WHEN TRUST MATTERS

ENERGY TRANSITION OUTLOOK
NEW POWER SYSTEMS

Electricity, renewables generation, and grids through to 2050

FOREWORD

New power systems – systems where most of the electricity is generated by solar and wind – are poised to become the new energy reality for almost every country in the next three decades.

Electrification, and more specifically, decarbonized electricity, is pivotal to the ongoing energy transition and central to the fight against climate change. It is also vital to the wellbeing of humanity: we are entering an era where electricity will bring clean, efficient, and modern energy to almost every individual on this planet.

We forecast that wind and solar are likely to supply 50% of the world's electricity by 2040. By mid-century, that share will rise to almost 70%. By then the amount of electricity consumed globally will have doubled compared with today's use.

These are some of the central findings in DNV's Energy Transition Outlook, now in its seventh edition. Behind that forecast is a comprehensive system dynamics model of the energy supply, use, and trade within and between 10 world regions through to 2050. The model is designed to capture dynamics that occur on an annual scale or longer. However, as you will discover in this report, the power market aspect of our forecast addresses supply and demand dynamics on an hourly basis. For example, we are able to show you what goes on with the new power system in the UK in 2050 during a hypothetical two-week period of adverse weather conditions and no wind power.

We expect to see an average 60% rise in GDP per capita between now and the middle of this century. As households become more prosperous, they will increasingly electrify their end uses. In doing so, they will take advantage of the large efficiencies that electricity brings – for example to mobility and heating – and in general we find that households will be spending less and less of their income on their energy needs. At a macro level, the world will be spending roughly half as much on energy as a percentage of global GDP in 2050 than it does at present.

Getting to that green prize is challenging and requires investment and bold policy underpinned by a sound understanding of energy technology. New market models must be implemented that ensure demand follows supply and not the other way around, which is the case at present. These are themes we explore in depth in this report. Variable renewables need to be paired with adequate storage. Changing patterns of demand, and especially new sources of power demand in transport, heat pumps, and electrolysis-based hydrogen must be anticipated and responded to. The power grid must more than double in capacity, and to the extent that new build transmission and distribution will take time, grid enhancing technologies (GETs) should be implemented to get the most out of the existing grid. This is one of a number of areas where investment in digitalization is critical across new power systems, including, as we show, investment in and deployment of artificial intelligence.

Our forecast is not insensitive to the present difficulties facing the renewables industry, particularly wind power, caused by tight supply chains and inflation. But these immediate pressures will only have a small dampening effect on the renewable share in the power mix by 2050. The main lines of development are clear. The rate at which the new power reality is embraced by countries will have a profound influence on the competitiveness of their economies. Clearly, though, it is not just economic efficiency which is at stake. The successful electrification of our energy system is the single most important step we can take in bringing the world closer to the ambitions of the Paris Agreement.

I hope this report inspires action.
As ever, I look forward to your feedback.

Remi Eriksen

Group President and CEO

DNV

About this report

This report expands upon our electricity forecast – Chapter 2 of our *Energy Transition Outlook*, 2023. Experts in DNV's Energy Systems unit have contributed additional material to this report in the fields of demand modelling, grid operations, digitalization and AI, and new market models and funding mechanisms for flexibility.

In this report we deepen coverage in particular of:

- Demand response and associated technical and financial considerations
- Modelling power systems by the hour to gauge the impact of adverse weather, including a case covering a windless fortnight in the UK power market
- Grid enhancing technologies
- The impact of digitalization, with a focus on resistance to change, cyber security, and AI
- The sensitivity of the flexibility market to heightened participation of the global EV fleet in providing vehicle-to-grid services, and to varying assumptions about the average duration of utility-scale Li-ion battery storage
- Market designs to promote flexibility and long-term investment in decarbonization of power

CONTENTS

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HIGHLIGHTS

1 Growing and greening of electricity

- Global electricity demand will double by 2050
- By 2040, 50% of the world's electricity will be supplied by solar and wind; by 2050 that share will rise to 70%
- Electricity will be almost 90% decarbonized by 2050

2 New demand patterns and flexibility

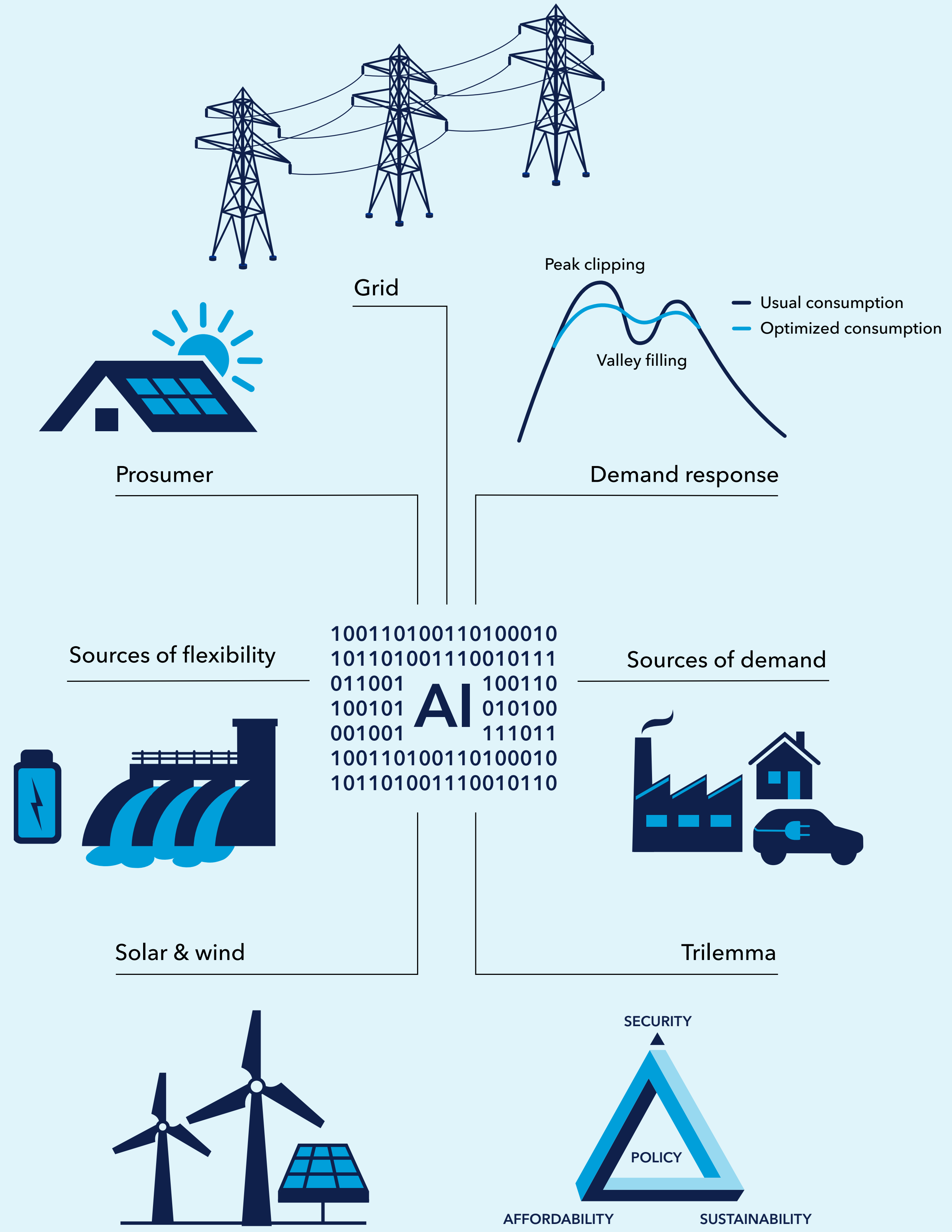
- The need for short-term flexibility will double by 2050
- Li-ion batteries will dominate flexibility needs worldwide by 2050, providing three times more storage than hydropower & pumped storage
- Enabling demand to follow supply will be a critical aspect of new power systems
- Innovative new market designs are needed to spur the rapid development of flexibility markets, demand response, and long-term investment in the decarbonization of power
- Robust cyber security and building trust into AI-enabled systems are critical enablers of digitalization

3 The grid is key to the success of the new power system

- Globally, grid capacity will grow by a factor of 2.5, with annual expenditure on grids more than doubling through to 2050, reaching USD 970bn
- Grid enhancing technologies (GETs) in combination can expand existing grid capacity by between 10% and 50% in the short to medium term while 'new wire' buildout accelerates
- GETs and new connections are contingent on a major digitalization upgrade

4 The new power system will be affordable for society and for individuals

- Despite higher grid investment, grid charges passed on to consumers will remain stable or decline in most world regions
- Unit costs of electricity for consumers are likely to remain stable; electrification will lower overall household energy expenditure
- New power systems are likely to deliver a substantial green dividend not only for households, but also for cities and nations, strengthening the case for a deeper and faster transition



EXECUTIVE SUMMARY

Rapid change: growing and greening

In the next 25 years, global electricity demand is set to double. In 2022, electricity represented 20% of world final energy use. By mid-century this will be 37%.

At the same time, electricity will be greening (Figure 1). Last year, the share of wind and solar in electricity generated was 13%. By 2040, those two sources will be responsible for 50% of electricity generation, moving rapidly to 70% by 2050. In 2050, 82% of all electricity will come from renewable sources – i.e. hydropower, geothermal, and biomass in addition to solar and wind. Nuclear will constitute just 6% of electricity generation by 2050 (falling from its present 9% share), despite a 41% growth in absolute terms from today, an indication of just how vast the coming changes to the power mix will be. That leaves just 12% of the world's electricity coming from fossil sources by 2050 – a remarkable reversal for coal, gas and oil, but still at distinct odds with a net-zero emission trajectory.

These changes will play out differently across the world's regions. A snapshot of regional power mixes in 2040 illustrates this (Table 1). By 2050, all regions are well above the 50% mark for solar and wind in their power mixes, with just North East Eurasia still heavily reliant on fossil-fired generation. Figure 2 illustrates the phenomenon of growing and greening electricity in the three largest regional electricity markets: China, North America, and Europe.

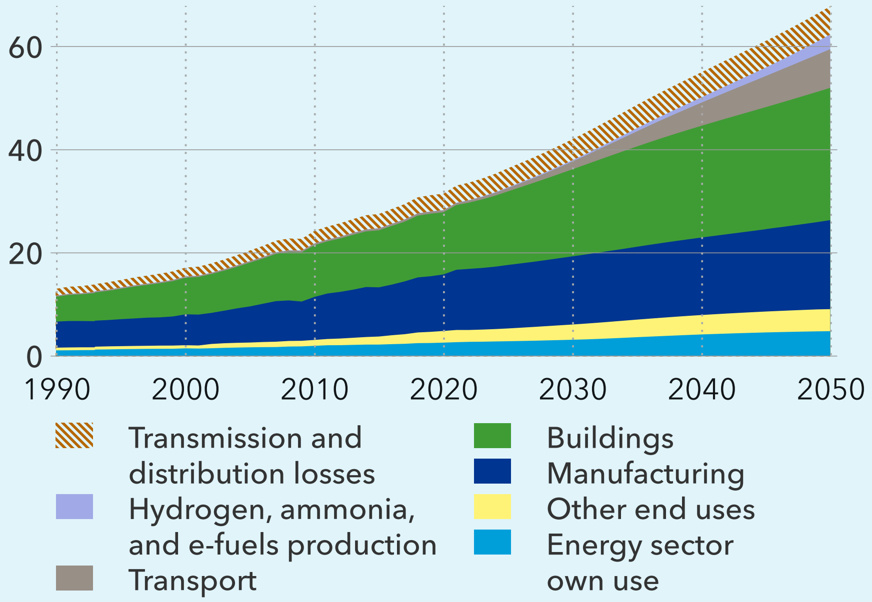
This remarkable expansion and decarbonization of power is driven both by policy and dramatic and ongoing reductions in the costs of wind and solar generation. The levelized cost of energy (LCOE) for solar generation is expected to halve between now and 2050, making solar the cheapest source of electricity at some USD 21/MWh. The LCOEs for wind are expected to drop by 44% (onshore), 36% (offshore fixed), and 75% (offshore floating) to 2050.

Just 12% of electricity will come from fossil sources in 2050 – a remarkable reversal, but a result at odds with a net-zero trajectory.

FIGURE 1

World annual electricity demand by segment

Units: PWh/yr



Historical data source: IEA (2023), GlobalData (2023)

FIGURE 2

Growing and greening of power systems in three regions

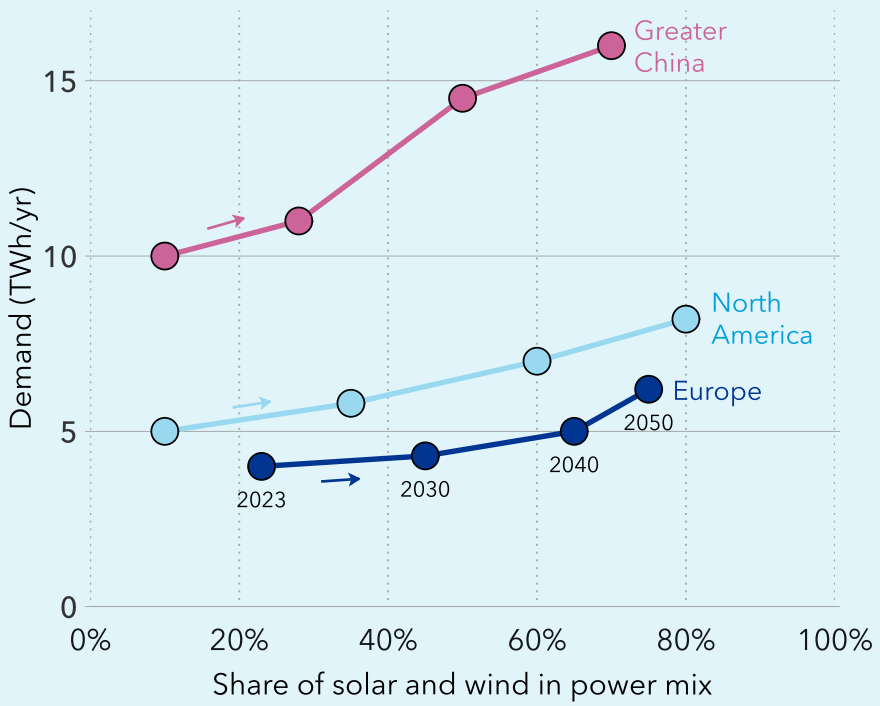


TABLE 1

Wind and solar share of regional and global power mixes

	North America	Latin America	Europe	Sub-Saharan Africa	Middle East and North Africa	North East Eurasia	Greater China	Indian Sub-continent	South East Asia	OECD Pacific	World
Share wind and solar 2023	16%	16%	24%	5%	6%	2%	13%	7%	6%	13%	16%
Share wind and solar 2050	80%	62%	62%	56%	56%	30%	75%	66%	62%	67%	70%
Year share crosses 50%	2037	2039	2033	2045	2045	after 2050	2040	2040	2045	2036	2040

New sources of demand

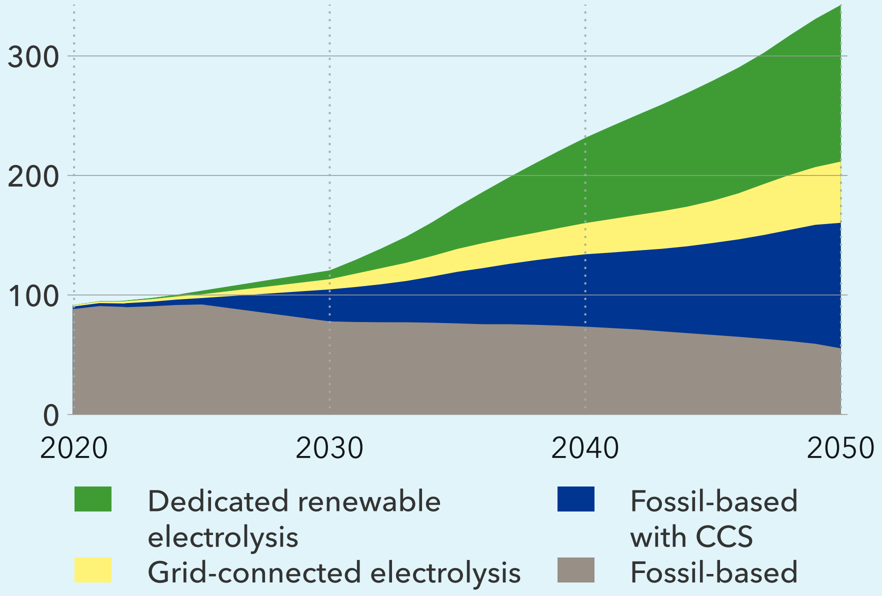
Global electricity demand will surge from 33 PWh to 68 PWh in 2050. This growth is largely driven by the burgeoning demand for existing applications as well as whole new categories of demand. The electrification of transport, three quarters of the world's vehicle fleet will be electric in 2050, adds 7 PWh as new demand. Electrolysers connected to the grid will use 3.4 PWh/yr (Figure 3) to deliver green hydrogen and e-fuels. As the climate warms, greatly expanded demand for space cooling will add an additional 7.5 PWh/yr of demand by mid-century.

As households steadily electrify around the world, electricity takes an increasingly larger share in the buildings energy mix, up from 34% in 2022 to 52% in 2050. Electricity use in manufacturing will almost double in absolute terms with particularly strong growth in the industrial heat pump market for the production of manufactured goods and a rise in the share of electric arc furnaces in steelmaking from 26% now to 49% by 2050.

FIGURE 3

World hydrogen production by production route

Units: MtH_2/yr



Does not include hydrogen use in residual form from industrial processes.

New patterns of demand

Enabling demand to follow the supply of variable renewable electricity generation will be an essential element in the future electricity system. This involves a reversal of the established paradigm that supply should always be aligned with demand. While taking into account the limitations of a given network, demand can be shifted to absorb spikes or troughs in renewable generation in the absence of storage or as an alternative to expensive storage options. The potential for demand response is very large. However, the financial gain for consumers should outweigh the effort, which is not always clear in the present power system. Automated activation of demand response by means of smart metering (with options for override decisions) along with advanced tariff schemes are prerequisites for effective demand response to scale among both residential and industrial consumers.

Demand response is likely to lead to new patterns of synchronous behaviour, which together with EVs and the electrification of heat, will make demand more correlated. This introduces challenges for electricity suppliers to adequately forecast the necessary production levels. However, the wider adoption of smart meters and other monitoring devices will make more data available for ever more sophisticated data-driven models to cope with shifting demand patterns.

New markets for flexibility and storage

As the share of variable renewable energy sources (VRES) grows in the energy mix, a major new market for flexibility of both supply and demand will emerge. We estimate that with the 8-fold growth in VRES, the global need for short-term flexibility will almost double (Figure 4). Flexibility markets will vary across geographies, depending on factors like renewables penetration and the availability of interconnectors within and between countries. Li-ion batteries emerge as the primary source of flexibility worldwide, and we anticipate a surge in their capacity to 1.2 TWh by 2030, further expanding to 27 TWh by 2050. These batteries will either be integrated with renewables or operate as standalone systems. The continued viability of thermal plants will increasingly be determined by their ability to operate with (rather than instead of) renewable generation. The ability to ramp power production up and down rapidly will become critical, as will operating costs during extended periods where cheap renewable power predominates.

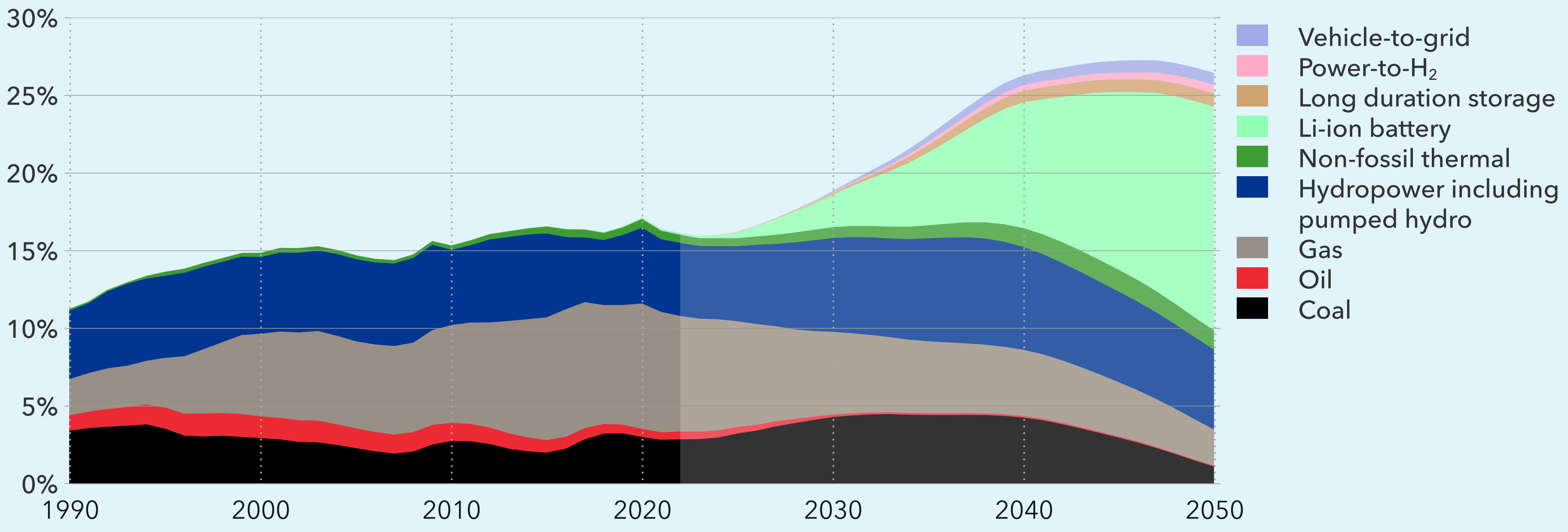
EVs will play an increasingly prominent role in the flexibility market. As smart metering schemes take hold along with incentives for vehicle-to-grid charging apparatus, we model that 10% of EVs – corresponding to about 15 TWh by 2050 – will be available at any given time to provide flexibility to the grid.

By 2030, costs for utility-scale Li-ion battery systems are projected to dip below USD 200/kWh, further reducing to approximately USD 140/kWh by 2050. As costs reduce, the average storage duration of Li-ion battery systems will increase. However, requirements for longer duration storage – up to 24-hours – will likely be met by different battery chemistries, with vanadium flow batteries showing promising techno-economic prospects. Pumped hydropower will continue to play a prominent role in long duration storage, however it is limited by geographical constraints. Finally, the production of green hydrogen with electrolysers powered by surplus renewable power will add an important additional element of flexibility.

FIGURE 4

Global flexibility provided by technology as a fraction of annual average demand

Units: Percentages



Unlocking the grid

"No transition without transmission" was repeated mantra-like at COP28 in the United Arab Emirates (UAE). We forecast that global grid, transmission, and distribution combined will double in length from 100 million circuit-km (c-km) in 2022 to 200 million c-km in 2050 to facilitate the fast and efficient transfer of electricity. The same grid will grow 2.5 times in capacity globally. A small but important part of this buildout is the rapid development of the offshore grid – growing some 14-fold, from 0.2 million c-km to 2.6 million c-km.

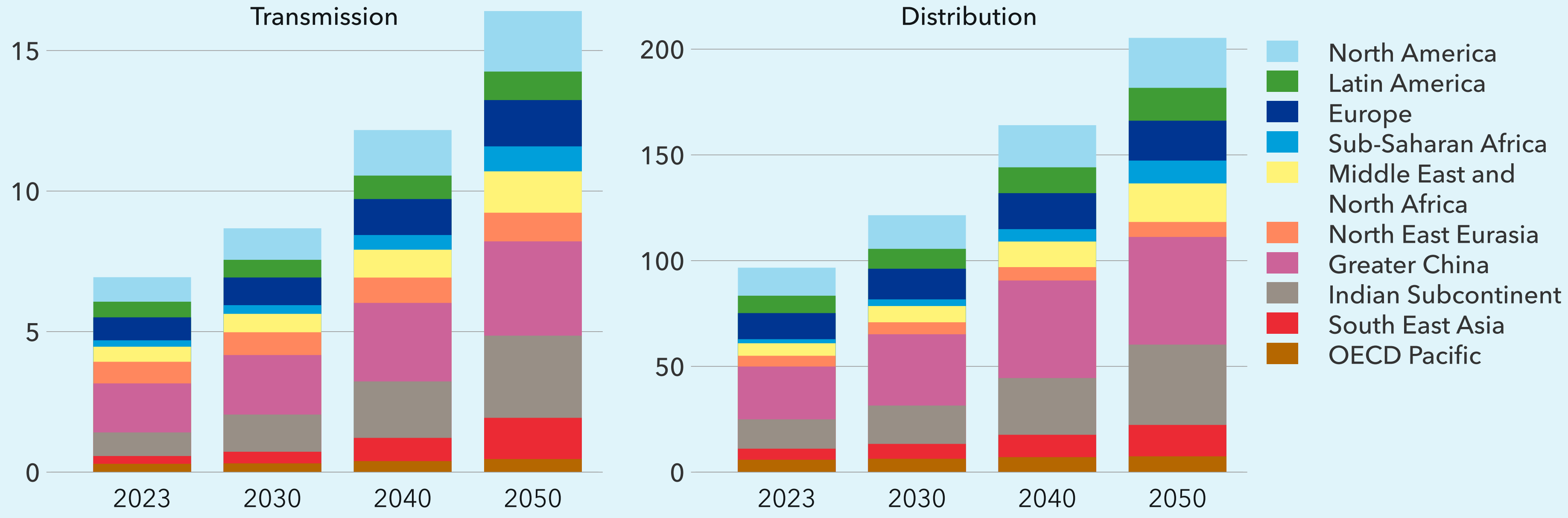
A vast newbuild programme lies ahead, and this is recognized in a host of policy packages in the US, China, the EU, Japan, and so on. There is also growing recognition of the importance of regional interconnection using HVDC lines, which hold the potential not only bolster energy security and flexibility, but also avoid a great deal of generation, storage, and related infrastructure investment in individual nations.

In the short term, the transition faces the challenge of 'gridlock', a term that broadly describes the growing queue of renewable projects and major demand centres applying for connection to the grid, as well as the looming problem of congestion, where demand and supply of electricity exceeds the (peak load) capacity of the grid infrastructure. A massive focus on new grid buildout is needed in almost every country. However, a very large potential exists for grid enhancing technologies (GETs) to address congestion by using the present grid infrastructure more efficiently – adding anything from 10% to 50% additional capacity – buying time for the massive newbuild programmes that need to be accelerated. However, we show that a major contingency for both GETs and newbuild is the pace and (cyber) security of the digital transformation of the grid control centres and infrastructure.

FIGURE 5

Transmission and distribution power-line length by region

Units: Million circuit-km



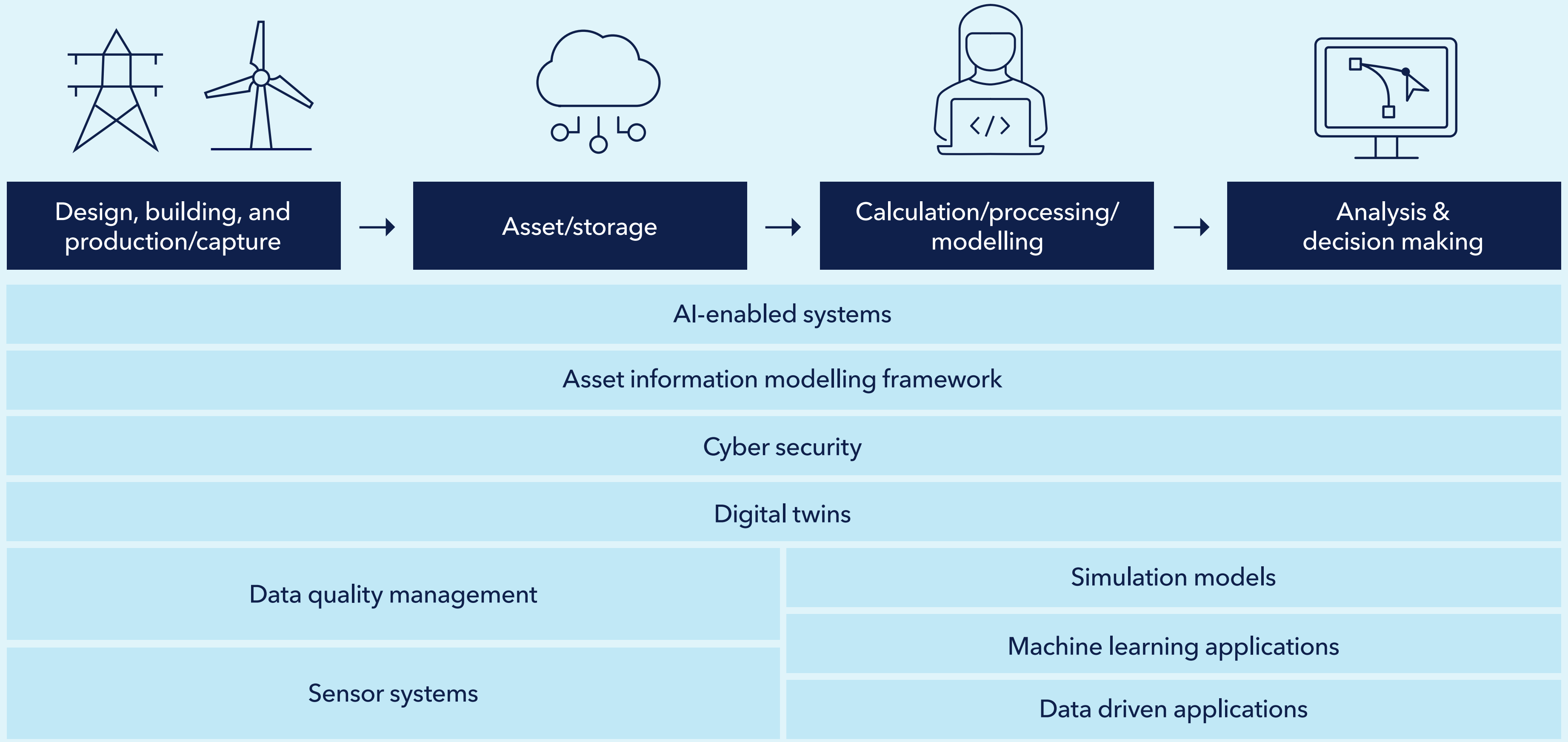
Historical data source: GlobalData (2023), DNV analysis

Digitalization and artificial intelligence (AI)

Present power systems are already among the largest and most complex cyber-physical networks in the world, with millions of interconnected devices acting in synchrony. New power systems will be greatly more complex still, with the introduction of vast quantities of variable renewables, storage, and demand-response. There is consensus among the power professionals we surveyed that investment in IT and operational technology (OT), including power electronics, sensors, and smart meters, will escalate in the coming years. The WEF (2023b) has estimated digital technologies can save USD 1.8trn of grid investment globally through to 2050, while failure to upgrade and digitalize network infrastructure carries cascading economic costs amounting to USD 1.3trn.

From a security perspective, the cyber-attack surface of digitally-steered generation, grids, and demand is growing by the day. A great deal is at stake. Globally, a raft of new cyber security legislation and regulation is already in place and expected to tighten considerably.

The building blocks of advanced digital systems



In addition to cyber security, we set out here our advice for a digitalization strategy across new power systems to focus on the building blocks of complex, digital systems. This includes, but is not limited to, adhering to standards and recommended working practices around: data quality management, assured data collection and transmission in sensor systems, digital twins and simulations models, asset information modelling frameworks, and finally assurance of machine learning and AI-enabled systems.

In our view, the impact of AI in new power systems is overestimated in the short-term and underestimated in the long term. We are very far away from a situation where power flow management of connected variable generation and unmodelled demand is entrusted to 'black box' AI, with attendant explainability and hallucination issues. However, AI is already making an impact in many ways across the value chain of power systems, and will play an important role in accelerating decarbonization. Chapter 3 details some of the more meaningful applications of AI, including optimization of renewable power generation, grid maintenance and outage prediction, dynamic line rating, and demand response management. In the medium term, AI will play an increasingly critical role in more accurate demand forecasting, enabling distribution network operators to react with greater precision and security to the evolving complexity of new patterns of demand, storage, and renewables infeed from prosumers.

AI's energy demand

In this report, DNV does not present a forecast of the power demand of data centres serving AI applications globally. We will present an estimate in our 2024 *Energy Transition Outlook* later this year. Initial research suggests additional power demand of low- to mid-single digit EJs by 2050 – shifting our overall energy demand forecast by roughly a percentage point. We observe there are many compensating factors, not least that AI itself will enable significant energy efficiencies not only in new power systems but myriad end-use applications.

The need for a systems perspective

This report covers the entirety of new power systems – from new quantities and sources of demand through grid networks serving that demand, and ultimately the power plants supplying increasingly decarbonized electricity. Our forecast proceeds on the basis of a system dynamics model that considers many feedback loops and interconnected relationships across the power system.

DNV promotes 'energy systems thinking', where all parties in the energy industry need to see the bigger picture when connecting and pursuing various technologies. For example, investment in a new wind farm has to consider many systems issues:

- Biodiversity and ESG impact
- Forecasts of other generation sources serving the intended market and the probability of price cannibalization
- Forecasts of demand and potential to supply hydrogen (or heat) with curtailed power
- The permitting system; access to data and AI to optimize design, siting, and operation of the farm itself
- The availability and timing of a grid connection for the farm

- Designing in robust cyber security covering all IT, OT, and contingent connectivity aspects of the wind farm

Policymaking at a national and regional level must be informed by a systemic understanding of the performance and demands placed on new power systems over time, including changes in the climate system. For example, regions with a fast-growing industrial sector, such as Sub-Saharan Africa will see an increase in load factor due to the continuous nature of industrial power consumption. Conversely, regions such as Greater China that have an increased share of fluctuating residential usage – especially very seasonal end-uses like space heating and cooling, combined with a reduced share of industrial demand and very high penetrations of solar and wind – will experience a continued increase in the peak load and declining load factor throughout the forecast horizon.

Affordability

We forecast annual global grid investments to double from USD 450bn in 2023 to USD 970bn by 2050. Grid expenditures will account for a little more than a quarter of total energy expenditures by 2050, while at present they only comprise 15%. The grid share is increasing due to the combination of grid expansion costs and the future reduction in fossil fuel expenditures.

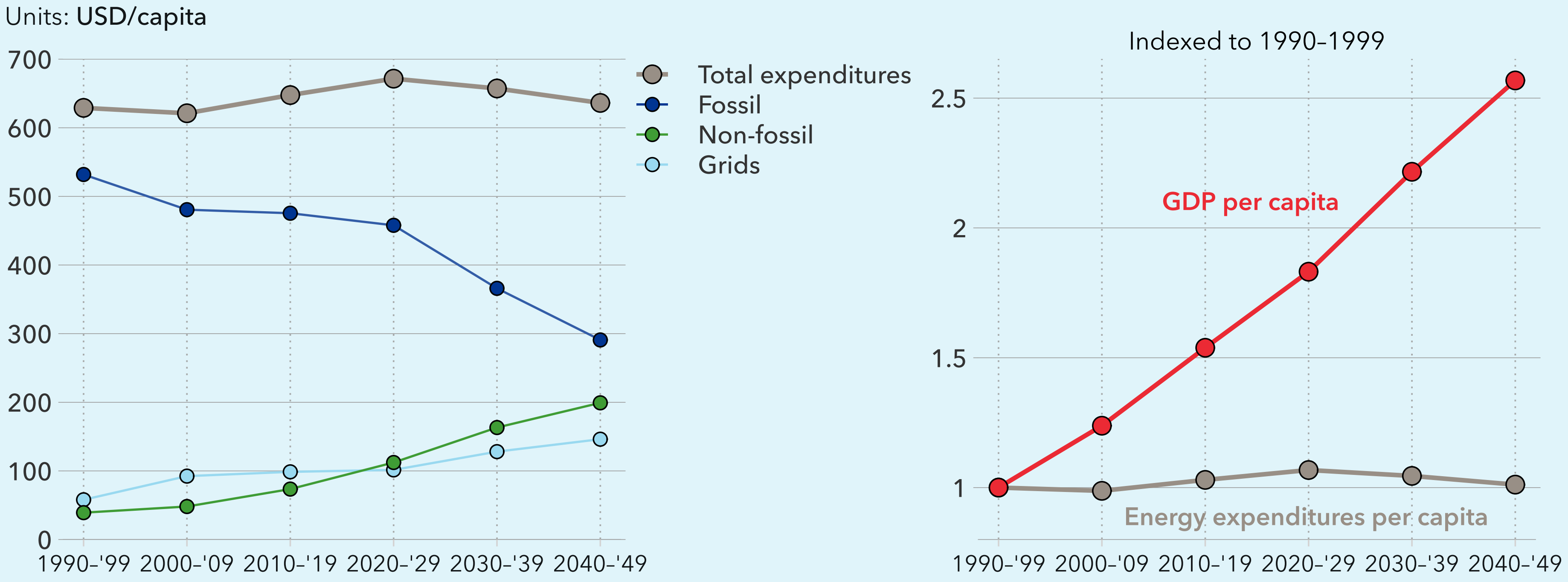
Rising grid costs will be passed on to consumers, but since grids will effectively be 'selling' at least double the electricity they currently carry, we find that these charges are either stable or fall across most world regions and at a global level. Modelling future electricity prices is challenging because of compensatory developments: grid cost recovery charges in tariffs might be stable because generations costs will fall with renewables penetration but flexibility costs may rise. Moreover, the tax component of consumer bills will vary across jurisdictions and may eventually include compensation paid by governments to renewables generators in cases where a high renewables penetration leads to low or even zero capture prices. With all these factors considered, we find it reasonable to assume that, in general, electricity prices are likely to remain fairly stable per kWh during our forecast period.

Of equal importance to electricity prices is the fact that as households electrify their end use, energy efficiencies (e.g. in electric transport or heat pumps) will lead to energy and cost savings. Our modelling suggests that average household energy expenditures will fall relative to rising GDP per capita levels across the world through our forecast period. This 'efficiency dividend' holds true at city, regional, and national levels. Transitioning quickly, intelligently, and securely to new power systems will be critical to the competitiveness of cities and states, and is vital in the context of the climate emergency.

> As households electrify their end use, the resulting efficiencies will lead to energy and cost savings.

FIGURE 6

Global average energy expenditures per capita



1 ELECTRICITY DEMAND AND SUPPLY

Electricity is pivotal in the ongoing global energy transition, shaping innovation and strategies in both supply and demand sectors. In many, if not most, national power systems, this transition involves a complete role reversal between renewable and conventional power sources, with the former becoming dominant and the latter playing complementary or secondary roles. At the same time, there will be scene-changing shifts in consumption patterns, investment flows, and technology advancements steering the future trajectory of global energy dynamics and environmental sustainability.

1.1 ELECTRICITY DEMAND

World electricity demand has been growing by about 3% per year since the 1980s, in line with economic growth. By 2050, we anticipate a surge in global electricity demand, more than doubling from 33 PWh demanded in 2023 to reach 68 PWh in 2050. These numbers include the energy sector's own use and transmission and distribution losses (Figure 1.1). Electricity will constitute 37% of the world's final energy demand in 2050, up from 20% in 2023. This growth is largely driven by the burgeoning demand for existing applications as well as whole new categories of demand, for example the electrification of transport and new energy solutions like green hydrogen production.

In 2022, nearly 50% of global electricity was consumed in residential and commercial buildings. Energy demand from the buildings sector is set to rise by 30% by mid-century, driven by population growth and higher living standards, with electricity taking an increasingly larger share in the buildings energy mix, up from 34% in 2022 to 52% in 2050. This reflects the growing dominance of more-efficient electric appliances in buildings, most notably heat pumps greatly expanding access to air conditioning, adding 8 PWh of annual electricity demand between 2023 and 2050 in the form of both space heating and cooling.

Manufacturing will remain the second-largest consumer of electricity, almost doubling in absolute terms between now and 2050 with particularly strong growth in the industrial heat pump market for the production of manufactured goods and a rise in the share of electric arc furnace in steelmaking from 26% now to 49% by 2050.

As Figure 1.1 shows, it is in transport where the real scene-shift occurs over the next three decades. The electrification of mobility introduces 7 PWh/yr of demand growth between 2023 to 2050, primarily due to the charging demands of an expected 2.6 billion EVs.

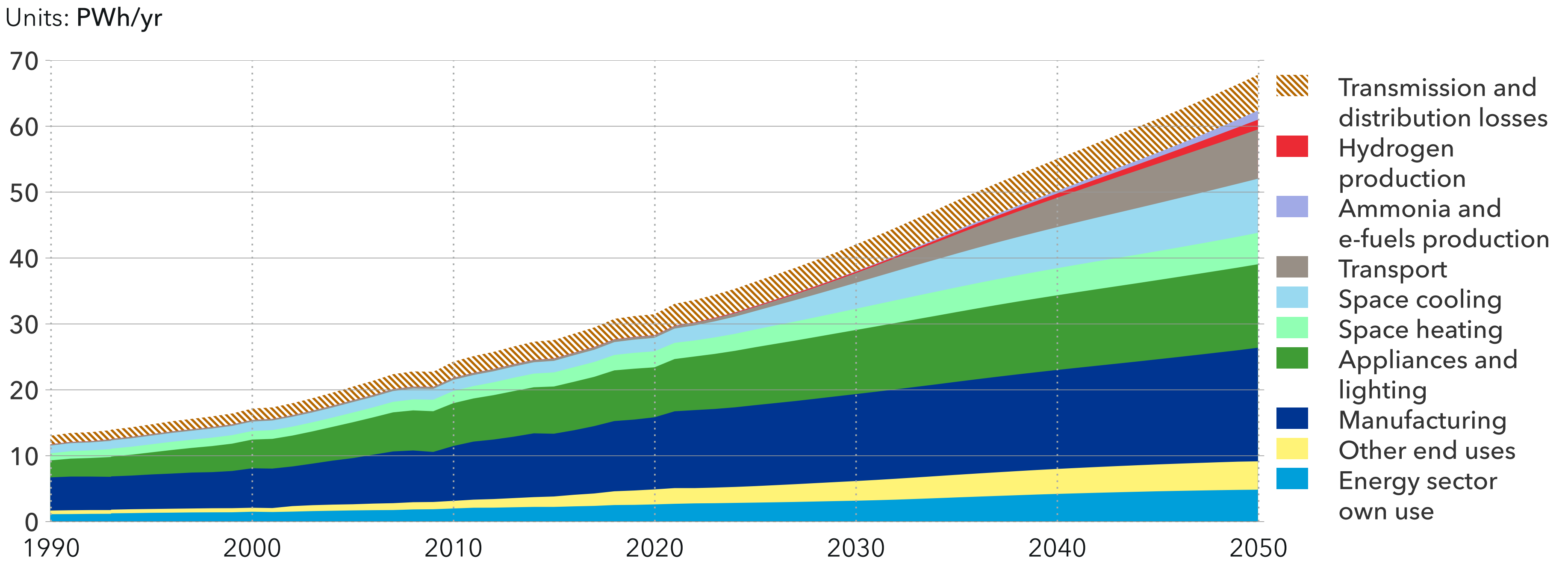
As we approach 2050, electrolysers connected to the grid will use 1.4 PWh/yr of electricity to deliver 28 Mt/yr of hydrogen, while another 1.7 PWh/yr will serve the production of fuels like ammonia or e-methanol. Not shown in Figure 1.1 is 10 PWh/yr of dedicated renewable electricity that will be applied to onsite hydrogen production from renewables.

> Electricity will constitute 37% of the world's final energy demand in 2050, up from 20% in 2023.

20 MW industrial heat pump for district heating in Mannheim. Image, courtesy Siemens

FIGURE 1.1

World annual electricity demand by segment



Historical data source: IEA (2023), GlobalData (2023)

The global growth in electricity demand is by itself remarkable, but the global numbers mask the life-changing aspects of electrification in regions where electricity access is currently lagging, such as the Indian Subcontinent and Sub-Saharan Africa.

For example, we forecast the residential space cooling electricity demand in the Indian Subcontinent growing seven-fold from 2023 to 2050, a 7% year-on-year growth, bringing relief to many millions of people from the potentially lethal effects of global warming towards 2050.

Similarly, access to electricity and household appliances which use electricity is an important factor in ensuring access to education (lighting), convenient clean water (water pumps), indoor air-quality (electric stoves), and freedom of movement (street lighting). In fact, in the last century, access to electricity and electric devices have probably been the single-most important contributing factor to gender equality in low- and middle-income regions, freeing up time for children, girls and women, who are generally burdened with labour and time-intensive household chores, to engage in often life-changing educational and recreational activities.

Significant variations exist in electricity-related levies among nations, with some European regions having taxes and levies amounting to over half of the electricity bill. We anticipate a tax shift away from electricity, but deviations from this trajectory, particularly in low-income countries, might hinder our electrification forecast's realization pace.

Importantly, the efficiencies inherent in switching from fossil sources are forecast to have a positive effect on average household energy expenditures, reducing energy bills in absolute terms in high income regions and in relative terms (measured against rising prosperity) in middle- and low-income regions. These effects are explored more fully in the concluding chapter of this report. Clearly, much is at stake with electrification: affordability, energy security, and, to the extent to which supply is renewably generated, sustainability. Investing in, planning for, and optimizing new power systems – the focus of the rest of this report – should therefore be high on the agenda for all policymakers.

Changing regional electricity demand

Greater China is the leading consumer of electricity as of 2023, accounting for 32% of global demand. While it is poised to maintain its leading position to 2050, its demand share will decrease to 26%. In contrast, we anticipate the Indian Subcontinent to leapfrog both Europe and North America by 2050, commanding 14% of the global electricity share.

Up until 2035, the Indian Subcontinent and South East Asia are set to showcase the fastest growth in electricity demand. From their existing low electrification rates across pivotal sectors – including cooling, appliances, and manufacturing – we predict extensive electrification initiatives and substantial demand growth within these regions.

Fast-forwarding to the timeframe between 2035 and 2050, Sub-Saharan Africa emerges as the global front-runner in electricity demand growth, averaging an impressive 5.8% annually. Factors such as potential economic advancements and an anticipated population surge underline Sub-Saharan Africa's monumental electricity demand growth. This evolution underscores the vast opportunity awaiting the region in harnessing renewable energy sources and electrifying a multitude of its end use sectors.

High-income regions like North America, Europe, and the OECD Pacific will have slower growth trajectories, attributable to their already-high rates of electrification coupled with modest economic expansion.

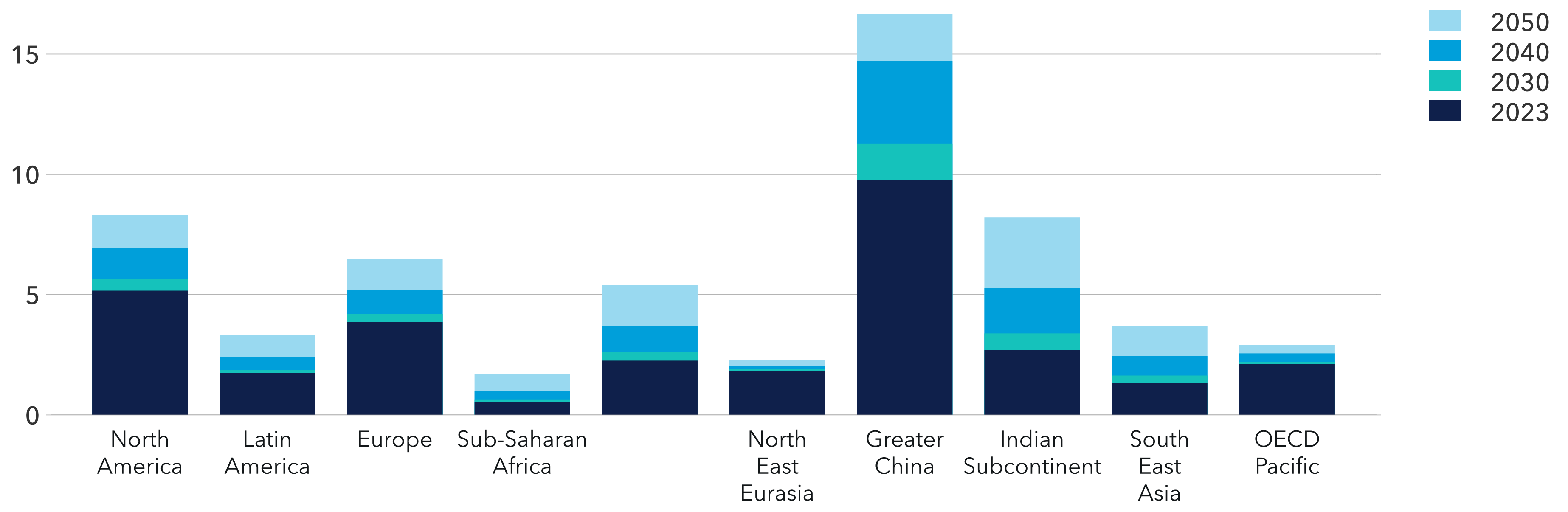
However, the advent of new electricity-consuming sectors, notably transport and hydrogen production, ensures that growth in electricity demand in these regions remains above stagnation even by 2050.

Diving deeper into recent trends in Greater China, we have observed its electricity demand growth rate, which has been above 5% annually, is predicted to decelerate to 3.2% by 2035 and then further diminish to less than 1% in the subsequent 15 years. Such a shift is anticipated due to China's impending population growth slowdown, and China's economy essentially restructuring to less energy-intensive manufacturing processes.

FIGURE 1.2

Electricity demand by region

Units: PWh/yr



By 2050, we envisage a nearly complete transition to EVs in China, leaving a negligible scope for electrification in the transport sector by the late 2040s. Unlike its western counterparts, Greater China might not heavily invest in grid-connected electrolysers, further stabilizing its mid-century electricity demand.

Lastly, in the Middle East and North Africa, there is a surge in the electrification of buildings, predominantly driven by the rising GDP per capita and consequent expansion in space cooling. This trend, combined with similar developments in South East Asia and Latin America, suggests an acceleration in electricity demand post 2035. In stark contrast, North East Eurasia might trail, with the slowest growth due to static population metrics and delayed electrification compared with its global peers.

It is important to assess the quality of electricity demand growth by region from the perspective of whether such growth is supplied by new and low-carbon sources of generation.

Figure 1.3 shows the electricity demand and low-carbon electricity supply growth for the ten different ETO regions under three distinct time periods. Additionally, the right axis shows the average share of low-carbon electricity in total electricity generation in the time-period.

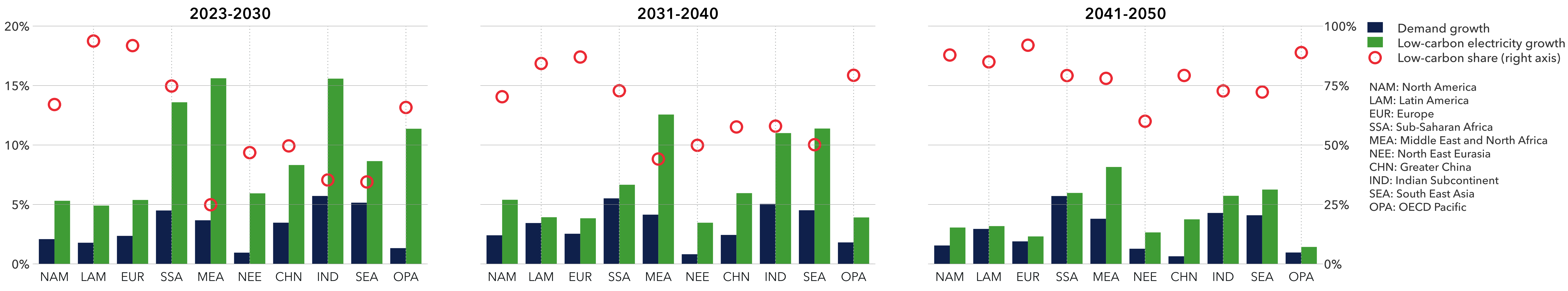
In no region, in any of the time-periods analysed, does the electricity demand growth outpace the low-carbon electricity supply growth. In fact, in all regions (except South East Asia) in the time-period of 2023-2030, the growth of low-carbon electricity is double that of electricity demand growth, signifying that for every kWh of new demand, two kWh of low-carbon electricity is generated. This occurs even in regions such as Latin America and Europe, with already-high rates of low-carbon electricity share.

While in the 2030s and 2040s the low-carbon electricity growth reduces, it never dips below that of the demand growth. This implies that new power generation technologies are going to revolutionize the electricity systems in all regions of the world, regardless of the current status of power systems in those regions.

> New power generation technologies are going to revolutionize the electricity systems in all regions of the world, regardless of the current status of power systems in those regions.

FIGURE 1.3

Comparison of electricity demand, and low-carbon electricity growth by regions



Changing electricity demand

Addressing trends in peak electricity demand, not just the annual averages, is crucial. Peak demand critically affects both power generators and the regional transmission and distribution grids. We need to bolster and expand the grid infrastructure, ensuring it can effectively transfer peak power from generators to consumers, even in areas without a rise in annual average demand.

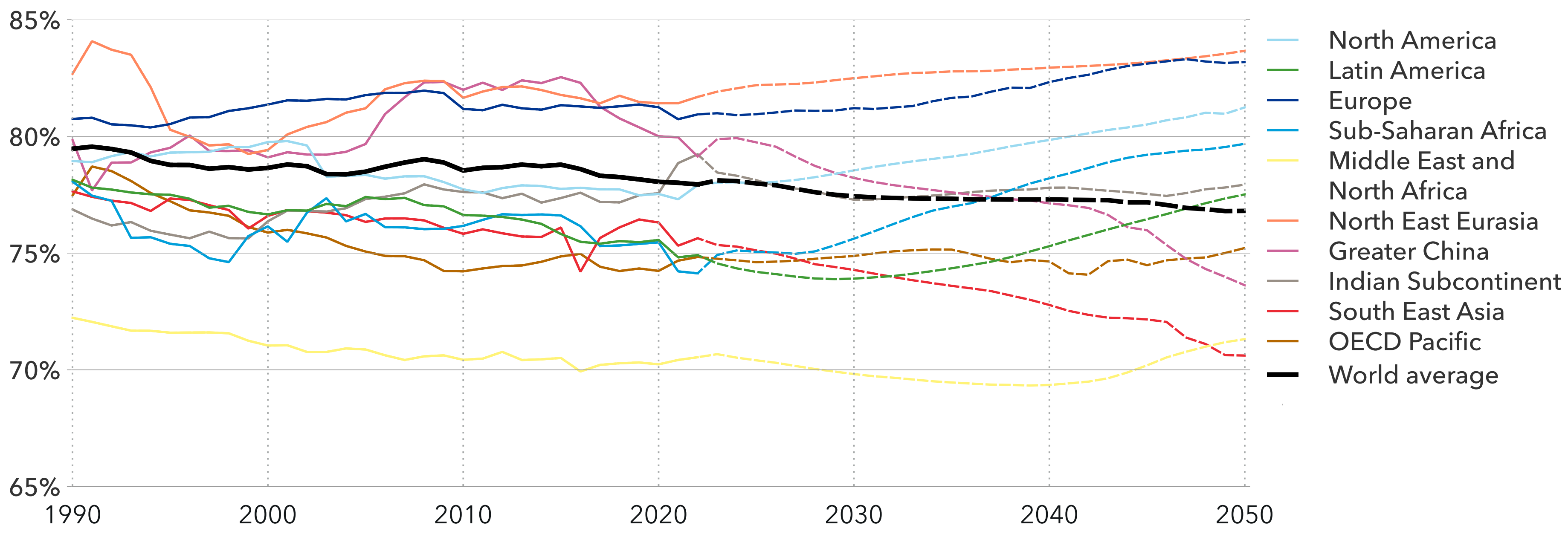
To understand the relationship between peak and average demand, we focus on the load factor – the ratio of average load to the system's peak load. This metric showcases the electrical load's consistency and variability. Our global estimate shows a 78% load factor in 2023, but we project a slight decrease to 77% by 2050 (Figure 1.4). Growth in peak load is slightly outpacing annual average demand, suggesting a trend towards increased variability. However, this very slight change is the result of many opposing significant factors happening simultaneously and at various rates across the world.

Firstly, integrating renewables, especially variable sources like wind and solar, magnifies electricity generation variability and impacts the load factor. However, advancements in both energy storage and grid management will buffer and even reverse

FIGURE 1.4

Load factor by region

Units: Percentages



Enabling demand to follow variable renewable electricity generation will be an essential element in the future electricity system.

these variations in many high-income regions. The drive towards electrifying transport, mainly the rising adoption of EVs, is set to redefine electricity demand patterns. Although concentrated EV charging could heighten variability, EVs introduce flexibility through controlled charging and vehicle-to-grid mechanisms. Moreover, demand-side management, through innovations like smart grids, real-time pricing, and demand-response schemes, will need to strike a balance between the needs of variable generation, demand and transmission, and distribution, pushing the needle towards a more balanced electricity consumption.

Concurrently, strides in energy efficiency will induce steadier electricity usage, affecting the load factor. Regions with escalating industrial operations such as Sub-Saharan Africa will see an increase in load factor due to the continuous nature of industrial power consumption. Conversely, regions such as Greater China that have an increased share of fluctuating residential usage, especially very seasonal end-uses like space heating and cooling, combined with a reduced share of industrial demand and very high penetrations of solar and wind, will experience a continued increase in the peak load and declining load factor throughout the forecast horizon. These developments are described more fully in DNV's recent report on China's energy transition. Notably, extreme weather events triggered by climate change could produce stark demand peaks, especially during events like heatwaves – an element not included in our prediction.

Enabling demand to follow variable renewable electricity generation will be an essential element in the future electricity system. Demand response involves providing incentives to shift or decrease electricity consumption of end users to assist in balancing the grid. This added flexibility will become increasingly important as grids become progressively more dominated by variable power generation such as PV and wind. Key facilitators for the broadening of demand response are smart meters and variable tariffs, incentivizing customers to shift or reduce consumption. Nonetheless, this process also brings new challenges to energy suppliers, balance-responsible parties (BRPs), and distribution system operators (DSOs) (see sidebar on settlement).

Dealing with unpredictable demand patterns

Historically, aggregated demand exhibited very stable and repeatable daily, weekly, and seasonal patterns. Consequently, even relatively simple models based on historical data could reliably forecast the demand patterns for a sufficiently large consumer base. However, the adoption of autonomous control algorithms making use of the variable tariff system disrupt these load patterns and result in synchronous behaviour. This phenomenon is further exacerbated by the electrification of heating, EVs, and residential PV generation and storage, making demand more corelated. As a result, the statistical averaging out of a large number of consumers will become less prominent in the future.

Unpredictable demand patterns have economic implications for electricity suppliers and BRPs by impeding their ability to adequately forecast the necessary production levels. Moreover, simultaneous load behaviour leads to voltage fluctuation and overloading of the grid, complicating the role of DSOs in reliably transferring and distributing energy. Nevertheless, the wider adoption of smart meters and other monitoring devices results in more available data and ever more sophisticated data-driven models. These models will provide more insight into the consumption patterns of different consumer groups, their correlation with environmental factors, and shifts in patterns resulting from the adoption of new technologies.

Opportunity demand

The development of opportunity demand is important in power systems that are dominated by variable renewable generation. This demand has the ability to switch between energy carrier, and thus has very clear opportunity costs set by the alternative carrier. Opportunity demand will bid to be dispatched for prices just below the alternative carrier and will mainly run during times of surplus production of variable renewable generation. With sufficient quantities in the system, this demand will be price setting. Examples are power to heat and power to hydrogen. In our model, the quantities of these demand subcategories are such that they become price setting. This effect is amplified by the short- and long-duration energy storage in the system.

Settlement in electricity systems

An essential enabler of demand response is the remuneration between the consumer and the electricity system, as well as the remuneration between the different parties in the electricity system itself.

In a vertically integrated power system (where there is one utility that generates, transport/distributes, and supplies electricity to its customers), the utility usually does not, and does not need to, take into consideration a sophisticated differentiation in time of use. Small, residential uses in general behave rather uniformly and distributing the overall cost of the infrastructure and generation proportionally based on annual use usually suffices.

However, when the system grows and multiple independent power producers (IPPs) start to sell electricity to the utility, the utility will have contracts with the IPPs about prices and when to dispatch. Electricity cannot be stored in large quantities, so the utility essentially contracts a generation service from the IPP that will be called upon when its customers need it.

When the utility loses its monopoly, IPPs can become suppliers and start selling electricity directly to end-users. Thus, the situation starts to become more complex. No longer can costs be aggregated by a single utility and distributed to its customers based on a general key measure like total annual usage. Instead, the 'generation services' of each independent producer need to be tuned to the specific demand of their customers, so these customers are supplied with the electricity generated by the IPP and not by other generators. Because all the electricity is supplied through the same grid infrastructure, each IPP needs to make sure that their generated electricity meets the forecast electricity demand of their clients for each predefined timestep (called a programme time unit, PTU or imbalance settlement period, IPS, which is usually 15 or 30 minutes). The IPP thus becomes a supplier as well as a balance responsible party (BRP) ensuring that the generation and demand in their portfolio are matching. Deviations from this balance (called imbalance) can occur because of forecast errors and are solved by the system operator, an independent party responsible for the power system (which is often combined with the responsibility for the transmission network). The system operator has contracted generation and possibly demand capacity to reestablish the balance. The 'bill' for activating these reserves is sent to the BRP(s) that caused the imbalance.

Demand from residential consumers without a smart meter is not known. Their meter is usually manually read once per year. Providers establish an average profile of these users that is used for the allocation of energy use to the responsible BRPs. At the end of the year, the allocation of electricity demand between BRPs is corrected and remunerated, based on the collected annual metering values, which are also used to bill the consumers. Sometimes meters have two counters that run depending on a switch that toggles by a frequency signal on the grid. This allows for a differentiation between two tariffs, such as a day/night tariff, i.e. during the day one counter is counting, at night the other counter is counting.

In a system with such traditional meters, the benefits of a demand response scheme beyond a day/night tariff will be shared proportionally between all BRPs and cannot be claimed by the BRP that initiated it. With the introduction of smart meters, i.e. telemetry meters that are read every ISP of 15 to 30 minutes, the allocation of demand can be done with actual demand. Not only does this allow for more advanced tariff schemes towards the consumer, such as prices adjusting hourly based on the day ahead wholesale market, but even more importantly, it also allows for the remuneration of the actual demand between BRPs, thus making it more worthwhile for them to engage in demand side management and demand response programmes.

Demand response

A consequence of the shift from dispatchable to variable, weather dependent, electricity generation is that a large portion of generation can no longer follow demand and, besides storage, demand will need to follow electricity generation while taking into account the limitations of the network.

For residential consumers, smart metering combined with time-of-use tariffs create the foundation of remuneration for changing demand patterns. The potential for demand response is large. However, it requires effort to change behaviour. The (financial) gain should outweigh the effort, which is not always clear in the current power system. Non-automated demand response – demand response based on behaviour – is limited because people have limited attention and interest in energy. This means demand response is either:

- Embedded in structural behavioral changes, such as triggered by day/night tariff e.g. people turning on the washing machines at night at the start of the low tariff period; or,

- Triggered by exceptional high incentives, such as critical peak prices, so it becomes worthwhile to pay attention and consciously change behaviour.

Unfortunately, the variability of VRES is neither exceptional nor does it follow a clear pattern (except for solar uncoupled with storage). This means that for demand response to be truly effective there needs to be automated activation. Consumers should ideally be able to overrule this and have some control in their desired strategies, which could include adapting their flexible demand to minimize the electricity bill, minimizing the use of electricity generated by fossil fuels, or to use as much locally generated electricity as possible.

The implementation of automated demand response of flexible demand, such as air-conditioning, EV (dis-)charging, and heat pumps can have different aggregation levels. It can be very local, such as an EV deciding to charge when (previously communicated) prices are low or a thermostat taking electricity prices into account. More coordinated demand will use HEMS (Home energy management system) or BEMS (Building energy management system) and can incorporate the size of the grid connection and power generation behind the meter. Coordination on a higher level by an aggregator will allow access to other, more volatile and potentially profitable, value pools such as the intraday wholesale market, balancing, and ancillary services markets.

For industry, automated demand response is a prerequisite for the same reasons. Today, this results quite often in a constant demand pattern, incentivized through several measures, from reduction in connection tariffs to lower taxation. Curtailment of industrial demand is a practice that has existed since the start of the electricity sector; it is an expensive measure that is primarily applicable for industry where electricity is a main costs driver. With the available IT, OT, and incentive structures available, industrial flexibility can be guided towards following variable generation and we include that in our modelling. At the same time, demand response in industry risks disruption of the core industrial process. This limits demand response to utility and ancillary processes that hold limited hazards to core processes and those which can be standardized across multiple plants and industries.

1.2 SECURING ELECTRICITY SUPPLY

The global electricity landscape is on the brink of monumental change, driven primarily by significant advancements and declining costs in solar, wind, and storage technologies. However, the infrastructural transformation involved is historically unprecedented and subject to physical and financial constraints. Thus, although we are currently seeing solar and wind being installed at record levels, it will take a decade for the power mix to start changing fundamentally.

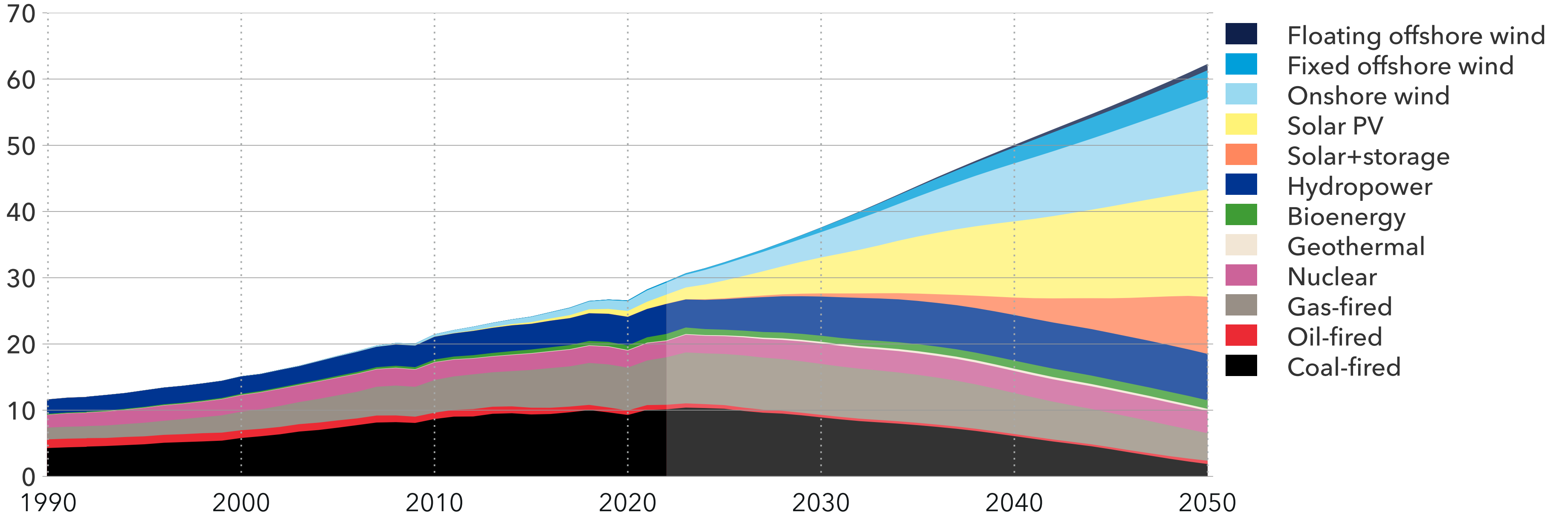
From its 2022 baseline of 9 PWh/yr, renewable electricity generation worldwide is set to grow a further 16.3 PWh/yr through 2035 (Figure 1.5). Yet, a corresponding increase in demand during the same period presents a challenge: while the growth in renewables is impressive, it might primarily meet the growing electricity demand rather than significantly curtail fossil-fuel reliance. It is only after the mid-2030s that we anticipate renewables will genuinely start surpassing new demand and begin a massive displacement of fossil-fired generation.

The evolution of the global electricity supply to 2050 involves a game-changing shift to renewable energy sources. This transition is primarily driven by significant advancements and declining costs in solar and wind technologies. As Figure 1.5 shows, by mid-century, solar is expected to claim a substantial 40% of the global power mix, bolstered by increasingly efficient storage solutions that enable energy utilization round the clock. Wind energy, though slightly more expensive, is not far behind and is expected to make up 30% of the energy landscape with significant contributions from both onshore and offshore installations. The integration of floating offshore wind farms marks a significant innovation, tapping into wind resources in deeper waters previously inaccessible. As renewable technologies mature and scale, their incremental deployment will lead to markedly reduced utilization of coal and natural gas plants,

FIGURE 1.5

World grid-connected electricity generation by power station type

Units: PWh/yr



Historical data source: IEA (2023), GlobalData (2023) particularly after 2040. Nuclear power, discussed more fully below, will expand but at nowhere near the rate of variable renewables.

Opportunities and challenges

The increasing share of renewables introduces several opportunities. The decline in operational costs for renewables compared with fossil fuels can lead to lower electricity prices and greater energy security. Additionally, the ability to harness local energy sources reduces dependence on imported fuels, which is particularly advantageous for energy-importing regions. The integration of smart grids and advances in energy storage technologies are primarily responses to the intermittent nature of renewable energy sources, facilitating investment in new technologies and improving data management to handle the variability associated with renewables.

This global shift towards renewables, also brings forth challenges in integration, reliability, and economic viability. The evolving energy landscape requires robust strategies to manage the variability of renewable sources and ensure a consistent energy supply, necessitating innovative approaches in technology, policy, and market design to fully realize the potential of a renewables-dominated grid. Our next chapter discusses these challenges in more detail.

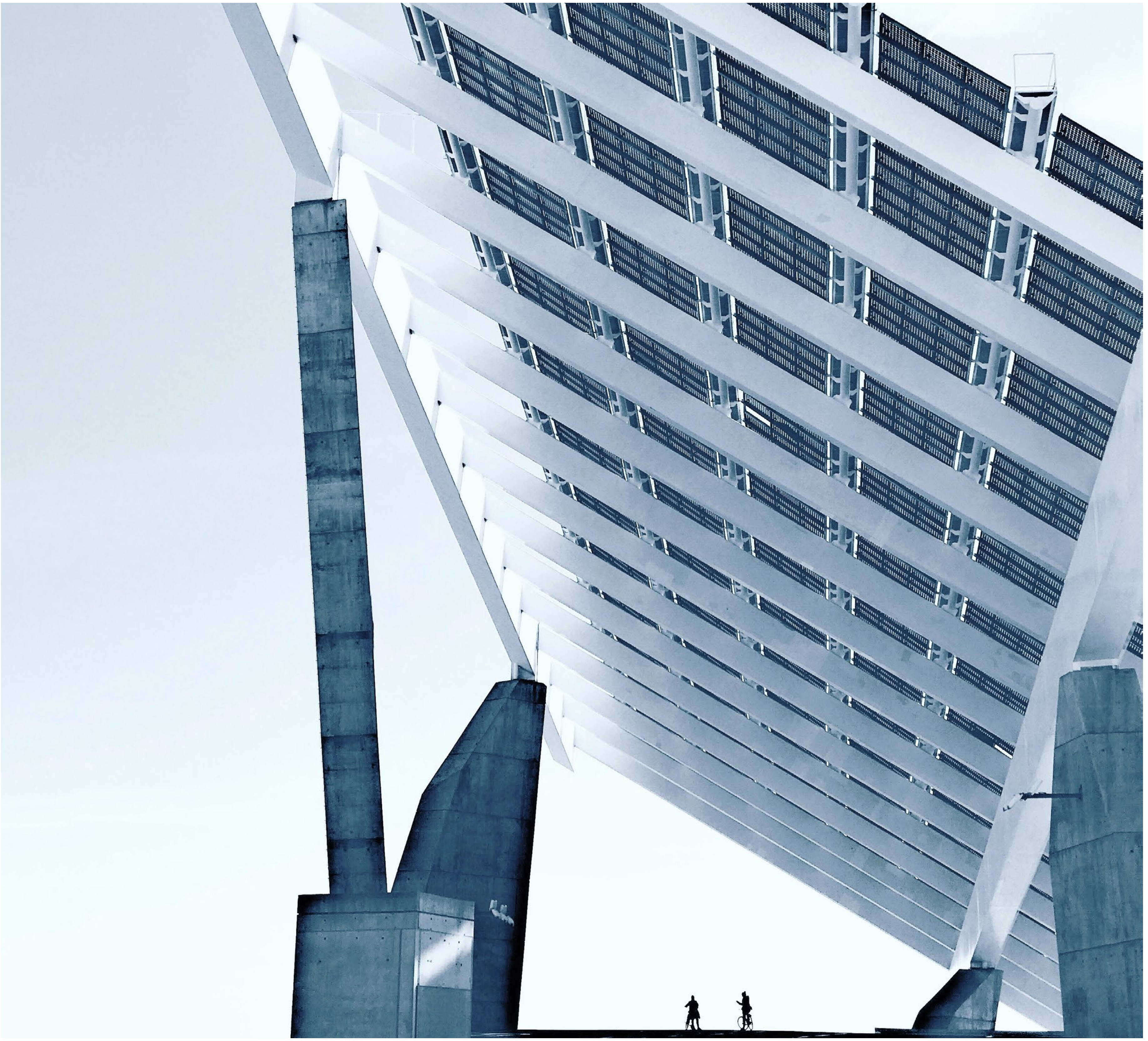
This transition also faces sensitivity to short-term economic fluctuations, notably in investment and operational costs. A prolonged hike in the cost of materials, such as the steel needed for wind turbines, and disruptions in the supply chain can significantly alter the cost trajectories of renewable technologies. Our analysis suggests that without the current supply chain and permitting delay disruptions, a smooth continued cost reduction path would have resulted in the cost of renewables being up to 4.5% lower in 2050. Offshore wind is particularly sensitive to these disruptions, as shown in Table 1.1.

A prolonged hike in the cost of materials and disruptions in the supply chain can significantly alter the cost trajectories of renewable technologies

TABLE 1.1

Sensitivity of the average investment cost of renewable energy in 2030 and 2050 to removal of current supply chain disruptions and grid delays

	2030	2050
Solar PV	-2.0%	-3.9%
Onshore wind	-1.4%	-3.0%
Offshore wind	-2.6%	-4.5%

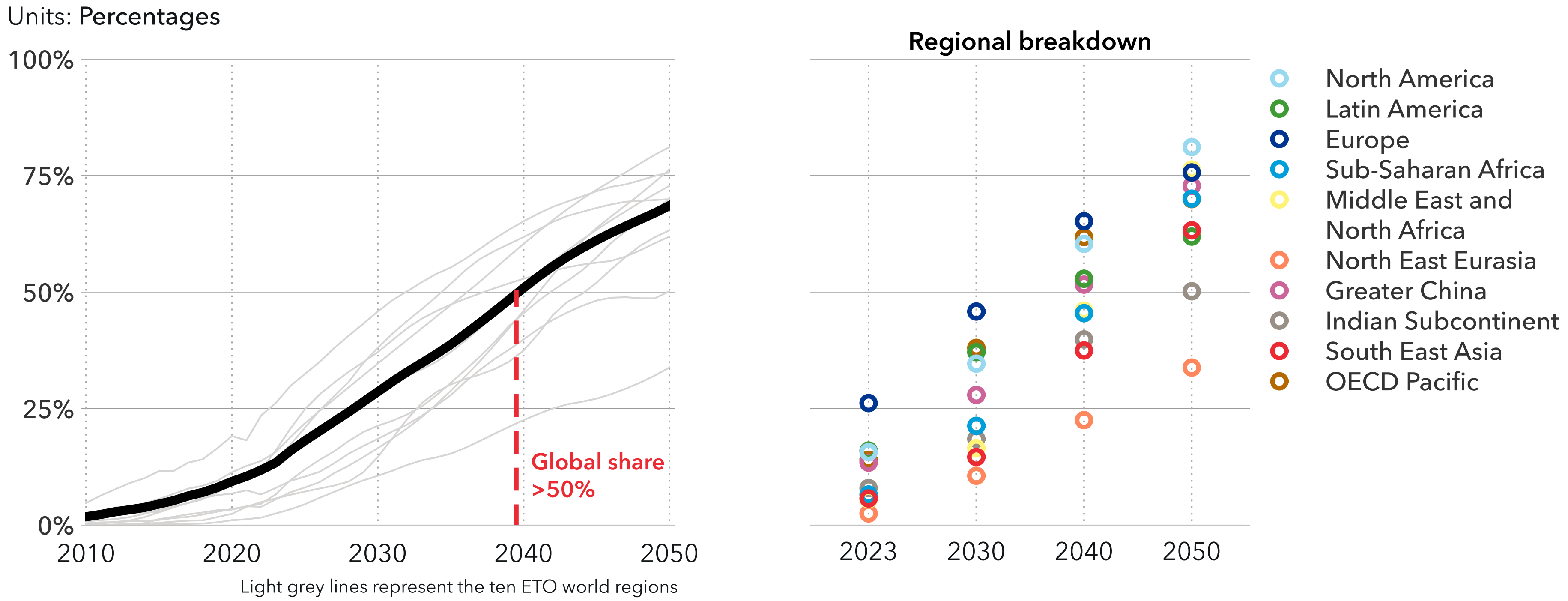


REGIONAL OVERVIEW

While the share of solar and wind in electricity generation global is set to exceed 50% in 2040, there are considerable regional variations (Figure 1.6). Europe has been a leader in solar and wind from early on and will keep its leading position until the 2040s. While North America and Europe has have been strong in regulatory support and advanced technological infrastructure to accelerate the adoption of renewables, Greater China has been equally successful in renewables by heavily investing in production and supply chains through government support. Conversely, in regions like the Middle East and North Africa, despite a high solar potential, the shift is slower due to ongoing reliance on natural gas. The Indian Subcontinent and Southeast Asia are poised for rapid growth in renewable capacity, building from a lower base and driven by escalating local and international investment in clean energy. Sub-Saharan Africa is also expected to follow a similar trajectory as those regions, primarily driven by its growing electricity demand. North East Eurasia, a region with a stable population, relatively low electricity demand, and abundant fossil resources, will trail significantly behind the pack.

FIGURE 1.6

Share of solar and wind in global electricity generation



Regional characteristics of power systems around the world

North America (NAM)
The region continues to rely significantly on natural gas, due to existing infrastructure and challenges in transmitting renewable energy from remote locations. However, a substantial increase in renewable energy share is expected by 2050, with solar and wind projected to provide 80% of grid-connected electricity. The region faces a significant 'place problem' for solar and wind energy, where the best resources for these renewables are far from demand centres, complicating transmission – particularly across state lines – and integration into the grid.

Latin America (LAM)
This region already has a high share of renewables, predominantly hydropower. Investments are increasing in solar and wind capacities, particularly in countries like Brazil and Chile, and are expected to significantly reduce reliance on fossil fuels by 2050. Chile, harnessing its geographical advantage, is investing heavily in solar power and green hydrogen, while Brazil aims to add wind to its already advanced bioenergy supply.

Europe (EUR)
Europe's electrification is driven by stringent regulations and renewable energy policies. The shift towards electric vehicles and increased industrial demands will significantly raise electricity needs, met largely by renewables, with solar and wind being predominant sources by 2050. A unique characteristic of Europe's electricity system is its extensive interconnected power networks, which are among the most developed in the world. This interconnectivity allows for a robust energy trading system that can balance surpluses and deficits across borders.

Sub-Saharan Africa (SSA)
Electricity plays a minor role currently, but a shift towards renewables is expected, driven by global investment in decarbonization. Solar and wind capacities are projected to rise, aiding in closing the electricity access gap without high-carbon phases. However, there is a pressing need for investment in transmission infrastructure, with economic opportunity costs associated with unreliable or absent power mounting alarmingly. New transmission lines are also needed to transition South Africa from reliance on its coal-fired power, which is responsible for a quarter of the continent's carbon emissions.

Middle East and North Africa (MEA)
This region will see a marked increase in solar and wind contributions to the electricity mix, with significant growth expected from the mid-2040s onwards as these technologies become more feasible and integrated with storage solutions. The region is ideal for solar power with integrated storage due to its high solar irradiance, abundant uninhabited land, alignment of solar generation with peak energy demand for cooling, and the opportunity to enhance exports by reducing domestic reliance on fossil fuels.

North East Eurasia (NEE)
The region will continue to benefit from low domestic gas prices in the near term. This economic advantage makes natural gas a competitively priced source of energy, continuing to shape the region's energy landscape even as it slowly transitions towards more renewable sources by 2050. Reliance on natural gas is especially pronounced in Russia, which has one of the largest natural gas reserves in the world, impacting the entire region's energy strategy.

Greater China (CHN)
China leads the world in both renewables production and uptake. Renewable energy is set to dominate its electricity production by 2050. China also leads in the manufacture and deployment of renewable energy equipment. China's power mix shifts from 30% renewables today to 55% by 2035, and 88% by 2050, when the combined share of coal, gas, and oil in the power mix will be reduced to less than 7%. Nuclear power also remains a significant part of the energy mix due to China's ability to rapidly scale construction and reduce costs through centralized planning and large-scale state-backed financing.

Indian Subcontinent (IND)
Despite the deep entrenchment of coal in the energy infrastructure of the Indian Subcontinent, particularly in India and Bangladesh, there is strong momentum towards renewable energy. Significant investments in solar and wind capacities are planned, set to accelerate in the 2030s. By 2050, these efforts aim to enhance electricity access and reliability across the region, reducing coal dependence and addressing persistent issues such as load shedding and uneven power distribution.

South East Asia (SEA)
South East Asia's heavy reliance on hydropower exposes the region to vulnerabilities to climate variability, such as droughts and floods, which can impact the reliability of power supply. To mitigate these risks and enhance energy security, countries are increasingly turning towards integrating more climate-resilient renewable energy sources like solar and wind. The expansion of these resources is expected to reduce dependence on hydropower, diversify energy mixes, and improve the sustainability of electricity systems in the face of climate change. This shift not only promises a more stable power supply but also aligns with global efforts to reduce carbon emissions.

OECD Pacific (OPA)
We expect significant growth in renewable energy capacity – particularly solar PV and wind – which will help make this region the world leader in electrification with a close to 50% electricity share in final energy. In Australia and New Zealand, the ample floor area per household makes these countries particularly suited for rooftop solar installations, unlike the more limited opportunities in densely populated urban landscapes like Japan and South Korea. Nuclear energy will also continue to contribute to the region's energy mix. Despite global debates about the future of nuclear energy, countries like Japan and South Korea will continue to rely on nuclear power.

NUCLEAR AND NEW POWER SYSTEMS

Any discussion of future power systems is incomplete without considering the role of nuclear energy. The sheer scale of the growth of solar and wind generation masks our forecast that nuclear generation will, in fact, grow considerably – by 41% in 2050 compared with 2022 levels.

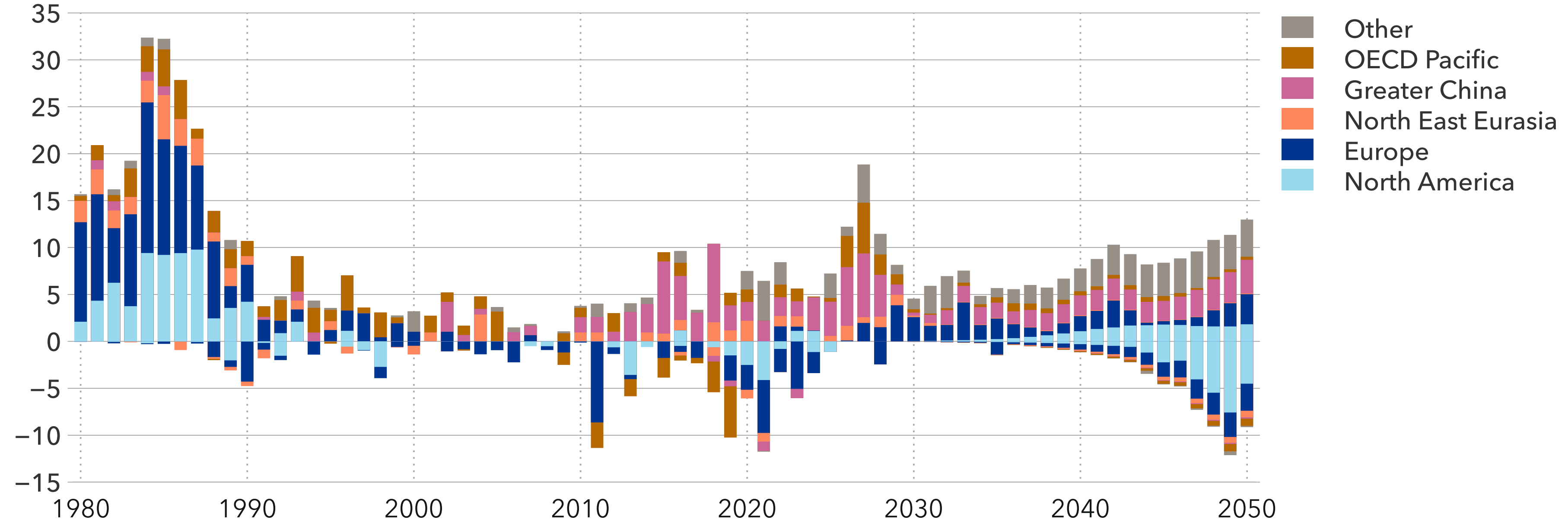
Our prediction for nuclear is, however, considerably below the *Declaration to Triple Nuclear Energy by 2050*, signed by 20 countries at COP 28 (with the notable absence of China and Germany among the signatories). Such a plan would necessitate the installation of 800 gigawatts of additional capacity by mid-century, the equivalent of bringing 30 large new reactors online every year by then (Tirone, 2024). We find less than half of that.

A buildout at such scale is unlikely in our view, even given the renewed interest in nuclear energy sparked by energy security concerns in the wake of Russia's invasion of Ukraine. Indeed, with the prolonged war in Ukraine, and ongoing tensions in the Middle East, a counter view is also emerging: a recent report issued by George Washington University (Squassoni, 2024) highlights that nuclear energy is vulnerable to the widening of geopolitical tensions and war.

FIGURE 1.7

Nuclear capacity additions and removals

Units: GW/yr



Historical data source: IEA WEB (2023)

The main reason why a nuclear renaissance similar to the 1970s is unlikely to reoccur has to do with cost: while DNV expects nuclear costs to be almost flat, the cost of solar wind, and batteries will continue to fall throughout our forecast period. The inexorable penetration of wind and solar disrupts the business case for nuclear. Nuclear plants need to run continuously to be economical, with any reduction in operating hours leading to increased levelized costs. Nuclear energy cannot be run cost-effectively with sufficient flexibility to optimally partner the variable renewables in the power mix, at least not at a level which matches the techno-economics of other sources of flexibility in the form of battery storage or purpose-built gas peaker plants.

For a more in-depth discussion of challenges facing nuclear, we refer readers to our *Energy Transition Outlook* (DNV, 2023a). Inter alia, we cover there the non-proven promise of Small Modular Reactors (SMRs): promising in the sense that the proliferation of SMR designs offers potential scale, cost, flexibility and other benefits; non-proven in the sense that SMR is a technology which does not yet exist in a non-military setting and the first reactors are likely only to be available around 2030 at the earliest. A critical issue is that SMRs would need to be produced at scale to take advantage of their modular characteristics: scale is needed for scale. Business cases for SMRs sometimes rely on the assumption that the plant may power hydrogen electrolysers directly when the plant power is curtailed by an abundance of cheap variable renewable power fed to the grid. However, running electrolysers intermittently presents separate economic challenges.

For these reasons, the uncertainty of the commercial viability of SMR is high, and DNV finds it likely that most new nuclear towards 2050 will be conventional design, but with an increasing degree of SMR design towards the end of the forecast period, and with regional variations.

Electricity generation

Our current Outlook reflects the renewed interest in nuclear energy sparked by energy security concerns (discussed in the sidebar). Our forecast shows nuclear energy output stable at today's levels for the coming years, but growing from the late 2020s (Figure 1.7). From today towards 2030, most added capacity will be based on site-built, large-scale reactors that are already in the pipeline.

Beyond 2030, additional capacity will most likely be a mix between site-built and factory manufactured SMR power plants. Nuclear energy output peaks at almost 3500 TWh per year by 2047 then stays flat until 2050, but at a level 41% higher than today.

North America, Europe, Greater China, and North East Eurasia are currently the top four nuclear energy regions. However, within a decade, Greater China's output will have grown to almost the same level as Europe and North America. Japan and South

Korea will double output from today by bringing new capacity online as well as reopening currently dormant plants. South East Asia will add 70 TWh of nuclear by 2050, but starting only in the late 2030s. The Indian Subcontinent will see the biggest increase of all regions, growing from today's 64 TWh to 260 TWh by 2050, with over 50 GW of installed capacity representing almost 10% of the world nuclear fleet.

Despite solar and wind penetration, the global average capacity factor of nuclear power plants will remain at its historical average range of 60-65%. However, there will be regional variations. North America, with its ageing fleet of reactors and increasing renewable share will see its nuclear fleet's capacity factor to drop from above 90% now to just above 60% by 2050.

Despite losing the cost war against solar and wind, one advantage nuclear will maintain over variable renewables is the revenue side of the equation. Unlike solar and wind, which will suffer from declining revenues compared with the average electricity market price, nuclear reactors will continue to enjoy an annual average income that is near and above the average. However, this revenue advantage will not be large enough to allow any meaningful competition with low-cost technologies in the energy capacity newbuild markets.

Finally, the worsening biodiversity crisis is also lending strength to the case for nuclear, which has a smaller physical footprint as most other low-carbon energy sources. We take this factor into consideration when weighing the future of nuclear.

Capacity build-out and decommissioning

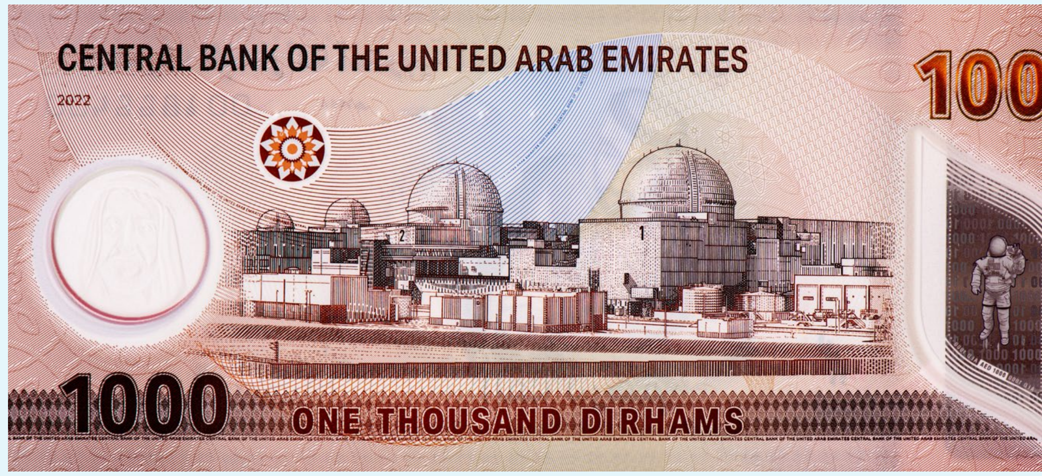
Several nations – such as Bangladesh, Belarus, Turkey, and the UAE – are just starting to pivot towards nuclear. However, the future of nuclear capacity will also be determined by what happens to existing power stations. Half the world's installed nuclear capacity is over 30 years old, and many reactors are approaching the end of their original design lifetimes. Some countries are likely to follow through with decommissioning rapidly, as Germany has done, but elsewhere the renewed focus on energy security coupled with the high cost of nuclear decommissioning, the relatively low cost of nuclear lifetime extension, and the difficulty of rapidly replacing large capacity retirements with low-carbon alternatives, have led some governments to consider extending nuclear plant lifetimes through upgrades and life-extension measures. For example, Belgium and Spain extended their nuclear decommissioning timetable from 2025 to 2035. France and Sweden are postponing their nuclear decommissioning plans, but with increasing debate over re-invigorating nuclear research and building new plants (Hernandez et al., 2023). South Korea's president has vowed to reverse phase-out plans, and Japan adopted a new plan in December 2022 that will maximize the use of existing reactors by restarting as many of them as possible and prolonging the operating life of ageing ones beyond the current 60-year limit (Reynolds, 2022).

Nuclear investments due to energy security

The changes in the geopolitical landscape, disruptions to natural gas supplies, and increased focus on energy security have prompted nations to reconsider their energy portfolios. Nuclear energy, which can provide a stable, domestic source of power, is an attractive option in this context but will come at a higher cost compared with alternative energy options. In our current model, we have included such policy choices for regions dependent on energy imports and where nuclear energy already exists.

Based on these factors, we find that regions are willing to install more nuclear. Compared with a world without such considerations, there will be 22 GW more installed nuclear capacity and 3.2% more electricity generated by 2050. However, this is achieved by additional support by governments/authorities in the range of 8% to 20% of the levelized cost of nuclear energy from 2023 to 2050.

The additional support governments are willing to give nuclear to secure energy supply is difficult to disentangle from other parameters affecting support for different power generation options – for example, the clean energy tax credit in North America. Also, it is worth bearing in mind that it is not only nuclear contributing to secure energy, but renewable options as well, which also will incur subsidy benefits from governments prioritizing local energy options. Nevertheless, slightly more nuclear generation is likely to be made available to satisfy energy security concerns, even though the subsidized buildout adds between 8% and 20% to levelized costs.



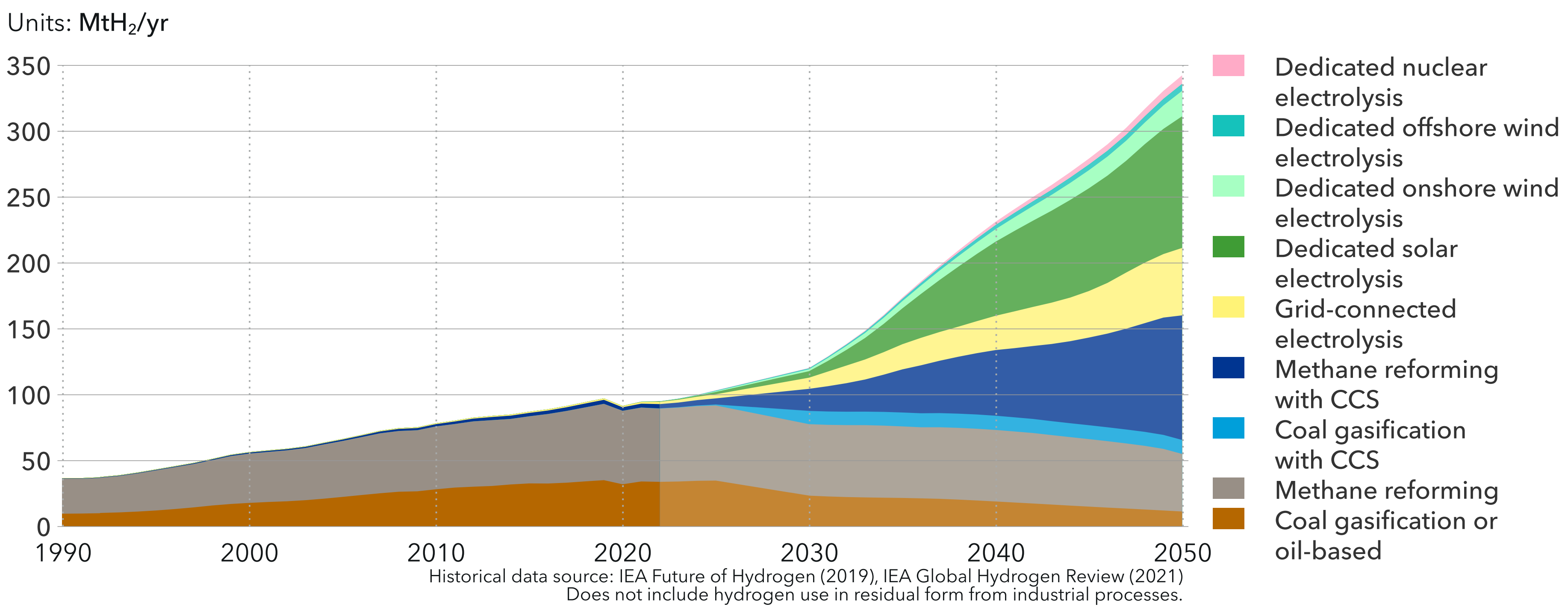
UAE banknote depicting the Barakah nuclear power plant in Abu Dhabi, which went into commercial operation in 2020.

HYDROGEN

Hydrogen is often described as bringing balance to new power systems. This is sometimes thought of in terms of storage and back-up capabilities. In our view, the main balancing role of hydrogen will not be physical (storage and re-electrification) as much as it will be economic (revenue from green hydrogen production from a superfluity of cheap VRES power in the grid).

FIGURE 1.8

World hydrogen production by production route



Power and seasonal storage

In regions characterized by significant penetration of VRES, hydrogen serves as a viable option for balancing peak demand and storing excess electricity for extended periods. However, it is important to acknowledge that this approach entails large energy losses and substantial storage requirements. When assessing the hierarchy of hydrogen applications, the utilization of hydrogen for re-electrification is likely to be the last in line. Nonetheless, starting from 2030, we anticipate the gradual incorporation of hydrogen into power generation facilities, albeit in limited quantities. Initially, this will primarily involve injecting hydrogen into natural gas grids. Subsequently, the share of hydrogen in power generation will expand, driven in part by the need for peak demand management.

We forecast the leading regions in this transformative journey to be OECD Pacific, followed by Europe and Greater China. These regions will increasingly harness hydrogen for electricity generation, with North America also joining in from the mid-2040s. By the middle of the century, we envision these regions collectively consuming nearly 10 Mt hydrogen per year for power generation purposes.

Green hydrogen

Dedicated renewables-based electrolysis is currently too expensive, averaging USD 5/kgH_2 globally. However, by 2030, costs are expected to drop significantly, with dedicated solar or wind electrolysis averaging around USD 2/kgH_2.
Key drivers of this cost reduction include a 40% decrease in solar panel costs and a 27% decrease in turbine costs. Furthermore, improvements in turbine sizes and solar panel technologies will increase annual operating hours by 10–30%, varying by technology and region. Additionally, the capital cost of electrolysers is anticipated to decrease by 25–30% due to reduced perceived financial risk.

For grid-connected electrolysers, the primary cost component is electricity, particularly the availability of affordable electricity. In the long term, the proportion of VRES in power systems will be the main factor influencing future electricity prices, with more VRES leading to more hours of very cheap or even free electricity. However, before 2030, the penetration of VRES in power systems will not be sufficient to significantly impact electricity price distribution. Therefore, any cost reduction in grid-connected electrolysers in the next few years will primarily result from government support and declining capital expenditures.

> As variable renewables become more prevalent in the energy system, the number of hours when hydrogen from electricity and electrolysis is cheaper than blue hydrogen will increase.

Looking towards 2050, two main trends will affect annual operating hours: increased competition from alternative hydrogen production methods and more hours with cheap electricity due to higher VRES integration. As VRES become more prevalent in the energy system, the number of hours when hydrogen from electricity and electrolysis is cheaper than blue hydrogen will increase. Consequently, grid-connected green hydrogen is expected to claim a similar market share as blue hydrogen. Close to 130 MtH_2/yr will be produced by mid-century from dedicated renewables, more than a third of the world's total hydrogen demand by then.

2 POWER ECONOMICS AND MODELLING

Here we explore capacity and flexibility markets and provide insight into the expected cost and revenue developments for renewables. We also analyse near-term challenges – including clogged supply chains, inflation, and permitting delays – and provide a glimpse into industry sentiment on these issues. In the longer term, key themes are exposure to price cannibalization, particularly for solar energy, which places a premium on flexibility and storage, and the need to address issues of adequacy, the ability to consistently meet demand. We show how these trends play out in our simulated modelling of 'power by the hour' in 2050 compared with today. In this report, we go further than the analysis presented in our annual *Energy Transition Outlook*, by presenting a simulation of hourly dynamics of the UK power market during adverse weather weeks (with wind capacity reduced by 80%) in the year 2050.

2.1 POWER MARKETS

The configuration of power markets varies widely, reflecting different regulatory frameworks, generation profiles, and policy objectives. Energy-only markets operate on the principle that generators are paid only for the electricity they produce, a model that incentivizes efficiency and market-responsive behaviour but can lead to volatility during periods of high demand or supply scarcity. In contrast, long-term and short-term markets exist within the framework of many national systems, facilitating more stable financial planning and allowing for adjustments to short-term fluctuations in supply and demand. On the spectrum of market models, centrally planned systems – often seen in state-controlled economies – directly dictate production and distribution, which can ensure consistent supply but may lack the flexibility and innovation fostered by more competitive environments. Outside of these markets, Power Purchase Agreements (PPAs) have emerged as pivotal instruments, particularly in the renewable sector, by securing long-term contracts between electricity generators and purchasers, which stabilizes revenue streams and fosters investment in new technologies.

In addition to these existing frameworks, the advent of renewable energy sources has prompted discussions around innovative market structures like capacity markets and flexibility markets. **Capacity markets** are designed to ensure that sufficient power generation capabilities are available to meet demand peaks, compensating generators for their readiness to supply power regardless of actual electricity production. This system aims to maintain reliability and stability as variable renewable sources, such as wind and solar, become more prevalent. Capacity markets around the world differ in their structure and operation, tailored to the specific needs and energy profiles of their regions. For instance, in the US, markets like PJM Interconnection hold annual or multi-year auctions where generators bid to meet estimated future capacity needs, ensuring long-term grid reliability. Meanwhile, in France, the market is based on capacity certificates that suppliers must hold in proportion to their customers' peak demand, promoting an ongoing balance between supply and demand.

Similarly, **flexibility markets** are gaining attention as tools to manage the variability of renewable energy sources. By financially valuing the ability to quickly ramp up or down production, these markets incentivize the development of agile energy sources and storage solutions. In the UK, National Grid operates various flexibility markets such as the Balancing Mechanism, which allow for short-term adjustments to balance supply and demand and keep the grid stable. Germany has also been exploring similar concepts through its Regelenergie market (regulating power market), which utilizes rapid response sources to balance the grid. The California Independent System Operator (CAISO) in the US has developed markets for ancillary services and demand response that contribute to grid flexibility. All these mechanisms provide compensation for resources that can quickly ramp up or down their output.

Another concept gaining traction is implementing of mechanisms to address the drop in capture prices in markets saturated with renewable energy, where the abundance of low-cost generation can depress market prices during periods of high supply, potentially deterring further investment in capacity. **Contracts for Difference (CfD)** mechanisms, such as those utilized in the UK, effectively serve this role. Under this arrangement, a subsidy compensates for the gap between the market price and a predetermined reference price, known as the strike price. This subsidy adjusts in response to real-time market prices, offering a financial safety net to generators when market prices are insufficiently low.

> Flexibility markets are gaining ground as a way of managing the variability of renewables by valuing the ability to quickly ramp up or down production.

As we look towards 2050, the challenge will lie in crafting market mechanisms that not only ensure economic efficiency and system reliability but also align closely with environmental goals and the integration of increasingly sophisticated energy systems and continued profitability of the power systems. This will require continuous adaptation and thoughtful regulation to balance market incentives with the broader public interest, ensuring that the shift towards a more sustainable and resilient energy landscape is both equitable and effective.

Market designs in our forecast

In the Energy Transition Outlook (ETO) Model, we have incorporated a three-part market design to drive investment in the power sector:

1. The first component, the energy market, assesses the regional electricity demand against the available supply, inclusive of a safety margin, for all hours of the year. Discrepancies between the supply and demand catalyse new investments. The choice of technology for these investments hinges on each technology's revenue-adjusted Levelized Cost of Electricity (LCOE), which factors in the annual average revenue deviation from the norm across all technologies. Increasingly, solar and wind are becoming the preferred choices within this market despite potential future revenue declines.

2. The second market, the capacity market, is engineered to guarantee sufficient reliable capacity to counterbalance the intermittency of renewable energy sources like solar and wind. This market activates investments when there is a shortfall between the peak electricity load (again, including a safety margin) and the available reliable capacity. The evaluation for new investments considers the availability of dispatchable generation, accounting for maintenance downtime, and statistically assesses the contributions from renewables and storage throughout the simulation. Investment decisions are predominantly influenced by the cost per unit capacity, with low-CAPEX dispatchable technologies such as gas turbines and diesel reciprocating engines often being the most viable options.

3. The third market, called the flexibility market, addresses the need for hour-to-hour flexibility, necessitated by the variance in residual load, which includes both the load and the supply from variable renewables. This market assesses how the variability in the system, influenced by load fluctuations and renewable output, can be mitigated. It statistically evaluates the contribution of each technology to system flexibility, including options such as dispatchable generation, storage, demand response, electrolysers, and interconnections. New investments are triggered when there is a gap between the required flexibility and what is available, with decisions based on the levelized cost of flexibility – a metric that averages the investment and operational costs of flexibility technologies over their lifespan. Storage technologies frequently emerge as top contenders in this market due to their operational characteristics.

2.2 COST TRAJECTORIES

The LCOE is essential for determining the cost-effectiveness and appeal of power station investments. The global average LCOE of technologies, which represents the cost of producing a megawatt-hour of electricity throughout a power station's lifespan, is depicted in Figure 2.1, illustrating its evolution across various power station types.

Solar PV and wind have already secured the most competitive LCOE in many areas. Their downward LCOE trajectory is due to technological learning rates and driven by technological advancements, economies of scale, and improved manufacturing and deployment practices. From 2020 to 2050, we project these rates at 12% for solar PV, 13% for onshore wind, and 15% for fixed offshore wind. This means every doubling in global capacity corresponds to a respective LCOE drop by these percentages.

Renewables

Solar PV is set to break the USD 30/MWh mark by 2030 at the global average, with on-site storage adding another USD 22/MWh to the levelized cost. Average onshore wind LCOE will follow solar PV with a five-year delay in reaching USD 30/MWh. We foresee 2030 global LCOE for fixed offshore wind to be around 68 USD/MWh, and for floating offshore to be at 140 USD/MWh. From 2030 to 2050, the global weighted average of solar PV LCOE will reduce by 1.5% per year, reaching USD 22/MWh. Onshore wind will experience an average 1.1%/yr reduction with a mid-century cost of USD 27/MWh. Fixed offshore wind will stay above the USD 51/MWh mark on average, but will be as low as USD 32/MWh in ideal locations. Floating offshore will maintain an average USD 16/MWh cost premium from bottom-fixed in 2050, but sites with consistent high winds and short distances to shore will

Technology cost learning rates for renewables
Technology learning rates are driven by technological advances, economies of scale, and improved manufatcuring and deployment practices. The rate is given as a percentage change in the Levelized Cost of Energy (LCOE) for every doubling in global capacity. In our forecast, the rates projected for renewable technologies is as follows:

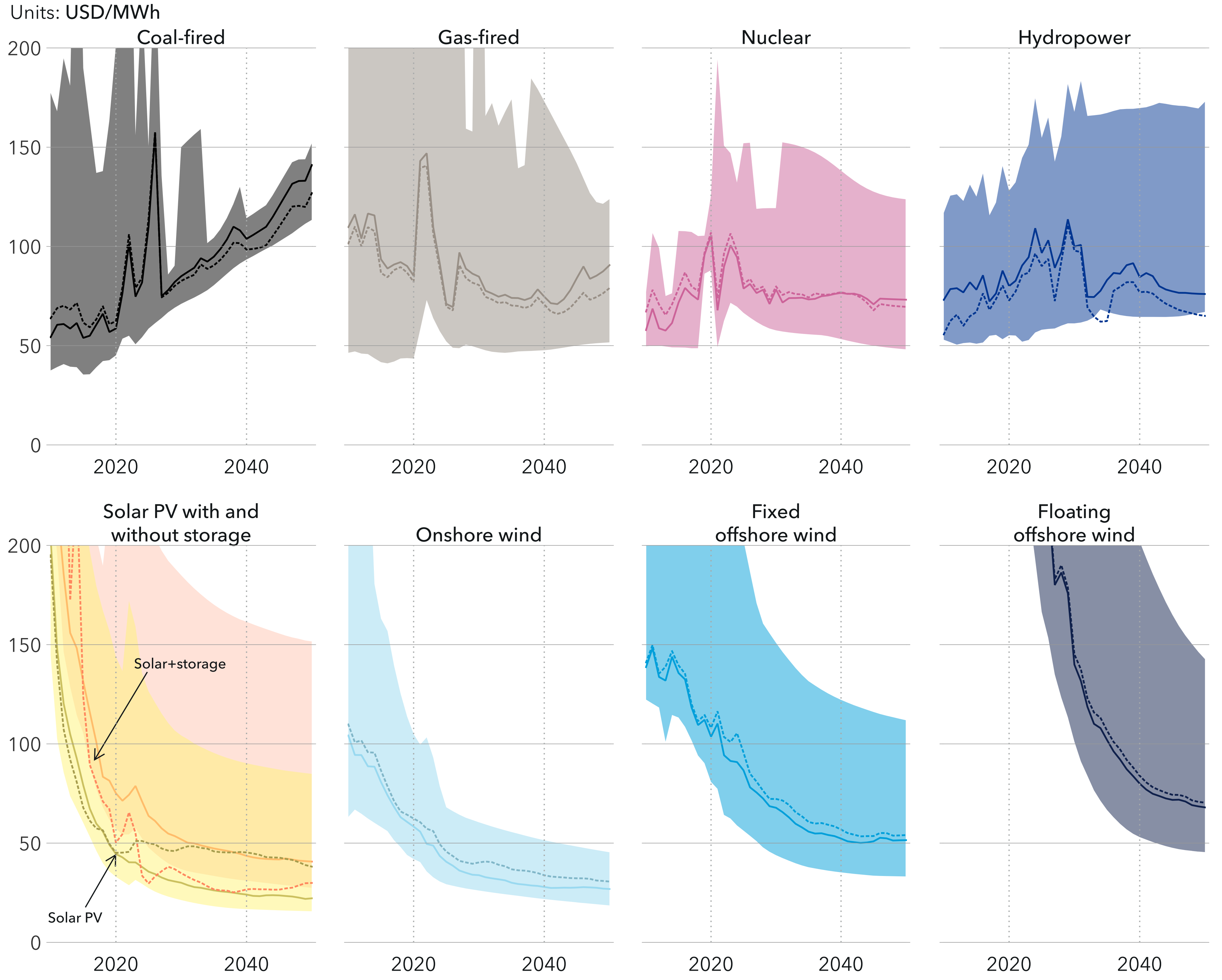
12% Solar PV

13% Onshore wind

15% Offshore wind

19% EV batteries

FIGURE 2.1
Average levelized cost of energy (LCOE) by power station type



Costs are for the year of financial close for new projects. Levelized cost includes CAPEX, OPEX, grid connection cost, carbon price, and CCS cost. Lines show global weighted average. Shaded areas show spread over 10 regions. Historical data source: GlobalData (2023), Lazard (2023), WoodMac (2023), IRENA (2023).

TABLE 2.1
Cost of capital assumptions by power station type and region

	Fossil-fuel fired				Nuclear				Mature renewables*				Emerging renewables**			
	2022	**2030**	**2040**	**2050**	**2022**	**2030**	**2040**	**2050**	**2022**	**2030**	**2040**	**2050**	**2022**	**2030**	**2040**	**2050**
NAM	12%	16%	18%	20%	6%	5%	5%	4%	6%	5%	5%	5%	11%	8%	5%	5%
LAM	12%	18%	18%	20%	10%	9%	9%	8%	8%	7%	6%	6%	13%	10%	6%	6%
EUR	15%	20%	23%	25%	6%	5%	5%	4%	5%	5%	5%	5%	10%	8%	5%	5%
SSA	9%	16%	18%	20%	10%	10%	10%	10%	8%	7%	7%	6%	13%	10%	7%	6%
MEA	12%	16%	18%	20%	6%	6%	6%	6%	8%	7%	7%	6%	13%	10%	7%	6%
NEE	14%	11%	11%	11%	14%	11%	11%	11%	14%	11%	11%	11%	19%	15%	13%	11%
CHN	6%	10%	15%	20%	6%	5%	5%	4%	6%	6%	6%	6%	11%	9%	6%	6%
IND	9%	16%	18%	20%	8%	8%	8%	8%	8%	7%	7%	6%	13%	10%	7%	6%
SEA	9%	16%	18%	20%	10%	10%	10%	10%	8%	7%	7%	6%	13%	10%	7%	6%
OPA	12%	16%	18%	20%	6%	5%	5%	4%	6%	6%	6%	6%	11%	9%	6%	6%

**Mature renewables include hydropower, bioenergy, solar, onshore wind, and bottom-fixed offshore wind.*
***Emerging renewables include floating offshore wind.*

be competitive in terms of LCOE. Hydropower costs are dependent on site-specific geological conditions, project scale, engineering challenges, and environmental and regulatory considerations. The global average cost is to remain around USD 75-100/MWh.

Conventional power stations

On the other hand, conventional power stations face limited scope for further technology-driven cost reductions. Consequently, factors like fuel costs, carbon pricing, and operational duration (capacity factors) will determine their future costs. While coal-fired power stations are observing an upward LCOE trend due to declining capacity factors, gas-fired power maintains a relatively steady capacity factor and a steady LCOE in the USD 50-120/MWh range, thanks to its lower carbon footprint and strategic shifts to regions with more affordable gas. The cost data for nuclear is scarce and a small number of projects can skew the data, but the general trend in OECD countries has been increasing cost due to cost overruns. With the balance shifting to China and Indian Subcontinent, and the emergence of small modular reactors, we expect average cost of nuclear to reduce to USD 70-80/MWh, with a range as low as USD 50/MWh. The real-term cost of capital is a significant component in the LCOE equation as it represents the return required by investors to fund a power project. It reflects the risk perception of investors about various technologies and regions. A higher cost of capital increases the overall financing cost of a power project, thereby raising the LCOE. Our projections on this can be found in Table 2.1. See Chapter 5 of our *Energy Transition Outlook* (2023a) for a more detailed discussion of our cost of capital projections across energy sources.

Energy-revenue adjusted LCOE

While LCOE has been the main metric in assessing the competitiveness of technologies, its inability to reflect revenues makes it an incomplete measure for determining future investments. To overcome this problem, as shown in Figure 2.1, we use the energy-revenue adjusted LCOE. This metric accounts for the difference between a technology's annual capture price and the prevailing wholesale price. Such adjustments ensure that technology earnings align with market demands.

Power stations also receive compensation for ensuring a certain portion or all of their capacity is available during times specified by the system operator. This arrangement underpins grid reliability and ensures adequate capacity during peak demand. As variable renewables grow, we anticipate a rise in these capacity markets. Emerging flexibility markets, which are not yet widespread, will likely become key in future power systems. Such flexibility markets compensate power producers and storage operators for their ability to rapidly adjust electricity output in response to grid demands. In our model, we segment these markets – energy, capacity, flexibility – distinctly. When there is a gap between demand and supply of energy, it can spur new investments, with the revenue-adjusted LCOE acting as a guide to identify the most cost-effective technologies. We also compute similar metrics for capacity and flexibility to influence the mix of new investments.

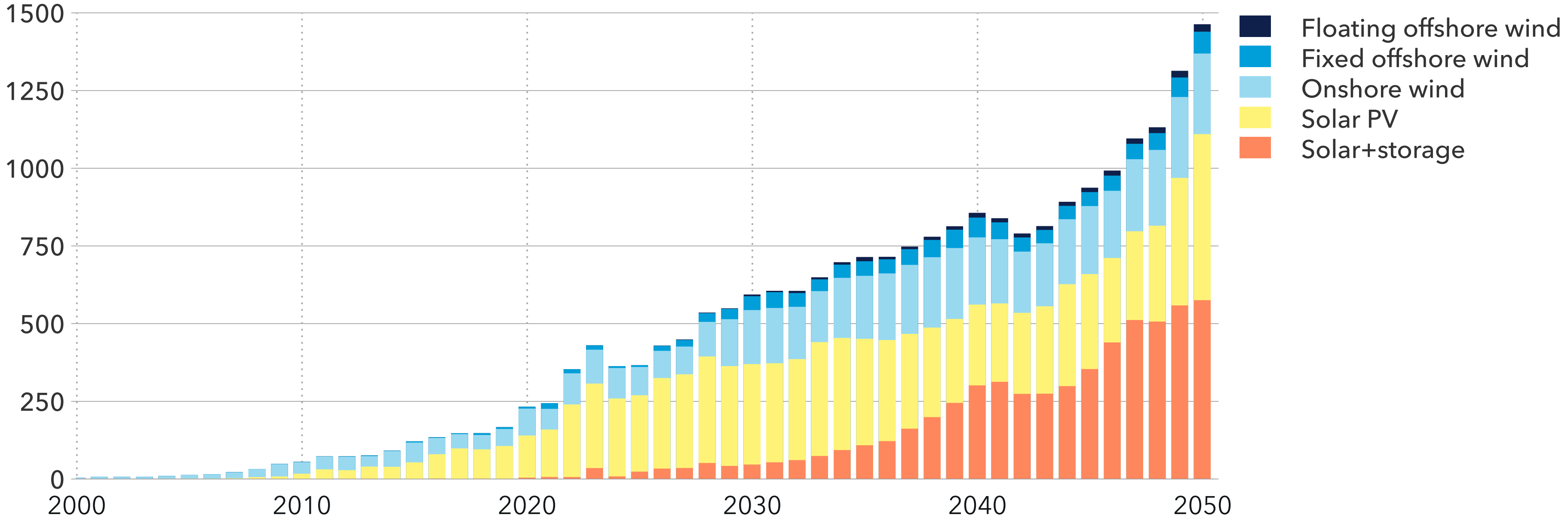
2.3 NEAR-TERM CHALLENGES

Delays in planning and permitting, especially in regions like the US, Europe, and the Indian Sub-Continent, are becoming major roadblocks to the energy transition. Wind energy projects, notably offshore, can face up to a decade of delay, while complex grid infrastructures can take up to 15 years due to, for instance, intricate negotiations with local communities or cross-border permit considerations. These setbacks not only inflate project costs but also sow uncertainties, potentially dissuading future investments. Figure 2.2 describes the trajectory of new solar and wind capacity additions we forecast up to 2050, showing a steady but restrained growth in the short term. While some regulatory initiatives, like Europe's *RePowerEU* plan and India's *Environmental and Social Impact Assessments* framework, aim to address these challenges, a broader shift in the regulatory mindset that prioritizes proactive grid investments and upgrades is crucial for a seamless energy transition. Our sidebar on Permitting Delays at the end of this chapter explores this issue in more detail.

FIGURE 2.2

Global solar and wind capacity additions

Units: GW/yr



Historical data source: GlobalData (2023), IRENA (2023)

In addition to the planning and permitting challenges faced by the renewables sector, renewable power confronts a set of pressing short-term challenges. The global uptick in interest rates, driven by major central banks, is set to inflate both debt and equity capital costs through 2023 and 2024, hampering the economic feasibility of projects. Manufacturers are grappling with dwindling profit margins due to surging raw material costs, especially steel for wind turbines, and accelerated technological evolution leading to component quality issues. Supply-chain bottlenecks have further exacerbated delays and costs for wind projects in particular. Concurrently, the rapid evolution in wind technology, marked by enhanced component designs and increasing rotor sizes, is temporarily curbing the traditional cost-saving benefits accrued from mass production. Furthermore, mandates for local content in emerging markets sometimes become impediments rather than incentives, as compliance proves overly costly or complex, leading to contract failures. We foresee the impact of this in the form of increased solar investment costs on the order of 10% in Europe until the early 2030s as it shifts its supply from China to Europe.

Industry sentiment

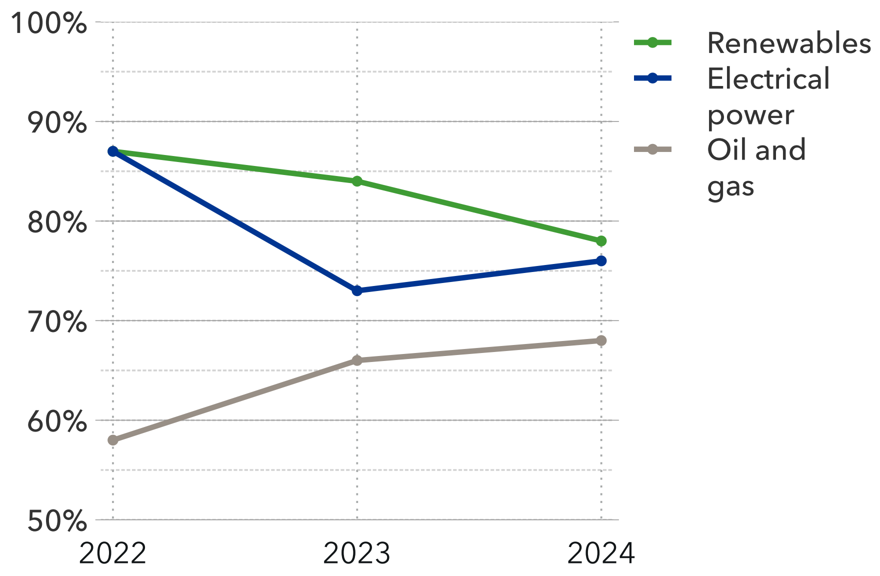
DNV's *Energy Industry Insights* (DNV, 2024a) research – now in its 14th year – explores the confidence, sentiment, and priorities for the energy industry in the year ahead. For our 2024 report, we canvassed the views of over 1,000 industry professionals in the opening months of this year. Nearly two thirds (64%) of renewables respondents believe that the year ahead will see more large, capital-intensive projects approved than in the past 12 months. Like other indicators, this is lower than last year (73%), but it suggests the growth of renewables will not slow down by much. As shown below, there has been some easement in negative sentiment regarding supply chain issues. However, permitting/licensing issues and inadequate infrastructure continue to be among the top 5 barriers to growth for renewables respondents, and 70% say that power grid infrastructure cannot yet adequately connect sources of renewable energy to areas of high demand. Just 21% say that current transmission capacity planning is sufficient to enable the expansion of renewables.

64% of renewables respondents believe that the year ahead will see more large projects approved.

FIGURE 2.3

Optimism for energy industry growth by sector

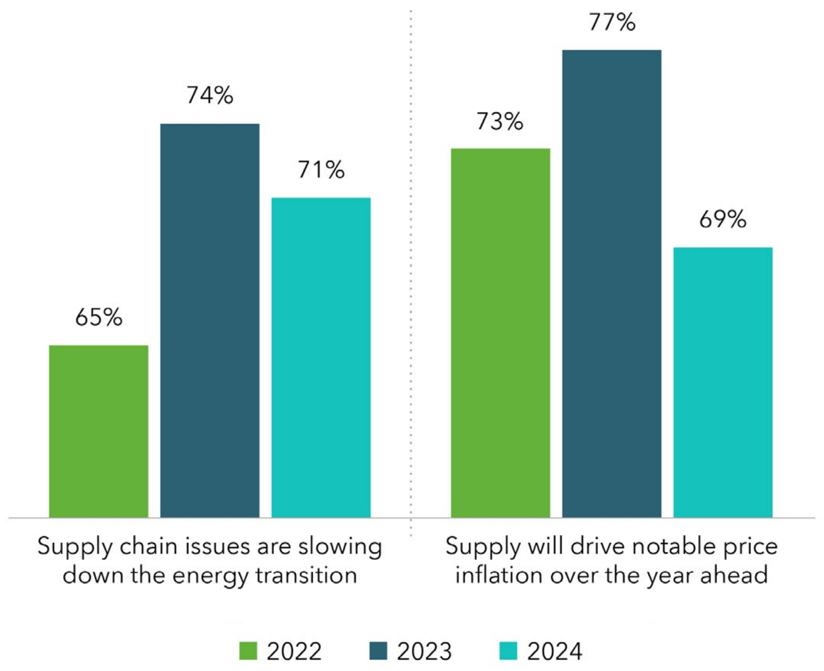
Units: Percentages



Percentages show 'net optimism' – the sum of 'somewhat optimistic' or 'highly optimistic' – about the growth prospects for (their part of) the energy industry in the year ahead.

FIGURE 2.4

Supply related barriers



'Gridlock' and permitting delays

Planning and permitting of power capacity and grid are increasingly a bottleneck, potentially acting as a barrier to the energy transition by delaying renewable capacity developments. It can take up to 10 years to build a wind energy project, especially offshore (WEF, 2023a). Deploying grid infrastructure is complex, involves multiple stakeholders, and can take up to 15 years. Delays result in increased project costs, and uncertainties for both project developers and investors, thus potentially decreasing the flow of capital.

Delays in renewable energy projects arise from several factors, including:

- Siting issues: Permission to build renewable energy projects meet contradictory energy, climate, environmental, and societal goals in specific areas, such as cultural or historical significance, biodiversity preservation, and the potential disruption of livelihoods on poductive land and water bodies.
- Interconnection challenges (gridlock): Permission to connect a renewable energy project to an existing transmission grid can be complex. If the grid is already heavily loaded, there may be insufficient capacity to accommodate the additional power unless upgrades or expansions of the grid infrastructure are made.

Delays in expansion of grid infrastructure arise from several factors, including:

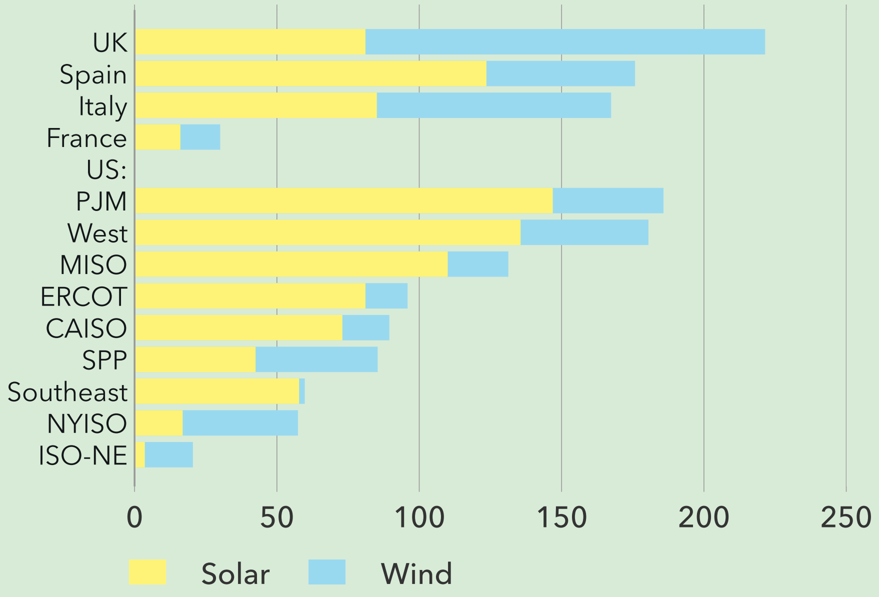
- Time-consuming processes to obtain permit to build high-voltage transmission lines, involving environmental impact assessments, public hearings, and negotiations with local communities.
- Lack of coordinated spatial planning and permitting process for generation sites, grids, and the related project infrastructure.
- Lack of anticipatory investment to accommodate distributed energy sources at the distribution level.
- Lack of appropriate cross-border, inter-state/province collaboration on permit considerations.

The extent of delays and the dynamic between renewable capacity and grids were highlighted by BloombergNEF (BNEF, 2023) as shown in Figure 2.5. Almost 1,000 GW of solar projects are stuck in the connection queue across the US and Europe, close to four times the amount of new solar capacity installed around the world last year. Over 500 GW of wind were also waiting to be plugged into the grid, five times as much as was built in 2022. These numbers are alarming, but we note that renewables projects tend to apply multiple times for the same wind/solar park in different locations. Moreover, a project may not be realized for a variety of reasons even if they receive a positive answer to a connection request from network operators. Nevertheless, there is a considerable and growing gap between the amount of renewable generation in the project development pipeline and transmission capacity.

FIGURE 2.5

Wind and solar projects waiting to be connected to the grid in Europe and the US

Units: GW



Adapted from BloombergNEF (2023a)

Delays are receiving regulatory attention

The permitting and siting process for both renewable plants and grids has received extensive attention since last year's ETO. Policymakers in several ETO regions have taken significant steps to expedite permitting.

In Europe, the *RePowerEU* plan, *Council Regulation 2022/2577* (December 2022), and the agreed upon *Renewable Energy Directive* (RED III) emphasize new, simpler permitting. For example, *RED III* details designated projects/areas of overriding public interest, digital processes, and swifter permitting deadlines (one year for pre-identified appropriate land/'go-to' areas, others with a two-year time frame, three for offshore wind construction permits). The *Trans-European Energy Networks – Electricity* (TEN-E) regulation aims to better interconnect national infrastructure across Europe (Euroelectric, 2022). In her recent State of the Union address, EC President Ursula von der Leyen unveiled a new EU 'Wind Power Package'. It aims to fast track permitting even more by improving auction systems, skills development, and access to finance, as well as stabilize supply chains (Sanderson, 2023).

In the Indian Subcontinent region, the *Environmental and Social Impact Assessments* (ESIAs) framework has expedited the delivery of renewable energy projects (WEF, 2023a). India has launched the *National Single-Window System* to provide investors and businesses with a one-stop-shop for approvals, and for advancing investments in an interstate transmission network (Mercom, 2022).

In the OECD Pacific region, the Australian Energy Market Operator developed the *Integrated System Plan (ISP)* (AEMO, 2022) which aims to broaden its scope from big transmission projects and speed up planning and approvals decisions for clean energy, wind and solar projects.

In the North America region, several steps at the federal level have been taken focusing on expediting permitting reform. We refer the reader to DNV's report *Energy Transition North America 2023* (DNV, 2023b) for further details.

Editor's note: for detail on how we reflect permitting delays in our supply forecast see discussion on page 52 and Figure 4.5.

2.4 LONG-TERM CHALLENGES

Price cannibalization

Price cannibalization is a looming challenge for the continued growth of variable renewables. Essentially, it refers to the phenomenon where revenues of variable renewables diminish due to a significant presence of solar and wind in the system, leading to more hours annually with prices dictated by these zero-cost technologies. This potential for price cannibalization threatens the future appeal of renewables that do not integrate storage, with solar PV being especially vulnerable.

From our studies, we have identified that solar PV starts feeling the pinch of price cannibalization once renewable penetration hits the 20% mark. As the penetration of renewables escalates, the capture price for solar PV correspondingly diminishes. To put this into perspective, at a 70% variable renewables penetration, solar PV's capture price dwindles to half the typical wholesale electricity rate. In contrast, due to the reduced correlation between wind generation patterns and electricity demand, wind energy feels a marginal cannibalization effect.

Interestingly, opportunistic generation technologies, such as solar combined with storage, alongside traditional fossil-fired power plants, will witness a surge in their capture prices compared to the regional average wholesale price. This trend is vividly illustrated in Figure 2.1, which showcases the disparity between LCOE and revenue-adjusted LCOE. Taking revenue adjustments into account, solar+storage emerges as the most promising electricity source, a conclusion further bolstered by its proportion in overall investments. While revenue adjustments somewhat uplift conventional generation's appeal over pure LCOE, the cost gap with renewables becomes overwhelmingly evident.

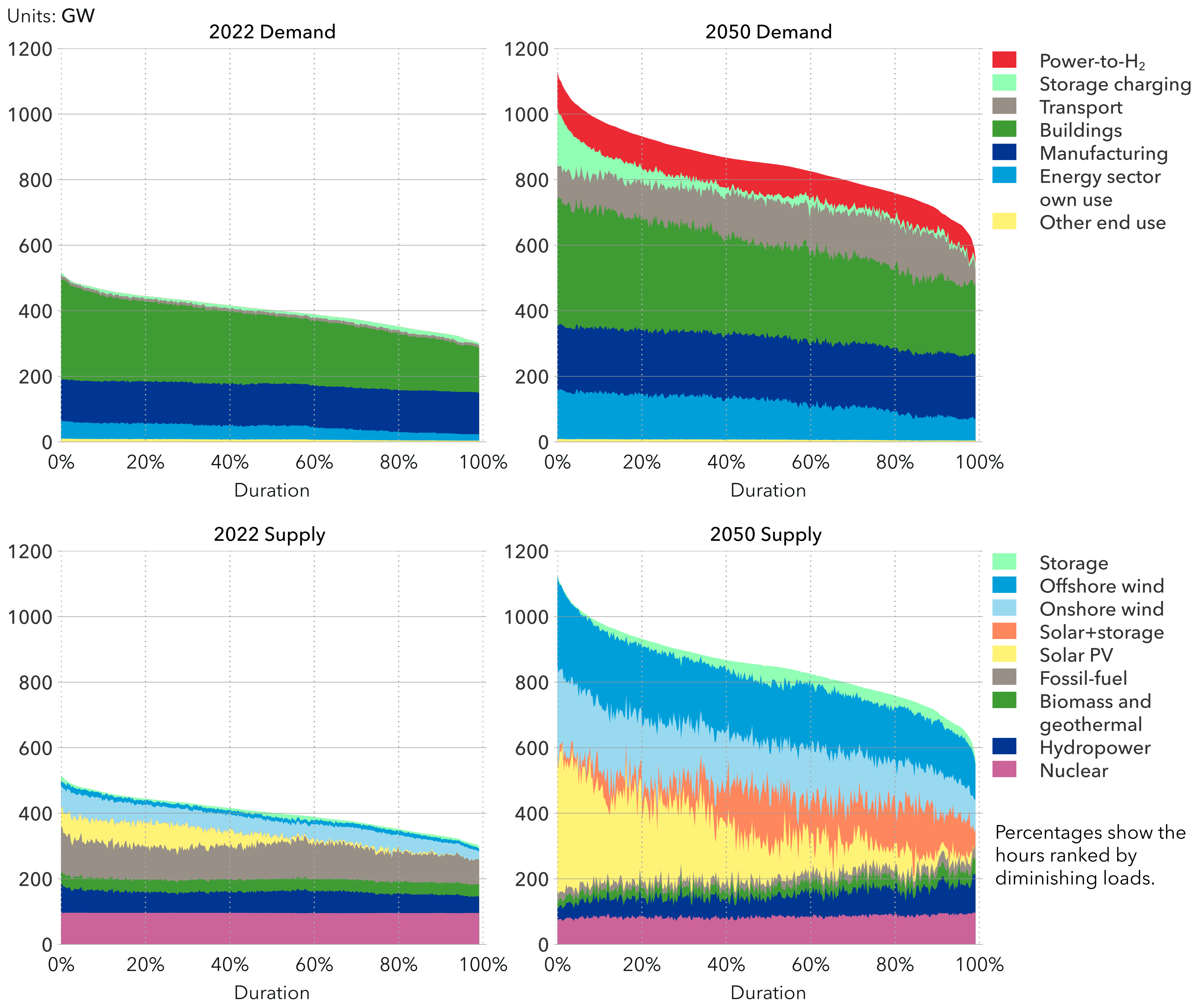
Flexibility

Flexibility in power systems is becoming increasingly paramount, as evidenced by the 2022 European electricity demand shown in Figure 2.6. Here, demand fluctuates between 290 and 510 GW, with these variations mainly attributed to daily end-use activities such as the operation of appliances, lighting, and water heating. Additionally, distinct patterns emerge due to variations across days of the week and months, resulting from factors like office closures over weekends and shifting electric heating and cooling demands throughout the year.

The curves display Europe's aggregate supply and demand, organized by total load. For clarity, hours are grouped, not plotted individually. This grouping causes the appearance of solar PV output at all times, even during hours when Europe has no solar generation due to lack of sunlight. Curtailed output is not shown.

FIGURE 2.6

Load-duration curves for European electricity supply and demand in 2022 and 2050



In a system devoid of solar and wind, addressing high demand would necessitate ramping up thermal power plants and deploying costly diesel generators. This typically escalates electricity prices, establishing a natural correlation between demand and price. However, as we decipher from the 2022 supply chart, renewables are already altering this conventional generation landscape. Solar PV, for instance, primarily generates electricity during daytime hours of peak demand. This diminishes the need for fossil-fuel generation, thereby influencing the operational patterns and economic viability of coal and gas power plants.

Fast forward to 2050, the effects of solar and wind on conventional generation become even more pronounced. So much so, it may challenge the very existence of constant, or 'baseload', generators like nuclear power. This doesn't mean there is room for nuclear or other conventional generation. However, any technology that relies economically on running continuously will suffer from continued increase in solar and wind penetration, which unavoidably increase the variation in supply. This heightened supply variation is poised to offer ample opportunities for flexible energy suppliers.

One lucrative avenue capitalizing on these fluctuations is price arbitrage. As price differentials expand throughout days, weeks, or even years, opportunities arise to purchase electricity inexpensively during times of abundant renewable output and to sell during peak pricing hours. However, competition looms large at both pricing extremities.

Fast forward to 2050, the effects of solar and wind on conventional generation become even more pronounced. So much so, it may challenge the very existence of constant, or 'baseload', generators like nuclear power.

Electrolysers, for example, might rival storage systems by buying cheap electricity to convert into hydrogen. Conversely, conventional generators will aim to maximize their operational capacity during high-priced periods to bolster revenues. Coupled with this, consumers, armed with smart meters and appliances, will increasingly shift their consumption patterns, moving from high-priced hours to cheaper ones. This evolving dynamic will eventually bring a self-balancing feedback into play: as flexibility providers increase, the demand for such flexibility reduces. For a comprehensive overview of this future flexibility landscape, the infographic on pages 12-13 dives deeper into operations of the power dispatch at various time scales, offering insights based on our simulations.

Furthermore, owners of flexible assets stand to gain via direct remunerations from system operators. Already, storage systems and power plants are compensated for ancillary services, such as frequency control, which allows minor supply adjustments ranging from milliseconds to several minutes. With the surge in variable renewables, we anticipate a more significant role for these flexibility markets.

Adequacy

Ensuring the future power systems' adequacy – the ability to consistently meet demand – remains crucial, especially with the rising integration of variable renewable energy sources and changing consumption habits. Moreover, increased electrification of sectors such as transport and heating adds complexity to demand patterns. A representation of the core of this challenge lies is shown in Figure 2.6, which presents the simulated electricity supply and demand distributions for Europe in 2022 and 2050. Contrary to intuition, the most pressing adequacy challenges in 2050 will not emerge during the hours of peak demand. The reason? Solar output, for example, aligns well with high-demand hours. Instead, the challenge appears during hours with minimal solar and wind output.

In our simulations, which use 2015 representative profiles for solar and wind output, the hour showcasing the largest disparity between demand and the sum of solar and wind output – the 'residual load' – demands no more than 772 GW from dispatchable generation sources. By 2050, combining dispatchable thermal generation (316 GW) and hydropower (606 GW) can surpass this residual load, even if some capacity is unavailable due to maintenance. Further bolstering this capacity, we expect at least 5-10% of 544 GW of solar+storage to be accessible even during winter days, complemented by 316 GW of standalone Li-ion batteries, 39 GW of long-duration batteries, and over 250 GW of vehicle-to-grid. Although the use of storage and vehicle-to-grid hinges on their charge state during peak residual load hours, we are confident that with strategic planning, a significant portion of this storage can be tapped into.

However, real-world power systems face additional challenges not covered in our simulations, such as grid constraints and unplanned outages, often exacerbated by extreme weather leading to extended low wind durations. Moreover, unexpected maintenance issues can further strain the grid's stability. Hence, systems incorporate extra safety margins. The key debate revolves around the precise margin required, influenced by the system's scale. For instance, smaller systems might need more substantial margins due to vulnerability to extreme weather, while larger, continental-scale systems can reliably assume non-zero wind and solar availability. Seasonal variations also play a critical role in determining these margins, especially during periods of peak demand. Our modelling also incorporates these safety margin needs. Additionally, enhancing inter-country connections and introducing other flexibility measures emerge as pivotal strategies for reinforcing this adequacy.

2.5 MODELLING POWER HOUR BY HOUR

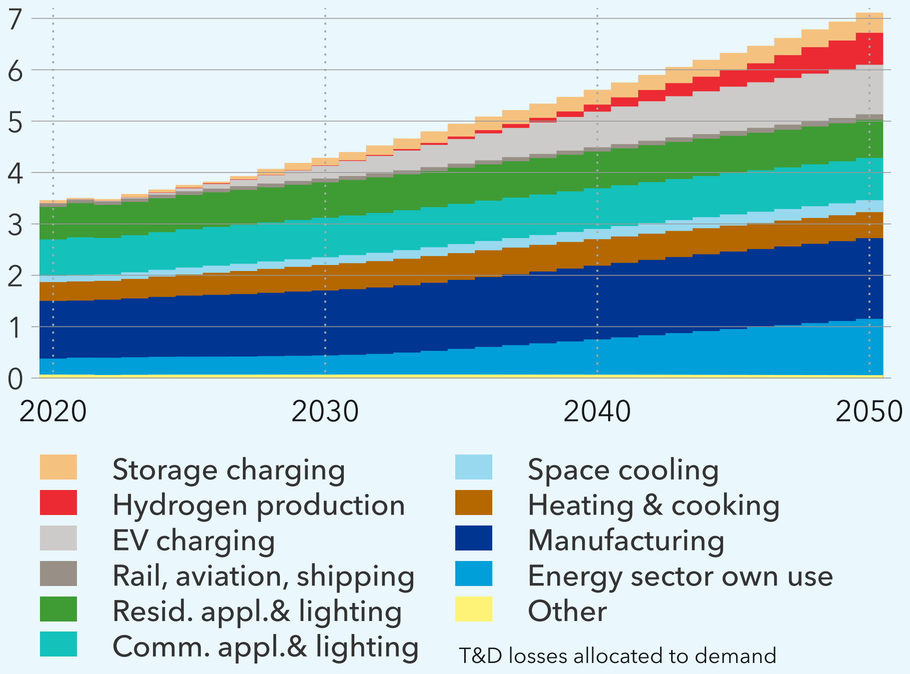
Here we illustrate how our hourly power dispatch model operates with reference to the Europe region in the year 2050.

Annual electricity demand by segment comes from the corresponding parts of the model. Investments for new capacity is based on energy, firm capacity, and flexibility needs. Technology mix is decided by revenue-adjusted levelized cost.

In the figure below, we expand the year 2050 over 52 weeks. Solar, wind, and heating/cooling load profiles fluctuate over the year. Dispatchable generation and storage react to price. All profiles are aggregated over Europe. Winter's low solar output is offset by higher wind and seasonal flexibility from conventional generation and power-to-hydrogen.

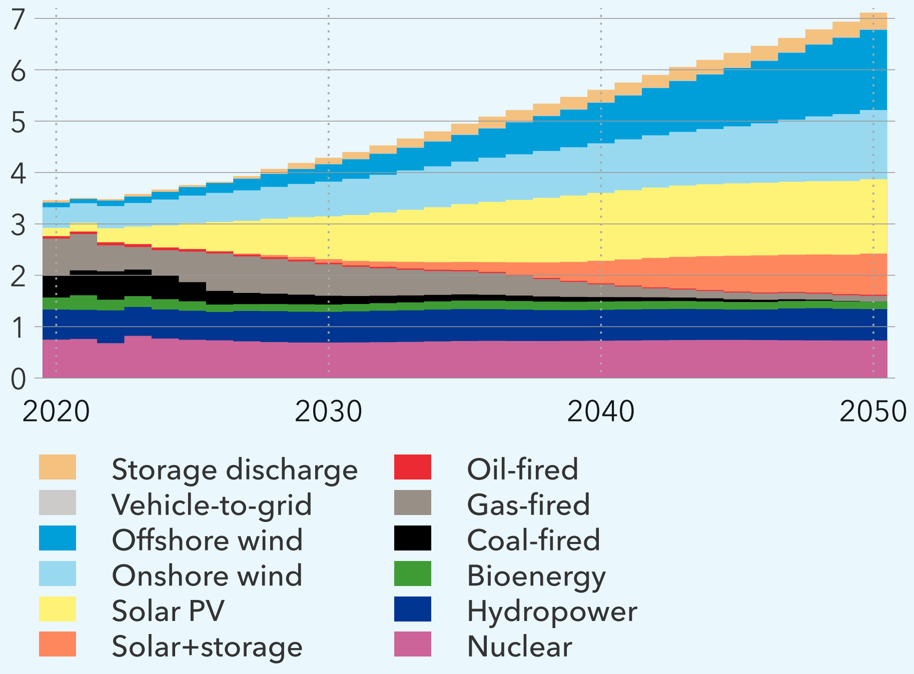
Europe electricity demand by segment; 2020-2050

Units: PWh/yr



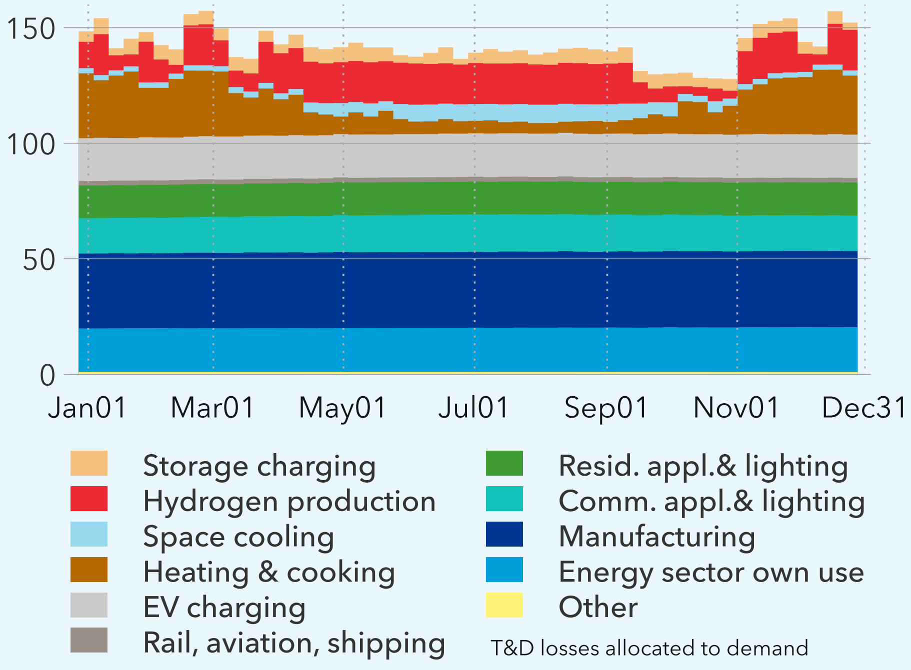
Europe electricity supply by source; 2020-2050

Units: PWh/yr



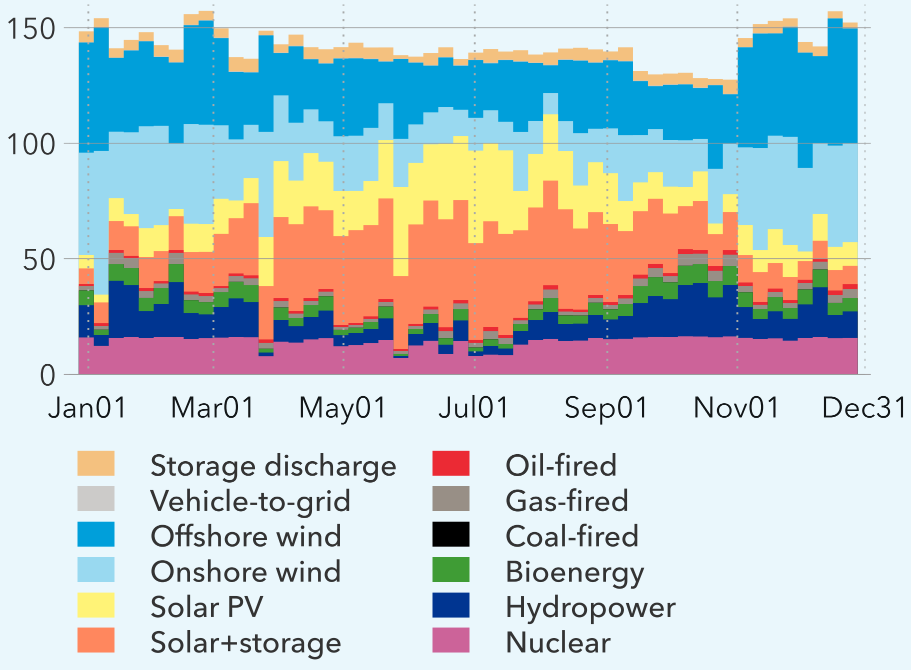
Europe electricity demand by segment; 2050

Units: TWh/week



Europe electricity supply by source; 2050

Units: TWh/week



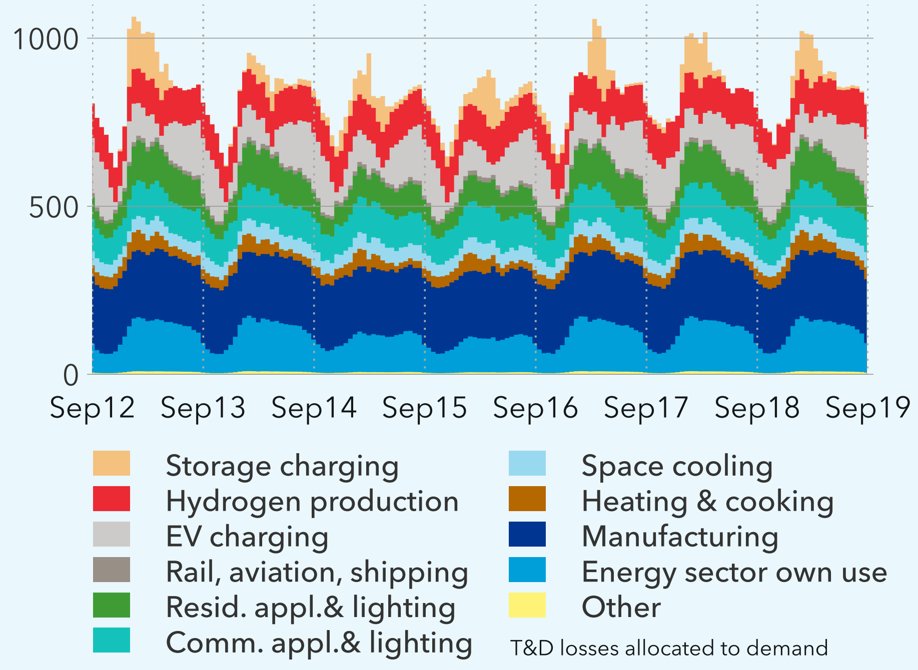
MODELLING POWER HOUR BY HOUR

The chart below focuses on week 37. Storage and hydrogen production respond to price signals. During midday, with abundant solar and cheaper electricity, electrolysis plants run and storage charges. At night, stored electricity is released while solar+storage plants provide power.

Hourly, the model sets demand and supply curves, shown below, representing them at every price. The intersection of these curves reveals the actual supply, demand, and price.

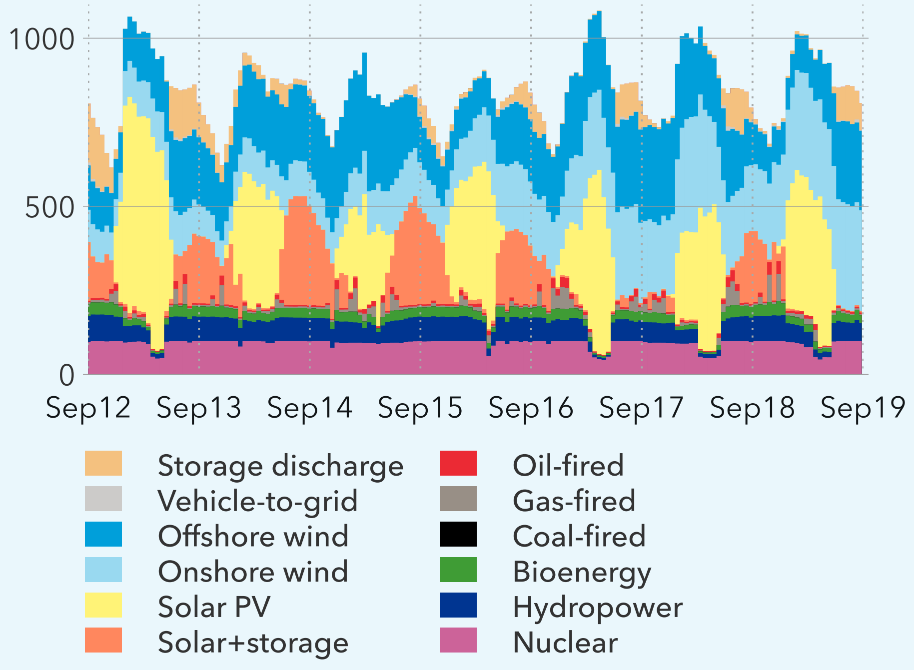
Europe electricity demand by segment; week 37; 2050

Units: GWh/hour



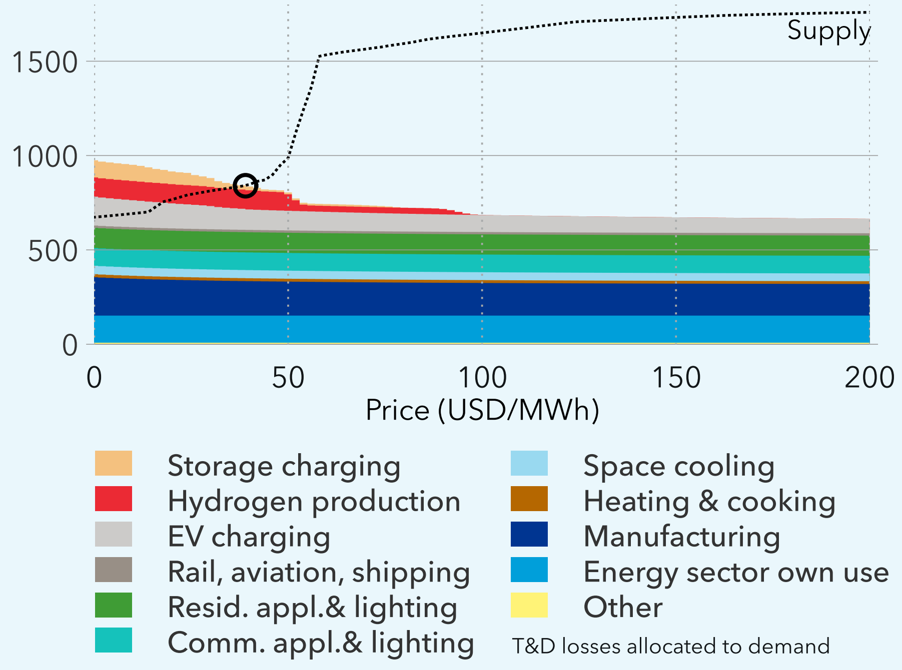
Europe electricity supply by source; week 37; 2050

Units: GWh/hour



Europe electricity demand curve; 13 September 2050; 17:00-18:00

Units: GWh/hour



Europe electricity supply curve; 13 September 2050; 17:00-18:00

Units: GWh/hour

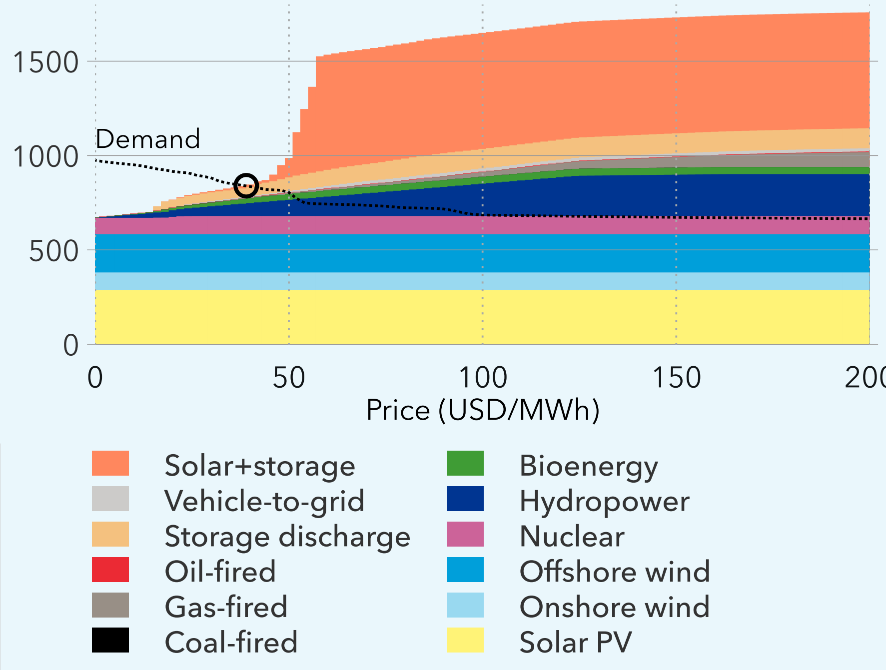
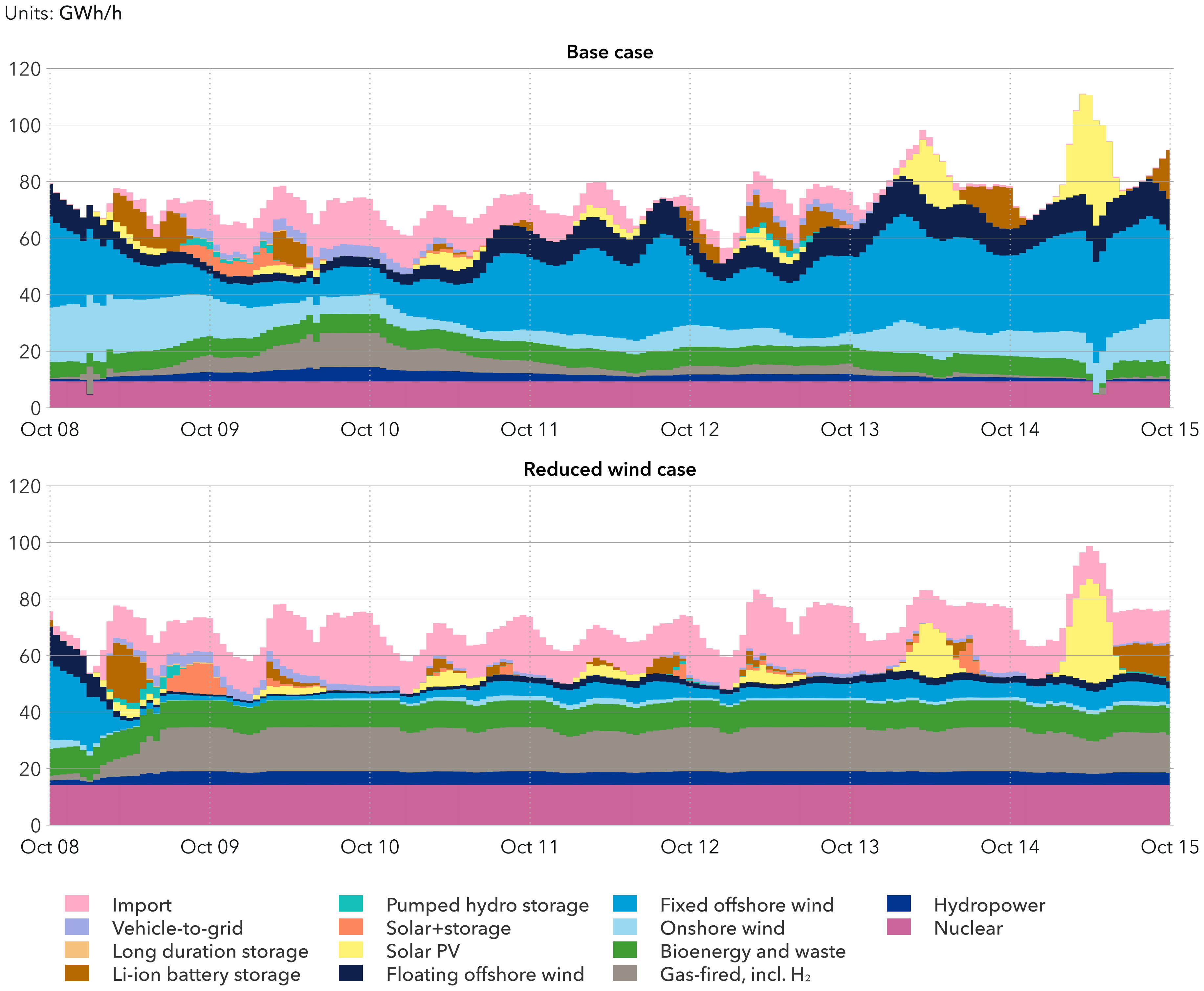


FIGURE 2.7
UK hourly electricity supply by technology in a selected week in 2050



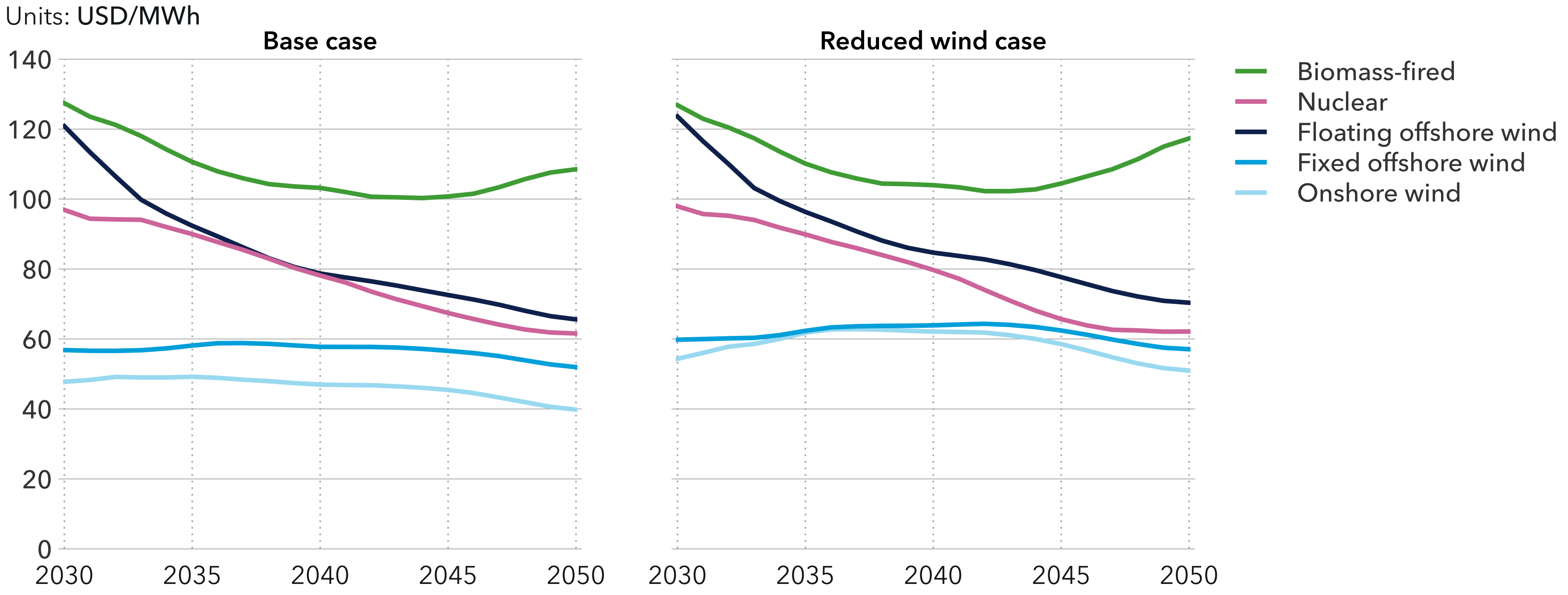
THE IMPACT OF A PROLONGED WIND DROUGHT

In our model, we employ fixed load and generation patterns to represent an average year. To assess the impact of extreme weather, we test a scenario where the UK experiences a two-week wind lull annually in weeks 41 and 42, reducing wind capacity by 80%. However, a recent study by Potisomporn et al. (2024) in Renewable Energy indicates that such a reduction for two weeks is highly unlikely. Their extensive analysis of low-wind events using ERA5 reanalysis data shows these events are rare and typically shorter. Therefore, this scenario represents an extreme condition test contrasting our baseline.

Figure 2.7 compares the generation mix for week 41 in 2050. The significant drop in wind output is offset by increased reliance on conventional generation technologies and imports. Storage does not show a drastic increase in contribution due to limitations in capacity. The price of electricity during this period increases drastically, eliminating any possibility for power-to-hydrogen to operate.

In the bigger picture, this change creates the biggest impact on the profitability of technologies. Figure 2.8 shows the revenue-adjusted LCOE trajectories of

FIGURE 2.8
Revenue adjusted LCOE trajectories of key technologies



key technologies in two cases. While in the base case, onshore wind and fixed offshore wind have more pronounced advantage over other technologies in the energy market, the gap is reduced in the reduced wind case, mostly due to changes in revenues.

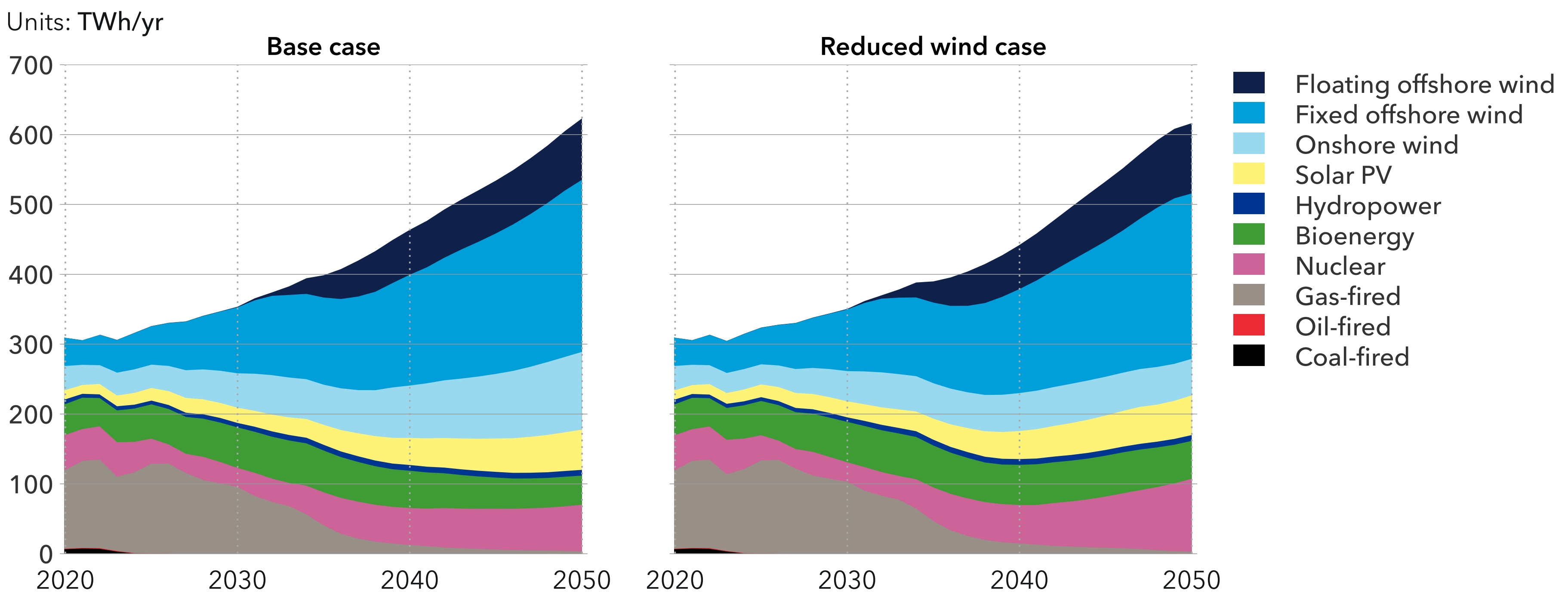
This change in the market economics impacts the investments of onshore wind, in particular, reducing UK's 2050 capacity by more than 50%, or 25 GW. This is compensated by increase in low-carbon conventional generation capacity: an additional 5 GW of nuclear capacity, 4 GW of biomass-fired capacity, and 7 GW of gas-fired capacity, gas-fired power plants mostly using hydrogen as fuel and only operating at low wind hours.

While increased system variability generally benefits storage technologies, an annual two-week wind drought does not enhance conditions for more storage. Storage systems thrive on frequent, short-duration fluctuations. Although theoretically, large storage capacities could partially mitigate such events, the lack of demand for storage during the rest of the year discourages investment. Therefore, despite potential benefits during extreme weather, the overall economic feasibility of investing in substantial storage infrastructure remains questionable.

Figure 2.9 below shows the trajectory of electricity supply in both cases. The change in profitability propagates through investment decisions over time

FIGURE 2.9

UK grid-connected electricity generation by power station type



creating a different electricity mix presented in Table 2.2. Although the change in the wind generation profile affects the competitiveness of technologies against each other, the price of electricity is only affected during the two-week period of wind drought and the annual average over 52-weeks is hardly impacted despite a shift in the generation mix from wind to mainly nuclear, as both have negligible marginal cost.

While our model explores a severe wind drought to test system resilience, a study by the University of Oxford (Abdelaziz et al., 2024) provides a more moderate and likely scenario for the impact of low-wind events. They find that while low wind speed events significantly affect energy output, these events are typically not as severe or prolonged as our model's scenario.

This has significant implications for conventional generation and storage capacity. In our extreme scenario, conventional generation and imports are heavily relied upon to compensate for the drastic drop in wind output, and storage systems reach their limits. Conversely, the Oxford study's findings imply that moderate wind reductions would require less drastic measures. Conventional generation would still need to increase, but not to the extent required by our extreme scenario. Storage systems might cope better with shorter, less severe wind droughts, leading to a more balanced and economically feasible approach to managing energy supply during low wind periods.

UKCP18 Science Overview (Lowe et al., 2018) highlights that while winter wind droughts might decrease, summer wind droughts could become more frequent due to shifting jet streams. This supports our model's assumption of seasonal wind variability but also suggests the need to account for potential increases in summer wind droughts.

A note by the Government Office for Science (Gov. UK, 2023) stresses the importance of considering compound low wind and solar events, which can lead to greater variability and unpredictability in renewable energy supply. Despite low share of solar in UK's power generation, our scenario could be enhanced by integrating such compound event considerations to better reflect real-world complexities.

TABLE 2.2

2050 UK power supply mix in two cases

	Base	Reduced wind
Onshore wind	17%	8%
Fixed offshore wind	38%	36%
Floating offshore wind	13%	15%
Solar PV	7.2%	7.0%
Solar plus storage	1.6%	1.7%
Nuclear	10%	16%
Hydropower	1.3%	1.3%
Bioenergy	5.8%	7.8%
Bioenergy with CCS	0.5%	0.5%
Methane	0.02%	0.02%
Methane with CCS	0.5%	0.4%
Hydrogen	2.4%	2.2%
Import	2.4%	3.1%

3 DIGITALIZATION AND AI

The power sector has been digital for decades, but as its systems grow in complexity and evolve towards autonomy, targeted investment in digitalization and IT is becoming as important as the physical build out of generation assets and the grid. Software, including AI, can help greatly in maximizing the capacity of existing infrastructure, while optimizing the design of new assets. In our annual survey of industry professionals (DNV 2024a), some two thirds of respondents expected their organizations to increase their spend on digitalization in the coming year – more than in any other area of investment.

3.1 ARTIFICIAL INTELLIGENCE IN NEW POWER SYSTEMS

AI will make a profound impact on new power systems in our forecast period. But in this context, AI is subject to Amara's law, which holds that we tend to overestimate the effect of a technology in the short run and underestimate the effect in the long run. DNV has yet to factor AI into our forecast of the world's energy system beyond general considerations of the impact of digitalization. As we explain in this chapter, these are early days for the widespread adoption of AI into the operating environment of power systems. There are significant barriers to uptake, including resistance to change as well as important technical and cyber security concerns. From an analytical perspective it is also very difficult to tease apart the broader effect of digitalization and the specific effect of AI. Nevertheless, we are monitoring developments closely and believe that AI holds considerable potential to accelerate the energy transition from its present course. Policy will, however, remain the main driver of the transition.

The growing influence of AI in power systems

Our research has revealed dozens of uses that AI is serving in the power industry already, some of which we cover in this chapter. AI is not new to the energy sector; expert systems and basic neural networks were in use 30 years ago, but the scope and capabilities of AI have increased with computational power. For instance, the performance of graphic processing units (GPU) – essential for managing AI's intensive data processing – has increased by 7,000 times since 2003 (Merrit, 2023). Advances in sensor systems, the IOT, cloud computing, allied with breakthroughs in computer vision, reinforcement learning, and auto machine learning were building serious momentum behind AI before the release of ChatGPT at the end of 2022. Generative AI and large language models have dominated public consciousness and discourse since then, obscuring remarkable ongoing progress with 'industrial AI' (see sidebar).

According to the WEF's white paper, *Harnessing AI to Accelerate the Energy Transition* (2023b) reductions in clean energy power generation of USD 1.3trn could flow from better AI-driven demand side management globally by 2050. In addition, savings of USD 188bn in grid equipment costs could flow through better AI-enabled management of transformers, while AI's contribution to flexibility solutions could reduce overall power system costs by 6–13%.

A recent study (Heymann et al., 2024) analysed over a quarter million academic and research papers on various aspects of AI in the power value chain published through to 2022. (See Figure 3.1). The authors show how the rate of published work has skyrocketed in recent years, with some 25,000 new papers now being added annually. The study finds that the focus of research currently falls mainly on AI applications in power retail (55 %), transmission (14 %), and generation (13 %).

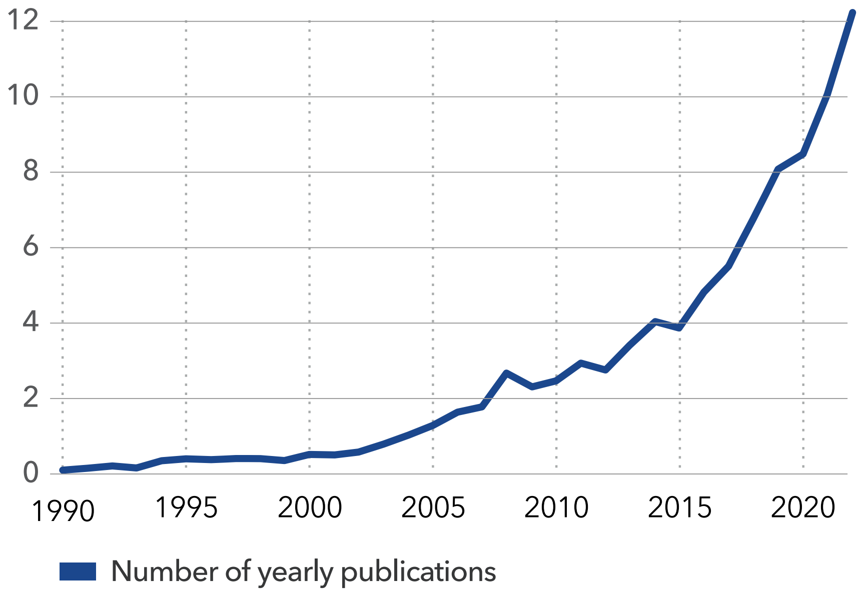
The predominance of AI research and applications in the downstream end of the power system value chain comes as no surprise. As we have shown in Chapter 1, demand patterns are shifting rapidly and AI is becoming crucial to managing energy demand – combining past data patterns with a growing mountain of new data on DER adopters, smart meters, demand response, V2G, etc. to predict changes in energy usage. These predictive systems not only interface with network operators for planning purposes, but with the electricity market in a range of AI-enhanced processes in price forecasting, the optimized bidding and aggregation of flexible demand, automated peer-to-peer trading, and so on.

The AI research and development pipeline is less active in transmission and generation because it involves decision support and augmentation of a complex physical environment, subject to very precise physical constraints. As Bill Gates (2023) has underlined, AI still does not control the physical world. We are only now witnessing the very beginnings of the fusion of robotics and AI into something called 'physical intelligence' (Rus, 2024). That is not to say that AI will not be needed in helping to manage the ever more complex distributed generation and expanding grid environment. As discussed in depth in Chapter 4, many grid operators are stretched to the limit and need the assistance of new digital tools and AI. Many utilities are using AI to analyse grid conditions and threats more quickly, enable remote and predictive maintenance of critical equipment, optimize topologies, and forge more agile contracts with partners and customers. However, AI is a long way from being given the task of managing a fully automated grid (Kim, 2023).

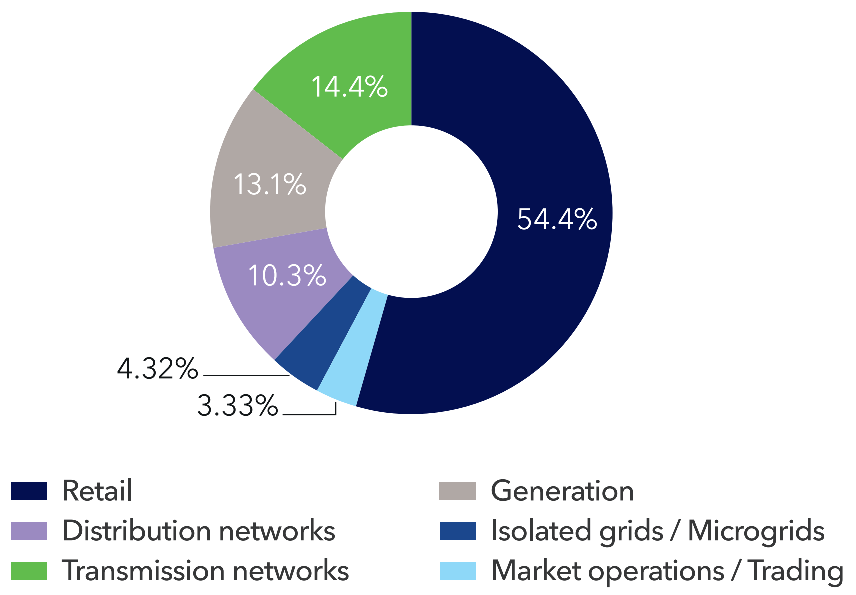
FIGURE 3.1

Published material relating to AI in the power industry

Units: 1000



Power system supply chain element



Charts redrawn from F. Heymann, H. Quest, T. Lopez Garcia, C. Ballif, M. Galus, *Reviewing 40 years of artificial intelligence applied to power systems – A taxonomic perspective*, **Energy and AI**, Volume 15, 2024.

Industrial AI

The immense scale of change which generative AI is forcing in service industries and marketing is very different to the enhancements AI is and will be bringing to the asset-heavy power industry. Here, two concepts are helpful. With reference to Figure 3.2, we draw a distinction between:

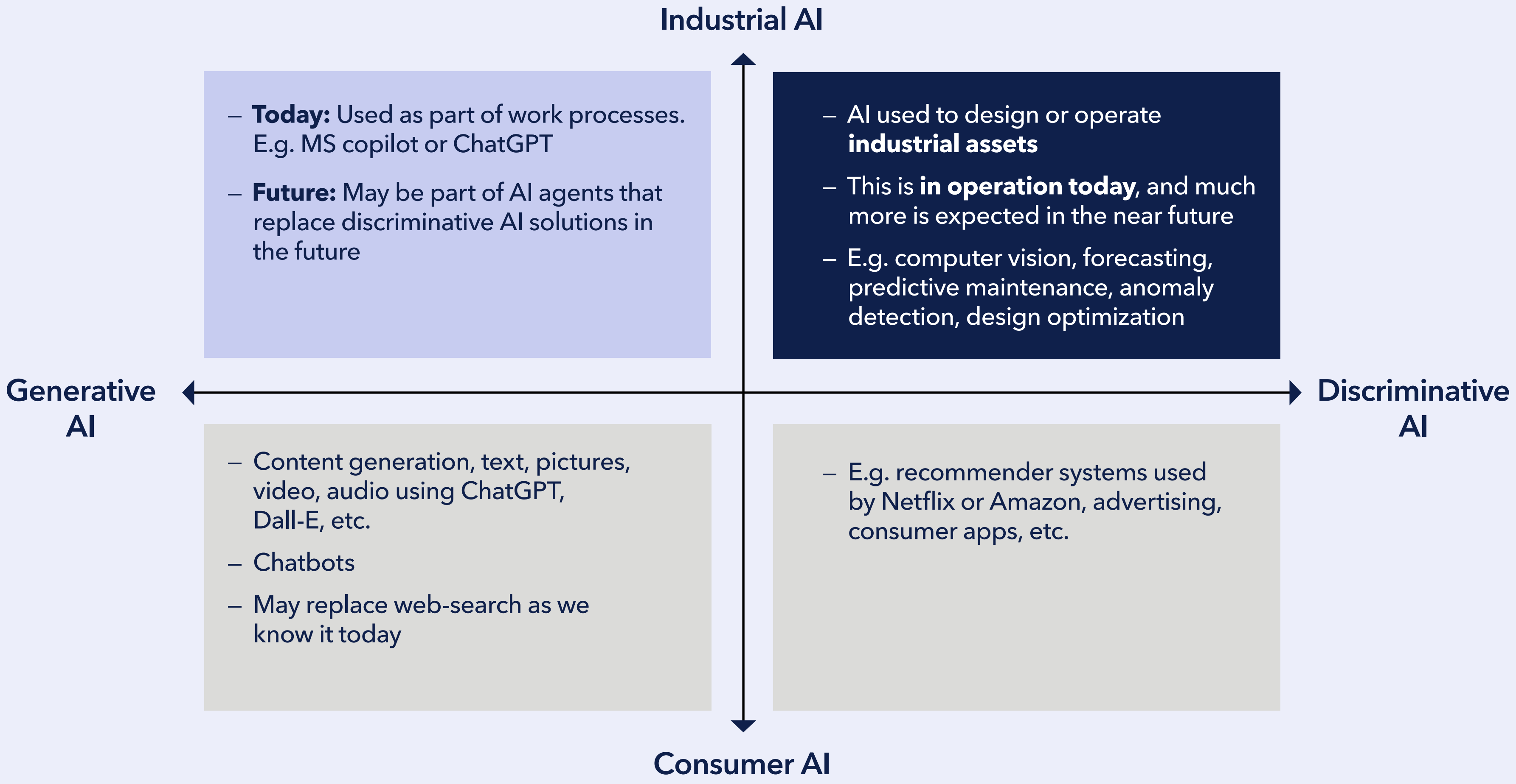
Generative AI – Models used to generate new data. These models aim to learn the underlying distribution of the data to produce new samples that are similar to the training data. Generative AI models include large language models (LLMs) like ChatGPT which are dominating the hype cycle at the moment. Their applicability to energy systems is currently limited to low-risk applications like productivity enhancement tools for staff (e.g. Copilot) and customer service applications (e.g. Chatbots), and to some early experimental work. However, as tools and methodologies evolve to deal with the well-known explainability ('black box') and hallucination issues associated with generative AI, industrial applications will develop over time.

Discriminative AI – Models used for prediction and inference based on existing data. They do not generate new data but instead focus on identifying patterns and making decisions based on those patterns.

This type of AI encompasses computer vision, forecasting, predictive maintenance, anomaly detection, design optimization, and so on, and broadly speaking can be termed 'industrial AI'. It is responsible for nearly all AI applications either serving power systems today or in the research and development pipeline.

> As tools develop to deal with 'back box' issues and hallucinations, generative AI will increasingly be used in industrial settings.

FIGURE 3.2

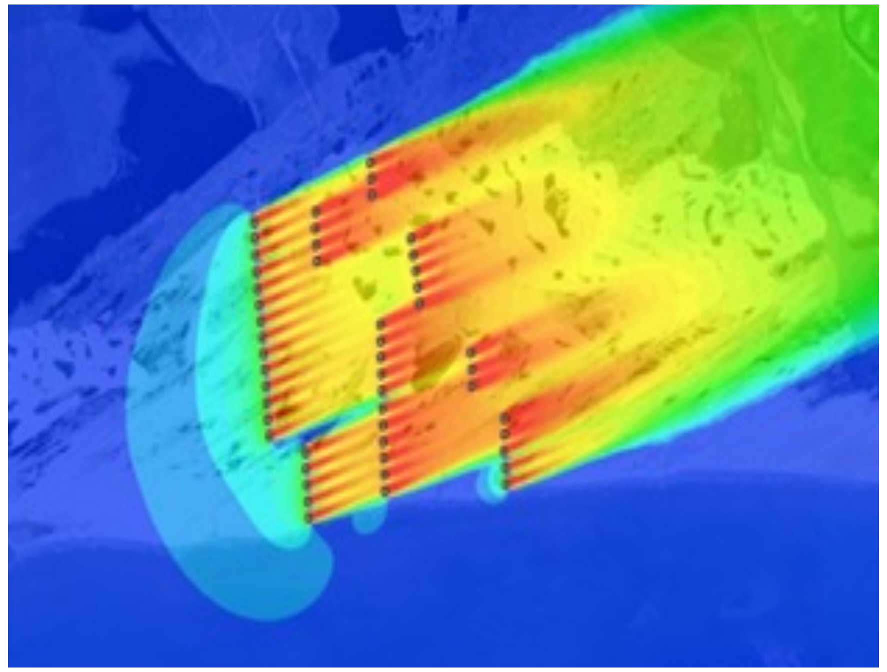


AI AT WORK IN THE NEW POWER SYSTEM VALUE CHAIN

Environmental Impact Assessments (EIAs) and permitting – With the proliferation of sensor networks and drones in biodiversity monitoring, deep learning models are being trained to automate the identification of species and habitats. In reviewing the applicability of AI technology to EIA practices, Sandfort et. al. (2023) find considerable potential for AI to bring precision and speed to process, analyse, and simulate ecosystem data. AI also contributes to data visualization and report generation, all of which has potential to speed up environmental planning and permitting processing. The authors caution about the need for the use of explainable AI (xAI) and to add transparency and call for publicly-funded high quality data repositories for AI training and reference purposes.

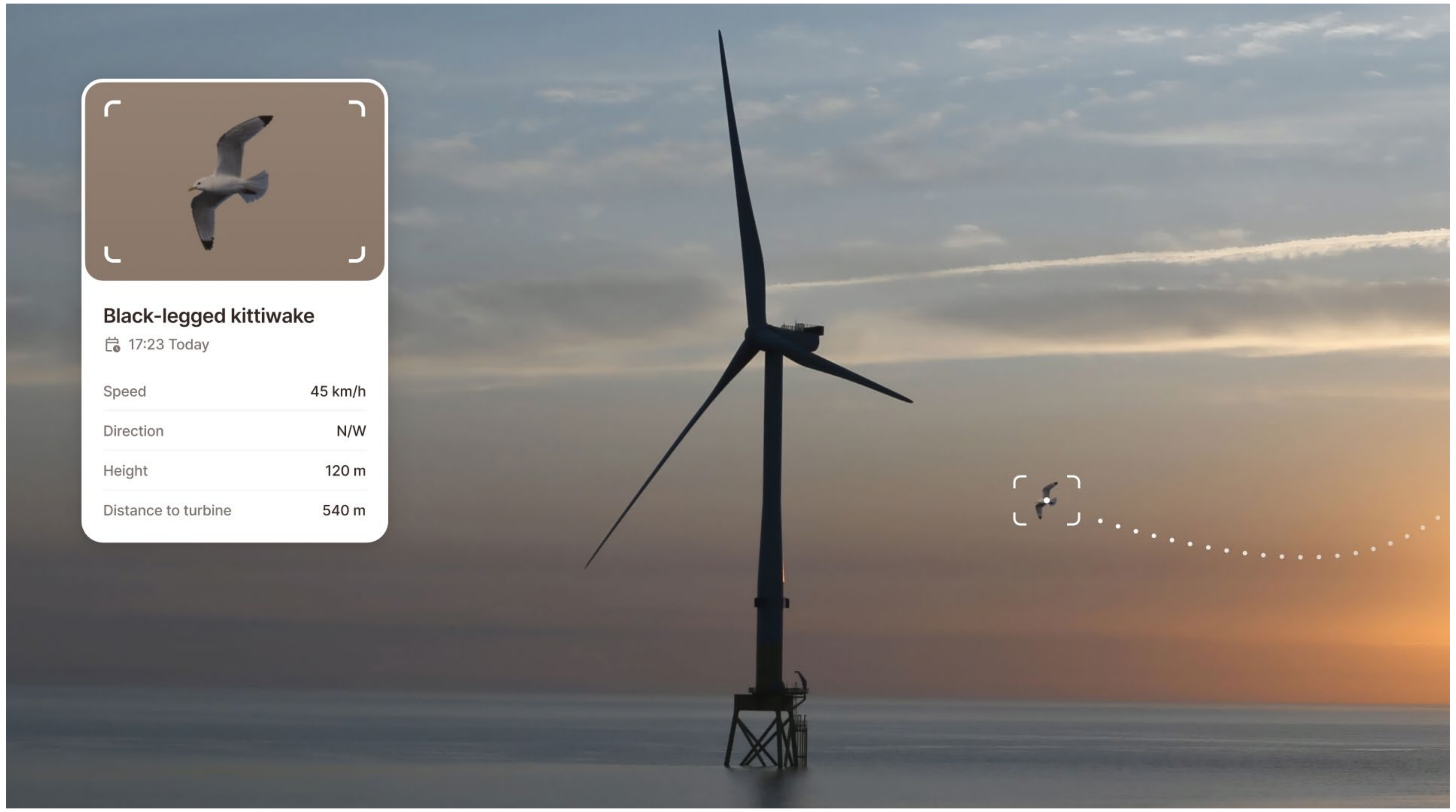
FIGURE 3.3

Wake modelling: machine learning can provide enhanced and expedited wind turbine interaction modelling.



Materials science and design – The use of AI in materials science and engineering is well documented (see, e.g. Papadimitriou et al., 2024), and has far-reaching implications for materials discovery and selection for generation and grid componentry and new battery chemistries. On the design side, one example is the use of invertible neural networks by the NREL labs in the US to improve the wind turbine blade design process. They recently reported a hundredfold acceleration over conventional methods (Vijayakumar et al., 2024).

Siting and design of renewable generation – There are many existing and emerging AI applications for the siting and design optimization of renewables installations. For example, Chinese researchers have developed the LightGBM machine learning model that uses satellite and sunshine data from over 2000 weather stations throughout China to find the most optimum locations to place double-sided solar panels to maximize their solar energy output. In the US, DNV venture partner HST uses AI-based decision engine and data analytics to optimize large scale solar installations for corporates and governments. HST also uses platform technology to smartly match developers with the energy buyers, risk management advisors, landowners, and other partners required for project execution.



The Norwegian company, Spoor, uses AI technology to monitor bird activity near wind power installations, increasing knowledge and improving reporting of biodiversity impacts. Image courtesy Spoor

Engineering wake models have been available in wind farm design software, such as WindFarmer, for 25 years to help wind farm developers understand the critical reductions in available energy through wake and blockage losses, and design better wind farms. Rapid engineering wake modelling approaches have been validated and tuned against the biggest wind farms operating today, but not against the planned mega-clusters of tomorrow. To reduce wake modelling uncertainty that is increasing with wind farm scale, DNV developed high-fidelity CFD wake modelling capability, but this is computationally intensive. An alternative approach underway is to train a machine learning surrogate model, CFD.ML, on the high-fidelity model results to provide enhanced and expedited turbine interaction modelling, simplifying full CFD models.

Maximizing renewable generation – Machine learning aids in matching supply with demand, maximizing the financial value of renewable energy and grid integration. Day-ahead forecasts of the output of solar installations are critical for achieving regulatory compliance, effective grid management, storage planning, and the effective management of microgrids. For example, Solcast, leads in solar irradiance data and forecasting globally, and delivers data to over 350 customers that manage more than 300 GW of assets. This data comes from tracking clouds and aerosols at 1-2 km resolution globally, using satellite imagery, global weather data, and proprietary AI/ML algorithms to produce over 600 million forecasts every hour. In a similar vein, DNV's Forecaster service employs a blend of advanced statistical methods and machine learning algorithms to sift through vast datasets, extracting the most accurate and relevant information for short-term forecasting. The service covers over 200 wind and solar sites in 20 countries with a total installed capacity of 150 GW.

Energy storage – AI can significantly improve the integration of energy storage with the grid. AI algorithms could adapt to changing conditions, adjusting energy storage parameters in real time to achieve a more efficient and reliable grid. The optimization of battery charge and discharge cycles can help to minimize energy losses while improving efficiency and prolonging battery system life. DNV has developed a Battery AI service where we can use AI capability to predict battery life based on different usage profiles. Finally, AI-driven simulations and modelling can help determine the optimal size and placement of energy storage systems.

Materials Innovation and R&D Acceleration – AI has the potential to significantly accelerate materials research for energy storage. Machine learning models predict material properties, aiding in the discovery of novel battery chemistries.

Power grids – For transmission and distribution system operators, AI emerges as a game-changer for core utility functions over the full value chain from grid planning, engineering, design to asset management and grid operations.

Conventional AI has long been used in grid planning, line routing, and transformer placement, and stands out as an area where generative AI makes a significant contribution. Recent research at MIT Laboratory for Information and Decision Systems (2024) shows that generative models trained on existing data can create additional, synthetic data to augment limited datasets, allowing for a range of what-if scenarios for grid planning beyond that which can be achieved with existing data alone. A similar approach has been followed by the PNNL ChatGrid project, which provides a generative AI-driven tool for grid visualization allowing engineers to pursue innovative designs while simulating various operating conditions.

For asset management, AI is being used to predict maintenance or replacement needs for grid components, preempting failures and boosting reliability. Moreover, AI can proactively analyse extensive sensor data to identify potential issues and anomalies before they occur. This proactive approach minimizes downtime and improves network reliability.

Utility companies are increasingly embracing AI for critical operations, notably in inspecting and managing physical infrastructure like transmission lines and transformers. PG&E leverages machine learning to analyse aerial images for identifying areas requiring tree trimming or equipment repairs, while Duke Energy employs AI for inspecting generation assets and automating anomaly detection in utility poles using advanced computer vision techniques. Other examples are E.ON's machine learning algorithm predicting medium-voltage cable replacements; Enel reducing power outages by 15% using machine learning to monitor power lines; the State Grid Corporation of China's extensive use of AI to analyse smart meter data and identify equipment problems; and DNV's own Smart Cable Guard product, used extensively in distribution networks to detect weak spots without digging up cables, which uses machine learning to improve noise reduction and eliminate false positives.

AI is integral to grid enhancing technologies (GETs), which are covered in depth in Chapter 4. Cases include the refinement of extensive sensor data with machine learning to facilitate dynamic line rating (DLR). LineVision (2024) recently announced the largest deployment to date of their sensor-based DLR system on the National Grid transmission lines in western New York.

AI-driven models for customer load data have broad applications, including grid modelling. The many use cases cannot adequately be covered here but are partly covered in Chapter 1 under demand response and in Chapter 4 on grids. The grand prize of AI effectively performing automated grid operations remains conceptual at this stage but has spurred intriguing experimental work.

Many important insights and new models emerged through the Learning to Run a Power Network competitions (L2RPN) in 2021 and 2022 organized by the US Electric Power Research Institute (EPRI) with several utility and academic institute partners. For example, machine learning models based on grid data show considerable promise in solving complicated grid optimization problems far faster than is currently done with conventional power flow calculations which rely on approximations of physics (Baker 2023; Behr 2021). Those concepts will undoubtedly cross into deployment in microgrids, intially with lower complexity and consequences of AI failure (see e.g. Shyni and Kowsalya, 2024). The industry will need many years of building trust into AI-enabled systems to arrive at a point where AI is entrusted to make split-second decisions for large grids under emergency conditions.

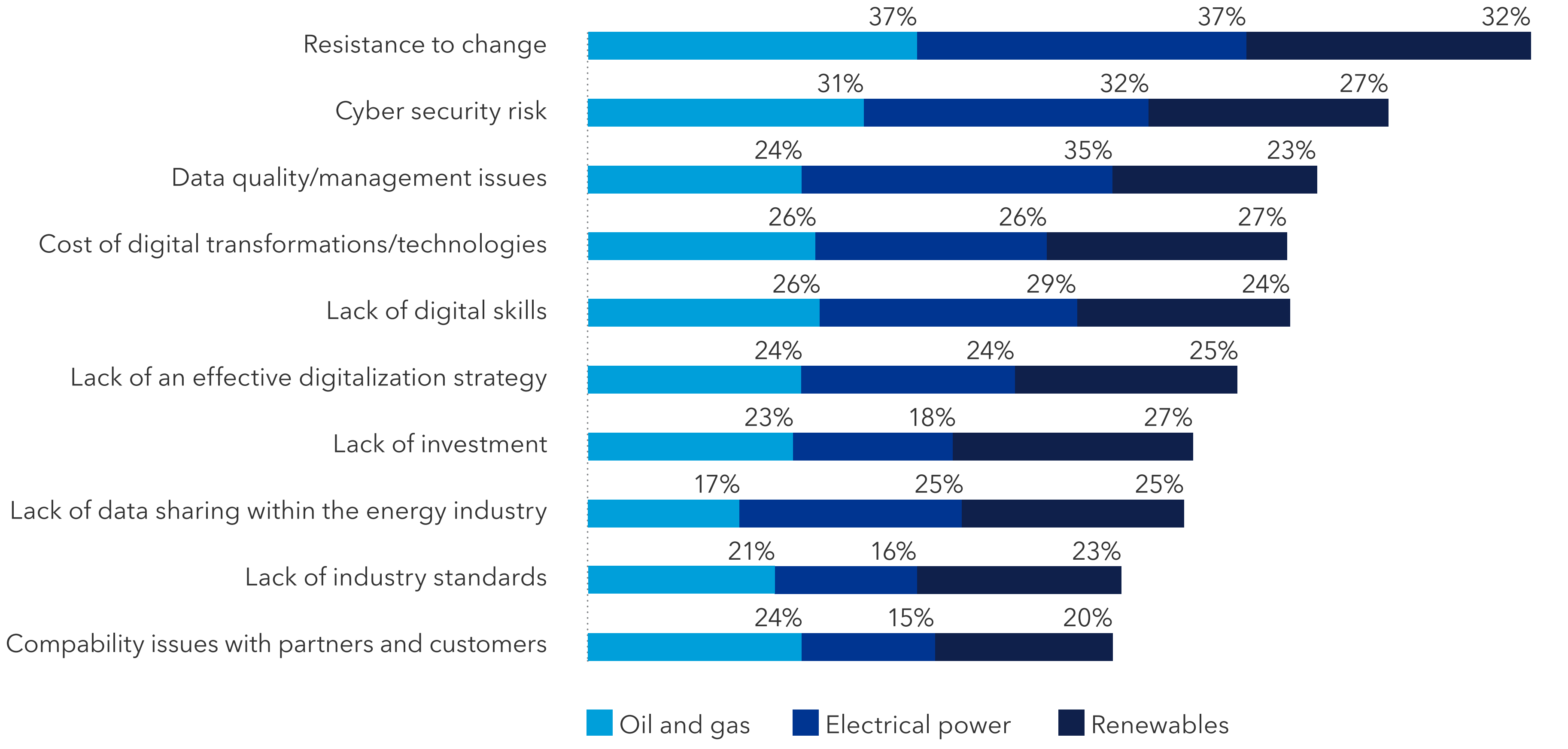
3.2 BUILDING TRUSTWORTHY INDUSTRIAL AI SOLUTIONS

The 2024 *Energy Industry Insights* report (DNV, 2024a) presents results from a survey of 1,300 senior leaders in the energy industry. One of the topics addressed in the survey was barriers to digitalization. As can be seen from the figure below, the top barriers are resistance to change, cyber security risks, data quality, cost, and lack of skills.

The 2023 *Energy Insights* report also found that only 12% of the surveyed companies were in advanced stages of implementing AI. In our view, this relatively low implementation rate is closely related to the barriers to adoption cited above. We comment extensively on issues relating to 'resistance to change' in Chapter 4, particularly regarding much-needed investment in net-gen digitalized control centre systems, where part of the difficulties relate to introducing profound changes to a conservative, physics-constrained, environment specifically incentivized to deliver stability. Here we are concerned

FIGURE 3.4

Top 10 biggest barriers to digitalization in the year ahead



with the adoption of AI where issues of trust are foremost.

DNV strongly encourages industry actors to view AI adoption from a systems perspective. This includes an industry perspective – for example foregoing investment in AI-driven DLR because legacy systems in the control centre cannot act on the information received to maximize line capacity utilization. We also encourage systems thinking in relation to advanced digital systems, where AI is effectively the final building block of a much larger, integrated and assured digital system (Figure 3.5). Each of the building blocks – quality data, cyber security, sensor systems, digital twins, and so on – has a co-dependent relationship with all other building blocks. This integrated approach is central to our suite of recommended practices – and the resulting assurance work – covering all the components of advanced digital systems, not least AI-enabled systems.

Regulatory considerations

Regulations covering AI are still evolving and struggling to keep up with the rapid pace of AI development. Power systems are critical infrastructure that will receive extra scrutiny from these regulations to ensure that they are safe and robust. The EU *AI Act*, for example, will require power grid AI to undergo additional assessments. In the next section, we detail an approach to building trust into industrial AI systems to satisfy not just regulatory compliance, but instil confidence in the adoption and use of AI by the power industry and its stakeholders – effectively addressing resistance to change.

Managing AI risk

For Industrial AI to be robust and trustworthy we must be confident we can deploy it with acceptable risk. Understanding both the (conventional) power-industry risks and the new AI-specific risks thus becomes key. This means we must take a systems approach and consider the "power system with AI inside".

Several aspects must then be considered, like the technical performance of the AI functions, the agency of the AI function inside the system, the interaction of AI with the other parts of the system and how this ultimately affects the various stakeholders, both technically, legally, and ethically.

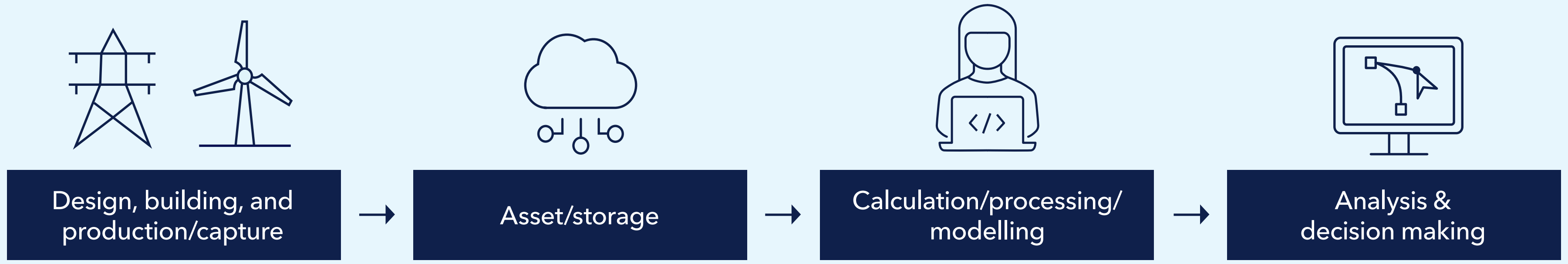
AI solutions act very differently to traditional industrial ICT solutions. A fundamental challenge is determining what design and operating requirements to put on the system and the AI function such that we maintain acceptable risk.

– We manage risk and ensure reliability through requirements such as redundancy in power grids with the n-1 criterion, and manage annual major accident risks related to offshore facilities with requirements such as annual major accident frequencies to be less than 10-4. These requirements have been shown to represent acceptable risk. Since we do not fully know all uncertainties introduced by AI, we cannot know if we even meet the requirements (old or new). Equally, given the power of AI to tackle probabilistic challenges in a dynamic manner when operating data is being used, one must also question whether the 10-4 failure frequency or all the redundancy requirements of the n-1 rule are set appropriately. AI could allow for smarter and better barrier management and thus provide new and unaccounted for risk reduction compared with today. In other words, AI could enable less redundancy and free up significant capacity, and regulators could tighten criteria on accident-related risks because AI drives better barrier management.

FIGURE 3.5

DNV's complete set of recommended practices for digital applications

THE BUILDING BLOCKS OF ADVANCED DIGITAL SYSTEMS



Assurance of AI-enabled systems
DNV-RP-0671

Asset information modelling framework
DNV-RP-0670

Cyber security
DNV-RP-G108; DNV-RP-0575; DNV-RP-0496; DNV-CP-0231

Assurance of digital twins
DNV-RP-A204

Assurance of data quality management
DNV-RP-0497

Assurance of data collection and transmission in sensor systems
DNV-RP-0317

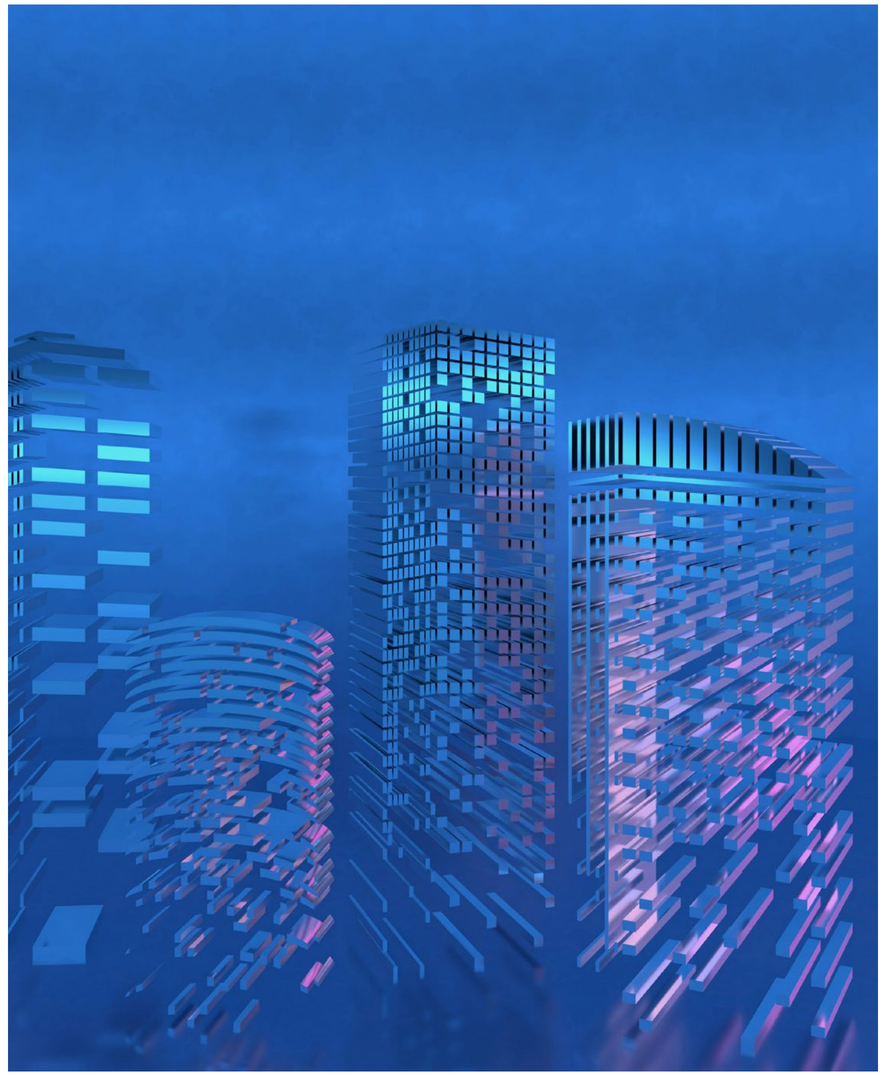
Assurance of simulation models
DNV-RP-0513

Assurance of machine learning applications
DNV-RP-0665

Assurance of data-driven applications
DNV-RP-0510

At the same time, AI may also introduce new risks. It is therefore vital to understand the uncertainty that comes with AI predictions

- We use cause-and-effect approaches based on physics: we know the relationships between voltage, current, resistance and temperature in a powerline – i.e. we have mathematical formulas and physics that we trust to describe the assets that we design and operate. Machine learning (ML) can learn these relationships with sufficient data and training, but it is more effective to build such first-principle insights into the AI through the physical models directly. Such 'hybrid' approaches are particularly useful in high-risk systems as the physical models can accurately represent the unlikely behaviour of the system ('tail behaviour'), where the data-driven ML models might suffer from lack of data. Hence, many operational decisions relying on "what if?" assessments are difficult to support with the AI predictions.



- We are used to applying barriers both to prevent incidents from happening and, if events occur, prevent them from escalating. ML can be used both in new types of barriers enabled by ML (like anomaly detection)or as part of existing barriers (e.g. improved prediction of hazardous events or failures). One then needs to question how much one can trust ML-enhanced barriers. Here, causation vs correlation, range of training data etc. comes into play. ML cannot be trusted to understand the underlying causations. So, if failure developments are outside the training data or if we want to understand the effects of potential actions or changes that are not in the training data, we cannot fully trust the AI model results. To overcome the challenges the following principles (or a combination thereof) can be applied:

- Science-guided AI: By combining AI / data-driven models with physics-based models, one can constrain the AI model and force it to operate within physical constraints. Such hybrid-models are particularly useful outside the normal operating envelope (at the onset of failures) as here we may have less data to train the AI model and therefore would expect it to be less trustworthy.

- Uncertainty-aware AI: By creating AI that has mechanisms to capture and present the uncertainties that are relevant for the question at hand or conclusion presented, the AI solution can help users to decide whether to trust it. Probabilistic machine learning models like Gaussian processes and Bayesian neural networks are examples of such solutions, where the predictions made by the models also come with estimates of the associated uncertainty.

- Causal-AI: By building cause-and-effect logic into the AI solution, it is forced to act within the limits of what is possible in practice. One may choose to build causal relationships into the model, from the knowledge we possess about the relevant system, or by using models that can infer causal dependencies from data.

It is very difficult to retrofit assurance methodologies after the AI solution has been built. Another challenge is that if the AI solution continuously changes, a one-off verification is of limited value – potentially becoming obsolete the minute it is issued. Hence, we recommend that assurance methodologies are addressed at the design stage and that continuous assurance processes are built in the AI solution. Ways of doing this are described in our Recommended Practice *Assurance of AI-enabled systems*.

Looking to the future

As we have shown in this chapter, AI is already solving challenges previously thought to be impossible. For example, Professor Kyri Baker (2023) has elegantly described how neural networks can be trained to solve the AC optimal power flow (OPF) challenge – an immensely complicated problem that grid operators have been trying to solve for decades (and hence rely on the cruder approximations of DC OPF calculations). A number of organizations, including DNV, have managed to solve complex technical questions by combining LLMs with AI-agents. These are tasks that it would take an experienced engineer significantly more time to solve. What if we were to unleash that force on the power system?

In the power sector, AI emerges as a transformative force, reshaping industry functions and processes. The timing could not be better, given the 'poly-crisis' of challenges the industry faces in the form of extreme weather, more distributed generation, storage management, V2G integration, an ageing workforce, and not least cyber security threats.
On top of that, new power systems are key to the decarbonization required to stave off the existential threat of global warming. In all of this, and provided, as we have shown, that risks are managed to an acceptable level, AI presents opportunities for advancing energy systems towards greater efficiency and sustainability.

4 GRIDS

The grid is the backbone of electrification and key to new power systems. At the same time, it is the single most important barrier to rapid electrification. The grid has taken about a century to reach its present size and capacity; we forecast this will more than double over the next quarter century. The second part of this chapter focuses on short-term strategies to tackle the growing problem of congestion – situations where rapidly growing demand and supply of electricity exceeds the (peak load) capacity of the grid infrastructure. A very large potential exists for grid enhancement technologies (GETs) to address congestion by using the existing grid infrastructure more efficiently, buying time for the massive newbuild programme that needs to be accelerated. However, we show that a major contingency for both GETs and newbuild is the pace and (cyber) security of digitalization.

4.1 GRID FORECAST

We forecast that global grid, transmission, and distribution combined will double in length from 100 million circuit-km (c-km) in 2022 to 205 million c-km in 2050 to facilitate the fast and efficient transfer of electricity. The same grid will grow 2.5 times in capacity globally, delivering electricity to cities, schools, industry, data centres, and the like. A small, but important part of this buildout is the rapid development of the offshore grid – growing some 14-fold, from 0.2 million c-km to 2.6 million c-km, mainly because of the proliferation of offshore wind.

Those regions lagging in electricity access, such as Sub-Saharan Africa and South East Asia, experience a large five-fold and three-fold growth, respectively. In contrast, OECD Pacific, already fully electrified, is expected to see only 30% more circuit-km between 2022 and 2050.

Surprisingly, even regions such as North America and Europe, which are fully electrified, are expected to see almost a doubling in transmission grid length due to electrification of the economy and the enormous amount of renewable power that will be connected to the grid. The windier and sunnier generating sites are often far from population centres, requiring long transmission lines to deliver their power to demand centres. Along with expansion, we expect to see modernization and refurbishment of power lines, especially in regions with an ageing grid, such as North America.

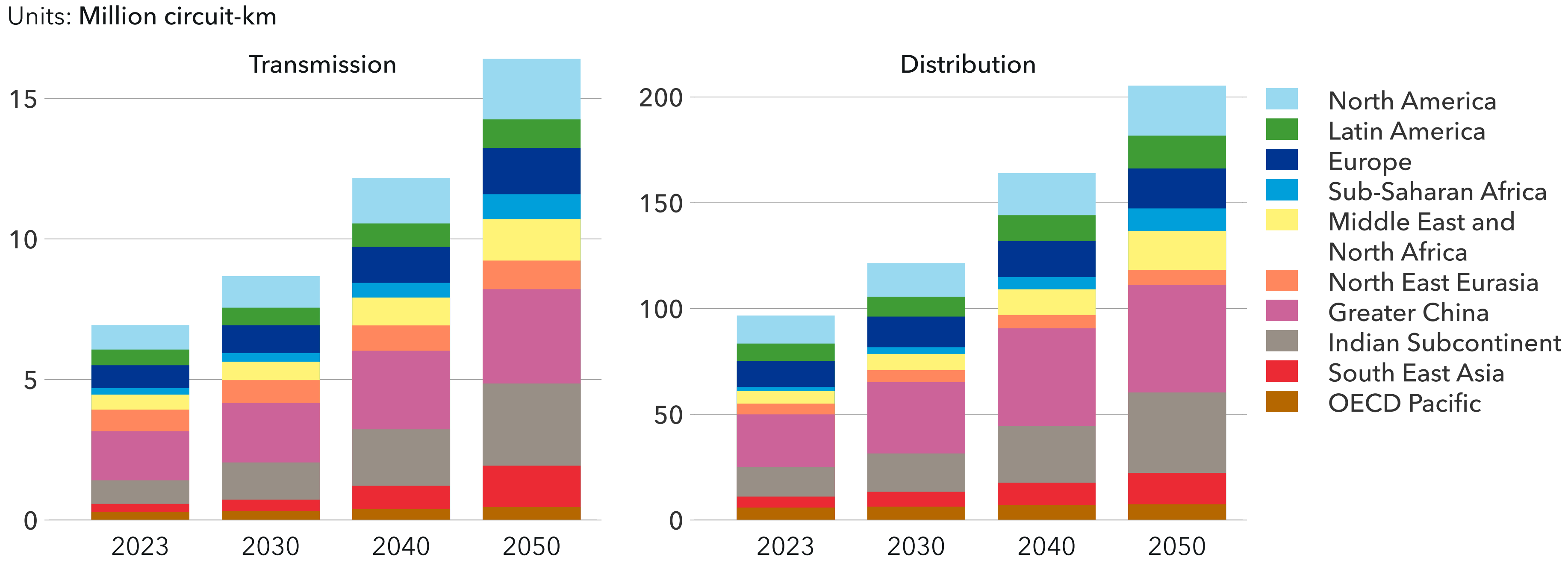
Transmission

Of the 100 million c-km transmission and distribution grid, about 20% is transmission grid. In total, the transmission grid system will grow from 7 million c-km in 2023 to about 16.5 million c-km by 2050.

New renewables coming online in remote places is the main reason for such a high year-on-year increase. For example, the wind and solar resources in the north and west of China make sense in terms of the profit calculus, but the demand-centres for these new wind and solar power plants are far away, concentrated in the coastal cities, and thus ultra-high-voltage (UHV) transmission lines need to be developed to transmit the cheaply produced electricity over long distance (DNV, 2024b).

FIGURE 4.1

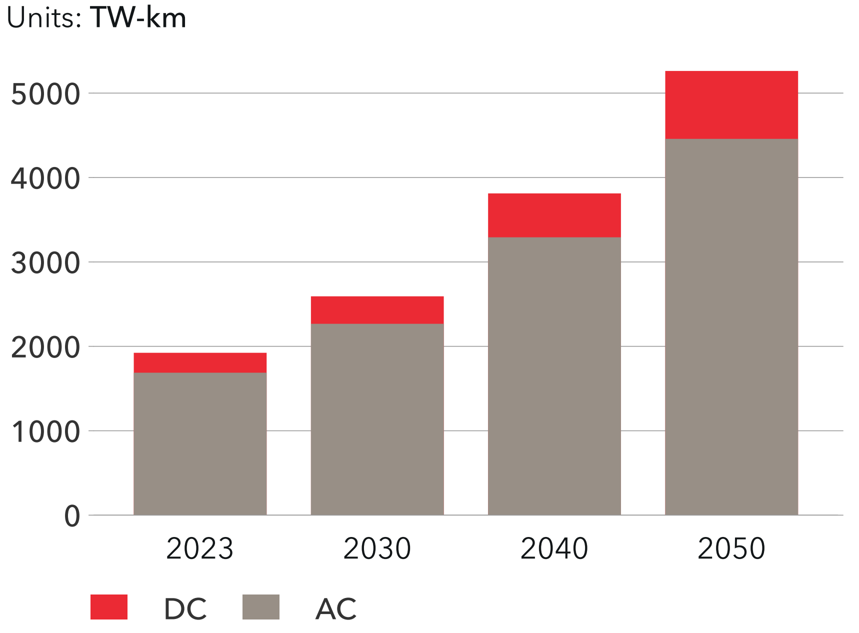
Transmission and distribution power-line length by region



Historical data source: GlobalData (2023), DNV analysis

FIGURE 4.2

Transmission grid capacity by type of current



Historical data source: GlobalData (2023), DNV analysis

Growth of HVDC lines

Of the total transmission line length, at present, about 1.5% or 109 thousand c-km, is high-voltage direct current (HVDC). By 2050, we forecast this to increase five-fold, to about 480 thousand c-km (Figure 4.3).

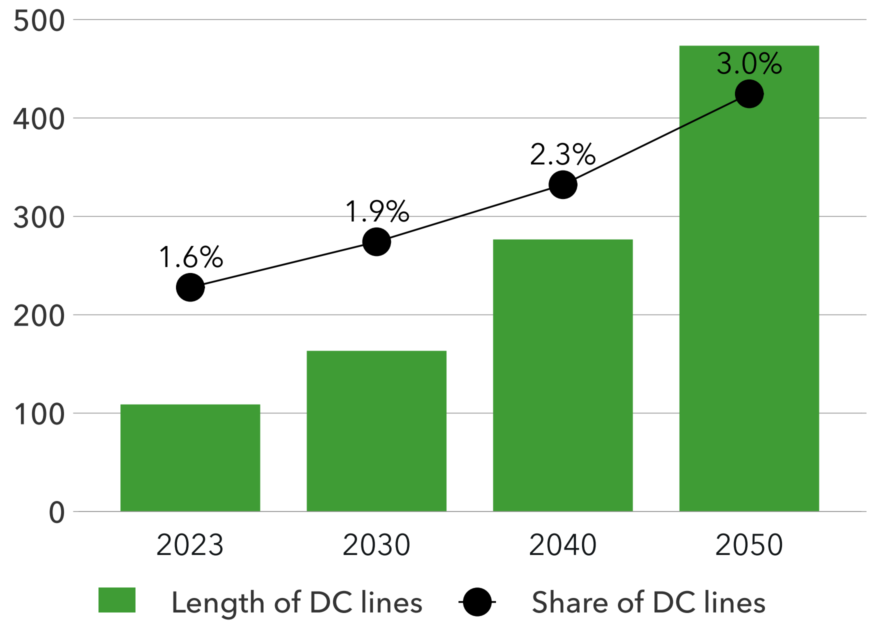
Such rapid increase of DC lines is driven by the following factors:

- DC is cheaper for transferring large amounts of electricity over long distances and often has a smaller environmental impact than the AC counterpart
- Due to their superior controllability, DC systems can provide strong support to the connected AC grids

FIGURE 4.3

Transmission DC line growth

Units: Thousand c-km



- Interconnections between different markets/countries are often implemented as HVDC lines due to technical and/or economic considerations
- Technology developments in HVDC allows for multi-terminal deployment making it possible to integrate more easily
- More competitors (OEMs) will enter the market, boosting the deployment of HVDC solutions as well as a driver to bring the CAPEX costs down

Offshore grid

By 2050 under-sea transmission grid lines will increase to 100 TW-km, from a meager 1 TW-km in 2023, connecting offshore wind farms to the transmission system.

Innovations like 'multi-purpose interconnectors' (MPI) connecting offshore wind farms and multiple countries, will improve system use and reliability. Projects like Energy Island and Meshed offshore grids, relying on multi-terminal HVDC technology, await breakthroughs in DC fault management and multi-vendor compatibility. The trend towards longer HVDC cables, like the 765 km Viking Link, continues with proposed projects like the 1600 km Atlantic Super Connection, the 3800 km XLCC, and the 4200 km Sun Cable. These aim to tap remote renewables without grid congestion, but are posing new challenges in HVDC control and maintenance.

The benefits of interconnectors: case study from South East Asia

The transmission grid's main role is to transfer high-voltage electricity, but it also supports power trading, enhancing the viability of renewables without heavy subsidies. In China, congestion-free electricity trading via HVDC interconnectors across provinces boosts profits from renewable generation. Europe's interconnected lines similarly benefit renewable trading and profitability.

DNV examined the benefits and implications of ASEAN cross-border interconnectors during the energy transition toward a fully decarbonized power sector in South East Asia by 2050 (DNV 2024c). In summary, the study showed that regional cooperation via cross-border interconnectors offers economic benefits and reduces resource requirements (e.g. 600 GW (20%) less solar capacity needed by 2050), but requires substantial additional interconnection capacity – up to 3.57 million kilometres of cable. See below.

The regional approach will require

3.75 mil km of additional electrical infrastructure

A fully interconnected ASEAN region would yield significant benefits over an approach in which in which each country pursues decarbonization individually without relying on interconnectors. Approximately USD 0.8trn (some 11% of the total) can be cut from the overall net present cost of ASEAN decarbonization by 2050.

The regional approach will reduce the need of

600 GW less solar capacity to be installed

13% footprint reduction

1.2 TWh electricity storage

16 TWh hydrogen storage

Distribution grid

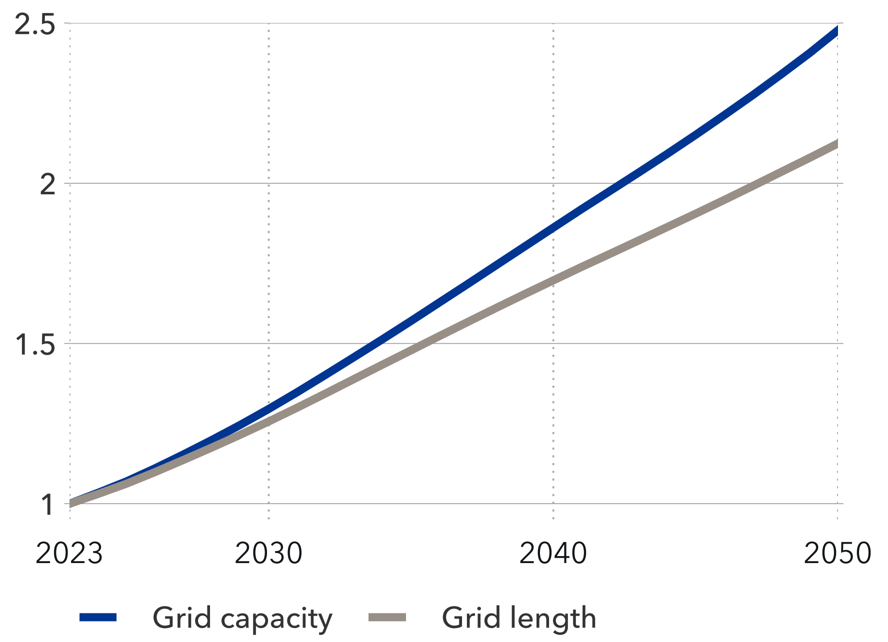
About 80% of the total grid in length is distribution grid – that conveys medium- and low-voltage electricity from substations to end users. The global distribution grid is projected to expand from 206 TW-km in 2023 to about 510 TW-km by mid-century, growing at 3% annually. This growth is driven by widespread electrification, as explained in Chapter 1, with increased electricity demand from existing sectors and new ones like EVs, industry, and data centres. Additionally, electrification is causing peak power demand to spike through seasonal and time-of-day use such as heating/cooling and EV-charging. Additionally, the distribution grid also needs to accommodate the rise of distributed variable renewable energy sources (DVRES). So, peakier power demand because of more electrification and voltage fluctuations due to DVRES needs to be handled on the distribution-side of the grid. Thus, the distribution grid needs to improve its capacity and adapt to heightened and variable demand.

Figure 4.4 shows the growth in distribution grid capacity and distribution line length globally to mid-century, indexed to 2023 levels. As one may see, distribution grid capacity grows at a slightly higher level than distribution line length, implying that there are technologies such as smart meters (with demand response), grid enhancing technologies (GETs), and virtual power plants (VPP) that enable grid capacity to grow beyond the capacity added by physical lines. We will be monitoring the uptake of GETs closely because there is reason to believe that these technologies are generally under-exploited, even in Europe, as a study by currENT Europe (2022) makes clear.

FIGURE 4.4

Distribution grid growth

Units: Indexed to 2023



Electrification is causing peak power demand to spike through increasing seasonal and time-of-day use such as heating/cooling and EV-charging.

Gridlock

The current grid has been built over the course of the last century; its capacity must now grow by 2.5 times in the next quarter century. New infrastructure clearly needs to be established at a much higher pace than ever seen before. As can be seen from Figure 4.1, most of the new build activity will take place in the 2030s and 2040s, with a relatively minor uplift between now and the end of this decade. Deploying grid infrastructure is complex, involves multiple stakeholders, and can take up to 15 years. Delays result in increased project costs, and uncertainties for both project developers and investors, thus potentially decreasing the flow of capital.

In our forecast of the most likely future, scaling up the world's grids to support the energy transition comes with a hefty price tag. By our estimate, more than USD 32trn will need to be invested by 2050 (from 2023), and North America, China, and the Indian Subcontinent would account for the majority of this grid investment. This investment is necessary, not only to expand and upgrade the networks, but also to replace ageing assets. Underpinning this estimate is the expectation that the regulatory mindset behind grids undergoes a considerable overhaul, as elaborated below.

A revamp of the regulatory mindset

Electricity grids are very regulated businesses, hence the driving force behind their expansion must inevitably come from regulators. Looking to historical grid trends is not a good indicator for the future. Considerable grid acceleration is needed for which regulators cannot rely on a business-as-usual regulatory environment. In mature electricity systems, the regulatory focus has been on maintaining the grid such that the modest or even stagnant electricity growth can be accommodated and overseeing that companies do not overinvest to avoid increasing grid tariffs.

Acceleration in grid investments needs to be done in an anticipatory and proactive way to enable onboarding of renewables and the electrification of transport, industries, and houses. If regulators continue to rely on the rear-view mirror, and fail to incentivize investments, there will be an insufficient deployment of infrastructure that could become a blockage to renewables and electrification objectives.

How we reflect delays in the Outlook

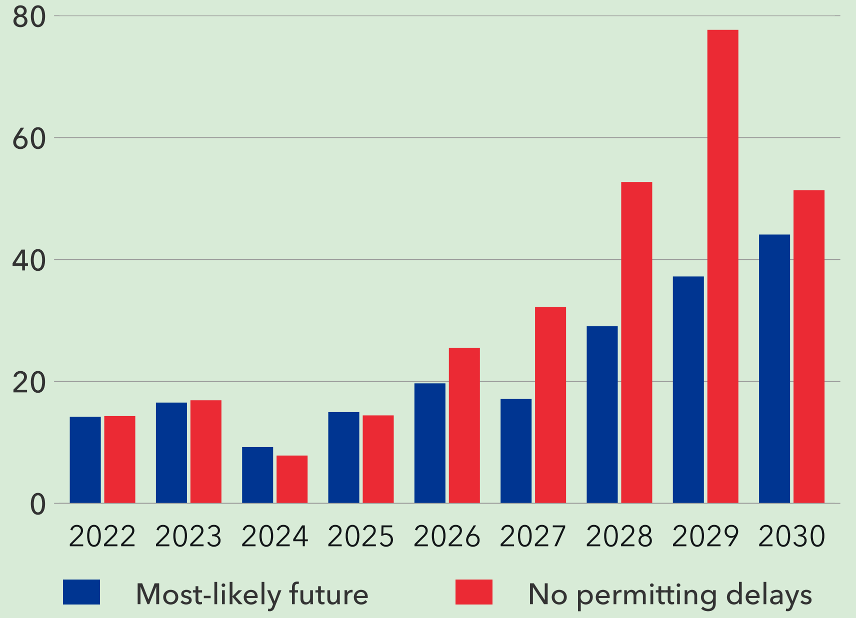
A critical input to our forecast is the 'pipeline' of new capacity additions in the power sector. These are differentiated by power plant type and by region, and the raw input data is provided by GlobalData (2023). This database collates all power plants at various stages of full or partial onboarding – e.g. announced, under planning, under permitting, under construction – and gives the year in which each is expected to start operating.

A project in its early stages has a relatively low likelihood of coming to fruition without any hitches. To reflect this real-life delay, we adopt a probabilistic approach. We modify the pipeline of new capacity additions by multiplying the capacities with a decreasing probability if they are at earlier stages in the pipeline, ranging from 10% for announced projects to 100% for projects under construction. The probabilities are further reduced based on a project's anticipated year of operation; projects slated for a more distant future are assigned a lower probability. Probabilities for the different stages of onboarding are adopted from the Lawrence Berkeley National Laboratory (2023). These delays are considered only for solar and wind projects.

Such permitting delays are prompting a behavioural countermeasure from project developers, which is also reflected in the pipeline of new capacity additions and our interpreted probabilities. Knowing that there are delays at multiple stages of a renewable project, developers are 'hedging' by asking for permissions and grid connections for projects that they themselves know may not get approved.

Figure 4.5 gives an illustrative example of the difference between our mostly likely future and a hypothetical future without permitting delays and supply-chain constraints. The figure presents the comparison between the two futures for global capacity additions of offshore (both fixed and floating) wind in the near term (2023–2030). The difference in our forecast and a case where there are no permitting delays and supply-chain constraints ranges from 2% to 100%.

FIGURE 4.5
Global offshore wind capacity additions with and without permitting delays
Units: GW/yr



4.2 CONGESTION

The current power grid is clearly not ready for the steep rise of customer demand and renewable infeed in the power grid at today's demanding pace. Not only will connection requests escalate (see 'gridlock' sidebar), but operators are increasingly having to cope with congestion in the power grid, which is the phenomenon where demand and supply of electricity exceeds the (peak load) capacity of the grid infrastructure. Congestion is becoming a significant issue, as it slows down economic growth, leads to the inability to connect customers, thwarts investment plans, and delays the energy transition.

According to DNV's *Industry Insights 2024* (our annual survey of energy professionals) permitting/licensing issues and inadequate infrastructure continue to be among the top 5 barriers to growth for renewables respondents, and 70% of survey respondents say that power grid infrastructure cannot yet adequately connect sources of renewable energy to areas of high demand. Just 21% say that current transmission capacity planning is sufficient to enable the expansion of renewables.

Getting the most out of the existing grid

There are many ways to tackle present and emerging grid bottleneck difficulties by getting more out of existing grids. For example, the US Department of Energy (DOE) has been actively funding GETs for several years, and in April 2024 released a summary report (DOE, 2024) detailing how a combination of grid modernization solutions "could cost effectively increase the capacity of the existing grid to support 20-100 GW of incremental peak demand when installed individually, while improving grid reliability, resilience, and affordability" (See Figure 4.6 below). The report weighs this potential capacity addition against the expected surge in regional electricity demand from data centres, manufacturing and other end uses which is expected to lead to a peak-demand growth of 91 GW over the next 10 years.

DNV has not quantified the potential effect of the widespread deployment of GETs over the next 3 to 5 years globally, but it is clear that grid modernization can have a substantial effect in de-bottlenecking the existing grid, serving new sources of demand, and allowing for substantial integration of renewable generation. Numerous studies have shown that better asset utilization and improved grid operation can indeed increase the grid capacity between 10% and 50% without building new infrastructure in new rights of way (Mirzapour et al., 2024; Siegner et al., 2024). It should be noted that many of these solutions have been in existence for well over a decade but are being given prominence now in public discourse owing to the urgency of expanding grid capacity.

Given the pressing need for new capacity now, it is worth considering why GETs are not further advanced. In some cases upgrading existing infrastructure offers a temporary solution only owing to the constraints related to existing materials, configurations, and structural properties. Risks must be identified and addressed along the way. Possibly the key barrier to GETs is financial. The US DOE recognizes that quickly implementing GETs to reduce the cost consumers pay for congestion does not "…earn the utility enough revenue to make them do something other than build more transmission – which is slow and expensive" (LineVision, 2024). The DOE has clearly signalled its intention to introduce performance incentive mechanisms and shared incentive models, similar to those already in place in the UK. In the EU, despite some instances where investment in GETs is treated on equal terms with other types of heavy CAPEX – overcoming the CAPEX/OPEX difficulty – solutions have yet to be put in place to pass some of the market welfare created by such investment back to the TSO (currENT Europe, 2022).

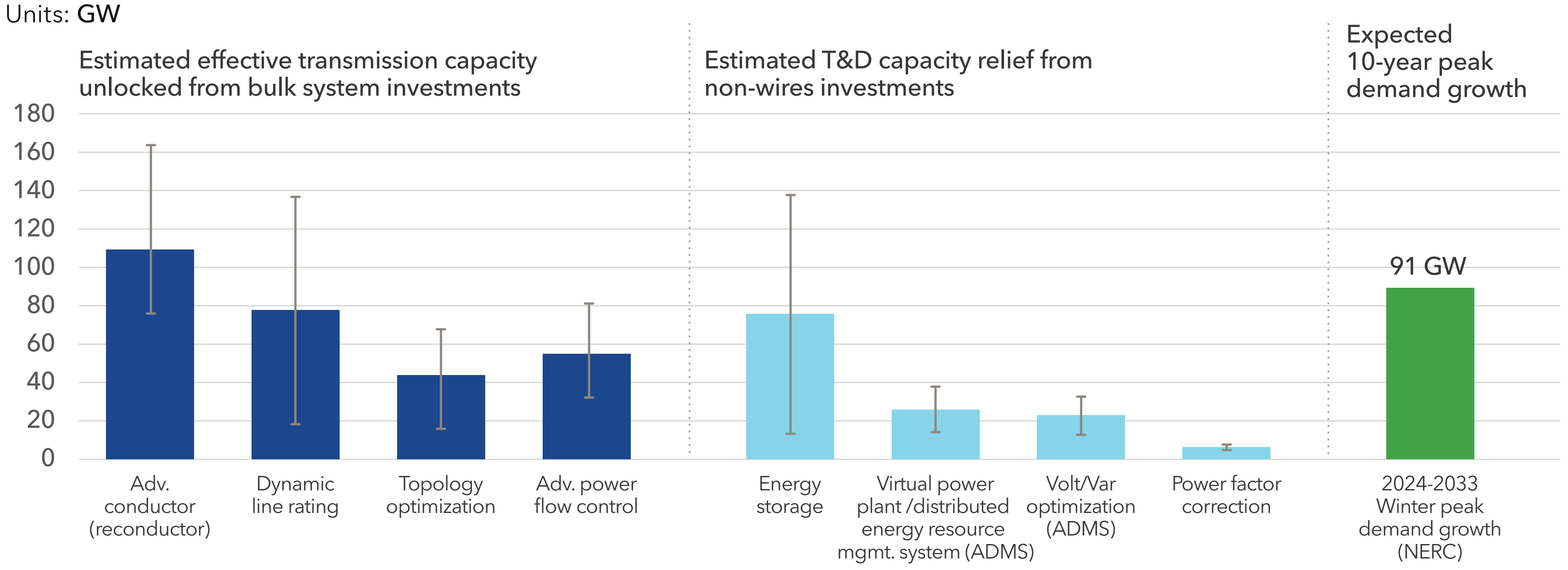
We caution that the scale of electrification worldwide means that enhancements to the existing grid must be accompanied by comprehensive and urgent plans for newbuild.

There are many ways to tackle present and emerging grid bottleneck difficulties by getting more out of existing grid.

FIGURE 4.6

Estimated transmission and distribution (T&D) capacity impact from full potential deployment*

Units: GW



HVDC is a critical part of the transmission solution set – while it has more limited use cases on existing ROW infrastructure, there are strong opportunities for new build corridors not captured here.

*Redrawn from DOE (2024) report Pathways to Commercial Liftoff: Innovative Grid Deployment (Figure 2, page 4).

Dealing with the congestion challenge

There are four main paths to tackle congestion while waiting for new infrastructure, which can be divided into so called 'wired' and 'non-wired' technologies:

I. Using the current infrastructure more effectively (non-wired technology)

II. Smarter grid operations (non-wired technology)

III. Uprating/upgrading the current infrastructure (wired technology)

IV. Changing the behaviour/shape of demand and supply via e.g. peak shaving etc. Including sector coupling (non-wired technology)

I. More effective use of current infrastructure

- Smarter **advanced system protection** can allow for significant more capacity. An example from Sweden showed 600 MW more capacity on an interconnector
- **Smarter settings of generator**: an example from Norway reveals that this could increase the capacity in a part of the grid by the equivalent of one more overhead line
- **Smarter use of breaker settings** to reduce losses: an example in one region in Norway showed a reduction of losses from 5.1 % to 4.9 %. The method showed that the losses can be reduced by as much as 30%
- Use of **dynamic line rating (DLR)** can add between 10% and 60% capacity to a connection. See discussion overleaf on DLR and reconductoring.

II. Smarter grid operations

- Use of **Power Management Unit (PMU)** applications allows one to operate the system closer to its limits
- Use of **probabilistic methods** could free about 40% more capacity for systems that are in n-1 operation (see discussion on control centres, page 57)
- **Advanced system protection** is needed to allow for more automatic handling of flexible customer contracts. Not all customers use their requested capacity continuously. By using smarter contracts, one can utilize the whole capacity of lines. An example from Norway showed that with smarter contracts and used of advanced system protection one can free up some 20 % capacity of a specific overhead line
- Reducing the consequences of a contingency or possible overload situations with **demand side response**

III. Uprating/upgrading current infrastructure

- **Voltage upgrading**: e.g. a 300 kV line is voltage upgraded to a 420 kV line. The towers and conductors are kept. Accurate insulation coordination and configuration, helps insulator and airgap adjustment for higher voltages. Often done using live line working, allowing for significant capacity upgrading in the same right-of-way (ROW) without causing outages
- **Temperature uprating**: modifications to uprate a line designed for e.g. 80°C to 100°C, allowing for significantly more capacity. Usually the ROW, conductors, and most of the towers are retained. Changes might be as simple as blasting away rocks to increase airflow, but could also involve increasing the height of certain towers
- **Re-conductoring**: retention of existing towers and insulators, but new conductors e.g. a High Temperature Low Sag (HTLS) installed to increase transmission capacity (see example, below)
- **Upgrading with tower top modifications**: the tower base remains but the top is replaced by a e.g. a composite based tower top, allowing for voltage upgrading from for instance 220 kV to 420 kV
- **Line re-configuration**: with minimal tower modifications the line configuration can be changed from e.g. simplex to duplex, while removing the ground wire and keeping the same towers, which sometimes need to be modified slightly
- **AC/DC conversion**: with minimal or no modification of the towers, an AC line can be converted into a DC one, allowing for a large capacity increase
- **Upgrading/uprating/modernizing**: with today's technology it is possible to refurbish or replace an overhead line with live line working in the same corridor

IV. Change of behaviour of supply and demand, including sector coupling

- **Flexibility markets** allow for customers to shift their consumption to a part of the day where a line is less congested, allowing additional customers to be served by the grid. (Often an overhead line is used to its maximum capacity just a fraction of its time. This typically occurs during demand peaks in winter or summer seasons that may be limited to just a few hours of the day.)
- **Aggregators** allow for smaller consumers of power to join forces to participate more meaningfully in flexibility markets and in the sharing of energy
- **Differentiated contracts** allows more customers to be connected to the grid
- **Micro-grids** allow consumers to share electricity with each other and by doing so reduce their reliance on need for grid power
- **Sector coupling** allows peak electricity demand to be reduced and along with the demand for distribution and transmission capacity

This is by no means an exhaustive list of options and does not incorporate new technology not commercially available.

Smarter asset utilization

Getting more out of existing grids usually involves a combination of the options given above. For example, DNV is involved in a project combining a number of technologies such as smarter system protection, dynamic line rating (DLR), probabilistic methods and demand-side management of large customers. The combined effect should see an increase in local and national grid capacity of some 25%. Figure 4.7 presents data from study of a TSO in Ireland after implementation of DLR on a circuit (Saha et al,. 2024). Under standard line rating (SLR) conditions, the average utilization of the circuit was below 20% for more than half of a year. With implementation of DLR, the data shows the potential of DLR to lift the circuit capacity by over 50% relative to SLR utilization for 60% of the year. For 20% of the year – predominantly during the colder months – the uplift in capacity was over 80%.

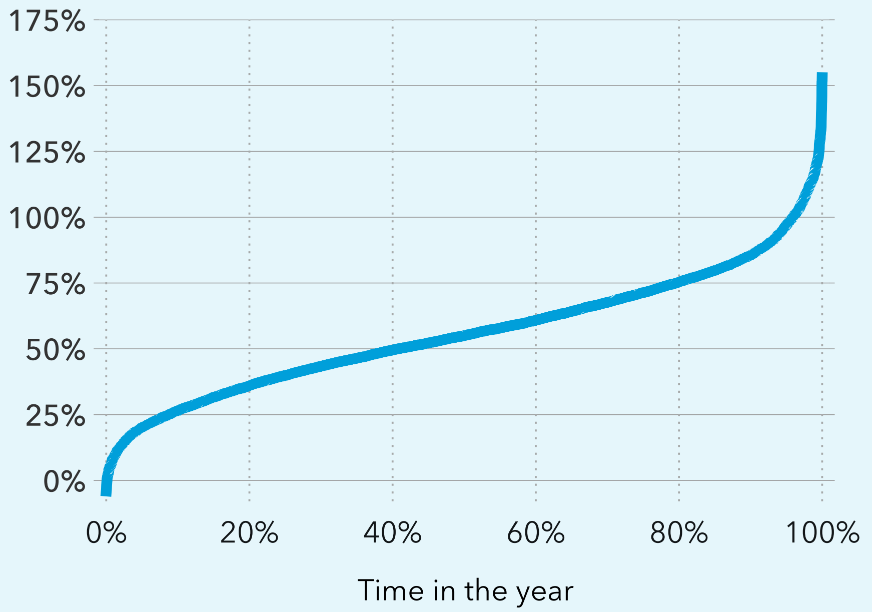
While DLR combined with AI aims to get the most out of existing power lines, operators may also have the option of reconductoring – i.e. replacing exiting conductors with advanced conductors to increase transmission capacity. A recent study (Chojkiewicz et al., 2024) has shown that by avoiding the expense associated in creating new rights of way (ROW) and building new towers, "reconductoring projects typically cost less than half the price of new lines, across all voltage levels, for similar capacity increases".

While dynamic line rating (DLR) might expand the capacity of existing lines, operators also have the option of reconductoring – replacing existing lines with advanced new, higher-capacity lines.

FIGURE 4.7

Possible gain from DLR over SLR for a selected power line

Units: Percentages



Data drawn from Saha et al (2024) *Maximizing power transfer and RES integration using dynamic thermal rating - Irish TSO experience* (CIGRE Paris Session, 2024)

RESILIENCE

Ensuring uninterrupted energy supply amidst climate change, cyber threats, and natural disasters requires a resilient power grid. This is now one of the major key strategic themes, meaning that the grid can survive disruptions, adjust, and recover quickly. It includes the concept of grid stability.

Globally, the push for grid resilience is driving innovation and investment in advanced technologies. In the US, the *Federal-State Modern Grid Deployment Initiative* is focusing on enhancing grid capacity and resilience against climate change impacts through advanced conductors and grid-enhancing technologies.

In Europe, the *Flexibility for Resilience* report (EC, 2022) by the European Commission underscores the necessity of system flexibility to counteract extraordinary events. Eurelectric's *Connecting the Dots* study (Eurelectric, 2021) forecasts that an investment of EUR 33bn will be necessary between 2020 and 2030 to bolster the resilience of the distribution grid. Additionally, virtual power plants (VPPs) are emerging as a key technology to enhance grid resilience by judiciously aggregating geographically distributed energy resources (DERs) as individual electrical entities, providing capacity and ancillary services to grid operations. Dynamic microgrids are also gaining traction, strengthening power system resilience by supplying the load locally through DERs when the connection to the main grid is not available.

STABILITY

The integration of renewable energy sources into the power grid introduces variability due to their dependence on weather conditions. This unpredictability can cause fluctuations in power generation, posing a challenge to the grid's stability which relies on a balance between supply and demand to maintain voltage and frequency within set limits. Traditional power grids relied on synchronous generation, where stability was provided by the kinetic energy of rotating masses. However, adding more inverter-based renewable energy sources, which lack the inertia that aids in frequency stabilization, to the grid affects the grid's frequency response and reactive power – both of which are crucial for grid stability. This necessitates advanced control systems to maintain a reliable power supply.

Flexible AC transmission systems (FACTS) enhance the controllability and increase the power transfer capability of transmission networks by swiftly managing reactive power flow, ensuring voltage levels remain within the desired range despite load or generation fluctuations. As an example the global STATCOM market size was valued at USD 643m in 2023 and is projected to grow to USD 1,096m by 2032, exhibiting a CAGR of 6.20% during the forecast period.

Grid forming converters (GFM) are also key in this transition. They independently regulate the frequencies, phase angles, and voltage amplitudes, thus supporting grid resilience and stability. Standardizing GFMs' implementation and functionality validation is vital for the rapid deployment of these systems in modern power grids.

The US DOE is funding various projects to advance grid-forming inverter technology, including the Universal Interoperability for Grid-Forming Inverters (UNIFI) initiative, which aims to standardize and validate these systems for widespread adoption. As of 14 February 2022, renewables have been enabled to provide stability services to the National Grid ESO. The *Grid Code modification GC0137* allows converter connected technologies, including renewables and interconnectors, to offer 'grid forming' or virtual synchronous machine capability.

Particularly with the addition of grid forming capabilities to Inverter-Based Resources, compliance with the *Grid Code* is becoming increasingly vital for ensuring the stability, reliability, and affordability of power systems. By meeting the technical performance standards set by the *Grid Code*, equipment can operate safely and efficiently, fostering interoperability and enhancing the resilience of the entire grid infrastructure.

As more inverter-based renewable energy sources are added to the grid, advanced control systems are needed to maintain a reliable power supply.

4.3 DIGITALIZED GRID OPERATIONS

Many grid operators, such as the TSOs that are within ENTSO-E and EPRI, are aiming for the next-generation control centre or a fully automated operation centre. We are approaching a future where grids will become too complex for human operators to manage; the number of the events that an operator needs to react to is increasing and there is less time to act because of decreasing inertia.

Wide-Area Measurement Systems (WAMS) enable the monitoring of power system dynamics in real time by acquiring data from phasor measurement units (PMUs), which is essential for maintaining the stability and reliability of the power grid. Integrated with EMS, operators can analyse the grid more accurately by running finer state estimations and potentially giving the control room confidence to allow more renewables on the network by monitoring low inertia. New systems such as dynamic stability assessment allows operators to analyse system's response to dynamic events such as sudden load changes, faults, or generator trips ensuring that that power systems can withstand disturbances while maintaining stable operation, playing a crucial role in grid reliability and security.

NextGen GridOps is an innovative approach to modernizing electrical grids, e.g. with distributed energy resource management systems (DERMS), employing smart grid technologies for real-time monitoring and automated decision-making. It involves deploying a smart architecture supporting a modular approach that allows flexibility and scalability to deploy new services to support new functionalities needed. Laying down the foundation using integration standards (e.g. SOAP, ESB, APIs) provides an integrated and comprehensive view of the entire system. A broad and growing steam of system data is becoming essential for grid operations and also planning. For example, smart meter data will assist Distribution Network Operators (DNOs) in pinpointing system limitations, allowing for more targeted investments, including network upgrades to accommodate more heat pumps or EVs.

Control centres as the real bottleneck

We have listed a selection of grid enhancement technologies (GETs) which hold much promise in adding much needed capacity. We have also described above innovative paths to digitalization grid operation. However, the potential for new technology becomes largely academic if you consider that adding new capacity via GETs or adding additional transmission and distribution capacity through newbuild comes to naught without corresponding upgrades to control centres. Many control centres are already stretched to the limit and cannot accommodate these changes. Additionally, very few control rooms are undergoing a true 'next gen' refit.

Why is that the case? Logic dictates that the relatively low CAPEX involved in the required ICT upgrade (roughly EUR 10m) would make this easier than, for

example, the roughly EUR 1m for a kilometre of new transmission infrastructure – especially when the extra capacity made available by upgrading a control centre may amount to the equivalent of one or more powerlines. However, there are profound barriers to change when it comes to upgrading existing control centres. These barriers are various and overlapping, but include:

- Resistance to change by control centre staff whose workload has increased to the point where there is little time for innovation and retraining. In broad terms, they are also incentivized to deliver stability, not change
- Upgrading control centres in real time over an extended period carries obvious technical difficulties and risks. A typical time to renew a control centre is 4 to 8 years
- The suppliers of new control centre systems and software are highly concentrated and few in number, and de-prioritize complex control centre innovation in favour of other market opportunities and vendor lock-in solutions may prevent further innovation in control rooms
- The co-ordinating upgrades across hierarchies of control centres (regional, national transmission, and local distribution control centres) is complex. In addition, distribution control centres are by definition smaller with smaller budgets. While there is an ongoing trend towards consolidation in the number of DSOs, they remain a junior partner in terms of the ability to finance and implement major ICT upgrades
- Suboptimal incentives from governments and regulators. The value and urgency of a next-gen control centre to unlock spare capacity and integrate new connections is not adequately known, understood, or reflected in tariff structures, policy, and tax regimes

As grid operators around the world brace for a CAPEX surge in the context of high interest rates and supply chain squeezes – particularly in high tech power cabling – attention is focused on strengthening balance sheets while these additional costs are recovered over time by rising tariffs passed on to consumers. Given the criticality of control centre upgrades and the relatively small CAPEX required, a strong case can be made from an overall public welfare perspective for specific, ringfenced incentives that would make such upgrades immediately economically rewarding for network operators.

Beyond return-on-investment considerations for network operators, a broader public conversation needs to be taking place about electrification and existing reliability requirements. That we are amid a transition where demand follows supply is generally understood. However, this is usually thought of in terms of demand being tailored to take advantage of excess supply. In our view, an equally valid consideration is demand *occasionally accepting the reality of inadequate supply*. Critical loads, for example from hospitals, data centres, defense, and emergency

services are increasingly being equipped with cost effective storage and backup systems to cope with power outages. In that context, the n-1 criterion for grids and the redundant capacity and equipment maintained to cope with contingencies can be questioned. Indeed, we need to pose even deeper questions to advocates of n-2 redundancy which would call for some 30% 'spare' capacity at any given point in a context where the energy transition is endangered by a lack of transmission capacity. Finally, with better data gathering and analysis and capability of next-gen control centres, grid operators will be far better equipped to anticipate and plan for the consequences of power outages, even as running grids at near-capacity (i.e. a partial abandonment of n-1 procedures and low system inertia) raises the probability of outages. Risk is a function of probability and consequence, and a risk-based approach to power provision should inform the transition to new power systems. A far greater risk of stalled decarbonization is at stake.

Data is the new oil

Quality, accessible, secure, and privacy-compliant data forms the bedrock of digitalization across new power systems, including higher-order AI applications. At stake, when aggregated across the world's power grids, are multiple EJs of additional clean energy delivery and efficiency gains. Readers will be reminded that one EJ is equates to 23.88 million tonne(s) of oil equivalent (Mtoe). In that sense, data really is the new oil.

Facilitating that exchange of data through an ecosystem of connected digital twins – enabled through a defined set of semantic data models – will be critical and a fundamental feature of a digitalized energy system. Compliance with communication and data standards is paramount in the power grid industry for ensuring interoperability and seamless exchange of information.

Data needs to be adequate, standardized, and interoperable across the energy sector. It is expected that the use of IEC CIM standard will become a requirement for all relevant data exchange the systems, driving standardization and interoperability and setting the foundation for a wider adoption across the energy system. Discussions are also underway to ascertain practical ways in which other energy vectors, e.g. gas networks will implement CIM.

Communication protocols (e.g. IEC 61850) are essential for network operations as they ensure devices from different manufacturers are interoperable, maintain data integrity, provide secure data transmission, and optimize network resources. They enable new concepts such as digital substations and innovative solutions such as modular substations. Other specialized communication protocols like Open Charge Point Protocol (OCPP) are designed for EV charging stations and management systems. They ensure interoperability between different manufacturers' charging stations and management systems, allowing communication and management of the EV charging infrastructure.

Cyber security

Power systems are among the most complex and critical of all infrastructure types and act as the backbone of economic activity. The energy system's increasing complexity and interconnectivity demand and the integration of ICT in system monitoring and markets has heightened vulnerability to cyber-attacks. Cyber security is therefore a critical element in the design and execution of digital transformation initiatives; the industry cannot reap the transformative benefits of digitalization without robust cyber security.

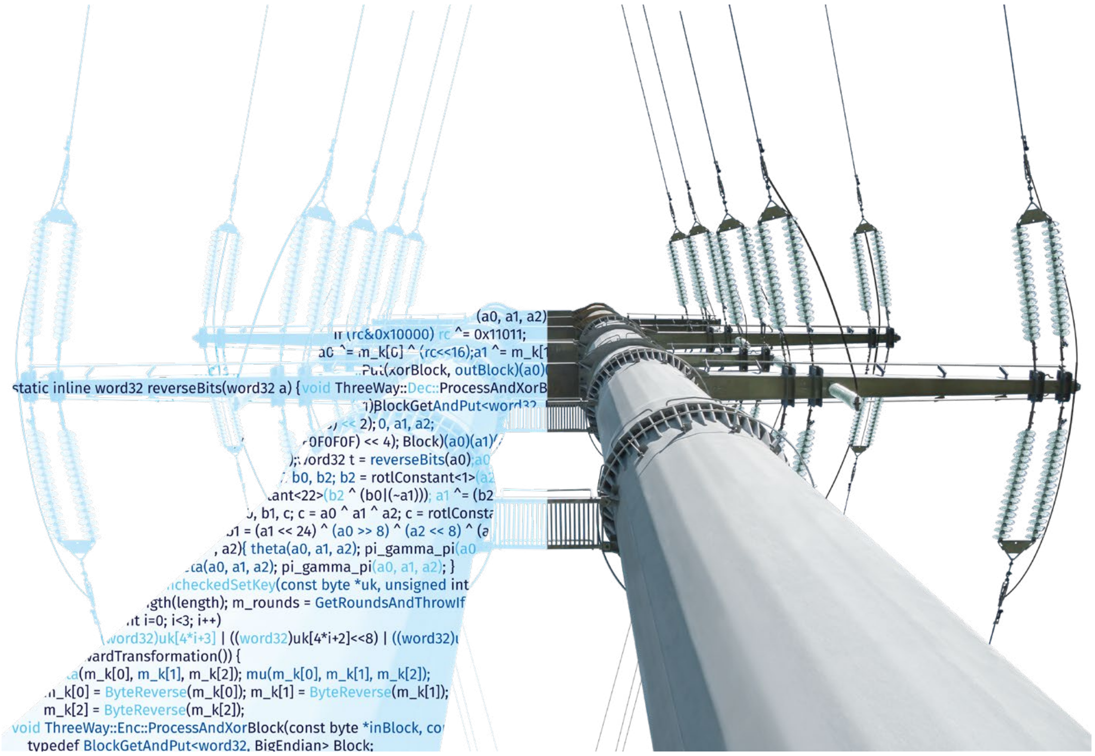
The DNV's *Cyber Priority report* (2023c) describes the escalating emphasis on cyber security within the energy sector. A growing number of industry professionals (reaching half of respondents last year) worry that their part of the energy industry is more vulnerable than ever to cyber-attacks. More than half of respondents stated they expected their organizations to spend more on cyber security this year than last.

Cyber security measures are designed to safeguard grid and asset operations by establishing a resilient, multi-tiered defence and surveillance system. This system requires attackers to penetrate multiple barriers to launch a successful attack, thereby significantly bolstering the security of digital assets and ensuring stringent control over vital grid infrastructure.

However, our research reveals that cyber security efforts are held back by a lack of in-house cyber skills, cost of investment, and inadequate oversight of vulnerabilities, including from the supply chain. These difficulties, combined with differences in direct experience of cyber security, is leading to a 'cyber perception gap' among energy professionals. Our research suggests, for example, that some senior leaders might not have the full picture of the threat. For example, the C-suite appear more confident that geopolitical uncertainty is translating into heightened cyber vigilance. Ultimately, there must be a consistent effort to ensure cyber awareness and appropriate action at every level of an organization, from C-suite to operational roles, to ensure a cohesive approach to safeguarding operations.

One key aspect here is that operational technology (OT) and IT rarely speak the same language. As these systems converge, this is a major risk. In critical infrastructure sectors, engineers, cyber specialists, IT, and others will increasingly need to work together to secure assets and infrastructure. This means speaking the same language and increasingly understanding both IT and OT. For many businesses, the main consideration here lies not in securing the next generation of connected OT, but in safely connecting existing assets and infrastructure that were never designed with cyber security in mind. In this sense, the
'convergence' of systems is a major risk, particularly when IT equipment is used in the process control domain principally as a cost control measure.

Regulation is the foremost driver of investment in cyber security in today's energy industry. The design and deployment of systems and digital infrastructures must adhere to stringent cyber-security policies and principles set, for example, by international standards such as ISO 27001, IEC 62443, IEC 62351, the *NIST Cybersecurity Framework*, as well as pertinent local regulations. Expectations are high concerning a new era of regulation. The sector must prepare to comply with a raft of new, stricter cyber security requirements in the coming years, as authorities encourage energy businesses to increase their resilience to emerging threats. However, we caution against the danger of reactive, regulation-dependent approaches to budgeting that is geared around complying with rules rather than achieving maximum resilience.



Solutions to accelerate grid development

The typical duration from planning to commissioning of a new grid connection is 15 years (Table 4.1), although it can be as short as five or as long as 25 years. There is an urgent need to make this process more efficient, effective, and smarter. This is an issue that almost all TSOs are actively tackling with varying degrees of success.

TABLE 4.1

Typical planning-to-commissioning schedule for a new connection

Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Government policy, PCI															
Grid development plan, master planning (TSO)															
Project definition, EIA, feasibility, corridors															
Public consultation process, NIMBY issue															
Permitting/policies/legal objections/court cases															
Design															
Contracting & installation															

DNV has been assisting a number of clients to identify areas of improvement for streamlining the process from policy to commissioning. An obvious solution would be to hire more resources, but there is stiff competition among TSOs and DSOs for new hires with suitable qualifications and experience. An alternative strategy pursued by some TSOs has been to working closely with government to streamline internal and external processes and introduce smarter ways of working with an extended staff base to cut the time needed by half.

Standardization

One way to speed up internal and external processes, and solve supply chain constraints, is standardization and a modular approach. DNV has several projects on-going, for example with standardization and modularization of substation design. Such approaches not only increase the quality of design but enable digitalized/automated permitting, procurement, contracting, and speedy installation.

Quality

Delays in the pace of planning, procurement, and construction place an additional premium on getting things right first time to avoid rework. Challenges with offshore cabling present a good example of this. A joint industry project (JIP) on offshore power cables initiated by DNV with more than 30 partners (suppliers, integrators, end users, and regulators) has highlighted several challenges associated with floating offshore substations, including the need for high-voltage dynamic cables and electrical equipment that can withstand the movements of floating structures.

Power cable failure is a significant issue, accounting for 75-80% of the total cost of offshore wind insurance claims. This is partly due to manufacturing, design, and installation errors. Furthermore, the lack of standards in offshore cables exacerbates these issues, leading to a higher cable fault rate as a percentage of the offshore grid system. Solutions lie in rigorous research and development, collaboration between industry stakeholders, and the establishment of robust standards for offshore cables. Results from the JIP are expected to bring distinct improvements to the design, installation, and maintenance of offshore cables, benefitting both existing and future offshore wind farms.

5 FLEXIBILITY AND STORAGE

Next to the grid buildout, flexibility capability and storage capacity are dominant themes in the operation of new power systems. This chapter presents our forecast of how these two critical markets are likely to develop during our forecast period.

5.1 FLEXIBILITY

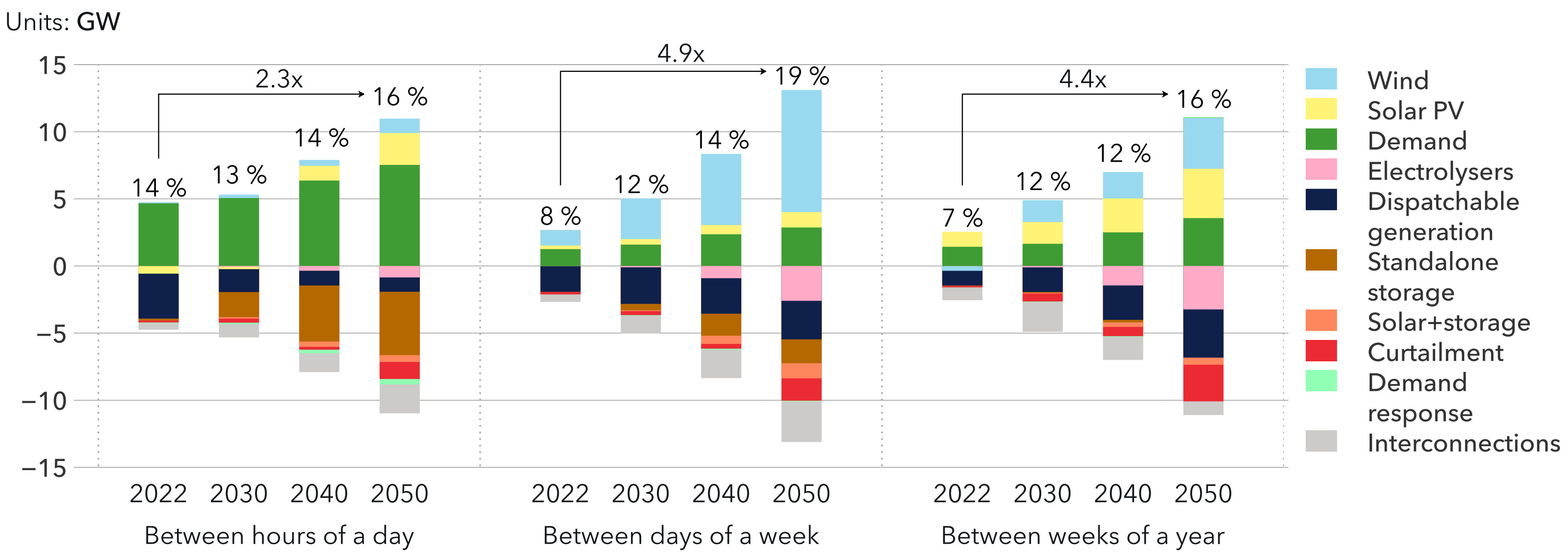
The power system operates within a mosaic of time-scales, each demanding varying degrees of flexibility to maintain stability and reliability. At the nanosecond to second scale, instantaneous adjustments are essential to match supply with demand, ensuring grid frequency remains within acceptable limits. Grid operators rely on fast-acting technologies such as synchronous condensers and grid-scale batteries to respond swiftly to fluctuations in generation or consumption. Moving to the scale of minutes, the integration of renewable energy introduces additional challenges due to its intermittency. Grid operators deploy advanced forecasting tools coupled with automated control systems to anticipate and mitigate imbalances, leveraging energy storage and demand response to smooth out short-term variability.

Flexibility case analysis – the UK

As the timescale extends to hours, the need for flexibility becomes more pronounced, particularly during periods of peak demand or renewable generation lulls. Figure 5.1 shows how the flexibility needs increase over time and how it varies at different time scales, in

FIGURE 5.1

UK flexibility requirements in the electricity supply by technology



Derived from hourly simulations without grid limitations, measuring variability through standard deviation changes attributable to each technology, where negative values indicate reduced variability and percentages represent standard deviation as a ratio to annual mean.

the example of the UK. On a daily basis, the need for flexibility has hitherto primarily been met by adjusting demand, with thermal power stations – formerly coal and now increasingly gas-fired – responding to these shifts. However, as the UK's energy system moves away from carbon, short-term flexibility will increasingly rely on storage and international connections. Post-2040, excess renewable energy may be reduced, and closer ties with European and Irish grids will assist in managing supply. Demand response becomes particularly important during high demand and low wind periods.

Across a week, wind energy's influence on variability is evident and is expected to rise significantly by 2050. However, storage's ability to manage weekly shifts is limited due to capacity constraints. Dispatchable generators, which are likely to transition to hydrogen, will continue to play a role. Electrolysers will utilize excess wind energy, while deficits will be balanced with imports, alongside contributions from dispatchable generators and batteries.

Seasonally, the fluctuation in solar energy rivals that of wind and demand. At this larger scale, battery storage cannot significantly contribute to flexibility. Once again, surplus energy will be directed to electrolysers, with any remaining excess requiring curtailment due to the limited capacity of electrolysers to absorb it.

Global trends

While the UK case provides interesting insight about growing flexibility needs, each power system will have their own unique characteristics due to their composition of demand and supply, weather patterns, and geographies. To get a broad overview of the global trends, we examine, the projected increase in the ratio of daily hour-to-hour standard deviations to average load (Figure 5.2). As Variable Renewable Energy Sources (VRES) capacity increases seven-fold, the global need for short-term flexibility will almost double. We gauge the flexibility contribution by observing the decrease in supply standard deviation with a particular technology compared to its absence.

With renewables projected to constitute a significant portion of the energy mix, the focus will shift towards enhancing the flexibility of both supply and demand sides. Significantly, Li-ion batteries emerge as the primary source of flexibility worldwide. These batteries will either be integrated with renewables or operate as standalone systems. Alongside this trend, thermal generation technologies will be affected. Existing thermal plants will increasingly serve the same grid as renewables, amplifying the importance of their flexibility. However, it's essential to note that not all thermal sources have the same ease in ramping their output up or down. Besides their technical adaptability, the economic viability of these thermal plants

FIGURE 5.2

Global flexibility provided by technology as a fraction of annual average demand

Units: Percentages

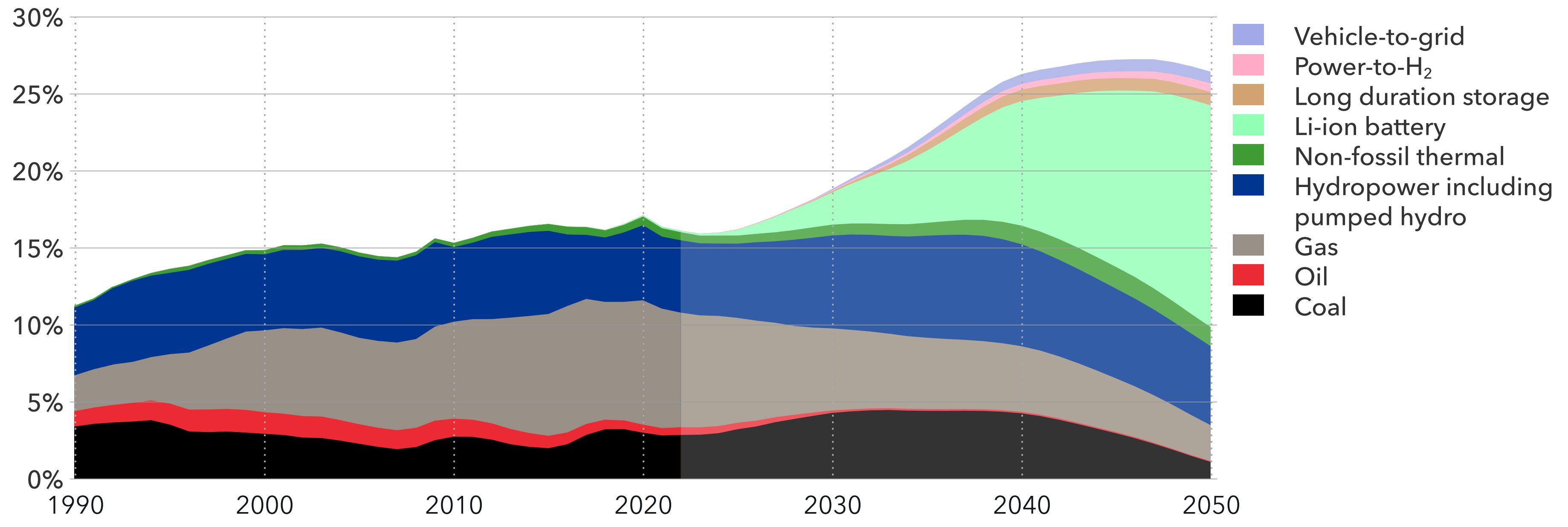
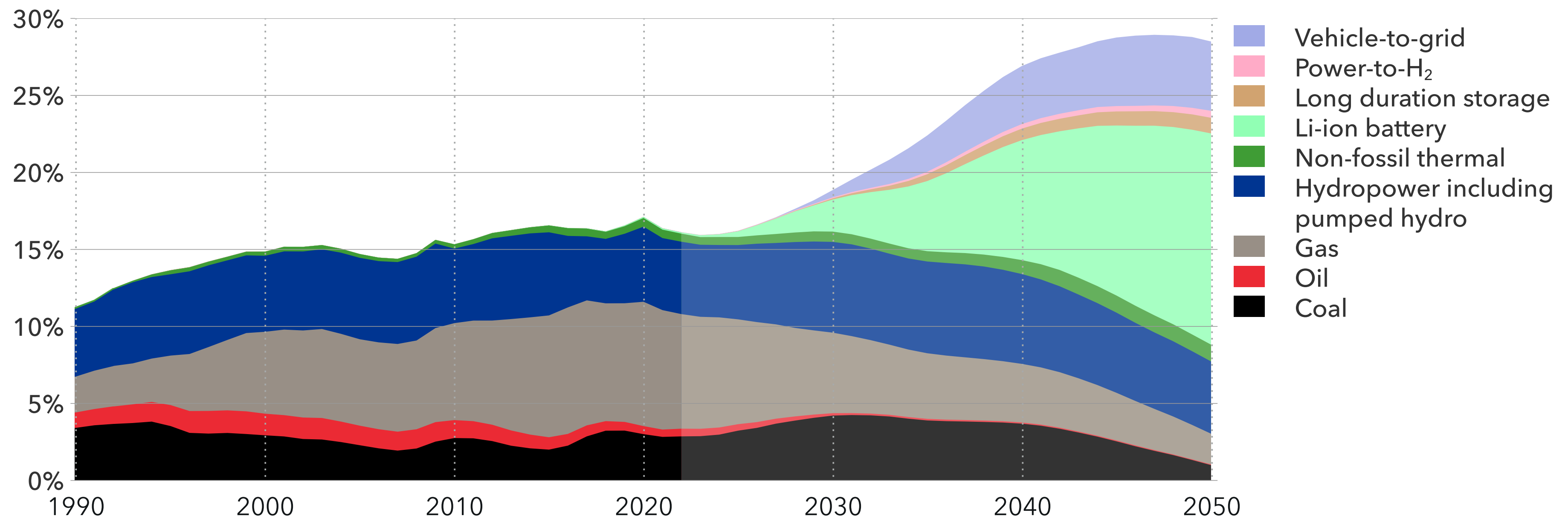


FIGURE 5.3

Global flexibility provided by technology as a fraction of annual average demand - increased V2G contribution case

Units: Percentages



becomes paramount, especially when VRES provides power at lower costs.

The transition to greater flexibility is not merely a matter of equipment. It demands tangible modifications like retrofitting specific parts and significant investment in automation and analytics. Improving the accuracy of renewable power generation predictions and refining demand responses will be instrumental in handling surpluses in renewables and in reallocating electricity usage from high demand periods to those with lesser demand. Moreover, there's a pressing need for innovative market structures. These should promote the adaptive functioning of thermal plants and introduce fresh contract models, alterations in grid codes, and new benchmarks.

Li-ion batteries emerge as the primary source of flexibility worldwide.

From a broader system perspective, we are witnessing the rise of smart grid features. The integration of tools like smart meters, Internet of Things (IoT) sensors, and advanced automation techniques promises more efficient energy flow management. An exciting development is the burgeoning 'prosumer' trend. The evolving technologies and market strategies are empowering an increasing number of consumers to offer flexibility through demand responses, vehicle-to-grid (V2G) systems, and behind-the-meter storage.

EVs deserve special attention in this flexibility narrative. More than just transportation mediums, EVs are evolving into crucial grid components. This transformation is fuelled by financial stimuli from net metering schemes and incentives for V2G-capable charging apparatus. With these incentives, EV owners could potentially offer stored energy to the grid during high demand, opening a revenue channel that can reduce EV ownership expenses and bolster the embrace of clean energy.

In our base run, we have assumed that 10% of the EV batteries of the entire fleet in the region are available for providing flexibility at any moment. However, the contribution from EVs to power market flexibility depends on various factors, including penetration of smart meters and two-way charging technologies, availability of flexible tariffs that allow two-way pricing, and their appeal. If we modify the assumption to allow 25% of EV batteries to be available at any time, we see a significant increase in V2G's contribution to the global power system flexibility. Rather than creating significant reductions in flexibility contributions of alternatives, this change creates additional flexibility in the system, giving rise to a small increase in global uptake of solar energy.

Lastly, another avenue of flexibility emerges from converting VRES into other energy forms like hydrogen. Strengthening the physical transmission systems and refining the connection between power generation and consumption hubs will further optimize the renewable power supply's utility.

Hystar's "HyPilot" electrolyser being installed at K-Lab at Equinor's Kårstø gas processing plant on the west coast of Norway. This highly anticipated field project unites Nordic industry leaders Equinor, Yara, and Gassco as well as ABB. ABB's low-harmonic insulated-gate bipolar transistor (IGBT) rectifiers and DC-DC converters will regulate the supply of electricity to enable the electrolyser to operate under realistic field conditions. ABB will provide local support and expertise on the ground in Norway throughout the project's duration. Operators will gather data during the 10,000-hour trial to demonstrate that green hydrogen can be produced cost-effectively and reliably by utilizing renewable energy sources, such as wind power. Image, courtesy Hystar

GREEN HYDROGEN

Hydrogen may often appear to compete with electricity in terms of policy support, financial subsidies, and infrastructure needs, and in general as an energy carrier for the future. However, as outlined briefly in Chapter 1, hydrogen also can play a supportive and cooperative role in new power systems. This balancing role mainly involves grid-connected electrolysers producing hydrogen.

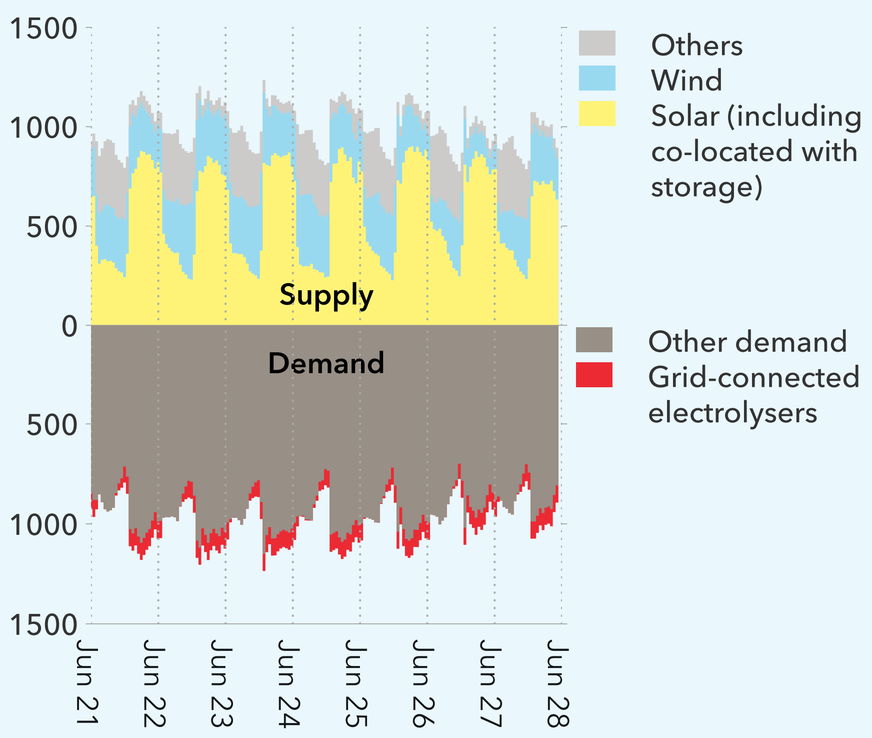
This can be illustrated with an example from North America. The infographics to the right shows a representative summer and winter week in 2048, and the corresponding simplified electricity supply and demand on an hourly basis. Electricity demand as depicted only shows the demand for grid-connected electrolysers versus everything else, for ease of explanation.

In a new power system, grid-connected electrolysers take advantage of cheap solar electricity to produce green hydrogen.

As shown here, this typical summer week in 2048 in North America has stand-alone and hybridized solar as the dominant electricity supplier. The provided electricity is thus going to be relatively inexpensive owing to the near-zero running costs of solar. As such, grid-connected electrolysers run in the North American grid, producing hydrogen and soaking up the excess solar electricity, and aid in reducing curtailment. The access to inexpensive solar electricity in almost all hours in a summer week ensures that the grid-connected electrolysers are running for most of the hours.

North America - supply and demand, summer week 2048

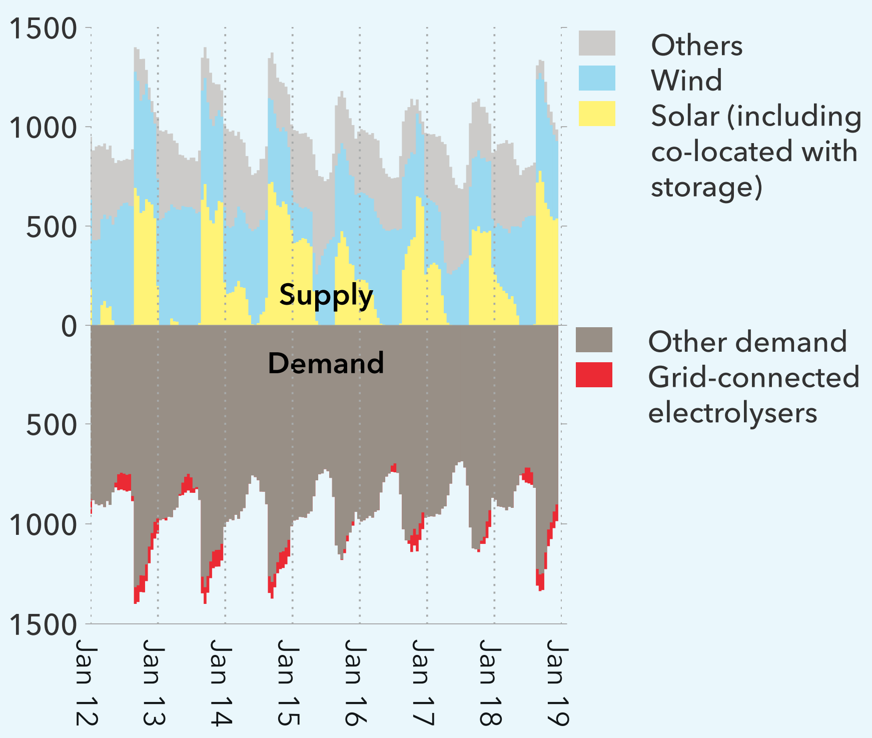
Units: GWh/hr



Contrarily, in a typical winter week in the same year (2048), wind is the dominant electricity supplier in North America. While wind electricity also has very low running costs, the levelized cost of wind is higher than that of solar. Grid-connected electrolysers are therefore likely to only run during hours of maximum solar electricity generation, with solar generation then effectively setting the electricity price for grid-connected electrolysers. This leads to the electrolysers operating during a smaller number of hours in a winter week than in a typical summer week, and only around the middle of the day when electricity generated by solar is plentiful in the grid. The disadvantages of running electrolysers intermittently (higher capital cost relative to unity, or continuous, production) will very likely be offset by the ultra-low cost of the solar-generated power (Jacobson et al., 2023). As this example illustrates, grid operators would be well advised to plan for the intermittent production of green hydrogen in new power systems with plentiful, cheap solar generation.

North America - supply and demand, winter week 2048

Units: GWh/hr



5.2 ELECTRICITY STORAGE

As we journey towards 2050, the crucial role of energy storage in the transforming power landscape becomes increasingly evident. Currently, pumped hydro is the primary method, as illustrated in Figure 5.4. However, hydro's growth potential is limited due to geographical constraints, meaning we need to turn our gaze to other emerging technologies to meet the burgeoning storage demands of the coming decades. Li-ion batteries are poised to fill this gap. We anticipate a surge in their capacity to 1.2 TWh by 2030, further expanding to a robust 27 TWh by 2050. Intriguingly, a significant portion of this capacity will be directly integrated with renewable generation.

A shift is underway in major battery storage markets like China, South Korea, Japan, and the US. As storage capacity surpasses 0.5% of grid capacity, the focus is transitioning from frequency-response management to broader applications such as price arbitrage or capacity provision. This shift translates into longer average storage durations, that range from two to four hours.

FIGURE 5.4

World utility-scale electricity storage capacity

Units: TWh

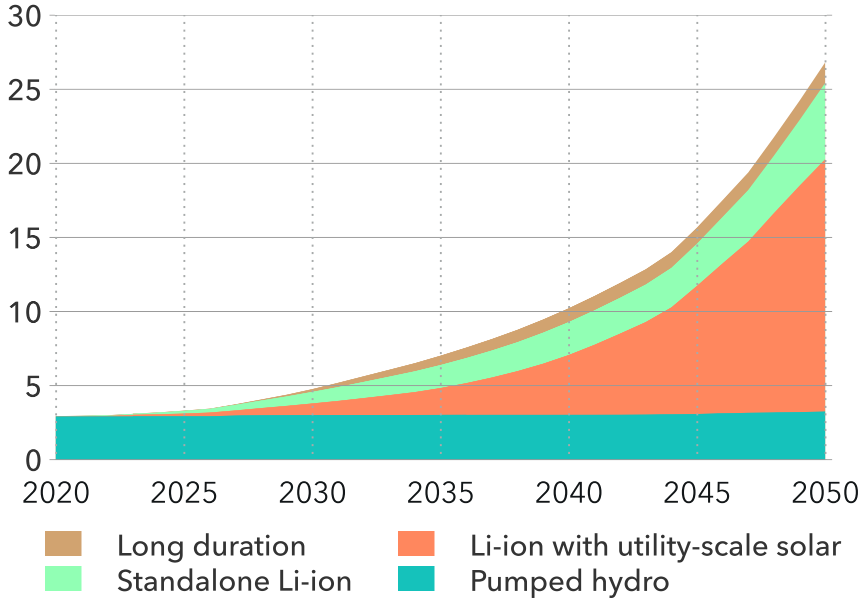
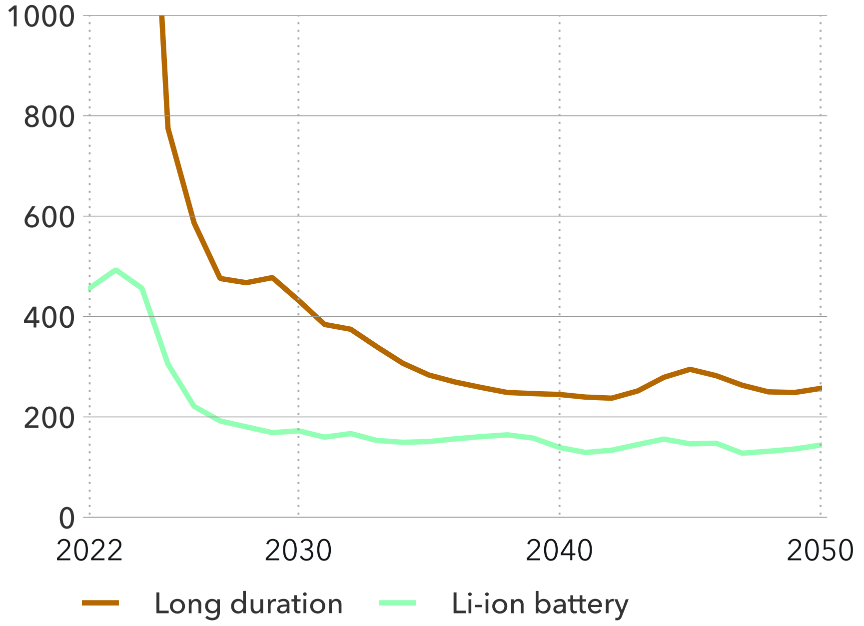


FIGURE 5.5

Average-size utility-scale Li-ion battery and long duration storage levelized cost

Units: USD/MWh



Alongside the rise of Li-ion, the market is showing an appetite for alternative, long-duration storage technologies. These span 5–24 hours and include flow batteries, zinc-based chemistries, and gravity-based storage methods. Our projections indicate a mainstream market entry for these solutions around the latter half of the 2030s, with a long-duration capacity target of 1.8 TWh by 2050.

Despite the dominance of Li-ion, which currently comprises 95% of the storage projects in which we are involved, the industry is on the brink of innovation. Supply-chain challenges, exacerbated post-pandemic, have nudged Li-ion battery prices upward. Nevertheless, we are optimistic about the cost trajectory.

By 2030, costs for utility-scale Li-ion battery systems are projected to dip below USD 200/kWh, further reducing to approximately USD 140/kWh by 2050, as illustrated in Figure 5.5.

Li-ion is not the sole contender in the storage race. In our forecast, we have historically modelled the potential of long-duration energy storage (LDES), particularly vanadium flow batteries for which research (Poli et al., 2024) has revealed promising techno-economic prospects for 8- to 24-hour applications and could offer cost advantages over their Li-ion counterparts. Emerging 'very-long duration' technologies suggest even more significant cost efficiencies. While their commercial viability remains under evaluation and they are not featured in this report, their development could reshape the battery landscape.

The real drive for these long-duration solutions will come from revenue models valuing longer storage durations and the broader adoption of VRES. As technology progresses and policies adapt, the demand for these extended batteries is primed to rise. Ultimately, our long-term storage market predictions hinge on potential cost innovations and policy encouragements, especially concerning fledgling battery technologies.

In the next section we present three scenarios where the storage duration of Li-ion batteries is extended beyond the 4-hour average we have used in our forecast to 2050.

Impact of storage duration on electricity storage dynamics

In general terms, the storage duration at present is two hours for stand-alone utility scale Li-ion batteries, and with increasing penetration of these Li-ion batteries, their duration will increase to four hours. However, there could be situations where in the future, due to higher-than-expected variability in electricity generation and better price arbitrage opportunities, we have stand-alone Li-ion batteries with *more than* four hours of duration. This could also be facilitated by better and more cost-effective stack fabrication technologies which lead to cheaper batteries.

It is important to know how these technological developments may impact the electricity storage market. In this section, we present three sensitivity cases, where the duration of stand-alone Li-ion batteries increase to 8, 10, and 12 hours to 2050, and compare it with our base forecast of four hours. It should be noted that the storage duration of only stand-alone batteries is changed for this sensitivity analysis. The storage duration of Li-ion batteries co-located with solar remains the same as in the ETO base case, where they change from two hours in 2023 to four hours by 2050. This is because the storage co-located with solar does not have that many opportunities to store more than four hours of electricity generation, given the restricted hours of operation of a solar power plant.

Results

We find a significant result from the sensitivity analysis we carried out. Changing the storage duration of stand-alone Li-ion batteries from 4 to 8, 10, and 12 hours *has minimal impact* on the installed global, utility-scale grid-connected electricity storage capacity. The change in global electricity storage capacity between the respective sensitivity cases and the ETO base case is ± 2% in 2050. So, in effect, changing the storage duration of stand-alone Li-ion batteries does not impact the total energy storage capacity.

When one drills down into the different storage categories and their sensitivity to the duration of storage of Li-ion batteries, there are some key findings. Increasing the duration of storage leads to higher installed storage energy capacity of Li-ion batteries, as shown in Figure 5.6. But, for the cumulative grid-connected electricity capacity to stay the same, some other energy capacity should correspondingly decrease. We find that there is no discernible impact on long-duration storage energy capacity with increasing storage durations. However, the energy capacity of Li-ion batteries co-located with solar PV reduces correspondingly as more and more stand-alone Li-ion batteries provide energy capacity, with increasing storage duration (Figure 5.6). Thus, this leads us to the finding that when the storage duration of stand-alone Li-ion batteries increases, the energy capacity of batteries co-located with solar is used less and less, since the stand-alone batteries can absorb the intermittency and variability of the electricity produced from solar PV in the grid.

The larger role stand-alone Li-ion batteries will play in the power system when their storage durations increase is further exemplified by Figure 5.7, where the number of hours Li-ion batteries supply energy in a year are given for North America and OECD Pacific, both expected to be mature markets for Li-ion batteries by mid-century. As can be clearly seen, in both the regions, the longer duration of Li-ion batteries implies a marked increase in the number of hours the storage supplies energy in the power system.

FIGURE 5.6

Global utility-scale Li-ion batteries, both stand-alone and co-located with solar; sensitivities

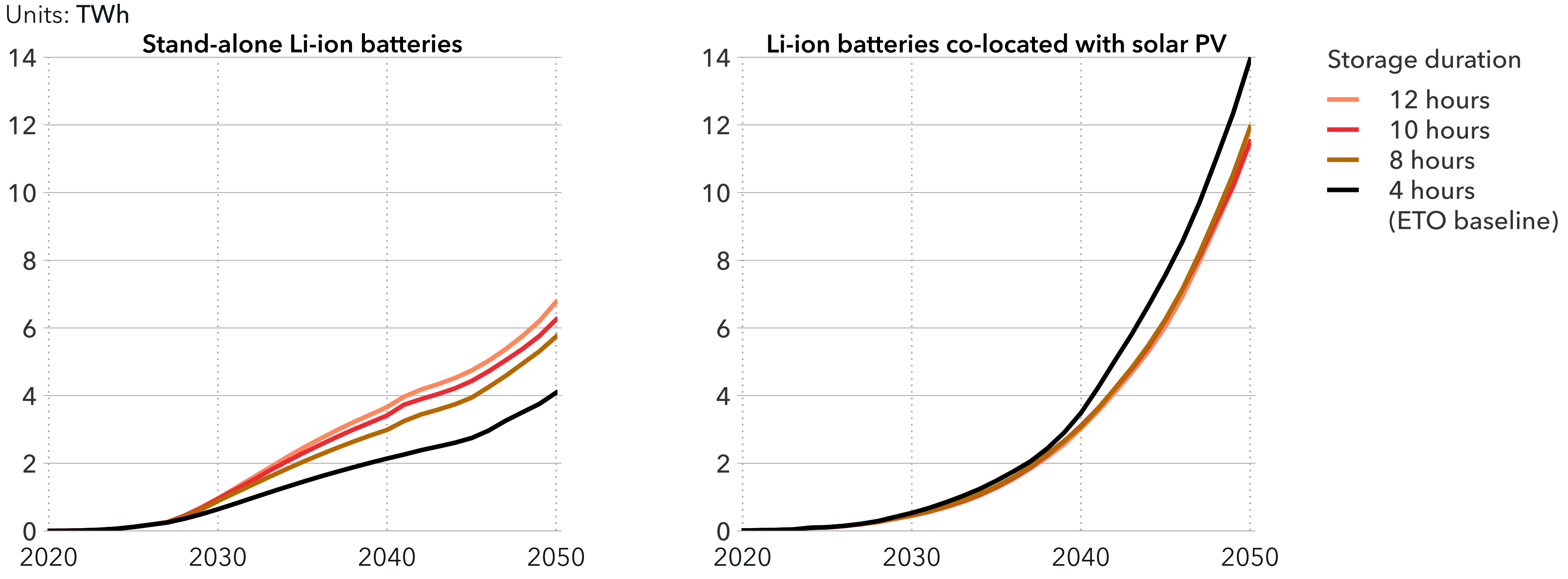
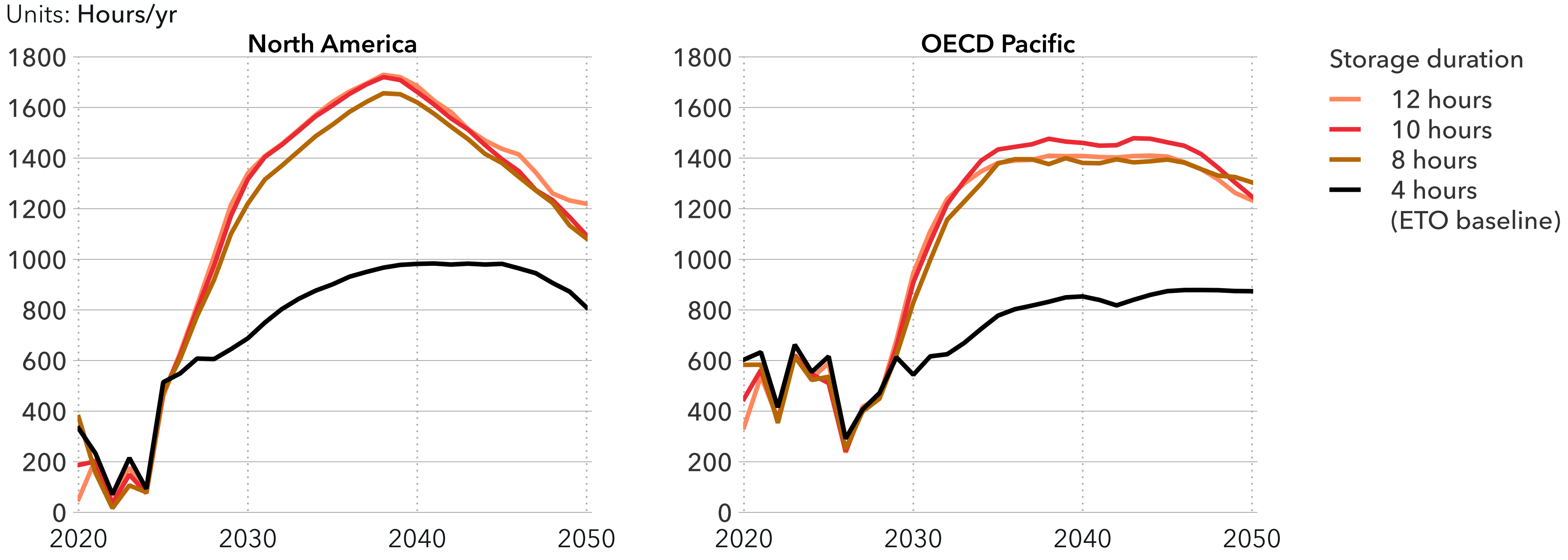


FIGURE 5.7

Annual supply hours from stand-alone Li-ion batteries in North America and OECD Pacific



PRICE ARBITRAGE AND LI-ION BATTERY STORAGE

As mentioned before, as the Li-ion battery production and value-chain becomes more established and batteries in the grid become more commonplace, the revenue streams of storage operators will also diversify. Then, price-arbitrage, which is essentially buying and storing electricity when it is very cheap and then selling it back to the grid when it is expensive, becomes a significant source of revenue. However, the decision to store/charge versus discharge hinges on the acceptable margin or differential between the price of electricity at the time of charging versus discharging, and this acceptable margin/differential is based on individual preferences, how the power system and markets function, and the penetration of variable energy sources in the grid.

In our ETO, we assume a relatively conservative charging and discharging behaviour. That is to say that unless the margin/differential between the electricity price at charging and discharging is considerable, the storage operators are not going to choose to charge/discharge. This assumption is reasonable given the round-trip losses of battery storage as well as battery life degradation with higher charge and discharge cycles. It is also reasonable to foresee that as the power market matures, and the penetration of variable renewables increase, that this margin/differential will shrink, also aided by the storage market becoming increasingly saturated. This will lead to storage operators more willing to charge/discharge more often and against weaker price signals, or in plain terms exhibit more 'aggressive' charging and discharging behaviour.

To test the impact a more aggressive charging and discharging behaviour may have on the power system, we ran a sensitivity case where the charging and discharging behaviour is more aggressive than our main ETO base case. The sensitivity test we conducted is denoted as the *'Aggressive case'*.

We find that there is no difference in energy or power capacity of the global stand-alone Li-ion batteries or the total grid-connected electricity storage capacity.

Instead what we do find is that more aggressive charging and discharging behaviour reduces the 'received price' of unit electricity for Li-ion batteries – i.e. the price garnered by the storage operators when they do choose to sell the electricity to the grid. This is to be expected since we model the storage operators choosing to discharge when the differential is lower than the ETO base case. One significant consequence we find is that while the price-arbitrage aggressiveness is the same across all the regions, the impact this has on the received price varies across different regions, as shown in Figure 5.8.

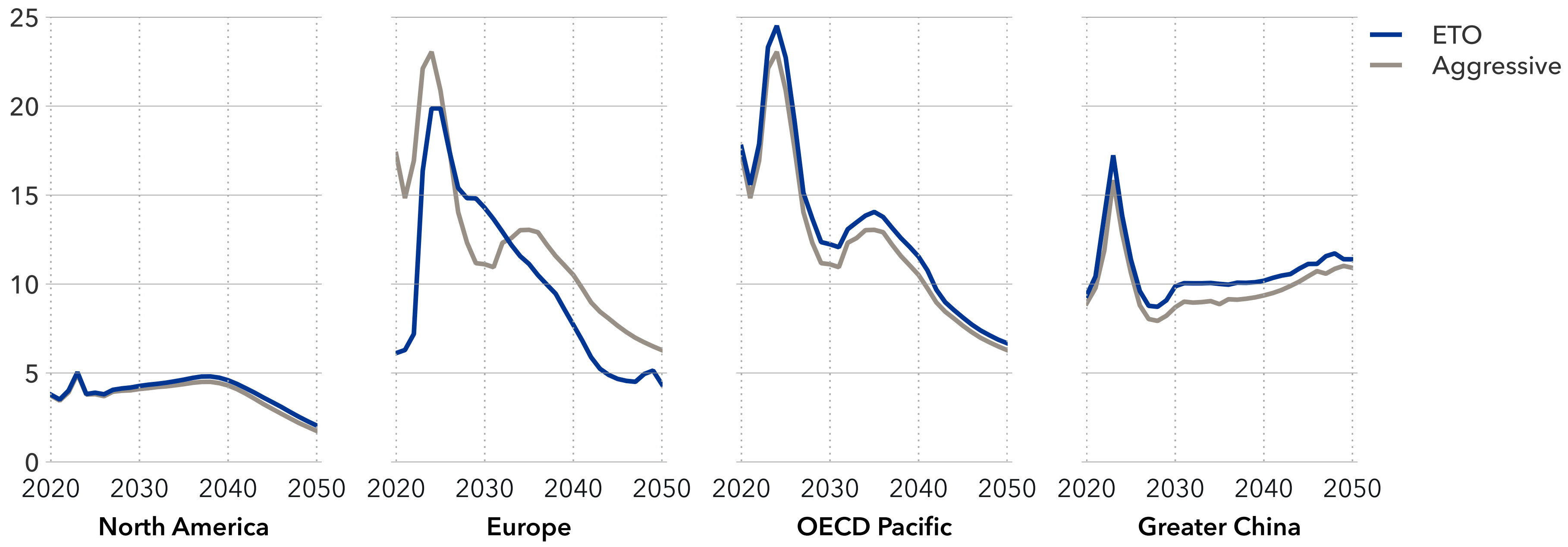
Figure 5.8 presents the received prices for Li-ion batteries for the ETO base case and the Aggressive case for North America, Europe, OECD Pacific, and Greater China. In all regions presented, the received prices for the aggressive case are lower than the ETO base case. However, the amount they differ varies across the regions. In the case of North America, with aggressive price-arbitrage, there is a 15% reduction in received prices by 2050, while in Greater China it is a mere 4%.

This finding leads us to surmise is that the impact of price-arbitrage is tempered by the power system characteristics such as VRES penetration, availability of stand-alone battery storage, and the maturity of the power and energy storage, as measured by the penetration of stand-alone storage. Moreover, how much of a capacity and balancing role stand-alone batteries play in the power system at an hourly scale over the year also impacts how aggressiveness translates to the operation of the batteries.

FIGURE 5.8

Received prices of Li-ion battery storage for selected regions

Units: US¢/kWh



This can be further exemplified by analyzing the hours in a year that Li-ion batteries provide energy in the power system (Figure 5.9). As can be seen, in all regions, the Aggressive case has more hours of battery operation than the ETO base case.

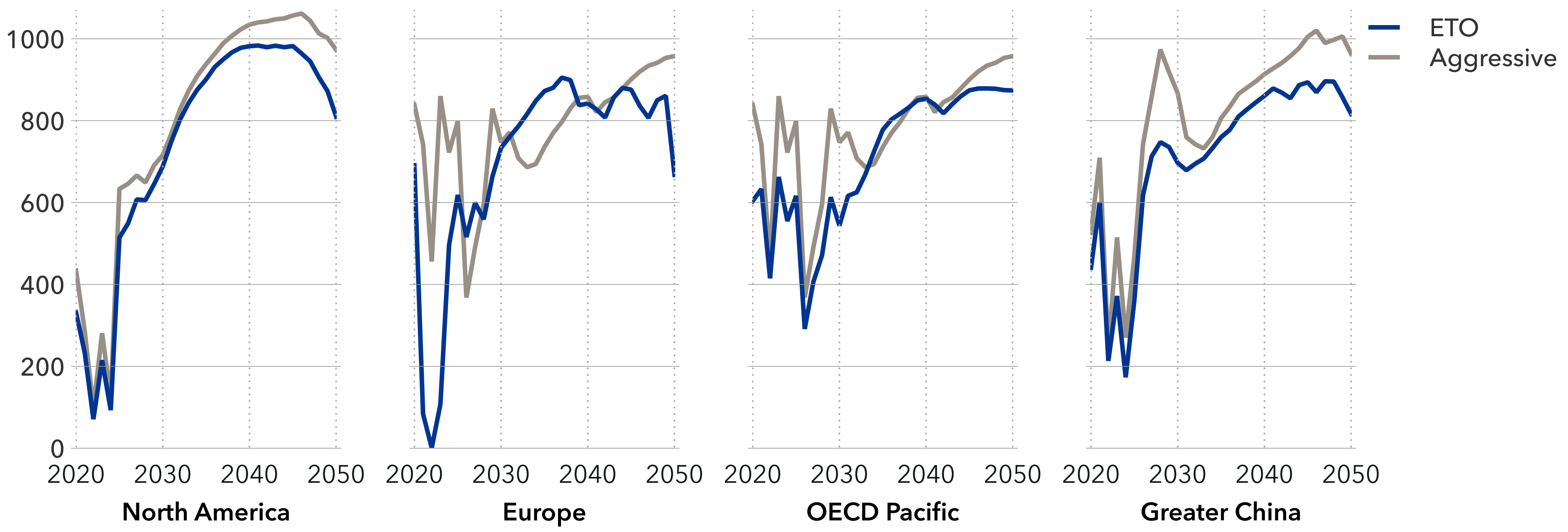
In North America, the Aggressive case has 20% more hours of supply than the ETO case in 2050, while in Europe, despite a reduction in received price of 13%, the Li-ion batteries operate for only 5% more than the base ETO case. On the contrary, in North America, storage operators are much more likely to sell electricity at a weaker price signal, even though the reduction in received price is 15%. So, overall, the aggressive price arbitrage brings about higher revenue for stand-alone Li-ion storage operators over the course of the year.

In summary, this implies that storage operators in the future will be well-placed to tailor their behaviour based on the power system characteristics and optimize their revenue based on the power system characteristics of their spatial market, while also playing the critical role of ensuring integration of new and renewable power technologies in the power system.

FIGURE 5.9

Annual hours of supply from Li-ion batteries in selected regions

Units: Hours/yr



Battery recycling

Recycling is already indispensable to limit the loss of critical minerals (e.g. lithium) in the manufacturing process, as production scrap can represent a large share of a factory output. It also provides a useful supplement to mining, but only in the long term, as it will take time for used batteries to be scrapped in significant amounts. For lithium, we expect the potential recovery from used EV and storage batteries to grow globally to 40 kt/yr by 2030, and 180 kt/yr by 2040.

Step	Investment*	
Collection – transport	Low	The end-of-life electric car or storage system is collected and disassembled. The battery is isolated and sent to the recycling facility
Discharging	+1 M€	The battery usually contains some residual energy, and must be discharged to avoid any fire hazard in the next stages. Remaining electricity can be recovered in some processes.
Disassembly – shredding	+10 M€	The different components of the battery are seperated. Black mass, which contains all the critical minerals, is sent for further processing.
Hydrometallurgy – pyrometallurgy	+100 M€	A series of thermal and/or chemical processes lead to the separation of the different metals in the black mass (nickel, cobalt, lithium, etc.) The metals are sold on the commodity market.

General description of the recycling process. The three last steps are sometimes integrated in a single process.
*Order of magnitude of investment in the recycling plant. Big variations can happen between projects.

6 POLICY AND AFFORDABILITY

In this chapter, we home in on policies and long-term financing arrangement for flexibility, which, as we have shown, is critical to the functioning of future electricity markets. The design and operation of electricity markets greatly influence the cost, and hence affordability, of delivered electricity, as we show in the concluding section of this chapter. For a wider discussion of policy covering global power and energy systems, we refer readers to our main *Energy Transition Outlook* (2023a) which carries an in-depth analysis of specific significant policy packages (in the EU, the US, China, etc.) and unpacks policy pull and push strategies designed to effect a transition across the whole energy system.

6.1 PROMOTING AND FACILITATING FLEXIBILITY

There is an increasing need for flexibility in new power systems and to enable power sector decarbonization. As discussed extensively in this report, this need is driven by the growing share of variable generation from wind and solar power on one hand, and the expectation of fluctuating demand caused by the electrification of other sectors – such as heat or transport – on the other. These emerging needs require action in several policy and regulatory areas.

First, it may be necessary to design and implement new ancillary services. Examples include the introduction of novel (synthetic) inertia products and fast frequency response in Ireland, the Nordic countries, and the UK, or the implementation of a flexible ramping product in California. These new services will require system operators and regulators to define appropriate technical requirements and products, amend existing standards, and even draft new technical rules.

Second, these new services will need to be integrated into the overall market and regulatory framework for the procurement, use, and remuneration of different (ancillary) services. In some cases, this may simply involve revising existing schemes and facilitating participation by novel service providers. In other cases, it may not only be necessary to develop new product definitions, but also to design and implement new contractual structures and/or market mechanisms.

In both cases, the specific needs and their required timings will generally be highly country- or market-specific. For instance, the need for novel inertia and/or frequency control services will usually be more urgent for smaller 'island systems' with a fast-diminishing share of conventional generation but be less critical for large synchronous interconnections (such as those in continental Europe, the eastern parts of the US, the Russian Federation, India, or China) or systems with a major share of hydropower. As a result, some countries or regions will require early action, while others may not need intervention for many years. Refining existing services, or introducing new ones, may be important and help trigger investments in additional flexibility. However, the overall volume of such needs and services will remain limited, as illustrated by the saturation of markets for frequency response in recent years which was caused by increasing battery energy storage participation.

> New ancillary services for flexibility, like fast frequency response, will require system operators and regulators to define appropriate technical requirements and products, amend existing standards, and even draft new technical rules.

In contrast, much larger flexibility needs can be expected in the wholesale and retail markets. Here, resources such as energy storage or demand response may play an important role in compensating for forecast errors or shifting energy across different hours or, in the future, days or even weeks and months. Various mechanisms and potential changes may be pursued to ensure that these flexibility potentials will be made available to the electricity market and can be used efficiently:

- First and foremost, it will be important to preserve appropriate price signals as provided by the merit order model and the principle of marginal pricing (see sidebar on the merit order model).

- As indicated especially by experiences in Europe, introducing intraday markets and shortening trading and settlement intervals not only enables markets to efficiently deal with increasing forecast errors, but also provides additional revenue streams for flexibility.

- A considerable share of future flexibility will be located 'behind the meter', i.e. with small commercial or residential consumers or prosumers for whom direct participation in the energy market will not be cost-efficient. Consequently, aggregators will need to play an increasing role.

- Most consumers are not directly exposed to volatile wholesale market prices and hence have very little incentive to adjust their consumption patterns. Dynamic and/or use-of-time tariffs may help but will not usually be flexible enough to reflect changing system conditions in real time. Here again, facilitating the entry of independent retail suppliers who can offer advanced pricing structures, potentially tailored to individual customer groups, may foster innovation and improve the scope for utilising existing sources of flexibility.

- Future electricity markets will need to facilitate decentralized, independent actions by distributed resources, even if this conflicts with traditional practices, such as centralized scheduling and dispatch. Besides helping to reduce operating costs, participation of independent new ventures tends to trigger innovation and the use of innovative technologies like artificial intelligence.

A considerable share of future flexibility will be located 'behind the meter', i.e. with small commercial or residential 'prosumers' for whom direct participation in the energy market will not be cost-efficient. Aggregators will need to play an increasing role.

The end of the merit order principle?

In the wake of Russia's war in Ukraine, many European countries faced extreme wholesale electricity prices. These were far above previous experiences and led to soaring profits for different types of generators. These 'windfall profits' caused massive criticism and reinvigorated accusations that the use of the merit order model and pricing at marginal costs are flawed. In response to this pressure, the European Commission and many governments intervened and implemented various measures to protect consumers against rapidly rising electricity and natural gas bills.

Still, the EU Agency for the Cooperation of Energy Regulators concluded that the merit order model was not behind the crisis and had instead helped to alleviate it (ACER, 2022). Indeed, marginal pricing is important for sending appropriate price signals, notably including any scarcity (or abundant availability) of electricity. In turn, these signals are an important precondition for incentivizing the availability and efficient use of flexibility. Rather than diluting such price signals, it is important that new flexibility providers can access the corresponding markets and exploit arbitrage opportunities.

6.2 INVESTMENTS FOR DECARBONIZED ELECTRIFICATION

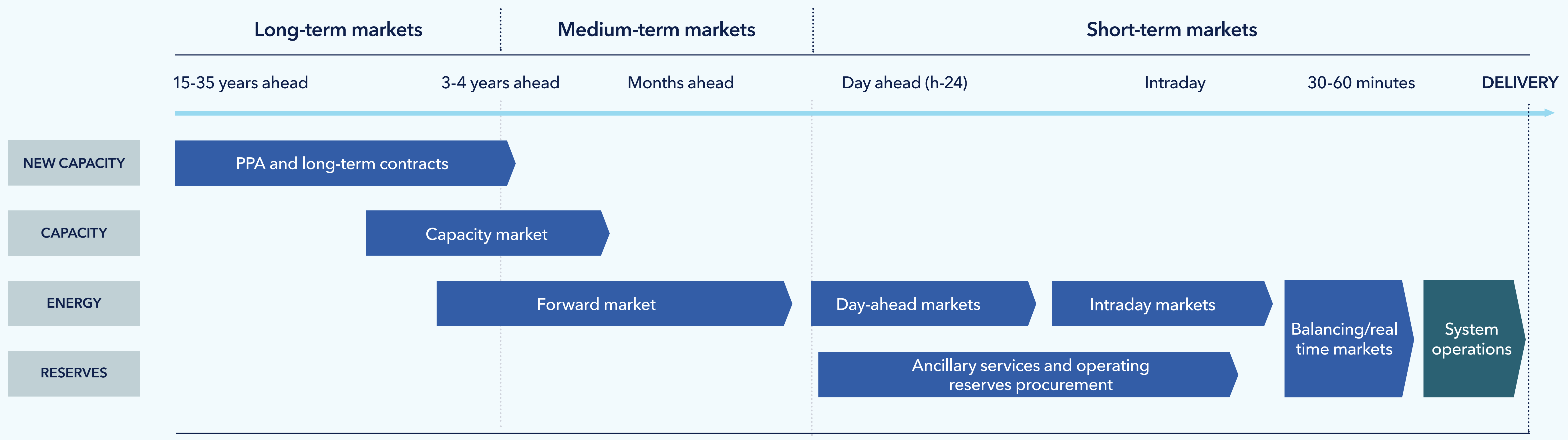
Our simulations foresee a need for massive investments into new low-carbon technologies and associated infrastructure. Over the next decade alone, an average of 500 GW of new wind and solar capacity will have to be built each year, rising to some 800 GW/year by 2040. This will require further investments in electricity storage, transmission and distribution networks, large-scale electrolysers, etc.

The electricity supply industry has always been one of the most capital-intensive industries. Nevertheless, the scale of current and future investment needs is unprecedented. Moreover, the scope for sufficient investments into highly capital-intensive, low-carbon technologies is challenged by several aspects:

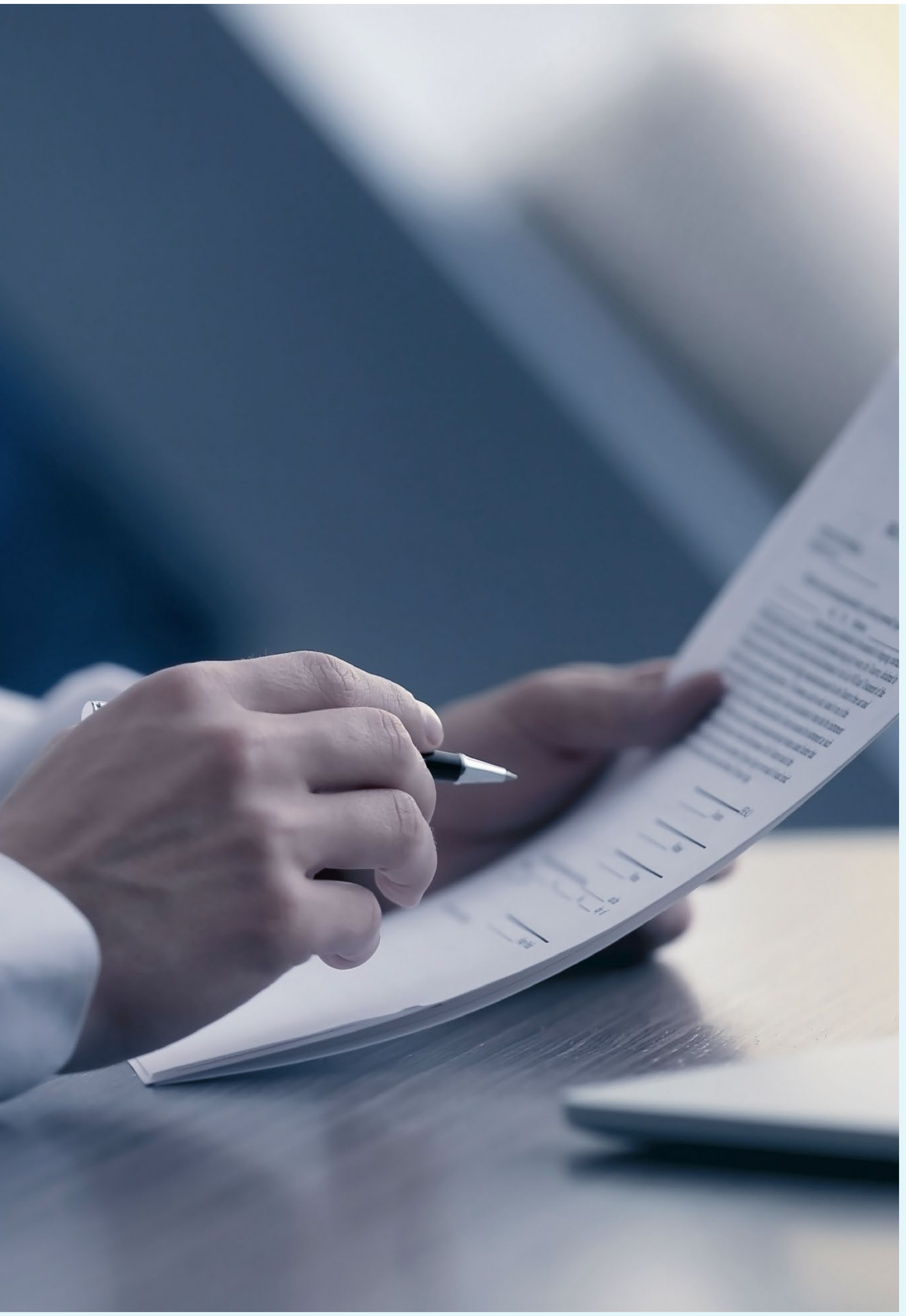
- As indicated in Figure 6.1, the principal structure of liberalized electricity markets is basically limited to short- and medium-term markets, the time horizons of which are substantially shorter than the lifetime of most low-carbon technologies.
- Moreover, as pricing in liberalized energy and ancillary service markets is based on short-term marginal costs, generator revenues are exposed to significant risks. These risks are further exacerbated by the disruptive nature of the energy transition, including an ever-increasing impact of uncertain and fluctuating generation from variable renewables or the expectation of an increasing variability of demand.
- Although many projections forecast a growing need for flexibility, most power systems presently have sufficient or even excess flexibility, resulting in very low prices. Scaling up the necessary technologies, such as energy storage or electrolysis, will require time. With scale, learning rate cost reductions will follow, but in the build-up phase, some form of support will be needed, similar to the stimulus given to the development of wind and solar power over the past two decades.
- The progress of decarbonization on the supply and demand side continues to be strongly influenced by political actions and decisions, which are hard to predict. Such government interventions may be necessary to promote the energy transition. Yet, the associated political and regulatory risks represent one of the strongest barriers to private investments.

FIGURE 6.1

Key building blocks of liberalized electricity markets



To cope with these challenges, mitigate risks for investors, and keep financing costs low, many countries have introduced additional long-term arrangements. These are summarized on next page. In most cases, and in contrast to short-term energy and ancillary services markets, these mechanisms rely on a much larger role of governmental and/or regulatory interventions or direct contracts with some form of public entities. Although green, corporate PPAs have gained substantial traction in some countries in recent years, their overall market share remains limited as only few consumers are willing (or able) to engage into such long-term arrangements.



Long-term backing for new sources of generation and adequacy

The first group of long-term arrangements includes various types of long-term contracts that are aimed at promoting the supply of energy from different generation and/or storage technologies. The lifetime of these agreements is generally linked to the economic lifetime of the underlying assets. Besides traditional feed-in-tariffs or feed-in-premium schemes, this notably includes power purchasing agreements (PPA) or contracts for differences (CfD) concluded with some public offtaker, such as a dedicated public entity or a (regulated) utility. In both cases, all costs and benefits are passed on, via the public offtaker, to all consumers or, in markets without retail competition, to 'rate payers'. Green, corporate PPAs/CfDs are based on direct bilateral agreements between generators and (corporate) consumers, whereby the private consumer bears all associated risks and benefits itself.

The second form of long-term backing involves capacity remuneration mechanisms that provide an additional remuneration for providers of 'firm capacity' – defined as the capacity being firmly available during critical situations (e.g. peak residual load). In some countries, this is achieved through payments of some administrated charges for available capacity. However, the prevailing model is capacity markets where a public entity contracts with resource providers for availability of firm capacity. While the time horizon of many of the earlier capacity markets in Northern America was limited to one or a few years, some European countries have introduced tenders for much longer contract durations in recent years that are linked to typical investment horizons.

As a final agreement example, France has introduced a decentralized capacity market, whereby retail suppliers are obliged to contract for a defined volume of capacity obligations with producers who are assigned corresponding 'capacity certificates' based on their firm capacity.

Some European countries have introduced tenders for much longer firm capacity contracts in recent years that are linked to typical investment horizons.

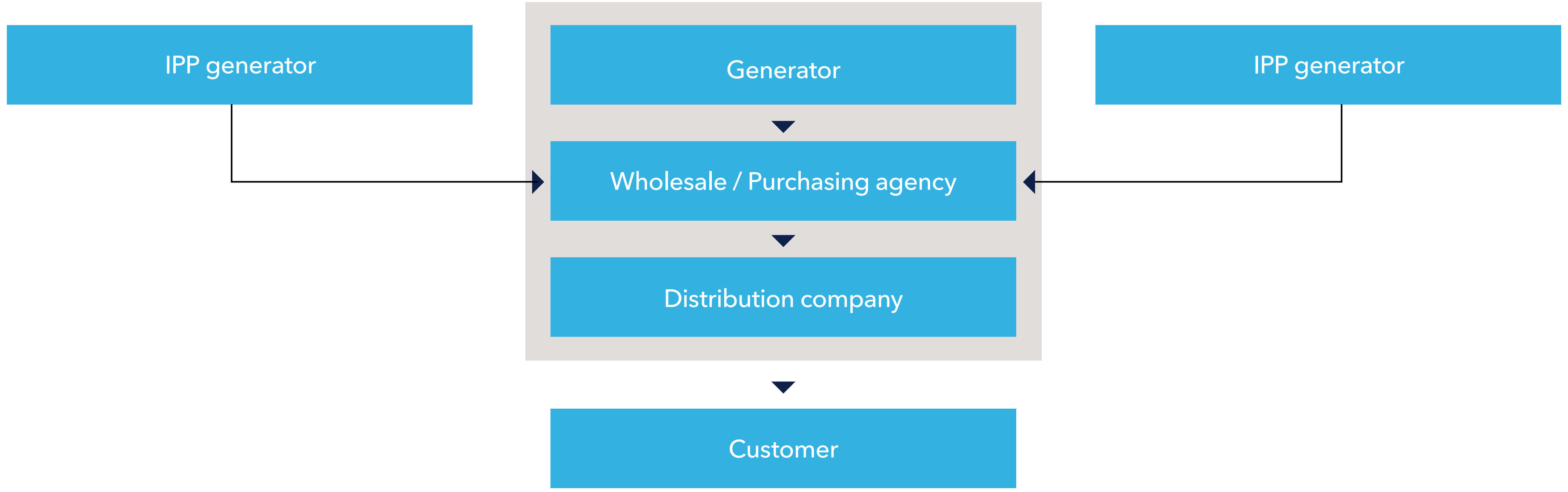
Counterparty	Long-term (energy) contracts	Capacity remuneration mechanisms
Public	– **Traditional FiT / FiP schemes** – **Public PPAs/CfDs**	– Capacity payments – **Public PPAs/CfDs**
Private	– Green / Corporate PPA/CFDs	– Decentralized capacity obligations
	Aimed at promoting new sources of generation (or storage)	*Aimed at ensuring resource adequacy*

SPECIFIC ISSUES IN NON-LIBERALIZED MARKETS

Much of the above discussion has focused on the situation in liberalized markets with unbundled generation, transmission (and potentially distribution) networks, and retail supply. In contrast, many countries (e.g. in the MENA region, Asia, or Africa) still rely on vertically-integrated utilities, or the single buyer model where a central entity (i.e. the single buyer) purchases all or a considerable share of electricity from generators under long-term PPAs (Figure 6.2).

FIGURE 6.2

Single buyer model



With an increasing penetration of variable renewables, these countries will naturally be exposed to the same technical challenges as those with fully-developed electricity markets and they should pursue the same technical solutions to resolve any corresponding issues. Simultaneously, using long-term PPAs for contracting of generation capacities is very similar to some of the mechanisms listed in our sidebar on long-term support, and numerous countries do indeed procure wind and solar projects under such arrangements. The primary risks for sufficient investments in these countries are thus often more related to the overall economic and political situation in these countries, the creditworthiness of public offtakers, and the governments' limited ability to underwrite the corresponding financial risks.

Countries without functioning wholesale markets may find it considerably more difficult to efficiently invest in and utilize potential sources of flexibility, especially with regard to the use of energy storage, demand response, and behind-the-meter sources. This is because, liberalized wholesale markets provide clear price signals about the fluctuating value of electricity at different times of the day or week. Similarly, ancillary services markets identify the value of such service and provide additional revenue streams to flexibility providers .

In the absence of such price signals, it is much harder to ensure economically-efficient scheduling and dispatch of available resources. In theory, it is possible to obtain similar results by using sophisticated energy management systems supporting optimal unit commitment and scheduling similar to those used in markets with centralized generation scheduling. However, in practice these countries still often rely on much simpler approaches – scheduling based on average rather than marginal costs, consideration of contractual rather than technical constraints, and even so-called take-or-pay constraints – which leads to suboptimal and more expensive outcomes, especially in the presence of variable renewables.

Moreover, even if such optimization systems were applied internally, the true economic costs of electric energy and ancillary services would not necessarily be visible to the staff responsible for scheduling generation and storage, and it certainly would not be visible to external parties, such as owners of behind-the-meter flexibility. This makes it much more difficult to incentivize providing distributed sources of flexibility, which will become increasingly important in the future.

> Countries without functioning wholesale markets may find it considerably more difficult to efficiently invest in and utilize potential sources of flexibility.

Overall, countries without liberalized markets may thus find it significantly more difficult to deal with the variability of certain renewable energy sources or new sources of consumption, such as EVs. Although investing in additional sources of centrally-controlled flexibility may overcome these challenges, this would lead to additional costs to consumers – an undesirable development given the much lower level of wealth and economic development in many of these countries. Consequently, substantial efforts may still be required to identify and develop mechanisms which may help to, at least broadly, mimic and reap the benefits of advanced market mechanisms.

6.3 AFFORDABILITY

Policy success hinges on solving the energy trilemma – managing the balance between the security, affordability, and sustainability of energy systems.

Decarbonized electricity is self-evidently a major contributor to the planet's sustainability compared with the fossil fuel alternative, but we must pay attention to biodiversity impacts in the buildout of renewables and grids.

In Chapter 1, we commented extensively on energy security and the willingness of governments to pay a premium for 'home-grown' energy – both renewables and nuclear – because of the current geopolitical uncertainties. The cyber security aspect of security is also key and is covered in Chapter 3. In this section, we address the remaining corner of the trilemma: affordability.

Grid charges

Renewable generation costs will undoubtedly fall. We do not find evidence in most regions to support the emerging dogma that the green dividend from renewables will be cancelled out by rising grid costs passed on to consumers.

We forecast the global grid investments to increase from USD 450bn in 2023 to USD 970bn by 2050. Grid expenditures will account for a little more than a quarter of total energy expenditures by 2050, up from the present 15%. The grid share is increasing due to the combination of grid expansion costs and the future reduction in fossil fuel expenditures.

The grid will be carrying (in effect 'selling') double the electrical power by 2050, which has an important effect on unit costs. Rising grid investments and expenditures do translate to grid charges billed to consumers, but this varies substantially across regions (Figure 6.3). The chart on the left of Figure 6.3 shows the regions with *increasing* grid charges in the future, compared with 2020. Sub-Saharan Africa, a significant portion of whose population has no access to electricity, will see a significant surge in its grid-charges, along with Latin America. North East Eurasia will also see a significant uptick in grid charges due to its ageing infrastructure and the backloading of renewable integration expected in the 2040s. In contrast, grid charges passed to consumers are either stable or fall in six out of the ten world regions we model and at an aggregate level globally (Figure 6.3).

The future cost of electricity

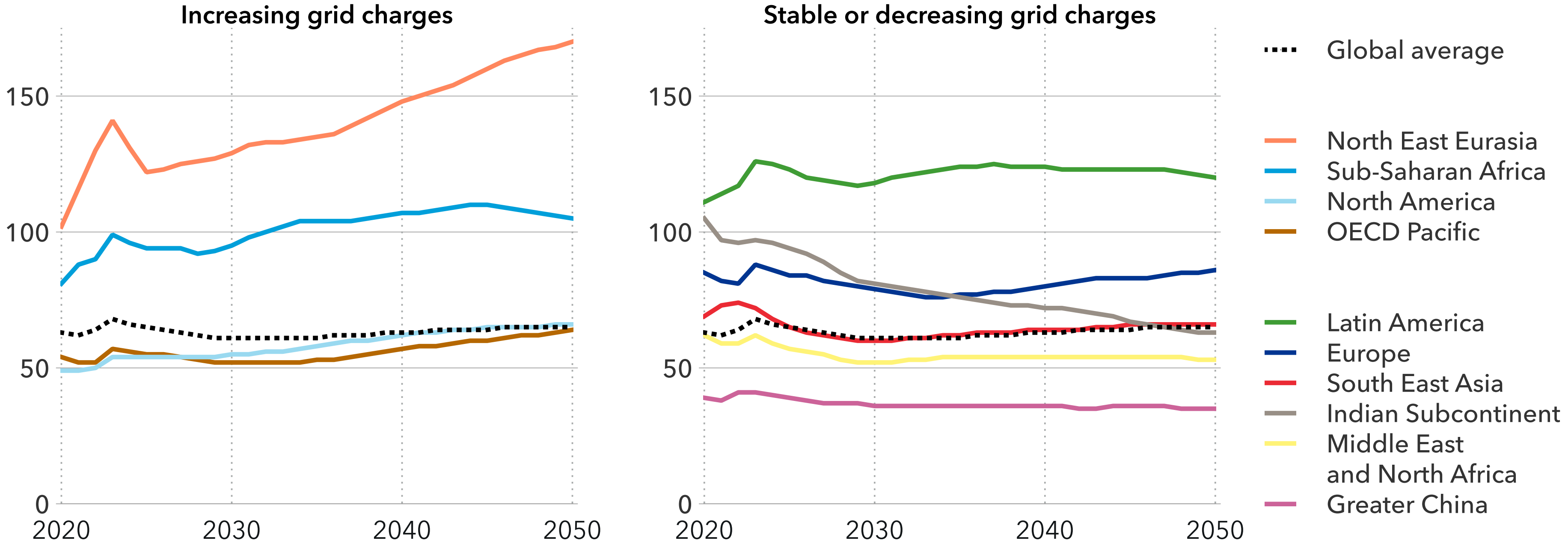
If grid expansion does not necessarily cost consumers more per kWh across most of the world, what does this portend for future electricity prices? The answer partly hinges on the extent to which electricity is taxed – for example, roughly one third of the electricity price paid by European house-holds is tax. It might be reasonable to assume that such taxes will not increase dramatically given the centrality of green electricity consumption to nations' decarbonization ambitions. On the other hand, taxes generally do not fall. The key variable in the future price determination is therefore the cost of flexibility in new power systems, as discussed above.

> Grid charges passed to consumers are either stable or fall in six out of the ten world regions we model and at an aggregate level globally.

FIGURE 6.3

Regional grid charges

Units: USD/MWh



DNV has modelled future electricity prices and finds that in many regions it is reasonable to assume that the prices paid by consumers will either remain stable or fall slightly per kWh. However, from an overall expenditure perspective, the replacement of household fossil fuel use by electricity – for example in transport and heating – has a far more dramatic effect. In other words, a significant efficiency dividend awaits most households.

Forecast household energy expenditure

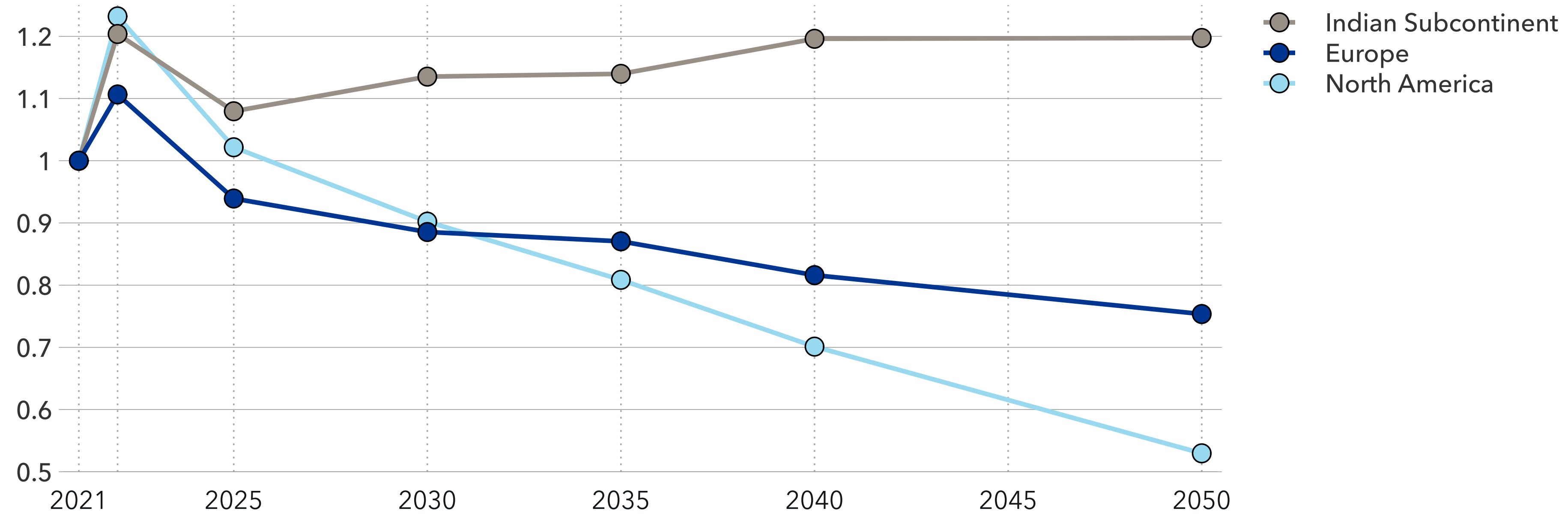
Figure 6.4 forecasts trends in household energy expenditures in North America, Europe, and the Indian Subcontinent. This household energy expenditure includes CAPEX for residential space cooling (such as the cost of air conditioners), heating (such as the cost of heat pumps), and cooking (such as the cost of electric stoves), and OPEX (the energy costs and energy taxes) of running all the household equipment and passenger vehicles.

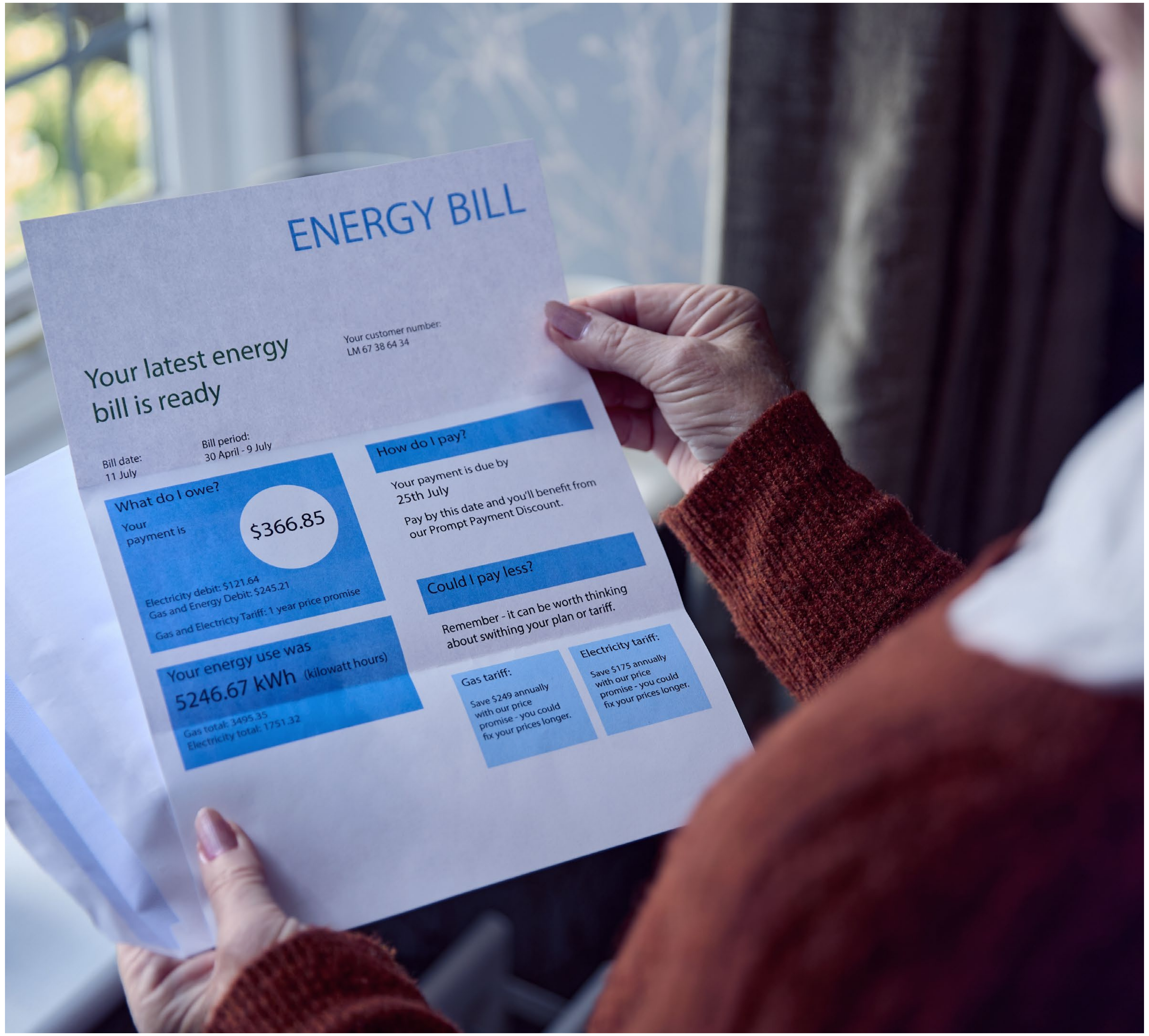
Households in Europe have recently seen their energy expenditure rising sharply, and this will last until the energy supply shocks are alleviated around 2025. By the late 2020s, household energy expenditures in Europe will be around 90% of their 2021 levels in real terms. There will be a stable period before a further decline to around 75% of 2021 levels by mid-century.

FIGURE 6.4

Household energy expenditures in selected regions

Units: Unitless, 2021 value = 1





After a longer sustained price shock in the 2022 to 2025 period, North America will follow an even steeper trajectory, with 50% lower energy bills by mid-century. In both Europe and North America, the benefits of investing in cheap renewable electrification are felt by households through generally cheaper energy.

Similarly, the Indian Subcontinent will see higher household energy expenditures in the short term, owing to price shocks, but these will gradually decrease over the coming years. However, increasing electrification, especially residential air conditioners, and higher household energy consumption, will dampen the effect of decreasing energy costs for households. Household energy expenditures will consequently rise slightly to 2050.

Note that over this period, average GDP per capita increases by a factor of more than three across the Indian Subcontinent. Therefore, on a relative basis measured as share of income, energy will be more affordable (as further illustrated in Figure 6.5).

Energy costs are also embedded in products and services, but our results show that the energy transition will at least have a positive impact on the visible part of these costs: direct household energy expenditure.

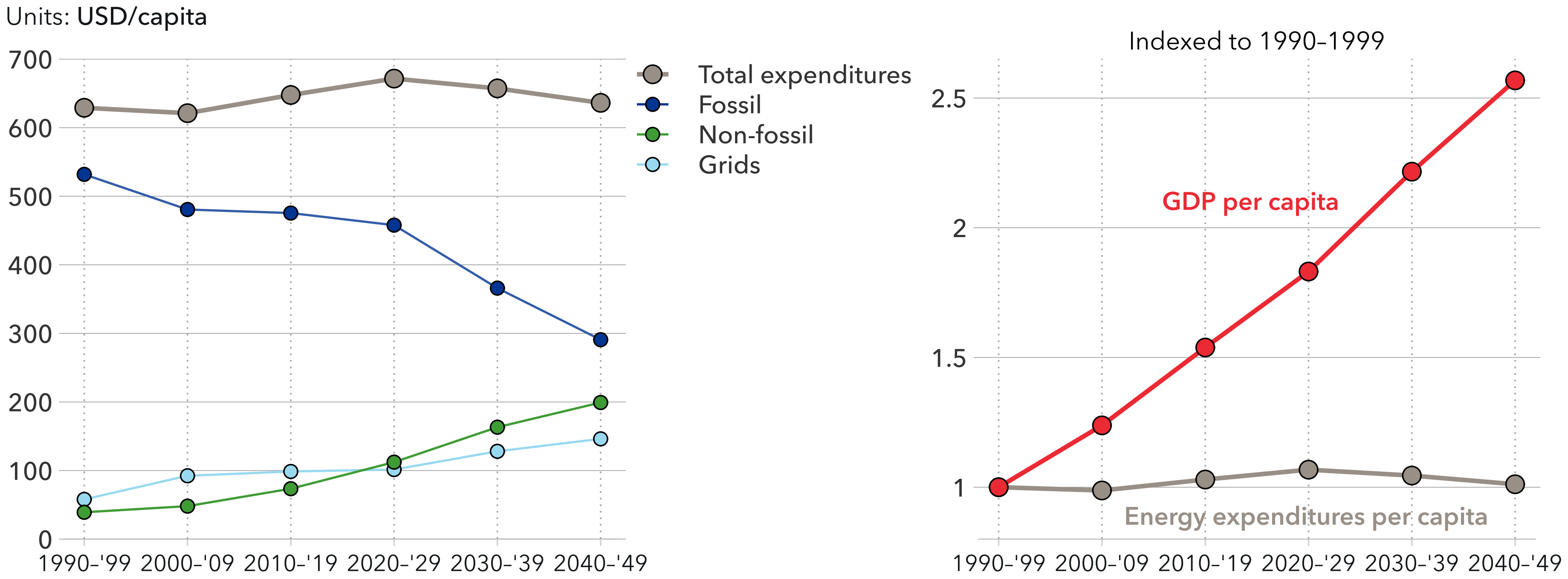
Competitiveness

Electrification and new power systems are becoming central to the functioning of almost all national economies and are poised to become even more important towards 2050 and beyond. As we have shown above, at the level of households, electrification carries a significant efficiency dividend. This holds true at city, regional, and national levels. Transitioning quickly, intelligently, and securely to new power systems will be critical to the competitiveness of cities and states. Bold and informed decision making is called for, quite apart from the obvious urgency attached to decarbonization in the context of the climate emergency.

On a global basis, total energy expenditure per capita is likely to decline lightly between now and 2050, while average GDP per capita increases by 60% over the same period.

FIGURE 6.5

Global average energy expenditures per capita



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Historical data

This work is partly based on the World Energy Balances database developed by the International Energy Agencyc OECD/IEA 2023, but the resulting work has been prepared by DNV and does not necessarily reflect the views of the International Energy Agency. For energy-related charts, historical (up to and including 2022) numerical data is mainly based on IEA data from World Energy Balances OECD/IEA 2023, www.iea.org/statistics, License: www.iea.org/t&c; as modified by DNV.

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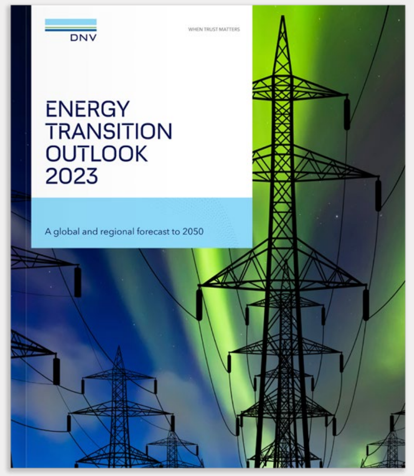

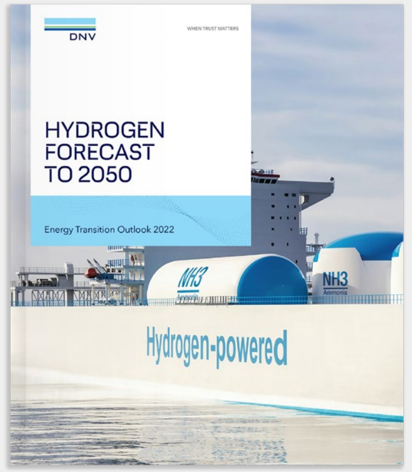

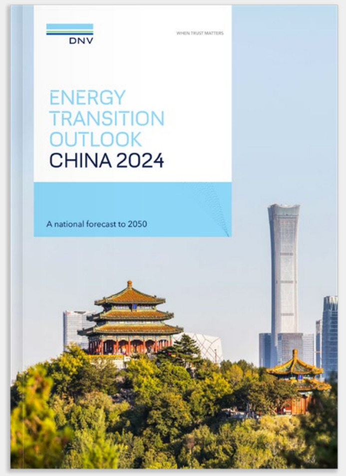

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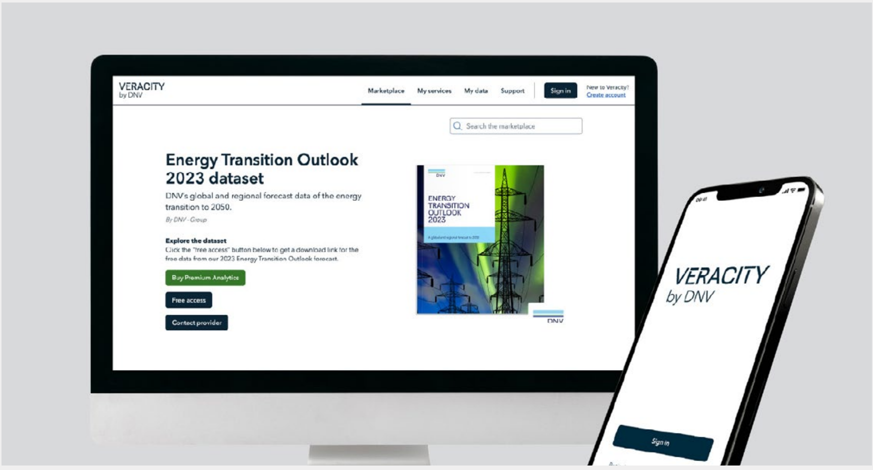

All the forecast data in DNV's suite of Energy Transition Outlook reports, and further detail from our model, is accessible on Veracity – DNV's secure industry data platform.

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