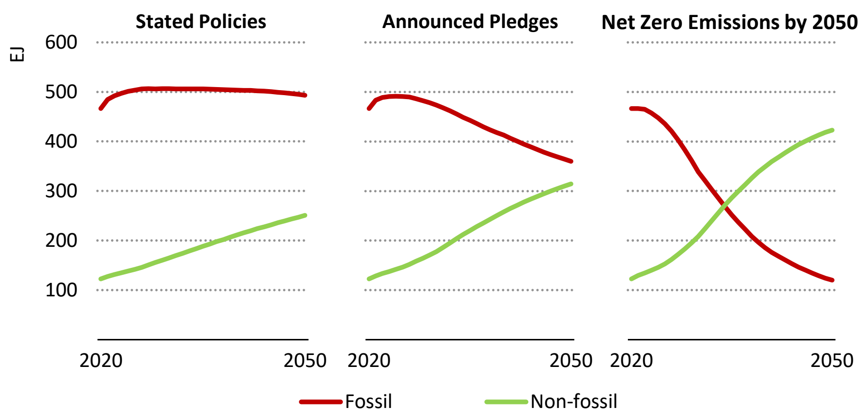
Secure transitions

...a clean break?

S U M M A R Y

- By design, the scenarios in this *Outlook* describe smooth, orderly processes of change. In practice, however, energy transitions can be volatile and disjointed affairs, contested by a diverse cast of stakeholders with competing interests, and there is an ever-present risk of mismatches between energy supply and demand.
- Energy security risks can materialise in various parts of the energy system, over different time frames, and they become more or less pronounced in different scenarios. In the Announced Pledges Scenario (APS), countries undertake clean energy transitions at different speeds, raising the risk of tensions in global trade and constraints on technology transfer. In the Net Zero Emissions by 2050 Scenario (NZE), the sharp drop in coal, gas and oil investment could destabilise regions and local communities dependent on income from these fuels if it is not carefully managed.

Figure 6.1 ▷ Energy supply to 2050 by scenario



In clean energy transitions, managing the decline in fossil fuel investments in parallel with a scale up in low-carbon technologies is essential for energy security

- In all scenarios, rising shares of wind and solar photovoltaics bring fundamental changes in how power systems operate, requiring policy makers to mobilise investment in all sources of flexibility in order to maintain electricity security. Digital technologies and smart networks play a central role in facilitating more reliable, interconnected and distributed power systems, integrating some 240 million rooftop solar PV systems and 1.6 billion electric cars by 2050 in the NZE, although they also open the door to increased cybersecurity risks. Investing in energy efficiency remains a cornerstone in all scenarios because it acts as a brake on peak demand and mitigates the need for additional infrastructure.

- As transitions accelerate, reliable operation of the energy system rests on an increasingly complex set of interactions between electricity, fuels and storage. In the NZE, 40% of energy consumed worldwide by 2050 has undergone at least two conversion steps on the way to consumers. By contrast, hardly any of the energy reaching consumers today has been converted more than once. Markets and regulation need to recognise the new interlinkages that arise among sectors as a result of these interactions, in particular those between electricity and various types of gas. Maintaining a gas delivery system brings energy security benefits, but clear interim and long-term sector-specific targets are essential to guide decisions on fuel delivery infrastructure as countries move towards a net zero emissions future.
- Increasing physical risks from a changing climate have to be factored in alongside mitigation priorities. Energy infrastructure around the world already faces risks from cyclones, coastal floods and inadequate water supplies. These risks are set to increase over time, highlighting the urgent need for policy action to enhance the resilience of energy systems in the face of climate change.
- Trade patterns, producer policies and geopolitical considerations continue to be of crucial importance to energy security even as the world shifts to an electrified, renewables-rich energy system. Higher or more volatile prices for critical minerals could slow global progress towards a clean energy future or make it more costly. Recent price rallies for critical minerals illustrate the point: all other things being equal, they will increase the costs of solar modules, wind turbines, electric vehicle batteries and power lines by 5-15%. If maintained, the price rises add USD 700 billion to the investment needed for these technologies in the current decade in the NZE.
- New vulnerabilities could also arise from rapidly expanding trade in hydrogen and critical minerals. The combined share of hydrogen-rich fuels and critical minerals in international energy-related trade doubles from 13% today to 25% in the APS and to over 80% in the NZE by 2050. Hydrogen trade increases to around USD 100 billion by 2050 in the APS, higher than the value of current international coal trade, and to USD 300 billion in the NZE.
- Uncertainty about the trajectory for future oil and gas demand increases the potential for mismatches between demand and investment, while trade flows are dominated by a relatively small number of countries, and most major oil and gas producers remain inadequately prepared for transitions. Oil and gas supplies in the APS and NZE become increasingly concentrated in a small number of low cost producer countries, with OPEC members and Russia accounting for 61% of global oil production in 2050 in the NZE, up from 47% today. At the same time, fossil fuel import dependency rises in Asia in each of the three scenarios, and flows between the Middle East and Asia account for an increasingly large share of global oil and gas trade.

6.1 Introduction

By design, the scenarios in this *World Energy Outlook* describe smooth, orderly processes of change. Energy markets, technologies and policies adapt to one another and evolve in a mutually consistent direction. Prices follow a smooth trajectory, international energy trade is assumed to be free of geopolitical friction, and the scaling up of clean energy technologies occurs in parallel with a gradual decline in investment in unabated fossil fuels. In practice, energy transitions can be volatile and disjointed affairs, characterised by competing interests, market imbalances and stop-go policies. The uneven distribution of gains and losses from transitions could deepen existing fault lines in the global political economy, or create new ones. Change could have sharp edges, and bring energy security risks with it.

As the commodity price shocks in 2021 showed, mismatches between supply and demand are the root cause of energy security risks. Such mismatches may be the consequence of short-term factors like unseasonal weather or interruptions to supply; they may also have deeper underlying causes like a lack of appropriate investment signals, inadequate market design or bottlenecks arising from a lack of infrastructure. The basic goal of energy security remains ensuring uninterrupted availability of energy sources at an affordable price, and the best strategies for achieving this remain diversity of energy sources, robust and consistent policy and well-functioning markets. Moving towards net zero emissions adds potential new energy security hazards, and traditional risks do not disappear, though they may evolve.

This chapter explores the security risks that arise across our scenarios. It starts with electricity security, which comes to the fore in transitions as reliance grows on electricity generated from solar and wind, bringing with it an ever-growing need for various forms of flexibility to maintain reliable system operation, facilitated by digital technologies. It then considers how transitions affect other parts of the energy system, including existing infrastructure – in particular for natural gas – as well as the new links that arise through more complex chains of energy conversions. We also explore growing concern with the risks that arise for energy infrastructure from a changing climate.

Further on, we consider changing patterns of global energy trade, investment and geopolitics. Critical minerals such as lithium, cobalt, copper or rare earth elements are essential to make tomorrow's clean energy system work and vulnerabilities in these areas could make global progress towards a clean energy future slower or more costly. Meanwhile, risks related to oil and gas supply do not disappear as the world moves towards net zero emissions. If the supply side moves away from oil or gas before the world's consumers do, then the world could face periods of market tightness and volatility. Alternatively, if companies misread the speed of change and over-invest, then these assets risk under-performing or becoming stranded. There are also potential hazards for markets as supply starts to concentrate in the lowest cost producers whose economies are most vulnerable to the process of change.

6.2 Energy security in increasingly integrated systems

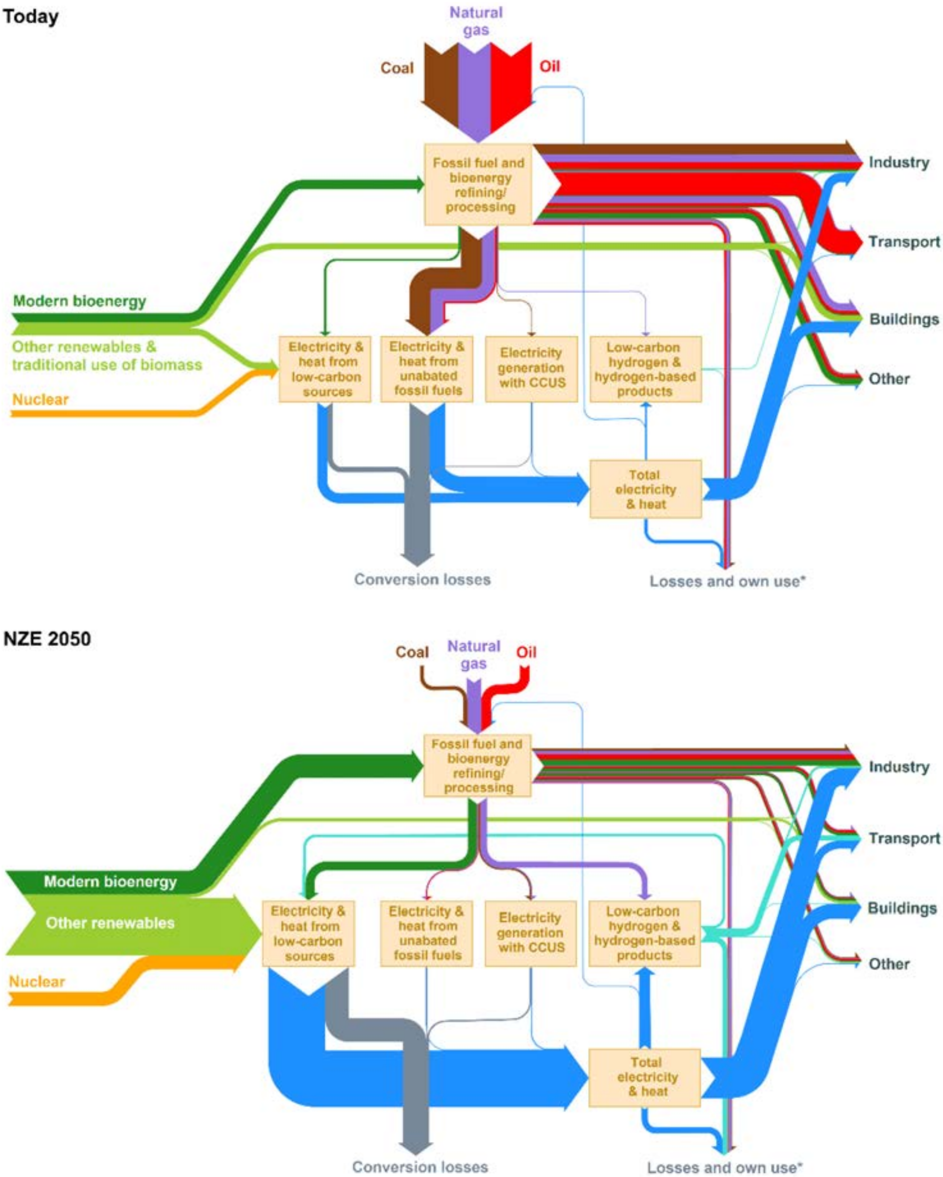
Today's energy sector in essence is a series of interlinked but largely independent delivery channels for fuels, heat and electricity to consumers. Between the extraction of primary energy and the final consumers stands a set of distinct sectors that transform fuels, largely to produce electricity and heat, and deliver the resultant products to users. A typical household today might use liquid fuels for transportation, gas or solid fuels for heating and cooking, and electricity for most other residential needs.

The energy systems that need to emerge during clean energy transitions are very different from those that exist today (Figure 6.2). In the energy system of the future, consumption narrows toward electricity, which is increasingly used by households and industries to meet demand for heat and transportation. The rest of the energy system becomes considerably more complex and integrated, but this process is mostly hidden from consumers, who continue to have their energy service needs met through familiar infrastructure.

Liquids and gases continue to play an important role, especially as new transformations of energy increase in importance, for example those that turn electricity into fuels or store it. There is an increasingly large premium on flexibility as a core component of system reliability, enabled by an array of digital technologies, as well as new interdependencies among the end-use sectors. An essentially uni-directional energy system, where energy flows from extraction and generation through networks to consumers, is replaced by a much more intricate web of interactions. Integration may also occur in parallel with the progressive decentralisation of energy, with the number of participants expanding and the unit size of energy technologies shrinking. Secure energy transitions require an understanding of the multi-directional flows of energy across this complex system, ensuring that change in one area is complemented where necessary by change elsewhere.

Efficient use of energy remains a cornerstone of any approach to energy security, and becomes even more important in clean energy transitions. End-user energy efficiency acts as a brake on peak demand, e.g. for cooling, and therefore mitigates the need for additional infrastructure upstream. A clean energy transition also calls for waste heat, bioenergy or other potential losses or by-products from economic activity to be put to productive use: action on this front can further dampen demand, but is likely to create integration challenges as supply chains become more closely interlinked. Meanwhile, more robust tools are required to manage flows of electricity into and out of multiple sectors as electricity accounts for an increasing share of consumption.

Figure 6.2 ▷ Global energy system today and in 2050 in the Net Zero Emissions by 2050 Scenario



Transformative changes in the energy system occur on the path to net zero emissions

* Includes transformation losses and fuel consumed in refining/processing, generation lost or consumed in the process of electricity production, and transmission and distribution losses.

Note: Traditional use of biomass in the buildings sector today is completely phased out by 2050 in the NZE and replaced by modern fuels.

6.2.1 Electricity security

Clean energy transitions reshape the electricity sector and the nature of electricity security. The central challenge in the years ahead will be to continuously match electricity demand and supply at all times as the share of variable sources like wind and solar photovoltaics (PV) grows. But there are plenty of other challenges. The impacts of climate change and cybersecurity threats both pose increasing risks to electricity security, and they will become more important still as electricity meets more of the world's transport, heating and industrial needs. Ensuring continued electricity security means institutionalising responsibilities and incentives; identifying, managing and reducing key areas of risk; monitoring progress; and making preparations for handling disruptions (IEA, 2020a).

Variable renewable electricity

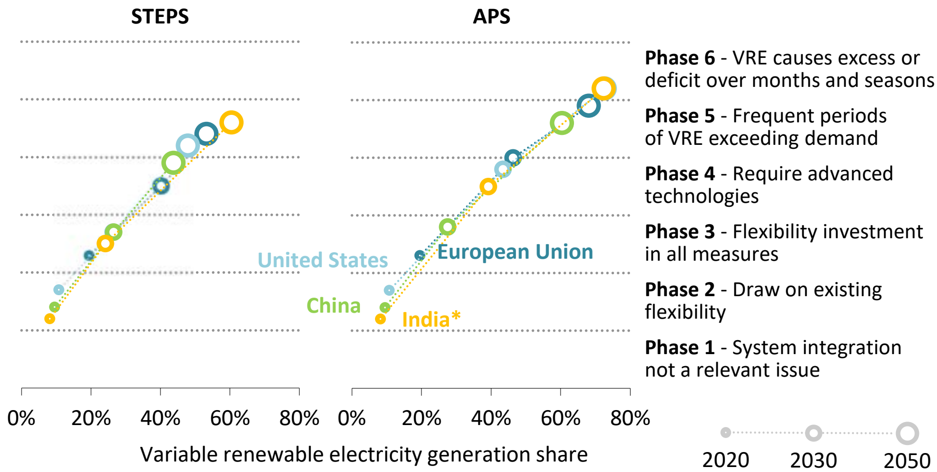
Strong growth in wind and solar PV across all scenarios and regions drives a shift from systems that are based predominantly on dispatchable generation to ones with abundant variable renewable electricity (VRE) and this require changes in the operation of electricity systems. To understand those changes, the IEA has developed a framework which characterises the different phases of renewable integration (IEA, 2018). The framework captures the evolving challenges[1] as countries transition to higher shares of VRE, and helps to prioritise actions that ensure continuity of supply. The framework has been applied to China, India, European Union and United States for the Stated Policies Scenario (STEPS) and the APS.

At present, China, India and United States are categorised as Phase 2, meaning that they are drawing on existing flexibility in their systems, with minimal changes to system operation. The European Union collectively has progressed to Phase 3, which requires additional investment in existing flexibility measures, including battery storage and the application of more advanced changes to system operations.

By 2030, India, China and United States progress to Phase 3 in the STEPS, and the European Union enters Phase 4 (Figure 6.3). In the APS, each region progresses to Phase 4 by 2030. VRE accounts for most or all generation for increasing periods of time in Phase 4, requiring sophisticated system management and frequent interventions by system operators to balance electricity demand and supply and to support power quality requirements. Ultimately, system operators will need additional tools to ensure grid reliability and stability in light of the increased deployment of VRE and could draw on the experience of countries such as Denmark and Ireland which have already reached Phase 4.

[1] Challenges depend on the unique characteristics of each country and region, including the size of its power system, the share and mix of variable renewables (solar PV and wind), the mix of other technologies and resources, operational practices and standards, and market and regulatory design.

Figure 6.3 ▷ Phases of renewables integration by scenario



Accelerated transitions bring new challenges related to the integration of variable renewables in power systems in all scenarios, and early action is needed to address them

Note: *values for India in the APS graph are based on the Sustainable Development Scenario.

By 2050, China, India, European Union and United States all reach Phases 5 or 6 in their energy transitions in the APS, and also in the STEPS (except for China, which comes close). Phases 5 and 6 have not yet been reached by any country. These phases are characterised by longer periods (from days to seasons) of mismatch between VRE generation and demand. During those periods, if VRE generation is inadequate to meet demand it has to be supplemented by sufficient dispatchable sources of generation, withdrawals from long-term storage systems, or measures to manage demand.

Maintaining security of electricity supply is a multidimensional task. Among other things, system operators need to ensure sufficient generation capacity to meet peak demand, provision of hour-to-hour and sub-hourly flexibility to accommodate changes in VRE generation or demand, and the ability to maintain power system stability[2] within very short time frames. As clean energy transitions progress, system planners will need to ensure that there is a seamless shift from traditional sources of flexibility such as coal and gas plants towards low emissions sources of dispatchable generation, even if they are utilised infrequently. Long-duration storage, including in the form of heat, could also play a part by moving excess VRE generation across weeks or months to times of shortage – a function currently performed by short- and long-term gas storage in many countries.

[2] The ability to maintain a state of operational equilibrium and to withstand disturbances.

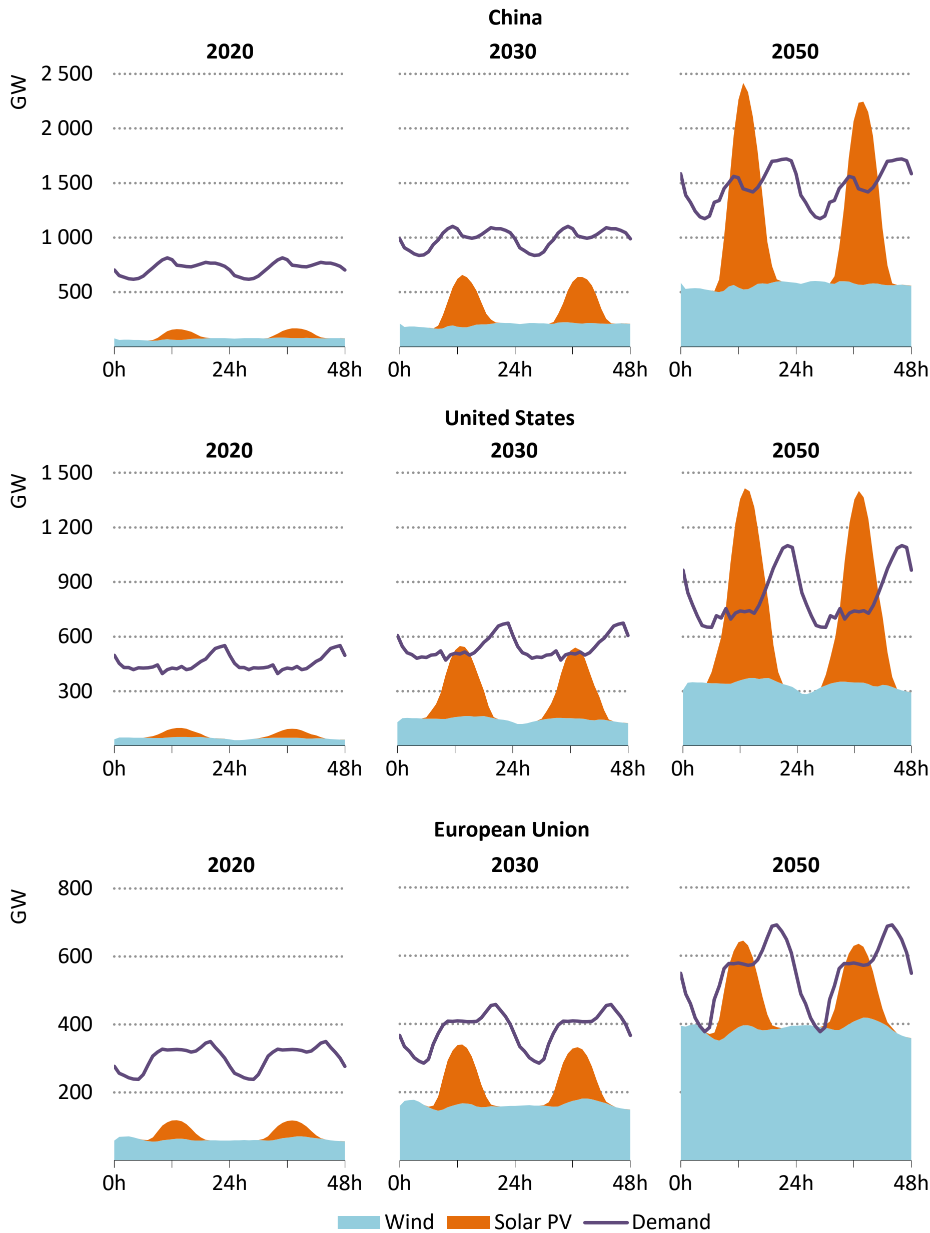
The weather dependent nature of wind and solar PV generation also requires short-term contingency plans to deal with sudden or unanticipated changes to generation patterns. Larger shares of VRE may increase the need for contracted reserve volumes and balancing markets that are closer to real-time. The volume of required reserves depends in part on demand and generation forecasting capabilities, and improvements in those capabilities could offset some of the increases that are required. The sources of reserve and balancing provisions could also evolve, for example with solar PV and wind providing downward reserve by decreasing their output, battery storage acting to smooth generation patterns, and efficiency and demand response measures to flatten peaks.

Electricity systems need to adhere to a set of physical boundaries and standards in order to maintain system stability and operate safely and reliably. Those boundaries include frequency and voltage constraints (IEA, 2021a). Traditionally, thermal generators have been able to play a central part in ensuring that systems can withstand and recover from changes in frequency because of their inherent inertia as rotating generators. With the share of non-rotating generation increasing, alternative solutions are likely to be required to ensure that frequency is maintained within safe ranges. Possible solutions include synchronous condensers (which can increase inertia levels), battery storage and demand response measures (which can respond quickly to changes in frequency). Nuclear power can also support system stability in those regions where it remains part of the generation mix. Where they exist, high voltage direct current interconnectors can provide additional support to respond to changes in inertia levels.

The task of meeting electricity service needs at all times will require very responsive sources of generation and demand that can be operated in an integrated way, as indicated when simulating the behaviour of selected power systems on an hourly basis during sample days in the first quarter of the year (Figure 6.4). For example, batteries could absorb high solar PV generation in the middle of the day and discharge it when demand picks up during the evening. Market frameworks and regulations that incentivise investment in flexibility and encourage consumers to shift demand at times of high or low VRE generation are essential to manage volatility and reduce the risks of supply-demand imbalances (see Chapter 4). System planners will also need to ensure contingency for instances when VRE output during the day is low combined with batteries in a low state of charge. Hydrogen and ammonia, carbon capture, utilisation and storage (CCUS)-fitted dispatchable generation and load-following nuclear power technologies are well placed to fill this gap.

Transmission and distribution networks have a vital part to play in enabling electricity systems to make full use of flexibility resources. Interconnections between regions are important in this context. They enable more efficient use to be made of flexibility resources by making them more widely available. They also provide for smoother VRE generation by providing countries/regions access to wind and solar PV resources across larger geographical areas with more diverse weather and wind patterns. Advanced economies typically enjoy high electricity interconnection levels, but some emerging market and developing economies have national systems that are very poorly interconnected with neighbouring ones and consequently have much higher flexibility needs relative to average demand.

Figure 6.4 ▷ Wind and solar PV generation and electricity demand for sample days in Q1 by region in the Announced Pledges Scenario



Clean energy transitions will reshape the profiles of electricity systems as rising shares of wind and solar PV bring fundamental changes in how systems operate

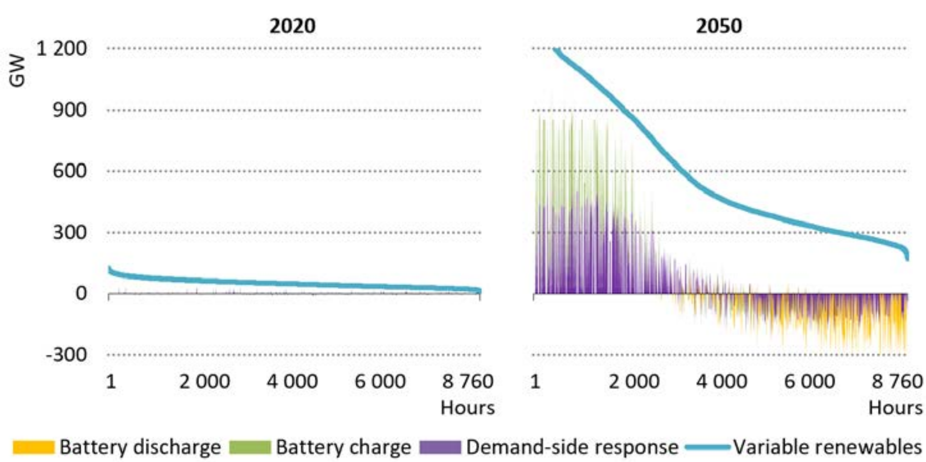
Notes: GW = gigawatts. Q1 = the first quarter of the year.

Digitalisation and two-way flows

Advances in digital technologies, declining costs and ubiquitous connectivity are accelerating the digital transformation of electricity systems. Spending on digital grid technologies reached USD 40 billion in 2019, making up around 15% of total network investment. Most of the investment in digital grids goes to smart meters and grid automation equipment (IEA, 2020b).

Digitalisation – combining data, analytics and connectivity – has tremendous potential to make energy systems more efficient, flexible and resilient in each of our scenarios. In the NZE, more than 70 000 terawatt-hours (TWh) are generated globally in 2050, which is almost three-times the current level, and the share of electricity in total final consumption reaches 50%. Digitalised and user-centric technologies, distribution networks and business models all facilitate a more interconnected and distributed electricity system, integrating some 240 million rooftop solar PV systems and 1.6 billion electric cars, and these digitalised electricity systems feature multi-directional flows of data and electricity. In the United States, for example, meeting net zero targets require a huge scale up in battery storage and demand-side response, which by 2050 are used to absorb a significant portion of the peak hourly output from VRE, while also playing a crucial balancing role when output is low (Figure 6.5).

Figure 6.5 ▷ Duration curves of variable renewables, storage and demand-side response in the United States in the Announced Pledges Scenario



Managing the rise in variable renewables requires the deployment of demand response and storage capabilities, enabling larger two-way flows between supply and demand

In this more interconnected power system, digital technologies such as machine learning could vastly improve the accuracy and temporal and spatial resolution of electricity supply and demand forecasts, increasing the resilience and flexibility of electricity systems as they integrate higher shares of variable renewables. Smart meters, machine learning and connectivity together could unlock the full potential of demand-side flexibility ranging from connected appliances and electric vehicles (EVs) to large industrial users. The number of connected products is doubling every five to ten years, and is projected to reach 100 billion in the next decade (4E EDNA, 2021).

There are additional ways in which digital technologies could help. Distributed ledger technologies such as blockchain have the potential to provide secure payment systems to facilitate electricity trading and EV charging, and to help integrate distributed energy resources, including rooftop solar PV. Sensors, machine learning and drones could help to detect outages, restore service and conduct preventative maintenance of electricity transmission and distribution networks to improve efficiency, extend asset lifetimes and reduce downtime. China Southern Power Grid, for example, has already used these technologies to reduce the number of interruptions by 7.5% annually between 2015 and 2020, while boosting maintenance staff productivity by 8% per year (ADB, 2021).

Unless well managed, however, the roll-out of digital clean energy technologies could involve unforeseen costs, reliability issues or behavioural change burdens. For example, digitally enabled demand response services could override consumer preferences for heating or cooling set points: this recently happened to some consumers with smart thermostats during a heatwave in Texas (Morrison, 2021). The most imminent concern is the increased risk to cybersecurity (Box 6.1). A successful cyberattack could lead to the loss of control over devices and processes in electricity systems, causing physical damage and widespread service disruption to consumers and businesses.

Box 6.1 ⊳ Managing digital security risks and enhancing cyber resilience

Digitalisation offers many benefits for consumers and electricity systems, but increased connectivity and automation throughout the system raise cybersecurity risks (IEA, 2017). For example, connected devices and energy assets such as EVs and smart meters could be compromised by attackers to launch a co-ordinated cyberattack causing large demand fluctuations and imbalances across a distribution grid, ultimately triggering an outage (Soltan, Mittal and Poor, 2018; Acharya, Dvorkin and Karri, 2020). Emerging digital technologies such as machine learning could help improve threat detection and thwart attacks, but equally could boost the capability of attackers. Attackers are also increasingly using cryptocurrencies to collect ransomware payments.

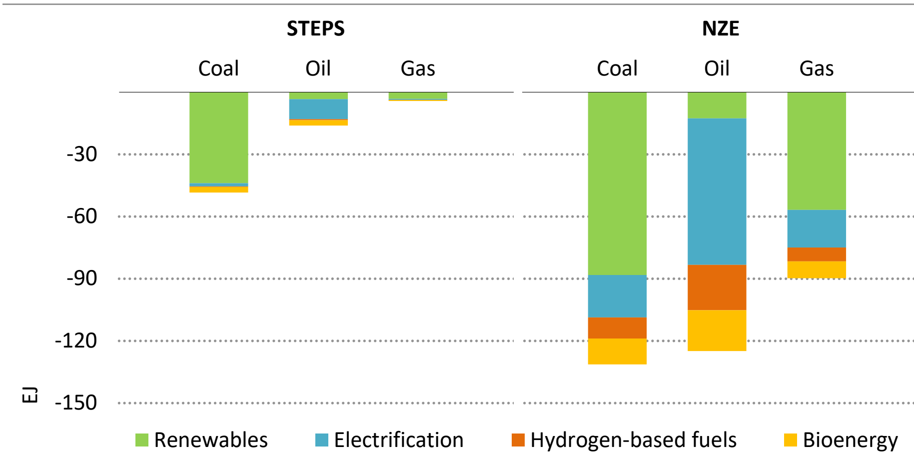
While the full prevention of cyberattacks is not possible, electricity systems have to become more cyber resilient. This means putting in place ever more robust network system and security management protocols, together with cybersecurity technologies and tools, in order to detect, withstand, adapt to and rapidly recover from incidents and attacks, while preserving the continuity of critical infrastructure operations. Policy makers, regulators, utilities and equipment providers have key roles to play in ensuring the cyber resilience of the entire electricity value chain. The recent IEA report, *Enhancing Cyber Resilience of Electricity Systems*, offers guidance to policy makers, electric utilities and other stakeholders on how policies and actions could enhance the cyber resilience of electricity systems (IEA, 2021b).

Digitalisation also raises concerns for consumer data privacy and security. Smart grids and demand response technologies rely on vast quantities of consumer-specific, real-time electricity usage data, raising important questions around data privacy and ownership. Policy makers need to balance privacy concerns with the operational needs of utilities and the wide-ranging potential of the digital transformation of electricity.

6.2.2 New demands on fuel infrastructure

In the NZE, half of final energy consumption by 2050 is provided by electricity, of which two-thirds is generated from variable renewable sources such as solar PV and wind, placing enormous demands on power systems. The other half of final energy consumption consists of liquids, gases and solid fuels of various sorts, almost all of which are low or zero carbon. By 2050, renewables and electricity displace 270 exajoules (EJ) of fossil fuels in the NZE, or around 60% of current demand, while bioenergy, hydrogen and hydrogen-based fuels displace a further 80 EJ (Figure 6.6).

Figure 6.6 ▷ Reductions in coal, oil and natural gas use from switching to electricity and low-carbon energy by scenario, 2020-2050



Renewables, electrification and low-carbon fuels not only replace fossil fuels for various end-uses but could also make use of repurposed fossil fuel delivery systems

These transformations have profound implications for the delivery systems used around the world for solid, liquid and gaseous fuels. Some parts of the infrastructure may be adapted or repurposed over time for low emissions fuels. Refineries could be retooled to process bioenergy feedstocks, for example, and coal-fired power plants to co-fire ammonia or bioenergy. Hydrogen or biomethane could be blended into natural gas pipelines and renewables used in existing heat delivery networks.

Other parts of today's delivery infrastructure are still operating in 2050 in each of the three scenarios to provide energy services in sectors not directly amenable to electrification. There is growing interest in employing gas storage for hydrogen, for example, although the suitability of different types of storage sites varies: some depleted gas reservoirs and aquifers contain contaminants that could react with hydrogen. Salt caverns have particular potential, but if all the existing 15 EJ of gas storage capacity was to be used entirely for hydrogen, it would hold 10-25% of the total low-carbon hydrogen produced in the NZE in 2050.

There is a need for some new infrastructure, especially in some emerging market and developing economies. In particular this is needed to enable hydrogen to be used for transport purposes and to supply new industrial facilities with hydrogen. New infrastructure is also needed to transport CO_2. The NZE sees almost 8 gigatonnes (Gt) CO_2 captured each year by 2050 from remaining fossil fuel use and from negative emissions technologies. Although none of it would be likely to be moved over long distances, substantial pipeline infrastructure would be needed nonetheless. Where new gas infrastructure is developed, it will be important to ensure that it is compatible with climate and other sustainable development goals, especially in emerging market and developing economies facing significant energy demand growth in the years ahead.

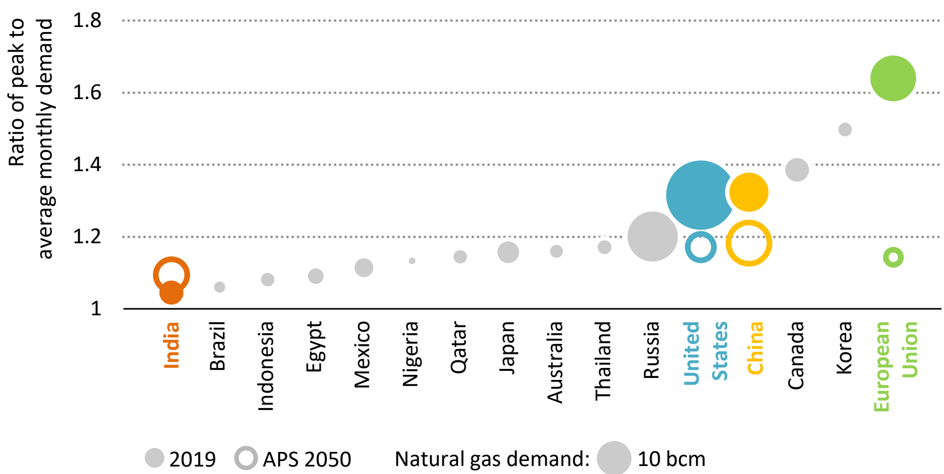
Deciding which parts of the current fossil-based infrastructure have a future in clean energy transitions is no easy task. In the case of natural gas, clear sector-specific targets, both interim and long term, could help to calibrate market player expectations about the investments required in midstream infrastructure, and to ensure that all such investments are matched where possible to low emissions supply options such as biomethane and hydrogen as well as to storage plans. Markets, regulations and certification will need to be adapted. It will be especially important to ensure that regulations are updated to recognise and value flexibility, and that long-term network planning is consistent with developments in other energy markets and delivery systems, particularly electricity.

Natural gas infrastructure and energy security

In many countries, natural gas infrastructure is a crucial asset for security of supply. In many parts of the northern hemisphere, where gas provides a large share of seasonal heating, infrastructure is designed to accommodate large peaks in demand: operators plan their networks around the capacity to supply the entire customer base during extremely cold winters (with a 1 in 20 year probability), even when a certain quantity of infrastructure is not available. Infrastructure is also crucial for the supply of gas to thermal power plants in order to provide flexible, dispatchable capacity to meet daily, weekly and seasonal peaks in electricity demand.

A suite of flexibility and other options to safeguard energy security are available across the natural gas supply chain. These options include spare production and import/export capacity. They also include gas storage, which worldwide currently amounts to over 400 billion cubic metres (bcm), equivalent to around 10% of annual global natural gas demand. There is also substantial gas deliverability in the form of linepack (the volume of gas stored inside gas pipelines): where grids are well developed, as in northwest Europe and the United States, this is an essential tool to meet short-term peaks in demand (SGI, 2020). Liquefied natural gas (LNG) import terminals play an especially important role in several countries in Asia: Japan, for example, has 285 bcm per year of LNG import capacity, equivalent to more than twice its annual demand, although its LNG storage capacity is far smaller.

Figure 6.7 ▷ Ratio of peak to average monthly natural gas demand in selected regions

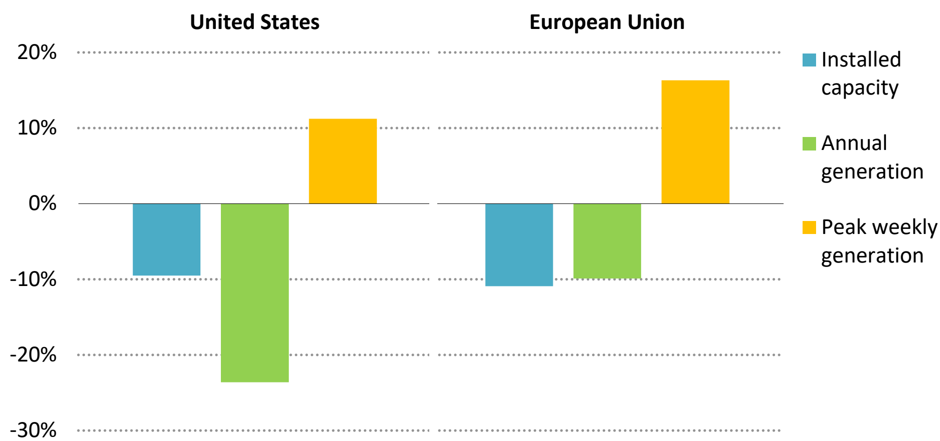


Natural gas demand has a strong seasonal element in many countries today. This weakens in countries with net zero pledges and does not become significantly stronger elsewhere.

In clean energy transitions, changes in the use of gas affects infrastructure in different ways. In advanced economies with net zero targets, the use of natural gas for space heating drops 30% by 2030 in the APS and is virtually eliminated by 2050. In the European Union, winter gas demand is around 90% lower in 2050 than today, and the seasonal variation falls from almost double the annual average to less than 20% more than the annual average (Figure 6.7). By 2050, only 12% of space heating demand in the EU is met by gaseous fuels, compared to nearly 45% today. This gradually weakens the case for maintaining long-duration gas storage.

Natural gas use in the power sector follows a different trajectory, and maintaining infrastructure, including storage to manage short-term peaks, remains crucial to ensure electricity security. This is true in all three scenarios over the next decade, but especially in cases where variable wind and solar PV power are added to the generation mix at a rapid pace, and where electricity takes a growing share of space heating demand. The experience of Texas in February 2021 illustrates the challenge: an extreme cold snap and a surge in electricity demand drove up demand for gas in both the residential and power sectors, and demand could not be met due to the combined failure of delivery pipelines and power plants (IEA, 2021c). Such vulnerabilities may become more pronounced: in the APS, installed capacity and annual generation from natural gas in both the United States and European Union are lower by 10-25% in 2030, whereas the peak level of weekly gas-fired power generation actually increases by 10-15% relative to 2020, reflecting a much more substantial role for natural gas in balancing variable renewables (Figure 6.8).

Figure 6.8 ▷ Changes in key gas-based electricity indicators in selected regions in the Announced Pledges Scenario, 2020-2030



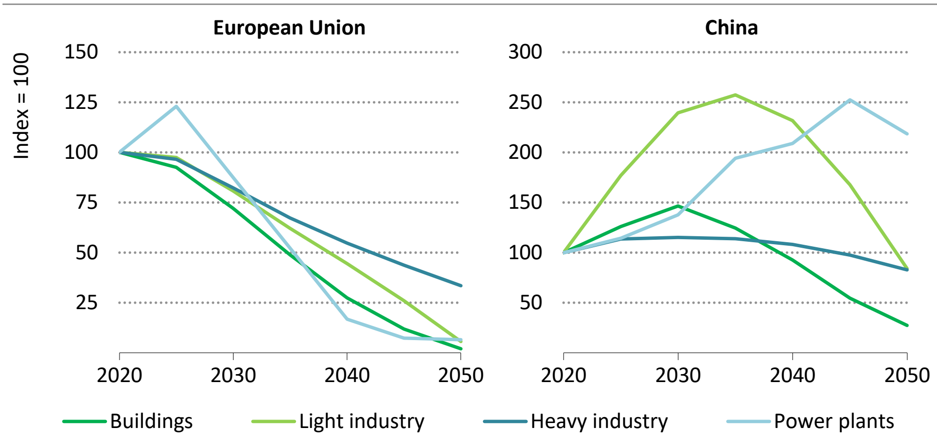
The call on natural gas to ensure electricity security becomes more important in the APS to 2030, even as overall demand and installed capacity decline

In emerging market and developing economies, gas-fired power generation in the NZE peaks in the late 2020s at a level over 40% higher than in 2020, but falls sharply thereafter, and provides a mere 1% of total power generation by 2050. Gas-fired capacity on the other hand increases strongly throughout the *Outlook* period, nearly doubling on 2020 levels by 2050. The result is that gas power plants, which also run on hydrogen and biogas, operate at 10% utilisation, compared to an average of 40% today.

After 2030, the flexibility services required of gas infrastructure are eroded by end-use efficiency gains and by the increasing use in the power sector of battery storage and demand-side response. However, there are still significant benefits in maintaining a parallel gas delivery system as a hedge against slow growth in building retrofit rates or power system flexibility (where many of the options remain in the early stages of technological maturity). Moreover, there is a longer term case for injecting biomethane into gas networks or repurposing them to transport hydrogen. In the NZE, biomethane and hydrogen make up nearly 30% of total grid-based gases by 2050. This would bring gains in terms of clean energy, but it would also create new security challenges that would need to be overcome: the different technical characteristics of hydrogen or the dispersed supply of biomethane would have to be managed within gas transportation infrastructure, and the use of different gases could lead to reduced flexibility if gas networks were to become less interconnected.

Assessing the viability of gas infrastructure in the transition to a net zero emissions economy also involves other complex trade-offs. Households, businesses and industries connected to the same gas grid may switch to other fuels at variable speeds (Figure 6.9), raising questions about how to sequence the decommissioning of assets while minimising adverse impacts on supply security or overall system flexibility (in addition to equity and affordability concerns). The record high spot gas prices in Asia and Europe in 2021 were a further indication of the potential for a mismatch between short-term signals to maintain or even expand gas infrastructure and the longer term case for reducing unabated gas consumption.

Figure 6.9 ▷ Changes in natural gas demand in selected sectors in the European Union and China in the Announced Pledges Scenario, 2020-2050



Infrastructure operators face the dilemma of accommodating uncertainty about natural gas demand in sectors with different infrastructure needs

Unless the transition is well managed, remaining consumers of natural gas would be at risk of supply shortages or volatility during the process of phasing out supply lines or delivery infrastructure. They would also be likely to incur higher costs: in the European Union, for example, the combined value of existing gas transmission and distribution networks is estimated at around USD 120 billion, and around USD 8 billion is spent each year maintaining it. On average, network charges comprise around 20% of household gas bills (EC, 2020), but this could rise if fewer consumers were to be charged higher fees to maintain infrastructure which was utilised less frequently. Innovative financial tools or regulatory interventions such as capacity markets may be required to maintain the option value of gas infrastructure, avoiding asset stranding even as total delivered volumes decline.

In the case of China, natural gas demand in the APS increases in all sectors in the decade ahead, and spending on gas networks rises by 50% compared to 2020, reaching over USD 8 billion by 2030. Gas use in buildings and light industry sees strong growth: these are sectors made up of dispersed, less energy-intensive customers, and therefore require high upfront investment in distribution networks across a wide geographic area. Demand in these sectors peaks in the 2030s, and falls below current levels by 2050. This implies either a relatively short capital recovery period for the investment in networks (meaning higher fixed charges for households and businesses) or higher tariffs on remaining large-scale gas consumers, such as heavy industry and power plants, for whom the drop in demand begins in the 2040s. Incorporating an eventual shift to non-fossil gases such as hydrogen or biomethane could help future-proof such infrastructure investments.

In emerging market and developing economies, a further challenge in a world moving towards net zero is to secure financing for new gas infrastructure where the longer term use case may be uncertain. Around 70% of debt financing for large-scale gas infrastructure projects in emerging market and developing economies (excluding China) comes from entities domiciled in countries with net zero emissions targets (IEA, 2021d). Such lenders may struggle to value the security of supply benefits, or to predict how they will be valued in future years by governments and regulators. Such benefits should ideally be assessed on the basis of whether any given gas infrastructure helps to displace more polluting fuels, aids the integration of renewables, supports the uptake of low emissions gases or provides access to modern energy services.

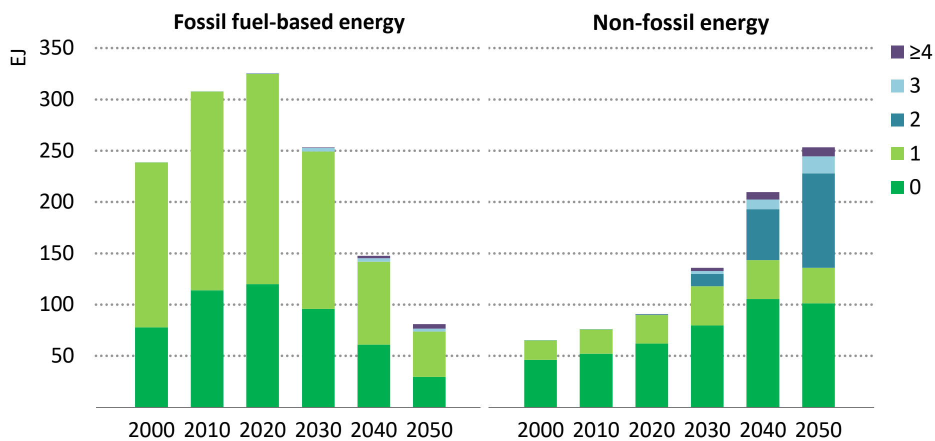
6.2.3 Additional energy conversions

As clean energy transitions progress, the resources entering the energy system require more conversions before they reach end-users. This trend leads to more integration of energy networks, and it has implications for energy security.

Conversions are needed when energy is in forms that are not what end-users want or need, as for example when coal needs to be converted into electricity, or when electricity is supplied at times or in places that are not matched with demand and must be converted until it can be used. These conversions involve changes to the chemical composition of fuel molecules or changes in the form of the energy, e.g. from electrical to chemical, kinetic, potential or thermal. A wide variety of technologies exist that can be used to convert energy until it is needed, e.g. pumped storage hydro, electrochemical batteries and fly wheels.

Around one-quarter of primary energy today is used in the same form as it is supplied. This includes nearly 40% (around 120 EJ) of all natural gas and coal produced in 2020, most of which was burned to produce heat for the world's factories and buildings or used directly as raw materials for chemicals. Most of the rest of the natural gas and coal that was produced (around 180 EJ) was converted to electricity and heat. Most other primary energy requires one conversion step in order to provide useful energy services: over the course of 2020, for example, 160 EJ of liquid fuels underwent refining processes to be produced from crude oil; 4 EJ were converted from bioenergy inputs; and less than 1 EJ was converted from coal and natural gas.

Figure 6.10 ▷ Total final consumption by the number of conversion steps from primary energy supply in the Net Zero Emissions by 2050 Scenario



Multiple conversions are needed to store electricity and heat and to produce low emissions fuels

Notes: Figure shows energy consumption by end-users. Conversions are counted based on the IEA method of constructing energy balances. Fossil energy combined with CCUS is allocated to fossil fuel-based energy. Carbon-containing hydrogen-based fuels are not derived from fossil carbon in the NZE.

By 2050, around 40% of energy consumed globally in the NZE undergoes at least two conversion steps, whereas today almost none does (Figure 6.10). The peak year for direct use of fossil fuels without conversion in the NZE is 2020 and, while there is a rise in the direct use of electricity from renewable sources, this is outpaced in terms of growth rates by new energy products, notably low-carbon hydrogen and hydrogen-based fuels such as ammonia and synthetic liquids. Energy products in 2050 that have undergone one conversion step include biofuels, district heat, nuclear power and low-carbon hydrogen from solar PV and wind, and natural gas with CCUS. Energy products in 2050 that have undergone two conversion steps include biomethane and low-carbon ammonia from fossil fuels with CCUS, while those involving three conversion steps include electricity from biomass, nuclear or fossil fuels with CCUS that have passed through one round trip in a battery or other storage device. In the NZE, some pathways emerge that involve even more conversions, such as the production of hydrogen or ammonia from electricity that has been converted and reconverted during storage.

The additional energy conversions featured in the NZE are an integral feature of a net zero energy system. They are a core means of providing the flexibility that systems need in order to match the supply of variable renewables and demand for electricity at least cost. The need – and the capacity – for flexibility in the NZE is considerable. Utility-scale battery storage reaches 3 000 GW, and there are millions of behind-the-meter potential enablers of flexibility, in the form of smart meters, EVs and charging infrastructure. However, each conversion step is associated with energy losses. Some of these are modest, such as the 5-20% of energy lost during two conversions in a lithium-ion battery. Some are more substantial, such as the roughly 50% loss experienced during the conversion of electricity to hydrogen-based synthetic liquids. In addition to conversion losses, electricity distribution losses alone more than double to reach 17 EJ by 2050 in the NZE as a result of electrification and demand growth. One major role for energy efficiency in the NZE is to offset conversion losses and thereby avoid a possible weakening of energy security (and increase in prices) resulting from the use of more primary energy per unit of delivered energy service.

Each additional conversion step requires equipment to be installed to facilitate it. In many cases, new market designs are also required to link various energy value chains. The web of interdependencies in the energy system, which is already extensive, becomes much denser. This raises important questions about how to judge whether such a system will be able to absorb disturbances or withstand shocks. Given that a network is only as strong as its weakest link, it is necessary for regulators to consider how much redundancy and storage capacity each part of the system requires. In some cases, additional conversions might provide "release valves" in times of congestion – for example if two-way flows are possible – but in others they might present risks of failure that could cascade back up their supply chains. As electricity comes to provide power for a bigger share of consumption, the potential impacts on consumers of a disruption to electricity supply also grow bigger and spread to new sectors. Such disruptions could arise externally from low probability weather events or cyberattacks, or internally from equipment failure.

Ensuring the security of supply chains with multiple conversions requires integrated system planning, and an appropriate balance of responsibility between public and private actors. The task for governments is to provide a policy architecture that enables investment choices that reflect the system value of assets during peak demand periods, without prescribing the technological pathway. There is a long history of energy governance and regulation directed to this end, but the rising complexity of energy systems calls for an ever-expanding suite of tools. Government efforts to ensure minimum safeguards may need to intensify, and may need to include action to set operating standards and support a level playing field for market participants, while staying at the forefront of developments in digital technology.

6.2.4 Building climate resilient infrastructure

The increasing physical risks from climate change are exemplified by a growing catalogue of recent extreme weather events such as heatwaves, periods of exceptional cold snaps, wildfires, droughts, cyclones and floods. Some of these events have disrupted the operation of critical infrastructure, including power plants, networks and offshore energy facilities. In the United States, for example, in August 2021 Hurricane Ida damaged long-distance power transmission lines and shut down many oil refining and petrochemical facilities in Louisiana and disrupted 95% of oil and gas production facilities in the Gulf of Mexico that went offline temporarily. Exceptionally cold weather in Texas took a heavy toll on the its natural gas and power supply in February 2021, while severe heat waves in California have strained the power system and caused load shedding. Such extreme weather events have also been responsible for significant power outages in Argentina and Australia over the past few years (IEA, 2021e). These events demonstrate that existing infrastructure can be far from resilient, and also expose consumers to energy price spikes.

One particular aspect of these severe weather events is related to the rising intensity of cyclones[3], which can cause serious damage to energy supply infrastructure, particularly in coastal areas. According to our geospatial analysis, around a quarter of the world's electricity networks are estimated to be at high risk of destructive cyclone winds.[4] The share is notably higher in North America and Australia, where over 40% of distribution networks are exposed to a high risk of damaging cyclone winds. LNG plants and refineries, a large part of which are located in coastal areas, are also heavily exposed to risks from violent storm surges, with some 50% and over 35% of today's facilities situated in very high risk areas respectively (Figure 6.11). The growth of offshore wind means that it is also increasingly facing hostile meteorological conditions requiring new turbine designs together with improved operational practices to deal with cyclone-force winds.

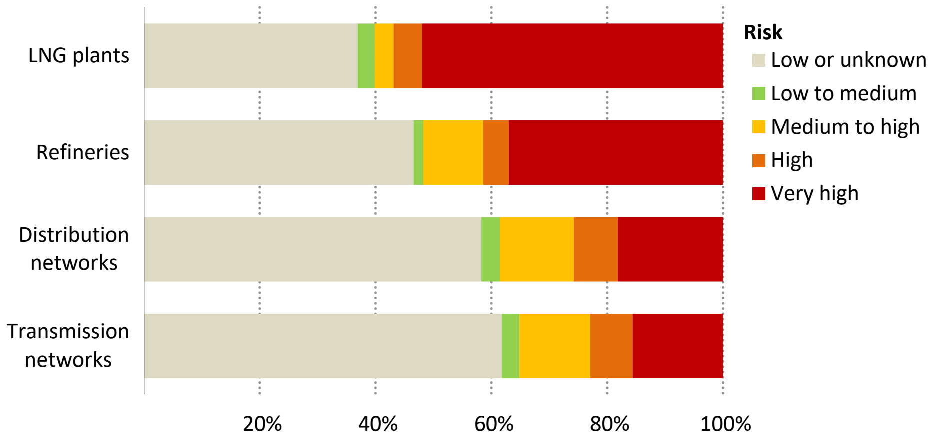
Climate change is increasing the frequency and intensity of short-term extreme weather events, and it is also causing more systemic shifts in general climatic conditions. For example, the global mean sea level is currently rising at almost double the pace observed during the 20th century. Rising sea levels, coupled with high tides and storm surges, have the potential to cause flooding affecting energy supply infrastructure in low lying coastal areas. They may also limit the availability of appropriate locations for new energy infrastructure. We have assessed the exposure of various energy supply assets to risks from coastal flooding, combining coastal flood risk datasets with the geographical co-ordinates of each asset. Around 13% of the world's coastal thermal power plants (200 GW of dispatchable generation

[3] A tropical cyclone is a generic term used to describe a rotating, organised system of clouds and thunderstorms that originates over tropical or subtropical waters. Once a tropical cyclone reaches maximum sustained winds of 119 km/hr or higher, it is then classified as a hurricane, typhoon, or tropical cyclone, depending upon where the storm originates in the world (NOAA, 2021).

[4] The risk exposure analyses in Section 6.2.4 were built on the geospatial analyses in *Electricity Security 2021: Climate Resilience* (IEA, 2021e).

fleets), 25% of onshore LNG plants and 10% of coastal refining facilities already are at risk of experiencing severe coastal floods.[5] These levels of risk will increase as sea levels rise.

Figure 6.11 ▷ Share of energy infrastructure capacity at risk of destructive cyclones, 2020



A large portion of electricity networks and fuel supply infrastructure is exposed to high risk from destructive cyclones

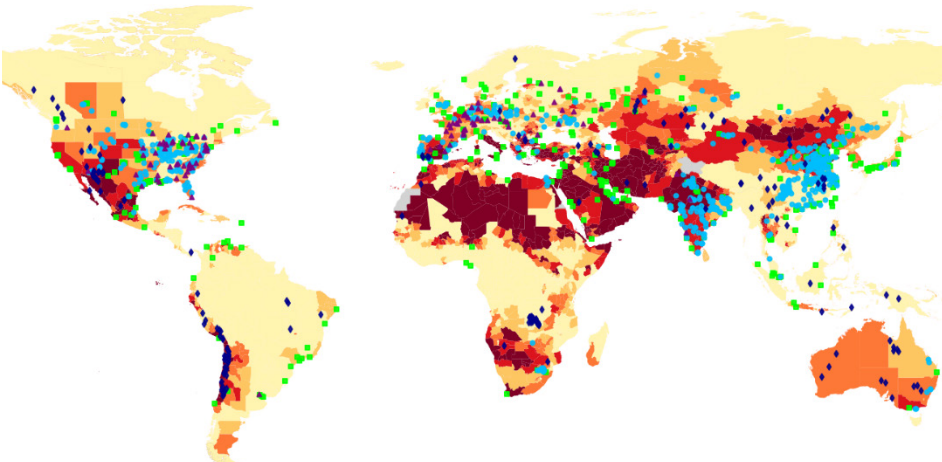
Notes: Risk levels are classified based on the probability of wind speed exceeding 80 kilometres per hour (1 in 50, 100, 250, 500 and 1 000 years). Those within 60 degrees latitude north and south are included in the assessment. Source: IEA analysis based on UNDRR (2015) and Arderne et al. (2020).

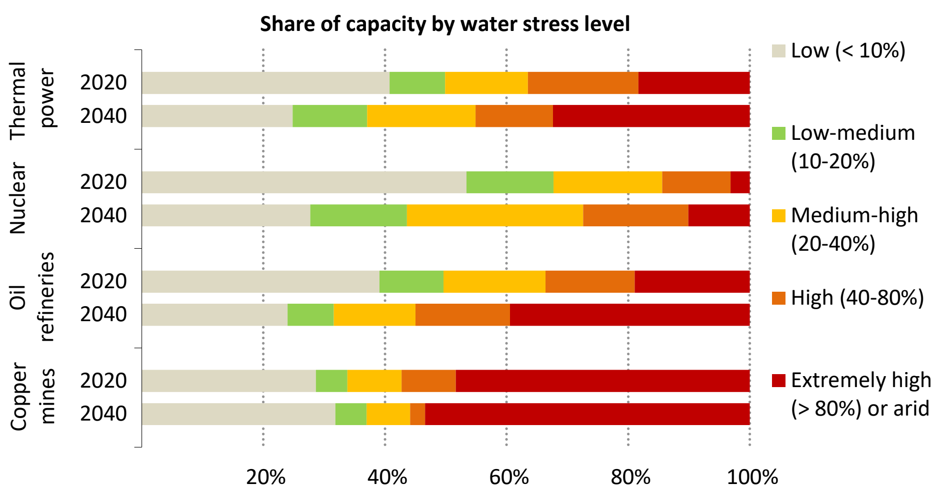
Changing climate patterns can also put stress on infrastructure that depends on hydrological conditions or adequate water supplies. A shift in precipitation patterns could have significant impacts on hydropower generation and lead to a major drop in capacity utilisation. Water shortages could also reduce output from thermal power plants using freshwater cooling, especially in regions where freshwater flows are dependent on seasonal rainfall. Around one-third of existing thermal and nuclear power plants using freshwater cooling are located in high water stress areas[6], and this share is set to increase over time as the changing climate turns today's low risk sites into high risk ones. Based on the projected water availability under the IPCC RCP 4.5 scenario (an intermediate emissions scenario), over 40% of freshwater-cooled thermal and nuclear fleets are projected to be in high risk areas by 2040.

[5] Based on the return period of 100 years and the sea level rise of 0.72 metres. The anticipated sea level rises in the representative concentration pathway (RCP) scenarios by the Intergovernmental Panel on Climate Change range from 0.59 metres in the RCP 2.6 (a low emissions scenario) to 0.72 metres in the RCP 4.5 (an intermediate emissions scenario) and to 1.1 metres in the RCP 8.5 (a high emissions scenario) by the end of the century (IPCC, 2019).

[6] For power plants where type of cooling systems information is not available, we estimated the cooling type based on the distance from the coast. Overall, around 40% of existing thermal (oil, gas and coal) and nuclear plants are estimated to use freshwater cooling.

Figure 6.12 ▷ Water stress exposure of freshwater-cooled thermal and nuclear power plants, refineries and copper mines





The share of energy supply infrastructure in high water stress areas is set to increase as changing precipitation affects water availability in many regions

Notes: Water stress levels are as defined in the Aqueduct 3.0 dataset according to the ratio of total water withdrawals over the total available surface and groundwater supplies. In the bottom chart, power plants include those estimated to use freshwater cooling and the share of copper mines is based on production.

Source: IEA analysis based on WRI Aqueduct 3.0 (2019) and S&P Global (2021).

The risks from water stress are not confined to electricity infrastructure. Other types of energy infrastructure are also dependent on water availability: these range from upstream oil and gas facilities that employ water flooding to increase production through to biofuel facilities that use irrigation and to refining operations that depend on water for operations. Around one-third of global refining capacity is currently located in high water stress areas, and this share is set to increase to 55% by 2040. Decreasing availability of water already affects refinery throughput in countries such as India, Iran, Iraq and Venezuela. Stable supplies of copper, a critical material used widely in clean energy technologies, are also dependent on the availability of high quality water resources. In 2019, severe drought affected mining operations in Chile, the world's largest copper producing region. Droughts have also had similar effects in Australia, Zambia and elsewhere. Over half of today's global copper production is concentrated in areas of high water stress, and there is no indication that this will change significantly in the future (Figure 6.12).

The increase in the frequency and intensity of natural disasters and extreme weather events highlights the urgent need for action by policy makers to enhance the resilience of energy systems to climate change. IEA analysis shows that around 25% of IEA member and association countries do not address climate resilience in their energy and climate plans and that most countries have scope to improve the level of their policy preparedness. The IEA Climate Resilience Policy Indicator is an initial effort to assess the level of climate hazard that a country is facing against its policy preparedness (IEA, 2021f). It is intended to help prepare the ground for climate risks to be incorporated into planning and regulation for future infrastructure development.

As a first step, policy makers should mandate assessments of existing infrastructure to determine vulnerabilities and adaptation priorities, focusing on areas that are critical to overall system operation and particularly susceptible to climate impacts. This would help with the identification of cost-effective resilience measures. Effective implementation of these measures could be supported by introducing appropriate incentives to attract investment. At the same time recovery plans need to be developed in preparation for possible disruptions. As ever, an integrated, systems-level approach will be essential to develop a resilient energy system that takes account of impacts of short-term weather events as well as long-term changes in climate patterns.

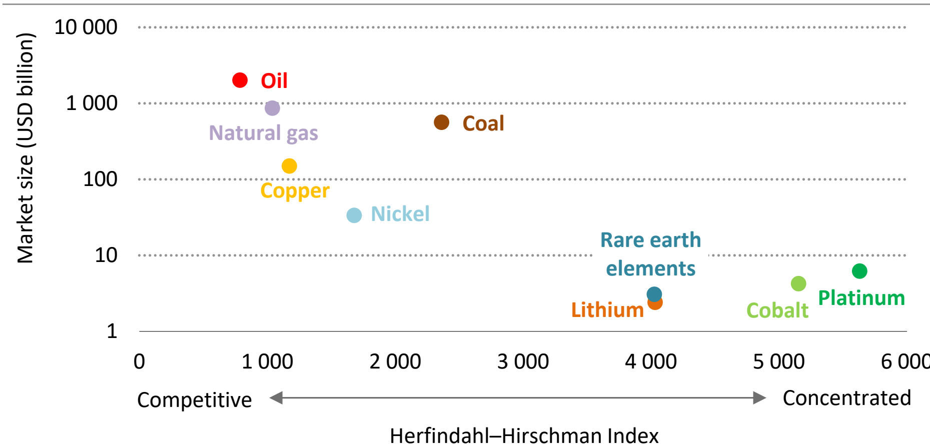
6.3 International aspects of energy security

In a world where fossil fuels represent the majority of energy supply, concerns about energy geopolitics understandably focus on major oil and gas resource holders, and on the international trade patterns that have formed around them. However, clean energy transitions bring about a major shift in the primary energy mix away from carbon-intensive fuels towards low-carbon energy sources. Although the share of fossil fuels in the mix has remained at around 80% over several decades, it declines to around 50% by 2050 in the APS and just over 20% in the NZE. This raises major questions about the nature and relevance of geopolitical concerns about energy.

Lower demand for oil and gas ultimately reduces some traditional energy security hazards, but they do not all disappear. Mismatches between the pace of demand and supply reductions could bring periods of price volatility even when demand is declining, while a relatively small number of exporters with low cost and low emissions resources tends to dominate oil and gas supplies in climate-driven scenarios, which means that physical disruptions, trade disputes or other geopolitical events in major producing countries could have a significant impact on global supply and prices. Moreover, the chances of social and political turmoil in some supplier countries could increase as lower global demand for oil and gas puts huge financial strains on those that rely heavily on hydrocarbon revenues.

Clean energy technologies such as solar PV and wind are sometimes seen as being immune from geopolitics. The hazards are undoubtedly lower, but the supply chains for these technologies are nonetheless subject to various risks arising from trade in equipment and raw materials. Critical minerals are of particular concern because many clean energy technologies are mineral intensive and the supply of minerals is concentrated in a smaller number of countries than is the case for oil and natural gas. A combination of smaller market size and higher levels of geographical concentration provides reasons for vigilance, especially as demand for critical minerals rises (Figure 6.13).

Figure 6.13 ▷ Market size and level of geographical concentration for selected commodities, 2019



Markets for critical minerals are much smaller and more concentrated than those for traditional hydrocarbon resources

Notes: The Herfindahl–Hirschman Index (HHI) is a measure of market concentration. It is calculated by squaring the market share of each producing country and summing the resulting numbers. An HHI of less than 1 500 is considered to be a competitive market, and an HHI of 2 500 or higher to be a highly concentrated market. The HHI for critical minerals is calculated based on mining operations. The values for refining operations are generally higher than those for mining.

Although most renewables are produced very close to where they are consumed, the rise of hydrogen could bring a new form of low-carbon energy into the global trading system. Every country has the potential to produce hydrogen, but differences in resource endowments and quality create incentives for trade (hydrogen could be exported in various forms, including ammonia or other hydrogen-rich fuels). The emergence of inter-regional hydrogen trade would add another international aspect to energy security in a decarbonising world.

Trade patterns, producer country policies and geopolitical considerations remain crucial even in an electrified, renewables-rich energy system, with different sets of players coming into play. In this section, we look at two areas – critical minerals and oil and gas – that face different prospects in energy transitions. We then move on to explore shifting patterns of international energy trade and their implications for energy security.

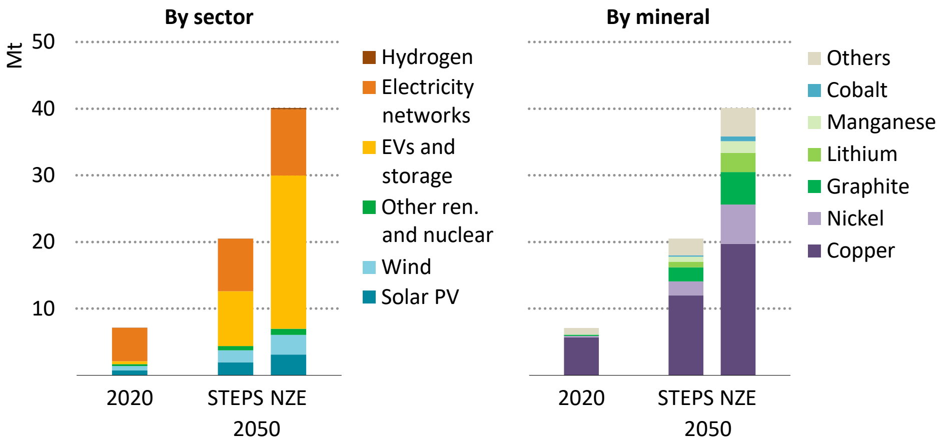
6.3.1 Critical minerals

The rapid deployment of low-carbon technologies as part of clean energy transitions implies a significant increase in demand for critical minerals. Solar PV plants, wind farms and EVs generally require more mineral resources to build than their fossil fuel-based counterparts. For example, the average amount of minerals needed for a new unit of power generation capacity has increased by 50% since 2010 as the share of renewables has risen (IEA, 2021g).

In the STEPS, overall requirements for critical minerals for clean energy technologies nearly triple between today and 2050. In the NZE, achieving net zero emissions globally by 2050 means record levels of clean energy deployment, and requires up to six-times more mineral inputs in 2050 than today. Mineral demand for EVs and battery storage increases by well over 50-times by 2050, while the expansion of electricity networks leads to a doubling of demand for copper for power lines in the period to 2050. Lithium sees the fastest growth among the key minerals, with demand up over 100-times its current level through to 2050, while cobalt, nickel and graphite also see rapid demand growth. Copper demand registers the largest absolute growth, rising by around 14 million tonnes (Mt) by 2050, expanding the size of the global copper market by 60% in the period to 2050 (Figure 6.14). As a result, in the NZE, clean energy technologies emerge as the fastest growing segment of demand for most minerals, evolving from a niche consumer to a leading source of demand.

The prospect of a rapid increase in demand for critical minerals – well above anything seen previously in most cases – raises questions about the availability and reliability of supply. Current supply and investment plans are geared towards a world of gradual and insufficient action on climate change, raising the risks of supply lagging behind projected demand in climate-driven scenarios. The challenges are compounded by long lead times for the development of new projects, declining resource quality, growing scrutiny of environmental and social performance and a lack of geographical diversity in extraction and processing operations. For example, the world's top-three producing nations control well over three-quarters of global output for lithium, cobalt and rare earth elements. The level of concentration is even higher for processing operations, with China having a strong presence across the board.

Figure 6.14 ⊳ Mineral requirements for clean energy technologies by scenario



In the NZE, mineral requirements for clean energy technologies increase by up to six-times by 2050, with particularly high growth for EV-related materials

Notes: Mt = million tonnes; ren. = renewables. Includes most of the minerals used in various clean energy technologies, but does not include steel and aluminium. (See IEA, 2021g for a full list of minerals assessed.)

The impacts of a shortage of mineral supplies would be different from those of an oil supply shortage. There would be no immediate effect on consumers driving EVs or using solar-generated electricity. Higher and volatile prices or supply disruptions nevertheless would be damaging because they could make global progress towards a clean energy future slower and/or more costly. Tightening supplies could prompt various industry and consumer responses such as demand reduction, material substitution, increased recycling or increased investment in supply. For example, a massive growth in battery deployment in the NZE could put substantial strain on mineral supplies and prices, triggering efforts such as switching to alternative battery chemistries that require less material inputs (Box 6.2). However, these responses have often come with non-negligible time lags or considerable price volatility. Sustained periods of higher critical mineral prices could push up costs of clean energy technologies and delay energy transitions, although they could help to bring new supply to the market or spur the development of alternatives.

Box 6.2 ▷ EV battery chemistries: Exploring constrained nickel and cobalt supply cases in the Net Zero Emissions by 2050 Scenario

Periods of high cobalt prices in the late-2010s led many EV manufacturers to look for ways to reduce cobalt use and develop batteries with higher energy density. As a result, EV batteries shifted away from cobalt-rich chemistries in recent years towards chemistries that use more nickel. We assume that this trend will continue, with NCA+ and NMC811[7] accounting for 65% of the light-duty EV market in 2050 compared with 35% in 2020.[8] In the NZE, a stronger focus on innovation and international co-operation leads to an accelerated market penetration of lithium-metal anode all-solid-state batteries. These have several advantages over the current generation of lithium-ion batteries, including higher energy density and improved operational safety.

Nonetheless, the mineral implications of a major increase in clean energy deployment in the NZE are huge. EV battery deployment in the NZE is over three-times higher than in the STEPS over the next three decades, and this could put a major strain on mineral supplies and prices, in particular for battery-grade nickel and cobalt. Demand for these two minerals in clean energy technologies is set to rise by nearly 40-times between 2020 and 2050 in the NZE. This could result in price volatility and market tightening and thus delay the achievement of the EV deployment targets set by many countries. Therefore it is conceivable that the NZE could see more EV batteries with lower critical mineral needs (such as lithium iron phosphate [LFP] and manganese-rich chemistries such as lithium nickel manganese oxide [LNMO] batteries), even if these might be sub-optimal from a performance perspective. Following the price rallies of nickel manganese cobalt oxide (NMC) precursors in the first-half of 2021, several companies have already dissented from the consensus view that nickel-rich NMC cathode chemistries will dominate future EV chemistries.

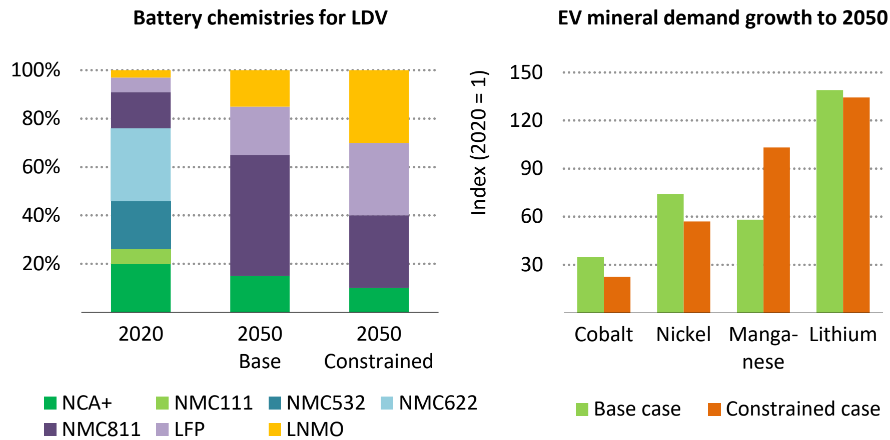
We have explored the potential impacts of an accelerated shift away from high nickel and cobalt chemistries in the *constrained mineral supply case* (Figure 6.15). In the constrained case, the share of NCA+ and NMC811 battery chemistries falls to 40% compared with 65% in the base case, and this is offset by an equivalent increase in the share of LFP and manganese-rich chemistries. As a result, there is lower demand for cobalt (-35%) and nickel (-23%) in 2050 than in the base case. This underscores the important role of technology choices and innovation in shaping future mineral requirements and alleviating potential supply strains. It also underscores the potential

[7] NCA+ = A nickel-rich (and lower cobalt) variant of nickel cobalt aluminium oxide (NCA) chemistry. NMC811 = nickel manganese cobalt oxide chemistry with 80% nickel, 10% manganese and 10% cobalt.

[8] The base case assumptions for battery chemistry shares have been updated to reflect recent company announcements and market developments since the publication of the *Role of Critical Minerals in Clean Energy Transitions: World Energy Outlook Special Report* (IEA, 2021g). In particular, the base case now assumes a higher share of lithium iron phosphate for passenger cars (27% in 2030) due to its increasing use in China and entry-level models from automakers worldwide.

trade-offs involved. For example, manganese demand in the constrained case is 80% higher while lithium demand decreases only slightly.

Figure 6.15 ▷ Battery chemistries and EV-related mineral demand growth in the Net Zero Emissions by 2050 Scenario in the base and constrained mineral supply cases



A switch away from high nickel chemistries towards LFP and LNMO chemistries in the constrained case shows complex trade-offs between mineral demand and prices

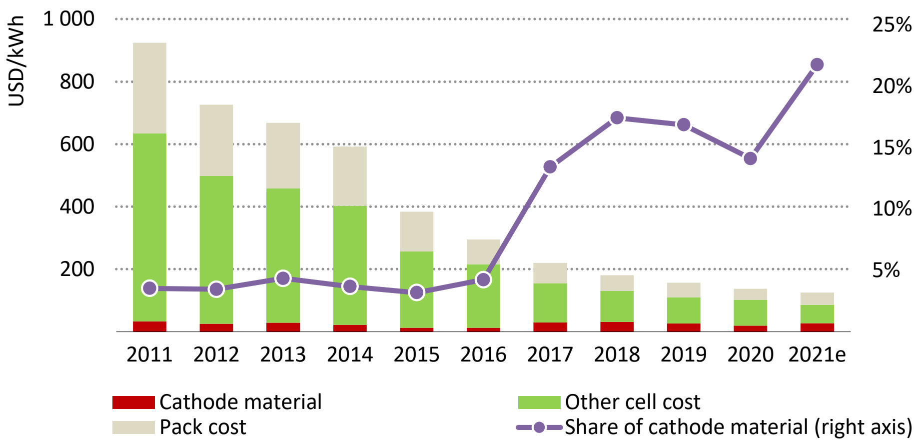
Notes: LDV = light-duty vehicles including passenger light-duty vehicles, light commercial vehicles and two/three-wheelers. LFP = lithium iron phosphate; LNMO = lithium nickel manganese oxide.

Impacts of mineral price increases on clean energy investment

Over the past decade, technology learning and economies of scale have pushed down the costs of key energy technologies significantly. For example, the cost of lithium-ion batteries has fallen by 90% since 2010. However, this also means that raw material costs now loom larger in total cost of clean energy technologies. The share of cathode materials in battery costs has continued to increase over the past decade, and has recently reached over 20% (Figure 6.16). When anode materials and other raw materials are added in, the share of raw materials rises further to some 50-70% (IEA, 2021g). Higher or more volatile mineral prices therefore could have a significant effect on the costs of transforming our energy systems.

The impact of raw material prices on total costs varies by technology, but the commodity price rallies in the first-half of 2021 illustrate the possible strains if these trends are sustained over the longer term. A combination of surging commodity prices, shipping costs and supply chain bottlenecks has put pressure on industry margins and equipment prices. Prices for new wind turbine contracts have reportedly increased in 2021, reversing the trends seen over the past few years (Wood Mackenzie, 2021). Steeply rising silicon and silver prices have similarly driven up the price of solar PV modules.

Figure 6.16 ▷ **Average pack price of lithium-ion batteries and share of cathode material cost**



Increasing significance of raw materials in total battery costs means that mineral prices could have a substantial impact on industry cost targets

Notes: kWh = kilowatt-hours. The 2021 values (labelled 2021e) are estimated based on material prices in June 2021. Cathode material costs include lithium, nickel, cobalt and manganese. Other cell costs include costs for anode, electrolytes, separator and other components as well as costs associated with labour, manufacturing and capital depreciation.

Source: IEA analysis based on BNEF (2020).

For **solar PV**, materials represent a major part of module costs. Key materials include silicon (10-15% of module costs) and silver (5-7%). Solar-grade polysilicon prices have more than doubled since last year while the price of silver has surged by around 30% (BNEF, 2021a). These increases have led to a cost increase of USD 0.04/watt, or around 16% of module costs. For a typical 100 megawatt (MW) utility-scale PV project, a 16% increase in the cost of a module represents a 4% hike in total project cost on a dollar-per-watt basis, if not compensated for by reductions in other cost elements.

For **wind**, turbine materials have typically accounted for around 15% of the total wind turbine price over the past decade (excluding foundations) (Elia et al., 2020). The shares of material costs vary by turbine type, but are typically dominated by steel, with copper, rare earth elements and zinc accounting for most of the balance. Since June 2020, steel prices have nearly doubled in China and tripled in North America, while copper prices have risen by 50% over the last year. These price rises have led to an 8-10% increase in the cost of turbine manufacturing which could increase total capital costs by around 5%. Prices of the rare earth elements used in turbines based on permanent magnet synchronous generators have also doubled over the past year, contributing to the rise in turbine costs.

For **electricity grids**, copper and aluminium costs are estimated to represent around 14% and 6% of total grid investment respectively, based on average prices over the past ten years. At the highest prices observed, these figures increase to almost 20% and 8% respectively, raising overall grid investment costs by around 9%. Average copper prices in 2021 so far have averaged over USD 9 300/tonne – close to the highest prices observed in the past decade – compared with an average price in the 2010s of around USD 7 000/tonne.

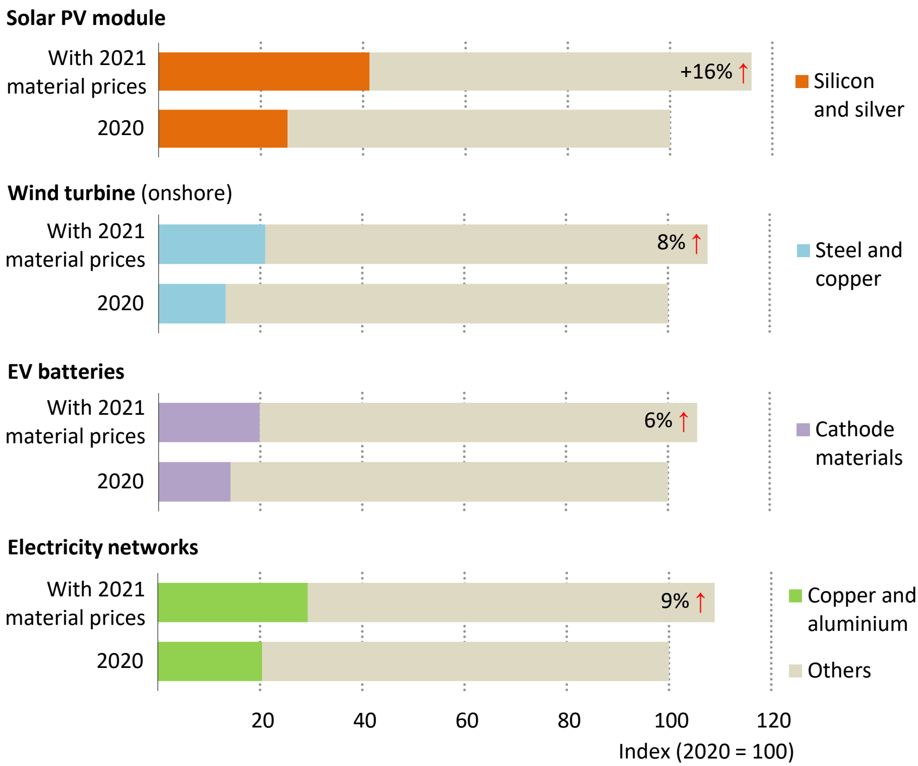
For **EV batteries**, average prices for cathode materials showed a broad-based increase in the first-half of 2021 of 20-40% for lithium and nickel, and two-thirds for cobalt. These translate into a 6% increase in the costs of EV batteries, provided that other cost elements remain the same (Figure 6.17). The impacts vary by battery chemistry. For NMC622 chemistries[9], a doubling of the prices of any of the three key minerals – nickel, cobalt or lithium hydroxide – results in pack costs increasing by 5-7%. If nickel and cobalt prices were to double at the same time, this would offset all the anticipated unit cost reductions associated with a doubling of battery production capacity (IEA, 2021g). In contrast, rising prices for iron, phosphorus and lithium carbonate have a limited impact on the cost of LFP battery packs, which dominate storage applications, because these three key materials account for just 2.5% of final capital expenditure at the project level (BNEF, 2021b).

It is uncertain if, and for how long, the surge in prices in the first-half of 2021 will continue. The rise in key material prices at the scale seen recently would generate upward pressure on total capital costs by 5-15%. This could add USD 430 billion to cumulative investment needs for solar PV, wind, batteries and electricity networks over this decade in the STEPS, and nearly USD 700 billion in the NZE. High material prices would require large reductions in other cost elements to keep the overall costs on a continued downward trajectory.

These risks to mineral supplies are real, but they can be mitigated through comprehensive policies and actions by government and industry. The *Role of Critical Minerals in Clean Energy Transitions* presented key areas of action to ensure reliable and sustainable mineral supplies (IEA, 2021g). Scaling up investment in new mining and processing facilities is vital. To attract capital to new projects, policy makers must provide clear signals about their climate ambitions and how their targets will be turned into action, while taking steps to strengthen geological surveys and streamline permitting procedures. Technology innovation on both the demand and production sides can bring substantial security benefits by promoting more efficient use of materials, enabling material substitution and unlocking sizeable new supplies. Stepping up efforts for recycling would enable valuable mineral resources to be recovered from spent equipment. These measures should form part of a broad strategy that also encompasses supply chain resilience, transparency and sustainability standards. The response from policy makers and companies will determine whether critical minerals remain a vital enabler for clean energy transitions or become a bottleneck in the process.

[9] NMC622 = nickel manganese cobalt oxide chemistry with 60% nickel, 20% manganese and 20% cobalt.

Figure 6.17 ▷ Impacts of 2021 material price increases on the costs of selected clean energy technologies



Rising costs of key materials could make clean energy technologies 5-15% more expensive, if not compensated by other cost reductions

Notes: This analysis applied the estimated 2021 prices for key materials in each technology to equipment costs in 2020, keeping other cost elements constant. Cathode materials for EV batteries include lithium, nickel, cobalt and manganese.

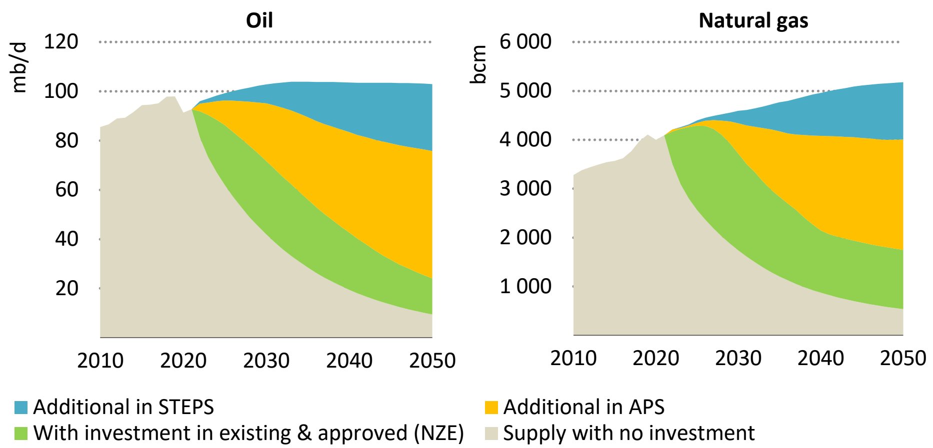
Source: IEA analysis based on BNEF (2020) and S&P Global (2021).

6.3.2 Oil and gas investment

The trajectory of oil and gas demand varies significantly across the three scenarios, and this naturally has implications for the investment required to ensure adequate supplies. In the STEPS, annual upstream oil and gas spending averages around USD 650 billion between 2021 and 2030, and USD 700 billion through to 2050, which is higher than the average investment in the 2010s. Over 60% of total investment is spent on developing new fields (Figure 6.18).

In the APS, investment requirements to develop new fields are reduced markedly. Average annual upstream oil and gas spending between 2021 and 2050 amounts to USD 495 billion, with spending on new fields down by a third compared with the STEPS. In the NZE, demand for oil and gas plummets to levels that do not require new field developments beyond those already approved, although investment in existing fields continues. At USD 235 billion, average annual upstream oil and gas spending between 2021 and 2050 is two-thirds lower than in the STEPS and, with the exception of fields already approved, is entirely spent on existing fields (Table 6.1). In this scenario, there is much greater focus on boosting productivity from existing fields and reducing emissions from operations (see Chapter 5).

Figure 6.18 ▷ Global oil and natural gas demand and declines in supply by scenario



In climate-driven scenarios, a large part of upstream oil and gas investment is spent on maintaining production at existing fields

Note: mb/d = million barrels per day; bcm = billion cubic metres.

Table 6.1 ▷ Average annual upstream oil and gas investment by scenario

USD billion (2020)		STEPS		APS		NZE	
	2020	2021-2030	2031-2050	2021-2030	2031-2050	2021-2030	2031-2050
Existing fields		244	255	240	204	288	171
New fields		403	436	331	251	77	0
Total	**330**	**647**	**691**	**572**	**455**	**365**	**171**

Note: New fields also include those that have already been approved.

The fact that no new oil and natural gas fields are required in the NZE does not mean that limiting investment in new fields will lead to the energy transition outcomes in the NZE. If demand remains at higher levels, reduced investment would result in a shortfall in supply in the years ahead, and this would lead to higher and more volatile prices. Therefore, a strong policy push to reduce oil and gas demand in line with the trajectory envisaged in the NZE is key to achieve deep reductions in emissions and to avoid the risk of market tightening.

Nonetheless, actions on the supply side remain crucial to orderly and rapid energy transitions. Over investment creates the risk of underutilised, unprofitable or stranded assets, putting greater financial pressure on producing countries and companies alike. For example, most of the 200 bcm worth of LNG projects currently under construction do not recover their invested capital in the NZE, with the total stranded capital estimated at USD 75 billion. Over investment also creates the risk of excess capacity that puts downward pressure on prices, requiring stronger policy efforts to offset the possibility of a rebound in demand. On the other hand shortfalls in investment, which cannot be ruled out even in lower demand scenarios such as the APS and NZE, would likewise be disruptive: higher oil or gas prices could become a political distraction and a signal to make new (and risky) upstream investments, even as they improve the competitiveness of lower carbon options. Supply-side actions to minimise emissions, especially methane leaks, remain essential in any scenario. In some cases, individual company actions to divest assets may bring the attendant risk that the new owners may be less transparent or concerned about environmental performance.

Oil and gas supplies in the APS and NZE are increasingly concentrated in a small number of low cost producers. The share of OPEC members and Russia in oil production rises from 47% in 2020 to 58% in 2050 in the APS, and to 61% in the NZE, comparable to the highest level in the history of oil markets in the 1970s. In practice, there would be a long queue of producers making claims to a shrinking oil market, complicating attempts at market management and increasing the possibility of a bumpy and volatile ride. Falling income from oil and gas compound the uncertainties facing many of the producer economies poised to take a larger share in future supply, underscoring the need for vigilance on the security of supply even in a world with contracting demand (Spotlight).

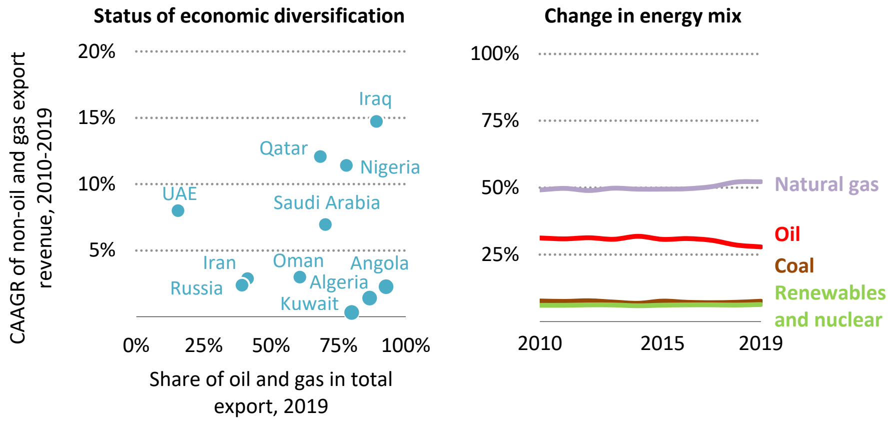
SPOTLIGHT

Diversification: Where do different producer economies stand?

The pandemic provided a preview of the social and economic strains that producer economies could face from reduced oil and gas revenue. Although higher prices in 2021 and the possibility of further tightening of markets in the 2020s provide some respite, there is little comfort for producers in our longer term projections. The decline in oil and gas demand and the consequent fall in prices in the APS and NZE lead to a major drop in hydrocarbon income in these economies. By the 2030s, annual per capita income from oil and natural gas in producer economies falls by a third in the APS and nearly 80% in the NZE from the levels in the 2010s.

Pressures on producers to reform and diversify their economies are not new, but energy transitions give additional urgency to the task. For the moment, however, there are few signs that major hydrocarbon-rich countries are moving fast. The value of non-oil and gas exports has been on an upward trend since 2010, and its share in total exports rose from 35% in 2010 to 57% in 2020. However, this increased share was largely attributable to the falling value of oil and gas exports rather than major strides in economic reforms (Figure 6.19).

Figure 6.19 ▷ Progress with economic and energy diversification in selected producer economies



While some countries have made strides towards economic diversification, progress has been very modest on energy diversification

Notes: CAAGR = compound average annual growth rate. Analysis based on 11 producer economies: Algeria, Angola, Iran, Iraq, Kuwait, Nigeria, Oman, Qatar, Russia, Saudi Arabia and the United Arab Emirates.

Source: IEA analysis based on export data from IMF (2021).

Progress has also been extremely modest in terms of energy diversification. For the moment, most producer economies do not have ambitious climate pledges, nonetheless they have cost-effective opportunities to invest in low-carbon sources – notably in solar power. However, the share of low-carbon energy in producer economies remains one of the lowest in the world. The only noticeable shift in the energy mix in recent years has been a slight move in favour of natural gas versus oil in some countries.

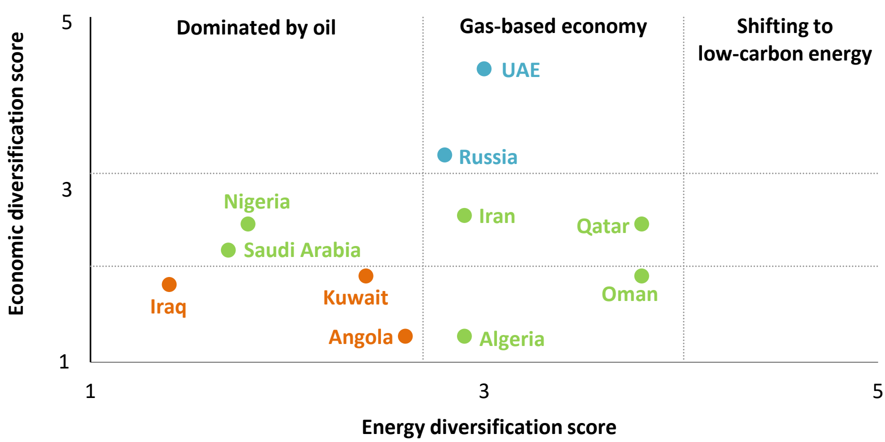
We have grouped the main producer economies into three categories based on their progress with economic and energy diversification (Figure 6.20). In the first group, Russia and the United Arab Emirates (UAE) are doing relatively well on both dimensions. In the UAE, the value of non-oil and gas exports has doubled over the past decade, halving the share of oil and gas export in total exports to 16% in 2019. In October 2021, the UAE became the first Middle East producer to commit to net zero emissions by 2050. There are signs, including a presidential order in May 2021, suggesting that Russia may now be looking more seriously at measures to reduce its emissions intensity as well, including growing attention to low-carbon hydrogen.

There are also countries, including Iraq, that are faring less well on indicators of both economic and energy diversification. These countries face an urgent need to develop holistic and realistic national economic diversification strategies alongside mechanisms to guard against revenue volatility. Iraq is taking steps in this direction, with the elaboration of a White Paper for Economic Reform to put the economy and the federal budget on a sustainable path, with a priority given to amplifying the role of the private sector.

Economic diversification is likewise a priority for the countries in our middle group, building on existing foundations. Qatar, for example, is investing in services, tourism and information and communication technologies while also strengthening its petrochemicals sector. Most of the countries in this group have an abundance of cheap solar resources which could help them to diversify their energy consumption structure, reduce emissions and potentially secure additional income from hydrogen exports. Saudi Arabia recently signed deals for seven solar power plants with a combined capacity of 3.7 GW as part of a national strategy to generate 50% of electricity production from renewables by 2030. It has also declared its ambition to become a major exporter of hydrogen and ammonia, produced via natural gas with CCUS or solar power.

6

Figure 6.20 ⊳ Categorisation of producer economies by economic and energy diversification performance



Each producer economy has a different track record of diversification, but none shows a visible shift towards low-carbon energy systems

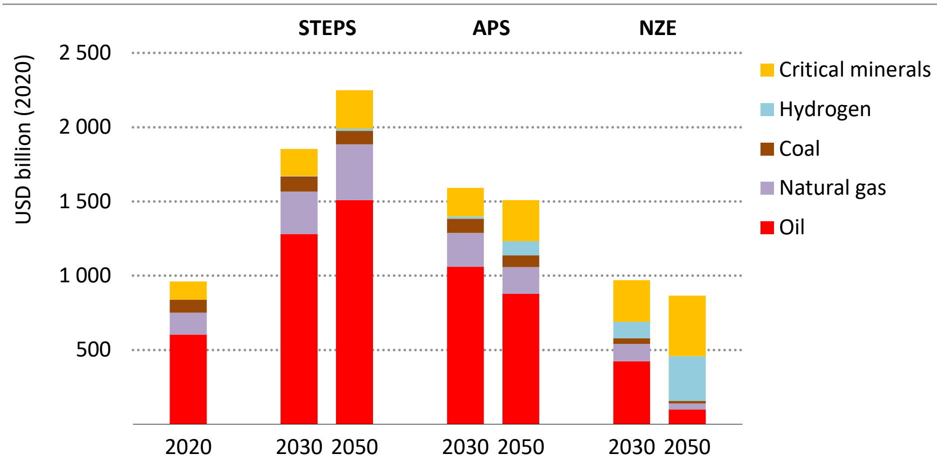
Notes: Economic diversification score was calculated as the weighted average of the share of non-oil and gas exports in total exports in 2019 (70%) and the growth of non-oil and gas export revenue since 2010 (30%). Energy diversification score was calculated as the weighted average of the share of oil, coal and traditional use of biomass in 2019 and the changes since 2010 (50% and 20% each) and the share of renewables and nuclear in 2019 (30%).

Source: IEA analysis based on export data from IMF (2021).

6.3.3 New patterns of energy trade

International trade plays a crucial role in today's global energy economy. It provides a major source of income for exporters and a means for countries without resources to secure supplies. It has, on occasion, been a source of geopolitical tension. For the moment, this trade is dominated by fossil fuels, oil in particular. However, changing energy consumption patterns in the APS and NZE herald some major shifts and bring new characters onto the stage – notably critical minerals and low-carbon hydrogen. The combined share of hydrogen and critical minerals in global energy-related trade doubles from 13% today to 25% by 2050 in the APS. In the NZE, the share rises further to over 80% by 2050 as the value of fossil fuels trade declines significantly, completely overturning the present dynamics of international energy-related trade (Figure 6.21).

Figure 6.21 ⊳ Value of international energy-related trade by scenario



Clean energy transitions are set to bring about a major change in longstanding global energy resource trade patterns

Notes: Values for hydrogen trade include volumes for liquid hydrogen, ammonia and synthetic fuels. Values for critical minerals trade include volumes for processed copper, nickel, lithium and cobalt, with assumptions that the ratio of trade value to total demand remains constant.

Source: IEA analysis based on historical critical minerals trade data from UN (2021).

Critical minerals are already widely traded worldwide, but their presence in global resources trade is set to increase further with the rise of clean energy. On a refined product basis, the value of key critical minerals such as copper, nickel, lithium and cobalt is estimated to double by 2050 in the APS from around USD 120 billion today. In the NZE, their value more than triples to USD 400 billion over the same period.

Although most low-carbon sources of energy are typically produced close to where they are consumed, the trade in hydrogen (or hydrogen-rich fuels) could prove to be an exception. Transport costs are relatively high, but there is still scope for regions with abundant low cost hydrogen production potential to export cost effectively to those with more limited production options. The value of the various forms of hydrogen trade grows from low levels today to around USD 100 billion by 2050 in the APS, higher than the value of current international coal trade, and to around USD 300 billion in the NZE. This poses important questions about infrastructure, market norms and energy security (Box 6.3). It also poses questions about which currency will be used for pricing and trading hydrogen and some critical minerals.

Box 6.3 ▹ Trading up: Creating an international market for hydrogen

Higher levels of low-carbon energy use in our scenarios create incentives for new forms of energy trade, and trade in hydrogen – including hydrogen-based fuels such as ammonia – looks set to increase. However, experience with establishing efficient international markets, especially for seaborne goods, suggests that the requisite infrastructure, standardisation and regulatory measures may take time to be developed and harmonised.

Practically all of the hydrogen and hydrogen-based fuels traded today are produced from fossil fuels without CCUS. International trade in hydrogen is limited, with only a small number of cross-border pipelines. Around half a million tonnes of hydrogen with a value of around USD 200 million was exported in 2019. The biggest exporters were Netherlands, Canada, Belgium, Sweden, France and Germany. Most exports were made by pipeline, with Canada being the only major road-based exporter. By contrast, the global anhydrous ammonia market, mostly for use in fertilisers, is thirty-times more valuable, with traded volumes equivalent to over 2 Mt hydrogen. Most ammonia is traded by rail or sea. Saudi Arabia, Russia, Indonesia, Canada and Malaysia were the biggest exporters in 2019. As with natural gas, pipeline transport offers the lowest cost trade route where it is feasible, and can readily be used for hydrogen converted to synthetic methane. However, pipelines could face competition from high voltage transport of electricity for direct use or as an electrolyser input in some cases.

The regions that stand to benefit most from future low-carbon hydrogen imports are today's importers of fossil energy. The most salient examples are Japan and Korea, which have ambitions to use low-carbon energy at a rate that is likely to quickly outpace their ability to meet demand locally. In the APS, Japan's demand for hydrogen and ammonia passes the level that can be competitively produced domestically before 2030, and imports rise to 1.3 EJ by 2050, equivalent to 11 Mt hydrogen per year.

Careful co-ordination and dialogue will be essential to bring forward new supply chains in a timely way. Many potential exporters do not yet have climate policy commitments on a par with countries whose policy pledges imply a future role for low-carbon hydrogen imports. Japan has engaged in dialogue with a number of countries, including Brunei, Saudi Arabia and the UAE, while Australia and Chile have developed plans to invest in export infrastructure. Korea and European countries also stand to gain from engaging countries, including those in the Middle East, North Africa and Latin America, to ensure that all countries have a shared stake in rapid clean energy transitions. Support measures such as long-term contracts will initially be essential if exporting countries are to invest in large-scale hydrogen production, storage and port infrastructure, or where possible to repurpose existing pipelines, and if importing countries are to be able to rely on imports for secure supplies.

In the APS, exports of hydrogen and hydrogen-based fuels from the Middle East reach the equivalent of around 13 Mt hydrogen per year, or 1 million barrels per day (mb/d). This helps in part to offset the decline in fossil fuel export revenues, but also means that new supply investments are required at a time when budgets are under pressure. The reliability of these new supply routes will also depend on how exporters manage the broader diversification of their economies.

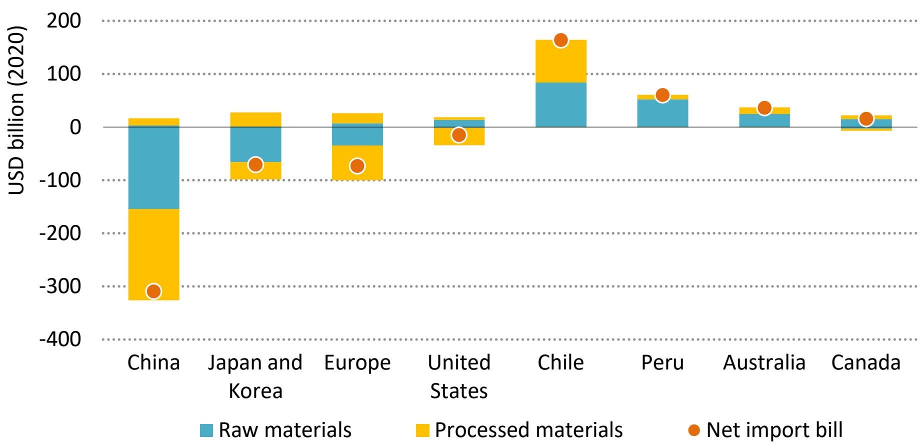
While some international trade takes place overland in our scenarios, the biggest import/export opportunities lie in connecting countries with different climates and geologies by shipping. There are competing options for shipping hydrogen with different efficiencies and maturities. The first demonstration vessel for liquefied hydrogen at 253 °C (90 °C colder than LNG) has recently been constructed with Japanese government co-funding. For applications that can use the ammonia directly, such as power plants, there is an emerging consensus that conversion to ammonia is the most promising means of transporting hydrogen over long distances, especially where pipelines are not viable. In all cases, infrastructure and certification norms for low-carbon cargoes need to be established this decade.

Many commentators point to the LNG market as a useful precedent and the parallels are striking: the technology was pioneered in the 1960s by companies working under the mandate of potential importer countries and in collaboration with potential exporters (with France, for example, working with Algeria on the development of facilities overseas), while the Japanese government was instrumental in facilitating the long-term bilateral contracts that allowed the industry to scale up from the 1990s and reduce transport costs. However, given that liquefaction and safe handling is less technically challenging for natural gas than it is for hydrogen, it is sobering to note that it took several decades to reach the point where very long-distance (so-called inter-basin) trade was possible, and 60 years until global liquefaction capacity could process LNG equivalent to Japan's total primary energy supply (which is around 10% of global gas demand).

Countries pursuing climate policies that would make imports of hydrogen and hydrogen-based fuel attractive have strong incentives to co-operate to ensure that hydrogen supplies do not become a bottleneck for energy security. Near-term objectives should include discussions between bilateral trading partners on whether new sources of financing are needed for export infrastructure and how to align policies that increase demand for hydrogen with the timetable for exports, for example by prioritising the market for fuels for which there is existing shipping capacity. Current demand for ships that can handle ammonia, for example, is often seasonal (in line with fertiliser use), and it may be possible to maximise their use by adding cargoes for energy applications. However, it is important that such bilateral discussions and contracts do not preclude the introduction by commodity traders of more international liquidity and trading over time as the market develops.

Critical mineral supply chains are set to involve multiple stakeholders since resource endowments, equipment manufacturing locations and consumption patterns are varied and complex. At present, Chile, Peru, Australia and Canada are among the top exporters of critical minerals and China, Japan, Korea and the European Union are major importers (Figure 6.22). As China has a decisive share in refining operations, around half of raw material trade flows to China. Somewhat counterintuitively, China also imports processed materials, highlighting the scale of the country's role in clean energy technology manufacturing. How these trade flows evolve is an open question, and the answer will depend in large measure on countries' industrial policies or strategic initiatives to ensure security of supply. A number of countries are looking to develop domestic mineral resources, or have ambitions to nurture supply chains for clean energy equipment manufacturing and materials production.

Figure 6.22 ▷ Average annual import bills and export revenues for selected critical minerals by country/region, 2015-2019



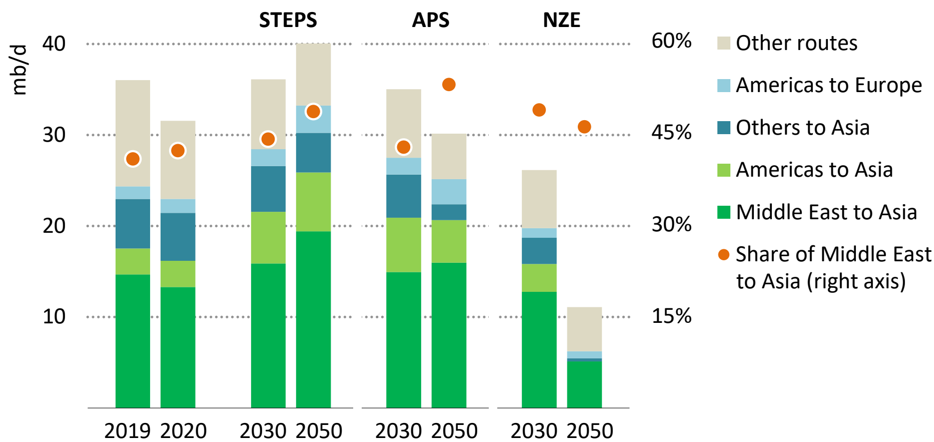
Critical minerals bring new trade patterns and geopolitical considerations into play

Notes: Calculated based on copper, nickel, lithium and cobalt trade. Positive values denote export bills and negative values denote import bills.

Source: UN (2021).

Around 760 gigawatt-hours (GWh) of global lithium-ion battery cell manufacturing capacity exists today, and some 3 600 GWh of new projects have been announced in recent years (BMI, 2021). While China has a large share of the project pipeline, a growing number of projects are also being planned in other parts of Asia, Europe and North America. These projects have the potential to help diversify supply sources and make supply chains more resilient. But there is also a risk that attempts to build domestic capability may in some cases prove to be expensive. Such attempts are most likely to be worthwhile where a country has a competitive edge of some sort or faces particular risks from disruption, but in general there is a balance to be struck between supply chain diversification and economic competitiveness. Part of the answer may lie in international collaboration, given the strong interest that many countries share in building secure and resilient global supply chains.

Figure 6.23 ▷ Seaborne crude oil trade by route and scenario



A concentration of global crude oil trade on the routes between the Middle East and Asia is set to intensify, especially in the APS

New dimensions of energy trade and geopolitics arise in clean energy transitions, but the traditional significance of trade in hydrocarbons does not vanish. As in production, oil and gas trade sees a similar concentration of flows, notably between the Middle East and Asia (Figure 6.23). In the STEPS, the share of seaborne crude oil trade from the Middle East to Asia, the current mainstay for global crude oil trade, rises from around 40% today to 48% by 2050. In the APS, relatively robust demand for hydrocarbon imports in developing economies in Asia coincides with an increased share of production among low cost producers in the Middle East: this combination pushes up the share of the Middle East-Asia route in total seaborne trade to 53% by 2050. This means that Asian importers continue to be exposed to risks arising from physical or geopolitical events in the Middle East or accidents near trade chokepoints. In the NZE, trade volumes shrink substantially with plummeting demand, but the share of trade flows between the two regions remains high, implying a continued, deep mutual dependence. Import dependency is also set to remain high for Asian importers across other fuels in all scenarios. In developing economies in Asia, as well as rising from 72% today to 80-90% by 2050 for oil under different scenarios, the level of import dependency rises from 24% to 50-55% for natural gas, and from 7% to 12-16% for coal.

Trade in oil products varies across the three scenarios, but a common denominator is increasing pressure on the global refining industry. Today's major importers, notably developing economies in Asia, continue to import significant volumes in the APS, so the volume of oil products traded internationally keeps rising despite the reduction in overall demand. Nevertheless, the decline in oil demand means that the window for new investment decisions in refining capacity, beyond those that are already approved, becomes increasingly small in this scenario. In the NZE, a broad-based plunge in demand means that export-oriented refiners face much greater challenges in finding outlets as domestic refineries seek to ensure that they meet as much of the remaining demand as they can.

A similar concentration of trade flows towards Asia is also seen for natural gas. In the STEPS, inter-regional natural gas trade rises by 40% between 2020 and 2050, reaching over 1 200 bcm, with emerging Asian markets leading growth. In the APS, there is still a rise of 20% to 2030, but this is followed by a slow decline after 2030 as growth moderates in places such as China and India, while Europe and Japan sharply reduce their imports as natural gas demand falls. In the NZE, import requirements peak before 2030 and fall below 400 bcm by 2050.

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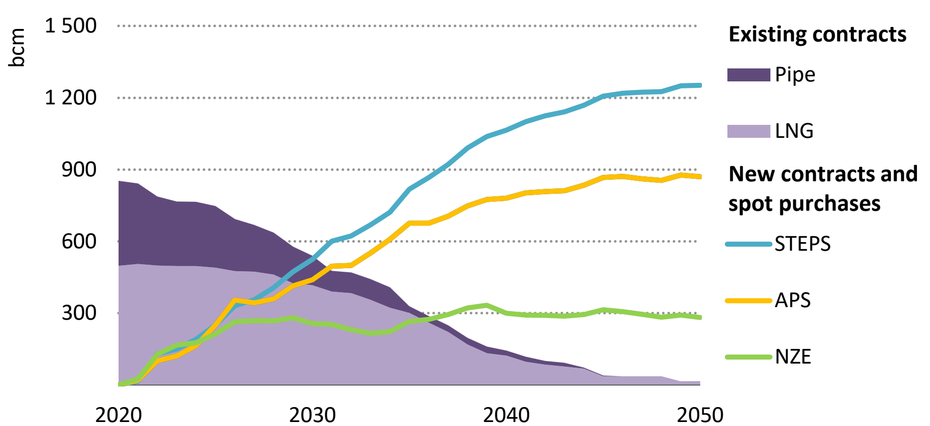
Figure 6.24 ▷ Natural gas import requirements by scenario



There is significant uncertainty about gas contracting needs for net importing regions

Note: Existing contracts includes sales and purchase agreements for projects currently under construction, which total around 150 bcm.

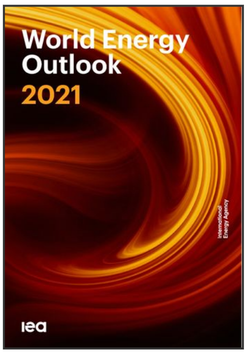
Given the wide differences in possible scenario outcomes, there is significant uncertainty about gas contracting needs for net importing regions (Figure 6.24). If no additional agreements are signed, the contract gap in the NZE would rise to 250 bcm per year by 2030, which could largely be met by renewing existing contracts, while in the STEPS this gap rises to over 500 bcm per year. These divergent trajectories illustrate the difficulties buyers have in agreeing to long-term offtake contracts, especially those that can underpin investment decisions for new projects. While contracts with minimum offtake commitments provide some measure of security of supply, there is also a risk of procuring volumes that may not be needed in future. A combination of flexible contracting and a vibrant spot market could give project sponsors confidence about finding an outlet for production. However, sufficient liquidity in the market would be required to ensure that investment decisions are made according to price signals that accurately reflect long-term supply-demand fundamentals in each region.

Europe's waning demand for natural gas in clean energy transitions has important implications for global gas trade. At present the region's large storage and import capacity helps to absorb surpluses and manage deficits of globally traded gas. In the absence of this release valve, pressure would grow on producers to provide more flexible gas supplies. There would also be pressure on importers, primarily in Asia, to develop storage or agree flexible contracts with consumers further downstream.

Conclusion

An evolving energy system calls for an evolving approach to energy security, maintaining close vigilance on the traditional risks while broadening horizons to encompass new potential hazards, based on a clear understanding about the way that security is being reshaped by clean energy transitions. Our analysis highlights the issues in play. A core concern is the possibility of investment imbalances and mismatches as the world moves forward with the transformation of the energy sector. Signals from policy makers to those making investment decisions are often not clear, or can change rapidly; the implementation of declared objectives can face delays, societal pressures can add momentum to transitions, or rule out technology options or new infrastructure in ways that slow them down; companies can misread the signals or simply shy away from investment in the face of increased uncertainty. The road to a zero-emissions system could well be a bumpy one.

As the world demands less oil, it may also see supply and trade being concentrated in a smaller number of producers who are themselves facing difficult transitions as traditional revenues decline. An electrified and renewables-rich energy system requires much more flexibility in power systems, which cannot be taken for granted, while creating new linkages with other aspects of energy supply – notably the delivery and storage of different kinds of gases. Digital technologies can help to manage the complexities of a more integrated energy system, but they also create concerns about cybersecurity. Critical minerals become a major new element in secure transitions, with demand increasing multiple times from today's levels, and many potential bottlenecks could emerge as deployment of solar, wind, batteries, electrolysers and EVs ramp up. Last, but not least, access to reliable and affordable energy, and attention to the social and economic consequences of change, are preconditions for maintaining public support for the transformation of the energy sector. The IEA, drawing on its longstanding and deep expertise in all aspects of energy security, is committed to support transitions that are secure, people-centred, affordable and rapid.



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