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WHEN TRUST MATTERS

ENERGY TRANSITION OUTLOOK 2023

A global and regional forecast to 2050

FOREWORD

If 'energy transition' means clean energy replaces fossil energy in absolute terms, then the transition has not truly started. The transition has happened in some regions and for many communities and individuals, but globally, record emissions from fossil energy are on course to move even higher next year. Up to the present, renewables have met some, but not all, of the world's additional energy demand. Optically, the transition seems to be in stall mode, with high oil and gas prices fuelling an exploration surge while many renewable projects are experiencing an increase in cost due to inflationary and supply-chain pressures.

So, when will the real global transition begin? Our prediction is that emissions from oil use will peak in 2025 and those from natural gas in 2027. EV uptake and solar PV installations, both of which are now at record levels, are set to continue strongly. Moreover, the *Fit for 55* and *RePowerEU* policies in the EU and the *Inflation Reduction Act* in the US are already demonstrating powerfully that decarbonization policies can work on a grand scale. In our forecast, non-fossil sources constitute 52% of the energy mix in 2050, a sharp increase from the 20% they represent today.

We have frequently used numbers to place a dimension on two corners of the energy trilemma: affordability (such as levelized cost and prices) and sustainability (such as carbon emissions intensity). So far, the third corner of the trilemma – energy security – has been largely viewed in a qualitative way. In the past 18 months the world has experienced the consequences of the 'grab for gas' in the wake of Russia's invasion of Ukraine and the reversion to coal in some regions as a cheaper alternative to gas. We have also seen increased attention to renewable projects in most places, as domestically-sourced energy is harder to disrupt and many governments are looking at nuclear with renewed interest.

Local sourcing of both energy and energy infrastructure is emerging as a prominent national objective. This year, our research team has revised our power sector forecast to better reflect the existing and future willingness of countries to pay a premium for locally-sourced energy – and that has notably impacted our results. For example, for the Indian Subcontinent we now forecast a slower transition with more coal in the energy mix, and in Europe the transition is accelerating with the alignment of climate, industrial, and energy security objectives.

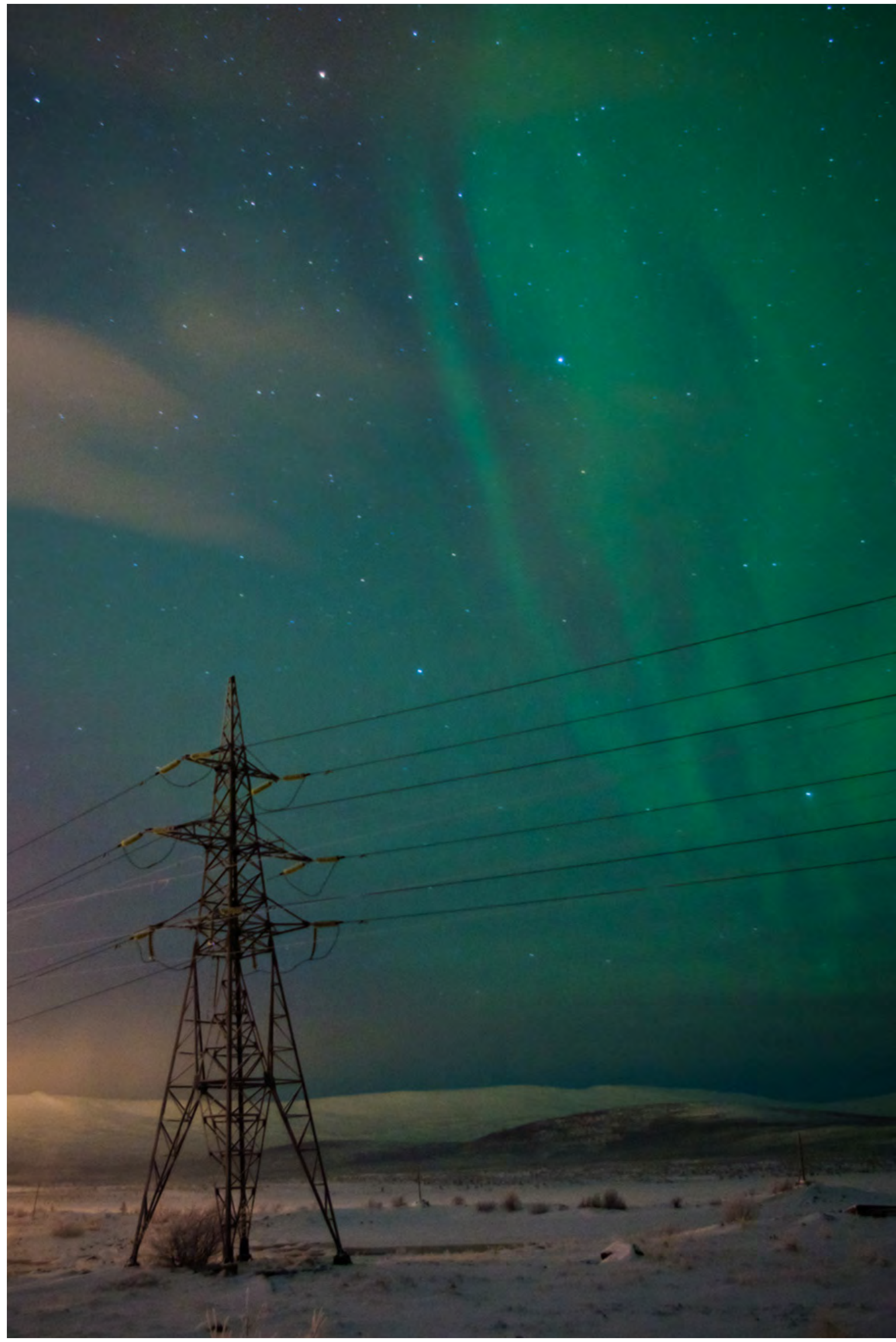
Short-term energy forecasting has been a thankless task in the recent context of the pandemic, war, and price shocks. However, within our system-dynamics approach, the long lines of development are clear: the energy landscape will look very different in the space of a single generation. We forecast a 13-fold increase in solar and wind electricity production by mid-century. Electrification will more than double between now and 2050, bringing efficiencies to the energy system, which, as we detail in this report, brings down the cost per unit of energy for consumers in the longer run. However, in the coming ten years, a critical issue is how quickly that can happen with a lack of electric grids and renewable supply-chain capacity emerging as critical bottlenecks to a faster transition. And a faster transition is most definitely needed because our 'most likely' forecast for our energy future through to 2050 translates into global warming of 2.2°C by the end of this century.

Achieving a net-zero energy system by 2050 to secure a 1.5°C warming future is more difficult than ever. That does not mean we should not be aiming for that target. With more expansive policies promoting renewable electricity and other zero-carbon solutions, not just in the high-income world, but globally, we have the means to keep the world on track to be at, or very near, net zero by mid-century.

Remi Eriksen

Group President and CEO

DNV



HIGHLIGHTS

The transition is still at the starting blocks

– Global energy-related emissions are still climbing and are only likely to peak in 2024. That is effectively the point at which the transition begins, even though across many nations and communities, energy-related emissions have already started to fall

– Over the last five years (2017–2022) renewables have met 51% of new energy demand and fossil sources 49%. In absolute terms, fossil-fuel use is still growing

– The 'grab for gas' in the wake of Russia's invasion of Ukraine, and the disruption of the oil market, has led to high prices and a surge in new oil and gas projects

– High gas prices have also seen several countries intensify coal-fired power generation over the last 18 months, driving emissions yet higher. Natural gas is losing its status as a 'bridging fuel' for the transition

Renewables outsprint fossils from the mid-2020s

– The transition involves both the addition of renewables *and* the removal of fossil sources (Figure 1)

– It will take the next 27 years to move the energy mix from the present 80% fossil 20% non-fossil split to a 48%:52% ratio by mid-century

– From 2025 onwards, almost all net new capacity added is non-fossil. Wind and solar grow ten-fold and 17-fold, respectively, between 2022 and 2050

– Over the next decade, new fossil production in low- and medium-income countries will largely be nullified by reductions in high-income countries

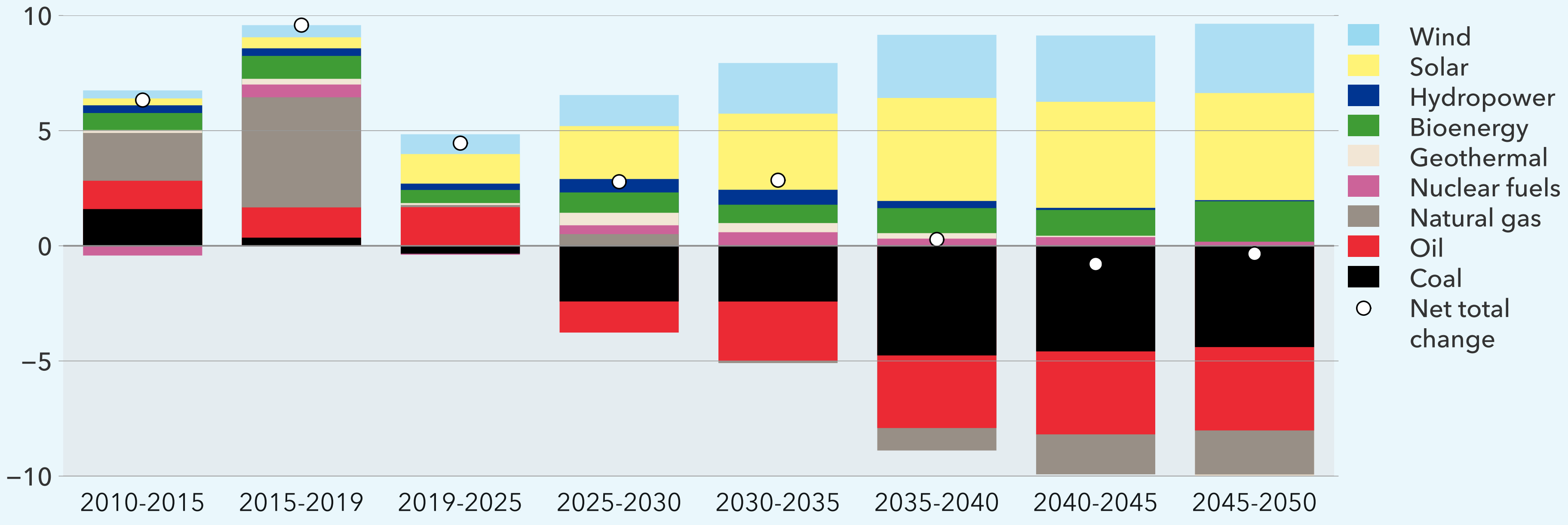
– Coal use peaked in 2014 but has come close to that level in recent years. However, its share of primary energy falls from 26% today to 10% in 2050

– Fossil primary energy demand declines from 490 EJ to 314 EJ by 2050. Cumulatively, the fossil energy *not* used compared with today's use amounts to 1,673 EJ or 275,000 million barrels of oil equivalent by 2050

FIGURE 1

Net change in primary energy supply by source

Units: EJ/yr

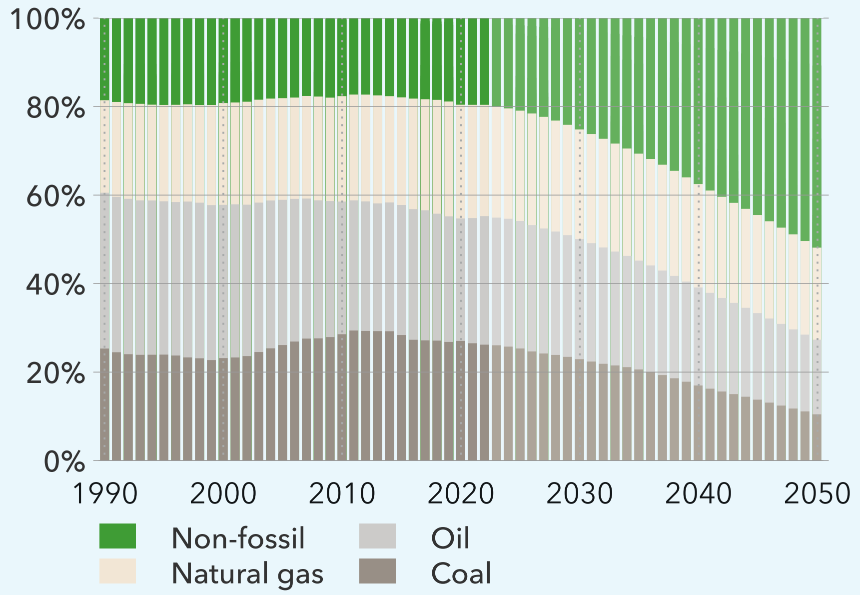


Net change of primary energy between 5-year intervals. 2019 used to avoid effect of COVID-19. Historical data source: IEA WEB (2023)

FIGURE 2

Fossil vs. non-fossil in primary energy supply

Units: Percentages



Historical data source: IEA WEB (2023)

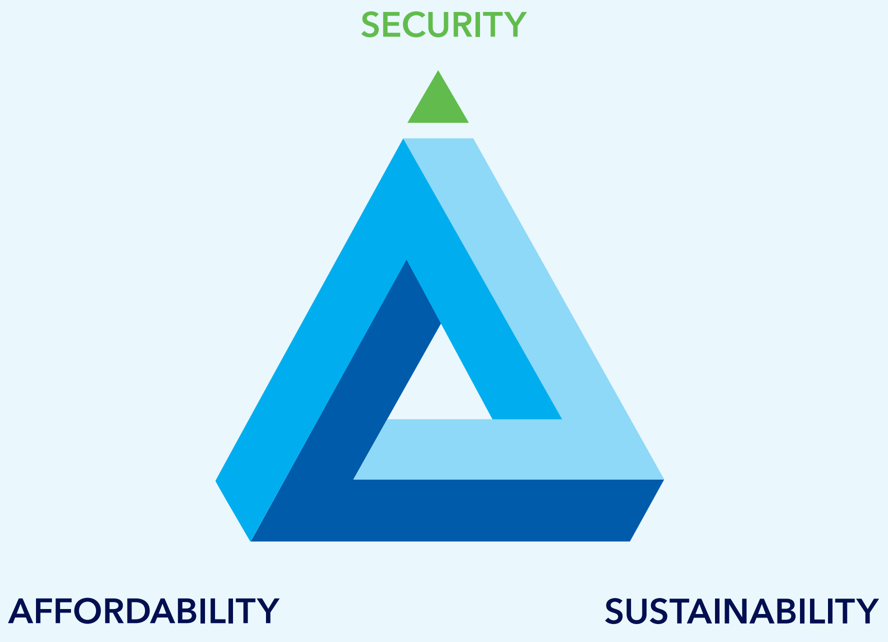
HIGHLIGHTS

Energy security is moving to the top of the agenda

- Geopolitical developments over the last 18 months have brought energy security into sharp focus with the disruption of energy supplies and price shocks for energy importers
- Worldwide, energy produced locally is being prioritized over energy imports

FIGURE 3

Energy trilemma



- This trend is favouring renewables and nuclear energy in all regions and coal in some regions
- We have now factored into our power sector forecast the willingness of governments to pay a premium of between 6% and 15% for locally-sourced energy
- Reshoring and friend-shoring policies are adding to supply chain complexities and costs already strained by inflation
- 2022 saw an increase in the levelized cost of renewables in several regions, particularly with wind projects, but we expect cost reductions to return to historic learning curve rates by 2028
- In the long term, energy security and sustainability will pull in the same direction, with decarbonizing energy mixes – with wind, solar, and batteries as the main sources – increasingly shielding national energy systems from the volatility of the international energy trade

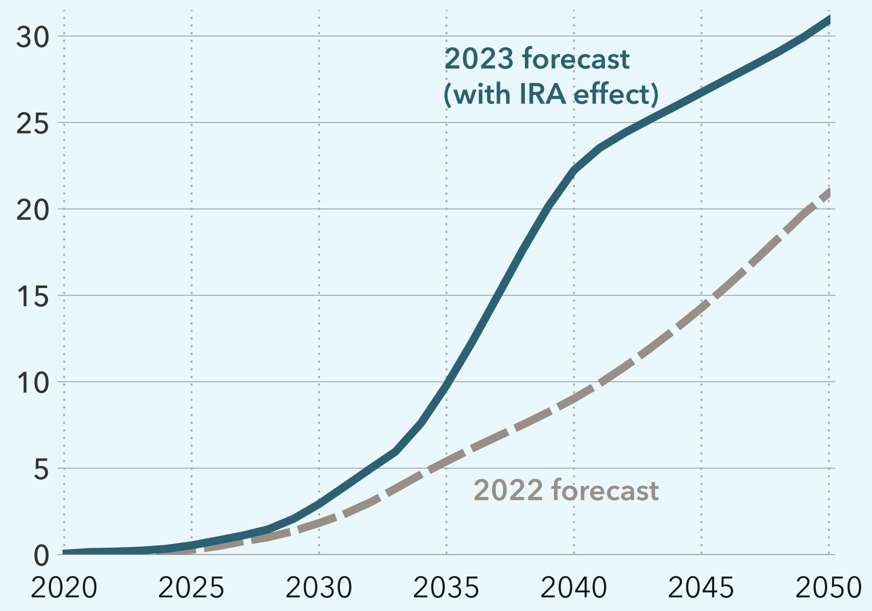
Progressive policy is making an impact

- Big decarbonization policy packages rolled out in the last year are supercharging the transition regionally and nudging it forward globally
- The *Inflation Reduction Act* is accelerating the transition in the US, with USD 240bn already committed in clean investments in response to the broad array of incentives under the Act

FIGURE 4

Hydrogen production in North America

Units: MtH_2/yr



- In the EU, the EU *Green Deal*, *REPowerEU*, and *Fit for 55* policy packages make Europe's net-zero goal more realistic
- Shipping is set for a faster transition due to the inclusion in EU's emission trading system and the IMO's ambitious new decarbonization strategy aiming for net zero by 2050
- The 'race to the top' in clean technology amongst the advanced economies will drive global learning benefits in e.g. hydrogen and carbon capture and storage technologies
- The scaling of clean tech in advanced economies will only partly benefit medium- and low-income regions where economic development and other SDGs are prioritized. De-risked financing is needed to accelerate the pace of the transition beyond leading regions

HIGHLIGHTS

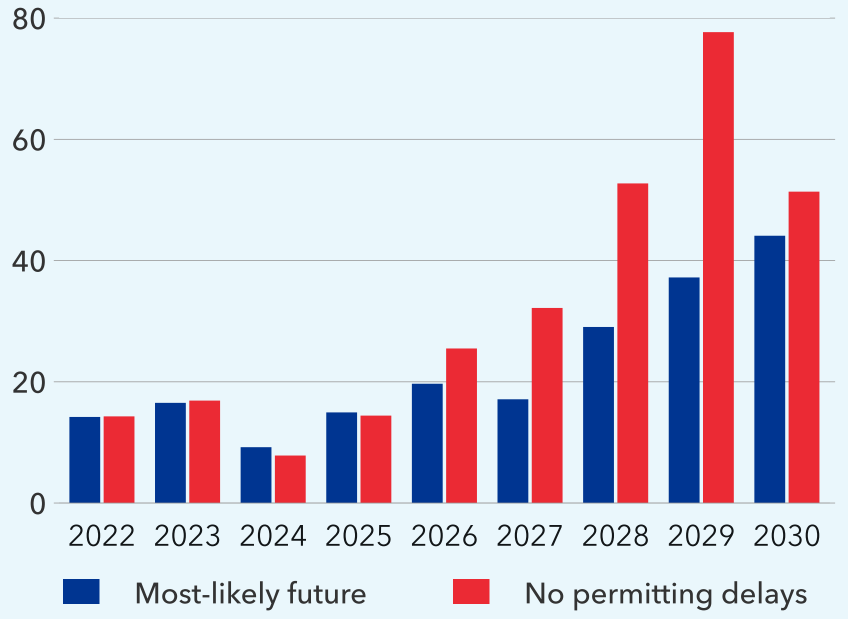
Gridlock impeding the near-term expansion of decarbonization technologies

– Despite inflationary and supply-chain headwinds, solar installations reached a record 250 GW in 2022. Wind power contributed 7% of global grid-connected electricity and installed capacity will double by 2030

FIGURE 5

Global offshore wind capacity additions with and without permitting delays

Units: GW/yr



– The 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. However, in the near term, transmission and distribution grid constraints are emerging as the key bottleneck for renewable electricity expansion and related distributed energy assets such as grid-connected storage and EV charging points in many regions, including the US, Canada, and Europe

– Our forecast factors in the impact of lagging grid capacity in the near- and medium-term on build-out rates of renewables

– Both the EU and the US are advancing policies to address permitting delays, but a deeper policy response is needed, which may encompass expropriation and financing to ease cable manufacturing production constraints

– Grid expansion is also important for the production of hydrogen, which in turn is dependent on more robust demand-side measure to incentivize offtake

Global emissions will fall, but not fast or far enough

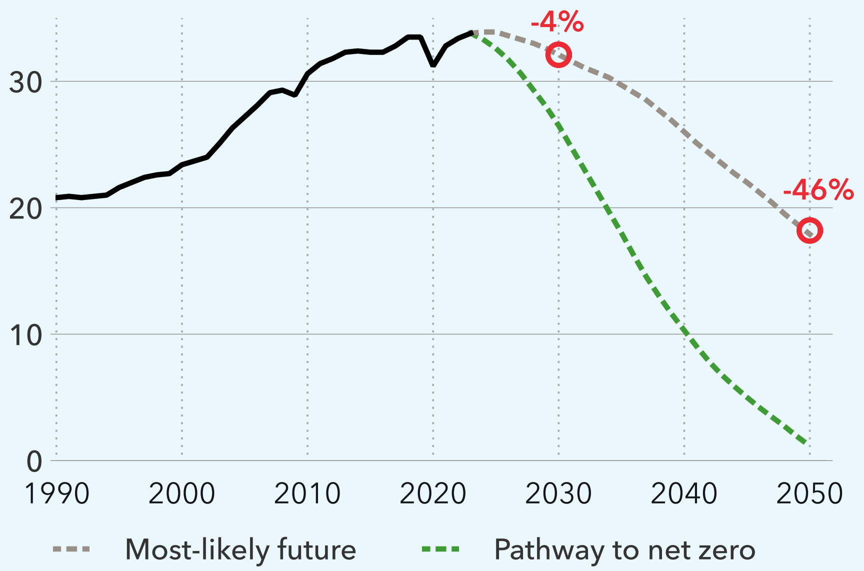
– We forecast global energy-related CO_2 emissions in 2050 to be 46% lower than today, and by 2030, emissions are only 4% lower than they are today

– The emissions we forecast are associated with 2.2°C of global warming above pre-industrial levels by the end of this century

FIGURE 6

World energy-related CO_2 emissions, after DAC

Units: $GtCO_2$/yr



– From 2024, the share of renewables in the primary energy mix will grow by more than one percentage-point per year, resulting in a 52% non-fossil share by 2050, up from 20% today

– The pace of the transition is far from fast enough for a net-zero energy system by 2050. That would require roughly halving global emissions by 2030, but our forecast suggests that ambition will not even be achieved by 2050

– Limiting global warming to 1.5°C is therefore less likely than ever

– While emissions rise, the consequences of climate change are becoming more visible and impactful, with extreme weather events becoming more frequent and damaging

ENERGY SECURITY AND A SHIFTING GEOPOLITICAL LANDSCAPE

Globalization – the free flow of ideas, people, goods, services, and capital – arguably started in earnest in the 19th Century once steamships ruled the waves (O'Rourke and Williamson, 2000). Since the end of World War II, spurred on by technological progress and the so-called 'long peace' in the post-war decades, the trend of moving things between nations has grown almost four-fold, as a measure of trade relative to global GDP (Aiyar et al., 2023). The end of the Cold War, the change in Chinese economic policy, and the creation of the World Trade Organization (WTO) in 1995, all boosted global trade, with medium-income countries and regions like China, South East Asia, and Latin America benefitting economically, with widespread gains in poverty reduction and improved livelihoods.

Against this backdrop, the world has now entered a period of slower expansion of cross-border cooperation and trade that started 15 years ago with the financial crisis. This is sometimes referred to as 'slowbalization'. During this period, trade measured as a fraction of GDP plateaued. We have also witnessed a more charged geopolitical landscape triggered by several significant events, such as the annexation of Crimea by the Russian Federation in 2014, the foreign policies pursued by President Trump, the COVID-19 pandemic, and the war in Ukraine.
Even though the annexation of Crimea in 2014 reinforced the US-Europe alliance, it also highlighted some areas of divergence within the alliance. Early warnings about the dependence of some European countries on Russian energy supplies went largely unheeded but were indeed prophetic.

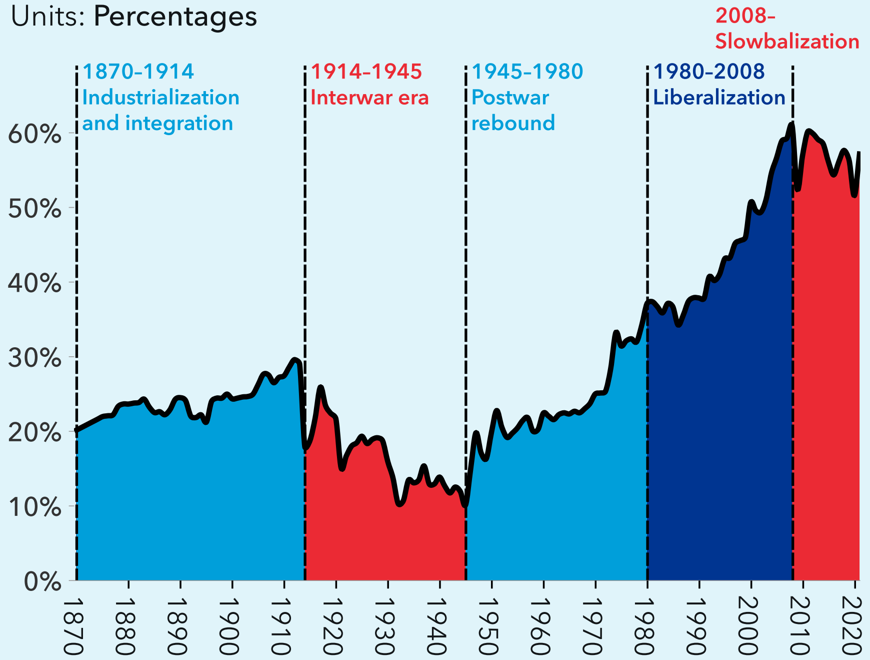
The COVID-19 pandemic revealed supply-chain vulnerabilities that decades of globalization had created. These included the pursuit of a 'better, cheaper, faster' mindset, an over-reliance on a relatively few manufacturing hubs, a lack of visibility into supply-chain dynamics, and inexperience in resilient sourcing from a diversity of suppliers. Initially, countries competed for access to medical supplies during the pandemic, but other shortages emerged rapidly due to shifts in demand, labour shortages, and other structural factors during the long months of lockdown. In the post-pandemic period there has been a rush to diversify supply chains, boost visibility through digitalization, and address vulnerabilities, not least cyber security. At the same time, governments have turned to policy incentives to launch or return production to their homelands (West, 2022).

Slowbalization: less international trade and more focus on national energy security, supply chains, and local manufacturing

The world economy has entered a 'slowbalization' phase dating back to the 2007-2008 financial crisis, characterized by a slowdown in the pace of international trade and weakening political support for open trade in a shifting geopolitical landscape. There is heightened focus on reshoring of production and, of relevance to our forecast, this often adds to the cost of energy CAPEX everywhere.

FIGURE 7

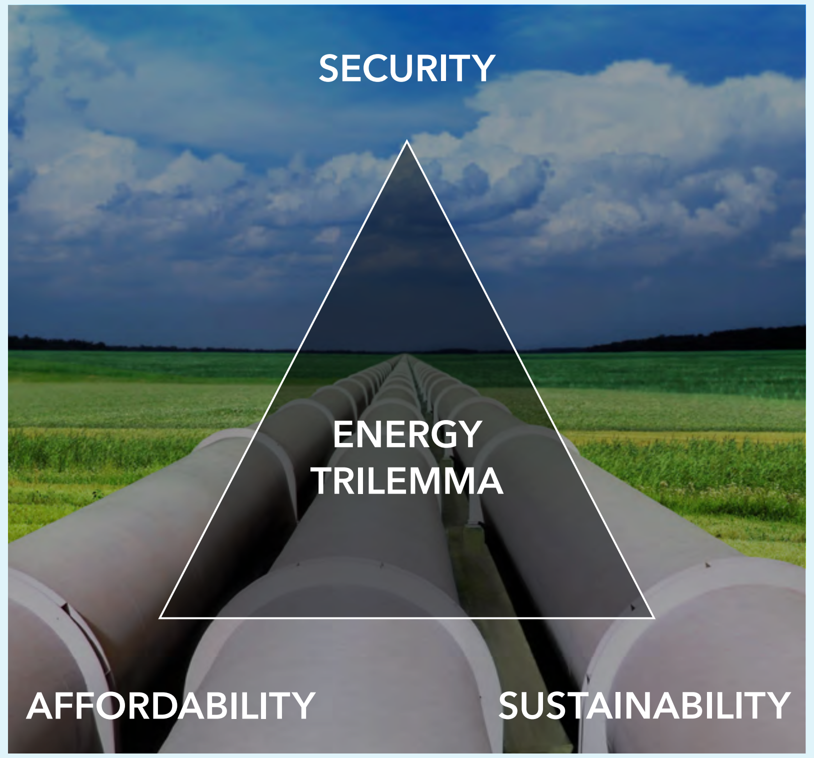
Trade openness index, 1870-2021



Adapted from PIIE (2022)

Energy trilemma

The energy trilemma describes the attempt to balance energy security, equity (accessible and affordable), and environmental sustainability. Since the signing of the *Paris Agreement* and the rapid advance of renewable energy, the quest to reduce emissions has been in the spotlight. However, energy security is now moving to centre stage due to the shifting geopolitical landscape and escalating tensions in some regions where control over energy is being used as a means to achieve political ends.



In particularly sensitive areas, for example microchip manufacturing, governments started drafting legislation to secure supply by boosting domestic R&D and production.

Anxiety over brittle supply chains was further increased after Russia's invasion of Ukraine in February 2022. The war instantly imperilled food security, both directly and through the curtailment of fertilizer supplies, and raised vulnerabilities in several supply chains. However, the principal impact of the war has been its disruption of global energy supply chains. Given that Russia is Europe's main supplier of natural gas (around 45% of imports in 2021), the war raised serious concerns about energy security in Europe. Fears of supply cuts as Europe looked for alternative gas supplies led to record increases in energy prices and global market imbalances and disruption. The situation prompted Europe to expedite its efforts towards energy diversification and green energy transition, focusing on renewable energy and energy efficiency measures.

This long chain of events, culminating in the energy supply shock of 2022, has embedded a shift in international relations and ushered in an era where energy security becomes the primary focus in the energy trilemma (see sidebar). Energy security concerns differ and diverge across regions. Energy importing regions will favour resources that are locally available or accessible from reliable partners; exporting countries will have to convince their partners that they are a trustworthy, long-term source of supply.

The effect on the energy transition

Enhancing security of supply is achievable through increasing domestic energy production, diversification of energy sources in the supply mix, or diversification geographically by using a variety of suppliers and transportation routes.

Energy security generally pulls in favour of renewable energy as the obvious, low cost, nationally-available resource. Nuclear energy is similarly favoured, but energy security can also slow the transition if countries turn to available fossil resources to address energy shortfalls.

Some of the emerging trends include:

A surge in energy prices resulting from Russia's invasion of Ukraine has certainly made renewable energy more competitive. However, it has also put economic pressure on many households and businesses, leading to energy poverty in some cases which has prevented or delayed investment in clean technology like electric vehicles (EVs) and heat pumps. At a national level, many low- and medium-income countries that were previously dependent on importing natural gas have had to switch to local energy resources, such as cheaper coal, in order to secure energy supply.

Investment in energy infrastructure, including energy storage and smart grid technology, is advancing the deployment of renewable energy. However, the tight market for fossil fuels and high prices for oil and gas has also led to a surge in oil projects that carry the risk of locking countries into a carbon-intensive energy system for years to come.

Increased supply-chain costs caused by disruptions in the production and delivery of intermediate goods, like steel and computer chips, have challenged global manufacturing supply chains and, combined with import tariffs, have created a new situation for global trade. Renewables projects, with tighter margins than many oil and gas projects, have been disproportionately affected by this chain of events, leading to a rise in cost of some renewable projects and attendant delays and, in some notable cases, failed auctions.

Nuclear is in vogue thanks to the changes in the geopolitical landscape and focus on energy security that have made nuclear energy a more attractive option for some countries, sending uranium prices to their highest level since the Fukushima accident. While we see concrete life-extension programmes, it is also likely that there will be a slightly broader uptake of nuclear energy. How big this will be depends on how nuclear manages to solve some of the same challenges it has faced before, such as cost overruns, safety concerns, waste handling, public opinion, and the proliferation risks associated with a potential higher uptake. General energy security concerns are, however, likely to accept the higher costs of nuclear, which leads to a slightly higher uptake.

A protectionist policy shift towards national energy policies that prioritize energy security, resilience, and independence could potentially speed up the energy transition, as countries invest more in locally available renewable energy sources. However, it also risks promoting protectionist policies that could hinder global cooperation on technology transfer, R&D, and action on climate change.

Societal responses to inflation and the cost-of-living crisis have stoked social unrest which could delay the energy transition as the focus shifts to short-term priorities. Conversely, it is possible that public sentiment could favour energy independence through renewables and nuclear and the acceptance of higher energy prices as strategic means to secure energy independence.

How we incorporate energy security and geopolitical trends into our forecast

In our view, the geopolitical changes and energy security described above have a direct impact on the energy transition and we have therefore taken initial steps to factor this into our forecast of the most likely energy future. Three key shifts have been considered, and we articulate each one separately with respect to their qualitative or quantitative impact on our forecasting model.

Energy security considerations in the power sector

We see nations/regions increasingly willing to support domestic energy resources to curb their dependence on uncertain energy imports and to hedge against the potential weaponization of energy. In some cases, energy resources which are predominantly imported are being penalized or deprioritized, even if short-term economics favour those sources. The prioritization of energy resources depends on the availability of different energy resources within a country's borders and on technological know-how and availability of a qualified workforce.

This behaviour is most pronounced in the power sector, and we have therefore made direct changes in our power sector modelling to reflect energy security considerations. These changes include the prioritization of both low-carbon and fossil-based energy resources. For example, regions such as Europe will prioritize nuclear and renewables, while the Indian Subcontinent will prioritize domestically available coal.

Inputs to the ETO modelling:

We have revised the regional policy support of different electricity generators in our ETO model to reflect support levels directly observed for the year 2022. These support levels are then projected forward to reflect an ongoing attention to energy security considerations ranging between 6% to 15% globally between 2023 and 2050 for all power generation sources. The support levels vary temporally and regionally, as stated above, with some regions favouring non-fossil sources and others fossil sources. We acknowledge the difficulties of disaggregating energy security-based support from, for example, decarbonization support. Adjustments to our model in this regard will therefore be subject to ongoing research.

Impacts on the forecast results:
To assess the impact of these new energy security factors, compared last year's forecast (which did not factor in energy security directly) with what we consider the most likely future this year.

On a global aggregated scale, the difference in primary energy demand is about 5%. However, that is attributable mostly to the revised and higher population forecast from WIC (2023). Overall, the change in the global shares of natural gas, coal, renewables, and nuclear are minimal in 2050. The effects of energy security considerations are more pronounced at a regional and power generator level. While the share of nuclear in global primary energy consumption increases from 5% to 6% in 2050, between the two forecasts, Europe's nuclear electricity generation in 2050 increases from 647 TWh/yr to 724 TWh/yr, a 12% increase. In Greater China, both coal and nuclear increase by 19% and 41%, respectively, from last year's forecast to this year's while there is less biomass and wind deployed. In 2050, the Indian Subcontinent has almost 500 TWh/yr more coal electricity in our most likely future than last year's forecast.

Reshoring energy technology manufacturing infrastructure
The second energy security shift we have considered is securing access to critical energy infrastructure within the regional energy system and the resulting short-term increase in cost of the energy infrastructure/technology. An example is building alternative local/national supply-chains (e.g. for solar panels) to diversify and control a region's own supply chains and domestic manufacturing to reduce dependence on supplies from one region.

Input to the ETO modelling:
We have considered the impact of reshoring energy technology manufacturing infrastructure as a short-term cost increase of 10% on the capacity costs of wind (both onshore and offshore), solar, and Li-ion batteries in Europe only. The cost increase gradually rises from 2023 and reaches a maximum of 10% in the year 2028 before returning to zero cost-increase by 2033.

We only consider this impact as a cost for reshoring for Europe because, given the existing region-differentiated technology costs that we input to the model for the above-mentioned energy technologies, it is uncertain whether these cost increases will manifest for other regions, such as North America, whose higher-than-global-average costs (based on pre-existing market factors) already reflect some of the reshoring costs.

Impacts on the forecast results:
The cost increase on wind, solar, and Li-ion batteries in Europe does not have a significant impact on Europe's or the world's energy transition. In the coming years we may, on the basis of new observations, consider such cost increases on rest of the world as well.

Regional restructuring of the global economy
There is an accelerating shift in sourcing and global manufacturing patterns to reduce dependence on a single manufacturing hub and boost supply chain resilience (The Economist, 2023). For example, we are likely to see some production moving out of China to other neighbouring countries in South East Asia and the Indian Subcontinent; in other instances, domestic manufacturing strategies are pursued, combined with strategic trade partners; other upstream initiatives are aimed at securing access to raw material sources. All of this is reflected in moderately changing manufacturing volume effects in our model, where the manufacturing sector output is reduced in some regions and diverted to others. The impact on global manufacturing energy demand of volume shifts is minimal, as the carbon intensity of the regional manufacturing subsectors does not differ markedly and the diverted volumes relative to total manufacturing is small. The impact in individual regions is low to moderate depending on the size of existing manufacturing sector volumes.

Conclusion
Securing access to energy has been a perennial and dramatic feature of the energy landscape since the 19th Century. Oil has been instrumental in shaping the geopolitics of the 20th Century, not least by fuelling conflicts and profoundly shaping the course of major wars. Going forward, we expect a future with a far wider mix of energy sources and for energy efficiency to play an outsized role owing to widespread electrification. Daniel Yergin recently characterized this shift, it is one involving a move "from a world of big oil to a world of big shovels" (Yergin, 2020). This characterization aligns with several studies documenting that the energy transition is mineral- and metal-intensive (World Bank, 2020; IRENA, 2023a).

The major shift we forecast is a transition from a world where energy is extracted in a handful of nations and traded over long distances to the rest of the world, to a situation where energy is produced locally, largely by renewables, and consumed locally in the form of electricity. Our forecast is that electrification will more than double over the next 30 years. This trend has intensified in recent years owing to energy security concerns which militate against dependence on energy through transcontinental pipelines and trans-ocean shipment. That, in turn, has prompted us to directly factor in 'energy security' as a driver of change in the coming energy future.

> We expect a future with a far wider mix of energy sources and for energy efficiency to play an central role owing to widespread electrification.

INTRODUCTION

About this Outlook

This annual *Energy Transition Outlook* (ETO), now in its 7th edition, presents the results from our independent model of the world's energy system. It covers the period through to 2050 and forecasts the energy transition globally and in 10 world regions. Our forecast data may be accessed at eto.dnv.com/data.

More details on our methodology and model can be found on page 200. The changes we forecast hold significant risks and opportunities across many industries. Some of these are detailed in our supplements:

– *Maritime forecast to 2050*
– *Transport in transition to 2050*

All ETO reports are freely available on www.dnv.com. In addition, we draw our readers' attention to ongoing insights into the energy industry published by DNV, which include our most recent Insight report, *Closing the energy storage gap.*

Our approach

DNV presents a single 'best estimate' forecast of the energy future, with sensitivities considered in relation to our main conclusions. However, we also publish our 'Pathway to Net Zero Emissions' scenario (to be launched ahead of COP 28), which is effectively a 'backcast' of what we consider to be a feasible, albeit challenging, pathway for the world to achieve net-zero emissions by 2050 to secure a 1.5°C warming future. We believe readers will find it useful to explore the dimensions of the gap between our 'best estimate future' and our net-zero pathway scenario.

Foundational aspects of our approach are illustrated below. These include the fact that we focus on long-term dynamics, not short-term imbalances. However, given the rising impact of energy security concerns, we describe how this impacts our forecast in the opening pages on this report.

The most significant updates to our model since the release of our 2022 ETO are listed on page 202. They include, for example, updated GDP and population numbers, revised wind cost and technology parameters, revised carbon prices, a detailed new bioenergy sector model, and the incorporation of new policy developments, most notably the effects of the US *Inflation Reduction Act.*

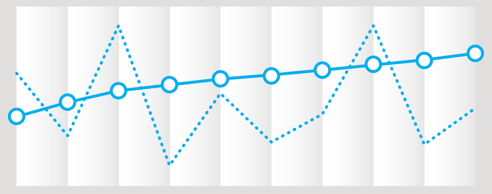
Independent view

DNV was founded 159 years ago to safeguard life, property, and the environment. We are owned by a foundation and are trusted by a wide range of customers to advance the safety and sustainability of their businesses.

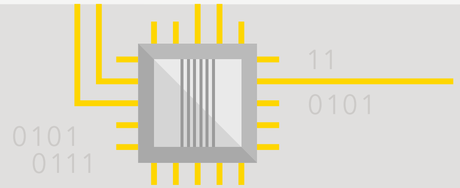
70% of our business is related to the production, generation, transmission, and transport of energy. Developing an independent understanding of, and forecasting, the energy transition is of strategic importance to both us and our customers. This Outlook draws on the expertise of over 100 professionals in DNV. In addition, we are very grateful for the assistance provided by a number of external experts and dialogue with other companies researching the energy transition. All contributors are listed on the last page of this report.

Our **best estimate**, not the future we want

A single forecast, not scenarios



Long-term dynamics, not short-term imbalances



Continued development of proven **technology**, not uncertain breakthroughs

Main **policy** trends included; caution on untested commitments, e.g. NDCs, etc.

Behavioural changes: some assumptions made, e.g. linked to a changing environment

CONTENTS

1 ENERGY DEMAND

Highlights

We quantify and forecast the energy demand for the major demand sectors: transport, manufacturing, and buildings.

We explore deep shifts in the energy carriers serving these sectors. This includes both direct electrification (e.g. in the case of EVs), and indirect electrification via hydrogen and its derivatives (e.g. in aviation. shipping, and manufacturing heat).

The chapter concludes with a consideration of the global shifts in final energy demand, which peaks towards the end of our forecast period and actually reduces slightly by 2050. In our discussion on energy efficiency, we analyse how this occurs despite the continued growth in demand for useful energy (i.e. energy services)

1 ENERGY DEMAND

This chapter details our forecast for the four sectors responsible for almost all energy demand: transport, buildings, manufacturing, and feedstock. In each sector, there has traditionally been a strong correlation between economic activity and final energy demand. In the coming three decades, this relationship will change: demand for *useful energy* will continue to rise but electrification and energy efficiencies will see a levelling off in final energy demand.

An all-electric refuse truck.
Image: courtesy Volvo Trucks

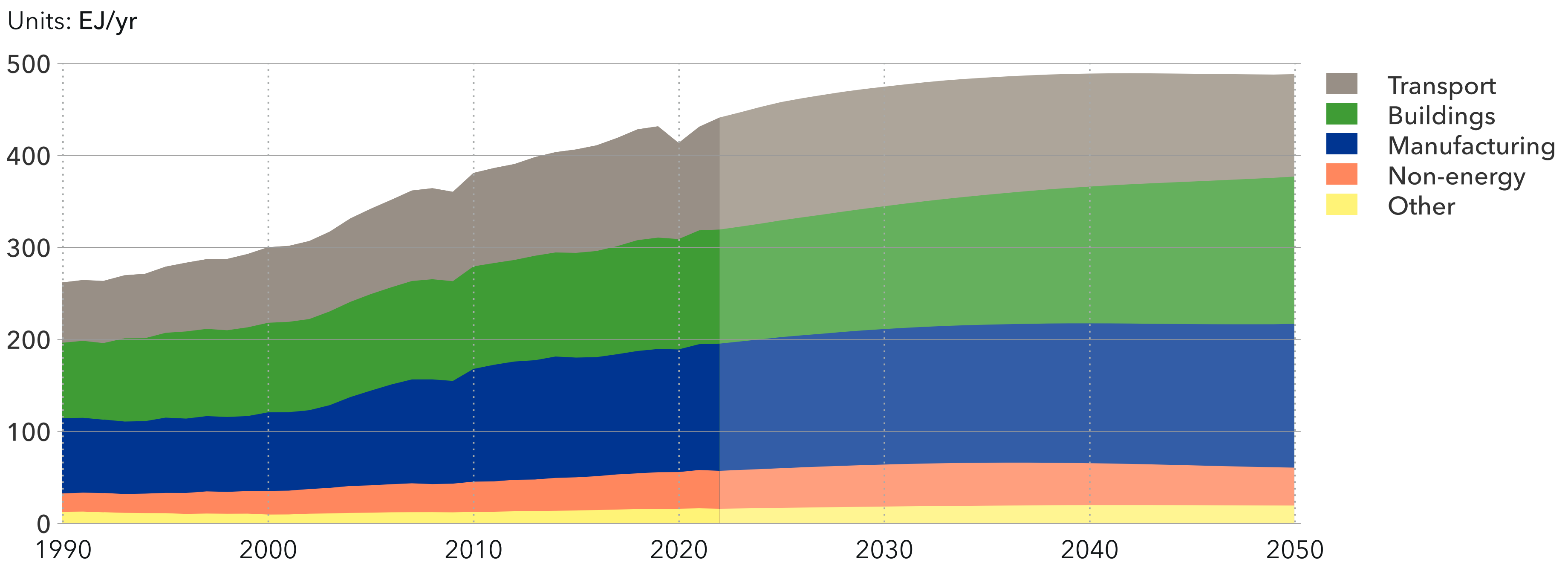
By 2050, we expect the global population to increase by about 20% to some 9.6 billion people and the global economy to almost double to USD 320trn, with an average growth rate of 2.4% from 2022 to 2050. Further details on population and economic growth are included in the Appendix A.1 of this Outlook.

The total amount of energy services required globally – measured in goods produced, km of transport, or square metre heated – will roughly double across the globe, but energy demand will not. Instead of doubling, energy demand will grow only 10% from 441 EJ to 489 EJ between now and 2050, as illustrated in Figure 1.1. Moreover, in the decade before 2050, final energy demand is virtually flat, effectively levelling off at 2040 levels. That is because massive efficiency gains, particularly those enabled by electrification, will almost offset the population and economic growth propelling demand for energy services, see Section 1.5 of this chapter.

It is not a given that energy demand will remain flat after 2050. Once most energy services are converted to electricity, which automatically improves energy efficiency in most sectors, energy demand may start to increase again. This could be countered by an eventual decline in the global population.

FIGURE 1.1

World final energy demand by sector



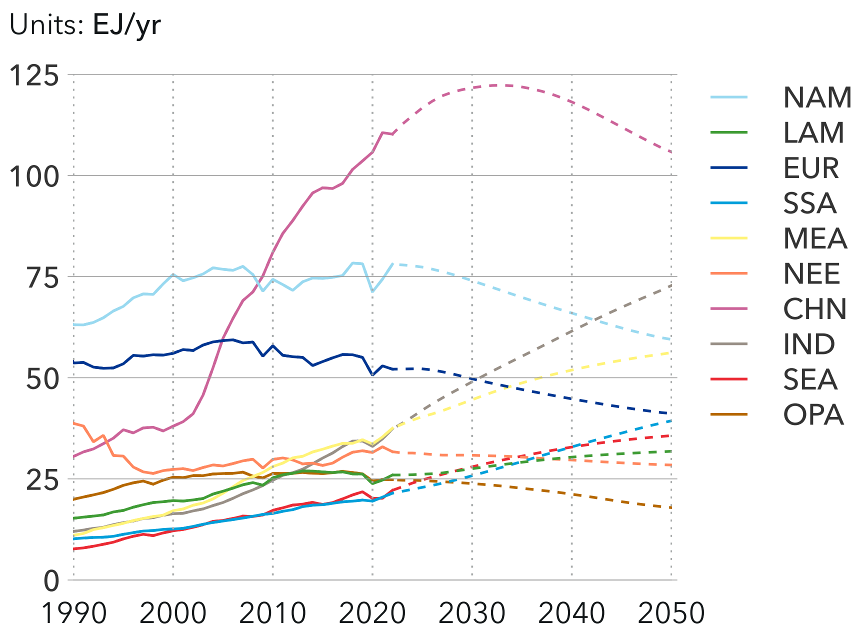
Historical data source: IEA WEB (2023)

'Final energy' in this Outlook and as shown in Figure 1.1 means the energy delivered to end-use sectors, excluding losses (for example, heat losses in thermal power plants) and excluding the energy sector's own use of energy in power stations, oil and gas fields, refineries, pipelines, and similar infrastructure. In terms of the main demand sectors the key developments include the following:

Buildings energy use for space cooling will more than triple, while space heating demand will decline somewhat due to new technologies like heat pumps reducing energy needs. Overall energy demand will increase 29% to 2050, at that time representing 33% of global energy demand, overtaking manufacturing as the biggest demand sector.

FIGURE 1.2

Final energy demand by region



Historical data source: IEA WEB (2023)

Manufacturing energy use will maintain its share of global energy use just above 30% in the entire forecast period, with absolute energy use increasing 13% to 156 EJ in 2050. Substantial efficiency gains and increased recycling moderate the increase. The feedstock sector will see energy demand grow by 11% and peak in the mid-2030s, before returning to present levels.

Road transport sector will see the strongest shift to electricity and therefore also the strongest efficiency gains, and while aviation and maritime cannot electrify similarly, global transportation energy demand peaks around 2030 and thereafter reduces to a level 9% lower than today in 2050, at that time representing 23% of global energy use.

Although global final energy demand will level off, this is not the case for all regions. In Europe and OECD Pacific, energy demand has already peaked, while in many of the middle- and low-income regions, energy demand will continue to increase through to 2050, as illustrated in Figure 1.2. Greater China's share of global energy demand is at 25%, but will decline to about 22% in 2050, while the Indian Subcontinent will overtake North America as the second largest energy consuming region in the 2040s.

Energy demand by carrier is summarized in Section 1.6. It is in carrier form that the story of the energy transition is most apparent, with a shift away from fossil fuels toward renewables and electricity.

A world using more energy, but demanding less of it!

As the world population grows and economy expands there is no escaping the fact that humanity will use progressively more energy services. Why do we therefore forecast an energy future where energy demand grows at a rate well below economic growth, and in fact levels off in the 2040s? The answer lies in the difference between 'useful energy' and 'final energy'.

Useful energy: is the energy output that serves a specific purpose, such as heating a stove, propelling a vehicle, lighting a room, or running a machine. In our forecast useful energy grows by 90% between now and 2050.

Final energy: is the total amount of energy required to meet various needs and, crucially, it includes both useful and *wasted* energy. Final energy demand refers to the energy delivered to end-use sectors (e.g. transportation, buildings, or manufacturing). In our forecast, global final energy demand grows by just 10% before flattening after 2040.

The difference between useful energy and final energy is clearly illustrated in the case of an internal combustion engine vehicle (ICEV), which is typically only 25% to 35% efficient – meaning that much of the chemical energy in the form of diesel or gasoline (the 'final energy demand') is wasted as heat, incomplete combustion, and friction before it provides the useful work of propelling the vehicle (useful energy). As ICEVs are replaced by EVs, enormous energy losses will be eliminated.

For a fuller discussion of the role of energy efficiency in the energy transition, see Section 1.5 of this chapter.

1.1 TRANSPORT

Transportation across the world is poised for both growth and deep transition. Between now and 2050, there will be a near-doubling in the size of the vehicle fleet; passenger flights will grow 140% above pre-pandemic levels; cargo tonne-miles at sea will expand by 40%; and rail energy demand will almost double while passenger numbers more than double. In 2022, all these transport activities consumed 121 EJ. Yet, in the much busier world of 2050 with more goods and people transported than ever, transport activities will in fact consume 9% less energy than at present, or 111 EJ. That will mainly be a consequence of the enormous efficiencies introduced through the electrification of road transport. A steady switch to zero-emission propulsion with biofuels and hydrogen and its derivatives in large parts of aviation and maritime will also contribute to total transport-related emissions falling 44%.

Current developments in global transport

Ultimately, reducing carbon emissions in transportation boils down to the fuel challenge. Emissions from transportation are spread across a vast network of more than a billion road vehicles, airplanes, and ships, and these emissions cannot be effectively captured. In addition to from carbon dioxide (CO_2), these emissions often consist of potent greenhouse gases (GHGs) and harmful particulate matter that can negatively impact both the environment and human health.

The pandemic led to decreased energy demand in all transport subsectors – air, road, rail, and sea. In 2020, total demand across these sectors dropped by 11%. Aviation saw the most significant decline, nearly halving from 2019 to 2020, and is projected to remain below pre-pandemic levels due to reduced business travel. Meanwhile, maritime energy demand fell by 4%, rail by 5%, and road by 7%. Post-pandemic, all these sectors have now come roaring back to life.

In 2022, global transport-related CO_2 emissions rose by over 600 million metric tonnes to reach about 8 billion metric tonnes, marking a 7.5% increase from 2021, but still marginally below 2019 levels. The growth was largely driven by aviation, which rebounded to about 70% of 2019 levels after pandemic-related lows. However, the increase in emissions was partially offset by the continued rise of EVs, with over 10 million EVs sold globally in 2022.

In 2022, the transportation sector accounted for 26% of the overall global energy consumption, predominantly sourced from fossil fuels. As shown in Figure 1.3, oil constitutes a significant 88% of the energy used in transportation, while natural gas and biofuels contribute 6% and 4% respectively, with electricity accounting for 1%. Currently, the energy mixes for aviation, maritime, and road transportation closely resemble that of the global transport sector, while rail predominantly relies on electricity for its energy source.

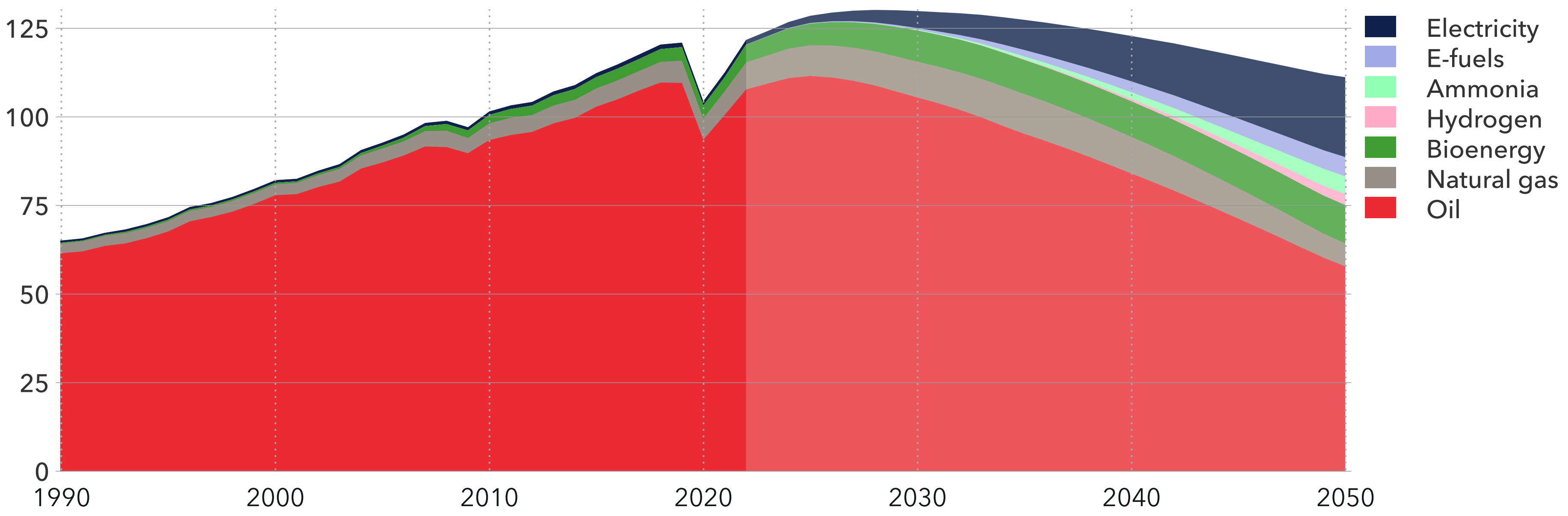
To combat local air pollution and global emissions, the integration of natural gas and biofuels, both in their pure forms and as blends with gasoline and diesel, was initiated several decades ago. While China abandoned its biofuel blending policy (2019) and the Middle East and North Africa, North East Eurasia, and Sub-Saharan Africa have no prominent biofuel requirements, other regions have either mandates for biofuel blends or provide preferential treatment to biofuels. Anticipating the continuation of emission-targeted policies and prohibitions, we expect these efforts to persist for another decade, with robust backing from both industry and consumers.

Over time, technological advancements and cost learning will render policies boosting biofuels and electrification unnecessary, particularly in road transport (responsible for 75% of energy usage in transportation) where EVs uptake is now growing exponentially. We caution, however, that prematurely withdrawing support for EVs, particularly for median and below-median income consumers, could reverse their adoption trend (Sheldon et al., 2023).

FIGURE 1.3

World transport sector energy demand by carrier

Units: EJ/yr



Historical data source: IEA WEB (2023)

Road

Fleet development

A more populous and prosperous world will see the world's vehicle fleet (passenger, commercial, and two- and three-wheelers) expand from 2.4 billion to 3.5 billion vehicles from 2022 to 2050. From 2035, this fleet size will start plateauing owing to the effects of automation and saturation. Vehicle-sharing will also increase and will generally mean that the distance driven per vehicles will be higher, implying that a levelling off of the fleet size does not necessarily impact mobility.

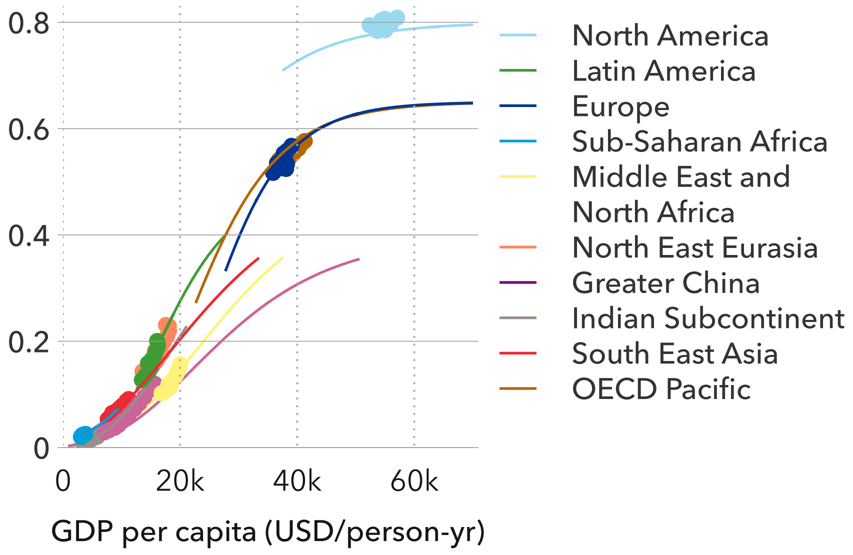
GDP per capita is a driving force behind vehicle density (number of vehicles per person). This link is influenced by various factors like geography, culture, technology, infrastructure, environment, and the presence of alternative transportation options. To forecast future vehicle density trends, we have utilized historical data fitted to a Gompertz curve (a type of S-shaped curve), shown in Figure 1.4. In some cases, expert opinions supplement this, allowing adjustments for the impact of policies promoting alternatives to road transport.

We divide the road transport sector into three categories: passenger vehicles, commercial vehicles, and two- and three-wheelers. 'Passenger vehicles' encompass those with three to eight passenger seats, including most taxis but excluding buses.

FIGURE 1.4

Road vehicle density by region

Units: Vehicles per person



Points show historical data from 2005 to 2015 (OICA, 2016). Lines show model estimates from 1980 to 2050. Excludes two- and three-wheelers

'Commercial vehicles' comprise other non-passenger vehicles with at least four wheels and are particularly prominent in less-developed nations. However, as these countries experience economic growth, the share of passenger vehicles in the fleet tends to rise. This trend is expected to stabilize in the near future.

Taxis currently constitute a substantial proportion of the global passenger-vehicle fleet. However, forthcoming structural shifts will change the overall size of the car fleet and, crucially, the total vehicle distance travelled. Communal use of passenger vehicles is more common in regions with lower incomes. Due to the efficiency and cost advantages offered by platform-based ridesharing services, this sector is poised for further expansion. This trend will likely lead to decreased private vehicle ownership, particularly in wealthier areas. Additionally, our projections account for the rising – but significantly delayed – presence of automated vehicles and the increasing fraction of shared vehicles. Automated and shared vehicles will drive between 20% and 90% more kilometres than a privately owned car, depending on region.

The increased utilization of digitally-enabled transport options (automation and ridesharing) might come at the expense of conventional public transportation, walking, and cycling. However, these shifts in modes of transport have not been thoroughly examined. Given the expected interplay of various factors, not least vehicle numbers and distances travelled, we anticipate that the overall distance travelled by vehicles will not be significantly impacted by automation or ridesharing.

The rise of EVs

EV adoption is taking off. Typically, individuals opting for an EV will make their choice by weighing up costs and benefits. Our approach entails simulated buyers choosing between increasingly affordable battery EVs (BEVs) with longer ranges over time, fuel-cell electric vehicles (FCEVs), and internal combustion engine vehicles (ICEVs) across three categories: passenger vehicles, commercial vehicles, and two- and three-wheelers. For passenger vehicle buyers, purchase price takes precedence, while operating costs hold more sway for commercial vehicle owners.

A notable hindrance to EV adoption in most regions is the scarcity of charging stations within reasonable reach, be it during travel or at destinations like home or work. Achieving substantial EV adoption hinges on both boosting the average fleet range and enhancing charging station availability. We project that the current battery cost-learning rate of 19% per doubling of cumulative capacity will persist throughout the forecast period. As a result, vehicle prices will decrease in the long term, despite a near-term rise attributed to material shortages and supply-chain challenges. Heightened competition among EV manufacturers, as recently observed in the world's biggest car market China, will help alleviate these price increases.

In Europe, the average battery size is anticipated to increase from the current 60 kWh/vehicle to around 90 kWh/vehicle in a decade. This expansion will extend vehicle ranges, rendering EVs even more appealing. Battery sizes will vary elsewhere, influenced by regional commuting patterns and corresponding range requirements.

Economics of EVs

Total cost of ownership (TCO) serves as a pivotal factor in purchase decisions, reflecting the influence of public policy support. Material scarcity and supply-chain limitations, including localization challenges, will initially exert upward pressure on vehicle expenses but are expected to ease over time due to competitive dynamics and innovative approaches. Beyond 2030, the decline in operational costs will lead to longer driving distances, consequently elevating the TCO per vehicle. Current TCO-influencing policies encompass buyer incentives for passenger EVs, varying from no incentives in low-income nations to several hundred USD in certain countries and exceeding several thousand USD in OECD regions, notably including the US under the *Inflation Reduction Act* (IRA). Both passenger and commercial vehicles benefit from these subsidies, which encompass substantial support for vehicle and battery manufacturers.

China and Norway, the leading nations in EV adoption rates (commercial vehicles in China and passenger vehicles in Norway), adopt a combination of EV preferential treatment and indirect subsidies for buyers. Meanwhile, in Europe, existing policies promote EVs by granting carmakers advantages for zero-emissions vehicles while imposing additional charges on fleets that surpass the set target (EC, 2019).

Commercial vehicles need larger batteries, and we anticipate more substantial and extended subsidies per vehicle. We expect continued willingness to provide such support in OECD regions and Greater China, enhancing the appeal of commercial EVs through the TCO effect by making ICEs less attractive via higher carbon pricing.

Beyond direct purchase and manufacturing subsidies, most regions employ various favourable operational incentives for EVs. These include privileges like bus lane access, free parking, and reduced or eliminated registration fees and road taxes. Road taxes are widespread globally and often feature an explicit carbon tax component in OECD nations (OECD, 2019). We anticipate a rise in tax and carbon price levels to reflect local air quality improvement efforts and initiatives aimed at curbing congestion and greenhouse gas emissions.

Assessing buyer preferences

When assessing the comparative benefits of BEVs, FCEVs, and ICEVs, we consider four significant factors, each with varying importance:

- Speed of recharging/refuelling
- Availability of charging/fuelling stations within reach
- Convenience of EV use
- EV's advantage in terms of ecological footprint

The ecological footprint advantage reflects the value attributed to using low-emission electricity or low-emission hydrogen as fuel and the associated environmental benefits. Notably, even EVs powered by electricity derived from a high-fossil energy mix exhibit better overall carbon efficiency throughout their lifetimes compared with equivalent-sized ICEVs (ICCT, 2018).

EVs will be 50% of new vehicles sales globally by 2031.

When contrasting the utility of EVs, FCEVs, and ICEVs across these four factors, the adoption of commercial EVs is markedly slower than that of passenger vehicles, despite the prolongation of subsidies.

As outlined in Figure 1.5, our projection indicates that EVs will comprise 50% of the new passenger vehicle market share in Greater China and Europe by the late 2020s, in the early 2030s in OECD Pacific and North America, and globally by 2031. This milestone remains a cornerstone of our forecast, largely unchanged over the past five years.

In lower income regions, adoption will take longer due to limited charging infrastructure and fewer subsidies. Nevertheless, even in areas with slower initial uptake, the 50% threshold will be reached by mid-century. By 2050, ICEVs will scarcely be sold in Greater China and Europe, while other regions, notably North East Eurasia, will still see ICEVs accounting for around 30% of new passenger vehicle sales.

We forecast FCEVs to enter the road transport landscape in visible amounts after 2030. In Greater China, they will represent up to 12% of the commercial EV fleet by 2050, with minor single-digit shares in Europe, OECD Pacific, and North America where hydrogen adoption is bolstered by respective policies. While FCEVs hold a cost and energy-efficiency disadvantage compared with BEVs, they are likely to find traction primarily in heavy, long-distance commercial vehicle transport. However, even within this domain, a notable portion will be claimed by battery-electric trucks, sharing the market for non-fossil fuel transportation alongside FCEV trucks. Commercial trucking may also continue to incorporate combustion technologies, allowing for biofuel utilization.

Policy backing is crucial for hydrogen integration in demand sectors. Although some countries like Japan and South Korea strongly advocate for FCEV adoption in their automotive emission reduction strategies, substantial obstacles persist in the widespread adoption of hydrogen in road transport. The conversion of power to hydrogen incurs significant energy losses, and additional efficiency reductions occur when hydrogen is converted back to electricity within the vehicle. Consequently, FCEVs can achieve an overall well-to-wheel efficiency of only 25% to 35%, significantly lower than the 70% to 90% range achieved by BEVs. Moreover, FCEV propulsion is more intricate and therefore more costly than that of BEVs. As a result, almost all vehicle manufacturers are leaning towards introducing exclusively BEV models.

Two- and three-wheelers represent a category of transport with minimal energy consumption in most regions, except for Greater China, the Indian Sub-continent, and South East Asia. Therefore, our vehicle demand and electrification modelling for two- and three-wheelers is confined to these three regions, exclusively encompassing registered vehicles (electric bicycles are categorized as household appliances rather than road vehicles). We project swift electrification within this segment; already, more than a third of all two- and three-wheeler sales in China are BEVs.

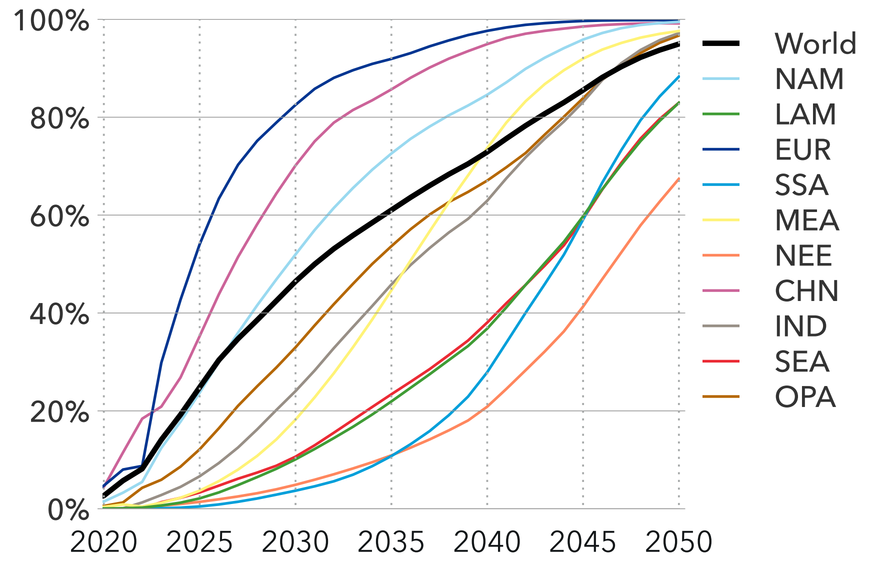
The electrification of commercial vehicles will take place at a slower pace than for passenger vehicles.

The world is divided into front-runner regions and slower adopters concerning the uptake of commercial BEVs. Greater China is poised to achieve a 50% sales share for commercial BEVs within roughly five years, followed by Europe two years later. In contrast, North East Eurasia is not expected to reach a 50% sales share for BEVs within our projected timeframe, as shown in Figure 1.6. Commercial FCEVs will play a role for heavy-duty long-haul trucking, although electric solutions are eating into this category at a faster rate than we had previously forecast.

FIGURE 1.5

Market share of electric passenger vehicle new sales

Units: Percentages

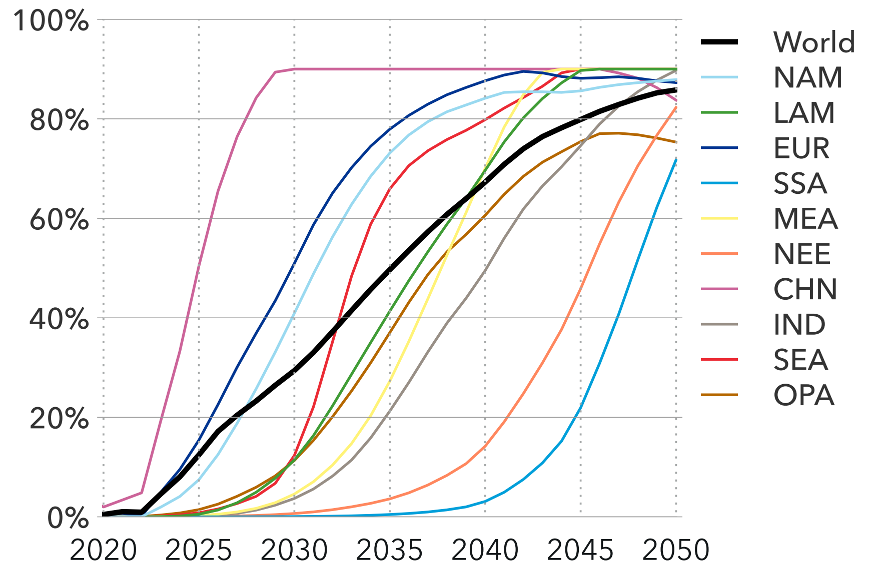


Electric vehicles include BEVs and FCEVs.
Historical data source: Marklines (2022), IEA EV Outlook (2023), EV Volumes (2022)

FIGURE 1.6

Market share of electric commercial vehicle new sales

Units: Percentages



Electric vehicles include BEVs and FCEVs.
Historical data source: Marklines (2022), IEA EV Outlook (2023), EV Volumes (2022)

The 2- and 3-wheelers are electrifying rapidly and more than a third of sales in this vehicle category are already electric in China.

Photo by Dennis Schroeder, NREL 48742

A transformation of the global vehicle fleet

Figure 1.7 depicts our projection for the vehicle fleet development, encompassing two- and three-wheelers, considering the impact of both increased ridesharing and automation. The current passenger vehicle fleet of 1.2 billion is estimated to grow to slightly below 2 billion by 2050, while the share of ICEVs dramatically declines from 97% to below 40% by mid-century. The conversion to electric power will encompass nearly the entire fleet of two- and three-wheelers by 2040, although the adoption of EVs in commercial vehicles lags behind advancements in the other two categories.

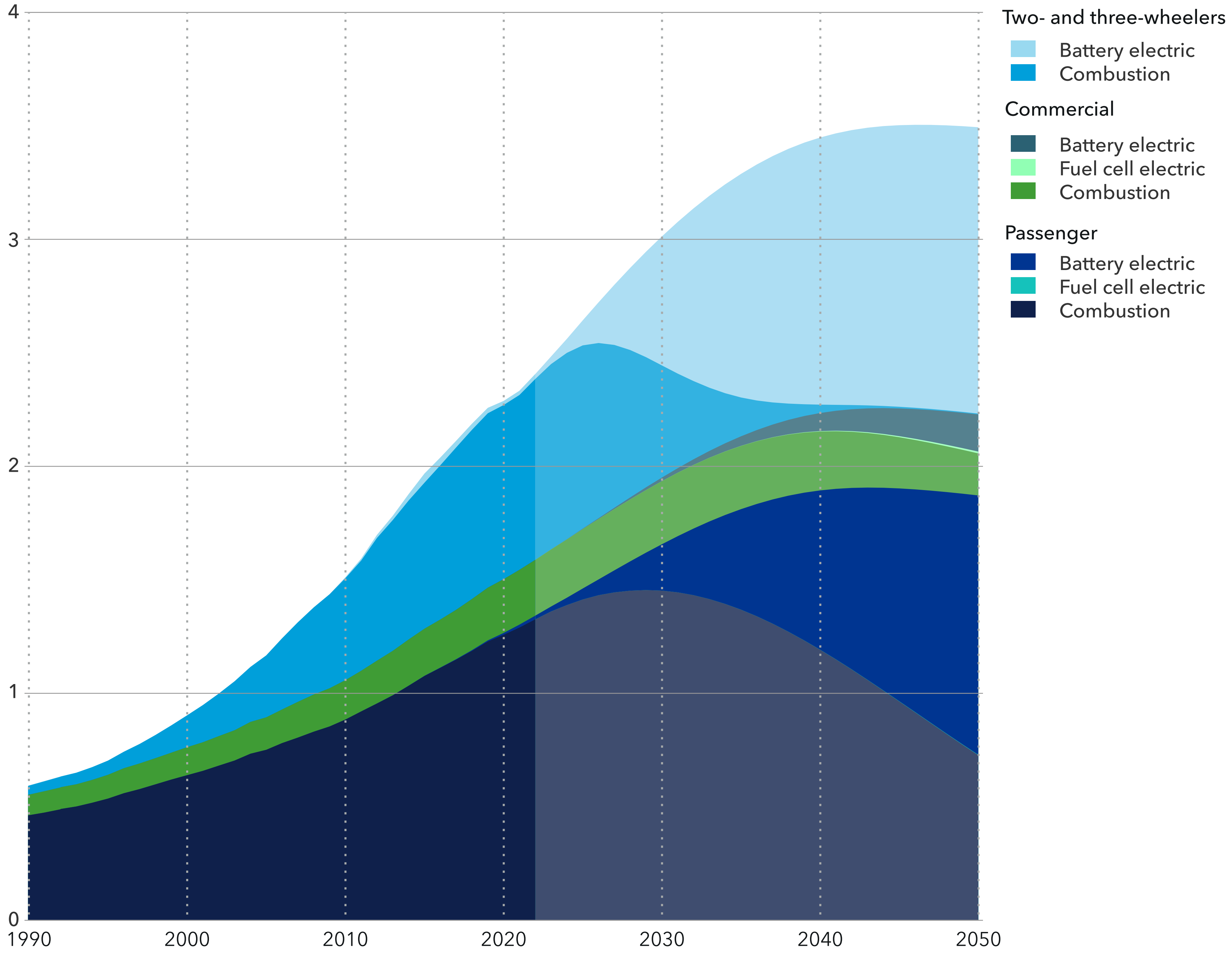
Even though EVs are predicted to constitute almost three-quarters (72%) of the global vehicle fleet by 2050, they will only contribute around 30% of the energy demand within the road subsector, while hydrogen FCEVs will contribute an additional 5%. The smaller segment of the vehicle fleet still reliant on fossil-fuel combustion will be responsible for the major portion of energy consumption. In 2050, oil will account for nearly 60% of the global road subsector's energy demand, with natural gas representing 4%.

> It is in carrier form that the story of the energy transition is most apparent, with a shift away from fossil fuels towards renewables and electricity.

FIGURE 1.7

World number of road vehicles by type and drivetrain

Units: Billion vehicles



Combustion vehicles include ICEs and PHEVs.
Historical data source: Marklines (2022), IEA EV Outlook (2023), EV Volumes (2022)

Aviation

Pre-pandemic, civilian aircraft consumed nearly 9% of the world's oil, and this share was on an upward trajectory. Global aviation, driven by improving living standards, had tripled in the first two decades of the century. This growth pattern established a clear link between GDP expansion, the number of travellers, and flight frequency. We forecast that by 2050, global passenger flights will reach 10.4 billion annually (Figure 1.8), marking a 140% surge from pre-pandemic levels. The most robust growth is anticipated in Greater China, followed by South East Asia.

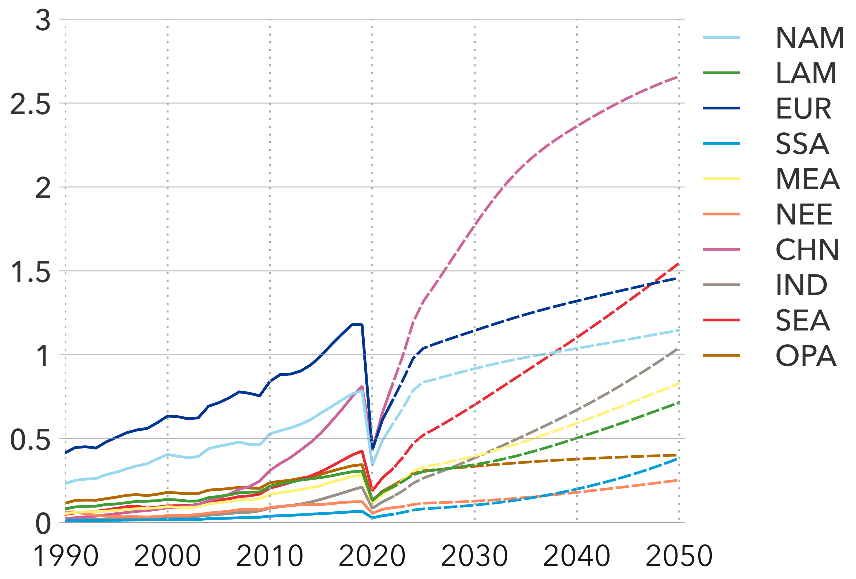
Despite the setback caused by COVID-19, which significantly curtailed air travel, passenger trip growth persists. While the impact on leisure travel was clearly temporary, the transformation in business travel patterns is set to continue. The pandemic introduced enduring changes in work dynamics that will lead to a 20% reduction in business travel throughout our forecast period.

Enhancements in aircraft and engine technology, refined routes, improved operational strategies, and incremental gains in load factors and aircraft size will contribute to ongoing efficiency improvements, quantified as energy usage per passenger-kilometre. Although annual efficiency progress will decelerate from the present 1.9% per year to 1.2% per year by 2050, the cumulative impact will restrict fuel consumption to a mere 40% increase (Figure 1.9), despite the anticipated 140% surge in flight numbers. Cargo flights will also rise, yet passenger flights will continue to dominate aviation. Currently, cargo trips account for 15% of global aviation energy consumption (WEF, 2020), and this proportion is projected to remain constant across all regions throughout the forecast period.

FIGURE 1.8

Air passenger demand by region of origin

Units: Billion passenger-trips/yr

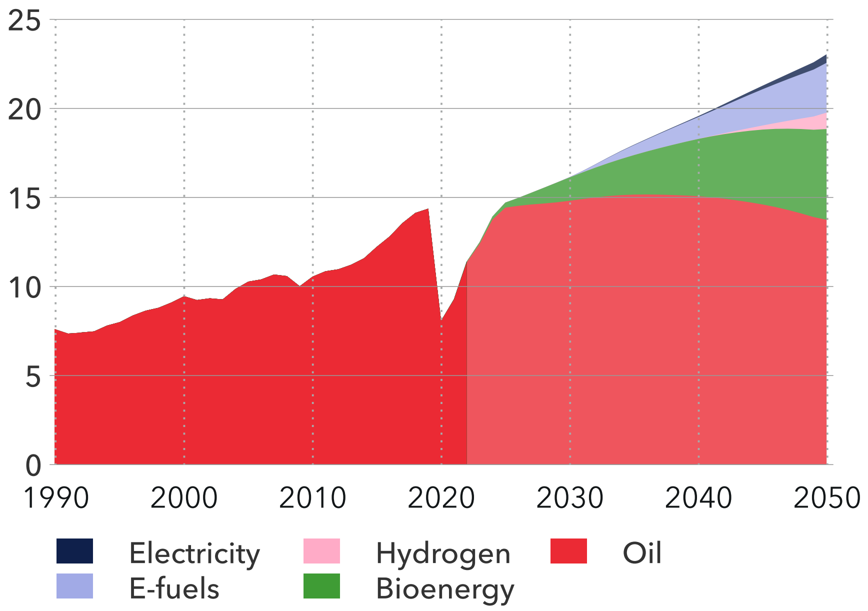


Historical data source: ICAO (2020), Airbus GMF (2018)

FIGURE 1.9

World aviation subsector energy demand by carrier

Units: EJ/yr



Historical data source: IEA WEB (2023)

TRANSPORT IN TRANSITION

See article on DHL Express – a front-runner with SAF, on page 53 in our *Transport in Transition* report.
[Download]

Image, courtesy: Deutsche Post DHL

Fuel mix

Aviation faces limited options to replace oil-based fuel, and is thus often labelled a sector hard to decarbonize. On the one hand, the adoption of low-GHG-emission technologies and fuels is eased by aviation having a relatively manageable group of stakeholders and an international governance framework facilitating decision-making. On the other hand, the future cost and availability challenges for alternatives to conventional jet fuel remain significant hurdles, inhibiting widespread adoption due to high expenses and limited supply and infrastructure.

Electrification is emerging as a viable propulsion solution primarily for short-haul flights only, due to battery weight. Commercial electric aircraft deployment is projected to commence before 2030, initially focused on very small aircraft carrying fewer than 20 passengers. This trend will expand in the 2030s to encompass slightly larger short-haul planes, predominantly in leading regions. Batteries possess notably lower energy density than aviation fuel, making hybrid-electric approaches pertinent for medium and long-haul flights. However, since only a minor share of aviation fuel is consumed during short-haul flights, electricity's share in the aviation fuel mix is predicted to reach only 2% by 2050.

Two alternative pathways under examination are poised to reshape the aviation fuel landscape: pure hydrogen and sustainable aviation fuels (SAF). This transition entails higher costs compared to current oil-based fuels, both in the short term and leading up to 2050. Thus, the impetus for changes in fuel and technology are anticipated to stem primarily from regulatory and consumer-driven dynamics. Notable examples encompass initiatives like the *ReFuelEU* initiative, aviation within the *Fit for 55* legislative package, augmented carbon pricing following the removal of aviation's free allowances in the future EU emissions-trading system (EU ETS) (EC, 2023a), and individual willingness to invest in sustainable aviation.

When employed as an aviation fuel, pure hydrogen presents certain advantages over SAF. Derived from renewable sources, a hydrogen value chain in aviation holds the potential for nearly emission-free transport, with careful management of resulting by-products (water vapour and NOx emissions). Nonetheless, hydrogen faces technical limitations due to its low energy density. The substantial hydrogen storage needed would necessitate a fundamentally different aircraft design, likely resulting in higher passenger costs. Moreover, the implementation of new designs requires a minimum of 20 years due to aircraft's extended operational life. Synchronizing aircraft design alterations and infrastructure adjustments, as well as revising handling and safety regulations, must coincide with technology advancements. Given the significant barriers impeding the widespread adoption of pure hydrogen in aviation before the mid-century mark, its share of the subsector's energy demand is projected to remain relatively modest, at approximately 4% by 2050.

Bio-based SAF has already made strides at a small scale due to mandatory biofuel blend rates in some countries. It is expected to experience rapid scalability due to regulatory impetus and consumer demand. Consequently, SAF is poised to be primarily comprised of biofuels in the near to medium term, reaching a 22% share of the fuel mix by mid-century. While the abundant production of sustainable biofuel poses challenges, aviation's greater capacity to pay, and limited decarbonization alternatives, make it a viable choice.

During the 2030s, the adoption of e-fuels based on hydrogen will gradually increase, with significant uptake anticipated in the 2040s. Nonetheless, liquid SAFs derived from renewable sources or biogenic origins offer a more fitting avenue for aviation decarbonization. These fuels are well-suited as drop-in options, seamlessly integrating with existing infrastructure and combustion technology.

Weighing the different advantages of hydrogen and e-fuels against each other, we will see three times more e-fuels – a 12% share in the mix – than pure hydrogen in the aviation subsector. This predominance of e-fuels is attributed to their versatile application across various flight types, in contrast to pure hydrogen, which is limited mainly to medium-haul flights. Despite this shift, oil will continue to be the primary aviation fuel source, retaining a 60% share in 2050 with a 21% increase in usage compared to present levels. Notably, the efficiency gains and gradual fuel mix transformation we forecast positions aviation to outperform the (currently under revision) goals of the *Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA)* for the partial decarbonization of aviation through to 2050.

Maritime

Maritime transport is currently the most energy-efficient transportation in terms of energy per tonne-kilometre, and more than 80% of globally traded goods are transported by sea (UNCTAD, 2021). At present, ships account for nearly 3% of global final energy demand, and 7% of global oil consumption, primarily for international cargo shipping.

In its most significant update since 2018, the International Maritime Organization (IMO) revisited its GHG strategy adopting the *2023 IMO Strategy on Reduction of GHG Emissions from Ships* and fortified its objectives aimed at decreasing emissions from maritime transportation.

The updated GHG strategy encompasses 'levels of ambition' that align with the overarching objective of diminishing emissions in the shipping sector, and which include amongst others:

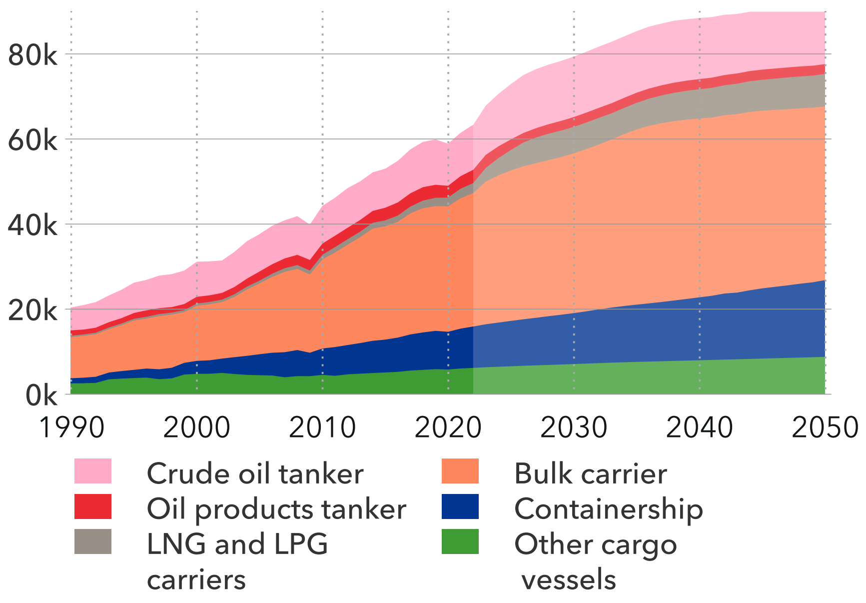
– "Striving to achieve net-zero emissions from international maritime operations by approximately 2050 (considering diverse national circumstances) and pursuing endeavours towards their eventual elimination, in line with the long-term temperature objective delineated in Article 2 of the Paris Agreement."

Aside from reaffirming its latest levels of ambition, the IMO's new strategy outlines 'tentative milestones' for 2030 and 2040. DNV analysis suggests (DNV, 2023b) that a blend of decarbonization measures, including fleet and ship optimization, wind-assisted propulsion, on-board CCS, energy efficiency enhancements, and a substantial transition to low- and zero-carbon fuels like gas and ammonia will be used in the process of achieving the strategy. The potential for electrification in maritime remains limited to shore power during docking and short-sea shipping due to the constrained energy density of batteries for deep-sea voyages.

In a world where GDP doubles by 2050, the demand for cargo transportation will outweigh efficiency gains. Consequently, cargo tonne-miles are projected to rise across most ship categories (Figure 1.10), with a total growth of 40% from 2022 to 2050.

FIGURE 1.10
World seaborne trade in tonne-miles by vessel type

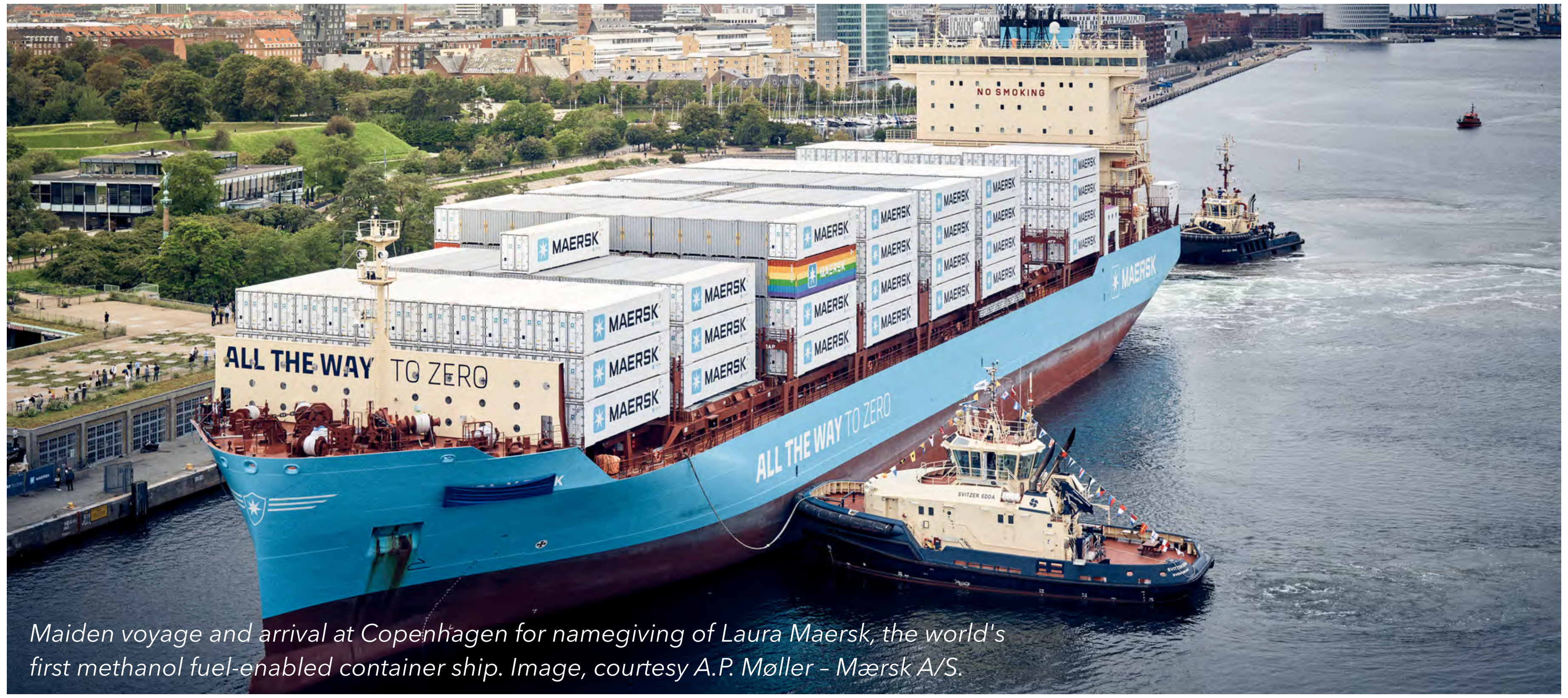
Units: Gt-nm/yr



Historical data source: Clarksons Research (2021)

While some categories, such as gas carriers, will experience growth, efficiency improvements and global trade pattern changes will lead to reductions in most segments. As a result, coal transport is expected to halve by 2050, and crude oil and oil products transport will decrease by 20%. It must be noted that in the coming years, transport on keel will become more expensive due to an increasing share of low-emission fuels in the maritime fuel mix. This might impact established transport routes in cases where domestic production might have an advantage over higher-priced transportation.

Global cargo shipping is a fundamental aspect of our analysis. The regional dynamics of fossil-fuel demand and supply dictate that any imbalances are resolved by transporting excess resources from surplus regions to deficit regions. Moreover, significant maritime transportation of fossil fuels takes place within individual regions. Similarly, the movement of raw materials and finished goods occurs both within and, notably, between regions.



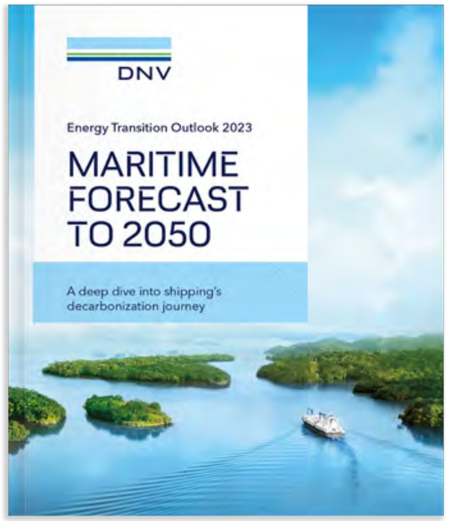
Maiden voyage and arrival at Copenhagen for namegiving of Laura Maersk, the world's first methanol fuel-enabled container ship. Image, courtesy A.P. Møller – Mærsk A/S.

Fuel mix

The view on the maritime sector's ability to decarbonize has progressed rapidly over the last five years, pushed by the IMO's decarbonization strategy introduced 2018 and revised in 2023. A shift in mindset within the sector towards shouldering its part of the net-zero challenge is evident, and will help to drive a significant change in fuel composition over the coming decades. Shifting away from its predominantly oil-based fuel mix today, the composition by 2050 will mainly encompass low- and/or zero-carbon fuels (84%). Among the low- and zero-carbon fuels, ammonia is projected to command the largest share (36%), followed by biofuel at 25% and e-fuels at 19%. The role of electricity, as previously discussed, is anticipated to be minimal at 4%. This extensive shift in fuel types will be bolstered by region-specific decarbonization initiatives.

However, the fuel switch in maritime industry depends on many factors such as advanced biofuel availability and sufficient availability of renewable hydrogen for e-fuel production. Those uncertainty factors are captured in DNV's 2022 version of the *Maritime Forecast to 2050* (DNV, 2022c) where 24 scenarios for the maritime sector's future fuel mix are outlined. Based on the updated IMO strategy and a push from both charterers and regulators such as the EU, our our main ETO 2023 has a more decarbonized fuel mix than last year's forecast. Nevertheless, this forecast acknowledges that the IMO ambitions lack enforcement mechanisms and might not be fully met, as the ambitions have yet to be translated to ship-specific regulations.

Our fuel mix forecast for maritime illustrated in Figure 1.11 is a result of our best estimate assessment and not the result of a cost competition-based model output. This implies that our view on the maritime fuel mix to 2050 holds significant uncertainties, partly described above and more fully detailed in DNV's *Maritime Forecast to 2050.*

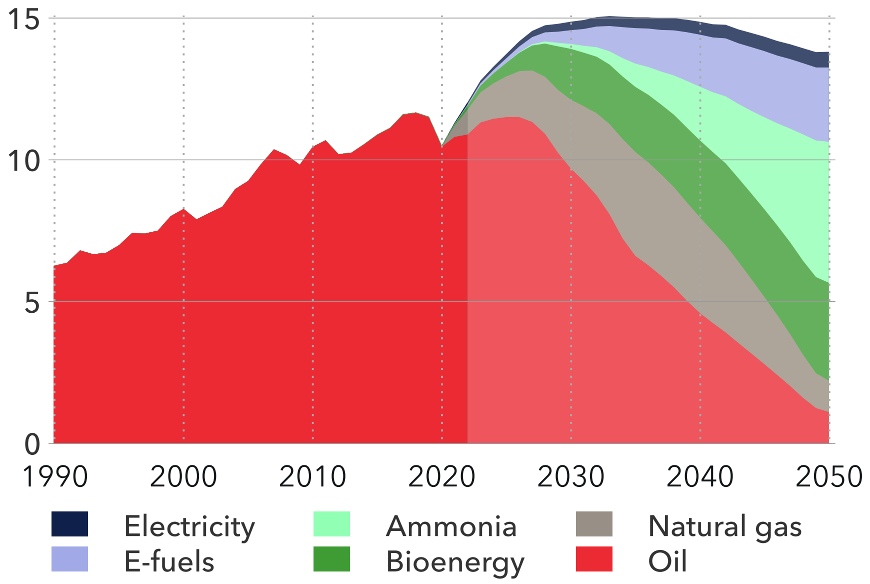


Our Maritime Forecast to 2050 provides valuable insights to empower information-based decision making for all maritime stakeholders on their decarbonization journey.

FIGURE 1.11

World maritime subsector energy demand by carrier

Units: EJ/yr



Natural gas includes LNG and LPG. Historical data source: IEA WEB (2023)

Rail

This subsector encompasses rail-based transportation, including urban rail systems. In 2022, rail accounted for just under 2% of global transport energy demand, approximately 0.5% of total global energy demand. By 2050, global passenger numbers are expected to more than double (+140%), resulting in a surge of rail travel to 9.9 trillion passenger-kilometres.

Rail freight transport is projected to grow by 90% by mid-century, with substantial regional disparities. Notably, Greater China anticipates doubling rail freight demand over the next three decades, while Europe's equivalent demand remains stable. Rail transport, particularly in urban areas, boasts superior space efficiency compared to other modes. Its suitability for electrification further positions it as an attractive choice for transport decarbonization. The increasing speed and competitiveness of high-speed trains vis-à-vis aviation, driven by decarbonization goals, also contribute to rail's expansion. Significant passenger growth is forecasted in the Indian Subcontinent and Greater China, propelled by rising living standards and robust public policy support for rail development. As depicted in Figure 1.12, nearly all passenger rail growth is expected to be concentrated in these two regions, with the Indian Subcontinent projecting a 57% share of global rail passenger transport in 2050 and Greater China contributing 27%.

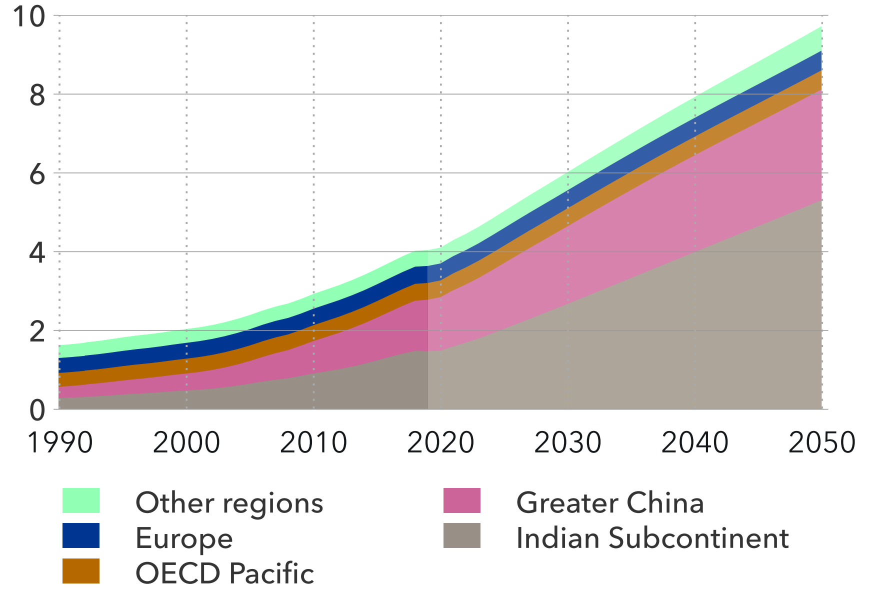
In regions other than Europe, where rail freight has historically thrived, increased rail freight volumes are spurred by GDP growth and transportation sector decarbonization strategies. Despite the remarkable surge in road-freight demand in Europe, the potential for further rail-freight expansion is limited due to congested tracks, enhanced road networks, and prioritization of passenger rail.

Energy-efficiency advancements will primarily revolve around electrification, complemented by efficiency gains in diesel-powered units. Figure 1.13 illustrates our projection that ongoing electrification trends will be maintained to meet rail transport demand, resulting in a 2050 fuel mix comprising 54% electricity (up from 41% today), 41% diesel, and 5% biofuel. While hydrogen holds potential to replace diesel on non-electrified rail, a large-scale adoption of gaseous energy carriers like hydrogen is not foreseen due to factors such as pulling power limitations for rail freight, the need for governmental support, and inadequate hydrogen refuelling infrastructure along main rail routes together with a strong competition for renewable hydrogen stemming from uptake in other (transport) sectors.

FIGURE 1.12

Rail passengers by region

Units: Trillion passenger-km/yr

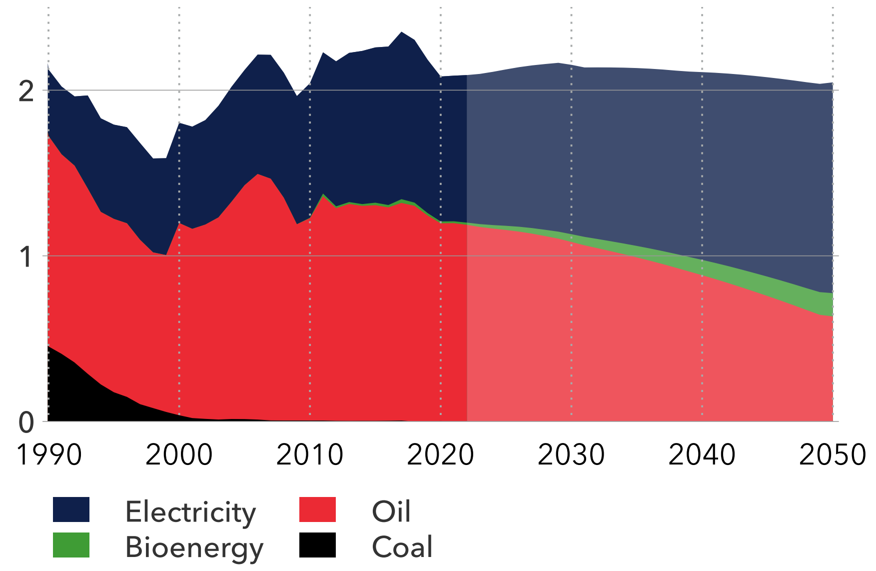


Historical data source: IEA UIC (2019)

FIGURE 1.13

World rail sub-sector energy demand by carrier

Units: EJ/yr



Historical data source: IEA WEB (2023)

1.2 BUILDINGS

Despite increasing electrification and improvements in the efficiency of thermal insulation and heating/cooling equipment, global energy demand for buildings is set to grow nearly 30% over the next three decades, from 125 EJ per year in 2022 to 161 EJ per year in 2050. The sector's share in final energy demand is also expected to grow from 28% now to 33% by mid-century. This is mainly driven by an increase in population and therefore in floor area demand, as well as a rise in per capita incomes leading to growing demand for space cooling and other electric appliances. Global warming further intensifies the demand for cooling.

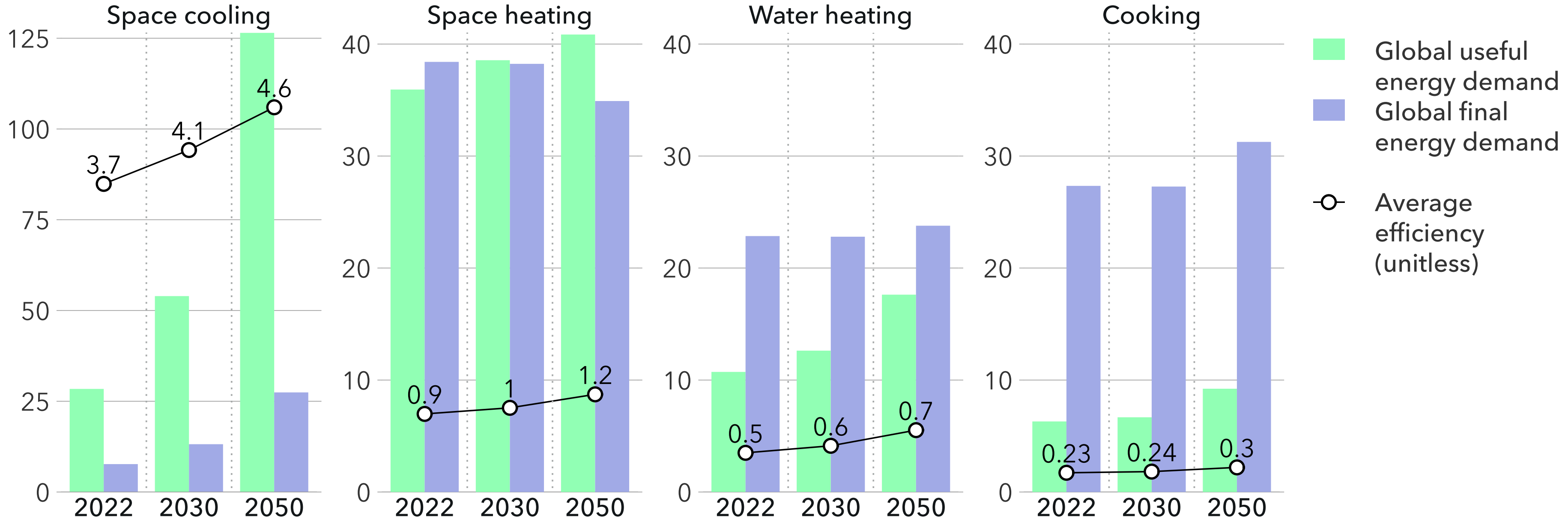
In 2022, 28% of the world's total final energy and nearly 50% of global electricity was consumed in buildings. About three-quarters (92 EJ) of this final energy demand was in residential buildings, and the rest (33 EJ) in commercial buildings including private and public workspaces, hotels, hospitals, schools, and other non-residential buildings. Total CO_2 emissions from this sector amounts to 3 $GtCO_2$, about 8% of total energy-related CO_2 emissions.

As the global population continues to increase and standards of living rise across the world, we will see a continuation of the historical growth in energy services provided in the buildings sector. However, the associated energy consumption will not increase at the same speed thanks to energy efficiency improvements, driven by higher efficiency standards, continued decline in the costs of energy-efficient technologies, and improvements in the building stock. For example, heat pump technology enables heat provision with an efficiency above 300% (the ratio between useful heating energy provided over the electricity used). Figure 1.14 shows developments in useful and final energy demand for four different end uses in buildings. As a general pattern, note the starkly different growth rate in the two bars representing useful and final energy. While useful energy demand (demand for energy services) keeps

FIGURE 1.14

Buildings useful and final energy demand and efficiencies of various end uses

Units: EJ/yr



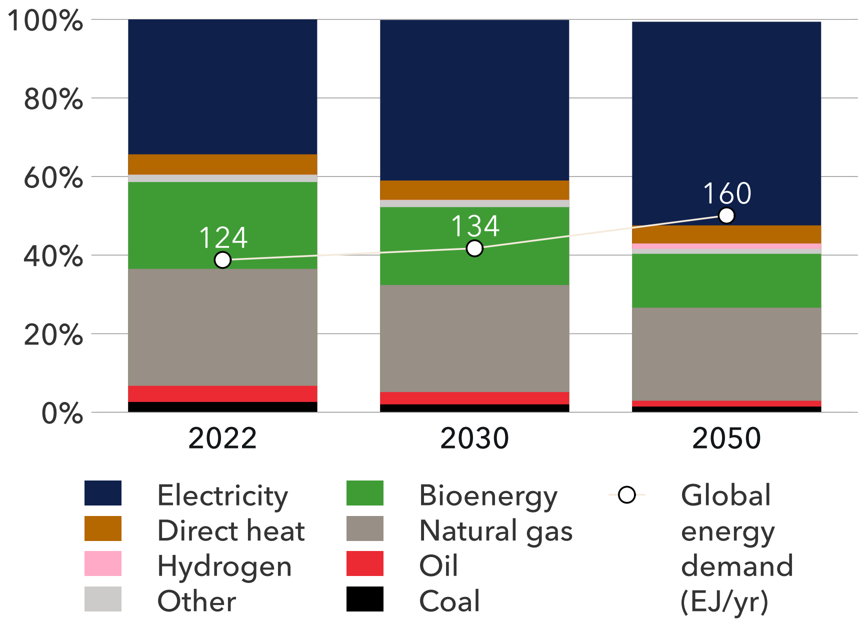
growing rapidly for all end uses, final energy demand does not grow as quickly (and drops in the case of space heating), as a result of improving efficiencies in equipment. This is most visible in space cooling which, despite the decoupling between useful and final energy demand, is still expected to be the most important source of growth in energy demand from buildings over the next three decades.

Figure 1.15 shows developments in buildings final energy demand by energy carrier. The most salient feature of the graph has to do with electricity taking an increasingly larger share in the mix, up from 34% in 2022 to 52% in 2050. This reflects the growing dominance of more efficient electric appliances in buildings, most importantly heat pumps. The growing share for electricity mostly comes out of the shares of natural gas and biomass with the former reducing from 29% in 2022 to 23% in 2050, and the latter from 23% to 15% over the same period. In the 2030s, we will start to see hydrogen use for heating purposes in buildings rising to a modest 1.1% share in the energy mix by 2050. This will be mostly in the form of hydrogen blended into natural gas pipelines at first, transitioning to some use of pure hydrogen as fuel further ahead. As outlined in more detail in DNV's *Hydrogen Forecast to 2050* (DNV, 2022a), hydrogen use will be rather limited in buildings because it will be relatively expensive from a levelized cost perspective, losing out competitively to increasingly cost-efficient heat pumps.

FIGURE 1.15

Buildings energy demand by carrier

Units: Percentages



Historical data source: IEA WEB (2023)

Appliances and lighting

In 2022, appliances and lighting used 27 EJ of energy, just over 20% of global buildings energy demand. We expect this demand to reach 43 EJ by 2050, with its share of global buildings energy demand rising to 27%. This projection takes into account significant expected improvements in the energy efficiency of appliances and lighting, as well as a more intensive use of both. First postulated by Jevons (1865) in the context of the impact of blast-furnace efficiency of coal consumption, the Jevons Paradox asserts that efficiency gains will lead to a demand increase as savings from efficiencies will be used to consume more. This rebound effect has many examples, from cars to refrigerators, across various times and cultures.

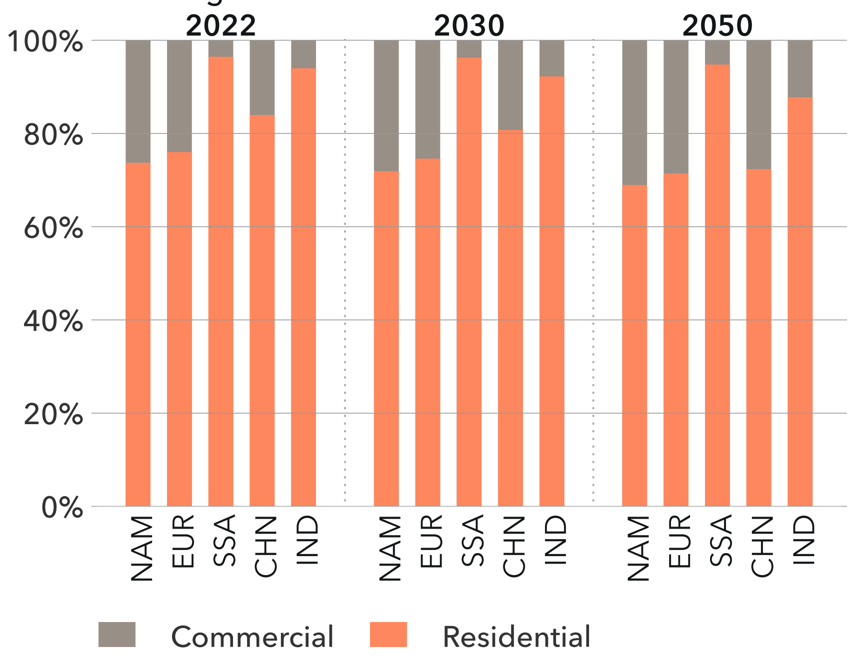
Building stock

The floor area of the building stock is one of the most important drivers of energy demand in buildings, since energy consumption in key end uses, such as space heating and cooling, scale with floor area. In 2022, the total global floor area of residential and commercial buildings covered 257,000 km², just above the size of the UK. The floor area of residential buildings is expected to grow globally by nearly 50% through to 2050, while commercial floor area will more than double in line with the growth in economic activity. This will result in a 58% expansion of combined residential/commercial floor area. Figure 1.16 shows forecast developments in the shares of residential and commercial buildings in five selected regions. The share of commercial buildings is expected to grow in all these regions because of GDP growth outpacing population growth. This is most visible in fast-growing regions such as Greater China and the Indian Subcontinent, where GDP will be growing much faster than population.

FIGURE 1.16

Commercial and residential buildings – shares of total floor area

Units: Percentages



By 2050, Greater China's total floor area of buildings will be about 105,000 km², which is equal to the current (2022) floor area across all four of the regions shown in the figure. It is perhaps not surprising then that buildings in Greater China will continue to consume nearly one-fifth of global buildings' energy use.

Space cooling

We estimate that space cooling accounted for only 6% of the energy demand of the buildings sector in 2022 but predict an increase to 17% by 2050, split roughly 70:30 between residential and commercial buildings, respectively, by 2050. Energy demand for cooling will grow from 7.7 EJ per year in 2022 to 27.5 EJ per year in 2050.

With anthropogenic emissions driving global warming, heat-related weather events are becoming more frequent and space cooling is becoming critical for adaptation. This also has energy and climate-justice dimensions to it since the countries and regions least responsible for this warming are going to be most affected by it (Sharples, 2023). Thus, in the future, living spaces and most indoor work in regions close to the equator will become unbearable without space cooling, which will be particularly needed by the infirm, elderly, and children.

Among our ETO regions, those with the highest future economic growth are also most vulnerable to heat-related climate events, such as the Indian Subcontinent, Latin America, and South East Asia. This is reflected as regional variations in the growth of cooling energy demand driven mostly by increases in cooling degree-days (CDD), and in air conditioner penetration due to rising income levels. CDD is the cumulative positive difference between daily average outdoor temperature and reference indoor temperature of 21.1°C. North America presently accounts for half of global electricity demand for cooling. However, in 2050, about 31% of cooling demand will be from Greater China, and only 13% from North America. Europe's electricity consumption for cooling will double between 2022 and 2050 (Figure 1.17).

Those regions with the fastest economic growth also happen to be those that demand the most cooling, measured in CDD. Currently, four regions have CDD above 1,000 Celsius degree-days per year: the Indian Subcontinent, the Middle East and North Africa, South East Asia, and Sub-Saharan Africa. Collectively, their economic output is expected to triple by 2050. The result would be a seven-fold increase in electricity consumption associated with space cooling for these regions (Figure 1.17). By mid-century almost half of all energy consumed for cooling will be in these regions with high CDD.

Space and water heating

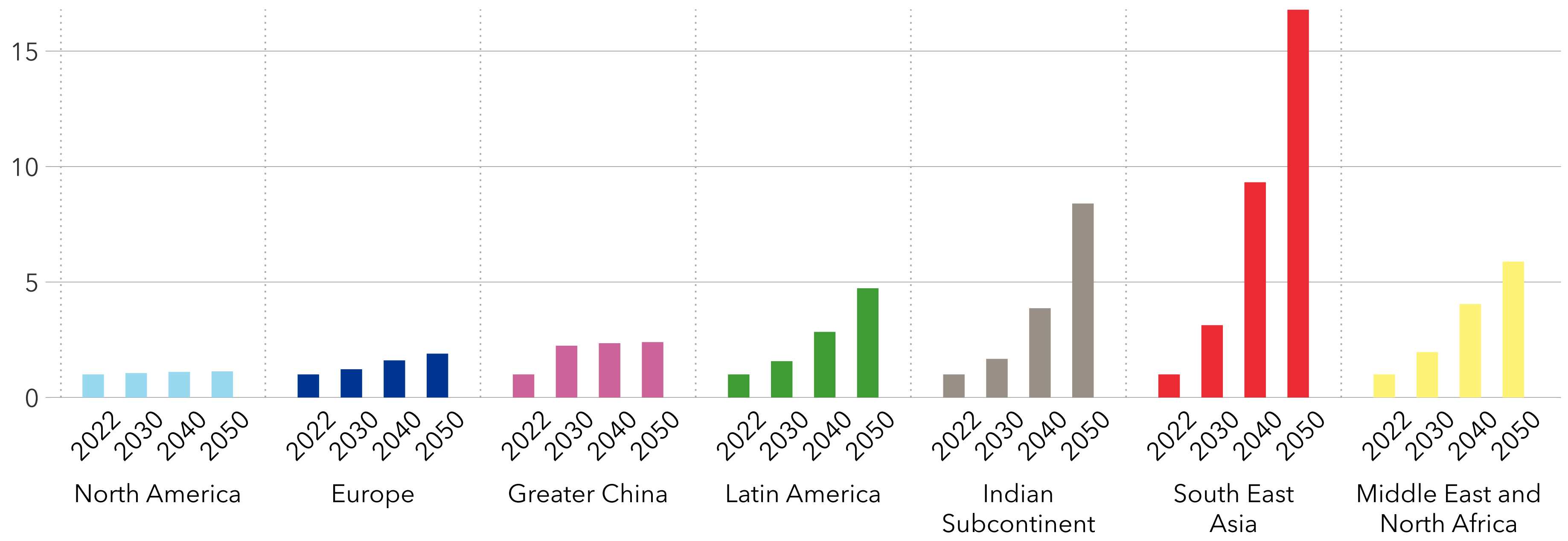
Space and water heating accounted for 32% and 18%, respectively, of the buildings sector's total energy consumption in 2022. With increasing population and floor area, demand for space heating will continue to grow, rising 12% in terms of useful heat demand by 2050. Improvements in insulation, and fewer heating degree-days (a measure of how cold the temperature is on a given day or during a period of days) due to climate change, will help reduce the rate of this growth. GDP per capita is the main driver of demand per person for water heating in residential buildings. The water heating demand of commercial buildings – about 27% of total final energy used for water heating – is driven primarily by floor area. Globally, demand for hot water will rise more than 60% from 11 EJ of useful heat in 2022 to 17.5 EJ in 2050.

Regions with colder climates (North East Eurasia, North America, Europe, and Greater China) create most of the demand for space heating. For water heating, the regional differences are mostly driven by standard of living. In higher-income regions, increasingly efficient hot water tanks are used continuously to serve multiple needs, from daily showers to washing dishes. In some lower-income countries, water is heated as required for basic needs using inefficient methods.

FIGURE 1.17

Cooling energy demand in selected regions

Units: unitless, 2022 value = 1



Average efficiency of heating equipment is defined as the ratio of useful energy provided to final energy demand. This efficiency varies widely between technologies, from less than 10% for traditional open wood-burning to more than 300% for heat pumps. Heat pumps extract more energy in the form of heat from the air or earth than the energy they consume in the form of electricity. Figure 1.18 shows developments in the share of heat pumps in providing useful heat and in final energy use. It also tracks the impact of these developments in technology uptake on the overall efficiency of space and water heating. By 2050, heat pumps will provide 32% of total useful energy for space heating and 22% for water heating, while using only 13% and 5% of final energy, respectively. Thanks mainly to the expected transition from less efficient technologies such as gas or biomass boilers to heat pumps for space and water heating – and because of gradual efficiency improvements in technologies – we see average efficiency rising from 0.9 in 2020 to 1.2 in 2050 for space heating, and from 0.5 to 0.75 for water heating.

The increased uptake of heat pumps is a result of the reduction in their cost, helped by cost-learning feedback loops where the cumulative installed capacity of the technology brings down production costs. Costs vary between regions, but with a global learning rate of 15%, we expect to see a reduction by mid-century in the levelized cost of heating by heat pumps in all regions. This cost reduction is expected to vary between 17% and 26% by region.

Globally, heat pumps will provide about a third of the useful heat for space heating in 2050 while consuming only 13% of the total final energy demand for space heating. In Europe, based on statistics from the European Heat Pump Association, around 3 million units of heat pumps were sold in 2022, increasing the total number of heat pumps installed in the region to 20 million. We forecast that heat pumps will maintain between 40% to 60% market share in space heating capacity additions through to 2050. In some local markets, like Norway, where cheaper electricity prices reduce operating costs and long winters ensure a higher return on investment, heat pumps constitute most of the market even though cold temperatures mean a lower seasonal coefficient of performance.

The move away from traditional biomass stoves for water heating is another big driver of efficiency improvements. Although consuming 26% of the final energy used globally for water heating in 2022, traditional biomass only provided 7% of the useful energy. Increased energy access will reduce the final energy represented by traditional biomass to 18% by 2050, resulting in savings of 1.8 EJ per year.

Figure 1.19 shows developments in the global energy mix for space and water heating in buildings, and

FIGURE 1.18

Share of heat pumps and overall efficiency in space and water heating

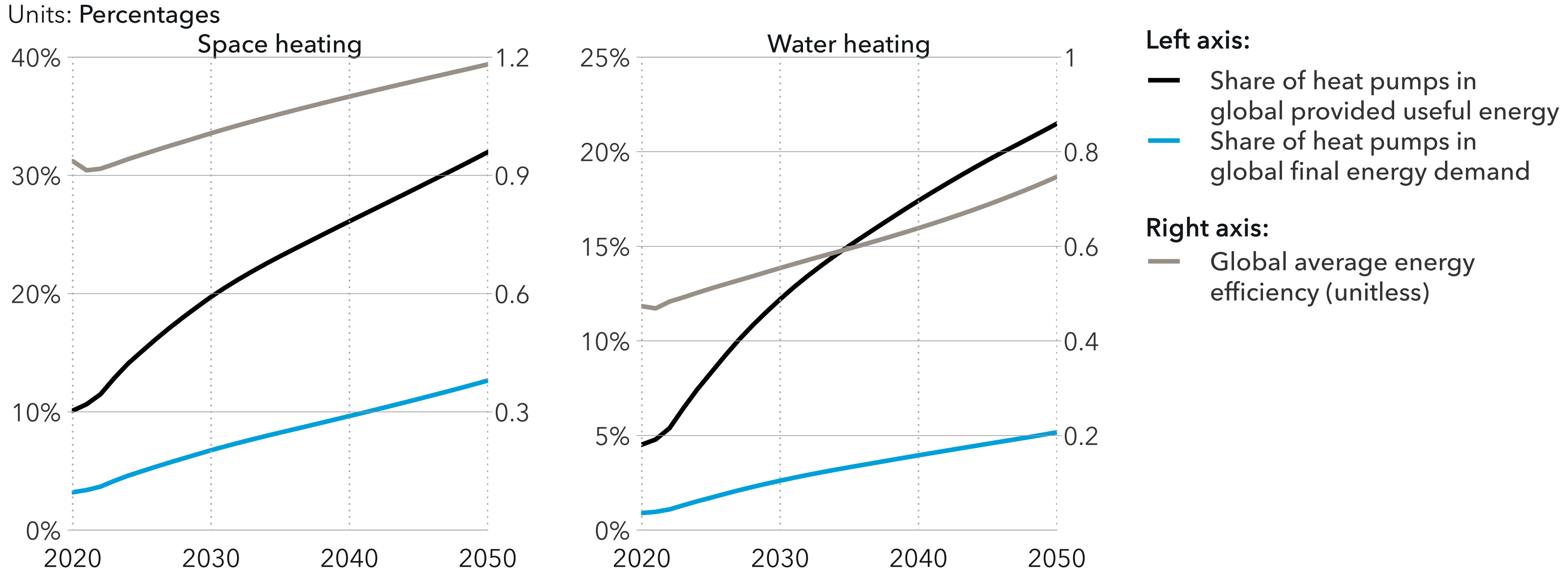
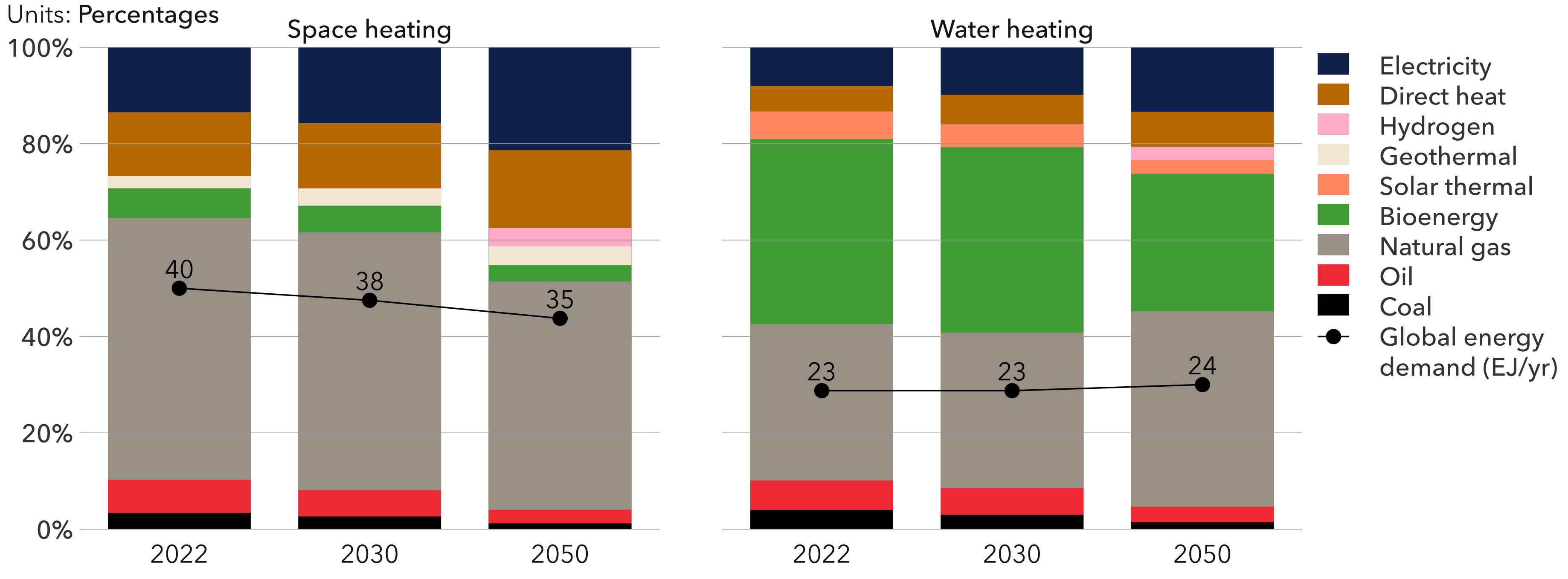


FIGURE 1.19

World space heating and water heating energy demand by energy carrier



total final energy demand for each end use. As a result of the above developments, final energy demand for water heating will stay stable in the range of 23–24 EJ/yr from 2022 to 2050, with a slight shift from residential to commercial buildings (due to higher growth in global GDP than in world population). Final annual energy demand for space heating will fall from 40 EJ to 35 EJ per year in the same period with further implementation of insulation and retrofitting measures, and as the use of efficient electric heat pumps spreads. In terms of the energy mix in space heating, the share of natural gas shrinks, giving way to electricity. In water heating, besides some increase in electrification, use of traditional biomass gives way to natural gas to some extent.

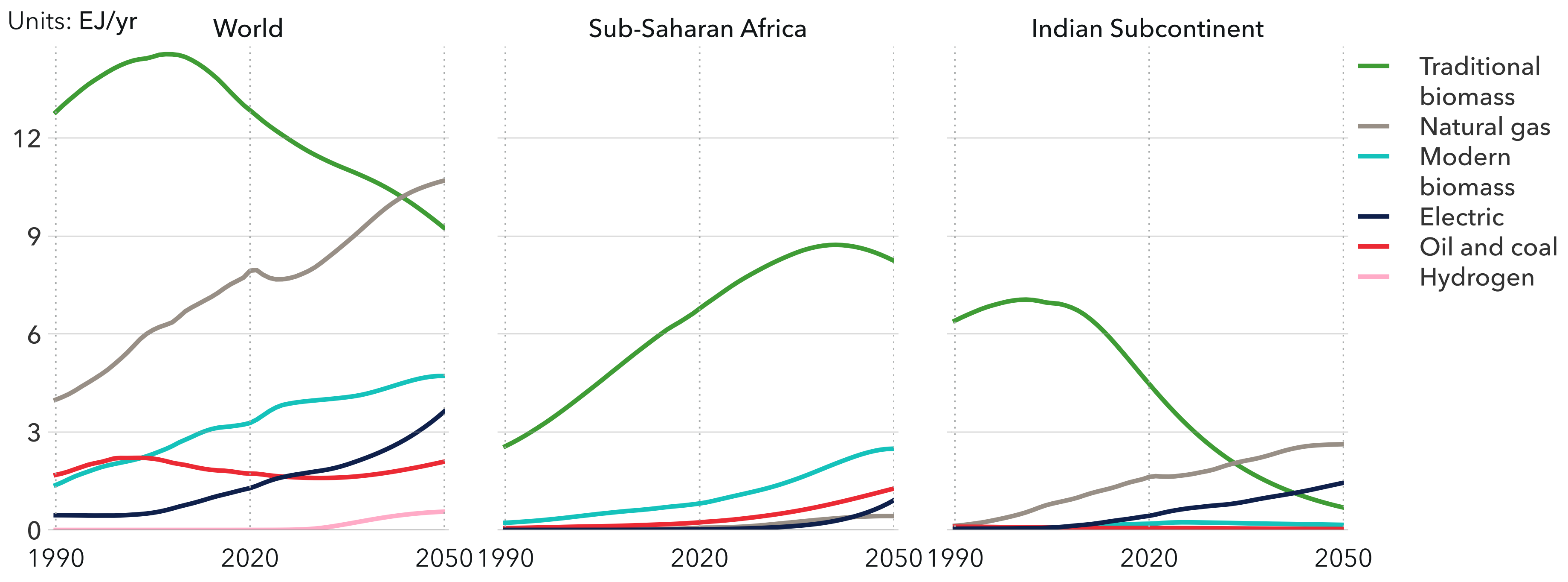
Cooking

Cooking energy demand is expected to grow 15% from 27 EJ in 2022 to 31 EJ by 2050. We estimate that in 2022, 42% of cooking energy demand is met by traditional biomass stoves burning fuels such as animal waste, charcoal, and wood. This represents a quarter of the global population, the majority of whom live in Sub-Saharan Africa and the Indian Subcontinent. By 2050, traditional biomass stoves will supply only 30% of cooking energy, following replacement primarily by electric and modern biomass stoves (Figure 1.20).

Cooking is an often-overlooked component of energy demand in buildings despite today accounting for a quarter of such demand, and 6.4% of total final energy demand. More importantly, the onus for cooking and sourcing the energy for it in regions such as Sub-Saharan Africa and the Indian Subcontinent traditionally falls on women and girls. Thus, coupled with the high prevalence of traditional biomass stoves, IEA (2023a) estimates that house-holds without access to clean cooking fuels spend five hours per day collecting fuel and cooking. Most of this time is spent by women and girls, which affects their opportunities for development, access to education, employment, and income (and frequently all four). Therefore, cooking energy is an important driver of gender inequality and productivity loss if there is no access to clean cooking fuels.

Cooking energy demand is an important driver of gender inequality and productivity loss, especially in regions with no access to clean cooking fuels.

FIGURE 1.20
Cooking energy demand for selected regions and the world



Energy efficiency through insulation, retrofitting, and building thermal characteristics

Adding insulation to the walls of a home. Photo by Werner Slocum, NREL 72236

Energy efficiency in buildings is an often under-utilized or 'hidden' energy source. Energy efficiency generally consists of efficiency due to the building stock and to the equipment and/or technology, such as efficiency of lighting fixtures.

Building stock efficiency is often a function of the building envelope and the insulation provided by the thermal properties of the materials used in a building. Energy efficiency of the building stock may also be impacted by building design, such as placement of windows, shading materials, window awnings, and so on.

Building efficiencies determine the overall space heating and cooling loads of buildings. In our forecast, building thermal characteristics (BTC) are influenced by the building code standards and the improvement in BTC due to retrofitting of buildings. There are *push and pull forces at play* that determine the dynamics of change of BTC at a regional level.

Pushing better BTC are the building codes and standards set by organizations with jurisdictions over localities, countries, or supra-national entities such as the EU, which are applicable to both existing and new residential and commercial buildings. Similarly, the EU also mandates retrofit targets for buildings stock, aiming to increase the efficiency and/or reduce the specific energy demands of buildings.

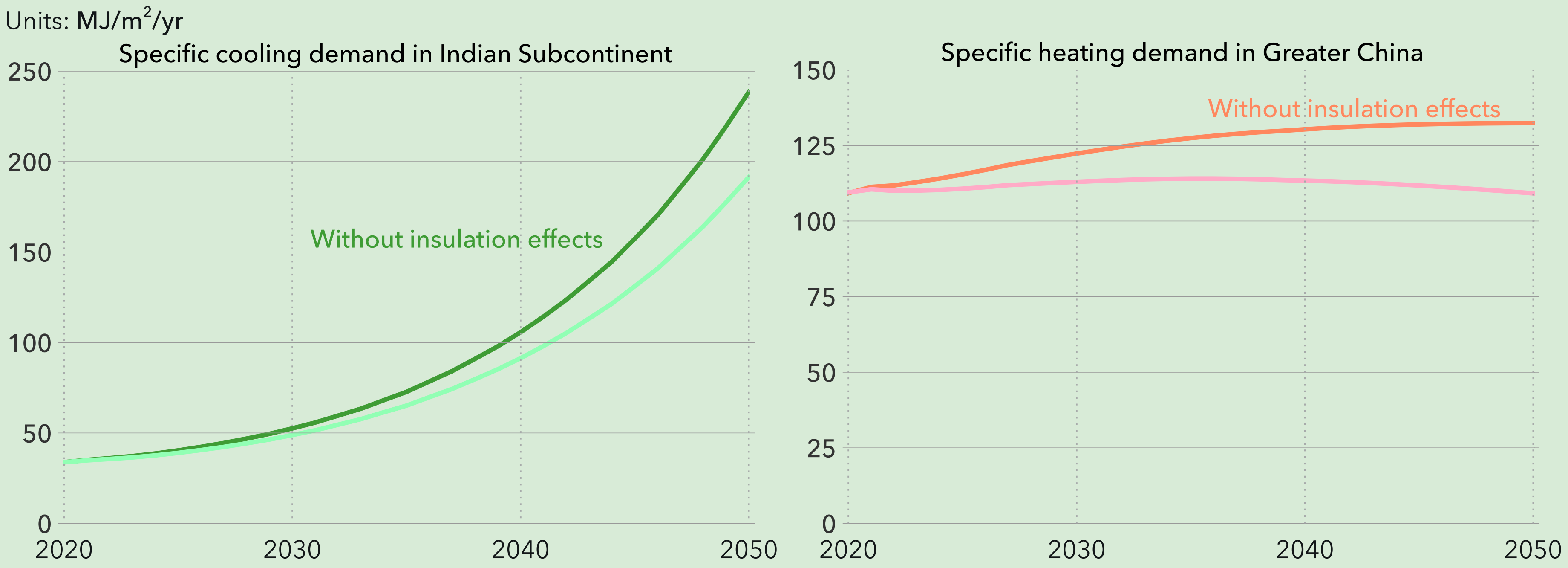
Pulling towards better thermal insulation and building energy efficiency are financial incentives available such as tax credits through the US *Inflation Reduction Act*, mainly for households to improve their energy efficiency (IRS, 2023).

In our ETO, specific heating and cooling energy demand, given as energy demand per year and per square metre are impacted not only by climate and prosperity, but also by the change in BTC through insulation improvement and retrofitting. We estimate how much of the old and new building stock will improve its BTC through retrofitting on a regional basis, and how much better BTC of new buildings are for each region. Combined, these two improvements reduce the specific heating and cooling energy demand of the overall building stock.

Figure 1.21 shows show the dynamics of change of residential specific heating demand of Greater China and residential specific cooling demand of the Indian Subcontinent, with and without improvements to overall BTC. In the case of the Indian Subcontinent, improvements in BTC reduce the specific cooling demand by 20% in 2050, which is a considerable saving in terms of energy demand. Similarly, in Greater China, the difference between specific heating demand with and without improvements in BTC is 18% in 2050. But more importantly, such improvements can dampen the peak in specific heating demand, thus 'bending the curve' of overall energy demand for space heating.

FIGURE 1.21

Effect of insulation on specific space heating and cooling demand



Historical data source: DNV analysis

1.3 MANUFACTURING

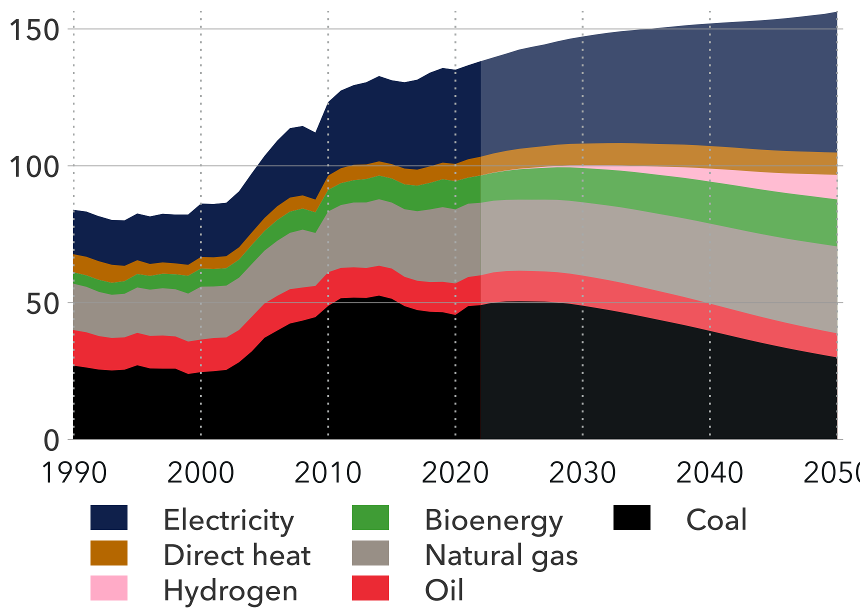
Manufacturing is currently the largest energy consumer at 138 EJ (31%) of final energy demand in 2022. Despite substantial energy-efficiency gains and increased recycling and reuse of materials and goods, the sector's energy demand will keep growing. It will increase an average of 0.5% every year, reaching 156 EJ by 2050.

Figure 1.22 shows the sector's energy mix today is dominated by fossil fuels, in particular coal and natural gas, which together supply more than half of its final energy. Their combined share will progressively decline in favour of direct electrification, hydrogen, and bioenergy, but the high heat often required poses a problem for using decarbonized alternatives. This is why the iron and steel, chemicals, and cement production industries are often described as 'hard-to-abate', as they cannot easily be decarbonized through electrification.

FIGURE 1.22

Manufacturing energy demand by carrier

Units: EJ/yr



Historical data source: IEA WEB (2023)

Additionally, the overwhelming majority of new installations still rely on fossil fuel-based technologies. As these plants are capital-intensive, long-term investments, there will be only moderate changes in the fuel mix during our forecast period. Coal will remain the largest energy carrier, driven by persistent use in Greater China and the Indian Subcontinent which, together, will still represent two-thirds of demand by mid-century.

This should not, however, minimize some forecasted progress in decreasing the sector's dependence on fossil fuels. For instance, low- and medium-heat needs will increasingly be supplied by industrial heat pumps (see factbox page 32).

Hydrogen will also be used for heating and as a reducing agent, meeting 6% of energy demand by the end of our forecast period. There will be huge regional differences in its share of the mix, from 1% in the Indian Subcontinent up to 20% in Europe.

Manufacturing in a tense world

Global geopolitical tensions have recently cast the spotlight on the dominance of certain regions, especially Greater China, in the global supply of essential technologies for the energy transition. Some of the deindustrialization trends that were observed in the last decades will be stopped and even reversed in some regions, though it will not lead to dramatic changes in energy demand. As highlighted in Figure 1.23, energy demand within the different groups of regions will progressively converge towards 2050. Different dynamics will be at play:

Greater China is a global manufacturing hub supporting domestic needs and export industries. The explosion of energy demand in the last two decades has been supported by a boom in construction of buildings and infrastructure, with steel and cement production representing half China's manufacturing demand today, and around a quarter of the country's total energy demand. Demand for these products will decline as construction slows down, but the inertia of newly installed and planned capacity additions will keep China at a very high level of demand.

OECD regions (North America, Europe, and OECD Pacific) have historically seen manufacturing's share in their economies decline, with services dominant. Reshoring of energy-intensive industries in the base materials and manufactured goods subsectors will halt the slow decline of related energy demand. Decarbonization will also be a key feature, with manufacturing CO_2 emissions halving by 2050.

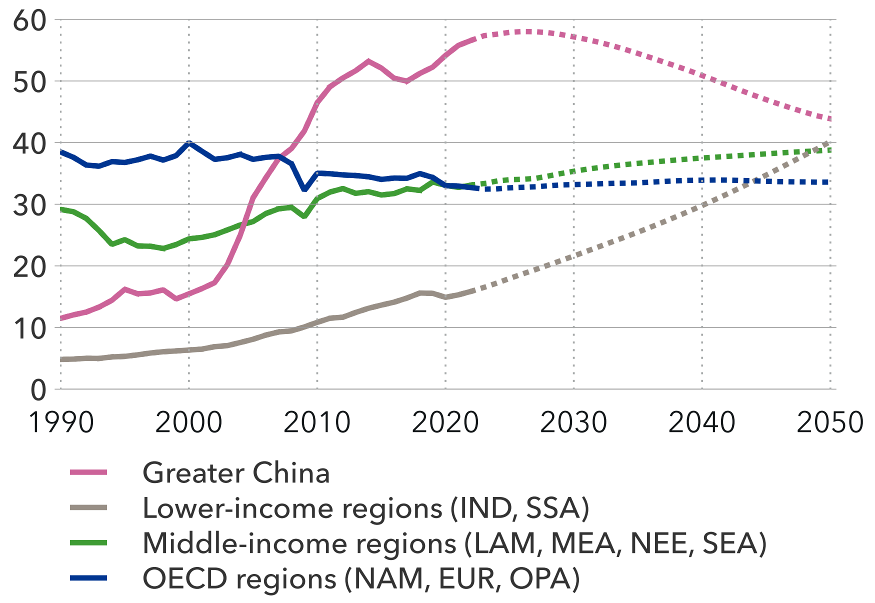
Medium-income regions (Latin America, the Middle East and North Africa, North East Eurasia, South East Asia) will see manufacturing continue to expand, mostly to support their growing economies. Consequently, energy demand will steadily increase by 0.6%/yr on average through 2050.

Lower-income regions (Sub-Saharan Africa and the Indian Subcontinent) will see the most spectacular developments, as both GDP and population increases will lead to fast-developing manufacturing capacity in all subsectors. Although not as dramatic as the past transition in China, energy demand will still increase 2.5-fold by 2050.

FIGURE 1.23

Manufacturing energy demand by group of regions

Units: EJ/yr



Historical data source: IEA WEB (2023)

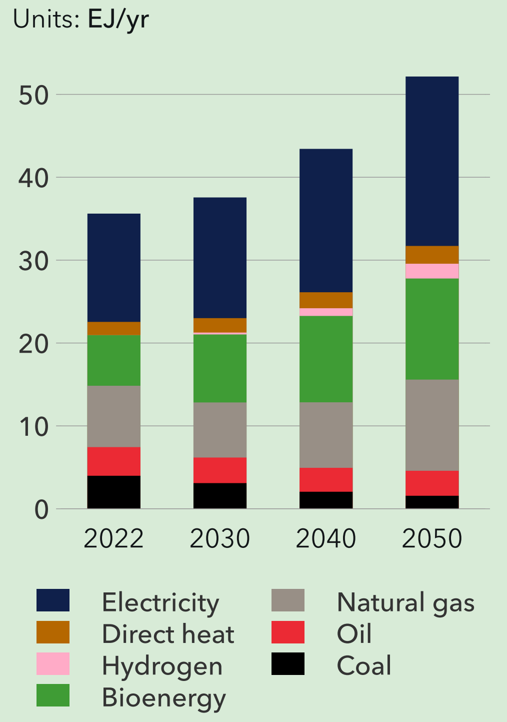
Manufactured goods

Includes production of general consumer goods; food and tobacco; electronics, appliances, and machinery; textiles and leather; and vehicles and transport equipment.

As economies grow, the demand for finished goods experiences a similar rise. Despite efficiency improvements, this expected growth in demand will lead to a 46% increase in related energy demand by 2050.

The subsector's great diversity is reflected in its energy use and fuel mix. Fossil fuels meet half its energy demand now, but their share will progressively decline as electricity, bioenergy, and hydrogen to a lesser extent, become attractive options to fuel the usually low- or medium-temperature industrial processes.

Around 50% of today's energy demand for the subsector is concentrated in three regions: Greater China and the Indian Subcontinent. These regions will continue to dominate, but the Indian Subcontinent will progressively take over China's leading position to represent more than a third of the subsector's energy demand by 2050.

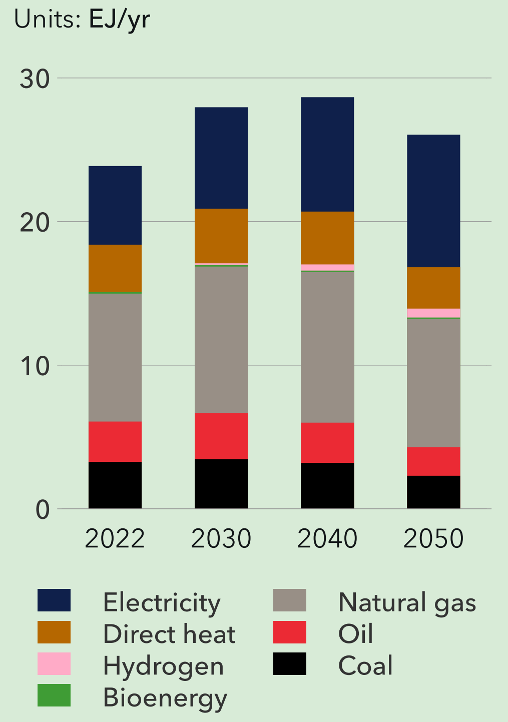


Chemicals and petrochemicals

Includes the manufacture of plastics and other petrochemicals, including ammonia and methanol used as feedstock.

The subsector's energy demand is expected to grow by about 20% between 2022 and the mid-2030s, then slowly decrease until 2050. The variation of energy demand is mostly attributed to demand for virgin plastics. This demand is initially expected to continue increasing exponentially but will become progressively attenuated by higher recycling rates in all regions (see Section 1.5 for more details).

Energy and non-energy uses are for the most part intertwined in today's industrial processes. Future processes like green ammonia production or electrified steam cracking will progressively decouple these two distinct uses in the subsector. However, long-life, multi-billion-dollar petrochemical sites operate on a fragile equilibrium. Heat recovery is well-developed, and excess heat or by-products from some processes often fuel others. Retrofitting options are consequently limited, as are potential energy-efficiency gains. This leads us to expect a slow transition in the energy mix, slow uptake of hydrogen for energy, and slow electrification.



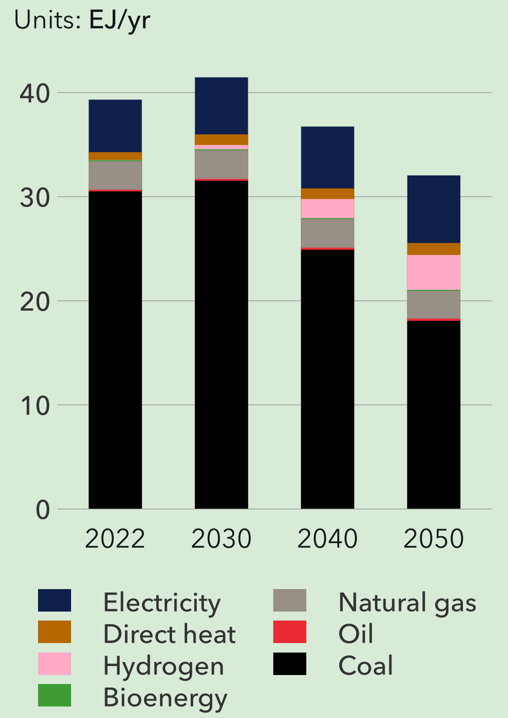
Iron and steel

Steel production has doubled in the past two decades, due mainly to infrastructure and industrial developments in China; we forecast it will increase 15% by the mid-2030s, and then plateau.

The Electric Arc Furnace (EAF) method's share in global steel production will progressively increase from 26% in 2020 to 49% in 2050, driven by reduced demand for steel and an increasing quantity of scrap steel becoming available. Consequently, energy demand for steelmaking will plateau after 2030.

Coal use will progressively decrease but will still meet more than half the subsector's energy demand by then. Indeed, steel will play a key role in sustaining demand for coal through to mid-century. The subsector accounted for a sixth of global demand for coal in 2022. As coal demand declines slower than in other sectors, steel will represent a third of that demand in 2050.

The increased share of EAF will lead to a 58% increase in electricity demand for steelmaking. A drive towards 'green' steel and direct reduced iron (DRI) will also increase the subsector's use of hydrogen for energy, from practically zero today to 9% of its fuel mix by 2050.



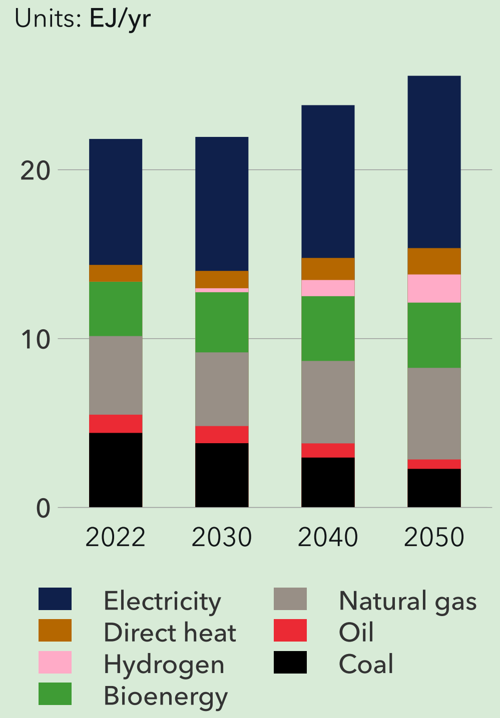
Base materials

Includes the production of non-metallic minerals (excluding cement); non-ferrous materials, including aluminium; and wood and its products, including paper, pulp, and print.

These energy-intensive industries produce materials (e.g. lithium, aluminium) for which demand will continue to grow in the coming decades, supported by the energy transition. Energy demand will as such grow by a sixth (17%) by 2050.

The fuel mix will be progressively decarbonized, both because of emission targets and a shift to materials for which production processes are well-suited for electrification. Electricity demand will thus increase by a third by 2050.

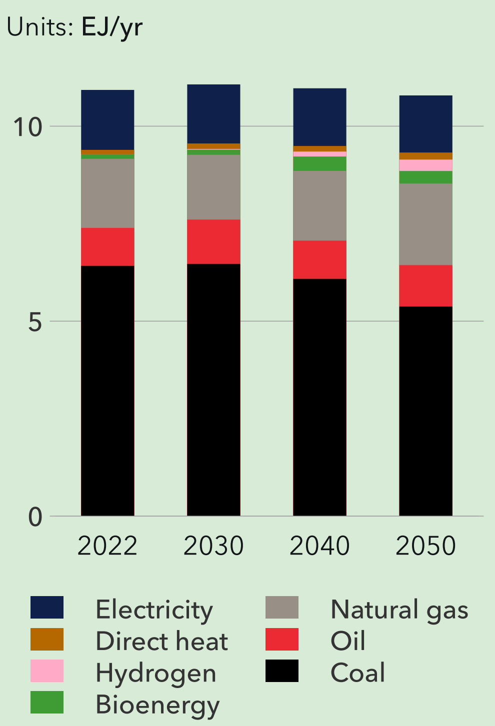
The subsector also currently represents 5% of global bioenergy demand, mostly for the pulp and paper industry. Bioenergy demand is expected to slightly increase, as demand for these products remains strong.



Cement

Cement production has more than doubled from 1.7 billion tonnes in 2000 to 4.1 billion tonnes in 2022. Global production will increase only slightly in the future, to 5 billion tonnes in 2050, as production in China slows and other regions such as the Indian Subcontinent step in.

Hydrogen and electrification are expected to play limited roles, due to high-temperature requirements and the necessity of abating the process emissions of cement regardless of the energy mix. The fuel mix will remain highly carbon-intensive, and decarbonization goals will be covered with carbon capture and storage.

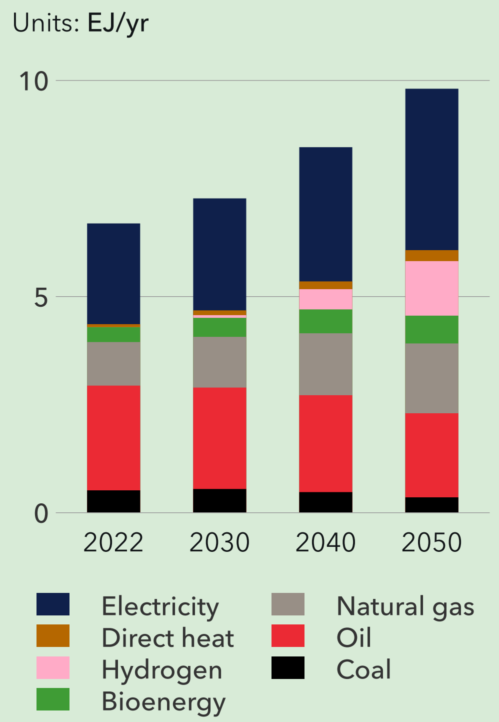


Construction and mining

Construction (of roads, buildings, and infrastructure) and mining is the smallest of the ETO manufacturing subsectors.

However, it will see the largest relative increase in energy use, growing 50% by 2050. The growth is especially pronounced in regions that will see rapid economic growth, including Sub-Saharan Africa (+260%), the Indian Subcontinent (+180%), and South East Asia (+70%).

Demand for fossil fuels will remain constant over our forecast period, while electricity and hydrogen will cover the additional needs, and represent half of demand by 2050.



Industrial heat pumps

Manufacturing processes consume significant amounts of process heat. Industrial heat currently represents about two-thirds of manufacturing energy demand, largely supplied by fossil fuels.

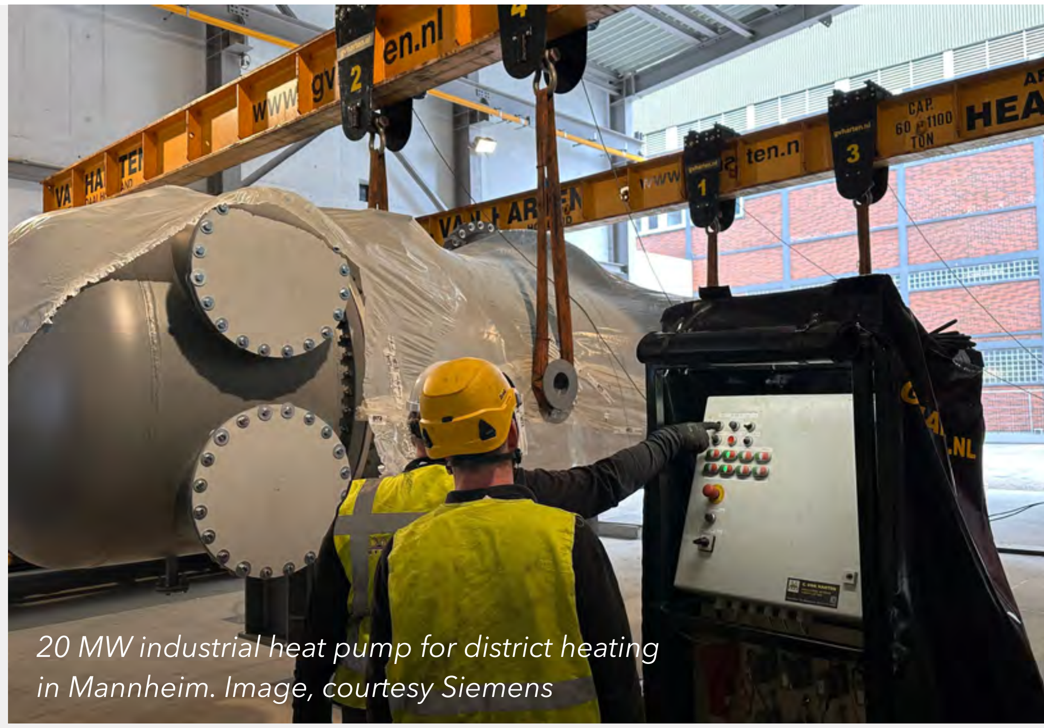
As for space heating (see Section 1.2), heat pumps, with efficiencies above 100%, are an attractive solution for providing decarbonized industrial heat. Heat pump efficiency is largely dependent on the temperature difference between the source and the sink. Consequently, a larger temperature difference leads to a lower efficiency. It is challenging to reach high temperatures if air is the heat source, like in space heating applications. But industrial processes often have significant amounts of low-grade waste heat, which can instead be utilized as a heat source to improve efficiencies. Process streams that need cooling are even better heat sources, as they can further improve the overall system efficiency.

As illustrated in Figure 1.24, process heating applications up to 100°C can be covered by mature heat pump technologies. Europe and Japan are leading the way in technology development, building on their well-established industrial heat pump industries to expand to high-temperature heat pumps.

High-temperature heat pump applications are currently made available only as pilots and small-scale industrial demonstrations, with specific investment costs between USD 200/kW and USD 1600/kW, capacities ranging from 30 kW to 70 MW, and the ability to supply heat at maximum temperatures up to 280°C. High-temperature heat pumps are expected to progressively be made fully commercially available and used between 2024 and 2027 (HPC, 2023).

While the investment cost is seen as a barrier for heat pump uptake, the costs will be reduced with more deployment in the future. Additionally, strategies such as sector coupling, heat-as-a-service, and flexibility services will improve the business case for industrial heat pumps and accelerate the deployment (WBCSD, 2022).

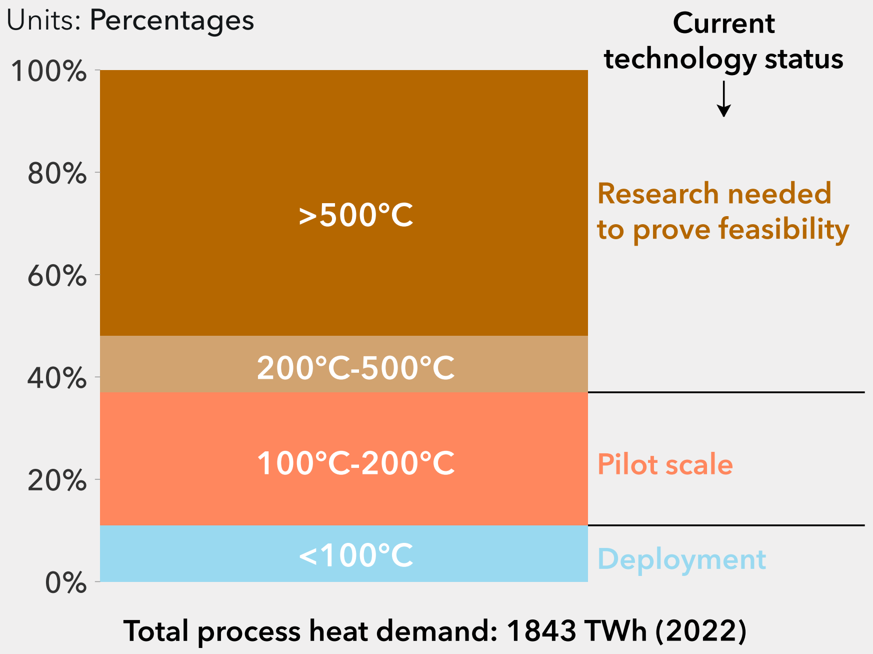
Heat pumps will be competitive in regions where the electricity to gas price ratios are lowest. In the European market, both electrification and energy efficiency are key drivers for heat pumps uptake, while energy efficiency takes precedence in markets like North America.



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

FIGURE 1.24

Process heating demand in Europe by temperature range



Adapted from SINTEF (2020)

1.4 NON-ENERGY USE (FEEDSTOCK)

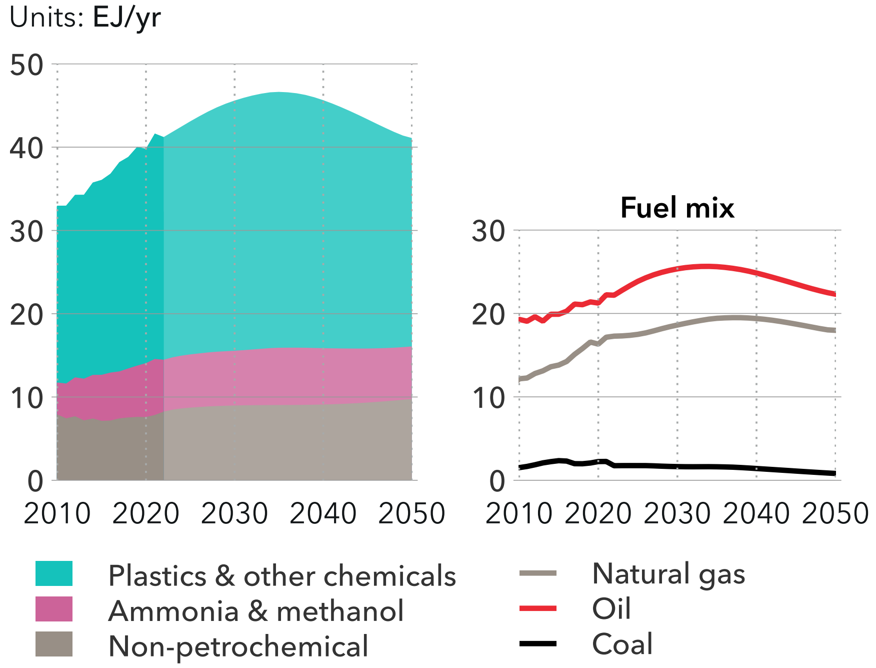
Non-energy use reflects consumption of coal, oil, natural gas, or biomass as industrial feedstock, and typically results in tangible products like plastics, paints, or fertilizers. In 2022, 41 EJ (about 8%) of global primary fossil-fuel supply was used for non-energy purposes.

Demand

Plastics production represented 18 EJ (45%) of total non-energy demand in 2022. Global plastics demand has grown significantly in recent decades, reaching 450 Mt per year in 2022. This growth is expected to continue and reach 860 Mt per year in 2050, as plastics consumption is strongly related to rising GDP per capita. However, even if plastics demand increases by 91%, non-energy use will only rise 28%. This is due to a significant increase in recycling rates during our forecast period. Secondary plastics obtained by mechanical recycling covered 7% of global demand in 2022. This will grow to 27% by 2050, owing to the generalization of recycling schemes in all regions, and to advances in recycling technologies, including feedstock recycling (UNEP, 2023). At the same time, the uptake of chemical recycling via pyrolysis and similar technologies will create a stream of recycled fuel that could be directly fed into traditional steam crackers, as a replacement for oil. We estimate that by 2050, 1.1 EJ of this recycled fuel will be produced each year, covering about 1% of oil primary energy demand.

FIGURE 1.25

World non-energy demand for energy carriers by end use



Historical data source: IEA WEB (2023), DNV analysis

Demand for ammonia, mainly driven by fertilizer consumption, is expected to slightly increase. Natural gas or coal (mainly in China) are currently used to provide hydrogen for the production. Ammonia produced via electrolysis-based hydrogen could reduce the non-energy demand, but subsequent reuse of CO_2 in the process to produce urea will limit interest in this alternative. Thus, production using fossil fuels (with and without CCS) will retain a 90% share in 2050.

Non-chemical uses include applications for asphalt (bitumen), lubricants, and solvents. Demand for these purposes is expected to increase from 6 EJ in 2020 to 10 EJ in 2050, driven by increased demand for road infrastructure in growing economies.

Fuel mix

Oil and natural gas dominate today's fuel mix for non-energy use, meeting 54% and 42%, respectively, of demand in 2022, with coal covering the rest of the mix. 90% of this coal use is in China, mainly for ammonia and methanol production.

Plastics production necessitates primary chemicals like ethene (ethylene) or propene (propylene), which can be obtained from cracking oil or from natural gas. Feedstock choice is dependent on local availability and prices. North America relies, for instance, on natural gas due to the abundance of ethane, a by-product of natural gas extraction. Regions with little fossil-fuel extraction, such as Europe or Greater China, will usually use naphtha, a fraction of oil which can be easily imported. In 2020, 64% of plastics feedstock demand was covered by oil and the rest via natural gas (methanol-to-olefins is not included here). These shares will remain stable to 2050.

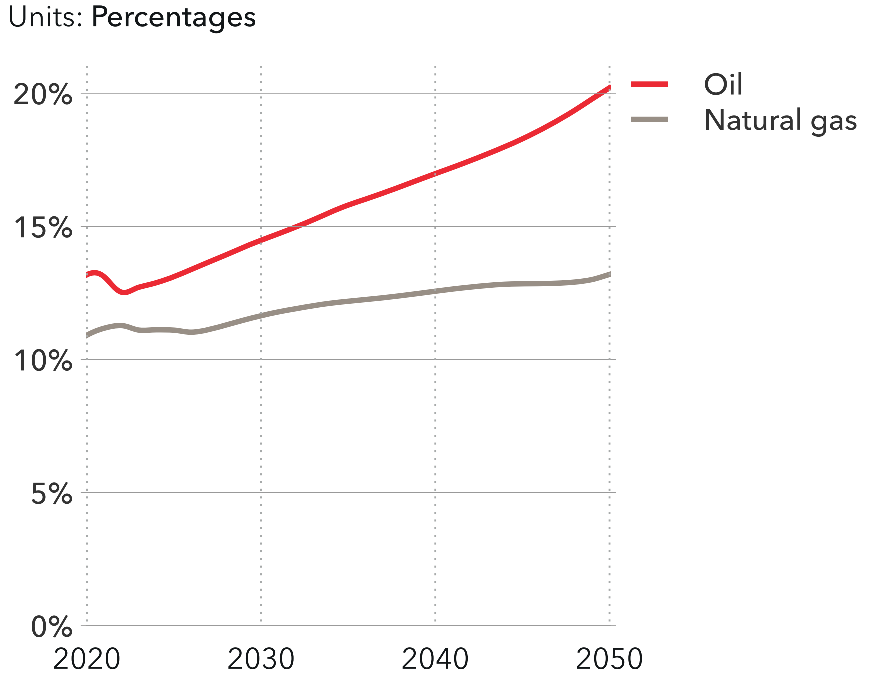
80% of ammonia is produced from natural gas by steam-methane reforming, and this share is expected to stay constant, with an increasing uptake of carbon capture. Coal gasification will be progressively phased out and will represent 7% of ammonia production in 2050 versus 18% in 2022.

The fuel mix for other chemicals is closely related to that for plastics, given that in most cases (not for methanol), the same primary chemicals obtained via steam cracking are used. Non-chemical uses are and will be covered by oil; for example, bitumen is essential for roads.

Overall, non-energy demand for oil and natural gas will increase. As Figure 1.26 shows, non-energy will maintain a constant share of total natural gas demand. For oil, the share of non-energy demand will gradually increase from 14% in 2020 to 22% in 2050 as demand grows for feedstock (particularly plastic) but will decline for other end uses like lubricants for road transport. Feedstock use will therefore be one of the key drivers for oil demand in the coming decades, with the caveat that it will peak in the 2030s and thereafter steadily decline.

FIGURE 1.26

Share of non energy use in global oil and natural gas demand



1.5 THE EFFECT OF ENERGY EFFICIENCY

As global populations expand and economies grow, we will see escalating demand for energy services including transport and consumer goods production, and for new categories of demand, including the production of hydrogen on a large scale. A key element of this surge is energy efficiency, which strives for maximum value from each energy unit.

Useful energy demand pinpoints how consumed energy is effectively converted into motion, usable heat, and light, and contrasts energy used efficiently with energy that is wasted. Figure 1.27 illustrates this by comparing global 'final' energy demand to 'useful energy' in 2022 and 2050. 'Final energy' is what is directly delivered to end-users in forms such as oil, gas, electricity, or hydrogen before that energy

is converted to energy services or 'useful energy' with associated losses.

Between 2022 and 2050, we project a 90% increase in global useful energy demand from 314 EJ/yr to 494 EJ/yr. In the same period, the final energy demand is expected to grow by only 10% to 489 EJ/yr. This difference is startling and historically unprecedented, and it is essential to delve into the nuances to fully understand the landscape we anticipate.

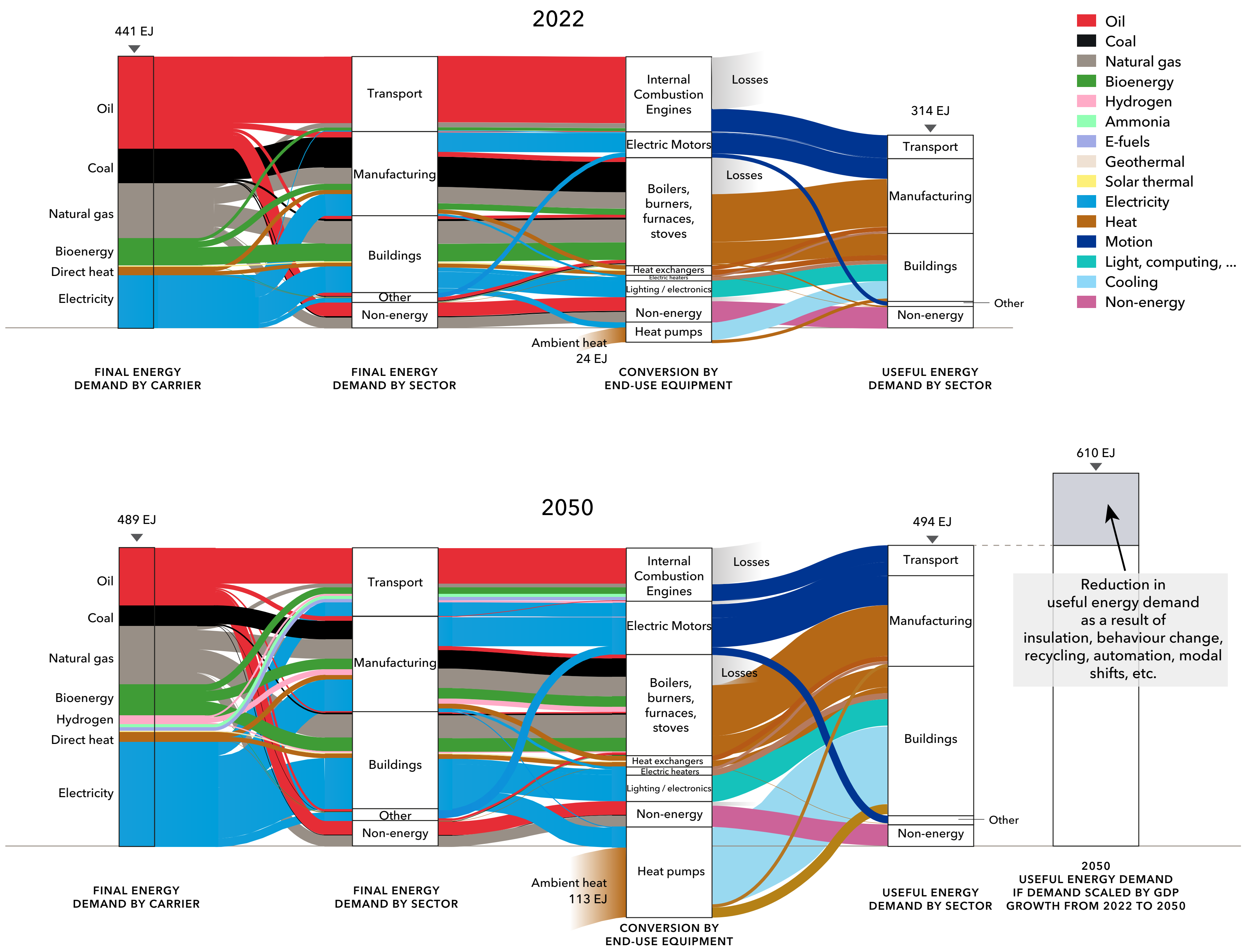
Our observations highlight the inherent inefficiencies in many energy-consuming systems today. Take the internal combustion engine, which is prevalent in the transport sector. Its tank-to-wheel efficiency typically lies between 25% and 35%. This pronounced inefficiency becomes even more glaring when compared with other energy-consuming systems.

Combustion equipment like boilers, burners, furnaces, and stoves – especially those fuelled by fossil fuels – reflect a similar story. Approximately one-third of the energy in fuels remains unused on a global scale. While we acknowledge that there are continuous advancements in technology aimed at reducing energy consumption across sectors, the changes are mostly incremental. Our projections indicate that by 2050, the average efficiency of combustion equipment will only increase to around 70%. This figure also factors in potential techno-logical shifts such as the adoption of gas for cooking instead of solid biomass.

On the brighter side, electrical equipment like electric motors and heaters consistently demonstrate high efficiencies, with many operating above the 90% mark. Heat pumps stand out, offering the ability to 'amplify' the input final energy into a greater output of useful energy by extracting ambient environmental energy. It is this potential that makes the push for elec-trification synonymous with the push for efficiency.

FIGURE 1.27

Flow of global final to useful energy demand through conversions by end-use equipment in 2022 and 2050



Historical data source for final energy: IEA WEB (2023), useful energy: DNV's own estimates

Air conditioners, functioning as reversed heat pumps, deserve a mention. We project that by 2050, the majority of heat pumps will be employed for space cooling. As income levels in previously low-income regions rise and as electrification continues its steady march, access to cooling will expand. This, paired with the challenges of global warming, leads us to anticipate that space cooling will emerge as the primary useful energy demand category by 2050.

The shift to renewables leads to a massive increase in the share of primary energy that is converted to useful energy – from half to three-quarters.

By 2050, the heat extracted by heat pumps will effectively offset the cumulative losses witnessed in internal combustion engines, boilers, heaters, furnaces, and stoves. As a result, the total useful energy supply is projected to marginally surpass total final energy. This represents a significant shift from the situation in 2022, when the global useful energy constituted a mere 72% of the final energy supply.

Strategies aimed at reducing the demand for energy services – such as insulating buildings, boosting recycling rates, or levying congestion charges on vehicles – play a significant role in our predictions. While these strategies do not directly improve the ratio of final to useful energy, they do have the potential to curb useful energy consumption or even negate the need for it altogether. By comparing the useful energy demand we project for 2050 with a hypothetical demand that would scale linearly with global GDP, we estimate that these strategies will reduce the energy demand by about 118 EJ/yr (19%) from an expected 610 EJ/yr. That is almost the equivalent the entire 2022 energy demand of China. However, it is also crucial to note potential rebound effects, such as consumers opting for larger vehicles when fuel is cheap or increasing their heating use if gas prices decrease. These could potentially drive up the demand for energy services.

Figure 1.27 also includes non-energy processes, including using fossil fuels as feedstock for products like plastics, bitumen, and other chemicals. Strictly speaking, these processes do not have an 'energy efficiency' as such, but we have included them in our considerations because non-energy use is often included in energy statistics.

Useful energy demand

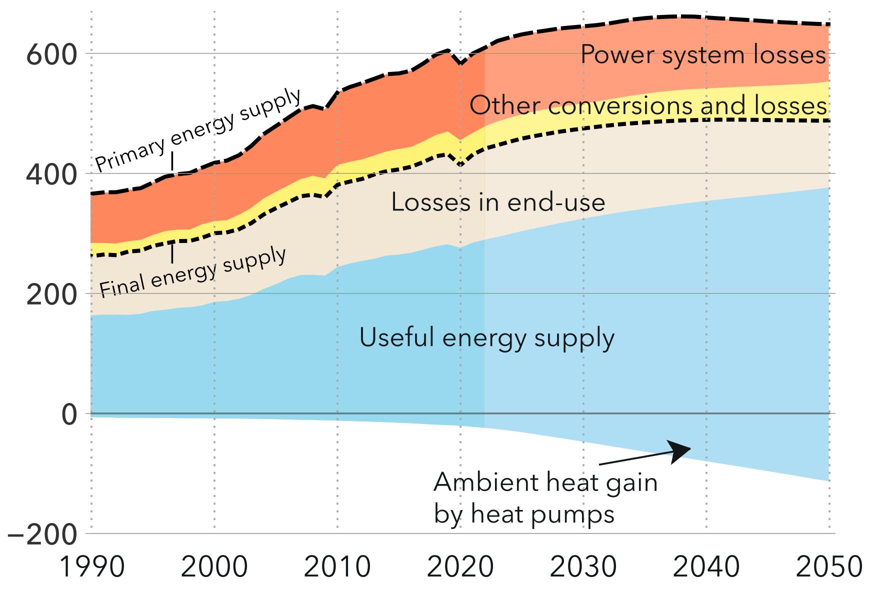
Figure 1.27 excludes considerations of electricity origins and associated generation losses. Contrasting 'useful' with both 'final' and 'primary' energy offers deeper insights. While 'final energy' refers to energy directly delivered to users, 'primary energy' denotes its raw, pre-transformed state. Energy sources like fossil fuels can be consumed directly, despite high conversion losses. However, secondary forms, including electricity, direct heat, and hydrogen, require transformation from primary sources, whether renewable or fossil-based. Figure 1.28 charts the evolution of loss sources in the global energy system. Power generation, encompassing electricity and direct heat, is the chief contributor of loss between primary and final energy. Other losses emerge from conversions like hydrogen production and the energy system's consumption, termed 'energy sector own use', and are not included in final energy demand.

Historically, traditional electricity generation from coal, gas, and oil was highly inefficient, losing much primary energy as heat. In 1990, global power system efficiency was just 34%. However, the shift to renewables, mainly solar PV and wind, leads to a massive increase in the share of primary energy that is converted to useful energy – from half to three-quarters. As these sources directly convert captured energy to electricity without heat loss, their generation is deemed 100% efficient. Nuclear energy stands at 33% efficiency, counting the heat from nuclear fuel decay as primary energy. As renewables dominate by 2050, power system efficiency will rise to 70%, up from 44% in 2022. Even with the doubling of electricity and direct heat demand from 2022 to 2050, power generation losses remain constant.

FIGURE 1.28

Losses in the global energy system

Units: EJ/yr



Historical data source for prinary and final energy: IEA WEB (2023)

Between 2000 and 2019 the primary, final, and useful energy supply grew at similar rates. The compound annual growth rate in this period has been 2.3%/yr for useful energy, 1.9%/yr for final energy and 2.0%/yr for primary energy. From 2019 to 2050, however, while useful energy provided will continue to grow at a rate of 1.5%/yr, final energy will only rise by 0.4%/yr and primary energy by 0.2%/yr.

The role of standards, policies, and initiatives

Improvements in energy efficiency often necessitate a financial commitment, typically in replacing outdated equipment with modern, efficient alternatives or updating existing structures to better conserve energy. While these upfront investments yield long-term benefits in the form of reduced energy consumption and cost savings, they can be inaccessible to those without ample resources. This highlights the essential role of standards and policies in ensuring that implementation of energy-efficiency measures is both affordable and widespread. The standards, policies, and initiatives for energy efficiency fall into different categories:

Appliance and equipment standards: Policies in this category dictate the minimum efficiency requirements for household and commercial appliances and equipment. For instance, the US Department of Energy (DOE) *Energy Policy and Conservation Act* (EPCA) prescribes energy-efficiency standards for various consumer products, ensuring they meet set efficiency thresholds.

Building codes: These standards establish the minimum energy performance metrics for new constructions and renovations to ensure energy conservation. The EU's *Energy Performance of Buildings Directive* (EPBD) exemplifies this by mandating that all new structures approximate a near zero-energy consumption by the close of 2020.

Vehicle emission and fuel-efficiency standards: Such policies specify both the acceptable emission levels from vehicles and their minimum fuel efficiency. For example, the *Corporate Average Fuel Economy* (CAFE) standards in the US outline strict fuel consumption norms for new passenger vehicles.

Utility demand-side management programmes: These initiatives by utility companies aim to reduce consumer energy use through incentives or assistance. Programmes might include rebates for purchasing energy-efficient appliances, or support for businesses to adopt energy-conserving measures in their operations.

Public sector initiatives: Governments often enact these to ensure that their own operations and public structures adhere to high energy-efficiency standards. Canada's *Greening Government Strategy*, which seeks a substantial reduction in greenhouse gas emissions from federal undertakings, is one such initiative.

Labelling and certification programmes: By providing consumers with clear information on a product's energy efficiency, these programmes empower informed choices. The ENERGY STAR programme, initiated in the US and now recognized internationally, is a prominent certification for energy-efficient products.

Market-based instruments: These mechanisms encourage the adoption of energy-efficient practices by offsetting their costs. Policies might offer tax breaks, subsidies, or grants for energy-efficient upgrades. The UK's *Green Deal*, which grants loans for such enhancements repaid through energy bill savings, is an illustrative model.

Behavioural programmes: Targeting the manner in which individuals and entities utilize energy, these initiatives promote energy-conserving habits. Japan's *Cool Biz* campaign encouraging lighter workplace attire to diminish air-conditioning use showcases this approach.

1.6 FINAL ENERGY DEMAND FROM ALL SECTORS

The final energy demand by energy carrier for all demand sectors combined is shown in Figure 1.29. The most noticeable change is the growing role of electricity in final energy demand.

In 2022, electricity represented just 19% of world final energy use. By mid-century, this will be 35%, with electricity demand doubling from 86 EJ per year in 2022 to 171 EJ in 2050, averaging 2.5% growth annually. The importance of electricity is also greater than the 35% indicates: with higher efficiency in its end use than the other energy carriers, we can safely say that more than half of all energy services in mid-century will be provided by electricity.

Technology, cost, and policy all contribute to the rise of electricity. With superior efficiency, electricity has an inbuilt advantage over other energy carriers. An often-repeated piece of general advice is to 'use electricity wherever electricity can be used'. Cost reductions for solar and wind power have been significant and are expected to continue, supporting electricity becoming cheaper than other fuels. New applications requiring modern energy are emerging – for example, communication appliances and air conditioning – for which there are few or no alternatives to electricity. Additionally, because electricity is fairly easy to decarbonize compared with other energy carriers, ever more ambitious decarbonization policies are also favouring electricity.

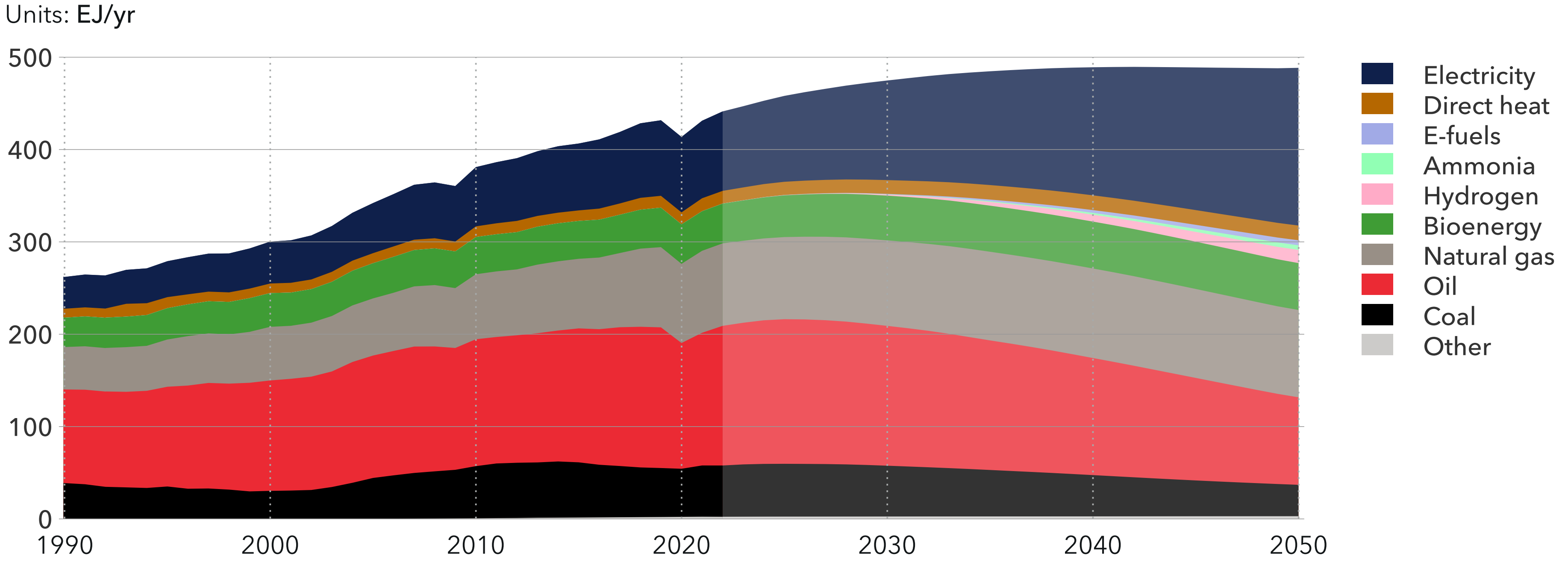
Hydrogen and hydrogen derivatives also grow strongly in the ETO forecast, but start from a very low base. From a negligible contribution today, they will reach 0.4% of final energy demand in 2030 and 5% by 2050.

Direct use of biomass remains more or less static at 10% of global energy demand throughout our forecast period. Direct use of fossil fuel reduces over the coming years, but the decline is less than for the fossil fuels used in electricity production. Direct use of fossil fuel meets 67% of today's final energy demand, but nearly a third less (47%) in 2050. The energy carrier adds nuance to this trend: coal use almost halving, oil use declining by more than a third, and direct use of natural gas remaining virtually static.

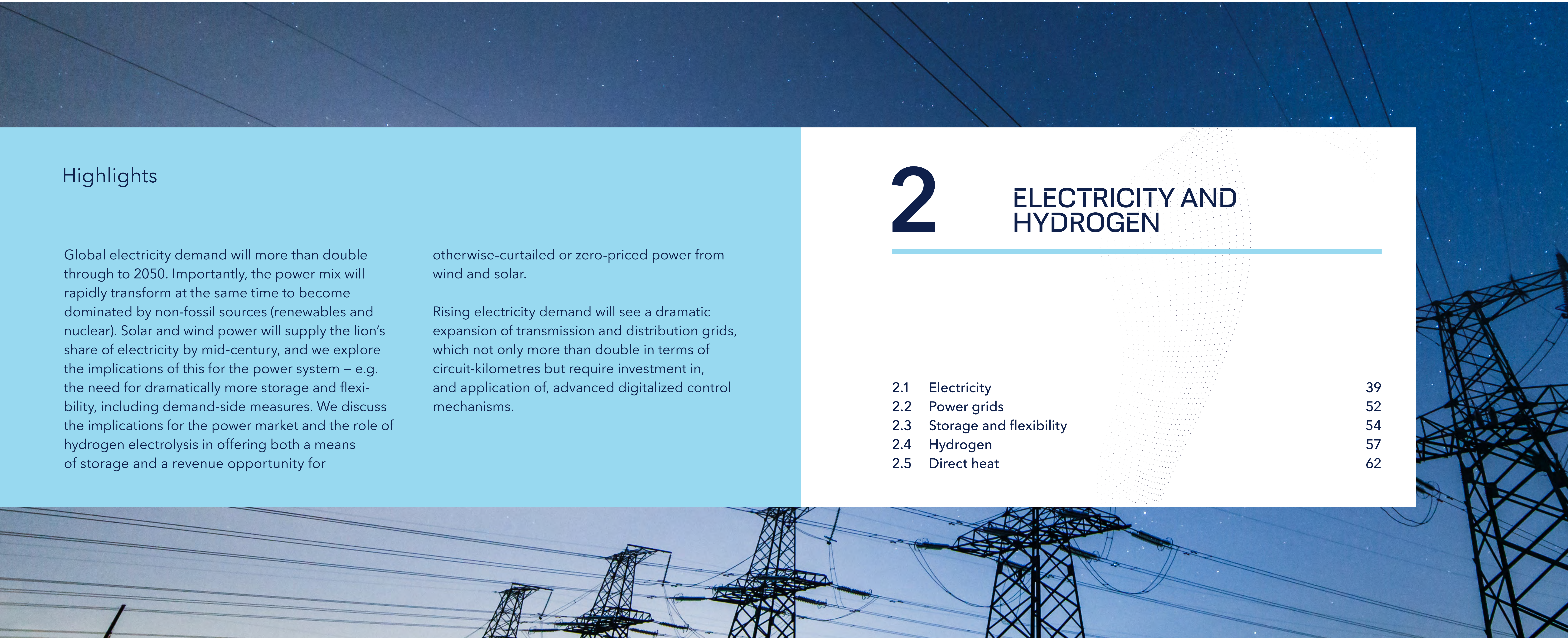
With higher efficiency in its end use than the other energy carriers, we can safely say that more than half of all energy services in mid-century will be provided by electricity.

FIGURE 1.29

World final energy demand by carrier



Historical data source: IEA WEB (2023)



2 ELECTRICITY AND HYDROGEN

Highlights

Global electricity demand will more than double through to 2050. Importantly, the power mix will rapidly transform at the same time to become dominated by non-fossil sources (renewables and nuclear). Solar and wind power will supply the lion’s share of electricity by mid-century, and we explore the implications of this for the power system – e.g. the need for dramatically more storage and flexibility, including demand-side measures. We discuss the implications for the power market and the role of hydrogen electrolysis in offering both a means of storage and a revenue opportunity for otherwise-curtailed or zero-priced power from wind and solar.

Rising electricity demand will see a dramatic expansion of transmission and distribution grids, which not only more than double in terms of circuit-kilometres but require investment in, and application of, advanced digitalized control mechanisms.

2.1 ELECTRICITY

Electricity stands central in the ongoing global energy transition, shaping innovations and strategies in both supply and demand sectors. This transition, delineated by the evolving interplay of renewables and conventional power sources, is marked by shifts in consumption patterns, investment flows, and technology advancements, steering the future trajectory of global energy dynamics and environmental sustainability.

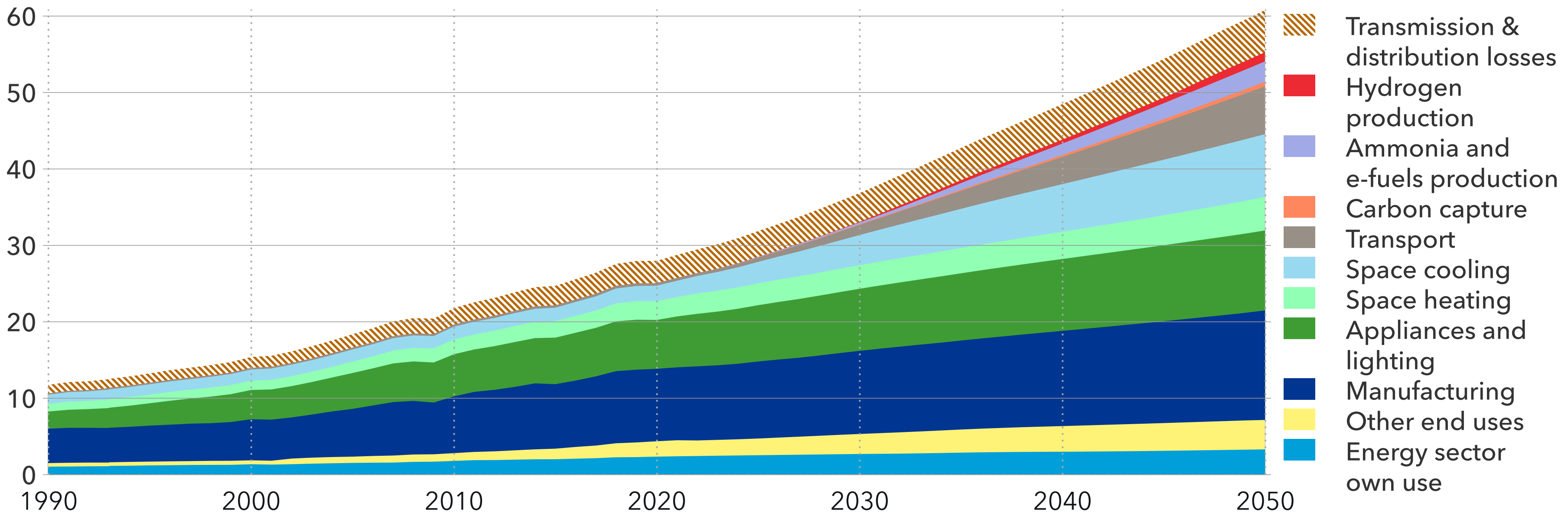
2.1.1 Electricity demand

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 29.5 petawatt-hours (PWh, or 29,500 terawatt-hours TWh) demanded in 2022 to reach 60.8 PWh in 2050. These numbers include the energy sector's own use and transmission and distribution losses (Figure 2.1). Electricity will constitute 35% of the world's final energy demand in 2050, up from 19.5% in 2022. 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 innovative energy solutions like hydrogen production.

FIGURE 2.1

World annual electricity demand by segment

Units: PWh/yr



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

In industry, electricity powers machines and appliances producing diverse goods. Fluctuations in product demand, in sync with economic activities, directly influence electricity consumption. Concurrently, buildings, driven by population growth and higher living standards, use electricity for an array of purposes from lighting to entertainment. While there are efficiency gains, for instance in lighting, new consumption areas, particularly space heating and cooling, are emerging. Heat pumps, despite their efficiency in transferring more heat than they consume, are set to amplify access to air conditioning, adding 5.9 PWh of annual electricity demand between 2022 and 2050.

Transport will account for a significant slice of the pie with 5.9 PWh/yr of the 31.3 PWh/yr spike in demand, primarily due to the charging demands of an expected 2.6 billion EVs. Additionally, manufacturing's electricity demand is rising, underlined by increased mechanization, especially in growing economies.

As we approach 2050, electrolysers connected to the grid will use 1.2 PWh/yr of electricity to deliver 24 Mt/yr of hydrogen, while another 2.7 PWh/yr will serve the production of fuels like ammonia or methanol. We also note an excluded 10.2 PWh/yr of renewable electricity reserved for onsite hydrogen production from renewables.

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. Many low-income countries have very small or no tax on electricity. Increasing the tax burden in these countries would create a similar deviation from our electrification forecast.

Regional variation in electricity demand

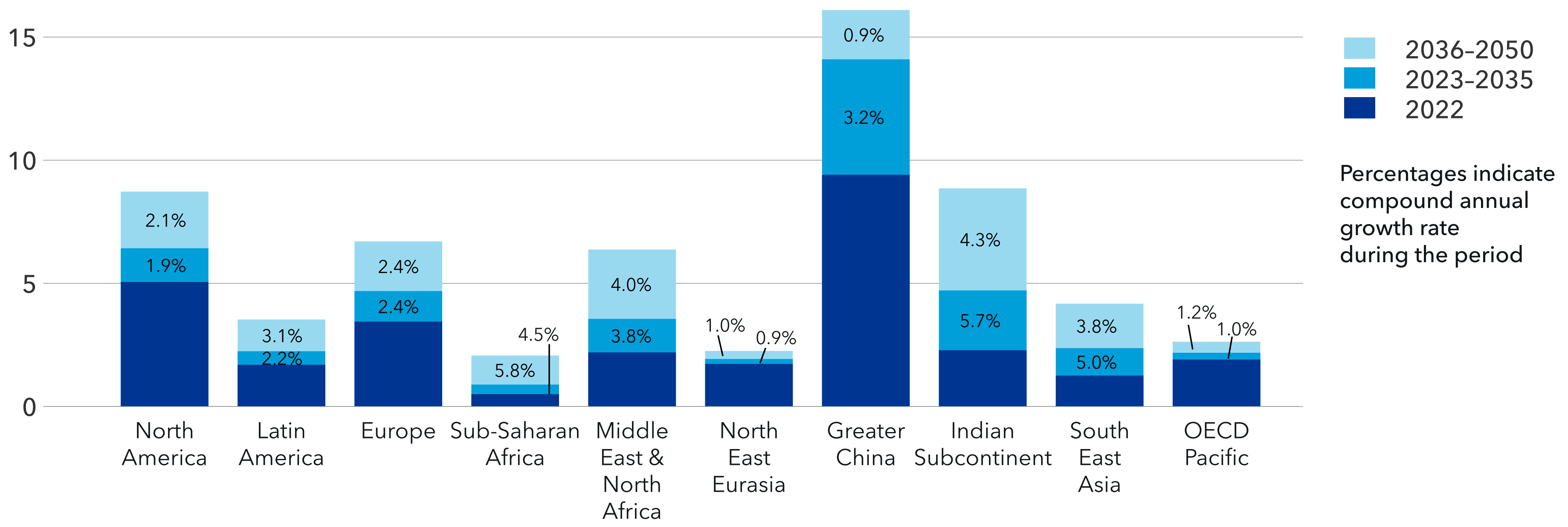
Greater China is the leading consumer of global electricity as of 2022, accounting for 32% of global demand. While it is poised to maintain its leading position come 2050, its demand share will decrease to 26%. In contrast, we anticipate the Indian Subcontinent to leapfrog both Europe and North America by 2050, commanding 14% of the global electricity share.

Up until 2035, the Indian Subcontinent and South East Asia are set to showcase the most remarkable

FIGURE 2.2

Electricity demand growth by region

Units: PWh/yr



Powerlines rising above Hong Kong – Greater China is the world's leading electricity consumer (32% of global electricity demand). This share will fall to 26% in 2050, but the region will still hold its leading position.

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, and 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 surge. This evolution underscores the vast opportunity awaiting the region in harnessing renewable energy sources and electrifying a multitude of its demand facets.

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 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% up to 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 and economic stabilization, coupled with its aggressive stance on vehicle electrification. 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.

Sub-Saharan Africa emerges as the global frontrunner in electricity demand growth, averaging an impressive 5.8% annually.

Lastly, in the Middle East and North Africa, there is a surge in building electrification, 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 stagnant population metrics and delayed electrification compared to its global peers.

Peak demand

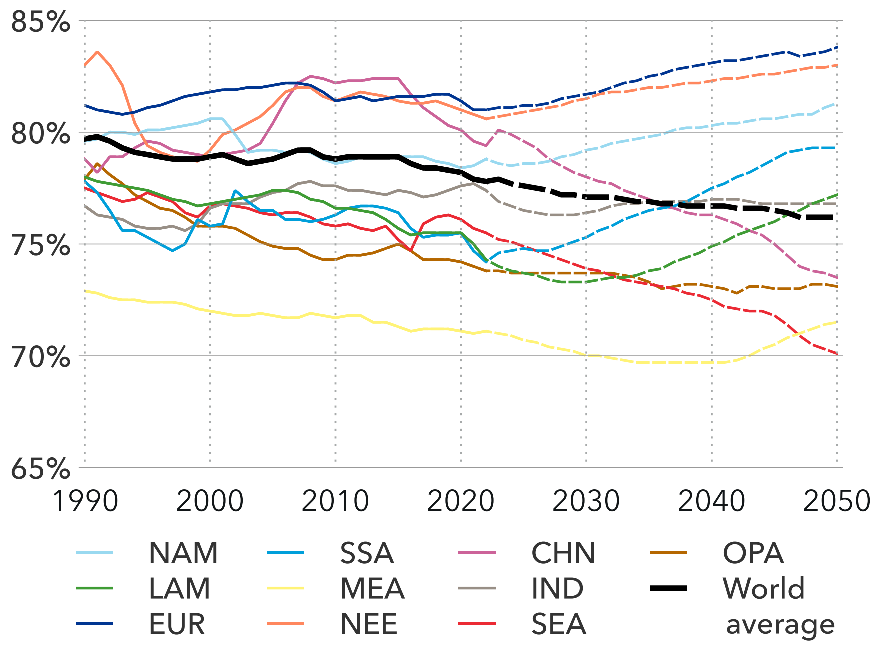
Addressing trends in peak electricity demand, not just the annual averages, is crucial. Peak demand critically affects both power generators and the regional transmission and distribution grids. We need to bolster and expand the grid infrastructure, ensuring it can effectively transfer peak power from 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 2022, but we project a decrease to 76% by 2050 (Figure 2.3). This signifies growth in peak load outpacing annual average demand, a trend towards increased variability, as the net result of many opposing factors happening simultaneously and at various rates across the world.

FIGURE 2.3

Load factor by region

Units: Percentages



Firstly, integrating renewables, especially intermittent sources like wind and solar, magnifies electricity generation variability and impacts the load factor, but advancements in energy storage and grid management will buffer and even reverse 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 via vehicle-to-grid mechanisms. Moreover, demand-side management, through innovations like smart grids, real-time pricing, and demand-response schemes, will help temper peak demand, 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. 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.

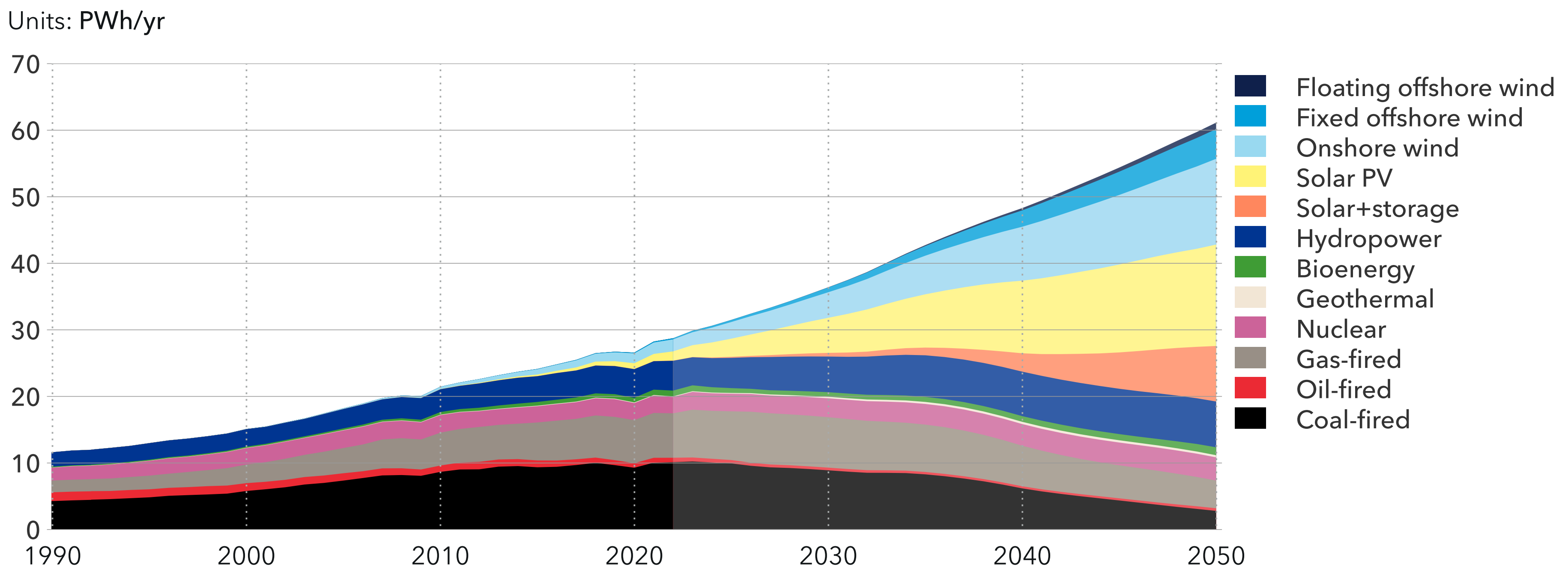
2.1.2 Electricity supply

The global electricity landscape is on the brink of monumental change. However, the transition from fossil fuels to renewables is peppered with challenges. From its 2022 baseline of 8.8 PWh/yr, renewable electricity generation worldwide is set to grow 15 PWh/yr through 2035 (Figure 2.4). Yet, an increase in demand by 13.6 PWh/yr 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 this demand and make inroads into replacing fossil fuels.

Renewables have been an integral part of the global electricity system for over a century, mainly in the form of hydropower. As Figure 2.5 reveals, 2003 marked the lowest share (17.8%) of renewables in the power system, after which they steadily recovered to a share of 31% in 2022. However, this is a rebound from a decline that lasted from the pinnacle of renewables in 1919 until 2003 (Figure 2.5). This decline can be attributed to the emergence of new energy sources, notably oil, natural gas, and nuclear power. The declining costs of solar, wind, and storage technologies offer a chance for reversal. We forecast that by 2033, the share of renewables will eclipse the 1919 peak of 51%, further expanding to a staggering 82% by 2050. Out of this, solar and wind will be responsible for a significant 69% of total share.

FIGURE 2.4

World grid-connected electricity generation by power station type

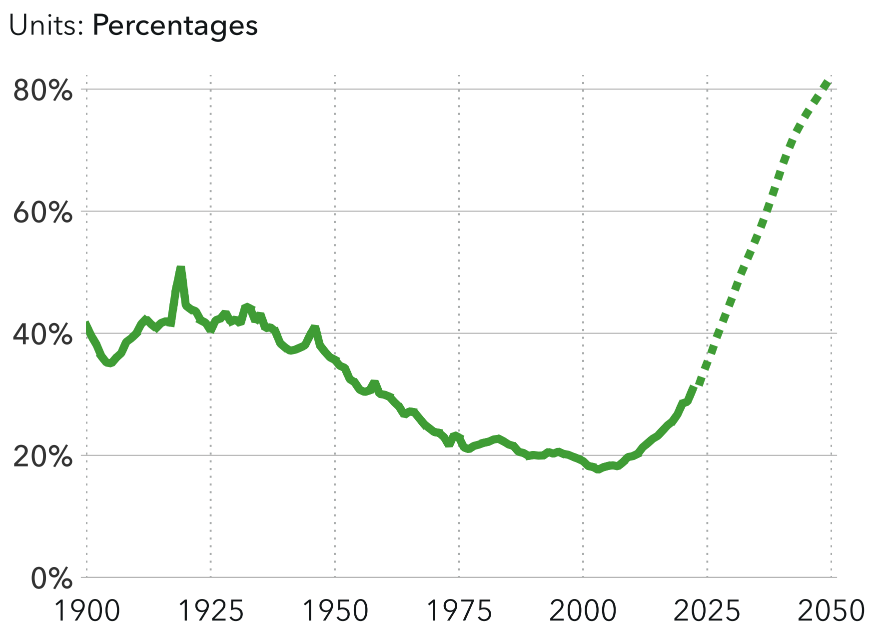


Historical data source: IEA (2023), GlobalData (2023)

Economics play a pivotal role in this shift towards renewables. Solar, with its dwindling levelized costs, will command a 39% share in the 2050 global power mix. Enhancing solar's appeal is the integration of storage solutions with solar, allowing energy consumption even after sunset. Although wind energy is generally more expensive than solar, it is expected to grow in popularity across all regions. Unlike solar energy, wind is a potentially 24-hour source of energy, even though its output can vary. Wind's contribution by 2050 is anticipated to be 30% of the power supply: 21% from onshore, 7.3% from bottom-fixed offshore, and 1.6% from floating offshore setups. The consistency and reliability of offshore wind, coupled with fewer constraints, forecast its growth at an impressive 12% annually from 2022 to the mid-century mark.

FIGURE 2.5

Share of renewables in global electricity supply



Historical data source: Pinto et al (2023), IEA (2023)

It is crucial to acknowledge that regions such as the Middle East and North Africa, the Indian Subcontinent, and North East Eurasia might not mirror this global trend immediately. Their continued dependence on fossil fuels arises from a combination of financial constraints and underdeveloped renewable infrastructure. Greater China's coal consumption for electricity generation will remain unparalleled until the mid-2040s when the Indian Subcontinent is poised to overtake it. Meanwhile, the use of natural gas will remain prevalent, with the Middle East and North Africa holding a leading position in gas-fired power generation for the coming two decades.

This tectonic shift in the energy domain will undeniably impact both conventional power providers and system operators. As renewables, especially solar and wind, become predominant, the space for traditional energy sources to provide energy will shrink. This transition signifies a role-redefinition for many power station operators, as their focus shifts to offering flexibility and backup during downtimes of renewables. It is notable that while fossil-fuel electricity generation is projected to fall by 50% between 2022 and 2050, capacity installation will see only a 22% reduction. This translates to a diminishing utilization rate for fossil-fuel stations. Interestingly, around 8% of global capacity will incorporate carbon capture by 2050, especially in regions with rigorous decarbonization policies, like Europe. Furthermore, hydrogen is earmarked to emerge as a notable player in power supply's decarbonization, solidifying its position in Europe and the OECD Pacific by 2050.

Traditional power stations are likely to face competition from energy storage systems in the future. Yet their vast and dependable capacities ensure they remain indispensable to the energy framework. These conventional plants will retain their influence in price-setting due to their high marginal costs. With these shifts, the concept of base load supply might become a relic of the past in numerous systems (see factbox on page 49).

As we navigate this evolving terrain, several debates and questions arise: What impedes the swift adoption of renewables in the next few years? Can a reliable electricity supply be maintained with a high proportion of solar and wind energy? Will the system necessitate vast electricity storage capacities? How will excess renewable power be managed? Is the financial lure sufficient for expanding generation and storage? Can the grid handle augmented demand and variability without escalating costs? The sections that follow, backed by our research and our model, endeavour to answer these questions and cast a light on the path ahead.

Cost trajectories

The levelized cost of energy (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 2.6, 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, driven by technological advancements, economies of scale, and improved manufacturing and deployment practices. From 2020 to 2050, these learning rates are projected at 12% for solar PV, 13% for onshore wind, and 15% for fixed offshore wind. This means each doubling in global capacity corresponds to a respective LCOE drop by these percentages.

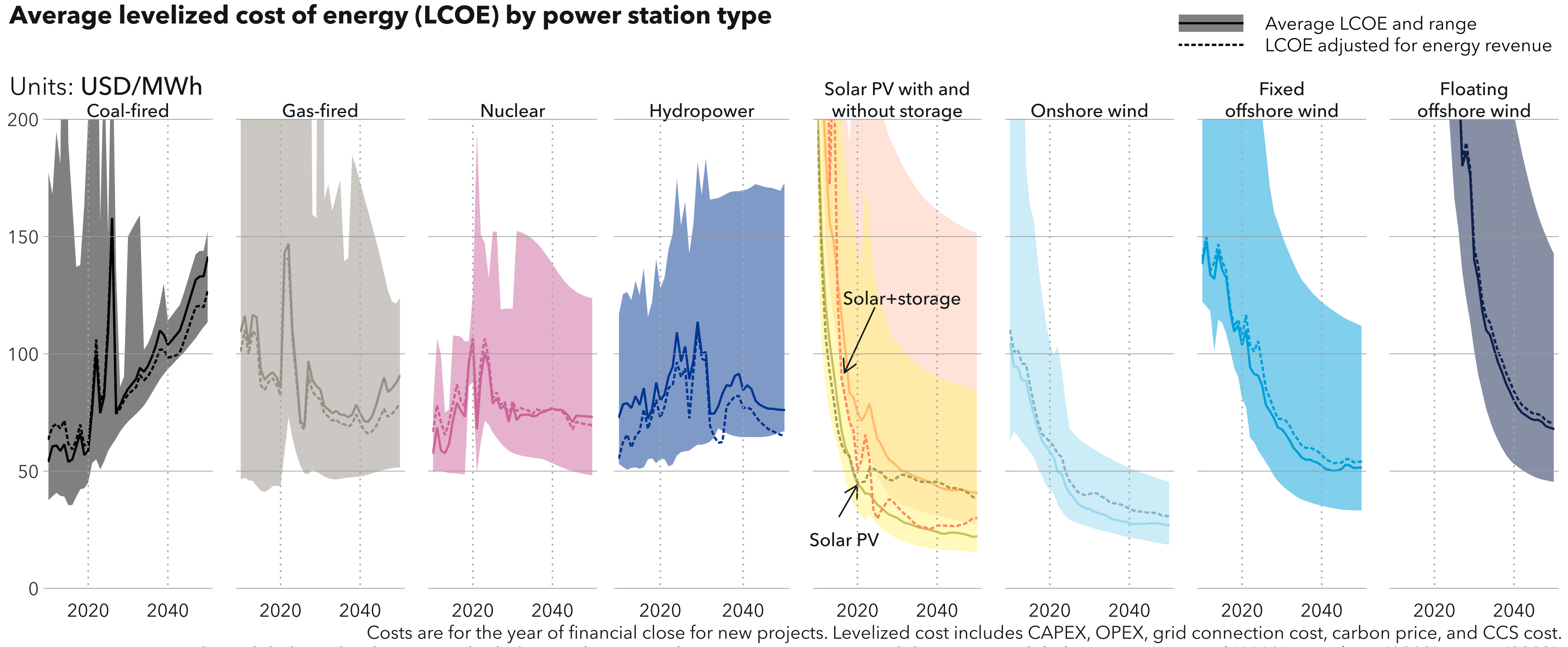
Solar PV is set to break the USD 30/MWh mark by 2030 at the global average, with on-site storage adding another USD 22/MWh to the levelized cost. Average onshore wind LCOE will follow solar PV with a five-year delay in reaching USD 30/MWh. We foresee 2030 global LCOE for fixed offshore wind to be around USD 68/MWh, and for floating offshore to be at USD 140/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 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.

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 experiencing 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 one of increasing cost due to cost overruns. With the balance shifting to Greater China and the Indian Subcontinent, and the emergence of small modular reactors, we expect the average cost of nuclear to decrease to USD 70–80/MWh by 2030s. 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.

FIGURE 2.6

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.

Our cost of capital assumptions can be found in Table 2.1. See Chapter 5 for a more detailed discussion of our cost of capital projections across energy sources.

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 limitation, as shown in Figure 2.6, 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.

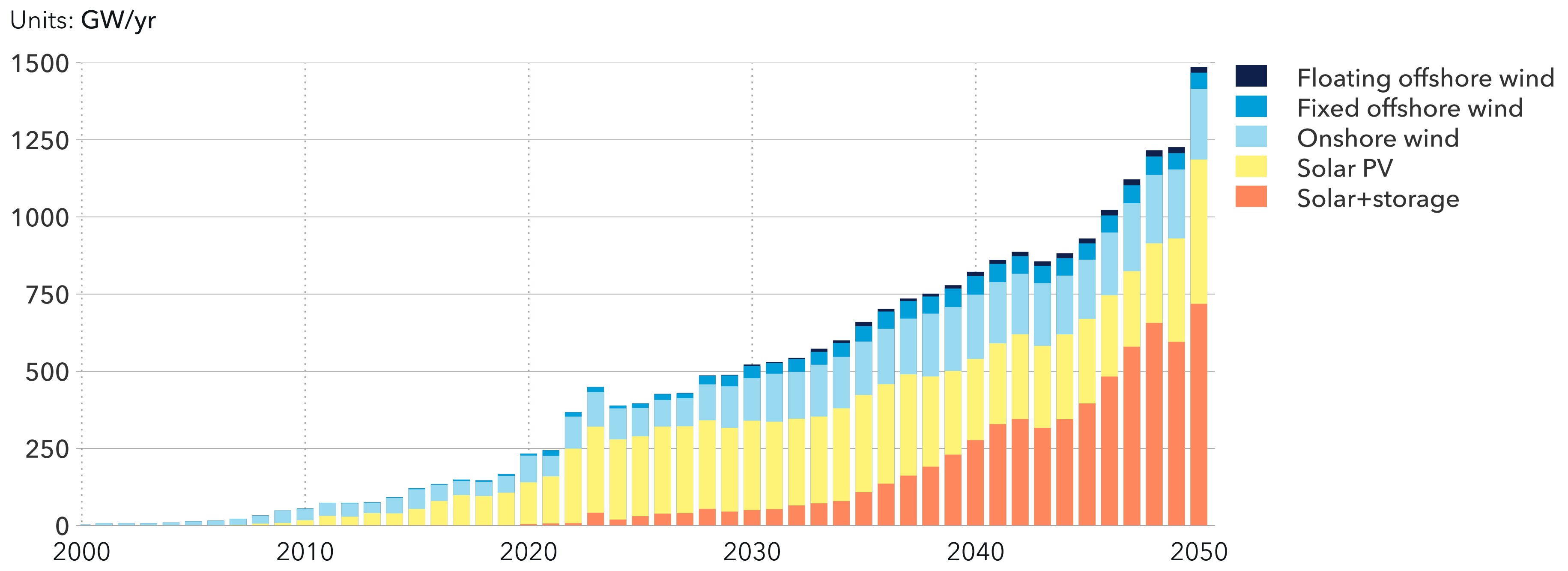
Power stations also receive compensation for ensuring a certain portion or all of their capacity is available during times specified by the system operator. This arrangement underpins grid reliability and ensures adequate capacity during peak demand. As variable renewables grow, we anticipate a rise 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.

Near-term challenges

Delays in planning and permitting, especially in regions like North America (the US), Europe, and the Indian Subcontinent, 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, for instance, due to 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 2.7 shows the trajectory of new solar and wind capacity additions we forecast up to 2040, showing a steady but restrained growth in the short term. While some regulatory initiatives, like

FIGURE 2.7

Global solar and wind capacity additions



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

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, prioritizing proactive grid investments and upgrades, is crucial for a seamless energy transition. Our discussion on permitting delays in Section 3.2 on page 73 explores this issue in more detail.

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. 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 of around 10% in Europe until the early 2030s as the region brings its supply from China to Europe. Section 3.2 has more on short-term challenges for wind industry.

Long-term challenges

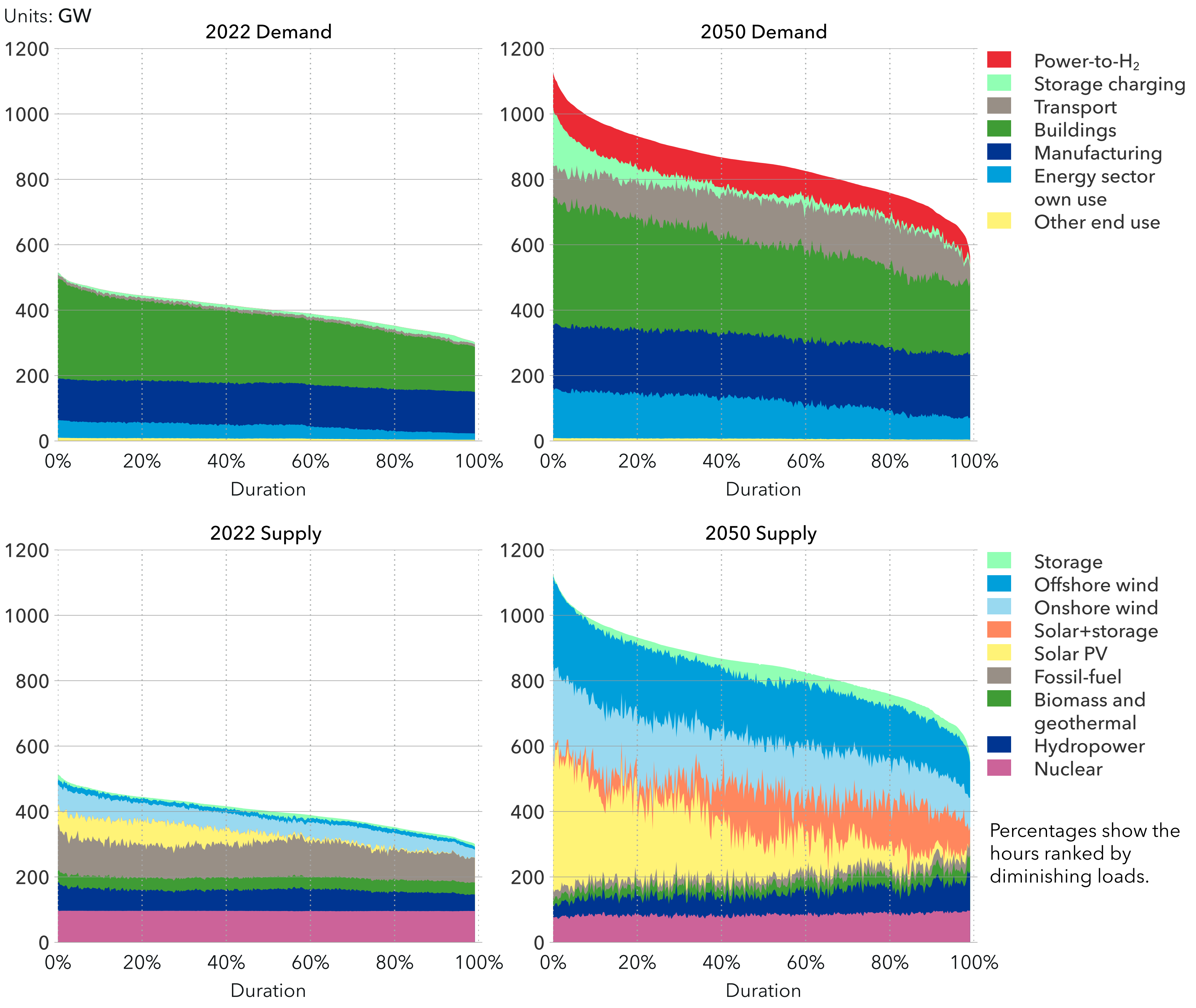
Adequacy

Ensuring the future power system's adequacy – the ability to consistently meet demand – remains crucial, especially with the rising integration of VRES and changing consumption habits. A representation of the core of this challenge is shown in Figure 2.8, which presents the simulated electricity supply and demand distribution 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.

FIGURE 2.8

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



The curve displays 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.

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. 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. 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.

Flexibility

Flexibility in power systems is becoming increasingly paramount, as evidenced by the 2022 European electricity demand shown in Figure 2.8. Here, demand fluctuates between 290 GW 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.

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, to the extent that they may challenge the very existence of constant, or 'base load', generators like nuclear power. 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. 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 decreases. For a comprehensive overview of this future flexibility landscape, the infographic on page 47 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. For a thorough exploration of this topic, turn to the factbox on page 50.

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.

> As flexibility providers increase, the demand for such flexibility reduces, bringing a self-balancing feedback into play.

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 2.6, 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.

MODELLING POWER HOUR BY HOUR

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

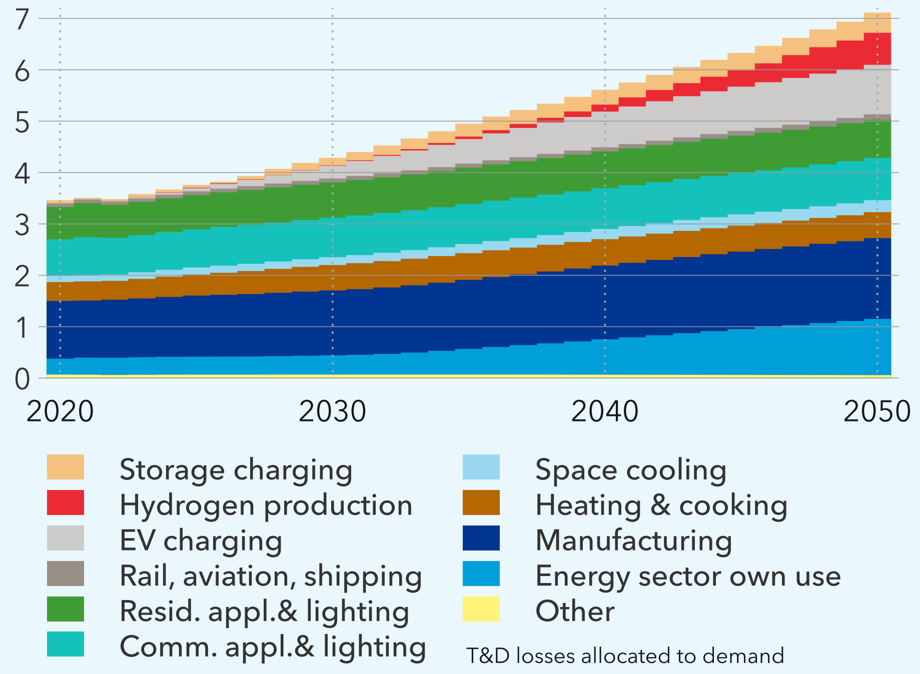
Annual electricity demand by segment comes from the corresponding parts of the model. Investment in new capacity is based on energy, firm capacity and flexibility needs. Technology mix is decided by revenue-adjusted levelized cost.

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.

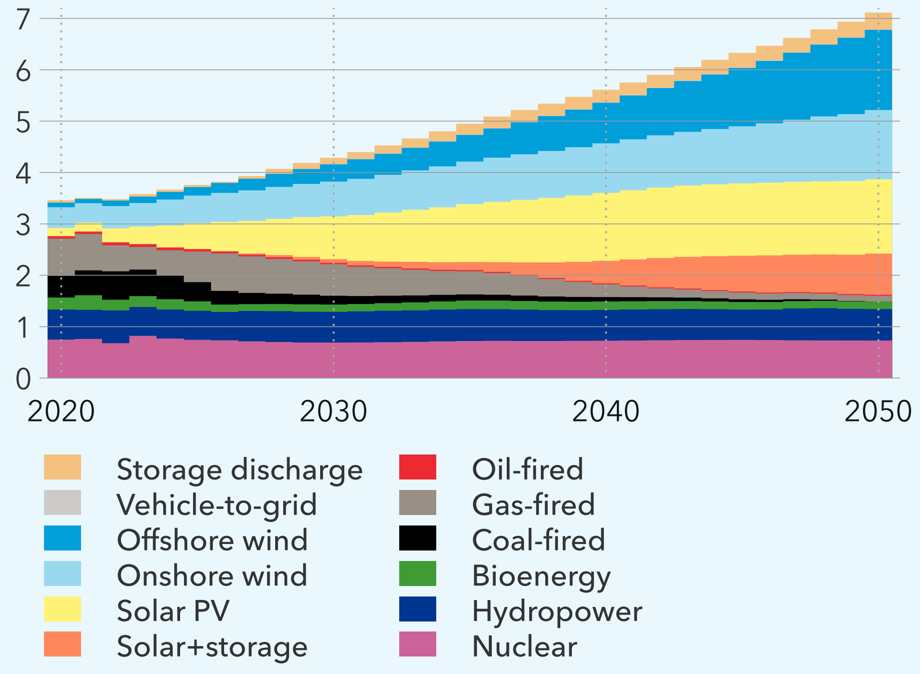
Europe electricity demand by segment; 2020-2050

Units: PWh/yr



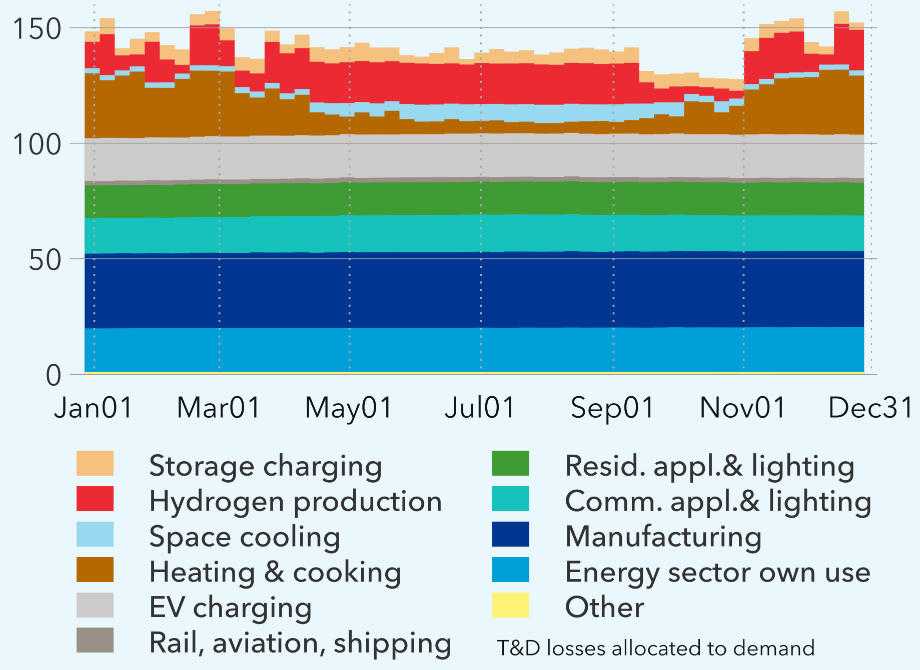
Europe electricity supply by source; 2020-2050

Units: PWh/yr



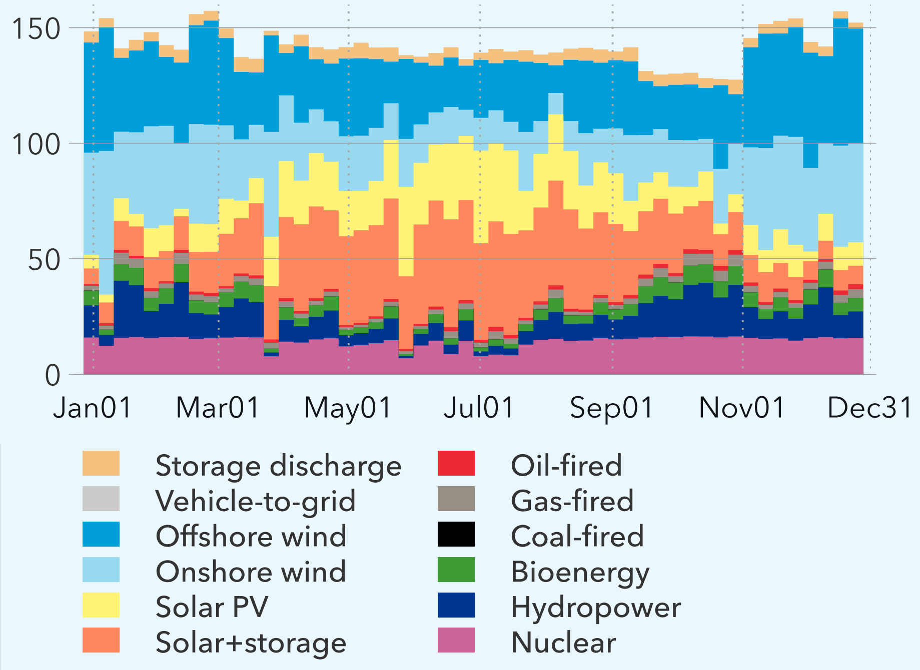
Europe electricity demand by segment; 2050

Units: TWh/week



Europe electricity supply by source; 2050

Units: TWh/week



MODELLING POWER HOUR BY HOUR

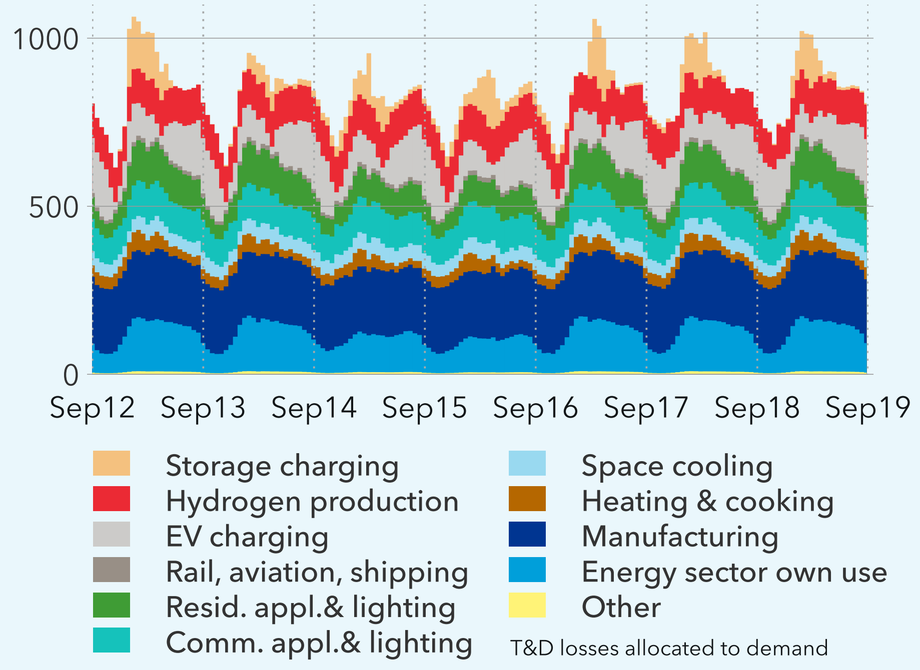
The chart below focuses on week 37. Storage and hydrogen production respond to price signals. During midday, with abundant solar and cheaper electricity, electrolysis plants run, and storage charges.

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.

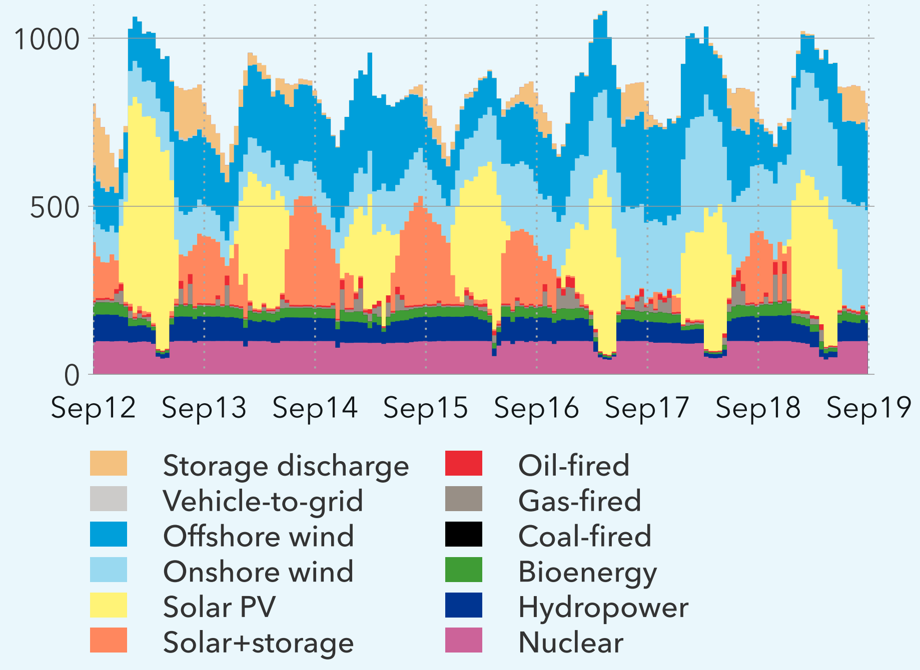
Europe electricity demand by segment; week 37; 2050

Units: GWh/hour



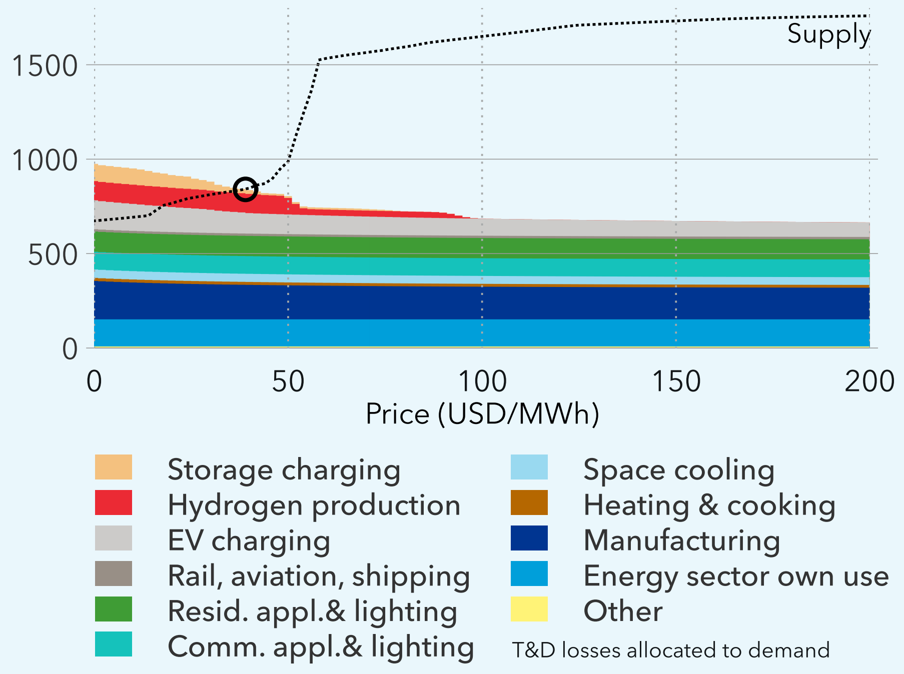
Europe electricity supply by source; week 37; 2050

Units: GWh/hour



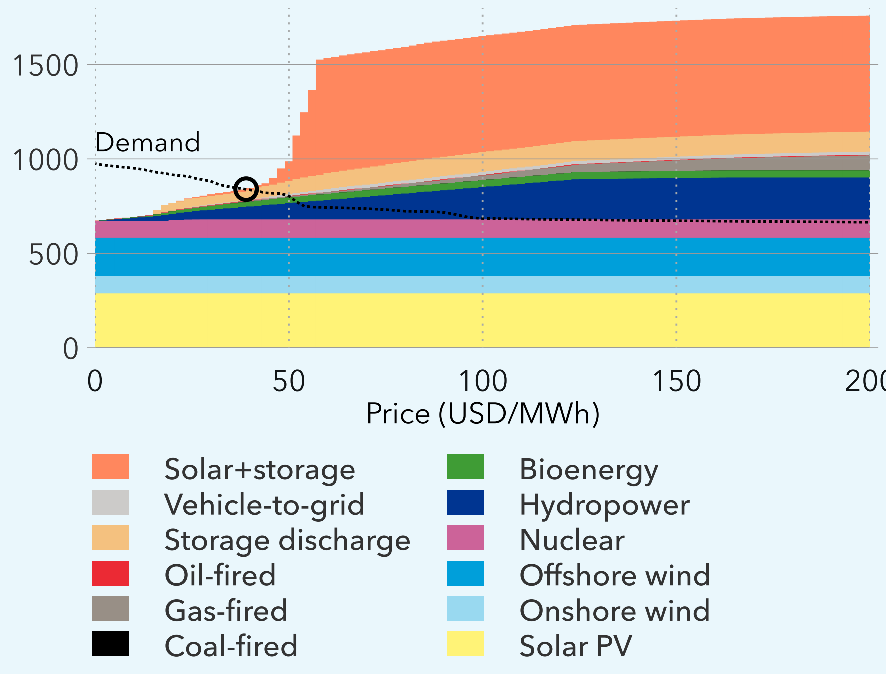
Europe electricity demand curve; 13 September 2050; 17:00-18:00

Units: GWh/hour



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

Units: GWh/hour



CHALLENGING THE CONCEPT OF BASE LOAD

In the future power system, the significance of base load will diminish as renewable power, especially from wind and solar, becomes more prevalent.

Base load

Base load (sometimes written as baseload) represents the constant and relatively stable level of grid-based electricity consumption and as such the minimum level of electrical power demand that occurs continuously over a given period. In general, power demand exhibits cyclic variations on a daily basis, but generally peaks during business hours and gradually decreases late at night and during the early morning hours. Throughout a 24-hour period there will be a minimum level of demand, which is effectively the base load, and this must be met regardless of fluctuating consumer demand or varying weather conditions.

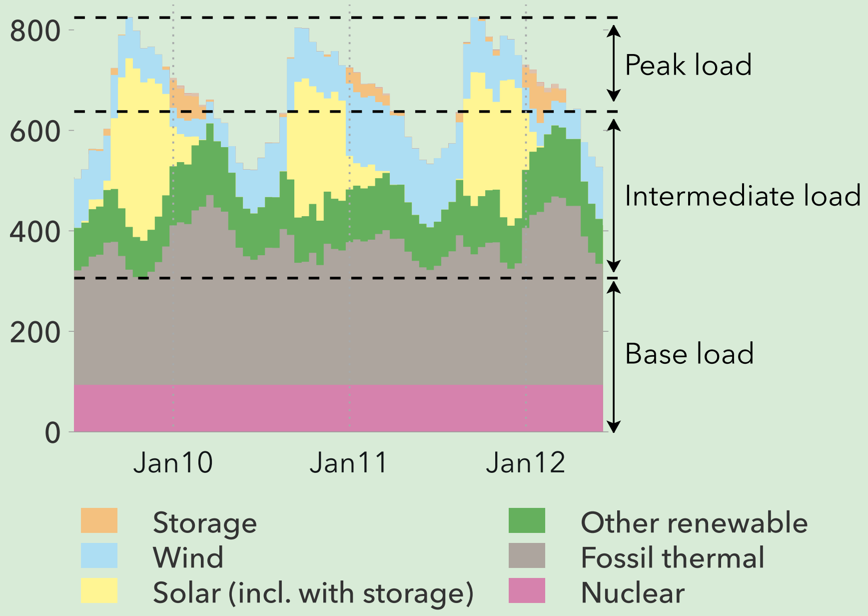
Base load usually represents 30 to 40% of the maximum load. The remaining power demand, known as above-base, is managed by intermediate and peak power plants that are integrated into the grid. Base load power plants offer significant advantages in terms of cost efficiency and reliable operation at optimal power levels. However, they also have certain drawbacks, including slower response times (except of natural gas plants), limited fuel flexibility, and reduced efficiency when operated below their maximum capacity.

Traditional power sources like coal-fired, gas-fired, and nuclear plants are associated with base load provision. Because base load must be provided at all times, the argument is often advanced that such power stations are 'essential'. This is in fact a myth. Base load is a function of electricity consumption, and is not defined by supply technology. As we demonstrate below, base load can be perfectly

FIGURE 2.9

Load for a typical winter week in North America in 2030

Units: GW



adequately supplied by variable renewables in combination with various storage technologies, which is generally either cheaper and/or cleaner than nuclear, coal, and gas. Additionally, the public is often led to believe that the more variable renewables added to a given grid, the higher the intermittency of supply and thus the need for 'traditional' base load increases. That is also a fallacy: owing to the law of large numbers, the greater the number and variety of renewable sources added to a grid, the lower the overall intermittency.

Historically, base load power has been supplied primarily by large-scale fossil power plants, but also nuclear and hydroelectric power plants. Base load plants are typically large-scale facilities and play a critical role in maintaining the efficiency of an electric grid. These plants operate consistently, generating power at a steady rate without the ability to swiftly accommodate peak demands or emergency situations. Consequently, the concept of base load is closely tied to the characteristics of fossil power generation sources and nuclear and hydroelectric power plants as they are characterized by their ability to operate continuously for extended periods with limited variations in their output.

Some argue that it is not feasible to build a large-scale electricity generation system using renewable energy sources exclusively because they are intermittent and unable to consistently provide base load power for 24 hours. This critique is deceptive. Base load is a characteristic of electricity demand, not

a characteristic of supply technologies. Nuclear or coal power plants operate in base load mode due to technical limitations, as they are incapable of operating in a more flexible manner. Additionally, these plants rely on high utilization to recoup their significant investment costs.

But it is simply a false claim that renewable energy cannot replace coal-fired electricity as a base load power source. If this fallacy gains widespread belief, it could hinder the development of renewable energy as a mainstream energy supply technology, confining it to a niche market instead of realizing its full potential.

In the future power system, the significance of base load will diminish. As renewable power, especially from variable sources like wind and solar, becomes more prevalent, supply and demand will be better harmonized in a flexible manner – as we have already shown in our discussion on flexibility above.

Renewable power generators can be classified into two main categories: dispatchable and variable. Dispatchable renewable power generators have the ability to regulate their output within a defined range, similar to conventional fossil-fuel power plants. These generators are capable of providing base load power when necessary. Examples of dispatchable renewable power sources include reservoir hydropower plants, biomass (including biogas) power plants, geothermal power plants, and concentrated solar power (CSP) plants equipped with thermal storage, such as molten salt.

Controlling the output of VRES, such as wind and solar photovoltaic (PV), is considerably more challenging. These are unable to consistently meet the demand for base load power at all times. However, this limitation does not necessarily pose a disadvantage, as the objective is not solely to fulfill base load power requirements. By combining VRES with dispatchable renewable power sources and storage or flexible fossil-fuelled power, it is possible to reliably meet the overall power demand, including base load, at all times. It is important to acknowledge that the variability of individual wind or solar plants is at its highest. However, when multiple plants of the same type are aggregated across a country or continent, the overall variability decreases. Additionally, combining different types of VRES, such as solar and wind, further reduces variability.

Several countries have already demonstrated that a combination of renewable energy sources can effectively mitigate variability. In Brazil, the interplay between hydropower and wind power is complimentary. Similarly, in Germany, PV and wind power generation complement each other, thanks to their contrasting seasonal variations.

The examples of Denmark, Germany, and Spain demonstrate that incorporating up to 50% VRES in the annual electricity supply poses minimal challenges, especially in power systems that are well interconnected with neighbouring countries. However, higher shares of VRES present significant challenges, necessitating a reevaluation of power system operation and planning. Even with the current moderate average VRES shares, there are instances when instantaneous penetration levels can reach high levels during certain hours, sometimes exceeding electricity demand. Consequently, the need for dispatchable power plants to cover the permanent minimum load diminishes and eventually disappears with increased VRES deployment. In future power systems with higher shares of VRES, the distinction between base load and other load types becomes less meaningful, and attributing power generating technologies accordingly becomes less relevant.

When multiple plants of the same type are aggregated across a country or continent, the overall variability decreases.

Changing electricity market design for high renewables penetration

Established power systems were designed around thermal generation with dispatchable production and increasing variable costs, matching supply to variable demand. This is changing where high penetration of variable renewables, such as wind and solar PV, enable generation at near-zero cost, leading to zero marginal production costs. By definition, generation from VRES will fluctuate, and there will be more volatile pricing set by demand and consumption levels.

As explained above, price collapse/cannibalization will occur unless demand is tailored to 'excess' supply (e.g. making green hydrogen and charging EVs when power is cheap). Conversely, price hikes will happen unless balanced by flexibility sources or additional capacity being available. The key point is that when supply becomes less controllable, managing demand will become increasingly important for loads to follow rises and falls in generation. Consumption adjusted by the price level will help to even out prices.

For continued renewables growth and electrification of end-use, regulatory frameworks must incentivize change:

Upstream: for continued investment in high CAPEX renewable generation assets; diverse technical flexibility resources over multiple timeframes (e.g. battery storage, real-time, day/week, months); and, available conventional capacity – despite low capacity factors – for resource adequacy.

Downstream: for engagement and active participation at the consumer level to provide operational flexibility and demand response (e.g. timing of heating/cooling).

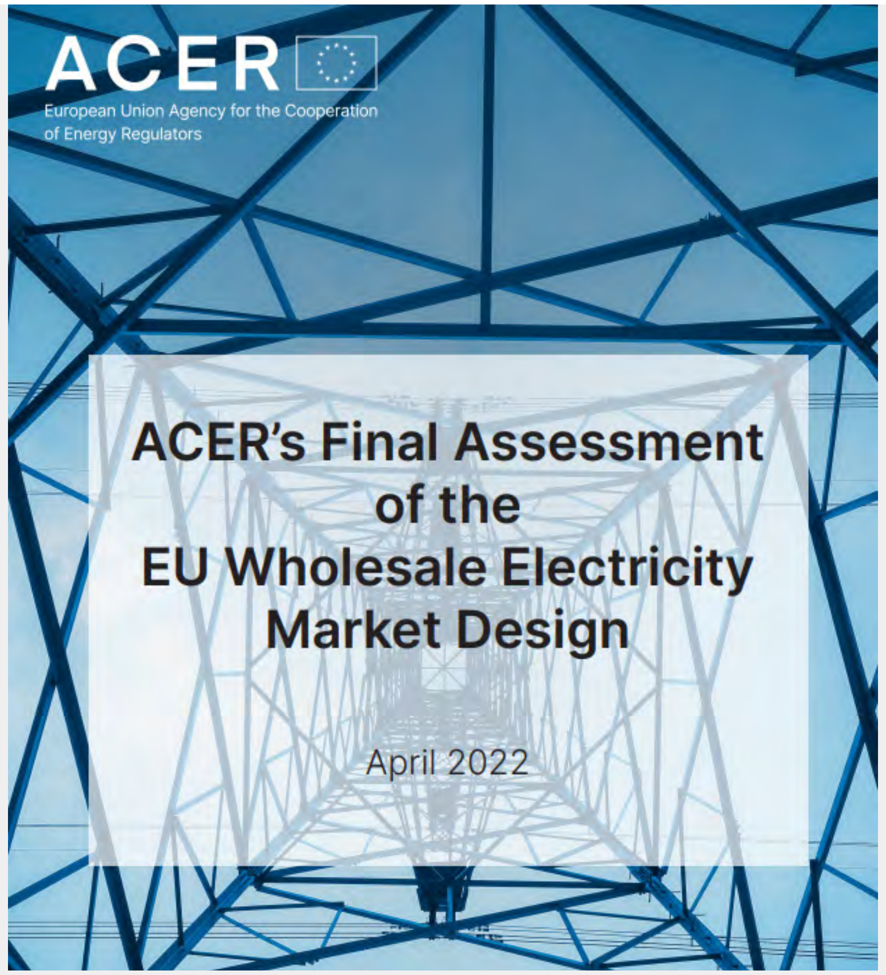
Future-fit market arrangements: The case of Europe

Energy bills surged in Europe as wholesale electricity prices soared from an average EUR 35/MWh in 2020 to above EUR 500/MWh in March 2022 (Cevik et al., 2022).

The main drivers were costlier gas-fired generation after Russia invaded Ukraine, a gas supply shortfall, loss of generating capacity, and drought. Under the marginal pricing (or 'merit order model') underpinning Europe's wholesale electricity prices, the most expensive technology for meeting demand in a given period sets the final electricity price. This is done according to the production cost determined by the energy sources used in generation, in this case natural gas.

Amid rising consumer bills, this model and electricity market reform came under scrutiny. "This market system does not work anymore. We have to reform it, we have to adapt it to the new realities of dominant renewables," said European Commission President Ursula von der Leyen (EU Parliament, 2022). However, the EU Agency for the Cooperation of Energy Regulators concluded that the current electricity market design was not behind the crisis and was helping to alleviate it (ACER, 2022).

The EU Commission's March 2023 proposal to overhaul electricity markets (COM/2023/148) is more evolution than revolution. It aims to boost renewables investment,



ACER published its assessment on EU wholesale electricity market design suggesting 13 measures for policymakers to future-proof the market design.

protect and empower consumers, and raise net-zero competitiveness by creating long-term certainty and restoring investor confidence. The key proposals are:

– Protect customers against fossil-fuel volatility, obliging Member States to ensure availability of market-based, long-term Power Purchase Agreements (PPAs) between producers and consumers, and guarantees for payment obligations.

– Introduce measures to bring more clean, flexible solutions (e.g. demand response and storage) to the system to compete with gas.

– Mandate all public support for new investment in infra-marginal and must-run renewable and non-fossil electricity generation to be through two-way Contracts for Difference (CfDs), with Member States obliged to channel excess revenues to consumers.

The Commission's proposal was progressing through the EU legislative procedure at the time of writing this Outlook.

What is important?

Preserve the price signal: Marginal pricing is how prices emerge naturally in free markets. It is important for price discovery and signalling scarcity. Price volatility triggers tomorrow's flexibility (technologies) and contributes to adequate demand response.

Preserve market integration: Market integration and cross-border resource sharing are means to secure supplies, but expanding renewable generation needs rapid infrastructure build-out (see Section 3.2).

Improve long-term markets: Investing in generation depends on project profitability over time and thus on long-term price expectations. Long-term contracts can provide a fixed price through mechanisms like capacity remuneration, PPAs, and CfDs from competitive tenders backed by governments, offering reliable revenue and less financial risk.

Prepare for crisis: In 2022, price levels were unacceptable societally. Future surprises are inevitable; so, interventions and support schemes must be in place to ensure continued support for the transition.

How we consider future market design in our forecast?

Our modelling of electricity is discussed in this chapter. While the LCOE metric is favourable to renewable generation, investment hinges on revenue prospects. We assume mechanisms (CfDs, capacity, flexibility) ensuring continued profitability. Capacity additions in the model occur under three headings: electricity demand, capacity demand, and flexibility demand.

– Electricity demand: the modelling uses the revenue-adjusted LCOE as a guide to identify the most cost-effective technologies to meet demand.

– Capacity demand: understanding that VRES are non-dispatchable and based on the residual peak load requirement, our model ensures adequate capacity through continued investment in conventional generation and storage.

– Flexibility demand: the model computes the need for ramp up/down based on supply and demand profiles and invests in new capacity for sufficient system flexibility.

2.2 POWER GRIDS

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 schools, factories, and cities.

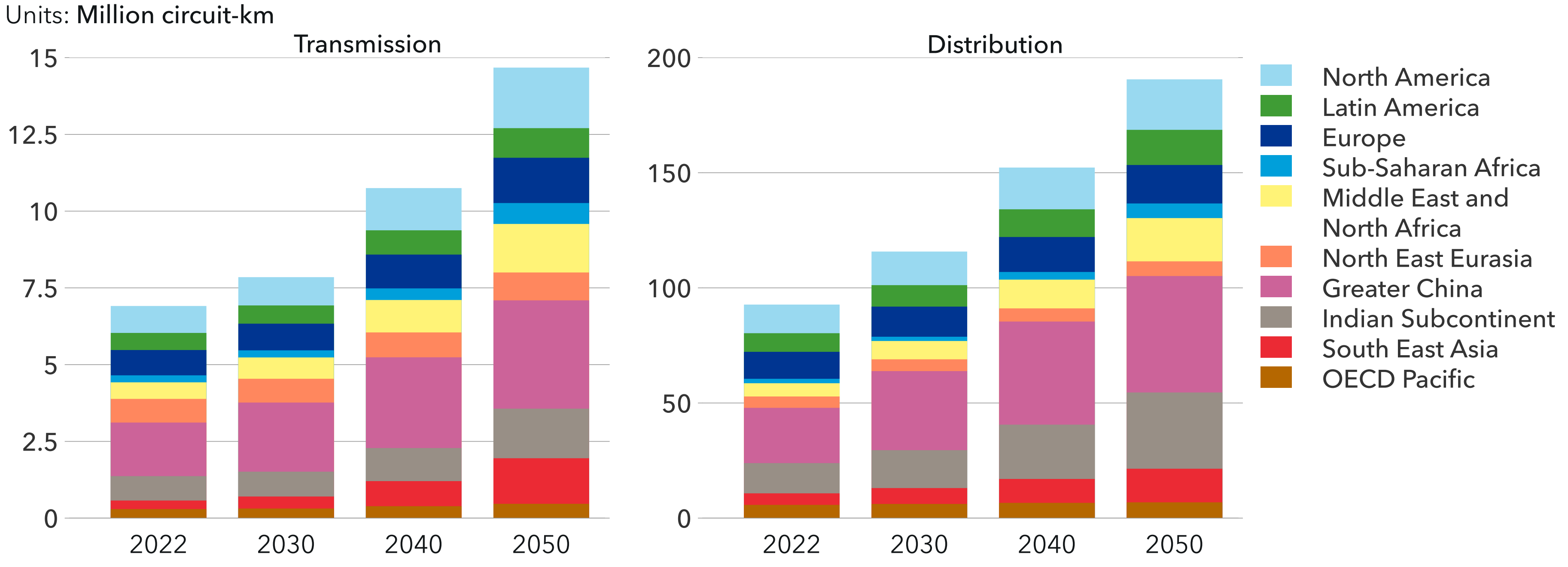
Often an under-appreciated part of the power system, the grid is the backbone of a modern, electrified, well-functioning society. With increasing electrification forecast in almost all world regions, a stronger and smarter grid is essential for delivering power, especially with rising electricity and power demand and greater use of variable renewable technologies.

The power grids for transmission and distribution can together be thought of as the biggest machine in any country. Transmission involves high, extra-high, and ultra-high voltage (all denoted for brevity as high voltage, HV) power lines, transformers, control centres, etc. They transmit electricity from power plants over long distances at high-voltage to minimize losses. Distribution grids consist of low and medium voltage power lines along with step-down transformers, distributing electricity to different demand centres, such as houses and factories.

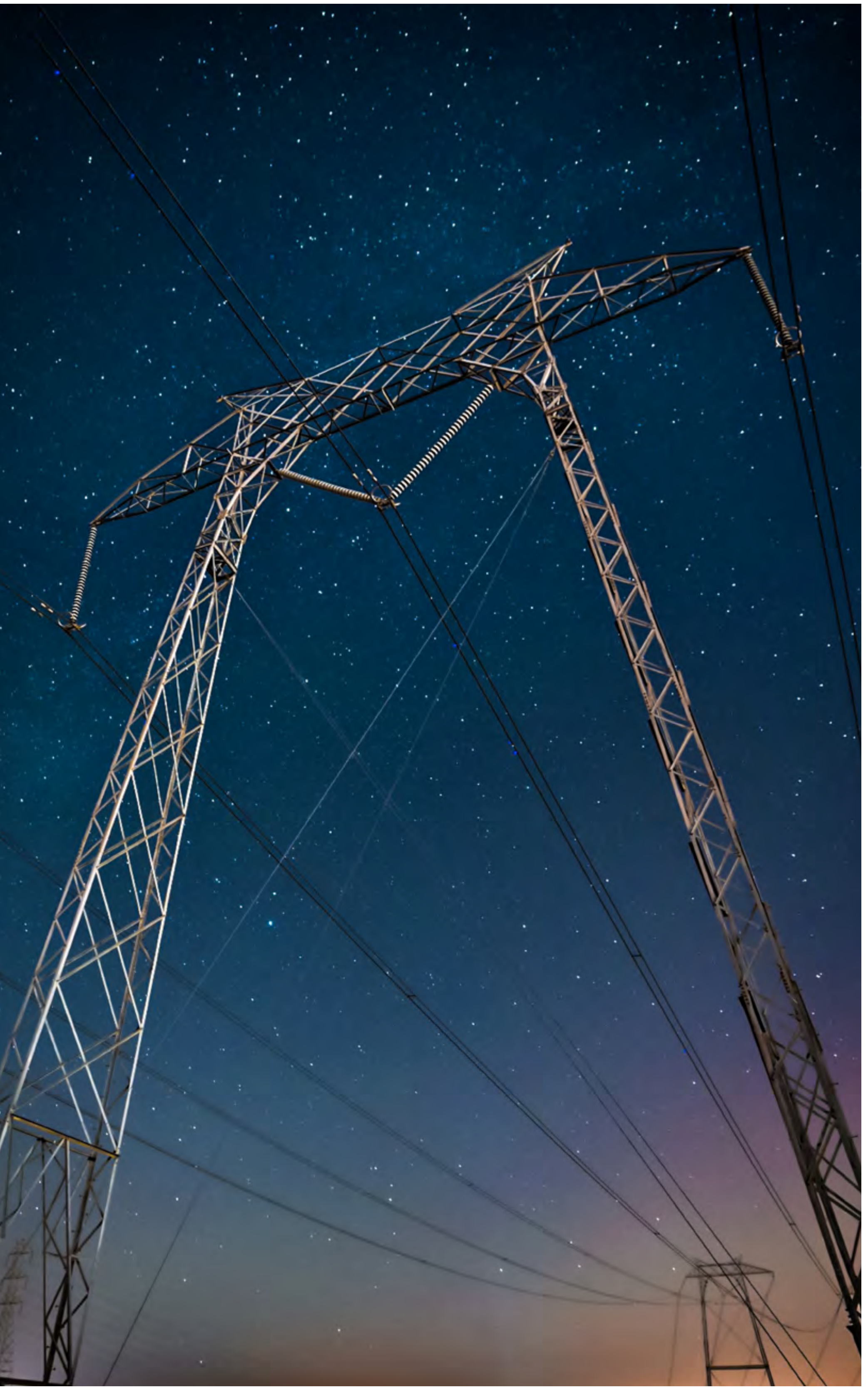
Figure 2.10 presents the regional growth of transmission and distribution lines in million c-km. Within the timeframe presented, all regions are expected to undergo growth in power lines. Those lagging in electricity access, such as Sub-Saharan Africa and South East Asia, experience a larger, three-fold growth, while OECD Pacific, already fully electrified, is expected to see only 20% more c-km between 2022 and 2050.

FIGURE 2.10

Transmission and distribution power-line length by region



Historical data source: GlobalData (2023), DNV analysis



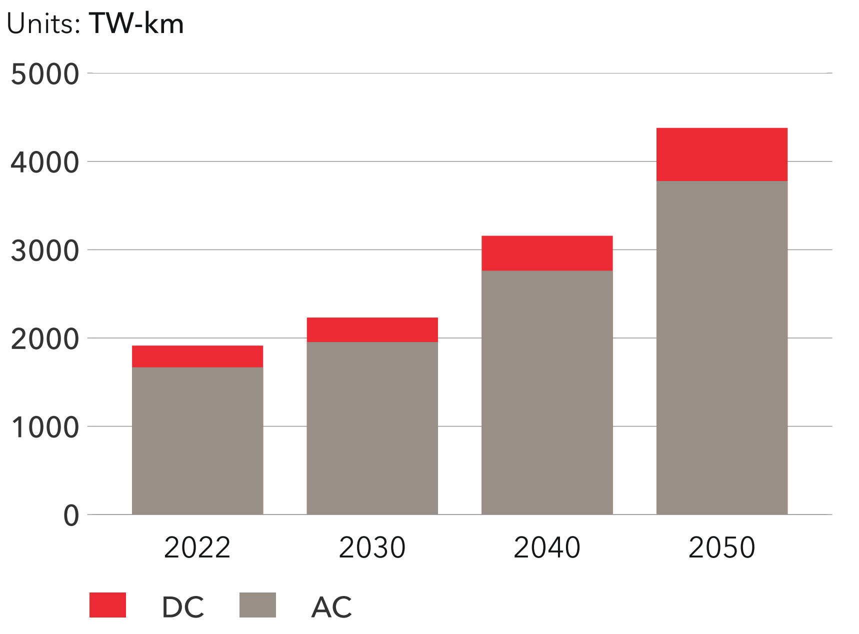
Surprisingly, even North America, a fully electrified region, is expected to see a doubling in transmission grid length due to electrification of the economy and the enormous amount of renewable power that will be connected to the grid. The windier and sunnier generating sites are often far from population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

Transmission grid

The growth in transmission grid capacity, as delivered by alternating (AC) and direct current (DC), is shown in Figure 2.11.

FIGURE 2.11

Tranmission grid capacity by type of current



Historical data source: GlobalData (2023), DNV analysis

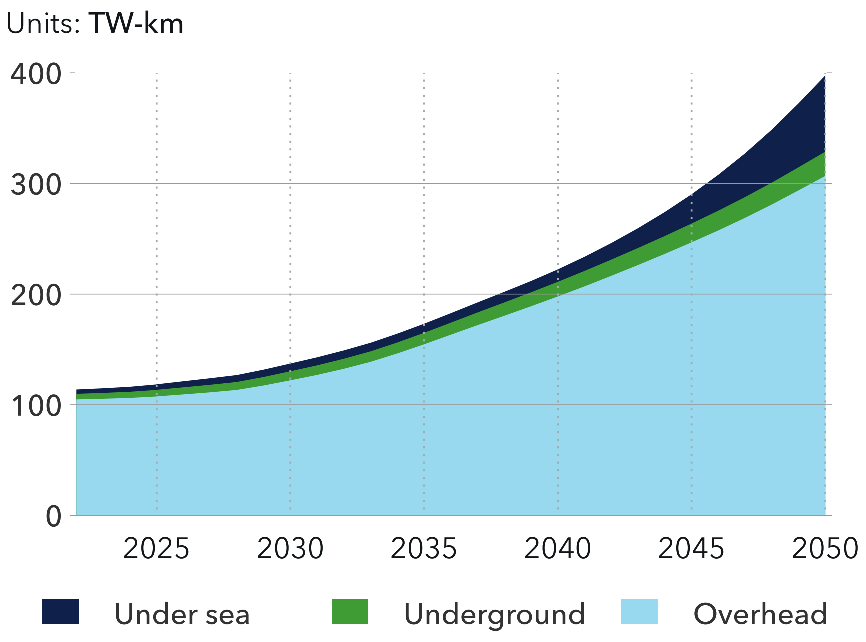
The upfront costs of DC are higher than for AC. However, DC is less costly on the basis of electricity transmitted per distance and has lower voltage losses. Besides this, HVDC lines are critical for integrating offshore wind power into the modern grid in the future. As shown in Figure 2.12, by 2050 almost 20% of the HVDC lines will be undersea, connecting offshore wind farms to the transmission grid.

Distribution grid

Globally, the distribution grid more than doubles from 200 TW-km in 2022 to about 500 TW-km in mid-century due to the rapid electrification expected in almost all regions. This electrification happens on two fronts which both contribute to the growth in the distribution grid. The first is higher electricity demand with more demand segments, transitioning to electricity, and new demand segments, such as EVs in road transport, being introduced. Second, the peak power demand of a region also grows due to more electrification – that is, electricity demand over a unit of time becomes 'peakier' or higher. On the supply-side, as distributed VRES grows, the distribution grid will need strengthening to handle voltage fluctuations such as the diurnal variations of solar power. This means that the distribution grid needs to grow its capacity and evolve to handle the higher power demand.

FIGURE 2.12

HVDC grid capacity by power-line type



Historical data source: GlobalData (2023), DNV analysis

Grid-enhancing technologies

As the share of VRES in electricity supply grows significantly, integration of renewables and grid modernization must work hand-in-hand to achieve grid reliability. Modernization of the grid will involve grid-enhancing technologies (GET) such as:

– Dynamic power line rating
– Power flow controllers
– Digital twin and/or real-time monitoring
– Advanced grid features, such as smart meters
– Measures to protect the grid from cyberattacks, inclement weather, and to increase resilience

2.3 STORAGE AND FLEXIBILITY

Venturing toward 2050, the intertwined tales of energy storage and flexibility take centre stage. As the world grapples with an evolving energy matrix, flexibility emerges as the linchpin. From Li-ion batteries to innovative grid features, the shift is palpable. Concurrently, the significance of storage accelerates, with a spotlight on not just daily needs, but seasonal demands. Dive into this section to explore the interplay of these pivotal components in our sustainable energy future.

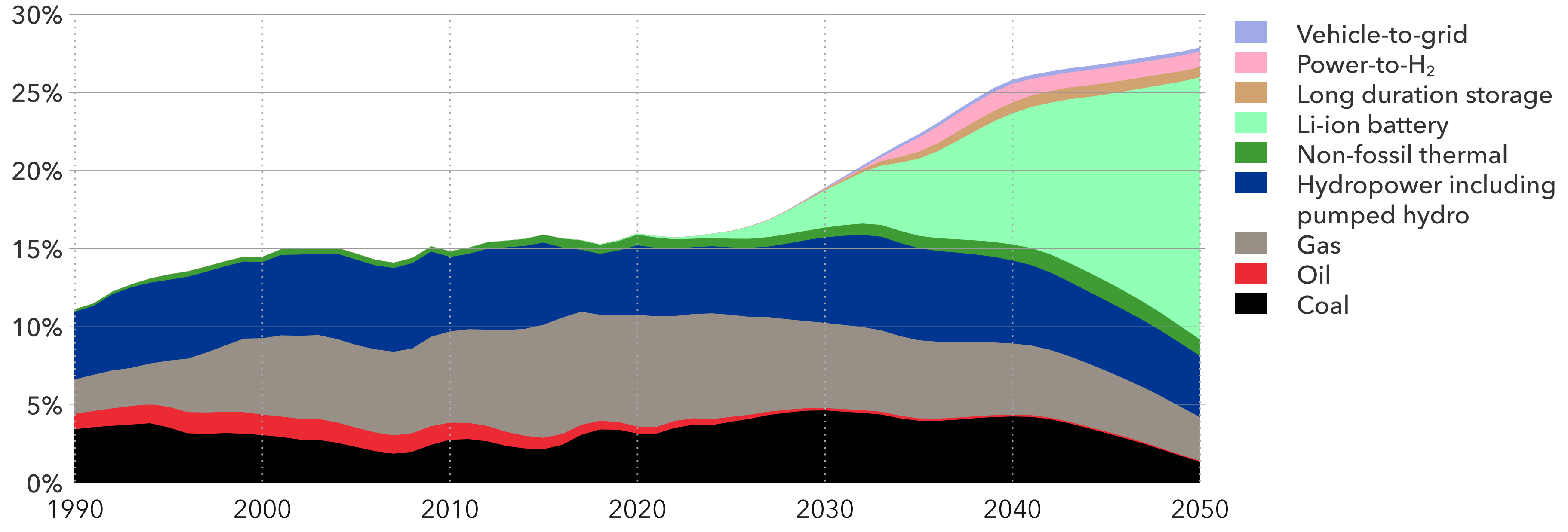
Flexibility

The global energy landscape is undergoing a major shift as we move towards 2050, and the key to managing this transition successfully is flexibility. As VRES capacity surges by a factor of seven, the global need for flexibility will almost double. In Figure 2.13, we examine the projected increase in the ratio of daily hour-to-hour standard deviations to average

FIGURE 2.13

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

Units: Percentages



load. This helps us to understand how each technology responds to this variability. We gauge the flexibility contribution by observing the decrease in supply standard deviation with a particular technology compared to its absence.

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 operate with renewables, amplifying the importance of their flexibility. However, it is 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, especially when VRES provides power at lower costs, becomes paramount.

The transition to greater flexibility isn't just about 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 is 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, as cited by the International Renewable Energy Agency (IRENA, 2019).

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.

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.

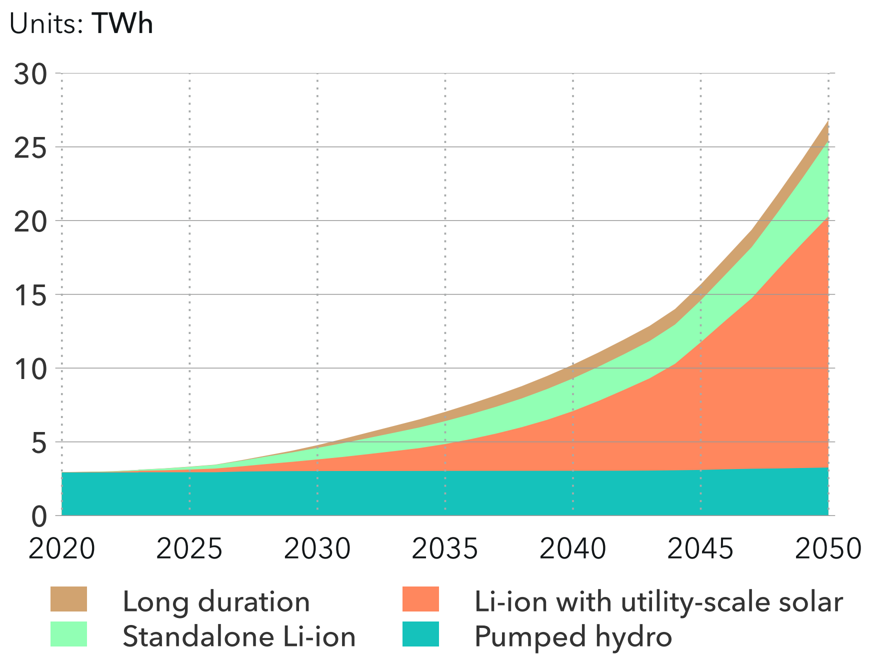
Storage

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 2.14, yet, its 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 1.6 TWh by 2030, further expanding to a robust 22 TWh by 2050. Intriguingly, a significant portion of this capacity is being integrated with renewable generation.

FIGURE 2.14

World utility-scale electricity storage capacity



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.

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 1.4 TWh by 2050.

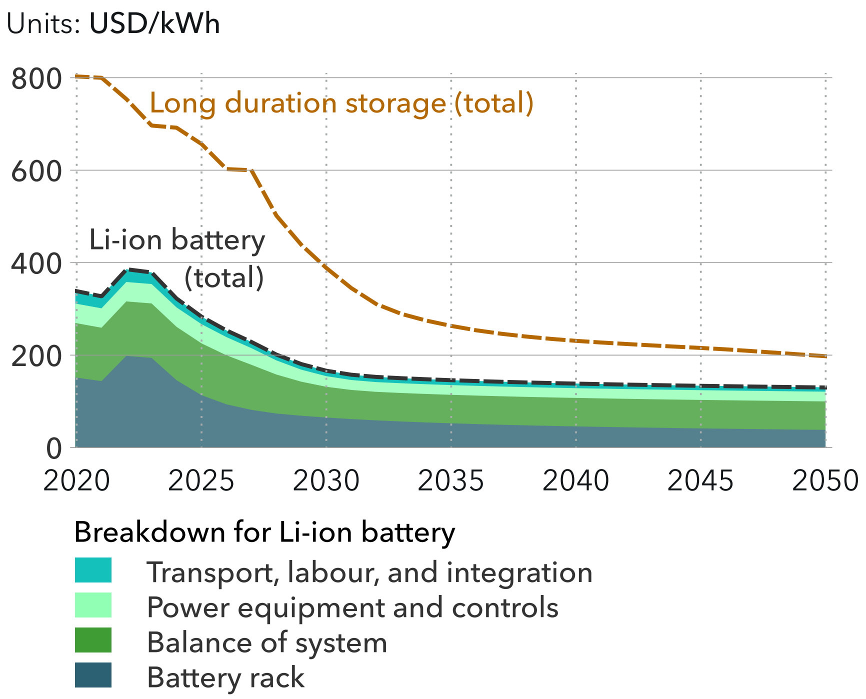
Despite the dominance of Li-ion, which currently forms 95% of the storage projects that we are involved, the industry is on the brink of innovation. Supply-chain challenges, exacerbated post-pandemic, have nudged Li-ion battery prices upward. Nevertheless, we are optimistic about the cost trajectory. By 2030, costs for utility-scale Li-ion battery systems are projected to dip below USD 200/kWh, further reducing to approximately USD 130/kWh by 2050, as illustrated in Figure 2.15.

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. These appear promising 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 the 2023 Outlook, 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.

FIGURE 2.15

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



Seasonal storage

Seasonal storage is pivotal in bridging the gaps between electricity supply and demand throughout the year. Essentially, it shifts the abundance of electricity generated during specific months to times when electricity consumption spikes. As we proceed into the future, seasonal variations in electricity supply and demand will accentuate, necessitating a more pronounced role for seasonal storage.

From the demand viewpoint, electrification of space heating, especially in regions with colder winters, will make electricity demand more cyclical. On the supply front, VRES, notably solar, will introduce a stark contrast in electricity output between summer and winter, especially in higher latitude countries.

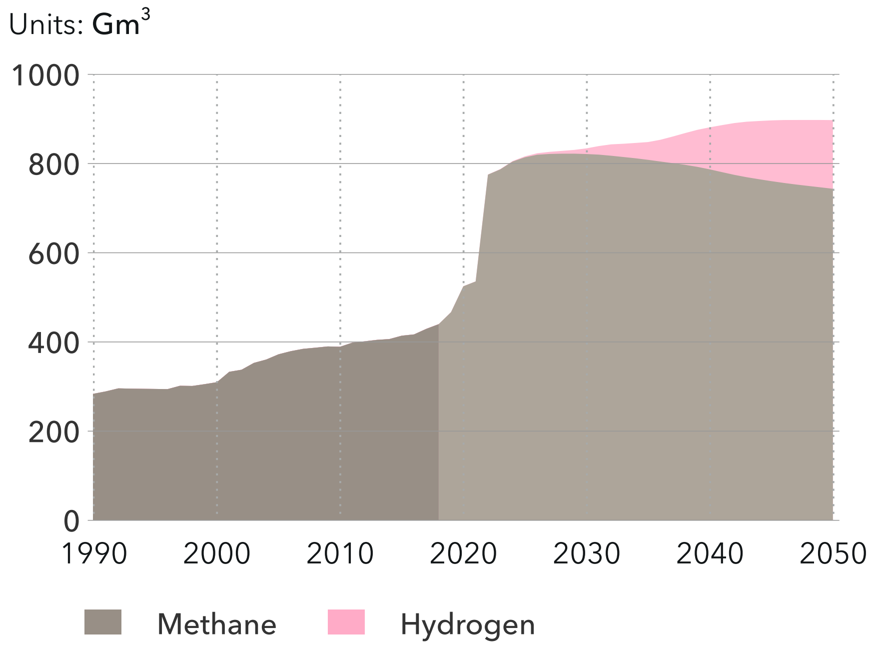
Identifying the right technology for seasonal storage depends on three main factors: storage losses, cost-effectiveness, and roundtrip efficiency. When it comes to offering efficient, affordable, and large-scale storage, chemical energy – specifically energy stored in molecules – emerges as the front-runner. Among the myriad of chemical storage possibilities, compressed hydrogen storage in salt caverns or former hydrocarbon fields appears to be a particularly promising, cost-effective method.

Our predictions, presented in Figure 2.16, lay out the projected global underground gas storage capacity in salt caverns and former oil and gas reservoirs. This is rooted in a meticulous examination of natural gas and hydrogen's weekly consumption and production patterns, along with the storage imperative to guarantee consistent supply. This is vital, not only for electricity reconversion but also for other applications such as heating and transport. As gas-dependent space heating declines, especially in the high-latitude zones of Europe and North America, the global dependency on seasonal natural gas storage will reach its zenith within the next five years. Contrarily, come 2050, we anticipate the development of around 70 billion m³ of hydrogen storage, with repurposed methane storage sites accounting for about 40% of it.

Our 2020 position paper, *The Promise of Seasonal Storage* (DNV, 2020a), delved deep into seasonal storage's significance. Through the lens of the Netherlands, the study underscored the challenge of distinguishing between adequacy, capacity, and seasonal storage, given the annual fluctuations in demand and VRES generation. A key takeaway is that seasonal storage's efficacy hinges on the concerted investment efforts by all stakeholders in the chain, from power-to-gas to physical storage and power generation.

FIGURE 2.16

World underground gas storage capacity



Historical data source: Cedigas (2017)

A 10 MW lithium-ion battery storage system, combined with the gas turbine at SCE Norwalk Peaker Plant, CA, the US. Image courtesy of Ysc usc creative commons

2.4 HYDROGEN

Hydrogen is critical for decarbonizing and moving hard-to-electrify sectors towards net-zero emissions. We forecast that hydrogen uptake will fall well short of the total required to meet the Paris Agreement, but nonetheless will spur industry transforming changes.

Renewable and low-carbon hydrogen plays a critical role in reducing emissions from hard-to-electrify sectors and achieving the objectives outlined in the Paris Agreement. In order to meet the Paris Agreement targets, hydrogen must account for approximately 15% of the world's energy demand by 2050. Our projections indicate that the global adoption of hydrogen and its derivatives lagging behind the requirements of the Paris Agreement, with hydrogen making up just 0.5% of the global final energy mix in 2030 and 5% in 2050. However, in some parts of the world the share of hydrogen in the energy mix will be twice as high as these percentages.

Although hydrogen's contribution to global energy demand is projected to reach only 5%, the developments in hydrogen technology and infrastructure over the next three decades will be significant – essentially, this is an entirely new energy source for one thirtieth (and climbing) of the world's energy demand. These developments have the potential to transform various industries. The estimated global expenditure on hydrogen production for energy purposes from now until 2050 is expected to reach USD 6.8trn, with an additional USD 180bn allocated for hydrogen pipelines and USD 530bn for the construction and operation of ammonia terminals.

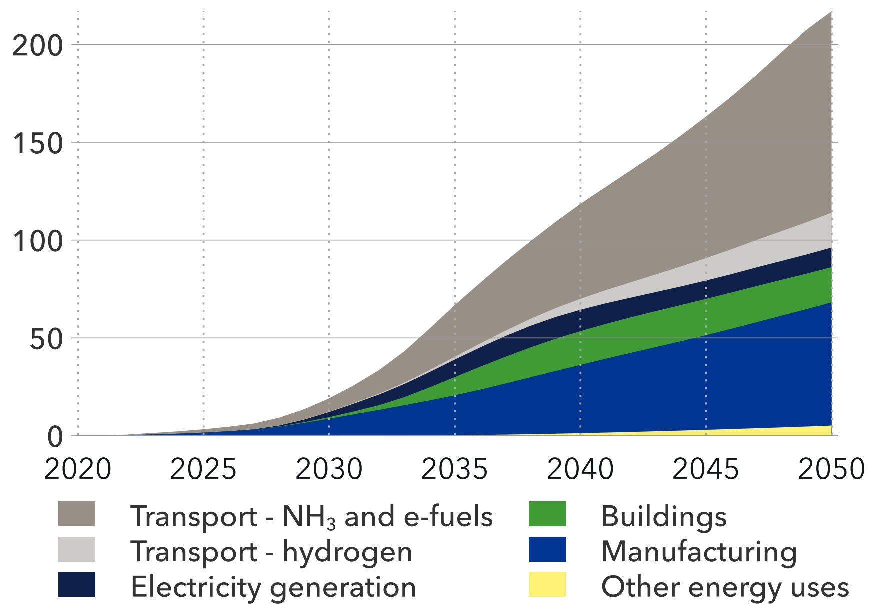
Hydrogen's future demand as an energy carrier will grow from its current negligible levels to surpass 238 MtH_2 annually by the year 2050 – in other words, a sharp upward incline, as illustrated in Figure 2.17. The predominant application of hydrogen will be in manufacturing (58%), followed by transport (20%), and buildings (14%), with the remaining portion allocated to electricity generation and various other purposes.

Hydrogen's future demand as an energy carrier will grow from its current negligible levels to surpass 238 MtH_2

FIGURE 2.17

World demand for hydrogen and its derivatives as energy carrier by sector

Units: MtH_2/yr



All non-transport uses are pure hydrogen.

Transport
We refer the reader to DNV's *Transport in Transition* report (DNV, 2023a) for a deep dive into changes in transport.

Maritime
Hydrogen will be critical in the efforts to decarbonize international shipping. Electrification will be feasible for onshore power when ships are berthed, and for short-distance sea travel such as close-to-shore ferry operations. Hydrogen-based fuels, such as ammonia and e-fuels, are anticipated to provide the majority of zero-emission fuels for the shipping industry by mid-century.

Our forecast indicates that the adoption of e-fuels (mainly e-methanol) in shipping will reach 480 petajoules (PJ) or 3% of the shipping fuel mix in 2030, increasing to 1,800 PJ (12%) in 2040 and 2,600 PJ (19%) in 2050.

Similar to e-fuels such as e-methanol, ammonia can utilize large parts of the existing infrastructure, albeit with higher production costs compared to current alternatives. When produced using renewable energy, the conversion losses are significant, necessitating a substantial increase in renewable power generation. However, capturing CO_2 during ammonia production from natural gas is relatively straightforward, making 'blue ammonia' the predominant choice for shipping in our forecast. Although ammonia has some toxicity concerns for ships, we anticipate these issues will be resolved, leading to large-scale transport from cost-effective production regions to global bunkering hubs. Initially, ammonia's uptake in shipping is expected to be slower than e-methanol, but it is likely to scale more rapidly toward the end of the forecast period. Our hydrogen forecast predicts ammonia usage in shipping to be 170 PJ (1% of the shipping fuel mix) in 2030, 1,900 PJ (13%) in 2040, and 5,000 PJ (36%) in 2050.

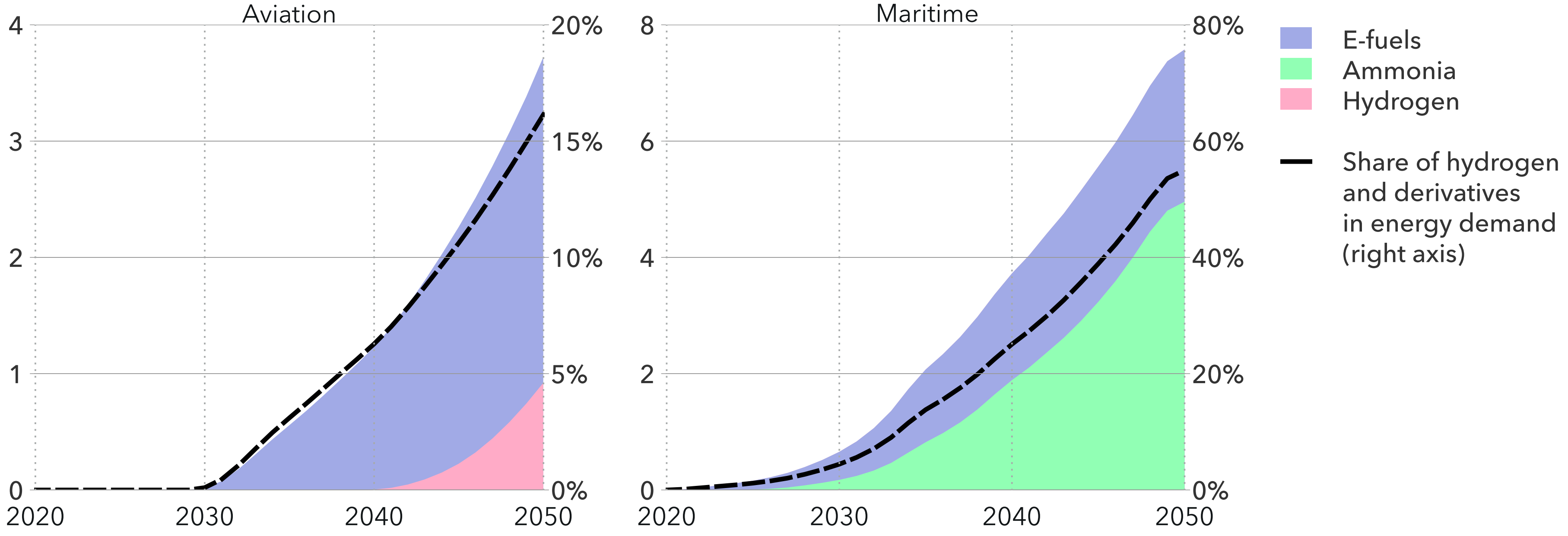
Aviation
Hydrogen, either in its pure form or as derived e-fuels, is projected to gain traction in aviation during the 2030s, primarily due to considerations of cost and availability. However, widespread adoption of e-fuels hinges on a substantial increase in renewable power production, as the current cost disparity, approximately four to five times higher than fossil kerosene, needs to be narrowed. In the aviation subsector, e-fuels are expected to outpace pure hydrogen by a ratio of three to one, accounting for a 12% share. This is mainly because e-fuels, as drop-in replacements, can be used across all types of flights. Conversely, pure hydrogen is limited primarily to medium-haul flights due to its lower energy density, and its extensive storage requirements would necessitate aircraft designs with higher per-passenger costs. Together, pure hydrogen and hydrogen-based e-fuels are projected to constitute roughly 16% of aviation energy usage by 2050.

Hydrogen will be critical in the quest to decarbonize international shipping.

MS Green Ammonia concept vessel. Image, courtesy Grieg Edge

FIGURE 2.18
World aviation and maritime subsectors demand for hydrogen and derivatives

Units: EJ/yr (left); Percentages (right)



Road transport

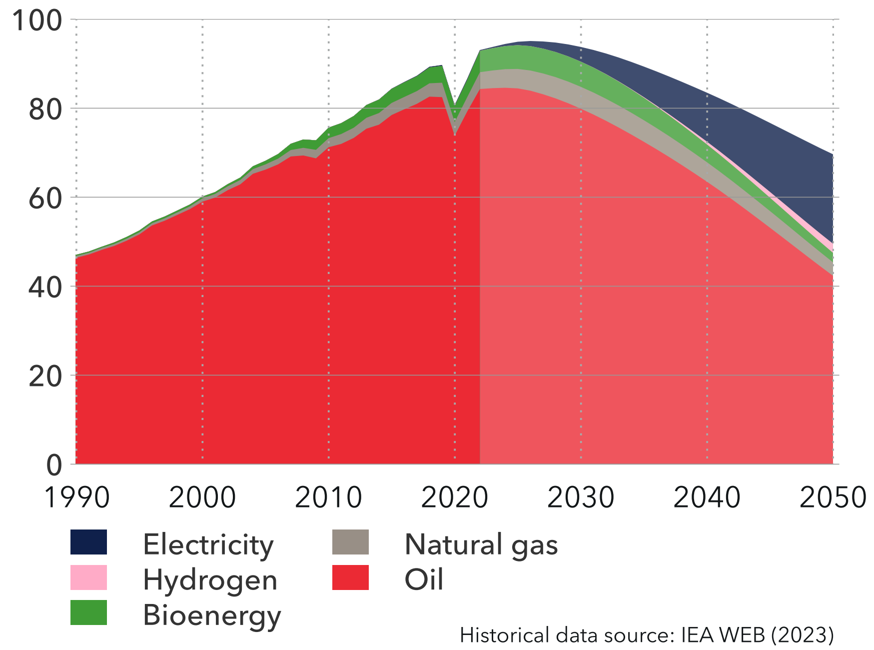
When it comes to road transport, propulsion via fuel-cell electric vehicles (FCEVs) is notably less efficient, more intricate, and consequently more expensive compared to battery-electric vehicles (BEVs). Due to these factors, vehicle manufacturers are solely concentrating on developing BEV models for passenger vehicles for zero-emission transportation. This emphasis on them is anticipated to result in BEVs capturing an impressive 95% share of new passenger vehicle sales globally by 2050, whereas FCEVs are expected to represent a mere 0.2% of new vehicle sales.

For a long time, hydrogen was perceived as the primary solution for decarbonizing heavy trucking.

FIGURE 2.19

World road sector energy demand by carrier

Units: EJ/yr



Historical data source: IEA WEB (2023)

However, the current landscape suggests that battery-electric solutions will also gain substantial ground in this segment. Consequently, we foresee hydrogen playing a relatively minor role in road transport, primarily in heavy-duty long-distance trucking. By the middle of the century, hydrogen is estimated to account for approximately 3% of the energy demand in road transport, slightly less than biomass and natural gas. It is worth noting that this usage considers that hydrogen will be employed in heavy-duty and long-distance trucking, where fuel consumption naturally tends to be higher. This translates to approximately 2,000 PJ in 2050, equivalent to 16.7 million tonnes of hydrogen (MtH_2) per year. Notably, about 20% of this demand will be concentrated in Greater China, primarily due to its large vehicle fleet and policy-driven focus on decarbonizing transportation. Europe and North America are projected to account for 25% of this share each, with the OECD Pacific region contributing another 20%.

Manufacturing

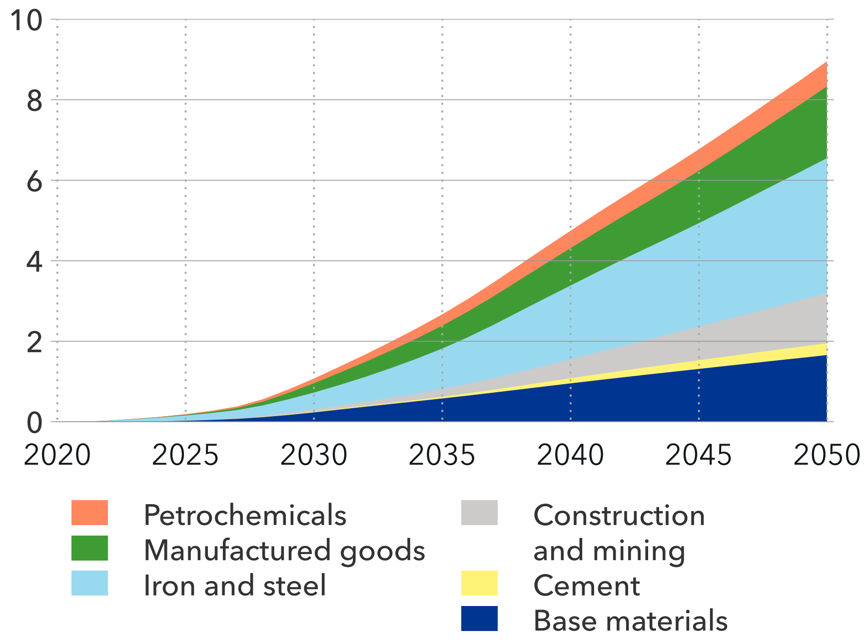
Hydrogen has the potential to substitute fossil fuels for generating high-temperature heat in industrial processes. However, the current utilization of hydrogen in these high-heat applications is minimal. This is primarily due to hydrogen's costliness as an alternative fuel, making it less competitive when compared to traditional fossil-fuel technologies. Additionally, hydrogen faces tough competition from bioenergy, particularly in scenarios with higher carbon prices.

Nonetheless, low-carbon hydrogen is anticipated to play a significant role in the manufacturing sector by 2050, particularly in regions leading the transition, such as Greater China and Europe. According to our forecast, the demand for hydrogen as an energy carrier in manufacturing will experience gradual growth, reaching nearly 9 EJ/yr, which is approximately 75 MtH_2/yr by 2050. This accounts for approximately 6% of the total energy demand in manufacturing and about 31% of the global demand for hydrogen as an energy carrier. Notably, the iron and steel industry will represent the largest portion of hydrogen demand in manufacturing, amounting to 3 EJ/yr or 37% of the total. This is in addition to the non-energy use of hydrogen in the direct reduction of iron, which will be approximately 0.7 EJ/yr, equivalent to around 5.8 MtH_2/yr.

FIGURE 2.20

World hydrogen demand in manufacturing by subsector

Units: MtH_2/yr



Buildings

In our analysis, we project hydrogen uptake in buildings to reach approximately 2 EJ/yr (about 15 MtH_2/yr) by the year 2050. This constitutes only a modest 1.3% of the total energy demand in the buildings sector. The predominant portions of this demand will be space heating (60%) and water heating (30%). This share of hydrogen remains quite small when contrasted with natural gas, which is expected to fulfil about a fourth of the energy demand in buildings by 2050.

The limited expected uptake of hydrogen in the buildings sector can be attributed to various factors including comparative efficiency, cost considerations, safety considerations, and the availability of infrastructure when compared against competing technologies, primarily electric heat pumps and district heating systems.

The utilization of hydrogen in buildings is anticipated to be concentrated in four regions characterized by the presence of existing natural gas infrastructure and relatively more accessible hydrogen sources, namely North America, Europe, Greater China, and the OECD Pacific regions.

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 notable 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.

The leading regions in this transformative journey are forecasted 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.

Hydrogen as feedstock

At present, hydrogen serves as a crucial feedstock in two key sectors: oil refineries and the production of ammonia for fertilizers. Our forecast indicates that while the absolute demand for hydrogen in these segments may experience a slight decline, there will be a growing requirement for hydrogen derivatives tailored for energy-related purposes. In fact, by the year 2050, the demand for hydrogen to produce e-fuels and ammonia as a fuel source will surpass the combined demand for hydrogen in oil refineries and fertilizer production.

As we advance towards 2050, the dominant position of CO_2-intensive production methods for feedstock hydrogen, such as methane reforming and coal gasification, is expected to diminish. These methods will be progressively replaced by more environmentally friendly alternatives, including methane reforming coupled with carbon capture and storage (CCS), grid-connected electrolysis, and electrolysis integrated with dedicated renewable energy sources.

Hydrogen supply

The composition of the future hydrogen supply will be influenced by two interrelated trends. Firstly, there will be an increasing utilization of hydrogen as an energy carrier, and secondly, there will be a gradual phasing out of existing production capacity in favour of more environmentally friendly alternatives. Given that the primary impetus for integrating hydrogen into energy systems is to reduce carbon emissions in sectors where electrification is not feasible, the contenders for the future of hydrogen production will predominantly be low-carbon methods.

By 2030, our forecast indicates that one-third of the global hydrogen supply will be derived from low-carbon and renewable sources. Within this mix, methane reforming with CCS will constitute 14% of the global total, while hydrogen generated through electrolysis will contribute 13%. By 2050, an overwhelming 85% of the world's hydrogen supply will originate from low-carbon pathways. This breakdown is as follows: 28% will come from methane reforming with CCS, 15% from grid-connected electrolysis, 28% from dedicated solar-based electrolysis, 7% from dedicated wind-based electrolysis, and 2% from dedicated nuclear-based electrolysis.

Blue hydrogen

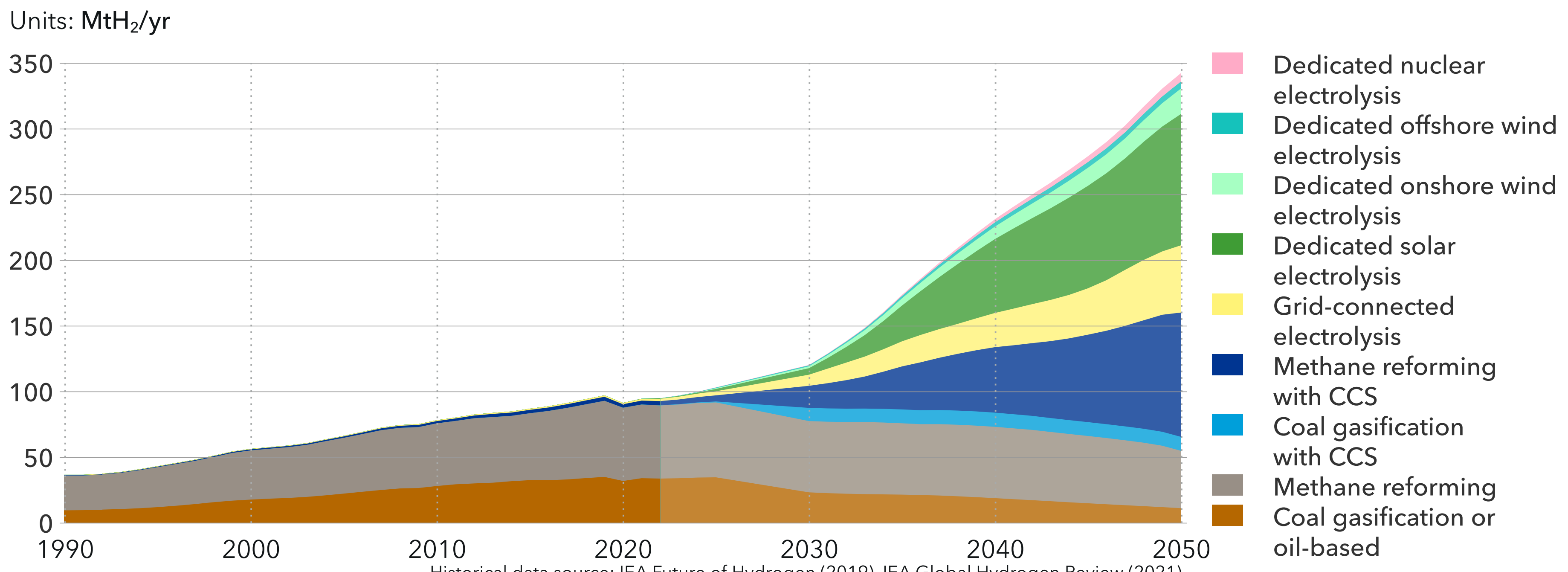
Cost and build-up speed are the primary factors determining production route shares in the supply mix. Currently, the most cost-effective low-carbon hydrogen production method is methane reforming with CCS, often called blue hydrogen, averaging just under USD 3/kgH_2. This average primarily reflects regions like North America and North East Eurasia with access to cheaper natural gas and does not consider the gas price increases since 2020, which raised blue hydrogen costs by 20–30% in gas-producing regions and 60–400% in gas-importing regions.

While gas prices are expected to decrease by the 2030s, blue hydrogen faces additional challenges. CCS technology is still evolving, and concerns about long-term storage, cost uncertainties, and limited economies of scale hinder its rapid deployment. Additionally, achieving CO_2 capture rates beyond 90% remains economically unviable, making blue hydrogen less competitive compared to other low-carbon renewable alternatives in the medium to long term.

By 2050, an overwhelming 85% of the world's hydrogen supply will originate from low-carbon pathways.

FIGURE 2.21

World hydrogen production by production route



Historical data source: IEA Future of Hydrogen (2019), IEA Global Hydrogen Review (2021)
Does not include hydrogen use in residual form from industrial processes.

Nevertheless, as capital expenditures for methane reforming and carbon capture decrease, hydrogen investments become less risky, and carbon prices rise, blue hydrogen is likely to gain a significant market share, particularly in ammonia and methanol production. The cost of carbon capture for ammonia production is lower than for merchant hydrogen. In 2050, 97 MtH_2/yr are produced globally from methane reforming with CCS, constituting 28% of the global hydrogen supply.

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 lead to increased 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.

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 becomes 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.

Hydrogen transport

Hydrogen will primarily be transported via pipelines for medium distances within and between countries, but it is unlikely to be transported between continents. Ammonia, being safer and more convenient for transport – especially by ship – is expected to account for 59% of energy-related ammonia trade between regions by 2050. To maximize cost-efficiency, over 50% of hydrogen pipelines worldwide will be repurposed from existing natural gas pipelines, potentially rising to as much as 80% in specific regions, as the cost of repurposing pipelines is projected to be only 10–35% of the cost of building new ones.

Pure hydrogen transport between regions will play a relatively minor role. Pipeline transportation is most cost-effective for large volumes and medium distances. For shorter distances and smaller volumes, methods like trucking and rail, typically using ammonia as the carrier, become more practical. Seaborne transport is a viable alternative for longer distances, but it requires energy-intensive and costly liquefaction at the export site and expensive regasification at import locations, adding USD 1.5–2/kgH_2 to costs. By 2050, less than 2% of global hydrogen will have been transported via ships, and only about 4% through interregional pipelines.

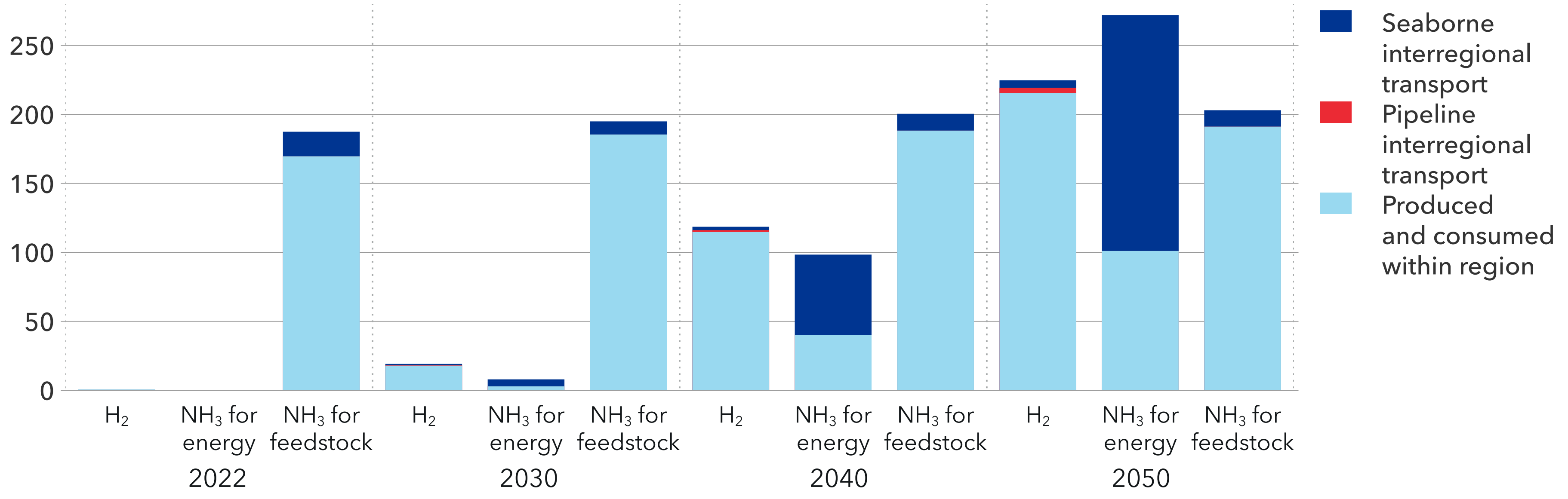
In our forecast, ammonia emerges as the preferred zero-emission fuel for international shipping. In this analysis, we assume that all seaborne hydrogen transport will involve liquid ammonia. We anticipate a 20-fold increase in ammonia seaborne transport between 2030 and 2050, with its usage growing from almost nothing in the mid-2030s to constituting 95% of the trade in 2050, totalling 150 million tonnes of shipments at that time.

By 2030, costs of renewables-based electrolysis are expected to drop to around USD 2/kgH_2.

FIGURE 2.22

Transport of hydrogen and ammonia

Units: Mt/yr



All numbers displayed in mass terms: Mt of H_2 or Mt of NH_3. The mass of ammonia converted from H_2 is approx. 5-6 times the mass of H_2.

2.5 DIRECT HEAT

Direct heat is a term that encompasses the thermal energy procured from power stations and certain industrial processes, and is conventionally delivered in the form of hot water or steam. This specific thermal energy, depending on its source and application, is either retailed to external entities such as district heating systems, local communities, or utilized more directly for industries' intrinsic operational requirements.

Globally, around 8% of households rely on direct heat for their space heating needs. However, this global average is somewhat skewed by the significant shares in certain regions: 42% in North East Eurasia, 20% in Greater China, and 14% in Europe. When evaluating the overall heat demand, space and water heating in residential, commercial, and public buildings consume approximately 42% of the world's direct heat. The industrial sector is slightly ahead, accounting for 43%.

District heating has seen variances in adoption rates across regions and through time. Historically, its uptake has not been driven purely by its environmental benefits. While it is undeniable that these communal systems can present economies of scale and therefore some cost-efficiency for consumers, other factors have been instrumental in its rise. For example, central planning has played a pivotal role, particularly in areas with high urban concentrations.

Three regions distinctly exemplify this trend due to their urban structure and governance models: North East Eurasia, Europe, and Greater China. In these regions, there is a pronounced inclination towards direct heat. Historically, these regions have leaned into central planning, which has facilitated the integration and expansion of district heating systems. North East Eurasia and Greater China dominate the global landscape of direct heat consumption, trailed by Europe, where countries like Germany stand out.

The industrial embrace of direct heat, especially when sourced from adjacent power plants or through pipelines, marks a noteworthy shift in energy consumption patterns. Industries, and notably those with high thermal demands like metal smelting or chemical processing, find direct heat an optimal solution. It presents an opportunity to optimize energy consumption patterns, diminish operational expenses, and in a world increasingly attuned to environmental ramifications, lower their carbon footprints. Using direct heat, these industries can tap into waste heat from neighbouring power facilities, driving both efficiency and sustainability.

In 2022, the global direct heat supply was predominantly powered by coal and gas, accounting for 48% and 42% respectively (Figure 2.24). Intriguingly, over two-thirds was sourced from combined heat and power (CHP) plants.

The ever-evolving energy landscape, technological innovations, and global shifts towards sustainability suggest an impending plateau in direct heat demand. By 2030, it is anticipated that the demand for direct heat energy will see a modest rise from approximately 15 EJ/yr in 2022 to just below 17 EJ/yr. This level is expected to stabilize up to mid-century.

The sources fuelling this demand are also poised for transformation. Coal, currently a dominant player, will likely cede ground to bioenergy (Figure 2.24). By 2030, bioenergy – predominantly leveraging municipal and industrial waste as fuel – along with natural gas-fired technologies, will drive down coal's share in direct heat demand to around 37%. Fast-forward to 2050, and coal's contribution is projected to plummet to a mere 5%, while bioenergy and natural gas will ascend, and are estimated to provide 37% and 58% of direct heat, respectively.

The evolution of direct heat will be influenced by shifting technological landscapes, market dynamics, and emerging energy alternatives. While regions like North East Eurasia, Europe, and Greater China have laid down a certain blueprint, each locale will inevitably craft its own path, weighing its unique needs and resources. It is imperative that we continue to scrutinize these trends, as they will not only dictate our energy narratives but also shape the broader contours of sustainable urban and industrial development in the decades to come.

FIGURE 2.23

World direct heat demand by region

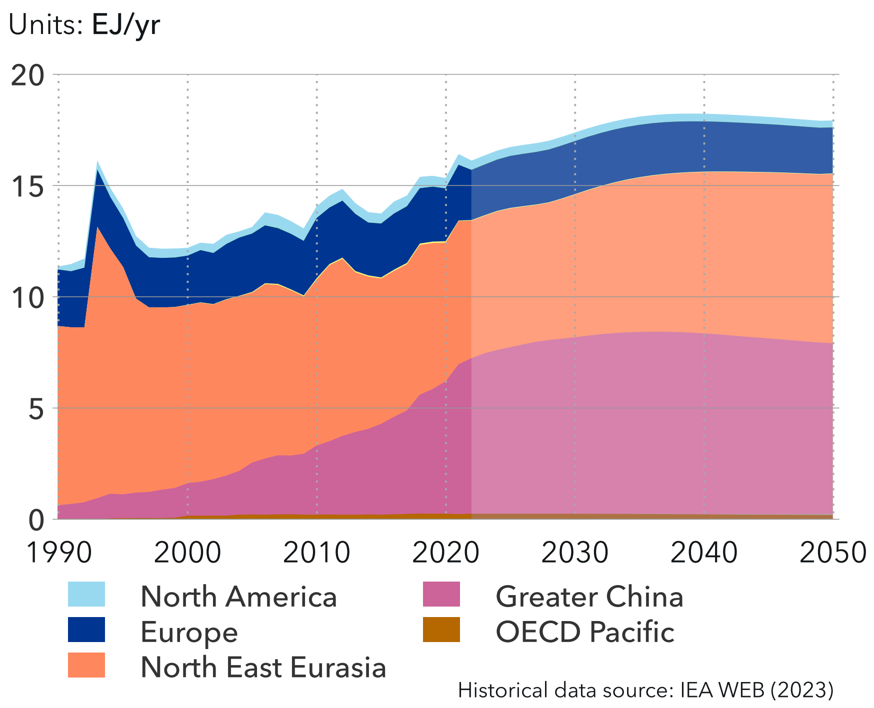
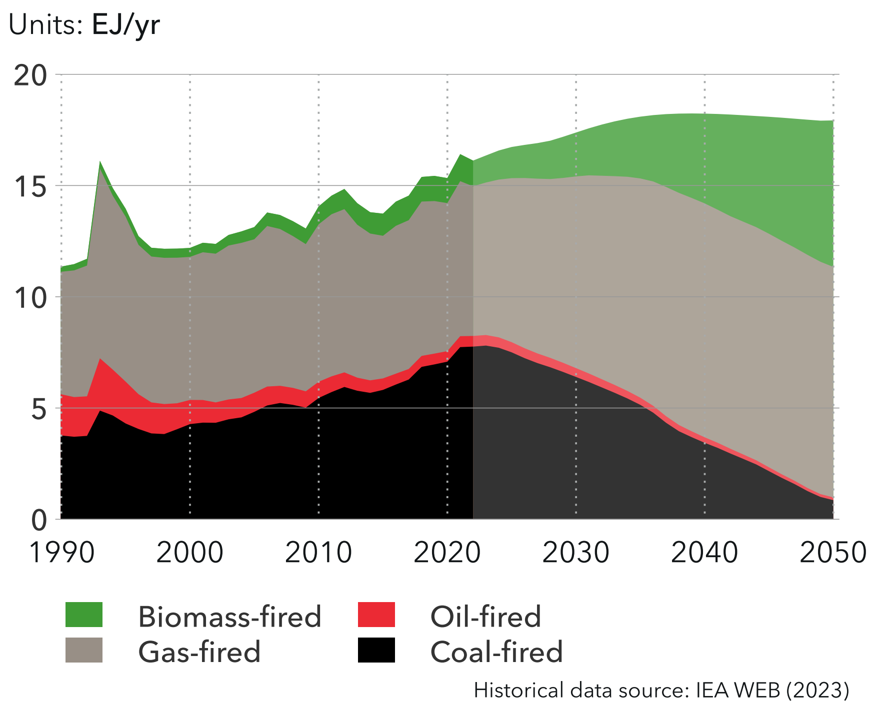
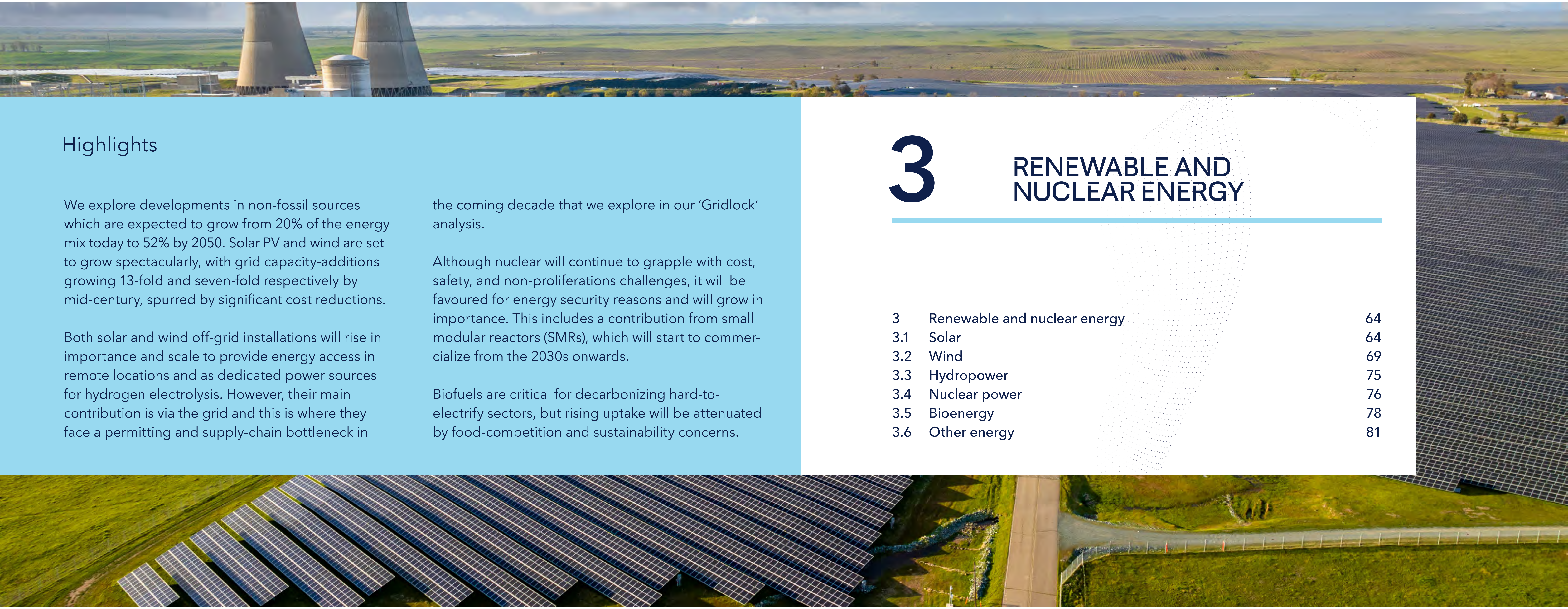


FIGURE 2.24

World direct heat supply by power station type





Highlights

We explore developments in non-fossil sources which are expected to grow from 20% of the energy mix today to 52% by 2050. Solar PV and wind are set to grow spectacularly, with grid capacity-additions growing 13-fold and seven-fold respectively by mid-century, spurred by significant cost reductions.

Both solar and wind off-grid installations will rise in importance and scale to provide energy access in remote locations and as dedicated power sources for hydrogen electrolysis. However, their main contribution is via the grid and this is where they face a permitting and supply-chain bottleneck in the coming decade that we explore in our 'Gridlock' analysis.

Although nuclear will continue to grapple with cost, safety, and non-proliferations challenges, it will be favoured for energy security reasons and will grow in importance. This includes a contribution from small modular reactors (SMRs), which will start to commercialize from the 2030s onwards.

Biofuels are critical for decarbonizing hard-to-electrify sectors, but rising uptake will be attenuated by food-competition and sustainability concerns.

3 RENEWABLE AND NUCLEAR ENERGY

3 RENEWABLE AND NUCLEAR ENERGY

In this year's forecast, we find that non-fossil energy will be 52% of the primary energy mix by 2050 – a slight uptick on our 2022 forecast. This chapter unpacks developments in and forecasts for the key non-fossil sources: solar PV, wind, hydropower, bioenergy, and nuclear.

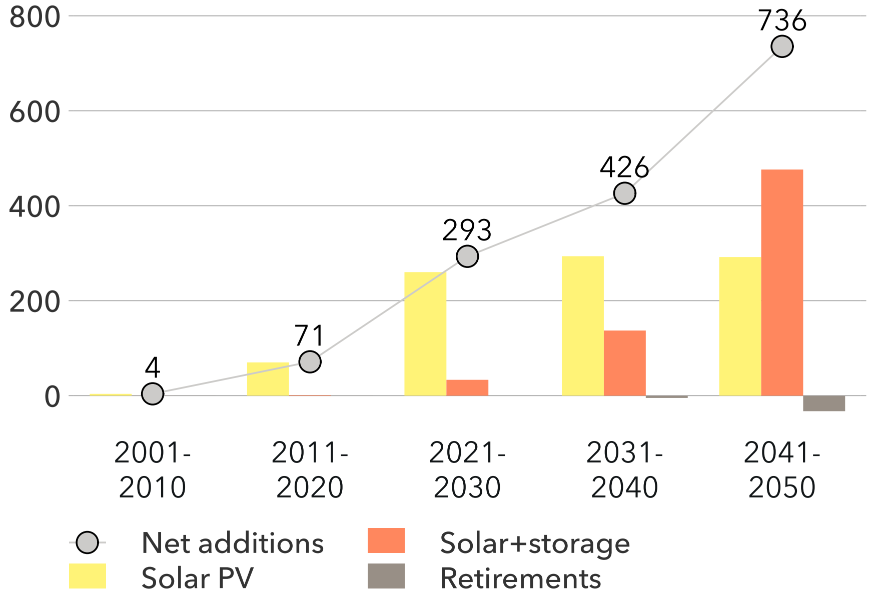
3.1 SOLAR

The growth of solar PV has been nothing short of astonishing. In 2004, solar installations were at a modest 1 GW per year. By 2019, that number had skyrocketed to 100 GW. Despite setbacks in 2021 – caused by the COVID-19 pandemic and tensions in North East Eurasia – 150 GW were added. By 2022, solar installations approached a staggering 250 GW. Unsurprisingly, the future trajectory is sharply upward. By 2040, we see global installations rising further to about 500 GW annually (Figure 3.1). It is worth noting that within a decade, 10% of all new PV will integrate dedicated storage, and by 2050, that number will ascend to 62%. If we look at the bigger picture, by 2050, we will witness solar PV capacities of 8.8 TW and an additional 6.5 TW for solar+storage, bringing the total to 15.3 TW, a 13-fold growth from 2022.

FIGURE 3.1

Global solar capacity additions and retirements, 10-year average

Units: GW/yr



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

By the mid-century, solar's footprint will account for 54% of installed generation capacity. However, it will account for only 39% of global on-grid electricity generation. Why? The efficiency or the capacity factors of solar power stations trail behind other renewable energy sources like wind and hydropower. Nevertheless, the underlying cause of solar's rapid proliferation lies in its dwindling costs. By the early 2020s, solar PV emerged as the most cost-effective form of electricity in numerous regions, but it is essential to understand that its cost reduction rate will decelerate over time.

The economics of solar PV undergo a shift with increasing penetration in the energy mix. In its early stages, solar PV primarily curtails the need for conventional energy during daylight. But with higher market penetration, solar (alongside wind) can often meet or even surpass the power demand, pushing electricity prices to near-zero or even negative values. This paradigm shift underscores the crucial role of storage systems, especially co-located solar+storage systems, in supporting solar growth during sunless hours.

Decoding the costs

Solar's cost competitiveness is rooted in its declining levelized cost of energy (LCOE). As of now, the global average LCOE for solar PV hovers around

USD 41/MWh and USD 69/MWh for solar paired with storage. Delving deeper, we expect the LCOE for solar PV to dip to approximately USD 21/MWh by 2050 (Figure 3.2), with some projects costing even less than USD 20/MWh. The catalyst behind this decline is the reduction in unit investment costs. Presently, these costs average USD 870/kW. As solar PV installations continue to double, these numbers are bound to drop, landing below USD 700/kW shortly after 2030 and shrinking further to USD 560/kW by 2050.

An intriguing aspect of solar's cost is the learning rate, which pertains to the decrease in costs with every doubling of solar production capacity. The learning rate for solar module costs is currently at 26%. However, this will slow, settling at around 17% by 2050. This shift occurs as cost components adjust to decreasing expenses. Despite this easement in the rate of cost reduction, solar PV is poised to be the unrivalled contender for the cheapest new electricity source globally, with exceptions only in areas with less conducive irradiation conditions like the higher northern latitudes. The learning rate for operational expenses (OPEX) is predicted to remain steady at 9% till 2050, thanks to the advent of advanced data monitoring and efficient maintenance practices.

Solar+storage: a revenue booster

Although solar+storage comes at a premium, it conveys a unique revenue advantage. The ability to store excess energy during peak sunlight hours and then sell it when prices soar, gives it an edge over standalone solar PV. Figure 3.3 illustrates how solar+storage opens up the possibility for solar energy to be utilized at night and how solar+storage operates so that it opportunistically takes advantage of higher prices on an example week in 2050 for North America.

This revenue edge is already discernible in the revenue-adjusted LCOE (Figure 3.2) in the 2020s, where solar+storage will outperform regular solar PV in terms of revenues. By 2040, we predict most of the global solar capacity additions to integrate storage. The synergistic pairing of solar and storage is not just about higher revenues; it is also about cost savings. Shared costs related to permissions, site selection, equipment, and grid connections cut down the initial investments. Operationally too, combined costs are slashed when these systems share transactional expenses.

Having solar and storage in tandem offers undeniable cost advantages. For example, consider the US scenario: before the 2022 *Inflation Reduction Act*, co-located storage projects reaped nearly 30% capital cost benefits from government incentives. This financial backing catapulted North America to the forefront of the solar+storage developments. But co-location has its challenges. Sites chosen for their solar potential might not always be financially optimal for the storage component. While standalone batteries thrive by buying low and selling high, this balance might be upset in a co-located setup. Policy shifts in 2022, which removed the need for batteries to source energy solely from renewables, might reduce the drive for co-location. Yet, given the falling prices of batteries and solar modules, it is undeniable that both co-located and standalone systems have a significant role in the energy tapestry of the future.

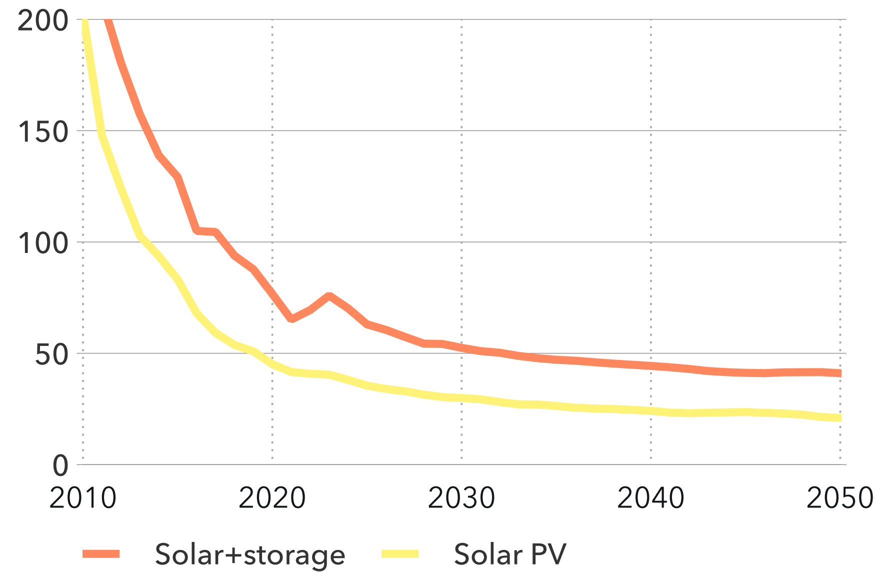
Regional trends

By 2050, we anticipate the solar energy to be led by Greater China and North America. However, it is important to analyse region-specific developments to understand the broader picture.

FIGURE 3.2

World average levelized cost of solar energy

Units: USD/MWh

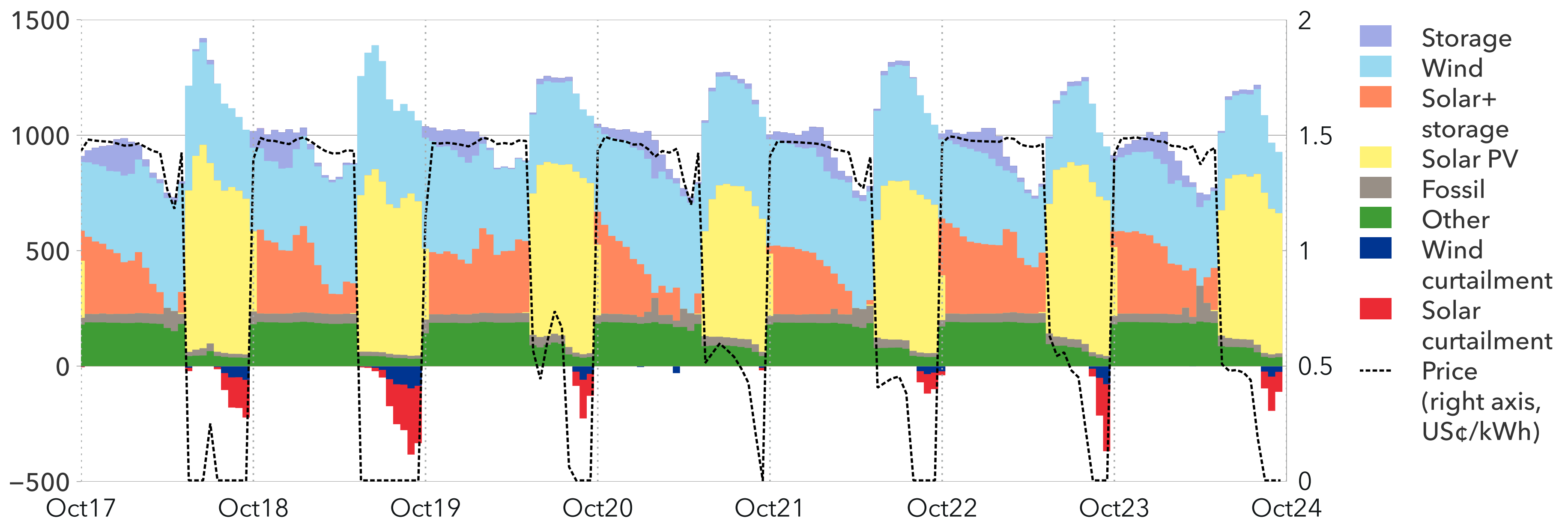


Historical data source: GlobalData (2023), IRENA (2023), DNV analysis

FIGURE 3.3

Hourly electricity supply in a typical 2050 week in North America

Units: GWh/hr



Greater China, as shown in Figure 3.4, secured its position as the front-runner in 2022 by producing 30% of global solar electricity, while North America trailed behind at 18%. Though both regions will experience a slight dip by 2050, they will nonetheless remain dominant in the solar energy hierarchy. Meanwhile, the Indian Subcontinent and the Middle East and North Africa will nearly triple their solar shares from 6% and 3% in 2022 to 14% and 12% by 2050, respectively. North East Eurasia, however, will continue to lag, contributing a mere 2% to the global solar electricity share.

Figure 3.5 further elaborates on solar electricity's prominence in the total electricity generation of various regions. A universal increase in solar's share from 2020 to 2050 is evident across all regions. Yet, the pace and reasons for this shift differ. Europe, with its world-leading decarbonization agenda and supportive solar policies, will witness solar surpass fossil-fuel generation by 2030. The overwhelming surge in solar will slightly decrease the share of other variable renewable energy sources (VRES) and nuclear.

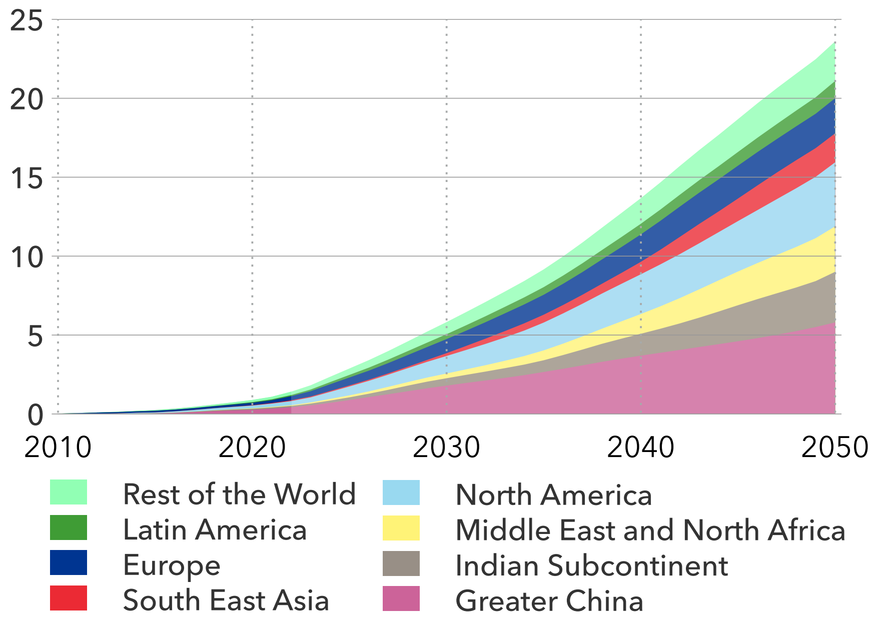
The Middle East and North Africa region, blessed with high solar irradiation, will harness solar for almost half of its electricity by 2050. This region's inclination towards solar is further enhanced by the relatively limited presence of other VRES like wind. Nevertheless, abundant domestic oil and gas resources delay the point at which solar surpasses fossil in electricity generation until post-2040. North America's solar expansion, on the other hand, owes its trajectory to compelling economics and strengthened policy endorsement.

Lastly, by 2050, the Indian Subcontinent is set to surprise with a 37% share of solar in electricity generation in that region, slightly edging out Greater China on that metric. As portrayed in Figure 3.6, this necessitates a connection of about 2.6 TW of solar capacity to the grid, second only to Greater China's 4 TW – which represents 26% of the total solar capacity set to be installed by 2050.

FIGURE 3.4

Grid-connected solar PV and solar+storage electricity generation by region

Units: PWh/yr

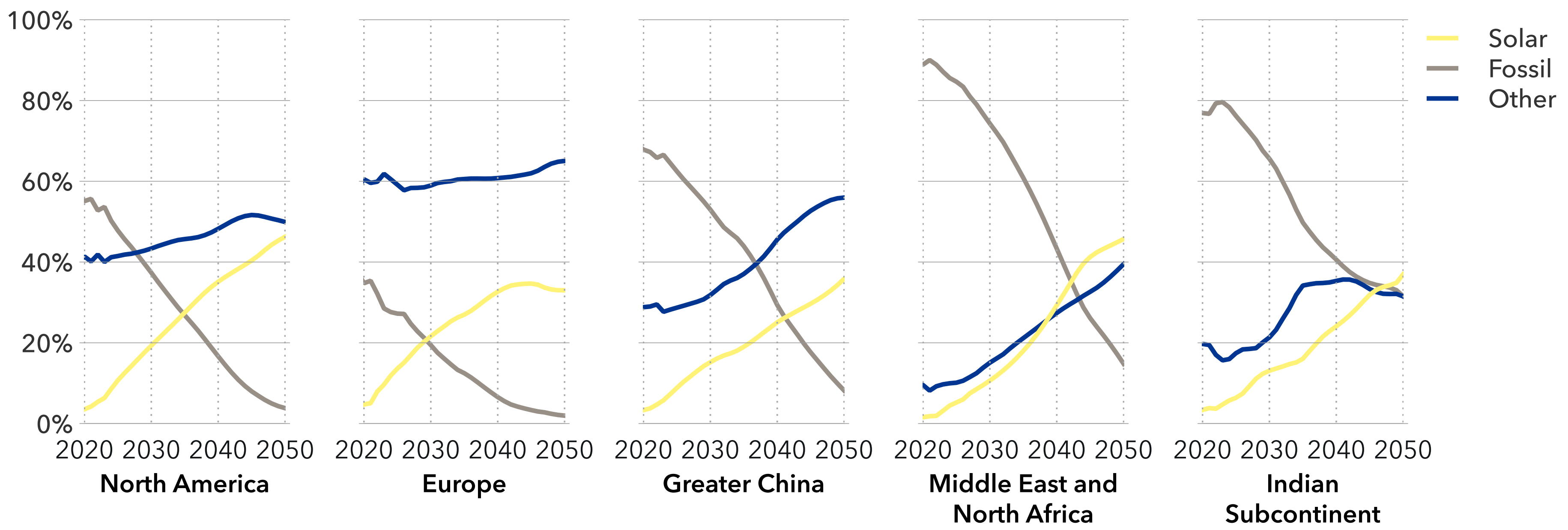


Historical data source: GlobalData (2023), IRENA (2023), IEA WEB (2023)

FIGURE 3.5

Share of solar, fossil fuel, and others in grid-connected generation in selected regions

Units: Percentages

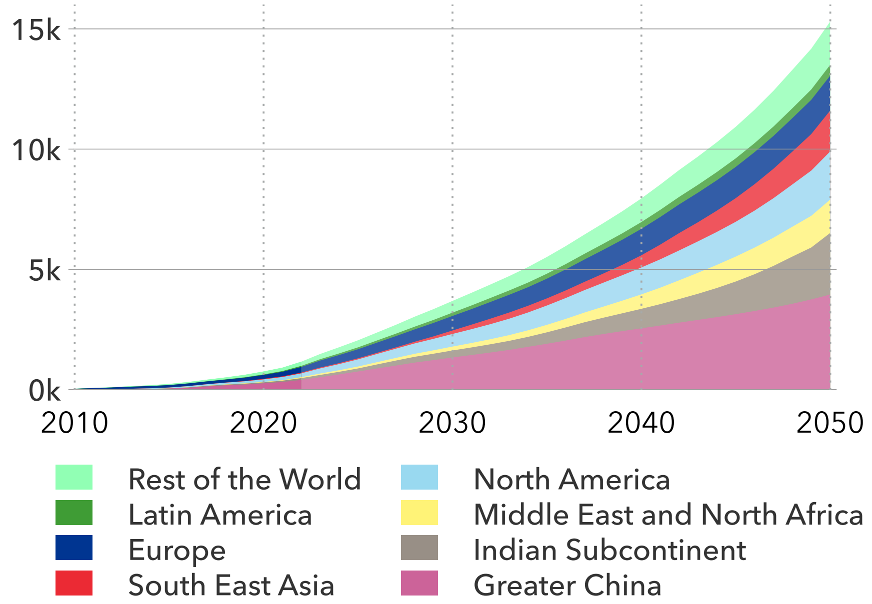


Historical data source: GlobalData (2023), IRENA (2023), IEA WEB (2023)

FIGURE 3.6

World grid-connected solar capacity by region

Units: GW



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

Off-grid solar capacity

Beyond the grid, we see the rise of off-grid solar, particularly in hydrogen production and serving isolated, often rural, demands. By 2050, nearly 3 TW of off-grid solar will be dedicated to hydrogen production, predominantly in Greater China (40%), Europe (26%), and North America (16%) (Figure 3.7). Further, about 137 GW will be located in remote regions in Sub-Saharan Africa and the Indian Sub-continent, delivering life-changing electricity access. These regions, despite the geographical challenges, offer vast untapped solar potential and hold the promise of transformational energy independence. This narrative underlines the future's duality: on one hand, we have vast centralized powerhouses, while on the other, we witness the rise of decentralized, individualized energy systems.

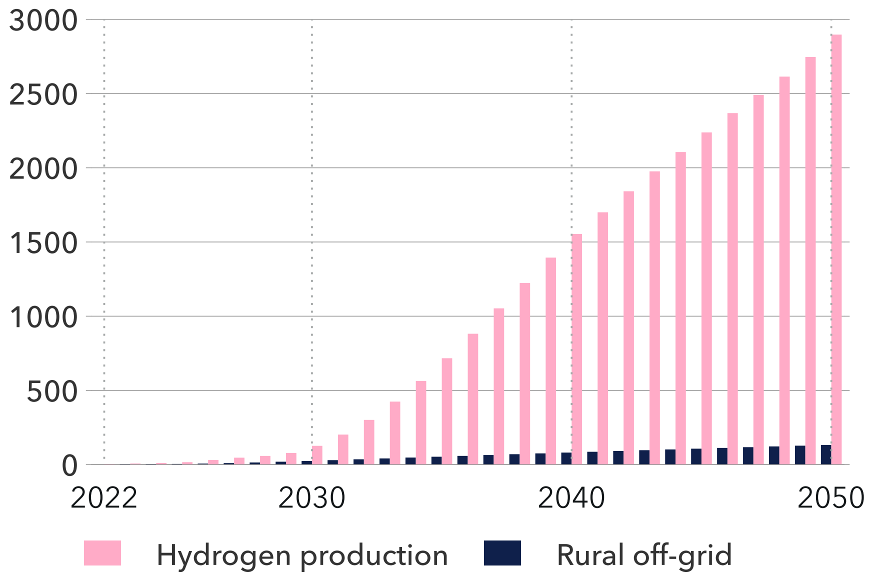
Sensitivities

Solar PV's deployment remains consistent across different carbon price assumptions. In our extensive model testing, we found that the impact of carbon prices on solar PV is minimal. The primary reason is that solar PV chiefly competes with wind and other renewables rather than fossil-fuel sources in the power generation sector. Thus, its positioning and growth is not heavily reliant on fluctuating carbon prices.

FIGURE 3.7

Globally installed solar off-grid capacity

Units: GW



By 2050, we will witness solar PV capacities of 8.8 TW and an additional 6.5 TW for solar+storage, bringing the total to 15.3 TW, a 13-fold growth from 2022.

Biodiversity and the energy transition

The 15th Conference of Parties (COP 15) to the UN Convention on Biological Diversity led to the international agreement to protect 30% of land and oceans by 2030 ('30 by 30') and adoption of the *Kunming-Montreal Global Biodiversity Framework* (GBF), agreeing on four goals and 23 targets to halt and reverse biodiversity loss by 2030.

The four goals are: increasing the area of natural ecosystems, restoring their integrity and normal functioning, reducing the human-caused extinction rate 10-fold, and protecting traditional knowledge of indigenous peoples and local communities. The GBF is not a legally binding treaty, and achieving goals and targets will be difficult and challenged by other, sometimes conflicting, priorities.

Still, GBF is expected to have a significant impact on the financial sector and energy companies alike, as countries around the world endeavour to develop new plans and regulations to meet their targets. UNEP-FI (2023) suggests five foreseeable regulatory actions: 1) mandatory nature-related disclosures and data, 2) increasing nature-positive financial flows, aided by harmonized taxonomies and standards, 3) biodiversity targets and due diligence obligations to form a mandatory part of companies' governance,

4) clarification of supervisory expectations and guidance on biodiversity risk-management, and 5) further international alignment in policy concerning nature-based sustainable finance.

The loss of biodiversity also needs to be seen against the background of other nature-related priorities and loss of acreage, including acreage for recreational purposes, visibility and sound impact on human settlements, and similar priorities. These concerns and priorities are strengthening together with the biodiversity concerns.

The close ties between energy transition and nature impacts

Electrification based on increasingly higher renewable electricity generation is a key feature of the energy transition, Figure 2.4 in Section 2.1.2 shows global power generation from renewable energy sources in 2050 will be six-fold higher than in 2022. With the establishment of GBF, this massive build-out will be subject to more scrutiny for its biodiversity implications. However, the evaluation of biodiversity impacts of energy production and distribution goes beyond renewable power generation. The GBF will be equally relevant for activities such as land-use/deforestation for biofuel production, mining transition minerals, land and ocean use for solar and wind farms, decommissioning of wind and solar facilities, and the construction of new transmission lines – all potentially leading to habitat loss, species extinction, disruptions to ecosystems and conflict in some societies. This is equally true for all fossil energy build-out, including pipelines for transport. One key consideration here is that global warming will cause massive biodiversity loss, and mitigating temperature increase by replacing fossil energy with renewables is an extremely important action for preserving biodiversity over time.

All forms of energy need to manage nature impacts

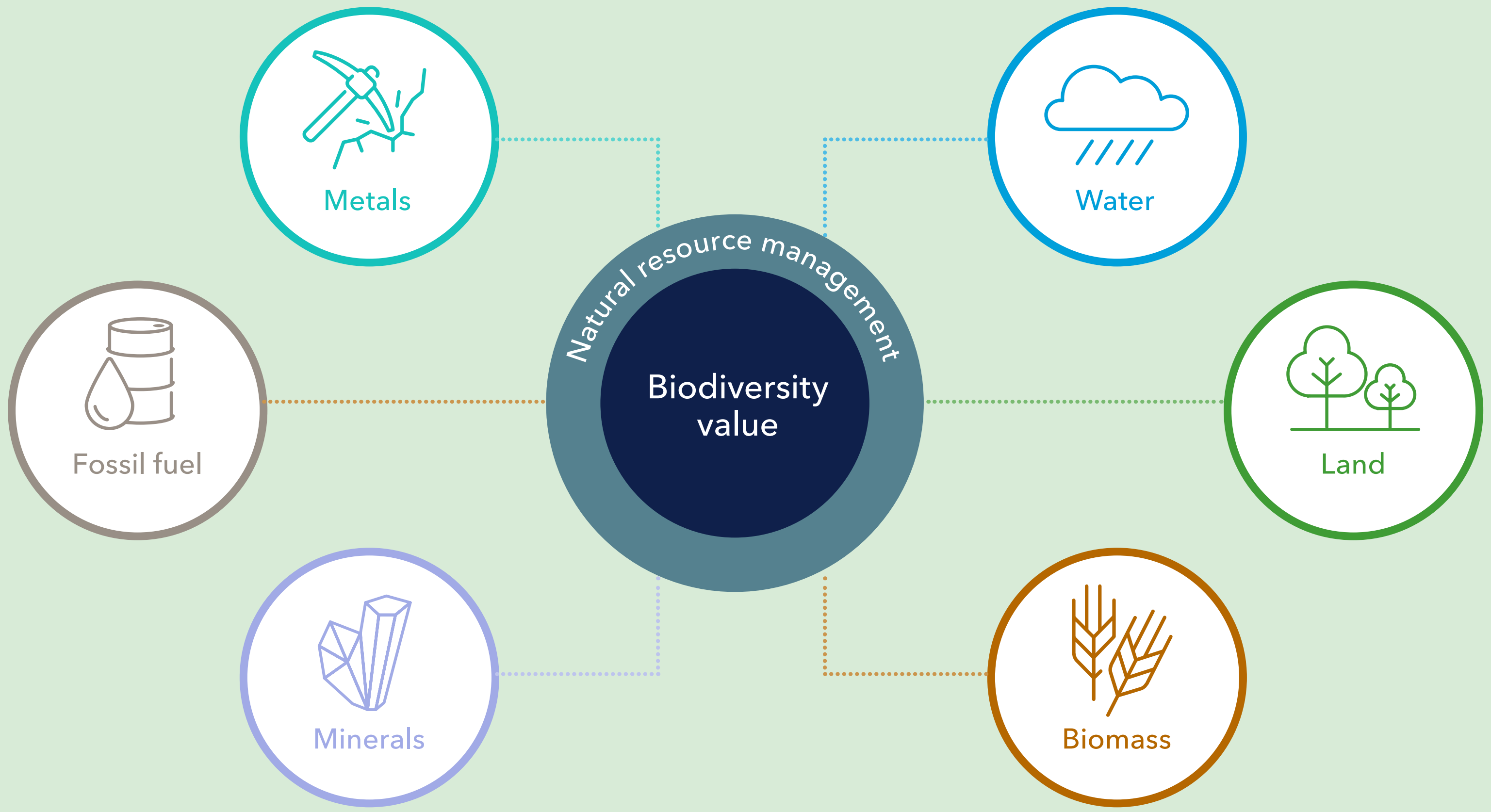
All energy projects affect biodiversity through their placement, construction, and transportation, as well as mining, drilling and extraction. The mineral requirements of transition-related renewable energy technologies as well as their end-of-life handling have received growing attention. However, energy options need judging on equal terms. This involves assessment of positive and negative effects, and by-products (e.g. biodiversity loss, emissions, waste) and decommissioning risks, colossal and costly in the context of nuclear power, as well as for the fossil-fuel extraction, distribution, refinement and use phases (Hartfoot et al. 2018).

Yet from a total environmental perspective, the potential and role of renewables in cutting energy system GHG emissions will likely outcompete more localized concerns. This is not to argue that their biodiversity and nature impacts should not be minimized and managed. On the contrary, all natural resource and energy projects (Figure 3.8) should be managed for their positive and negative contributions, with a view to land, climate, and water footprints and in the degree to which the affected sea, land, and habitat is degraded.

In Appendix A.4 to this Outlook we discuss land and sea-areas required to support the forecast renewable growth. DNV's Outlook does not reflect specific constraints on the energy supply side set by biodiversity requirements. However, the support levels we include for renewables, and the time for permitting and similar processes, are scaled to also reflect nature and biodiversity priorities. With the implementation of the GBF, we expect a deepening of regulatory efforts for decarbonization and for accountability/responsibility along energy value chains and across project lifecycles. Regulatory interventions will deepen to minimize and mitigate biodiversity risks and losses, and these developments will be monitored for future Outlooks.

FIGURE 3.8

Energy-related biodiversity management



Adapted from IRP – International Resource Panel (2021)

3.2 WIND

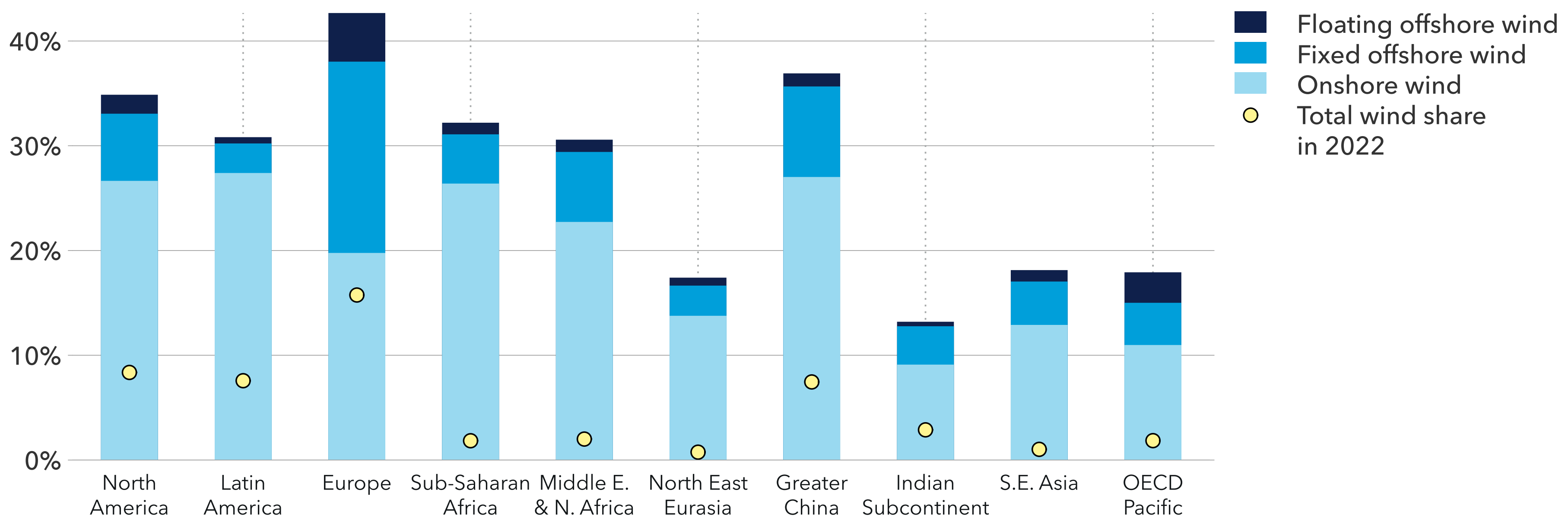
We forecast a nine-fold growth in grid-connected wind power generation globally, from 2,000 TWh in 2022 to 18,300 TWh by mid-century. This is accomplished by only a seven-fold growth in global wind capacity, thanks to increasing capacity factors of wind generation, especially in offshore wind. We expect total installed wind capacity to grow from 950 GW in 2022 to 6,400 GW by 2050.

Over the last year, the wind power sector has faced significant challenges. Cost inflation impacting LCOE, supply-chain disruptions, concerns about turbine and rotor quality, and shrinking profit margins for original equipment manufacturers (OEMs) all converged (DNV, 2023c), resulting in what many describe as the perfect storm. These issues have prompted us to revise our forecasts for this year. Specifically, we predict a minor reduction in wind power generation and installed capacity by 2050 compared with our projections in last year's Outlook (DNV, 2022b).

FIGURE 3.9

Share of wind in electricity generation in 2050 by region

Units: Percentages



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

In 2022, wind power contributed 7% to the global grid-connected electricity output. The lion's share of this was from onshore wind farms, while a mere 0.6% was attributed to fixed offshore wind. However, this distribution was not uniform across the globe. In regions such as North East Eurasia and South East Asia, wind power represented a minuscule 1% of electricity generation. In stark contrast, Europe's grid saw wind power meeting 16% of its electricity needs, as depicted in Figure 3.9.

Our long-term projections remain optimistic for wind power. This is fuelled largely by regional commitments to decarbonize and the attractiveness of fostering emerging wind technology industries. High-income countries with limited land availability are currently facing a unique predicament. On one hand, onshore wind technology in these regions has matured and is ready for deployment. On the other, deciding where to place these turbines is sparking debates and conflicts (Supreme Court of Norway, 2021), highlighting the need for careful planning and strategy. Also, the regulated subsidy levels – for kicking off new technologies used in floating wind projects and for balancing the current cost inflation and stimulating wind power in new countries and regions – will be key in the future. Regulation clarity, speed, and firmness will all play crucial roles in underpinning the adoption of wind power for all countries.

Electricity generation

From 2022 to 2050, global wind electricity generation is set to experience a significant leap, growing from 2,000 TWh to an impressive 18,300 TWh, marking an annual average growth rate of 8%. At the onset of this period, in 2022, onshore sites were the dominant players, accounting for 91% of the wind generation, while offshore wind farms in shallow waters provided the remainder. However, by 2050, the landscape is expected to shift: while onshore wind will still lead with 70%, fixed offshore will rise to cover 25%, and floating wind turbines in deeper waters will contribute 5% to the total wind electricity.

Several factors are driving this rapid expansion. The primary catalyst is the world's growing demand for electricity. Beyond that, the economic efficiency of wind energy is becoming increasingly evident in many locations. Despite initial high costs, the long-term financial benefits, combined with the pressing need to reduce carbon emissions, make wind energy an attractive solution.

Photo by, Dennis Schroeder, NREL

Furthermore, regions like Europe and Greater China are strengthening wind energy plans as a strategic move towards bolstering their energy security. By investing in domestic energy production through wind, these regions are reducing their reliance on imported energy sources. In terms of regional contributions to on-grid wind electricity, Europe is anticipated to lead the pack with 43%, boasting an equal split between onshore and fixed offshore sources. Trailing close behind are Greater China at 37% and North America at 35%.

However, this anticipated growth is not simply a matter of installing more turbines. It is crucial to consider the economic dynamics of wind power. Factors such as installation capacity, the costs associated with capacity and maintenance, and the efficiency with which these turbines operate, play a critical role. Moreover, as the industry grows and matures, the cumulative effect of hands-on experience is expected to drive down costs further, making wind power not just an environmental imperative but an economic one too.

Capacity factors

Geographical wind patterns and the diameter of the rotor influence the capacity factor of wind power. Over the past two decades, both onshore and offshore turbines have experienced consistent growth in rotor diameters, which in turn has led to an increase in their rated power.

With larger and more efficient rotors, not only has there been a rise in electricity generation from wind, but the LCOE has also decreased. This rotor size evolution means that even sites with less favourable wind patterns are now viable because they can generate more power. The global average capacity factor for onshore wind stood at 24% in 2022, but with advancements in digital control and rotor design (DNV, 2019), it is projected to rise to 30% by the 2030s and level off at 32% by 2050.

However, growth in rotor diameter for onshore wind is gradually slowing. With prime wind sites in established markets like North America, Europe, and China already being utilized, increased capacity factors are now being driven by newer markets, such as South East Asia and the Middle East and North Africa.

In contrast, offshore wind projections are even more promising. While the current capacity factors for existing offshore turbines hover around 30%, projects that were started in 2022 are predicted to have capacities of 35% to 45% and these numbers are anticipated to rise. By mid-century, the average offshore wind capacity factor could be 42% to 43%, and even exceed 50% in regions with optimal wind conditions. The relative novelty of the offshore wind market, combined with ongoing improvements in tower and foundation technologies, allows for the exploitation of windier sites in aquatic regions, even with the higher initial investment compared with onshore wind.

Levelized cost of energy – LCOE

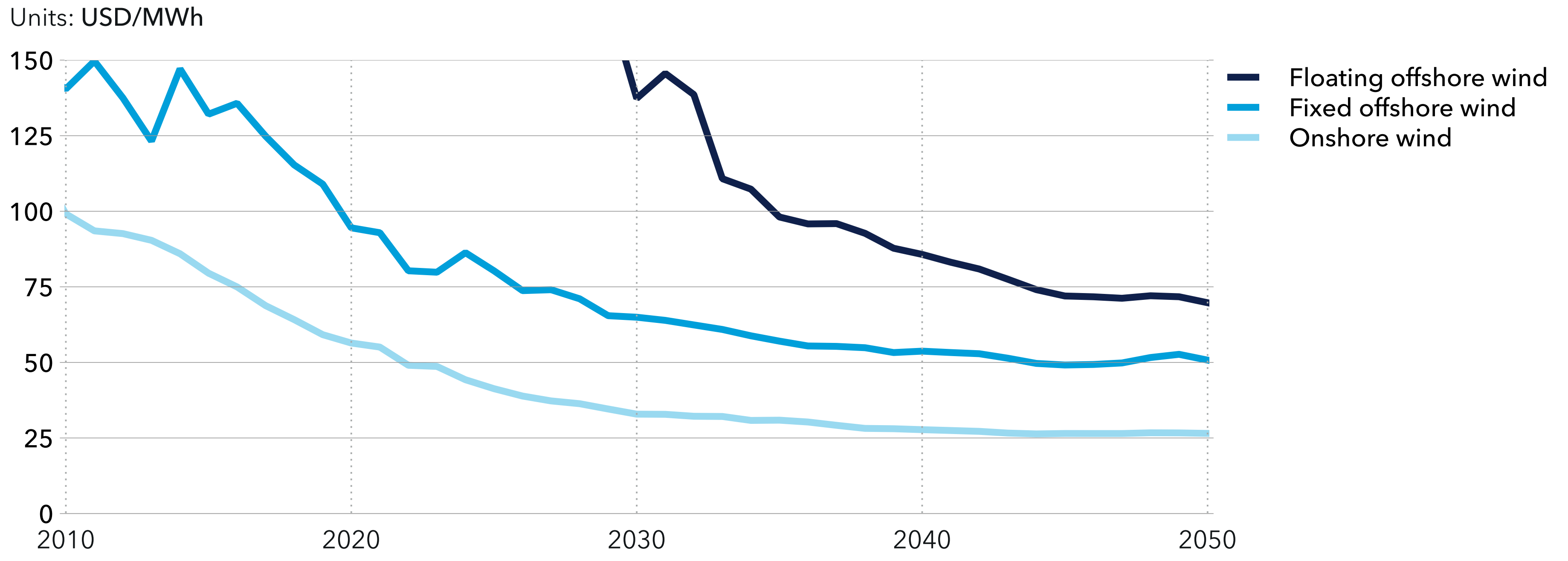
Figure 3.10 illustrates the global LCOE for three types of wind power generators: onshore, fixed offshore, and floating offshore. While we had seen a consistent decrease in LCOE over the years, last year marked a change. The decline slowed or even reversed in several global markets, including North America and Europe. This change in trend, compounded by short-term wind market challenges, such as financing and quality concerns (see fact box overleaf), influenced changes we made this year to our LCOE forecast.

From a 2022 baseline of USD 49/MWh for projects at financial close that year, we anticipate the global weighted average LCOE for onshore wind to drop to USD 33/MWh by 2030. Thereafter, the pace of this LCOE reduction is predicted to decelerate from 2030 to 2050. This is primarily due to a halt in rotor size advancement and the crowding of the most optimal sites. Over these two decades, we expect the LCOE to further drop from USD 32/MWh to USD 27/MWh.

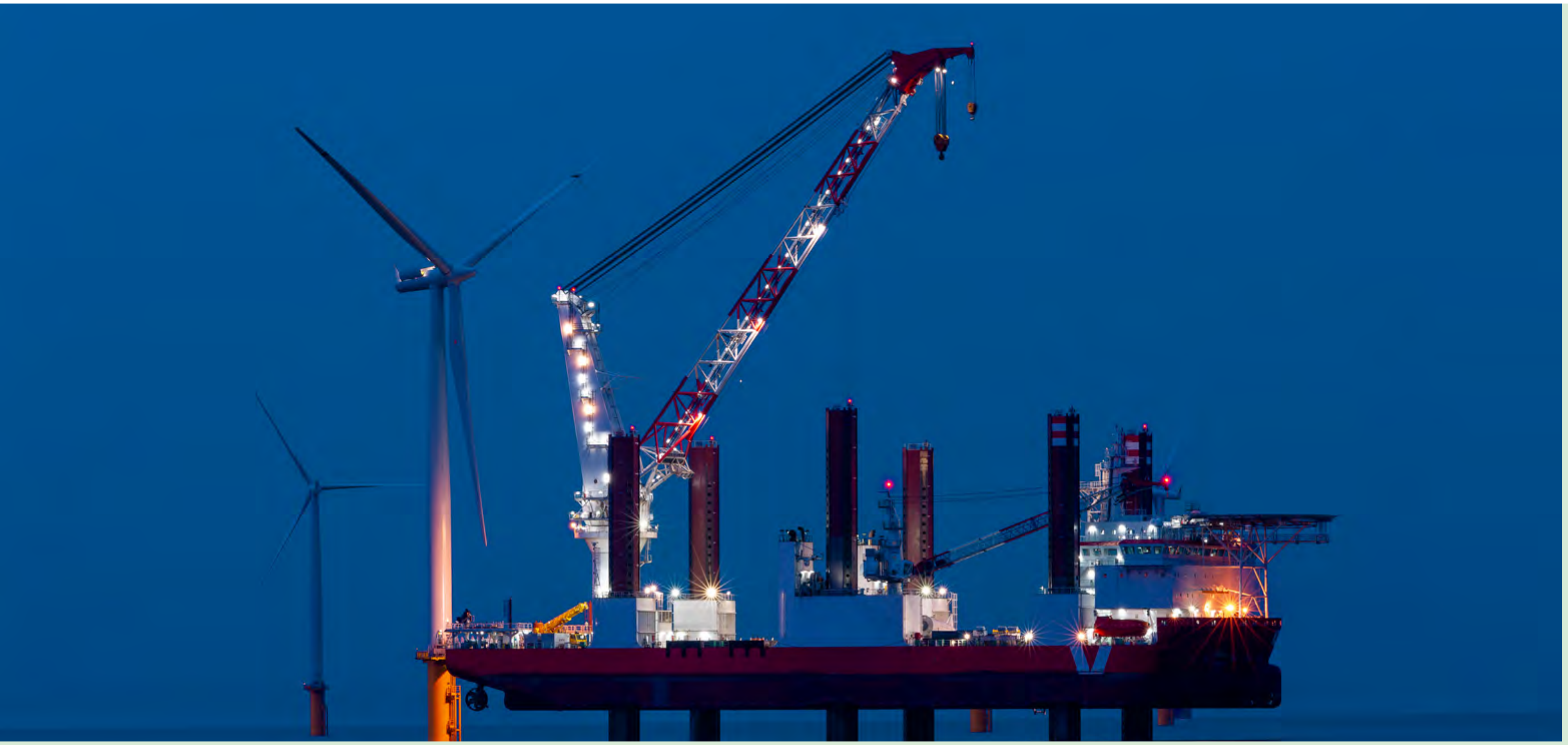
Currently, the LCOE for floating offshore wind (USD 270/MWh) is more than three times that of fixed offshore wind (USD 80/MWh). Despite the recent LCOE deceleration, our medium-term outlook remains optimistic. By 2032, floating offshore wind is predicted to cost only twice the amount of fixed offshore wind. By the mid-21st century, the global cost difference between them is projected to be about 30% due to the benefits of economies of scale and improved efficiencies in production. To provide specific numbers, by 2050, we estimate the global average LCOE for fixed offshore wind at around USD 51/MWh and floating offshore at approximately USD 67/MWh, with these cost reductions driven by volume increases and the advantages of experiential learning.

FIGURE 3.10

World average levelized cost of wind energy



Historical data source: GlobalData (2023), DNV analysis



Short-term challenges for wind power

The wind power market has been buffeted by head-winds exacerbated by the cost-inflationary pressures that have affected many mature economies. Two recent examples are the failures of wind power auctions in the North Sea in the UK (Reed, 2023) and in the Gulf of Mexico in the US (Noor, 2023). Here, we systematically outline the array of challenges, giving brief explanations.

High interest rates and cost of capital

The central banks of almost all major economies have increased the interest rate for borrowing (explained in Section 5.3), which has led to the expectation that the cost of both debt and equity capital will see elevated levels in 2023 and 2024 and only return to 2022 levels by 2025. This short-term increase in cost of capital severely curtails the financial viability of wind projects, deterring project developers from investing in wind.

Dwindling profits and margins for OEMs

Elevated costs of raw materials, such as steel for wind turbine, rotor, and hub manufacturing, has affected the profit margins of OEMs, leaving them very little room for manoeuvring as forward-signed contracts must still be honoured. Similarly, rapidly evolving technology development cycles have also led to quality issues in components, thus increasing the costs and reducing the margins.

Supply-chain snarls

While elevated costs are one thing, the inability to source raw materials, components, and appropriate skilled labour have also added to the delays in wind power projects going ahead, contributing to longer lead times, translating to elevated costs.

Gridlock, delays in building transmission lines

While projects may be ready, struggles to plan, permit, and build transmission lines to transmit the electricity generated from wind farms to the load-centres in certain regions place severe restrictions on project profitability (as expanded on in Section 2.1.2).

Suppressed cost-learning effects

The continuous development of technology, with improvements to design of components and size of rotors and turbines, will somewhat dampen the cost-learning effect, which normally accrues through producing high volumes of the same product. Significant changes to design and sizes imply that the learning is only transferred partially. We expect this to be a short-term effect, ending once the design and size increases stabilize.

Local content requirements

Many wind power markets mandate local content in domestic projects as prerequisites for awarding of contracts to stimulate and boost local manufacturing industries. In some nascent markets, such requirements prove to be too costly and/or too difficult to adhere to, resulting in contracts not being awarded (Buljan, 2022).

Why are we still optimistic?

These short-term challenges are not show-stoppers for wind, and should rather be considered small speed-bumps in the near future, for the following reasons:

- Unlike solar, wind has less diurnal variability, and thus serves as a complementary generation option in many regional grids with a high share of solar generation, such as North America.
- Expected capacity factor increases in the future, especially for offshore wind, and extension of lifetime with repowering possibilities push the cost calculus considerably towards an investment decision.
- National and sometimes sub-national decarbonization goals come with contracts for difference and premium payments, which stimulate the market.

Installed capacity

Total installed capacity of wind power in 2022 was 950 GW, 93% of which was onshore wind turbines. We expect total wind capacity to grow to 1,950 GW by 2030 and subsequently reach 6,400 GW by mid-century.

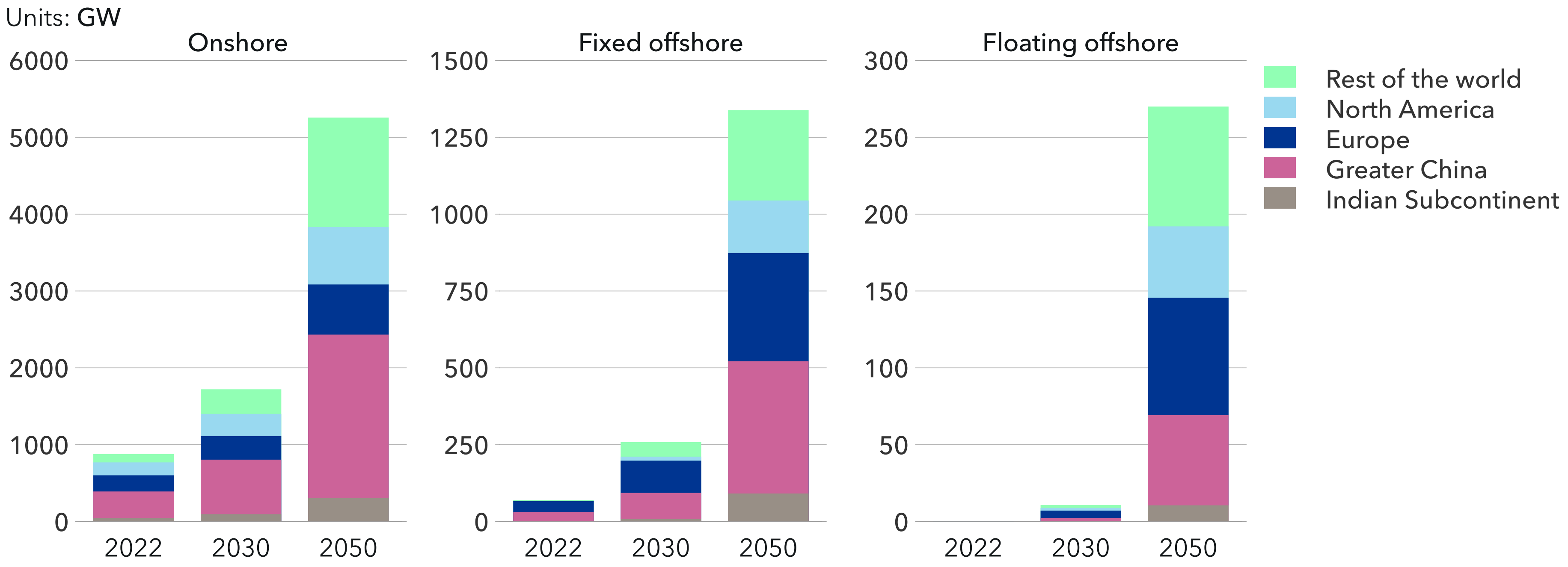
When breaking these numbers down by region, as shown in Figure 3.11, some interesting trends emerge. This figure divides the installed capacities into three categories: onshore, fixed offshore, and floating offshore wind turbines. Greater China stands out as the dominant player in both onshore and fixed offshore capacities. This surge is not just due to the rapid rate of installations but is also fuelled by economic incentives from the region's emerging carbon market in the power sector.

On the other hand, Europe is shaping up to be the leader in the floating offshore wind market, particularly leveraging developments in the North Sea.

Beyond these figures, it is worth noting that wind power will serve more than just our electricity needs. A dedicated portion of this capacity will be specifically geared towards hydrogen production through electrolysis. Our forecasts indicate that by 2050, there will be 385 GW of onshore and 100 GW of fixed offshore wind capacity dedicated solely to hydrogen production on a global scale.

FIGURE 3.11

World installed wind capacity by region



Historical data source: GlobalData (2023), DNV analysis

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, 2023). 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.

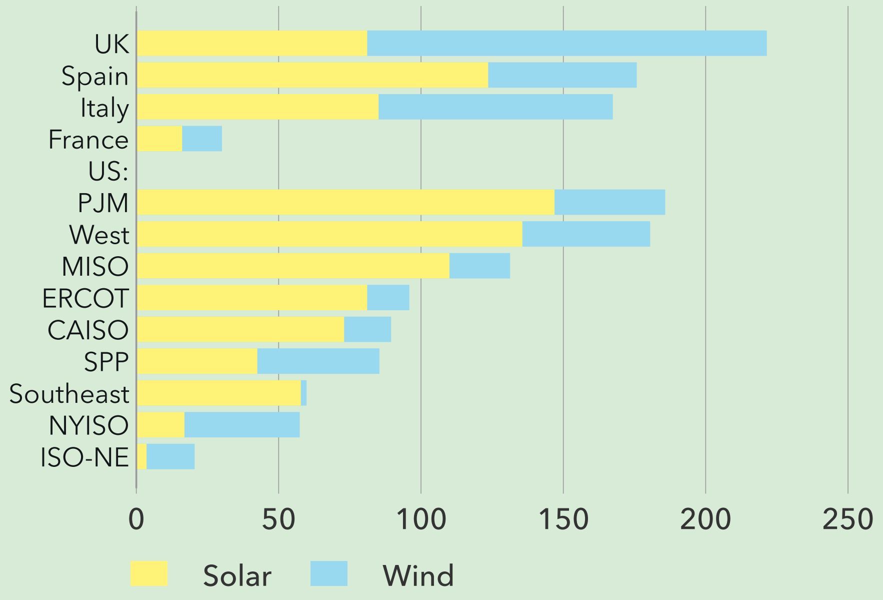
– Lack of coordinated spatial planning and permitting process for generation sites, grids, and the related project infrastructure.

– Lack of anticipatory investment to accommodate distributed energy sources at the distribution level.

FIGURE 3.12

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

Units: GW



Adapted from BloombergNEF (2023a)

– 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, 2023a) as shown in Figure 3.12. Almost 1,000 GW of solar projects are stuck in the interconnection 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.

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) emphasize new, simpler permitting. For example *RED III* details on 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; to improve auction systems, skills development, and access to finance; and, to 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, 2023). 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, and we refer the reader to DNV's report Energy Transition North America 2023 (DNV, 2023c) for further details.

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

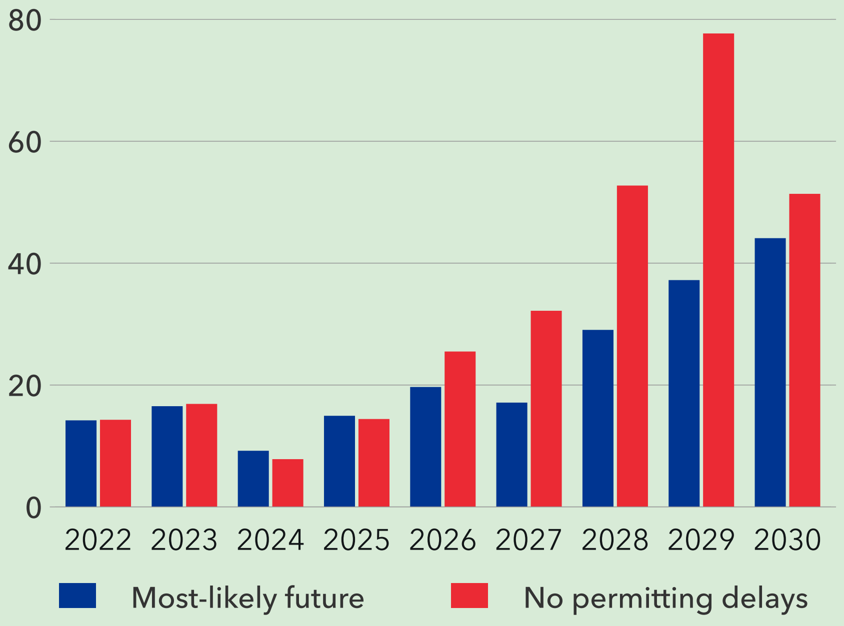
32trn will need to be invested by 2050 (from 2023), and North America, China, and the Indian Subcontinent would account for the majority of this grid investment. This investment is necessary, not only to expand and upgrade the networks, but also to replace ageing assets. Underpinning this estimate is 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.

FIGURE 3.13
Global offshore wind capacity additions with and without permitting delays

Units: GW/yr



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 grid tariffs from rising.

This regulatory mindset is completely outdated, reactive, and drags progress back by decades.

Furthermore, the reality is that the grid is a 'public good' and a critical part of national infrastructure, akin to the military, for example. The externalities and consequences resulting in not upgrading, expanding, and modernizing the grid have serious implications, not least of all for decarbonizing the energy system.

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 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 3.13 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%.

3.3 HYDROPOWER

Hydropower is the original means of renewable electricity generation. In 2022, it represented comfortably more than a third (37%) of total renewable energy generation, and more than a seventh (15%) of overall electricity generation. However, in contrast to solar PV and wind, hydropower growth towards 2050 will be moderate.

In many parts of the world, solar PV and wind will compete strongly with hydropower, causing average electricity prices to decline and creating adverse conditions for new hydropower. However, policy continuity for hydropower projects and rising electricity demand will ensure that hydropower projects will continue to be pursued, at least in low-income economies.

There is a compatible relationship between VRES and hydropower. As solar PV and wind energy will grow strongly, there is increasing need for dispatchable power that provides the necessary flexibility for the grid, both for daily and seasonal variation management. Hydropower is excellent from this perspective, being both zero-emission and easy to turn on and off as needed. Although we might see increased competition on price, this ability enables hydropower to receive much higher average prices and ensure profits despite having a higher LCOE than wind and solar PV.

Pumped hydro, which increases water volumes by harnessing surplus solar and wind energy to pump water back up to the reservoir, has additional capacity to provide energy when needed. However, because pumped hydro requires new investments, which could involve biodiversity challenges and energy losses, many areas will continue with traditional hydropower without pumping facilities. Run-of-river hydro, though lacking storage and therefore only partially dispatchable, will also continue to play a role.

Forecast

Hydropower generation has doubled over the last 20 years, and growth will continue until it slows down and plateaus in 2040 (Figure 3.14). Until then, most of the growth will be in Greater China, the Indian Subcontinent, and South East Asia. After 2040, growth in hydropower generation will stabilize in all regions. In 2050, such generation will provide little more than a tenth (11%) of the total electricity supply, down from 15% in 2022, but the growth from today is more than half (54%) in absolute terms.

Most regions will see moderate growth in hydropower capacity towards 2050. The largest capacity additions will be in Greater China, the Indian Subcontinent, and South East Asia. In 2050, the highest absolute installed grid-connected capacity is seen in Greater China (490 GW), the Indian Subcontinent (280 GW), and Latin America (260 GW).

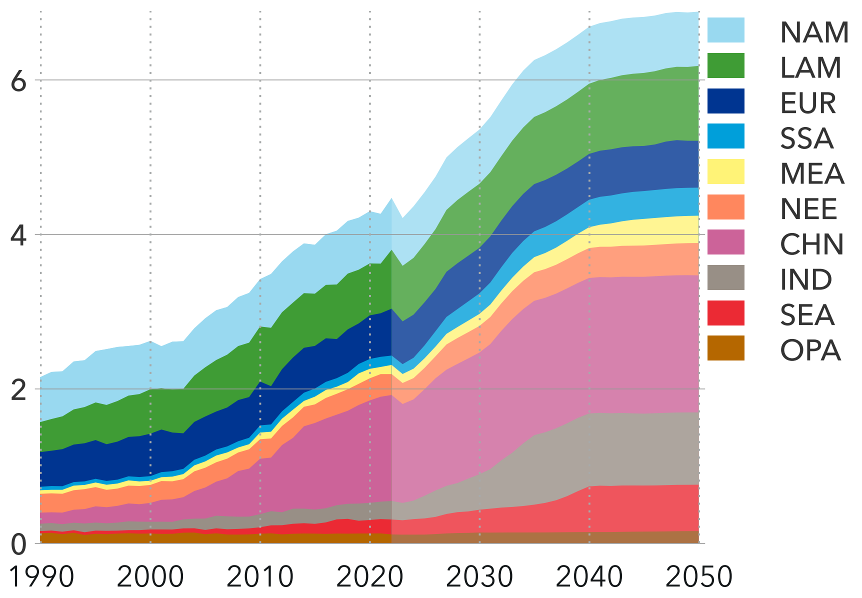
Hydropower and climate change

Global warming may challenge the hitherto prevailing view that hydropower is the most reliable source of power. Climate change accelerates melting of mountain glaciers and induces greater rainfall variations and recurrent droughts. Even if absolute precipitation is likely to increase with higher temperatures, the changes create uncertainty over future hydropower output. This was dramatically illustrated recently in China's Sichuan province where a drought-induced hydropower deficit caused the province's coal-fired plants to run at maximum rated capacity, leading to yet further water draw-down for power station cooling (Zhang, 2023).

FIGURE 3.14

Hydropower electricity generation by region

Units: PWh/yr



Historical data source: IEA WEB (2023)

Furthermore, hydropower has a dual purpose to generate electricity and manage water resources for flood control and irrigation. Ensuring that hydropower schemes are equipped to manage the coming challenges in rainfall and weather patterns can contribute to reduced damage to local communities and crops in extreme weather conditions.

The size and regional placement of hydropower schemes are also important to consider. While small hydropower schemes are generally low impact, large dams can have regional effects and influence the water flow in areas where water is already a scarce resource. In these areas, climate change might exacerbate conflict around its control, and could possibly endanger already fragile agriculture and drinking-water supply to growing populations.

The effects of these various parameters are hard to quantify and are not directly accounted for in our forecast. However, they might significantly influence the purpose of hydropower in coming decades, and we will pay attention to these changes.

3.4 NUCLEAR POWER

Changes in the geopolitical landscape following events such as the annexation of Crimea by Russia, the COVID-19 pandemic, and the invasion of Ukraine have shifted the conversation about energy sources, including nuclear energy. However, whether this will result in a 'nuclear renaissance' will be dependent on many factors, not least the cost of future nuclear power.

Historically, nuclear power has offered a reliable and carbon-free source of continuous electricity at reasonable cost, particularly addressing concerns about energy security. However, the 2011 Fukushima disaster in Japan, followed by Germany's decision to phase out its nuclear power plants, has made the past decade challenging for the nuclear industry. In developed countries, it has struggled to compete with both traditional fossil fuel-based electricity and emerging renewable energy sources, but the renewed emphasis on energy security, driven by the war in Ukraine, has led many regions to reconsider nuclear power. Nuclear energy offers a stable supply of electricity with less reliance on fuel imports from other countries, such as natural gas. With the development of Small Modular Reactors (SMRs, see factbox), the industry expects to standardize the technology and harmonize the regulatory regimes, thereby reducing costs and improving cost predictability, and thus anticipates significant market growth.

Developments in nuclear technology, such as SMRs and other advanced reactors, promise safer, more flexible, and potentially more cost-effective options than current nuclear power plants. However, even when considering those concerns, nuclear will have to compete with the continuous cost decline of renewables and solve the existing challenges facing today's nuclear fleet. Even though long-term waste storage can be considered technically solved, few countries have selected and approved sites for long-term waste management, with only Finland constructing such a site at present. In OECD countries, new nuclear plants have been beset by long construction times stemming from several factors, including moving targets in regulatory regimes, increased material cost, and reduced labour productivity. For example, the commissioning of two new reactors at Plant Vogtle in Georgia, the US, was seven years late and had cost overruns of USD 17bn (Amy, 2023). However, the future looks slightly more favourable for nuclear build-out due to the increased focus on energy security.

Electricity generation

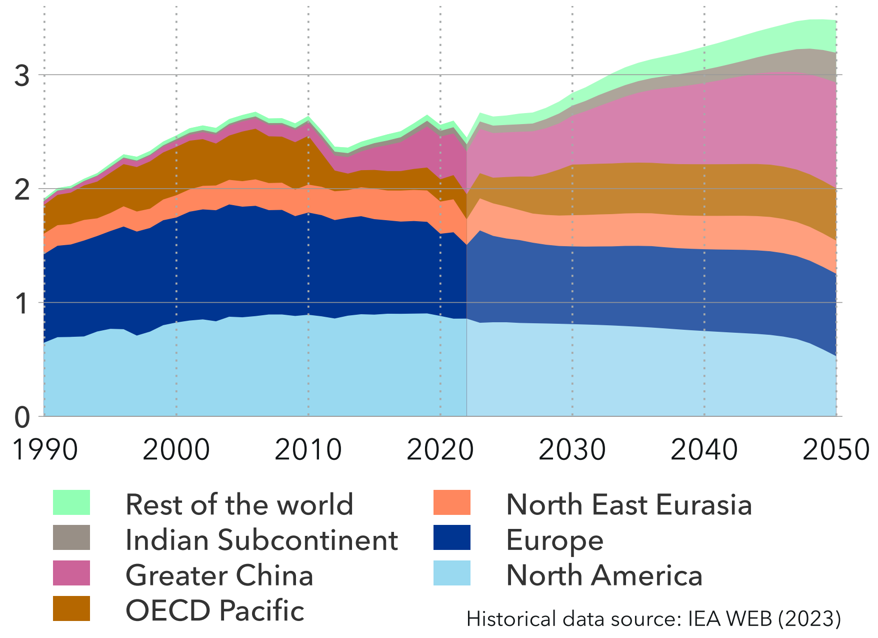
Our Outlook this year reflects the renewed interest in nuclear energy sparked by energy security concerns. Our forecast shows nuclear energy output stable at today's levels for the coming years, but growing from the late 2020s, see Figure 3.15. From today towards 2030, most added capacity will be based on site-built, large-scale reactors and is 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 those currently dormant. 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 relative 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.

FIGURE 3.15

Nuclear power generation by region

Units: PWh/yr



Historical data source: IEA WEB (2023)

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 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, such as Germany, are most likely to follow through with decommissioning rapidly, but elsewhere the renewed focus on energy security coupled with the high cost of nuclear decommissioning, the relatively low cost of nuclear life time 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 decomissioning 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 aging 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 could come at a higher cost compared with alternative energy options. In our model this year, we have included such policy choices for regions dependent on energy imports and where nuclear energy already exists. Based on our implementation, 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. With this caveat, we find that the total overall additional costs from nuclear, as a consequence of energy security, is around 13% per year.

New capacity
Small modular reactor technology has increasingly been praised as the next-generation technology to take over. But, just like existing nuclear plant designs, SMRs need to demonstrate cost competitiveness, high safety levels, and solve non-proliferation and waste-management challenges. There is limited evidence to support claims that SMRs will solve the cost hurdle. The APR-1400-based Barakah nuclear power plant in the United Arab Emirates may however be considered as preliminary evidence of cost control and cost reductions achieved using standardized modules. Government financed projects could assume a lower discount rate than private investors who perceive policy and technology risks, thus making nuclear more competitive. Pulling in the other direction on cost is SMRs size where material use, and thus cost, per MW increases the smaller a module gets; so, the question is where the sweet spot for modular nuclear is?

New SMR reactors are safer by design, relying on more passive safety and having to comply with increasingly stricter regulations. However, new designs remain to be tested. The potential impact of SMR technologies on weapons proliferation is unclear. SMR technologies requiring higher-enriched uranium fuel could pose a greater proliferation risk than the current 5%-enriched uranium (Holt, 2017).

SMRs could eventually make an important contribution, in particular to the decarbonization of hard-to-abate sectors, including shipping and aviation, through dedicated powering of production of low-carbon hydrogen, ammonia, and e-fuels, and also in the propulsion of merchant ships. We see specific use cases emerging where SMRs are especially well-suited to compete. These include areas that are remote or unsuitable for large-scale renewables deployment, commercial shipping unable to use cheap renewable electricity directly, and large sources of manufacturing demand, such as steel, cement, and petrochemicals. These industries will need to secure a supply of electricity combined with heat and possibly hydrogen. In all these use cases, an SMR could support energy supply as a cheaper alternative to hydrogen derivatives, or through flexibly supplying electricity to the grid or factory depending on the availability of cheap wind or solar energy. At other times, it could divert to increase its production of hydrogen.

Small Modular Reactors (SMRs)

Small Modular Reactors are a *design concept* referring to the size, capacity, standardization, and modular manufacturing for in-factory mass production. SMRs are small enough to be shipped to the plant site where several reactor modules can be integrated to the needed capacity and operated as a single system in a single housing. This production approach may reduce costs in the long run but will likely increase costs in the short term due to investment needs in manufacturing facilities and higher material intensity. The small size also facilitates installation underground, immersed in water pools, contributing to increased safety. SMRs span a range of reactor technologies from proven light-water technologies to novel, untested technologies. Modern reactor technologies have passive safety systems and a number of new safety features that arguably improve safety. In the long run, novel reactor technologies may reduce radio-toxic waste, in particular if a *closed fuel cycle* is achieved.

So far, US regulators have approved only one SMR design, the NuScale Power Corporation VOYGR. But other countries like France (NUWARD SMR) and many companies have submitted designs for approval, planning operational start-up earliest by 2030. There are also designs being developed in China and Russia, but there is uncertainty as to whether they will be accepted elsewhere in the current geopolitical landscape. While SMRs hold the promise of providing stable, carbon-neutral energy, especially in areas unsuitable for large-scale renewable deployments, their widespread adoption is contingent on numerous factors, including public acceptance, regulatory agility, and economic viability. In addition, with SMRs comes probably an order of magnitude more sites, in more countries, which could negatively impact safety, waste management, and proliferation risk.

3.5 BIOENERGY

Currently, bioenergy stands as the foremost renewable energy source and is a key option for meeting energy demands through to 2050, particularly in sectors that pose challenges for electrification.

Bioenergy is derived from various biomass sources, encompassing organic waste, agricultural and livestock residues, forest wood, and energy crops. The applications of bioenergy are as diverse as its origins. For instance, solid biofuels like wood or charcoal are used for heating buildings, cooking, and in combined heat and power plants. Wood chips are increasingly being integrated into coal-fired power plants to curtail emissions. One of the most outstanding examples of this use is Drax Power Station, located in Yorkshire, the UK, which has undergone a transformation towards full biomass utilization. However, questions remain about the actual carbon reductions achieved, especially because of sourcing biomass from faraway places such as Canada.

In the gaseous form, bioenergy, including biogas generated from waste, is utilized for power generation, as a fuel source, and, when further refined, as biomethane. Biomethane, in particular, has garnered significant attention due to escalating natural gas prices and growing concerns about domestic energy security. Additionally, liquid fuels produced from crops, algae, or genetically modified organisms hold promise for hard-to-decarbonize transportation sectors such as aviation and maritime.

Is it carbon neutral?

The combustion of biomass, which includes biofuels, is typically considered carbon neutral, meaning that no carbon emissions are counted. This aligns with the assumptions made by the Intergovernmental Panel on Climate Change (IPCC) that the carbon present in biomass is ultimately reabsorbed from the atmosphere through photosynthesis, assuming that the plants burned are replaced with new ones. However, the putative carbon neutrality of biofuels is heavily debated among many scientists, primarily due to the disparity in the timing of CO_2 reabsorption by new plant growth, which is considerably slower compared with the rapid release of CO_2 during combustion. Moreover, there are significant concerns associated with direct and indirect land use changes – converting natural vegetation to grow biofuel feedstocks typically releases a large amount of carbon from soil and plant biomass, creating a 'carbon debt' that can take years to repay (Royal Academy of Engineering, 2017). Other concerns relate to emissions from agricultural equipment and fertilizers.

Looking ahead, the sources of biomass for biofuels are expected to gravitate towards residues and biowaste. Second and third-generation biofuels are likely to undergo rigorous scrutiny before being deemed sustainable and carbon neutral for use. As the infrastructure for the next generation of biofuels is developed during the transition period up to 2030, those produced from unsustainable sources like energy crops may still play a significant role in the biomass sector. Even so, ongoing debates surrounding the trade-off between food and fuel production will likely prioritize the use of biomass that would not otherwise be utilized for feeding the global population.

The temporal perspective of biomass emissions is a crucial concern. In our projections, potential additional emissions stemming from activities like deforestation to create space for crops intended for liquid biofuel production are accounted for within the category of agriculture, forestry, and other land-use (AFOLU) emissions. Emissions associated with the transport of biomass are categorized under the transport sector. Nonetheless, the prevailing viewpoint is that biomass, and consequently biofuels, remain carbon neutral over an extended period. Additionally, biomass-based value chains have the potential to be carbon negative, such as when organic waste is utilized as a feedstock for energy production rather than being left to decompose and produce methane emissions.

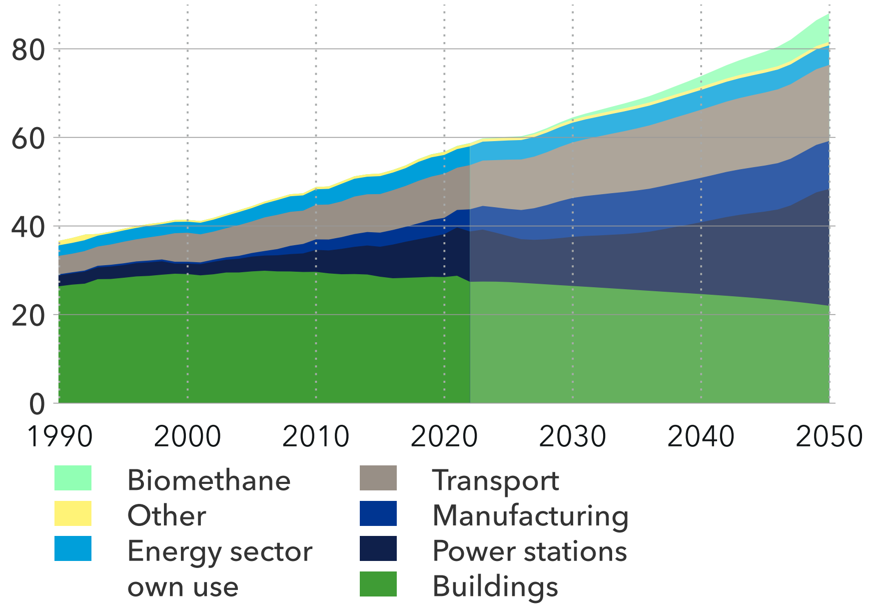
Forecast

The global demand for bioenergy derived from biomass has nearly doubled since 1980. Figure 3.16 illustrates that the use of biomass for energy purposes will continue to grow to mid-century. The primary drivers of this growth will be transport and manufacturing. The overall contribution of biomass to primary energy supply is expected to see a marginal increase, reaching approximately 11% by 2050, compared to the current 10%. The utilization of bioenergy in the transport sector is expected to experience significant growth, primarily in the form of liquid biofuels, with gaseous biofuels playing a minor role in this sector. This growth is projected to be substantial, doubling between 2022 and 2050, making bioenergy a crucial energy source for decarbonizing transport and accounting for a 10% share of transport energy consumption. This expansion will be primarily driven by decarbonization policies, including mandates and carbon pricing, and consumer-push, coupled with the limited availability of alternatives, particularly in aviation and maritime transport, where electrified propulsion technologies are less feasible.

FIGURE 3.16

World bioenergy demand by sector

Units: EJ/yr



Historical data source: IEA WEB (2023)

Currently, almost all bioenergy use in the transport sector occurs in road transport (99.5%), primarily in the form of blends with gasoline and diesel, with a minimal amount in gaseous forms like biomethane. However, this landscape is anticipated to shift by 2050. Aviation and maritime transport are expected to increasingly adopt biofuels to diversify their fuel sources and promote decarbonization. By 2050, road transport is projected to witness a 60% reduction in its current bioenergy demand share, driven by ongoing electrification efforts and reduced demand for blended fossil fuels. This trend is further supported by intensified competition for biomass sourcing from other transport subsectors. Maritime transport is expected to account for 32% of biofuel use in transport by mid-century, with the largest portion (47%) being used in aviation.

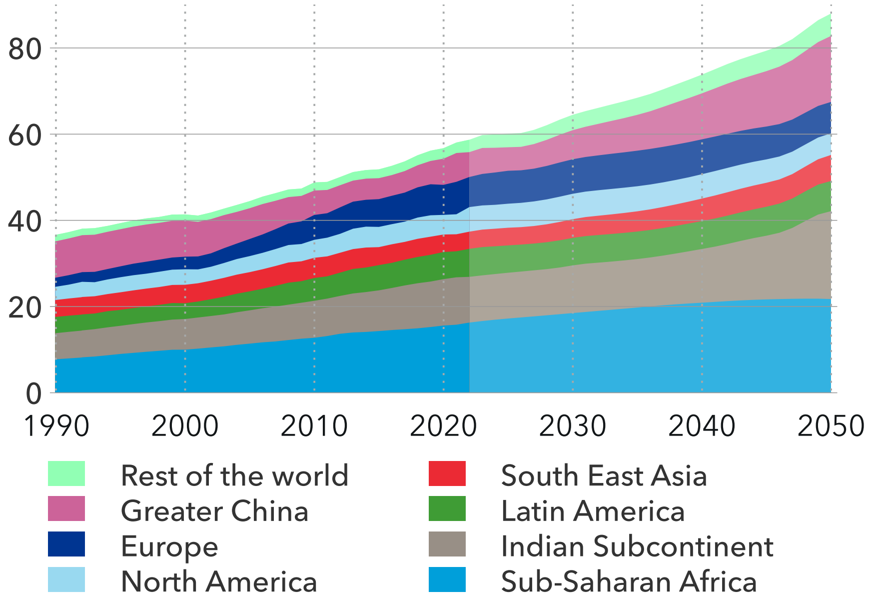
In the buildings sector, the use of bioenergy is anticipated to decrease by about 20% by 2050. This decline can be attributed primarily to reduced reliance on traditional biomass in low-income regions for space heating and cooking fuel. Nonetheless, bioenergy will continue to play a prominent role in the energy mix for buildings, with approximately one-third of bioenergy still being utilized in this sector by 2050, compared to 50% in 2022.

Power stations are poised to increase their consumption of bioenergy by 30% between 2022 and 2050, elevating power generation to taking up a third of biomass by mid-century. In 2022, manufacturing accounted for 17% of global bioenergy consumption, and this share is expected to grow by some additional 3% during the forecast period, reaching slightly above 20% in 2050.

FIGURE 3.17

Bioenergy demand by region

Units: EJ/yr



Historical data source: IEA WEB (2023)

Regional Trends

Figure 3.17 indicates that the regional distribution of demand is forecasted to undergo only gradual changes throughout the forecast period for most regions. However, certain regions are expected to experience substantial increases in their utilization of bioenergy, notably the Middle East and North Africa with a remarkable more than doubling, Greater China (+90%), South East Asia (+35%), and the Indian Subcontinent (+80%). It is worth noting that while these percentages represent significant growth, the starting point for bioenergy use in the Middle East and North Africa is relatively low. Meanwhile, North America and Europe are projected to experience a slight decline in bioenergy use.

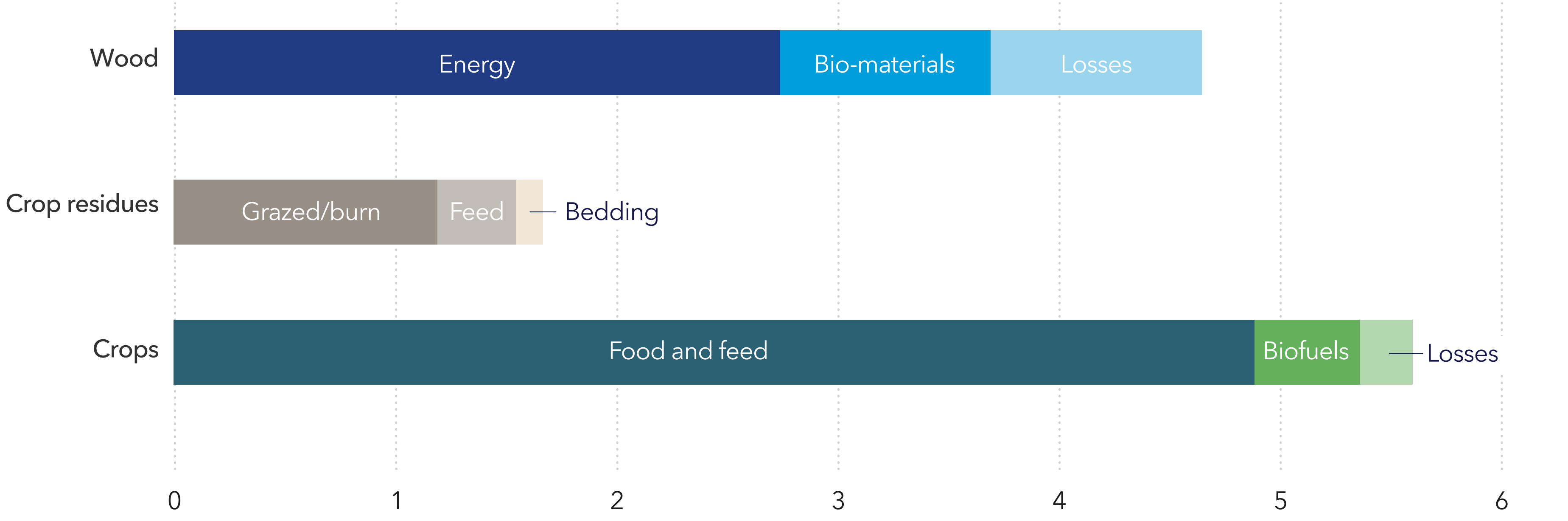
Over the forecast period, Sub-Saharan Africa is poised to maintain its position as the largest global consumer of biomass, maintaining a stable share of 27% worldwide. Furthermore, the overall demand for biomass is expected to rise, and the global composition of biomass utilization will undergo a significant transformation. This transformation will entail a shift away from traditional forms of biomass, such as wood or charcoal that are commonly used for activities like cooking, towards a greater reliance on modern biofuels derived from waste. These modern biofuels will find applications, for instance, in aviation and maritime sectors. In certain regions, traditional biomass currently serves as the dominant energy source for residential buildings. While this direct usage is expected to evolve, it will remain a substantial energy source in selected regions.

The overall demand for biomass is expected to rise, and the global composition of biomass utilization will undergo a significant transformation.

FIGURE 3.18

Biomass use today

Units: Bn tonnes/yr



How much bioenergy is available, and for which industries?

Biofuels stand as one of a limited number of options for decarbonizing aviation and the deep-sea portion of the world fleet. Today, the main categories of biomass being utilized are wood, crop residues, and crops. Biomass is used primarily for food and feed (crops) or energy (wood), as depicted in Figure 3.17. Only a fraction (4%) is used for the production of biofuels. In order to expand biofuel production in the future to meet decarbonization objectives, we need to make sure that this does not compromise the current system of biomass usage. As a result, expanded biofuel production must be based on sustainable biomass sources such as agricultural by-products, residues of forestry and wood industries, municipal waste, and industrial residues. Incorporating sustainability as a factor in the potential assessment is highly important. Moreover, non-sustainable use of biomass could erode the emission reduction potential of bioenergy.

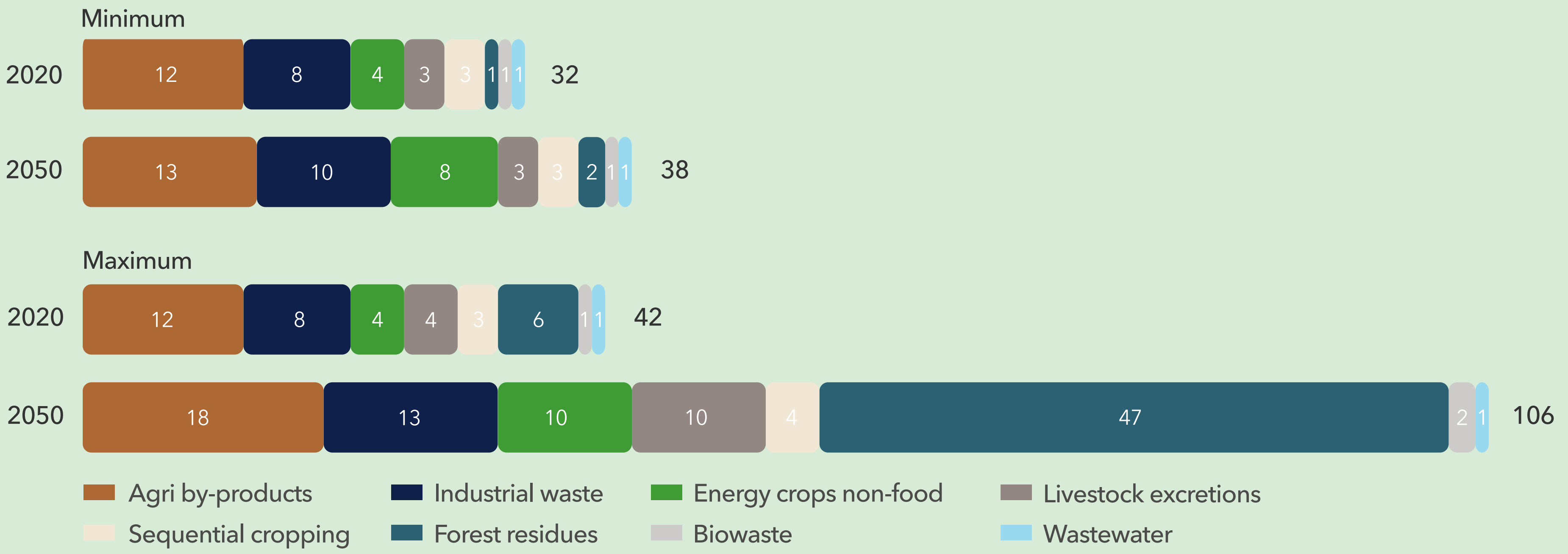
As the question about the future availability of biomass is a pressing one and has been widely recognized, there are numerous studies available depicting their view on availability of sustainable biomass. However, some are not very transparent regarding their assumptions, just cover a certain geography, or show a large bandwidth of results. Therefore, and in order to strengthen DNV's competence on the subject of biofuels in shipping and other industries, and improve input-data applied in DNV tools and models (e.g. GHG Pathway model, Fuel Price Mapper, ETO), a thorough assessment on the sustainable potential of biofuels up to 2050 has been done. We estimate that the exploitable biomass potential today lies between 32 EJ and 38 EJ. In the future, this could grow to between 42 EJ and 106 EJ (see Figure 3.18). The reason for the wide range in potential is due to the diverse information found in literature (e.g. on the dry matter content of straw), leading to a wide set of results. These estimates are in line with the EU *RED II* directive of sustainable biofuels as a guideline, as such exclude, for example, conversion of land to accommodate production of agricultural raw material for biofuels.

We assume that a very low share of the exploitable potential for biomass is tapped today, due to the fact that production of biofuels from sustainable biomass sources is itself low. Assuming that all future expansion of sustainable biomass usage (e.g. in maritime and aviation) will have to come from exploitable and sustainable sources, we see a strong increase in demand towards 2050. We see that the gap between exploitable potential and demand for biomass becomes narrower and narrower as time passes, with some overlap starting from about 2035. We provide more information about this quite complex topic in our recent white paper *Biofuels in shipping* (DNV, 2023d).

FIGURE 3.19

Total sustainable and economical biomass potential by feedstock category

Units: EJ/yr



3.6 OTHER ENERGY

Other renewable energy sources are likely to remain marginal on a global scale between now and 2050. For example, solar thermal and geothermal combined will provide around 1% of world primary energy by mid-century and concentrating solar power (CSP) even less.

In this Outlook, 'solar thermal' refers to heat generated in solar water heaters. Globally, primary energy supply from solar thermal energy will start declining from 1.24 EJ in 2020 to 0.46 EJ in 2050. Over 82% of this energy heats buildings and will mainly be in use in China. This region will also be responsible for most of the decline in solar thermal as heating water from electricity takes over. Section 1.3 discusses in more detail how buildings use energy for heating water.

CSP, though not modelled, is another technology which is not yet large-scale. This technology concentrates a large area of sunlight onto a receiver, generating both heat and electricity. While this improves the efficiency of power generation, it adds additional manufacturing complexity and cost. This complexity has hindered the roll-out of CSP technology, and well publicized failures such as at the Crescent Dunes facility in the US have eroded faith in it. Two types of CSP plants exist, either parabolic trough power plants or molten-salt tower / central receiver power plants, with both technologies still needing to mature. China currently leads the way in CSP installations, announcing new installations in 2022 and 2023 which will bring the country's capacity to 3 GW. Spain also has a modest amount of CSP (around 2.3 GW), though the largest CSP installation today is the Noor Power Station in Morocco. Though LCOEs are starting to become low enough to be competitive with other renewable technologies, we do not see this technology reaching a large-scale build-out during the forecast period.

Geothermal technology extracts the heat found under the surface of the earth, and uses this either directly for heating and cooling, or converts it into electricity. For electricity generation, high temperature resources are needed – a minimum of 150°C – while for heating and cooling lower temperatures can be used (90–150°C). These high temperature resources limit the areas where geothermal energy can be produced for electricity to tectonically active regions where water or steam is close to the surface, and many of the best places to implement this technology have been used.

Geothermal energy provides a stable source of energy with high capacity factors and is seen as a renewable technology which could provide a stable source of energy, in contrast to variable solar and wind power. The technology for high temperature geothermal energy is reasonably mature, so for future innovation the industry now looks to novel technologies such as enhanced or engineered geothermal systems, advanced geothermal systems, and supercritical geothermal systems. Some synergies may exist between the technologies used for the extraction of oil and gas and geothermal technology, and some oil and gas companies have shown interest in exploring geothermal energy. The largest barriers to the widescale implementation of geothermal are the high upfront capital expenditures, long project development timelines and higher risks during initial phases of exploration, all of which lead to challenges in financing projects.


Geothermal energy in Iceland

As of 2022, geothermal energy provided 3.72 EJ (0.62%) of the world's primary energy supply, and by 2050 this will rise to 6.13 EJ (0.93%). Worldwide, geothermal energy is overwhelmingly used by power stations, with the exception of Greater China, where the demand comes mostly from buildings. South East Asia and OECD Pacific will lead the world in geothermal energy in 2050 with it making up around 3% of these regions' energy mix. Although geothermal energy has the technological potential to grow in some applications, high costs in most of the world will limit its expansion.

As of 2022, geothermal energy provided 3.72 EJ (0.62%) of the world's primary energy supply, and by 2050 this will rise to 6.13 EJ (0.93%).


Scientists checking large pulsed power machine which creates nuclear fusion in nuclear fusion research facility.

Potential future energy sources
As stated in the introduction, we base our forecast on continued development of proven technologies, including advances in these technologies. Such improvements, like technological developments in solar PV and wind, are already included in their respective sections.

Technologies that are not yet proven, and marginal technologies that are not expected to scale, are not included in our forecast. Ocean energy is one of them. There are several types of ocean energy, including tidal barrage energy, tidal stream energy, wave energy, ocean thermal energy conversion (OTEC), and marine current power. Of these four, the first three are the most highly developed today, with a 2020 installed capacity of 521 MW tidal barrage, 10.6 MW tidal stream, and 2.31 MW wave power generation capacity (IRENA, 2020). The LCOEs of these technologies, and the investment costs, are declining but remain higher than for other forms of renewable energy. Other barriers to their large-scale implementation are limited suitable locations, often far from an existing grid, with accordingly high grid-connection costs. There is also concern about the environmental impact of these structures, including noise, risk of collision with marine animals, and changes to the flow and water quality.

In December 2022, a nuclear fusion reaction produced, for the first time, more energy than it took to drive the reaction.

Despite all that, plans have been made for new tidal stream installations, the largest being the four-phase MeyGen project in Scotland. Situated between the Scottish mainland and the Island of Stroma, the site has ideal depth, water flows, and proximity to the mainland. Phase one, comprising of four 1.5-MW turbines, has been operational since March 2018 and has generated 51 GWh as of March 2023. There are proposals for other tidal projects in the UK in East Anglia and on the river Mersey, and the EU currently has 17 major projects in progress, with over 160 MW of capacity. In the future, it looks like ocean energy technologies will be suited to niche markets – for example, small island developing states where it would be more costly to import energy – or coupled to another operation to provide it with power, such as oil and gas platforms or aquaculture operations. In other cases, ocean energy could be used directly (i.e. not first converted to electricity), to avoid additional cost and componentry, for example for wave-powered desalination (Garanovic, 2022).

Nuclear fusion is a similar case. For several decades, nuclear-fusion technologies have been discussed as a carbon-free source of energy. Several promising research projects focusing on smaller fusion systems are currently being piloted. Advances in computing power, materials science, and manufacturing, together with the rising availability of venture capital, have enabled recent progress in fusion technology. Once the domain of governmental research labs, private companies are now bringing expertise in other areas, and stronger commercial focus, as they seek to realize the potential of this technology (see details in our *Technology Progress Report*, DNV 2021a). In December 2022, a nuclear fusion reaction produced, for the first time, more energy than it took to drive the reaction. The availability of fuel – primarily deuterium – is almost limitless, but there are large uncertainties about if and when successful operation of nuclear fusion will occur. Even with a breakthrough, there will still be a significant delay before energy on a scale comparable to other power sources will be provided. Therefore, we confine our forecast to traditional fission technologies.

During the period covered by this Outlook, one or more of the emerging energy technologies may achieve a breakthrough, such that they become cost competitive. However, to have a significant impact on our forecast, they would need to grow much faster than incumbent renewable technologies. We do not see this happening at scale and have therefore excluded emerging technologies from the forecast.

Highlights

This chapter charts the decline of fossil fuel sources from what has been termed the 'beginning of the end of the fossil fuel era' in the closing years of this decade. First to start a steady decline will be coal, despite the current resurgence in coal use linked to the energy supply shocks set in train by Russia's invasion of Ukraine. For oil, it is mainly the electrification of road transport that tips demand from its steady rise in recent years towards a steady decline from 2027 onwards. Oil's current 29% share of primary energy supply will ebb away to reach 17% of primary energy by 2050.

Natural gas will surpass oil as the world's largest primary energy source in the mid-2030s. However, the replacement by renewable sources of gas in the power mix is the main reason behind natural gas usage peaking in the mid-2030s and then gradually declining in 2050 to a level only slightly higher than today's usage. LNG and pipeline transport will increase even when global gas demand does not, due to a shift in demand patterns to regions with little pipeline imports.

4 FOSSIL FUEL

4 FOSSIL FUEL

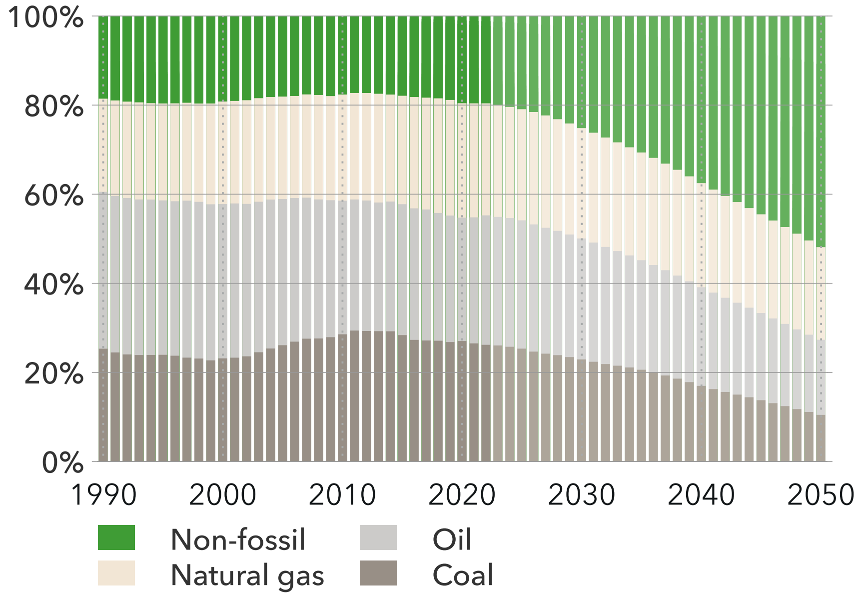
Fossil fuel currently covers 80% of global primary energy supply. This share has been stable for several decades but is set for dramatic change as the uptake of renewable energy sources is growing rapidly. We forecast that, before the end of this decade, the fossil slice of the pie will start shrinking by more than one percentage point per year to be less than half (48%) of the primary energy mix by mid-century.

Over the coming decades, we will see a gradual phase-down, first of coal, which has the highest carbon footprint, and thereafter oil. Gas will come later, and it maintains a high share of the primary energy supply mix throughout our forecast period. Even though renewables are already competitive in most places with fossil-fired electricity, it will take many years for low- and zero-carbon energy sources to dislodge fossil fuels from the broader energy system. Nevertheless, we have been clear and consistent in our Energy Transition Outlooks over the years that demand for fossil energy – coal, oil, and gas combined – will begin an inexorable decline before the end of this decade. For the first time this year, the IEA concurs with our view, and has begun to state that the world is at the "beginning of the end" of the fossil-fuel era (Birol, 2023). Figure 4.1 illustrates our forecast for how the composition of fossil energy sources, and the non-fossil share, will change by 2050.

FIGURE 4.1

Fossil vs. non-fossil in primary energy supply

Units: Percentages



Historical data source: IEA WEB (2023)

Today, 14% of the world's oil, 10% of the gas, and 1% of the coal is not used for energy purposes, but as feedstock in plastics, petrochemicals, asphalt, and similar products. This fossil fuel is not burned and does not cause direct emissions. The use of fossil fuel for these non-energy purposes will continue longer than burning it for energy, and the non-energy share of fossil-fuel use will grow over the forecast period. If we subtract what is used for feed-stock, the share of fossil fuel in the energy mix will reduce to 45% instead of 48% in 2050. Section 1.4 describes feedstock in more detail.

If you subtract the non-energy use of hydro-carbons, the share of fossil fuel in the energy mix will reduce to 45% instead of 48% in 2050.

4.1 COAL

Annual global coal demand experienced a rapid surge from 4.7 Gt in 2000 to its pinnacle at 8 Gt in 2014; since then its use has fallen steadily. The economic and trade contractions resulting from the COVID-19 pandemic caused a 7% reduction in coal demand in 2020. Although coal will recover to some extent, it will never reclaim its previous peak, instead dwindling to nearly one third from its present level by 2050.

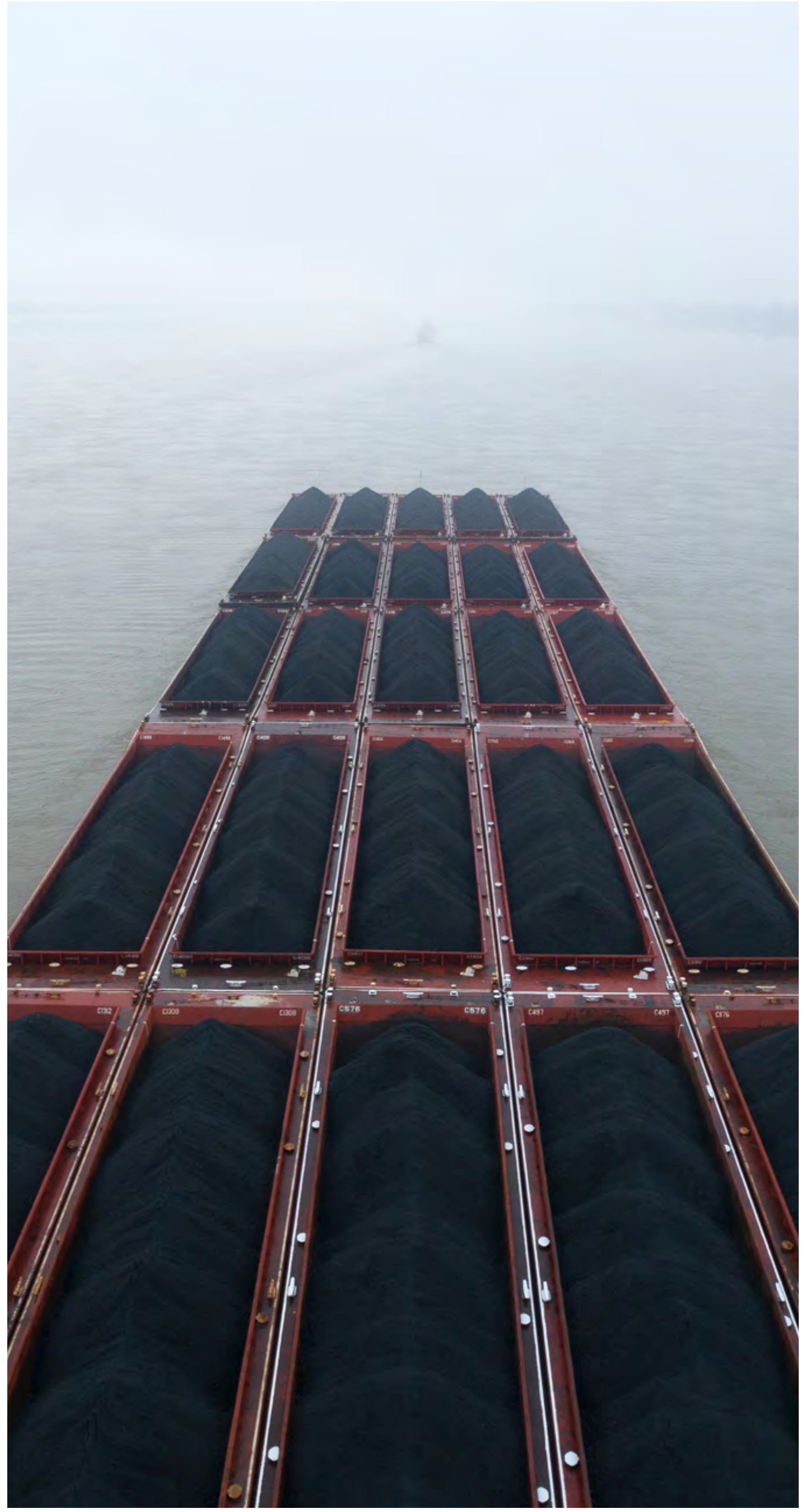
The war in Ukraine has triggered a resurgence in coal-based power production in several parts of the world, but mainly in Europe. While policymakers work to achieve a structurally lower gas consumption, some countries may reactivate previously closed or placed-on-reserve coal plants in Europe.

Such reactivation has hitherto been relatively limited in most European countries but has been substantial in Germany with approximately 10 GW of coal capacity coming back online. We expect Europe to maintain these elevated levels of coal-fired power generation for the coming years.

At the same time, China granted approval for a greater number of coal power plants in the past year than in the past seven. For perspective, this equates to approximately two new coal power plants receiving the green light every week. This noteworthy development comes despite the global trend of many countries moving away from using coal.

The surge in approvals for new coal power plants appears to be a reaction to two key factors: recurring droughts and the unprecedented summer heatwaves in 2022 and 2023. These resulted in heightened demand for air conditioning and placed stress on the power grid at a time when depleted river levels, including in certain segments of the Yangtze River, led to reduced hydropower generation. In addition, soaring prices for liquefied natural gas due to the conflict in Ukraine have given further impetus to China's use of coal for energy security reasons.

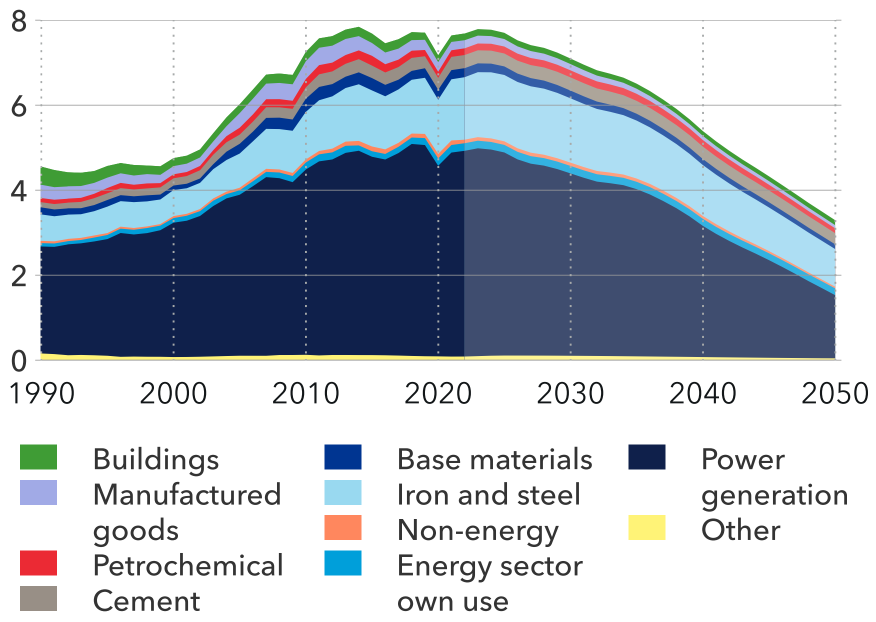
Coal has historically served as an economical and reliable source of power, making it the preferred technology for electricity generation in numerous countries. Power generation consequently emerged as the primary catalyst for coal demand, accounting for nearly two-thirds (63%) of coal consumption in 2022 (Figure 4.2). Besides power production, coal is a crucial heat source in manufacturing and serves as a carbon feedstock for reducing iron ore in steel production. However, in low-heat manufacturing processes, coal will gradually be replaced by electricity, especially to address local pollution issues, as seen in China's transition from coal to gas for industrial applications. In other global regions, gas boilers and electricity will facilitate a gradual reduction in coal use for most industrial heating needs.



For higher-temperature processes like cement, iron, and steel production, transitioning away from coal will be more challenging. Despite its substantial carbon emissions, coal will remain a preferred choice, but its use will be challenged by technological advances and hydrogen. In the short term, coal demand for high-heat processes will slightly increase before declining rapidly after 2030. In iron and steelmaking, global coal demand is expected to drop by nearly a fifth by 2050.

FIGURE 4.2

World coal demand by sector



Historical data source: IEA WEB (2023), US DOE (2010), Heat Roadmap Europe (2015)

Greater China, currently the largest coal consumer, will witness a 70% reduction in coal use, primarily due to declining steel production (down 65%). In contrast, the Indian Subcontinent will see a doubling of coal demand for iron and steel, nearly matching Greater China's demand by mid-century.

Coal consumption has significantly decreased in North America and Europe, primarily due to shifts to natural gas and renewables in the power sector. In North America, the decline has been attributed mainly to low gas prices, but is now beginning to follow Europe, where the growth of renewables is playing a central role. By mid-century, coal usage in OECD regions, notably North America and Europe, will have declined by approximately 90% and 80%, respectively. Even coal-rich OECD Pacific regions will witness a substantial 75% decline in coal consumption.

In the decade leading up to 2020, only the Indian Subcontinent (with a 45% increase) and South East Asia (with a 90% increase) have seen consistent growth in coal use. Nevertheless, all regions are projected to experience a long-term reduction in coal consumption, though short-term trends may vary.

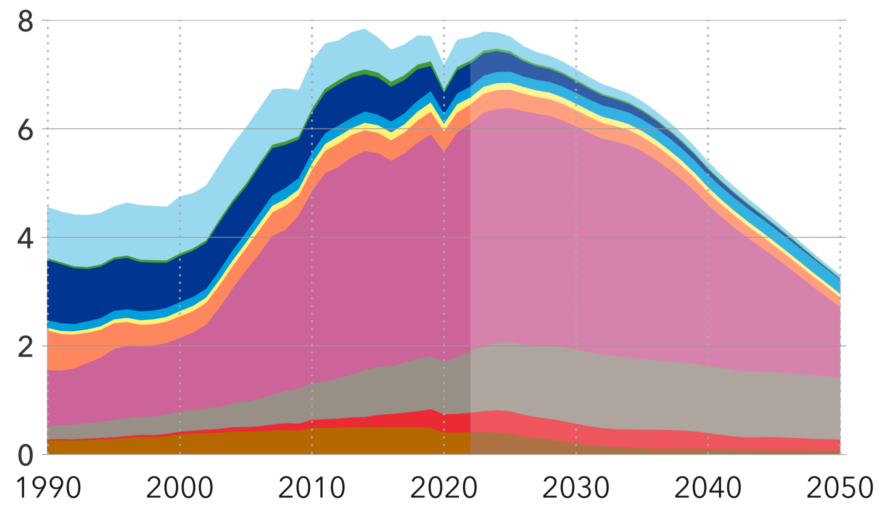
As described above, coal will face competition from natural gas and renewables in OECD countries in the short term but will see expansion in many developing nations. Beyond 2030, stricter emissions regulations, increased competition from renewables, and advancements in energy storage and flexibility technologies will enhance the dispatchability of renewables, diminishing the competitive position of fossil fuels, particularly coal. Consequently, new capacity additions will dwindle, retirements will rise, and capacity utilization will decrease. This pattern aligns with the coal 'death spiral' feedback loop: as coal plant utilization declines, its cost increases, further eroding its competitiveness, making coal-generated power less economically viable, and subsequently reducing its use.

Most brown coal and a substantial portion of hard coal are consumed within their respective regions of production. Only four of our ten regions are net importers of coal: Europe, Greater China, the Indian Subcontinent, and the Middle East and North Africa. China, the largest producer and consumer of coal, is also the largest importer. However, the gradual and long-term phase-down of coal-fired power plants in China and reduced coal use in manufacturing will progressively diminish its coal demand, with imports remaining high until around 2040 before declining significantly towards 2050. Driven by India's efforts to enhance self-sufficiency, the Indian Subcontinent will reduce its reliance on imported coal. Major coal-exporting countries like Australia, Indonesia, Russia, and South Africa will continue as exporters, but with decreasing export volumes throughout the forecast period.

FIGURE 4.3

Coal demand by region

Units: Gt/yr



NAM EUR MEA CHN SEA
LAM SSA NEE IND OPA

Historical data source: IEA WEB (2023)

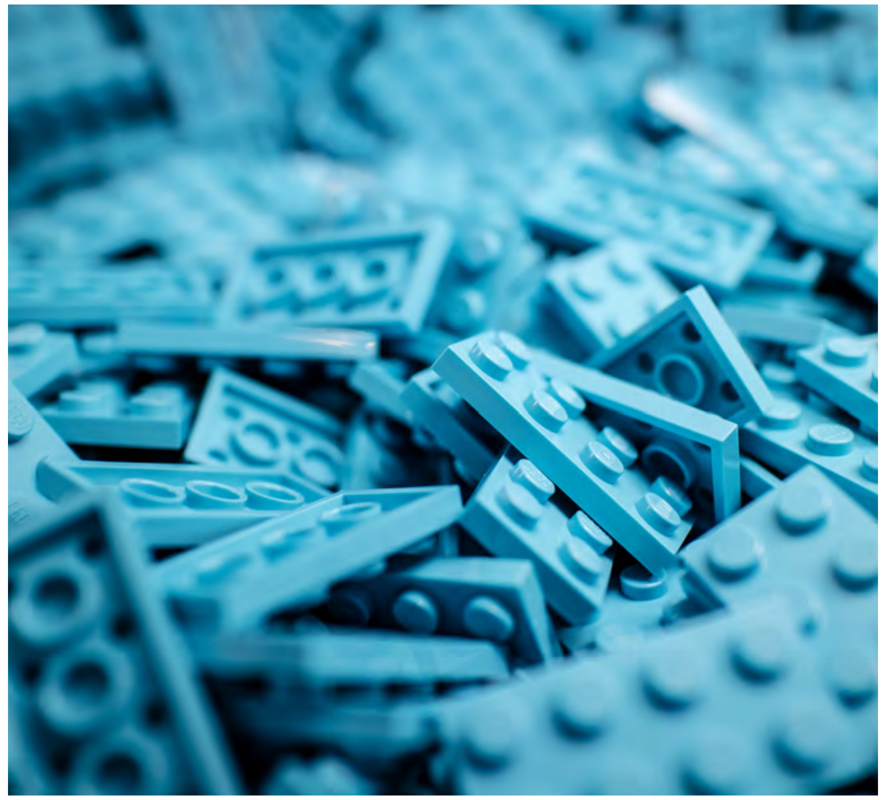
4.2 OIL

Oil has long been the largest contributor to the energy supply since surpassing coal in 1964. The share of oil in the primary energy supply has been around 29% over the last decade and will remain so until 2027 when it will start declining to 17% in 2050.

Sectoral demand

Driven by the ever-increasing demand for transport, due to population and economic growth, the demand for oil has been steadily rising by about 1% per year for decades despite temporary dips like those in 2008 and 2020. Last year (2022), global crude oil demand almost reached its pre-pandemic (2019) level of 83.3 Mb/d (161 EJ). Despite EV sales gaining momentum and the ongoing build-out of non-fossil electricity generation capacity, global oil demand is expected to increase by between 3% and 4% over the next three years before levelling off and then starting to decline before 2030. In 2050, we expect demand of 52 Mb/d, 40% less than in 2025. As electrification in road transport accelerates, the decline between 2035 and 2050 is almost twice that seen over the period from 2025 to 2035. Figure 4.4 shows historical and projected developments in global oil demand by sector from 1990 to 2050.

Oil demand from the transport sector in 2022 was 108 EJ, still less than in 2019 (10 EJ) pre-COVID, because of the economic slowdown in high-income countries directly impacting fuel consumption. Oil's share of energy demand in transport has been around two-thirds (70%) since 2017 (except in 2020), but with EVs dominating new vehicle sales from the early 2030 declines to 61% towards the end of our forecast period. Electrification of passenger vehicles will happen sooner than for commercial trucks and vans. Passenger and commercial vehicle oil demand will decline 58% and 33%, respectively, over the next three decades. Oil use in aviation, shipping, and rail transport (collectively termed 'other transport' in Figure 4.4) will initially grow for a few years. Thereafter, the shift toward biofuel, green ammonia, e-kerosene, and other low-carbon fuels will reduce this oil demand by 30% from 23.4 EJ in 2022 to 15.5 EJ in 2050. Detailed information and analysis for transport fuels are in Section 1.1.

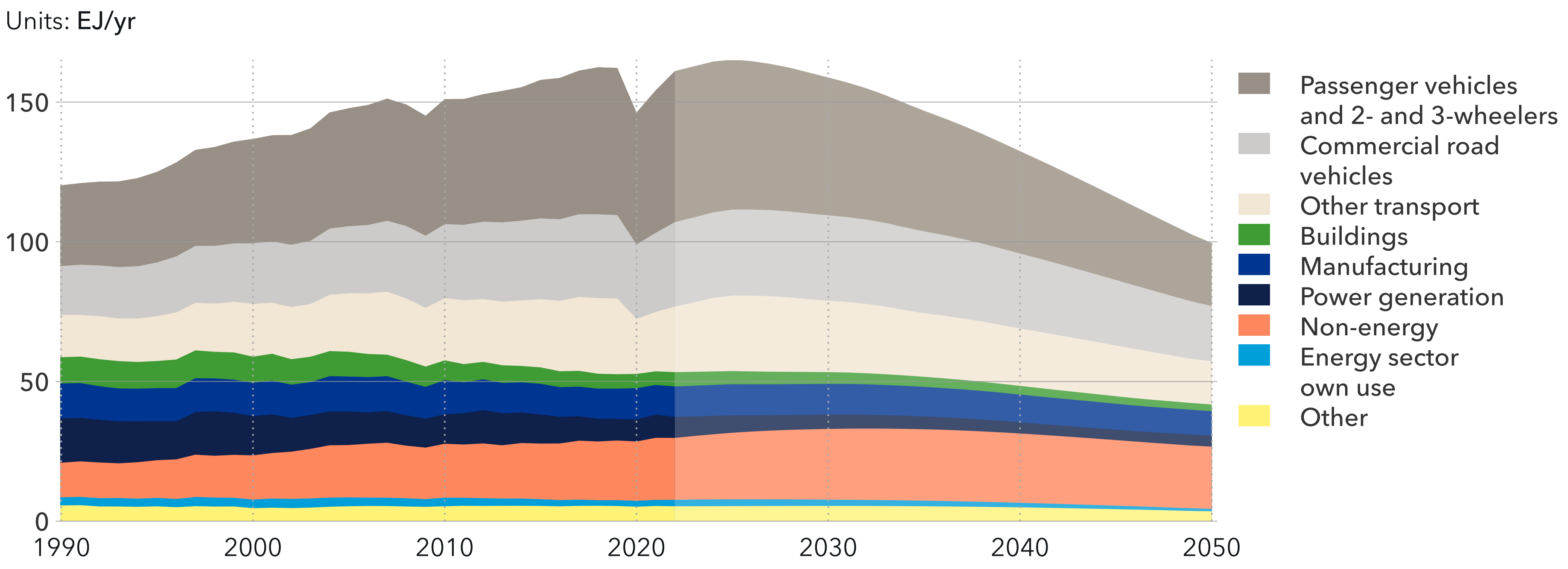


Oil's second largest sectoral demand is as feedstock for non-energy use such as in the petrochemical industries, including plastics production. The share of non-energy in oil demand, which does not entail any direct CO_2 emissions, has been around 13% for the last two decades. With declining oil use for most energy purposes, the share of non-energy use in oil demand rises from 14% today to 22% In 2050. In absolute terms, oil demand for non-energy use will increase from around 22 EJ/yr (10 Mb/d) today to 26 EJ/yr (11.5 Mb/d) by 2035, then slowly decline to 22 EJ/yr (10 Mb/d) by 2050, due mainly to a decrease in plastics production caused by demand-side reduction and substitution measures as well as higher rates of recycling (see Section 1.5 for more details).

The third largest sector in terms of oil use is manufacturing, which will continue to demand around 11 EJ for the next decade before it declines to 9 EJ, though its share of oil demand will rise from 7% to 9% by 2050, reflecting the decline in oil demand in other sectors. Oil or its products are also used in buildings, power, 'other' sectors, and for producing the oil itself. Nevertheless, these uses are small (less than 10% of total oil demand) and remain so throughout our forecast period.

FIGURE 4.4

World oil demand by sector



Historical data source: IEA WEB (2023)

Regional oil demand

Figure 4.5 shows the year of peak oil demand (and production) varying significantly by region. High-income regions peak early, low-income regions either later or not within the forecast period at all. Much like the broader energy demand trend, global oil demand is shifting eastward and southward. For many decades, North America had the highest absolute level of oil demand. However, the region's projected escalation of electrification in road transport over the next few years (see Figure 1.4 in Chapter 1) will see Greater China, with manufacturing as its largest sector, surpass North America's oil demand after 2026.

Our forecast shows that by 2050, the Middle East and North Africa, Greater China, and the Indian Subcontinent will emerge as the top three regions for oil demand. The bottom three will be Sub-Saharan Africa, OECD Pacific, and Europe. Table 4.1 compares forecast growth rates for crude oil demand in each region up to 2050.

Although North America's oil demand will reduce drastically due to EV growth, its demand per capita is projected to remain the highest for the next two decades. By 2050, North East Eurasia has the highest oil demand per capita followed by the Middle East and North Africa and North America. Figure 4.6 compares regional oil demand per capita in the period 2010 to 2050. Sub-Saharan Africa will maintain a much lower oil demand per capita than the other regions throughout the forecast period.

TABLE 4.1

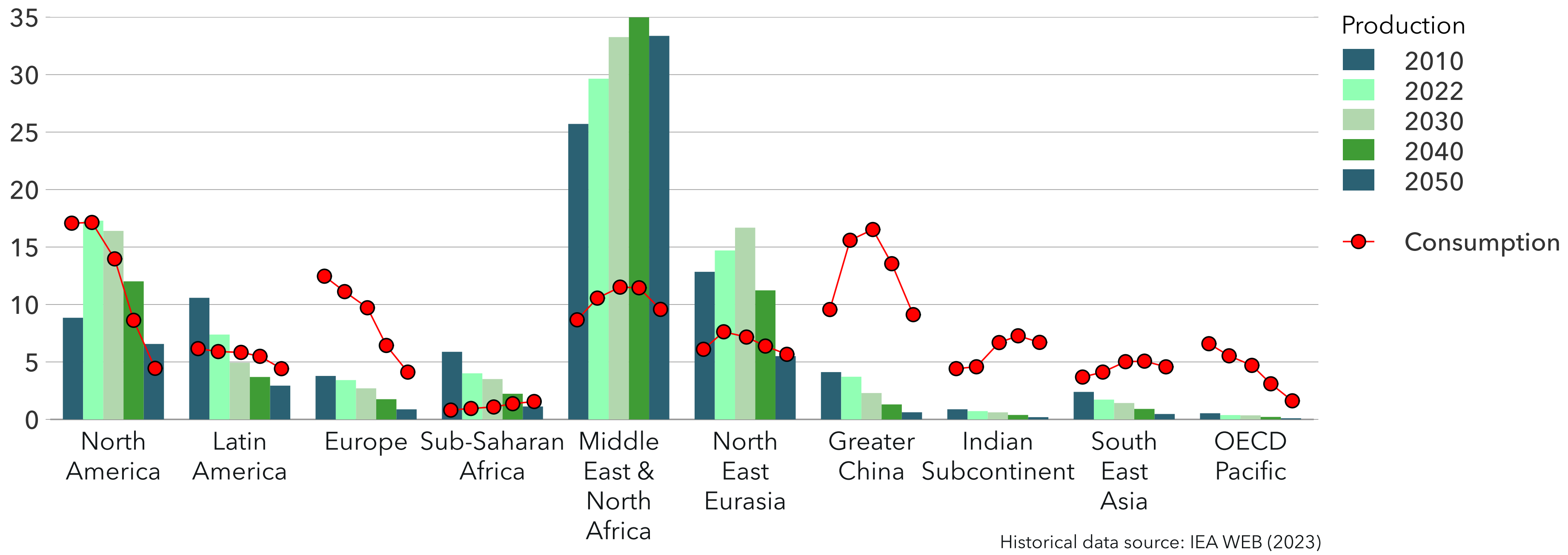
Crude oil demand growth rate per region

Year / Region	CHN	EUR	IND	LAM	MEA	NAM	NEE	OPA	SEA	SSA
2022 to 2030	6%	(-12%)	49%	0%	8%	(-17%)	(-7%)	(-13%)	27%	16%
2030 to 2040	(-19%)	(-31%)	10%	(-2%)	(-1%)	(-37%)	(-11%)	(-31%)	5%	27%
2040 to 2050	(-30%)	(-34%)	(-8%)	(-18%)	(-17%)	(-45%)	(-11%)	(-45%)	0%	14%

FIGURE 4.5

Crude oil production and consumption by region

Units: Mb/d

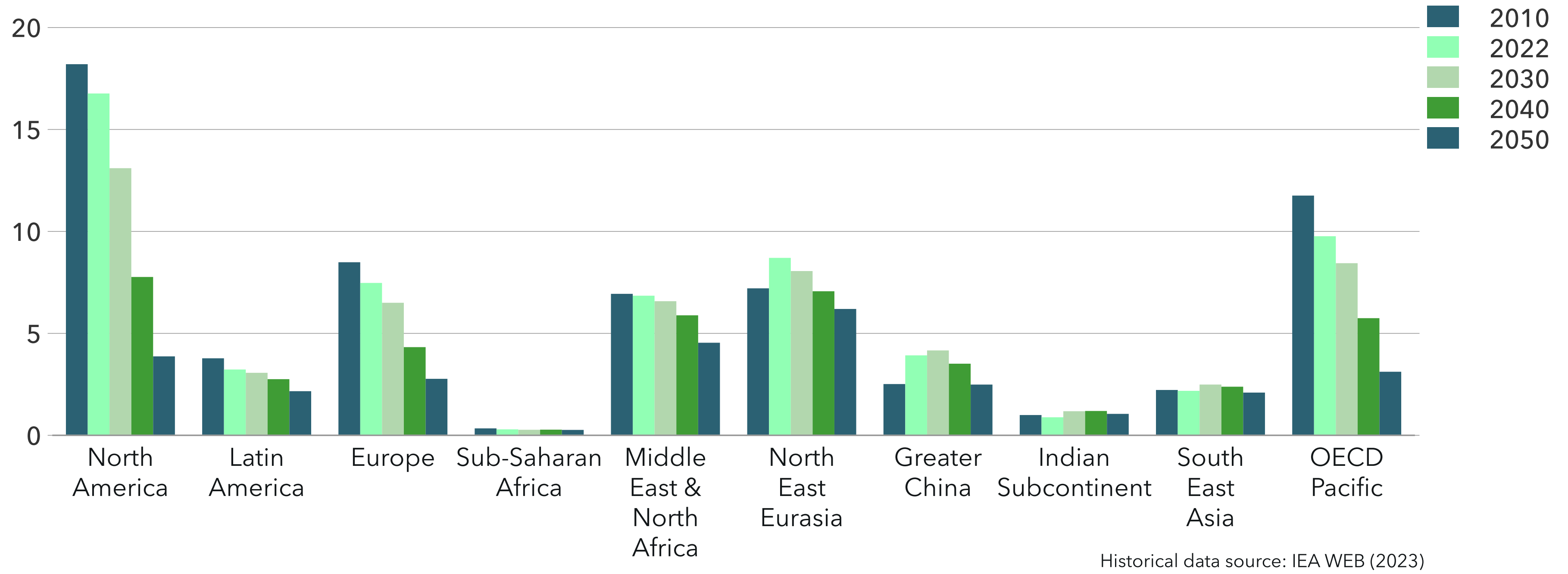


Historical data source: IEA WEB (2023)

FIGURE 4.6

Crude oil demand per capita by region

Units: Bbl/(person-yr)



Historical data source: IEA WEB (2023)

Oil production and trade

In 2022, crude oil production was 8% higher than in 2021. Most of this increase occurred in the Middle East, North America and, despite sanctions, in North East Eurasia. In 2022, oil companies earned record profits, benefitting from the surge in oil and gas prices that followed Russia's invasion of Ukraine. Global upstream investment in oil and gas exploration and production is at its highest since 2015, growing 11% year-on-year to USD 528 billion in 2023. Figure 4.5 forecasts that while all regions will reduce crude production, the Middle East and North Africa's share, which has been about 35% for the last three decades, will nearly double to 64% (from 30 Mb/d in 2022 to 33 in 2050). The region has the cheapest oil, and the cost of producing oil is expected to be more critical when demand reduces and market competition is tighter. History has shown that reliance on one region producing well over half the world's oil could be considered a risk, and OPEC and other policies prioritizing high prices adds to the uncertainty. This dynamic is expected to engender a sustained focus on energy security in importer regions which is likely to further boost renewable energy at regional and local levels. Consequently, the significance of oil in the geopolitical landscape is likely to wane in the coming decades.

Our model separates offshore, onshore conventional, and onshore unconventional oil production. As unconventional capacity has a shorter average lifetime than conventional, both onshore and offshore regional distributions of capacity additions are not directly comparable. Globally, the distribution remains relatively stable over the forecast period.

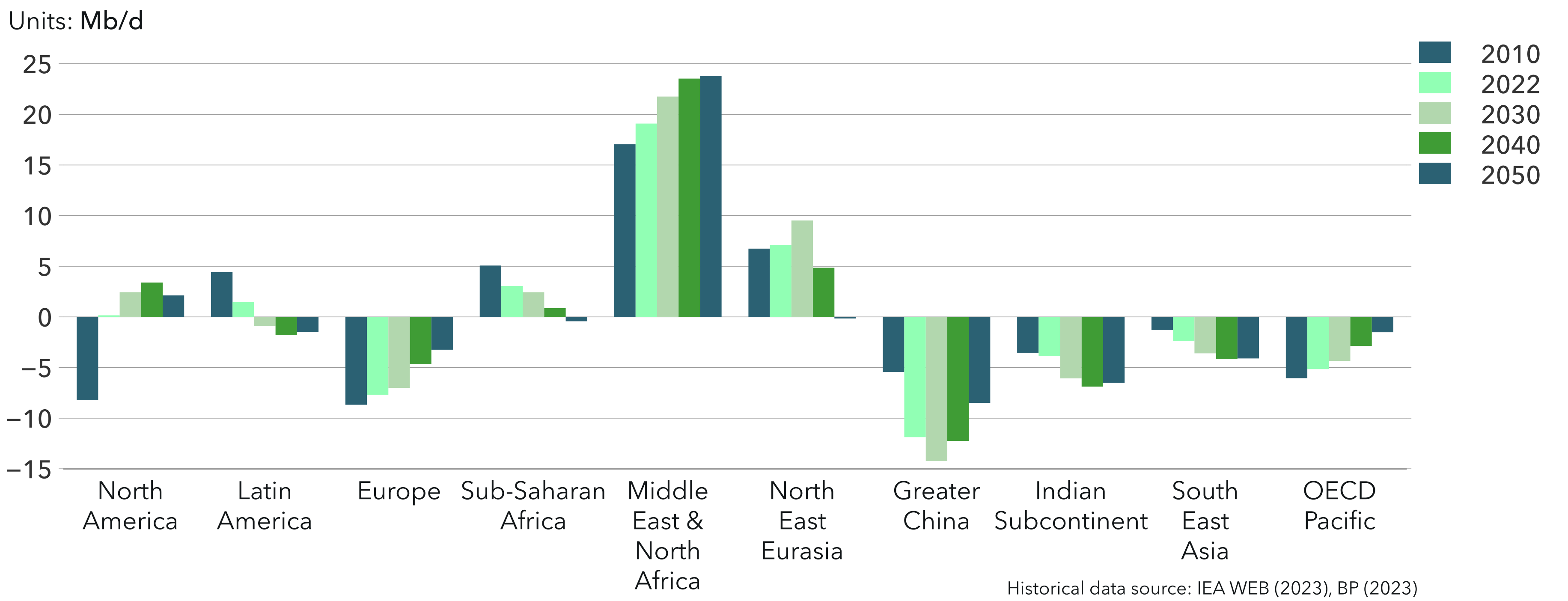
The share of conventional onshore oil increases from around 52% today to about 58% by 2050, while the share of offshore production declines slightly from around 32% to 27% and the share of unconventional onshore production initially rises slightly from 18% before falling to around 15%. Naturally, there are large regional variations, with conventional onshore dominating in the Middle East and North East Eurasia, whereas in North America the lead is now taken by unconventional onshore.

It should be added that uncertainty over where oil will come from is high. In our ETO model, oil production equals demand, and regions do not develop their oil resources if cheaper oil can be supplied by other regions. Although global oil production will always equal demand over time, since storage is limited, regional distribution might not follow the same disciplined pattern assumed in our model. The reduction in oil demand will make it less attractive for the industry to expand production into challenging environments such as deep water, high pressure, and/or remote locations like the Arctic.

Looking at Figure 4.7, the Middle East and North Africa and North East Eurasia are net oil exporters and will continue exporting throughout our forecasting period. Greater China, Europe, the Indian Subcontinent, OECD Pacific, and South East Asia have been net oil importers historically. They will maintain this status even though the import volume for Greater China, Europe, and OECD Pacific will decrease by 30%, 50%, and 70%, respectively. The Indian Subcontinent and South East Asia oil imports will increase by 80% and 120%, respectively. North America has been a net exporter of oil since 2020 as the US flipped from importer to exporter – Canada has always been a net exporter. Latin America will be a net oil importer before the end of this decade.

FIGURE 4.7

Oil net export by region



Historical data source: IEA WEB (2023), BP (2023)

Thanks to shore-based electrification, Equinor's Johan Svedrup field has a carbon intensity of just 0.67 kgCO$_2$/boe in 2022 through electrifying more of its platforms versus a weighted average for North Sea production of some 12 kgCO$_2$/boe (Kennet et. al., 2022). Image courtesy Equinor/Lizette Bertelsen/Jonny Engelsvoll

Carbon intensity of producing fossil fuels

Carbon intensity (CI) expressed as kilograms of carbon dioxide equivalent per barrel of oil equivalent (kgCO$_2$eq/boe) is a measure of the scope 1 and scope 2 GHG emissions associated with producing crude oil. The global volume-weighted CI estimate for crude oil production was 65 kg CO$_2$eq/boe, according to the US Department of Energy Office of Scientific and Technical Information, (OSTI), in 2015.

Emissions in oil and gas operations (upstream, midstream, and downstream) are categorized, measured, and reported based on direct (scope 1) and indirect (scope 2) emissions. For example, in upstream exploration and production (E&P) activities most emissions are associated with stationary combustion (flaring, turbines, heaters/coolers), venting, and fugitive emissions of natural gas (scope 1), and the electricity used to produce oil and processing of natural gas and their sites (scope 2). Note that scope 3, emissions from the value chain, mainly from the combustion of the oil and gas itself when it is used in engines, plants or similar, account for 80 to 95% of total carbon emissions from oil and gas companies. However, reporting scope 3 is not obligatory, and is not included in carbon intensity calculations.

According to IEA, in 2021, scope 1 and scope 2 GHG emissions from oil and gas operations (including midstream and downstream) were about 5.1 GtCO$_2$eq, accounting for 15% of global emissions. Within this, methane emissions accounted for 44%, flaring 5%, and the rest originated from own energy use during production, crude transport, refining, and the transportation of oil products and liquefied natural gas (LNG) (IEA, 2023b).

Depending on the crude's quality and on regulation where it is produced, when the associated gas produced is not economically saleable, it is either flared, vented (directly emitting methane, which is discussed in Chapter 7), or reinjected. The top nine flaring countries continue to be responsible for the vast majority of flaring. Venezuela, Algeria, Iran, Libya, Iraq, Nigeria, Russia, Mexico, the US, and China collectively accounted for nearly three-quarters (74%) of flare volumes and just under half (45%) of global oil production (World Bank, 2023a).

The Global Gas Flaring Reduction partnership estimates that in 2022, gas flaring released 357 MtCO$_2$eq, 88% (315 Mt) of it in the form of CO$_2$ and the rest (42 Mt) as methane. Note that there is significant uncertainty surrounding methane emissions from gas flaring. For example, if the average flare is just five percentage points less efficient in burning the gas than generally assumed, then the amount of methane released globally would be three times higher than currently estimated.

Some countries have introduced policies to reduce flaring. For example, Norwegian regulations requiring operators to meter gas and taxing flaring-related CO$_2$ emissions have been effective and have reduced flaring emissions by more than 80% since the mid-1990s. Moreover, enhancing efficiency and adopting electrification strategies, where renewable electricity replaces fossil-based power, can substantially reduce emissions. Notably, Norway achieved the lowest offshore carbon intensity on average, 7 kgCO$_2$eq/boe. The Johan Sverdrup field offshore Norway had a CI of 0.67 kgCO$_2$eq/boe in 2022 through electrifying more of its platforms.

As institutional investors and private investment funds are requesting companies to evaluate and disclose carbon emissions impacts and climate-related risks to their portfolios, it is becoming imperative for oil and gas companies to do more CI-related portfolio analysis. Several companies have announced targets to reduce their scope 1 and 2 emissions using carbon intensity as a key metric to indicate their performance.

4.3 NATURAL GAS

Over the past 50 years, the share of natural gas in global primary energy supply has risen from 16% to 26%. Our forecast indicates that this trend will continue, with natural gas surpassing oil as the world's leading energy source by the mid-2030s.

The transition from coal to gas is propelled primarily by local environment and climate considerations that favour the lower carbon intensity of gas and its higher efficiency during combustion. Additionally, the efficient distribution of natural gas through extensive pipeline networks and LNG infrastructure has significantly enabled this shift. Going forward, natural gas demand will vary by region, typically increasing in low- and medium-income regions and reducing in OECD regions. Furthermore, there will be demand for natural gas in new sectors, particularly with increasing use in maritime transport, and as a feedstock for making blue hydrogen and ammonia.

Sectoral Demand

Figure 4.8 shows historical and forecast natural gas demand in different sectors. Natural gas demand in 2022 was 166 EJ, dominated by power generation demand. It will increase to 175 EJ in 2027, maintaining that level for 10 years before declining to 149 EJ.

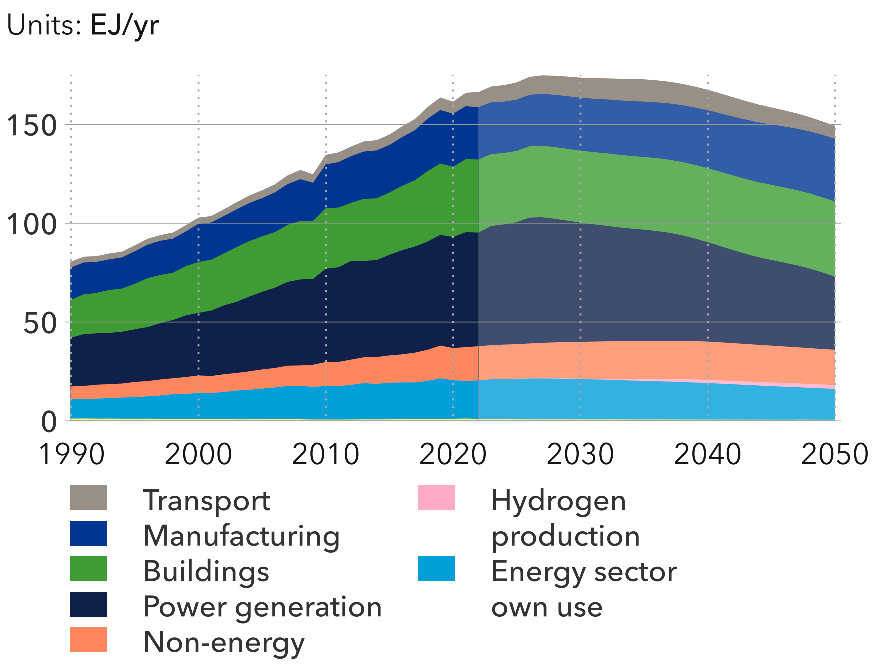
Over the past 10 years, power generation accounted for 35% of gas use. This share will rise to 37% (64 EJ) in 2026 before receding to 25% (37 EJ) by the end of our forecast period, a shift driven by the expansion of renewable energy sources. Demand for gas from the buildings sector will stay almost flat at the present level of 37 EJ. Manufacturing's appetite for gas in 2050 will increase from 27 EJ today to 32 EJ, while its share of demand for gas increases from 16% to 21%. From a relatively low starting point, gas demand in the transport sector will almost double by 2040. It will then decline by almost half by 2050 due to its increasing displacement in its main application, shipping, by the rise of hydrogen derivatives such as ammonia and e-fuels. The share of non-energy applications (largely petrochemicals) in demand for gas will remain stable at 10% as demand for products that use gas as a feedstock remains at current levels and hydrogen is increasingly used. Own use (demand from the oil and gas and energy industries during production and distribution) will grow over the next five years but will return to today's level by 2050. Decreases in own use are likely to arise from efficiency gains, from the electrification of production facilities, and from less flaring. Some of this use in the energy sector will be for liquefaction and regasification of gas that is transported as LNG. Gas demand for hydrogen production will increase from negligible levels in 2022 to 2 EJ in 2050.

Regional Demand

In 2022, global gas demand was 4,795 billion m^3, almost the same as in 2021. In Europe, gas consumption fell by 9% due to record-high gas prices, energy conservation policies (including industrial production curtailment measures) following the sanctions against Russian gas, and mild temperatures. Gas consumption decreased by 2% in North East Eurasia due to sanctions hitting Russian industry. In India, high LNG prices cut gas demand from the power, refining, and petrochemical sectors by 11%, and a similar development has been seen in other countries that cannot afford LNG at the record-high prices.

FIGURE 4.8

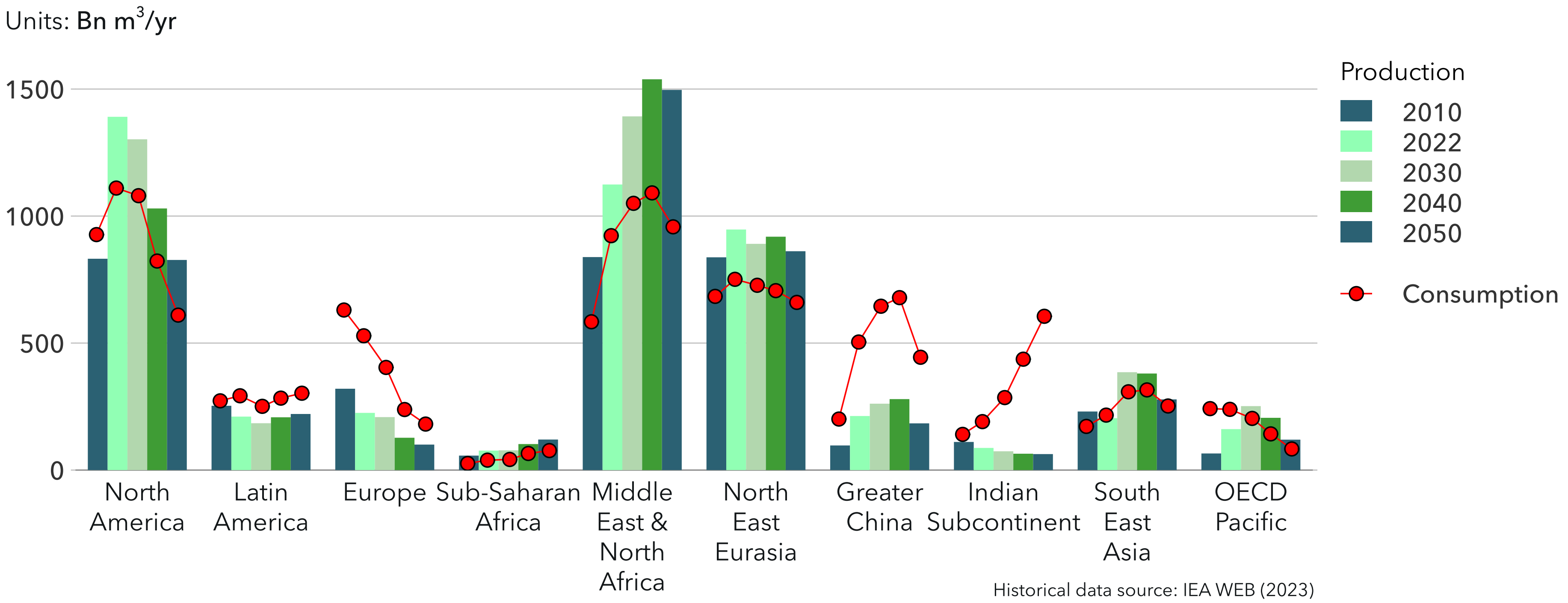
World natural gas demand by sector



Includes natural gas liquids and biomethane. Historical data source: IEA WEB (2023)

FIGURE 4.9

Natural gas production and consumption by region



Historical data source: IEA WEB (2023)

In our forecast, global demand for natural gas increases to 5,035 billion m^3 (175 EJ) around 2027 and plateaus for about a decade before gradually declining to 4,173 billion m^3 in 2050, a sixth (17%) lower than in 2035. Looking at Figure 4.9, in Europe and OECD Pacific, gas consumption keeps declining to about 35% of 2022 values by 2050. In Greater China, it will grow 28% by 2030, plateau until 2040, and then decline to 444 billion m^3, 12% less than in 2022. Gas demand in the Sub-Saharan Africa and the Indian Subcontinent will double and triple by 2050 (compared to 2022). The rise in demand in Greater China and the Indian Subcontinent is driven by strong policy support for natural gas consumption in the short term, and the shift from coal to gas to reduce local pollution.

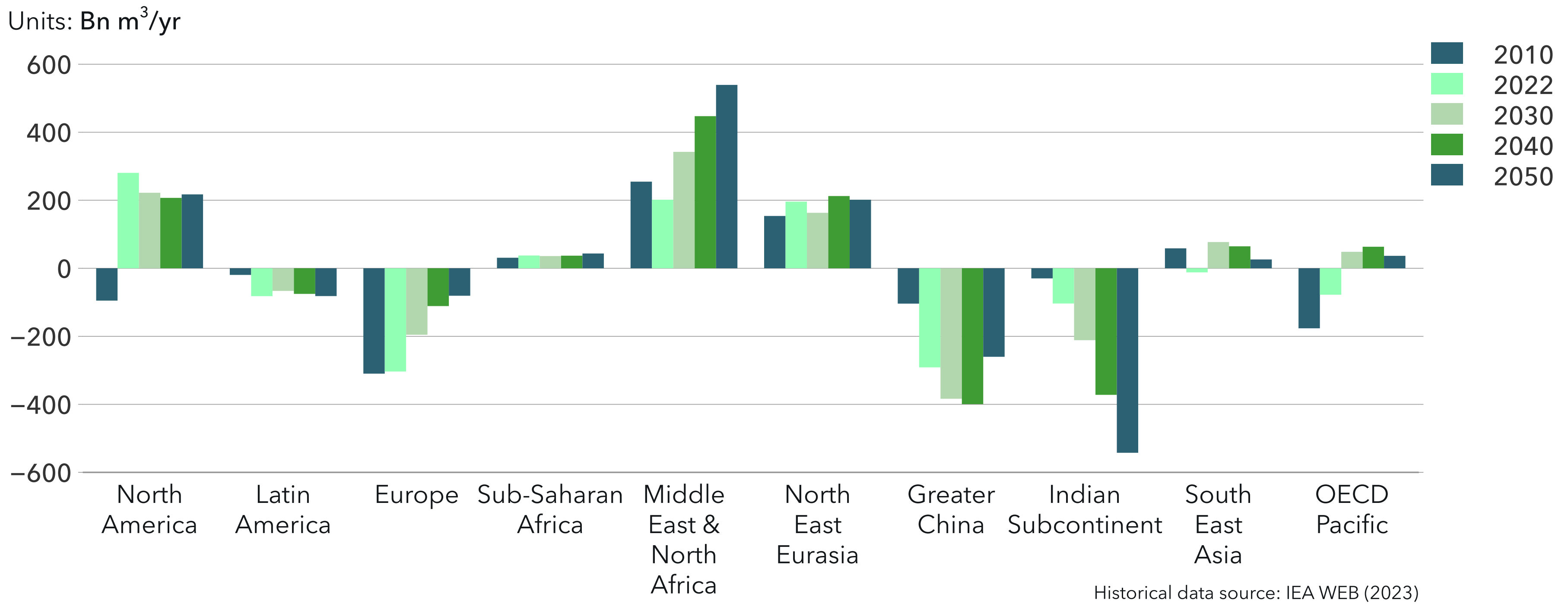
Natural gas production and trade

In the coming decade, global natural gas production is anticipated to rise by 10% compared with 2022, reaching 5,063 billion m^3 in around 2027, then stabilizing for approximately a decade before gradually declining about 15% to 4,272 billion m^3 by the end of the forecast. Figure 4.9 shows that in 2050, Middle East and North Africa gas production increases by 33% and its share also increases by 10% to 35%, while production in North America and Europe will halve, reflecting a 10% drop in gas shares in both regions. North East Eurasia gas production and its share are projected to be slightly lower than current values.

Figure 4.10 compares natural gas net export and import by region. The Middle East and North Africa and North East Eurasia, have been exporters throughout their production history and will remain so. The former’s export volume doubles by 2050. North East Eurasia’s export volume stays almost the same, though its markets shift with export to Europe dropping to near zero and countries in Asia taking over, first for LNG and later through new pipelines. North America shifted from being an importer of natural gas to an exporter in 2014; in 2022, with 280 billion m^3, it became the second largest exporter of gas. However, with the reduction in demand, North America’s export volume will gradually decrease to a third of its current volume by 2050. OECD Pacific has the highest interregional trade, with Australia being the world's second largest LNG exporter, and Japan and South Korea importers. However, as production in Australia increases and gas demand decreases in Japan and South Korea in the next two years, supply will surpass demand and the region will shift from net import to net export. Europe has been the largest importer region in recent decades, reaching a record volume of 370 billion m^3 in 2021. With Russia's invasion of Ukraine, European policy moved to slash the region’s dependency on imported Russian gas. The import volume in 2022 decreased to 303 billion m^3 and will continue to decline such that by 2050 import volumes with be one fifth lower than present levels. Greater China and the Indian Subcontinent each have high demand and limited domestic natural gas resources.

FIGURE 4.10

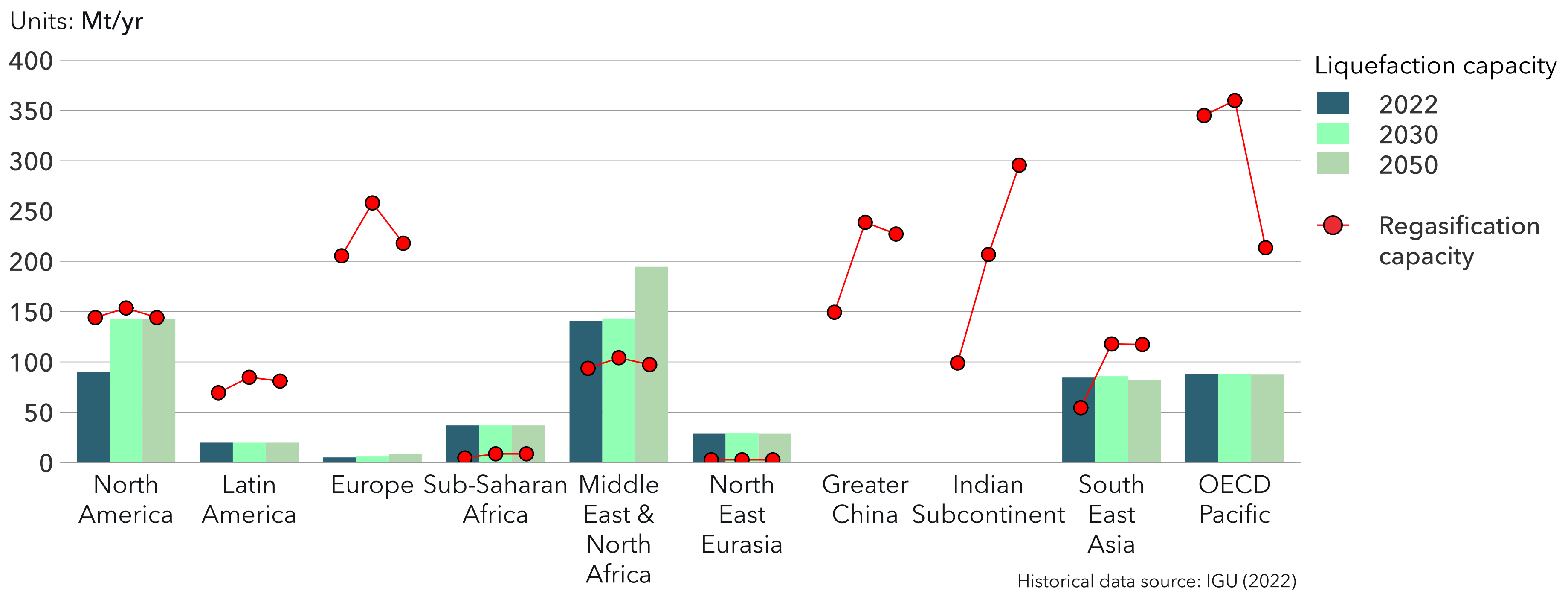
Net natural gas export by region



Historical data source: IEA WEB (2023)

FIGURE 4.11

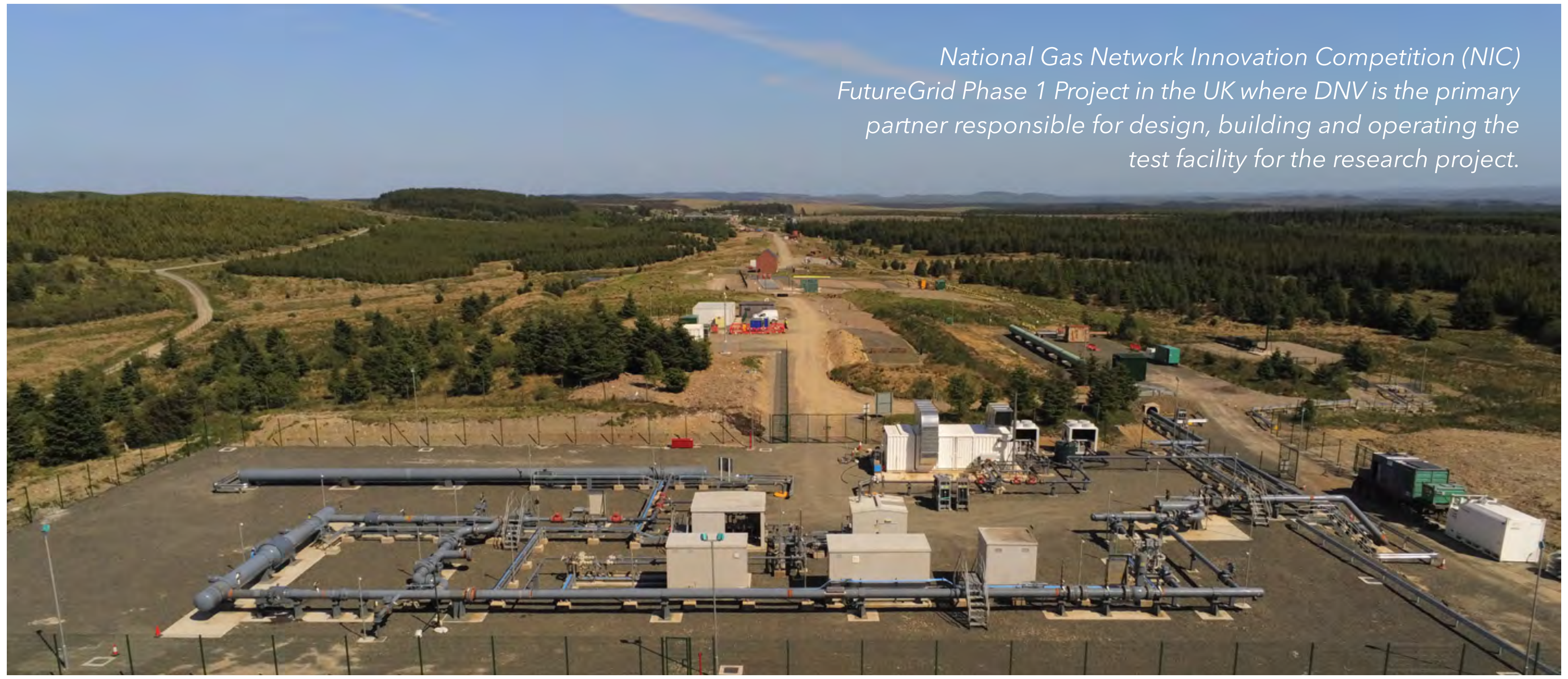
Gas liquefaction and regasification capacity by region



Historical data source: IGU (2022)

In Greater China, gas imports will increase in the coming decade, followed by a steep decline through to 2050 as its consumption of natural gas decreases. The Indian Subcontinent will significantly increase imports – mostly as LNG – to satisfy a near doubling in its demand for natural gas, requiring substantially greater LNG regasification capacity in the region.

Gas transport is expensive and accounts for a significant proportion of the cost of delivered energy. Piping gas is cheaper than shipping it when it comes to shorter distances, but LNG is still expected to increase its share. In fact, LNG and pipeline transport will increase even when global gas demand does not, due to a shift in demand patterns to regions with little pipeline import, and a heightened focus on energy security and diversity of supply. Figure 4.11 shows global capacity for regasification and liquefaction by region. The Middle East and North Africa region has the largest installed liquefaction capacity today. However, North America – being distant from its natural gas export customers – will increase its liquefaction capacity by 37% to reach the same level as in the Middle East and North Africa in 2030. Capacity in the latter region will increase by 26% between 2040 and 2050. LNG liquefaction capacity stays the same in other regions up to mid-century. On the regasification side, capacity will grow by 47% and 66% in Greater China and the Indian Subcontinent, respectively, between 2022 and 2050.



National Gas Network Innovation Competition (NIC) FutureGrid Phase 1 Project in the UK where DNV is the primary partner responsible for design, building and operating the test facility for the research project.

The role of pipelines

The energy sector has used pipelines for more than a century. Initially, they were developed to transport crude oil from oil fields to refineries, and later for distributing refined petroleum products. Their efficiency lies in their ability to move large volumes of liquid or gas with minimal energy input, making them cost-effective and environmentally favourable compared with other transport modes.

Despite the rapid growth of wind and solar power generation, it is expected that natural gas and oil will continue to supply about 40% of the world's energy needs by mid-century. As long as oil and gas play a vital role in our lives, it will be necessary to transport these molecules over extensive distances to ensure that those who require them can reap the benefits. Transporting molecules via pipelines offers greater safety, efficiency, economies, and a reduced GHG emissions footprint when compared to shipping, trucking, or rail transportation. Pipelines can also offer benefits compared to transporting electricity via grids, which is why there are different setups discussed for what are called energy islands.

The increased use of LNG as a consequence of Russia's invasion of Ukraine will reduce the amount of natural gas being transported through pipelines, leading to a reduction in the total length of such pipelines worldwide.

However, as the world shifts towards cleaner energy sources and seeks to reduce GHG emissions, hydrogen has emerged as a promising alternative to fossil fuels. Pipelines, with their established infrastructure and their operators' experience in handling gases, can play a vital role in the hydrogen economy. Several factors contribute to their suitability:

- **Large-scale transport:** Pipelines can efficiently transport hydrogen over considerable distances without significant energy loss, providing a means to distribute clean energy on a regional or even global scale.
- **Safety measures:** Hydrogen-specific materials and safety protocols are being developed to ensure secure hydrogen transportation.
- **Reduced emissions:** Pipelines can offer lower GHG emissions due to their energy-efficient nature.
- **Hydrogen blending:** Pipelines can facilitate the blending of hydrogen with natural gas in existing networks while maintaining compatibility with existing infrastructure.
- **Infrastructure repurposing:** Existing natural gas pipelines can be repurposed to transport hydrogen with proper modifications, reducing the need for entirely new infrastructure.

4.4 SUMMARIZING ENERGY SUPPLY

In this section, we summarize the primary supply of energy from all energy sources, including fossil fuels. DNV uses the primary energy content method in its calculations, for which details on the counting method can be found in (DNV, 2018). Considerable losses occur in the global energy system. Energy is mainly lost when it is converted from one form to another – for example, heat losses in a power plant converting coal to electricity. Losses also occur during the transport of energy, such as electrical power lost as friction in grids. World primary energy consumption is therefore considerably higher than final energy consumption, with conversion losses alone exceeding 100 EJ per year.

Primary energy also includes the energy sector's own use of energy to extract the energy itself. For some energy carriers this share is quite high; for example, around an eighth (12%) of the primary energy consumption for natural gas.

The historical and forecast world primary energy supply is shown in Figure 4.12 and Table 4.2. A key result from our analysis, as shown in the figure, is that global primary energy supply will level off from around 2035. This will occur despite the expansion of the global population and economy because conversion losses reduce considerably as the share of non-fossil energy increases. The amount of energy services such as heating, lighting, and transport will continue to increase with a growing and more prosperous population. However, energy-intensity improvements – a large share of which will come from electrification, but also from many other areas – means that energy services can, over time, be delivered with less use of primary energy.

Primary energy supply will reach its maximum in 2038 at 663 EJ per year, 9% higher than today, then reduce about 2% to 656 EJ in 2050.

The primary energy supply mix will change significantly over the coming 30 years. As described in the introduction to this chapter, the fossil share will fall from 80% today to 48% in mid-century. In historical terms, this reduction of more than one percentage point per year for fossil fuels is comparatively fast. The decline is quickest for coal, going from 26% to 10% over the next 28 years, followed by oil, which falls from 29% to 17% over the same period. The natural gas share remains almost static throughout.

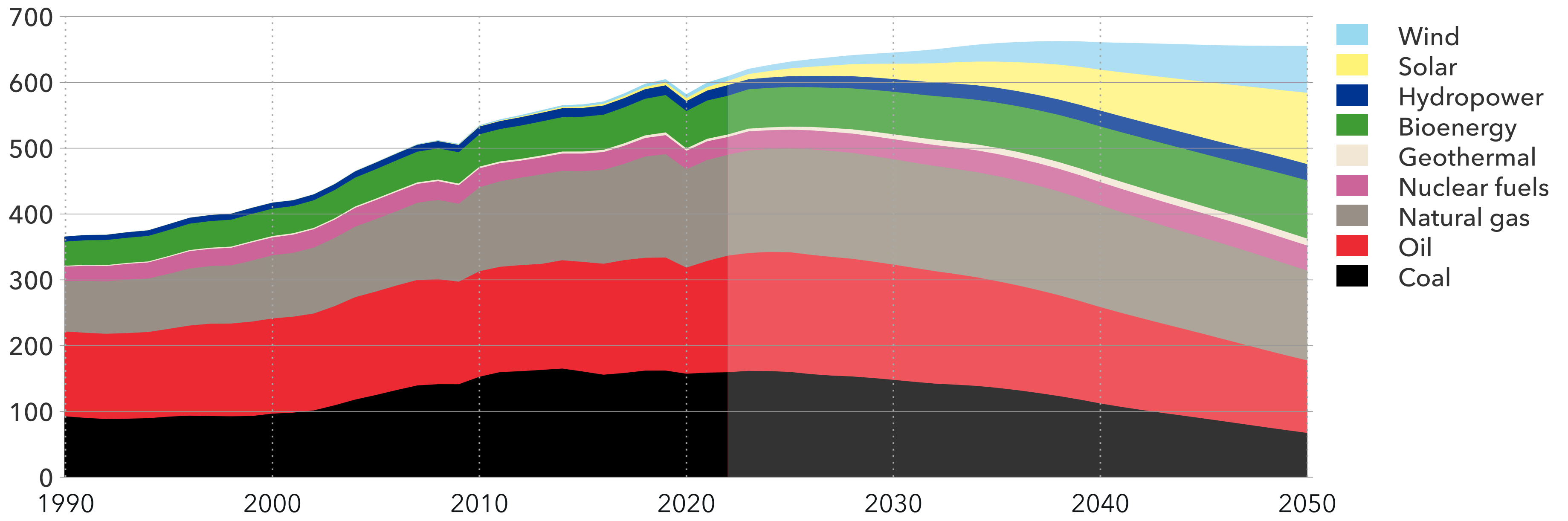
The share taken by nuclear energy will increase slowly over the forecast period, ending at 6% in 2050, while the renewables share will triple from 15% today to 46% by the end of the forecast period. Within renewables, the large increase will be driven by solar and wind, which will see 17-fold and nine-fold increases in primary energy supply towards 2050, respectively. Solar will reach 17% and wind 11% of the global primary energy mix in 2050, with further growth expected beyond mid-century. Bioenergy and hydropower will also grow, in both relative and absolute terms.

Cumulatively the amount of fossil fuels not used relative to today's usage amounts to 13 VLCCs of oil equivalent each day through to 2050.

TABLE 4.2
World primary energy by source (EJ/yr)

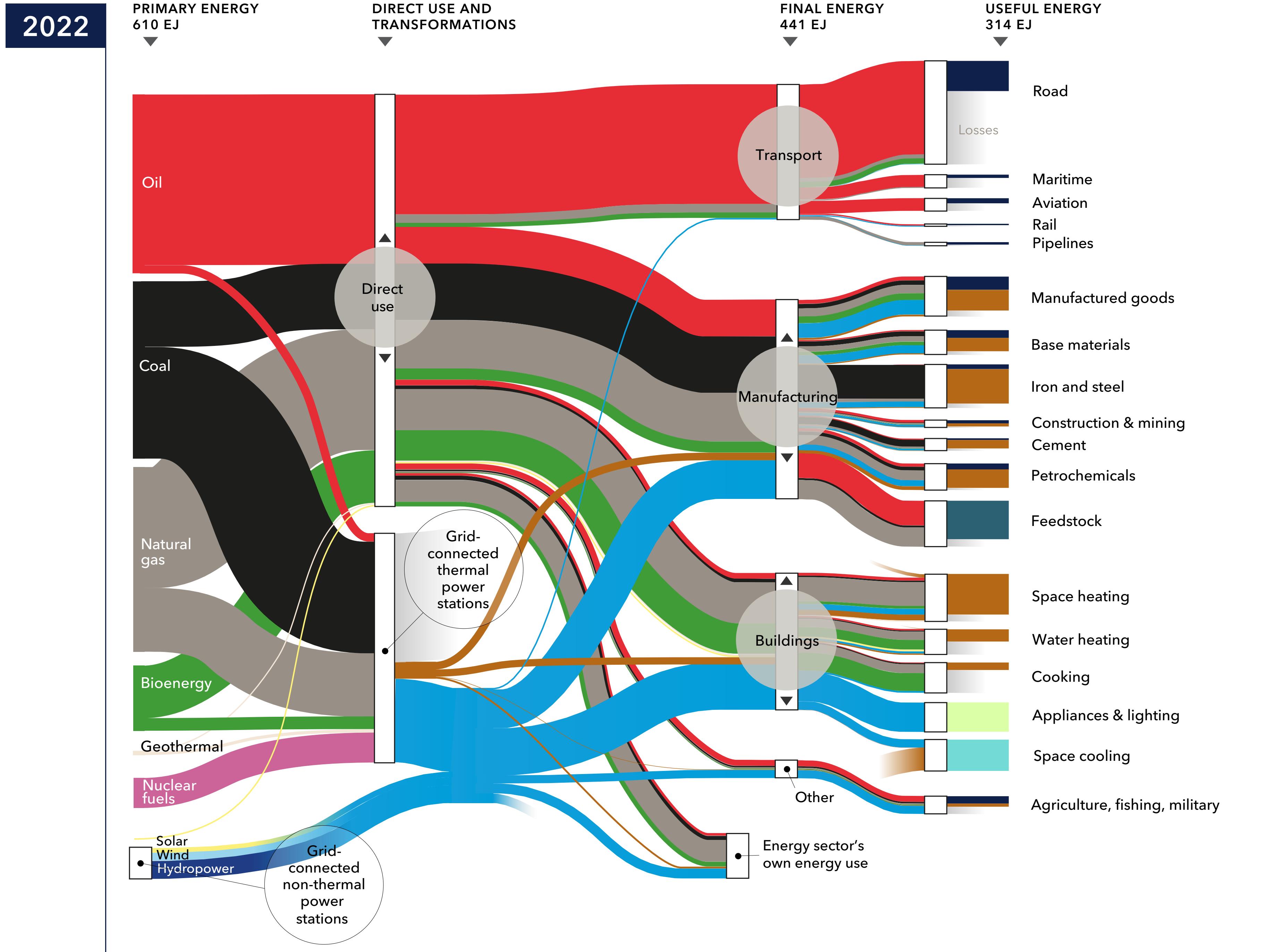
Source	2022	2030	2040	2050
Wind	7	17	42	71
Solar	7	23	62	109
Hydropower	16	19	24	25
Bioenergy	59	65	74	88
Geothermal	4	7	11	11
Nuclear	27	31	35	38
Natural gas	153	160	155	137
Oil	177	175	146	110
Coal	160	148	112	67
Total	**610**	**645**	**661**	**656**

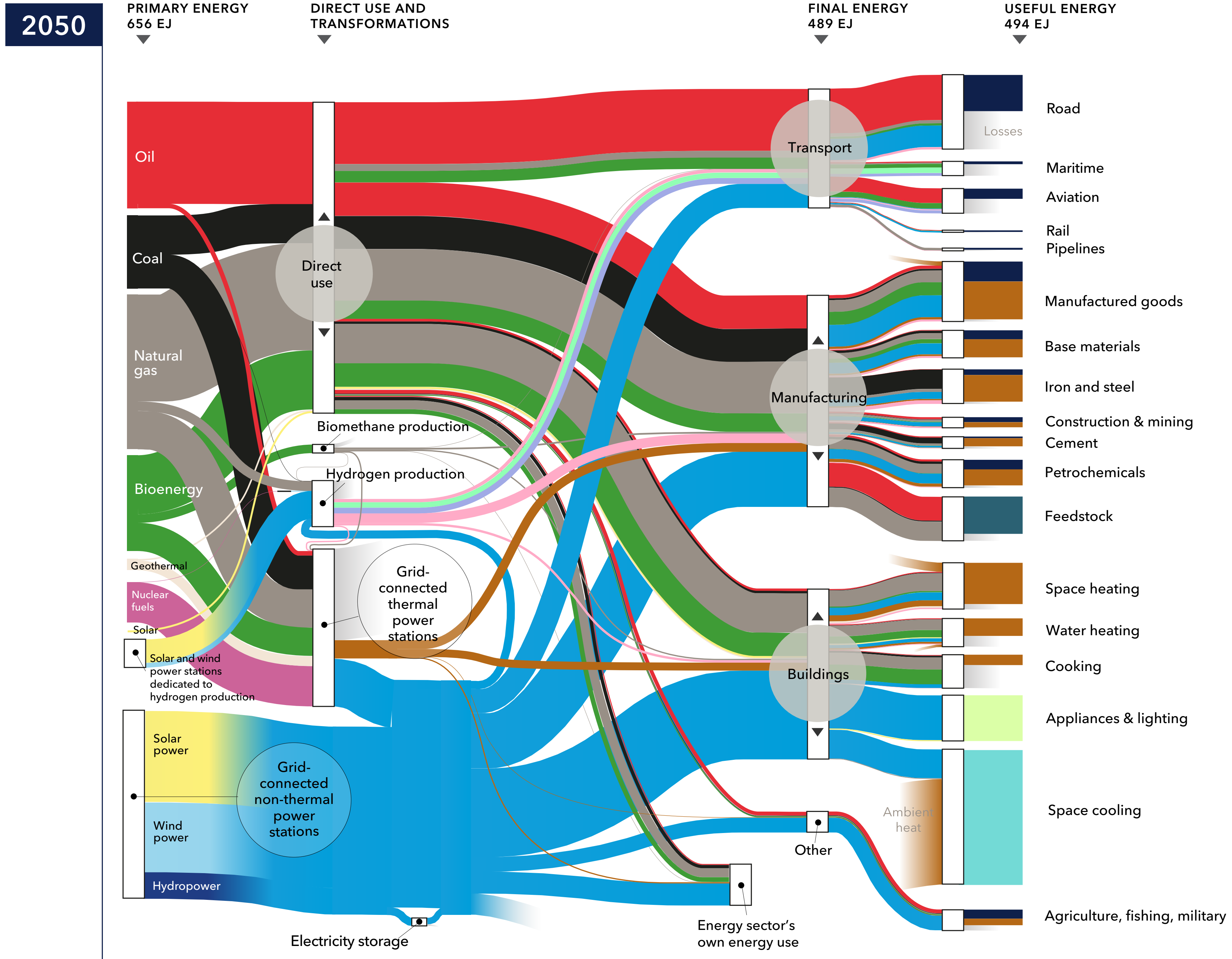
FIGURE 4.12
World primary energy supply by source



Historical data source: IEA WEB (2023)

COMPARISON OF ENERGY FLOWS





Oil
Coal
Natural gas
Hydropower
Wind power
Solar power
Bioenergy
Geothermal
Nuclear heat
Electricity
Heat
Hydrogen
Methanol
Ammonia
Motion
Light, computing, etc
Cooling
Feedstocks

5 FINANCING THE ENERGY TRANSITION

Highlights

Global annual energy expenditures will rise by 22% over our forecast period. This compares with a near doubling of global GDP during the same period. Energy expenditures will thus be a diminishing share of global GDP. In this sense, the transition we forecast is affordable even before factoring in the avoided costs of climate damage.

The transition we forecast will result in:

- A partial transfer of expenditures from fossil to non-fossil and grids
- A resulting shift from operational (OPEX) to capital (CAPEX) expenditures in a more electrified energy system
- A reshuffling of regional energy expenditures

These changes have a positive impact for consumers in most regions. We discuss how average household energy expenditures in Europe and North America are likely to be 75% and 50%, respectively, of 2021 levels by 2050. Household expenditures will rise in absolute terms across the Indian Subcontinent due to growing prosperity. However, this slight rise in energy expenditure contrasts with GDP per capita increasing by a factor of three in the Indian Sub-continent during the same period.

5.1 ENERGY EXPENDITURES

The energy transition we forecast is not only compatible with a near doubling of global GDP by 2050, but also leads to considerable savings at a global level. Some aspects of the transition, like the roll-out of renewables or grid build-out, will require very large upfront investment. This is why some consider the transition to be 'unaffordable'. Our results suggest the opposite, and energy expenditures representing a declining share of global GDP.

This is a startling conclusion from the perspective of policymakers – i.e. far from coming at a green premium, the energy transition in fact involves a substantial green reward, paying dividends to society for generations to come – and is something that DNV has emphasized consistently over the years in our annual *Energy Transition Outlooks*.

World energy expenditure
We consider energy expenditures as the upstream costs related to energy production and transport to the user. Using this definition, total world energy expenditure was USD 5.2trn in 2022, with investments in low-carbon technologies surpassing USD 1trn for the first time (BNEF, 2023b). We project world energy expenditure to increase 22% to USD 6.4trn by 2050, due mainly to the rise in population and final energy demand. Note how this 22% expenditure rise compares with the projected near-doubling of global GDP over our forecast period.

Overall, our research indicates that from an expenditure perspective, some parameters will remain stable over our forecast period:

– The unit cost of energy will stay stable around USD 12 to 13/GJ
– Global energy expenditures per capita will continue to oscillate around USD 650/person/yr, much in line with the values observed since 1990.

The stability of these costs contrasts heavily with the transition we forecast, which will result in:

– A partial transfer of expenditures from fossil to non-fossil and grids
– A resulting shift from operational (OPEX) to capital (CAPEX) expenditures in a more electrified energy system
– A reshuffling of regional energy expenditures

Not only will these changes have a positive impact for the consumer in most regions, as described later in this section, but an additional co-benefit of the energy transition we forecast will be the considerable savings due to the slowing down of climate change (see factbox), and the considerable financial benefit of cleaner air, which we do not quantify here but is well documented elsewhere (OECD, 2016).

Less fossil, more renewables

Until now, non-fossil expenditures have not replaced but have effectively been added on top of fossil-fuel expenditure as the world's energy demand has climbed. Over the last five years (2017–2022) renewables represented 53% of the additional energy demand worldwide with fossil sources (and not nuclear) taking up the remaining share. As shown in Figure 5.1, we expect that situation to change. In 2022, fossil fuels made up 71% of the total world energy expenditure but we forecast that this share will almost halve to 36% by 2050.

Not only do the relative shares change, the absolute USD values of expenditures under these three categories also change. Between 2022 and 2050, fossil expenditure will decrease 40% in USD terms, non-fossil will almost triple, and grids will more than double. However, the majority (54%) of cumulative expenditures in the 2022 to 2050 period will be for fossil energy, compared to 77% in the 1990 to 2021 period.

From operating to capital expenditures

Figure 5.2 presents the breakdown of CAPEX and OPEX for the categories: fossil, non-fossil, and grids. The expenditures are presented as an average expenditure over 10 years leading up to 2020, 2030, and so on.

Overall CAPEX will represent a slightly decreasing share of expenditures, from 55% in 2022 to 49% in the early 2040s, before a slight rebound. This is explained by two opposite trends:

- A successive reduction in fossil CAPEX as the world shifts increasingly to non-fossil energy. While CAPEX declines continuously, fossil OPEX continues to increase in the 2020s and 2030s because of continuing use of upstream infrastructure built in the lead up to the 2020s. We project a structural shift away from fossil CAPEX and OPEX from the 2030s. The succeeding decades will see less and less such CAPEX and OPEX.

- A successive increase in non-fossil and (connected with it) grids OPEX and CAPEX. Renewables are CAPEX-heavy, and we project CAPEX almost twice as high as OPEX, despite the uninterrupted decade-to-decade increases in OPEX.

Further, additional investment costs (not computed in our model) will have to be carried by end-users in a more electrified energy system. For individuals, heat pumps and electric cars are typical examples of technologies for which levelized costs are lower than for fossil-based alternatives, but upfront costs are higher. In the manufacturing sector, switching to electricity- or hydrogen-based processes may also entail higher investments than for conventional technologies. This highlights the essential role of the cost of capital to support the decarbonization of the energy system, as discussed in Section 5.3 of this chapter.

In terms of the breakdown of non-fossil expenditure, we foresee large growth in solar+storage and fixed offshore wind, from relatively small levels in 2020. However established renewable technologies such as solar PV and onshore wind continue to dominate in terms of absolute numbers in our forecast.

We expect floating offshore wind to experience tremendous growth in expenditures, but from a very small level in 2020. On the other hand, solar PV and onshore wind see a three-fold increase in expenditures from 2020 levels by 2050. Given that these technologies are already established today, it is unsurprising that their expenditure growth rates are not as high as for floating offshore wind.

FIGURE 5.1

World energy expenditures

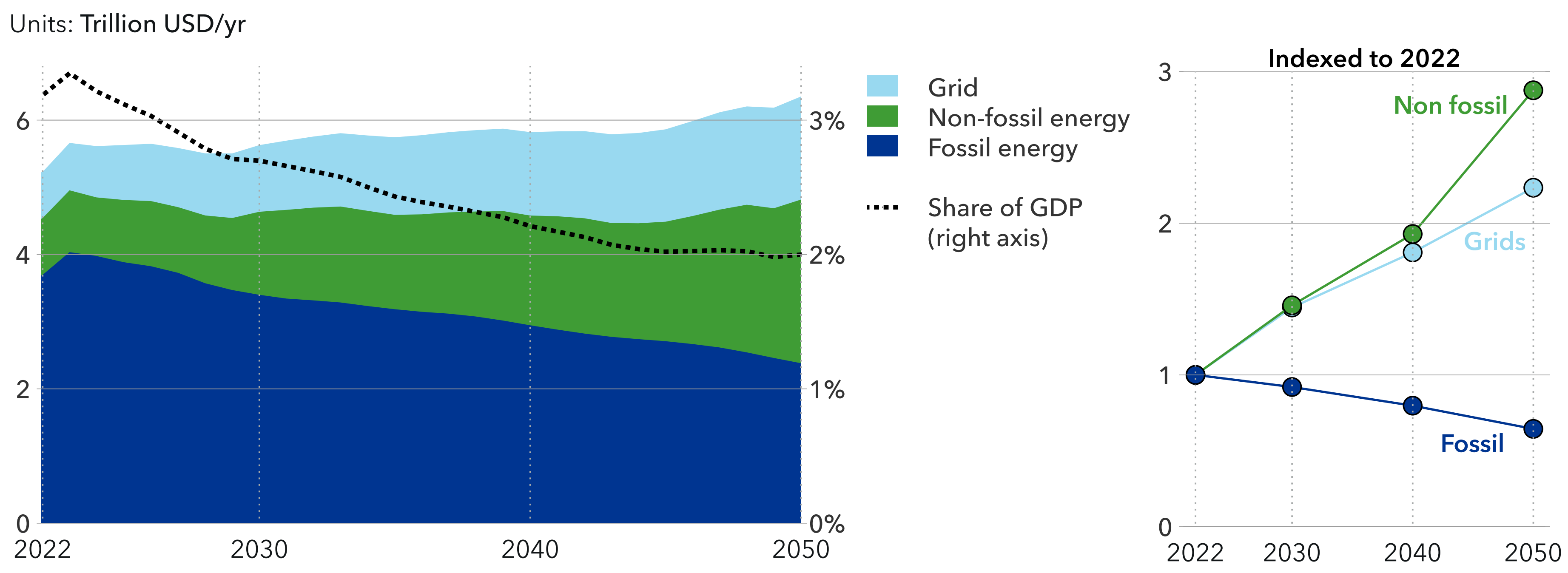
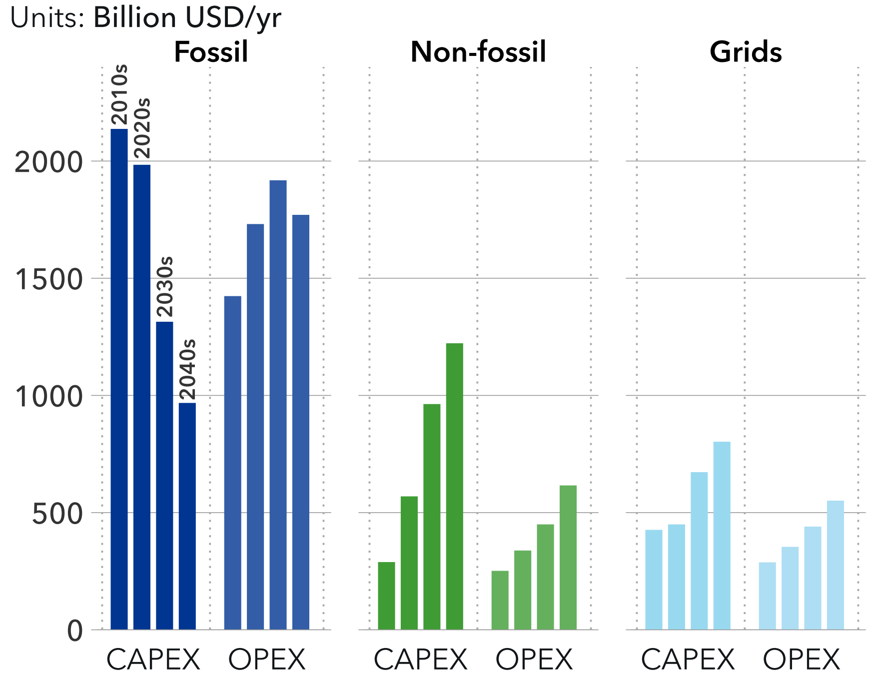


FIGURE 5.2

World energy CAPEX and OPEX, 10-year average



Regional reshuffling

The regional distribution of energy expenditure will also be greatly affected by the transition away from fossil fuels. This transition, and the related general trend towards relocation of energy production to a more regional level, will induce important transfers in expenditures.

Investments in fossil production will increase in regions such as the Middle East and North Africa, at least in the short term.

Figure 5.3 shows the change in energy expenditures in North America, the Middle East and North Africa, and Europe. These three Outlook regions are selected to contrast how the transition is expected to unfold in terms of expenditures in two fossil-fuel producing regions (North America, the Middle East and North Africa) and one (Europe) with relatively less fossil-fuel production and already ahead of the curve in the transition to non-fossil energy.

Both North America and the Middle East and North Africa have lower CAPEX for fossil fuel in 2050 compared with 2021. That said, North America's CAPEX starts reducing after 2030, while the Middle East and North Africa's transition away from fossil-fuel investments happens a decade later. Even more significantly, OPEX in the Middle East and North Africa keeps increasing, implying that the region will go on producing fossil fuels and operating existing fossil-fuel infrastructure at increasingly high levels from now until at least 2050. In contrast, North America's OPEX starts declining after 2030, signalling the start of its gradual transition away from operating fossil-fuel infrastructure.

Note that our definition only considers expenditures for the final installation (e.g. wind farm, oil platform), but parts of key supply chains will continue to be dominated by some regions in the foreseeable future. The most striking example is probably the current dominance of China in most parts of the solar PV supply chain, where most of the investments are expected until 2030 (IEA, 2022).

Consumer perspective – a green prize for households

In the introduction to this chapter we underlined that the energy transition is affordable from a global perspective. As shown in Figure 5.4, this conclusion is also confirmed with a per capita analysis, with GDP per capita growing linearly from the 1990s while energy expenditures remain stable throughout our forecast period.

However, this conclusion is often not shared by consumers (Guthridge, 2023). As mentioned previously, a first reason is that the transition implies important investments. Although these investments might be profitable over the long term, upfront costs

FIGURE 5.3

Average yearly energy expenditures in selected regions

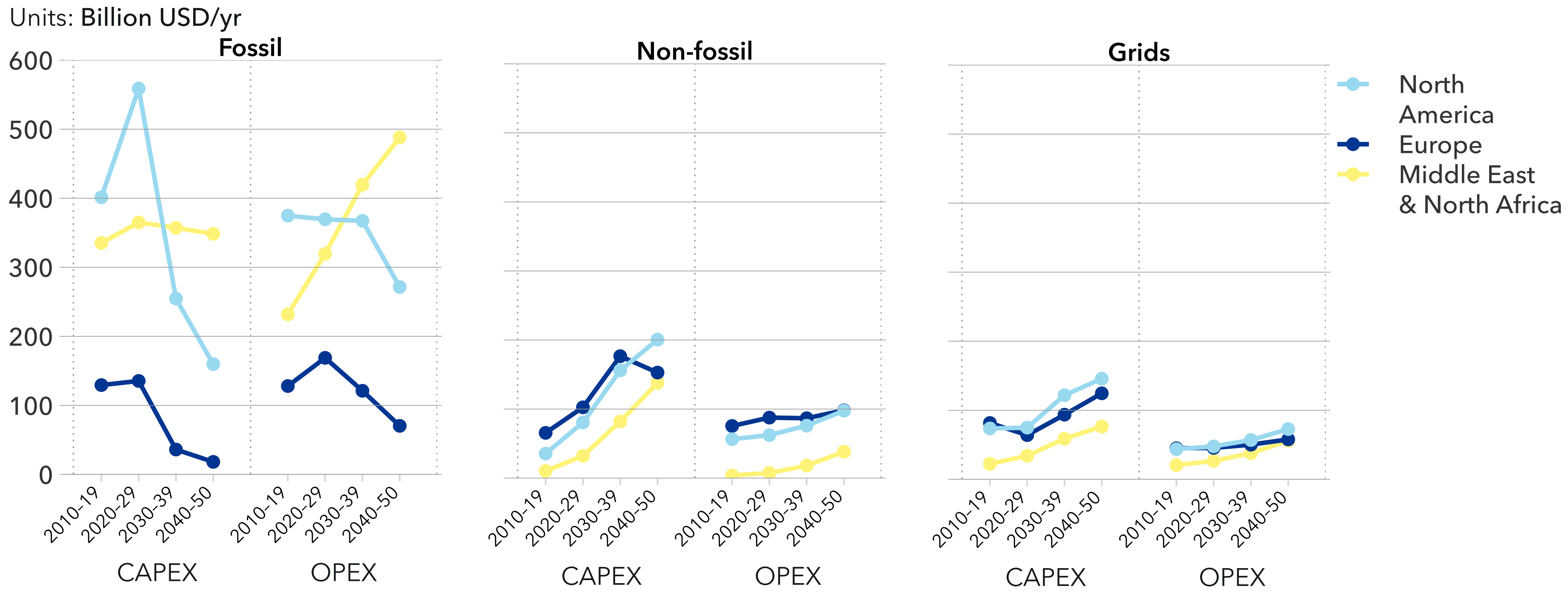
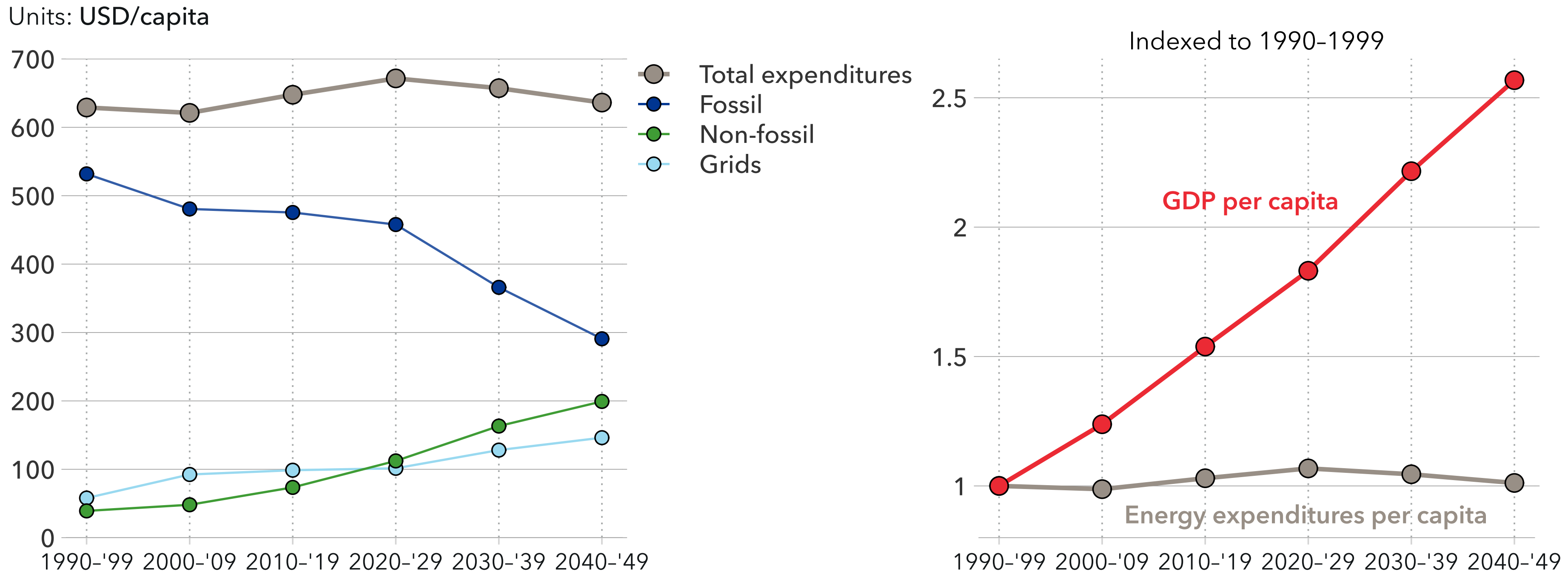


FIGURE 5.4

Global average energy expenditures per capita



and lack of visibility on the future regulations and economic situation can favour the status quo.

The second reason is that expenditures are not market prices paid by the consumer, which include margins, taxes, and/or subsidies. The gap is especially visible in the recent context of high energy prices, with energy producers making exceptional profits while their production costs are not increasing.

Figure 5.5 forecasts trends in household energy expenditures in North America, Europe, and the Indian Subcontinent. This household energy expenditure includes CAPEX for residential space heating and cooling (such as cost of air conditioners), water heating (such as cost of heat pumps), and cooking (such as cost of electric stoves) and OPEX, which is 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.

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 its household energy expenditure above past levels in the short term owing to price shocks, but gradually decreasing 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 and so on a relative basis measured as share of income, energy will be more affordable.

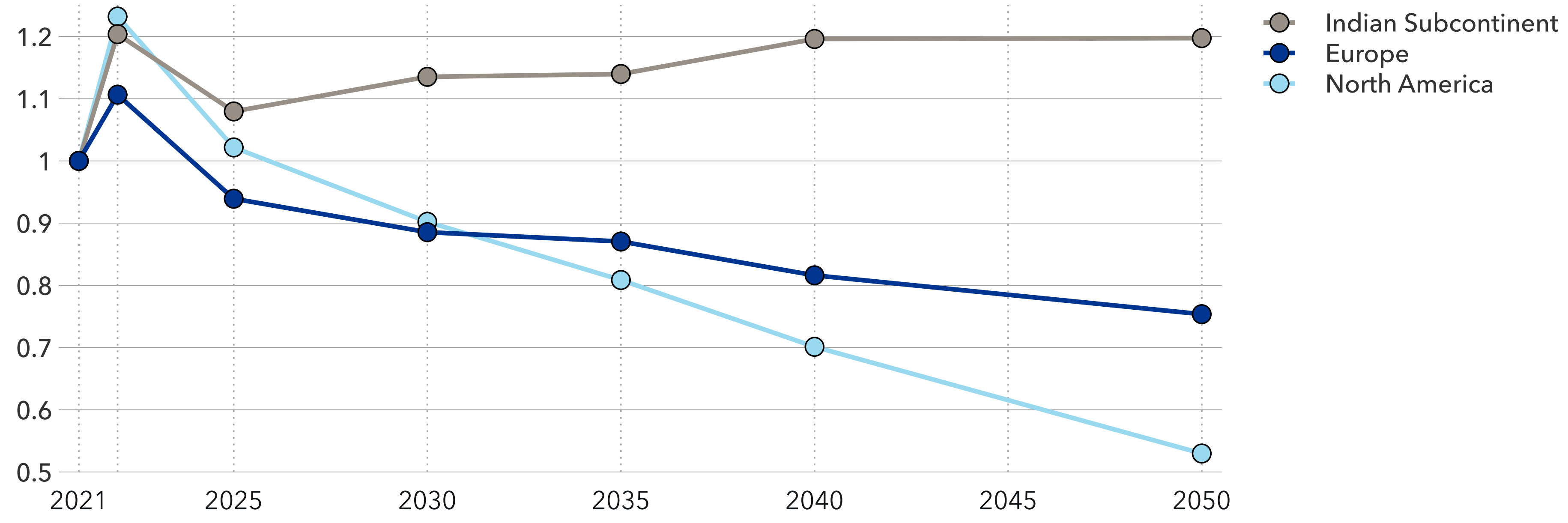
Energy costs are also embedded in products and services, but our results show that the energy transition will at least have a positive impact on the visible part of these costs: direct household energy expenditure.

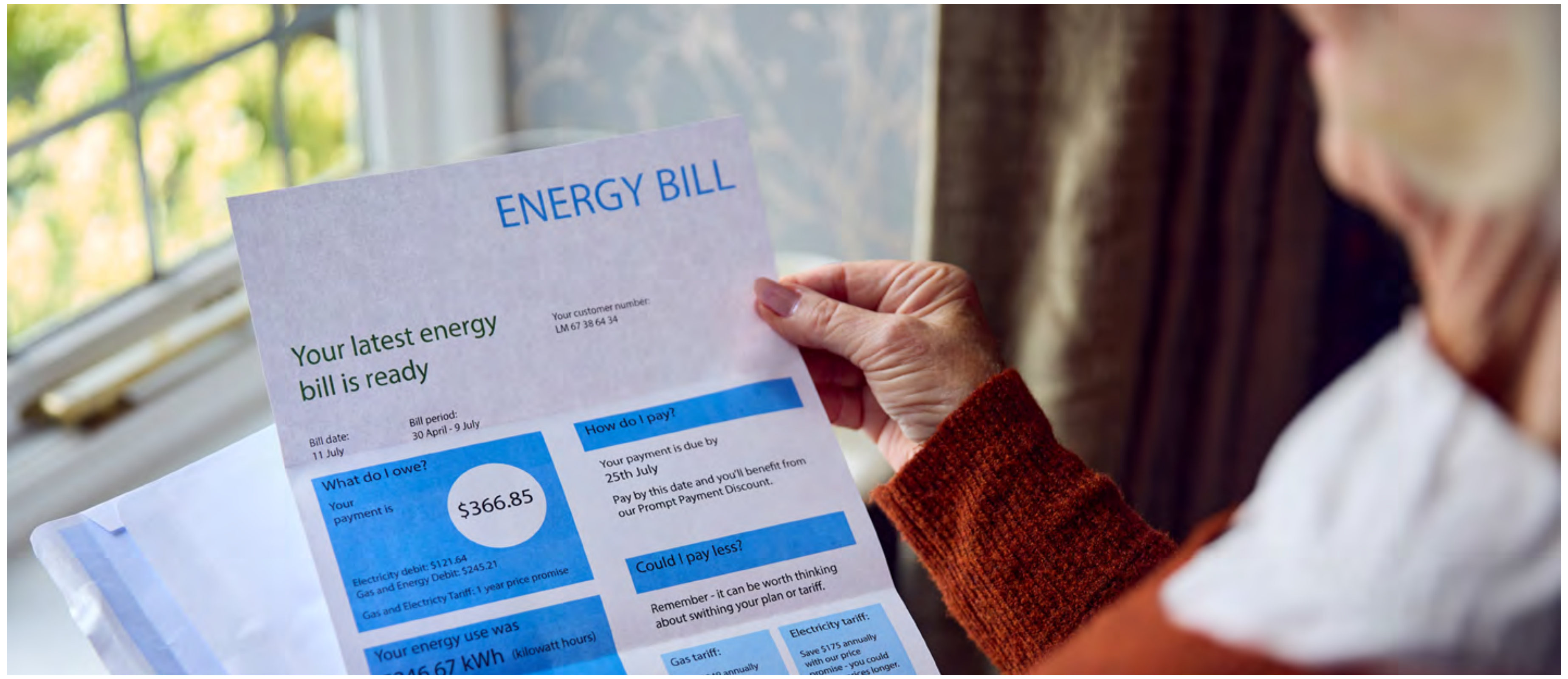
We forecast that by 2050 average household energy expenditure will be 75% of 2021 levels in Europe and 50% lower than 2021 levels in North America.

FIGURE 5.5

Household energy expenditures in selected regions

Units: Unitless, 2021 value = 1





5.2 CHALLENGES AND OPPORTUNITIES FACING INVESTORS

The global and geopolitical developments we introduced at the beginning of this report have trickle-down implications for investors at the project level. In this section we will first review the challenges and opportunities facing investors and then discuss the cost of capital.

Challenges

The war in Ukraine has led to supply-chain disruptions, impinging on the availability of critical resources necessary for renewable energy projects. This, in turn, has driven up costs, making it tougher to fund these projects. Additionally, the war has heightened geopolitical uncertainties, making investors more cautious and potentially hampering investment flows into the energy sector.

Inflationary pressures across many major economies, exacerbated by the war and the post-COVID environment, are further complicating the scenario. Outside of China, which has hovered on the brink of deflation for much of 2023, this has led to increased costs of raw materials and equipment, along with wage push inflation, making renewable energy projects more expensive to procure and slower to develop, particularly in North America and Europe.

Furthermore, as we detail in Chapters 2 and 3, grid connection availability is becoming a constraint, due to the increased demand for electricity and the disruption in energy supply chains, exacerbating both time to market for projects and the timing of returns for investors.

Alongside the above-mentioned challenges, the financing landscape of the renewable energy sector is also being reshaped by rising interest rates. As central banks shift their policies to combat inflation, the cost of borrowing has increased substantially. This shift directly impacts the financing of renewable energy projects, which are often highly leveraged.

Opportunities

Against the backdrop of these challenges are the compelling economics of renewables. Solar PV and wind are becoming more competitive in terms of levelized cost of energy (LCOE), with costs projected to decline significantly due to technological advancements and economies of scale.

By 2030, solar PV's LCOE will reach USD 30/MWh and onshore wind's LCOE will hit this mark by 2035. In contrast, conventional power stations, like coal and gas, have limited potential for cost reductions, and with rising fuel and carbon prices, their operating costs are expected to stay above USD 60/MWh on the global average, though in some regions, it will stay as low as USD 20/MWh. Thus, in the next five to ten years, renewable energy sources are poised to be at least as cost-effective as fossil fuels even in regions with the least renewable-friendly policies.

However, it is important to consider that while the operational costs of renewable energy technologies are typically low, the initial investment can be relatively high. Additionally, the cost of renewable electricity can be influenced by a range of factors including geographic location, technological maturity, market competition (particularly if competing fossil sources are subsidized), and policy frameworks. Therefore, while renewable electricity is progressively becoming cheaper, it is crucial to examine the broader economic and policy landscape to get a complete picture of its cost-effectiveness.

5.3 HOW WILL COST OF CAPITAL EVOLVE?

Cost of capital is a major factor for investors in new energy generation
Cost of capital (CoC) is one of the key cost drivers for capital-intensive projects like new power generation, power grids, and gas infrastructure, and for end-use subsectors such as buildings, equipment, and zero-emission vehicles.

DNV uses the levelized cost to compare competing technologies, where the ratio of lifetime costs to lifetime generation (like electricity or hydrogen production), are discounted back to a common year using a discount rate that reflects the cost of capital. With higher discount rates, the break-even price, that satisfies equity and debt returns, moves up.

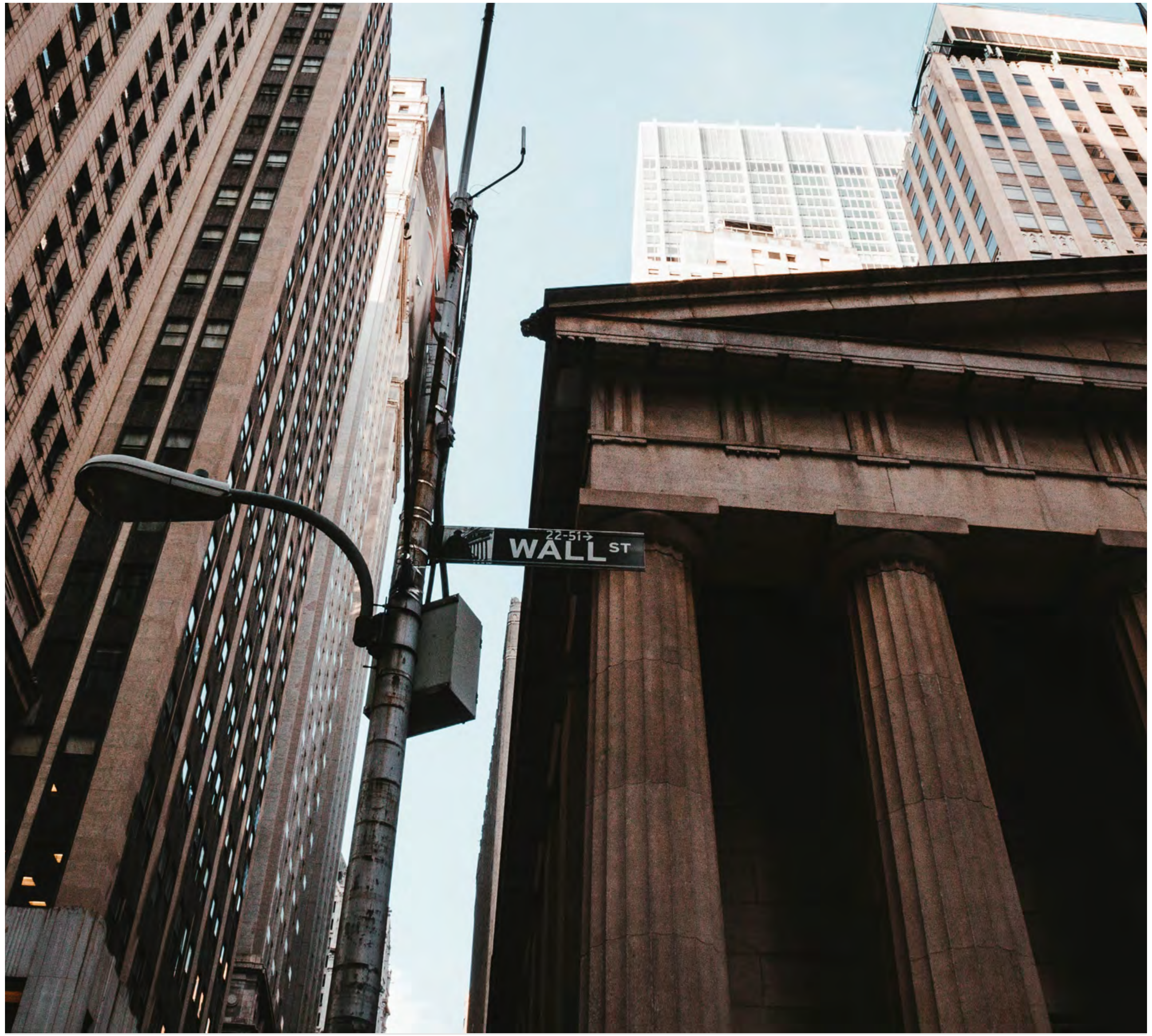
Hence, predicting the competitiveness of, for example, competing power generation technologies now and in the future, requires carefully weighed CoC predictions. It is a crucial parameter in our forecast to 2050 and DNV has therefore continued focus on the granularity of the CoC.

In this year's Outlook, DNV makes assumptions on today's CoC per technology, per region, and not least on the speed and direction of capital reallocation between technologies up to 2050. This is a challenging task because it requires answers to questions like: "How does inflation impact borrowing costs across geographies?", "Are investors and governments continuing to finance coal?", and "Are companies who reduce their emissions in line with net zero rewarded by the capital markets with a lower CoC?"

To answer these questions and create credible inputs for CoC, DNV has primarily utilized its internal team of finance experts and their hands-on project experience from transaction advice to provide informed opinions. Multiple internal workshops have been supplemented with a desktop study, literature research, and review of financial reports from power producers and oil and gas companies in various regions.

Evolution of cost of capital
DNV forecasts that clean energy expenditure will increase to around USD 1.3trn per year in 2030, building up towards USD 2.5trn per year in 2050. We observe a massive redirection of capital from fossil energy expenditure to non-fossil energy to finance this growth. However, the years of abundant capital, available at low cost, chasing few renewable energy projects has been replaced with a more complicated risk picture (DNV, 2023e).

Short term – Inflationary pressure sends mixed signals across the globe
In the short term, inflationary pressure impacts CoC. In Europe and the US, interest rate hikes by central banks to tame inflation are uppermost in minds. Banks and investors are revaluing their portfolios



and borrowing costs are elevated across the full energy value chain. The soaring costs for offshore wind companies in Europe and the US are, to a large extent, explained by the sudden increase in borrowing costs in these geographies, resulting in deteriorating margins, contract renegotiations, and delayed investment decisions.

Meanwhile, in Greater China and to a lesser extent the Indian Subcontinent, deflation risk presents the reverse challenge. Central banks there have for the last year been reducing interest rates and thereby borrowing costs. These regional differences in central bank behaviour impact CoC and hence the cost of new energy for end-users.

This exemplifies the importance of accurate CoC predictions that distinguish between geographies and technologies. DNV has reviewed policy rates and inflation development in all regions to account for this mixed bag of signals that impact borrowing costs. DNV predicts, based on forward curves from central banks, that the impact on CoC due to inflationary pressure is short-lived towards 2030.

Inflation pushes up risk-free interest rates, so the impact on the cost of debt is similar for mature technologies, whether it is fossil or renewables. However, the impact of the increased cost of borrowing does not have a uniform effect on emerging technologies, because the debt-to-equity ratio is different for technologies at distinct stages of their product life cycle. Mature technologies typically have more debt financing than equity financing, and hence the increase in CoC will be higher compared with less mature technologies, which have more equity financing.

Longer term – Risk perception drives the cost of capital

In the longer term, our CoC should accurately reflect the impact of debt and equity costs on intra-technology competition and the opportunity cost and risk associated with the investment choice.

The main driver for these variables is risk perception, which varies by region. In Europe, we observe European banks exiting from financing new coal-fired power plants, but this is not the region where DNV predicts new capacity. Hot spots for new coal-fired power will be Greater China, the Indian Subcontinent, and much of South East Asia, regions where GHG emissions and air pollution are still often outweighed by a drive for economic growth and increased energy demand. State-owned entities provide the bulk of equity and debt, with low return requirements and subsidized interest rates keeping CoC down. Similarly, European banks that used to finance working capital needs for coal trade are replaced by banks from coal-producing countries, such as Australia, Indonesia, and South Africa. Multilateral finance institutions continue to play an important role in financing fossil-fuel. As an example, the African Development Bank and the World Bank provided most of fossil fuel finance in Sub-Saharan Africa between 2016 and 2021 (Climate Analytics, 2022), mainly financing new fossil gas-fired power generation. Both institutions have internal policies guiding investment decisions: the African Development Bank can finance new coal-fired power plants while the World Bank cannot, but can finance upstream gas if urgently needed from an energy security perspective. This illustrates that capital for the fossil industry will get scarcer and more expensive, but the speed of reallocation differs by region.

Next to regional differences, risk perception also varies by technological and commercial readiness. Less mature technologies, like green hydrogen production, will be perceived riskier today than in 2040, when technology has matured and been proven in both production and end-use sectors. The market and business case for certain use cases has matured too, resulting in lower risk, lower borrowing costs, lower equity-return requirements from investors, and a higher leverage all driving down the cost of capital. Whether financing coal in Europe or South East Asia or hydrogen value chains now or in a decade, setting mid- to long-term assumptions about the cost of capital is a tough and dynamic challenge.

Cost of capital predictions used in 2023

We categorize our inputs under two major categories of technologies: mature and emerging.

Mature technologies may then be further considered as:

- Oil and gas upstream, midstream, and downstream technologies including grey and brown hydrogen and gas- and oil-fired power generation
- Coal-fired power generation and production
- Mature renewable technologies: solar and solar+storage, onshore and bottom-fixed offshore wind, biomass, hydropower
- Nuclear power

Emerging technologies are:

- Floating offshore wind
- Grid-connected and dedicated electrolyser-based hydrogen
- Production of green ammonia, e-fuels, and SAF
- Geothermal power

Figure 5.6 presents the CoC for energy technologies assumed in the ETO for North America and Greater China. For all technologies, one can see the short-term increase in CoC from 2022 to 2023 due to inflation in the US, while this trend is absent in China. For both emerging and mature renewables and nuclear, after the temporary increase in CoC in 2023, the levels come down towards 2050, with the perception of risk decreasing. For fossil fuels, the opposite is expected.

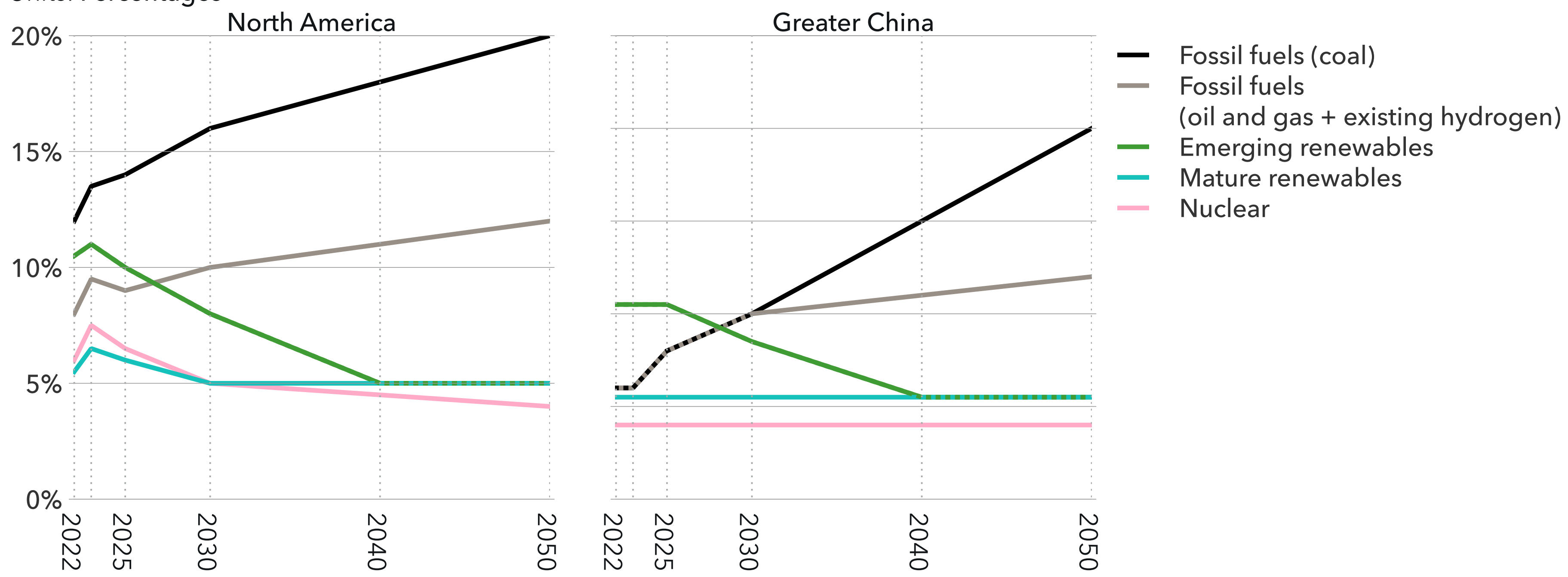
Mature renewables
In the short term, all regions except Greater China see an increase in risk-free rates due to increases in steering rates by central banks. With high debt ratios in this category, the impact of increased borrowing costs is expected to be around 1.5% from 2022 to 2023. This is in contrast to emerging renewables, where increased borrowing costs have a slightly milder impact due to lower leverage. Following forward curves from central banks, we predict an inflationary impact until 2025 and then tapering off towards 2030. Our forecast assumes that CoC for these technologies will come down all the way to between 5% and 7% by 2030, differentiated by country risk premiums, and then stay constant throughout, until mid-century.

Emerging renewables
Unlike mature renewables, emerging renewables have a higher risk premium, and hence their average CoC is expected to be much greater, at levels between 11% and 14% in 2023. From 2023, the CoC for these technologies gradually decreases, driven by the assumption that the inflation pressure on borrowing costs is short-lived, and by the expectation that these technologies mature gradually and attain parity with mature renewables by 2040.

FIGURE 5.6

Development of cost of capital in selected regions

Units: Percentages



Oil and gas
We expect oil and gas in 2023 to have a higher CoC than mature renewables in all regions except the Middle East and North Africa, mostly because it is now perceived as riskier than mature renewables. That region consists of top oil and gas producers at low cost, like Saudi Arabia and United Arab Emirates, and is therefore rewarded with attractive financing terms, expected to last over the full forecast towards 2050. CoC inputs for the other regions vary between 6% and 11% in 2023, with all seeing an upward trend towards 2030 and 2040, driven by increased perceived risks and capital moving away from new oil and gas production.

Coal
Investors in Europe and North America already perceive coal as significantly higher risk than other fossil fuels or renewable energy projects, as evidenced by a clear increase in loan spreads over the past decade. We do expect growing economies in low- and medium-income countries to continue to finance new coal investments at competitive rates towards the 2030s, after which we expect a rapid increase in risk and therefore CoC, driven by reduced availability of capital in all regions and falling demand for coal. We forecast large variations in CoC between the regions in 2023, ranging from 6% in Greater China to 16.5% in Europe, and large increases in CoC towards 2050, with inputs ranging from 20% to 25%.

Nuclear
We expect CoC to be low and stable over time, with inflationary impact tapering off towards 2030. We expect large government intervention in most regions, where returns on investment are regulated. We expect that public funding and support will be available, motivated by energy security, safeguarding knowledge in nuclear technology, and shielding investors from some of the safety concern risks. Resulting CoC predictions for 2023 range from 4% in Greater China to 11.5% in Latin America. Towards 2050, we do not expect large deviations, with inflation normalized by 2030 and certain regions developing economically, thereby reducing the spread between the regions to 4% and 8%.

The cost of capital is decided by three variables:

1) The cost of debt (the combination of the risk-free rate and the risk premium, or margin, together often referred to as borrowing costs)

2) The cost of equity (the equity return required by investors)

3) The ratio between these two (the leverage)

The economics and risks of climate change

A pervasive misconception deterring energy transition investments is that the switch to low-carbon energy is prohibitively 'expensive' (Oxford Martin School, 2022). Much in line with the findings of the study by Way et al. (2022), we predict that the investments involved in the transition we forecast will see the world spend progressively less on energy as a proportion of GDP. Moreover, as detailed in this chapter, households will also reap a dividend from the transition we forecast in the form of significantly lower expenditure on energy. Those are direct benefits of decarbonization, but of far greater importance are the avoided costs of climate damage and adaptation associated with a slow energy transition.

We see the world at risk of significant economic and societal setback in a future where climate change goes unmitigated beyond temperature limits set by science, as rooted in the *Paris Agreement* and reinforced by the *Glasgow Pact*.

In 2023, the global average temperature has already risen to about 1.1°C above pre-industrial levels (NASA Earth Observatory, 2023), and a record +1.5°C in July. As we detail in Chapter 7, the emissions associated with our forecast see a further increase to around 2.2°C above pre-industrial levels by 2100.

Fossil fuels in energy systems are by far the largest contributor to climate change, and energy systems will themselves be impacted by climate damage. Impacts will vary from acute disruptions of energy supplies to compromised infrastructures during extreme weather events. These encompass heat-waves, drought, and variability in precipitation (e.g. snowless years) that impact water supplies, adversely affecting hydropower output and water availability for cooling in power plants. Warmer temperatures impact thermal generation efficiency, and decrease the carrying capacity of transmission lines while boosting electricity demand for cooling (see Section 1.2), and might impact resource potentials in solar and wind, the latter with a decreasing trend. We have yet to see comprehensive global studies on the extent and costs of these weather-related energy system effects, but as examples suggest, there will be a rising need for robust weatherization (weather-proofing) of energy assets for resilience to climate change impacts. For example, in freezing conditions, wind turbines need materials and electronics rated for lower temperatures, along with heaters and other de-icing measures. In hot, desert environments, turbines require sand-proofing and ventilation engineering adjustments.

Looking beyond the energy system, impacts from climate change are already being felt across world regions: from extreme hazards to slow-onset disasters such as droughts, ocean acidification, faster sea-level rise, and changing disease patterns.

While climate change and its impacts are headed into uncharted territory, so too are the socio-economic consequences. Even if limited to 2.2°C, climate change will result in large material losses with immense societal implications and vast areas becoming uninhabitable. Furthermore, climate-related disasters are intensifying already, hindering progress towards the *Sustainable Development Goals* (UNECOSOC, 2023).

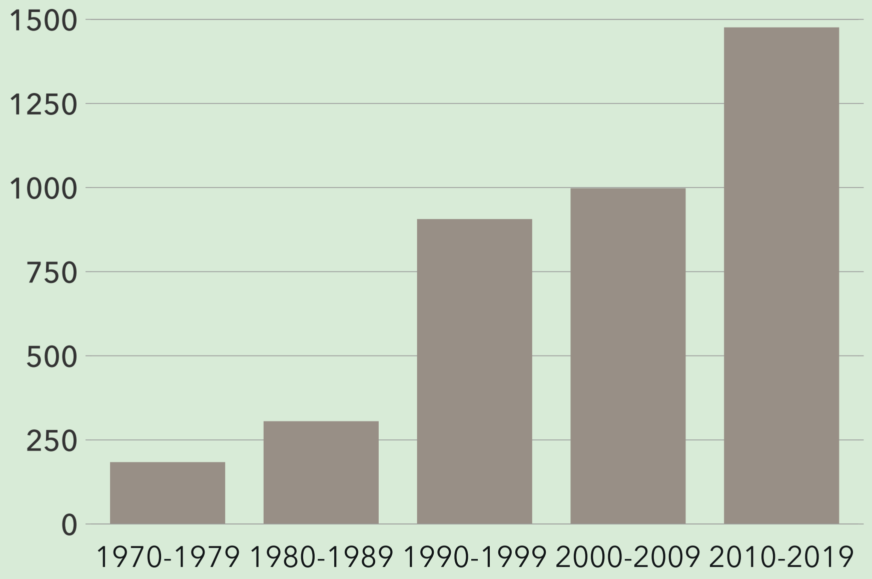
Rising economic losses

Climate change is causing a higher frequency of extreme weather events with devastating impacts as shown in Figure 5.7. Extreme weather, climate, and

FIGURE 5.7

Reported economic losses by decade

Units: billion USD



Adapted from WMO (2023)

water-related events caused nearly 12,000 disasters from 1970–2021. Reported economic losses are USD 4.3trn and rising (WMO, 2023). As evident from the figure, the number of climate-related disasters and the costs of climatic and meteorological hazards are escalating, and the increase in absolute losses is likely to continue to grow faster than GDP.

Reinsurers play a key role in providing risk knowledge. Munich RE's January 2023 presentation summarized the position: "Climate change is taking an increasing toll. Weather-related natural disaster figures for 2022 are dominated by events that, according to the latest research findings, are more intense or are occurring more frequently." The flooding in Pakistan saw 1,700 people killed, with direct losses estimated to be at least USD 15bn, enormous given the country's GDP (MunichRE, 2023a). Similarly, Cyclone Freddy losses in Mozambique and neighbouring countries came to approximately USD 1.5bn, but with low insurance penetration, only a negligible portion of the losses was insured (MunichRe, 2023b).

S&P Global, which gives countries credit ratings, has assessed climate-change impacts on GDP for the IPCC climate change pathway 'RCP 4.5' (based on current policies and resultant GHG concentrations with an average temperature increase in the 1.1°C to 2.6°C range). S&P estimated that 4% of world GDP would be exposed to losses from physical climate risks by 2050, but with significant regional variation such as 10% to 18% of GDP for the South Asia region.

Economic loss estimates show that lower- and lower-medium-income countries are likely to see 3.6 times greater losses on average than higher-middle- and higher-income countries, while the lower- and lower-medium-income countries have less capacity to adapt, having weaker institutions and less financial capacity (Munday et al. 2022).

Significant investments in climate adaptation (building resilience to both current and future changes) will be needed, and higher adaptation investment will tend to mean lower residual damage. According to the *2022 Adaptation Gap Report*, the estimated annual adaptation cost is USD 160–340bn by 2030 and USD 315–565bn by 2050 (UNEP, 2022). Hitherto, adaptation efforts tend to be fragmented, sector-specific, and unequal across regions, with notable gaps among lower-income regions. It is also essential to recognize the connection between the limits to adaptation and resulting residual damage that it is too late to mitigate (by reducing emissions) or adapt to. This is challenging to quantify let alone allocate responsibilities and both adaptation costs and loss and damage compensation are central points of contention in international climate negotiations.

Avoiding planetary risks

There will be a dramatic uptick in climate-related risks and related losses with every increment of global warming. Scientists are also warning against climate tipping points (McKay et al., 2022; IPCC, 2021) – critical thresholds beyond which a system reorganizes, often abruptly and or irreversibly. Large biophysical systems that regulate the climate system (e.g. the Amazon rainforest, the summer ice cover in the Arctic, and the permafrost system), if pushed too far, can shift irreversibly to create cascading risks (ice-sheet melt, forest dieback, permafrost thaw) across interconnected systems, likely to have severe impacts on human society and becoming increasingly difficult to manage.

The *Climate Change 2023: Synthesis Report* (IPCC, 2023) has never been clearer in its language and message: "Climate change is a threat to human well-being and planetary health (very high confidence). There is a rapidly closing window of opportunity to secure a liveable and sustainable future for all (very high confidence)."

The 1.5-degree Celsius target is not an arbitrary, negotiated number, it is a planetary safety vault. Our forecast global temperature increase is not compatible with the *Paris Agreement*. However, a 1.5°C future is still achievable. We describe how in DNV's upcoming *Pathway to Net Zero Emissions* report where we outline a pathway to a net-zero energy system that is compatible with the continued growth of global GDP and in line with current projections from the IMF among others. The important takeaway is that the effects of climate change would be significantly lower in the 1.5°C scenario – more than justifying any additional investment needed for faster decarbonization and a more just transition.

6 POLICY AND THE ENERGY TRANSITION

Highlights

This chapter explores policies impacting the energy transition and describes **12 policy considerations directly factored into our Outlook.**

We discuss four key issues affecting transition dynamics and describe **10 opposing forces** that shape the transition.

We outline our view on a **policymaker's toolbox** with available policy options to advance the transition. Then we demonstrate the policy toolbox in select energy areas and sectors, followed by a discussion of **expected carbon price developments** across 10 defined global regions.

We present a **high-level outline of the status of policy in the Outlook regions.**

We conclude by describing the policy analysis and factors influencing our Outlook and applied regionally across our forecast period.

6.1 POLICY AND THE ENERGY TRANSITION

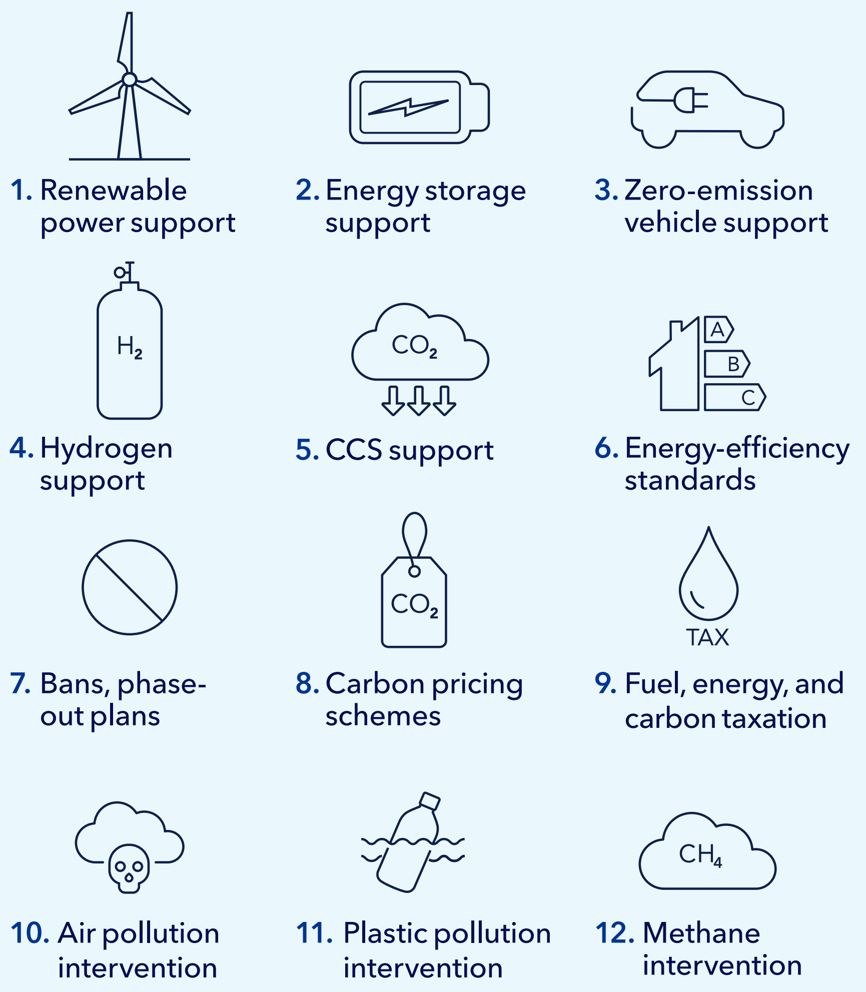
This chapter explores policies impacting the energy transition. The priority list for policy-makers is long – infrastructure, production capacity, permitting, demand creation, and maintaining energy security while keeping costs under control. The stakes are high. Unless sights are set on collaboration and spending on transition opportunities in a globally inclusive manner, emission reductions will fail in the low-income regions, with cascading risks and planetary crisis as the future outcome. Tapping into the policy toolbox we describe below can help the transition stay the course.

Multiple and often opposing forces are shaping the transition and are tracked in our analysis (Table 6.1). The key challenge for policymakers is managing short-term pressures without making decisions or investing in energy assets that undermine long-term societal goals such as the *Paris* and *Biodiversity Agreements*.

'Polycrisis', a suitable way to describe a coalescence of crises, was the catchword when world leaders began the year at the World Economic Forum in Davos. The energy transformation has been, and is, centre stage in this year's news cycle and there is a policy race to respond to interrelated crises (e.g. climate change, environmental destruction, inflation, security) which directly impacts the transition. We continuously map, track, and assess such responses, proposals, and law-making for their likely impacts. Policy inputs (Figure 6.1 and Section 6.5) reflect policy developments and provisions since last year's forecast.

FIGURE 6.1

Policy factors included in our Outlook



DNV notes four key issues gaining prominence globally since last year's ETO.

1. Delivery is lagging world climate commitments

The annual *Net Zero Stocktake* (NZT, 2023) puts *Paris Agreement* achievement into serious question and shows the urgency and need for action over announcements. It finds that country-level net-zero targets cover almost all (92%) of the global GDP and the vast majority (88%) of global GHG emissions. In 72 countries, net-zero targets have legal force, and target-setting at the company level is expanding. However, net-zero integrity is lagging in terms of robust delivery plans.

This is indeed problematic. The 1.5°C objective is a physical scientific limit above which climate change threatens the stability of planetary health (IPCC, 2023). Policymakers and the communities they represent are already battling immense climate-change impacts (see factbox page 105) at an average global temperature increase of around 1.1°C since 1880 (NASA Earth Observatory, 2023). Extreme weather events – heat-waves, drought, storms, wildfires, and floods – are among the costliest disasters (Munich RE, 2023a,b). Staying within 1.5°C means roughly halving CO_2 emissions by 2030 and reaching net zero around mid-century (IPCC, 2023).

2. The geopolitical backdrop

Among leading economies, the energy transition has been invigorated and propelled by a real race in industrial policies and support for positioning in clean energy value chains. Transition policies are playing out against a backdrop of geopolitics, disruption of energy markets from Russia's invasion of Ukraine, and pandemic-related supply-chain and security concerns. Attention to energy independence has also intensified, with mounting focus on China's dominant position in critical materials and energy tech-nologies relevant to a net-zero future. Critical minerals

In her state of the union address on 13 September 2023, European Commission President Ursula von der Leyen reiterated Europe's commitment to the energy transition, but with a protectionist edge: "From wind to steel, from batteries to electric vehicles, our ambition is crystal clear: the future of our cleantech industry has to be made in Europe." Image credit: CC-BY-4.0: © European Union 2019 – Source: EP.

are now fully entrenched in the net-zero transition discourse. Several studies have documented that the energy transition is mineral- and metal-intensive (e.g. World Bank, 2020; IRENA, 2023a). Reserves, and industry ownership, are geographically concentrated in many cases, and there is also the challenge of responsibly and sustainably scaling capabilities for mining and refining.

Trade, climate, energy, and industrial policies are increasingly meshed in incentives encouraging domestic manufacturing and 'friend-shoring' through supply-chain networks with allies. The concept of national security is broadening to include energy as seen in the US *Defense Production Act* (2022) that aims to spur production of clean energy technology. See detailed coverage on the shifting geopolitical landscape in the introduction to this report.

3. Staying power of fossil fuels

Despite government objectives seeking to curtail carbon-intensive energy, tight market conditions in both oil and gas have seen high prices and upstream oil and gas investments rising (Nakhle, 2023). Capital spending by oil and gas companies is growing, driven by a sustained favourable commodity price environment, strong cash flows, and cost inflation (Xu et al., 2023). DNV's *Energy Industry Insights 2023 – Trilemma and Transition* finds that a greater proportion of oil and gas respondents say they will increase their investments in hydrocarbons in the year ahead. Evidence of transformation of private international oil companies (IOCs) into energy companies is brittle. Investment in low-carbon activities represented only a minor share of total investment. For example, low-carbon plays accounted for just 12% of 2022 capital expenditure among supermajors ExxonMobil, BP, Shell, TotalEnergies, and Chevron (InfluenceMap, 2022). The IEA finds the oil and gas industry capital spending on low-emission alternatives to be less than 5% of its upstream spending in 2022 (IEA, 2023c). The largest state-owned national oil companies (NOCs) in Brazil, Russia, India, China, and South Africa (BRICS) are making only limited progress in aligning their innovation spending with low-carbon goals (Jaffe et al., 2022). We have yet to see a robust and forthright response from the hydrocarbon industry to our finding, with which the IEA now concurs for the first time this year, that the world is at the "beginning of the end" of the fossil-fuel era, which will peak before 2030 (Birol, 2023).

4. Missing climate finance and carbon pricing extend fossil-fuel investment

Non-fulfilment of the annual USD 100bn pledge from developed to developing countries not only jeopardizes climate justice, but also delays economically viable decarbonization projects. There was a shortfall of around USD 17bn in 2020 as assessed by the Independent High-Level Expert Group on Climate Finance (Songwe et al., 2022) at the request of the Egyptian Presidency of COP27 and the UK Presidency of COP26. The Expert Group's analysis also concluded that, separately from the USD 100bn per year, USD 1trn annually in external finance to developing countries (other than China) by 2030 is needed to deliver the *Paris Agreement*, reinforced by the *Glasgow Pact*. The combination of missing support and insufficient carbon pricing (coverage, price level) is holding back the transition in the regions where population and energy demand are growing. Among low-income countries, there is little disincentive to investing in coal as a cheaper alternative to expensive imported natural gas (The Economist, 2023b; IMF, 2022a), and, indeed, China has boosted its own investment in coal over the past year in response to both market forces and drought conditions which have placed its hydropower sources under stress.

Image: courtesy UNFCCC COP27

6.2 THE TRANSITION CONTEXT SHAPED BY 10 OPPOSING FORCES

We choose to highlight 10 opposing forces. This is not an exhaustive list but includes the topics which have dominated the energy transition discourse since our 2022 Outlook. In keeping with Schumpeter's theory of creative destruction, some forces are triggering change, while others are hindrances that uphold the status quo, making for a rather messy transition which nevertheless remains orientated towards decarbonization.

TABLE 6.1

10 opposing forces shaping the transition

1.	**Landmark global agreements** The *Paris Agreement* 2015 and the *Biodiversity Agreement* 2022 unite objectives. Net gain for the environment is to be pursued in parallel with net zero.	**Let-down in implementation** Fossil CO_2 and methane missions are increasing, deforestation remains high[1]. Planetary boundaries are being crossed, undermining critical life-supporting earth systems[2].
2.	**Public support for climate action** Climate change tops world risks[3] and impacts abound. Public polls show demand and support for climate action[4].	**Competing concerns on the public agenda** Rising cost of living and short-term concerns[5] threaten to distract world leaders and deflate transition policy.
3.	**Progressive clean energy policy** Front-runners have progressed policy frameworks with incentives to manufacturing, economy-wide deployment, and market redesign for high renewables integration.	**Bottlenecks** Inadequate grid development commensurate with networks' importance. Lengthy siting/permitting processes, skills shortage, and supply-chain cost inflation, causing clean energy project logjam.
4.	**Record spending on renewables** Clean energy investment (2022), including on energy efficiency, grew 19% from 2021 levels[6] and is expected to extend its lead over spending on fossil fuels in 2023[7].	**Uneven geographical distribution** 90% of clean energy spending is from advanced economies and China. Only 1.5% of renewable investments (2010-2020), were in Sub-Saharan Africa[8]. Popular fossil-fuel subsidies hamper renewables competitiveness[9].
5.	**Strong pace for renewables in power** Wind and solar are cost-effective sources of new bulk power generation. Energy price shocks make the economic case for non-fossils more compelling.	**Critical solutions have unfair competition** Hydrogen, CCS, DAC, SAF as critical net-zero solutions meet skewed competition from unabated fossil fuels and insufficient carbon pricing.
6.	**More rigour in pledges** UN taskforce requires non-state entities' pledges to have concrete interim targets and set out ways to reach net zero in line with IPCC and IEA 1.5°C pathways[10].	**Insufficient risk governance** State entities and policymakers pay insufficient attention to transition and physical climate risks to inform their own pledges and decision-making.
7.	**Crackdown on corporate greenwashing** There is pressure from regulators and activists to end misleading statements (e.g. EU *Green Claims Directive*, ISSB's sustainability and climate-related disclosures).	**Greenhushing and jurisdictional delays** Companies are opting for bare minimum transparency on environmental commitments. Mandatory application of standards requires regulatory endorsement.
8.	**Surge in climate litigation** Climate cases against governments and corporations grow year-on-year around the world for courts to determine responsibilities[11].	**Corporates escaping responsibilities** The Net Zero Insurance Alliance is disintegrating[12], and the Shell case exemplifies attempts of corporate manoeuvring to litigation: appeal, name change, relocation[13].
9.	**Investors propel the transition** Initiatives, e.g. Institutional Investors Group on Climate Change (IIGCC) focus on Paris-alignment, also calling banks to action. Emergent reform of multilateral finance institutions will enhance climate finance and 'fit-for-purpose' response to polycrisis[14].	**Troubles crowding in mainstream investments** Real and perceived geographical-, technology-, and project-specific risks in low-income regions continue to deter private sector investing[15]. In high-income regions, unrealistic price and licence fee expectations from national governments hobble renewables auctions.
10.	**Front-runners advance solutions** Solutions for deep decarbonization are available. Multiple public-private innovation initiatives are bearing the weight of bringing them to commercial readiness.	**System inertia** Non-power, low-carbon technologies production capacities are scaling slowly. Decommissioning of expensive capital equipment before end of technical lifetimes is undesirable.

1. Friedlingstein et al., 2022, **2.** Rockström et al., 2023, **3.** WEF (2023), **4.** OECD (2022), **5.** Gebrekal (2023), **6.** IRENA (2023b), **7.** IEA (2023c), **8.** IRENA (2023b), **9.** Black et al., 2023

10. UN (2022a), **11.** Setzer et al., (2022), **12.** Smith et al. (2023), **13.** Owens (2023), **14.** Gordon (2023), **15.** Songwe et al. (2022)

6.3 THE POLICY TOOLBOX

In previous Outlooks, we have detailed what we label the 'policy toolbox'. All policymakers have a generic technology-opportunity space and a suite of known policy categories with proven measures available for catalysing structural shifts in energy systems.

For clarity, the policy toolbox and its high-level categories are illustrated in Figure 6.2. In its real-world application, at the level of sectors or supply chains, blended policies (policy packages) are used concurrently to create predictable framework conditions that de-risk investments and business engagement in the transition.

Beyond goals and fiscal mechanisms (like carbon prices or energy tax reforms), policymakers need to allocate equal attention to policies which 'push' and 'pull' technologies. Technology-push policy incentivizes and fosters technology development, new production, and supply infrastructures. Demand-pull policy stimulates certainty on demand, market deployment, and offtake arrangements.

FIGURE 6.2
Policy toolbox

POLICY TOOLBOX

GOALS & PRIORITIES

Purpose: Structure and inform national and sectoral policy
- Plans – e.g. long-term low greenhouse gas emission development strategies (LT-LEDS), NECPs (EU) to inform short- and mid-term priorities, policies, and investment pipelines
- Industry, sector agreements – e.g. IMO, ICAO decarbonization targets and strategies
- Public-private partnerships – joint innovation undertakings leveraging private sector resources (e.g. First Movers Coalition)

FISCAL POLICIES

Purpose: Integrate goals and level the playing field
- National budgeting and government entities aligning with SDGs, nature, or climate goals
- Fiscal measures – e.g. carbon pricing schemes, energy taxation reform reflecting environmental performance, fossil-fuel subsidy removal

TECHNOLOGY-PUSH

Purpose: Stimulate technology development and cost reduction
- Funding support – e.g. R&D, demonstration, investments in production capacity and critical supply chains
- Infrastructure investments – e.g. grids, charging, refuelling corridors
- Technical requirements – e.g. emission limits, fuel economy, efficiencies
- Taxonomy – e.g. eligible sustainability investments

DEMAND-PULL

Purpose: Stimulate demand and incentivize market uptake
- Market requirements - e.g. fuel blending, zero-emission mandates, phase-out policy (ICEs, fossil-fuel boilers), renewable capacity quotas, carbon intensity reduction targets
- Economic instruments - e.g. investment/purchase and operation incentives, feed-in tariffs, contracts for difference, clean public procurement
- Mandatory disclosure - e.g. of low- or zero-carbon use, lifecycle emissions

The policy toolbox at work

Listed below are national and international policy examples. The lists are not exhaustive, but exemplify the policy toolbox categories in select energy areas and sectors. Policy examples are also given in Chapter 8 on Outlook regions.

POWER & GRIDS	
Goals & Priorities	– 174 countries have renewable power targets (REN21, 2023a) – e.g. Germany 80% by 2030, the US and Canada for decarbonized power by 2035. Some regions have economy-wide renewable targets – e.g. EU 2030 binding 42.5% of final energy consumption, or Denmark for a 100% renewable energy supply by 2050 with a high rate of electrification and sectoral integration.
Fiscal	– Power sectors are part of carbon pricing schemes globally. Reform of energy taxation for increasing alignment with environmental performance and climate objectives is seen in Europe (EU).
Technology-push	– EU investment support emphasizes offshore renewable generation and offshore wind manufacturing supply chains as 'strategic net-zero technology', eligible for State aid under its *Temporary Crisis and Transition Framework* (TCTF). The US *Inflation Reduction Act* (IRA) offers investment tax credits to manufacturing facilities for clean energy equipment. – Nuclear power receives investment support, also for life extension, and is prioritized for energy security reasons (e.g. China, Europe including the UK, Japan, South Korea, and the US). – Clear investment signals and attention to speed grid infrastructure investments and digitalization. Regulation to streamline the approval process for grids and interconnections is needed - e.g. with initial steps being taken in Europe and North America.
Demand-pull	– Utility-scale projects, in most regions, are allocated on a market basis through competitive tendering procedures/auctions, triggering demand and providing a stable revenue guarantee to project developers (contracts for difference, CfDs). A targeted market uptake (capacity quantity) is achieved by combining tender volumes with a renewable energy obligation on electricity suppliers, or by requiring a specified percentage of renewables in the mix. In the US, the IRA offers production tax credits. – Complementing tenders by adding storage for grid resilience is common (e.g. Europe, China, North America). Some regions rely on capacity markets for a reserve margin which involves a payment mechanism to existing or new flexible capacity for resources to be available to meet peak demand. – Phase-out policies for coal are predominantly a high-income region phenomenon - e.g. Europe accounts for almost half of announcements. – Nuclear relies on operational support - e.g. the (US) IRA production tax credit.

	HYDROGEN
Goals & Priorities	– National hydrogen strategies set priorities, timelines, and targets. These have been multiplying in Outlook regions, and are most concrete in terms of hydrogen energy in regions with net-zero mid-century ambitions.
Fiscal	– Carbon pricing impacts cost-competitiveness against conventional fossil-fuelled technologies (captive production at/or close to industrial consumer). At a sufficient level, it can also incentivize low-carbon production routes for hydrogen as a feedstock, which further reduces the cost of low-carbon production routes through cost learning. – Carbon pricing impacts cost-competitiveness of blue hydrogen versus electrolyser-based hydrogen production routes, which is tied to the cost-competitiveness of CCS. – Europe (EU) is progressing reform of energy taxation for increased alignment with environmental performance. Low- and zero-emission fuels and heating fuels will be subject to lower minimum rates to promote hydrogen use.
Technology-push	– Funding programmes provide investment grants/loans to promote hydrogen production plants, cluster and infrastructure development (e.g. the IPCEI Hy2Use project). Funding is also available for international projects to accelerate global hydrogen developments – e.g. Germany's International PtX Hub initiative, and EU Team Europe Renewable Hydrogen Fund. – Support for capital expenditure (CAPEX) is the dominant early-stage form of support to co-finance infrastructure and production capacity. This is available to decarbonize existing hydrogen production, new merchant production, and for transformation projects for hydrogen-based fuels (i.e. e-fuels, ammonia).
Demand-pull	– The North America and Europe regions have support to both operating expenditure (OPEX) and CAPEX. – The 45V hydrogen production tax credit in the US IRA supports low-carbon hydrogen produced based on carbon intensity ($kgCO_2/kgH_2$). Canada is introducing a tax credit based on the emission intensity of production. – The *European Hydrogen Bank* will accelerate the renewable hydrogen market in the EU and European Economic Area by providing operational support to hydrogen produced, with spillover effects for hydrogen price and demand in end use. A fixed premium per kilo of H_2 for a 10-year period will be set via auctions. – The EU *Renewable Energy Directive*, RED III ambition for at least a 29% renewable share in final energy consumption in transport by 2030 includes targets for non-biological renewable fuels.

Please see DNV's *Hydrogen Forecast to 2050 (2022a)* for additional coverage of hydrogen efforts in ETO regions.

	CARBON CAPTURE, UTILIZATION, AND STORAGE (CCUS) & DIRECT AIR CAPTURE (DAC)
Goals & Priorities	– The UK government *CCUS Investor Roadmap* with its CCUS delivery plan from 2021 to 2035. – The EU's CCUS *SET Plan strategy* to 2030.
Fiscal	– Carbon pricing impacts the cost-competitiveness of CCS. – The Carbon Emissions Reduction Facility of the People's Bank of China has a structural monetary policy instrument providing financial institutions with low-cost loans to support decarbonization projects, including CCUS.
Technology-push	– Funding programmes provide investment grants/loans to CCS installations and related infrastructure. Examples include the US *Infrastructure Investment and Jobs Act* (IIJA); EU Innovation Fund with support of up to 60% of CAPEX; UK CCS Infrastructure Fund and the 2023 funding announcement of up to GBP 20bn (around USD 25bn) for CCUS applications, including for DAC, over the next two decades; Norway's support to the Longship demonstration project, and grant to industrial-scale CO_2 capture (Heidelberg Cement); the US *Chips Acts* increasing R&D funding to DAC; Canada's tax credit of 60% (capital costs) for DAC projects. – Relaxed *State aid* rules in the EU's *Temporary Crisis and Transition Framework* (TCTF) incentivize production of CCS equipment with aid up to 100% of the total investment cost if granted in a competitive bidding process, and otherwise up to 45%.
Demand-pull	– US exemplifies support to OPEX in addition to CAPEX. The IRA extends support (45Q) to CO_2 captured and stored (USD 85) or reused (USD 60). DAC tax credits are USD 180 (stored) and USD 130 (reused). – Norway extends government funding to OPEX provided projects secure sufficient own funding (e.g. Fortum Oslo).

Brevik CCS – the world's first CO_2-capture facility at a cement plant. Image courtesy, Heidelberg Cement

The policy toolbox – demonstrated on demand sectors

	TRANSPORTATION	BUILDINGS	MANUFACTURING
Goals & Priorities	– International Maritime Organization (IMO) *2023 Strategy on Reduction of GHG Emissions* to reach net zero from international shipping close to 2050 (July 2023). – The International Civil Aviation Organization (ICAO) long-term global aspirational goal for net-zero emissions by 2050 (October 2022).	– China's *14th Five-Year Plan for Building Energy Efficiency and Green Building Development*. – *EU's REPowerEU Plan* and *Energy Efficiency Directive* target (11.7% reduction by 2030).	– China's sectoral guidelines for industrial carbon peaking by 2030. – Japan's 10-year *Green Transformation (GX) Basic Policy* adopted 2023. – South Korea's *Green New Deal* (2020) with 2025 targets. – Australia law (2023) requiring about 5% annual industry GHG emission cuts through 2030.
Fiscal	Road: – EU emissions trading system (ETS2) for upstream fuel suppliers (2028). Fuel taxation and effective carbon tax increase in regions with fossil-fuel taxation, but with fossil-fuel subsidies prevailing in some regions. Maritime & Aviation: – Global carbon levy (IMO negotiations); *Carbon offsetting and reduction scheme for international aviation* (CORSIA), piloting from 2021. – Aviation and shipping in EU ETS.	– EU ETS2 (buildings, road transport) for those bringing fuels to the market (2028). – Future electricity taxation model favourable to electrification is expected (e.g. revision of the EU's *Energy Taxation Directive*).	– Removal of carbon price exemptions – e.g. EU ETS phase-out of free allowances parallel to phasing in the *Carbon Border Adjustment Mechanism* (CBAM). – China's gradual enrollment of energy-intensive industries in national emissions trading system. – Government directed funding (e.g. National Green Development Fund) and discounted lending from the People's Bank of China. – Relaxed *State aid* rules to decarbonize industrial production processes (EU's *Temporary Crisis and Transition Framework*, TCTF).
Technology-push	Road: – Tightening of fuel economy and tailpipe CO_2 standards. – Investment support to charging and refuelling infrastructure.	– Energy-efficiency improvements through energy-efficiency standards for appliances, as for renewable energy use.	– Pilot and demonstration support (e.g. Hybrit green steel supported by Swedish Energy Agency, EU Innovation Fund). – 2030 national investment plan (EUR 5.6bn) to reduce emissions of heavy industries (France).
Technology-push (continued)	Maritime & Aviation: – Government investment funding to mature, scale and expand production capacity, related infrastructure, value chains (drop-in sustainable fuels + new fuels). – Public-private partnerships – e.g. Green Voyage 2050, Green Shipping Corridors, Clean Skies for Tomorrow.	– Funding to boost production of electric heat pumps (e.g. US Department of Energy).	– The IRA with USD 6bn for demonstration of low-carbon industrial production technologies. DOE *Industrial Heat Shot™* to deliver decarbonization tech (US). – China's state-owned companies directed to develop decarbonization initiatives/technologies.
Demand-pull	Road: – ICE phase-out policy (e.g. EU-wide 2035, country signatories in the Accelerating to Zero Coalition). – EV purchase incentives vary from insignificant in some regions to commencement of subsidy declines in mature regions, such as Europe. Feebates lowering running costs and benefits to owners are common across regions. – Targets and purchase incentives for FCEVs (e.g. Japan, South Korea, California). – Biofuel blending mandates (e.g. India 20%, Indonesia 35%, Malaysia 20% in 2025). Maritime & Aviation: – Increasingly stringent limits (*FuelEU Maritime*) and reduction targets (IMO) for carbon intensity of energy use. – Binding targets for sale, purchase, and blending mandates expected for non-conventional fuels (e.g. *ReFuelEU*).	– Mandatory building energy codes exist in 40% of countries (REN21, 2023b). For example, India's Bureau of Energy Efficiency (BEE) plans to update its building sector code – *Energy Conservation and Sustainability Building Code* – to target reduced energy consumption and carbon emissions for both commercial and residential buildings, and addressing energy but also embodied carbon, waste management, and water efficiency. – Purchase incentives or tax credits for heat pumps, and electric cooking equipment. – Higher retrofitting rates of buildings and envelopes based on bans on fossil boilers (e.g. Europe), and tax credits for insulation and weatherization of buildings.	– 19 countries have policies that incentivize or mandate the use of renewables in industry (REN21, 2023b). – Energy efficiency management (e.g. China's policy for mandated energy intensity reductions, and 'reuse and recycle' rates – e.g. waste steel target to reduce energy consumption). – The IRA provides USD 6bn for demonstration and deployment of low-carbon industrial production technologies. – The EU *Green Deal Industrial Plan* (2023) for at least 40% domestic capacity, and recycling at least 15% of critical raw material.

Please see DNV's *Transport in Transition report (2023a)* for a deep dive on the transport policy landscape.

How will carbon prices develop?

The rationale for carbon pricing is to introduce a financial incentive to cut emissions. The potential remains largely untapped, and carbon pricing will need to be expanded in both coverage and price level if it is to drive transformational changes to meet the *Paris Agreement* goals. Given pressures on public budgets, the revenue potential from carbon pricing schemes should be a motivational factor.

Highlights from annual global expert reference reports – the International Carbon Action Partnership (ICAP, 2023) and the World Bank (WB, 2023) – are:

- 23% of global emissions are covered by carbon pricing (taxes and emissions trading systems) compared with just 7% 10 years ago.
- 73 carbon-pricing instruments have been implemented worldwide, 5 more than in 2022.
- USD 100bn is the revenue that ETS and carbon tax instruments are approaching.
- Almost 40% of the revenue is earmarked for green spending, and 10% is used to compensate households or businesses.

Maturing carbon pricing systems is a lengthy process. For example, reaching European ETS levels takes 10 to 20 years and depends on political willingness to adjust schemes with increasingly stringent caps and phasing out exemptions. In most jurisdictions, carbon prices are insufficient to drive decarbonization, but are gradually gaining momentum along with other decarbonization efforts. However, there is insufficient momentum to drive any of the world regions close to the levels of carbon pricing we expect to see in Europe by 2050.

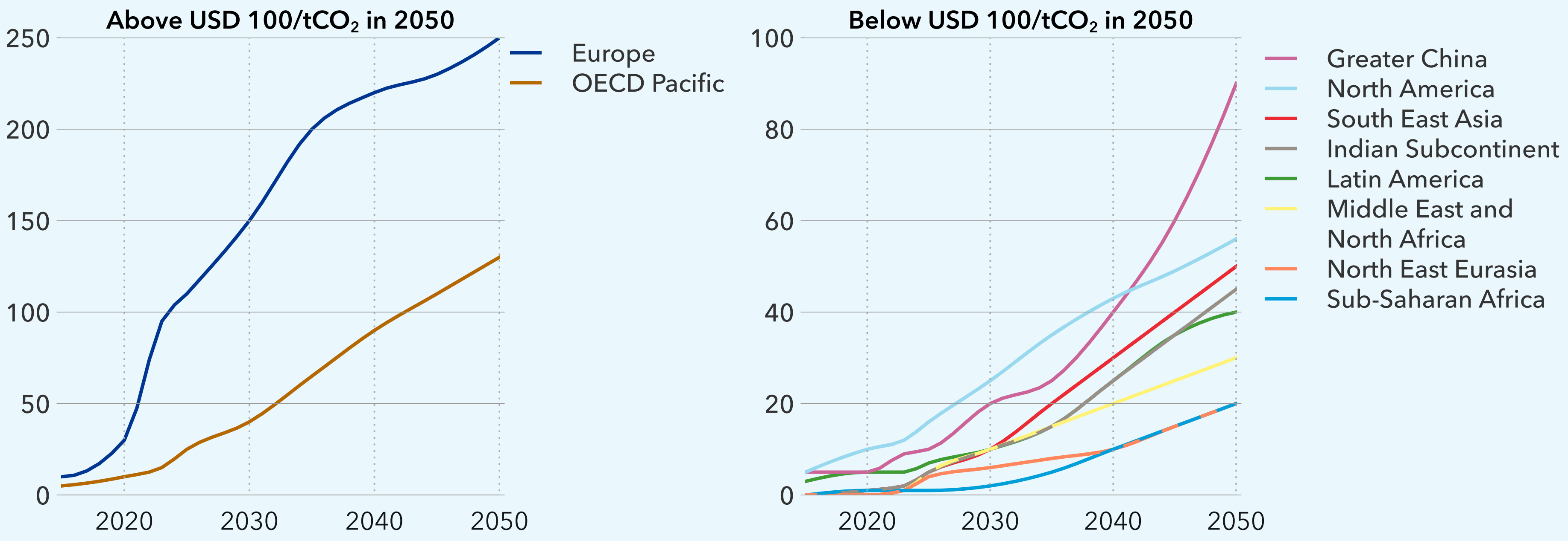
Based on research including recent policy developments, review of status reports from leading organizations, estimates from carbon price market forecasters, and conversation with experts in academia, we derive a best estimate of the trends and future price levels in existing schemes for inclusion in the analysis (Figure 6.3).

23% of global emissions are covered by carbon pricing (taxes and emissions trading systems).

FIGURE 6.3

Carbon price by region

Units: USD/tCO_2



Regional carbon price (CP) highlights

- **North America (NAM):** Canada has federal, economy-wide CP policy with a predictable price increase. In the US, CP is decided at the state level and not assumed to expand to additional states. Variation in state and sector coverage and free allocation is reflected. The regional average carbon price level is USD 25/tCO_2 (2030), USD 43/tCO_2 (2040), and USD 56/tCO_2 (2050). The effective CP on industrial emissions is some 50% lower.

- **Latin America (LAM):** Some countries have carbon taxes but at low levels, except Uruguay. Some plan to introduce ETS schemes. For example, in Mexico to transition its pilot to an operational phase. There is mention of ETS in Brazil and Colombia, but little clarity on timing and implementation. The regional average carbon price level is USD 10/tCO_2 (2030), USD 25/tCO_2 (2040), and USD 40/tCO_2 (2050).

- **Europe (EUR):** CP is a key instrument to fund the green transition. Higher burden on EU ETS sectors (62% emissions reduction target by 2030). Expansion in scope (ETS1 including maritime; ETS2 buildings and transport from 2028). Free allocations are phased out in 2034, and there is a declining cap trajectory to zero around 2040. Industry abatement measures will increasingly be price-setting. The regional average carbon price level is USD 150/tCO_2 (2030), USD 220/tCO_2 (2040), and USD 250/tCO_2 (2050).

- **Middle East and North Africa (MEA):** Net-zero announcements with a 2050 time horizon presage some level of CP. Announcements on carbon credit market (Saudi Arabia) and pilot ETS (Turkey). Manufacturing exposure to EU CBAM. The regional average carbon price level is USD 10/tCO_2 (2030), USD 20/tCO_2 (2040), and USD 30/tCO_2 (2050).

- **North East Eurasia (NEE):** Russia, the largest economy in the region, has trade shifting away from Europe, which lessens CP introduction pressure. Existing schemes (e.g. Kazakhstan) remain at low CP levels. The regional average carbon price level is USD 6/tCO_2 (2030), USD 10/tCO_2 (2040), and USD 20/tCO_2 (2050).

- **Sub-Saharan Africa (SSA):** Domestic CP initiatives are expected from 2035 onwards. South Africa proposed to gradually increase its carbon tax to 2050. Nigeria's announced ETS has little clarity on timing and implementation. The regional average carbon price level is USD 2/tCO_2 (2030), USD 10/tCO_2 (2040), and USD 20/tCO_2 (2050).

- **Greater China (CHN):** The national ETS, targeting large emitters, evolves slowly. Expansion of scope, eventually covering eight high-emitting industries, will happen gradually to 2030, likely mirroring EU CBAM exposure. A switch to an absolute cap and auctioning is expected by the early to mid-2030s. A carbon tax is being discussed for smaller emitters, outside national ETS. Industry abatement measures will increasingly be price-setting after 2040 to achieve 2060 carbon neutrality. The regional average carbon price level is USD 20/tCO_2 (2030), USD 40/tCO_2 (2040), and USD 90/tCO_2 (2050).

- **Indian Subcontinent (IND):** Net-zero announcement (India 2070). India plans a carbon credit trading system, tradeable domestically and suggested to be operational in the late 2020s, covering 40% of emissions, but with no absolute cap. CP drivers are exposure to carbon-border tariffs/CBAM and revenue potential. The regional average carbon price level is USD 10/tCO_2 (2030), USD 25/tCO_2 (2040), and USD 45/tCO_2 (2050).

- **South East Asia (SEA):** There are net-zero announcements and emerging CP schemes. Singapore with steady CP increase through to 2030. Indonesia has begun its first ETS stage for power (2023). Malaysia plans a voluntary ETS scheme. Exposure to carbon-border tariffs/CBAM affecting export activities and net-zero supply-chain attention are key CP drivers. The regional average carbon price level is USD 10/tCO_2 (2030), USD 30/tCO_2 (2040), and USD 50/tCO_2 (2050).

- **OECD Pacific: (OPA)** CP plan an important role in net-zero policy mix and is well established with extensive sector coverage, and tightened by reform (New Zealand, South Korea). Japan decarbonization strategy includes several carbon pricing schemes, e.g. a mandatory ETS from 2026 onwards. Australia is strengthening its CP instrument. The regional average carbon price level is USD 40/tCO_2 (2030), 90/tCO_2 (2040), and USD 130/tCO_2 (2050).

At COP26 (Glasgow 2021), Canada launched the Global Carbon Pricing Challenge aiming for 60% of global GHG emissions to be covered by a carbon price by 2030. Chile, the Republic of Korea, New Zealand, the UK, and Germany have joined as of mid-2023.

6.4 SYNOPSIS ON THE STATE OF POLICY IN ETO REGIONS

The summary of transition policy in the Outlook regions presented below suggests that high-income regions are pushing forward to transition and decarbonize all energy subsectors. These regions are also increasingly taking charge in industry decarbonization to progress technologies such as CCS and low-carbon hydrogen. Other regions continue to focus predominantly on power sector transitions while also positioning themselves for hydrogen energy. The energy transition of each Outlook region is covered in Chapter 8.

Policy developments among high-income regions
The North America, Europe, and OECD Pacific regions have mid-century net-zero ambitions, and their energy demands are stable. An immense scale of government intervention in energy systems, and competition in clean tech support and investment stimulus, are in play with comprehensive policy packages aiming to steer economy-wide decarbonization. There are large discrepancies in terms of fiscal policies such as the inclusion of carbon pricing in the policy mix, as seen in the previous carbon price highlight.

In North America, Canada's *2030 Emission Reduction Plan* has accompanying measures to achieve sector-by-sector decarbonization. In the US, the *Infrastructure Investment and Jobs Act* (IIJA) and the *Inflation Reduction Act* (IRA) are landmark bills to address climate change. Unlike the US, Canada's decarbonization regulation combines incentives as well as disincentives (e.g. explicit carbon pricing, ICE phase-out policy). Europe has stepped up its transition efforts and all toolbox categories are in play. Plans are detailed and fiscal measures include carbon pricing and revision of the *Energy Tax Directive*. Concerned about energy industry relocation, the EU launched its *Green Deal Industrial Plan* (February 2023) to complement existing initiatives (*EU Green Deal*, *Fit for 55* package, *REPowerEU*) and enable a supportive environment for European manufacturing capacity. In OECD Pacific, South Korea's *2050 Carbon Neutral Strategy* and *Green New Deal* comprise USD 135bn in investments in both green and digital technologies. With its *Sixth Strategic Energy Plan*, Japan's government plans to invest more than USD 1trn (JPY 150trn) in decarbonization (*Green Transformation (GX) Basic Policy*). Australia's government will invest around USD 17bn (AUD 24.9bn) in decarbonization over this decade, and New Zealand's net-zero climate plan is supported by the Climate Emergency Response Fund, generated from emissions trading, and earmarked for climate spending.

The race for leadership in cleantech, in which country legislation merges industrial and decarbonization objectives, clearly adds momentum to the transition. However, trade and policy measures spiralling into country-specific modalities, and technical standards developed separately, risk jeopardizing an effective, harmonized, and global response to address climate change. A race among the deepest subsidy pockets coupled with protectionism is one that emerging economies with industrialization aspirations cannot compete in (FT, 2023). There is a risk that new, protectionist industrial policies will serve to shift decarbonization resources to the few rather than expanding them for the many. While understandable that transition spending aims to accrue primarily domestic benefits, the downside is that subsidy packages are perceived as threats to other regions' competitiveness. For example, the EU *Green Deal Industrial Plan* and relaxed *State aid* rules, are direct responses to the US IRA (see DNV's separate report on *Energy Transition North America* (DNV, 2023c). Furthermore, protectionism and retraction from multilateral trade jeopardizes the benefits of global cooperation in technology development, production and transfer, and a lack of cooperation is likely to push up technology costs, making the transition more costly for everyone.

Policy developments in medium-income regions
Greater China, South East Asia, Latin America, the Middle East and North Africa – but not North East Eurasia – are characterized by high annual growth in demand for power. Among these economies, Greater China is a front-runner in the transition. Long-term planning permeates the entire energy system with working guidance, targets, and support measures specified in five-year plans (e.g. 14th FYP 2021–2025), steering for emissions peaking in 2030 and carbon neutrality by 2060. Its overseas energy infrastructure investments, as part of the Belt and Road Initiative, are extending into Asia, Africa, the Middle East, and Latin America.

In Latin America, major economies have adopted carbon-neutrality ambitions by 2050 (Argentina, Chile, Colombia, and Brazil). Some countries have policy focused on higher renewable power penetration, export-focused hydrogen production with expanding co-financing partnerships (e.g. Europe, Japan, and South Korea), and on transport electrification. Others have no consistent public policy towards the transition, and are in fact reversing policy to favour fossil fuels (e.g. Mexico, Venezuela).

In South East Asia, Singapore is a green economy policy pioneer. Regional renewable power policies are common, in which Vietnam is a leader. Countries with plans for a coal-to-gas switch are struggling given LNG cost volatility from the international grab for gas. In general, national energy transition frameworks lack concrete implementation plans (Fallin et al., 2023). To accelerate the transition from unabated coal generation and consider net-zero commitments among many ASEAN countries, bilateral and multilateral financing will be important, such as the Just Energy Transition Partnerships with Indonesia and Vietnam.

In the Middle East and North Africa, countries are setting increasingly higher targets for renewable power deployment. Hydrogen policies focus on green and blue hydrogen, and derivatives production, also with ambitions to capture global hydrogen markets. Policies for domestic use of hydrogen demand are under development (e.g. in the United Arab Emirates and Oman). Major transition projects involve state-owned energy companies or sovereign wealth funds.

In North East Eurasia, decarbonization policy in Central Asia is in the early stages. The ongoing Russian war on Ukraine is putting the energy transition there on hold. However, renewable energy will play a key role in Ukraine's energy sector recovery, supported by the Multi-agency Donor Coordination Platform, uniting the EU, G7 countries, and international financial institutions.

Policy developments among low-income regions
The Indian Subcontinent and Sub-Saharan Africa regions have energy deficits. Broad development needs and population growth mean these regions will account for most of the world's energy demand growth in the future. The main regional agenda is energy addition while controlling emissions. The most comprehensive policy approach to energy system decarbonization is seen in the Indian Subcontinent with India prioritizing subsectors and energy areas accompanied by supportive National Mission programmes for technology development.

Sub-Saharan Africa countries have a predominant policy focus on the power system and renewable energy, though green hydrogen policy is evolving in select countries through funding partnerships with Europe (e.g. Germany and Namibia). In general there is a policy lacuna on stabilizing and building out power grids across the subcontinent – a prerequisite not only for basic energy access for millions of people but also for any substantial progress in renewable energy. South Africa has the most extensive grid in the region, but arguably one of the most problematic worldwide (Allen, 2023). Official development assistance and bilateral and multilateral financing institutions play key roles in the Indian Subcontinent and Sub-Saharan Africa regions, one example being the Just Energy Transition Partnership to help South Africa's transition away from coal. However, across these region, Europe's scramble to replace Russian gas is raising policy interest for developing regional natural gas resources, for export and domestic consumption, as well as coal.

Strenghtening and modernizing Africa's electricity grid is a key enabler of a just transition and should be a major policy focus.

How we are considering pledges in our analysis

2023 sees the first global stocktake as a key deliverable of COP28 in Dubai, in the United Arab Emirates. The process was kicked off at COP26 Glasgow (2021). It is meant to assess the collective progress of efforts to address climate change and meet *Paris Agreement* goals. Simon Stiell, Executive Secretary of the United Nations Framework Convention on Climate Change (UNFCCC) described the process as "an exercise that is intended to make sure every Party is holding up their end of the bargain, knows where they need to go next, and how rapidly they need to move to fulfil the goals of the Paris Agreement… it is a moment for course correction" (UNFCCC, 2023a).

The annual Nationally Determined Contributions Synthesis Report from October 2022 (UNCC, 2022) indicated the global collective effort to be gravely off-target. The "*Technical dialogue of the first global stocktake*" report, published in September (UNFCC, 2023b), lays the scientific and technical base for the conclusion of the first global stocktake. It summarizes 17 key findings and makes clear that there is progress but much more needs to be done (key finding 5) to reduce global GHG emissions by 43% by 2030, and 60% by 2035, compared with 2019 levels, and to reach net-zero CO_2 emissions by 2050 globally (IPCC, 2023).

In our analysis, we closely monitor pledges related to the *Paris Agreement* but do not pre-set our EETO model to achieve them. Announcements are initial steps in planning, but their achievement depends entirely on adequate policies. Most countries have inadequate short-term policies, despite the boldest pledges.

What matters for DNV's forecast is that policies are both enacted and implemented. In other words, it is target-setting and plans coupled with sectoral policies, supportive measures, and aligned finance and investment that will set the direction, scope, and pace of the transition.

In our analysis, we closely monitor pledges related to the *Paris Agreement* but do not pre-set our ETO model to achieve them.

6.5 POLICY FACTORS IN THE ETO

Our forecast factors in policy measures spanning the entire policy toolbox (Section 6.3). 12 policy considerations exert influence in three main areas:

a) Supporting technology development and activating markets, thus closing the profitability gap for low-carbon technologies competing with conventional technologies.

b) Applying technology requirements or standards to restrict the use of inefficient or polluting products/technologies.

c) Providing economic signals (e.g. a price incentive) to reduce carbon-intensive behaviour.

The policy analysis informing our Outlook ensures detailed coverage on the largest economies that combined represent 80% of total energy use of each Outlook region. We map policy documents for existing, enforceable policy/measures and indications of planned and future policy developments to assess their likely impact. Model-specific policy factors are thus derived based on policy mapping.

In deriving an ETO model-specific policy factor we take the following steps:

– consider and differentiate regional willingness/ability to implement support / subsidies

– translate country-level data into expected policy impacts, then weigh and aggregate to produce regional figures for inclusion in our analysis

Next, we detail policy factors in the analysis.

1. Renewable power support

– Renewable electricity build-out is advanced by governments in all regions, increasingly through market-led approaches such as tendering processes and auctions for certain volumes of renewable power.

– Support mechanisms guarantee the profitability of renewable generation, including: 1) investment or production tax credits (North America) for a fraction of lifetime, with support removed after 10 to 14 years or when targeted emissions (power sector) have come down 75%, and 2) Contracts-for-Difference (CFDs; two-sided or one-sided) depending on region, and reflecting regional auction strike prices.

– Energy security considerations are reflected by favouring domestically available energy sources (e.g. solar and wind, coal or natural gas, nuclear). We assume incentives in the range from 6% to 15% of the levelized cost of electricity, based on existing support levels countries provide and information available on willingness to pay for energy security. The energy sources and technologies incentivized are region dependent, reflective of resource endowments and technological know-how. Incentives are provided to nuclear and variable renewable energy sources (VRES) in Europe, OECD Pacific, and Greater China. In Sub-Saharan Africa, South East Asia, and the Indian Subcontinent incentives are provided to coal and VRES. In the Middle East and North Africa and North East Eurasia gas is incentivized. Conversely, the energy resources on which there is import-dependence are provided disincentives.

– Carbon pricing and cost of capital increase reduce the attractiveness of fossil-based generation.

2. Energy storage support (batteries)

– Existing and planned policy support is translated to an average support as a percentage of battery unit costs for battery-storage technologies.

– Support levels increase with the share of variable renewables in regional electricity generation, incentivizing investment in flexibility while reflecting regional differences in willingness/ability to implement support.

3. Zero-emission transport

- Our model reflects an average regional EV support for both battery-electric vehicles (BEVs) and fuel-cell electric vehicles (FCEVs), based on existing support at the country level.
- We account for subsidies, tax exemptions, and reduced import duties, and translate these into an average CAPEX support per region per vehicle type.
- We assume a slight initial growth and a decline in preferential treatment from the current levels thereafter. The support is capped by the EV cost disadvantage.
- We mapped Country-level targets for public fast-charging (greater than 22kW) infrastructure roll-out to identify EV uptake barriers. As charging infrastructure expands over the next decade, this is increasingly likely to be on market terms, and associated grid-infrastructure build-out will follow without constraints.

4. Hydrogen support

- On the supply-side, hydrogen infrastructure and production have projects receiving support to either CAPEX or OPEX, whichever is higher: 1) CAPEX support is estimated on the basis of total annual government funding programmes and reflected as a percentage subsidy for the capital cost of low-carbon hydrogen production routes, or 2) OPEX support, e.g. in Europe reflecting the CfDs expected from the Hydrogen Bank, and in North America reflecting the tax credit 45V (US) and Canada's investment tax credit to green hydrogen. The full subsidy remains until 2030 and is gradually halved to 2050 unless specific end-data is available. The support on the supply-side has spill-over effects for hydrogen demand in end-uses through reductions in hydrogen price.
- For the demand-side, a hydrogen-policy factor reflects CAPEX support to manufacturing and buildings but varies by region in terms of policy focus and percentage level of CAPEX, according to government funding programmes. The full subsidy remains until 2030 and is then gradually halved to 2050.
- For road transport/vehicles, the speed of hydrogen uptake is determined by a hydrogen-policy factor reflecting, among other parameters, FCEV CAPEX support including refuelling infrastructure. Examples are incentives driven by municipality-based CAPEX reduction policies for hydrogen-fuelled public buses.
- For shipping and aviation, fuel-mix shifts are driven by fuel-blending mandates and carbon pricing.
- CCS in low-carbon hydrogen production is mainly driven by regional carbon prices. The main trigger for CCS uptake will be where carbon prices are higher than the cost of CCS. In addition, regional policies providing specific support for CCS are considered to enable the initial uptake and reduce costs. This policy support will be reduced when carbon prices become high enough to sustain growth. For the North America region, blue hydrogen is supported via the 45Q tax credit (see CCS) as the 45V and the 45Q tax credits cannot be stacked.

5. Carbon capture and storage & direct air capture support

- Historical CCS implementations, and their future project pipeline of plants and storage are fully incorporated through 2030, as reported by the Global CCS Institute (2022). These projects receive investment and operational government support.
- Regional carbon prices determine the uptake of CCS in power, manufacturing, and industrial processing.
- Regional policy support for CCS beyond the carbon price is integrated based on the gap between regular CCS costs and carbon pricing to account for this gap and enable initial CCS uptake. Projects receive support reflecting government funding programmes as a percentage subsidy for the capital cost, and in the North America region reflecting the tax credit 45Q (US), which also distinguishes between capture-storage and capture-utilization. Policy support is reduced when the gap between carbon price and CCS costs is closed.
- Direct air capture support reflects recently announced funding in the North America region. In the US, the IRA (2022) increased the 45Q tax credit to USD 180/tCO_2 captured

for storage via DAC. We have implemented this in our model as subsidies in the region. A much lower level of subsidies (one sixth of that) is also assumed for Europe to reflect the European Commission's target to store up to 50 $MtCO_2$ a year by 2030, including from DAC, as well as the UK's 2023 announced funding of up to GBP 20 billion (around USD 25 billion) for CCUS applications, including for DAC.

6. Standards for energy efficiency

– Standards and regulation (existing and planned) for energy use and efficiency improvements in buildings, transport, and industry sectors are incorporated.

– Buildings: Standards for insulation against heat loss, heat gain and energy use for appliances and lighting are used as guides for setting the input assumptions. However, the policy effects are not quantified explicitly. Additionally for North America and Europe regions, higher retrofitting rates of buildings and envelopes based on subsidies and/or tax credits for insulation and weatherization of buildings.

– Vehicles: Efficiency and emissions standards per region are incorporated and translated into normalized test-cycle values (New European Driving Cycle, NEDC). An adjustment factor per region is applied to derive real-world fuel consumption from the theoretical NEDC values. The fuel-efficiency trajectories towards 2050 follow the trends determined by these real-world-adjusted standards, corrected for EV uptake.

– Shipping: IMO 2050 GHG strategy (IMO, 2023) significantly strengthened its ambition levels in 2023 and now aims for net-zero emissions from ships "at or around 2050". Enforcement mechanisms are under consideration for implementation in 2027. In the meantime, the Carbon Intensity Indicator (CII), Ship Energy Efficiency Management Plan (SEEMP), and Energy Efficiency Existing Ship Index (EEXI) are well underway, and the inclusion of shipping in the EU ETS is encouraging a fast decarbonization response from part of the global fleet. Several regional and national policy measures are driving the availability of low- or zero-emission fuel sources, although maritime will be in strong competition with other sectors to access them. Hence the importance of efficiencies, especially those that are digitally enabled, at vessel and fleet level for the industry to meet the IMO ambition levels.

7. Bans, phase-out plans and mandates

– Bans on ICE vehicles are not incorporated in the forecast, but model results are compared with announced bans.

– Phase-out plans on nuclear power are incorporated. For coal-fired power generation, our forecast references the phase-out plans. However, due to market economics and reduced cost-competitiveness, shutdowns might happen earlier than phase-out plans suggest.

– Regional biofuel-blend mandates currently in place are considered and we foresee further strengthening of these in front-runner regions such as EUR and NAM. Mandates will likely be enhanced in the future to include other sustainable aviation fuels (SAFs).

– Region-specific pushes both from business and from individuals that are willing to pay for sustainable aviation will enable a gradual increase in uptake of uncompetitive (on cost) aviation fuels such as hydrogen and SAFs.

8. Carbon pricing schemes

– Our carbon-price trajectories (Figure 6.3) are reflected as costs for fossil fuels in manufacturing and buildings, and in power, hydrogen, ammonia, and methanol production where progressive participation in the same regional and/or sectoral carbon-pricing schemes is assumed. Some regions (CHN, EUR, NAM, OPA) are projected to reach carbon-price levels in the range of USD 20 to 150/tCO_2 by 2030 and USD 56 to 250/tCO_2 by 2050. Across all 10 regions, carbon pricing by mid-century is projected to range between USD 20/tCO_2 (NEE and SSA) and USD 250/tCO_2 (EUR).

– Carbon-price exemptions: We have reflected carbon-price exemptions available to many industries and lack of carbon prices in jurisdictions inside our regions. For Europe, we assume exemptions to be removed by 2034 in line with EU policies. For North America, manufacturing sector carbon prices apply roughly to 50% industries on average throughout our forecast horizon.

TAX

9. Taxation of fuel, energy, carbon and grid connections

- Fossil fuels used in road transport are taxed at the consumer level, labelled as fuel or carbon taxes.
- Effective fossil-carbon rates are incorporated in fuel prices for road transport, with taxation highest in Europe, and the rate showing increase in regions with taxation. Regions North East Eurasia, South East Asia, and the Middle East and North Africa, are estimated to have fossil-fuel subsidies.
- We assume that these taxes will increase in line with a region's carbon-price regime, rising at a quarter of the carbon-price growth rate.
- Energy tax rates incorporated for other demand sectors (buildings, manufacturing) encourage switching from fossil fuels to electricity and hydrogen. Electricity taxation declines in high-tax regions to enable electrification of end-use sectors. In order to support hydrogen uptake, hydrogen is expected to be exempt from energy taxation through to 2035 in all regions. In regions prioritizing domestic use of hydrogen, the tax exemption has a phase-out profile, with hydrogen increasingly facing tax levels similar to those applied to the region's future industrial electricity to assure a harmonized energy taxation system.
- Taxes and grid tariffs for grid-connected electrolysers are assumed to be a 25% surcharge over the wholesale electricity price.
- Taxes on electricity for transport are calculated from the share of charging types and their prices compared with the residential price, and applied in regions, except those with negative taxation on fuel use (i.e. fossil-fuel subsidies).

10. Air pollution intervention

- Policy interventions are reflected by an air-pollution cost proxy that transfers costs of control measures to an operating cost per kWh, incorporated in power and manufacturing sectors.
- A regionally dependent ramp-up rate is used, going from 0% to 100% implementation of the operating cost over a certain period, indicating that regulations will be gradually enforced on more and more pollutants and plants.

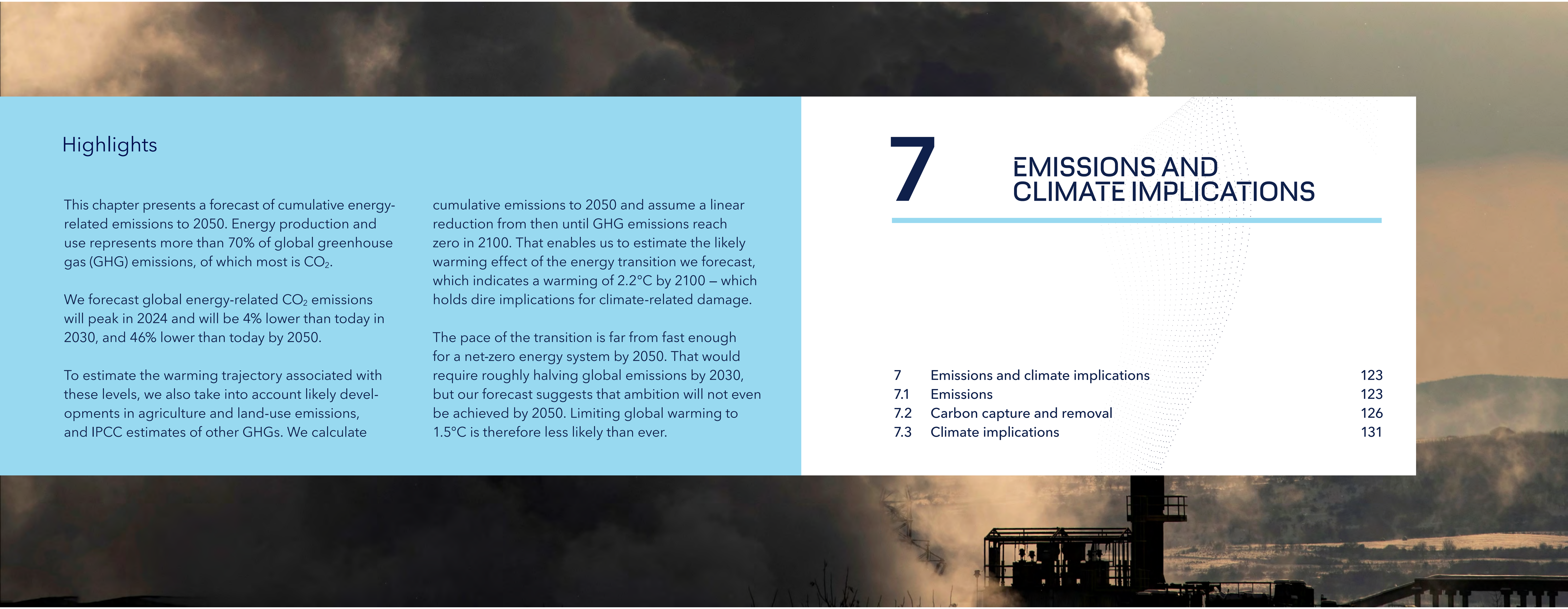
11. Plastic pollution intervention

- Policy interventions on plastics, such as mandated recycling, taxes on unrecycled plastic, trade restrictions, and extended producer responsibilities are incorporated in the form of recycling rates and an effect of reduction and substitution on demand.
- The projected recycling rates (mechanical and chemical) and the effect of reduction and substitution builds on the *Reshaping Plastics* report for Plastics Europe (Systemiq, 2022), assuming that the most-likely future policy interventions correspond to those in the Circularity scenario (a combination of the 'Recycling' and Reduction & substitution' scenarios). Among the regions, EUR is expected to be a front-runner and the other ETO regions are assumed to follow with delays ranging from 5 to 15 years.

CH_4

12. Methane intervention

- Methane intervention and abatement, such as that which results from the Global Methane Pledge (launched at COP26, 2021, promising at least 30% reduction from 2020 levels by 2030) are incorporated. Partial energy-sector reductions are achieved as a result of carbon prices deployed against methane abatement technologies and their marginal costs. Additionally, for North America, increased methane fees induce greater methane abatement.



7 EMISSIONS AND CLIMATE IMPLICATIONS

Highlights

This chapter presents a forecast of cumulative energy-related emissions to 2050. Energy production and use represents more than 70% of global greenhouse gas (GHG) emissions, of which most is CO_2.

We forecast global energy-related CO_2 emissions will peak in 2024 and will be 4% lower than today in 2030, and 46% lower than today by 2050.

To estimate the warming trajectory associated with these levels, we also take into account likely developments in agriculture and land-use emissions, and IPCC estimates of other GHGs. We calculate cumulative emissions to 2050 and assume a linear reduction from then until GHG emissions reach zero in 2100. That enables us to estimate the likely warming effect of the energy transition we forecast, which indicates a warming of 2.2°C by 2100 – which holds dire implications for climate-related damage.

The pace of the transition is far from fast enough for a net-zero energy system by 2050. That would require roughly halving global emissions by 2030, but our forecast suggests that ambition will not even be achieved by 2050. Limiting global warming to 1.5°C is therefore less likely than ever.

7 EMISSIONS AND CLIMATE IMPLICATIONS

In this chapter, we chart how energy-related emissions will almost halve (-46%) between now and 2050, once they have peaked in 2024 at 34 $GtCO_2$. We then estimate their climate impact in conjunction with other greenhouse gas emissions. To arrive at derived levels of global warming by 2100, we also take into account an extrapolation of remaining emissions after 2050 – i.e. beyond our forecast window. We find that the world is on track to experience 2.2 degrees of warming by the end of this century.

Over 70% of the annual greenhouse gas (GHG) emissions related to human activities come from the energy sector. Most of these emissions result from burning fossil fuels. While carbon dioxide (CO_2) makes up the bulk of these emissions, methane (CH_4) is also a significant GHG, particularly in projections of future climate impacts.

In this chapter, we present an estimation of global CO_2 emissions linked to the energy sector up to 2050, based on the ETO forecast. By integrating these estimates with non-energy-related CO_2 emissions (e.g. those stemming from industrial processes and land-use) and projected energy emissions post-2050, we can deduce the total cumulative emissions. With CO_2 concentration levels thus derived, we can calculate the anticipated global climate response, especially in terms of average global temperature elevation. In addition to our projections for CO_2 emissions from the energy sector, we also incorporate potential trends in emissions from agriculture and land-use (significant contributors to both CO_2 and CH_4 emissions).

Subsequently, we examine the potential climate ramifications. Additionally, we shed light on CH_4 emissions originating from the energy sector, along with projections associated with shifts in the energy infrastructure.

It should be noted that our assessment does not delve into specific climate effects such as flooding, droughts, or forest fires. Instead, our focus remains on the overarching average temperature rise correlated with our forecasted cumulative CO_2 emissions.

The effects of COVID-19 resulted in energy-related CO_2 emissions dropping by approximately 7% in 2020, a reversal unprecedented in recent history. But as economic activity picked up, so too did energy use and emissions.

7.1 EMISSIONS

Emissions from energy-related activities have grown in step with a growing population and GDP. Of the cumulative energy-related emissions added to the atmosphere since the start of the Industrial Revolution, around 1850, it is estimated that 50% have been added to the atmosphere in the last 50 years (Buis, 2019).
In 2014, a plateau seemingly started with emissions staying flat for several years. However, in 2018 they started to grow again. The effects of COVID-19 resulted in energy-related CO_2 emissions dropping by approximately 7% in 2020, a reversal unprecedented in recent history. But as economic activity picked up, so too did energy use and emissions.

The anticipated bounce back of emissions after the pandemic has been quicker than we originally

anticipated and by 2022 the emissions were at the same levels as the previous peak year in 2019. Russia's invasion of Ukraine has further disrupted the energy transition, with the net effect of a slight increase in emissions in the coming years as countries shift focus from decarbonization to securing the supply of energy, which in many regions means increased coal use or temporarily running oil-based electricity generation (aided by the possibility of price-capped or discounted Russian oil exports). Based on global energy demand, annual energy-related CO_2 emissions rose to 33.4 $GtCO_2$ in 2022 and we expect emissions to peak now by 2024 at 34 $GtCO_2$ before declining gradually to 32.1 $GtCO_2$ in 2030, only slightly lower than 2019 (i.e. pre-COVID-19). By mid-century, energy-related emissions are expected to be 18.1 $GtCO_2$ per year, 46% less than in 2022 (Figure 7.1).

Figure 7.1 shows coal is today's main contributor (43%) of energy-related CO_2 emissions, followed by oil (31%) and natural gas (25%). Emissions of CO_2 from coal will see the strongest decline (61%) between 2022 and 2050.

Emissions from oil will decrease by 45% in that time, whereas those from natural gas grow towards 2027 and then drop to 75% of today's emissions by 2050.

Sector emissions

The power sector is currently the largest contributor to energy-related CO_2 emissions: 13.4 Gt in 2022, 40% of all energy-related emissions that year. The transport sector made up 25% (8.5 $GtCO_2$) of the total, while manufacturing accounted for 19% (6.3 $GtCO_2$). The rest is made up of buildings emissions and the energy sector's own use.

In 2050, the power sector will remain the biggest emitter (30%), but with annual emissions reduced to 5.4 $GtCO_2$. Transport's share will increase to 26% by then, but in absolute terms its emissions will reduce to 4.8 $GtCO_2$.

Emissions from manufacturing decline to 4.2 $GtCO_2$ (23%) as seen in Figure 7.2. The dynamics behind these emission reductions are summarized as follows:

– **The power sector** shows the fastest sectoral decarbonization to 2050. Solar and wind will make up the majority of the added capacity towards 2050. This, combined with retirement of fossil thermal power plants and expansion of nuclear, will reduce emissions from power generation significantly. In some regions, fossil plants will be fitted with CCS which will also contribute to a 60% reduction in power sector emissions from today to 2050.

FIGURE 7.1

World energy-related CO_2 emissions by fuel source

Units: $GtCO_2$/yr

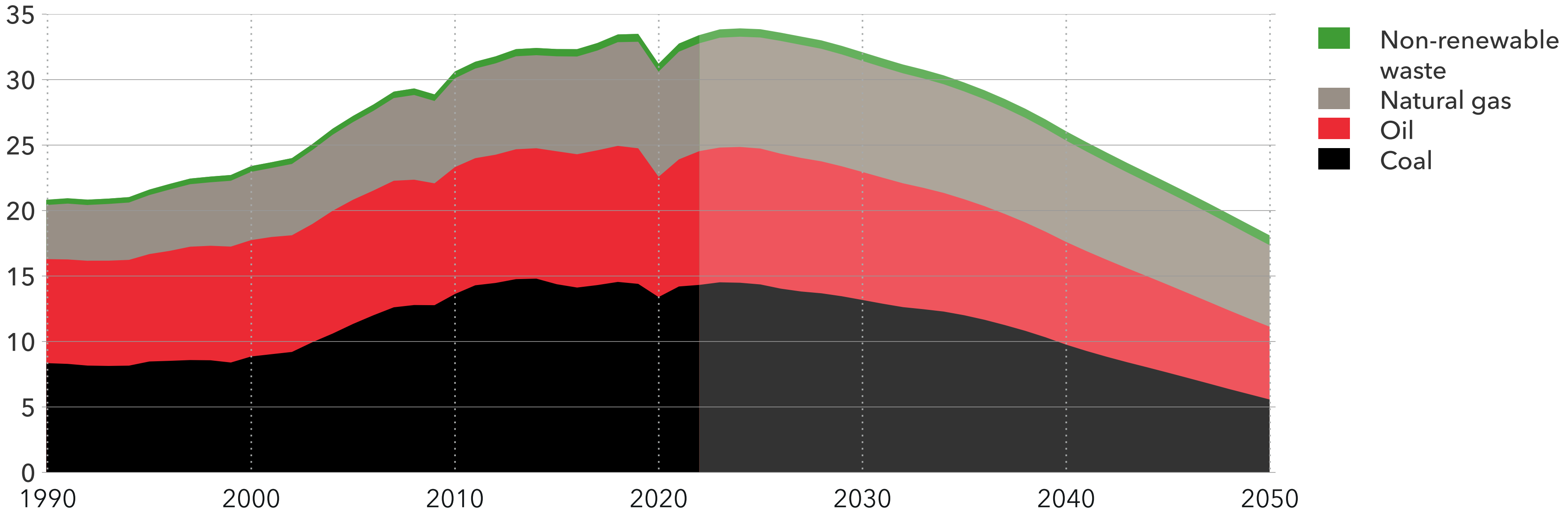
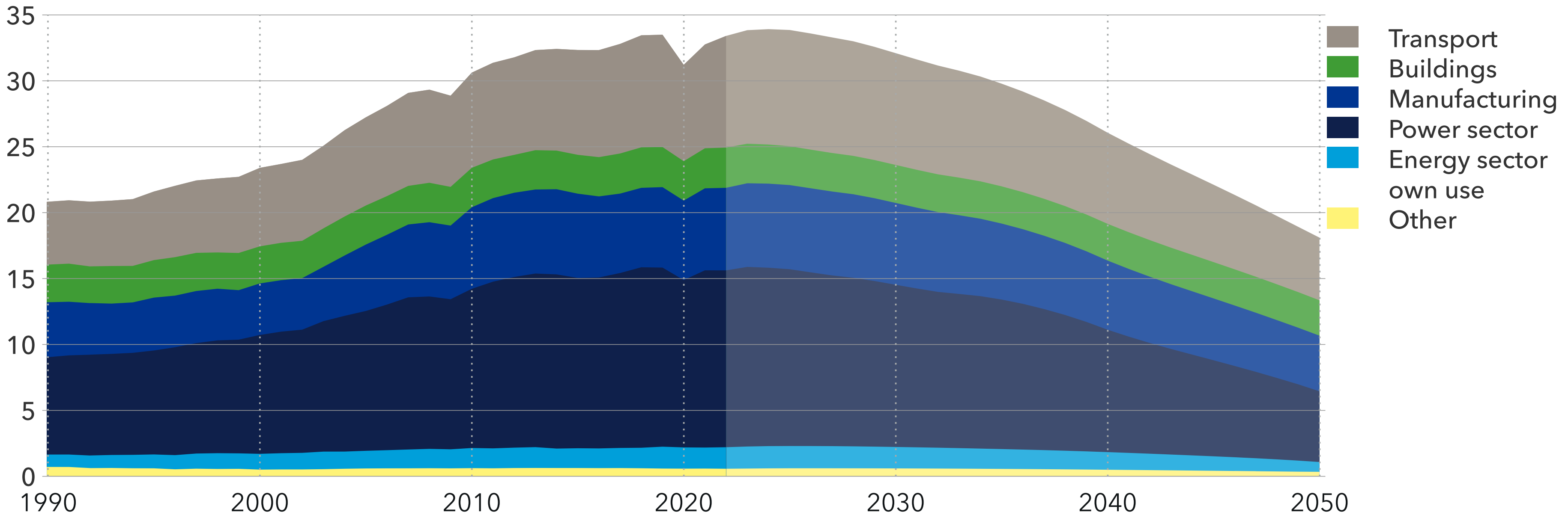


FIGURE 7.2

World energy-related CO_2 emissions by sector

Units: $GtCO_2$/yr



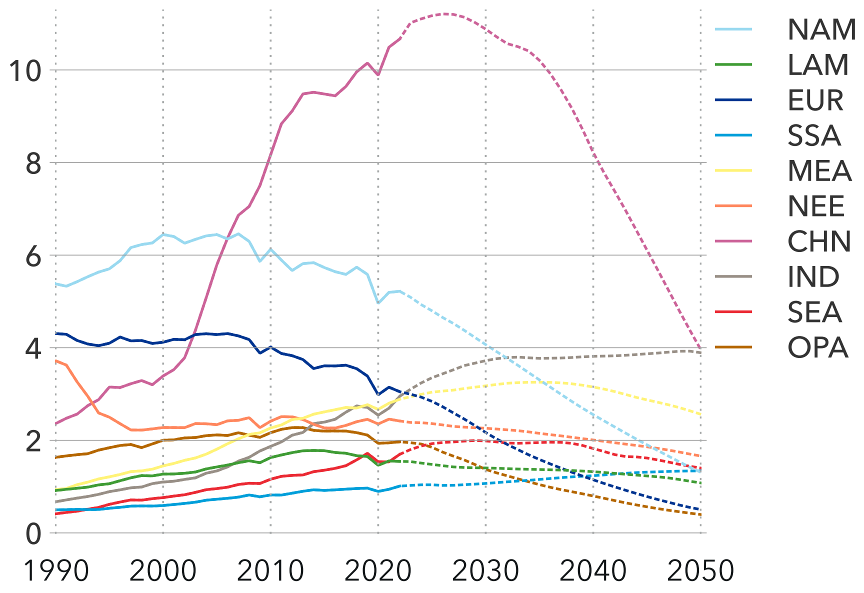
Emissions from hydrogen production is allocated to own-use sector.

– The transport sector saw a sharp decline in emissions in 2020 due to the COVID-19 pandemic. In the longer term, the defining trend of road transport electrification will result in emissions declining 44% by 2050. The electricity powering EVs will increasingly be coming from renewables, enabling EVs to operate in a zero-emission mode. However, it is only by the mid-2020s that overall transport emissions start to decline. This is because even though the growing number of EVs reduce emissions, the effect is initially countered by transport growth and a lack of emission reductions in shipping and aviation.

FIGURE 7.3

Energy-related CO_2 emissions by region

Units: $GtCO_2$/yr



Historical data source: IEA WEB (2023)

– The manufacturing sector emissions will decline steadily over the whole forecast period with electrification, fuel-switching, and (CCS). However, replacing fossil fuel sources for some applications, especially for high heat process, is likely to prove too difficult or expensive – hence total emissions will decline by only third towards mid-century.

– The buildings sector direct emissions see only a limited decline due to a significant growth in the number of commercial and residential buildings. Continuous improvements in energy efficiency and switching to cleaner sources of fuel for heating (e.g. electricity combined with heat pumps) will be the main reasons behind an overall decline of 12% despite a large growth in floor space.

Regional emissions

Our 10 Outlook regions have different starting points and very different emission trajectories over the forecast period. Greater China, currently the largest emitter by far, will reach peak emissions before 2030; its emissions will then decline to mid-century, when they will be 63% less than in 2022.

The Indian Subcontinent will continue to grow its emissions towards 2050, initially very rapidly, but then plateauing by the mid-2030s and ending 32% higher in mid-century than in 2022. Sub-Saharan Africa will show an increase of 33% compared with 2022. As Figure 7.3 displays, all other regions will reduce their energy-related emissions, led by Europe (-83%), OECD Pacific (-80%) and North America (-75%). North East Eurasia will have the highest emissions per capita at 5.0 tonnes in 2050, followed by North America and the Middle East and North Africa at 3.3 tonnes per person (see graphic on Energy, GDP and population, Section 8.12). We describe regional emissions in more detail in Chapter 8.

Process-related emissions

In addition to CO_2 emissions from combustion of fossil fuels, there are significant emissions from industrial processes that either consume fossil fuels as raw material for feedstock (e.g. plastics and petrochemical products) or through processes that produce CO_2 through a chemical reaction (e.g. cement and other industrial processes). These process-related emissions, together with estimates of the subsequent capture of some of these process emissions, are included in our analysis as part of the manufacturing sector. In 2022, these emissions were an estimated 3.8 $GtCO_2$, of which almost half were from calcination in the cement-production process. The remainder of the emissions were from ammonia production and small shares from coke ovens and the production of lime or other chemicals.

We expect a slight rise in construction and industrial growth, which largely drives process emissions, over the next 10 years, and then a stabilization. However, while output might stabilize at a higher level than today, improvements in production and technical efficiencies, combined with increasing shares of these emissions being captured, mean that the resulting emissions level will decline towards 2040, and fall even more quickly in the decade to year 2050. In mid-century, process-related industrial emissions will be 20% less than today.

Land-use emissions

CO_2 emissions from AFOLU (agriculture, forestry, and other land-use) are not included in our forecast and modelling, but at 4 $GtCO_2$ per year they are greater than Europe's emissions. Therefore, these emissions are substantial enough to warrant inclusion of land-use emissions when considering global CO_2 emissions, especially when considering the climate implications. Emissions from land-use have been growing slowly over the last 20 years, historically averaging 5 $GtCO_2$ per year, but with large annual fluctuations. Most recent research has adjusted land-use emission down slightly from the historical average. Even incorporating last year's forest fires, the latest such estimate shows a slight decline to 3.9 $GtCO_2$ per year in 2021 (Global Carbon Budget, 2022).

There is currently considerable uncertainty about changes in future land-use, as some countries with large forest areas are losing them at double-digit percentage rates compared with previous years, most of them due to non-fire related losses, but increasingly due to forest fires (Global Forest Watch, 2022). Taking this uncertainty into account, we expect that climate and sustainability concerns will eventually affect policy, creating pressure to control land-use changes. Thus, our best estimate is that annual CO_2 emissions from land-use changes will slowly decline towards 3 Gt in 2030, and then reduce linearly to 2 Gt in 2050, almost 40% less than today's annual levels.

7.2 CARBON CAPTURE AND REMOVAL

Carbon capture and removal can help reduce CO_2 emissions from sectors that continue to use fossil fuels. Carbon capture refers to the separating and capturing of CO_2 from sources with high-concentration, such as in flue gases of fossil-fuelled stations and heavy industries (e.g. cement or petrochemicals). Carbon removal refers to the process of removing CO_2 in low concentrations from the atmosphere. In both cases, the captured or removed CO_2 can be either utilized for producing value-added products (such as e-fuels or fizzy drinks)[1], or transported and stored in geological or marine reservoirs. Thus, carbon capture and storage (CCS) is a method of countering and reducing industrial emissions, whereas direct air carbon capture and storage is a negative emission technology.

Today, CCS is primarily applied as part of enhanced oil recovery, where there is a viable business case. Total commercial CCS capacity by September 2022 was 43 $MtCO_2$ per year, with an additional 200 $MtCO_2$ per year either in construction or in various stages of development (GCCSI, 2022). Going forward, we expect that operators of large point sources in the power and manufacturing sectors will increase the capture of carbon from their processes and waste streams. Additionally, we expect all carbon emissions from hydrogen production as an energy carrier to be captured in the steam methane reforming (SMR) process, and we foresee capture of an increasing share of emissions associated with hydrogen production for feedstock. Some capture is also expected when flaring occurs during natural gas processing.

> For all the existing and announced policies on CCS, its uptake will be very limited in the near- to medium-term, and effectively too late and too little in the longer term.

However, for all the existing and announced policy on CCS, its uptake will be very limited in the near to medium term, and effectively too late and too little in the longer term. It is only in the 2030s, when carbon prices start to approach the cost of CCS, that uptake accelerates and deployment at scale begins. In 2050, we find emissions captured by CCS to be 1.2 $GtCO_2$.

In the near term, the largest contributor to CCS will remain the natural gas processing industry, with a share of about 40% in global CCS by 2025.

1. In the ETO, we only model carbon capture, transportation and storage. Utilization of the captured carbon lies outside the boundaries of our model.

The Drax Power Station in the UK showing biomass storage tanks and carbon capture capabilities.

Globally, we expect only about 6% of remaining emissions to be captured by 2050, demonstrating the need for a significantly faster uptake of carbon capture and storage to get us closer to net-zero emissions by 2050.

In the near term, power generation will also account for a significant share of CCS (12.5% in 2025), but this will continually decrease in importance with the increasing uptake of renewables in power generation.

Going forward, CCS will grow most rapidly in the production of hydrogen and its derivatives. By 2050, by far the largest single contributor to CCS uptake will be ammonia production. Ammonia synthesis is the largest carbon dioxide emitting chemical industry process, accounting for about 1.8% of global carbon dioxide emissions (The Royal Society, 2020). Almost all the hydrogen used in ammonia production today is produced from fossil fuels, primarily from steam methane reforming (GCCSI, 2022). By 2050, we forecast that nearly half of all global CCS, around 580 $MtCO_2$ per year, will be in ammonia production. Similarly, the production of e-fuels, such as e-methanol as energy carrier, will be the second most important contributor to CCS uptake with a share of 14% by 2050, with the production of hydrogen itself contributing another 10%. In total, the production of hydrogen and its derivatives (including ammonia and e-fuels) account for nearly three-quarters of CCS by 2050, with the rest originating from various high heat industries.

Which of the sectors that will demonstrate more CCS deployment is reflective of the costs of the technology for a given application. Today, the cost of CCS for all applications is prohibitively high, owing to a large extent to the energy penalty incurred by the capture process (Figure 7.5), with natural gas processing and direct heat production at the lower end (USD 36-67/tCO_2 avoided) and most of manufacturing processes and e-fuels production at the higher end (USD 190-230/tCO_2 avoided) of the costs range globally. By 2050, natural gas processing and direct heat production will still have the lowest CCS costs (USD 30 and 42/tCO_2 respectively), while the costs of more expensive applications in manufacturing (production of plastics, base materials, cement, and construction and mining) and e-fuels production will decline towards USD 75 to 150/tCO_2 globally due to learning.

By 2050, the regions with the highest remaining emissions are expected to be Greater China and the Indian Subcontinent, each with about 4 billion tonnes of CO_2 emissions per year remaining. These regions, however, are expected to contribute little to CCS, each capturing less than 2% of their total remaining emissions. CCS development is thus not happening at sufficient speed or scale to make a significant impact in reducing emissions in these major carbon-emitting regions. At the other end of the spectrum, Europe is expected to capture nearly 200 million tonnes out of a total 700 million tonnes, or in other words nearly 30%, of its remaining emissions by 2050, enabled by the highest carbon prices expected among our ETO regions. Globally, however, we expect only about 6% of remaining emissions to be captured by 2050, demonstrating the need for a significantly faster uptake of CCS to get us closer to net-zero emissions by 2050.

FIGURE 7.4

Energy-related CO_2 emissions captured by sector

Units: $MtCO_2$/yr

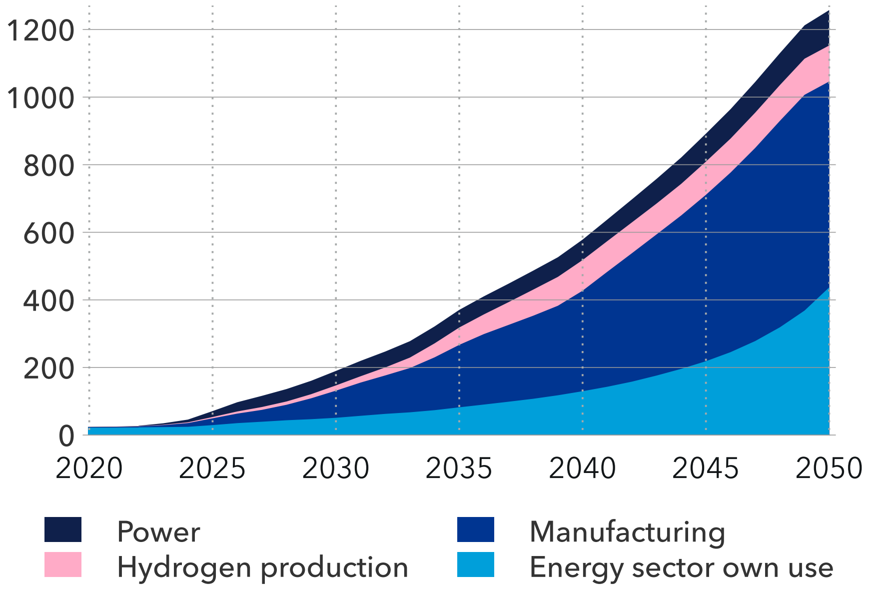
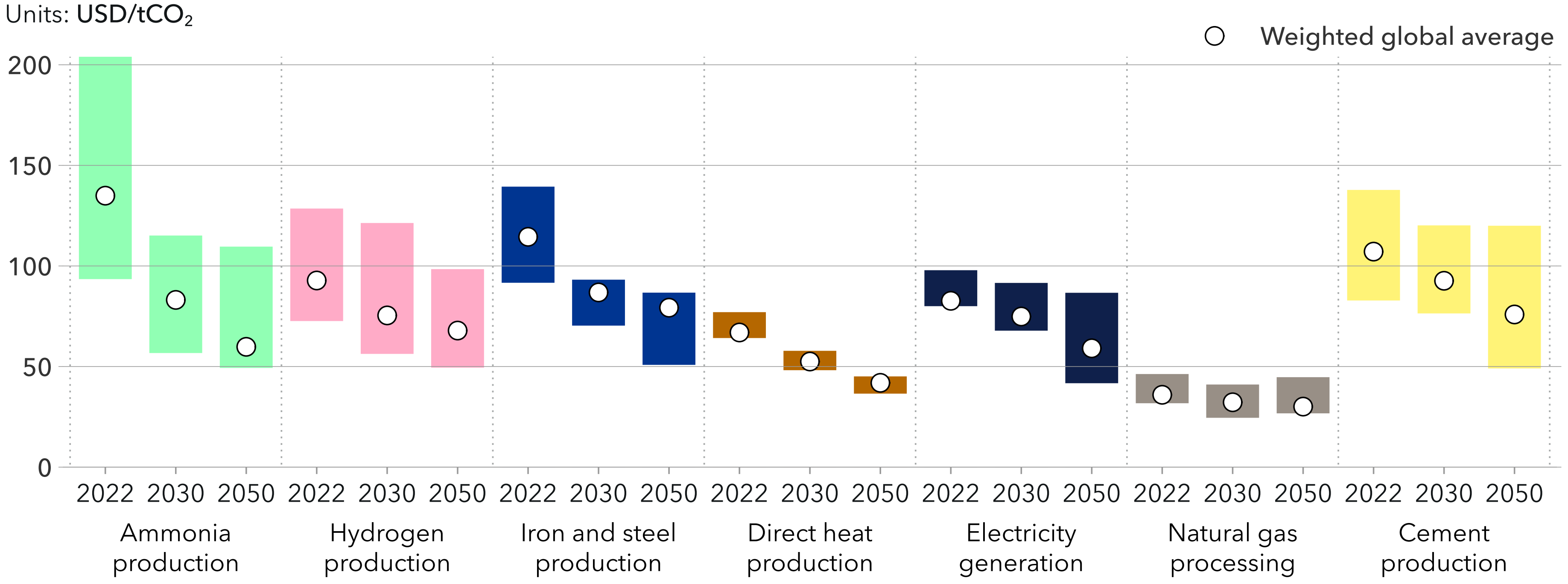


FIGURE 7.5

Cost of carbon capture and storage for selected sectors

Units: USD/tCO_2



Direct Air Capture

Direct air capture (DAC) refers to the process of removing CO_2 in low concentrations from the atmosphere. The CO_2 can be permanently stored in deep geological formations or used in commercial applications. This means that DAC+S (direct air capture plus storage, also referred to as direct air carbon capture and storage – DACCS – or carbon dioxide removal, CDR) is a negative emission technology that can be used for offsetting emissions from other sectors (such as aviation). DAC, however, is still an emerging technology that is prohibitively expensive to be deployed at scale. Capturing and removing CO_2 in low concentrations in the atmosphere (over 100 times more dilute than in the flue gas from a gas-fired power plant) is intrinsically energy- and equipment-intensive. Today, the only commercial operating DAC projects are the two facilities built by the company Climeworks in Switzerland and in Iceland, removing a total of about 0.005 $MtCO_2$/yr – a negligible share of over 33 billion tonnes of global energy-related emissions today. Other pilot projects, such as one by Climate Thermostat in the US or another one by Climate Engineering in Canada, are in partial operation, but the CO_2 removed from the air in these facilities is not always stored.

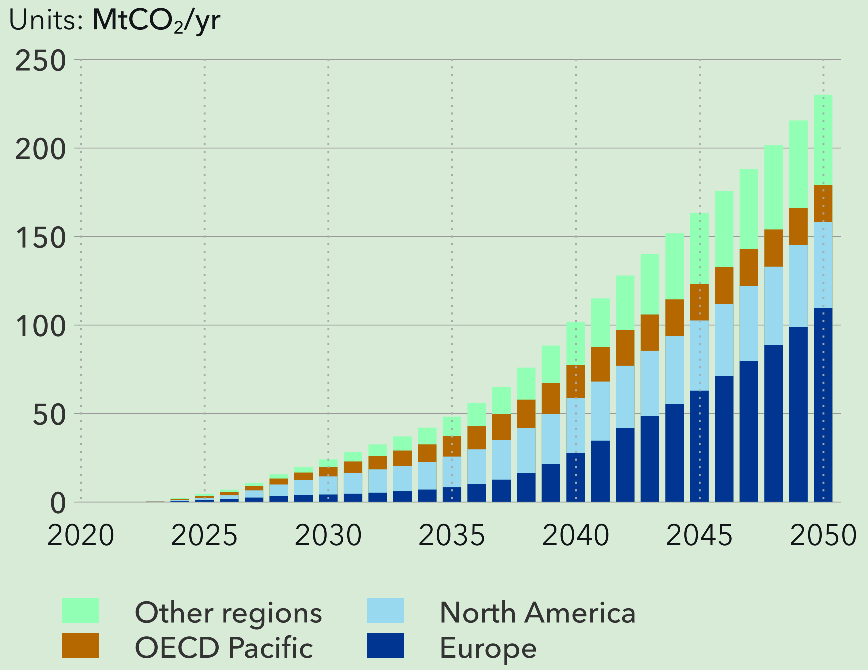
In terms of the future prospects for DAC, over 130 DAC facilities are now at various, but mostly very early, stages of development (IEA, 2023d). Companies operating in this field have made ambitious announcements, such as a target of one million tonnes CO_2 removal capacity by 2030 set by the pioneering company Climeworks. The company is expected to operationalize a 0.036 $MtCO_2$/yr facility called Mammoth by 2024 in Iceland. In the US, the company Carbon Engineering (recently acquired by 1PointFive) is developing what they expect to be the world's largest DAC facility, with an expected capture capacity of 0.5 $MtCO_2$/yr by 2025, and plans to scale up to 1 $MtCO_2$/yr. Various regions and countries, including the US, Canada, the EU, the UK, and Japan have set different targets for carbon capture and removal, including via DAC. Considering announced ambitions along with present-day realities, we foresee CO_2 emissions removed via DAC to reach up to about 12.5 million tonnes per year by 2030, focused primarily in North America (thanks to the tax credit support envisioned in the *US Inflation Reduction Act*[2]) as well as in Europe, the other pioneering region in DAC. As a point of reference, this level of carbon capture was achieved in 2010 by the now more established CCS technology, representing a 20-year lag between DAC and CCS. In the longer term, we expect that DAC will contribute to removing just above 200 $MtCO_2$/yr by 2050.

As an emerging technology, it is expected that the costs of DAC will drop substantially over the coming decades[3] as more nations and corporate entities recognize the vital role of negative emission technologies in enabling a net-zero future. However, given the prohibitively high costs at present, scaling up at the rate required for the cost learning curves to drive costs down to commercially viable levels still needs substantial policy support or voluntary corporate social responsibility-motivated support. It is also worth noting that DAC will be in competition with other negative emissions technologies, chief among which is bioenergy with CCS (BECCS) which, where available, is more established and less expensive. Innovation in CO_2 use, including synthetic fuels, could drive down costs and provide a market for DAC, and major companies such as 1PointFive are already exploring these opportunities.

DAC shows great promise for decarbonization after 2050 but will not scale fast enough to make a meaningful difference to emissions before then. It is nevertheless an exciting niche and very meaningful at the scale of individual companies. We note that any pathway to net zero by 2050 will have to accelerate DAC technology enormously to offset remaining emissions from hardest to abate sectors (e.g. aviation).

FIGURE 7.6

CO_2 emissions captured by Direct Air Capture (DAC)



Direct air capture shows great promise for decarbonization after 2050 but will not scale fast enough to make a meaningful difference to emissions before then.

2. See DNV's recently published report on the *Energy Transition Outlook in North America* (DNV, 2023c).
3. In the ETO model, we have assumed a cost learning rate of 4.5% for DAC, which means that we expect the technology costs to drop by 4.5% with every doubling of cumulative global installed capacity. Due to the inherently energy- and equipment-intensive nature of the technology, this learning rate is significantly lower than what we have assumed, for instance, for CCS (point-source carbon capture) at 13%.

Methane emissions

Methane (CH_4) is the second largest GHG contributor to global warming after CO_2. 30% of the rise in global temperatures since the Industrial Revolution is due to doubling the concentration of CH_4 in the atmosphere. Two key characteristics determine the impact of different greenhouse gases on the climate: the length of time they remain in the atmosphere and their ability to absorb energy. Methane has a much shorter half-life (12 years) than carbon dioxide. However, methane is a more potent GHG than CO_2 per tonne of GHG emitted: 29.8 times more potent over the 100-year Global Warming Potential (GWP) time horizon and 82.5 times so in a 20-year GWP perspective (IPCC, 2021).

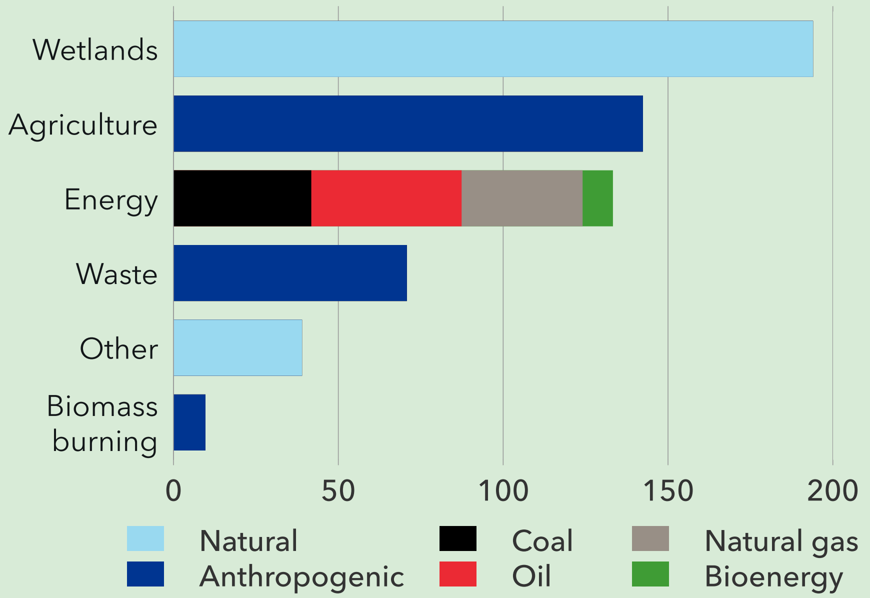
According to the Global Monitoring Laboratory (GML), the 2022 methane increase was 14.0 ppb, the fourth-largest annual increase recorded since NOAA's systematic measurements began in 1983, and follows record growth in 2020 and 2021. As shown in Figure 7.1, on average, 40% of methane emissions are from natural sources and the rest from anthropogenic emissions, driven by the agricultural sector (40%), followed closely (37%) by the energy sector and the rest from waste and burning biomass (IEA, 2023e).

According to the IEA Global Methane Tracker, total anthropogenic CH_4 emissions in 2022 were estimated at 356 Mt (IEA, 2023e). When converted to their CO_2 equivalent value using 100-year GWP, that amounts to 10.6 $GtCO_2eq$, which is a little less than a third of the global CO_2 emissions from the energy sector. This is not an insignificant amount, especially given that mitigating involuntary CH_4 emissions is fiscally expedient as it may be used as energy, thus fractionally reducing the need for extraction. In the first quarter of 2023, preliminary numbers from GML suggest that anthropogenic CH_4 emissions have increased in 2023 compared with 2022 (March 2023: 1920.74 ppb vs March 2022: 1908.97 ppb), our results also show a 3% increase in energy-related CH_4 emissions from fossil fuels.

FIGURE 7.7

Sources of methane emissions in 2022

Units: $MtCH_4/yr$



Adapted from IEA Global Methane Tracker (2023)

Global Methane Pledge

The *Global Methane Pledge* (GMP) was launched in 2021 and signed by 149 countries who account for 45% of total anthropogenic CH_4 emissions. It aims to reduce global anthropogenic methane emissions by 30% in 2030 compared to 2020 levels. However, the Pledge does not specify the contribution of countries or methane-emitting sectors (fossil fuel production, agriculture, and waste) to achieve this global goal (Global Methane Pledge, 2021). Despite its very good intentions, the Pledge has obvious drawbacks. One is that several countries with large CH_4 emissions, such as the Russian Federation, China, Kazakhstan, and Venezuela, among others, are conspicuously absent from it. Second, while the GMP puts forward a global target, it does not disaggregate the easier-to-abate sectors from the total emissions; such sectors include, among others, fossil-fuel extraction and use, where abating CH_4 emissions has a negative cost, or a net monetary benefit.

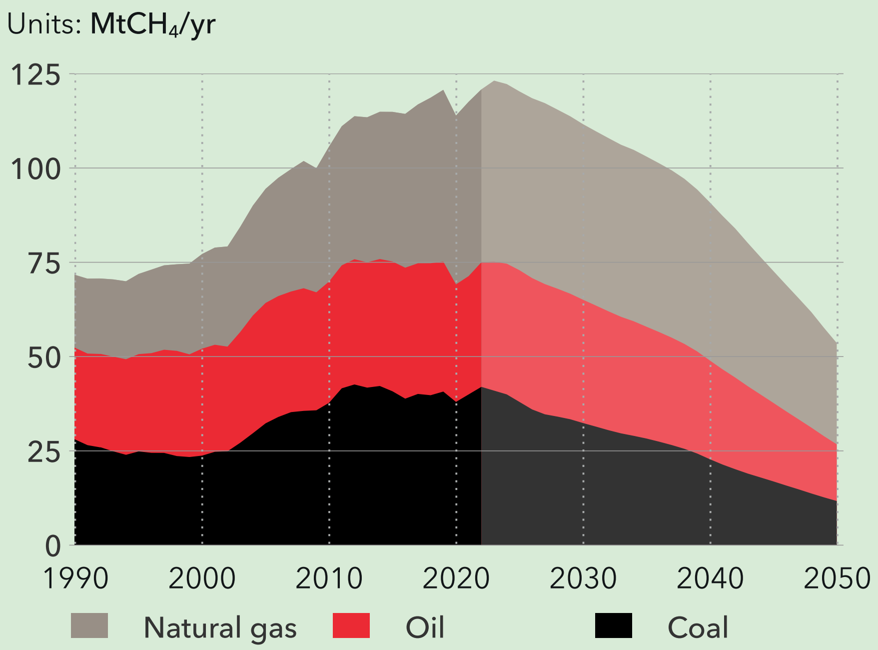
Methane emissions from fossil fuels

In our Outlook, we present the CH_4 emissions from the coal mining process and from oil and natural gas extraction, transmission, and distribution. Historical data on CH_4 emissions from all fossil fuels are obtained from EDGAR, the Emissions Database for Global Atmospheric Research (EC-JRC-PBL, 2021). The resulting emissions are projected based on activity levels of oil and natural gas production by field type (conventional onshore, offshore, and unconventional), and coal production. For oil and gas CH_4 emissions, we also separate the CH_4 emission mechanisms, namely vented, fugitive, and incomplete flaring.

Our projection indicates that the world will fail to meet the *Global Methane Pledge* by 2030, at least in terms of CH_4 emissions from fossil fuels. The CH_4 emissions from fossil fuels are 118 Mt per year in 2030, even 3% more than the 115 Mt emitted in 2020 (Figure 7.7). We project CH_4 emissions of 97 Mt per year in 2040, 16% less than in 2020. By mid-century, CH_4 emissions will be half of what they were in 2020, primarily thanks to the reduction in demand for coal and oil. In 2022, CH_4 emissions from natural gas were 40% of the total emissions, with coal and oil having respectively shares of 31 % and 29%, respectively (Figure 7.8), but we estimate these shares will change gradually, with coal CH_4 emissions seeing a very large reduction due to the demand reduction. By mid-century, half of the methane emissions from fossil fuels will be due to the extraction, transmission, and distribution of natural gas, with oil contributing 28%, and coal 22%.

FIGURE 7.8

Methane emissions from fossil fuel by source



Historical data source: EDGAR (2022)

Why only CO_2 and CH_4?

Other greenhouse gases, such as NOx, HFCs, and CFCs, are more potent climate gases (measured in GWP per tonne of gas emitted) and more persistent than both CO_2 and CH_4. However, we do not consider these in our report. There are two main reasons for this. First, the energy sector is not a significant contributor to these emissions. Second, the quantities of these gases are low despite their high potency. Thus, these emissions could potentially be much more easily reduced through regulation and are not correlated with our energy systems model.

By mid-century, CH_4 emissions will be half of what they were in 2020, primarily thanks to the reduction in demand for coal and oil.

7.3 CLIMATE IMPLICATIONS

Our forecast gives future levels of CO_2 emissions per year and enables us to determine the corresponding climate response and its associated temperature increase. We focus only on first-order effects and do not include possible tipping points and feedback loops, such as melting permafrost and peat fires, which would accelerate global warming. Other climate implications, including those directly associated with emissions (e.g. acidification of the oceans) and indirect consequences such as sea-level rise, are not dealt with in this Outlook which concentrates on the energy transition and its associated CO_2 emissions.

CO_2 concentration

The concentration of CO_2 in the atmosphere is measured as parts per million (ppm). Pre-industrial levels were around 280 ppm (Global Carbon Project, 2020), and emissions related to human activities, particularly burning fossil fuels, have resulted in a significant increase. The most recent reading, in June 2023 was again another record level of 419.51 ppm (NOAA GML, 2023). Over the last 60 years, there has been an increase in the concentration of over 100 ppm, which is of the same magnitude as the entirety of shifts observed over the previous 800,000 years (IPCC, 2021).

We forecast a continuation of CO_2 emissions to the atmosphere linked to human activities, albeit at a decreasing rate. In contrast to methane, which on average oxidizes after approximately 12 years (IPCC, 2001), it takes hundreds to thousands of years for CO_2 to disappear naturally from the atmosphere (Archer et al., 2009). Thus, with the lengthy persistence of CO_2 in the atmosphere, the cumulative concentration of CO_2 gives a direct indication of long-term global warming.

As there is a causal link between concentration and long-term temperature increase (IPCC, 2021), it is possible to calculate the expected temperature increase based on the cumulative net global amount of CO_2 in the atmosphere. Similarly, limiting global warming to a given level with a given probability, taking into account the effect of other anthropogenic GHGs and pollution, gives the maximum amount of cumulative net global anthropogenic CO_2 emissions, often referred to as the global carbon budget.

Carbon budget

The carbon budget includes several uncertainties. These include the accuracy of data on historical emissions, the accuracy of the estimated warming to date, the role of other GHG emissions in current warming, Earth system feedbacks, and the delay between emissions having reached net zero and the additional amount of warming inherent in the system. The closer we get to the temperature increase that we wish to avoid (i.e. increase above 1.5°C), the more these parameters contribute to uncertainty.

Despite these uncertainties, the carbon budget has proved to be a reasonable method to indicate potential future warming levels based on different scenarios for energy-related emissions. For our temperature thresholds, we have used the 'likely' (meaning 67% probability) carbon budgets from the IPCC Sixth Assessment Report (IPCC, 2021). By selecting a 67% chance to stay below the selected temperature, we have chosen to increase the certainty of limiting warming to our selected respective temperature thresholds. IPCC concludes that to stay below 1.5°C, we have to limit cumulative emissions from 2020 onwards to 400 $GtCO_2$, and to 1,150 $GtCO_2$ to remain below 2.0°C.

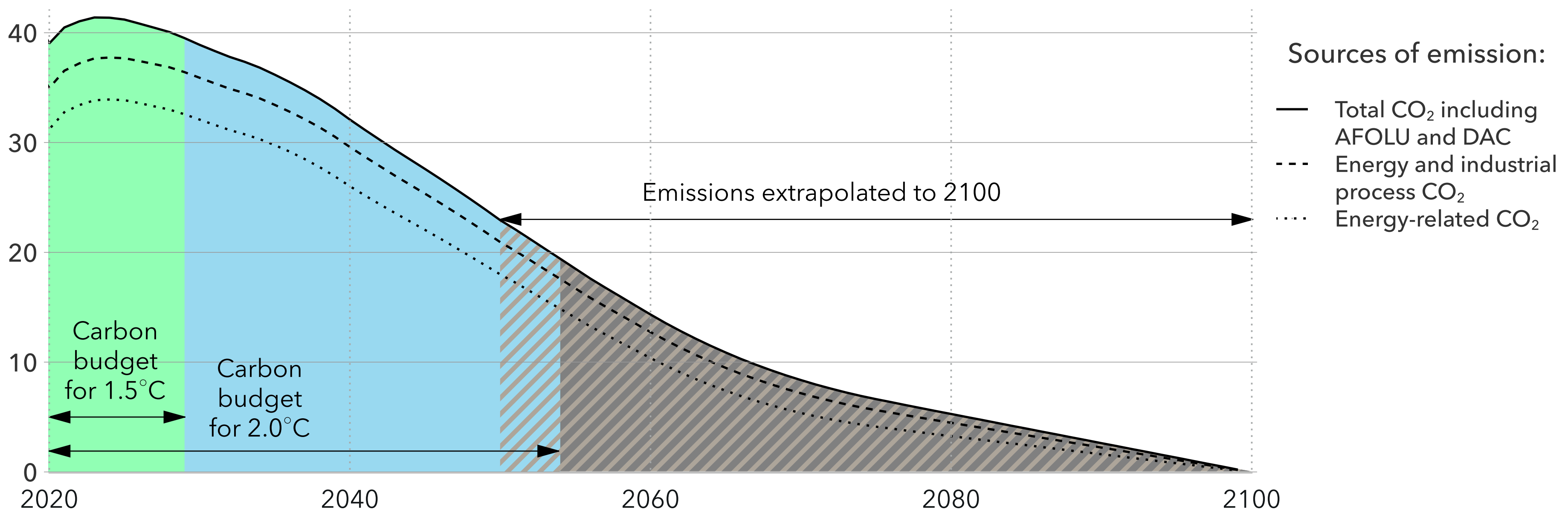
The IPCC carbon budgets have taken account of emissions from other GHGs. Methane emissions from fossil fuels or changes in agricultural practices, including fertilizer use or aerosol emissions, can have considerable influence on the size of the carbon budget. We use the IPCC scenarios in line with 'very low' and 'low' non-CO_2 emissions estimates that follow a similar path to our CO_2 emission trajectory. If emissions from non-CO_2 GHGs are larger, then the carbon budget will be smaller and associated temperature increase larger.

Using the IPCC carbon budgets and the cumulative CO_2 emissions from our forecast, we find that the 1.5°C budget will be exhausted in 2029. The carbon budget associated with the 2.0°C threshold will be exhausted in 2054, outside the forecast period. The CO_2 emissions from energy-related activities as well as industrial process and land-use emissions will still be considerable post-2050 and will continue many years thereafter. Thus, the question arises: 'What temperature increase does our forecast suggest?'

FIGURE 7.9

World CO_2 emissions and associated carbon budgets

Units: $GtCO_2$/yr



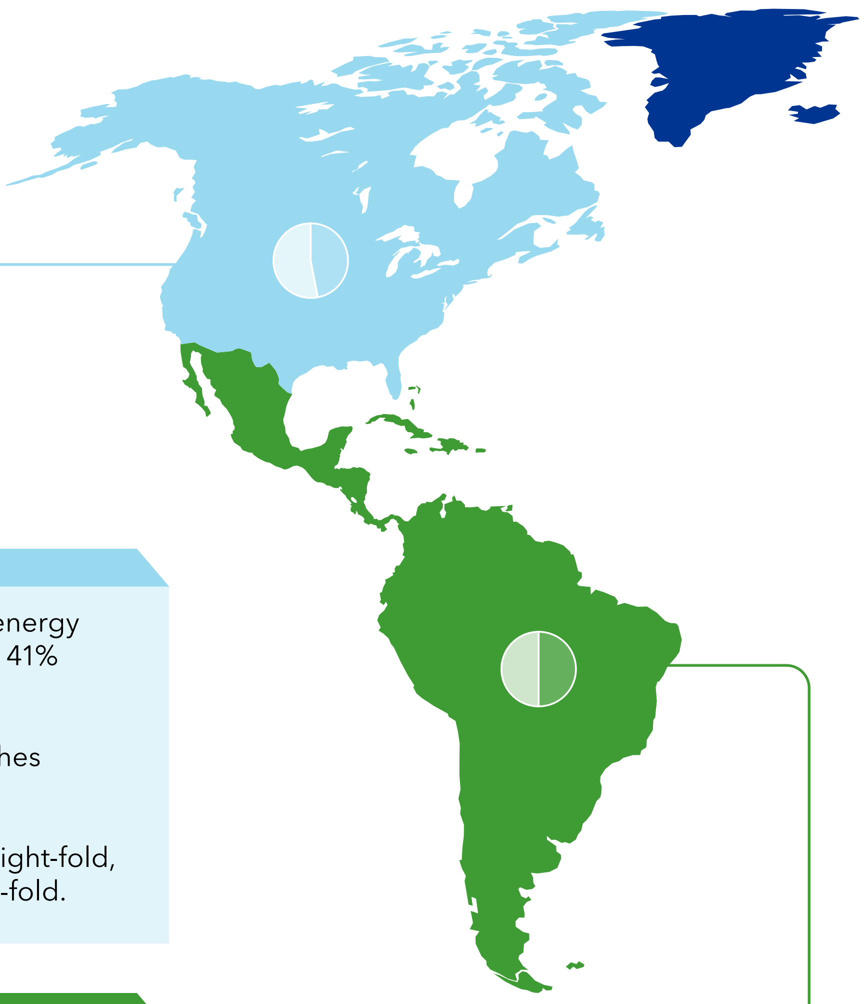
Temperature increase

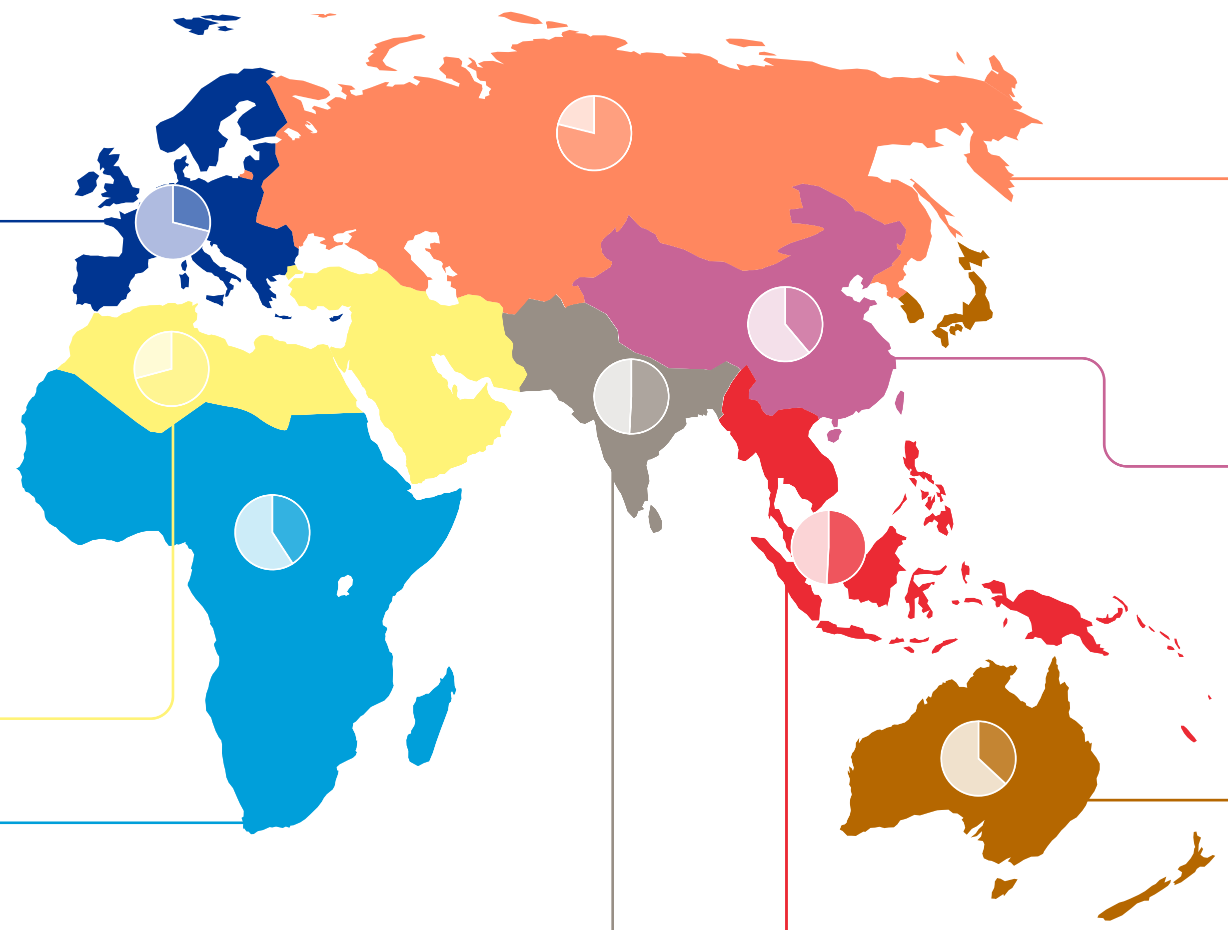
Our forecast and associated CO_2 emissions end in 2050. Therefore, in order to use the overshoot of the carbon budgets to evaluate a likely temperature increase, we must assess the emissions for the latter part of this century. By 2050, the emissions trajectory shows a relatively steep decline, with increasing amounts of CO_2 captured by CCS. Beyond 2050, our analysis assumes we will arrive at net-zero CO_2 emissions before or at the end of this century.

To estimate the CO_2 emissions and global warming by the end of the century, we extrapolate the development of emissions and their capture towards 2100. Capture occurs only within the sectors shown in Figure 7.4; so, for sectors such as transport or buildings where there is zero or marginal capture, we extrapolate a decline in line with our forecast but ending at net zero before or by 2100. The approach gives us estimated cumulative emissions of 407 $GtCO_2$ between 2050 and 2100 (Figure 7.9). This estimate does not include any large-scale negative-emissions technologies that may be able to reduce the atmospheric CO_2 concentrations significantly. With the updated climate response from IPCC AR6 (IPCC, 2021) using the 67% 'likely' overshoot of 328 $GtCO_2$ compared with the 2.0°C budget suggests that the world will reach a level of warming of 2.2°C above pre-industrial levels by 2100.

8 REGIONAL TRANSITIONS

8 WE ANALYSE 10 GLOBAL REGIONS





North America

Share of electricity in final energy demand doubles, reaching 41% by 2050.

CO_2 captured by DAC reaches almost 50 Mt/yr by 2050.

Solar grows 15-fold, wind eight-fold, and utility-scale storage 20-fold.

Latin America

Fossil fuels will be meet half of final energy demand in 2050, dominated by oil (27%) and natural gas (22%).

Solar PV and wind power grow significantly to account for 62% of power generation in mid-century.

23 Mt/yr of hydrogen and derivatives are exported by 2050, driven by the lowest levelized cost for solar-powered hydrogen production.

Europe

Electricity demand is set to double by 2050 due to electrification of sectors like transport.

Transmission and distribution lines will grow by 45% by 2050, along with a four-fold increase in interconnections with neighbouring regions.

Emissions to decline by 86% from 1990 levels, but Europe likely to fall behind 2030 targets if stricter EU targets are implemented.

Middle East and North Africa

Electricity's share of final energy demand more than doubles to 32% in 2050.

Wind and solar provide 77% of electricity, solar contributing 46% and a quarter of this in solar+storage plants.

Annual hydrogen production as an energy carrier grows from 0.2 Mt in 2030 to 9.3 Mt in 2050.

Sub-Saharan Africa

Oil and gas exports will dramatically decrease as production declines and regional consumption increases.

Together wind and solar will make up 70% of the electricity mix in 2050.

Transmission and distribution lines will triple, but less than 20% of the population will have grid access by 2050.

Indian Subcontinent

Together wind and solar will make up 50% of the electricity mix in 2050.

Space cooling energy demand in buildings will grow the most as GDP grows and the number of cooling-days increases.

Coal will have a 20% share of the primary energy mix in 2050, the highest of all our regions.

South East Asia

Primary energy today stems from 80% fossil fuels, but this will decrease to 51% by 2050.

Solar and wind combined expand from less than 1% in 2022 to a 22% share in 2050.

Electricity's share in final energy demand grows from 18% today to 36% by 2050.

North East Eurasia

Natural gas will meet 50% of primary energy demand in 2050. Renewables will account for 34% of electricity generation.

Russia's natural gas exports will remain lower than before the invasion of Ukraine; oil exports are rebounding but delivering lower revenues.

Emissions decline by 35% but account for the highest emissions per person globally.

Greater China

Electricity's share of energy demand doubles to 44% in 2050, the highest of all regions with more than 90% from renewable energy sources.

The share of coal in power generation (current 60%) reduces to 24% in 2040 and 5% in 2050.

From 2022 to 2050, Chinese energy intensity will reduce by 54% (from 4.8 to 2.2 MJ/USD) and its carbon intensity of energy use will reduce by 60% (from 103 to 42 gCO_2/MJ).

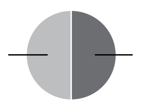
OECD Pacific

By 2028, all new power generating capacity additions will be based on renewables or nuclear.

Nuclear power generation doubles from today to 2050.

The economy is decoupling rapidly from emissions and energy, which due to declining population is accelerating this process further.

KEY



8.1 NORTH AMERICA (NAM)

This region consists of Canada and the US

	Population (Million)	GDP* (USD Trillion) GDP/person (USD)	Energy use (EJ) Energy use/person (GJ)	Energy-related CO_2 emissions (GT) Energy-related CO_2 emissions/person (Tonnes)
2022	373	28 74 000	104 279	5.2 13.8
2050	419	41 97 000	77 184	1.3 3

*All GDP figures in the report are based on 2017 purchasing power parity and in 2022 international USD

8.1 NORTH AMERICA (NAM)

Characteristics and current position

Climate change affects weather patterns and causes more natural disasters touching every corner of North America, as seen in the 2023 Canadian wildfires, record-breaking heat waves (NOAA, 2023), and hurricane Idalia introducing elevated risks and increased public acknowledgement of extreme weather hazards.

In the US and Canada, both federal governments have set zero GHG goals for 2050 and have intermediate reduction targets for 2030 at 50 to 52% below 2005 levels (US) and 40 to 45% (Canada). Both countries aim for zero-emission electricity in 2035, but despite decarbonization ambitions, there is a deep-seated reluctance to step away from fossil fuels and the region's fossil fuel advantage in light of global energy security concerns.

The decarbonization challenge is grand. The energy mixes of the region are currently dominated by fossil fuels, and energy-related emissions account for over 80% of domestic GHG emissions in both the US and Canada.

The region's policy focus is on cleantech industrial positioning, carbon-free domestic energy developments, and encouraging economic activity in critical strategic areas for securing supply chains while addressing climate change.

Landmark bills passed in 2021 and 2022 in the US were the *Infrastructure Investment and Jobs Act* (IIJA), the *CHIPS and Science Act* and the *Inflation Reduction Act* (IRA). Similarly, Canada's *Budget 2023 A Made-in-Canada Plan* emphasizes climate action and a growing clean economy underpinned by a supportive federal policy toolkit. Unlike the US, Canada's decarbonization regulation combines incentives as well as disincentives such as explicit economy-wide carbon pricing.

Pointers to the future

– North America is at a historic inflection point with a confluence of forces that promises to drive the energy transition:

  - Policy packages are a major boost for clean energy in the region. Mounting and long-term incentives offered by the IIJA, the IRA and Canada's Budget 2023 providing a 10-year window of certainty for investments.
  - ESG investment disclosure requirements, despite their contentious nature, are advancing climate-related risk reporting and investments disproportionately targeted in furtherance of the energy transition and decarbonization.
  - Compelling benefits to local communities that have been historically under-served, or fossil-fuel focused, ensuring a just energy transition.

– However, if unaddressed, permitting snarl-ups and under-investment in grids can jeopardize the decarbonization and the transformation that are intended by policies enacted in the region.

– Renewables and other low-carbon energy will be cheaper to extract, produce, and transmit than fossil-based energy, even without taking negative externalities into account. While spending 4% of region GDP on energy expenditure in 2022, this fraction of GDP will reduce to around 2.5% by mid-century.

– The transition will shrink both household energy bills and expenditures.

– Decarbonization goals will be within reach with investments in renewables, hydrogen, carbon capture and storage (CCS), and direct air capture (DAC) all being front-loaded in the 2030s thanks to incentives. However, goal achievement will be hampered by lack of disincentives, such as a region-wide cost on carbon emissions, which also raises the risk of 'carbon leakage' between US states.

Watt's up, North America

As a celebration of DNV's 125th year anniversary in the US, we published a dedicated deep-dive report on the *Energy Transition North America* in September 2023 (DNV, 2023c).

In this Outlook, we summarize the salient aspects of the North American energy transition and invite readers to explore these developments in greater depth in our full North America report.

- North America's energy system undergoes a vast transformation. Electricity's share in final energy demand doubles from 21% today to 41% by 2050.
- Electricity makes significant inroads into the key demand sectors: transport (25%), buildings (70%), and manufacturing (34%), leading to lower loss of energy, which is inherent in fossil-fuels use, and higher energy efficiencies.
- Hydrogen and its derivatives combined increase from virtually nothing today to 10% by 2050. Hydrogen production as energy grows from very small levels to 53 Mt by 2050.
- Solar sees 15-fold growth and wind eight-fold growth, despite the short-term supply-chain and cost inflationary pressures.
- Short-term delays in grid capacity expansion threaten this renewables boom. Despite this, we forecast the transmission grid capacity will expand 2.5-fold between 2022 and 2050, especially since the grid is seen as a strategic necessity for this transformation. However, a great deal hinges on the timing of this expansion.
- In keeping with the boom of variable renewable energy sources (VRES), stand-alone grid-connected energy storage presents a significant business opportunity for power price arbitrage, and we expect energy storage capacity to grow 20-fold from today to 2050.
- CO_2 emissions captured by CCS processes increases from 17 Mt in 2022 to 242 Mt by 2050. DAC increases from virtually nothing today to about 50 Mt by 2050.

Not fast enough for net zero

The energy transition we expect to see unfold in North America is not fast enough to reach the climate targets of the region. Compared with 1990 emission levels as a common reference point for all regions, North America as a region is targeting total reductions of 36.1% in energy-related emissions by 2030. This target is lower than stated nationally determined contributions (NDC) pledges, as 1990 emissions were less than in 2005. We estimate CO_2 emissions will decrease by 37% compared to 2005 levels (24% compared with 1990 levels), meaning the region's target will not be achieved. By 2050, our estimates indicate that the region will have reduced its energy-related emissions by 75% compared with 2022 levels and will still be emitting 1.3 $GtCO_2$ per year in 2050 despite the region's net-zero pledges.

8.2 LATIN AMERICA (LAM)

This region stretches from Mexico to the southern tip of South America, including the Caribbean island nations

	Population (Million)	GDP* (USD Trillion) GDP/person (USD)	Energy use (EJ) Energy use/person (GJ)	Energy-related CO_2 emissions (GT) Energy-related CO_2 emissions/person (Tonnes)
2022	688	12.3 18 300	35 52	1.5 2.3
2050	744	20.8 27 900	39 52	1.1 1.5

*All GDP figures in the report are based on 2017 purchasing power parity and in 2022 international USD

8.2 LATIN AMERICA (LAM)

Characteristics and current position

At present, renewables account for a third (33%) of Latin America's total energy supply, more than double the global share of renewables (13%) (OECD et al., 2022). With biomass, geothermal, hydropower, solar, and wind resources, regional carbon intensity is among the lowest globally.

Latin America can take a strategic position in the energy transition with raw materials, low-carbon fuels, and renewable electricity. This potential is exemplified by the region having: 60% of world lithium reserves, 40% of the copper, and 30% of the nickel (OECD et al., 2022); high renewable electricity shares (Paraguay about 99%, Uruguay about 90%); and Brazil's longstanding biofuel production and hydropower. However, climate change is disrupting the water cycle and thereby impacting regional hydroelectric generation.

Competitive tendering has triggered impressive growth in non-hydro renewables to today's combined 69 GW of utility-scale solar and wind capacity (GEM, 2023). There are curtailment risks, and frameworks promoting regional electricity interconnection are inadequate (Levy et al., 2023).

Focus on distributed generation and further renewables penetration (e.g. Chile, Colombia, and Costa Rica's RELAC initiative for 70% renewables in the 2030 power mix) underpins hydrogen export aspirations.

The region has world-class unconventional fossil-fuel resources, and several countries have significant oil and gas production. Brazil and Guyana are surpassing Mexico and Venezuela to lead in oil production (Cardenas et al., 2023).

Agriculture, forestry, and land-use (AFOLU) account for around 40% of the region's GHG emissions, with another 43% coming from the energy sector, well below the 74% global average (UNDP, 2022).

Pointers to the future

- Argentina's lithium export surged 234% in 2022 (Jones, 2023). A modest renewable power mix target (20% by 2025, from around 12% in early 2023) will hinder 2030 hydrogen ambitions requiring more than 5 GW electrolysis capacity. Reducing natural gas prices and imports motivates further VacaMuerta shale investments, such as the pipeline to Buenos Aires.

- Brazil aims to maintain hydropower in absolute terms (but losing share to wind and solar). Wind and solar will grow rapidly, and being a first mover (with Colombia) within offshore wind regulation will enable hydrogen energy (*National Energy Plan 2050*). A doubling in oil and gas production is planned by 2030, coupled with carbon-intensity reduction efforts.

- Chile targets 25 GW electrolysis capacity by 2030. A USD 1bn budgeted green hydrogen and derivatives fund (Chile Ministry of Finance, June 2023) will rely on international contributions such as from the EU (EEAS, 2023). Chile targets 100% EV new sales by 2035 and industrial decarbonization through electrification and green hydrogen.

- Colombia pursues 3 GW electrolysis capacity and 50 kt/yr blue hydrogen by 2030 with international support such as Germany's International PtX Hub. The government (Decree 1476, August 2022) provides regulatory certainty. An offshore wind tender (2023) is planning four to six projects, and its *National Electric Vehicle Law* will push sales and infrastructure.

- Mexico's government favours fossil fuels for energy security reasons. The renewables-focused Sonora plan (BN Americas, 2022) lacks clarity and political risk hinders investment. The forthcoming 2024 federal election has the renewables sector hoping for more favourable policy.

Energy transition: strong growth of solar and wind domestically and a major exporter of renewable hydrogen globally

Latin America's final energy demand has tracked relatively flat in the past decade, reflecting only marginal improvement in standards of living. Only after 2025 does income per capita rise again, leading to a moderate 23% increase in the region's final energy demand between 2022 and 2050 (Figure 8.2.1). An overwhelming 87% of this increase will be met by electricity generation, which will more than double. The share of electricity in final energy demand will therefore increase from 18% to 31% in the same period. Renewables will become even more potent in the regional energy mix; their share in primary energy demand will increase from around 30% today to almost a half (48%) in 2050 (Figure 8.2.2). While biomass and hydropower, the current leaders in the supply of renewable energy in Latin America, will retain their shares, most growth in renewables will come from solar PV and wind. Despite this impressive growth in clean energy, half of the final energy demand will still be met from fossil sources. Oil and natural gas will dominate the fossil energy, meeting 27% and 22% of the final energy demand, respectively. Coal and nuclear fuels will remain insignificant energy sources in the region.

Energy demand

Among Latin America's energy demand sectors (Figure 8.2.3), buildings' energy use will increase most – by 42%. Such an increase reflects the spreading of heating and cooling services to new segments, driven by a combined effect of rising living standards and growing population, and powered predominantly by electricity. Energy demand in manufacturing will grow modestly by 35% as the effects of income per capita and population will be paced by efficiency gains and greater use of electricity. In the transport sector, increasing electrification will almost completely counteract the vehicle fleet expansion: energy demand will peak in the late 2030s and then decrease to roughly its current level by 2050.

Renewables

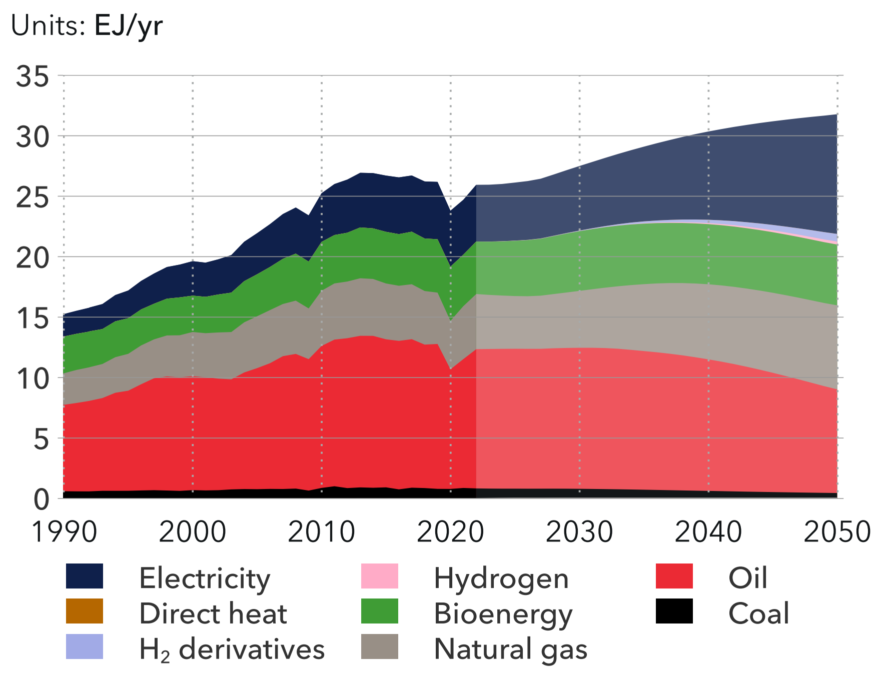
Today, renewables already have a two-thirds (66%) share in power generation in Latin America, the highest among all the ETO regions. Also, Latin America is currently the only region where more than half the electricity is generated from renewables. The largest renewable source is hydropower supplying 46% of total power production.

However, there is substantial potential for growth of other renewable sources of power in the region, which is already being reflected in recent investment in new capacity. Given the near-perfect conditions for solar power in the Atacama Desert and elsewhere in other parts of the Latin America region, countries such as Chile, Argentina and, to some extent, Brazil are investing in solar power to decarbonize energy and other sectors. Almost all South America's coastline features conditions favourable for wind power. Brazil ranked third in the world for new wind capacity installations in 2022 (GWEC 2023).

> Renewables are already two-thirds (66%) of the power mix in Latin America, the highest among all the ETO regions, but there is still substantial room for growth in renewable sources.

FIGURE 8.2.1

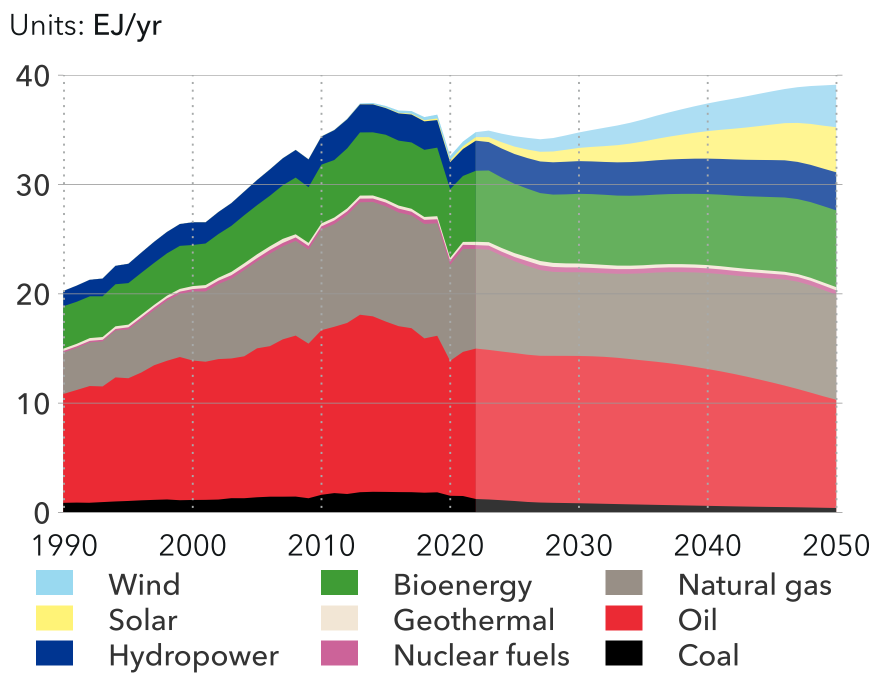
Latin America final energy demand by carrier



Historical data source: IEA WEB (2023)

FIGURE 8.2.2

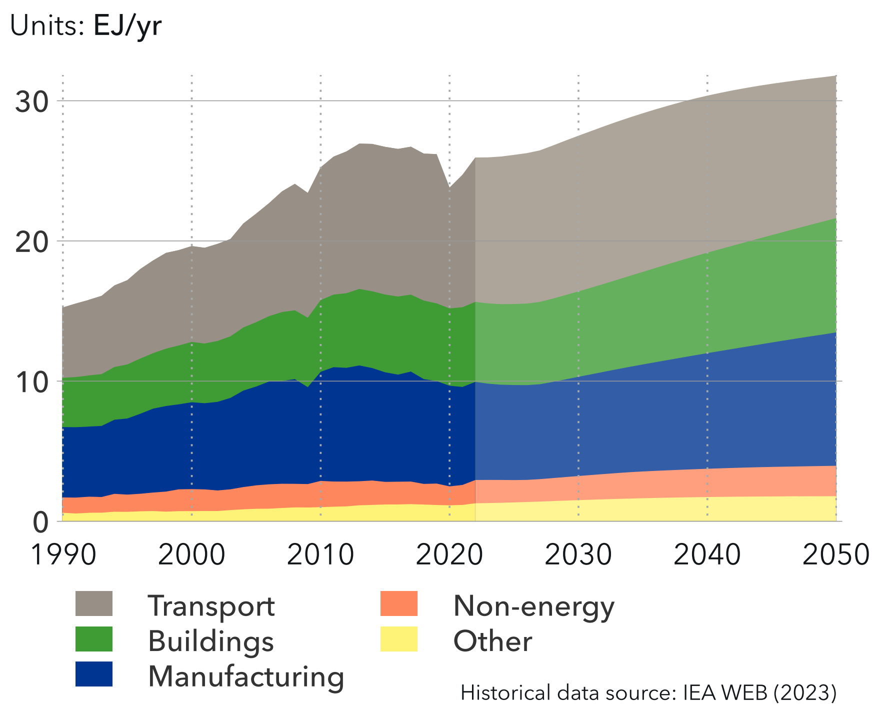
Latin America primary energy consumption by source



Historical data source: IEA WEB (2023)

FIGURE 8.2.3

Latin America final energy demand by sector



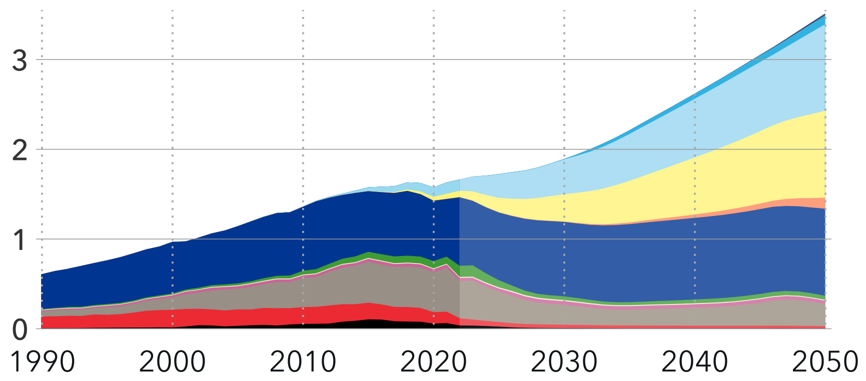
Historical data source: IEA WEB (2023)

Owing to these developments, and while hydropower will increase slightly in absolute terms, the increasing demand for electricity will be met by solar and wind. We forecast that solar and wind will grow significantly in the coming decades, respectively providing about 16% and 21% of power generation in 2030, and almost 32% and 30% by 2050 (Figure 8.2.4). The share of hydropower will therefore decline to 28% in mid-century. The increasing role of renewables in power will be accompanied by a corresponding decline in the share of fossil fuels from 32% currently to only 8% in 2050. Almost all the remaining fossil-fuelled power generation will be provided by natural gas-fired plants.

FIGURE 8.2.4

Latin America grid-connected electricity generation by power station type

Units: PWh/yr



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

Hydrogen

While strong electrification through solar and wind power growth is the main driver of the region's energy transition, Latin American countries are also investing heavily in renewable hydrogen. Today, Latin America produces only about 5% of the world's hydrogen output, almost entirely from unabated fossil fuels, for the region's manufacturing sector. Its role in the global hydrogen market will change significantly in the next three decades. Since electricity will drive decarbonization of sectors fit for electrification, the region's abundant renewable resources give it the opportunity to become an exporter of hydrogen to Europe, North America, Asia and, to a lesser extent, a producer of hydrogen for domestic decarbonization. However, significant uptake of hydrogen production is only envisaged to start in the next decade, as costs will need to continue their decline and governments need time to establish the many frameworks enabling hydrogen production, export, and potential domestic use.

From the early 2030s, hydrogen produced by electrolysis powered by dedicated renewables will start taking off more rapidly, reaching around 19% of total hydrogen production in 2050. This share is dramatically higher than today, but lower than that of hydrogen produced from fossil fuels abated with CCS. The latter will account for around half of total hydrogen output in 2050. Only about 11% of hydrogen will be produced from unabated fossil fuels.

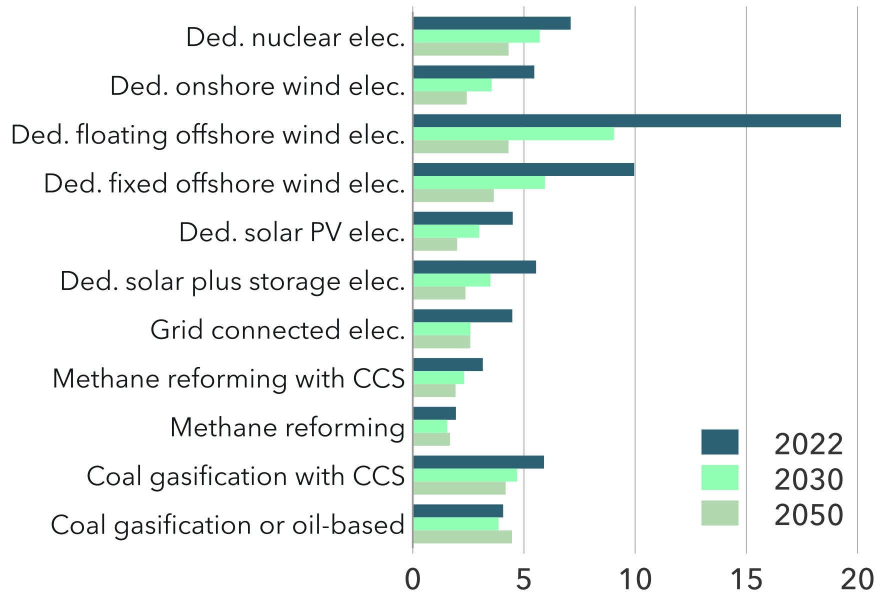
Thanks to high capacity factors, Latin America will be among the regions with the lowest levelized cost for solar-powered hydrogen production. In fact, the region's solar-based hydrogen is cheaper than most of its competitors, such as wind-based hydrogen (Figure 8.2.5). From the late 2040s on, solar-based hydrogen production will be competitive with natural gas-based hydrogen production at just above USD 2/kg. Wind-based hydrogen production will remain slightly costlier than solar-based on average in the region. At promising wind sites, however, the levelized cost of hydrogen might be even lower than for solar-based hydrogen.

Given the low levelized cost of hydrogen production and the vast potential for solar power exploitation and promising wind resources, Latin America will in fact become a major hydrogen exporter. We forecast that about 23 MtH_2 of hydrogen and its derivatives will be exported annually from Latin America by 2050. Almost all of this will be exported as ammonia and for energy purposes (93%), with half of the ammonia shipped to North America to support its IRA-supercharged hydrogen demand; the remainder will go to Asia and Europe.

FIGURE 8.2.5

Latin America levelized cost of hydrogen production

Units: USD/kgH_2



Ded. = dedicated; elec. = electrolysis

To realize these projections, the region must properly plan the challenging part of this undertaking: hydrogen transport. It appears that it will do so, including pipelines for intraregional distribution of hydrogen, and export terminals for hydrogen conversion to ammonia. Latin America's strong natural gas pipeline network will be repurposed for hydrogen to support the ambitions.

Biofuels

Besides being in a good position to supply other regions with green hydrogen from solar and wind, Latin America has great potential to further displace imported fuels domestically with biofuels like bioethanol, biodiesel, and biogas/biomethane.

Brazil`s sugarcane ethanol programme, launched in 1975, Argentina's soya biodiesel, and Colombian palm oil biodiesel are prime examples of the region's success in providing renewable alternatives to fossil fuels. Latin American countries are promoting biofuel use through strong mandates with high blend rates of ethanol and biodiesel. The region's share in upgrading its biogas to biomethane, which has a better overall supply-chain footprint, is very high. Currently, about 35% of Latin America's biogas production is further refined to biomethane (IEA, 2020). By 2050, biomethane will replace 4% of domestic methane demand in the region.

As a result of those ambitions and the associated energy transition going forward in Latin America, use of oil for energy, the region's largest such source today, will decline by a quarter. In addition, growth in the use of natural gas for energy will stall soon and will not overtake oil as the largest primary energy source within the forecast period (Figure 8.2.2). Biomass, in the form of liquid biofuels in transport, as a gaseous energy carrier substituting natural gas and as solid biomass in the buildings sector, will retain its 18% share in primary energy mix towards 2050 and support Latin America's energy transition.

Emissions

The region's average carbon-price level is projected to increase to USD 10/tCO_2 in 2030, and USD 40/tCO_2 by 2050. There are carbon-pricing schemes, such as taxation in Argentina, Chile, Colombia, and in some Mexican states. Pricing is presently low but additional pricing instruments are under consideration, such as in Brazil (see Section 6.3).

Higher pricing could also come to avoid carbon-border adjustment mechanisms from large trading partners such as China and Europe, both of which have carbon pricing in place and are seen as possible trade partners for, among other products, low-carbon hydrogen.

Latin America's energy-related CO_2 emissions peaked around year 2015. They will decline further through the 2020s, stabilize in the 2030s, then decrease by 30% from 2022 levels by 2050, reaching 1.1 GtCO_2/yr (net of DAC) as shown in Figure 8.2.6, and 1.23 Gt if including non-energy process emissions. The decline will be more pronounced in transport and manufacturing, driven by efficiency gains, a changing energy mix, and to a smaller extent by carbon capture. Today and in the future, oil contributes most to emissions (almost 50%), and is mainly used in Latin America's transport sector. The natural-gas dominated manufacturing and buildings sectors together contribute another third to Latin America's emissions in 2050. By then, CCS will reduce CO_2 emissions by 108 Mt/yr in mid-century, equivalent to around 9% of the region's emissions by then.

In the context of global climate policy, country NDC pledges indicate an increase in the regional target of limiting increases in emissions to about 61% by 2030, relative to 1990. Our Outlook shows energy-related emissions rising around 53% over the same 40-year period. This suggests that the regional target will be achieved by a good margin, indicating a low level of ambition.

It should be noted that there are uncertainties in comparing targets and forecasts. Some countries are unclear about whether targets in NDCs also include non-energy-related CO_2 emissions. Especially in Latin America, there is a large difference between targets including and excluding LULUCF (land use, land-use change, and forestry) due to the influence of the rainforest on the total emissions.

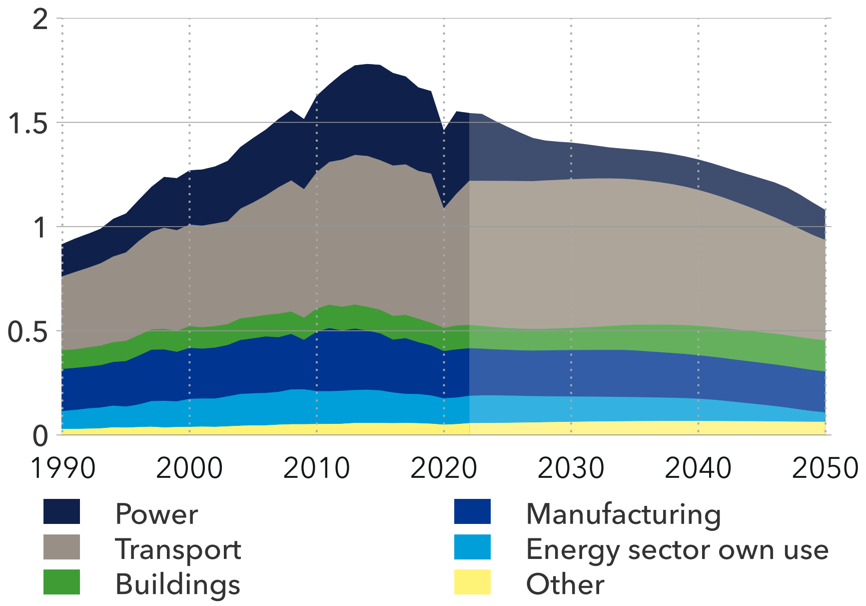
On a per capita basis, Latin America's 1.6 tCO_2 per person emissions in 2050 are comparable to those in India and South East Asia, and are 37% lower than currently in the region. It should also be noted that some Latin American countries, including Brazil, Argentina, Colombia, and Chile have indicated – or have already adopted – carbon-neutrality targets by 2050. However, these targets often take into account the land and forestry sector, which means CO_2 uptake from rainforest areas are included.

Energy-related CO_2 emissions decrease by 30% from 2022 levels by 2050.

FIGURE 8.2.6

Latin America energy-related CO_2 emissions by sector

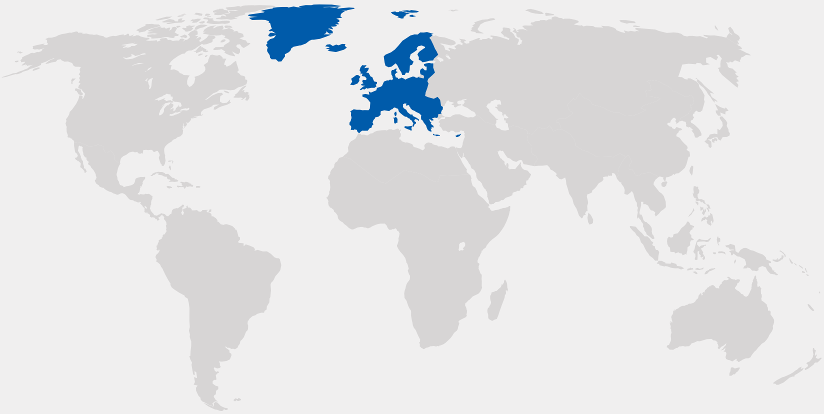
Units: GtCO_2/yr



Historical data source: IEA WEB (2023)

8.3 EUROPE (EUR)

This region comprises all European countries, including the Baltics, but excluding Russia, all the other former Soviet Union Republics, and Turkey



	Population (Million)	GDP* (USD Trillion) GDP/person (USD)	Energy use (EJ) Energy use/person (GJ)	Energy-related CO_2 emissions (GT) Energy-related CO_2 emissions/person (Tonnes)
2022	543	28.8 53 000	67 124	3.1 5.6
2050	542	40.0 74 000	60 111	0.5 0.8

*All GDP figures in the report are based on 2017 purchasing power parity and in 2022 international USD

8.3 EUROPE (EUR)

Characteristics and current position

The EUs energy import dependency stood at 55.5% in 2021 (Eurostat, 2023). Russia's invasion of Ukraine puts independence and security on top of the energy agenda.

The gas demand reduction regulation has caused an 18% drop in consumption (August 2022 – May 2023) and is extended to March 2024 (DG-Energy, 2023a). The EU has established gas alliances with suppliers in the US, the Middle East, Africa, and South America, while also increasing its LNG import capacity.

Prompted by other regions' cleantech spending, the EU launched the *Green Deal Industrial Plan* (GDIP) for a supportive environment to scale European net-zero capacity (technologies and products). The Plan complements existing initiatives (i.e. *European Green Deal*, *Fit for 55* package, the *REPowerEU* plan).

Part of the GDIP is the *Net-Zero Industry Act* to increase domestic manufacturing capacity and faster permitting of strategic net-zero projects, and the *Critical Raw Materials Act* to secure the supply and supply chains of strategic raw materials to net-zero transitioning (40% of annual deployment needs by 2030).

The EU's *Temporary Crisis and Transition Framework* (TCTF) loosens *State aid* rules through 2025 to support strategic sectors (e.g. batteries, solar panels, wind turbines, heat pumps, electrolysers, and CCS equipment) with aid up to 45% or 100% if competitive bidding, and allows 'matching aid' in case of relocation risks.

The electricity market reform proposal (March 2023) focuses on protecting consumers against price volatility through power purchase agreements (PPAs) and boosting renewables to make energy cheaper (EC, 2023b).

Pointers to the future

- European governments are speeding up energy system-wide transformation.
- The *Energy Efficiency Directive* targets a 11.7% reduction of final energy consumption by 2030.
- The *Renewable Energy Directive* (RED III), increasing ambitions from 32% to a binding 42.5% of energy consumption in 2030, striving for 45%, will mean roughly doubling the expansion of renewables (about 22% in 2021).
- *RED III* will create a market ramp-up for e-fuels (renewable fuel of non-biological origin – RFNBO). In transport, aiming for a 29% renewable fuel supply (2030) with binding 5.5.% sub-targets for advanced biofuels and RFNBO. In buildings, the indicative renewable target is 49%. Industry's indicative target is a 1.6% annual increase to 2030, and 42% of hydrogen use from RFNBOs by 2030 and 60% by 2035.
- Regulatory certainty for green hydrogen acceleration includes: delegated acts defining what counts as renewable hydrogen (or its derivatives RFNBO) and methodology to calculate GHG emissions (EC, 2023c); and the *European Hydrogen Bank* to provide producers with fixed 10-year green subsidies (DGCA, 2023).
- Renewable power and grids will be the backbone to reach targets. Implementing the *REPowerEU* plan means the renewable electricity share grows to 69% in 2030 (592 GW solar PV and 510 GW wind) (DG-Energy, 2023b). More variable renewables will require significant grid reinforcement and demand response solutions.
- Permitting reform, including designating projects/areas of overriding public interest and swifter permitting deadlines will need implementation, while ensuring public support in the process.

Energy transition: front-runner striving for energy independence

Today, as the continent targets a 2050 horizon for climate neutrality, its leadership in climate policies resonates globally. The *European Green Deal*, an emblematic initiative, underscores this commitment, offering a blueprint for sustainable future growth. Europe's interconnectedness – both in terms of energy grids and shared policy ambitions – is pivotal. It not only facilitates cross-border energy exchanges but also fosters collaborative policy-making. This transcontinental unity, however, does not diminish the region's diversity. Each nation, with its unique energy matrix and challenges, contributes to a holistic European approach that is both inclusive and tailored. It is this blend of shared purpose, combined with respect for regional nuances, that sets Europe apart. As the continent marches ahead, its energy transition story – rooted in its past, informed by its present, and visionary in its outlook – offers invaluable insights for the world at large.

Primary energy use and renewable targets

Over the past few decades, Europe's primary energy consumption has undergone significant changes (see Figure 8.3.1). In the 1980s, fossil fuels accounted for a dominant 92% of the energy mix. However, by 2022, this had reduced to around 70%. This decrease was primarily due to a sharp fall in coal consumption, complemented by the growth of nuclear energy and natural gas. The 2000s marked a turning point, as solar and wind energy began making notable inroads into the energy scene. By 2020, solar had grown to 0.7 EJ, while wind energy, starting from zero, reached 1.7 EJ. Moreover, coal consumption dramatically declined from its peak of 21 EJ in 1980 to just 7 EJ in 2022.

Building on the achievement of the 20% renewable target in 2019, a year ahead of its 2020 deadline, the *Renewable Energy Directive* 2018/2001/EU set a new binding target for the EU: a minimum of 32% renewable energy by 2030. On 14 July 2021, under the *European Green Deal*, the European Commission introduced the *Fit for 55* legislative package, proposing an increase in this target to 40%. However, in May 2022, the *REPowerEU* plan proposed a further increase to 45% by 2030. Regrettably, neither proposal was legally ratified. In March 2023, a provisional agreement was made between the European Parliament and the Council to elevate the binding renewable energy target to a minimum of 42.5% by 2030. This agreement will come into force once formally adopted by both the European Parliament and the Council.

It is essential to understand how the EU defines its renewable share. The renewable percentage encompasses hydropower, geothermal, wind, solar, and the ambient heat utilized in heat pumps for heating and hot water (excluding cooling). Gross available energy is used to measure this, excluding energy lost in fossil-fired power stations and from international aviation and maritime activities. Thus, the EU's definition deviates from the calculation of renewables in primary energy consumption.

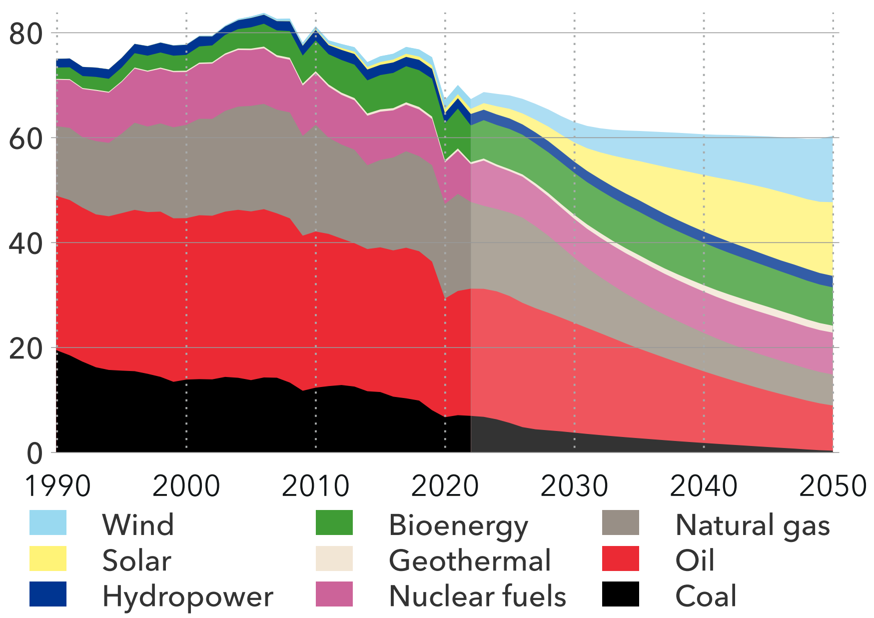
Projecting forward, the share of renewables in Europe's primary energy consumption is anticipated to rise from 18.5% in 2022 to 29% in 2030, reaching 62% by 2050. Factoring in the aforementioned definitional discrepancies, but also acknowledging geographical variations between our Europe region and the EU, our assessment suggests that the EU's binding 32% renewables target in gross available energy may be barely attainable. The loftier goal of a 42.5% share is likely to be reached only by 2035.

By 2050, solar energy is predicted to dominate the energy composition, accounting for 23%, closely trailed by wind at 21%. Nuclear energy, bioenergy, and hydropower are expected to sustain their current contribution rates. The anticipated shift towards renewables, coupled with widespread electrification and a strategic transition from fossil fuels, will lead to a decline in primary energy consumption: from 67 EJ in 2022 to 60 EJ by 2050.

FIGURE 8.3.1

Europe primary energy consumption by source

Units: EJ/yr



Historical data source: IEA WEB (2023)

Energy independence

Europe's quest for energy independence is intricately woven into its historical, geopolitical, and economic narratives. Traditionally anchored to external energy supplies, notably Russian gas and Middle Eastern oil, Europe has experienced vulnerability in its energy security. This fragility was evident during events like the 1973 oil crisis and more recently, the 2022 Russian invasion of Ukraine. Such episodes underscored Europe's need not just to secure consistent energy supplies, but also to diminish geopolitical threats and foster strategic autonomy.

Perspectives on energy independence diverge across the continent. Eastern European countries, influenced by their historical contexts and geographical closeness to Russia, remain cautious about relying heavily on a single energy source. In contrast, Western European nations balance their strategies, taking into account environmental imperatives, the desire for a diversified energy portfolio, and economic considerations.

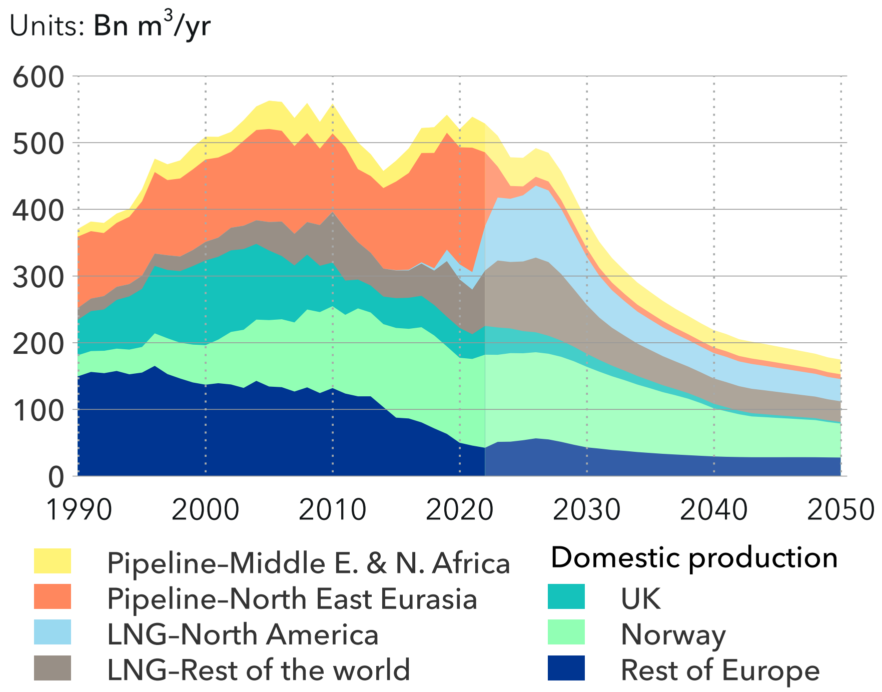
Despite these aspirations, Europe's energy landscape reveals a substantial dependence on imports. In 2022, the European Union, positioned as the world's primary energy importer, drew 69% of its oil and 57% of its natural gas from external sources.

In 2022, the European Union, positioned as the world's primary energy importer, drew 69% of its oil and 57% of its natural gas from external sources.

In its mission to enhance energy autonomy, Europe's strategies encompass diversifying its energy supply sources, fortifying infrastructure resilience, and amplifying domestic energy production. The European *Green Deal*, which seeks to position Europe as the first climate-neutral continent by 2050,

FIGURE 8.3.2

Europe natural gas supply by source



underscores the importance of renewable energy, prioritizing energy efficiency, and moderating energy consumption. After Russia invaded Ukraine in 2022, Europe diversified its energy suppliers, increasing its production in countries like Norway and amplifying its LNG procurement from North America, the Middle East, and elsewhere (see Figure 8.3.2).

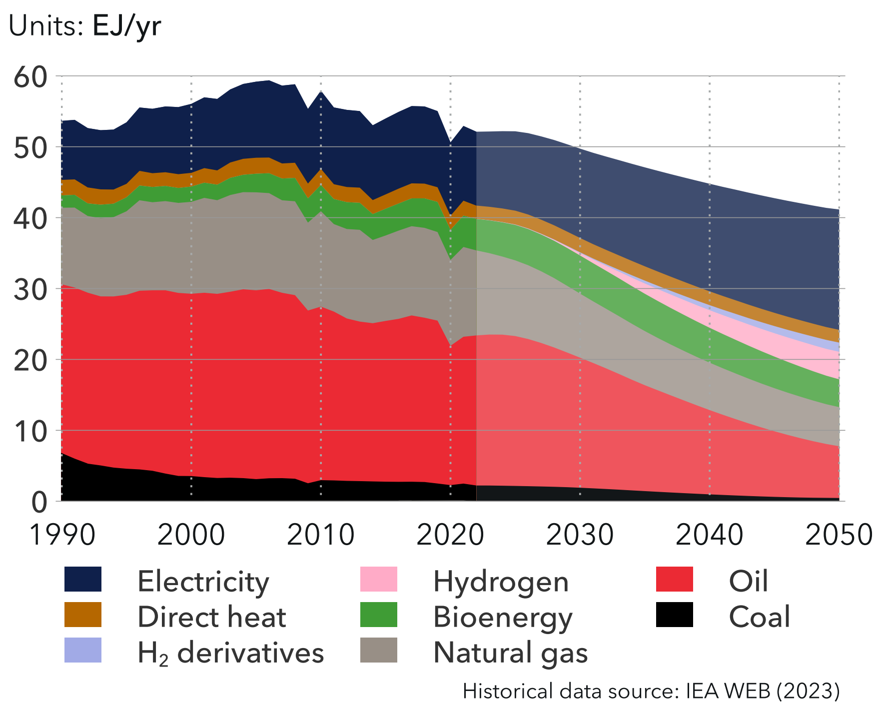
However, a pivot to renewables introduces its own set of challenges, especially concerning supply-chain dynamics for crucial minerals such as lithium, cobalt, and rare earth elements. For instance, China's substantial investments in solar PV equipment over the last decade outpace Europe's by 10-fold. With China accounting for 75% of the EU's solar PV imports, the nature of this dependence is shifting. Although the value of these solar imports in 2020 was considerably below fossil-fuel expenses, the shift to domestic production is anticipated to elevate the costs of solar panels in Europe. Policies aimed at homeshoring are predicted to add roughly 10% to the solar PV CAPEX until the early 2030s.

Peering into 2050, advancements in technology, resolute policies favouring renewables, and Europe's collective determination for strategic autonomy suggest a more self-reliant energy scenario. Still, achieving absolute independence appears unlikely. The approach will probably move towards a blend of local energy production, diversified imports, and robust international partnerships. This strategy, coupled with an anticipated decline in demand, portends a substantial decrease in imports: 59% for oil and 66% for natural gas from 2022 levels by 2050.

The role of nuclear energy and hydropower in this energy tapestry cannot be understated, though opinions on their adoption differ across Europe. Countries like France and Sweden view nuclear power as pivotal for energy autonomy and carbon reduction, with the former sourcing a substantial segment of its electricity from nuclear facilities. Meanwhile, the UK aims to transition from large-scale nuclear setups to small modular reactors. On the other hand, Germany, still influenced by the Fukushima disaster's aftermath, has chosen a path away from nuclear, focusing more on renewables. Rich in water resources, nations like Norway and Switzerland champion hydropower, considering it both a sustainable energy solution and a strategic linchpin for energy independence.

FIGURE 8.3.3

Europe final energy demand by carrier



Historical data source: IEA WEB (2023)

Final energy demand

Final energy demand in Europe will change profoundly in the next three decades, as illustrated in Figure 8.3.3. Population in Europe will remain stable, around 540 million inhabitants, and GDP per capita will increase by 39%. In contrast, final energy demand will decrease by 21% as the combined result of demand reduction due to better insulation, improved public transport, measures to reduce demand such as congestion charging, other behavioural changes, as well as energy-efficiency gains and rapid electrification. Fossil-fuel use will be increasingly confined to a few sectors. Oil demand will decrease from 22 EJ in 2022 to 7.7 EJ in 2050 and will mainly come from non-energy use in the petrochemical industry (52%) and transport (34%). In the meantime, demand for natural gas will decrease from 18 EJ to 6.9 EJ, with a strong remaining demand for cooking, space and water heating (75%), and manufacturing (15%) to a lesser extent. The use of bioenergy in end-uses will grow until 2030 and will start to be replaced by electricity and hydrogen as sustainability concerns lead to stricter regulation of bioenergy use.

Electrification

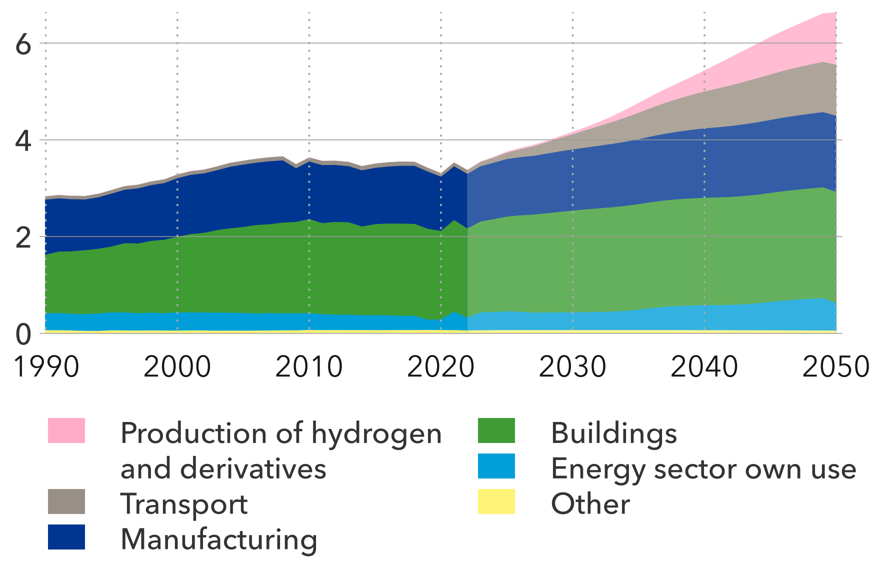
Electrification is crucial for energy efficiency, decarbonization, and ensuring energy independence. By 2050, Europe's electricity demand is predicted to surge from 3.4 PWh in 2022 to 6.6 PWh. One of the most prominent changes we will see in our daily lives is the electrification of road transport.

Motivated by stringent regulations, such as the EU's prohibition on the sale of new internal combustion engine (ICE) passenger vehicles by 2035, there is a forecasted shift towards battery-electric vehicles. Excluding plug-in hybrids, these vehicles are expected to rise from 1.5% of the total passenger vehicle fleet in 2022 to 23% by 2030 and an impressive 93% by 2050. Countries like Norway are spearheading this transition, targeting a 46% EV fleet share by 2030. Commercial vehicles pose a different set of challenges, with their electric share currently negligible. However, this segment is predicted to achieve 9% by 2030 and a very much higher 75% by 2050. This shift in road transport alone will result in an additional 900 TWh of annual electricity demand by 2050 – equivalent to one-third of Europe's current electricity consumption.

FIGURE 8.3.4

Europe electricity demand by sector

Units: PWh/yr



Historical data source: IEA WEB (2023)

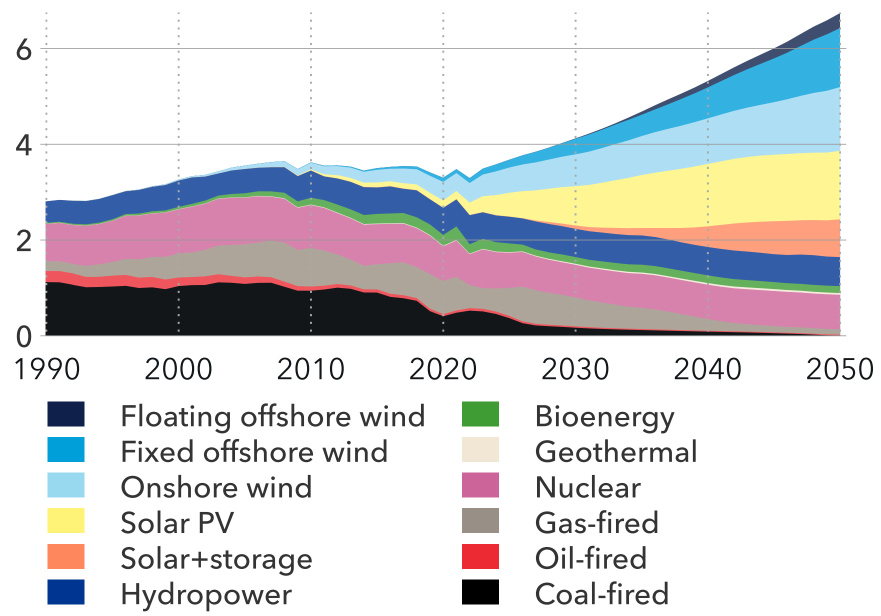
Over the next decade, the remaining increase in electricity demand will largely stem from conventional end-uses: buildings, road transport, and manufacturing. By the late 2030s, hydrogen production from grid-connected electrolysers will emerge as a significant consumer of electricity.

The shift in road transport alone will result in an additional 900 TWh of annual electricity demand by 2050 – equivalent to one-third of Europe's current electricity consumption.

FIGURE 8.3.5

Europe grid-connected electricity generation by power station type

Units: PWh/yr



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

The backbone of this electrification and decarbonization will be power sourced from renewables, bolstered by acceleration policies like those from *REPowerEU*. Navigating this growth will demand strategic approaches to power generation and grid management. While Europe has established shared guidelines, such as the EU green taxonomy and carbon pricing, individual nations will apply diverse strategies based on their resources, incentives, and industrial policies.

For instance, the Iberian Peninsula aspires to harness its solar and wind resources, positioning itself as Europe's renewable powerhouse. In contrast, Northern Europe, with its immense wind potential and limited solar capability, is looking to heavily invest in wind energy, particularly in the North Sea region for both fixed and floating wind turbines. While nuclear energy remains a contentious topic, it will likely persist as a staple in countries with a historical reliance like France, the UK, and some Eastern European nations.

Looking ahead to 2050, the power landscape is anticipated to be diverse but nearly completely decarbonized. Wind power will emerge as the leading renewable source, contributing almost half (43%) of the total electricity generation, followed closely by solar power.

To support this burgeoning electricity demand, Europe must bolster its interconnected power networks. This will necessitate consistent investments in expanding, reinforcing, and optimizing power grids. Despite Europe's extensive interconnected networks, bottlenecks like permitting delays and grid connection availability have hampered renewable growth. To overcome these challenges, the Council and the Commission agreed in March 2023 to expedite permits for renewable projects. A synchronized planning approach between countries, focusing on simultaneous grid and renewable developments, can further streamline the process. By 2050, we anticipate a 45% growth in transmission and distribution lines and a four-fold increase in interconnections with adjacent regions, ensuring both grid stability and dependable power supply.

Towards a flexible power system

As Europe forges ahead towards 2050, the region is experiencing a transformative shift in both power demand and supply. Being at the forefront of integrating variable renewables, Europe's power system is encountering unprecedented challenges that necessitate enhanced flexibility. This flexibility is paramount to ensure that power supply can reliably meet demand amidst the inherently intermittent nature of renewable sources like solar and wind. Storage solutions are pivotal in this regard; they act as a buffer, capturing excess energy during periods of high generation and releasing it during lulls. Interconnections between nations play a critical role, allowing regions to balance surpluses and deficits, effectively turning neighbours into backup providers. Meanwhile, conventional generation sources, although gradually diminishing in prominence, still offer invaluable stabilizing effects, supplying power during extended periods of low renewable output.

Europe stands to reap enormous benefits from policies that advance demand-side flexibility (DSF) – i.e. the ability of customers to change their consumption and generation patterns based on external signals. In a 2022 study conducted with Smart Energy Europe, DNV included a scenario with the full activation of flexibility from buildings, EV, and industry in 2030. The results indicated consumers would directly save EUR 71bn annually, with further tens of billions of benefits in avoided peak generation capacity, less curtailment of renewables, lower requirements for distribution grid investments, and – most importantly – 37.5 million tonnes saved annually in GHG emissions.

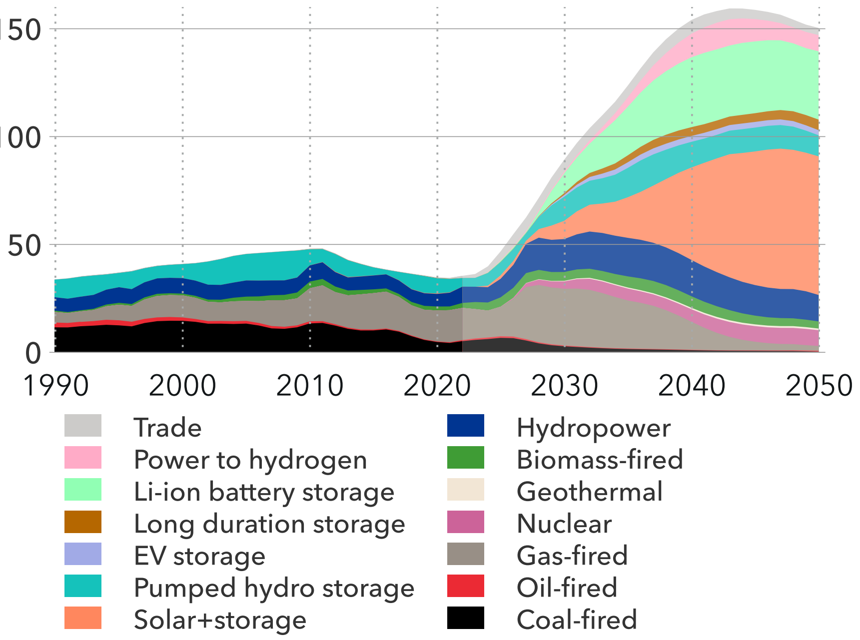
Figure 8.3.6 shows a way to quantify flexibility. By measuring the change in standard deviation with and without a particular technology in the system, we measure how much the variability is reduced by inclusion of that technology in the power system. One prominent observation is the rising importance of renewable and sustainable options, such as biomass, geothermal, and solar+storag, which show an increase in standard deviation impact over the years. As we move towards a cleaner energy future, these technologies will likely play an increasingly important role in reducing variability and enhancing system flexibility. At the same time, fossil-fuel options like coal-fired and gas-fired technologies, still hold substantial weight in providing system flexibility. However, given the global push towards decarbonization, these are more likely to be phased out or complemented by carbon capture technologies in the coming years.

Another interesting trend is the rise of storage technologies, including long-duration storage, Li-ion battery storage, and pumped hydro storage. The growing importance of these technologies indicates a shift towards a more adaptable and resilient power system that can better accommodate the intermittent nature of renewable energy sources. Vehicle-to-grid has also shown promise, albeit from a very low base, and given the projected surge in EV adoption, this could become a key flexibility provider by 2050. Power-to-hydrogen also offers a fascinating avenue for flexibility, potentially serving as a multi-sectoral energy vector that could integrate the electricity, heating, and transport sectors.

FIGURE 8.3.6

Europe reduction in hourly variability supplied by technology

Units: GW



Interconnections have emerged as another essential aspect in enhancing flexibility, particularly in more recent years. As countries diversify their energy portfolios and develop complementary strengths and needs, cross-border energy trade could offer another layer of system robustness and flexibility. This will be increasingly important as Europe seeks to balance the variable output from renewable sources across a continent with diverse geographic and climatic conditions.

Hydrogen, a future major energy carrier

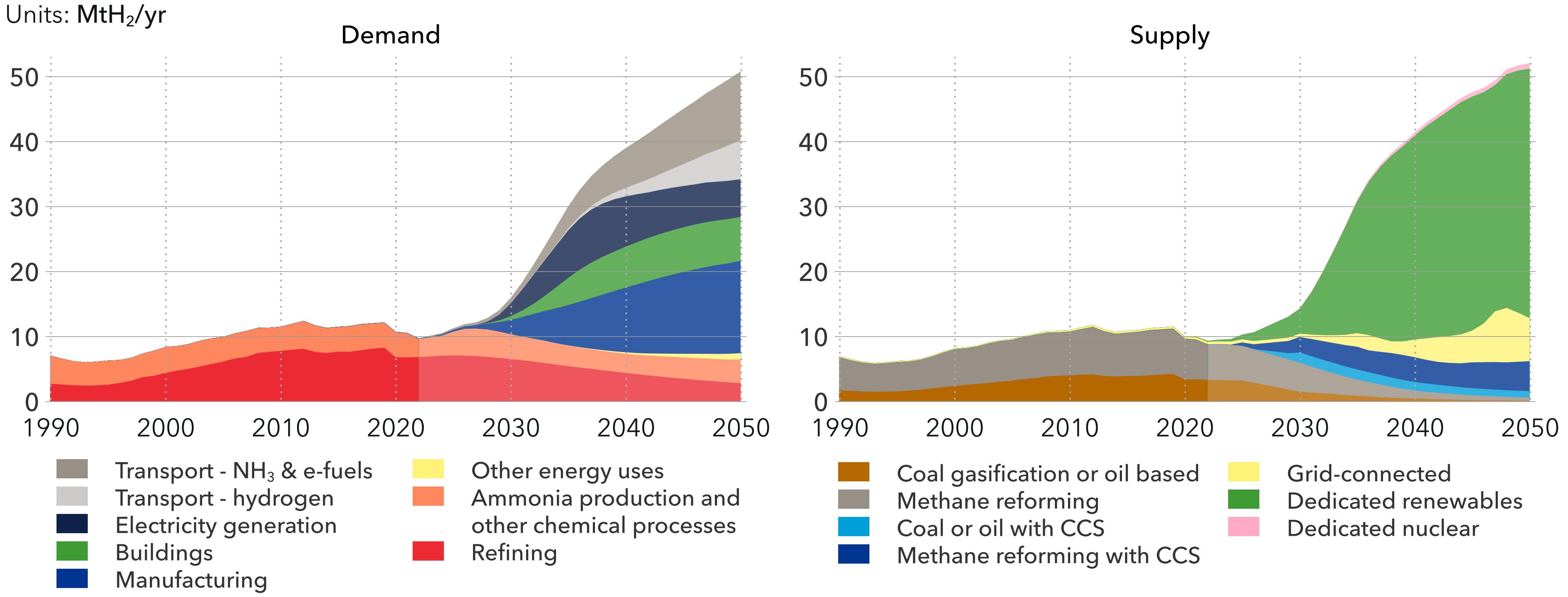
As Europe strides towards a sustainable future, hydrogen is emerging as the linchpin in its green energy matrix. With projections suggesting it will cater to 4% of the continent's final energy demand by 2035 and a substantial 12% by 2050, hydrogen's role is indisputable.

The manufacturing sector, often perceived as a bastion of traditional energy consumption, is poised to witness a profound transformation. By 2050, it is anticipated that a monumental 17.9 Mt of hydrogen will address 20% of Europe's manufacturing energy requirements, significantly outstripping the global average of 6%. This is not merely a shift in energy sources, it is a complete overhaul of methodologies. Notably, the iron and steel industries, which have been historically dependent on coal, will undergo radical change. The application of coal in these

FIGURE 8.3.7

Europe hydrogen demand and supply

Units: MtH_2/yr



industries will dwindle, largely supplanted by innovative hydrogen-based techniques, such as direct reduced iron (DRI). Pioneers like Hybrit have already taken the leap with pilot productions, with others like Arcelor plotting ambitious courses. Come 2050, hydrogen is projected to fulfil half of Europe's steel industry energy demand, echoing a broader continental commitment to sustainable production.

Yet, the hydrogen revolution is not confined to industrial juggernauts. Homes across Europe will soon be beneficiaries of this versatile energy source. The continent's sprawling gas network is ripe for a hydrogen-centric retrofit, ushering in an era of sustainable domestic energy. By the dawn of the 2030s, we can expect households to increasingly tap into pure hydrogen for their heating needs, although traditional sources will retain their primacy in the broader energy mosaic.

Europe's transportation narrative will also be rewritten by hydrogen. As we venture deeper into the 2030s, long-distance trucks traversing the continent's highways will be powered increasingly by hydrogen, with consumption estimates touching 4.6 Mt/yr by 2050. Similarly, the maritime and aviation sectors will not be left untouched. Derivatives of hydrogen, including ammonia and other e-fuels, are set to become the preferred choice, contributing an additional 12 Mt/yr of hydrogen consumption by the half-century mark.

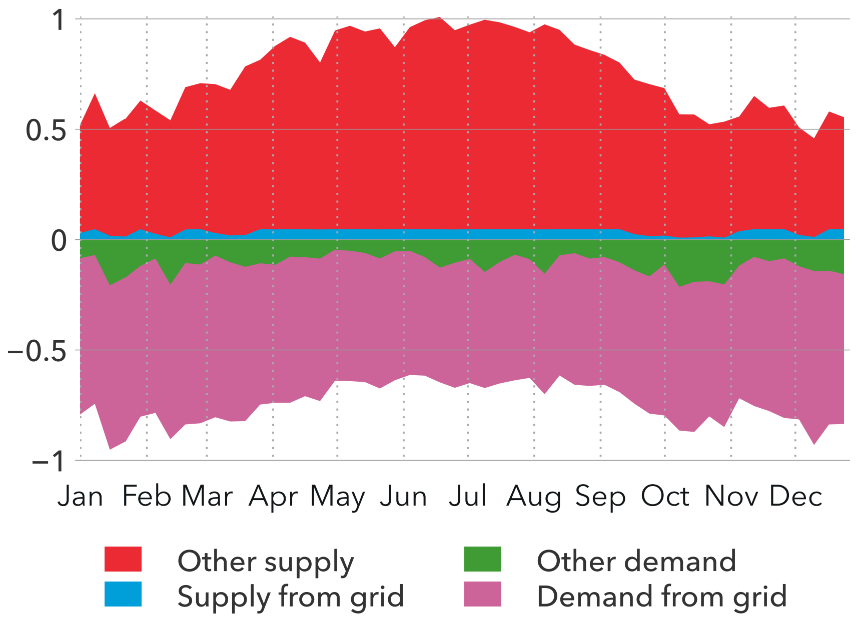
The electricity generation landscape will also be reshaped by hydrogen's ascendance. Despite inherent inefficiencies in its transformation back to electricity, the promise of hydrogen as a long-term storage solution – especially during extended periods of renewable excess or deficit – cannot be overlooked. It is projected that by 2035, a significant 7.3 Mt/yr of hydrogen will be harnessed to generate electricity, translating to 3.3% of Europe's power supply. With the eventual retirement of many traditional gas-fired stations, hydrogen will persist as a resilient and green power mainstay.

In Figure 8.3.8, we delve deep into the production and consumption patterns of hydrogen, both within the power sector and in other applications across the depicted region. By 2050, hydrogen's role in the power sector becomes more pronounced. During sun-rich summer months, electrolysers fed by grid electricity operate at peak capacity. However, when solar and wind outputs wane during certain times of the year, there is a dip in the capacity utilization of electrolysers. Consequently, power stations increase their reliance on hydrogen as a fuel source.

FIGURE 8.3.8

Weekly merchant hydrogen supply and demand in Europe in 2050

Units: MtH_2/week



Yet, it is worth noting that the power sector is not the sole consumer of hydrogen. Its demand in space heating is particularly seasonal, accounting for 20% of the annual hydrogen consumption in 2050. Hydrogen's use in sectors like aviation also exhibits seasonal fluctuations. To maintain a steady hydrogen supply, storage solutions become crucial. Predictions based on Figure 8.3.8 indicate that by 2050, at least 6.4 Mt of hydrogen storage will be needed to balance the temporal misalignment between supply and demand. This corresponds to about 10 weeks' worth of supply. Given the importance of maintaining a buffer, the final storage capacity is expected to exceed this estimate.

European nations, recognizing the strategic and environmental significance of hydrogen, are rallying to its cause. Individual countries are setting ambitious targets, each contributing to a unified continental vision. Denmark, France, Italy, Germany, and Spain are leading the charge with bold production goals, buoyed by substantial capital investments. Still, challenges loom large, with Europe potentially falling short of its *REPowerEU* plan's objectives.

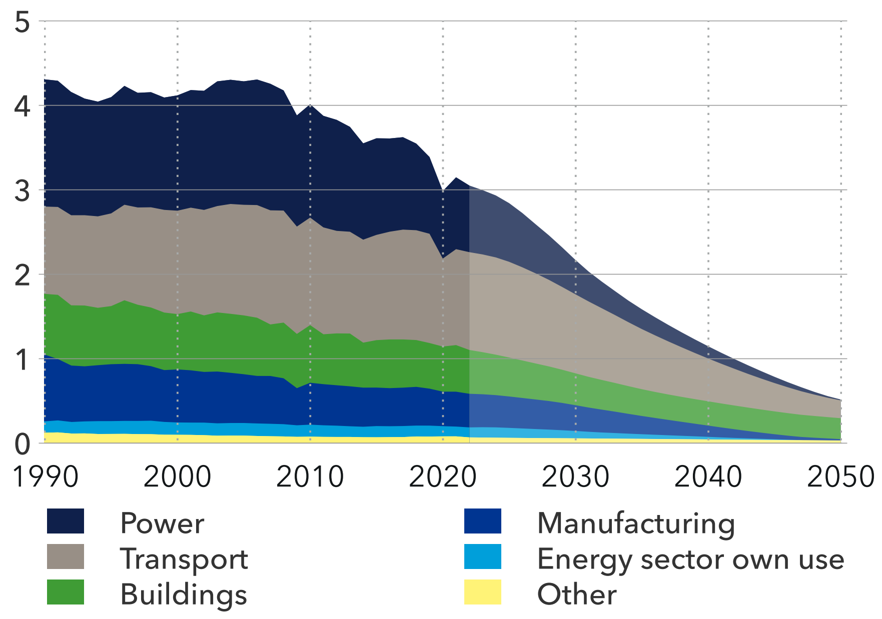
Supplementing internal production, Europe will lean on external imports, anticipating 4 Mt/yr by 2050. Key regions like the Middle East and North Africa will play crucial roles, with pipelines ferrying in 1.2 Mt/yr of the projected imports. The remainder will be sourced globally, primarily in the form of ammonia transported by ships.

The underpinnings of this burgeoning hydrogen economy are renewables. Wind is expected to contribute around 60% of dedicated production, with solar chipping in with 40%. As we approach the 2040s, the focus will shift towards grid-connected electrolysis, driven by the availability of copious, affordable electricity from renewable sources.

FIGURE 8.3.9

Europe energy-related CO_2 emissions by sector

Units: $GtCO_2$/yr



Historical data source: IEA WEB (2023)

While some may argue for the early adoption of technologies like steam methane-reforming (SMR), their long-term economic viability in Europe remains questionable.

Emissions

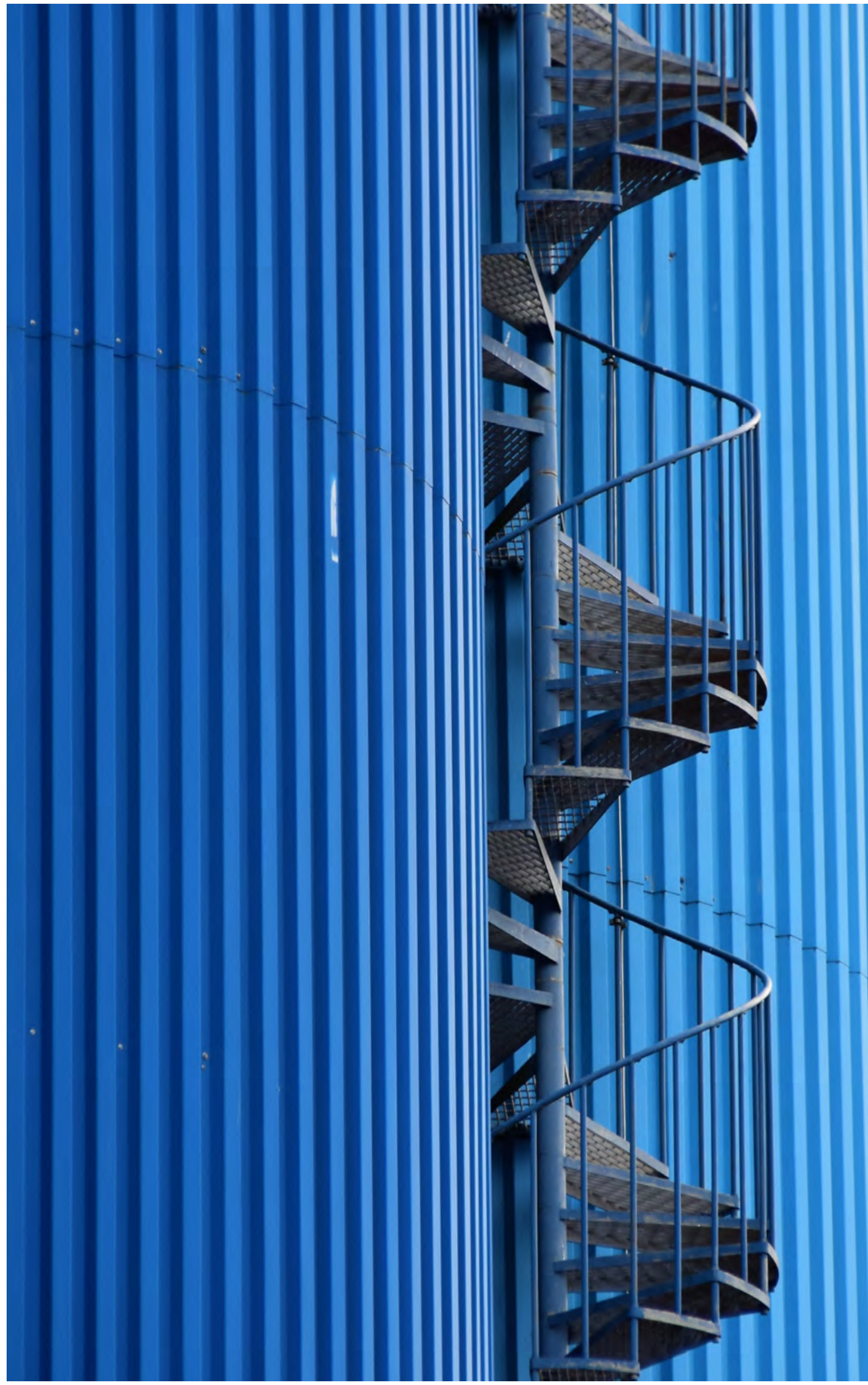
Figure 8.3.9 illustrates that the sectors of transport and manufacturing are at the forefront of reducing emissions. In the manufacturing sector, a decline in coal and gas usage plays a significant role, with green electricity, more affordable than ever, filling the gap. While emissions from coal usage will sharply drop, almost nearing extinction as its consumption diminishes, those from oil will take longer to subside. In the next three decades, oil-based emissions will persistently make up approximately half of CO_2 emissions. However, by 2050, they will have decreased to around a quarter of their current levels, primarily due to reduced oil consumption.

We foresee a regional average carbon price of USD 150/tCO_2 by 2030, increasing to USD 250/tCO_2 by 2050. Europe, having already introduced national and regional carbon pricing systems, showcases evident price increments. The EU ETS serves as a pivotal financing mechanism for transitioning to greener alternatives. Although 90% of industrial emissions currently enjoy exemptions from carbon pricing, we anticipate this privilege being phased out by 2034. Consequently, all industrial emissions across Europe will come under the carbon pricing umbrella.

When considering the EU and the UK's commitments in NDCs, they aim for CO_2 emission reductions of 55% and 68%, respectively, by 2030 when compared to 1990 levels. Keeping in mind that our predictions exclude country-specific and non-energy-related emissions, and that Europe's domain extends beyond the EU, our forecast suggests a 50% reduction in Europe's energy-related CO_2 emissions by 2030 from the 1990 benchmark. This is an improvement on the EU's original *Paris Agreement* commitment of 40%, yet it does not reach the 55% mark. By 2050, Europe's energy-related CO_2 emissions will have declined by 83% from 2022 levels, resulting in annual emissions of 0.51 $GtCO_2$, signifying that Europe might not fully achieve the prevalent net-zero pledges among its nations.

By 2050, after the successful capture and storage of 210 $MtCO_2$ by CCS and 110 $MtCO_2$ by DAC, the overall annual emissions in 2050 will stand at 530 $MtCO_2$. This means CCS, while having limited traction in Europe, will manage to capture 25% of the continent's energy-related emissions by that year, the highest percentage across all regions. Nonetheless, even with a carbon price tag of USD 250/tCO_2, CCS will encounter limitations in its supply chain and capacity, preventing it from fully neutralizing carbon emissions. This underscores the challenges of transporting and permanently storing carbon.

Europe's emissions will decline by 83% from 2022 to 2050.

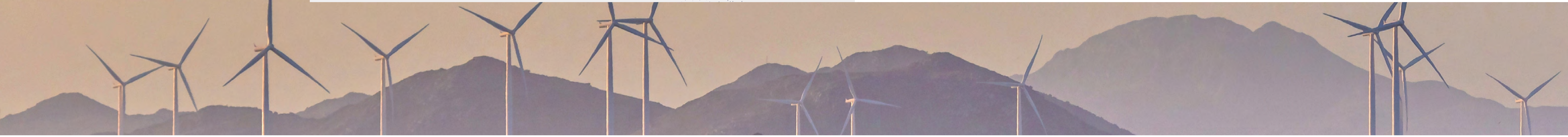


8.4 SUB-SAHARAN AFRICA (SSA)

This region consists of all African countries except Morocco, Algeria, Tunisia, Libya and Egypt, which are included in the Middle East and North Africa region

	Population (Billion)	GDP* (USD Trillion) GDP/person (USD)	Energy use (EJ) Energy use/person (GJ)	Energy-related CO_2 emissions (GT) Energy-related CO_2 emissions/person (Tonnes)
2022	1.2	5.5 4 600	28 24	1.1 0.9
2050	2.1	20.2 9 400	47 22	1.5 0.7

*All GDP figures in the report are based on 2017 purchasing power parity and in 2022 international USD



8.4 SUB-SAHARAN AFRICA (SSA)

Characteristics and current position

The region suffers from large energy generation and access gaps. Nearly half of the population lacks access to electricity (UNCTAD, 2023). In 2022, rising energy prices further slowed progress towards clean and affordable energy access (REN21, 2023a). Unreliable power is a major drag on economic activity, and results in costly and often polluting backup solutions.

Fossil fuels dominate electricity generation (66%). Solar PV accounts for a meagre 2% despite abundant renewable resource potential – often adjacent to severely underserved communities. Less than 1.5% of renewable energy financing invested internationally between 2000 and 2020 went to Sub-Saharan Africa (IRENA, 2023b).

The frequency of extreme weather events is increasing: e.g. tropical cyclone Freddy (March 2023) hitting Mozambique and neighbouring countries, devastating floods in Nigeria (2022), Horn of Africa drought (2020-2023). Capacity to shoulder reconstruction costs is limited and hampers much-needed new infrastructure build-out.

A confluence of challenges affect the region: the post-pandemic economic environment aggravated by geopolitical tension, climate-related investments remaining insufficient, and tighter global financing conditions and rate hikes by central banks in response to surging inflation. Many vertically integrated power utilities are state-owned which limits competition and private sector involvement. High indebtedness of governments negatively impacts the capacity to finance energy investments. Corruption generally favours fossil energy sources (Sayne, 2020; Burkhardt, 2023).

The region's energy transition priorities are energy and infrastructure expansion. The African Union Commission conceives of a just energy transition that includes universal access to modern energy, industrialization, job creation, and deploying clean technologies to decarbonize energy systems and put Africa on track for climate-friendly development (African Union, 2022).

Pointers to the future

- With underdeveloped legacy fossil-fuel based infrastructure in many region countries, and the combination of technology progress and renewable resource potential, the region stands on the cusp of a development path that leapfrogs to cleaner, flexible, and more efficient energy systems.
- Further natural gas investments in reserve rich Nigeria, Mozambique, the Republic of Congo, Mauritania, and Angola. will be spurred by domestic consumption and exports to high-demand markets, such as Europe replacing Russian supplies. But Europe decarbonizing towards 2050 will see oil and gas imports declining. Economic diversification through reinvestment of hydrocarbon revenue in renewable energy will be a precondition for seizing clean transition opportunities and avoiding lock-in to high emissions and potential stranded assets.
- Higher renewable electricity penetration is technically and economically feasible and will be the fastest-to-market solution in meeting energy needs. But just-transition finance initiatives, such as the Just Energy Transition Partnership (JTEP USD 8.5bn) to accelerate South Africa's decarbonization, will be key to transition fossil-fuel reliant countries.
- Concessional finance and loss guarantees, from multilateral finance institutions, are expected to help renewable energy projects and infrastructure build-out get off the ground and crowd in private sector investors.
- The availability of abundant renewable energy resources and large quantities of mineral resources provide an opportunity for industrial expansion, in terms of energy provision and establishment of local energy technology value chain steps, and for breaking the trade pattern of low value-added commodity exports.

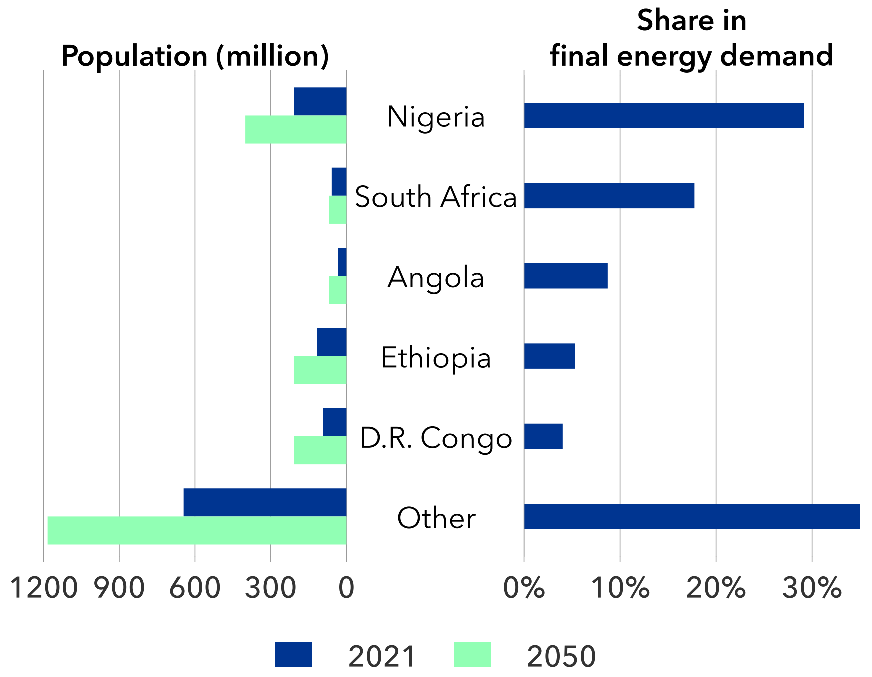
Energy transition: a green transition for a growing poulation

Sub-Saharan Africa is one of the regions that will undergo the most impressive transformation in our forecast period. It is currently the ETO region with the smallest energy demand, accounting for 5% of global energy demand, while representing 15% of the world population.

The shape of the transition will be decided in a handful of countries, as most of the energy demand is currently heavily concentrated locally, with Nigeria and South Africa accounting for about a half of the demand (see Figure 8.4.1). But the dynamics differ between those two countries in terms of energy demand, population, and GDP per capita.

FIGURE 8.4.1

Evolution of population for highest energy-demanding countries in Sub-Saharan Africa



Historical data source: IEA WEB (2023), UN (2023)

Across the region, the population will almost double while the region's economy quadruples over the forecast period. By 2050, 21% of the global population will be in Sub-Saharan Africa and the region's energy demand growth is projected to increase by 90% from today's level, while still representing only 8% of global energy demand by mid-century. By 2050, we forecast that two thirds of the energy demand from the region's fast-growing economies will be met by non-fossil sources. Traditional biomass will still represent about a half of the demand, but solar and wind will together grow to a 13% share.

International interest

The region is receiving increased global attention, and the development of the subcontinent's energy system will be at the crossroads of several global forces.

The US and China are tussling for influence across the continent. The BRICS summit in August 2023 demonstrated political alignment with China and a push to expand the BRICS membership to counter Western influence. However, given its own economic woes, China's capacity to invest in Africa appears constrained in the medium term. Africa is receiving heightened diplomatic attention from the US, as demonstrated by the December 2022 US-Africa Leaders summit in Washington, DC (Jalata, 2023).

In terms of climate justice, the region will probably experience the most severe effects from climate change, although it has historically been responsible for a very small amount of global emissions. The call for global action in helping to address this pressing issue was repeated at the Africa Climate Summit held in September, where a new financing architecture for development and energy transition was proposed.

There is rising interest in the subcontinent's rich endowment of natural resources. Primary goods (agricultural products, minerals, metals, fossil fuels), currently dominate the region's exports. China has expanded economic relations to become the region's largest trade partner, accounting for 20% of total trade value (IMF, 2019). The energy transition will continue to attract interest to the region, with for instance D.R. Congo representing more than two thirds of global production of cobalt, currently used in batteries. In December 2022, the United States signed a MoU with the DRC and Zambia to strengthen the supply chain for EV batteries.

Fossil fuel dependence

Close to half of Sub-Saharan Africa's export value is composed of fossil fuels, even though the subcontinent has a relatively small role in global fossil fuel production, with respective shares of 4% for coal, 5% for crude oil and 2% for natural gas. There is a longstanding presence of international oil and gas companies with Sub-Saharan Africa countries relying on these players in the development of hydrocarbon resources. The lived experience of the region's oil-producing countries tells a story where oil wealth has not been successfully converted into diversified economies; in both Angola and Nigeria,

> By 2050, Sub-Saharan Africa will be home to 21% of the global population but will account for just 8% of global energy demand.

the region's largest economy, earnings from petroleum production make up 50% of government revenue. At the same time, there is a high dependence towards imported refined products (66 billion USD in 2021), which almost offsets revenues from petroleum exports (44 billion USD - World Bank, 2022).

The opening of the very large Dangote refinery in recent months is a step towards alleviating Nigeria's fuel crisis. The country has had almost zero refining capacity for a number of years due to theft, vandalism and structural neglect of existing refineries. To maintain affordable prices for the local population, the government had heavily subsidized gasoline. As this became unbearable for the state budget, the government scrapped the 10 billion USD/yr subsidy in May 2023, leading to large street protests as petrol prices have soared. Similar protests against fuel hikes have been observed in Angola and Kenya in 2023, showing the vulnerability of this fossil-fuel subsidies model.

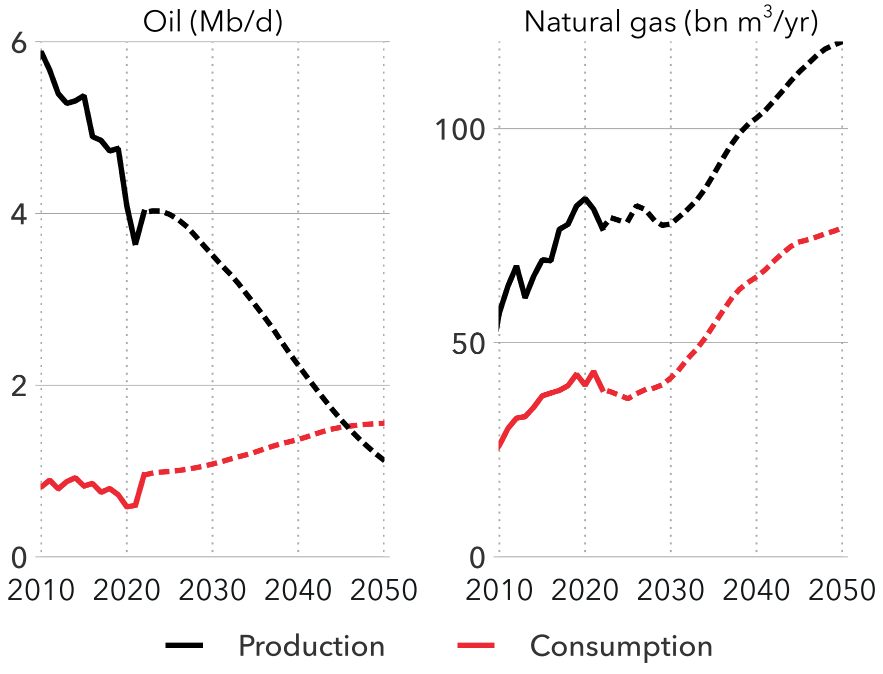
On average, oil and gas assets in Africa are 15% to 20% more expensive and exhibit 70% to 80% higher carbon intensity compared to global counterparts (McKinsey, 2022). As a result, we forecast the region to become less attractive for investors. The resulting trends are shown in Figure 8.4.2:

- Crude oil production will continue to decline to around a quarter of today's level by 2050. At the same time, consumption will increase, and the region will even become a net importer of oil products in the mid-2040s.

- Natural gas production will on the other hand increase by more than 50%, but exports will only rise by 20%, as regional consumption also increases.

FIGURE 8.4.2

Sub-Saharan Africa oil and natural gas flows



Our forecast underlines the further need for diversification of revenue streams, as petroleum export revenues will decline while the population continues to grow.

The opportunity for leapfrogging

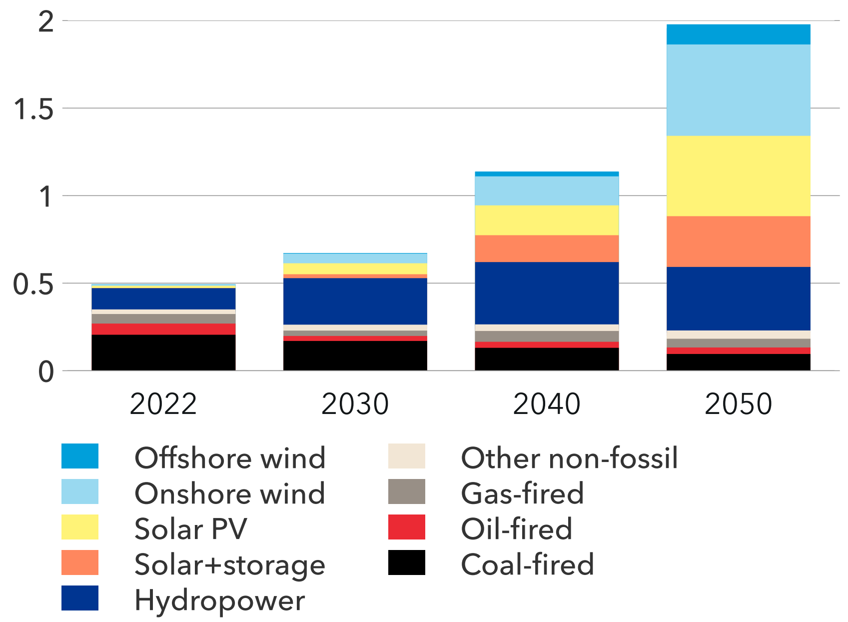
Electrification is key to the energy transition, but electricity still plays a minor role in Sub-Saharan Africa. For instance, France (144 GW), had more installed electricity capacity than the entire Sub-Saharan region (143 GW) in 2022.

South Africa alone is home to 58 GW generation capacity from all sources, with coal-fired capacity holding by far the largest share in the national power mix (86% of all Africa's coal-fired generation capacity is found in South Africa).

FIGURE 8.4.3

Sub-Saharan Africa grid-connected electricity generation by power station type

Units: PWh/yr



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

Electricity uptake is restricted by a slow increase in demand sectors such as transport and across the subcontinent last year electricity represented only 6% of final energy demand, a value three times below the global average. There are, however, targets focusing on renewables expansion in power generation, e.g. Kenya for 100GW capacity by 2040, and others for renewable power shares around 30% to 40% by 2030, Tanzania for 50% by 2030. Renewable energy auctions have been implemented in Uganda, South Africa and Zambia; Ghana, Tanzania and Kenya are adopting similar practice, that will boost the installation of new capacity.

A dramatic shift is predicted for the region's power systems. Drivers of such a shift will primarily come from global flows of capital seeking decarbonization, both from public (multilateral development agencies and donor government investments) and private investors. The changing on-grid electricity mix is summarized in Figure 8.4.3.

South Africa will be decommissioning coal-fired plants and both coal and oil-fired generation are set to decline across the entire region. Today, 66% of on-grid generation is fossil-fired, hydropower accounts for 25%, and other renewables have minor shares. Over the forecast period, this picture will flip. By 2050, fossil-fuelled power will only make up 9% of on-grid generation, in which coal-fired plants will account for 5%. Hydropower will account for 18% and other renewables will have 33% of the on-grid power mix, with solar PV (with and without storage) combined accounting for 38% and wind power 32%.

Utility-scale grid-connected non-hydro renewables (like solar PV and wind) will especially scale from the late 2030s onwards, but prior to the utility-scale expansion, there will be significant off-grid capacity additions, as we detailed in the 2022 Outlook (DNV, 2022b).

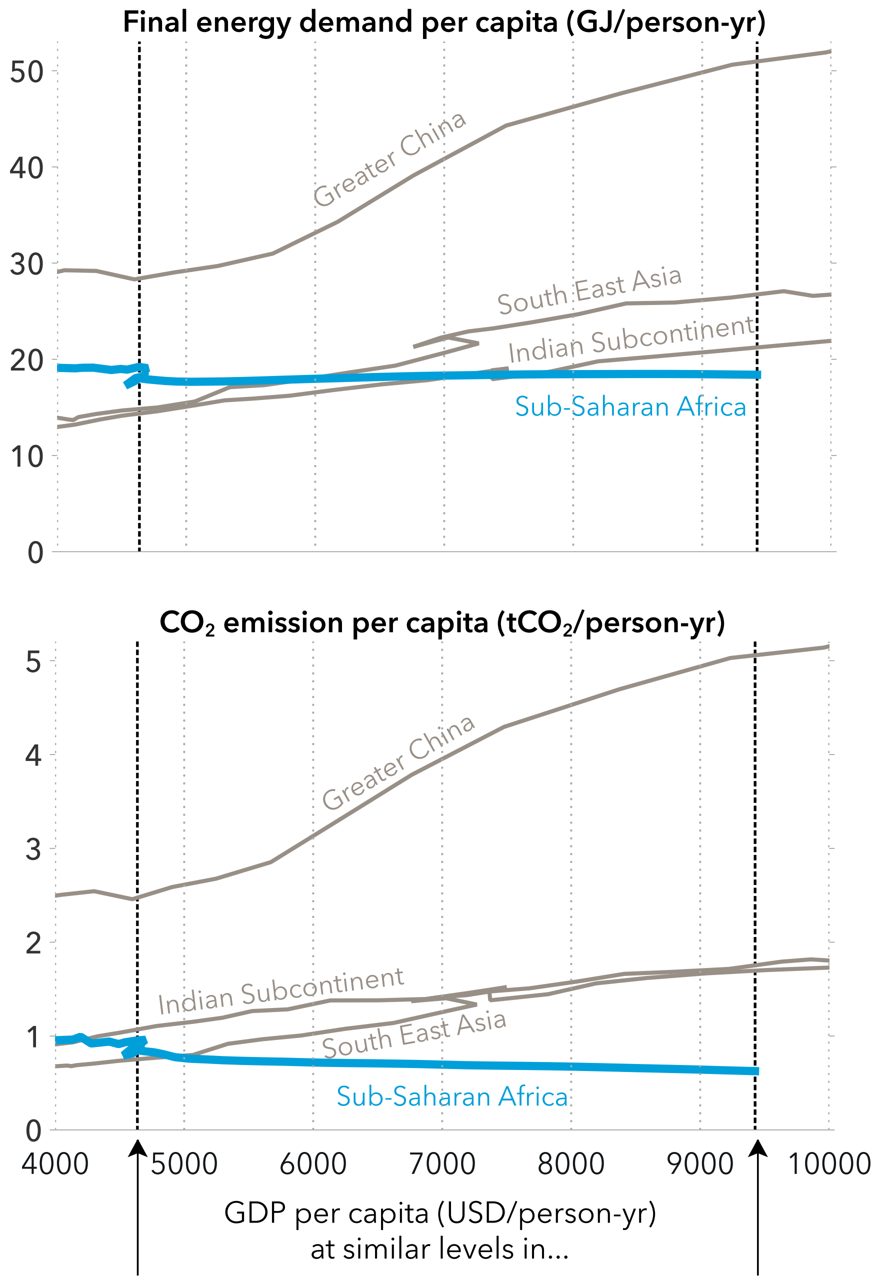
Supported by this unique decarbonized power mix, Sub-Saharan economies will have the opportunity to close the electricity access gap without going through the high-carbon phase that industrialized regions have experienced, as shown in Figure 8.4.4. In other words, the region can and will leapfrog straight onto a greener pathway with low-carbon energy technologies. The key challenge, however, remains sufficient generation and transmission capacity to make a substantial difference to the subcontinent's development trajectory.

The grid challenge

What matters to Africa is not so much the percentage uptake of renewable in the power mix as the scale of electricity generation and availability. Sub-Saharan Africa's grid-connected electricity demand per capita is only at one third of the Indian Subcontinent level and well below global average. About a half of the population presently lacks access to electricity. In fact, a larger share of the population currently has access to off-grid diesel generators than to traditional grids (DNV, 2022b).

FIGURE 8.4.4

Comparison of per capita indicators trajectories vs. GDP per capita



2022	Sub-Saharan Africa	2050
1999	Greater China	2007
1988	South East Asia	2007
2009	Indian Subcontinent	2025

There is insufficient interconnection between the different countries in the region, hindering the development of new utility-scale power plants and tapping into the vast potential of variable renewables (wind and solar PV). These sources are more vulnerable to poorly developed grids than fossil-fired power plants, as their integration requires a finely balanced and highly interconnected grid.

As demonstrated in other regions of the world, building up transmission lines can be done quickly. For instance, the world's longest transmission line – the HVDC Bel Monte line in Brazil, completed in 2019 – took just 18 months to build. The challenge in Sub-Saharan Africa is not really a permitting problem that is leading to a bottleneck in grid build-out in higher-income regions with established power systems. Sub-Saharan Africa's low grid development is rather a combination of a lack of finance, technological know-how and suitable business models.

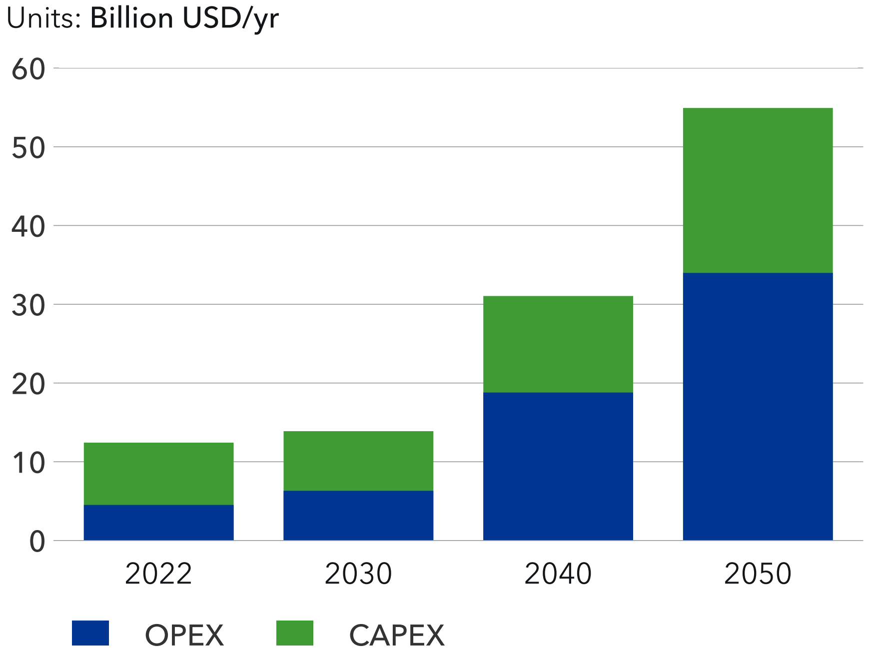
This has been clearly acknowledged, and international support is building. One of the latest examples being the agreement between IRENA and AUDA-NEPAD to support a more "interconnected, flexible and reliable power grid" (IRENA, 2023c). China is also active through its Belt and Road Initiative, with several power-lines already financed alongside numerous renewable power plants. Regional initiatives like the African Single Electricity Market initiated by the African Union in 2021 are also important to build the essential cooperation for renewable power expansion. In addition, strategies and technologies to combat cable theft, a particular problem in South Africa, are urgently needed.

Our forecast (Figure 8.4.5) shows that grid expenditures will grow four-fold to 2050, with investments (CAPEX) growing from USD 5bn in 2022 to more than USD 30bn in 2050. This will especially support the tripling of transmission (greater than 37 kV) power line length across the region. The region will however by far retain the lowest grid length per capita globally, with 330km per 100,000 inhabitants by 2050. The two other lowest GDP per capita regions, Indian Subcontinent and Latin America will reach 1500km and 2200km, respectively.

Despite all these developments, we still forecast grid-access to stay low, with less than 20% of the population connected by 2050 (DNV, 2022b). For the rest of the population, especially in remote rural areas, mini-grids and off-grid systems, mostly solar based, will be the most viable solutions. These solutions are easier to put in place, as they have lower cost, require less central planning, and can be adapted to local needs. They are considered as essential complementary tools to close the energy access gap as quickly as possible (World Bank, 2023d). However, we caution that off-grid renewable energy-based projects regularly fail to transition from pilot, donor-sponsored projects, and require robust financing, local skills development and targeted policies (Nyarko et al., 2023). Although non-transmission strategies, including off-grid access and mini-grids, will bring basic electricity access to hundreds of millions of people in Africa and India, industrial development requires robust grid build-out. For Sub-Saharan Africa, the grid remains key in unlocking the subcontinent's economic potential.

FIGURE 8.4.5

Sub-Saharan Africa grid expenditures



By 2050, fewer than 1 in 5 people in Sub-Saharan Africa will have access to grid-connected electricity.

Sectoral demand and fuel mix

The breakdown of energy demand by sector and their corresponding fuel mix is given in Figure 8.4.6.

Buildings

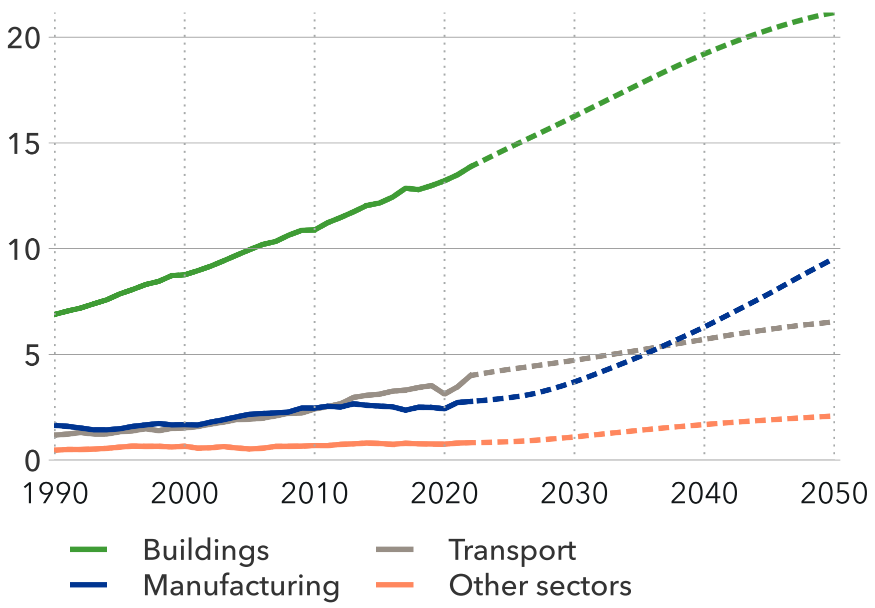
With a growing population, buildings will remain the biggest source of final energy demand. They presently constitute 68% of demand, and we foresee this declining to account for 49% in 2050. Much of the buildings stock existing by the end of the forecast period has yet to be built, and we project the floor area of residential and commercial buildings to more than double and triple, respectively.

Energy demand in the sector will be driven by a combination of more residential/commercial space,

FIGURE 8.4.6

Sub-Saharan Africa energy demand by sector

Units: EJ/yr



Historical data source: IEA WEB (2023)

a more prosperous population, and improved standards of living/comfort (e.g. air conditioning). Greater energy efficiency will partially counteract this as the technologies meeting the expanding energy needs will change so that energy use of buildings increases by only 37%. Energy from mostly inefficient traditional biomass, supplying 92% of energy for use in buildings today, will decline to around 70% by mid-century. Electric power (on-grid electricity and off-grid solar PV) will expand to account for 17% of the energy for buildings. An expansion in off-grid solar PV solutions will fuel growth in the use of appliances and lighting, accounting for 24% of this segment's demand in 2030 and 45% by mid-century.

Manufacturing

The level of activity in the region's manufacturing sector is presently small, with low levels of industrialization, and dominated by extractive industries and export of raw materials with little further value added. The region is the most commodity-dependent region in the world (UNCTAD, 2023) and in 2019, Africa's manufacturing value added (MVA) per capita of about USD 207 was about 12% of the global average (IRENA, 2022). Manufacturing will grow strongly, and its energy demand will double, and its share in final energy demand will double from its present 12% to reach 24% by 2050.

Transport

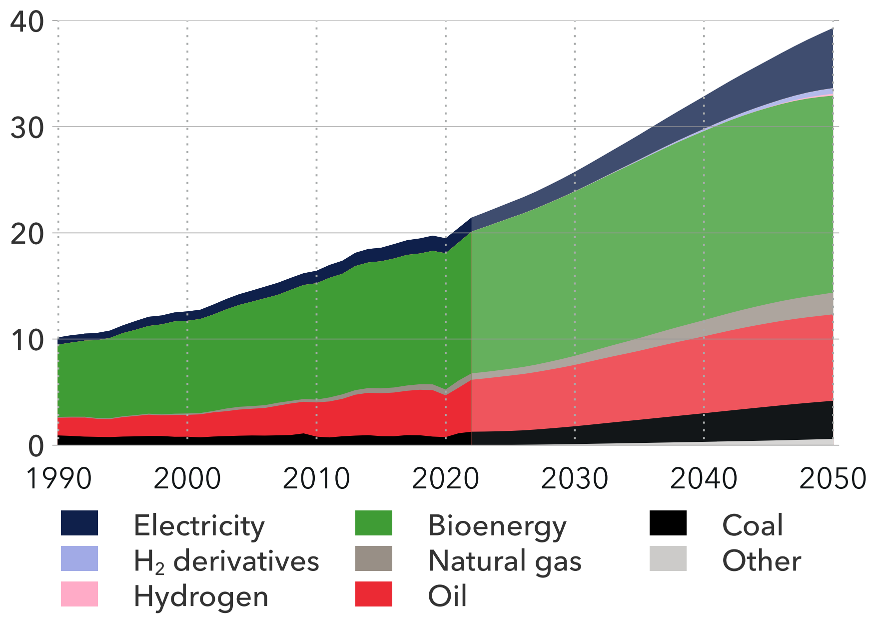
Transport energy demand presently is 99% reliant on oil. In road transport, the number of vehicles will increase almost three-fold over the forecast period. Internal combustion engine passenger vehicles (ICEVs) still account for more than 90% of sales of new vehicles in 2040, and though the sales share declines to 26% in 2050, the fleet is still 68% oil dependent then. Energy demand for transport purposes will more than triple. Specifically, oil use in road transport will double, and oil will still represent 87% share of the subsector's energy mix, with electricity accounting for just 12%.

While there are some initiatives in electric mobility, there is a lack of supporting policies, and the region's electricity deficit also hinders electrification of road transport. There is also uncertainty about the role of second-hand EVs coming from higher-income regions in electric uptake. Unlike petrol cars, used EVs might not be imported in Sub-Saharan Africa, as regions will keep access to valuable battery components.

FIGURE 8.4.7

Sub-Saharan Africa final energy demand by carrier

Units: EJ/yr



Historical data source: IEA WEB (2023)

Fuel mix

Overall, our forecast for energy demand (Figure 8.4.7) in Sub-Saharan Africa indicates some positive trends: a steady use of biomass hides its declining share in the energy mix (reducing from 66% to 40%), and a more than 300% rise in electricity use to 2050 as its share increases from 7% to 15%. However, use of coal and especially oil expands, both retaining much higher shares than natural gas, with oil's persistence reflecting a lack of gas infrastructure.

Emissions

Our projection for the regional average carbon-price level is USD 2/tCO_2 in 2030 and USD 20/tCO_2 by 2050 (see Section 6.3). We expect slow adoption and limited explicit carbon pricing instruments in the region due to the predominant development focus. Future schemes will be motivated by access to climate finance and to avoid carbon-border adjustment mechanisms.

In the context of global climate policy, Sub-Saharan African country pledges in NDCs suggest the regional target is for emissions to grow no more than 68% by 2030 relative to 1990. These are unconditional targets, and some countries expect further reductions provided there is international support. Our Outlook indicates energy-related CO_2 emissions rise 114% over that period, suggesting that the ambitions are not met. Looking ahead to 2050, very few Sub-Saharan African countries have adopted targets to reduce CO_2 emissions. Our Outlook estimates energy-related emissions of 1.3 GtCO_2 per year in mid-century, 33% above 2022 levels.

8.5 MIDDLE EAST AND NORTH AFRICA (MEA)

This region stretches from Morocco to Iran, including Turkey and the Arabian Peninsula

	Population (Million)	GDP* (USD Trillion) GDP/person (USD)	Energy use (EJ) Energy use/person (GJ)	Energy-related CO_2 emissions (GT) Energy-related CO_2 emissions/ person (Tonnes)
2022	536	12.9 23 000	54 96	2.9 5.1
2050	770	28.9 37 000	72 93	2.6 3.3

*All GDP figures in the report are based on 2017 purchasing power parity and in 2022 international USD

8.5 MIDDLE EAST AND NORTH AFRICA (MEA)

Characteristics and current position

The region is a cornerstone of the global energy system, accounting for more than half (57%) of the world's oil reserves and two-fifths (41%) of its gas reserves (Keltie, 2022). In 2022, it produced more than a third (36%) of the world's oil and nearly a quarter (24%) of its gas.

Recent high oil prices have brought strong economic growth and record company profits to Gulf states, but also a spiralling liquidity crisis among energy importers such as Egypt.

Ample solar irradiation and areas with suitable wind resources make conditions favourable for renewables-based electricity generation. Renewable capacity reached a record high 12.8% (3.2 GW) increase in 2022 with Iran, Israel, United Arab Emirates (UAE), and Jordan leading in the region (IRENA, 2023b).

The region's hydrocarbon-producing countries aim to maintain their world-leading energy-export position by developing low-carbon solutions, such as hydrogen and carbon capture, utilization, and storage (CCUS), to guarantee future revenues. The Gulf Cooperation Council (GCC) countries have joined several international initiatives, such as the Carbon Sequestration Leadership Forum, the Oil and Gas Climate Initiative, the Net Zero Producers Forum, and the Global Methane Pledge.

State-owned companies and sovereign wealth funds are transition investment vehicles. For example, the Kingdom of Saudi Arabia (KSA) is pouring USD 270bn into its power sector between now and 2030, with investments in CCS and is also investing in domestic EV manufacturing. The UAE renewable energy company Masdar's global portfolio of clean energy projects was valued at USD 30bn in early 2023 (Zawya, 2023).

Pointers to the future

- Renewable electricity is primed for rapid expansion driven by competitive tendering and countries targeting increasing shares of renewables in power generation. Tunisia is aiming for 30%, Israel 40%, Morocco 52%, and KSA 50% by 2030, while Egypt is aiming for 40% by 2035. The UAE targets 14.2 GW renewable capacity by 2030 (from current 3.7 GW).

- Renewable electricity will meet soaring domestic electricity consumption, free up oil and gas for exports, and facilitate electrification in extractive industries. The Greece-Egypt (GREGY) interconnection prospect, currently in an accelerated development phase, would enable clean electricity supply to Europe (EuroNews, 2022).

- In low-carbon hydrogen, UAE is aiming for 25% of the global market by 2030 with electrolysis capacity to produce 15 Mt/yr by 2050, and is piloting use domestically through the Dubai Electricity & Water Authority (DEWA) Green Hydrogen project with Siemens. In Oman, Hydrom recently awarded USD 20bn to three projects, covering renewable generation, production, derivatives conversion, and offtake (Hydrom, 2023). KSA has initial agreements to develop a USD 5bn green ammonia production facility as part of the USD 500bn NEOM Green Hydrogen Company development.

- In road transport, policy is developing. A Gulf Cooperation Council (GCC) states' charging corridor is proposed (ETN, 2023). UAE promotes EVs for a 50% share of total passenger vehicles in 2050. Israel aims for fully electric public transport by 2030 and internal combustion engine phase-out (passenger vehicles) by 2035. Morocco is pioneering heavy electric trucks (Smith, 2023). However, fuel-price subsidies will delay the transition.

- UAE is hosting COP28 in 2023. Several region countries have net-zero commitments, but these ambitions are dwarfed by fossil-fuel expansion plans.

Energy transition: oil for export and renewables at home

As one of the most fossil-fuel-rich regions, the Middle East and North Africa has not been at the forefront of the energy transition so far. Things are starting to change, however, with global zero-carbon targets pushing the region's countries towards developing their own carbon-neutrality targets and low-carbon fuel strategies. Egypt, for example, is aiming to provide the lowest-emission natural gas and is emerging as an exporter of low-carbon LNG, electric power, and green ammonia to Europe and beyond. Morocco is on track to achieve its renewable energy targets with a 52% share of renewables in its electricity mix, exemplified by generating 1.77 GW from hydropower, 1.43 GW from wind, and 0.83 GW from solar, all in 2022. In the Gulf, KSA, UAE, and Oman have issued ambitious hydrogen strategies, and are set to exploit abundant access to solar and wind power and to use natural gas reserves for blue hydrogen (Dubai Future Foundation 2022).

Figure 8.5.1 shows developments in primary energy supply for the Middle East and North Africa region. Primary energy is expected to grow by a third (33%) over the next three decades, from 54 EJ in 2022 to 72 EJ in 2050. Nearly a third (31%) of this growth happens before 2040 as annual oil increases 8% from 18.5 EJ to 20 EJ, and gas supply rises nearly 23% from 31 EJ to 38 EJ. Energy supply grows by only about 2% between 2040 and 2050 due to greater electrification of various sectors and a doubling in the energy that comes from non-fossil energy carriers (11 EJ to 23 EJ). Energy supply from oil and gas decreases by 20% (20 EJ to 16 EJ) and 16% (38 EJ to 32 EJ), respectively. By 2050, with 27% renewables in the primary energy supply mix, this oil- and gas-rich region will still rely predominantly on fossil fuels to provide its energy, even though today's shares of oil (35%), gas (58%), and coal (4%) in primary energy are expected to fall to 22%, 45%, and 2%, respectively, by mid-century. The overall regional picture can be described as oil giving way to solar to a significant degree, natural gas persisting as a 'transition fuel', and wind being slow to take off; large areas in the region with abundant low altitude wind resources and advances in wind turbine design to cope robustly with hot, sandy conditions will enable this.

Electricity

Figure 8.5.2 visualizes trends in on-grid electricity generation by power station type for the region. In this picture, the transition is more marked than for overall primary energy. Between 2022 and 2050, annual electricity generation grows three-fold, from 2,135 TWh today to 6,310 TWh by 2050. While almost absent from the mix today, solar and wind are expected to provide 46% and 31%, respectively, of the region's electricity by 2050. 28% of this solar electricity generation is expected to be in solar+storage power stations, a technology expected to start taking off in the mid-2040s in the region. Most of the wind power will be onshore in our forecast, with fixed offshore wind farms constituting 22% of total generating capacity and floating offshore expected to be around 4% by mid-century.

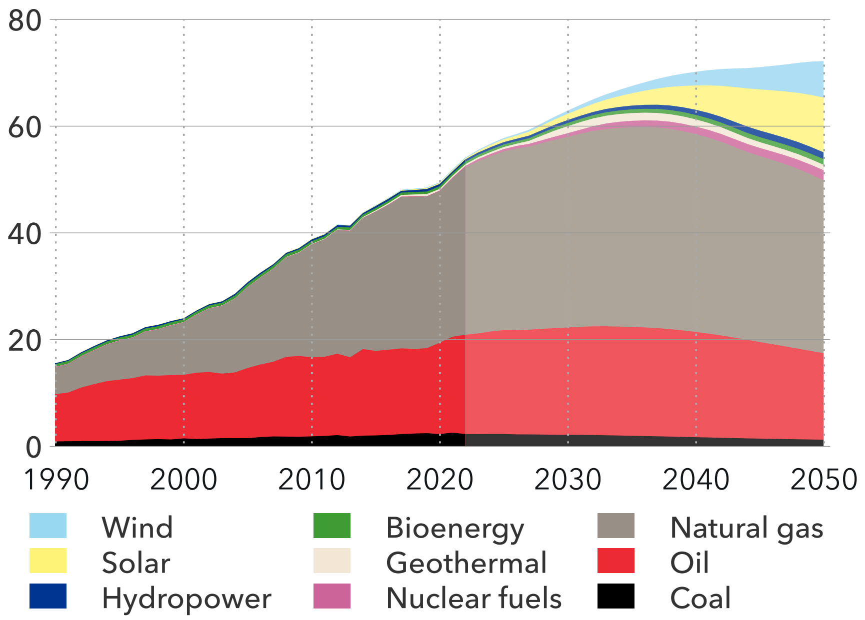
Final energy demand

Figure 8.5.3 depicts the growth in total energy demand by demand sector from 1990 to 2050. Total energy demand rises by half (50%) over the next three decades, from 37.5 EJ in 2022 to 56.2 EJ in 2050. The growth rate for 2037 to 2050 is half that seen in 2022 to 2037, due to trends in transport. Annual demand from road transport is expected to peak around 13.6 EJ between 2037 and 2041, thereafter gradually declining to 13 EJ in 2050 due to EV uptake in the 2040s. In mid-century, the share of electricity in the road transport energy mix is expected to be

FIGURE 8.5.1

Middle East and North Africa primary energy consumption by source

Units: EJ/yr

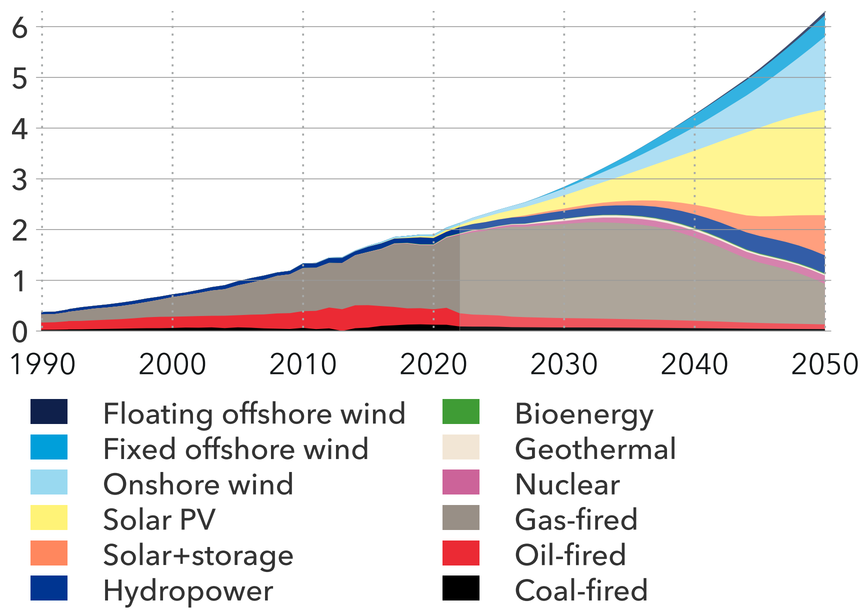


Historical data source: IEA WEB (2023)

FIGURE 8.5.2

Middle East and North Africa grid-connected electricity generation by power station type

Units: PWh/yr

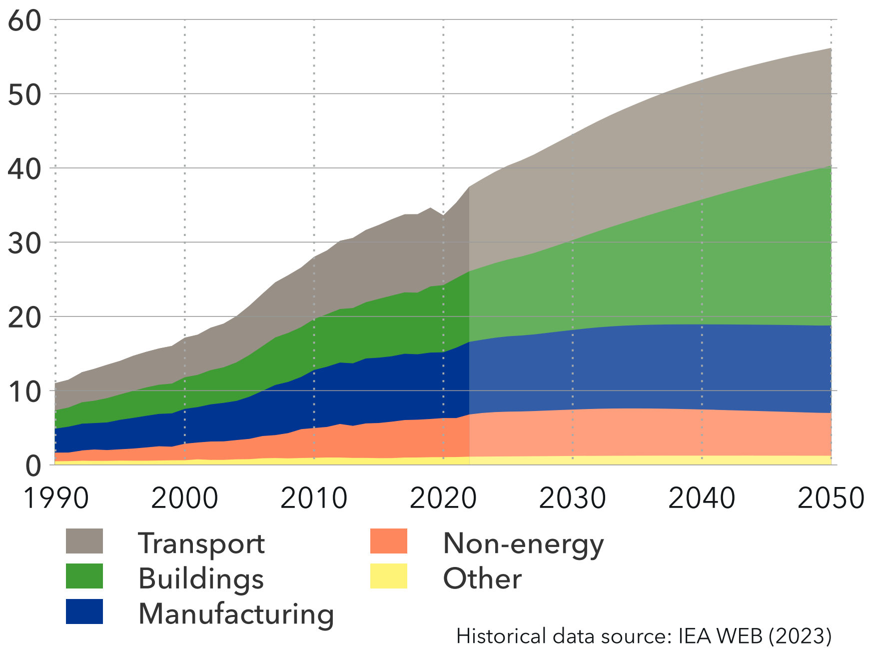


Historical data source: IEA WEB (2023), GlobalData (2023)

FIGURE 8.5.3

Middle East and North Africa final energy demand by sector

Units: EJ/yr



Historical data source: IEA WEB (2023)

nearly a fifth (19%) as the Middle East and North Africa is moving forward with implementing policies and regulations around EV charging infrastructure. While the region's current EV adoption might appear modest, a new dawn is emerging. The UAE's capital Abu Dhabi recently published its regulatory policy for EV charging infrastructure toward its target of carbon-neutrality by 2050. In May 2023, Einride AB, a Swedish freight mobility company, and the UAE Ministry of Energy and Infrastructure partnered to deploy a freight mobility grid ranging over 480 kilometres across Abu Dhabi, Dubai, and Sharjah, and comprising 2,000 electric trucks, 200 autonomous trucks, and eight charging stations (Einride 2023). Saudi Arabia has been working on its own brand of Evs, CEER, to produce EVs for domestic sales and regional exports in addition to owning about 60% of luxury EV maker Lucid Motors (Goldberg, 2023).In Bahrain, Gauss Auto Group, an American manufacturing corporation, partnered this year with Bahraini company MARSON Group to open an EV manufacturing plant in the country (Gauss Auto, 2023).

The fastest growing demand sector is buildings, with space cooling in turn the quickest growing subsector (Figure 8.5.4). Out of the total 18.7 EJ growth in annual total energy demand in all sectors, 4.2 EJ (23%) originates from a surge in demand for space cooling, which grows more than five-fold from 0.9 EJ to 5.1 EJ per year. This is despite a 30% improvement in the average efficiency of cooling equipment, meaning that useful energy demand for space cooling is expected to grow even more rapidly. This spectacular rise in demand for space cooling is due in part to the warming climate, leading to a 30% increase in the number of cooling degree days by 2050. Other drivers for increased space cooling demand are a doubling of GDP per capita in the region and a more than doubling of building floor area reflecting population growth and a rising standard of living.

Key questions are which energy carriers are going to meet the 56.2 EJ of annual energy demand in the region by 2050 and how will the carrier mix differ from today. Figure 8.5.5 depicts developments in energy demand by carrier. Note the remarkable near tripling in electricity demand from 6.2 EJ to 17.8 EJ per year while doubling its share in total energy demand. Oil demand remains relatively steady, but its share in the mix diminishes from 37% to 24%. In parallel, the demand for natural gas rises from 16 EJ to 22 EJ, yet its share declines from 42% to 39%.

From hydrocarbon to hydrogen

Figure 8.5.6 shows the take-off in annual hydrogen production in the Middle East and North Africa starting in the 2030s. It will grow 50-fold in two decades, from around 0.2 Mt in 2030 to nearly 9 Mt in 2050. The rates of growth for blue hydrogen (from methane reforming of natural gas with CCS) and green hydrogen (via electrolysis using grid-connected electricity) are almost the same for much of the forecasting period. However, toward the end of the Outlook, green hydrogen surpasses blue hydrogen.

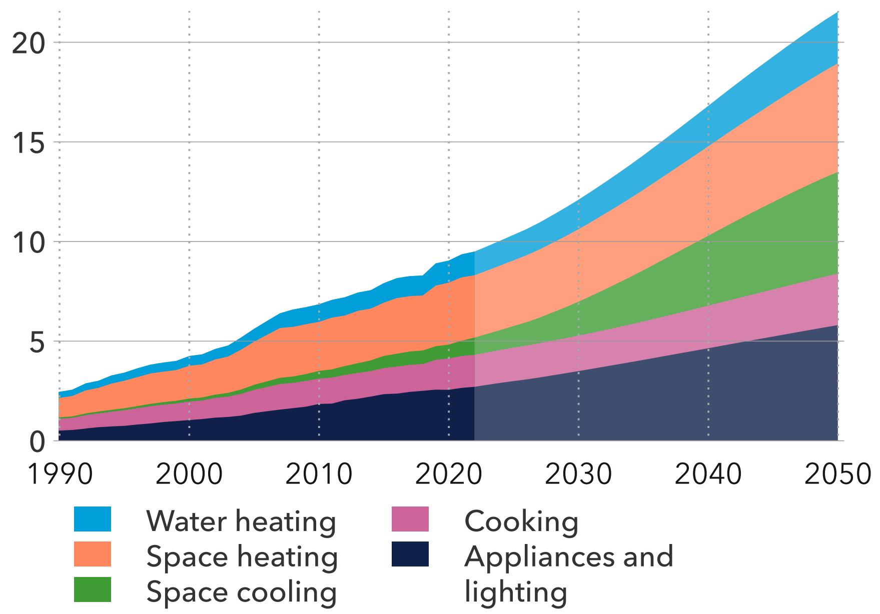
This eventual divergence is a direct result of developments in the levelized cost of hydrogen production, as demonstrated in Figure 8.5.7 for selected production pathways. Thanks to low prices for locally extracted natural gas, blue hydrogen remains the most economically viable route throughout the forecast period. However, with the rapid growth in solar electricity generation (shown in Figure 8.5.2) and the associated reduction in costs thanks to cost-learning curves, dedicated solar and grid-connected electrolysis become competitive production pathways after 2045.

Recent market and policy developments in the region indicate a clear push for green and blue hydrogen and derivatives like ammonia and e-methanol. The region

FIGURE 8.5.4

Middle East and North Africa buildings energy demand by subsector

Units: EJ/yr

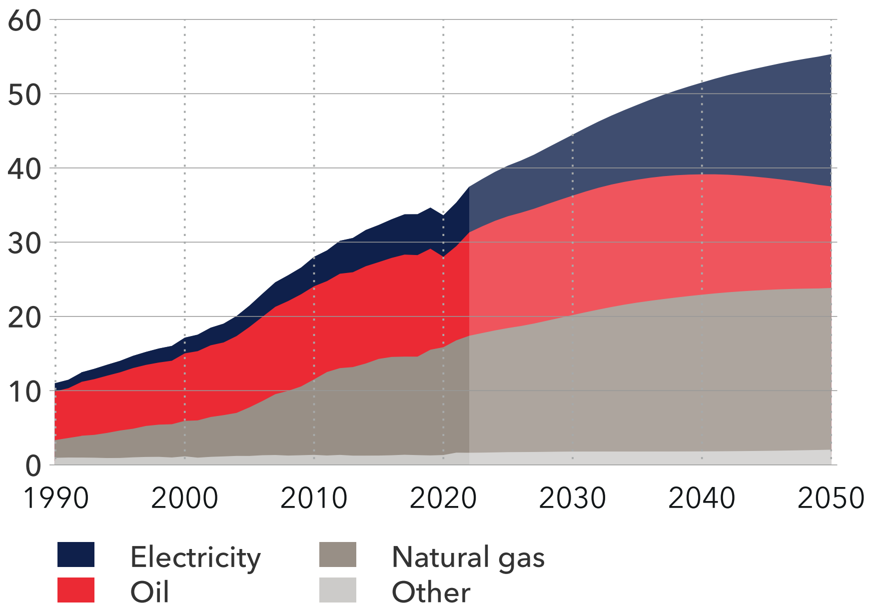


Historical data source: IEA WEB (2023)

FIGURE 8.5.5

Middle East and North Africa buildings energy demand by carrier

Units: EJ/yr

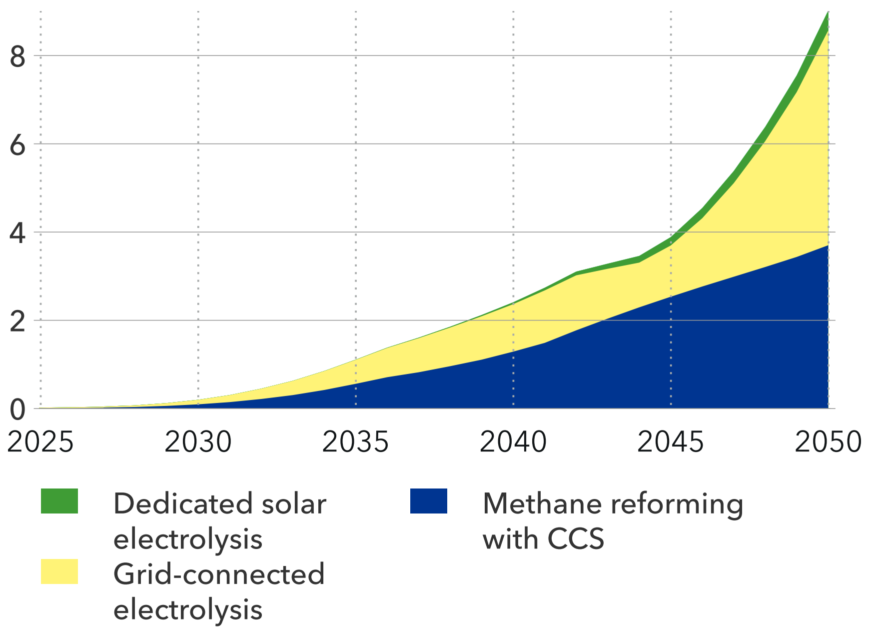


Historical data source: IEA WEB (2023)

FIGURE 8.5.6

Middle East and North Africa hydrogen production as energy carrier

Units: MtH_2/yr



has an abundance of the prerequisites. For green hydrogen, there are high-yield renewable resources and large areas of unused flat land for renewables and electrolysis plants. For blue hydrogen, there are abundant cheap natural gas resources. As electricity and natural gas are cheap, local demand for expensive green hydrogen is expected to be relatively low, at least in the near term. Considering the potential for cost-effective production of low-carbon hydrogen and derivatives alongside the region's ideal position at the nexus of growth markets across the eastern and western hemispheres, Middle East and North Africa countries are set to become key global suppliers in the emerging global hydrogen market. By 2050, about 4.8 Mt/yr of hydrogen is expected to be exported via pipeline and seaborne trade, mainly to Europe and OECD Pacific (particularly Japan and South Korea), as well as around 21 Mt/yr of ammonia via shipping to various other regions. Figures 8.5.8 and 8.5.9 show Middle East and North Africa ammonia exports to other regions. The Middle East and North Africa is expected to be the sole exporter of pure hydrogen to Europe to supply clean energy within the framework of the EU's *REPowerEU* plan to reduce dependence on Russian natural gas.

Hence, export has emerged as the central focal point within the national hydrogen strategies unveiled by the UAE, KSA, Oman, and Qatar.

In UAE, Dubai Electricity & Water Authority (DEWA), in collaboration with Germany's Siemens, initiated the region's first industrial-scale green hydrogen pilot scheme in 2021. According to an energy ministry official, UAE aims to produce 1.4 Mt/yr hydrogen – 1 Mt/yr green hydrogen and 0.4 Mt/yr blue hydrogen – by 2031 and a 10-fold increase to 15 Mt/yr by 2050. Two hydrogen hubs for production will begin in the Ruwais and the Khalifa Industrial Zone Abu Dhabi (KIZAD), and by 2050 there would be a total of five hubs (El Dahan, 2023).

Saudi Aramco seeks to meet a significant share of global blue hydrogen demand by 2025 and has already exported the world's first blue ammonia cargo, to Japan in 2020 (Benny, 2023), and to South Korea in 2022 (Al Monitor, 2022). KSA company NEOM Green Hydrogen Company's USD 8.4bn facility being built in Oxagon is set to be the world's largest commercial-scale green hydrogen production facility when commissioned in 2026. It will produce 600 t per day of clean hydrogen by electrolysis using thyssenkrupp technology, nitrogen by air separation using Air Products' technology, and up to 1.2 Mt/yr of green ammonia (NEOM, 2023; Bell, 2023).

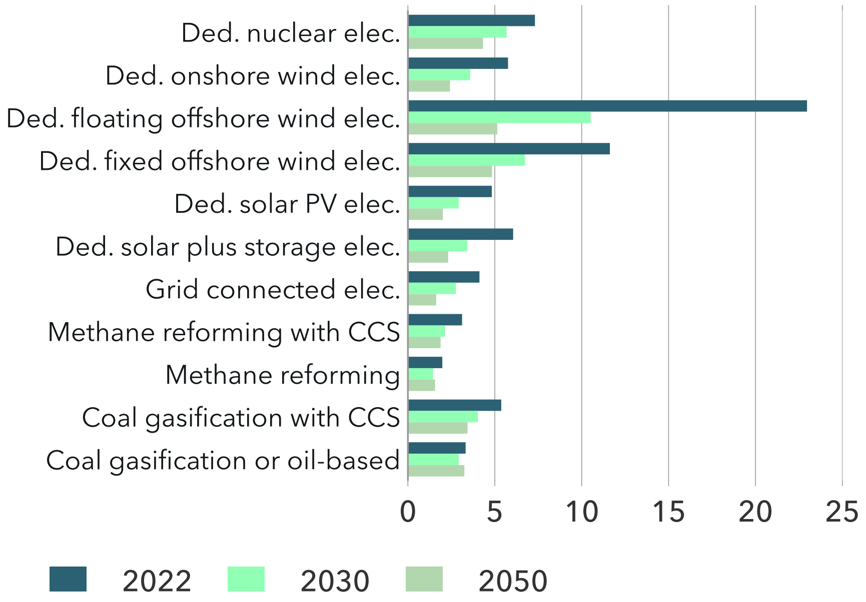
Oman's strategy on green hydrogen aims to increase production to around 1 Mt/yr by 2030, about 3.5 Mt/yr by 2040, and up to 8.5 Mt/yr by 2050 (IEA, 2023f). In 2022, Qatar announced its intentions to build Ammonia-7, the world's largest blue ammonia plant. The USD 1.1bn facility would produce 1.2 Mt/yr of ammonia and should be launched in 2026 (Arab News, 2022). In March 2023, Rabah Salami, director of Algerian policies on hydrogen, announced that Algeria aims to supply Europe with 10% of the latter's clean hydrogen requirements by 2040 (Kim, 2023). At a green hydrogen roundtable hosted by Egypt's prime minister Mostafa Madbouly in August 2023, he said that the country has a USD 83bn project pipeline that would yield up to 15 Mt/yr of green ammonia and e-methane (Parkes, 2023).

The race to become the main low-carbon hydrogen hub in the region is pushing governments to accelerate and increase efforts in establishing regulatory frameworks to support these ambitions. However, as requirements for green hydrogen differ from one

FIGURE 8.5.7

Middle East and North Africa levelized cost of hydrogen production

Units: USD/kgH_2

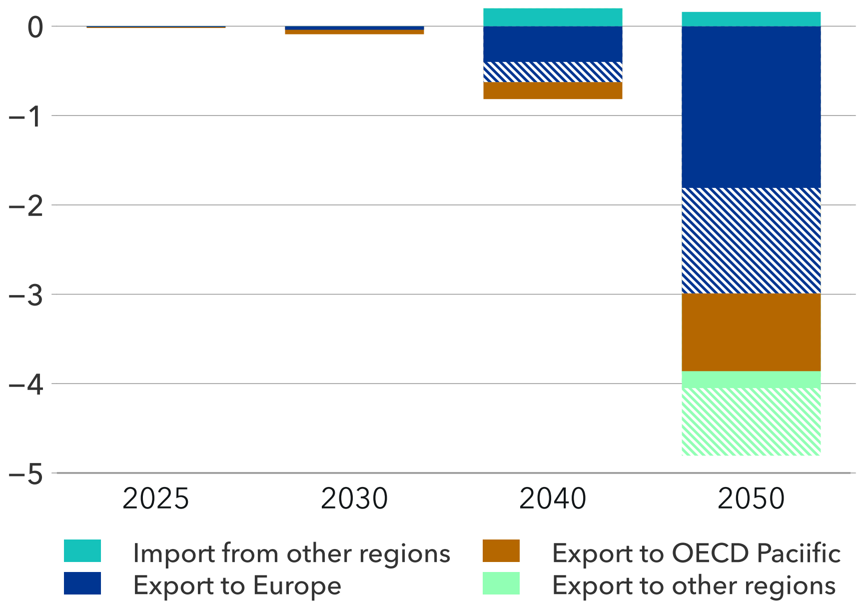


Ded. = dedicated; elec. = electrolysis

FIGURE 8.5.8

Middle East and North Africa pipeline and seaborne hydrogen trade

Units: MtH_2/yr

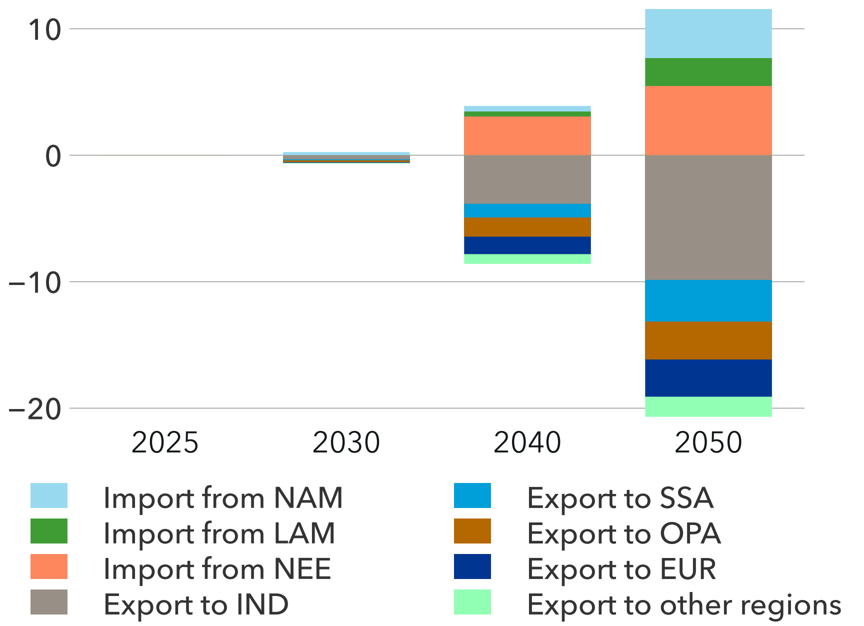


Solid colour = seaborne; hatched = pipeline.

FIGURE 8.5.9

Middle East and North Africa trade of ammonia as energy carrier

Units: MtNH_3/yr



importing region to another, Middle East and North Africa countries are also actively exploring private and public certification schemes that would allow them to satisfy the requirements of importers.

Carbon capture

In 2022, the operational CCUS facilities in the region had approximately 4.3 $MtCO_2$/yr of capture capacity. Projects contributing to this capacity include those of Al Reyadah / Emirates Steel in the UAE (capacity 0.8 $MtCO_2$/yr), Aramco Uthmaniyah CO_2EOR Project (0.8 $MtCO_2$/yr), SABIC Carbon Capture & Utilisation Project in Saudi Arabia (0.5 $MtCO_2$/yr), and QatarGas in Qatar (1.2 $MtCO_2$/yr). These facilities are important pillars in the industrial diversification strategies of these countries and are therefore also included in their decarbonization drives aiming to future-proof these sectors.

As hydrogen demand expands across the region, prominent entities like Aramco, ADNOC, and QatarEnergy have teamed up with global firms to jointly explore and capitalize on the burgeoning opportunities within blue hydrogen and CCUS projects. Qatar has ambitious plans to capture over 11 $MtCO_2$/yr by 2025 (Pradeep, 2022), a pivotal initiative aimed at reducing the carbon intensity of the nation's LNG facilities by 35%, along with a 25% reduction in the carbon intensity of its upstream facilities. The UAE has set its sights on scaling up its capture capacity to 5 $MtCO_2$/yr by 2030, while KSA envisions achieving an ambitious 44 $MtCO_2$/yr capture by 2035 (Mills, 2023). Figure 8.5.10 shows the ramp-up of CCS and DAC. These forward-looking initiatives underscore the Middle East and North Africa region's proactive approach to carbon capture, but a great deal more needs to be done as the following discussion on emissions outlines.

Emissions

Carbon pricing is presently low or negative given fossil-fuel subsidies, and slow adoption is expected. Our projection (see Section 6.3) for the regional average carbon-price level is USD 10/tCO_2 (2030), USD 20/tCO_2 (2040) and USD 30/tCO_2 (2050).

In the context of global climate policy, country pledges in NDCs indicate that the Middle East and North Africa, viewed as a region, has a regional target for emissions to increase by no more than 244% by 2030 relative to 1990. Our Outlook suggests that energy-related CO_2 emissions after CCS (CCS volumes are shown in Figure 8.5.10) will be limited to a 241% increase by then, demonstrating that emission targets will be met and could be enhanced. There are however some uncertainties in the comparisons of targets and forecasts, as some countries are unclear about whether the targets reported in NDCs also include non-energy-related CO_2 emissions. Most Middle Eastern emission targets are given in relation to a business-as-usual trajectory.

Energy-related CO_2 emissions are expected to keep rising until the mid-2030s, when they peak at around 3.3 $GtCO_2$/yr, approximately 13% above today's level. In 2050, energy-related CO_2 emissions (after CCS and net of DAC) in the region have decreased by around 11% compared with 2022 levels, to 2.6 $GtCO_2$ annual emissions (Figure 8.5.11).

Some of the region's countries have net-zero targets by or around 2050. The UAE led the way among the region's petrostates in announcing a commitment to achieve net-zero GHG emissions by 2050. Israel and Oman also have 2050 net-zero ambitions, Turkey for 2053, and Bahrain, Kuwait, and KSA for 2060. To reach net-zero objectives, it will be imperative to step up carbon pricing and emission abatement policies.

Energy-related CO_2 emissions will peak at some 13% above today's level in the mid-2030s before falling to 11% below 2022 levels by 2050.

FIGURE 8.5.10

Middle East and North Africa CCS by sector and DAC

Units: $MtCO_2$/yr

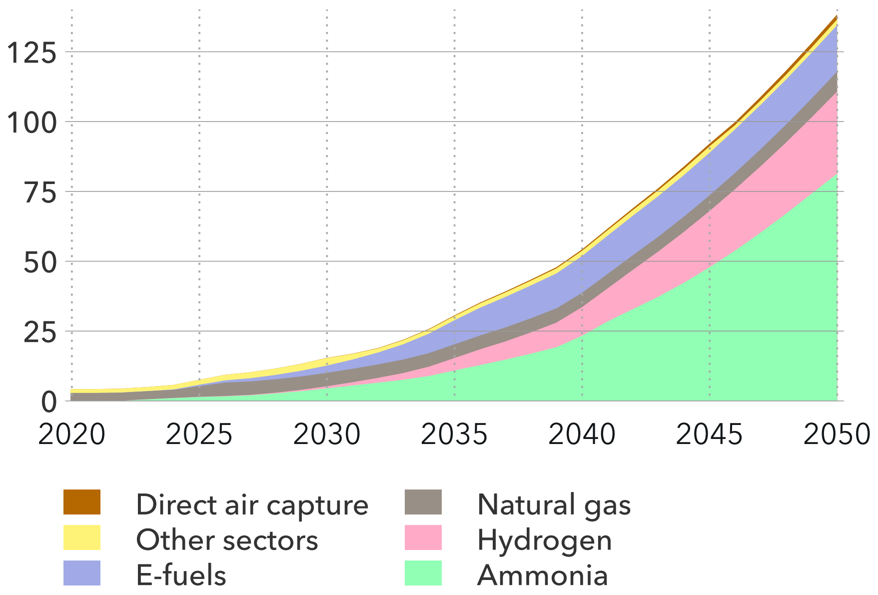
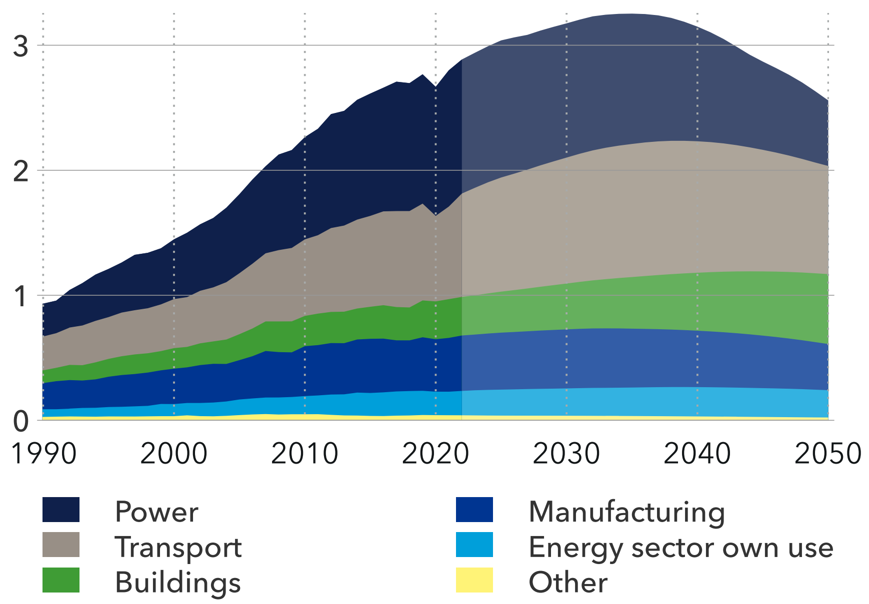


FIGURE 8.5.11

Middle East and North Africa energy-related CO_2 emissions by sector

Units: $GtCO_2$/yr



Historical data source (IEA 2023)

8.6 NORTH EAST EURASIA (NEE)

This region consists of Russia, Mongolia, North Korea, and all the former Soviet Union states, including Ukraine but not the Baltics

	Population (Million)	GDP* (USD Trillion) / GDP/person (USD)	Energy use (EJ) / Energy use/person (GJ)	Energy-related CO_2 emissions (GT) / Energy-related CO_2 emissions/person (Tonnes)
2022	320	7.0 / 22 000	45 / 141	2.4 / 7.6
2050	334	10.8 / 32 000	42 / 126	1.7 / 5.0

*All GDP figures in the report are based on 2017 purchasing power parity and in 2022 international USD

8.6 NORTH EAST EURASIA (NEE)

Characteristics and current position

North East Eurasia produced 20% of the world's natural gas and 15% of its crude oil in 2022. Coal is also abundant. Region countries have high energy intensity of GDP, and there is a heavy dependence on fossil fuel export revenue.

Russia dominates the region in size, population, and economic output. It is the world's second-largest producer of hydrocarbons (13% of global gas and second only to KSA in oil exports). In Central Asian countries, China has grown its upstream investments with ownership stakes in oil and gas production in Kazakhstan and natural gas pipelines from Turkmenistan traversing Uzbekistan and Kazakhstan to China.

Russia's invasion of Ukraine has had far-reaching impacts on the global energy system. European countries are planning to phase out energy imports from Russia, and the sabotage of the Nord Stream and Nord Stream 2 pipelines significantly reduced Russia's export capacity to Europe. Gas exports (outside the former Soviet Union) fell 46% in 2022 (Bloomberg, 2022a) compared to 2021, a trend that is continuing into 2023.

Russia's oil export has maintained its volumes, but at much lower values due to the price cap set by the US, EU, and allies. However export destinations have changed, and recent signs point to some clawback in prices.

Environmental advocacy organizations have been classified as subversive activity in Russia. And against the backdrop of energy transition, the region is at risk of falling behind in low-carbon energy technology. For Russia, this risk is magnified by the effect of sanctions, withdrawal of international capital, and flight of skilled professionals.

Pointers to the future

- Decarbonization efforts in Central Asia are in their early stages. It remains to be seen if climate goals are realistic in terms of policies and implementation. Promotion of renewables only started in 2018 (Sabyrbekov et al., 2023). The Central Asia Energy Trade and Investment Forum (2023), convening international financial institutions and policymakers, signals emerging emphasis on solar, wind, hydropower, and modernizing electricity grids (World Bank, 2023b).
- Russia will continue to reroute its fossil energy to alternative markets, such as gas exports to Kazakhstan and Uzbekistan, via Turkmenistan pipelines for indirect access to China, and a possible pipeline completion through Afghanistan and Pakistan (TAPI) to export gas to India. The initiatives Russia is taking in Central Asia could partially compensate for the lost export volumes to Europe.
- In Ukraine, renewable energy will play a key role in energy sector recovery, also aiding decarbonization and integration with the EU. Reconstruction costs are estimated to top USD 411bn (World Bank, 2023c). G7 leaders (G7, 2023) announced the intent to freeze Russia's sovereign assets in G7 jurisdictions until Russia pays for the damage caused to Ukraine.
- The Multi-agency Donor Coordination Platform for Ukraine, launched January 2023, unites the EU, G7 countries, and international financial institutions. It will aim to coordinate economic support for Ukraine's immediate financing needs and future economic reconstruction, with energy infrastructure being a priority sector.

Energy transition: hydrocarbon powerhouse with renewables growth emerging

Our previous Outlooks have underlined that exporters of fossil fuels will invariably be the laggards of the energy transition. This applies to North East Eurasia countries, which are generally autocratic, with unempowered electorates, and are not willing to invest in fundamental change.

In our forecast, the region's energy system generally retains today's characteristics through to mid-century. Final energy demand in 2050 is only about 10% lower relative to current levels, with a similar sectoral split and little change in the mix of energy carriers (Figure 8.6.1 and Figure 8.6.2). Fossil energy remains at current levels, though electricity creeps up primarily at the expense of coal as buildings' owners and users take advantage of electricity's added convenience.

We foresee similar developments in primary energy demand, as portrayed by Figure 8.6.3. Natural gas continues to dominate, constituting slightly more than half of the mix. On the non-combustion side, solar and wind will grow strongly relative to their currently negligible shares reflecting ambitious targets (relative to the rest of the region) for renewables in Kazakhstan and Ukraine. However, despite the growth, solar and wind will each provide only about 3% of primary energy in 2050.

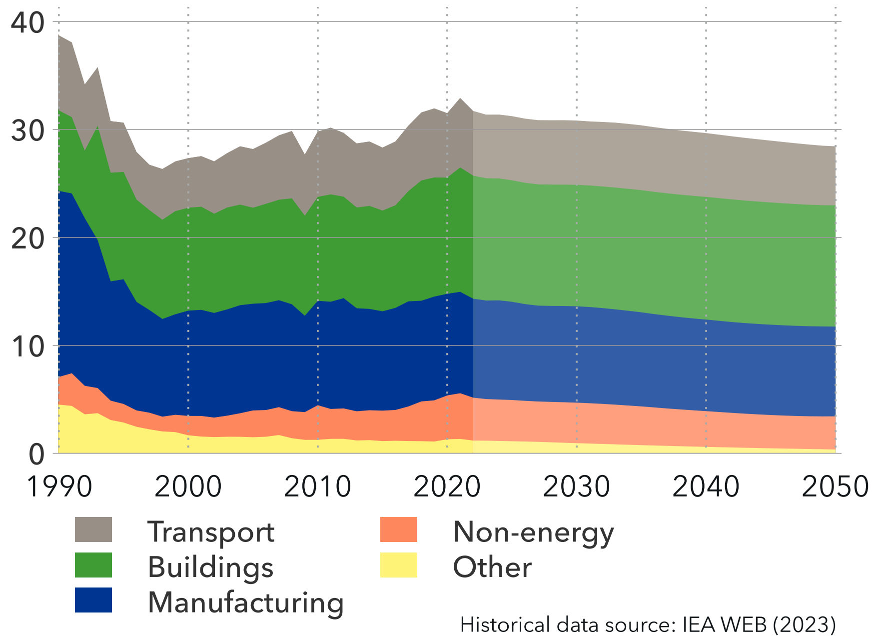
Electrification

The 32% increase in electricity production to 2050 will mostly come from renewables, but gas will still provide close to one third of power in 2050 (Figure 8.6.4). Low domestic gas prices – also benefitting from lost export opportunities as a result of the Ukraine war and continued sanctions even after the war eventually ends – make coal less competitive and its share in power production reduces from 15% presently to 3.5% in 2050. By mid-century, hydropower output will have increased by 54% to generate almost a fifth of the region's electricity. Growing from virtually nothing today, solar and wind power will together generate 34% of electricity in 2050, which will be 72% higher than hydropower generation. Looking at specific countries, Kazakhstan generated 4.5% of its electricity from renewables in 2022, thereby slowly moving towards its ambitious targets for renewables to reach 15% of the power generation mix by 2030, and 50% by 2050 (Satubaldina, 2023). Some of the described increases in renewable power are likely to reflect the rebuilding of the Ukrainian energy sector in the coming years, where renewable energy will be the key. Specifically, Ukraine is aiming to increase the share of renewables in its electricity generation towards 50% to boost energy security (Dreves et al., 2023). Potential future integration of Ukraine with the EU will only reinforce the increasing role of renewables for that country, which will contribute to some extent to the energy mix of the region.

FIGURE 8.6.1

North East Eurasia final energy demand by sector

Units: EJ/yr

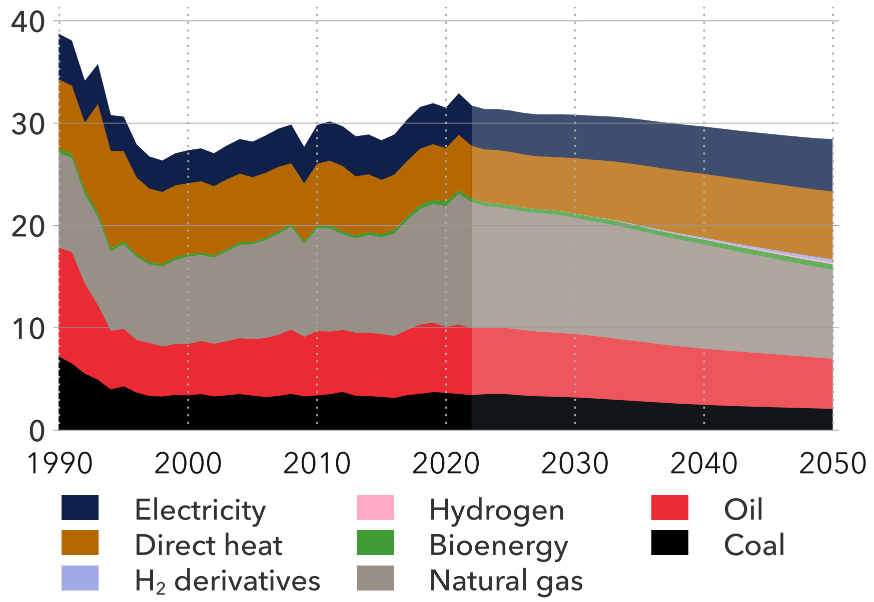


Historical data source: IEA WEB (2023)

FIGURE 8.6.2

North East Eurasia final energy demand by carrier

Units: EJ/yr

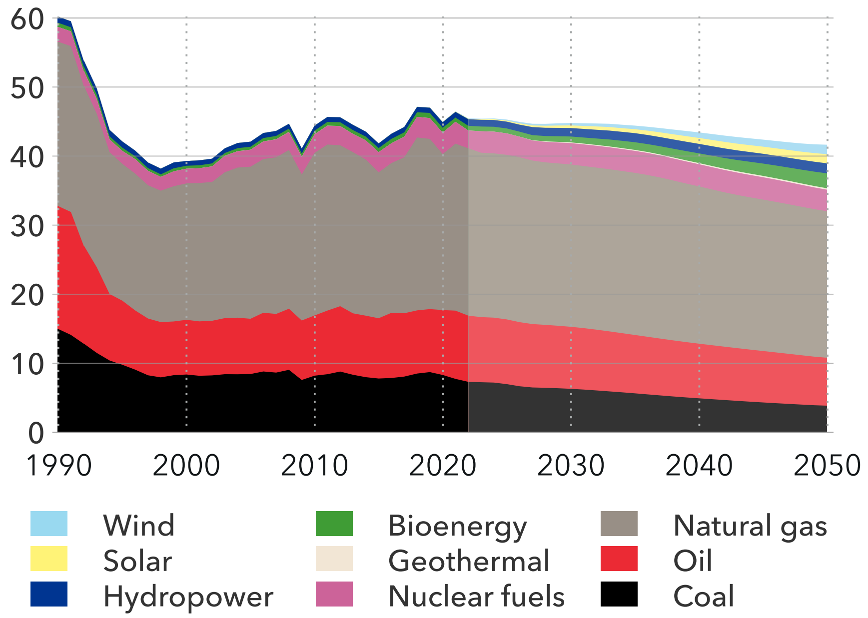


Historical data source: IEA WEB (2023)

FIGURE 8.6.3

North East Eurasia primary energy consumption by source

Units: EJ/yr

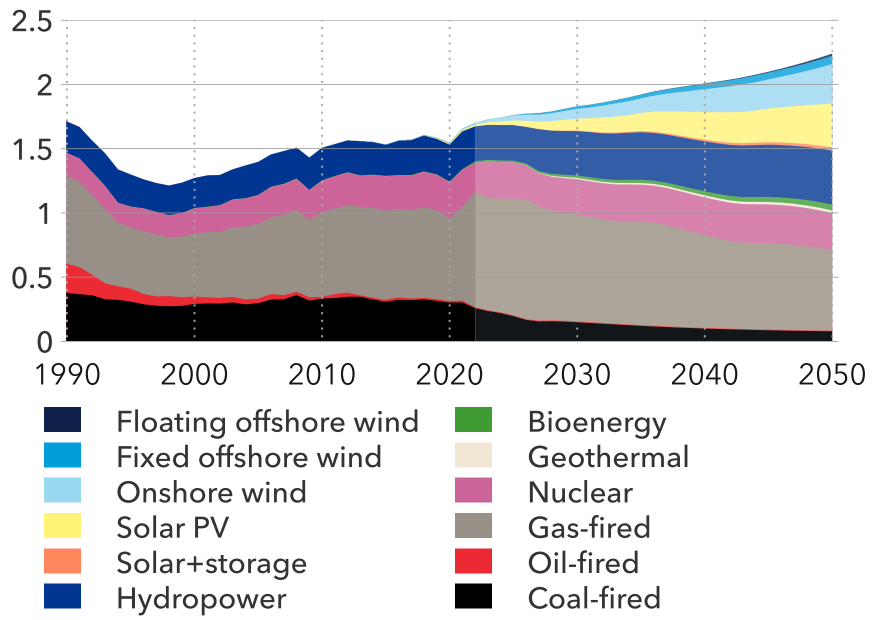


Historical data source: IEA WEB (2023)

FIGURE 8.6.4

North East Eurasia grid-connected electricity generation by power station type

Units: PWh/yr



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

Hydrocarbons

The region's exports and energy production future hinge on the future of its oil, gas, and coal exports. More than one third of the fossil energy production is exported to other regions – 51% of coal, 48% of oil, and 24% of gas. Europe (EU) was the main market for gas exports transported mainly through pipelines. Russia halted these exports indefinitely in autumn 2022. Europe is determined to pivot away from Russian gas, and thus imports are assumed to be replaced by other suppliers going forward. In addition, the EU has imposed a price cap on natural gas to curb the high volatility of gas prices. Other countries in the region will, however, continue some exports, but not in sufficient quantities to influence a 50% reduction in the region's global gas exports over the next 30 months (totalling 157 billion m^3 in 2024).

In the longer term, Russia is likely to be more interested in selling its gas to the highest bidder, and this will not be Europe. An increased build-up of transport infrastructure – pipelines to the east and LNG terminals in the north – will only partially replace current piping of gas to Europe, so the region's gas exports will decline (Figure 8.6.5). Domestic demand will not take up the slack. Regional gas production peaked in 2021 at 1,047 billion m^3. Production will fall by 15% to 890 billion m^3 in 2031 while global gas production is increasing by 7%. This trend is already evident in North East Eurasia. Gazprom's gas exports to China more than doubled in 2022 compared to the previous year, but the company's total gas exports still declined by 45%, resulting in its total gas production falling by 20% over the same period (Kardaś, 2023).

We therefore foresee that with potential new alternative export destinations for Russian gas established, the region's gas exports will pick up by the early 2030s while remaining lower than pre-invasion levels, and will comprise 188 billion m^3 by 2050. Furthermore, these natural gas exports re-routed eastward would most likely need to be sold at a discount in order not to harm the energy business in Kazakhstan, Uzbekistan, and Turkmenistan.

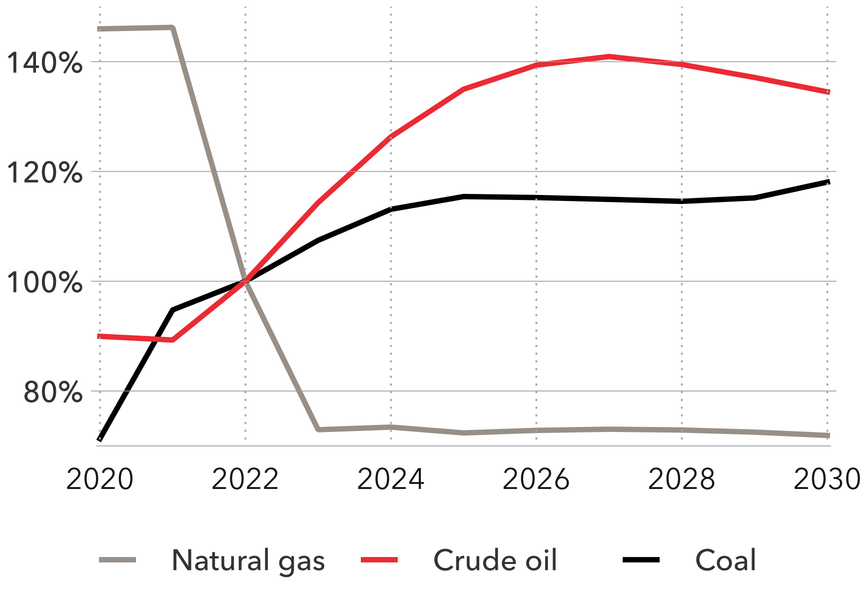
Despite the EU-imposed import ban on seaborne crude oil imports from Russia, and a broader G7 oil-price cap on Russian oil products to prevent it from earning a wartime premium, Russia has managed to redirect its oil to new customers. IEA (2023g) estimates that China and India together accounted for nearly 80% of this redirected oil in April 2023. Oil exports are back to pre-war levels and will even increase by 40% within the coming five years. Similarly, coal exports will increase 42% by 2035 but decline towards 28% of today's levels by 2050.

Oil and coal exports are much easier to redirect than natural gas as they can be transported on keel more readily. Though much oil transport is through pipelines, trains and trucks can also be used cost effectively over land without the need to convert to or from solid form. However, enabling long distance transport from the region requires significant infrastructure. An additional complication arises when oil and coal are exported overseas: this requires ships and western shipowners are subject to sanction rulings against Russia. Moreover, insurers are typically required to follow sanctions against Russia and, given the dominant role of western insurers, even non-western ships will find it hard to operate in this trade. While seaborne oil and coal exports from the region continue, this can be explained by non-western insurers increasing their underwriting market share or ships travelling without insurance. Even though Russia is currently finding buyers for its oil, it is likely to be sold at a heavy discount to Brent benchmark prices. Moreover, Russia's aggression against Ukraine raises considerable risks for the economic future of the region.

FIGURE 8.6.5

North East Eurasia fossil energy net exports, 2020 to 2030

Units: Percentages, relative to 2022



Emissions

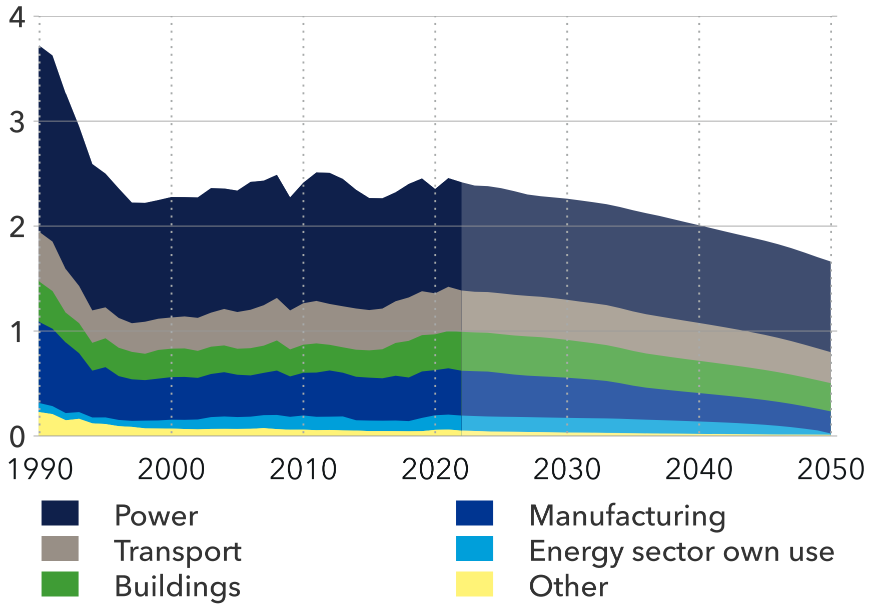
Our projection for the regional average carbon-price level is USD 6/tCO_2 in 2030 and USD 20/tCO_2 by 2050. Slow adoption and low carbon-price levels are expected (see Section 6.3).

Energy-related CO_2 emissions will fall by 31% to mid-century, by a similar fraction in buildings and transport (27% and 23%, respectively), and by almost half in manufacturing, as shown in figure 8.6.6. Higher emissions reductions in manufacturing are due to increasing ammonia production via methane reforming with CCS. The region's total CO_2 emissions will be 1.8 Gt CO_2 (including non-energy process emissions) in 2050, representing the highest emissions per person of any region.

FIGURE 8.6.6

North East Eurasia energy-related CO_2 emissions by sector

Units: $GtCO_2$/yr



Historical data source: IEA WEB (2023)

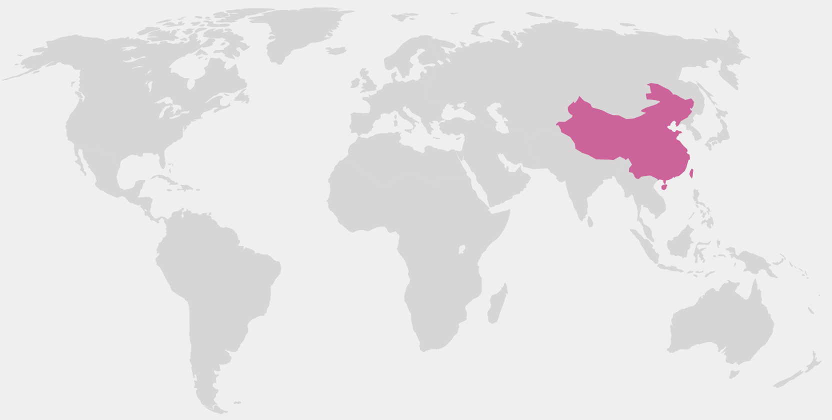
While other regions experience both strong electrification and a greening of electricity, such developments are rather weak for North East Eurasia. Electricity does grow compared to other energy carriers, but only from 12% now to 18% of total energy demand in 2050. The use of natural gas in power production declines 30% but still maintains the single largest share in generation. Coal remains in the power mix by mid-century, but with a much lower share than now. The low carbon prices hinder the uptake of CCS, and so, apart from the use of CCS for ammonia and hydrogen production, less than 1% of manufacturing or power sector emissions are captured in 2050.

In the context of global climate policy, our interpretation of country NDC pledges in the region is that the region targets a 26% reduction in energy-related emissions by 2030, relative to 1990. As energy-related CO_2 emissions after CCS are forecast to be down by 39%, the region as a whole reaches its climate goals before the target year. However, as the Soviet Union collapsed in 1991, emission statistics are problematic; they indicate emissions falling a full 40% between 1990 and 1997. Although industrial production fell by half in the same period, emissions reduction statistics may well overstate the extent of the decline. However, the reported rise in emissions between 1997 and 2020 appears to be a robust observation.

North East Eurasia sees the lowest reduction in emissions of any industrialized region, with a decrease of 31% of emissions between 2022 and 2050. Russia and Kazakhstan have set net-zero targets for 2060, and Ukraine for carbon-neutrality in 2060, which have a very low probability of being achieved. On the other hand, the recovery efforts aimed at rebuilding the energy sector of Ukraine will likely emphasize the role of renewables as both a cleaner and secure source of energy, which will to some extent be reflected in how green the energy mix of the whole region will be.

8.7 GREATER CHINA (CHN)

This region consists of Mainland China, Hong Kong, Macau, and Taiwan



	Population (Billion)	GDP* (USD Trillion) GDP/person (USD)	Energy use (EJ) Energy use/person (GJ)	Energy-related CO_2 emissions (GT) Energy-related CO_2 emissions/person (Tonnes)
2022	1.45	33 22 800	159 110	10.7 7.4
2050	1.34	67 50 000	146 109	4.0 3.0

*All GDP figures in the report are based on 2017 purchasing power parity and in 2022 international USD

8.7 GREATER CHINA (CHN)

Characteristics and current position

Price stability, energy security, and economic goals are overriding objectives in Chinese policies.

China's central government provides steadfast planning to steer the transition. The '1+N' policy framework – 1 referring to the high-level policy framework and long-term climate change strategy (NDRC, 2021) and N to climate action implementation plans for key areas and sectors – is to deliver its pledge of peaking carbon emissions before 2030 and achieving carbon neutrality by 2060.

China's provinces are tasked to develop 1+N strategies following the national framework. Most have developed local sectoral five-year plans (2021–2025), but have yet to develop roadmaps for carbon neutrality (CCNT, 2023)

In 2022, nearly half of the world's low-carbon transition spending was in China at USD 546bn (BNEF, 2023b). Cumulative solar capacity is 413 GW, onshore wind 360 GW, and offshore wind 31 GW. China's battery companies have more than 60% global market share, and China alone accounted for 35% of global EV exports in 2022 (Nikkei Asia, 2023).

State-owned Chinese companies play a key role in decarbonization: following policies to adjust their energy production/consumption structures, meeting emission reduction targets, and progressing technologies technically and commercially. For example, Sinopec operates the world's largest solar-to-hydrogen project (Xinjian region) to produce 20,000 t/yr green hydrogen, powered by 300 MW solar.

China is taking an active role in climate diplomacy and expanding its climate-change cooperation (MEE, 2022). The first half of 2023 had 55% of the Belt and Road Initiative's energy spend going into renewables (GFDC, 2023).

Pointers to the future

- China aims to rebalance its economy towards domestic consumption and high-quality growth, pivoting from industry and investment spending (e.g. infrastructure, real estate) to consumption and services, thereby adjusting the economy to lower energy intensity.
- In decarbonization-relevant technology areas, innovation clusters will be facilitated, and scaling is expected to rely on mandates for uptake (e.g. CCS, hydrogen). The New energy vehicle (NEV) policy is extending incentives to further penetration.
- The national emissions trading scheme will cover high-emission sectors (70% of emissions) with sectoral expansion happening gradually to 2030, pressured by the EU's carbon border adjustment mechanism (CBAM).
- China's government backs control of fossil-fuel consumption but drought-inflicted hydropower shortages has it leaning on coal to secure supply, albeit with low coal-plant utilization and the acknowledged need for an alternative longer-term solution.
- Energy security is the basis for promoting renewables. Key targets are: 1,200 GW installed wind and solar capacity by 2030 and increasing the non-fossil share in the energy mix to 25% in 2030 and 80% by 2060.
- As renewable energy resources are concentrated in the northwest and consumption centres in the east and south, transmission will expand. Manufacturing relocation to high VRES areas will be pursued.
- Offshore wind will receive provincial subsidies. Tradeable green certificates will add value to grid-connected renewable power and are expected to drive green power demand, such as from multinational, export-oriented, and state-owned enterprises that have requirements for green power consumption (NEA, 2023a).
- China released the *Blue Book on the Development of New Power Systems* in June 2023 (NEA, 2023b). Beyond power system developments, it envisions CCUS uptake between 2030 and 2045, and electricity and hydrogen as the main body of end-use consumption evolving between 2045 and 2060.

Energy transition: an immense shift sullied by coal

In 2022, China accounted for 18% of the world population and 20% of global GDP. Energy demand, closely correlated with both population and economic growth, has soared – China now accounts for 26% of global primary energy demand. It is more like a continent than a country, and comparisons like China being the world's biggest producer or consumer of something are therefore of less relevance than when making many other country-vs-country comparisons. What is important is that China is responsible for a third of global energy-related CO_2 emissions, so developments there are crucial to whether the world will meet its emissions reduction target and climate objectives.

The central government of China is very strong and sets a direction that the country is largely following. The stability of the government also makes for more uniform developments than in many countries where there are frequent changes of government and leadership. Hence, China is more predictable from a forecasting perspective. Still, even Chinese long-term planning has limitations; one good example is the current demographic shift that looks like it has resulted in a much faster population and workforce reduction than foreseen in Chinese government plans.

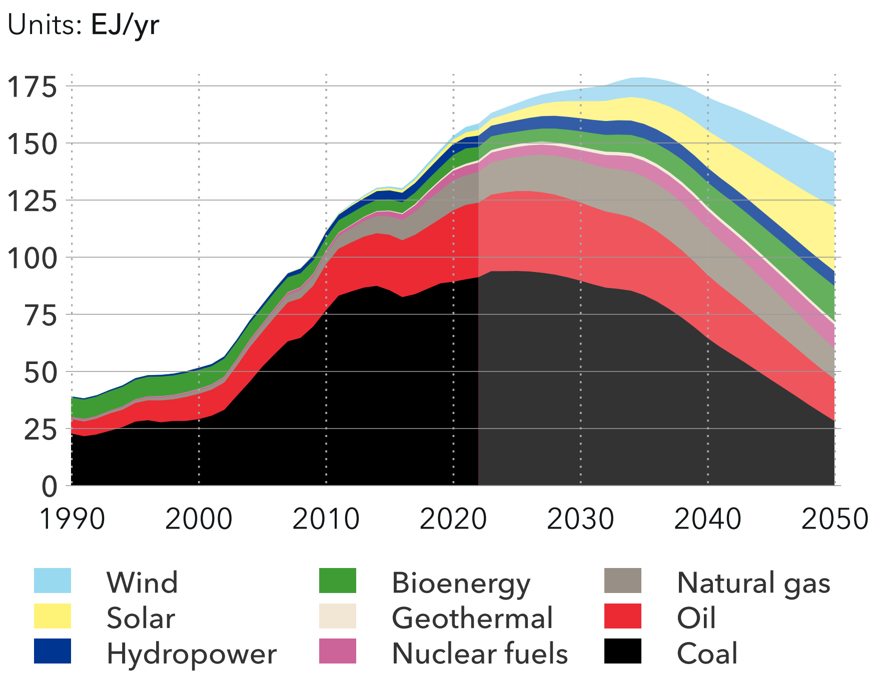
China's primary energy supply has nearly tripled over the last two decades, as illustrated in Figure 8.7.1. The strong increase came first and foremost from coal, which in 2022 accounted for 58% of primary energy use in China and 54% of global coal consumption.

Since 2013, China's energy use has also started to diversify into almost all other energy sources, with strong growth in natural gas, hydropower, nuclear, solar PV, and wind. Coal and oil in the energy mix increase slightly – worryingly so in the case of coal – in the next couple of years before they gradually decline to a third and a half, respectively, of their current volumes by 2050. In 2050, the share of fossil fuel will reduce to about 10% in primary energy supply.

The forecast energy supply and demand trends in the coming decades are closely linked to the demographic and economic developments of the region. They are also strongly influenced by government energy and environmental policy.

FIGURE 8.7.1

Greater China primary energy consumption by source



Historical data source: IEA (2023)

China's population peaked at 1.426 billion in 2022 (UNDESA, 2023), and is expected to be about 90 million less in 2050 than today. The reduction in the workforce is even greater, and this influences productivity and economic growth. With a smaller workforce, salaries are likely to grow more than in neighbouring countries. Even with increased automation, a significant share of China's manufacturing will move to countries with cheaper production. A strong domestic market and a focus on 'Made in China' protecting domestic manufacturers may counter some of these trends.

Average annual economic growth has been more than 8% for 30 years while the GDP per capita experienced a 10-fold increase in the same period. We expect it to slow significantly, with an average growth of 2.3% for the next 30 years due to population reduction and demographic shifts, and to China becoming a more mature economy, with fewer productivity gains in industry. Over time, its long-term economic growth rate will more closely resemble that of other medium and high-income countries. By 2050, the GDP per capita is projected to be more than double its current value, reaching USD 50,000 per year.

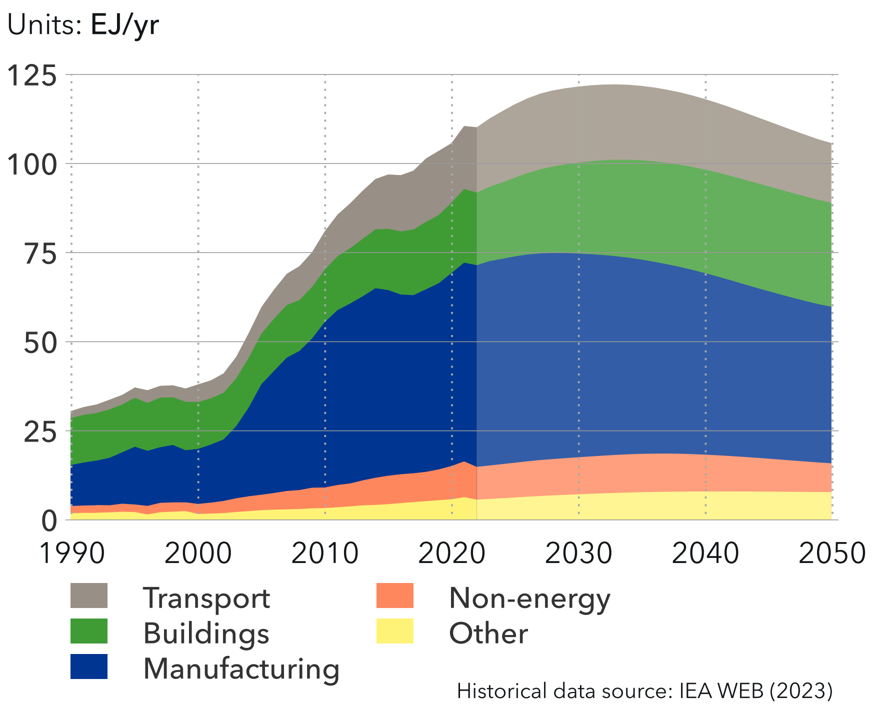
Energy demand

The demographic shift and economic growth influence not only manufacturing but also transport and buildings. The density of passenger vehicles is expected to undergo significant growth, with a potential peak around 2040, reaching approximately 90% more than the 2022 count of about 256 million vehicles. However, a high level of urbanization and extensive build-out of public transport will mean vehicle density remains lower than in OECD countries. In the 2040s, a reduction in population alongside greater automation and car sharing will reduce vehicle numbers. Aviation is likely to triple through to 2050 as an increasing number of Chinese become middle class, including many pensioners who would like to travel.

The urbanization rate in China is growing rapidly; today, almost two-thirds of the Chinese population lives in cities. Most of them also live in new high-rise buildings, a situation very different from urbanization in North America, for example. Small family sizes

FIGURE 8.7.2

Greater China final energy demand by sector



Historical data source: IEA WEB (2023)

and an increased standard of living will see building stock in China grow 26% for residential buildings and 160% for commercial buildings by 2050. For details, see Figures 1.4 and 1.5 in Chapter 1. A strong focus on energy efficiency will limit growth in buildings' energy use, which is relatively stable from 2030 onwards. While energy needs for heating, water heating, and cooking will be relatively stable, energy needs for cooling increase more than six-fold over the next 20 years, and by 2050 represent 29% of Chinese buildings' energy use, just behind energy needs for heating with a 34% share.

Overall final energy use will grow 9% from today to peak in 2033 at 122 EJ, and will then decline to 106 EJ by 2050, as shown in Figure 8.7.2. A rapid demographic shift is aiding this reduction, which is otherwise mainly driven by the rate of energy-efficiency gains being greater than that of economic growth. By 2050, manufacturing will still be the largest sector of energy demand with a 41% share in the total, down from 51% today, while buildings' share will grow from 19% to 28%. Transport's share will initially grow from 16% now to 18% by 2027, then decline to 16% in 2050 as electrification of road transport scales from the late 2020s.

While energy consumption is to a large extent influenced by demographics and economics, Chinese policy is the most important factor influencing the energy mix. Technology and cost development also play a major role in the transition from a fossil to a renewable energy system, but energy and climate policy are interwoven in every change. Energy and climate policies are also linked to all other priorities of the government, including economic growth, geopolitics and national security, national and social stability, and energy security.

As China uses more than half (54%) of the world's coal and emits 32% of energy-related CO_2, there is pressure from other countries for China to reduce its emissions faster. From the Chinese authorities' point of view, a balance is important, with emissions reduction having to find its way among all the other priorities in the country. As in all other nations, sometimes the priorities pull in the same direction, and sometimes they are opposing forces. The Chinese government's stability enables priority-based long-term planning to a greater extent than in other regions. However, geopolitical, economic, and technological trends that China's government is unable to foresee will always influence and alter the long-term plans.

China's most pronounced climate policy is its commitment for CO_2 emissions to peak around 13 $GtCO_2$/yr before 2030, and to reach climate neutrality in 2060 (CCICED, 2022). On the 2030 goal, there is an array of supporting targets, goals, and measures, both in the present *14th Five-Year Plan* (FYP) to 2025 and the 15th FYP period to 2030. On the 2060 goals, there are very few supporting measures yet. Although not explicitly stated in official documents, recent information from China's special envoy for climate change Xie Zhenhua that 2060 carbon neutrality includes all types of GHGs is a very important specification (OIES, 2022).

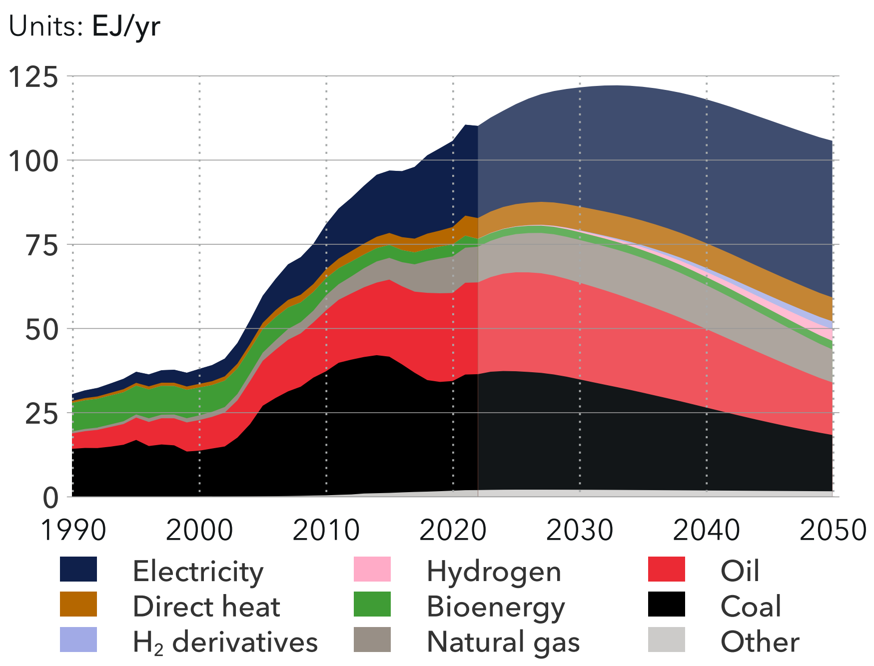
Electricity taking hold in demand sectors

Electrification of energy demand sectors is the key means to reduce emissions because power generation is effective and relatively easily decarbonized. As illustrated in Figure 8.7.3, electricity currently meets 25% of final energy demand in China. We forecast this will increase to 44% in 2050, which would be the highest share among all our Outlook regions. Electricity use will grow in all main demand sectors – buildings, manufacturing, and transport. Extensive programmes are underway in all these sectors to speed up this transition.

The most visible impact of electrification is on road transport. China dominates global EV production, for which it had a 60% share in 2022 (EV Volumes, 2023). It is also a leader in domestic EV uptake, though the typical Chinese EV has a much smaller battery size on average than European and US counterparts. Most EVs produced outside China use Chinese batteries, illustrating that for China, EVs are not just a consideration within energy and climate policies. It is also industrial policy to enter the global market for vehicles, which Europe, Japan, and the US have dominated for decades. DNV expects the uptake of EVs in China to be the fastest among all regions, with EVs reaching half of new vehicle sales there by 2027 and EVs constituting half the entire fleet of vehicles by 2031. The country is also leading the transition to EVs for commercial vehicles and two- and three-wheelers.

FIGURE 8.7.3

Greater China final energy demand by carrier



Historical data source: IEA WEB (2023)

China also has goals for hydrogen-powered passenger and commercial vehicles. As detailed in Chapter 1 of our Outlook, our modelling currently indicates that hydrogen cannot compete with EVs in the passenger vehicle segment and will only power about 3% of commercial vehicles in 2050, which, owing to hydrogen's inefficiencies adds up to 13% of that segment's energy demand by then. This is likely to be the pattern of uptake in China too, with hydrogen acting as a supplement to electricity in heavy duty transport.

Direct use of coal represents a third of Chinese energy demand today, and the fuel will maintain its share for the next five years before halving to cover 16% of demand in 2050. One significant driver of this reduction will be a halving of coal use in manufacturing as heavy industries like iron, steel, and cement production decline in size and change production methods. The reduction of coal use in electricity generation will be even greater, as described below.

Oil's share in the energy carrier mix will reduce from 25% to 15% as road transport (the biggest user of oil products) electrifies. While non-energy use of oil ultimately reduces toward the end of the 2030s, oil use in feedstock (e.g. for chemicals and fertilizer production) will overtake oil use in transport as the largest user of oil.

Coal-to-gas switching is a prominent policy in China for buildings and manufacturing. Direct use of gas grows over the next decade before starting to decline from the end of the 2030s as hydrogen, for example, begins to replace it. As coal is a domestic energy source and natural gas is mostly imported, geopolitical developments over the past year might slow the governmental focus on coal-to-gas switching, which is more about local air quality than GHG emissions and cost.

Hydrogen is negligible as an energy carrier today, but will start to replace some coal and gas use in manufacturing in the 2030s. In the 2040s, we will see the uptake of ammonia in shipping and e-fuels in aviation. In total, hydrogen and its derivatives will have a 3% share of energy demand in 2050. Production in China will be predominantly green hydrogen produced via electrolysis powered by dedicated renewables. There will also be a large shift in how hydrogen is produced for use as industrial feedstock, from coal gasification today to green hydrogen from electrolysers in the future.

Electricity generation

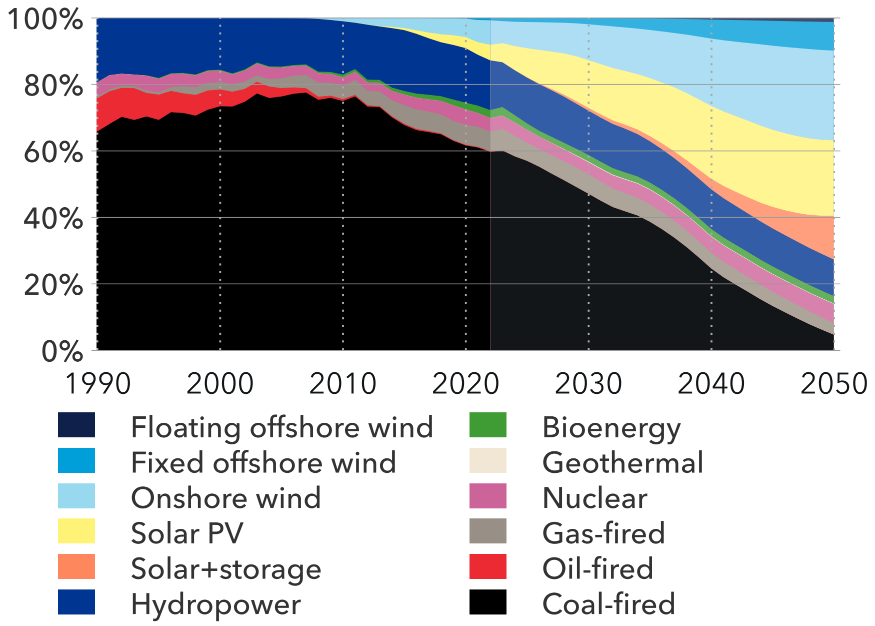
China's annual electricity production will almost double from 9.2 PWh to reach 16.2 PWh in 2050. As shown in Figure 8.7.4, coal's share of the energy mix has already reduced from 73% a decade ago to 60% today and will further decline to 47% in 2030 and only 5% in 2050. Gas maintains a minor share of 4% in 2050, and oil is negligible by then, meaning that only 9% of China's electricity will be generated from fossil fuels in mid-century.

Nuclear in China is interesting. It presently has 4% of the electricity mix, 375 TWh per year. Remarkably, China's nuclear capacity expansion rivals that of the rest of the world combined. Projected across the coming decades, China's nuclear capacity and production are projected to grow 2.5 times, reaching 930 TWh/yr over the next few decades, constituting a 6% share of the electricity mix by 2050. While nuclear power station costs in China are lower than those in OECD countries, they remain more capital-intensive compared with other plant types. Nevertheless, driven by energy security policies, China is committed to further enhancing its nuclear share in power production.

FIGURE 8.7.4

Greater China grid-connected electricity generation by power station type

Units: Percentages



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

However, it is in renewables where the lion's share of growth occurs, dictated by climate, energy, and industrial policies. China already dominates global solar PV production and uptake and has recently assumed the same role in wind. The share of wind-generated electricity in China is 8% in 2022 and will grow to 13% in 2030 and 37% in 2050. Solar PV has a higher growth rate from a 5% share in 2022 to 15% in 2030, and 36% in 2050.

The 2025 targets for renewable installations in the 14th FYP and the 2030 solar and wind target (1.2 TW) are likely to be exceeded. Including both grid-connected and off-grid (for green hydrogen production), we expect 1.4 TW of installed solar PV capacity by 2030, reaching 5.1 TW in 2050. Similarly, installed wind capacity including off-grid is expected to be 0.8 TW by 2030, with 0.7 TW being onshore wind. The growth will continue; we expect 2.5 TW onshore by mid-century, 430 GW of fixed offshore, and 59 GW of floating offshore.

Hydropower is also large in China, producing 1.4 PWh annually today, a figure that will grow 25% (to 1.8 PWh) over the next decade and thereafter stabilize. With a share of 15% in 2022 and 11% in 2050 of the total electricity mix, this dispatchable renewable energy source is crucial to balance the variable renewable production from solar PV and wind, but it is also subject to climate risks in the form of more extreme rainfall variability and droughts.

Is coal peaking in China?

The short answer is that coal use will ease off this decade, but not before a half-decade at sustained record levels which threaten China's reputation as a leader in the transition. China's coal use increased steeply until 2013 and has since hovered around that year's level. Coal consumption increased between 2021 and 2022 and soared further in 2023. We project that consumption will plateau for the next four to five years before gradually reducing to a third of its current level at the end of the decade. In 2022, 86.6 GW of new coal-fired power plant capacity was approved compared with only 18.6 GW in the previous year (Energy Foundation China, 2023). President Xi's commitment in 2021 that coal use will peak in China in 2025 (Stanway et al., 2021) has not been repeated in the last two years, which increases doubt about the priority that the Chinese government is assigning to this.

The power generation and manufacturing sectors are the major coal consumers in China. According to our Outlook (Figure 8.7.5), coal consumption in both will continue growing for the next five years. Thereafter, Chinese manufacturing's rapid electrification will result in its current coal demand of 30 EJ/yr halving by 2050. As described above, coal's share in electricity generation will reduce from 60% today to 5% in mid-century. Towards the end of the Outlook period, manufacturing (15 EJ/yr) will overtake power generation (10 EJ/yr) as the largest consumer of coal in China. Coal use in buildings, which is relatively small, will fall in the coming years to be largely replaced by natural gas.

In 2021, China announced it would stop financing and supporting technology for coal plants overseas. This is an important step that increases the costs of new coal-fired generation in other regions and helps the transition to cleaner technologies. According to Global Energy Monitor, overseas coal project financing by China in 2022 had fallen 78-fold outside of China since its peak at USD 39bn in 2017 (Hurley et al., 2023).

If Chinese coal use follows the path in our forecast, the resulting annual emissions from coal will fall from 8.1 $GtCO_2$ today to 2.3 $GtCO_2$ in 2050, making a crucial contribution to reducing global emissions, but will still be too high for the world to reach net zero.

The carbon intensity of Chinese energy use reduces from 103 to 42 gCO_2/MJ over the coming three decades and is first and foremost coupled with the reduction in Chinese coal consumption.

Energy efficiency

Energy efficiency is another key lever for the relatively fast energy transition in China. Urbanization and general technology improvement both contribute to the shift. However, the doubling of electricity's share in the energy mix is by far the biggest contributor, and even more important when electricity also becomes renewable. The efficiency improvements come in all sectors, as all electrify, but there are many other initiatives to improve energy efficiency.

Energy intensity, measured as MJ of primary energy per unit of GDP, is a key metric Chinese policymaking is focusing on. We find that the present energy intensity of 4.8 MJ/USD will reduce to 2.2 MJ/USD in 2050. The annual reduction rates will fall from around 4% today to less than 2% towards 2050, as shown in five-year intervals in Figure 8.7.6. The main reason for the slowdown is that the electrification growth rate – in road transport, for example – will slow down, though the overall electrification rate still rises. Figure 8.7.6, also explaining the trends in primary energy (Figure 8.7.1), shows an interesting transition in a country that has strong energy-efficiency growth, declining GDP/capita growth, and declining population.

Energy security

Energy security is a high priority for China. In 2022, President Xi Jinping said the nation's carbon goals should not clash with other priorities, which include securing adequate supplies of food, energy, and materials "to ensure the normal life of the masses" (Bloomberg, 2022b). Coal is predominantly domestically supplied, but in 2022, 58% of natural gas and 76% of oil were imported. The non-fossil energy – nuclear, bioenergy, and renewables – is also developed mainly domestically with few foreign resources except some minerals and metals needed for making wind turbines and solar panels.

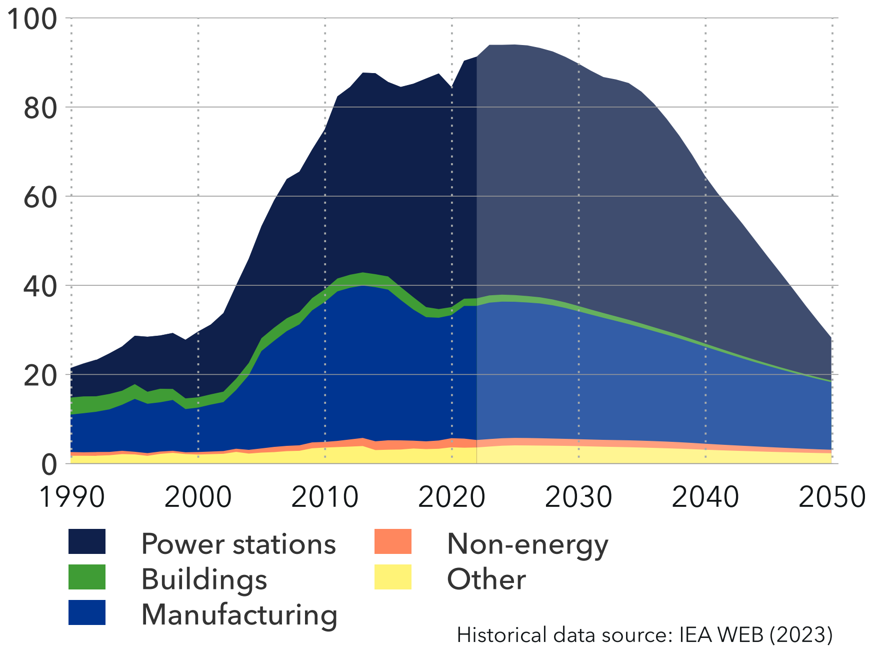
We do not expect any dramatic change in this picture within the forecast period. There are ample coal supplies domestically, but it will not be possible for China to increase oil and gas production to levels at which the country is wholly self-supplied. In our results, the shares of imported oil and natural gas needed to meet demand grow until 2030 and 2040, respectively, before gradually decreasing. China is constantly positioning itself towards the large oil and gas exporting nations in the Middle East to have supplies available. Recent Western sanctions against Russia following the invasion of Ukraine has given China an opportunity to further strengthen energy cooperation with Russia. Russian oil and gas not being sold to Europe is available to China, including through new pipelines that will be constructed to cement long-term imports. Figures 8.7.7 show the historical and forecasted trend for China's gas import via pipeline, dominated by North East Eurasia (mostly Russia) or as LNG dominated by two supplier regions: OECD Pacific and the Middle East and North Africa.

Nevertheless, China's long-term aim is to be energy independent. The switch to renewables over the coming decades will make China less and less reliant on imported energy from any other country, though full energy independence is not achieved in our forecast period.

FIGURE 8.7.5

Greater China coal demand by sector

Units: EJ/yr

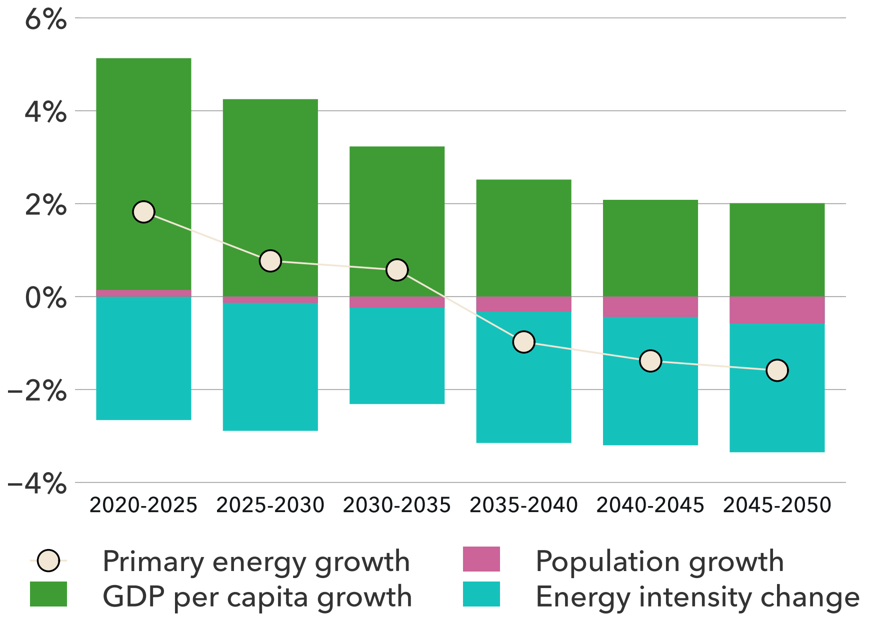


Historical data source: IEA WEB (2023)

FIGURE 8.7.6

Greater China primary energy growth as a function of population, GDP/capita and energy intensity improvements

Units: Percentages/yr



Emissions

In 2022, almost a third (32%) of global energy-related CO_2 emissions – 24% from coal, 8% from other fuels – were from Greater China. This share has increased steadily, with the highest growth (from 14% to 27%) being in the period from 2000 to 2010. It is expected to increase slightly to 34% by mid-2035, after which China's emissions will fall much more rapidly than the global average, with China accounting for 22% of global energy-related CO_2 emissions in 2050.

In absolute terms, China's emissions, shown below in Figure 8.7.8, are the biggest in the world, at around 10.7 $GtCO_2$ of energy-related emissions in 2022, a new record high. The sector that reduces its share of emissions fastest, and electricity impacts emissions from all the demand sectors. As shown in Figure 8.7.4, in moving from coal to renewables, the power sector's share of energy-related CO_2 emissions reduces from the current 51% to 33% in 2050, with an absolute reduction from 5.5 $GtCO_2$/yr to 1.3 $GtCO_2$/yr. Manufacturing's sectoral share of energy-related CO_2 emissions in 2022, the second largest among main energy demand sectors, increases from 27% today to 35% in 2050, albeit while halving in absolute terms. The CO_2 emission from buildings stay almost the same as today, but transport emissions halve through to 2050, demonstrating that all sectors will reduce CO_2 emissions at about the same pace.

Our projection for China's average carbon-price level is USD 20/tCO_2 in 2030, USD 40/tCO_2 in 2040, increasing to USD 90/tCO_2 by 2050, a level exceeded only by Europe and the OECD Pacific regions. The upward pricing trend is underpinned by the inclusion of more sectors and expanding coverage in China's national emissions trading scheme (see Section 6.3).

We forecast that 71 $MtCO_2$ will be captured by CCS by 2040. Figure 8.7.9 shows that the ramp-up of CCS will be steep during the 2030s and plateaus after 2047. CCS will be largest from process emissions (e-fuel and ammonia production), which reach 54 $MtCO_2$/yr in 2040, and from manufacturing (iron and steel), where capture increases to 14 $MtCO_2$/yr in 2050. As well as CCS, the region develops and increases DAC, reaching 7 $MtCO_2$/yr in 2050. Investing in CCS projects is driven by economic consideration, so as long as stability and security of energy supply remain the highest priorities in energy policy, most investment is directed towards renewables, nuclear power, and grid infrastructure.

Comparing the DNV forecast with official Chinese goals and other Chinese forecasts – from China National Petroleum Corporation, for example – we find that the main target of peaking CO_2 emissions before 2030 is met unless we see a high level of Chinese AFOLU emissions, which is unlikely. The forecast CO_2 emissions peak (energy-related and non-energy process emissions) is in 2026.

Regarding the Chinese target to reduce carbon intensity (per unit of GDP) by 65% from 2005 levels by 2030, our Outlook suggests a reduction of 59% by then, indicating that this target will be missed.

China's high-level goal of carbon neutrality by 2060 cannot be read from our forecast, which stops in 2050. Energy-related CO_2 emissions after CCS (and net of DAC) are expected to have decreased 63% compared with 2022 levels, with 3.9 $GtCO_2$/yr remaining in 2050. The direction in 2050 is clear, but the present trajectory makes it unlikely that full carbon neutrality will be achieved by 2060, unless China changes course to decarbonize, and specifically de-coal, its economy even more rapidly.

FIGURE 8.7.7

Greater China gas import from region via pipeline and LNG

Units: Bn m^3/yr

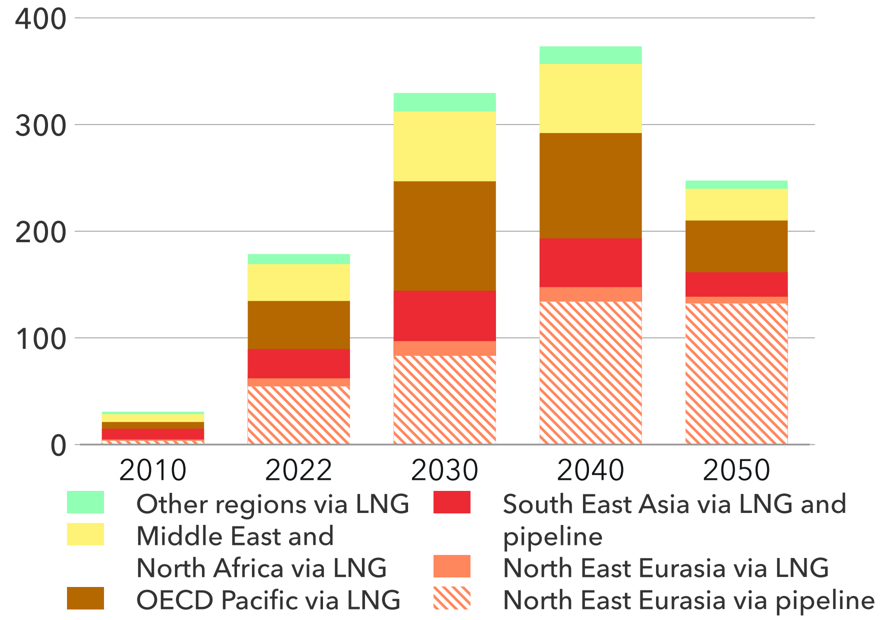
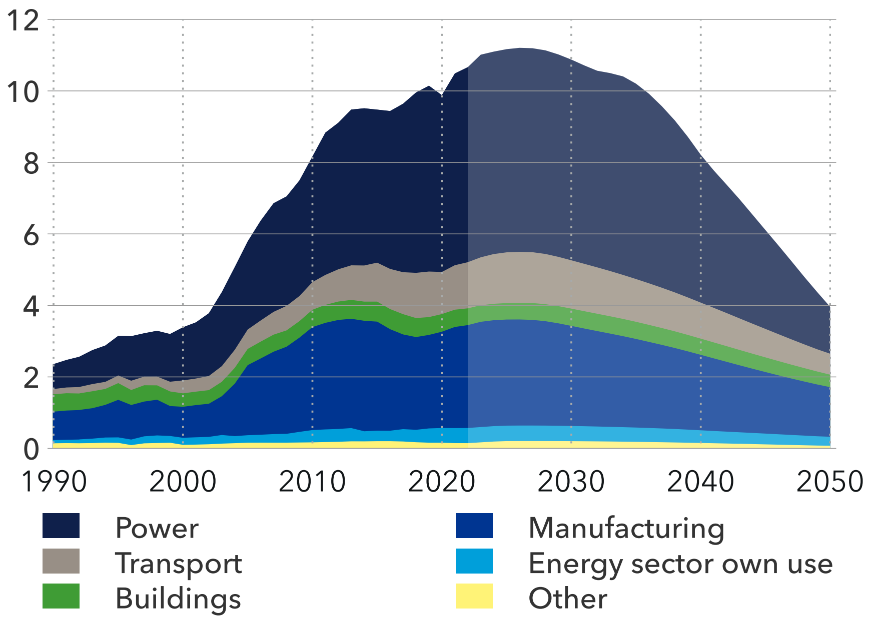


FIGURE 8.7.8

Greater China energy-related CO_2 emissions by sector

Units: $GtCO_2$/yr

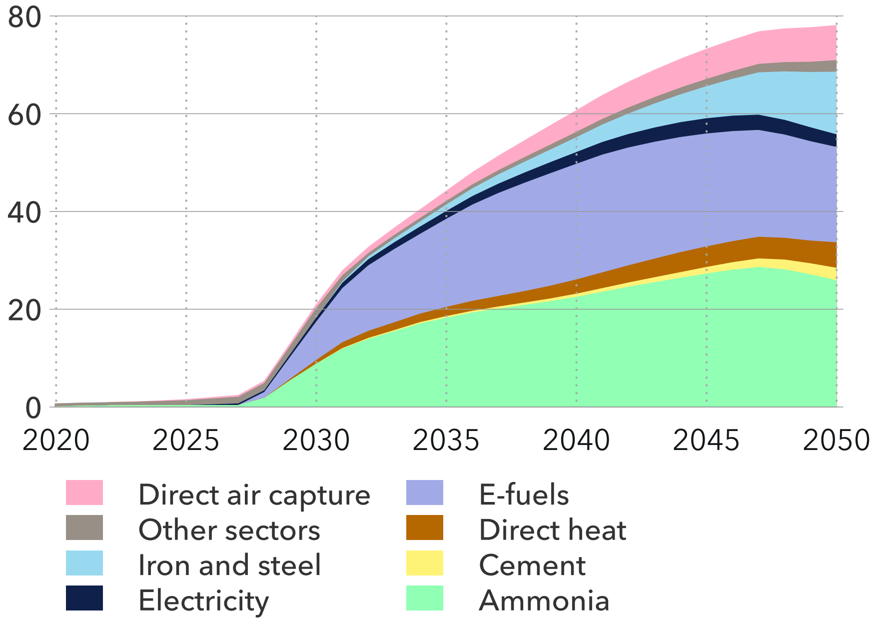


Historical data source: (IEA 2023)

FIGURE 8.7.9

Greater China CCS by sector and DAC

Units: $MtCO_2$/yr



8.8 INDIAN SUBCONTINENT (IND)

This region consists of India, Pakistan, Afghanistan, Bangladesh, Sri Lanka, Nepal, Bhutan, and the Maldives

	Population (Billion)	GDP* (USD Trillion) / GDP/person (USD)	Energy use (EJ) / Energy use/person (GJ)	Energy-related CO_2 emissions (GT) / Energy-related CO_2 emissions/person (Tonnes)
2022	1.88	15.4 8 000	51 26	3.0 1.6
2050	2.32	48.9 21 000	101 43	3.9 1.7

*All GDP figures in the report are based on 2017 purchasing power parity and in 2022 international USD

8.8 INDIAN SUBCONTINENT (IND)

Characteristics and current position

In 2023, India surpassed China as the world's most populous country. Pakistan and Bangladesh rank 5th and 8th, respectively. A key challenge in this region is to achieve higher levels of human and economic development while controlling GHG emissions. India's G20 presidency (2023) focuses on being a voice of the Global South to catalyse greater climate financing.

India's share of fossil fuels in generation capacity is 57% (49% coal, with 41% from renewables including hydropower, and about 2% nuclear) (Ministry of Power, 2023). Coal capacity additions have been in decline. Renewables accounted for 84% of new power capacity in 2022. Wind capacity is around 43 GW (March 2023) and solar 62 GW (November 2022).

Fossil fuels and imports dominate the energy mixes of Sri Lanka, Pakistan, and Bangladesh. India's 'Neighbourhood First' policy seeks to support Sri Lanka's economic recovery and renewable energy.

Pakistan's current economic crisis is tied to fossil-fuel imports, accounting for 40% of its primary energy supply. The government has backtracked on its 2020 moratorium on building coal generation, and announced a quadrupling of power plants fuelled with domestic coal (Dunne et al., 2023).

In Bangladesh natural gas is 84% of the power mix with LNG imports increasing. Nuclear plants are under construction (WNA, 2023).

The region is hit by severe climate change intensified impacts, such as scorching temperatures and massive floods from heavier annual and summer monsoon precipitation (IPCC, 2021).

Pointers to the future

- Regional emission reduction ambitions are dependent on international finance and technological assistance.
- India is extending decarbonization policies beyond the power sector but net-zero 2070 sectoral strategies are scarce. The *Amendment of the Energy Conservation Bill* (2022) advances efficiency and decarbonization measures, also preparing for a domestic carbon credit market.
- India's 2030 targets include: 50% non-fossil power and 500 GW renewable capacity. Promotion through government tenders / long-term contracts, and a mandate on new coal plants to install/purchase renewable capacity of 40% of their thermal capacity by 2025.
- The *National Hydrogen Mission* commits above USD 2bn to H_2 investment, emphasizing renewables-based H_2 and initial use in fertilizer production and refineries, then steel.
- Transport electrification targets (2030) for new vehicle sales are: 30% for passenger, 70% for public/commercial, and 80% for two- and three-wheelers, with *FAME II* scheme purchase and infrastructure support. A blending target aims for 20% bioethanol by 2025.
- India's wind manufacturing capacity (greater than 10GW/yr) will see increased utilization given government tender volumes. Solar manufacturing will expand with *Production Linked Incentive* (PLI) support. National strategy development to secure critical mineral supply chains will be in focus (CSEP, 2023).
- Pakistan's goal of 60% of energy from renewable sources including hydro by 2030 will depend on multilateral and bilateral partnerships.
- Bangladesh targets a 40% share of renewable electricity by early 2040s, from around 3% today. The first contribution from nuclear power supplies is planned by the mid-2020s (WNA, 2023).

Energy transition: climate change looming

The Indian Subcontinent is the most populous of our 10 regions, with 1.9 billon people in 2022 and heading for 2.3 billion by 2050. It has fast-growing national economies. Its large imports of oil and natural gas make it vulnerable to supply issues and price shocks. These directly contributed to the complete breakdown of electric power in Pakistan in January 2023 (Dunne et al., 2023). Coal has historically been the dominant energy source, and recent high oil and gas prices have pushed some countries to consider a return to coal power to ensure domestic energy security, while others are looking to solar and wind to fill the need.

However, substantial development of renewables is possible, with geography and climate especially favouring solar power. India, the region's largest country, has enacted climate-friendly legislation to push for more solar and wind power, EVs, and green hydrogen. Pakistan and Sri Lanka have pledged that 65% and 70% of their electricity respectively will come from renewables including hydropower by 2030. With scarcity of spare land and almost no resources for onshore wind, Bangladesh aims to achieve 40% of renewable energy usage by 2041 and will rely on significant import of renewable power for the energy transition.

Nepal and Bhutan are self-sufficient in electricity production with more than 99% of total generation from hydropower. However, both are now focusing on utilizing the untapped hydropotential to play a significant role in future renewable energy supply in South Asia. The Maldives, with 1,192 small islands and known for tourism, is heavily dependent on the import of diesel for electricity and is focusing on solar power generation to make electricity cheaper, reduce the import bills, and protect the local ecosystem.

The transition is especially important to the region because it is among those most acutely feeling the adverse effects of climate change – heatwaves, droughts, floods, and tropical storms. Pakistan experienced severe flooding in October 2022, while India was hit with heatwaves in spring 2023. Our forecast indicates, for example, that energy demand for space cooling will skyrocket – an eight-fold increase across the region. Developing renewable solar and wind power can bring domestic energy security and reduce GHG emissions, helping to mitigate extreme weather events. Our Outlook sees the subcontinent still tethered to coal and costly imported oil and gas in 2050 – and responsible for 21% of global energy-related emissions by then (on a par with China). However, we see a great growth in solar and wind power, and the addition of more renewable capacity today and throughout the forecast period will lead to renewables' share in its energy mix significantly increasing later.

Top of the coal pile

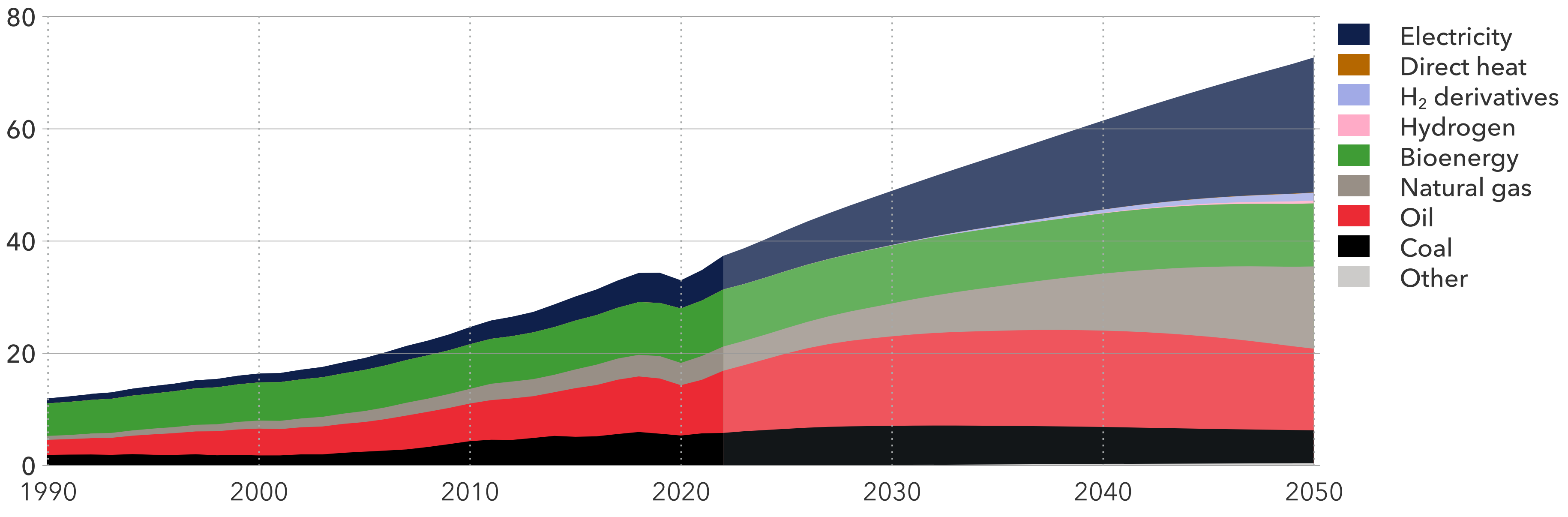
Despite all the pledges, the near-term development of the energy sector leaves much to be desired. We foresee coal still supplying much of the energy and remaining an important source in 2050. India has slowed down annual capacity additions, suggesting a phase-down approach. We see no signs of phase-out of coal-fired power plants; the fuel will still be heavily used in power stations and manufacturing in mid-century.

Within the energy demand mix (Figure 8.8.1) – which counts the direct use of coal in manufacturing, transport, etc. – coal will peak in 2031, declining from 15% now to 8% in mid-century. In the primary energy supply mix (Figure 8.8.2) – which includes the use of coal to make electricity – coal peaks in 2035 and declines from 39% now to 20% in 2050, the highest such percentage among our regions. Over half (52%) of the region's electricity in 2030 is sourced from

FIGURE 8.8.1

Indian Subcontinent final energy demand by energy carrier

Units: EJ/yr

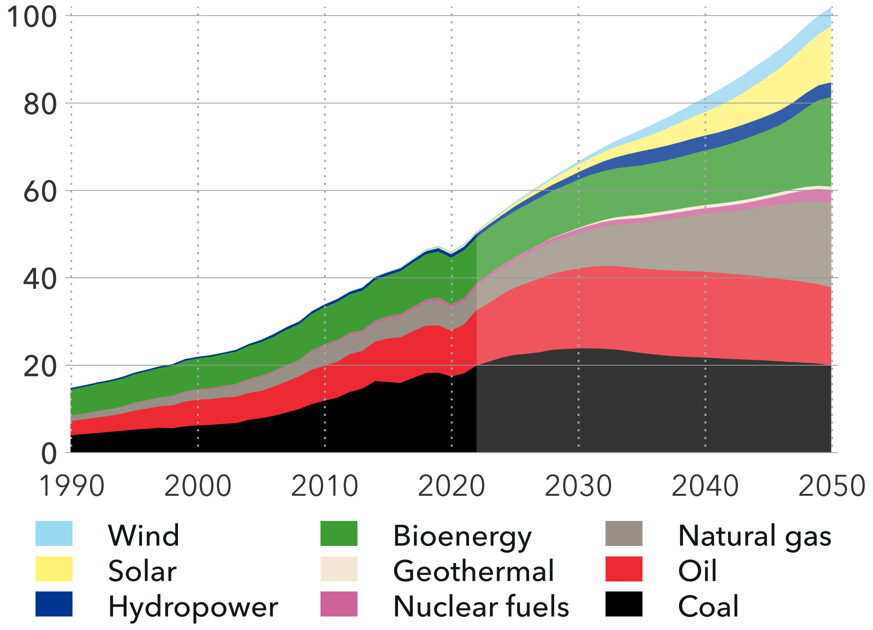


Historical data source: IEA WEB (2023)

FIGURE 8.8.2

Indian Subcontinent primary energy consumption by source

Units: EJ/yr



Historical data source: IEA WEB (2023)

coal-fired plants, but only 18% by 2050 – with coal use in electricity generation peaking in 2031 (Figure 8.8.3). The Indian Subcontinent will meet most of this demand for coal domestically, with only 8% imported by 2050.

Today, the Indian Subcontinent lags only the Greater China region in coal consumption, but the latter's consumption will have decreased enough by 2050 for the Indian Subcontinent to assume a slight (unwanted) lead. Other fossil fuels will remain important in the Indian Subcontinent up to mid-century, most being imported (Figure 8.8.4). These imports will be costly, and reliance on them will weaken the region's energy security. Oil consumption will peak in the early 2040s at 7.27 Mb/d, before declining slightly by mid-century. Natural gas consumption does not peak before 2050.

The limited rise of renewables

The Indian Subcontinent will make some progress in transitioning to renewable energy, but later than in many other regions, taking off only in the 2030s. Both solar PV and solar+storage will grow as prices drop. Today, these renewables share less than 5% of the electricity mix (Figure 8.8.3), but this will rise to 15% by 2030 and almost 37% in 2050. Wind generated electricity more than triples from under 3% today to 13% in 2050. By 2040, 95% of new additions to the grid will be solar or wind, averaging 76 GW per year between 2030 and 2040. This shift towards renewable power will be key in reducing power deficits in the region for its growing population and increasing energy security.

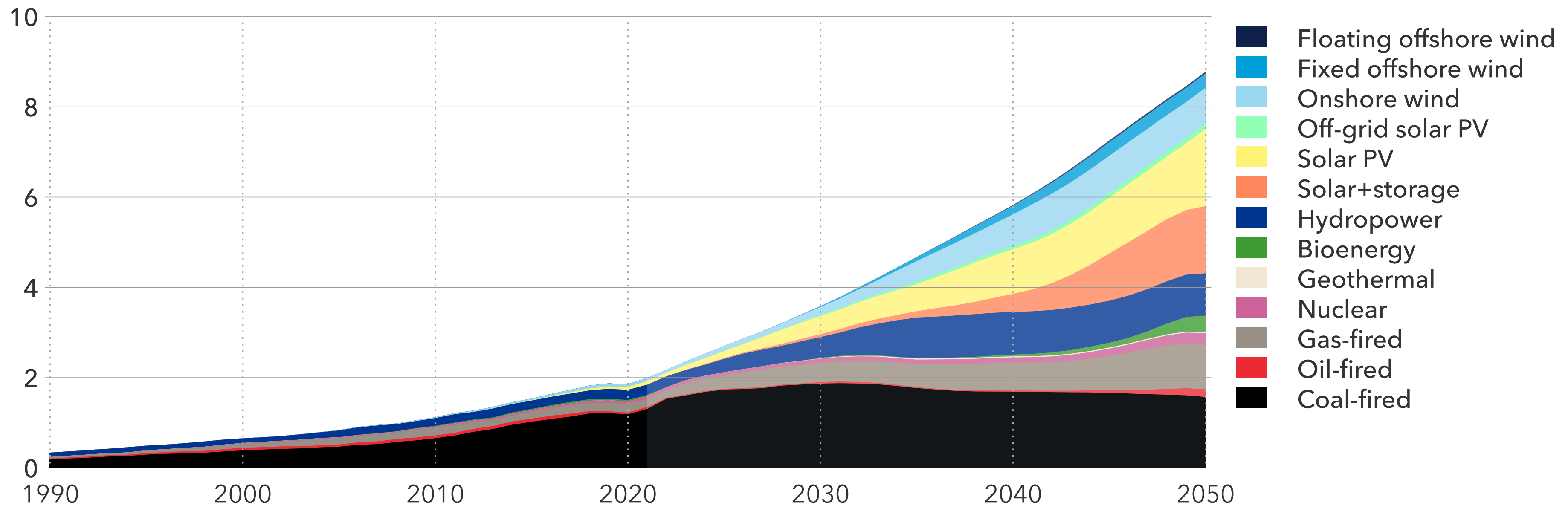
The growth of renewable energy will change the dynamics of energy production in the Indian Subcontinent. While the traditional production of coal will still remain, new jobs will be created with the need to build and install wind and solar power, and new skill sets will also be needed in these industries. The region will therefore need to also build a qualified workforce to meet these installation demands, which will ensure that the Indian Subcontinent can meet its growing demand for energy. The region will certainly need to develop substantial energy generation capacity as population, economic growth and access to electricity rise, causing annual energy demand to almost double from 37 EJ now to 73 EJ in 2050, when it will be the second biggest energy consumer among our 10 regions.

While the demand mix will remain dominated by fossil fuels – oil, gas, and coal supplying 48% of energy in 2050 – with all the aforementioned renewable capacity additions, electricity's share doubles from 16% today to 33% in mid-century (Figure 8.8.1). Continued dependence on fossil fuels will be costly and damaging for energy security, leaving the region open to similar price shocks and

FIGURE 8.8.3

Indian Subcontinent electricity generation by power station type

Units: PWh/yr



Historical data source: IEA WEB (2023), Global Data (2023)

FIGURE 8.8.4

Share of fossil fuel consumption not produced domestically

Units: Percentages

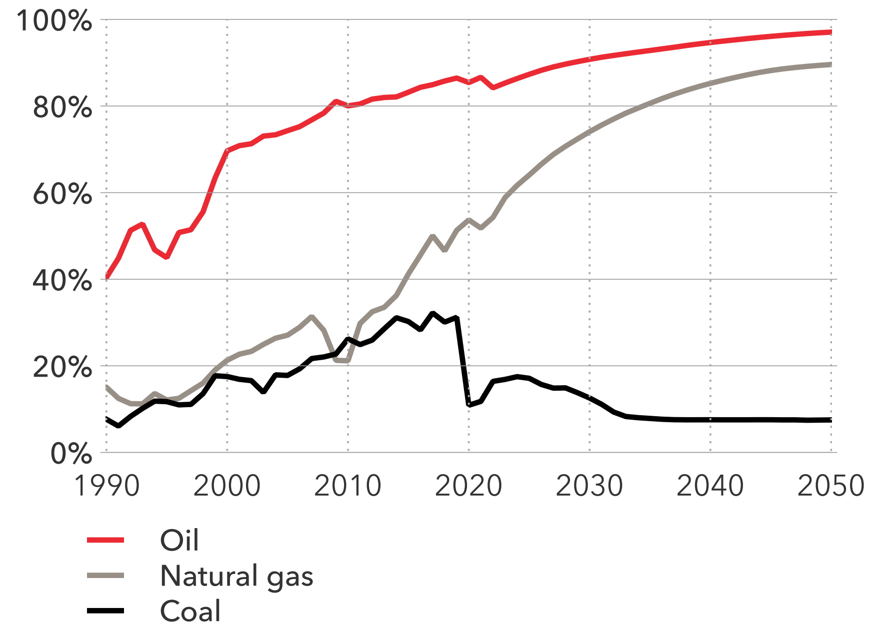
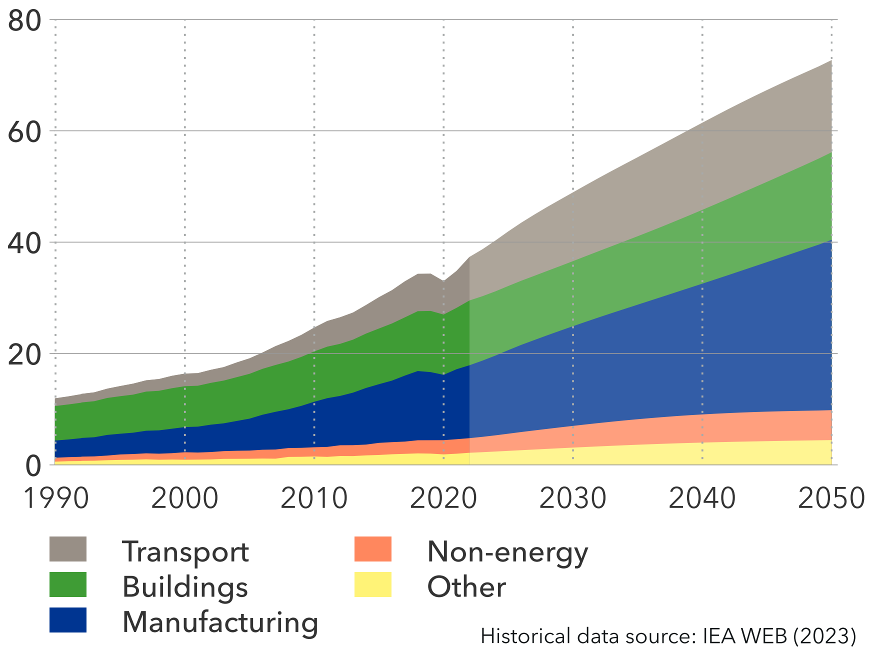


FIGURE 8.8.5

Indian Subcontinent final energy demand by sector

Units: EJ/yr



Historical data source: IEA WEB (2023)

supply issues to those seen today. Among other energy carriers, biomass will make up a significant 15% share while geothermal, hydrogen, and nuclear will remain negligible.

Sectors see energy changes

In terms of the different sectors, manufacturing will account for 42% of energy demand in 2050 as the region continues to be a manufacturing powerhouse, with manufacturing energy demand more than doubling from 13 EJ/yr to 31 EJ/yr. The equivalent shares for transport and buildings in 2050 will be 23% and 22%, respectively (Figure 8.8.5). In terms of energy sources for manufacturing, coal will be overtaken by electricity in 2043, producing an energy mix of 26% electricity and 18% coal in 2050, with natural gas at 22% and biomass at 25%.

In buildings, we see the effects of economic growth and energy efficiency through electrification. Cooking is a good example of this; while population rises, energy used for cooking declines slightly as more people have access to more efficient cooking technology. The percentage of houses without access to modern cooking decreases dramatically from 42% today to less than 1% in 2050, improving living standards and respiratory health. Consequently, the energy needed for appliances and lighting will more than double. Demand for energy for space cooling rises from 3% of the mix now to over 20% in mid-century as climate change increases the number of cooling-days per year and more people access air conditioning (Figure 8.8.6). Electricity will be the main energy carrier, supplying over half the power needed in the buildings sector.

In transport, electricity will grow to 23% of the energy mix, but oil will still dominate at over 50%. India itself is pushing for a market share of EVs, especially electric two- and three-wheelers. We see this as achievable, with an 81% share of new sales of two- and three-wheelers being electric by 2030, and almost all (98%) in 2050. Such EVs will represent 37% of total two- and three-wheeler vehicles in service in 2030, and 99% by mid-century (Figure 8.8.7). Electric passenger vehicles will see a much slower and later uptake, just 7% of all vehicles in service in 2030, and only 66% by 2050. These vehicles will also have the smallest average battery capacity (48 kWh) of all our regions.

As for other energy carriers, the region has some installed nuclear capacity, and nuclear has a place in Indian, Pakistani, and Bangladeshi plans for a renewable energy future. By 2050, nuclear will make up a small 3% of both the region's primary energy supply and its electricity mix. For hydrogen production, growth comes mainly after 2040. Feedstocks will be the main area of production, making up 86% of the hydrogen production in 2050, and mainly being blue or grey. The other 14%, hydrogen as an energy carrier, will be over 60% green hydrogen production in 2050. Overall hydrogen production will increase from 8.5 Mt in 2030 to 27 Mt in 2050. However, some counties in the region have high ambitions for hydrogen capacity build-outs and it is possible that we will see higher capacity sooner.

Energy use per capita across the subcontinent has historically been among the lowest in the world due to vast numbers of people being energy-deprived. Today's annual energy use per capita (27 GJ) will rise to 32 GJ in 2030 and 44 GJ in 2050. In mid-century, only Sub-Saharan Africa will have a lower energy use per capita. The share of renewables in energy use per capita will increase from a quarter (25%) in 2022 to 43% in 2050 (Figure 8.8.8), a percentage that will be on a par with regions such as South East Asia and Latin America.

FIGURE 8.8.6

Indian Subcontinent buildings energy demand

Units: Unitless, 2010 value = 1

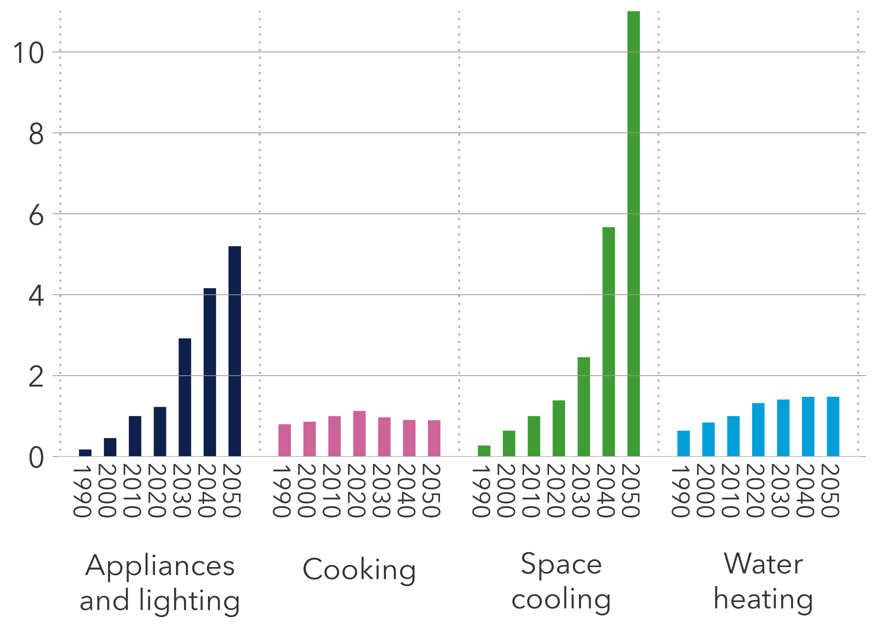


FIGURE 8.8.7

Indian Subcontinent two- and three-wheeler fleet and sales

Units: Million vehicles

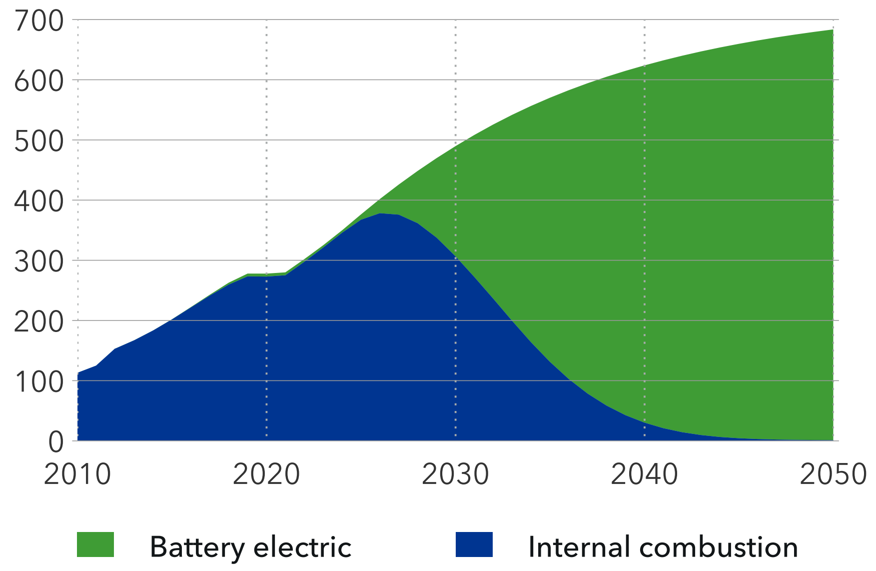
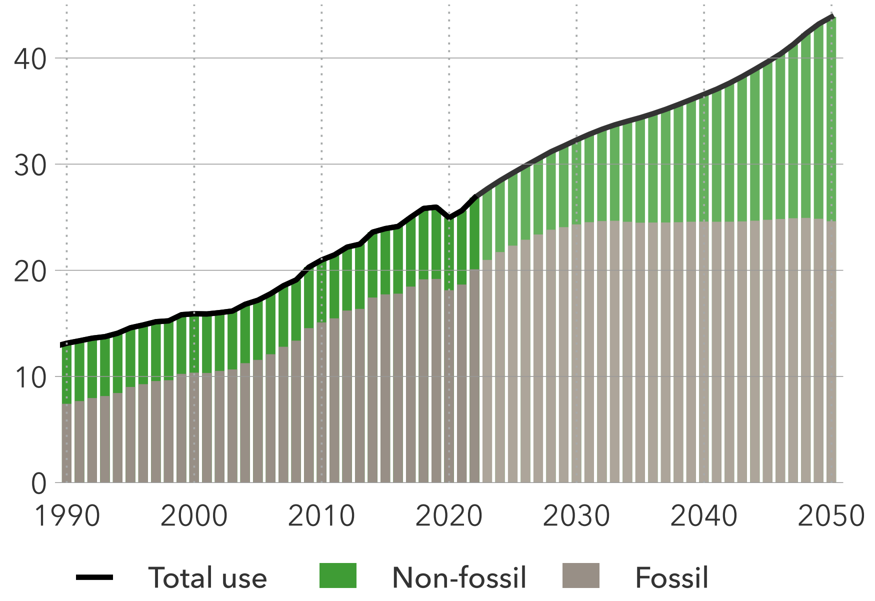


FIGURE 8.8.8

Indian Subcontinent energy use per capita

Units: GJ/(person-yr)



Historical data source: IEA WEB (2023)

Our forecast indicates that energy demand for space cooling will skyrocket – an eight-fold increase across the region.

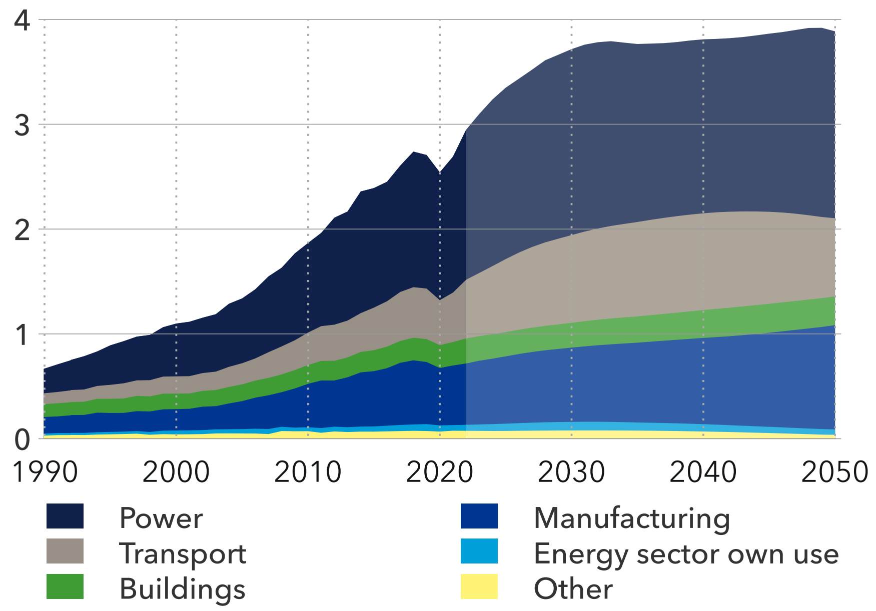
Emissions

Today, the region's annual energy-related carbon emissions (2.9 $GtCO_2$) are similar to that of the Middle East and North Africa. Despite being the most populous region, the Indian Subcontinent's aggregate emissions remain behind many other regions, including Greater China and North America. This will change however, as the Indian Subcontinent's annual emissions are expected to rise, reaching 3.9 $GtCO_2$ by 2030 and plateauing throughout the 2040s, reaching 3.89 $GtCO_2$ in 2050 (Figure 8.8.9) to put it on par with Greater China in having the most emissions of our 10 regions. However, while the Indian Subcontinent's emissions grow and plateau, China's emissions will have been on the decline from the late 2020s. The dominant source of emissions in the Indian Subcontinent is coal (45% in 2050) and reflects the reluctance of the region to abandon a domestic source of energy and risk being outcompeted by more prosperous regions for high-priced oil and natural gas.

FIGURE 8.8.9

Indian Subcontinent energy-related CO_2 emissions by sector

Units: $GtCO_2$/yr



Historical data source: IEA WEB (2023)

FIGURE 8.8.10

Indian Subcontinent emissions, energy, and economic indicators

Units: Unitless, 2010 value = 1

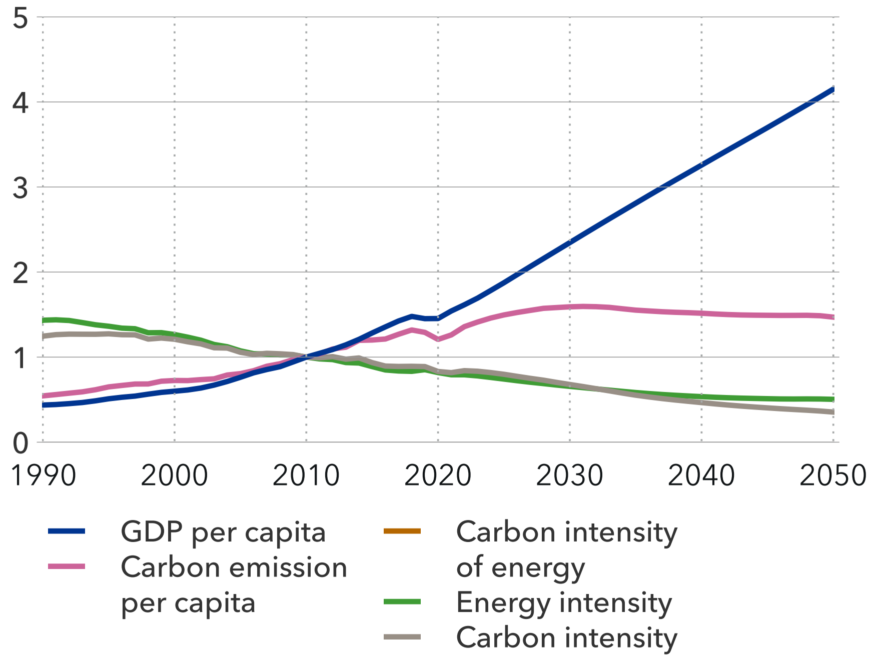


Figure 8.9.10 shows the changes in five intensity indicators, indexed to 2010: GDP per capita, carbon intensity of energy, carbon intensity of the economy, carbon emissions per capita, and energy intensity. GDP per capita is rising while energy intensity is decreasing, a result of energy-efficiency gains and rising shares of the secondary and tertiary sectors in the economy. There is a slight rise in carbon emission per capita – due to initial low energy use per capita and continued reliance on fossil fuels – but it peaks in 2032.

Our projection (see Section 6.3) for the regional average carbon price is USD 10/tCO_2 in 2030, rising to USD 45/tCO_2 in 2050. There is currently no explicit carbon pricing in the region and slow adoption is expected. India's emissions trading scheme is not setting an absolute emissions cap and will take time to mature. The low carbon price explains limited deployment of CCS in the Indian Subcontinent, which will not grow much in the 2030s, taking off only in the 2040s and rising to 81 $MtCO_2$/yr in 2050. Most of these emissions will be captured in e-fuels production, with 18% from electricity generation, which is important as coal use is still significant in this sector in 2050.

In the context of global climate policy, the Indian Subcontinent's country NDC pledges aim to limit growth in emissions to no more than 320% by 2030 relative to 1990. Our Outlook indicates energy-related CO_2 emissions increasing by 450% over this period. There are uncertainties in comparing our forecast with pledges, as some major countries also include non-energy-related CO_2 emissions in their targets. India is committed to reduce carbon intensity of GDP by 45% between 2005 and 2030, similar to how China sets its reduction target. This commitment is not easily measured in our forecast since we predominantly focus on energy-related emissions, and because our model does not regionalize non-energy-related CO_2 emissions. Our results suggest a reduction of 35% in carbon intensity by 2030 for the Indian Subcontinent.

India announced its net-zero carbon emissions target by 2070 at COP26. Our ETO forecast ends in 2050, when the region is expected to have 3.9 $GtCO_2$ of energy-related emissions (net of DAC). Between 2022 and 2050, the region increases its energy-related CO_2 emissions by 32%, and hence does not show a trend towards net-zero carbon emissions in 2070.

Our Outlook indicates energy-related CO_2 emissions increasing 450% by 2030 relative to 1990 levels. Between 2022 and 2050, the region increases its energy-related CO_2 emissions by 32%.

8.9 SOUTH EAST ASIA (SEA)

This region stretches from Myanmar to Papua New Guinea, and includes the Pacific Ocean States

	Population (Million)	GDP* (USD Trillion) GDP/person (USD)	Energy use (EJ) Energy use/person (GJ)	Energy-related CO_2 emissions (GT) Energy-related CO_2 emissions/ person (Tonnes)
2022	688	9.5 14 000	31 45	1.7 2.5
2050	778	25.2 32 000	46 59	1.4 1.8

*All GDP figures in the report are based on 2017 purchasing power parity and in 2022 international USD

8.9 SOUTH EAST ASIA (SEA)

Characteristics and current position

The economic powerhouses of the region are Indonesia, Malaysia, Philippines, Singapore, Thailand, and Vietnam. Electricity demand has risen around 6% annually in the past decade and is rising with increasingly affluent populations.

South East Asia's energy systems are skewed towards fossil fuels with coal entrenched in power systems. The region's coal fleet is young (less than 15 years) and expanding. Vietnam commits to no new coal after 2030, and Indonesia to phase out coal by 2055. Indonesia is, after Australia, the world's second largest coal exporter.

The fossil-fuel impact on air quality is immense in terms of hazardous airborne particles (PM 2.5) which on average fluctuate between 19 and 22 μg/m^3 (AQLI, 2021) while the WHO recommended level is 5 μg/m^3. The region is vulnerable to climate-related risks, both physical and transitional (Pongpech et al., 2023).

ASEAN countries have been net oil importers since before 2005. Energy security focus is mounting with prospects of increasing reliance on fossil-fuel imports and with fuel markets being volatile and sensitive to crises, although imports vary amongst countries (ACE, 2022).

A range of renewable resources are advantageous to renewable power expansion. There is high solar potential across countries. There is exploitation of hydropower in e.g. Indonesia, Lao PDR, Malaysia, and Vietnam being the countries with the most installed capacity, and Cambodia and Myanmar with above 50% shares in electricity generation. The Philippines and Indonesia have extensive geothermal resources. Vietnam and the Philippines are gaining traction for offshore wind developments.

ASEAN, at the regional level, aims for 23% of primary energy supply from renewables and a 35% share in the power mix, by 2025.

Pointers to the future

- Nine of ten ASEAN countries have pledged to achieve net-zero targets – for example, Malaysia and Vietnam by 2050, and Indonesia by 2060 – but are at the beginning of the journey in terms of policy clarity. Coal-to-gas switching plans will need reconsidering given high gas prices.

- Balancing regulated (low) electricity prices for affordability while also attracting foreign investment for industrialization with low-carbon investments in power systems will be a challenge (Zheng et al., 2023).

- Storage and modernization of grids will be needed to accommodate the rise in renewables and maintain energy security. The *Interconnection Masterplan Study III* suggests up to 21.8 GW extension of transmission capacity (Utama et al., 2023) to optimize cross-border renewable electricity sharing among otherwise resource-diverse countries.

- Policy will support renewable power expansions: Malaysia targeting 70% in the power mix by 2050, Vietnam advancing competitive tendering procedures to also scale offshore wind while the region trend is feed-in tariffs (e.g. in Thailand) coupled with annual capacity quotas and storage (Chandak, 2022), and Singapore supporting hydrogen imports to eventually supply 50% of power needs by 2050.

- The ASEAN taxonomy for sustainable finance (ASEAN, 2023) will steer clean investments. International funding will up the pressure on coal phase-down aided by concessional capital, such as the Energy Transition Mechanism (ADB, 2023), the JETPs, Just Energy Transition Partnerships, with Indonesia (USD 20bn) and Vietnam (USD 15.5bn), and the G7 Partnership for Global Infrastructure and Investment (PGII) mobilizing decarbonization investments.

Energy transition: trying to break fossil dependence

South East Asia initially appears well placed for a shift towards renewable energy, yet the actual transition remains unrealized (Weatherby, 2020). Despite ample solar and wind potential (NREL, 2020), the region faces challenges in advancing renewable infrastructure, including interconnectors and transmission from remote areas with high solar irradiation and wind potential to the region's highly populous cities. The abundance of coal and natural gas resources perpetuates a reliance on these energy sources for both power generation and primary energy supply. Notably, the region has emerged as a primary coal exporter, 400 Mt in 2022, surpassing North East Eurasia's 290 Mt.

The coal sector converges with mining, processing, energy, and steel, which are deeply ingrained within the region's economies. A pertinent illustration comes from Indonesia, the area's most populous nation, where coal phase-out encounters strong resistance. Particularly within this context, resource holders wield disproportionate sway over political deliberations, making withdrawal from coal highly problematic.

Concerned nations and regions unsettled by South East Asia's persistent coal utilization strategy are seeking to stimulate a shift from such dependency by offering substantial financial arrangements to facilitate the transformation of energy and power sectors towards environmentally friendly practices (Listiyorini et al., 2022). However, the war in Ukraine has cast a shadow over this transition from coal. Many regional governments had bet on LNG as a cost-effective bridge between their current reliance on coal and an eventual transition to renewables (Fallin et al., 2023). However, volatility in prices from the constriction in natural gas supply from North East Eurasia leads to heightened demand for the region's coal in the immediate timeframe. This greater demand fosters the attraction and profitability of coal investment, thus escalating the potential for coal's even deeper integration within the energy framework.

Primary energy consumption
The reliance on coal and fossil fuels is apparent in the region's pattern of primary energy consumption. As depicted in Figure 8.9.1, four-fifths (80%) of primary energy consumption originates from fossil fuels. While this proportion is forecast to decrease to a half (51%) by 2050, it will still exceed the global mid-century average of 48% among all our regions. Within the 80% fossil-fuel share in 2022, oil accounts for 33%, and coal and natural gas 24% and 23%, respectively. Our forecast indicates coal's share to be 10% by 2050 and a reduction to 18% in the natural gas share. More concerning is the only marginal decline of oil's significance from a 30% share in 2022 to 24% in 2050, with more or less flat oil consumption over that period. Broadly speaking, renewables are effectively satisfying new energy demand growth in South East Asia, and are not displacing fossil sources to any significant degree by mid-century.

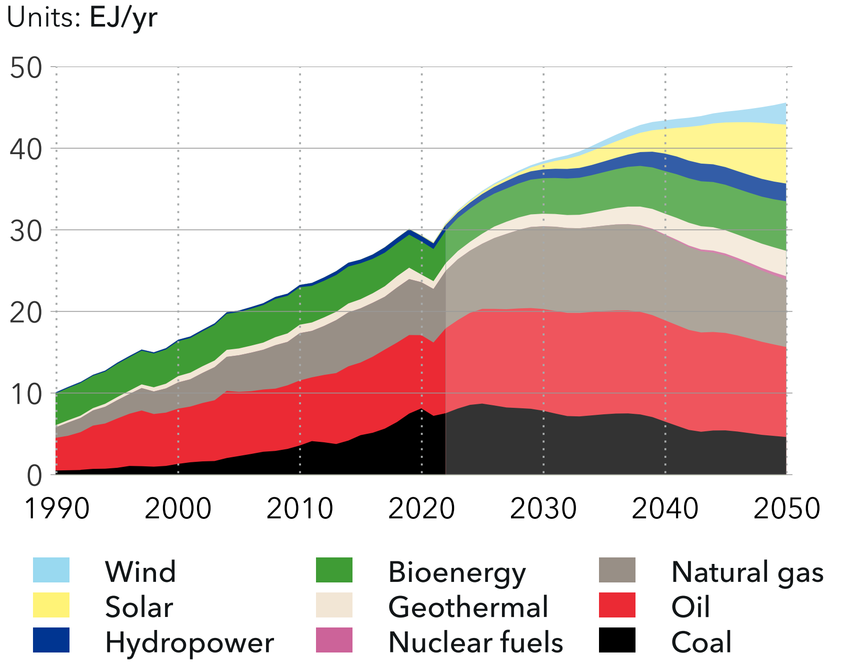
Solar and wind sources expand from their present minor stake in primary energy consumption (less than 1% combined in 2022) to a 22% share by 2050. The prominent economies of the region, such as Indonesia, Malaysia, Singapore, Thailand, and Vietnam, have grappled with establishing consistent and enduring policies to endorse renewables. However, indications suggest a shifting landscape. For instance, Vietnam's adoption of renewable policies like feed-in tariffs has played a pivotal role in propelling the adoption of renewables (solar, wind) and fostering industry growth (DNV, 2021b). Despite challenges posed by grid limitations hindering variable renewables' integration, investments in onshore and offshore wind power are flourishing.

> Broadly speaking, renewables are effectively satisfying new energy demand growth in South East Asia, and are not displacing fossil sources to any significant degree by mid-century.

Final energy demand
Figure 8.9.2 illustrates the composition of the region's final energy demand by energy carrier. Electricity's 18% share in final energy demand in 2022 doubles to 36% by 2050. This concurrent expansion aligns with a near five-fold increase in electricity generation over the period.

FIGURE 8.9.1

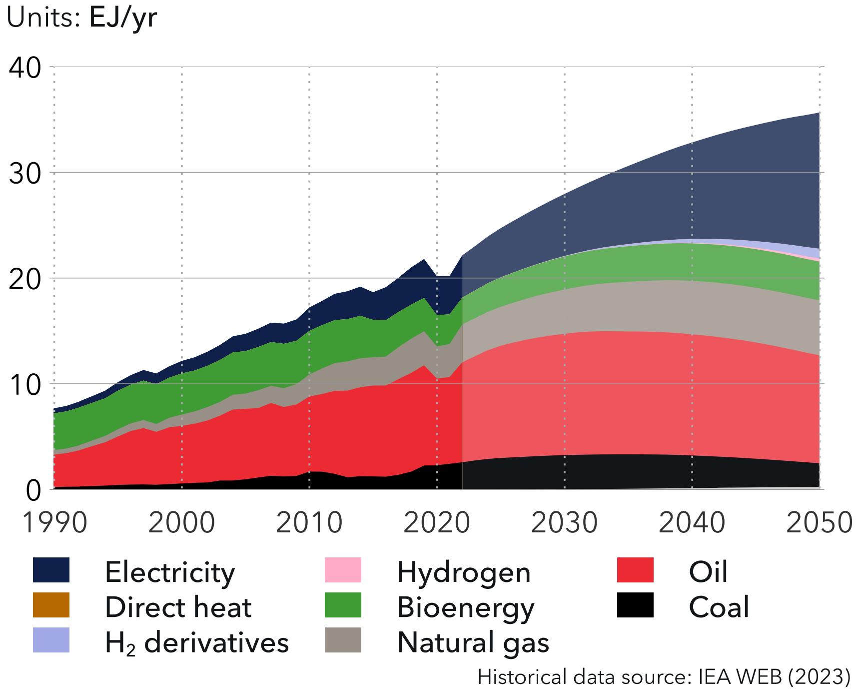
South East Asia primary energy consumption by source



Historical data source: IEA WEB (2023)

FIGURE 8.9.2

South East Asia final energy demand by carrier



Historical data source: IEA WEB (2023)

Regarding electricity generation within South East Asia, a distinct shift toward a renewables grid is evident, as displayed in Figure 8.9.2. The share of fossil fuels in the power mix dwindles from 70% in 2022 to 15% by 2050, at which time a substantial portion is attributed to natural gas. Notably, both solar PV and solar+storage witness a significant upswing in their contributions to electricity generation, escalating markedly from the late 2030s to collectively account for nearly two-thirds (63%) of total electricity generation by 2050.

Parallel to electricity, oil retains a paramount role in fulfilling energy demand in South East Asia. While oil's share in final energy demand diminishes from 43% in 2022 to 28% in 2050, absolute oil demand increases from 9 EJ to slightly above 10 EJ annually across the same time span, with most of that oil used in transport.

In terms of electricity demand growth, the buildings sector takes the lead in South East Asia, accounting for 2 EJ (640 TWh) in 2022 and 8.5 EJ (2,400 TWh) by 2050 in our forecast. Among end-uses in the sector, space cooling requirements are responsible for the most pronounced surge in electricity demand.

Exposed to volatile markets

South East Asia`s dependency on fossil fuels (80% of primary energy in 2022) exposes the region to the inherent volatility of fossil-fuel prices, a susceptibility further heightened by external geopolitical factors, such as the ongoing war in Ukraine disrupting the natural gas supply. Since the mid-1990s, the region has remained an importer of oil, and elevated oil prices have exerted notable pressures on both consumers and the wider economy. While annual oil production stood at about 1.7 Mb/d in 2022, consumption reached 4.1 Mb/d, resulting in roughly 2.4 Mb/d of oil being imported into the region, 40% of it to Thailand and the Philippines combined. These imports were primarily sourced from the Middle East and North Africa. Oil imports will peak around 2045 at 4 Mb/d. Although South East Asia is forecast to remain a net exporter of natural gas, some of its countries also need to import gas from abroad, remaining subject to the vicissitudes of the market.

A well-executed energy transition holds the promise of shielding South East Asia from the risks associated with volatile fossil-fuel prices and the kind of supply shocks associated with the global ‘grab for gas’ following Russia’s invasion of Ukraine. By diversifying the energy mix and strategically integrating renewables like solar, wind, and potentially emerging technologies such as advanced energy storage systems, the region can significantly advance both its economic stability and environmental sustainability.

How the transport sector can support the transition

The transport sector is in a great position to reduce oil dependency through rapid electrification of South East Asia’s passenger vehicle fleet. We forecast that most of the region’s oil demand in mid-century will, as now, come from the transportation sector, particularly from road transport (72%) as depicted in Figure 8.9.3. The transport sector's annual oil demand will grow to 8 EJ in the early 2030s, then decline back to its 2022 value of 7 EJ while the region’s vehicle fleet grows from about 300 million vehicles to more than 500 million over the same period.

South East Asia also boasts a substantial fleet of two- and three-wheeled vehicles alongside its four-wheelers. This fleet of two- and three-wheelers is forecast to grow by 43% from 227 million vehicles in 2022 to 324 million by 2050. We estimate that fewer than 2.5 million of the 324 million in mid-century will be internal combustion engine vehicles (ICEVs), implying that an impressive 99% will be electric two- or three-wheelers.

Likewise, in conjunction with rising GDP per capita, an increasing number of people will transition from two-wheelers to passenger vehicles, primarily for greater comfort and extended range. Consequently, we predict a tripling of the passenger vehicle fleet from 58 million in 2022 to 160 million by mid-century. We forecast that, by then, less than half the total passenger fleet will be EVs, with the remainder being ICEVs.

EV adoption will lag regions such as Greater China, despite South East Asia's stature as an automotive manufacturing hub and its proximity to China. Several factors contribute to South East Asia’s sluggish embrace of EVs: higher initial costs compared with ICEVs, lack of supportive policies like EV adoption targets and consumer incentives at point of sale, regulatory delays and uncertainties from governments, and underdeveloped recharging infrastructure. None of these challenges are insurmountable, but without bolder policies to promote EV uptake, the region’s pathway towards net zero is very difficult to discern through the smog of exhaust emissions.

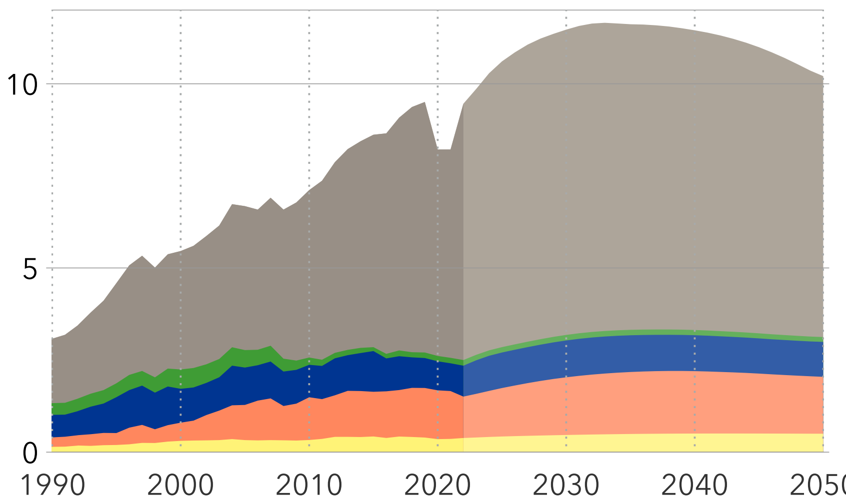
Metropolitan areas within South East Asia, including Bangkok and Jakarta, grapple with numerous challenges due to traffic congestion primarily caused by passenger vehicles. These issues encompass significant local air pollution, productivity losses incurred during traffic delays, and GHG emissions during idling.

Without bolder policies to promote EV uptake, the region’s pathway towards net zero is very difficult to discern through the smog of exhaust emissions.

FIGURE 8.9.3

South East Asia oil demand by sector

Units: EJ/yr



Historical data source: IEA WEB (2023)

Recognizing that EVs alone will not resolve traffic congestion, urban governments in the region have shifted their focus to mass transit systems, particularly within densely populated urban areas. In this context, the term 'mass transit' encompasses various forms of city and suburban rail systems (Future Southeast Asia, 2022). Noteworthy examples of cities currently constructing mass transit networks include Ho Chi Minh City and Hanoi in Vietnam, Vientiane in Laos, and the expansion of urban rail transit in Bangkok, Thailand.

In our forecast, mass transit is not considered a distinct entity, but is included within rail transport. For South East Asia, we anticipate that the energy demand for rail transport will climb from 26 PJ/yr in 2022 to 44 PJ/yr by 2050. Notably, we foresee a growing electrification trend within rail transport, which is poised to enhance energy efficiency. In 2022, only half of the energy utilized for rail transport was sourced from electricity. By 2050, we expect almost all the energy for rail transport to be electric.

While rail transport's share in total energy demand from the transportation sector remains steady between 2022 and 2050 in South East Asia, it is crucial to emphasize that the absolute surge in energy requirements for rail corresponds to a notably greater reduction in energy demand for road transport. Rail transport is inherently less energy-intensive, and the projected 18 PJ/yr upswing in rail transport energy between 2022 and 2050 translates into a substantially more pronounced decline in energy demand for road passenger transportation. Furthermore, the supplementary advantages of alleviating road traffic congestion, mitigating air pollution, and preventing productivity losses all contribute to an increased inclination towards rail transport, particularly in densely populated or remote areas within South East Asia.

In summary, concerted efforts are being undertaken to guide the region away from its fossil-fuel dependence. However, these efforts necessitate comprehensive and sustained policy support spanning a wide spectrum of measures.

Emissions

Our analysis expects the average carbon price level for the region will reach USD 10/tCO_2 in 2030 and rise to USD 50/tCO_2 by 2050. While explicit carbon pricing mechanisms are presently limited within the region, several countries are progressively taking measures to introduce or expand such schemes by mid-decade, as elaborated in Section 6.3. Annual energy-related CO_2 emissions from South East Asia are projected to peak at 2 Gt around 2030 before receding to 1.4 Gt by 2050, equivalent to the region's 2016 emissions. Notably, emissions were measured at 1.6 Gt in 2020, with a reduction of nearly 0.2 Gt stemming from the COVID-19-induced economic slowdown in comparison to 2019.

Presently, coal consumption constitutes the foremost contributor to emissions, though our forecast underscores that oil emissions will surpass those from coal in 2029 and continue to dominate through to 2050 (Figure 8.9.4). This trend is primarily attributed to the ongoing dependence of the transportation sector on oil. While manufacturing currently claims the largest emissions share among end-use sectors, the transport sector is projected to catch up, resulting in nearly equal key demand sector contributions to total CO_2 emissions by 2050 (Figure 8.9.5). This dynamic stems from our projections of accelerated electrification in manufacturing in contrast to transport.

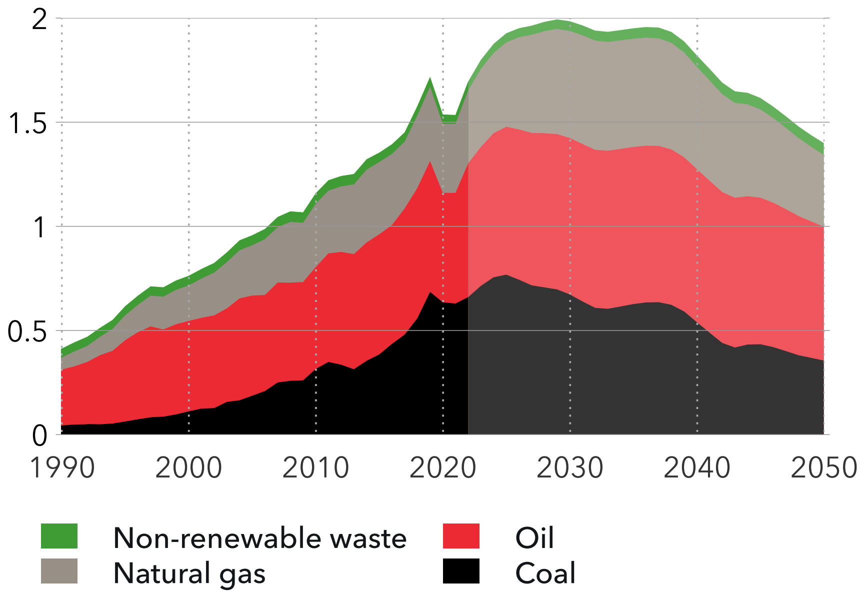
In the context of global climate policy, South East Asia's country pledges in NDCs imply a regional goal of restraining energy-related CO_2 emission increases to no more than 378% by 2030 compared to 1990 levels. Discrepancies in targets and forecasts arise due to uncertainties concerning whether targets include non-energy-related CO_2 emissions. Our Outlook has energy-related CO_2 emissions increasing by 382% by 2030, suggesting that pledges fall short, but are close to being met.

South East Asia nations have set net-zero emission targets around mid-century. Laos, Malaysia, and Vietnam for 2050, Indonesia for 2060, and Thailand for 2065 have outlined long-term targets, though comprehensive policies are yet to be developed. Energy-related CO_2 emissions are at 1.4 GtCO_2/yr in 2050, 18% below 2022 levels.

FIGURE 8.9.4

South East Asia energy-related CO_2 emissions by carrier

Units: GtCO_2/yr

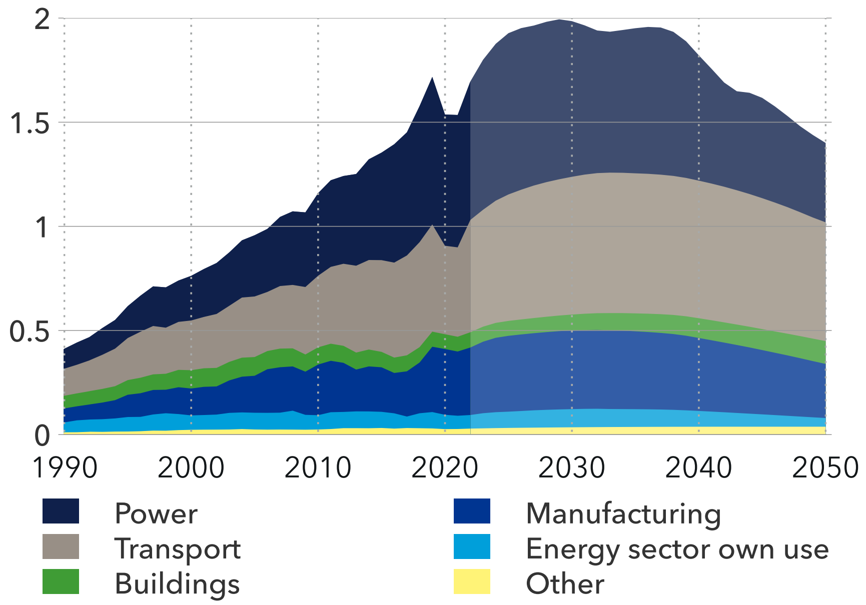


Historical data source: IEA WEB (2023)

FIGURE 8.9.5

South East Asia energy-related CO_2 emissions by sector

Units: GtCO_2/yr



Historical data source: IEA WEB (2023)

8.10 OECD PACIFIC (OPA)

This region consists of Australia, New Zealand, Japan and South Korea

	Population (Million)	GDP* (USD Trillion) GDP/person (USD)	Energy use (EJ) Energy use/person (GJ)	Energy-related CO_2 emissions (GT) Energy-related CO_2 emissions/ person (Tonnes)
2022	207	10.8 52 000	35.2 170	2 9.5
2050	189	13.8 73 000	25. 133	0.4 2

*All GDP figures in the report are based on 2017 purchasing power parity and in 2022 international USD

8.10 OECD PACIFIC (OPA)

Characteristics and current position

The mature economies in this region have diverse energy use and resources. The Australian Federal Government (elected May 2022) committed to an emissions reduction target of 43% by 2030, relative to 2005 levels, and is enshrining its net zero 2050 commitment into legislation. New Zealand, Japan, and South Korea depend on energy imports and have all committed to net zero by 2050. Region countries have joined the Global Methane Pledge (Australia in October 2022).

Australia has excellent renewable energy resources, particularly wind and solar, now contributing to 35% of electricity generation and with potential for far more. GHG emissions in Australia remain high with the country deploying its vast coal and gas resources to meet domestic energy demand as well as for export, with record volumes of LNG exported in 2022.

Japan's primary energy mix is 85% fossil-fuel reliant. Securing alternative suppliers other than Russia is a main priority. Most of its geothermal and hydropower potential is already deployed. Geographic factors constrain new renewables and grid connectivity. It plans to develop offshore wind and a nuclear power return was approved in December 2022 (Reynolds et al., 2022).

New Zealand relies heavily on renewables for electricity, particularly hydropower and geothermal, and to a lesser extent wind and solar. Fossil fuels still dominate energy supply but there is accelerated interest in hydrogen. A longstanding ETS system is in place.

South Korea was the world's seventh-largest energy consumer in 2021 and its energy system is dominated by fossil fuels (over 80%), also responsible for 66% of electricity. Renewables make up 7% of electricity generation (IEA, 2023h). The *10th Basic Energy Plan* prioritizes a shift back to nuclear (Tachev, 2023).

Pointers to the future

- Australia's energy transition plans include substantial investment in transmission infrastructure to underpin system-wide transformations. A collaborative approach, with states and territories, in the new National Energy Transformation Partnership provides the basis for energy market reform, development of net-zero technologies such as offshore wind and hydrogen, and manufacturing. An update is underway to the *National Hydrogen Strategy,* in part to respond to the attractive IRA credits in the US.

- Japan's government targets 30 to 40 GW offshore wind capacity by 2040. The *Green Transformation (GX) Basic Policy* provides a 10-year, JPY 150trn, investment roadmap for economy-wide decarbonization. Target examples include: up to 38% renewable power by 2030, CCUS value chains, expansion of green steel supply, carbon-neutral cement, and 100% EVs and FCEVs (passenger) by 2035 (GR Japan, 2023).

- New Zealand published its emissions reduction plan in May 2022, setting the direction for climate action for the next 15 years and establishing the policy for how its first emissions budget shall be met. It comprises action across the economy including increasing access to EVs, improving energy efficiency, introducing emissions pricing for agriculture, measures to reduce waste, and establishing new forests to act as carbon sinks as well as increase biodiversity.

- South Korea released its *Green New Deal* in July 2020 to achieve its GHG reduction goals. The government intends to increase hydrogen demand in the transportation, electric power, and industrial sectors, aiming for 30,000 commercial FCEVs and 70 hydrogen refuelling stations by 2030, and for 7% of power generation from hydrogen by 2036 (Li, 2022). The 2030 renewable power target, previously 30%, is now set for 22%.

Energy transition: slowing while speeding up

The region we define as OECD Pacific is different compared with other regions in that the countries are all industrialized but do not share common borders and connected grids. Population density, energy resources, and infrastructure vary greatly from Japan's north to New Zealand's south. Commonalities are access to abundant wind resources and plenty of coastline to capitalize on the growing offshore wind market. However, to complement variable wind and solar, Japan and South Korea will increase the share of electricity generation from the use of nuclear, as a clear measure of increasing their energy security.

Primary energy use is 29% lower in 2050 compared to 2022 levels, which is equal to about a 1.2% decline per year. This development points towards an economy less dependent on primary energy, but is also an effect of declining population. Total energy use is declining from today towards 2050, but electricity based primarily on renewable energy and nuclear is increasing its share from 25% to 42% by 2050. This change, together with other decarbonization efforts and energy-system efficiencies, creates a noticeable change in some key parameters. Figure 8.10.1 shows how the economy is decoupling rapidly from emissions and energy use in the economy, which is accelerating due to declining population.

Power sector

The region will see significant growth in renewable energy capacity. Much of this capacity is utility-scale solar PV, sometimes including storage, which will mainly be installed in Australia. Rooftop solar will find applications in all countries in the region, but in Australia and New Zealand the floor area per household is larger than in both Japan and South Korea, which limits rooftop availability for the north-eastern countries. Wind will grow considerably, initially onshore with offshore starting in the mid-2020s. Much of the wind capacity (167 GW) will be installed to supply the grid, but a considerable share of the capacity (11 GW) will be dedicated to produce hydrogen, ammonia, and e-fuels. By mid-2020, the majority of additional capacity for power generation in the region is from renewable energy or nuclear, as shown in Figure 8.10.2. By 2050, 72% of on-grid electricity is based on renewable energy and another 15% comes from nuclear power generation. The region will see continuous additions of nuclear capacity coming online during the forecast period, both existing nuclear that has been temporarily shut down and new capacity that will be built. Nuclear supplied the region (Japan and South Korea) with 220 TWh of nuclear electricity in 2022 which will more than double to 450 TWh by 2050.

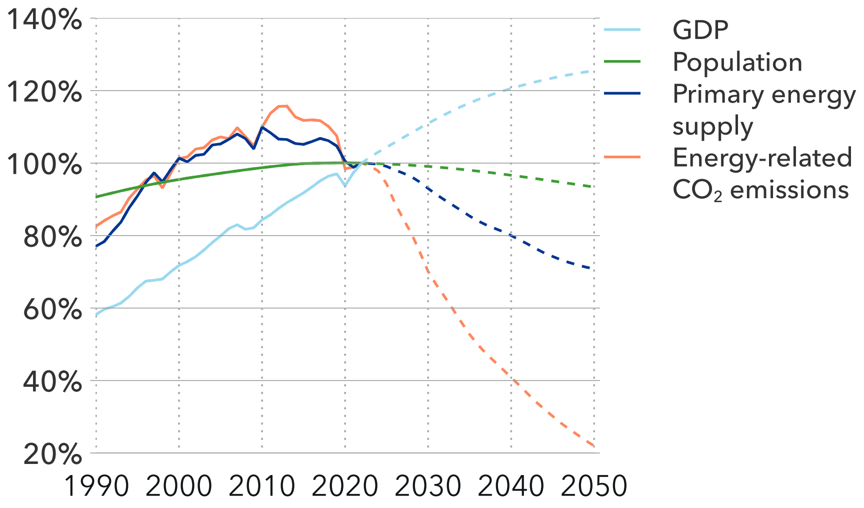
Transport

The region will transform its transport system from being based purely on oil and gas to being only 41% fossil-fuel based with the rest running on electricity (27%), bioenergy (9%), and 23% on hydrogen and its derivatives (Figure 8.10.3). In aviation, having the slowest subsector transition, most of the fuel is still oil-based (60%) in 2050, and the rest will be based on bioenergy and e-fuels. All countries in the region have lengthy coastlines and are dependent on shipping for imports and exports. In 2050, the maritime fuel mix will only be 16% fossil-based whereas ammonia will take centre stage and represent 36% of all shipping fuel, though uptake will

FIGURE 8.10.1

OECD Pacific decoupling of economic growth from other key parameters

Units: Percentages of 2022 levels



Economic activity (GDP) will continue to grow rapidly compared to population, which will rise relatively slowly. Energy use (primary energy supply) will first increase, and then flatten out; meanwhile, energy-related CO_2 emissions will almost halve by 2050.

Historical data source: UN (2023), IMF (2023), World Bank (2023), Gapminder (2018), IEA WEB (2023)

FIGURE 8.10.2

OECD Pacific capacity additions (including off-grid) becoming operational by power station type

Units: GW/yr

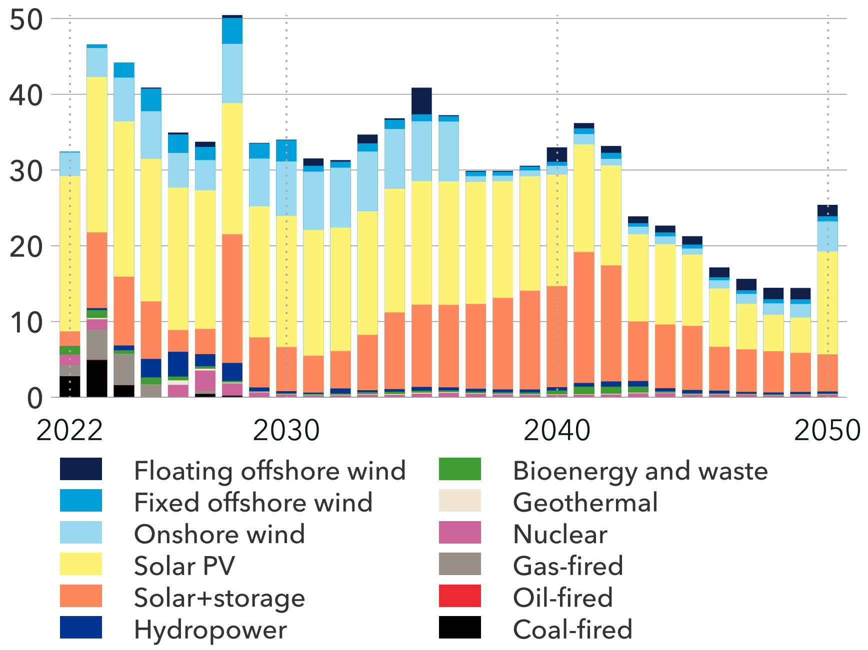
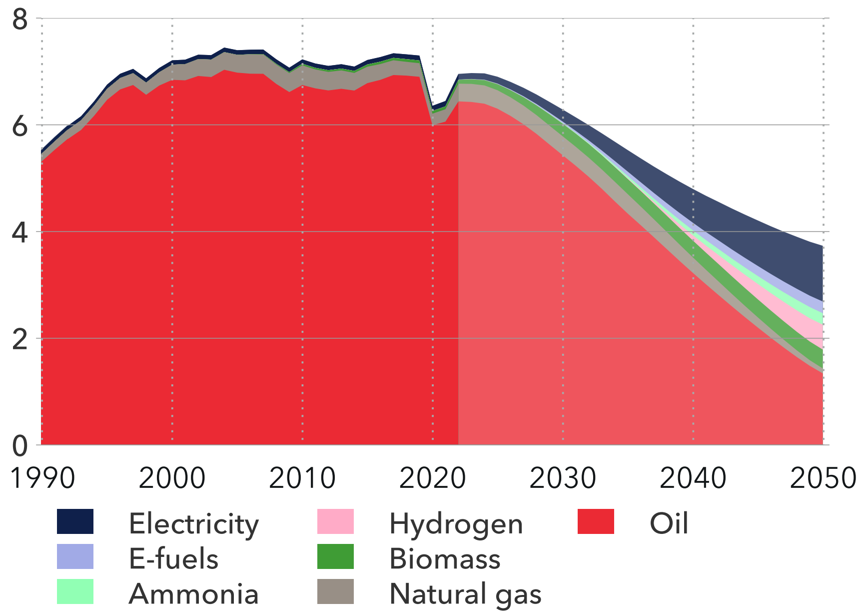


FIGURE 8.10.3

OECD Pacific transport sector energy demand by carrier

Units: EJ/yr



Historical data source: IEA WEB (2023)

be most prevalent after 2040. Road, representing 58% of final energy demand for transport purposes in 2050, will transform to have a 40%:60% split between fossil and non-fossil. Here electricity (39%) and some hydrogen (18%) will be the main means of decarbonizing road transport.

Hydrogen and its derivatives

OECD Pacific countries are expected to be at the forefront of hydrogen production and use as an energy carrier. Hydrogen and its derivatives will represent 10.4% of the final energy demand in the region by 2050, the second highest share after Europe. Initially, it is primarily in refineries that hydrogen will play a role in the region. By 2050, the manufacturing sector (23%), synthetic fuel production (20%), and road transport (18%) will represent the biggest users of total hydrogen demand. While we do not model intraregional trade, it is fair to assume much of the hydrogen produced will be from dedicated solar PV-based electrolysis plants in Australia, combined with production from grid-connected electricity. Much of the derivatives such as ammonia and e-fuels will be transported to South Korea and Japan for use in transport, manufacturing, and buildings, and in some instances converted back to hydrogen for electricity generation.

Energy imports and exports

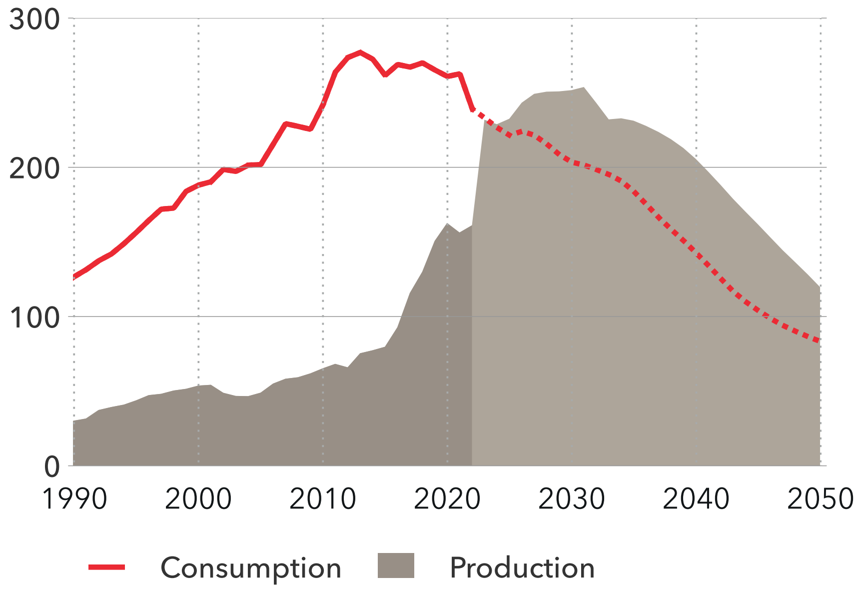
Natural gas has been and is in great demand by the North Asia countries Japan and South Korea, whilst production comes from Australia. Recent capacity additions increase the region's gas production, which means that the region goes from net importer to net exporter in 2022 (Figure 8.10.4).

Hydrogen demand more than doubles from less than 8 Mt in 2020 to 18 Mt in 2050. Hydrogen demand and supply largely match for the region with a small amount (0.6 Mt/yr) imported mainly by pipeline from Greater China, and some seaborne transport of 1.5 Mt. Ammonia and methanol will see growth trajectories equivalent to hydrogen and will represent about 15 Mt and 13 Mt/yr, respectively, in demand by 2050. Most of the use is as an energy carrier. However, production capacity will be limited and thus OECD Pacific will turn to imports to satisfy growing demand. For ammonia, this would mean 10 Mt/yr imported by 2050, as seen in Figure 8.10.5.

FIGURE 8.10.4

OECD Pacific natural gas consumption and production

Units: Bn m^3/yr

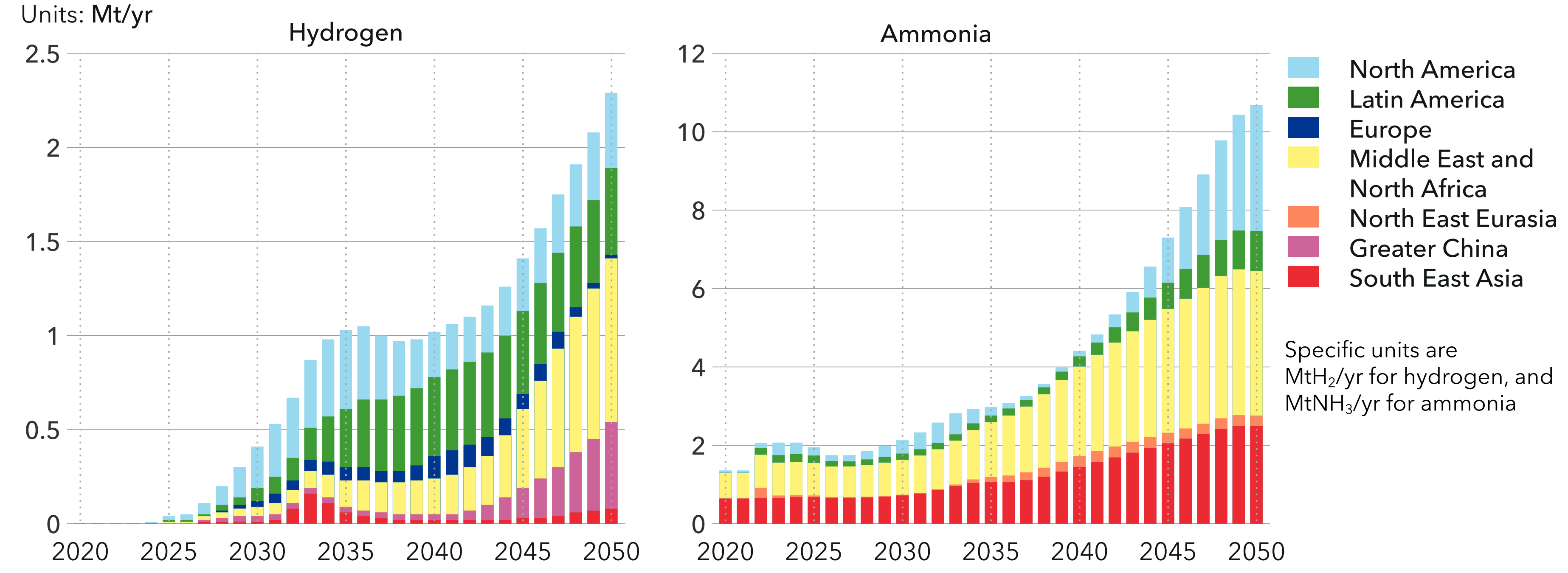


Historical data source: IEA (2023); GlobalData (2023)

FIGURE 8.10.5

OECD Pacific hydrogen and ammonia imports by source region

Units: Mt/yr



Emissions

The OECD Pacific country pledges in NDCs indicate a regional target of reducing energy-related CO_2 emissions by 12% by 2030, relative to 1990. Our forecast indicates that energy-related CO_2 emissions will decrease 16% by 2030 compared to 1990 levels, indicating that the targets are met. New Zealand was first in the region to enshrine in law its 2050 net-zero emission target (non-agricultural activities) in 2019, followed by Australia in 2021. South Korea and Japan have pledged carbon neutrality by 2050. For the region, energy-related CO_2 emissions are expected to be 0.4 $GtCO_2$ per year (net of DAC) in 2050, 80% below 2022 levels, but still not meeting the net-zero emission targets, see Figure 8.10.6.

Declining primary energy use combined with declining population will lead to emissions falling continuously during the forecast period. All sectors reduce their emissions, but the fastest rate will be from coal use in the power sector declining 88% between 2022 and 2050. Most of the remaining emissions will be found in the manufacturing sector (36%), though they will decline by 62% to 2050. Transport is the second largest source of emissions (27%), though they fall by more than three-quarters (78%) by 2050. Overall, looking at the energy carriers, natural gas will represent 40% of the emissions in 2050, while oil is 33% and coal with the largest decline goes to 25%.

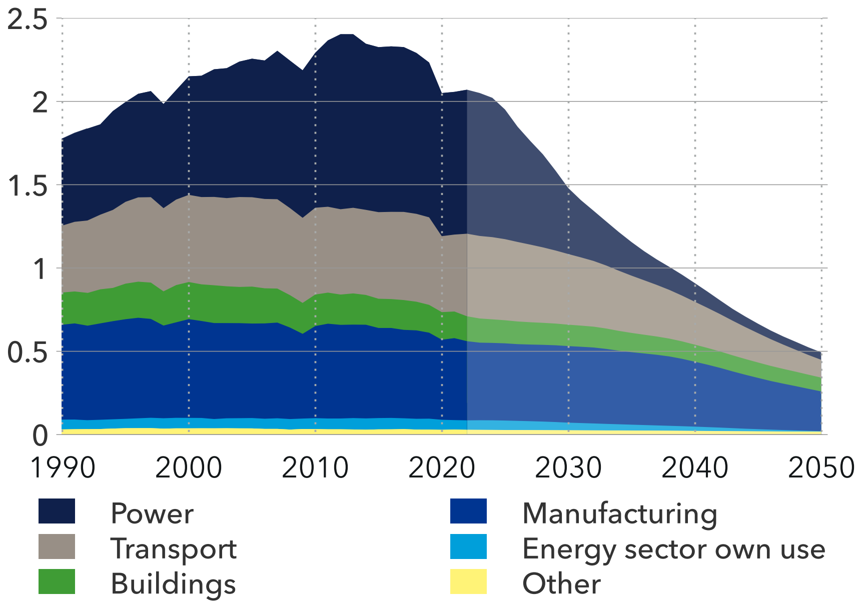
Our projection for the regional average carbon-price level is USD 40/tCO_2 in 2030 and USD 130/tCO_2 by 2050. Carbon pricing will play an important part of the policy mix to achieve net-zero 2050 targets adopted by all countries in the region (see Section 6.3). The amount of captured emissions from industrial processes amounts to 71 Mt/yr or 6% of globally captured CO_2 emissions. In addition, we expect another 20 Mt/yr to be captured from the atmosphere through negative emissions technologies.

Declining primary energy use combined with declining population will lead to emissions falling continuously during the forecast period.

FIGURE 8.10.6

OECD Pacific energy-related CO_2 emissions by sector

Units: $GtCO_2$/yr



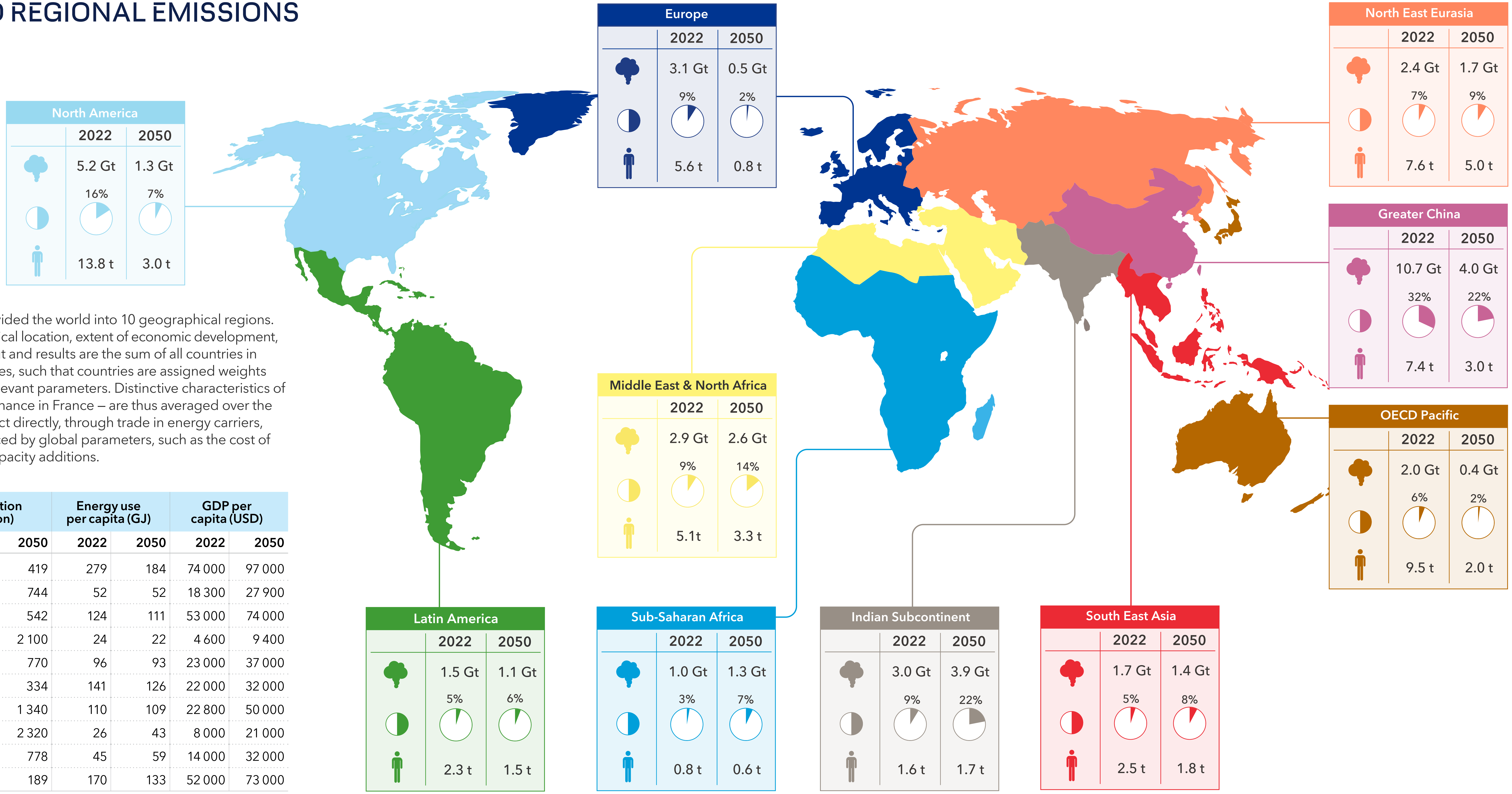
Historical data source: IEA WEB (2023)

8.11 ENERGY-RELATED REGIONAL EMISSIONS

Total energy-related CO_2 emissions

Share of world emissions

Energy-related per capita emissions



10 world regions. In this Outlook, we have divided the world into 10 geographical regions. These regions are chosen based on geographical location, extent of economic development, and energy characteristics. Each region's input and results are the sum of all countries in the region. We use relevant, weighted averages, such that countries are assigned weights relative to population, energy use, or other relevant parameters. Distinctive characteristics of certain countries – for example, nuclear dominance in France – are thus averaged over the entire region. In our modelling, regions interact directly, through trade in energy carriers, and indirectly, by affecting and being influenced by global parameters, such as the cost of wind turbines, which is a function of global capacity additions.

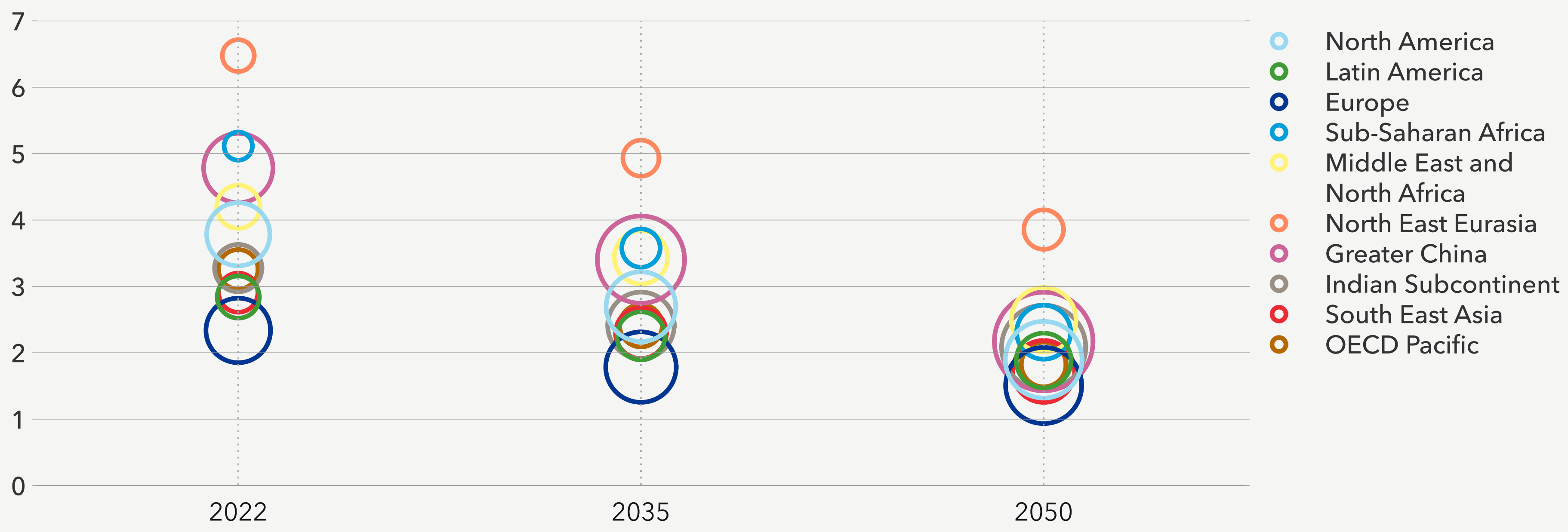
	Population (million)		Energy use per capita (GJ)		GDP per capita (USD)	
Region	**2022**	**2050**	**2022**	**2050**	**2022**	**2050**
North America (NAM)	373	419	279	184	74 000	97 000
Latin America (LAM)	688	744	52	52	18 300	27 900
Europe (EUR)	543	542	124	111	53 000	74 000
Sub-Saharan Africa (SSA)	1 200	2 100	24	22	4 600	9 400
Middle East & North Africa (MEA)	536	770	96	93	23 000	37 000
North East Eurasia (NEE)	320	334	141	126	22 000	32 000
Greater China (CHN)	1 450	1 340	110	109	22 800	50 000
Indian Subcontinent (IND)	1 880	2 320	26	43	8 000	21 000
South East Asia (SEA)	688	778	45	59	14 000	32 000
OECD Pacific (OPA)	207	189	170	133	52 000	73 000

8.12 COMPARISON OF REGIONAL ENERGY TRANSITIONS

FIGURE 8.11.1

Primary energy intensity of GDP

Units: MJ/USD

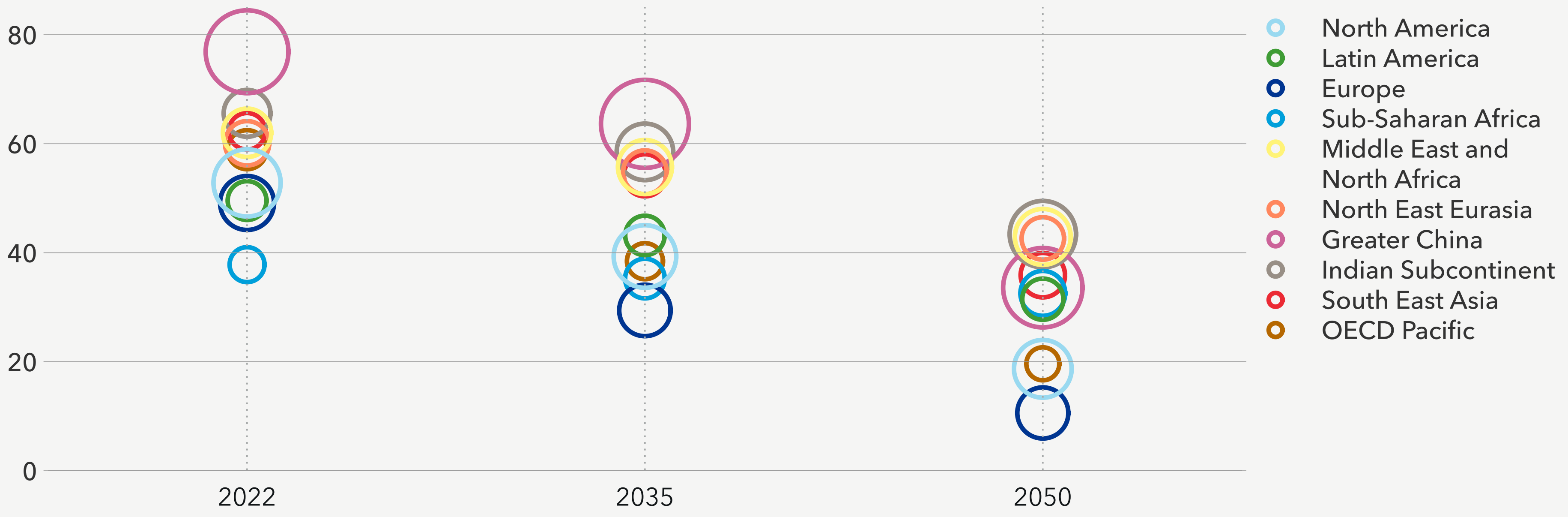


Circle area is proportional to GDP.

FIGURE 8.11.2

Carbon intensity of primary energy consumption

Units: gCO_2/MJ



Circle area is proportional to total primary energy consumption.

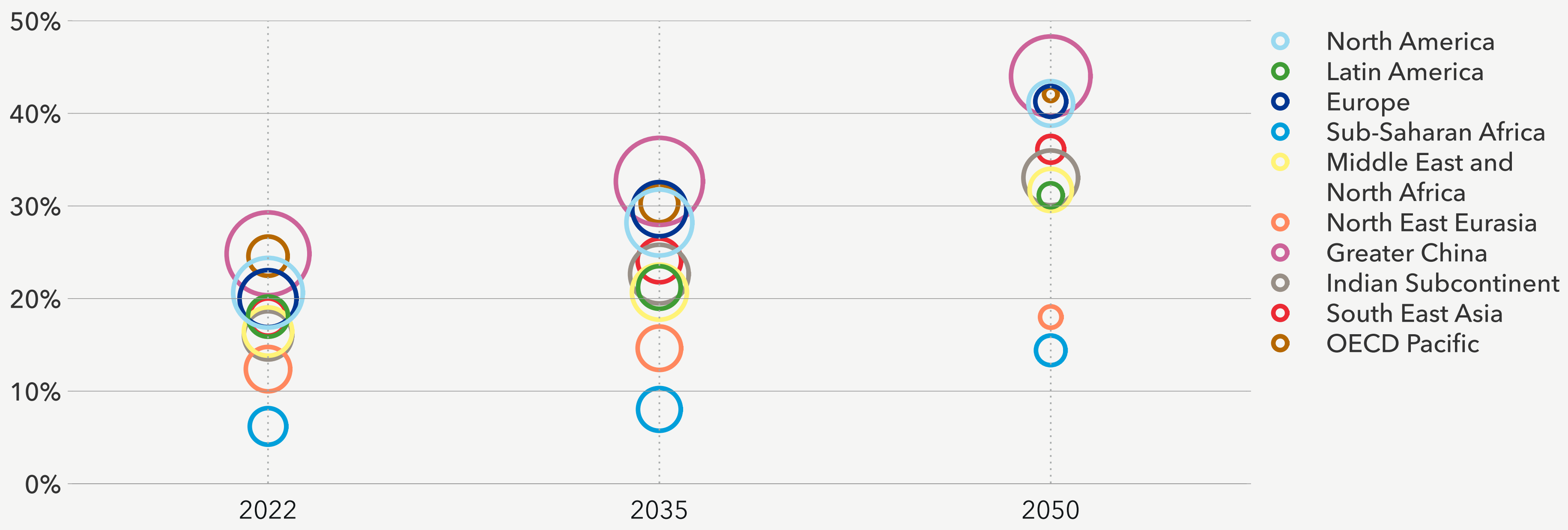
Energy intensity is measured as primary energy consumption per unit of GDP. All regions experience a decline in this measure due mainly to efficiency gains associated with the steady electrification of energy end-use, but also to the increasing share of renewables in electricity generation, reducing losses to heat. Despite a 40% decline in energy intensity between 2022 and 2050, North East Eurasia remains the region with highest energy intensity in 2050. Europe continues to require the least amount of energy per dollar of economic activity, followed by South East Asia, and OECD Pacific. By 2050, regional differences are, however, minor as regional energy intensities trend towards 2 MJ/USD, with the exception of North East Eurasia.

Carbon intensity is measured as grams of CO_2 per megajoule of primary energy consumption. Decarbonization is most rapid in Europe, OECD Pacific, and North America with their carbon intensities declining by 80%, 67%, and 65%, respectively. North East Eurasia and Sub-Saharan Africa have the least improvement in carbon intensity (29% and 13%). North East Eurasia will become the most carbon-intensive energy system in 2050. The spread between the leading and lagging region remains fairly consistent between 2022 and 2050 at some 30 gCO_2/MJ.

FIGURE 8.11.3

Share of electricity in final energy demand

Units: Percentages

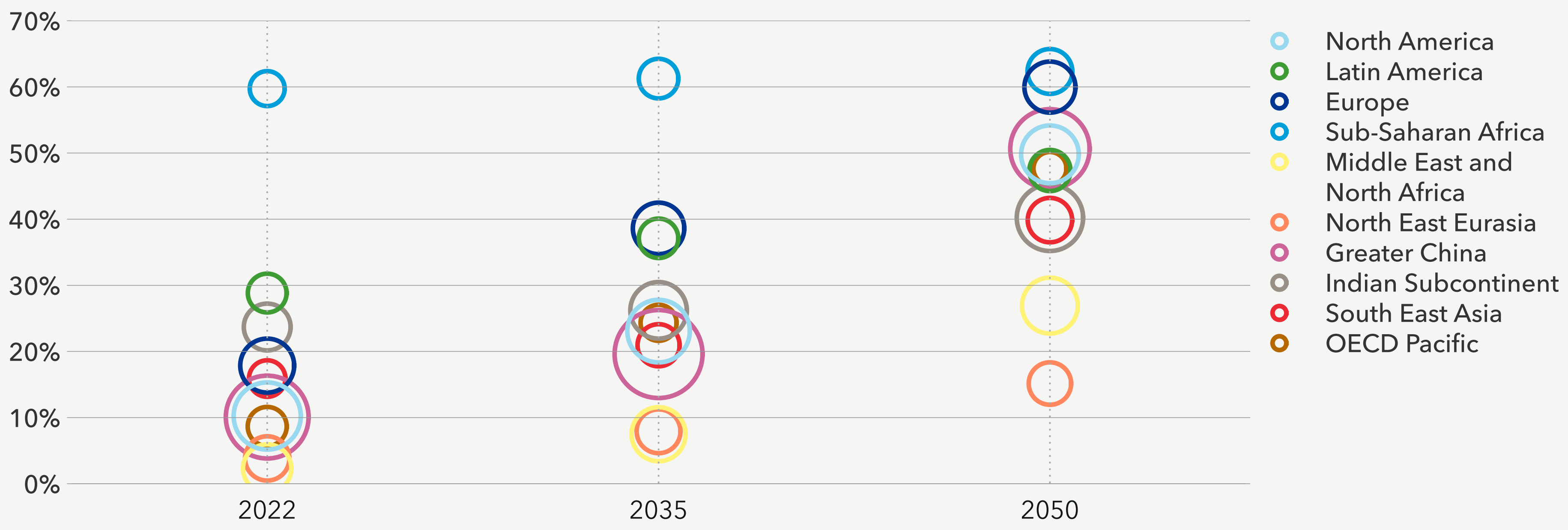


Circle area is proportional to total final energy demand.

FIGURE 8.11.4

Share of renewables in primary energy consumption

Units: Percentages



Circle area is proportional to total primary energy consumption.

Electrification is measured as the share of electricity in the final energy demand mix. This share is increasing everywhere and is fastest in Sub-Saharan Africa, where electrification will more than double, from 6% in 2022 to 14% in 2050. By 2035, Greater China will overtake OECD Pacific as the most-electrified region with electricity meeting 33% of final energy. In 2050, Greater China leads with electrification at 44%, followed closely by Europe, North America and OECD Pacific. By then, North East Eurasia and Sub-Saharan Africa lag behind the rest of the world by a large margin.

Renewables include biomass, solar, wind, geothermal, and hydropower. Because of its high share of traditional biomass, Sub-Saharan Africa remains the region with the highest share of renewables. The Middle East and North Africa will see the fastest relative growth rate in this measure, from 2% in 2022 to 27% in 2050, but because fossil fuels will still be dominant in 2050, it will have the second-lowest renewables share by then. OECD Pacific will see the second-largest relative increase, with its share of renewables growing from 9% to 48%. Most of the world clusters between 40% and 60% of renewables in primary energy consumption by 2050, with only North East Eurasia and the Middle East and North Africa, having lower shares.

Highlights

This appendix contains details on the key inputs to our model, including population, economic growth, and a consideration of resource limitations (in terms of both raw material and land or sea area required by the transition we forecast).

We also provide a summary of the workings of our system dynamics-based model behind the forecast given in this Outlook and list notable changes to our model over the last year.

APPENDIX

A.1 TEN REGIONS

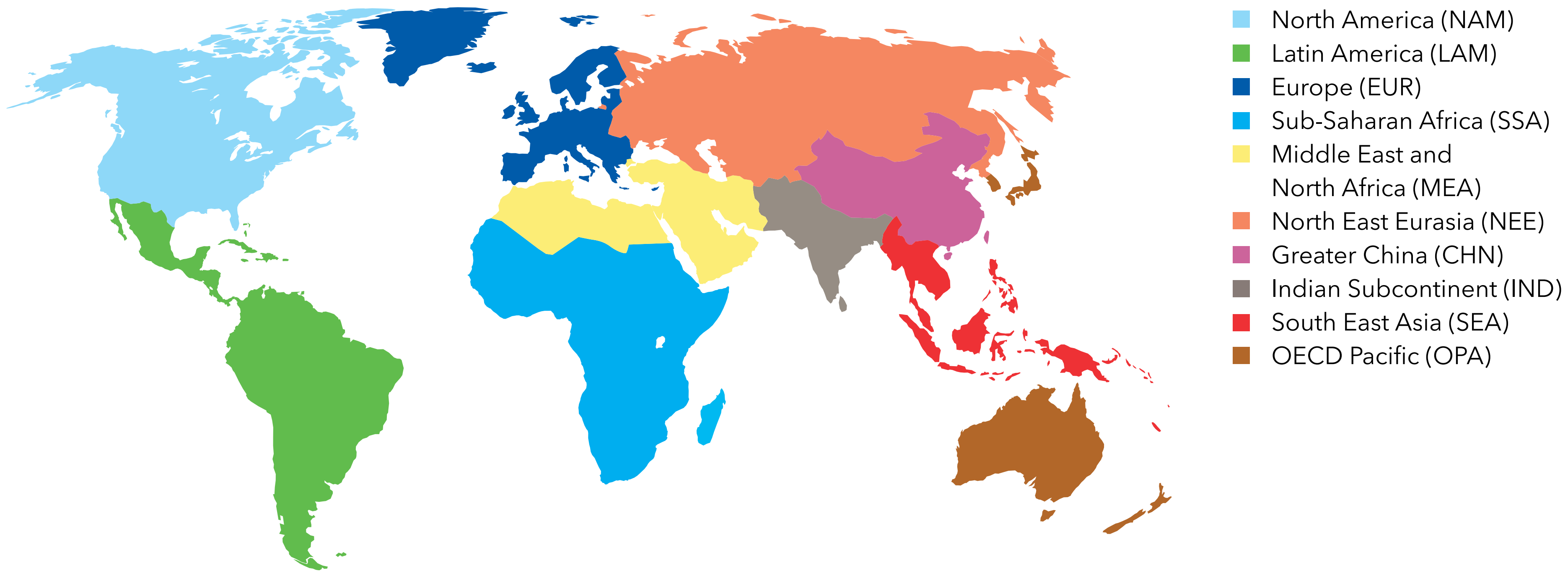
In this Outlook, we have divided the world into 10 geographical regions. These regions are chosen based on geographical location, extent of economic development, and energy characteristics.

Each region's input and results are the sum of all countries in the region. Where relevant, weighted averages are used, such that countries are assigned weights relative to population, energy use, or other relevant parameters. Distinctive characteristics of certain countries – for example, nuclear dominance in France – are thus averaged over the entire region.

In a few places, we refer to 'OECD regions'; that comprises the three regions North America, Europe, and OECD Pacific. We also use the terms 'high income', 'medium income' and 'low income' countries and regions, broadly in line with the definition established by the World Bank (Prydz et al., 2019).

Detailed discussions, results, and characteristics of the regional energy transitions are included in Chapter 8 of this Outlook, presenting regional analyses and forecast energy transitions for each of the 10 world regions.

FIGURE A.1



A.2 POPULATION

A typical energy forecast starts by considering the number of people that need energy.

The source most frequently used for population data and projections is the UN Department of Economic and Social Affairs, which publishes its *World Population Prospects*, normally every other year. The forecast in the latest update, published in July 2022, runs to 2100. Other entities that separately produce population forecasts include the US Census Bureau and the Wittgenstein Centre for Demography and Global Human Capital in Austria, WIC (2023).

The Wittgenstein Centre places more emphasis than the UN does on considering how future education levels, particularly among women, will influence fertility. As noted by Lutz (2014), urbanization in developing countries will result in fertility rates falling; having many children is a greater economic burden and less of a necessity in cities than in traditional, rural settings. Furthermore, evidence indicates that higher levels of education among women are associated with a lower fertility rate (Canning et al., 2015). Sustainable Development Goal (SDG) #4 Quality Education and SDG #5 Gender Equality are providing further impetus to improving female education.

Fertility is low in both the OECD and China, and in non-OECD regions it is falling considerably. In Sub-Saharan Africa, the reduction in fertility has been slower than in other parts of the world, and the total fertility rate is still at about 4.5 births per woman, falling by about 0.6 births per woman per decade. However, we assume that urbanization and improved education levels among women will, eventually, also accelerate the decline in fertility rates in Africa.

The Wittgenstein Centre uses several scenarios related to the Shared Economic Pathways (SSPs) developed by the Inter-governmental Panel on Climate Change, IPCC (van Vuuren et al., 2011). In this Outlook, we follow the central scenario (SSP2) for population and use it as a source of inspiration for other forecast inputs.

Using the Wittgenstein population projections for SSP2, we arrive at our 2050 population forecast of 9.6 billion, which is an increase of 22% from the most recent UN (2022b) population estimate of 7.9 billion.

Our 2050 figure of 9.6 billion is 1% lower than the latest UN median estimate of 9.7 billion. Had we used the UN median population projection, most of our energy demand figures would have increased commensurately, but with regional variations. The difference would, however, have been minor. The main uncertainty lies in the long term (2100 and beyond) forecast, where most mainstream forecasts, including the UN's, now indicate a peak in global population before 2100.

A.3 PRODUCTIVITY AND GDP

GDP per capita is a measure of the standard of living in a country and is a major driver of energy consumption in our model. From a production point of view, it is also a good proxy for labour productivity, as it reflects the amount of economic output per person.

This year, we have introduced two changes related to our forecast of GDP per capita. First, we updated the historical GDP per capita from 2011 to 2017 international purchasing power parity dollars, as per the latest update of the *World Economic Outlook* by IMF (2022b). Second, we switched from our own forecast, which was based on the inverse relationship between GDP per capita level and its growth rate, to using the GDP per capita growth rates implied by the OECD (2021) and International Institute for Applied Systems Analysis (IIASA) projections.

Measured in purchasing power-adjusted constant (2022) USD, historical GDP per capita developments from 1990 to today, along with forecast developments towards 2050, can be seen in Figure A.2.

With the updates, the general trends in productivity improvements and relative positions among the regions remain similar to the ones in our forecast last year. The fastest growth in GDP per capita, between 2022 and 2030, will still be in Asia, but also in Sub-Saharan Africa. The Indian Subcontinent will have the highest growth rate, at an average of 6.0%/yr, followed by Sub-Saharan Africa at 4.6%/yr, South East Asia at 4.5%/yr and Greater China at 4.6%/yr, as shown in Figure A.2.

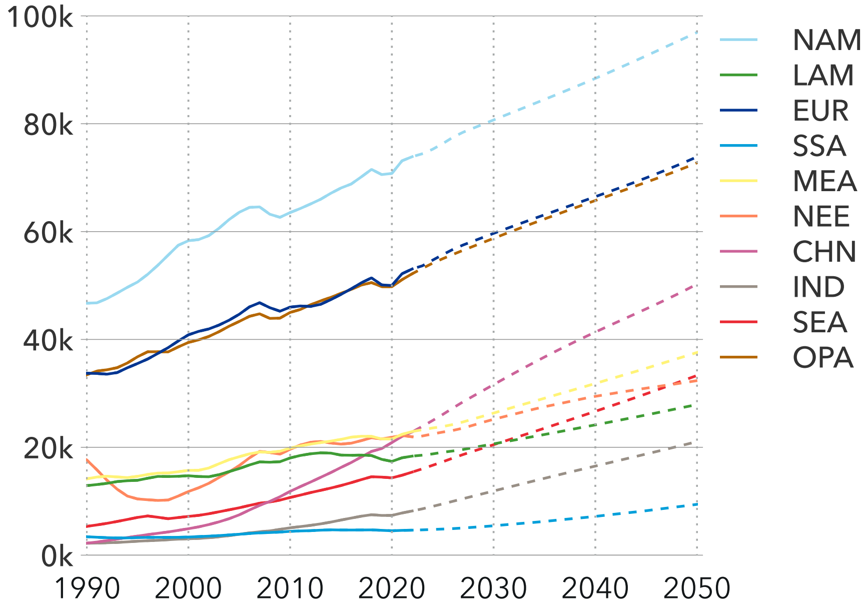
As these economies mature, growth in GDP per capita will slow down after 2030. The period between 2030–2050 will be characterized by a more even spread of prosperity improvements globally, with highest growth in the low-income regions. The region with the fastest GDP per capita growth will be the Indian Subcontinent, with a CAGR 2.9%/yr, followed closely by Sub-Saharan Africa at 2.8%/yr. Improvements in the standard of living in economically developed regions will reduce to 1.1%/ yr or lower in the 2030–2050 period. The forecast beyond 2030 does not include any larger changes in the relative positions among the productivity of the different regions.

World GDP is expected to grow from USD 164trn/yr in 2022 to USD 317trn/yr in 2050. This near doubling over the 28-year period is a result of a 22% increase in population and a 60% increase in average GDP per capita, with large regional differences. Figure A.3 illustrates the combined effect of population change (x-axis) and GDP per capita growth (y-axis); the decadal growth figures are included in Table A.1.

FIGURE A.2

GDP per capita by region

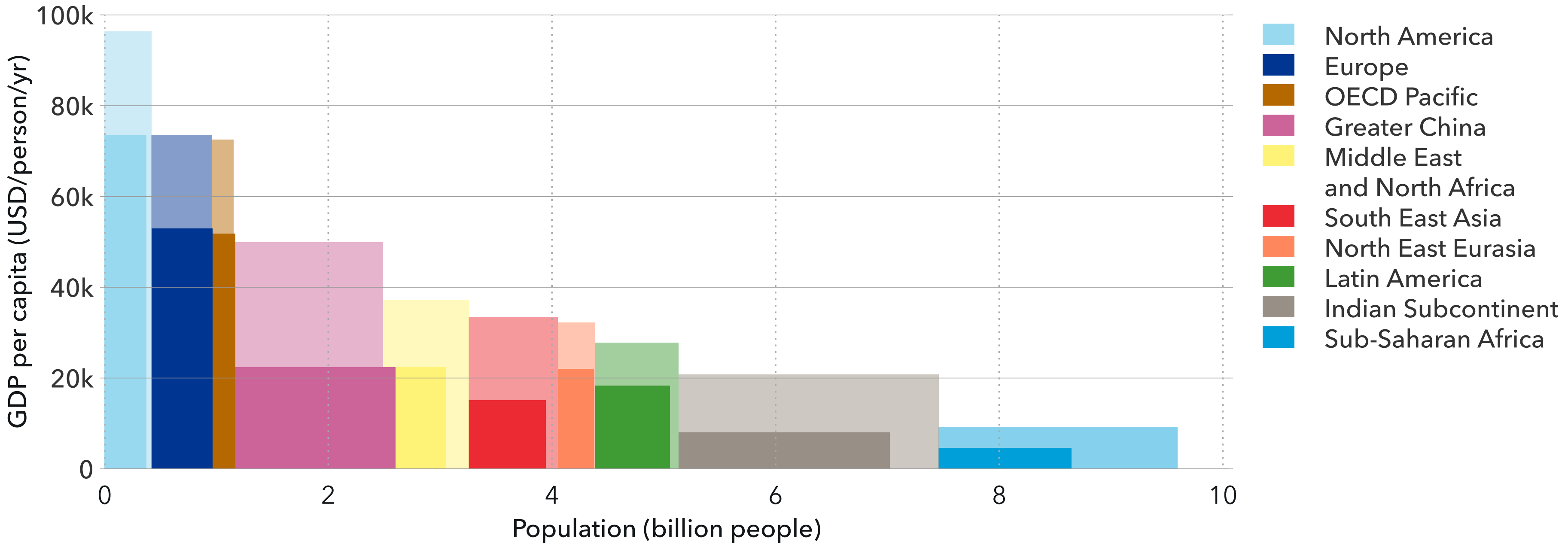
Units: USD/person/yr



Historical data source: OECD (2021), UN (2022), IMF (2023), WIC (2023)

FIGURE A.3

Change in population, GDP per capita and GDP between 2022 and 2050 by region



Darker boxes represent 2022, lighter boxes represent 2050. Historical data source: OECD (2021), UN (2022), IMF (2023), WIC (2023)

As Table A.1 shows, the world experienced a 3.2% compound annual GDP growth from 2000 to 2020. In the 2040s, this will gradually slow to 1.9%/yr, combining the effect of slowdown in population growth with the economies of more and more countries becoming service orientated. Nonetheless, most economies around the world will continue to grow, albeit at varying rates, with likely exceptions only in mature economies that are experiencing marked population decline, such as Japan. Compared to last year's forecast, only Greater China will grow its economy at slightly higher rate, while North America and OECD Pacific will grow on average at the same rates. The rest of the regions will show slightly lower average growth rates bringing the average annual global GDP growth rate from 2.7 to 2.5%/yr.

World GDP is expected to grow from USD 164 trn/yr in 2022 to USD 317 trn/yr in 2050.

TABLEA.1

CompoundannualGDPgrowthratebyregion

		2000-2020	2020-2030	2030-2040	2040-2050	2020-2050
NAM	North America	1.8%	1.9%	1.3%	1.3%	1.5%
LAM	Latin America	2.0%	2.3%	2.1%	1.7%	2.0%
EUR	Europe	1.2%	1.9%	1.0%	1.0%	1.3%
SSA	Sub-Saharan Africa	4.2%	4.5%	5.0%	4.6%	4.7%
MEA	Middle Eastand North Africa	3.5%	3.7%	3.0%	2.5%	3.1%
NEE	North East Eurasia	3.3%	1.6%	1.7%	1.1%	1.5%
CHN	Greater China	8.0%	4.3%	2.4%	1.5%	2.7%
IND	Indian Subcontinent	6.1%	6.1%	4.1%	2.9%	4.4%
SEA	South East Asia	4.8%	4.5%	3.2%	2.5%	3.4%
OPA	OECD Pacific	1.4%	1.5%	0.8%	0.6%	1.0%
	World	**3.2%**	**3.2%**	**2.4%**	**1.9%**	**2.5%**

A.4 RESOURCE LIMITATIONS

Our forecast describes the energy transition towards 2050. During the coming three decades there will be a profound shift in the added capacity and a shift in demand for resources. Historically the energy system has relied on fossil sources since the Industrial Revolution, and is now headed for an energy mix where renewables take a slightly-larger-than 50% share by 2050.

This shift will not only impact the structure of the energy system but there will be large shifts in demand for surface area and raw materials to support the transition. Coal mines will shutter, and nickel and lithium mining boom; instead of extracting oil and gas from offshore platforms there will be solar panels and turbines harvesting sun and wind resources for energy.

One central feature of our forecast is the increasing rate of electrification of the world's energy system. Road transport will increasingly be powered by electricity and energy stored in batteries. In 2050, there will be 1.3 billion EVs on the road and transitions on this scale require sufficient raw materials to build the infrastructure and end-use technology. Supply of natural resources must be capable of expanding at rates that can support demand, both sustainably and cumulatively. Although we expect there will be local resource demand challenges and price volatility in the future, the overall picture is that there are enough raw materials and land to support the transition.

Expansion of existing extractive industries combined with agility, technology and materials choices, and greater recycling and reuse of resources will be important for ensuring that major disruptions are avoided.

Our *Pathway to Net Zero* (see separate report) is a 'back cast' designing a future compliant with the *Paris Agreement* and limiting global warming to 1.5°C. The pathway is prescriptive in that it describes one possible pathway, and not one that is optimally designed using multi-variant selection criteria. Success in implementing this or other pathways to net zero requires war-footing policies which includes the extensive use of land and surface areas as well as intensified raw material demand extraction. Land, sea, and mining permits, financing, and distribution of existing resources would need to be managed through multilateral collaboration that takes into account the complex challenges facing reaching 1.5°C, and which would have to be far more effective in resolving resource access and limitations than market forces alone. How such a scenario could play out is the subject of future research. At present, our investigation of resource limitations has been confined to our 'most likely' forecast – the main subject of this report.

Land and sea areas to support renewable growth

We forecast a 16-fold increase in solar PV capacity (incl. off-grid) by 2050, with sufficient land and building area as a prerequisite to support such expansion. In our model, solar PV is installed at utility scale, in microgrids, on the roofs of residential or commercial buildings, or off-grid as capacity to produce hydrogen. The first two of these categories combined with off-grid capacity compete with other uses of land. In our Outlook, we forecast 14% of all solar to be installed on rooftops and commercial buildings globally. 16% of total capacity (2.9 TW) is further installed to support hydrogen production. Applying an estimated average 60 MW/km^2 for non-rooftop solar-PV installations indicates a requirement of less than 1% of total land area globally in 2050. Even for regions with large shares of solar PV in their power mix, the land-area requirement is not unmanageable. For example, 1.4% of agricultural land in Greater China and 1.9% in South East Asia will be used for solar PV installations in 2050. Co-use of land for grazing or for certain types of agriculture is also possible, and therefore it seems unlikely that the expansion of solar PV will encounter land-area limitations overall. We are also seeing a growing interest in and developments involving floating solar PV which can alleviate pressure on available land.

We predict a nine-fold capacity rise in wind energy, and the question arises as to whether there will be sufficient land and ocean-surface area. Onshore wind has a relatively small footprint, effectively just the base of the tower, so there will be no lack of land area. However, the siting of tall, rotating structures in densely populated areas is a growing societal concern. In our analysis, we have reviewed the overall technical potential and only included areas with sufficient wind speeds, while avoiding densely populated or ultra-remote locations. With these limitations and using an estimated area demand of 5 MW/km^2 giving almost 1 km of space between each turbine, then all onshore wind farms cover 1,000,000 km^2. This equates globally to less than 1% of available land, or in comparison about 2.1% of agricultural land. The expected capacity represents, at the most extreme, 11.3% of the technical potential in South East Asia and much lower in the rest of the regions. Thus, it is not availability of land that will be the limiting factor, but rather peoples' collective acceptance of visual, noise, and other environmental impacts associated with land-based wind power.

In contrast, offshore wind is located far from populations and provides plentiful energy in our Outlook. Our analysis and modelling include both fixed offshore wind and, in water depths exceeding 50 m, floating offshore wind. Globally, there will be enough sea areas and coastline to accommodate the forecast amount of offshore wind. Europe and Greater China will account for 57% of global installed offshore wind capacity. Europe and the North-Sea basin are expected to install mostly fixed (85%) but also floating offshore wind. Greater China will install the largest amount of offshore wind. The mean water depth of 44 m off the region's coastline and in the Yellow Sea is well suited for this purpose, so there, 88% will be bottom fixed. When considering the technical capacity, only a fraction of the installations will be floating offshore wind, but Greater China as well as the Indian Subcontinent will install 31% and 55% respectively of the technical potential of fixed offshore wind by 2050. This would mean that Greater China (including Taiwan) coastal areas would utilize almost 30% of its coastline for installing offshore wind. Growing concerns concerning biodiversity and other uses of the ocean will need to be managed to successfully install such large amounts of offshore wind. Offshore energy extraction, fishing as well as the growing area of ocean-based food farming will need to collaborate successfully – and explore synergies – to ensure enough areas for all parties to thrive.

Water scarcity and the energy transition

Water is a scarce resource and water stress is a global challenge, experienced more acutely in some regions than in others. Water scarcity and stress is expected to be exacerbated by climate change. Access to and additional cost for water can have an impact on the energy transition. As part of understanding the effect, we have identified three areas of the energy system where water is of importance. Cooling in power plants, electrolysis of water to produce hydrogen, and increased use of water as part of carbon capture and storage (CCS) implementation.

Thermal power plants use water for cooling. Currently, heat waves create a double challenge as use of air conditioning peaks when both ambient air and water temperature makes cooling less effective. In such situations, curtailments may be required to prevent overheating. Additionally, warmer temperature leads to dry spells and less available water. Such phenomena will worsen in the future where air conditioning will be more extensive and cooling water will experience shortages and less cooling effect. Coffel and Mankin (2021) find that for every degree Celsius of warmer weather, curtailment increases by 1 percentage point. On peak days in a 2°C future, they find that curtailment (for this reason) in thermal power plants will increase by 4.5%. They cite that the 2019 heat wave in France forced 8% of French power plant capacity (mainly nuclear) to be curtailed. On the cost side, Lubega and Stillwell (2019) find that cooling water costs are so low that using higher water costs as an incentive for improving energy efficiency (thus automatically impacting water use) will not work. Water costs are such a small fraction of total costs that to impact plant economics, water costs would have to be multiples of municipal water costs which has little chance of happening.

Electrolysis based hydrogen production in 2050 represents over 70% of all hydrogen produced. However, when reviewing the costs of such production, water costs are negligible in contrast to the cost of power for electrolysers. Even when water is assumed to be obtained through desalination, the cost for water will be around 2% of total cost (Blanco, 2021). In energy terms, water use is about 1% of total energy consumption when operating an electrolyser plant.

CCS uses water in pre-combustion (in power plants) and post-combustion Steam Methane Reforming (SMR) processes. In both instances, increases of water use compared to the non-CCS case, an increase of 100% has been observed. Thus, in regions with growing power generation or manufacturing sectors utilizing CCS, a doubling of water demand could impact such projects. For this reason, future CCS processes are projected to add less than half, typically a quarter, of a CCS process' water consumption. Yet, even an increase by one quarter will come on top of increased water consumption from expanded thermal energy use in manufacturing as well as combusting power installations. Thus, precaution should be observed in regions with expected growth of CCS combined with manufacturing or power generation, such as in the case of the Middle East and North Africa or South East Asia.

In conclusion, a warmer future will make thermal power plants marginally less fit than today as water shortages and increased water temperatures will be more prevalent. The combined effect of less thermal power output, and the marginal cost component provided by thermal plants' water usage leads us to conclude that the power sector will not be significantly impacted by water-related challenges.

There is no reason to make water scarcity an economic risk for electrolysis. On the other hand, just as for thermal power plants, electrolyser location will need to take water availability into consideration: there may be locations where lower power costs come at the expense of water availability. However, even 'energy islands' will be able to solve this through desalination of surrounding salt water, as both the costs and the energy use of providing such water will be dwarfed by power consumption and non-water infrastructure costs.

CCS typically increases water use in a power plant or an SMR facility by 25 to 50%, depending on the technology used. Yet, since the uptake of CCS coincides with decreasing use of combusted energy, post-combustion power plants will not lead to increased water stress in most regions. However, in the Indian Subcontinent, Middle East and North Africa, and South East Asia, where thermal combustion will expand at the same time as CCS is added, stresses might hamper the roll-out of CCS and/or increase water costs. Especially in the context of a pathway to net zero, CCS installations and electrolyser capacity are significantly higher, and thus locations should be investigated for water availability today and in the future.

Demand for raw material

We have considered the energy transition's footprint on demand for materials. For example, solar PV panels are expected to consist mainly of crystalline silicon cells (DNV, 2021a) where the main component is silicon, which is considered an abundant material (USGS, 2023) even though there are some limitations to processing facilities to enrich the silicon to a high enough grade needed for the photovoltaic panels. New thin-film technologies, which are not yet prevalent but are showing potential, will further reduce the overall demand for material. Wind turbines use common building materials, but the vast amounts of steel and cement necessary will put pressure on those hard-to-abate sectors to reduce their embedded carbon footprint during production to ensure low lifecycle emissions from wind. There could be supply-chain challenges for rare earth elements, which are abundant but expensive and resource-intensive to extract, especially in the case of neodymium used for permanent magnets in the turbines.

> The transition will not be significantly constrained globally by the availability of either land or sea area, water, or raw materials.

Growth in the number of EVs and vehicle battery sizes will drive a 175-fold increase in global battery capacity by 2050. This will spur the demand for minerals currently used in Lithium-ion batteries unless new battery chemistries are developed. The forecast growth in battery capacity is by far the largest driver of demand for minerals. Lithium, nickel, manganese, and cobalt used in battery anodes and cathodes are where we expect the biggest supply challenges. Battery manufacturing capacity is growing exponentially and there are several initiatives to increase supply for lithium and nickel, while for cobalt the supply chain is less geared for demand surges, and we therefore identify cobalt as a critical resource for the energy transition. See our Appendix in ETO 2020 (DNV, 2020b) for a detailed analysis of cobalt supply and demand. The price of cobalt has fluctuated, doubling in cost before reducing over the last year (LME, 2023). There are clear signs that auto manufacturers are diversifying their use of battery chemistries: BYD, a big Chinese manufacturer, focuses solely on LFP (Mining, 2021) and 95% of commercial vehicles in China, and many of those exported, use LFP chemistry. For its standard-range Model 3 vehicle, Tesla has decided to use LFP batteries without cobalt, while for their long-range and performance vehicles, they use a cobalt-based battery but are working on developing a cobalt-low or free high-performance battery.

In our view, the energy transition we forecast will not be significantly constrained globally by the availability of either land or sea area, water, or raw materials. Narrowing the perspective, some regions may struggle to find raw materials and some land and sea areas will be contending with competing uses, while others will enjoy an abundance. Historically, such imbalances would be solved by global collaboration and trade. The intensified focus on energy security also includes security of supply of critical resources, so many regions are reviewing their strategy and dependence on other regions providing the raw materials necessary for securing their energy supply or transition. The effect will further augment existing imbalances and could affect costs in the short to medium term. It warrants continuous monitoring.

Also, when considering a more ambitious energy transition focusing on reducing emissions in line with a Paris compliant 1.5°C future, there will be a further strain on resource demands. Every national plan for reaching net zero should include a plan for the needed natural resources and how to secure such supply. Many of the minerals and metals required are in low-income countries which would benefit from climate finance support, and thus could be an important aspect of negotiations around accessing such resources. We aim to revisit the topic of resource availability and understand the possible limitations a net-zero future would entail in future research.

A.5 ETO MODEL

Our forecast is based on the ETO model, which is a comprehensive system-dynamics simulation model that captures the interrelationships between supply and demand across various interconnected modules. In this model, each facet of the energy system, as depicted in Figure A.4, is represented by specific modules, encompassing:

- Final energy demand, including buildings, manufacturing, transport, non-energy sectors, and others.
- Energy supply, covering coal, gas, and oil production.
- Transformation processes, such as power generation, oil refineries, hydrogen production, and biomethane production.

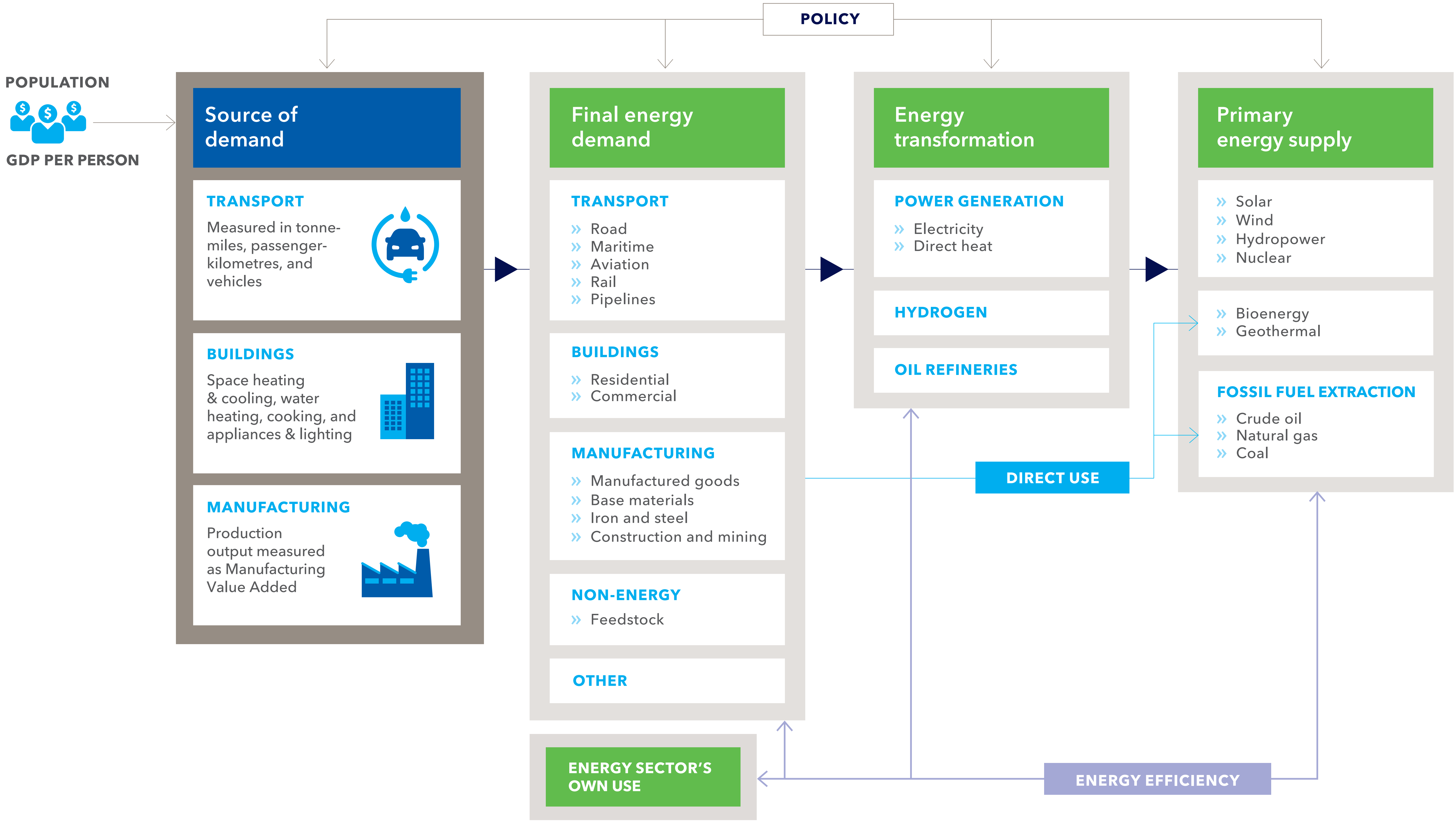
Additionally, it incorporates other relevant developments like economic conditions, grids, pipelines, CCS, energy markets, trade volumes, and emissions.

These modules interact by exchanging information on demand, costs, trade volumes, and various parameters to produce a coherent and comprehensive forecast.

Modelling process

The model's equations and parameters draw upon a diverse array of sources, including academic papers, external databases, commercial reports, and the collective expertise of individuals both within and beyond DNV. Examples of external databases that

FIGURE A.4



have been utilized include the IEA World Energy Balances, IRENA Capacity & Generation Database, GlobalData Power Database, Marklines Automotive Industry Portal, Rystad Upstream Database, UN Comtrade Database, and Clarksons Shipping Intelligence Network.

In order to ensure the reliability of our forecasting, we have conducted numerous workshops and discussions involving DNV industry experts. This collaborative effort has engaged nearly 100 individuals who have played various roles, such as serving as conduits to historical data sources across multiple domains, ensuring the quality of model sectors and their inter-relationships, and providing expert assessments of the final outcomes.

Timescale

The ETO model covers the period from 1980 to 2050. To assess the model's accuracy in reproducing historical developments and thereby validate our forecasts, we have employed historical simulation data. The model is a continuous-time model, with years as the base time unit. It is specifically designed to capture dynamics that occur on an annual scale or longer. Dynamics of shorter duration, such as within-year fluctuations in oil demand, are indirectly represented through annual parameters and are not explicitly integrated into the model. The power-market module, however, stands as an exception, as it addresses supply and demand imbalances on an hourly basis.

By intentionally disregarding short-term fluctuations that transpire over the course of months or a few years, the Outlook's reliability diminishes when examining shorter time periods. For instance, while we can confidently compare the average growth rate of gas demand over 10-year intervals, analyzing the growth rate for a specific year in isolation might not yield meaningful insights.

Nevertheless, we deviate from this approach to incorporate the anticipated short-term impacts, as well as long-term effects, resulting from events such as the COVID-19 pandemic and Russia's invasion of Ukraine. These events are expected to influence social behaviour, economic activity, and energy consumption, necessitating consideration of their effects across both short and long timeframes.

Geographical scale:

The spatial resolution of the model is limited to 10 world regions. These regions engage in direct inter-actions, primarily through the exchange of energy carriers, while also having indirect interactions by influencing and being influenced by global variables. An example of this indirect interaction is the impact of global capacity additions on the cost of wind turbines. Although we do not create explicit models for individual countries or states within these regions, we accommodate the inherent variability by employing statistical distributions for the model parameters.

For instance, the investment cost associated with a specific type of power station is represented as a parameter following a normal distribution. This statistical approach allows the model to account for disparities between countries and sub-technologies. Consequently, the model can recognize that certain countries might make capacity additions for a given technology, even if the average cost for that technology appears to be prohibitively high.

Modelling principles

When designing the ETO model, our foremost objectives were to incorporate three fundamental characteristics of the global energy system: inter-connectedness, inertia, and non-linearity. The entire energy supply chain, spanning from demand to supply, constitutes a vast and interconnected system. What happens in solar PV technology can impact power generation demand for coal, which subsequently affects shipping volumes for bulk carriers and the demand for oil in the maritime sector. Inertia is an inherent feature across all facets of the energy system, whether it is within household appliances or oil refineries, and it acts as a decelerating force on energy transitions. Furthermore, many processes exhibit non-linear behaviour, where a unit increase in one factor does not consistently produce the same effect on another variable. Our model is designed to mirror these key characteristics.

While numerous energy models adopt an econometric approach and assume equilibrium conditions, our model diverges from this approach. Instead, it simulates the consequences that arise from its underlying goals, parameters, and interrelationships. The model explicitly represents the time delays involved in achieving desired states, thereby enabling us to forecast both the trajectory and pace of energy transitions.

Our model does not assume optimality or rationality as prerequisites. Its methodology is notably influenced by behavioural economics, where decision-making can be predicted based on the specific circumstances, even though the decisions themselves may not always align with utility-maximizing rationality. For instance, we consider the fact that private buyers may place greater emphasis on the initial purchase price of a vehicle compared to commercial purchasers. Consequently, private buyers may opt for a technology with a lower upfront cost, even if it turns out to be more expensive in terms of total ownership costs.

Our ETO model is deterministic rather than stochastic. We have relied on historical data and our best judgment to provide expected values for all input parameters, and each model run yields an exact output since there is no randomness embedded within the model. Nevertheless, there exist multiple sources of uncertainty in the outputs, and the model does not provide confidence levels for these uncertainties. To partially address this issue, sensitivity tests have been conducted to help us comprehend how model results change when specific input parameters are adjusted. Our intention is to present a transparent model rather than a black box. This approach facilitates discussions about the results and allows for the exploration of alternative assumptions or values if there is disagreement with the chosen ones. While the exact calculations emerging from a complex model may not be easily verified using a simple calculator, we are transparent about the parameters used and their relationships.

Continuous improvement

The model's structure and input data are updated to:

- offer a more comprehensive and precise portrayal of the global energy landscape
- generate new outputs that hold significance for our stakeholders
- adapt to the latest developments in the energy sector

The most significant changes to the model since our 2022 Outlook are:

- incorporation of the new policy landscape, particularly the comprehensive US IRA package, renewable power support, hydrogen support, and CCS support
- revised carbon prices
- adjustments to power sector investment costs, taking into account regional preferences for or against specific energy carriers due to energy security considerations
- representation of the effect of reshoring/onshoring on cost trajectories
- updated GDP data from the IMF's 2017 ICP survey, for updated accurate purchasing power parity calculations
- updated population and GDP projections, including detailed data for secondary and tertiary economic sectors
- revised wind cost and technology parameters
- restructured categories of manufacturing end-use and electrification potential
- detailed new bioenergy sector model
- improved modelling of inter-regional power trade, with restrictions for certain European regions
- enhanced power station investment logic to ensure consistent availability and clearer mechanisms for energy, capacity, and flexibility needs
- improved storage cost formulas that better differentiate between energy storage and power cost components
- more robust and less ambiguous CCS capacity modelling
- improved cost modelling for direct air capture
- revised representation of the 'other' sector, including agriculture, fishing, and military energy use, reflecting efficiency improvements
- updated logic for building insulation
- new parameters for heat pumps' co-efficient of performance (COPs)
- explicit modelling of fuel-cell vehicles uptake in road sector
- revised parameters for automated vehicles, EV uptake, battery sizes, and charging infrastructure
- revised natural gas trade formulations that more accurately takes price differentials into account
- an improved, more robust formulation for the grid sector
- updated historical data, including energy prices

Energy demand

We assess energy demand by considering various factors, including policy and behavioural influences. These effects can be explicit, like how increased recycling affects the demand for plastics, or implicit, such as the impact of expected electricity prices on the adoption of electric heating. Our estimation of sectoral energy demand follows a two-step process:

First, we calculate the energy services provided, such as passenger-kilometres in transportation, manufacturing output in tonnes, or the heat required for water heating. Subsequently, we employ parameters related to energy efficiency and the dynamics of energy sources to predict the final energy demand by sector and energy carrier. Regional demand for energy services is determined using non-linear econometric models, primarily driven by population and GDP per capita. However, we also integrate various other technological, economic, social, and environmental factors as needed.

In the context of road transport, the number of vehicles needed increases with regional GDP growth, but this effect saturates at different levels for each region, following a non-linear pattern. Vehicle demand is additionally influenced by factors like driving distance and vehicle lifespan, which are impacted by the adoption of autonomous and shared transportation solutions. We explicitly model the connection between maritime trade and the production/consumption balance of energy and non-energy commodities.

For non-cargo vessels, air travel, rail passengers, and freight demand, we rely on GDP as the primary driver. In the buildings sector, we estimate energy requirements for both residential and commercial buildings across five end uses. Factors such as building insulation, climate, and floor area play significant roles in determining regional space heating and cooling demand. Hot water demand is associated with living standards and population, while cooking energy needs are estimated based on household size and population. Commercial buildings' energy demand is closely tied to GDP from the tertiary sector, which increases with GDP per capita and influences floor area and energy service demand.

In the manufacturing sector, we gauge energy services using the value added in USD, considering base materials, manufactured goods, and construction and mining separately. For iron and steel production, we measure output in tonnes. The total value added in manufacturing within each world region is driven by the GDP of the secondary sector and is divided into subsectors based on historical shares. Demand for iron and steel is linked to activities such as building construction, vehicle manufacturing, shipbuilding, and overall economic activity. We differentiate between process and non-process heating, machines and appliances, iron ore reduction, and on-site vehicles in terms of energy services.

Our choice of energy carrier is informed by levelized costs in buildings, manufacturing, and electric vehicle adoption. For other end uses, we project energy mix based on historical trends, which have been subject to expert evaluation in our workshops, with adjustments made as necessary.

Energy carriers

Within the 12 energy carriers we consider in our modelling, seven serve as primary energy sources. These primary energy sources can be utilized directly without undergoing any conversion or transformation processes. The remaining energy carriers represent secondary forms of energy derived from primary sources. Primary energy sources encompass coal (including peat and derived fuels), oil, natural gas (covering methane, ethane, propane, butane, and biomethane), geothermal energy, bioenergy (comprising wood, charcoal, waste, biogases, and biofuels), solar thermal energy (thermal energy generated by solar water heaters), and off-grid PV (electricity generated by solar panels not connected to the grid). Secondary energy sources consist of electricity, direct heat (thermal energy produced by power stations), ammonia, e-fuels, and hydrogen.

Energy transformations

We place special emphasis on electricity generation. We have conducted a comprehensive analysis encompassing regional equilibrium prices, supply dynamics, and demand patterns across a spectrum of 12 power generation types, four storage technologies, 12 distinct load segments, and power-to-hydrogen conversion. This analysis spans hourly intervals over an entire year. While the profiles of load segments and variable renewable generation are deterministic, they exhibit variations from year to year. Specific load segments and all components except for variable renewable generation and storage technologies respond to pricing signals.

In terms of investments in power stations and storage facilities, we employ a profitability-driven algorithm. Our assessment of the necessary additional generation capacity is grounded in the anticipated growth in electricity demand and the estimated retirements of existing capacity. The composition of capacity additions is determined through a probabilistic model that considers the expected market prices and the levelized cost of electricity. We explicitly consider the impact of support mechanisms for renewables, carbon pricing, and the cost associated with CCS.

Regarding investments in energy storage, these decisions are guided by the expected market prices and the levelized cost of storage, both of which are informed by our hourly power market module. The role of direct heat in our analysis is diminishing, and we employ a straightforward extrapolation method to estimate regional direct heat supply mixes.

Hydrogen can be supplied through different means, including electrolysis or from fossil fuels, utilizing methods such as SMR or coal gasification. We differentiate between hydrogen produced via electrolysis using grid electricity and hydrogen generated by off-grid dedicated renewables-based electrolysers. Our models dynamically calculate annual operating hours and expected electricity prices for electrolysis within the hourly power market module. The investment mix in hydrogen production capacity is determined by comparing the levelized cost of hydrogen from various technologies.

Extraction of fossil fuels

In addressing the supply of energy from primary sources, our model centres its attention on the extraction of oil, natural gas, and coal. Our approach to determining regional production dynamics for oil and gas is cost-based. Regarding oil supply, we depict production capacity as a globally competitive process driven by cost considerations across regions and among three field categories: offshore, onshore conventional, and unconventional. Given that transportation expenses typically constitute a minor fraction (less than 10%) of the final crude oil cost, we utilize the total breakeven prices of potential fields to estimate the future location and type of oil production.

Our approach to modelling regional gas production slightly differs from that of crude oil. Initially, we assess the proportion of gas demand to be met from a region's own sources, taking production and transportation costs into account. Subsequently, to determine the development of new gas fields while considering resource limitations, we establish competition among three field types based on regional breakeven prices. The model also incorporates regional refinery capacities and capacities for gas liquefaction and LNG regasification.

For coal production, we differentiate between hard coal and brown coal. Each region's hard coal supply is determined by its mining capacity, which expands in response to increased demand and is bounded by the geological availability of reserves. In the case of brown coal, we assume that most regions are self-sufficient.

Trade

Trade, particularly the maritime transportation of energy carriers, represents a critical element within our model. In the case of crude oil, the difference between a region's production and the input required by its refineries establishes whether there is a surplus available for export or a deficit necessitating imports. These imports are typically transported via seagoing vessels. In the context of natural gas, any shortfall in fulfilling demand from regional production is distributed to exporting regions based on their existing shares as trading partners in the gas trade, as well as anticipated changes in the costs of importing gas between these trade partners. Intra-regional trade is determined as a constant factor of regional gas demand. Similar to natural gas, when it comes to coal, we presume a consistent mix and trading partner shares. Coal from exporting regions is imported by regions experiencing domestic shortfalls.

Furthermore, our model incorporates the manufacturing sector as a fundamental reference point for the trade of non-energy commodities, encompassing raw materials and manufactured goods.

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Historical data

This work is partly based on the World Energy Balances database developed by the International Energy Agency© 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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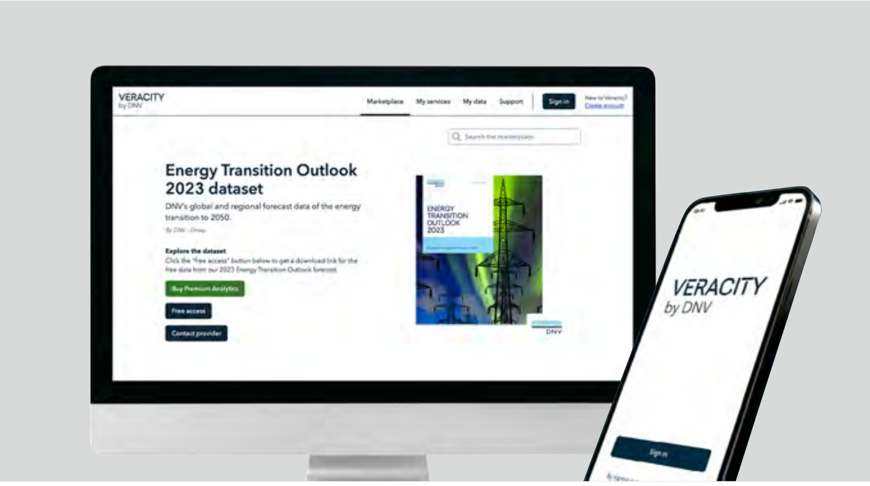

All the forecast data in DNV's suite of Energy Transition Outlook reports, and further detail from our model, is accessible on Veracity – DNV's secure industry data platform.

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This report has been prepared by DNV as a cross-disciplinary exercise between the DNV Group and our business areas of Energy Systems and Maritime across 20 countries. The core model development and research have been conducted by a dedicated team in our Energy Transition Outlook research unit, part of the Group Research & Development division, based in Oslo, Norway. In addition, we have been assisted by internal and external energy transition experts, with the core names listed below:

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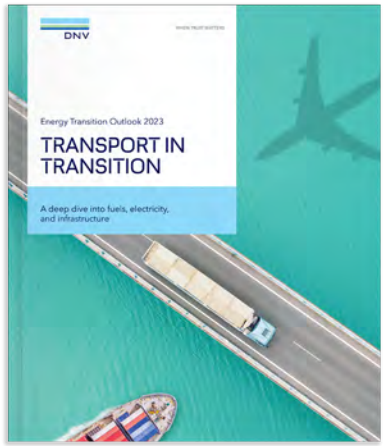

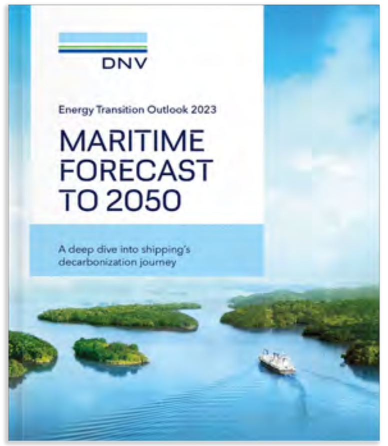

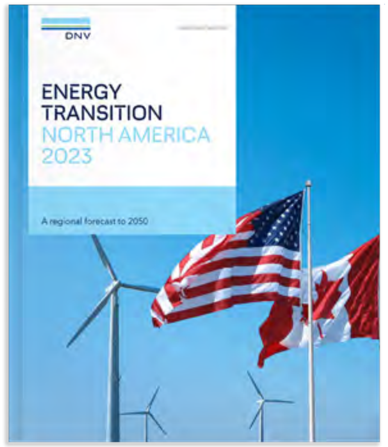

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