to making necessary enhancements on the retail side. Updating retail tariffs so that they more closely reflect the value of electricity, and allowing greater participation of third parties to provide system services, could help increase the participation in demand response of both large and small consumers, be it through their retailers or independent aggregators.

In the future, and particularly considering the objectives for digitalisation and transport electrification, it will be important to enhance retail market design to foster greater flexibility in charging.

Benefits of interconnection

Korea has an isolated power system, meaning that there are currently no interconnections with neighbouring countries. Since 2016 the Korean government has actively engaged with the Asia Super Grid initiative, a long-term project to build a cross-border power system between North East Asian countries. The major projects include interconnection with China (2.4 GW, 330 km), Japan (2.4 GW, 340 km) and the Russian Federation (3 GW, 1 000 km) (MOTIE, 2020). The cross-border interconnection is expected to bolster the countries' decarbonisation efforts and energy security by allowing the trading of electricity produced in Mongolia and Russia for consumption in China, Korea and Japan. Through a feasibility study in 2018, KEPCO estimated that the construction of the interconnection with the three countries would cost over USD 6.2 billion (IEA, 2020).

In many systems, interconnection has increased the security of supply and lowered costs while increasing the integration of renewables (IEA, 2019c). Interconnections have security benefits as they allow access to more diverse supply and demand resources and the sharing of reserves. Economic benefits include access to cheaper supply sources and the avoided costs of building additional generation capacity and transmission networks. For instance, a once-isolated system like Ireland's has installed two interconnectors with the United Kingdom and is supporting three new interconnector projects, including 500 km undersea cables (700 MW) with France, which is approximately 1.5 times longer than the Korea-China and Korea-Japan interconnector projects. The cost of building the Celtic Interconnector with France is expected to be EUR 930 million. Interconnectors provide system operators with additional flexibility to maintain their system's balance with a high share of VRE (RTE, 2021). Wind resources account for a quarter of total generation in Ireland (IEA, 2019d).

Interconnection projects such as the Asia Super Grid project can take advantage of countries' different resources and generation mix, as well as their different load profiles, the difference in supply and demand bringing complementary effects (KEEI, 2019).

While the projects in the Asia Super Grid are at different stages of planning, the countries need to consider a number of challenges in order to fully gain the economic and operational benefits of interconnection. First, as the economic benefits of interconnection may be unequally distributed between all involved countries, it is often difficult to agree on how to share the costs of interconnector development under the "beneficiary pays principle". Moreover, cross-border trading arrangements, grid codes and regulations across countries need to be harmonised. The spectrum of integration spans from highly differentiated markets on the one hand to unified markets on the other, where system operations encompass different time horizons, from long-term system planning to real-time dispatch (IEA, 2019e). For instance, the Korean and Japanese systems would need arrangements to deal with current differences in pricing mechanisms and settlement schedules. The integration of markets and operations are an integral step to achieving the benefits of cross-border trading and enabling the efficient operation of interconnectors.

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Chapter 3 – Maintaining operational security

Reflecting VRE in system operation and planning

The output of VRE plants changes the shape of the system's net load, with the result that their varying output will have an impact on the amount of electricity required from conventional power plants to meet demand. To ensure the continued secure and economic operation of the system, operators increasingly need effective processes that can reflect the characteristics of VRE and their potential contribution to the system. This requires sufficient information to assess the current and future state of the system (visibility and forecasting) and appropriate tools to act on this information (controllability).

Improving system visibility at high shares of VRE

Sufficient visibility of VRE output is crucial for maintaining security of supply when VRE provides a growing proportion of the system's electricity. A central element in ensuring visibility of system conditions is adequate information about the power plant fleet, both renewable and conventional. The visibility of large-scale VRE plants is essential to operate the system reliably and at least cost. This visibility takes the form of live (real-time) communication of data describing their output, as delivered to the system operator (IEA, 2017).

As the Korean power system evolves, the potential for uncertainty will not only be driven by deviations between forecast and actual load, but also by greater variability in electricity consumption profiles, particularly when considering self-consumption (so-called prosumers). This leads to a twofold challenge. Because dispatchable assets are used to serve the residual load, as more renewables enter the power system there may be insufficient aggregate headroom from available conventional generation to make up for sudden changes in VRE output. Second, if current practices for forecasting and monitoring VRE output are maintained, including limitations on monitoring infrastructure and data sharing, reserve requirements are likely to rise significantly. Thus, updated reserve sizing practices will be needed, taking into account Korea's lack of interconnection to other power systems.

As a consequence, KPX needs to build a real-time monitoring system for VRE. Not all VRE plants currently have devices for real-time remote metering. This complicates data collection and its consideration in forecasts and scheduling, but new plants with a capacity greater than 20 MW are required to have real-time telecommunication devices. KPX and KEPCO are planning to introduce real-time monitoring devices cost-effectively by setting different requirements for plants of different scales. They are further planning to build a data-sharing platform between them as KEPCO's PPA units are not incorporated into KPX's monitoring system.

The requirement for VRE plants larger than 20 MW to have real-time monitoring devices is stated in the updated grid connection codes and stipulates real-time data at 4-second intervals. For units between 1 MW and 20 MW, however, the only requirement is a data collection device to provide data to KPX within a 1-minute interval. At the initial stage (Phase 1 of VRE integration), with a relatively low share of VRE, it is reasonable to require real-time visibility from large-scale VRE units; however, it will be important to update the requirements or forecasting practices for smaller units as the number of small units connected to the system increases. This is further discussed in the grid code section in this chapter.

Improving the quality of forecasts

Forecasting is critical for cost-effective system operation, particularly with rising proportions of VRE, which requires a flexible system. Appropriate forecasting of renewable production can greatly assist in anticipating the potential imbalances and reduce uncertainty around the availability of generation capacity, while reducing the amount of conventional generation that must be held in reserve. The forecast should be updated at several intervals, from days ahead to minutes before real time. Forecasts are more accurate the closer they are to real time. System operators use accurate forecasts to determine unit commitment and reserve requirements, which can minimise ramping requirements of conventional plants and the need for operating reserves, potentially resulting in system cost savings (IEA, 2017).

At present, renewables forecasting is entirely performed by KPX as renewable generation is exempt from balancing obligations. New VRE plants above 20 MW are required to provide meteorological data to KPX and KEPCO in real time at 4-second intervals, including temperature, wind speed and direction and solar irradiation data, but there is no forecasting obligation on VRE plants. In the updated grid code, VRE plants are only advised to provide forecasting data to KEPCO to assist their forecasting. The Korean government is currently developing a mechanism that will reward VRE generators and aggregators larger than 20 MW according to the accuracy of their output forecasts relative to technology-specific baselines. Under this arrangement any generator whose forecast accuracy is better than the baseline would receive a premium.

Both the control centres and VRE plants should implement forecasting systems. However, to maintain system security, system-wide forecasting provides a more accurate perspective on VRE output. Therefore the wider the pool of VRE power plants from which KPX and KEPCO receive data, the more accurate the overall forecast will be. If advanced centralised forecasting were implemented in the system control centre, KPX would have better tools with which to dispatch across necessary timeframes. Accompanied by appropriate communication channels with existing assets, this would allow existing assets to provide the required amounts of flexibility to ensure system stability. The use of forecasts requires changes in operational practices. KEPCO and KPX need to be aware and convinced of the benefits of integrating forecast data in their daily operations.

With more VRE plants connecting to the grid, a renewable control centre may become an important feature to consider, to provide KPX with state-of-the art tools for real-time monitoring of VRE plants in the system as well as VRE forecasting from days ahead to minutes before real time. A growing number of countries, such as Spain and India, are increasingly making use of national and regional control centres to manage VRE integration (IEA, 2018a; 2020).

Improving generation scheduling and system operation

Operational decisions affecting power plants are taken on a range of timescales up to real time. They are made by both the market operator and power plant operators depending on the structure of the electricity industry. These decisions involve unit commitment and the plant output level (power plant dispatch), which needs to be decided in advance taking into account the response time of each type of power plant.

Due to the technical constraints in the power system, unit commitment and power plant dispatch call for a certain degree of forward planning. However, many power systems tend to lock in operational decisions well in advance of when they are required from a technical perspective – weeks or even months ahead. Long-term contracts between generators and load-serving entities – in this case KEPCO as a single-buyer – may prevent power plants from providing flexibility to meet changes in net load cost-effectively. This is undesirable for least-cost operation of the system, in particular at growing shares of VRE. KPX and KEPCO should consider the following key practices in generation scheduling with the rising share of VRE:

- Allow for frequent schedule updates as close as possible to real time (up to five minutes before real time is best practice).
- Aim for short dispatch intervals (five minutes is current best practice), while deciding the dispatch by looking ahead several dispatch intervals.
- Avoid locking in power plants over the long term with physically binding generation schedules.
- Co-optimise generation schedules with the provision of system services.

Current practices in balancing and reserve sizing

In addition to influencing how the operation of dispatchable power plants is planned, growing shares of VRE have important implications for system services and related markets. Determining the size of system reserves needs to strike a balance between security of supply and cost. Historically, balancing the power system has only required forecasting load and scheduling generation to meet this load in a largely predictable way, with days or even weeks of anticipation. For system operators, the main indicator of balance in the system is by measuring the frequency, set at 60 ± 0.2 Hz in Korea. It is a critical feature of system security as any deviation above or below might endanger equipment and lead to a system failure.

Because load may differ in real time, plants may fail to reach their desired output, or there may be outages on major lines or at generators, system operators may need to issue special instructions to balance the system. With increased variability, the need to balance the system may increase to such an extent that it is necessary to contract additional reserves. With a larger share of VRE, it becomes relevant to set reserves where the overall reserve requirement varies from day to day. More reserves are needed during cloudy days compared to clear and sunny days. This so-called dynamic reserve allocation becomes more important as the VRE share rises. In many countries around the world system operators are making use of competitive market instruments to optimise the cost of procuring these reserves. The use of HVDC transmission lines connecting the mainland and Jeju Island is potentially significant for reserve allocation since they can lead to the smoothing of VRE output over a wider grid network and hence reduce the reserve requirement.

System stability

The advent of more variable renewables affects how the system can be kept in a secure state at all times. The challenges are related to the stability of the power system, which characterises its ability to withstand disturbances on very short timescales. Stability becomes one of the key concerns as systems approach Phase 4 of system integration (as discussed in the previous chapter).

While many power systems around the world have ambitious annual targets for the proportion of VRE in overall generation – as a building block of decarbonisation or net-zero targets – there are particular challenges that come up before VRE reaches a majority share of overall generation. Even at an annual share of 30% to 40%, instantaneous hourly penetration of VRE in generation can present power systems with operational challenges. This challenge can be both system wide and location specific and relates to inertia and system strength.

Power systems have traditionally been based on synchronous generation, which is deemed as grid forming because it sets reference voltage values and keeps the system in balance. However, new converter-based technologies have historically been designed as grid-following technologies. This means that in order to maintain a stable output and work well within the power system, converter-based technologies have conventionally been designed and calibrated to follow the reference signal from conventional generators. Consequently, power systems as a whole are designed to rely on a certain level of inertia that keeps the system in balance at very short timeframes.

Synchronous generators can easily make up for loss of output in the case of a generator outage. Provided that the disturbance is not significant relative to the remaining synchronous generation, the stored kinetic energy in the rotating parts will be partially transferred into electrical energy and fed into the system. In classic power systems dominated by synchronous generation, it is easier to maintain the frequency following a disturbance, as each individual generator is able to transfer limited kinetic energy to compensate for the disturbance (IEA, 2021).

As converter-based assets[1] – such as wind, solar PV and battery storage – increase their share in the power system and displace conventional generators with higher marginal costs, in specific hours there may be more converter-based than synchronous generation online. Even at relatively low shares of VRE penetration this situation has already been observed in a number of power systems, for example in France's Brittany region, in Denmark, in the Texas panhandle region and, most recently, in south-eastern England. In particular in the case of Korea, Jeju Island and the potential for significant converter-based generation deployment along Korea's western coast bring the prospect of localised grid stability challenges and, therefore, the need to plan accordingly.

[1]Converter-based assets include converting alternating current(AC) into direct current(DC) and vice versa.

To this end, a range of technical solutions are available to maintain system strength, which vary in technological maturity and applicability to specific power system situations. At the more mature end of the spectrum is the option of synchronous condensers, which have been developed in specific isolated or island regions where, in certain hours, converter-based generation can represent the majority of generation. However, new approaches can be helpful, such as enabling and deploying fast frequency response from converter-based resources or new technologies such as grid-forming electronic controls in converter-based assets.

At a technical level, these new solutions have yet to be demonstrated in large-scale meshed power systems, and their economic feasibility needs to be assessed against considerations of overall impact on system costs and institutional decisions on who owns and operates such assets or how they are accounted for in long-term reliability planning. The experiences from the Irish, Danish and Australian power systems already offer some experiences that might be relevant for policy makers in Korea, particularly in light of the geographical concentration of offshore generation and the importance of small-scale solar PV.

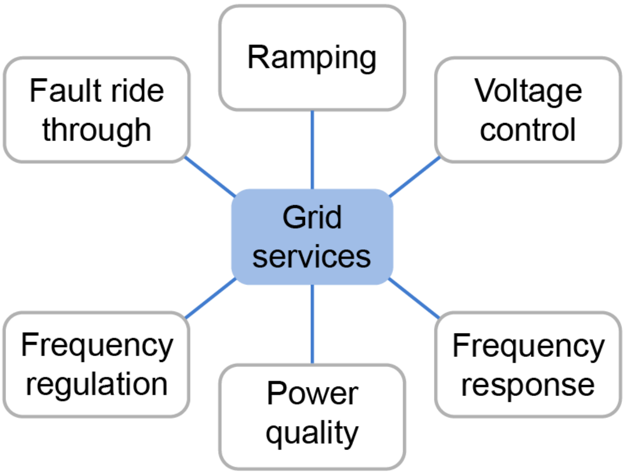
Grid code improvements for a resilient power system

Appropriate rules for grid connection are a critical requirement to ensure the operational security and stability of the system with growing VRE deployment. This set of rules is referred to as a grid code. In general, grid codes cover many elements, including connection, operation, planning and markets.

Grid codes are particularly relevant for wind and solar PV plants because their characteristics and the way they connected to the grid (via power electronics) are different from conventional generators. During the initial phases of VRE its impact on the system is minimal and its influence on grid stability can easily be managed. As the amount of VRE displacing conventional generation increases, so the need grows for VRE to contribute to providing grid support services, such as frequency regulation and active power control, reactive power and voltage control, and operating reserves (IEA, 2017).

The behaviour of VRE is not only dictated by its design, but also by the way it is programmed to operate, which can be set to suit specific requirements of the system. As a result, system operators can set more precise technical requirements for VRE plants connected to the grid. As regards grid services that are required from both conventional and VRE generators, the grid code should address six technical services to increase system flexibility. These grid services (ancillary services) could be mandated and/or financially incentivised.

Figure 3.1 Essential grid services as part of the grid code



Source: IEA (2018b), Thailand Renewable Grid Integration Assessment.

Grid code updates are central to unlocking the full range of services that new technologies can provide and ensuring that they contribute to supporting the system.

Policy makers and regulators should continuously revise grid codes to suit the evolving needs of the power system as the share of VRE increases. These changes can address all parts of the power system, including adjustment to the requirements for conventional generation to facilitate VRE integration. The frequency of grid code revision depends on how rapidly the power system and the energy sector are evolving. A number of countries such as Germany, Ireland, Spain and Denmark have undergone grid code revisions in response to increasing shares of VRE.

Korea has specific grid connection codes for VRE, which are referred to as NRE Grid Connection Standards. The connection standards are categorised according to whether the NRE plant is connected to the transmission system or the distribution network, and cover technical requirements that NRE resources have to provide under normal conditions and during system events. These connection standards have recently been updated to accommodate the increasing proportion of NRE on the system by expanding coverage to all inverter-based technologies rather than just wind energy. The technical requirements are applied to NRE connected to the grid, either at the transmission or distribution network levels depending on the area (mainland and Jeju Island), and vary according to the size of plant and voltage levels. The main requirements of the technical standards are to improve the **visibility**, **controllability**, **monitoring** and **forecasting** of NRE plants. For example, generators smaller than 20 MW are not required to install real-time telecommunication devices. These are used to provide visibility of NRE plants in real time at a 4-second resolution, allowing system operators to monitor and control the plant.

Prioritising technical requirements in grid codes

The grid code requirements for VRE generators can be categorised according to the phase of VRE deployment, which is influenced by the instantaneous share of VRE. The main technical requirements relating to VRE include: protection systems; communication systems; frequency/active power and voltage/reactive power control; VRE forecasting tools; voltage and frequency ranges of operation; spinning reserve requirements; fault ride through (FRT); and synthetic inertia. For example, the controllability and visibility of larger VRE generators are essential regardless of the phase of VRE integration. This involves developing communication systems and architecture that have features such as supervisory control and data acquisition (SCADA), automatic generation control capability, and relevant forecasting systems. As the system approaches Phase 4, inertia-based fast frequency response or “synthetic inertia”, which can be extracted from VRE, can help to address frequency stability challenges.

Table 3.1 Incremental technical requirements for different phases of VRE integration

	Always	Phase 1	Phase 2	Phase 3	Phase 4
Technical requirements	• Protection systems • Power quality • Frequency and voltage ranges of operation • Visibility and control of large generators • Communication systems for larger generators	• Output reduction during high frequency events • Voltage control • FRT capability for large units	• FRT capability for smaller (distributed) units • Communication systems • VRE forecasting tools	• Frequency/ active power control • Reduced output operation mode for reserve provision	• Integration of general frequency and voltage control schemes • Synthetic inertia • Standalone frequency and voltage control

Note: Power quality refers to specifications for generators regarding their main properties, such as voltage, frequency and waveform, which should match the power system’s requirements.
Source: IEA (2017), Getting Wind and Sun onto the Grid: A Manual for Policy Makers.

In Korea the main technical requirements for VRE plants are included in the latest NRE Grid Connection Standards, including protection systems, frequency and voltage ranges; visibility and control of VRE plants; and communication systems, particularly for plants that are larger than 20 MW. However, some of the key issues could be considered in future revisions. A key component is the FRT requirement for all VRE plants, regardless of size, to remain connected for a certain period of time in the case of faults from voltage disturbances on the system. The code should establish the number of sequential disturbances that VRE plants are required to withstand and a specific timeframe to remain connected. The lack of precise requirements for FRT can cause VRE plants to trip automatically, causing sudden drops in system frequency, thus posing electricity security risks. This has occurred in many countries and regions, such as Europe and South Australia, and has led to significant grid code reviews.

It is also important to establish technical requirements for VRE units smaller than 20 MW to provide system services. During initial phases with low shares of VRE in the system and limited penetration of distributed generation, as is currently the case in Korea, it may not be necessary for smaller units to contribute to providing system services. However, as the number of small-scale units begins to rise, it will be important to ensure the same degree of controllability for smaller distributed units as for centralised generation. Faced with a very large number of small-scale distributed VRE units, many countries are reforming grid codes to place a requirement for more sophisticated capabilities on small-scale distributed units connected to low-voltage networks.

To ensure appropriate grid codes are in place as the proportion of VRE on the system grows, policy makers and regulators should consider the following factors:

- Establish an appropriate process for developing grid codes applicable to VRE. KPX and KEPCO, in collaboration with policy makers and regulators, could determine whether a new grid code is needed or if an existing grid code should be revised to accommodate the connection of VRE generators. This process should be transparent and consult with all relevant stakeholders, particularly project developers, manufacturers, and owners/operators of existing power plants.
- Consider state-of-the-art international industry standards as a basis for grid codes. KEPCO and KPX could refer to state-of-the-art industry standards and international experiences when identifying the technical requirements of the code and modify them to suit the context of Korea.
- Monitor grid code progress elsewhere. KEPCO, KPX and relevant stakeholders can monitor developments in other power systems, particularly those with high VRE deployment, to make sure that any relevant lessons are incorporated into Korean grid codes.

- Continuously assess and revise grid codes to ensure their suitability. KEPCO and KPX can monitor the grid codes on a continuous basis to ensure they suit the needs of the power system, which will evolve as more VRE plants are connected to the grid.

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Chapter 4 – Long-term system planning

Current practices for long-term planning

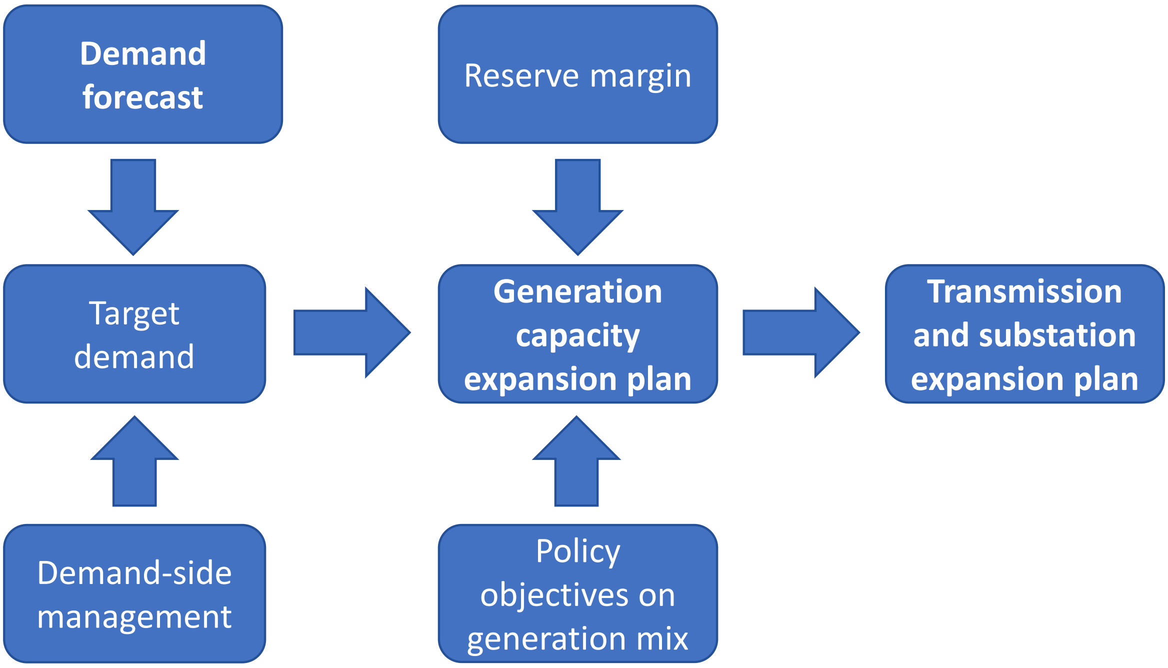
Long-term planning in Korea is undertaken by MOTIE, which publishes the BPLE every two years covering a 15-year horizon. This long-term strategy includes the planning of new generation installations, major transmission lines and substation facilities. The 9th and most recent BPLE covers the period from 2020 to 2034. The BPLE follows the policy objectives set out in the Energy Master Plan, which lays out a 20-year plan for the broader energy sector.

The institutional arrangements for drafting the BPLE start with setting the basic agenda and organising a governing committee and two subcommittees, one for demand and another for capacity planning. Six working groups have been established since the 8th BPLE, which are responsible for demand forecasting, demand-side management, generation planning, reserve margin, renewable energy and power system transmission planning.

After the working-level plan is devised, it goes for consultation among relevant ministries. For the 9th BPLE, the Ministry of Environment has been particularly involved with a strategic environmental impact assessment process. The process includes reporting to the standing committees in the national assembly, a public hearing, and finally a review by the Electricity Policy Review Board.

The key components of the energy plan are the demand forecast, generation expansion plan and transmission expansion plan, with other working groups feeding in to these.

Figure 4.1 Key components in Korea's long-term demand forecasts



The demand forecast is based on two macroeconomic models, one for total demand growth and the other for peak demand growth. Total electricity consumption is forecast using the Electricity Panel Model, which is based on panel data analysis of around 100 countries and the interaction between electricity demand, GDP and prices. Previously, up until the 5th BPLE, a bottom-up demand model was used. Macroeconomic modelling was introduced in the 6th plan and updated to the current approach in the 7th plan.

The load forecast also takes into account demand reduction targets from demand-side management. This considers improved energy efficiency, energy management systems and demand response, BTM solar, ICT and ESS, retail rate design, and other demand-changing factors such as EVs and generation for self-consumption in industry.

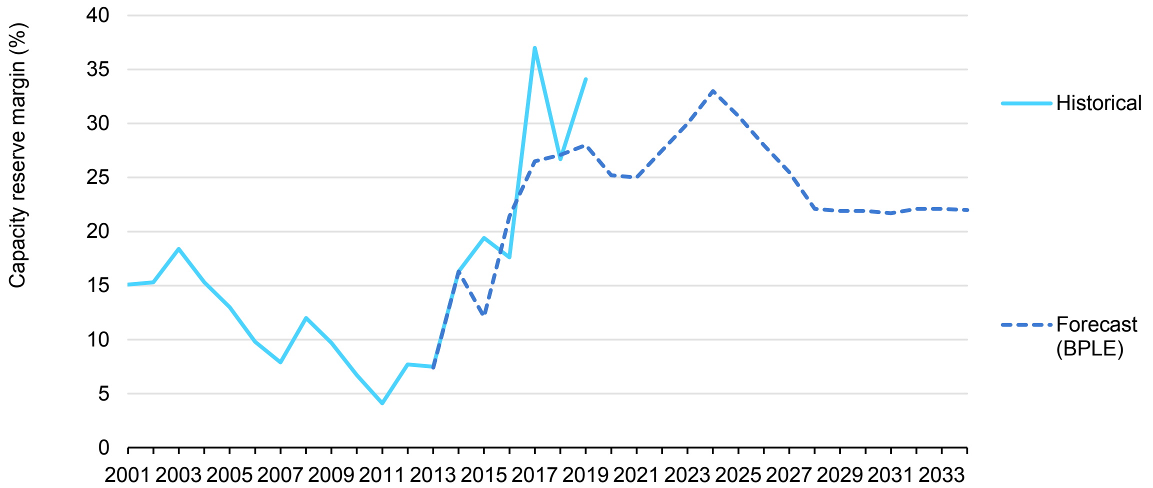
Reference demand minus demand-side management targets leads to annual "target demand" for the next 15 years, with an annual average growth rate in demand and peak load.

The generation capacity expansion plan takes into account government objectives in the generation mix, existing capacity and the retirement schedule. The plan targets a capacity reserve margin to ensure a level of capacity that can be relied upon above the peak demand from the load forecast (target demand).

The reserve margin consists of two parts: the adequacy reserve and reserve for uncertainty. The adequacy reserve takes into account a loss of load expectation (LOLE) target of 0.3 days per year based on planned and forced outages, retrofits, variability of VRE and forecast errors. The reserve for uncertainty accounts for uncertainty in the demand forecast and possible delays in installation of power plants. In 8th and 9th BPLEs, adequacy and uncertainty reserve were set at 13% and 9% respectively.

The capacity reserve margin fell to as low as 4.1% in 2011, when rolling outages occurred in Korea. The declining reserve margin was particularly due to demand growth that was much faster than expected. In addition, 4 150 MW of power plant capacity that was expected to be operating by 2013 was delayed or cancelled during the period of the 5th plan.

Figure 4.2 Historical and planned development of capacity reserve margins



Note: Forecast comes from different BPLEs by year (the most recent available for the relevant years): 2020-2034 9th BPLE; 2017-2019 8th BPLE; 2015-16 7th BPLE; 2013-2014 6th BPLE.
Source: MOTIE (2020a), Annual Performance of Power Supply, https://www.index.go.kr/potal/main/EachDtlPageDetail.do?idx_cd=1163.

Korea's capacity reserve margin fell to a very low level in 2011, but has subsequently recovered.

In order to reduce the risk of shortfalls in the future, the approach to setting the reserve margin was modified for the 6th BPLE with the addition of a new component to the reserve margin, the uncertainty reserve, to cover uncertainty in the demand forecast. The uncertainty in the demand forecast is determined by averaging the annual gaps between the demand forecast and actual demand. Revisions to the demand forecast approach were also initiated, as mentioned above.

The 6th BPLE planned an additional 3 900 MW of capacity to prepare for delays in construction. In the 7th BPLE an additional component was included in the uncertainty reserve to account for supply-side uncertainty, allowing for delays in construction. The Energy Utility Law was also reinforced in 2015 to allow MOTIE to forfeit construction permits in the case of delays in power plant construction.

In calculating the reserve margin, for centrally dispatched thermal plants the full installed capacity is considered. However, for renewable energy each technology is assigned a capacity credit so that only a percentage of the installed capacity is considered when calculating its contribution (13.9% for solar PV and 3.1% for wind). This capacity credit is determined by the Net Qualifying Capacity methodology used by the California Independent System Operator (CAISO). Korea has a 90% exceedance level for this, using the minimum capacity factor that each renewable source can meet in 90% of the peak hours in the most recent three years (KPX, 2018). This 90% exceedance level is higher than CAISO, which applies 70%.

Up to and including the 7th BPLE, capacity planning was highly centralised and regulated, with power producers required to submit their intent of construction as an input to the process of drafting each plan and for it to be reflected in the BPLE to be able to build a plant. From the 8th BPLE, the policy was changed so that after capacity planning in the BPLE is decided, power producers submit their intent of construction and the government evaluates them and grants permits to selected producers. Power plant proposals must also meet environmental standards and be in line with the national emission reduction targets (Government of Korea, 2020).

The BPLE also includes a **transmission and substation expansion plan**, which spans a 15-year horizon. Based on the plans laid out in each BPLE, KEPCO sets the transmission plan with its own regional demand forecast for coincident and non-coincident peak load, dividing the country into 6 regions and 42 districts.

The 8th BPLE includes projects to ensure the reinforcement of transmission infrastructure to accommodate expected demand growth and the increased construction of decentralised NRE generation facilities. In Korea new renewable generation capacity is mainly arising in rural and mountainous areas and requires the construction of additional lines to bring generation to load centres.

KEPCO and KPX are obliged to purchase all electricity generated from VRE sources, which requires the expansion and upgrade of the transmission networks to ensure they are capable of accommodating a growing share of solar and wind. This is particularly relevant for the southern, eastern and western coastal regions.

New generation capacity is guaranteed by law to be connected to the network and has to pay for the connection. However, there is an exception for NRE generating facilities below 1 MW capacity, for which KEPCO covers the connection costs.

Box 4.1 The 15 September rolling blackouts in 2011 (KPX, 2012)

On 15 September 2011 high temperatures in Korea led to electricity demand that significantly exceeded the expected demand, and low frequency resulted from a lack of power reserve to cope with the shortage. To prevent a nationwide blackout, a rolling blackout was implemented from 3.11 pm to 7.56 pm.

From 10.50 am on the day the rolling blackout was implemented, actual electricity demand increased above the expected demand. However, it was not considered a dangerous situation at the time. KPX considered the reason for the rapid increase to be the return to work after the holidays, so no other actions were taken other than to operate PSH. The power reserve began to drop below 4 GW in the morning, reaching a critical level. However, the power reserve then bounced back again to over 4 GW as the load decreased at lunchtime.

Subsequently, the power reserve declined again as demand increased from 1.05 pm. In response, KPX adjusted the transformer tap at 12.50 pm to reduce the load, and at 2.01 pm it reduced the load through auto power saving. At this time the power reserve dropped below 1 GW, the critical reserve threshold. However, based on their usual experience, staff decided that it was still possible to maintain the supply and demand balance by adjusting the transformer tap and using auto power saving and direct load control measures without a rolling blackout.

However, at 1.55 pm the Chungju hydropower plant with 115 MW capacity became non-operational due to insufficient water. As a result, the power reserve dropped further to 838 MW at 2.20 pm, and KPX issued a “red or serious” level warning. At 2.35 pm Boryeong CCGT with 220 MW also stopped functioning, further decreasing available capacity. Additionally, most PSH capacity was operating at reduced capacity due to low water availability in their reservoirs. All these factors led to the power reserve dropping below 500 MW and a frequency drop to 59.5 Hz. This combination of developments risked damaging the supplementary power supply in the system’s nuclear plants, which could eventually stop generating. At 3 pm the nationwide electricity system was on the verge of collapse due to a chain shutdown of power generators, leading to the need for load shedding.

In order to prevent a nationwide outage, emergency load adjustments – a rolling blackout – were implemented from 3.11 pm. A total of 5 GW of load were shed sequentially for 1 hour in specific areas. At 4 pm electricity demand decreased. The situation improved after 4.30 pm as the frequency stabilised and the power reserve recovered. From 4.47 pm to 7.56 pm the rolling blackout was sequentially suspended. During this period, the outage time in each area was about 1 hour.

Although the duration of the blackout was not long, the economic loss caused was significant because it was not announced in advance. Businesses and other services, including transport and major institutions such as banks, hospitals and public institutions, suffered significantly from the power outages.

The scale of the loss reported in the KPX rolling blackout white paper was about KRW 7.5 billion.

In the aftermath, the government pursued long-term improvements by enhancing the demand forecasting system and stepping up the power reserve standard.

This event prompted extensive review of the adequacy of supply and improvements in operational practices. Government guidance improved emergency procedures and response plans during summer and winter peak periods, while the 6th BPLE planned large amounts of new thermal plant capacity, introduced start-up time requirements for reserves and expanded utilisation of demand-side resources.

Future practices for long-term planning

Integrated planning and co-ordination need to minimise costs and maximise system resilience

Traditional network planning processes have primarily focused on expanding supply infrastructure (generation, transmission and distribution networks) to meet projected electricity demand growth over the next 20 to 30 years. However, the power sector landscape is changing. This is largely due to increases in the uptake of VRE and distributed energy resources, including demand-side flexibility and the electrification of transport and heat. Power sector planning needs to become more sophisticated by taking into account the role and impact of these developments. A well-integrated planning approach that considers these factors will help identify pertinent options for future power systems in a timely manner.

The importance of integrated generation and network planning is magnified as the level of VRE deployment increases, since the development of VRE projects can easily outpace the development of network infrastructure. Geographic concentrations of VRE in areas with high resource potential can push up against the limits of the electricity network, which ultimately drives up the cost of delivered electricity. Network development will increasingly need to anticipate where renewables are likely to be built, while policy makers and regulators will need to explicitly link incentives for new network lines to other policies that support investment in renewables.

Overall, the planning processes for the Korean power sector show a considerable degree of integration. The Energy Master Plan lays out a combined vision for the entire energy sector, including demand structure and efficiency, the clean energy transition and expanding distributed energy. This is picked up in the BPLE process where the different working groups on demand management and renewables feed into generation and transmission planning. In addition to the BPLE, multiple plans are devised under the Energy Master Plan, including the Energy Use Rationalization Plan containing Korea's energy efficiency targets and the District Heating Supply Plan that covers the country's co-generation plants.

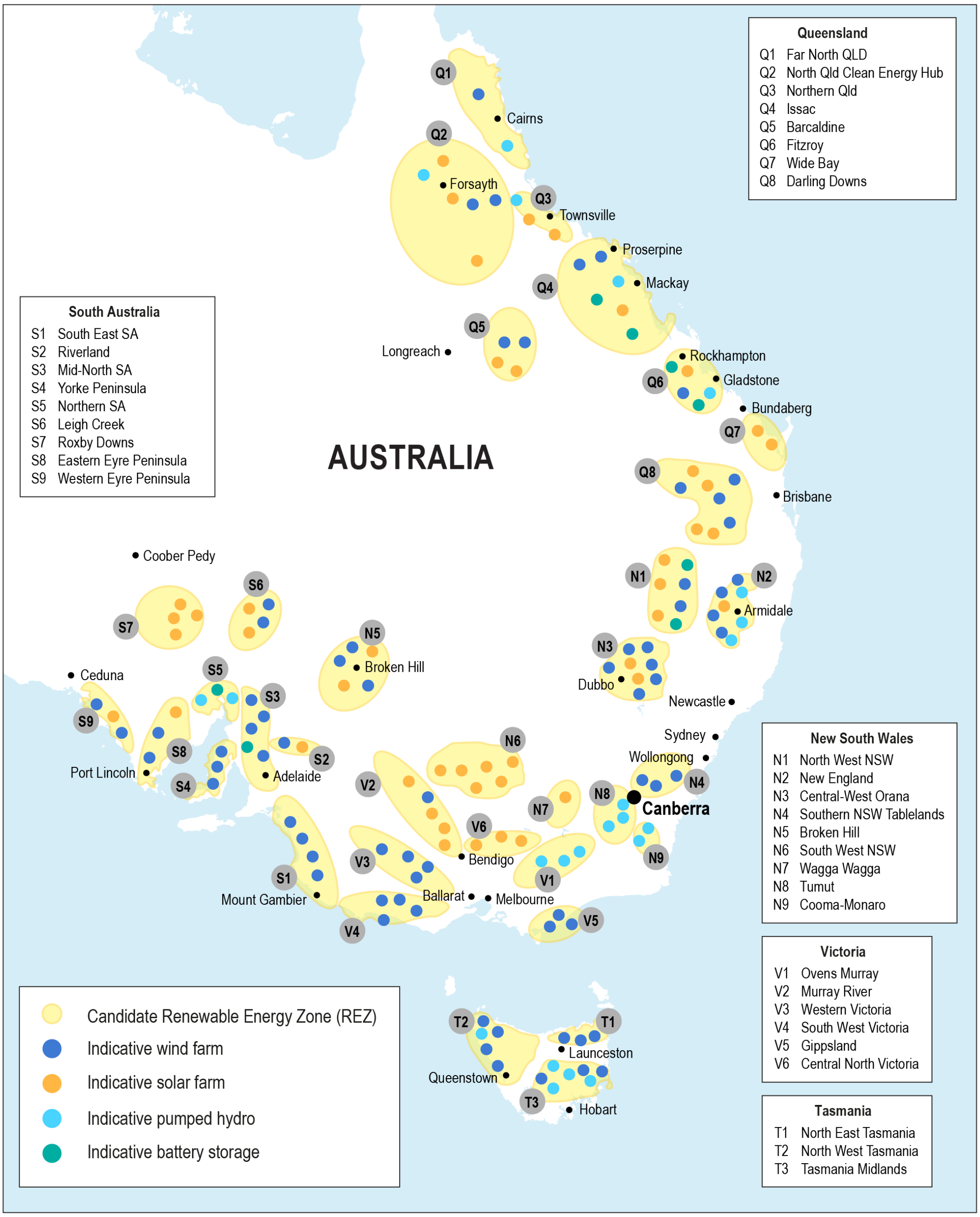
As in most IEA member countries, Korea has experienced delays in the construction of transmission lines due to opposition from the local population. To address the low public acceptance of new transmission lines and transformation facilities, the government enacted the Act on Transmission Facilities and Assistance to Adjacent Areas in 2015. One objective of the act is to improve conflict resolution between the project proponents, local government and other stakeholders. One key demand of local residents is that new transmission facilities be installed underground and the government is also committed to increasing the involvement of residents early on in the site selection process (IEA, 2020).

The REZ approach, which has been adopted in several jurisdictions such as South Africa, Mexico and ERCOT in Texas, brings together network planning and the development of renewables projects. REZs are geographical areas that are characterised by high-quality renewable resources, potential for grid integration and strong developer interest. The process to establish REZs requires co-ordination from relevant stakeholders in the energy sector, including the regulator, utilities and potential renewables developers.

The success of this approach owes partly to the fact that network expansion can be started ahead of constructing generation plants, to allow for its longer development timeline. In addition, developing co-ordinated network investment for multiple VRE generators increases efficiency relative to planning infrastructure on an individual project basis.

Most recently, the Australian NEM is developing REZs as part of its Integrated System Plan to identify future transmission developments to reduce overall costs (AEMO, 2020). This will require adjustments to the regulatory framework and the approach to network development. Such co-ordination also becomes increasingly important in the integration of large-scale offshore wind, as seen in the medium-term hub connections planned in Germany, the Netherlands and Belgium, as well as in the long-term with large-scale offshore hubs being considered by Denmark, the Netherlands and Germany.

Figure 4.3 Planned network investments in Australia



This map is without prejudice to the status of or sovereignty over any terrotory, to the delimitation of international frontiers and boundaries and to the name of any territory, city, or area.

Source: AEMO (2020), *2020 Integrated System Plan*, https://www.aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en.

Reliability standards should go beyond the average frequency of adequacy shortfalls

Traditionally, reliability has been ensured by using a reserve margin approach, where a certain amount of capacity above the peak is maintained to account for all sources of uncertainty in supply and demand, including contingencies such as outages and unavailability of variable generation. Corrections can be made to this margin to cover demand response and interconnection flows. Many regions are increasingly moving towards standards that are set in terms of the expected frequency or size of shortfalls, which have the advantage of quantifying the probability of shortfalls in system adequacy. With detailed modelling, it is possible to quantify the level of reliability to be expected for a system at a given reserve margin. These relationships are system-specific, however, and past relationships may not hold up during energy transitions.

Probability-based metrics describe how not all load may be supplied, with two main parameters:

- **The dimension of load not served**, by focusing on either magnitude (amount of energy not supplied) or frequency (how often periods with unserved load occur).
- **The likelihood or probability of unserved load**, by focusing on an "average" case, or explicitly evaluating "tail risks" (high-impact, low-frequency occurrences).

Table 4.1 Selected reliability metrics and their characteristics

Reliability metric	Dimension	Probability
Reserve margin	Available capacity margin (% of peak demand)	None
Expected energy not served (EENS)	ENS magnitude (MWh)	Average value
Loss of load expectation (LOLE)	ENS frequency (hr/yr or days/yr)	Average value
P95 (95th percentile)	ENS frequency (hr/yr)	Tail risk, 1 in 20 year event
Loss of load probability (LOLP) for a specified ENS volume	ENS frequency (hr/yr)	Probability of a specified ENS level

Note: ENS = energy not served.

Currently there is little standardisation of reliability standards between regions, with many countries still using reserve margins and others progressing into adopting a range of probabilistic metrics, although a standardisation initiative is ongoing in Europe, for example. Most countries using probabilistic metrics apply only a single measure, with the consequence that in a single region not all the main variables (magnitude and frequency, average and tail risk) are typically considered.

The current approach in Korea combines a probabilistic standard with a reserve margin approach. The standard is expressed in terms of a probabilistic metric, LOLE, which is set at 0.3 days per year. At the same time, meeting the standard in practice involves targeting a certain reserve margin – for the 9th BPLE planning period this is set to remain above 22%, and reach 33% at its peak in 2024. In the last few years in practice the margin has reached as high as 37%.

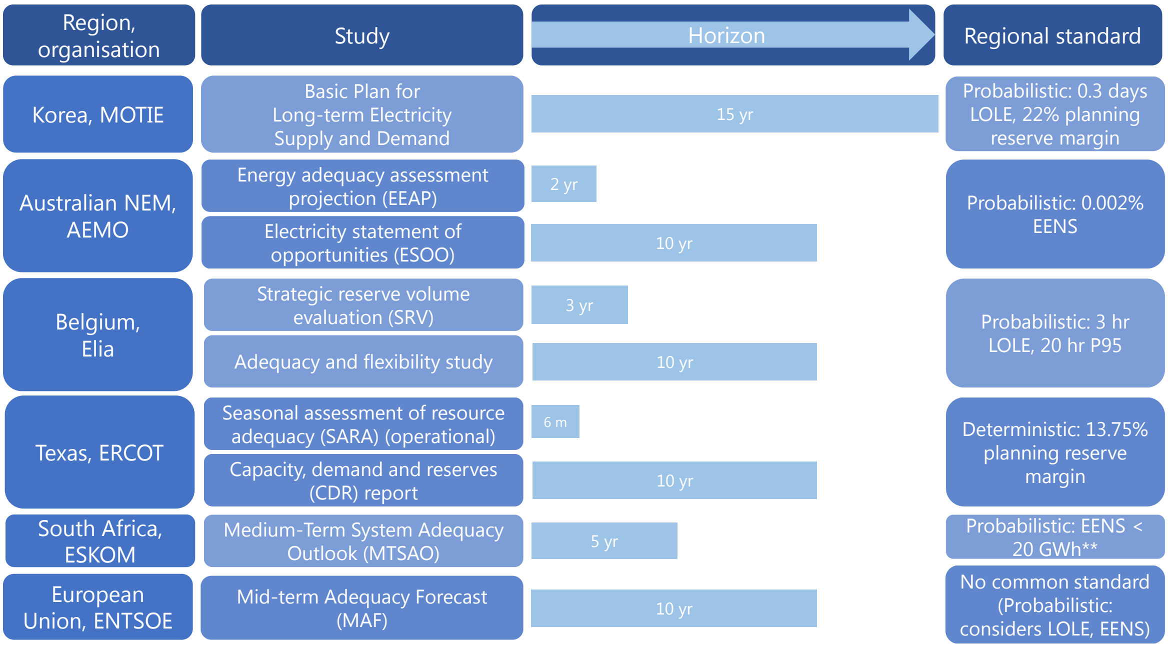
During the energy transition it will become increasingly important to consider more than only the average probability of outage expressed in LOLE. Beyond the average frequency of outages, the depth and duration of outages also have implications for the impacts of supply shortfalls and as a result affect their acceptability. For example, even if there are few events, longer interruptions could be unacceptable for a country like Korea with a summer cooling peak, since long outages in extreme weather situations can entail safety risks. Similarly, a very "deep" shortfall where a large proportion of load cannot be supplied is likely to be unacceptable even if it is of very short duration. Alone, none of the individual metrics above can capture all relevant aspects. While the metrics are related (for example, as LOLE increases so does P95), these relationships differ between systems and are also expected to change with increasing renewables as systems go through their energy transition.

In the context of energy transitions with higher shares of renewables and greater flexibility enabled, it is highly recommended to move from reserve margin approaches to probabilistic metrics, to monitor metrics that encompass both the magnitude and frequency of energy not served, and to consider both average and more extreme system conditions. As electricity becomes more important in our economy, policy makers and regulators need to review the reliability standards applied to the electricity system so that they remain consistent with the cost of power interruptions to society, as well as taking into account societal acceptability and the cost to society of both average and extreme outage events.

Detailed probabilistic adequacy assessments become more critical

Adequacy assessments are routinely undertaken in many power systems today. They contribute to the suite of power system planning processes that ensure a reliable system and inform system operators, policy makers and all market actors on how to meet reliability obligations. Regions often have multiple adequacy assessments that focus on different time horizons. Some assessments have a legal basis while others are for information purposes only, and many are required on an annual basis while some additional assessments are performed ad hoc.

Figure 4.4 Comparison of adequacy assessment methodologies



Power systems with rising shares of renewables are increasingly making use of probabilistic assessments in long-term planning to better understand the effect of greater variability on various adequacy scenarios.

Adequacy assessments can also be used to examine different development pathways or scenarios for both electricity demand and supply. Including scenario analysis in adequacy assessments is an important measure to guide investment needs while accounting for policy and development uncertainty. There is a general trend towards simulation approaches with increasing levels of detail in multiple dimensions.

In Korea the planning process up to and including the 7th BPLE made use of the Wien Automatic System Planning Package (WASP-IV), which is a planning tool allowing for capacity expansion optimisation with the capability of targeting reliability criteria such as LOLE based on a probabilistic treatment of generator outages. In the 8th BPLE, WASP was only used for calculating the reserve margin needed to meet the 0.3 days per year target. Overall, for both the 8th and 9th BPLE, an optimisation approach to capacity expansion was not implemented as the policy objectives from the 3rd Energy Master Plan set the course for capacity additions over the respective planning periods.

Instead, the equivalent load duration curve method was applied to calculate the loss of load probability and hence evaluate the ability to meet the LOLE reliability standard. This approach allows for probabilistic analysis that incorporates the uncertainty in generator outage patterns as well as the variability of renewable supply and load. In addition, in the Korean assessment different scenarios are created by forecasting the upper and lower limits of future uncertainties, such as GDP, temperature and renewables variability.

The incorporation of these uncertainties within probabilistic analysis for generator outages in the BPLE is a very positive step for preparing to integrate large shares of variable renewables. At the same time, the current approach still lacks some of the benefits of more detailed probabilistic analysis based on detailed Monte Carlo simulations, which are being applied in an increasing number of regions. For example, ENTSO-E in Europe has adopted Monte Carlo simulation since 2016 and is still actively developing the methodology it applies (ENTSO-E, 2017; 2020), and the approach is also used in countries including Australia, Belgium and France. As energy transitions advance, older approaches become less fit for purpose in particular because of their limitations in evaluating systems with more VRE, demand response and interregional dependencies.

Korea should consider the implementation of Monte Carlo-based simulations – this could be part of the existing planning process, but could also be a supplementary exercise as is the case for a number of regions. This would open the door to multiple improvements for the accuracy and comprehensiveness of the assessment, including:

- Options for a more detailed and accurate assessment of the VRE contribution, accounting for variability in weather patterns across decades-long time frames as well as site-specific parameters and correlations over larger areas.
- The opportunity to better represent load variability, accounting for correlated variations in renewables across decades-long time frames and the price-responsiveness of various demand sectors, and including explicit demand response options.
- The ability to better represent planned and non-planned generation and transmission outages and their interactions.
- The possibility of assessing adequacy across larger regions, allowing the potential adequacy contribution and interaction of interconnected areas to be accounted for.
- Improved inclusion of system operating reserve margins and main system contingencies.

In a simulation approach, generation and transmission outage statistics can be combined with a detailed representation of the physical topology of the system. Possible outcomes can be simulated for many different random patterns of outages across all technologies. This provides a more accurate picture as opposed to considering each piece of infrastructure separately, and also provides a statistical spread of possible outcomes. Linking with the discussion on reliability standards above, a Monte Carlo analysis allows the assessment of all aspects of reliability risk, including the frequency, depth and duration of potential outages. This allows all parameters that are relevant to acceptability to be tracked, rather than only average risk. For example, forthcoming analysis from the IEA on secure energy transitions in the power sector includes a case study on Monte Carlo analysis for China's electricity system in 2035 (IEA, forthcoming).

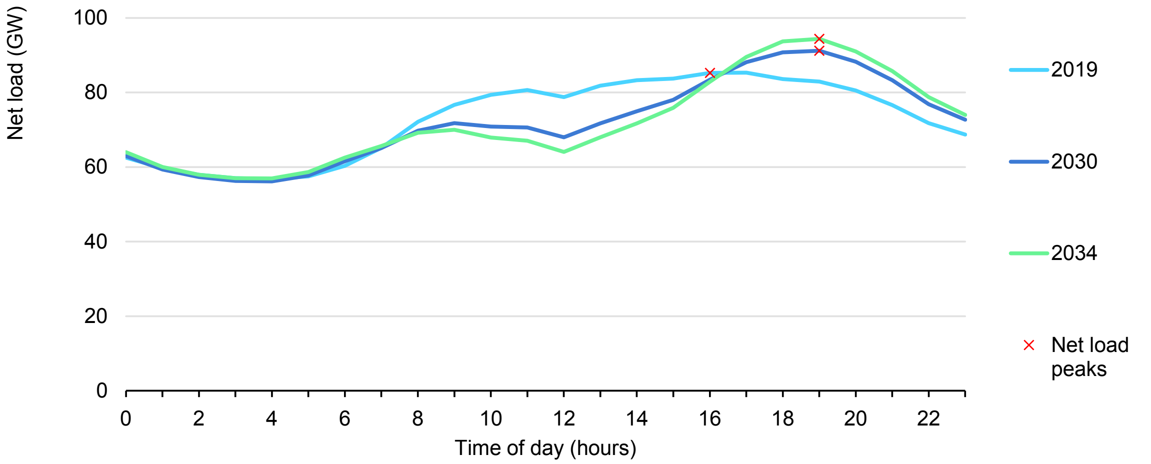
A good illustration of the benefits for Korea of undertaking a more comprehensive probabilistic assessment is in the context of VRE increasing its share of generation. In assessing the contribution of renewables to adequacy, the interaction between renewable generation and peak load periods is fundamental. For the 8th BPLE, to determine the contribution of renewables to the reserve margin, Korea applied a method based on the net qualifying capacity method used in California for this purpose. The approach helps to address some of the challenges inherent in assessing the contribution of VRE to adequacy, for example using several historical years of data (three in this case) to help account for inter-annual variability of renewable supply, and focusing on several peak time periods rather than a single peak hour or day.

However, this method still focuses on specific peak periods – for Korea currently this is 1 pm–5 pm in July and August and 10 am–2 pm in December and January. However, as renewables input increases, the peak requirement for dispatchable capacity is determined by the load profile minus renewables supply, i.e. net load. Analysis of the load and net load peaks for the present and 2034 illustrates that the impact of renewables is different for the winter and summer peaks – in winter they cause a shift in the days where the peaks occur and in summer they push the peak timing to later in the evening. The timing of the system peak load in Korea has varied between summer afternoons and winter mornings over the past decades, with the two peaks quite close together in magnitude. While the 9th BPLE anticipates a future peak in winter, this implies the need to pay continued attention to reliability needs for both summer and winter peaks.

Table 4.2 Timing of winter and summer total and net load peaks in 2019 and 2030

Peaks	2019	2030
Winter total load	9 January, 9 am	9 January, 10 am
Winter net load	9 January, 9 am	12 February, 10 am
Summer total load	13 August, 4 pm	13 August, 5 pm
Summer net load	13 August, 5 pm	13 August, 8 pm

Figure 4.5 Evolution of summer net load peaks with an increasing share of VRE, Korea



Note: In 2019 peak demand occurred on 13 August, while the load projection in 2030 has a winter peak according to the assumptions in the 9th BPLE. For this section the load forecast is generated using 2019 load as the basis and peak and total growth rates from the 9th BPLE. Current VRE profiles were scaled up, using data from KPX, based on the projected increase in installed capacity from 2019 to 2030.

Source: IEA analysis using installed load growth projections from the 9th BPLE and VRE generation profiles from KPX.

The Korean summer net load peak is expected to shift into the evening with increasing solar generation in 2030 and 2034. As a result, the capacity contribution of solar in summer needs to be reassessed for each future capacity level, as further solar capacity will not contribute to peaks occurring after sunset.

As a result of interaction between renewables generation and the load profile, a capacity credit (i.e. the percentage of renewables capacity that contributes to peak load) calculated on the basis of the tightest hours today will not accurately capture the contribution to a future system – as the renewables penetration increases, the capacity contribution needs to be reassessed. While it is possible to adjust the existing method to account for these changes, moving to a full probabilistic assessment based on many years of weather data is a powerful tool to integrate the variability of renewables fully into the assessment, so that the system-specific contribution of renewables can be assessed accurately for future years.

An integrated probabilistic assessment can also capture the interaction between renewables generation and new elements on the demand side. For example, in the 2030-2034 Korean system, evening EV charging would be expected to exacerbate the summer peak, and as a result smart charging programmes become more important. This is in contrast to the situation today where evening charging has little effect on peak demand seen in summer afternoons or on winter mornings. By integrating estimates of the charging curve into the projected demand profile it becomes possible to both account for these interactions and model the impact of smart charging approaches. While it is positive that demand-side targets in Korea are currently reflected in the BPLE, assessments may miss the complex interaction between demand-side measures and the variability of the load profile in combination with renewables output when decision makers seek to incorporate these targets in the form of modifications to the demand or peak growth rate.

Ultimately, probabilistic simulation approaches provide a platform for weather-dependent correlated variables, such as load and renewables generation, to be assessed using data across decades-long time frames with the support of long-term weather datasets that have become available over recent years (e.g. ENTSOE Medium-Term Adequacy Forecast). Other sources of uncertainty such as generator outages and demand forecast uncertainty – as well as uncertainties in the input data and assumptions – can also be included in the assessment so that the combined probabilities of different elements are considered together. In this way the risk and profile of potential outages can be more accurately assessed, and at the same time the contribution of more complex time-dependent resources such as renewables generation and demand response can be better included.

Understanding Korea's target reliability standard and planning reserve margin in the context of energy transitions

Even rare, isolated power outages can have severe economic consequences as well as posing health and safety risks. At the same time, the levels of demand seen in the highest peak load hours occur only rarely, and building sufficient generation to cover all possible levels of demand under all possible circumstances implies a high cost for infrastructure that is little used.

Reliability standards target a balance between the costs of power interruptions versus the infrastructure costs associated with increased reliability and define the point at which capacity investment should be undertaken. An unnecessarily high reliability standard implies increased costs for capacity that is little or never used, while too low a standard results in the risk of capacity shortfall.

An important distinction is that reliability standards set in terms of energy shortfalls focus on adequacy – sufficiency of the system to meet peak demands – and do not encompass types of outage based on other variables. It is also important to recognise that the reliability standard does not directly predict how often load shedding or full blackouts will occur. It is an indicator of the level of sufficiency in the system. Power systems should always have emergency mechanisms in place to help manage the system under conditions of stress.

Most outages are not due to adequacy shortfalls, although those that are include some of the most long-term and economically damaging outages. This large downside risk typically drives a relatively conservative approach to reliability.

The first component of Korea's planning reserve margin, the adequacy reserve, is 13% to cover planned and forced outages, retrofits, variability of VRE and forecast errors. This value is similar to planning reserve margins in other regions (e.g. 15% in China, 13.5% in ERCOT). The uncertainty reserve adds another 9%, to account for uncertainty in the demand forecast and possible delays in the installation of power plants, bringing the total planning reserve to 22%.

As a target margin this is quite high compared with other countries, although it is worth noting that many regions in practice sit quite far above their target reserve margin or reliability level. In addition Korea currently has no cross-border interconnections, so it cannot rely on spare capacity in neighbouring systems to ensure adequacy. A KEEI study comparing the 22% planning reserve margin of Korea with historical reserve margins in OECD countries with similar or larger maximum loads (the United States, Japan, France, Germany and the United Kingdom) found that the Korean target is close to or even lower than average historical margins in those countries, which ranged from 21% to 37%. Conversely, the observed margins were lower for another set of countries with smaller power systems than Korea's, but with similar economic growth rates and electrical systems, such as Mexico, Turkey and Australia at 15% to 19%.

Given the low level that the Korean capacity reserve margin fell to in practice in 2011, and the necessity of rolling outages to manage peak demand in the summer of that year, it is appropriate that measures were undertaken to ensure capacity would be sufficient in future years. It is noted that changes were made on multiple fronts to this end.

During energy transitions, a strong analytical basis to understand reliability and its costs becomes increasingly important to ensure that systems can continue to meet traditional expectations of reliability while embracing new technologies and maintaining appropriate economic efficiency.

VOLL helps to quantitatively assess outage costs to support setting reliability standards

Many reliability standards are based on experience-based rules defining an acceptable level of interruptions. Reliability standards can also link directly to an economic quantification of the cost of supply shortfall, or the value of lost load (VOLL, expressed in USD/kWh), so that a balance is achieved between the cost of outages and the cost of new capacity or operating little-utilised resources.

To set reliability standards based on this economic balance requires careful estimation of the VOLL, as well as the cost of new entry,[1] the potential for supply and demand flexibility and especially consumers' willingness to pay, which is evolving strongly. Great Britain, for example, uses a LOLE of 3 hours per year as a reliability standard. This is based on the average of nine possible cases, considering various estimates of the VOLL and costs of new entry. A reliability standard of a 3 hours per year LOLE is also applied in many other systems.

Table 4.3 Definition of LOLE reliability standard in Great Britain based on the average of nine scenarios centred on VOLL and the cost of new entry

Equilibrium reliability standard in LOLE (hr/yr)		Cost of new entry (GBP/kW)		
		LOW GBP 31.89	CENTRAL GBP 47.18	HIGH GBP 66.21
VOLL (GBP/MWh)	35 490	0.90	1.33	1.87
	16 940	1.88	**2.78**	3.91
	10 290	3.10	4.59	6.43

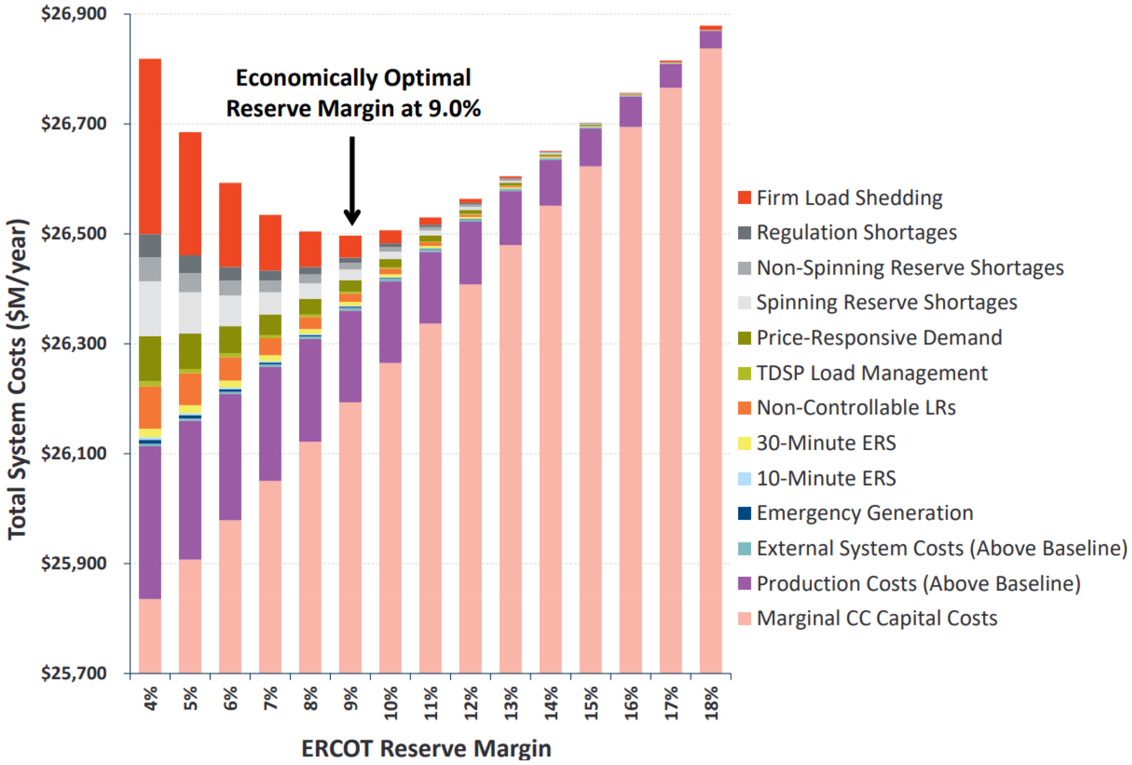
Source: DECC (2013), *Annex C: Reliability Standard Methodology*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223653/emr_consultation_annex_c.pdf.

In most regions reliability standards appear to be set above the theoretical economic optimum – higher reserve margins come with higher costs, as more resources are paid to stay online even if they are seldom used. There is still a benefit to be recognised, however, as they provide a certain level of insurance and the costs of overcapacity to society are at least partially compensated by the economic value of avoiding interruptions. This means that beyond an optimal level, the net cost of additional capacity in the system initially increases slowly, as reduced interruptions bring additional benefits – up to a point. This relationship has been explicitly investigated for the ERCOT system, where the potential benefits from minimising load curtailment risks are negligible beyond a reserve margin of 12%. This is only 3% percentage points higher than the overall economic

[1] Cost of new entry here refers to the cheapest cost for new peaking plant.

optimal reserve level at 9%, and below the reserve margin of 13.5% that would be enforced by a “1 event in 10 years” planning standard.

Figure 4.6 Total system costs across planning reserve margins



Source: ERCOT(2018), Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region, http://www.ercot.com/content/wcm/lists/143980/10.12.2018_ERCOT_MERM_Report_Final_Draft.pdf

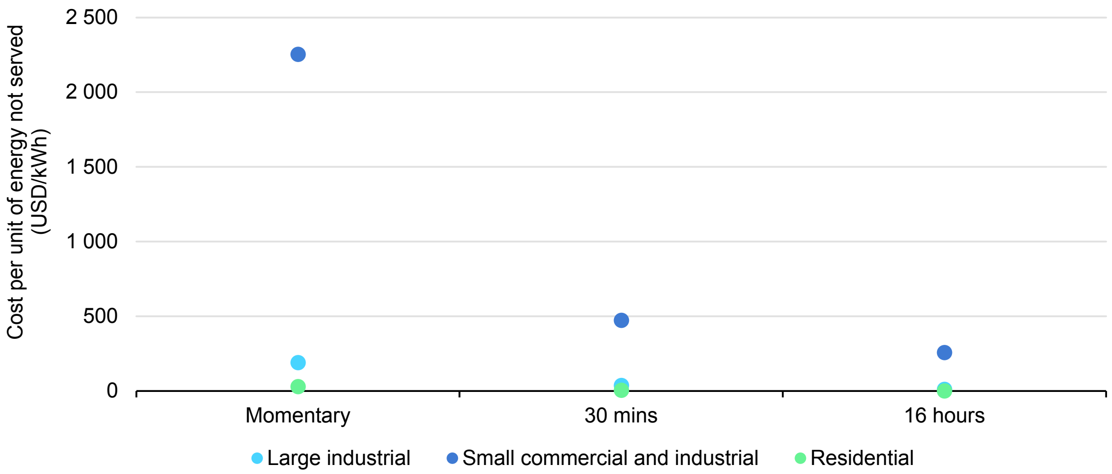
Regardless of whether VOLL is used directly in setting the reliability standard, VOLL approaches such as those adopted in the United States and most European countries can be useful for policy makers to better understand the varying impacts of supply disruptions on different consumers at different times. Understanding VOLL potentially helps to identify targeted measures to manage reliability through, for example, demand response programmes, operational practices and infrastructure investment.

Every outage is different, and the economic impact of an outage can depend on many factors:

- **The affected consumer group**. For example, in the United States a countrywide assessment of the value of reliability found differences in the economic impact of supply disruptions on various consumer groups, with the cost per kWh for small commercial and industrial consumers being up to nearly 200 times that for residential consumers for the same outage duration (Sullivan, Schellenberg and Blundell, 2015).

- **The duration**. The US study also found the cost per kWh for momentary outages could be almost 24 times the cost per kWh for long-duration (16 hour) outages, although the total cost of longer outages is of course higher.
- **The time of day**. A 2013 assessment of the economic cost of electricity supply interruptions in Germany estimated that, at a national level, average total hourly costs amount to around EUR 430 million, but reach a peak between 1 pm and 2 pm on a typical December Monday at EUR 750 million (Growitsch et al., 2013).
- **The region**. The German study also found that the greatest impact was concentrated in the states of Baden-Württemberg, North Rhine-Westphalia and Bavaria, which have larger populations and greater economic activity compared to the rest of the country. Relative costs between consumer groups also vary from studies covering different regions; for example a study on VOLL frequency distribution in the European Union found that residential loads show a higher average VOLL than most other segments (ACER and CEPA, 2018), in contrast to the US study where the highest costs were for small commercial and industrial users.
- **The season**. Power outages can have different impacts across consumer groups depending on whether they happen in the summer or winter, expressed as the share of economic losses (Growitsch et al., 2013).

Figure 4.7 Comparison of VOLL values across consumer groups



Source: Sullivan, Schellenberg and Blundell (2015*), Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, https://emp.lbl.gov/sites/all/files/lbnl-6941e.pdf.

VOLL estimates vary widely depending on the duration of outages and the consumer groups affected. Region, season and time of day also affect the cost of outages.

Finally, VOLL is meant to capture the marginal cost of a small amount of electricity not supplied, derived for each customer, be it a household or commercial and industrial customer. It does not evaluate broader impacts on the entire economy from large-scale events, long-term supply shortfall, or lack of electricity access. Irrespective of the actual cause, traditional VOLL assessments fail to reflect the economic damage caused by long-duration and large-scale supply interruptions.

Thus the VOLL is integral in very specific applications. These include cost-benefit analysis of grid investment, at the transmission level for interconnectors as well as for distribution (undergrounding, faster fault detection, etc.). VOLL can also be used to determine an appropriate target level of LOLE for the reliability standards that are used in adequacy assessments to determine capacity requirements, and to set targets for specific cost-reflective market designs.

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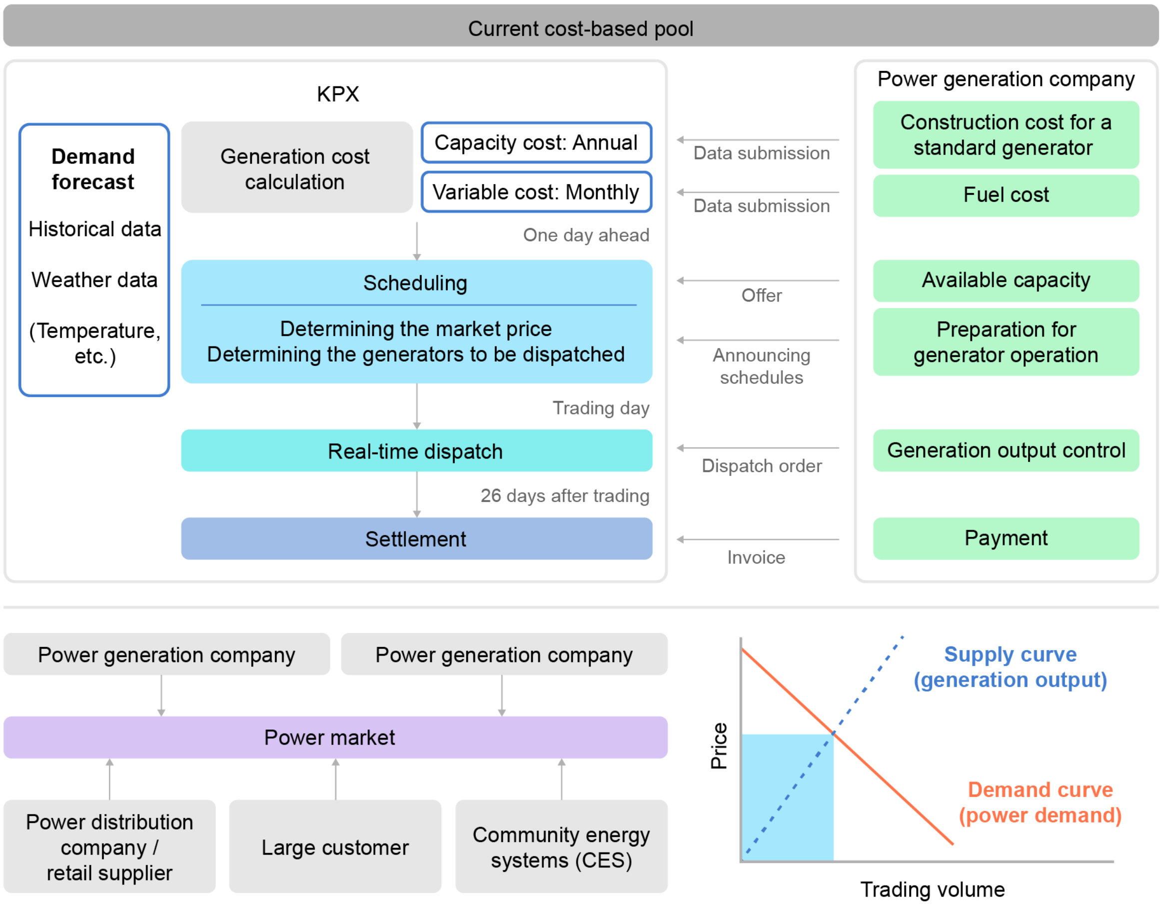
Chapter 5 – Improving market design

Current practices for wholesale market operation and reserves

Korea runs a cost-based mandatory pool in the wholesale market. The remuneration is based on both a capacity payment and the SMP. The capacity payment covers the unit's fixed costs and is determined annually by KPX. KPX runs the wholesale market based on the audited variable cost of the marginal plant. The variable costs of plants are reviewed on a monthly basis and determined by KPX. Variable costs are mainly based on fuel cost and include the following components: fuel cost per gigacalorie, heat rate coefficient to formulate a quadratic curve of fuel consumption according to output level, cost of hot start-up and shutdown, auxiliary demand, and other costs (e.g. water).

Figure 5.1 Korean electricity market planning and procurement process



Source: KPX (2015), *Electricity Market Trading Process*, https://www.kpx.or.kr/eng/contents.do?key=299.

In the past, KPX scheduled the system in two steps: the first was a day-ahead dispatch used to set the price; the second was a constrained dispatch model that took into account network and reliability constraints. Based on the security-constrained dispatch model, KPX adjusted the schedule for plants in real time and remunerated them in two ways depending on whether they were instructed to reduce or increase their output to stay within the power system's security constraints. Following a reform introduced in December 2020, the KPX price formation mechanism has been updated to account for network and reliability constraints. This is an effective change that will assist in the integration of VRE generation, while mitigating the potential increase in the need for post-market balancing and the corresponding costs. However, there is still ample room for further improvements in the KPX price formation mechanisms.

Currently, in order to ensure that all thermal generators have enough spare capacity, fossil-fired units' declared availability is capped at 95% of their rated output in the first scheduling step. The remaining 5% is required to be available for reserves and is remunerated on a regulated cost-basis through specific upward and downward dispatch payments, CON (constrained on) and COFF (constrained off) respectively. KPX makes sure that enough reserves are available in every hour based on the headroom available at scheduled generators.

In order to procure sufficient reserves, KPX uses three types of frequency control products: primary, secondary and tertiary. However, because the system has asymmetric remuneration mechanisms depending on whether plants are dispatched upwards or downwards, there is concern that the reserve mechanisms reward only the avoided regulated cost in each specific hour, rather than remunerating the system value of assets that deliver according to the power system's needs. Furthermore, KPX currently has a fixed yearly budget for ancillary service costs, an approach that may need to be reviewed as the share of VRE increases and the need grows for improved mechanisms to mitigate and allocate balancing costs.

Table 5.1 Structure of ancillary services operated by KPX

Frequency control type	Steady state	Contingency	Control	Response time	Duration	Resources
Primary	Primary reserve		Automatic provision from generators	10 sec	5 min	Generators (GF), primary ESS
Secondary	Frequency control reserve	Secondary reserve	KPX EMS automatically giving orders based on cost and response time	5–10 min	30 min	Generators (AGC), secondary ESS
Tertiary		Tertiary reserve, quick response resources	KPX operator manually giving orders (PSH is preferred)	30 min (tertiary reserve) 20 min (quick response)	4 hr	Generators

Notes: EMS = energy management system; GF = governor free service; AGC = automatic generation control.
Source: KPX (2021), *Rules of Market Operation*, https://kpx.or.kr/www/selectBbsNttView.do?key=29&bbsNo=114&nttNo=21790&searchCtgry=&searchCnd=all&searchKrwd=&pageIndex=1&integrDeptCode=.

This same issue has been observed in a number of markets that either, through product design or the price formation mechanism, insufficiently acknowledge the opportunity cost of asset dispatch and how this affects later settlement periods. Moreover, they may fail to recognise the value provided by fast-acting resources that may be able to serve steep system ramp requirements. This is one of the key areas of improvement for the Korean power market, which need to be addressed in more detail in further studies.

Integrating balancing services and the wholesale market

Current reform in the market

The day-ahead energy market structure, as currently implemented in Korea, complements systems that have a traditional generation mix. Because committing thermal generating units involves significant start-up costs, minimum run times and other fixed costs above the cost of fuel, accounting for and optimising the decision to commit resources one day before operation reduces overall system costs compared to an approach that only considers fuel costs. However, with the introduction of significant amounts of VRE, along with demand response, there is a growing need to adjust dispatch schedules to reflect new information about supply and demand conditions closer to operation.

A real-time market is therefore desirable so that adjustments can be made to commitment decisions that will optimise system resources. Instead of procuring energy and ancillary services separately, ideally the two should be harmonised within the same optimisation step in the day-ahead, intraday and balancing markets. Particularly with the increase in VRE and distributed energy resources that are able to offer ancillary services, such as BESS and smart appliances, offers of energy and ancillary services can be co-optimised. In this way, the lowest-cost combination of resources can be chosen while respecting the security constraints of the system. The resulting bids, offers and prices will also provide valuable information about the long-term economics of the system and reveal where investment in generation and transmission is necessary.

Addressing balancing responsibilities

The capacity payment, SMP, ancillary service costs, and redispatch costs (CON, COFF) are included in KEPCO's buying cost and are passed onto customers via tariffs. Currently there is no penalty for either demand or supply causing an imbalance. While the price formation reform of December 2020 is expected to help reduce the overall level of redispatch, it will still be necessary to allocate appropriate balancing responsibilities so that power market actors have an incentive to reveal their availability and consumption as accurately as possible.

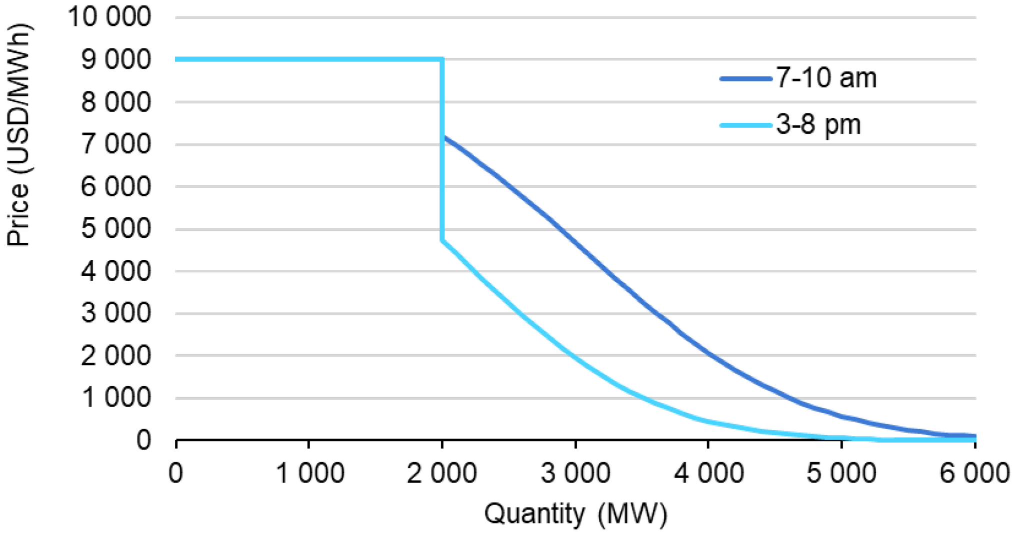
With the introduction of the real-time market due around 2025, there is also a plan to introduce an imbalance system similar to the UK flagging and tagging approach, which is generally analogous to ERCOTs scarcity reserve curve described below. An additional option for improving efficiency in Korea's power market could be the introduction of virtual markets, as done by some US independent system operators. Virtual markets can improve convergence between day-ahead schedules and real-time operations, and provide the incentive for market participants to improve their forecasting and short-term balancing.

Linking scarcity and price signals across market horizons

A cost-based SMP system can be preferable to market-based pricing in a number of circumstances. It is particularly valuable in systems in which there is little competition between generation providers, which makes the markets susceptible to gaming. Even in this situation, however, it is important to express the value of energy not simply as linked to the price of the marginal fuel, but also to the value of maintaining electricity security and avoiding loss of load events. This is particularly relevant for systems in which there is potential for significant penetration of resources without fuel costs. Resources such as battery storage, PSH and demand response require new bidding structures where price formation accurately reflects the value of scarcity.

An operating reserves demand curve is one way to administratively reflect the value of the contribution towards adequacy provided by resources that can quickly respond to changes in system conditions. For example, in ERCOT in the United States, a system with an energy-only market, the average price was USD 47.06/MWh in 2019, but for 28 hours the energy price was over USD 1 000/MWh and for 2 hours the price reached the system-wide offer cap of USD 9 000/MWh. These hours with price spikes represent the majority of revenues for peaking power plants and flexibility providers like distributed energy resources, storage and demand. Introducing scarcity pricing is important to reflect the increasing value of reserves as available reserves decline and encourage investment in flexibility.

Figure 5.2 Operating reserves demand curve in ERCOT



Source: ERCOT (2020), *Methodology for Implementing ORDC to Calculate Real-Time Reserve Price Adder*, http://www.ercot.com/content/wcm/key_documents_lists/89286/Methodology_for_Implementing_ORDC_to_Calculate_Real-Time_Reserve_Price_Adder.zip.

An operating reserves demand curve creates an incentive for resources to be available during periods of shortage whenever they may occur.

Current practices in capacity payments

In a cost-based pool system – particularly one in which the payment mechanism is based on average costs across a broad range of unit types – the recovery of fixed and sometimes variable power plant costs depends on capacity payments. In particular, peak generators will theoretically rely on capacity payments to recover all their fixed costs as well as some variable costs that are not captured by the SMP. In Korea capacity charges are paid to centrally dispatched generators according to the available capacity registered in the day-ahead market, regardless of the actual amount of electricity traded or generated.

The capacity payment is decided based on fixed costs (construction cost + fixed operational cost) divided by the rated available hours over the expected lifetime of the reference generator. The reference generator indicates the long-term marginal generator, which is an open-cycle gas turbine, and remains unchanged despite the fact that there are only CCGTs currently operating in Korea. The capacity payment is then adjusted according to the technical characteristics of each generator, such as age and location on the system.

The capacity payment can be a viable solution for the “missing money problem” that arises in energy-only markets, when price caps eliminate a key source of rents that would be received by generators and which are meant to cover their fixed costs. In addition, the grid is an essential facility that has unique characteristics such as the need to match supply and demand in real time to maintain system stability. This creates a security of supply externality whereby an individual consumer or plant operator can negatively affect other system users with their behaviour.

While Korea has prioritised policies to encourage demand-side management to reach adequacy goals, including the use of distributed energy resources, energy efficiency and variable retail rate schemes, these policies have not yet been fully implemented. Therefore, the system operator needs to ensure – through the capacity payment – timely investment and adequacy levels so that enough marginal resources are available to meet a reliability standard that is greater than most individual users' private VOLL. The capacity payment has thus contributed towards the investment in new resources that have substantially increased the reserve margin and improved reliability metrics.

Improvements to the capacity payment mechanism

The capacity payment in Korea varies slightly compared to other systems, such as PJM in the United States, which base their markets on the principle that capacity value should reflect the missing money of the marginal generating unit, i.e. the net of the annualised fixed costs and the margin received on energy and ancillary service payments in the market. KPX instead pays the fixed cost based of the reference generator, and does not adjust for energy and ancillary service revenues. Margins received in the energy market will need to cover fixed costs for units that are infra-marginal, or baseload, as they receive both the difference between their variable costs and the hourly SMP and the capacity payment, which covers some, but not all, of the unit's fixed costs.

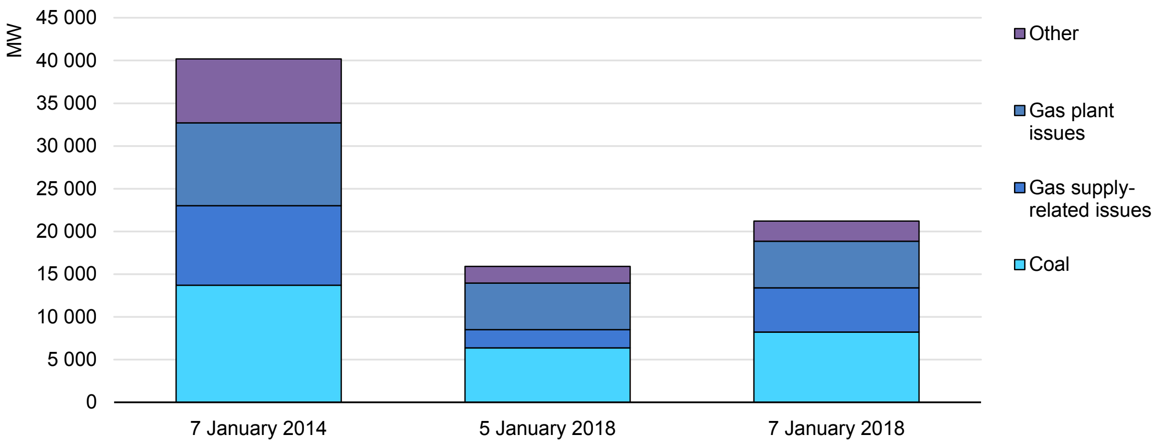
In Korea capacity payments support renewables through a fuel switching factor, with coal receiving a penalty and more efficient LNG plants receiving a bonus. Using technology-specific pricing is also not as flexible and adaptable when incorporating new technologies like distributed energy resources, multiple battery storage chemistries, demand response or energy efficiency. A system that compensates all resources equally, based on the annualised net CONE (cost of new entry), which is CONE less the energy and ancillary service margin, will more closely align the adequacy value of each resource with the costs paid by consumers. This would remove the role of the fuel switching factor in providing an environmental incentive, which can be more efficiently addressed by other markets such as a carbon price.

The capacity market design should also reward actual resource contribution towards system adequacy by linking the payment to resource availability during periods of system stress instead of just year-round availability. In Mexico, for example, the capacity payment is based on 100 hours, calculated ex post, during which the system was shortest of reserves. In this way, the payment relates more directly to the value provided to the system by avoiding reserve shortages and load-shedding events and the economic damage that they incur.

For example, PJM introduced a capacity performance mechanism in 2016 as a response to a severe cold snap called the "polar vortex" in January 2014, which drove outage rates up to 22% among capacity-cleared resources due to fuel supply issues, ambient temperature effects on unit performance and boiler system failures. As a result, energy prices reached nearly USD 2 000/MWh and PJM had to take extraordinary measures, including voltage reduction and emergency demand response, to avoid load shedding.

The capacity performance mechanism introduced penalties to generating units that had received a capacity payment but did not perform during specified "performance intervals", which include emergency conditions when the system is stressed. The penalties can reach up to 150% of the yearly capacity payment received by a generating unit. In response, generating facility owners invested to strengthen the resilience of their fleets, including procurement of spare parts, weatherproofing of components and firming of gas supplies. The relative performance of the generating fleet in the 2014 polar vortex and the early 2018 cold snap that brought similar weather conditions to the PJM region demonstrates the effectiveness of the penalties. Unit outages were less than half in 2018 than in the 2014 event and, particularly, resources common to both years performed even better, lowering their outages rate from 12.4% to 5.5%.

Figure 5.3 Unit outages in PJM during stress periods before and after the introduction of capacity performance penalties



Source: PJM Interconnection (2018), *Strengthening Reliability: An Analysis of Capacity Performance*, https://www.pjm.com/-/media/library/reports-notices/capacity-performance/20180620-capacity-performance-analysis.ashx?la=en. –

Performance of capacity resources was significantly improved during stress periods after the implementation of non-performance penalties.

Regulation and oversight in the Korean power sector

The Korean Electricity Regulatory Commission (KOREC) was established in 2001 within MOTIE under the Electric Utility Act to oversee the regulation of the newly created single-buyer market, review issues concerning the rights of electricity consumers and settle disputes related to the electricity business. The Electricity Market Surveillance Committee, an entity under KOREC, is responsible for market monitoring. While KOREC has important enforcement functions, its role is limited to an advisory one. There is no independent electricity sector regulator in Korea and MOTIE remains the key regulatory entity. MOTIE's responsibilities also include the granting of electricity business licences, the approval of market rules, the approval of transmission and distribution tariffs and retail sales prices, and the regulation of wholesale electricity prices.

As the system operator, KPX is in charge of ensuring the security and quality of power supply. The Ministry of Economy and Finance is responsible for evaluating the performance of all public entities, including KPX and KEPCO. However, the metrics it uses only target supply reliability, without considering cost efficiency. They are benchmarked by past performance, requiring improvement every year by year, with no absolute targets in place for supply reliability. This could signal to KPX that it should achieve higher reliability no matter how costly (e.g. by introducing advanced systems for weather forecasting). The role of the regulator should include monitoring to manage increasing system costs in the context of the energy transition. There is a need to develop clear metrics and incentives to ensure that new system costs are handled as cost-effectively as possible.

The importance of strong regulators

The transition to a low-carbon power system requires the incorporation of policies such as carbon pricing and renewables support policies into a consistent electricity market framework. Competitive markets are an important tool, but they must be supplemented by regulation to ensure an effective transition to low-carbon power at least cost. The table below provides a high-level overview of such a market framework, i.e. the rules set by government and regulators and the associated role of competitive markets.

Table 5.2 Dimensions of market frameworks for decarbonisation

Objective	Policy	Type of regulation	Competitive markets
Low-carbon investments	*Carbon pricing*	• Carbon regulation	• Carbon price (trading scheme) • Long-term contracts
	Additional policy: Support schemes	• Low-carbon long-term support	• Auctions set support level • Integration in markets
Operational efficiency/ reliability and adequacy	*Short-term energy markets*	• Market rules • Scarcity pricing • Reliability standards	• Energy prices with a high geographical resolution • Energy prices with a high temporal resolution • Dynamic pricing offers
	Additional policy: Capacity markets	• Capacity requirements • Demand response product definition	• Capacity prices • Demand response participation
Network efficiency	*Regulation*	• Regional planning • Network cost allocation	• Congestion revenues • Transmission auctions
Consumption	*Retail pricing*	• Network tariff structure • Taxation and levies	• Retail competitive prices • Distributed resources

Source: IEA (2016), *Repowering Markets*, https://www.iea.org/reports/re-powering-markets.

As Korea's power system continues to diversify, both in terms of generation technologies and number of participants, it will need to update the rules for market operation and access. At the same time, oversight of market behaviour and outcomes will be critical to instilling confidence in the market and attracting investment. Therefore, the government should elevate the status of KOREC as the regulator of the power sector, and strengthen its responsibilities regarding market monitoring and the setting of both retail and non-discriminatory network tariffs in an efficient, cost-reflective manner, in addition to its current advisory roles (IEA, 2020a).

The government will also need to enhance the level of transparency of market operations through data sharing if it hopes to attract diverse market participation and new entrants. Data in sufficient spatial and temporal granularity related to generation, transmission and demand, released in a timely fashion, helps to identify potential operational efficiencies, investment opportunities and new business models, including distributed energy resource providers, aggregators and competitive retailers. Additionally, it assists outside experts such as consultants and academics to conduct research that can identify policy and operational improvements in market design or identify instances of market power abuse.

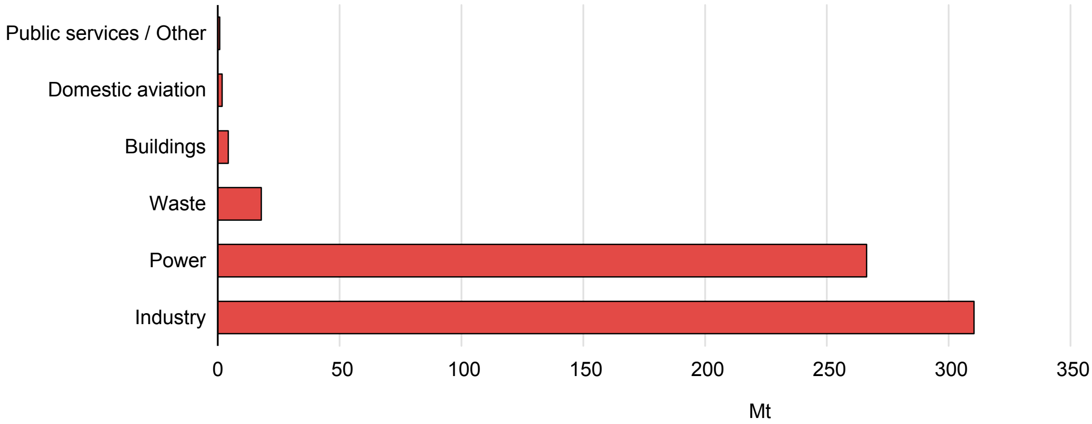
Linking carbon and power markets

Brief description of current ETS scheme

In 2015 Korea was the first country in Northeast Asia to introduce a nationwide emissions trading scheme (ETS) to reduce GHG emissions gradually in energy-intensive sectors, covering 70% of the country's GHG emissions (ICAP, 2020). Mandatory participation is required from companies whose total annual emissions were more than 125 kt CO_2 (or 25 kt CO_2 per facility unit) over the past three years. The emission units in the current ETS scheme comprise the KAU (Korean Allocation Unit), which is allocated by the government, and the KCU (Korean Credit Unit), which is transformed from the KOC (Korean Offset Credit) available via an offset scheme. The trading of these emission units is possible through a spot market operated by KPX, an over-the-counter market and an auctioning system.

Korea's ETS covers heat and power, industry, buildings, domestic aviation, waste and public services, with emissions from 2018 shown in the figure. Despite coverage of over 70%, the scheme suffers from low liquidity. Most allowances have been allocated free of charge either through grandfathering or based on benchmark emissions for different technologies used in different sectors. During Phase 1 (2015–2017) most sectors received 100% free allowances (including the electricity sector) through grandfathering, except for aviation, cement and oil refining which received free allowances using benchmark emissions for different products (Kuneman et al., 2021). During Phase 2 (2018–2020) this was expanded to seven sectors, including the electricity sector which was allocated 97% of its allowances free of charge. This will fall to 90% when moving on to the third phase (2021–2025).

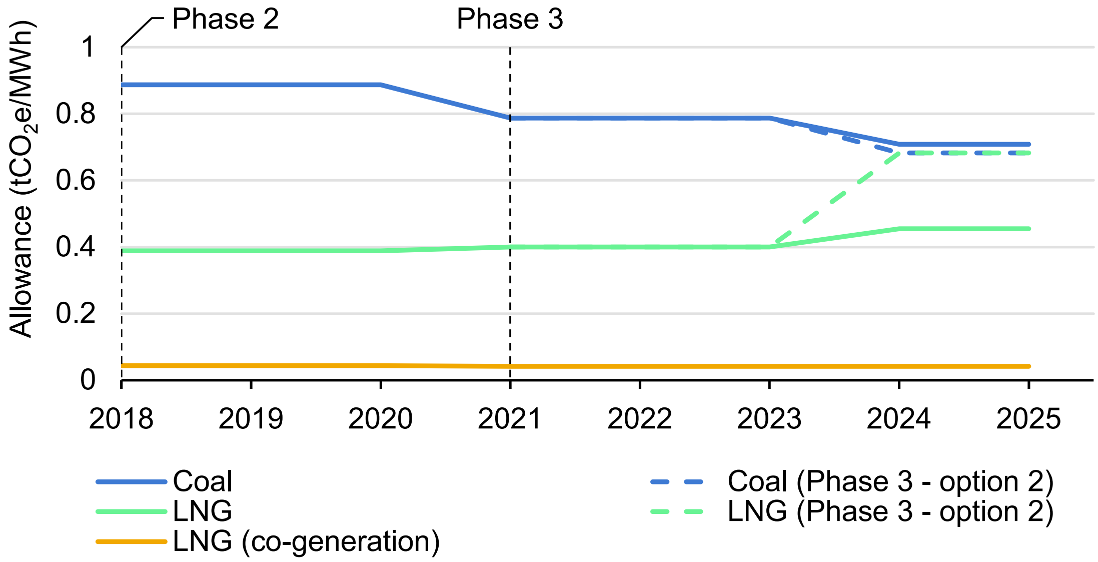
Figure 5.4 Emissions covered by the Korean ETS in 2018 by sector



Source: Kuneman et al., 2021.

To set the allowances for each generation technology in the power sector, as well as the price and volume limits for allowances, the ETS scheme has developed technology-specific benchmarks, regulating GHG emissions according to every unit of generation from power plants with the same fuels. The Ministry of Environment has proposed to reform ETS benchmarks for coal-fired and LNG thermal plants, gradually tightening coal benchmarks and loosening LNG benchmarks. This proposal was adopted with two different options diverging from 2024, introducing a uniform benchmark or a reduced gap between the benchmarks can remain under certain conditions: if additional policies on coal generation cap and price bidding are enforced (Figure 6.5).

Figure 5.5 Electricity sector benchmark allowances by technology

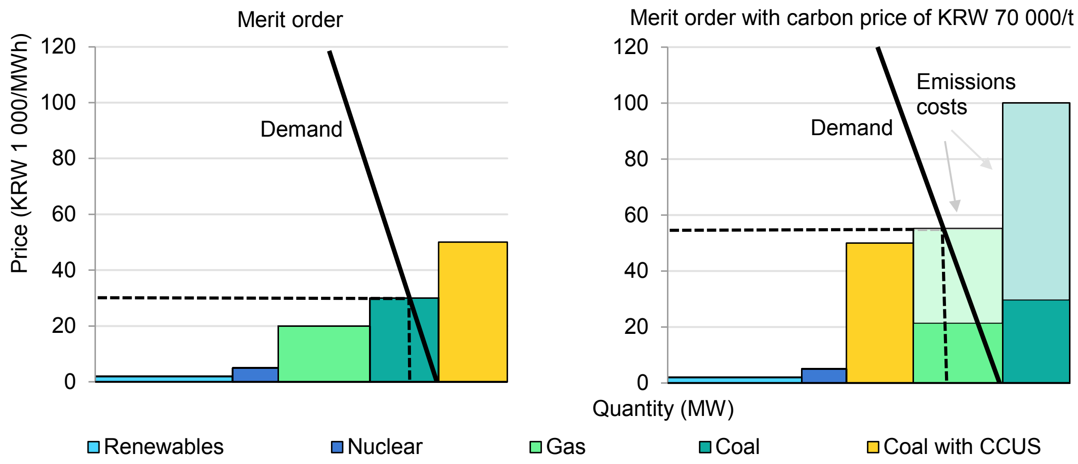


Source: Kuneman et al., 2021.

In 2018 the power sector was a net buyer of allowances, accounting for 44% of ETS emissions but 60% of allowances (GIR, 2020). As a result, price developments in the market are heavily influenced by the sector. Under the current market framework, the cost of ETS allowances is not reflected in the wholesale market prices, but is instead passed through to customer tariffs as KPX compensates generators for emissions exceeding the allocated allowances; the power sector must buy allowances to account for this. Hence, being a net buyer should increase their ETS costs, which are in turn paid by KEPCO and passed on to consumers. KPX compensates generators to cover the cost of buying allowances based on the net amount of allowances they purchase on the ETS and the average purchase price of allowances for each power producer, albeit a volume and price limit is in place according to benchmark emissions for each fuel type. While this compensation scheme can provide a slight incentive for efficient power plants, the combination of technology-specific benchmarks and the lack of a carbon cost in dispatch has significantly limited the incentive for the power sector to reduce GHG emissions.

In the 8th BPLE, the government stated its objective to introduce “environmental dispatch”, which aims to incorporate the cost of allowances into the electricity market to strengthen the competitiveness of LNG plants and facilitate fuel switching to less polluting sources of electricity (Kuneman et al., 2021). KPX has proposed amending its rules on the operation of the electricity market by 2021, with the Cost Evaluation Committee under KPX being tasked with integrating the cost of allowances into each generators' variable cost, which is used to determine the merit order and wholesale market prices. An illustrative example of how a carbon cost may shift the merit order for dispatch in Korea is shown in the figure.

Figure 5.6 Effect of carbon price on merit order for dispatch with representative operational costs of different generation technologies

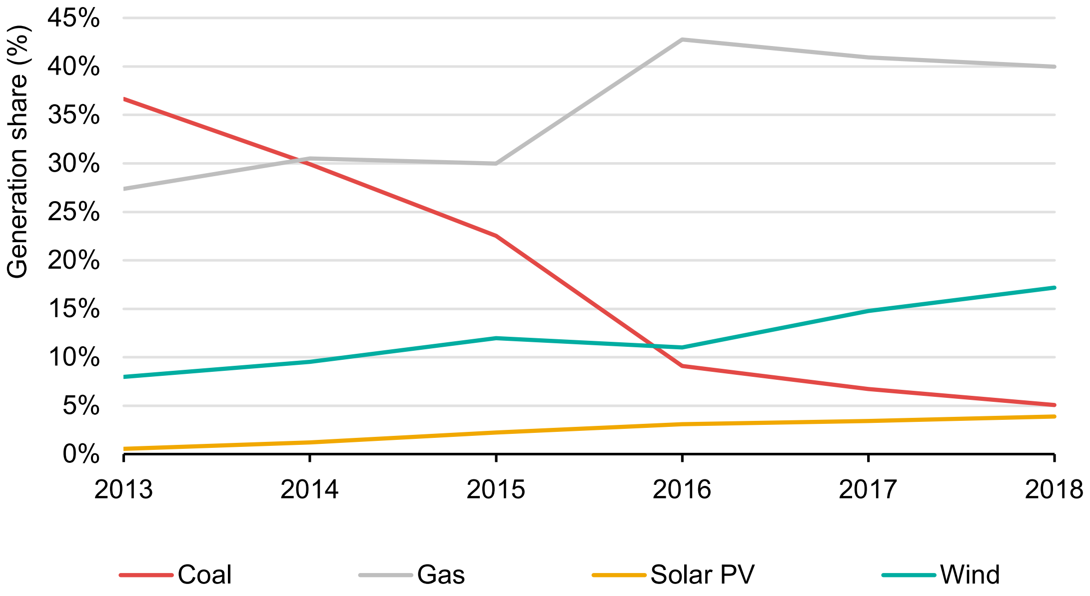


There are also plans to introduce a price-based pool market after 2024, which will enable decentralised price-setting for generators, allowing them to bid individually into the market based on their own cost profiles. This would allow the full costs of allowances to be passed through to the wholesale market.

While transitioning to an environmental dispatch will aim to re-establish the price signal in the ETS to reflect the cost of abatement via cleaner energy resources, there will be important considerations. Particularly during the period when the ETS costs transition into the wholesale market, there may instances where certain generators receive windfall profits that will ultimately be costs borne by the end consumer. While it would be necessary to remove the existing compensation scheme upon the transition of ETS costs into the wholesale market, it may also be necessary to implement an additional financial mechanism that restricts potential windfall profits for low-carbon generators as the market establishes liquidity and experiences price volatility.

At the same time, there may also be a need to support longer-term investment decisions due to similar teething issues, and so consideration of a minimum carbon price may also be needed. This was the view of the UK government when it implemented the carbon price support, whereby a UK-specific tax is added onto the price of carbon in the EU Emissions Trading System (Howard, 2016). First introduced in 2013, this has helped to provide stronger market signals for clean energy investment and dispatch than the EU ETS, and has facilitated both growth in renewable generation and a dramatic reduction in coal-fired generation, its share of generation declining from 37% in 2013 to 5% in 2018. The share of VRE generation grew from 9% to 21% over the same period.

Figure 5.7 Decline in the share of coal generation in the United Kingdom after the introduction of the carbon price support



Source: IEA (2020b), *World Energy Balances*. https://www.iea.org/reports/world-energy-balances-overview

Furthermore, in order to discover the true cost of abatement through market price signals, consideration should be given to the removal of other possible market distortions or inefficient environmental policy. Such distortions can arise, for example, from higher taxation per unit on some fuels despite lower carbon intensity. Since 2013 and through a subsequent amendment in 2019, Korea has taken good steps towards removing such distortions that may affect the effectiveness of the ETS.

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Chapter 6 – Climate resilience and cyber security

Integrating climate resilience in Korea's long-term planning for the power sector

The electricity sector has played a major role in climate change mitigation efforts in Korea. With a third of national GHG emissions coming from electricity generation, the Korean government has pushed for a clean energy transition. The energy transition is expected to contribute 42.2% of the power sector's GHG reduction (140.5 million tonnes) by 2030. Most importantly, Korea has recently announced a move towards the goal of carbon neutrality by 2050. Accordingly, the government submitted an updated long-term development strategy and nationally determined contribution to the United Nations Framework Convention on Climate Change.

However, the increasing climate impacts that affect all stages of the energy value chain underline the importance of adaptation efforts in the sector. Climate change directly affects generation potential and efficiency, physical resilience of transmission and distribution networks, and demand patterns. Adverse climate impacts could lead to longer electricity outages, causing serious concern in maintaining electricity security. In Korea increasing anomalies in climate patterns, such as heatwaves and tropical nights, have caused surges in electricity demand and an increase in outage incidents in residential buildings. Demand in winter has also risen due to extreme cold waves (MOE, 2020). The likelihood of climate-driven disruptions is expected to increase with more frequent or intense extreme weather events in Korea.

Currently, adaptation plans in the country have mainly focused on smart grids and demand management, and implementing systems to address potential reductions in generation efficiency. However, additional measures may be necessary to further strengthen the country's adaptation efforts and secure electricity security. This section provides general principles and international examples for policy makers and key actors in Korea to minimise risks from adverse climate impacts and improve the resilience of the power system.

Box 6.1 Climate change and risks to Korea's electricity sector

Korea's Meteorological Administration has performed future projections for the country using the representative concentration pathways (RCPs) defined in the IPCC Fifth Assessment Report. In all RCP scenarios, Korea's mean surface temperature change is expected to be faster than the global warming trend. While the impact of climate change on annual precipitation levels will vary by region and RCP scenario, precipitation will be increasing in Korea. In future years Korea is expected to have more days of extreme weather events related to high temperature, fewer events driven by low temperatures and an increase in extreme precipitation events (Korea Meteorological Administration, 2018).

Projected changes in climate patterns in Korea by 2071-2100

Representative Concentration Pathway	Current (1981-2010)	RCP 2.6	RCP 4.5	RCP 6.0	RCP 8.5
Mean surface temperature (°C)	11.0	12.8	13.9	14.0	15.7
Days with heatwave (day)	7.3	9.5	16.0	17.2	28.5
Days with cold wave (day)	16.9	5.2	0.7	0.0	0.0
Precipitation (mm)	1 162.2	1 226.5	1 201.0	1 241.1	1 314.7
Maximum precipitation across 5 consecutive days (mm)	207.0	224.4	224.5	236.3	241.3
Daily intensity of precipitation (mm/day)	15.1	15.8	15.8	16.1	16.5

Source: Korea Meteorological Administration (2018), *Korea Climate Change Projection Report*.

Various types of climate risk arise from changes in climate patterns. On the supply side, higher temperature leads to both a decrease in the efficiency of thermal generators and solar PV, and to higher losses in transmission. Korea's second national adaptation plan (NAP) briefly identifies efficiency loss in generation and transmission and distribution as climate risks, and demands measures to minimise the loss.

Temperature rise will affect electricity demand in the form of greater air-conditioning demand. Surges in demand can be intensified by heatwaves and pose a serious threat to the electricity system, as evidenced by the 2011 rolling blackout in Korea. The NAP recognises this as a major risk and calls for the facilitation of demand management.

However, there are many types of climate risk in the electricity sector that have yet to be explored in Korea. These include changes in hydrology, increasing frequency of wildfires and infrastructure damage due to costal floods and soil erosion. The forthcoming IEA Electricity Security Special Report on Climate Resilience (IEA, forthcoming) includes a detailed outlook of the various types of risk and how they can be addressed.

Assessing climate change risks and impacts

The first step in enhancing the climate resilience of the electricity system is performing a comprehensive and systematic assessment of risks and impacts based on scientific evidence. The second NAP briefly identified several risks associated with the electricity sector, such as physical damage or reduced efficiency in generation, transmission and distribution and unreliable power supply due to increasing demand for heating and cooling. However, they are currently limited in scope compared with the various and complex impacts different climate patterns can have on the entire electricity value chain.

The Korea Meteorological Administration has already developed a monitoring system and future scenarios for climate change (http://www.climate.go.kr/home/). Accumulated scientific data on current and future climate change patterns – not only temperature but also precipitation, extreme weather events, typhoons and sea level rise – should be incorporated into assessing the risks and vulnerability of the electricity system, to fully identify long-term adaptation needs.

Governments can support adaptation efforts by developing the climate change impact, vulnerability and risk (CCIV) assessment or practical tools specifically for the electricity system. In the European Union several countries have fully completed baseline requirements for climate adaptation assessments that are required for member states. Another example is from the United States, where the government has performed a national assessment of climate change's impacts on and risk to the energy system, and the necessary adaptations. They also provide diverse tools for exploring climate hazards and assessing vulnerability and risks in the US Climate Resilience Toolkit (https://toolkit.climate.gov/).

Mainstreaming climate adaptation in energy plans

The second NAP calls for national energy plans , such as the Energy Master Plan and the Basic Plan for Supply and Demand, to consider climate change. While the latest energy plans include extensive measures for mitigation, there should be greater effort to integrate climate adaptation objectives in energy plans and regulations. Mainstreaming climate adaptation can send a strong signal to utilities to strengthen the resilience of electricity systems during the design, operation and maintenance phases.

Sending the right signals is especially important as climate adaptation can remain unaddressed due to market failure. The benefits of enhancing climate resilience and the costs of climate impacts are unevenly distributed across the electricity value chain. While climate change may lead to increased interruption of electricity supply and larger societal cost, generation companies and system operators are expected to bear a fraction of the entire costs (IEA, 2020). In addition, the benefits of investment only become tangible a number of years after the investment has been made, making timely investment difficult for business. The government can further address the issue of market failure by creating the right incentives for utilities, for instance by requiring regular assessment of climate risks under operational and maintenance rules.

Implementing concrete climate resilience measures

The power system's climate resilience is its ability to anticipate, absorb, accommodate and recover from the effects of a potentially hazardous event related to climate change. Measures to improve the resilience of the power system include physical hardening of assets, improvements in system operation, better recovery planning and capacity building.

Support physical hardening

Physical system hardening covers technical and structural improvements to power plants and transmission and distribution lines. As the second NAP outlined, vulnerable energy supply facilities can be managed to help to withstand climate impacts and avoid critical damage on the supply side. For instance, Puerto Rico has identified measures at all levels of the power system after Hurricane Irma, including relocation of generation facilities in vulnerable costal and river-located areas to further inland. The resilience of substations can be enhanced by building flood barriers, securing more backup facilities and reinforcing roofs and walls to withstand stronger winds. In addition, transmission and distribution lines in highly vulnerable areas can be upgraded with galvanised steel poles.

Such measures should be evaluated when integrating climate resilience into the power sector's long-term planning. This may help protect the system against the effect of typhoons such as Maysak in 2020, which caused short, localised power outages, damaged electricity networks and prompted the shutdown of some nuclear plants as a preventive measure. Power system vulnerability in power system's like Korea's is characterised both by the relatively high share of overhead transmission and distribution networks, and also by particular characteristics, such as the world's highest population density in the vicinity of a nuclear complex, with 5 million people living within a 30 km range of its east coast facilities. Governments, policy makers and planners can support this process by providing technical assistance to identify risks to power system infrastructure and accounting for this in long-term investment plans.

Smart solutions to improve climate resilience

Efforts to improve visibility and controllability of the power system achieve more than enabling the integration of variable renewables in a secure manner. Fast detection and restoration of outages through advanced metering infrastructure enable system operators to reduce the impact of outages. As a major adaptation action, the Korean government has expanded the installation of advanced metering infrastructure to build a smart grid (Government of Korea, 2015).

The benefits of deploying microgrids need to be reviewed in the light of different regional conditions. They can reduce adverse climate impacts by isolating vulnerable parts of a power system and ensure local flexibility is met with local sources. In regions where the local VOLL is very high and grid interconnection is the weak element, microgrids can be highly valuable, while in other places higher degrees of interconnectivity across larger areas may be a better solution to improve system security.

In addition, utilities and system operators can take advantage of accurate forecasting of weather to take pre-emptive measures. For instance, the Australian Energy Market Operator (AEMO) incorporates probabilistic analyses of credible faults caused by weather events into their dispatch decisions. In California private utilities have introduced operational protocols to de-energise certain lines during high-risk periods of wildfire. These examples show how weather forecasts can be used to anticipate extreme weather events and take pre-emptive measures.

Recovery planning

Recovery efforts by diverse actors should be properly co-ordinated to minimise the magnitude of interruptions and restore operation to normal as quickly as possible. Policy makers should prioritise recovery efforts, identifying vulnerable infrastructure and planning for quick service restoration, to avoid long-term critical damage to key infrastructure and protect the most vulnerable groups. In addition, as workforce shortage may lead to delays in recovery after extreme weather events, policy makers and key actors need to ensure that sufficient workforce resources are in place to enable recovery.

Support capacity building

While the Korea Adaptation Centre for Climate Change has developed tools to assess climate risks and vulnerability, and assist the development and implementation of adaptation policies at all levels, there is relatively little linkage to the electricity sector. Capacity building in the implementation of risk and impact assessments, forecasting and early warning, emergency response and recovery would help ensure that critical central and local government authorities have the capacity to respond to emergencies in the power system.

Strategies and policies for cyber resilience

Cybersecurity in the context of critical infrastructure protection

Since 2009 the Korean government has created several national cybersecurity strategies after major cyber threat and hacking incidents. The 2011 National Cyber Security Master Plan clarified the roles of the National Intelligence Service and relevant ministries. Between 2014 and 2017 the Cyber Threat Analysis & Sharing System (C-TAS), created in 2013, shared information on over 170 million cyberthreats with about 170 Korean companies and organisations that are C-TAS members. Furthermore, the 2019 National Cybersecurity Strategy has appointed the National Security Office (NSO) as responsible for oversight on cybersecurity. Under the NSO, responsibilities are decentralised, with the National Intelligence Service in charge of the public sector, and the Ministry of Science, Technology and ICT responsible for the private sector. The Ministry of National Defence also takes part in cybersecurity tasks. This framework, however, only describes the overarching institutional framework for cybersecurity across all sector, rather than specifically for the power system.

Securing the bulk power system

Closer attention has been paid to cyberthreats to the electricity sector since the 2014 cybersecurity breach on Korea Hydro & Nuclear Power when plans and manuals relating to two nuclear reactors, electricity circuits, and data on more than 10 000 employees were stolen. The attackers blackmailed the organisation by saying that they would reveal the information to the public unless the operation of the nuclear fleet was stopped. Although no actual damage occurred, this event revealed the vulnerability of the power system to cyberattacks and consequently led to the formation of National Cybersecurity Posture and Capability Strengthening Plan in 2015.

Overall, the country's cybersecurity strategies focus on critical infrastructure from a defence perspective. The three national plans, in 2011, 2015 and 2019, have respectively introduced preventive measures for the encryption of classified information, expansion of central government protection capabilities and, most recently, the task of publishing guidelines and evaluation metrics, and facilitating private-sector participation. These protections apply to the power sector from the critical infrastructure perspective, but may still need additional measures to ensure full protection across the system's value chain.

While the electricity system's designation as critical infrastructure is already a good first step towards securing it, the present set of mechanisms focus mainly on the bulk power system, rather than distributed resources and the grid edge. For instance, the Framework Act on the Management of Disasters and Safety focuses on critical infrastructure that has the potential to cause great damage to security, the economy and society, and to other systems. As a result, a total of 20 major electricity facilities were designated as critical infrastructure in 2017, including nuclear, thermal and hydropower plants, as well as monitoring and control systems of major generators and substations (KPX, 2018).

However, Korea is making progress in building expertise through the establishment of institutions to increase cyber resilience in Korea's power system. Following the Act on the Protection of Information and Communications Infrastructure, MOTIE established a Cyber Security Center, with KEPCO KDN (KEPCO Knowledge, Data & Network Company) as the operational agent to conduct real-time monitoring for cyberattacks, response and information sharing, and vulnerability assessment of critical information and communications infrastructure. In 2019 MOTIE, the National Intelligence Service, KEPCO KDN and all public generation companies initiated a joint study to create a cybersecurity monitoring system to be embedded in the systems for generation control and dispatch.

Further efforts include projects to test cybersecurity in nuclear instrumentation and controls, cyberattack simulation training for private companies carried out by Korea Internet & Security Agency (KISA), and the development of intrusion detection technologies and procedures. For instance, following an analysis of cyberthreats to critical infrastructure, KPX identified that up to 95% of cyberattacks come from abroad and has therefore developed and implemented a blocking prioritisation scheme that shields web-connected software from international connections. Since its introduction at KPX's control centre last year, the Enhanced Security Control platform has significantly contributed to strengthening the system as measured by various metrics.

Table 6.1 Improvements in cyber resilience following the establishment of the Enhanced Security Control platform, 2019 vs 2018

Performance indicator	Improvement
Danger of intrusion	92% lower
High-danger threat event	30% lower
Cyberattacks against intrusion prevention systems	67.3% lower
Malignant internet protocol address identified	42.9% lower
Cyberthreat search response time	Reduced by 7.1 hours

Source: News World, *KPX Introduces World's 1st ESC Model to Reinforce Cyber Security*, http://newsworld.co.kr/detail.htm?no=7338.

Ensuring a coherent cybersecurity strategy across the value chain

Complementary to the cybersecurity measures implemented at the bulk power system level, the KISA published its Guidelines for Smart Energy System Cybersecurity in 2019. These guidelines set out a number of recommendations for advanced metering infrastructure, energy management systems, BESS and charging infrastructure. While this is already a good step in the right direction to secure the grid edge, it is important to establish clear implementation and enforcement mechanisms to ensure these practices are adopted, particularly in light of the digitalisation objectives of the Green New Deal released in November 2020.

The prospect of an increasing number of service providers, for example demand-side aggregators, highlights the importance of ensuring that cybersecurity goes beyond large generators and is actually embedded across the whole value chain. This may range from basic encryption and cybersecurity standards for IoT-enabled devices, to equipment sold to large utilities and operators. To this end, it is crucial to engage manufacturers and industry, ensuring effective implementation as well as recognising the international nature of some cybersecurity threats.

While developing policies and regulatory requirements for preparedness and response frameworks, policy makers should ensure they strike a balance between prescriptive policies that may facilitate the tracking of implementation, and the ability to adapt these requirements to the ever-evolving nature of technology and cybersecurity threats. This can be done by establishing standing bodies that both constantly work to monitor and update cybersecurity priorities, and ensure coherence across all levels of the power system and across ministries and other governmental bodies. The IEA Special Electricity Security Report on Cybersecurity (forthcoming) includes a more detailed picture of potential measures and implementation considerations.

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Abbreviations and acronyms

AEMO	Australian Energy Market Operator
BESS	battery energy storage systems
BPLE	Basic Plan for Long-term Electricity Supply and Demand
BTM	behind the meter
CAISO	California Independent System Operator
CCGT	combined-cycle gas turbine
CCUS	carbon capture, utilisation and storage
CONE	cost of new entry
C-TAS	Cyber Threat Analysis & Sharing System
EENS	expected energy not served
ENS	energy not served
ENTSO-E	European Network of Transmission System Operators
ERCOT	Electric Reliability Council of Texas
ESS	electric storage system
ETS	emissions trading scheme
EV	electric vehicle
FRT	fault ride through
GDP	gross domestic product
GHG	greenhouse gas
HVDC	high-voltage direct current
ICT	information and communications technology
IoT	Internet of things
IPP	independent power producer
KAU	Korean Allocation Unit
KCU	Korean Credit Unit
KEEI	Korean Energy Economics Institute
KEPCO	Korea Electric Power Corporation
KEPCO KDN	KEPCO Knowledge, Data & Network Company
KISA	Korea Internet & Security Agency
KOC	Korean Offset Credit
KOREC	Korea Electricity Regulatory Commission
KPX	Korea Power Exchange
LOLE	loss of load expectation
LOLP	loss of load probability
MOTIE	Ministry of Trade, Industry and Energy
NAP	national adaptation plan
NEM	National Electricity Market (Australia)
NRE	new and renewable energy
NSO	National Security Office
PPA	power purchase agreement
PSH	pumped storage hydro
PV	photovoltaic
RCP	representative concentration pathway
REC	Renewable Energy Certificate
REZ	renewable energy zone
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	supervisory control and data acquisition
SMP	system marginal price
SPSH	seasonal pumped storage hydro
VRE	variable renewable energy
WASP	Wien Automatic System Planning Package

Units of measure

GW	gigawatt
GWh	gigawatt hour
hr	hour
Hz	hertz
km	kilometre
kt CO_2	kilotonnes of carbon dioxide
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
min	minute
mm	millimetre
MW	megawatt
MWh	megawatt hour
t	tonne
t CO_2-eq	tonne of carbon dioxide equivalent
TWh	terawatt hour
yr	year

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