ENERGY TRANSITIONS TOWARDS CLEANER, MORE FLEXIBLE AND TRANSPARENT SYSTEMS

Final Report

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A report from the International Energy Agency (IEA) to the G20 Energy Transitions Working Group (ETWG)

Ministerio de Energía
Presidencia de la Nación

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Argentina's G20 Presidency 2018 asked the International Energy Agency (IEA) to analyse progress in G20 countries towards cleaner, more flexible and transparent energy systems. At the first meeting of the G20 Energy Transitions Working Group (ETWG), held in Buenos Aires on 22-23 February 2018, G20 members discussed their energy transitions and shared experiences and best practices. Sixteen countries shared their experiences through Voluntary National Self-Assessments, out of which the following G20 members, Argentina, Brazil, China, Germany, India, Indonesia, Italy, Japan, Mexico, South Korea, Turkey and United Kingdom as well as G20 invited countries Chile, the Netherlands, Singapore and Spain.These are reproduced in Annex I, and are only being shared among the G20 membership, but will not be divulged publicly.

A first draft report was presented to the G20 ETWG 1 meeting on 22 February 2018. This final report incorporates feedback received during the ETWG 1 meeting and additional written comments submitted during March and April by the G20 membership, and was presented to – and discussed at - the ETWG 2 meeting, in Bariloche, on 13-14 June 2018. The Executive Summary, containing key guidelines on energy transitions as well as suggested G20 collaborative actions, was distributed to the G20 Energy Ministers, who convened in Bariloche on 15 June 2018.

A. Executive summary[1]

Diverse energy transitions in G20 countries

G20 countries lead energy transitions globally as their governments foster sustainable economic development and a cleaner energy future. Energy transitions are driven by multiple goals, including modernising and diversifying the economy; improving energy security by reducing import dependency and securing energy access; improving air quality; and mitigating climate change.

Because the national resources of G20 economies differ, and because GDP growth, per-capita energy use and emissions vary from country to country, the energy sources and technologies on which G20 energy system transitions are based are highly diverse. The pathways chosen by individual G20 countries to transform their respective energy sectors are also reflected in the Paris Agreement's Nationally Determined Contributions (NDCs) and the 2030 United Nations (UN) Agenda for Sustainable Development and its sustainable development goals (SDGs), including those on energy.

Transitions towards cleaner energy systems

Energy efficiency has improved across G20 economies, with energy intensity 21% lower in 2015 than in 2000. Indeed, energy efficiency has become the main factor limiting CO_2 emissions growth, having a greater impact than advances in renewable energy. G20 energy intensity fell at an annual rate of 2.4% during 2010-15, but doubling the pace of energy efficiency improvements globally by 2030 (to around 2.6% per year, as set out in SDG 7 would require that coverage of sectors be vigorously expanded through efficiency policies and minimum performance standards. Anticipated growth in space heating and cooling needs, without concurrent adoption of strict energy efficiency standards, could strain electricity security. Similarly, as population growth and economic development drive transport demand, ambitious fuel economy standards for trucks could complement existing vehicle standards and cut global diesel consumption growth substantially. Because energy efficiency mitigates both demand and emissions growth, it is central to cost-effective and secure energy transitions worldwide, as IEA analysis confirms.

Several G20 economies are at the forefront of the transition to cleaner energy systems and accounted for most of the global renewable power capacity additions in 2016. Many have been leading renewable energy deployment in recent years, with wind and solar photovoltaic (PV) the fastest-growing electricity generation sources, complementing the already strong role of hydropower. This trend is supported by robust policy frameworks, technological innovation and increasing competition, which have led to major cost reductions. Over the next five years, the majority of G20 countries are expected to reach double-digit shares of variable renewable energy (VRE) in their electricity supplies, with system integration emerging as a major challenge to the further deployment of solar and wind generation. Meanwhile, heat and transport are two important end-use areas in which renewable energy sources are growing much more slowly. In 2016, only 9% of global heat demand was covered by modern renewables, while 3% of transport energy demand was met by biofuels. Although the number of electric vehicles (EVs) powered by renewable electricity is rising rapidly, they remain a small proportion of total vehicles overall.

[1] This document has been produced by IEA, at the request - and under the close guidance - of Argentina´s G20 Presidency 2018. Its contents have been discussed and enriched by the representatives of the G20 membership, but do not necessarily reflect their national or collective views.

There has been sustained strong momentum in cleaner energy investment thanks to a combination of supportive policies, increasingly competitive technologies such as wind, solar PV and LED technologies. In 2016, total investment in the electricity sector surpassed that of the oil and gas sectors for the first time. Within electricity, investment in coal-fired generation declined, while in renewables it remained flat in monetary terms but supported record capacity additions thanks to declining costs. Meanwhile, investment in energy efficiency rose 9% in 2016.

Sustainable and fair energy transitions

Today, G20 countries' energy consumption is predominantly fossil fuel-generated. Coal remains the single largest fuel in the G20 electricity mix. Despite notable increases in renewables capacity for electricity and decline in energy intensity in recent years, the overall share of oil, gas, coal and nuclear in the fast growing G20 energy supply has not varied substantially in the past 30 years. However, individual G20 countries are expecting to see a rapid decline in coal use, where energy demand stagnates and the power sector moves towards cleaner sources.

To put the world on a sustainable pathway in line with the UN Sustainable Development Agenda for 2030, current and intended actions of the world's governments are not yet sufficient to fully achieve all three goals: better air quality, improved energy access and reduced emissions – without major additional investment. The IEA Sustainable Development Scenario of the IEA *World Energy Outlook* 2017 shows that a sustainable energy future in G20 countries requires a global economy twice as efficient as today's, with three times as much renewable electricity (around 50% by 2030 and 60% by 2040), and double the share of renewables in final energy consumption by 2030. Current investments in a broader portfolio of clean power technologies remain below levels required to place the world on a sustainable development pathway in line with the UN's SDGs while maintaining supply security.

Although transitioning to sustainable energy implies an eventual decline in fossil fuel use – driven by phase-out decisions in many countries - oil, gas and coal will continue to be important in the energy mixes of many countries for years to come.

To achieve consensus for a fair and sustainable energy transition, greater attention should be paid to supporting innovation in cleaner energy technologies; supporting and retraining affected workers in new technologies and for new jobs needed, and managing associated impacts such as possible fluctuations in energy costs for end users.

Technological innovation is critical for reducing the environmental impact of fossil fuel-based generation and driving cleaner energy technology progress. Despite overall positive trends in the development of electric vehicles (EVs) and battery storage, global spending on energy research and development (R&D) has stagnated in recent years (although most preliminary data show the possibility of increases). Additional impetus is required to boost investments in large-scale hydropower, biofuels, low-carbon heat and transport, nuclear (for countries choosing this option) and carbon capture, utilisation and storage (CCUS). G20 countries have a dual role as a corrector of market failures and a shaper of market developments. Mission Innovation is a landmark intergovernmental initiative to which the majority of G20 members adhere that seeks to mobilise support for doubling clean energy research and development over five years. Technologies related to electrification of vehicles, powertrains and related products appear to be attracting the majority of private sector investments.

Developing more flexible energy systems

Energy systems across G20 countries must adapt to changing energy demand patterns, rising shares of variable renewables, new opportunities presented by EVs, and greater digitalisation of the energy sector. Safeguarding power system stability and mobilising flexibility are therefore becoming critical challenges as shares of variable renewables grow and as nuclear plants age and fossil fuel plants are retired in many G20 countries. Amid these challenges, energy security remains a priority in energy system transformation and flexibility a core requirement.

Maintaining energy security as variable renewables enter the system in greater strength will require a higher number of flexible dispatchable power plants, strengthened power grids, expanded interconnections through regional integration, increased use of demand response, and more energy storage. With cleaner power systems, opportunities abound for the greater electrification of other sectors, notably transport. Equally, a more electrified transport sector could offer flexibility options for the power system.

Regional market integration is under way in many G20 countries, impelled by the need to achieve higher economic efficiency, security of supply and cost-effective integration of renewable energy. Regional integration and collaboration is highly developed in North America, the European Union, in Asia and in Latin America and the Carribean. Defining principles of regional gas and power market integration and security include: regional planning and resource adequacy assessments; the development of interconnectors; the creation of regional institutions; and gradual market and regulatory harmonisation.

The role of natural gas for the energy transitions

Natural gas has a significant potential in the coming decades, as it can enable the power system flexibility needed for the large-scale integration of lower-emitting fuels across the energy systems – not only in power generation but in industry, heating and cooking, and transportation. The role of gas-fired power generation is expected to rise notably in countries that have decided to phase-out coal and regional collaboration and market integration becomes crucial to ensure security of supply.

Unconventional and new gas resources have been unlocked thanks to rapid technological innovation and many G20 countries have substantial reserves. The social and environmental benefits of natural gas depend upon effective regulation and high industry standards to ensure continued public acceptance of gas and to limit methane emissions.

The IEA global gas security review 2017 has shown that despite some convergence in global gas prices and flexibility with the second wave of liquefied natural gas (LNG) supplies, gas security cannot be taken for granted. Continuous investment and the development of liquid, regionally integrated gas markets with larger balancing zones and gas hubs across borders, through domestic pipelines and/or LNG, are essential to foster security of supply, economic efficiency (especially price convergence) and transparency.

Increasing transparency of energy markets and systems

Transparency is fundamental to build consensus on energy transitions among concerned stakeholders and society at large. Transparent pricing is of primary importance for consumers to understand the costs of energy and for markets and energy systems to achieve cost-effective outcomes. G20 countries have consistently demonstrated their commitment to reducing inefficient fossil fuel subsidies, making the pricing of energy more efficient and transparent. Reforms of inefficient fossil fuel subsidies can be maintained over time when they are supported by policies and efficiency measures that cushion the impact of subsidy reforms on vulnerable consumers and increase public awareness and encourage investment.

Guiding the energy transition requires consistent data across sectors: timely, robust data are needed to track and adjust policies when necessary. Data on energy consumption by end use, and on the factors that influence consumption, help countries devise energy efficiency indicators that enable them to assess the need for action and to track progress.

Well-designed and flexible policies are needed to ensure that all market participants may harness the benefits of digitalisation, including the coupling of sectors through smart charging. Although G20 countries may benefit from digitalisation to increase transparency and consumer engagement as well as data quality and availability, digitalisation also introduces privacy and cybersecurity challenges.

Opportunities for G20 collaboration on energy transitions

Argentina's G20 presidency year falls on the 10th anniversary of the Group's first Leaders' Summit in Washington in 2008. For the first time, G20 leaders will meet in Latin America, a region that may be strongly influential in building consensus on energy transitions, given its considerable oil and gas resources and a highly dynamic renewables investment landscape, turning the region into a growth region for renewable investment, thanks to its policy performance.

"Building consensus for fair and sustainable development" is the motto and top priority of the Argentine Presidency, notably in the context of energy transitions. Argentina's inclusive energy agenda builds on a broad set of existing G20 commitments, including the G20 Principles on Energy Collaboration elaborated under the Australian Presidency 2014 and the ouctomes and legacies of the 2015-2017 leaderships of Turkey, China and Germany.

Many G20 countries are engaged in presenting and sharing their energy transition experiences through such venues as the Berlin Energy Transition Dialogue and the Suzhou Forum, as well as in collaborative initiatives, such as the International Solar Alliance, the Global Geothermal Alliance, the Biofuture Platform, International Energy Agency (IEA) Technology Collaboration Programmes (TCPs), the Clean Energy Ministerial (CEM) and Mission Innovation (MI). Sharing experience means also to recognise the variety of energy transition pathways – determined by resource endowments, energy sector priorities and energy mixes – among G20 member countries.

This global momentum provides a strong foundation for future collective G20 energy transition efforts. Transitioning towards cleaner, more flexible and transparent energy systems can be an ideal opportunity for G20 collaboration, allowing each country to share its real-world experiences with energy transition challenges. The following guidelines are suggested to help collaborative efforts take these real-world challenges into consideration and to embrace the spirit of collaboration.

The G20 Hamburg Climate and Energy Action Plan for Growth invited international organisations to offer their support by providing regular update reports relating to global transformation of the energy sector and further investment needs.

As its point of departure, this section presents key G20 energy sector trends as well as current global energy investment trends (with the focus on G20 countries); it then places these trends in the context of ongoing energy transitions to 2040. It outlines progress towards meeting the UN's energy sector SDGs for 2030 and demonstrates how energy transitions in G20 countries up to 2040 can support multiple aspects of the UN sustainable development agenda to not only achieve the objectives of the Paris Agreement[2], which addresses emissions across the economy, but to attain universal energy access and cut dangerous air pollution. This would clearly have multiple benefits for economic development, human health and the environment.

- With the objective of building consensus for fair and sustainable development, G20 economies can build momentum to **engage in closer collaboration and exchange experiences on best practices in their energy transitions** with regard to energy planning, resilience and energy security, regional co-operation and market integration, the role of fossil fuels in the transition, energy efficiency indicators and renewable energy, energy market design and power system flexibility.
- To **foster investment from private and public sectors** across a broad mix of energy sources and technologies, G20 countries should support **stable and robust regulatory frameworks and transparent energy pricing structures** to facilitate private sector investment.
- To stimulate **innovative financing**, including through green bonds, the G20 collectively should aim to leverage support from Multilateral Development Banks (MDBs) and multilateral climate financing institutions to facilitate investment in key regions, including through the G20 Finance track.
- Accelerated innovation in the deployment of energy efficiency, renewable energy and a broad mix of cleaner energy technologies are necessary to foster energy transitions compatible with the objectives of the UN SDG goals. Building on the success of wind and solar PV, the G20 can bring down **technology costs by investing in the research and development of a broader range of critical clean energy technologies** and by **strengthening investment and efforts beyond the power sector.** The G20 can benefit from expanded collaboration through a variety of cooperative venues, such as CEM, MI, and TCPs, the Biofuture Platform, the International Solar Alliance, and others.
- To ensure cost-effective and secure energy transitions, G20 members aim to **accelerate the rate of energy intensity improvement**, collectively aiming to double the annual rate by 2030 by expanding sectoral coverage through minimum performance standards and related labelling programmes across industry, transport, buildings and appliances.
- To maximise benefits for air quality, energy access and climate change mitigation, G20 countries could aim to **triple the share of modern renewable electricity** and **double the share of renewable energy in total energy consumption by 2030** with accelerated deployment of renewables in **transport, heating and cooling, and industry,** which supports the greater electrification.
- Amid rising shares of variable renewable energy (VRE) and power system transformation through greater digitalisation and more decentralised energy in the medium term, the G20 should **foster collaboration on power system flexibility to put forward a G20 roadmap**, assessing contributions from flexible power grids and

[2] The Paris Agreement entered into force on 4 November 2016, thirty days after the date on which at least 55 Parties to the Convention accounting in total for at least an estimated 55 % of the total global greenhouse gas emissions have deposited their instruments of ratification, acceptance, approval or accession with the Depositary. Two G20 countries have not deposited their instruments and one member is reviewing its position.

power plants, regional integration and interconnectivity, and energy storage and demand response, as well as greater electrification and digitalisation.

- G20 countries should underline **regional collaboration as a guiding principle of energy transitions** to ensure the secure and cost-effective transformation of energy systems, based on flexible, regionally integrated and transparent energy markets and systems. **Regional network planning, including interconnectors, and market harmonisation rules** can provide an institutional framework for both government and industry collaboration. Regional market integration and power and gas market interconnections are integral to cost-effective energy transitions.

- As many countries have identified **natural gas as a flexible and cleaner fossil fuel** for energy system transitions, the G20 should emphasise continued investment in gas supply infrastructure and greater regional integration, as well as flexible and diverse LNG contract terms to strengthen gas trade, supply security and resilience to market volatility.

- To track the energy transition across sectors and the economy as a whole, the G20 should take stronger action to **close energy data gaps**, especially on energy end-use data, public/private spending on energy R&D and digitalisation of the energy sector. Digitalisation is already transforming energy systems, breaking down boundaries between energy sectors, enabling integration across technologies and improving overall flexibility.

- As **technology innovation** is vital to enable and accelerate cost-effective energy transitions, the G20 recognises the need to boost global clean energy technology transfer and RD&D efforts as they bring economic and societal benefits, such as reducing GHG emissions and local pollution that are not yet sufficiently valued by markets. The G20 should commit to increased engagement in other multilateral efforts, including through a variety of co operative venues. The G20 as a whole should build an **energy innovation agenda** as part of the collaboration on energy transitions.

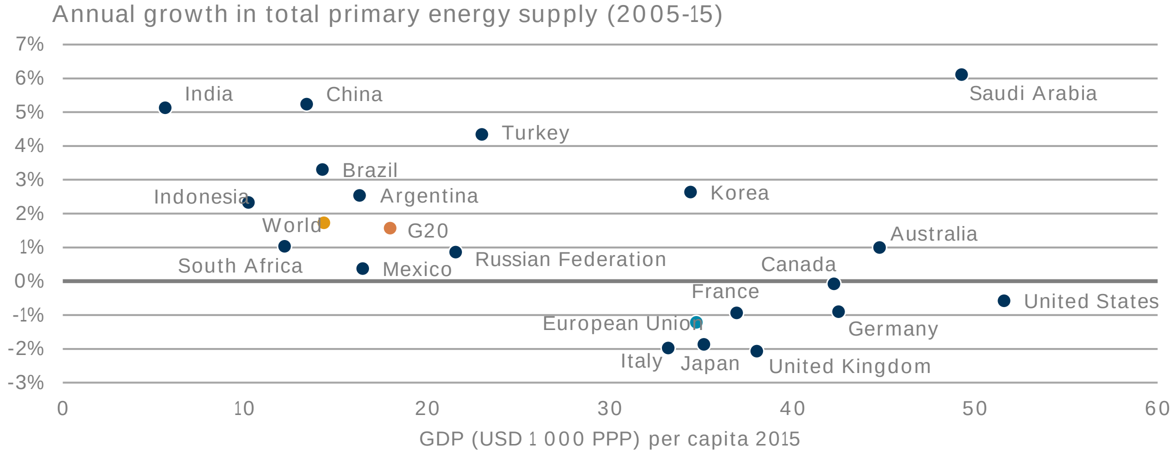
B. G20 energy transition trends

B.1. G20 energy transitions: Energy sector trends

G20 members account for 85% of the global economy, 75% of world trade and two-thirds of the global population. In 2015, G20 countries collectively accounted for 81% of energy-related CO_2 emissions and 77% of global energy consumption. Energy pathway changes in this group of countries have a significant impact global energy markets and the technologies. Annual growth in total primary energy supply (TPES) during 2005-15 (Figure 1) illustrates that gross domestic product (GDP) has been the driver for energy demand growth in half of the G20 countries in the Middle East, Asia, Latin America and the Pacific. TPES growth in EU countries, the United States and Canada has declined owing to greater energy efficiency and structural changes to their economies.

The G20 collectively relies on a high share of fossil fuels in its total energy supply. Coal remains the largest energy source for electricity generation, accounting for 44%, while oil products dominate G20 energy consumption (39%) and natural gas has grown in importance (Table 1). While coal use has declined strongly in recent years (especially in the United States and the European Union), it still fills most of the fuel needs for increased power generation in China and India, and plays a major role in South Africa and Australia. It is within this context that G20 economies have become leaders in fostering cleaner energy systems, holding 82% of global renewable power capacity in 2015. In the G20 electricity mix as a whole, however, wind and solar energy shares remain low (4% wind and 1.2% solar).

Figure 1. Growth in energy demand and income per capita



Source: Adapted from IEA (2017a), World Energy Statistics and Balances (database), www.iea.org/statistics.

Despite overall totals, individual countries within the G20 are very diverse and have differing GDPs and per-capita energy use, varied fossil fuel imports and different CO_2 emissions profiles (Figure 2).

Figure 2. G20 total primary energy demand, 2015

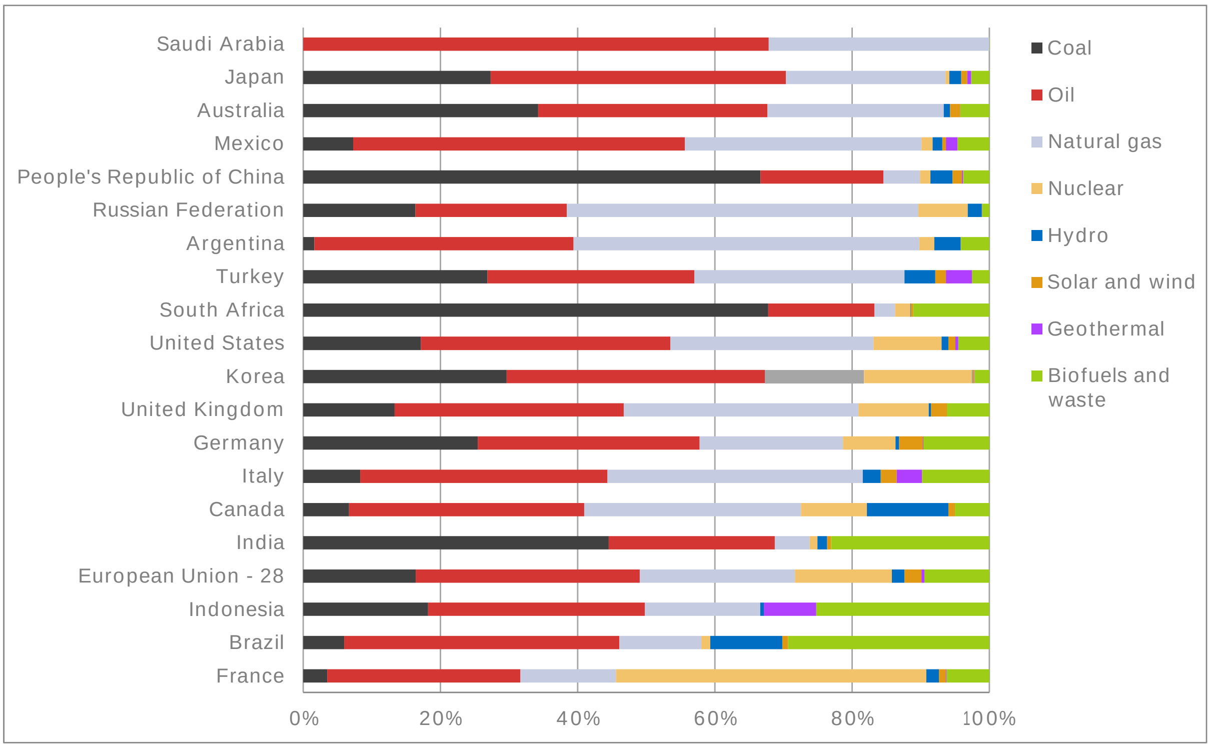


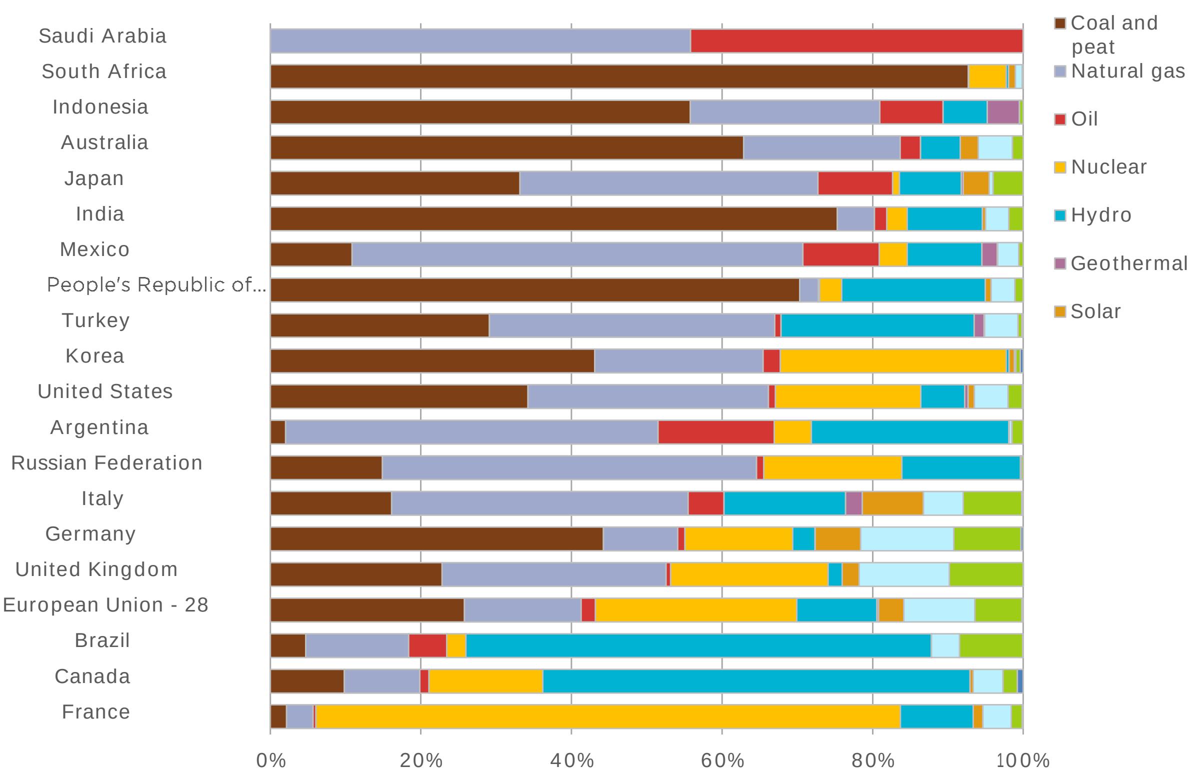
Table 1. Trends in fossil fuel shares in G20 countries

Share in fossil fuels in G20	1990	2000	2008	2015
Total Primary Energy Supply				
Natural gas	19%	20%	20%	20%
Oil in TPES	35%	35%	31%	29%
Coal in TPES	28%	27%	32%	33%
Electricity Generation				
Natural gas	14%	16%	19%	19%
Oil	10%	6%	4%	3%
Coal	41%	43%	45%	44%

Source: IEA (2017a), *World Energy Statistics and Balances (database),* www.iea.org/statistics.

The energy transitions in G20 countries therefore vary considerably, although they share some features. Many countries have outlined their energy transition plans based on international commitments, reflecting common but differentiated responsibilities and capacities. Each country's NDCs reflect its national goals, and international commitments to sustainable development are enshrined in the UN's 2030 Agenda for Sustainable Development.

Figure 3. G20 electricity generation by source, 1990-2015



Note: TWh = terawatt hour. Coal and peat includes: Coal, peat, oil shale and coal products. Oil includes: Crude, natural gas liquids, feed -stocks and oil products and other includes tide, wave and ocean, heat and other undefined sources.

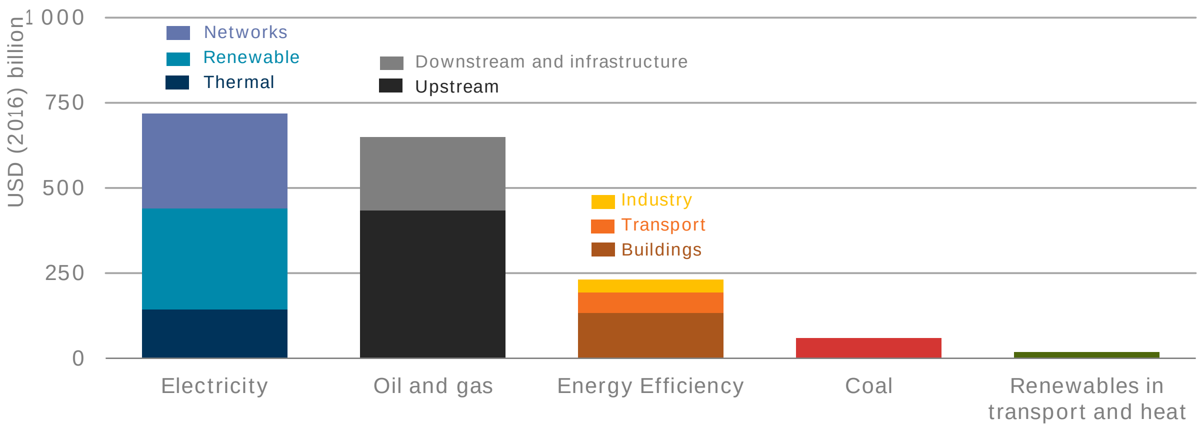
Source: IEA (2017a), *World Energy Statistics and Balances (database),* www.iea.org/statistics.

B.2. Energy sector investment trends

Investment made today will leave its mark for decades to come. Because investments in energy infrastructure have decades-long impacts on energy systems, the energy sector presents exceptional opportunities as well as challenges for investors and governments that must deliver capital at the right time and place while considering long-term consequences. It is crucial to understand the investment landscape as well as investment challenges across all energy sources to be able to craft the most appropriate policies for future investments to enable more flexible, transparent and cleaner energy systems.

Total worldwide energy investments in 2016 are estimated at just over USD 1.7 trillion[3] – 12% below the previous year in real terms.[4] For the first time, the electricity sector moved ahead of oil and gas to become the largest recipient of energy investments, based on the strength of clean power and the corresponding grids (Figure 4). Investment in clean energy sources – including renewables and other low-carbon power generation, energy efficiency and electricity networks – totalled USD 850 billion in 2016 (10% higher than in 2014) and was over half of total investment. Despite persistently low energy prices, energy efficiency was the fastest-growing sector. Supportive policies continued to encourage the purchase of energy-efficient appliances and building improvements, the primary destination of energy efficiency spending.

Figure 4. Global energy investments, 2016



Source: IEA (2017b), *World Energy Investment 2017.*

In the electricity sector, investments to expand, modernise and digitalise the grid – important for the transition to clean energy – continued to rise in 2016. Although investment in renewables dipped in 2016, partly due to lower technology costs, it remained robust owing to record solar PV deployment. Investments in fossil fuel power dropped more significantly, however, as the commissioning of new coal plants in China declined sharply. As a result, the share of power-related investments in renewables and networks increased to 80%. In the past two years, total supply-side investments in low-carbon components, including electricity networks, have grown by twelve percentage points to 43%, closing the gap with fossil fuel supply investments.

Nevertheless, trends in some clean energy sectors are less encouraging. Although commissioning of new large-scale clean power plants based on hydro and nuclear resources

[3] Unless otherwise stated, economic and investment figures are cited in real 2016 USD, converted at market exchange rates.
[4] See IEA (2017a), *World Energy Investment 2017*, for a detailed analysis of energy sector investments.

remained strong in 2016, final investment decisions for future plants fell to their lowest level in more than a decade. For CCUS, despite the largest investment to date for a plant that came online in early 2017, a lack of new projects entering construction indicates that current policies do not adequately support further investment. Finally, despite the importance of tackling emissions in transport and heating, investment in biofuels for transport and for solar thermal heating installations continued to fall in 2016.

Falling unit capital costs, especially in upstream oil and gas and in solar PV, was a key reason for lower investment, though reduced drilling and less fossil fuel-based power capacity also contributed. Despite a drop of 36% from 2014 to 2016, the oil and gas supply sector continues to claim two-fifths of global energy investment. It can therefore be concluded that the oil and gas sector is also going through a transformation. A large part of the 2016 investment decline can be explained by the industry's success in significantly reducing costs, but nevertheless, as the industry refocuses on shorter-cycle projects, it is more important than ever that policy makers monitor long-term supply adequacy.

Compared with the fossil fuel supply sector and fossil fuel power plants – for which ownership by public sector bodies, including state-owned enterprises, accounts for around half of investments – renewable power benefits from a higher share of private sector financing. In 2016, private stakeholders, including companies and households, accounted for about three-quarters of ownership in renewable power investments. Excluding hydropower projects, which tend to be much larger, private ownership in solar PV, wind and other renewable power investments was over 85% in 2016. This corresponds with estimates that 90% of global renewable energy investment in 2016 was financed by private sources (IRENA and CPI, 2018). Mobilising diverse sources of private financing will continue to be a key catalyst for attracting the investments needed for clean energy transitions, and it also responds to the G20's priority of "Infrastructure for development: Mobilising private resources to reduce the infrastructure deficit".

Global spending on energy R&D amounted to USD 65 billion in 2015. Despite growing recognition of the importance of innovation, spending on energy technology generally – and on clean energy specifically – has not risen from USD 27 billion in the past four years. While corporate spending on oil/gas R&D has declined in the past two years, spending on clean energy has risen; this rise has been offset, however, by declines in clean energy R&D spending by governments.

China remained the primary destination for energy investment in 2016, receiving 21% of the global total. With a 25% decline in commissioning of new coal-fired power plants, energy investment in China is increasingly driven by low-carbon electricity supply and networks, and by energy efficiency. Energy investment in India jumped 7% from 2015 to 2016, cementing its position as the third-largest country behind the United States in terms of energy investments, owing to a strong government push to modernise and expand India's power system and enlarge access to electricity.

The rapidly growing economies of Southeast Asia together account for over 4% of global energy investment. Despite a sharp decline in oil and gas investments, the US share of global energy investments rose to 16% (remaining higher than for Europe, where investments declined 10% from 2015), mainly owing to renewables. North America as a whole accounted for around one-fifth of global energy investment in 2016, with one-fifth of this total allotted to renewables. Latin America represented only 5% of global energy investment in 2016, but the share of investment in renewables (30%) was one of the highest of world regions.

B.3. The energy sector's role in meeting sustainable development goals for 2030

Energy is at the heart of sustainable development. Access to modern energy services – both electricity and facilities for clean cooking – is a fundamental prerequisite for social and economic development in those countries where parts of the population still lack access. And where modern energy services are in place, minimising the environmental and health impacts of energy production and transformation is a critical part of environmental sustainability. This is true on a local and regional basis, as seen in health impacts arising from air pollution, and globally, in energy sector GHG emissions and air pollution. The energy sector is the predominant source of these emissions.

The UN SDGs provide a comprehensive framework for measuring progress towards sustainable development. The 17 goals, comprising 169 specific targets, cover many aspects of social, economic and environmental development. The SDGs integrate multiple policy objectives within one framework, recognising, for example, that ending poverty requires strategies that build economic growth and address a range of social needs, and also tackle climate change and strengthen environmental protection.

While energy underpins many of the social and economic SDGs, it is fundamental for three goals particularly: SDG 7 on ensuring access to affordable, reliable, sustainable and modern energy for all by 2030; SDG 3 on health and on substantially reducing the number of deaths and illnesses from air pollution (3.9); and SDG 13 on taking urgent action to combat climate change and its impacts.

It is important to consider the energy transitions under way in G20 countries in the context of these energy-related development goals. Most countries of the world, including G20 members, outlined their plans for tackling climate change in the form of NDCs to the Paris Agreement and are working on long-term low greenhouse gas emissions development strategies. Many G20 countries also frame their climate contributions in the context of other policy goals, including ending poverty and reducing air pollution. A broader view of the development implications of the energy transition is therefore outlined in this paper.

B.3.1. Progress towards energy-related SDGs

Many countries have made significant strides in addressing the three main energy-related SDGs,[5] particularly in increasing energy access for those currently deprived of it. Overall, however, the current and intended[6] actions of the world's governments are not yet sufficient to fully achieve all three goals (IEA, 2017b).

Energy access

The number of people without electricity access worldwide fell from 1.6 billion in 2000 to 1.1 billion in 2016. This translates into a rise in global electrification from 73% to 86% of the population, thanks to record grid investment in 2016 and newer business models for decentralised energy solutions. The three G20 countries that had access rates below 95% in 2000 had all made rapid progress by 2016: in India electrification grew from 43% to 82%,

[5] The IEA has been tracking energy access for several decades and is the co-custodian of the UN data/indicators on targets for renewables (SDG 7.2) and efficiency (SDG 7.3), and for SDG 7 (as well as SDG 9.4 on emissions per unit GDP – but relates to the industry goal). The UN High-Level Political Forum on Sustainable Development is in charge of following up on the UN 2030 Agenda and SDGs.

[6] In its New Policies Scenario, the IEA projects where the global energy sector appears to be heading based on the effects of policies currently implemented and those already announced by governments. For a full explanation of this scenario, see *World Energy Outlook 2017.*

in Indonesia from 53% to 91% and in South Africa from 66% to 81%. The bulk of the remaining population without electricity access is in India (239 million) and sub-Saharan Africa (588 million). Looking ahead, India has ambitious plans to achieve complete electrification in the upcoming years, despite its growing population. Under current and planned policies, the vast majority of people remaining without electricity access by 2030 are likely to be in sub-Saharan Africa (602 million, of which only about 1 million in South Africa), as existing policy efforts in these countries are expected to be outpaced by population growth.

Global progress has been much slower on clean cooking facilities, another crucial part of access to modern energy services. Despite growing awareness of the health risks of indoor cooking with solid fuels, and after decades of effort targeting access to modern cooking, an estimated 2.8 billion people still do not have access to clean cooking facilities, almost the same number as in 2000. There has nevertheless been progress in G20 countries, for example in China, where the share of the population relying on solid fuels for cooking has dropped from 52% in 2000 to 33% today (though still totalling over 400 million people), and in Indonesia where the share relying on solid fuels has dropped from 88% to 32%. Brazil and Argentina have almost eliminated lack of access to clean cooking. Progress has been very slow in sub-Saharan Africa, where population growth has outpaced progress and 84% of the population still uses solid biomass, coal or kerosene for cooking. Looking ahead to 2030 under current and announced policies, a significant portion of the population is likely to be without access to clean cooking, including in G20 economies: more than 500 million people in China and India combined, and around 800 million in sub-Saharan Africa.

Energy-related emissions

Global growth of energy-related CO_2 emissions has slowed significantly in recent years, flatlining from 2014 through 2016. The IEA estimates that energy-related CO_2 emissions rose 1.4% in 2017 after remaining flat for three years, to reach an historic high of 32.5 gigatonnes (Gt). Clearly, the success of technological progress, policies and market dynamics supporting a switch from coal to gas in the power sectors of some countries; increased renewable power uptake; and continued energy efficiency improvements are not enough to shift emissions in the energy sector.

Although G20 countries collectively account for more than 80% of energy-related CO_2 emissions, individual countries within the group register different GDPs and energy use per capita, differing fossil fuel import levels, and distinct CO_2 emissions profiles (Figure 1). While some G20 countries have achieved flat or decreasing emissions in the recent past, others with lower GDP per capita, such as India and Indonesia, have shown increasing emissions even though their level of CO_2 emissions per capita is still below the global average. This diversity is reflected in the highly varied set of NDCs put forward by G20 countries. China appears set to achieve its headline NDC goal to peak CO_2 emissions by 2030, whereas in India, even though current and proposed policies promise to slow emissions growth, they could nonetheless double by 2040. Despite such growth, however, per-capita CO_2 emissions in India are still expected to be below the world average by 2040. Brazil's CO_2 emissions from energy are expected to increase moderately as a result of economic growth, so the achievement of its NDC will depend on continued progress in limiting emissions from the land sector and deforestation. Globally, CO_2 emissions continue to grow under current and announced policies set in the NDCs and do not peak before 2040, and therefore remain above the trajectory required by the Paris Agreement and SDG 13.

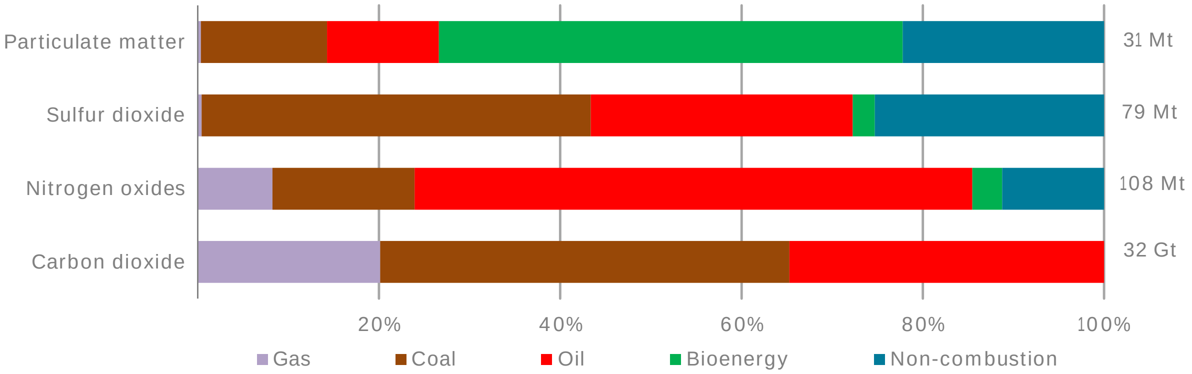
Air pollution and other greenhouse gases

Air pollution is recognised around the world as a pressing environmental and health concern. Almost 6 million people each year die prematurely from the impacts of air pollution: around 2.9 million premature deaths are linked to outdoor air pollution, and around 2.8 million to household air pollution. Household air pollution is primarily linked with the traditional use of biomass for cooking (further underlining the importance of SDG 7 on access to modern energy), while outdoor air pollution is mostly related to energy production and use. Globally, emissions of all major air pollutants have declined since 2010 despite continued GDP growth. Sulphur dioxide (SO_2) emissions have declined the most, thanks to less coal-fuelled power generation and regulations limiting the sulphur content of transport fuels. Air pollution and its effects are complex and highly localised, however, so air quality differs considerably by country. For example, air quality has improved in advanced economies owing to decades-long targeted regulations, but it nonetheless remains a serious issue in many cities. In China, air pollution has become a major social and economic concern; as a result, stringent and widespread regulations have been introduced that target the energy sector, such as measures to slow investment in new coal-fired power plants and to support the uptake of EVs. In India, air pollution regulations, including for transport vehicles, have been scaled up following recent high-profile air pollution episodes in Delhi and other cities.

Looking forward, the combined effect of existing and announced policies globally will be lower emissions of all air pollutants (including process-related emissions), despite an increase in global primary energy demand of about 30% by 2040. SO_2 emissions are projected to be 25% lower in 2040 than in 2015, nitrogen oxides (NO_x) to be 14% lower, and particulate matter 2.5 ($PM_{2.5}$) emissions to fall by 7%. But the air pollution problem remains far from being solved, particularly in many developing countries where strong energy demand growth will outpace efforts to minimise air pollution. Further, the health impacts of air pollution are complex; for example, as populations in many advanced economies age, their vulnerability to air pollution increases. The result is that despite policy measures taken, the number of premature deaths attributable to outdoor air pollution alone is projected to rise by 40% globally by 2040, to 4.2 million per year. The SDG 3.9 target therefore will not be met without significant additional action.

In terms of air pollution from natural gas, although its combustion does emit NO_X, emissions of the other major air pollutants (PM and SO_2) are negligible. The combustion of gas releases approximately 40% less CO_2 than coal combustion, and 20% less than the burning of oil. Taking into account the efficiency of transforming thermal energy into electricity, a combined-cycle gas turbine (CCGT) emits around 350 grammes of CO_2 per kilowatt hour, well under half of what a supercritical coal plant emits for the same amount of electricity.

Figure 5. Share of fossil fuels in energy-related emissions of selected pollutants, 2016



Notes: Mt = million tonnes. Non-combustion emissions are process emissions in industry and non-exhaust emissions in transport.

Source: IEA (2017c), *World Energy Outlook 2017.*

Gas-fired power plants have technical and economic characteristics that suite strategies favouring the expansion of variable renewables, but along with CO_2, methane – the primary component of natural gas and a potent GHG – is also emitted during combustion, and emissions of methane along the oil and gas value chain threaten to reduce many of the climate advantages claimed by natural gas. However, 40-50% of methane emissions from the oil and gas sector could be cancelled out using approaches that have zero or negative costs (because the captured methane can be sold). Implementing cost-effective oil and gas methane actions alone would have as much effect on average global surface temperature rise in 2100 as shutting down all China's existing coal-fired power plants.

B.3.2. Towards the integrated achievement of energy-related SDGs

What needs to be done to drive the changes needed to achieve the energy-related SDGs both in the G20 and globally? This section briefly presents a pathway towards these goals, the IEA's Sustainable Development Scenario (SDS).[7]

First, this scenario demonstrates that universal energy access can be achieved by 2030 without compromising climate change objectives. Projections show that universal energy access, when achieved partly through renewables, does not result in a net increase in global GHG emissions because slightly increased CO_2 emissions are more than offset by declines in other GHG emissions, notably methane (owing to reduced biomass combustion). Second, this scenario demonstrates that achieving climate-related objectives while improving air quality requires a different energy transition pathway than one focused solely on climate change mitigation.

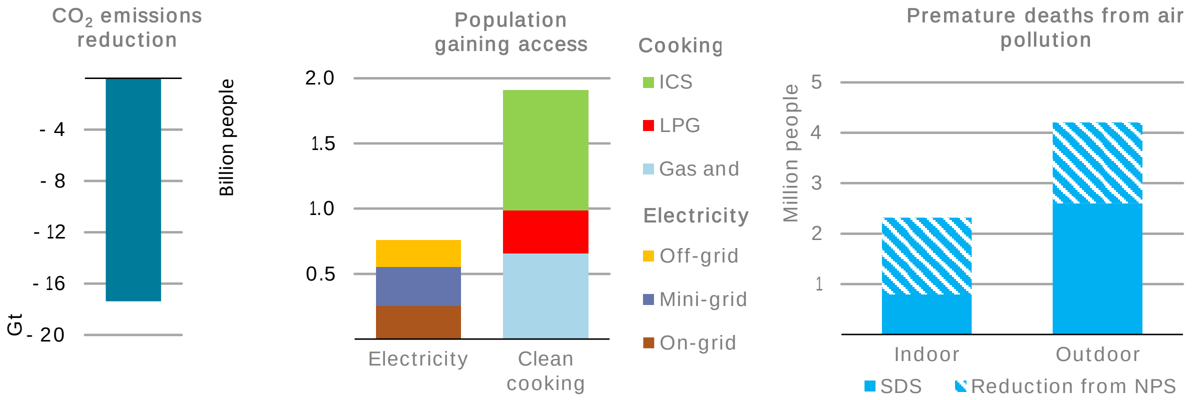
CO_2 emissions could drop by nearly half to around 18 Gt in 2040, but this would require significant improvements in energy efficiency (twice today's level across the globe) as well as greatly scaled-up renewable electricity generation (more than 3 000 gigawatts [GW] of solar PV in 2040 – 50% more than in a climate-only scenario). Such a scenario could achieve universal energy access, substantially increase the share of renewable energy in the global energy mix by 2030 (SDG 7.2) and double the global rate of energy efficiency improvement by 2030 (SDG 7.3). The share of renewables in final energy consumption in 2030 would be more than double what it was in 2016, and annual global energy intensity decline would be 2.5 times greater than between 1990 and 2010, overshooting the target. Putting the world onto such a pathway would significantly improve air quality and reduce premature pollution-related deaths. Although effects would vary across countries depending on current and planned policies, total deaths attributable to outdoor air pollution would drop from 4.2 million to 2.6 million per year.

In the SDS, coal demand peaks by 2020 – and is half what it would be in 2040 under the IEA's New Policies Scenario (NPS). By comparison, the IEA estimates that coal demand grew in 2017 after a two-year decline, and it forecasts continued demand growth for at least the next five years. In the SDS, 90% of coal decline occurs in the power sector, in which the share of coal falls to 6% in 2040 from 37% today (see Figure 7); CCUS would account for 9% of the cumulative CO_2 emissions reductions needed to 2040. In the power sector, China and the United States would become major markets for CCUS deployment, accounting for 80% of global capacity. The speed and scope of declining coal use in the major coal-consuming countries (China, India, United States) thus relies strongly on CCUS deployment

[7] For more detail, see SDS section in IEA, 2017b.

in the SDS (see section C.3.3). In the SDS, oil demand peaks soon after coal and declines to 73 million barrels per day (mb/d) in 2040. Most of the oil demand decline happens in the transport sector, with EVs making up over 40% of global car stock by 2040. The SDS assumes a 15% overall reduction in oil use in 2030, especially in transport (-20%) and power generation, compared with a pathway that maintains current policies.

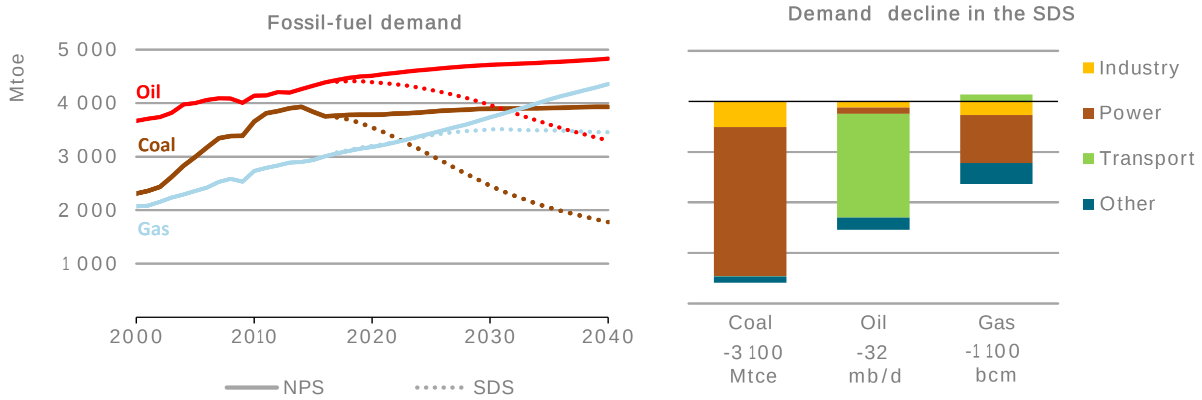
Figure 6. Outcomes of the SDS in 2040



Notes: ICS = improved cook stoves; LPG = liquefied petroleum gas.

Source: IEA (2017c), *World Energy Outlook 2017*.

Figure 7. Fossil fuel demand by scenario (left) and decline by sector in the SDS relative to the NPS, 2040 (right)



Note: Mtoe = million tonnes of oil equivalent.

Source: IEA (2017c), *World Energy Outlook 2017*.

However, the second-largest source of oil demand – non-energy use, including petrochemicals – remains stable as no changes are expected with implementation of the SDS. The transition outlined in this scenario relies on natural gas, with consumption increasing nearly 20% between 2016 and 2030, and thereafter remaining broadly flat to 2040. However, the contribution of natural gas to decarbonisation would vary across regions and sectors, and over time. In energy systems heavily reliant on coal, notably those of China and India, natural gas can play a sustained role, allowing the replacement of the most inefficient coal use, whereas in more mature gas markets its emissions reduction potential is less important than its function of providing flexibility to support the integration of variable renewables. The 'bridge' for gas is longer in areas where cost-effective renewable alternatives are less available, and in some industries and parts of the transport sector.

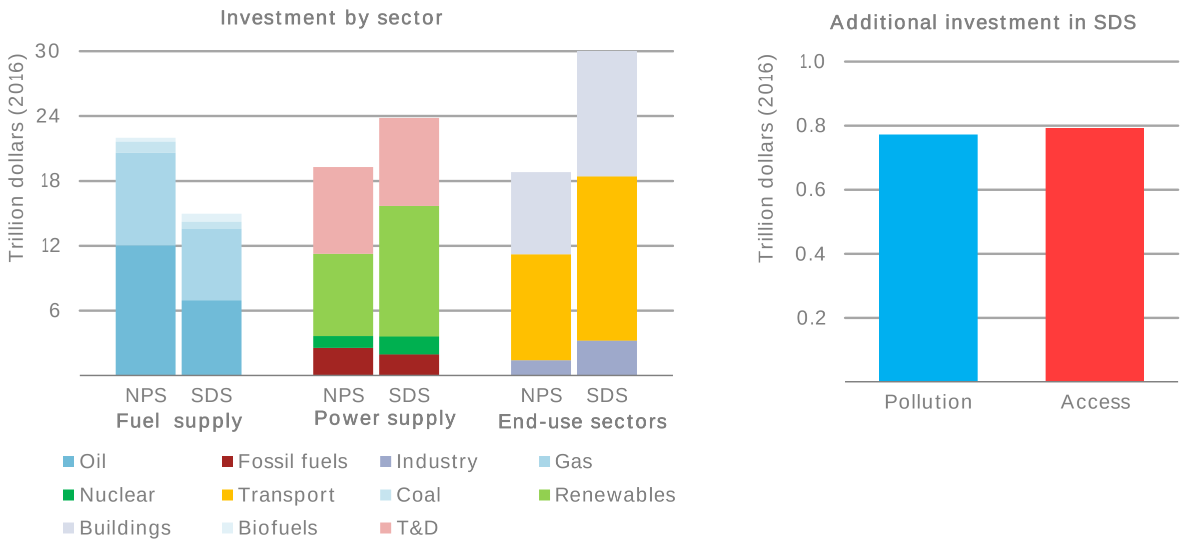
B.3.3. Investment needs for the transition to sustainable energy systems

Setting the world on the SDS pathway would require total cumulative energy sector investment of USD 69 trillion to 2040. Although this is a significant increase from current investment (USD 2.8 trillion on average per year, versus today's USD 1.7 trillion), it is only 15% higher than the significant investment needs projected under current and planned policies. The shift of investments to the demand side and to electricity would be significant.

Investments in the power sector and energy end-use sectors are much higher under the SDS than in the NPS: cumulative investments to 2040 in both renewables (USD 500 billion per year) and end uses (including efficiency, USD 1.2 trillion per year) are around 60% higher. However, investments in fossil fuel supplies would be much lower (Figure 8). The extra investments required to achieve energy access and air quality goals are minor relative to the total (around USD 0.8 trillion each to 2040). The shift to greater investment in electricity reflects its importance in powering an increasingly connected and digitalised global economy, as well as its role in reducing air pollution and in supplying energy to new consumers (supporting energy access).

The nature of financing needed for investments in sustainable energy system transitions will depend on the roles of different asset types, the policies and market designs supporting the business models of these assets, and wider financial system developments.

Figure 8. Cumulative energy sector investment needs, 2017-40



Source: IEA (2017c), *World Energy Outlook 2017.*

Investment in large-scale clean energy projects and electricity networks will continue to be crucial, and financing for these assets will depend on the balance sheets of well-capitalised energy companies, project financing from commercial lenders and the creditworthiness of utilities functioning as reliable purchasers of power. However, with the scaling up of decentralised renewable energy, energy efficiency and digital technologies, new financing approaches oriented to consumers and businesses, and based on advanced payment platforms, are likely to become more prominent.

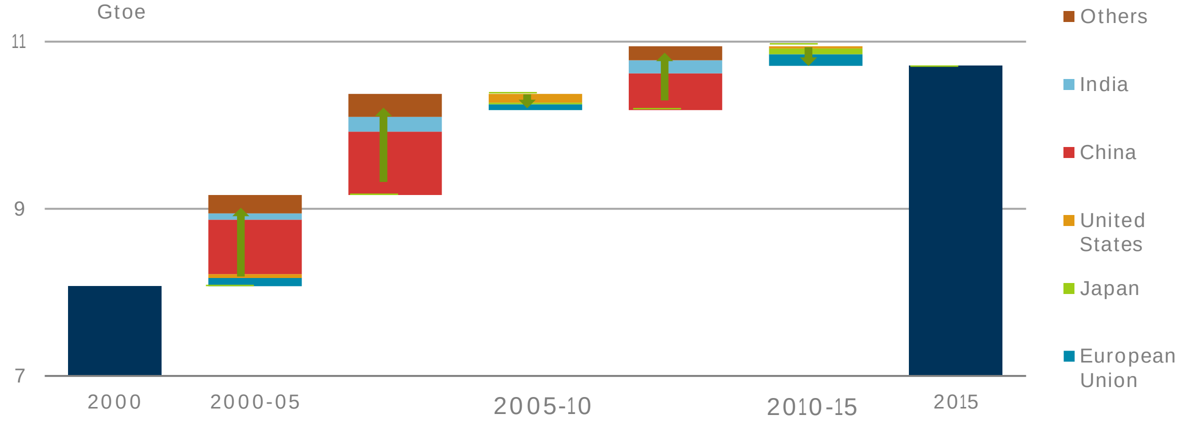
Furthermore, there is considerable potential for small-scale clean energy assets to tap into the considerable financing available from institutional investors and capital markets. Channelling these sources will depend on strong business cases for the underlying assets, and the ease with which these projects may be standardised, aggregated through bundling loans and other financial instruments, and securitised. Some initial examples are asset-backed securities for rooftop solar PV, such as SolarCity's various bonds, and green mortgages (in the United States, in 2017 Fannie Mae issued USD 27.6 billion in green mortgage-backed securities [MBS] [CBI, 2018]).

C. Cleaner energy systems across G20 countries

C.1. Status of global energy efficiency action

Demand-side trends in G20 countries significantly impact the world's energy systems and economies, and the environment. G20 energy demand has increased by one-third since 2000 and currently accounts for 80% of the world's energy consumption. Growth has been driven by China and, to a lesser extent, India and other emerging economies. Between 2005 and 2007, however, energy demand peaked in Canada, the European Union, Japan and the United States. Meanwhile, China's rate of energy demand growth fell each year between 2010 and 2015. Annual G20 energy demand growth overall has therefore slowed, from 2.6% per year between 2000 and 2005 to 1% between 2010 and 2015 (Figure 9).

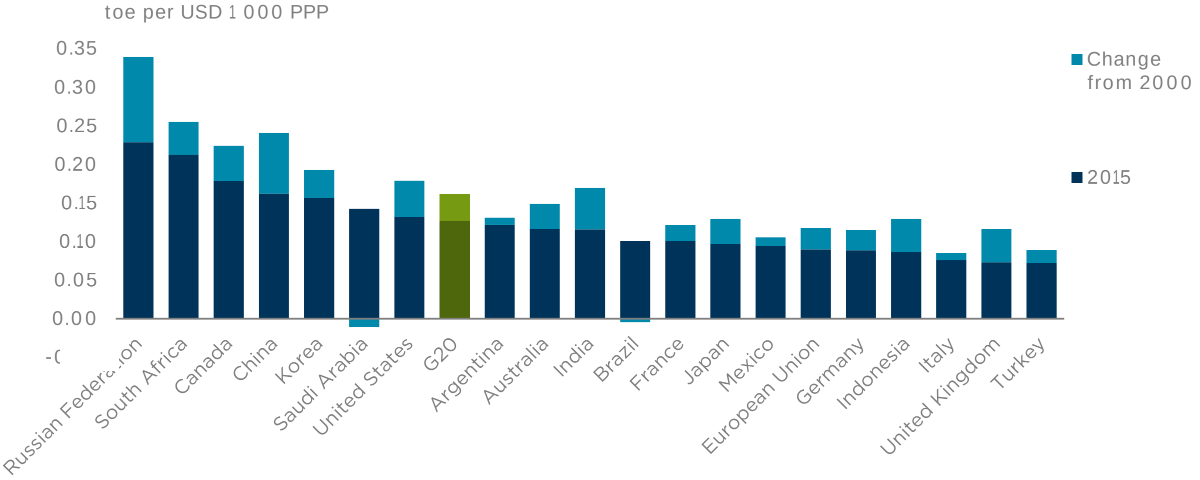
Figure 9. G20 energy demand



Note: Gtoe = gigatonnes of oil equivalent.
Source: Adapted from IEA (2017c), *World Energy Statistics and Balances* (database), www.iea.org/statistics.

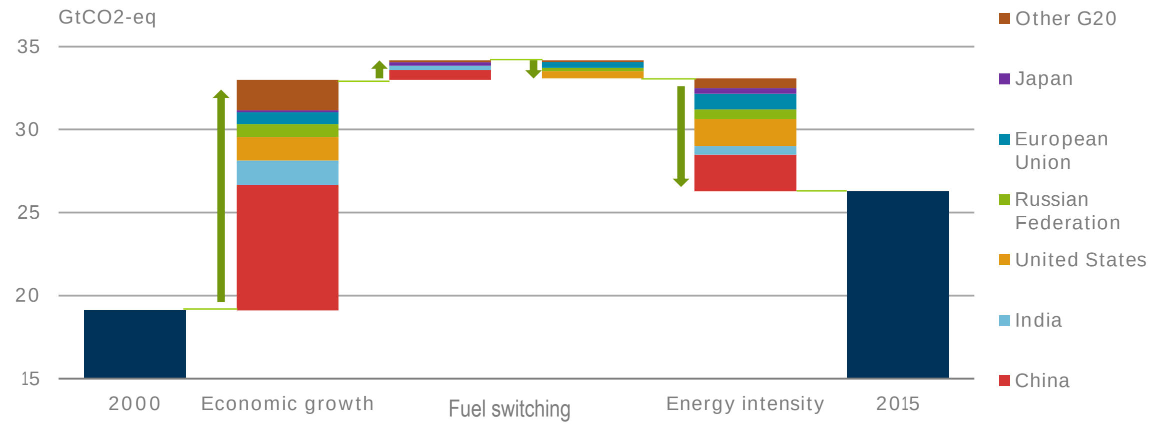
Energy intensity of almost all G20 economies has fallen since 2000. The greatest improvements have been in the Russian Federation, although it continues to have the highest intensity levels. The most significant percentage gains were made in the United Kingdom, which has the lowest intensity along with Turkey (Figure 10). Energy intensity gains made since 2010 have been strong, averaging 2.1% per year (compared with 1.3% per year over the previous three decades).

Figure 10. Primary energy intensity



Note: toe = tonne of oil equivalent.
Source: Adapted from IEA (2017c), *World Energy Statistics and Balances* (database), www.iea.org/statistics.

Figure 11. Factors influencing G20 CO_2 emissions growth



Note: $GtCO_2$-eq = gigatonne of carbon dioxide equivalent.
Sources: Adapted from IEA (2017c), *World Energy Statistics and Balances* (database), www.iea.org/statistics; IEA (2017d), *CO_2 Emissions from Fuel Combustion* (database), www.iea.org/statistics.

Falling energy intensity has also been the main factor limiting G20 CO_2 emissions growth. Since 2000, economic growth across G20 countries has applied significant upward pressure on emissions.

Changes in the supply-side energy mix have had a negligible impact in aggregate: in Asia, increases in the share of coal in the energy mix have been only partially offset by an increasing share of renewables; in other G20 countries, the increasing share of renewables has aligned with coal-to-gas switching to drive down emissions. Without energy intensity reductions in G20 countries, the increase in annual emissions since 2000 would have been double the 6 Gt per year registered (Figure 11).

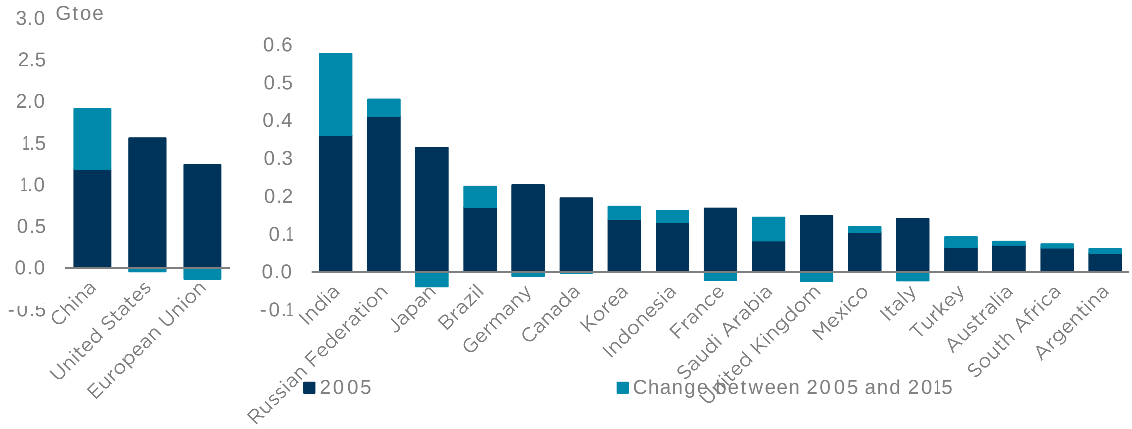
Between 2005 and 2015, total final consumption (TFC) of energy grew by 17% across G20 countries, with the largest proportionate increases in Saudi Arabia (74%), India (61%) and

China (60%). In Japan, the European Union, the United States and Canada, however, TFC was lower in 2015 than it had been in 2005, with drops of more than 10% in the European Union and Japan. In 2005, the European Union consumed more final energy than China, but by 2015 China's TFC was more than 70% higher than the European Union's.

C.1.1. Energy efficiency in key sectors

In the **residential sector** energy consumption per unit of floor area has decreased 29% in G20 countries since 2000,[8] with the largest absolute improvements in Russia. Korea's residential energy intensity has fallen the most proportionately, partly owing to the large number of newly built living accommodations; it is the only G20 country in which floor area has more than doubled since 2000, growing by 119%. In Argentina, natural gas consumption has risen considerably, outpacing the rise in floor area (Figure 13).

Figure 12. Changes in TFC since 2005

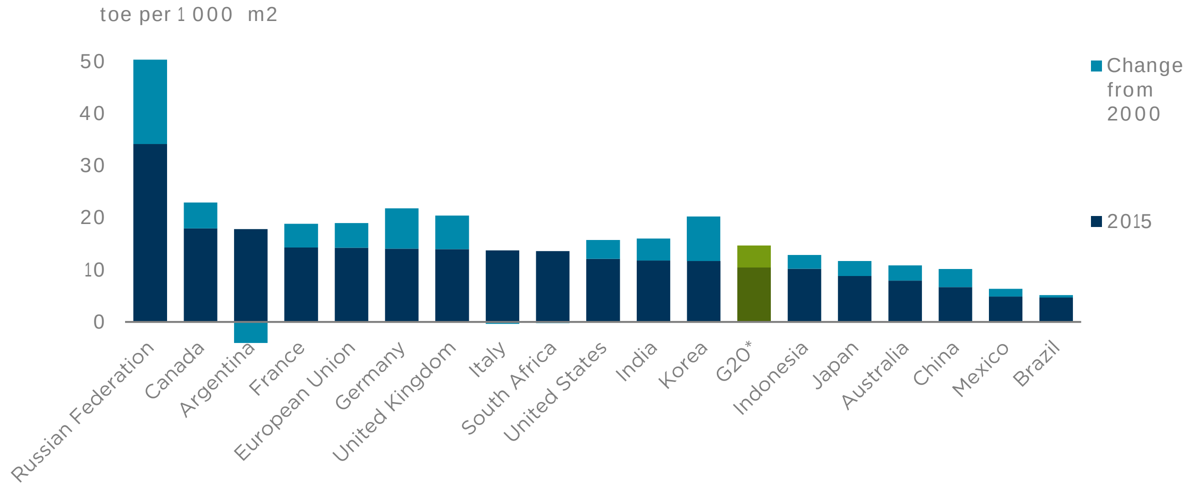


Source: Adapted from IEA (2017c), *World Energy Statistics and Balances* (database), www.iea.org/statistics.

Higher energy intensities are associated with colder climates, so it is no surprise that all the G20 countries with higher energy intensities are in non-tropical regions. Space heating remains the largest end use by far in G20 countries, but space cooling is the fastest-growing, with recent reductions in Japan and the United States more than offset by a 70% increase in cooling energy consumption in Brazil, China, India, Indonesia, Italy and Mexico since 2010. Without strong efficiency policies, space cooling will significantly raise the costs of maintaining electricity network adequacy.

[8] Based on 18 out of 20 G20 members according to data availability.

Figure 13. Residential energy consumption per unit of floor area



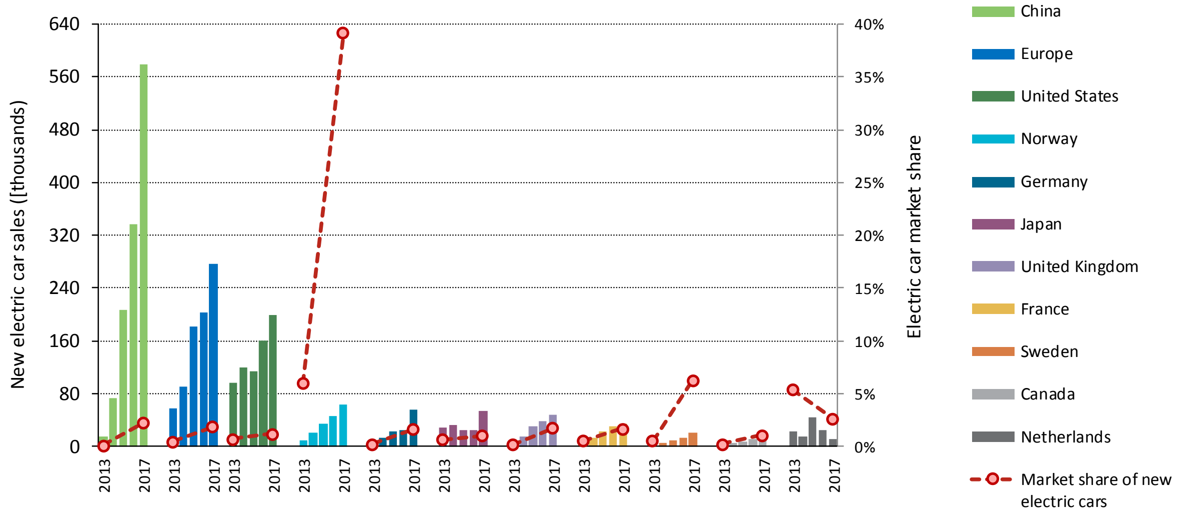
*G20: calculations based on 18 out of 20 G20 members according to data availability.

Sources: Adapted from IEA (2017e), *Energy Efficiency Indicators: Highlights* (database), www.iea.org/statistics/topics/energyefficiency/; IEA (2017f), *Energy Efficiency 2017*; and IEA (2017g) *Energy Technology Perspectives 2017*, residential model.

In **transport,** energy intensity (fuel economy) of new light-duty vehicles (cars, passenger light-duty trucks and light commercial vehicles) fell by 14% in G20 countries between 2005 and 2015, with all countries for which data are available showing an improvement (Figure 15). The greatest improvements were in Turkey, which had the second-lowest average intensity among G20 countries in 2015, at 5.5 litres of gasoline equivalent per 100 kilometres (Lge/100 km). Although Turkey does not have specific fuel economy policies, it has high fuel taxation rates and imposes an annual vehicle circulation tax that rises with engine size. The lowest average energy intensity is in France (5.2 Lge/100 km), where a 'feebate' scheme incentivises the purchase of vehicles with superior performance. The highest energy intensities are in North America, where vehicles tend to be heavier, larger and more powerful than those sold elsewhere. Both in North America and in many other G20 countries, a growing market share of sport utility vehicles (SUVs) and pick-up trucks since 2010 has slowed the rate of fuel economy improvement.

Electric cars clearly offer the best efficiency advantage over conventional internal-combustion engines (ICEs). In 2017, global sales of electric cars surpassed 1 million units (1.1 million) for the first time, accounting for 1% of the global car sales and leading to a global stock of 3 million electric cars on the road. China is leading this development, accounting for nearly half of global electric car sales. Norway has the highest stock share, with almost 40% of new sales being electric in 2017. With 3 million electric cars on the road in 2017, the penetration of electric cars is still limited to 0.3% of the global car fleet today.

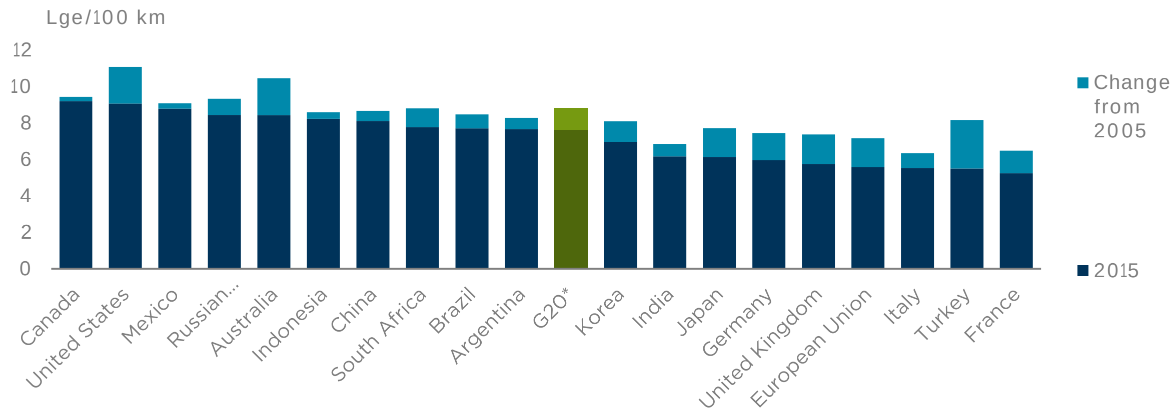
Figure 14. Global electric vehicle deployment, 2010-17



Source: IEA (2018a), *Global EV Outlook 2018*.

Despite current low penetration, a number of markets have adopted policies that clearly support rapid EV uptake, including China's new mandate for ultra-low/zero-emissions EVs that requires shares of 10% in 2019 and 12% in 2020 and imposes penalties limiting access to the market for non-compliance. Proposals by the European Commission to update fuel economy standards for passenger cars and light commercial vehicles – aiming for 30% lower CO_2 emissions in 2030 than in 2021 (EC, 2017a) – and India's aim that by 2030 "most, if not all vehicles in India [will be] power[ed] by electricity" (GOI, 2017) will also drive uptake. Announcements from France and the United Kingdom to ban ICEs in 2040 also encourage the shift towards electrification, and six G20 countries have collectively committed to the aspirational goal of a 30% market share for EVs by 2030 through the Electric Vehicle Initiative (EVI).

Figure 15. New light-duty vehicle energy intensity



*G20: calculations based on 19 out of 20 G20 members according to data availability.

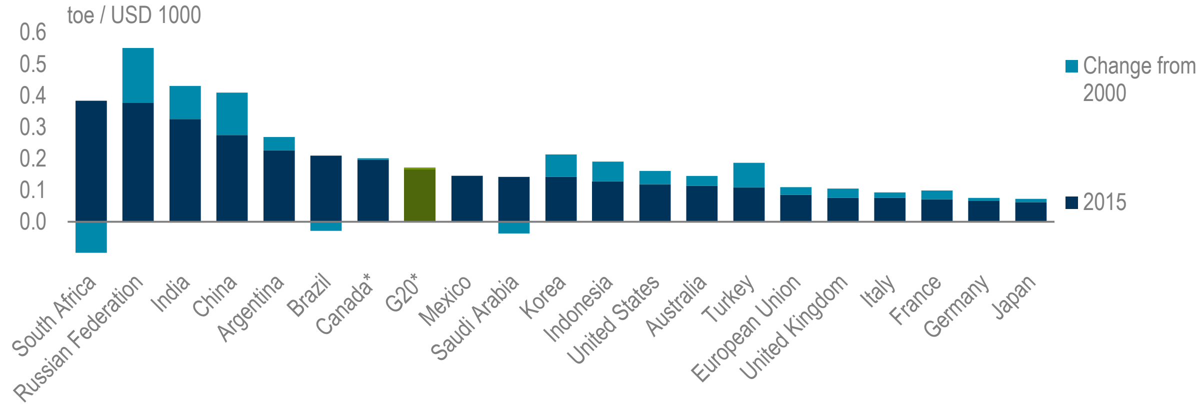
Source: IEA (2017r), "*International comparison of light-duty vehicle fuel economy: Ten years of fuel economy benchmarking*". Fuel economy is calculated using the Worldwide Harmonised Light Vehicle Test Procedure (WLTP).

Policies and standards for improving energy efficiency and reducing the emissions intensity of road freight vehicles have not yet been as widely adopted as for passenger vehicles. If all G20 countries were to adopt truck standards, global diesel consumption could be reduced by around 2.5 mb/d by 2040 (10% of fuel consumed by heavy-duty trucks globally).

Standards to improve the fuel economy of passenger vehicles cover more than 80% of passenger vehicle sales globally, while standards to improve the efficiency and emissions intensity of heavy-duty trucks are only enforced in Canada, China, India, Japan and the United States, although a regulatory framework has been proposed in the European Union. Vehicle electrification is also being developed for heavy-duty vehicles, starting with buses. Global battery-powered electric bus stock grew to about 345 000 vehicles in 2016, double what it was in 2015, with China leading globally at around 300 000 battery electric units. Electric buses are now becoming economical for trips of around 150 km per day, whereas in the case of trucks electrification for urban deliveries and other municipal services is mostly competitive with diesel, but electrification for long-haul freight is further from the market. Policy options under consideration include priority access to toll roads, the inclusion of freight in zero-emissions vehicle mandates, and funding for the demonstration of electric road systems.

Industrial energy intensity among G20 economies is influenced by numerous factors. Production activity within energy-intensive sectors such as iron and steel, aluminium, oil refining, pulp and paper, and cement significantly influence overall industrial energy intensity. Activity in these industrial sectors is driven by availability of raw materials and demand for final products, and countries that have access to lower-cost energy, particularly gas and electricity, attract more energy-intensive industries. In addition to efficiency improvements, energy intensity reductions since 2000 reflect ongoing structural changes, with more gross value added to the economy by less energy-intensive sub-sectors such as automotive, machinery, and food and beverage manufacturing (Figure 16).

Figure 16. Industry energy consumption per unit of gross value added at market exchange rates



Notes: Negative changes from 2000 indicate that industrial energy intensity has increased since 2000.

Results for Canada only show the change from 2007, due to data unavailability prior to that year. The relatively small change from 2000 for the G20 as a whole reflects a greater contribution of more energy-intensive industries to the G20 average between 2000 and 2015;

G20 calculation based on 19 out of 20 G20 members according to data availability. Industry includes Industrial Sector International Classification divisions B and C, and excludes repair and installation of machinery and equipment. Energy use associated with transformation losses and feedstocks is not included.

Sources: Adapted from IEA (2017c), *World Energy Statistics and Balances* (database), www.iea.org/statistics; World Bank (2017), *World Development Indicators 2017,* http://databank.worldbank.org/data/reports.aspx?source=world-development-indicators.

Energy management systems are an increasingly common method to improve industrial energy efficiency. Launched in 2011, the international standard for energy management, ISO 50001, is the basis for industrial energy efficiency policies and incentives in several G20 countries. Incentive schemes are very useful drivers. Germany's sizeable tax reductions for companies with ISO 50001 certification has resulted in the country holding 45% of certifications globally at the end of 2016. Early evidence suggests that, when properly implemented, energy management systems such as ISO 50001 unlock industrial energy efficiency gains that cannot be attained in a business-as-usual scenario.

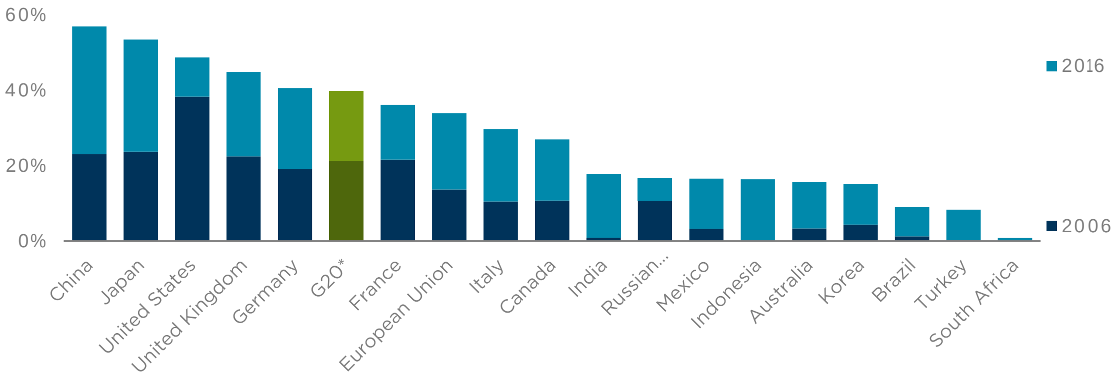
C.1.2. Policy progress

Energy efficiency progress in the G20 has been driven by a combination of policy, prices and technology. Policy has had played a particularly important role, given the market failures affecting the uptake of energy-efficient goods and services. Recognising the central role of policy, all G20 governments have set energy efficiency targets. However, the number of new policies being introduced has slowed down.

Some, such as those in the European Union and Latin America, focus on limiting overall energy consumption; others, particularly in Asia, target reducing the energy intensity of economies, with China having both energy consumption and intensity targets to 2020. In Australia and the United States, energy productivity (the mathematical inverse of energy intensity) is targeted: productivity has positive economic connotations and progress is measured by an indicator that moves upwards. Other supplementary targets are also in place in some G20 countries: Indonesia targets the rate of change of energy intensity; Mexico and the European Union countries target energy savings attributable to policy; and Japan has transactional targets related to the penetration of energy-efficient technologies. To meet these targets, many G20 governments have significantly increased policy efforts in the past decade, and collaborative efforts have been prioritised through the G20 Energy Efficiency Leading Programme, introduced during China's presidency in 2016.

Regulatory policies, such as minimum energy performance standards for appliances and equipment, building codes, corporate average fuel economy standards and mandatory industry targets have been particularly strong drivers of efficiency gains since 2008. The share of energy used by equipment covered by these policies rose from 21% in 2006 to 40% in 2016 as more policies were put in place and building, car and appliance stocks were expanded and/or replaced by equipment meeting the standards. China has the highest energy use coverage (57%), partly because of the broad scope of its industry sector targets.

Figure 17. Energy use coverage of codes and standards



Note: G20 calculation based on 18 out of 20 G20 members according to data availability.
Source: IEA (2017i), *Energy Efficiency 2017*.

Other emerging economies are making strong progress and coverage is rising quickly as the effects of recently implemented regulations permeate through the stock of equipment, but the potential for further gains is significant (Figure 17).

Along with regulatory measures, other measures aimed at transforming the market for energy efficiency have been developed in G20 countries: labelling programmes to improve information available to consumers; consumer incentives to help bring efficient technologies to the mass market; and reforms to more accurately reflect the societal costs of energy in consumer prices. Lower oil and natural gas prices since 2015 have allowed governments to reduce subsidies without raising end-user prices too sharply. For example, in 2017 Mexico began liberalising gasoline and diesel prices, Indonesia gradually reduced subsidies for electricity and in February 2017 increased electricity prices for certain residential customers, and in January 2018 Saudi Arabia almost doubled the price of gasoline as it reduced subsidies (Box 1). However, in 2018, oil and gas prices are rising again and some of the reform efforts come under pressure. Both regulatory measures and incentives can be more easily sustained and made successful in the medium to long term if they are promoted through outreach campaigns and education initiatives. Changing attitudes and preferences in favour of energy-efficient behaviours means that policy objectives can be met at lower cost to tax payers, and that regulatory measures can achieve political consensus more easily. Monitoring and evaluating behavioural interventions to understand their impacts are essential to improve policy outcomes.

Box 1. Reforming inefficient fossil fuel subsidies to prepare the ground for saving energy

Fossil fuel subsidies are prevalent around the world. The rationale for offering them has often been to achieve particular political, economic and social objectives, for example to reduce energy poverty, ensure energy access and redistribute wealth stemming from the exploitation of national resources. In practice, however, untargeted fossil fuel subsidies have rarely been an efficient or effective tool to meet these policy objectives, and in many cases they disproportionately benefit wealthier people who consume more of the subsidised product. Fossil fuel subsidies also encourage inefficient energy use and discourage investment in energy-efficient equipment and renewables. The IEA estimates that the global value of fossil fuel subsidies was USD 260 billion in 2016, of which oil and electricity each accounted for around 40% (IEA, 2017a). The value has been declining since 2012 due to lower international fuel prices and to subsidy reforms. Many governments around the world have taken advantage of lower fuel prices to reduce subsidies without raising end-user prices too steeply, thereby reducing political sensitivity and public opposition to the process.

Supporting policies and measures, especially pertaining to efficiency and renewable energy, can accompany subsidy reforms to reinforce their impact. When they raise end-user prices, subsidy reforms increase public awareness about energy efficiency, reduce payback times and encourage investment in efficiency improvements. In Indonesia, for example, the average payback period for gasoline-fuelled vehicles with better fuel economy could be reduced by up to 30% (to around two years) by the complete removal of gasoline subsidies (IEA, 2017h). Strengthening efficiency measures can also soften the impact of future demand and price increases, improving a country's energy security.

Following their 2009 commitment to "phase out and rationalise over the medium term inefficient fossil fuel subsidies that encourage wasteful consumption", in 2013 G20 members initiated voluntary peer reviews of fossil fuel subsidies. So far, China, the United States, Germany and Mexico have been peer-reviewed, with Italy and Indonesia coming next. Exchanging information on challenges and best practice for effective implementation can help G20 countries successfully pursue these reforms.

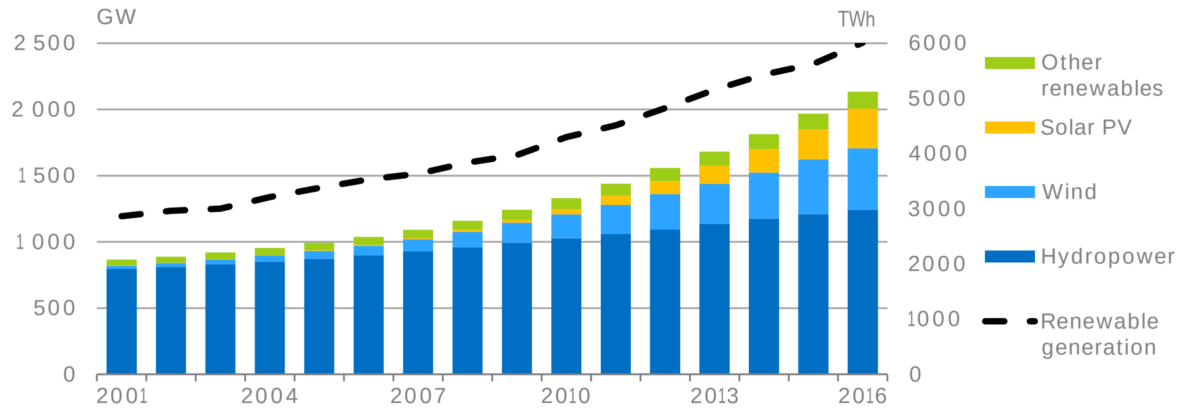
C.2. Status of global renewable energy development

C.2.1. Global renewable energy trends

Renewable energy has been growing at a rapid rate in recent years, particularly in the electricity sector, driven by policies and steadily falling technology prices. Renewable power capacity expanded almost threefold between 2001 and 2016, while generation doubled (Figure 18). In 2016, new renewable capacity additions reached a record high of 165 GW, compared with 22 GW in 2000.

While hydropower continues to provide the largest share of renewable capacity (58%, or 1 240 GW), most of the recent growth has come from wind and solar power. In fact, solar PV broke installation records with 74 GW added (50% more than in 2015), to reach a total installed capacity of nearly 300 GW. This was the first time a net capacity expansion of any single renewable technology was larger than for any other fuel, including coal (57 GW); almost half of this solar capacity was brought online by China. Thanks to economies of scale and technological innovation, the costs of solar PV and wind power have dropped significantly, so the expansion of wind power has also been rapid. However, as these technologies are variable in their operation, their integration requires energy system adjustments, which are described in more detail in section D.2.

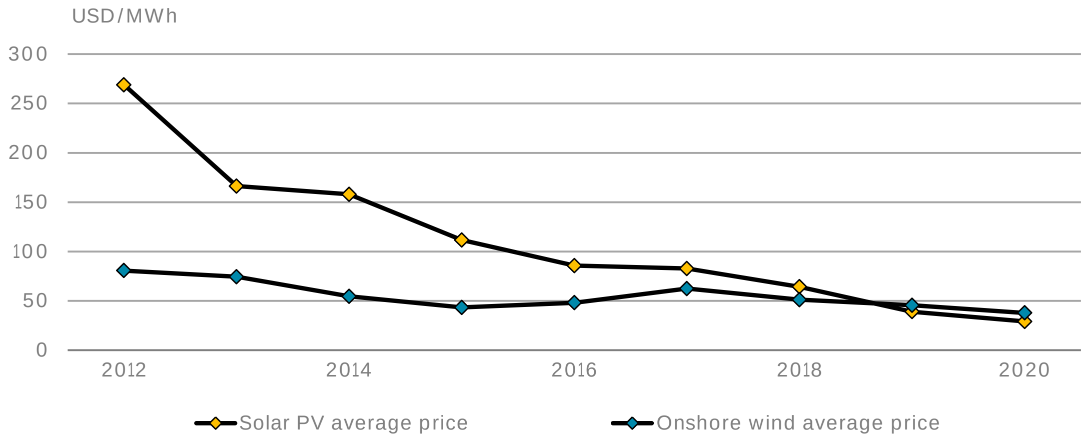
Figure 18. Global renewable electricity capacity and generation by technology, 2001-16



Source: Historical renewable capacity data for OECD countries based on IEA (2017j), *Renewables Information 2017.*

Policies – particularly feed-in tariffs (FITs) – have been important in driving renewable power deployment, economies of scale, technology innovation and cost reductions. Nearly 80% (around 130 GW) of all renewable capacity commissioned in 2016 was brought online with the support of administratively set FITs. This trend is set to shift, however, as governments increasingly adopt competitive auctions with long-term power purchase agreements.

Figure 19. Onshore wind and solar PV auction average price by project commission date



Note: MWh = megawatt hour.
Source: IEA (2017k), *Renewables 2017.*

Competition through auctions is accelerating cost reductions, particularly for solar PV (Figure 19). With electricity accounting for less than 20% of final consumption,[9] the progress of renewables in key end uses is especially important for energy system transitions. Heat for space heating, industrial processes and cooking accounted for over 50% of final energy used in 2015, with renewables supplying only 9% of heat consumed; transport (29% of TFC) had an even lower share of renewables (4%). Growth has been much slower than for electricity in both heat and transport, and policy support has been more limited than for electricity, as illustrated in the investment trends outlined in section B.1.

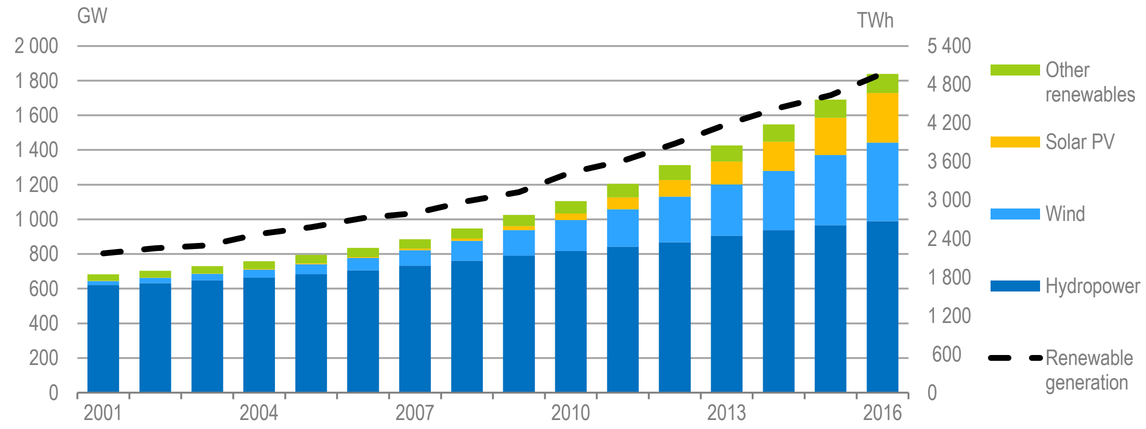
C.2.2. Renewable energy trends and outlooks in G20 countries

C.2.2.1. Renewable electricity overview

G20 countries have led the global boom in renewable electricity installations, and in 2016 they accounted for just over 80% of the world's renewable capacity and generation. During 2010-16, renewable power capacity growth was led by China, followed by the European Union, the United States and India. China alone brought over 40% of G20 renewable capacity growth online, a total of 318 GW over 2010-16. The European Union accounted for 22% (160 GW) of growth in total additions, followed by the United States (12%/86 GW) and India (5%/35 GW). Expansion was driven primarily by FITs and other forms of policy support, ambitious targets and falling technology costs. Wind expanded the most during 2010-16, adding 276 GW, followed by solar PV (247 GW) and hydropower (171 GW). Other renewable technologies together accounted for almost 40 GW (concentrated solar power [CSP], for example, which is much less developed than solar PV) (Figure 20).

[9] Excluding electricity used for heat.

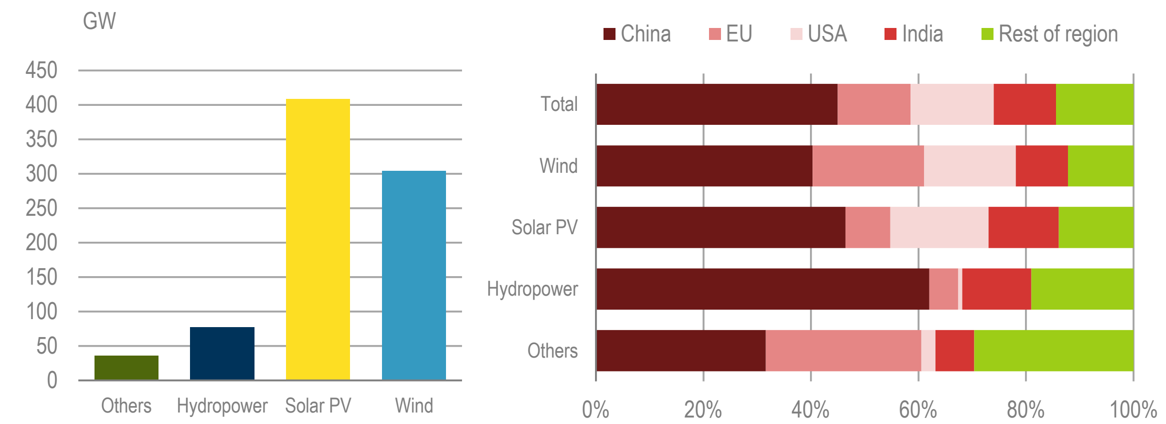
Figure 20. G20 renewable electricity capacity and generation, 2001-16



Source: Historical renewable capacity data for OECD countries based on IEA (2017j), *Renewables Information 2017*.

Looking ahead, the renewable generation capacity of G20 countries is forecast to expand by 825 GW over 2017-22, to reach 2 665 GW and account for 90% of global growth. Renewables expansion overall becomes increasingly focused on wind and solar, as they together represent 86% of G20 growth in the next five years, and for the first time, solar PV is expected to surpass wind to lead capacity growth (Figure 21). Approximately 410 GW of solar PV is expected to become operational, driven by continuous policy support and cost reductions, with growth led by China, the United States, India, the European Union, Japan and Mexico – together responsible for 90% of all G20 solar PV additions.

Figure 21. Renewables capacity growth in G20 countries, 2017-22



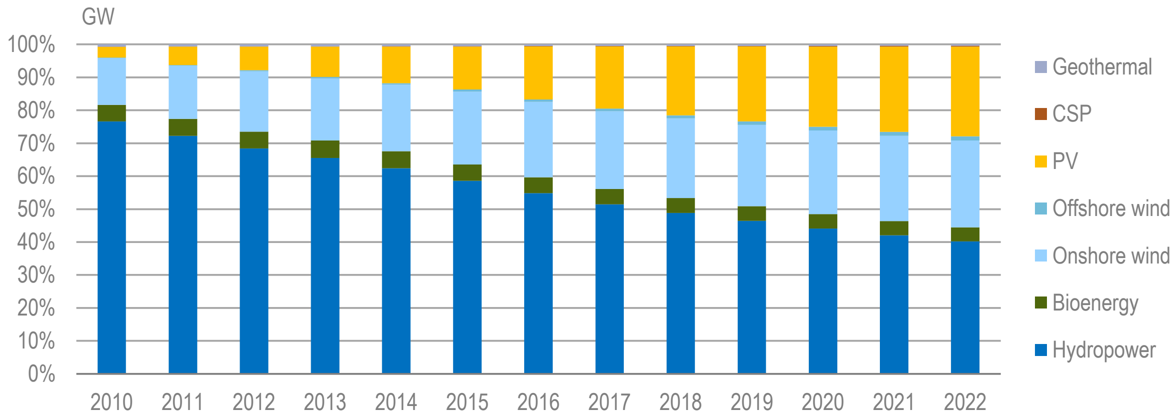
Source: Based on IEA (2017k), *Renewables 2017: Analysis and Forecasts to 2022.*

C.2.2.2. Renewable electricity outlook to 2022

Wind capacity in the G20 is poised to expand by around 300 GW over 2017-22, of which offshore projects account for only 25 GW, or 3% of all additions. China, the United States, India, Germany and France are projected to lead the expansion with 85% of G20 growth. China is expected to commission the largest volume of offshore wind capacity of a single country (+7.5 GW), but the European Union will lead cumulative growth (+16.5 GW) with additions in the United Kingdom, Germany, the Netherlands and Denmark. Although hydropower dominated G20 capacity additions in 2011-16, its growth is expected to decline

55% over 2017-22 (Figure 22). Overall, G20 countries are expected to commission two-thirds (75 GW) of global hydropower additions. China will lead this growth with more than 40 GW, followed by Brazil, India, Turkey and Canada. In China, however, large hydropower project planning has slowed due to concerns over social and environmental impacts, and to overcapacity due to a relatively lower demand outlook and grid integration challenges. Brazil is forecast to see 10 GW of additional installed hydro capacity by 2022, as the current macroeconomic environment, coupled with sluggish project implementation due to lower demand, will also challenge growth.

Figure 22. Share of renewable electricity capacity in G20 countries, 2010-22

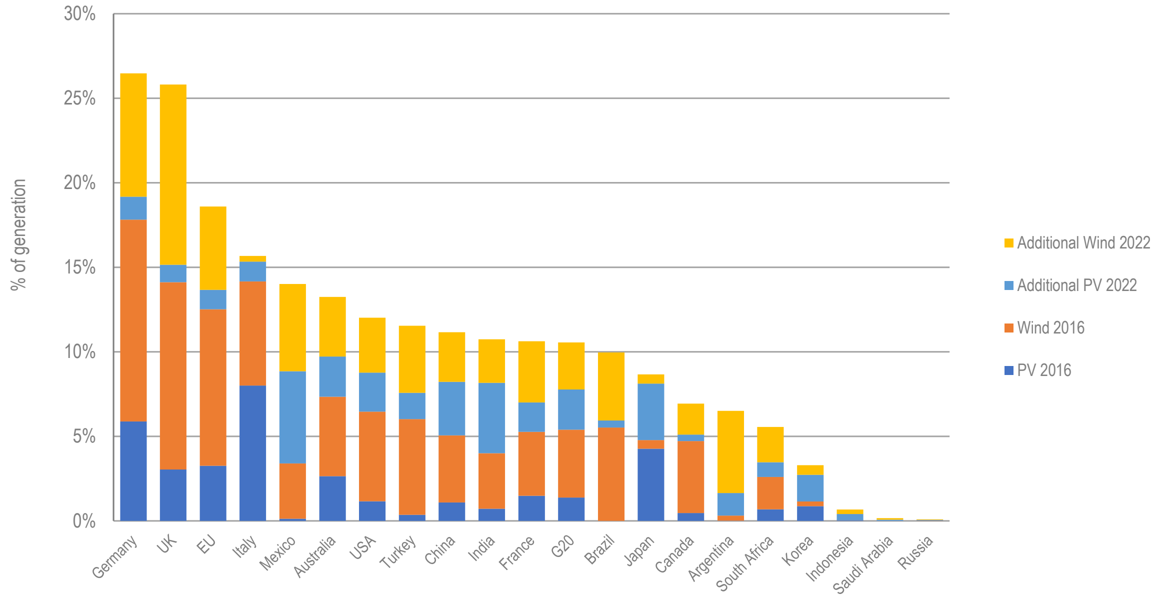


Source: Based on IEA (2017k), *Renewables 2017: Analysis and Forecasts to 2022*.

The rapidly rising contribution of wind and solar PV is driving change in power systems around the globe, due to the variable nature of these technologies. This is analysed in more detail in section D.2.

Among G20 members, Germany will have the largest share of VRE, with wind and solar PV accounting for 26.5% of total power generation in 2022 (Figure 23). VRE capacity will also increase in growing economies such as China and Mexico, with wind and solar combined accounting for 11.2% in China and 14% in Mexico by 2022. Many G20 countries are expected to reach double-digit shares in the next five years.

Figure 23. Share of VRE generation in G20 countries, 2016 and 2022



Source: Adapted from IEA (2017k), *Renewables 2017: Analysis and Forecasts to 2022.* Data reflect IEA forecasts, not political targets set by the countries.

C.2.2.3. Renewable heat

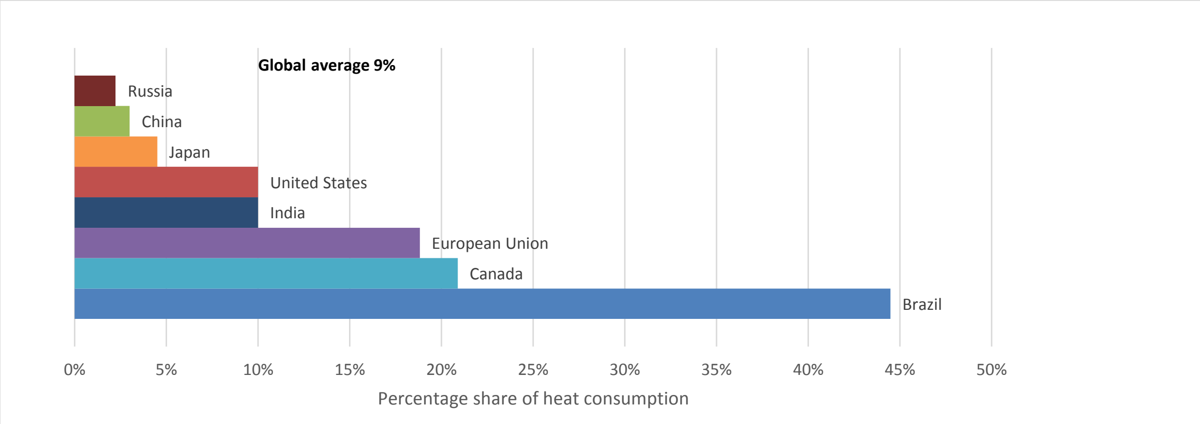
Heat, used mainly for space and water heating as well as industrial process heat, accounts for over 50% of global energy demand. G20 countries claim more than three-quarters of global heat consumption, China being the largest heat consumer overall, followed by the European Union and the United States (Figure 24).

Renewable heat supplies 9% of G20 heat demand on average, with large variations among countries. The European Union and the United States are the largest consumers of renewable heat, which meets 19% of EU and 10.5% of US heat demand. By contrast, in Russia renewable heat accounted for only 2% of the country's substantial heat consumption, and the share in Japan is also low at 4%. Renewable heat in the G20 grew 13% between 2010 and 2015, with growth the most rapid in China (renewable heat consumption more than doubled during this period, albeit from a low level). This growth was driven by ambitious solar thermal and geothermal targets in China's 12th Five-Year Plan. In the European Union, the Renewable Energy Directive (RED) has resulted in greater renewable heat deployment, supported by a range of policy measures such as installation grants, renewable heat obligations and building codes.

Bioenergy dominates heat consumption and is being used for both space heating and industrial heat. In the buildings sector, the European Union accounted for 45% of bioenergy consumption in 2015, while in industry Brazil, India and the US consumed half of global bioenergy for heat. Brazil had the highest use of bioenergy for heat in the industrial sector in 2015, with 1.4 exajoules (EJ) consumed. The principal use is in the food and drink industry, as Brazil is the world's largest sugar producer.

Solar thermal (e.g. water heating in buildings) has grown rapidly over the past decade, mainly in China, which accounted for 75% of growth in 2016. The European Union, Turkey, Brazil, India and the United States are the other main global markets for solar thermal heat. Geothermal heating is also important in several locations, with 10% average annual growth in installed capacity in the European Union over the last five years.

Figure 24. Renewable heat consumption shares in G20 countries



Renewable electricity is making an increasingly important contribution to heat consumption. Electricity accounted for 7% of heat demand in 2015, and as the share of renewables in the electricity supply rises, renewable electricity provides a greater share of heat demand (currently 2%). Furthermore, electric heating is increasingly being provided by very energy-efficient heat pumps that capture the heat in ambient air or the ground. There are no adequate global data on renewable heat produced by heat pumps, however, except in the European Union, where the contribution of heat pumps is counted under the targets of the RED.

C.2.2.4. Renewable transport

Biofuels are the principal form of renewable energy in the transport sector. In 2016, biofuels accounted for just over 96% of all renewable energy consumed in road transport, and the remainder is ascribed to EVs.[10] Biofuels met around 3% of transport energy demand, and most biofuel consumption is currently in road transport (mainly passenger light-duty vehicles). With a growing number of flights using biofuel blends (>100 000 undertaken to date), biofuels are poised to play a central role in the aviation industry's long-term decarbonisation plans. In 2017, global crop-based conventional biofuel production increased 2% year-on-year to around 2.4 mb/d (140 billion litres),[11] 94% of which was in G20 countries.

Brazil and the United States remain the two principal biofuel-producing countries by far, together accounting for around 70% of global output (by volume) last year. Other major G20 producers are Argentina, Canada, China, India and Indonesia, as well as a number of EU member states. Ensuring ongoing growth in the US ethanol industry will require the opening of new export markets, since it is anticipated that gasoline demand will stabilise and then drop with increasing vehicle efficiency. In Brazil, market prospects are poised for a boost from a new policy framework ('RenovaBio') that aims to increase the share of sustainable biofuels in the energy mix to 18% – in line with its NDC target for 2030.

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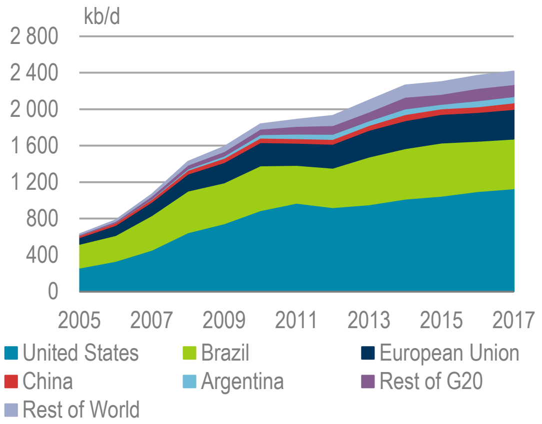
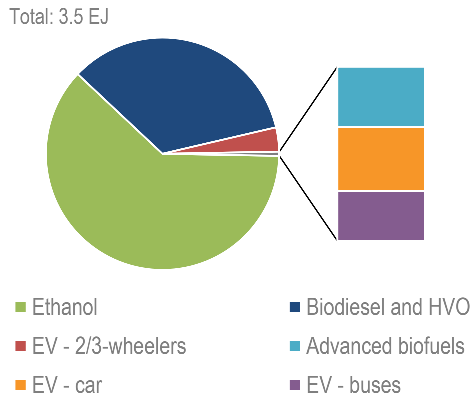
[10] The fuel economy of EVs is two to three times higher than for ICE vehicles, so in terms of service demand (e.g. per passenger kilometre), the contribution of EVs is higher.
[11] Three-quarters of which is ethanol, the remainder being biodiesel and hydrotreated vegetable oil (HVO).

Figure 25. Conventional biofuels production 2005-17 (left) and road transport renewable energy consumption in 2016 (right)





Note: kb/d = thousand barrels per day.

Most biofuel production is policy-driven, principally through mandates that stipulate low-level blending with petroleum products. Mandates have proven effective in shielding biofuels from low oil prices; however, lower petroleum product prices cause market-specific challenges, such as a less attractive investment climate and limited opportunities for discretionary blending above mandated volumes. Some jurisdictions have adopted regulations based on defined reductions in the life-cycle carbon intensity of transport fuels, for example in California and Germany, with similar approaches also under development in Canada and Brazil.

C.3. Cleaner energy technologies

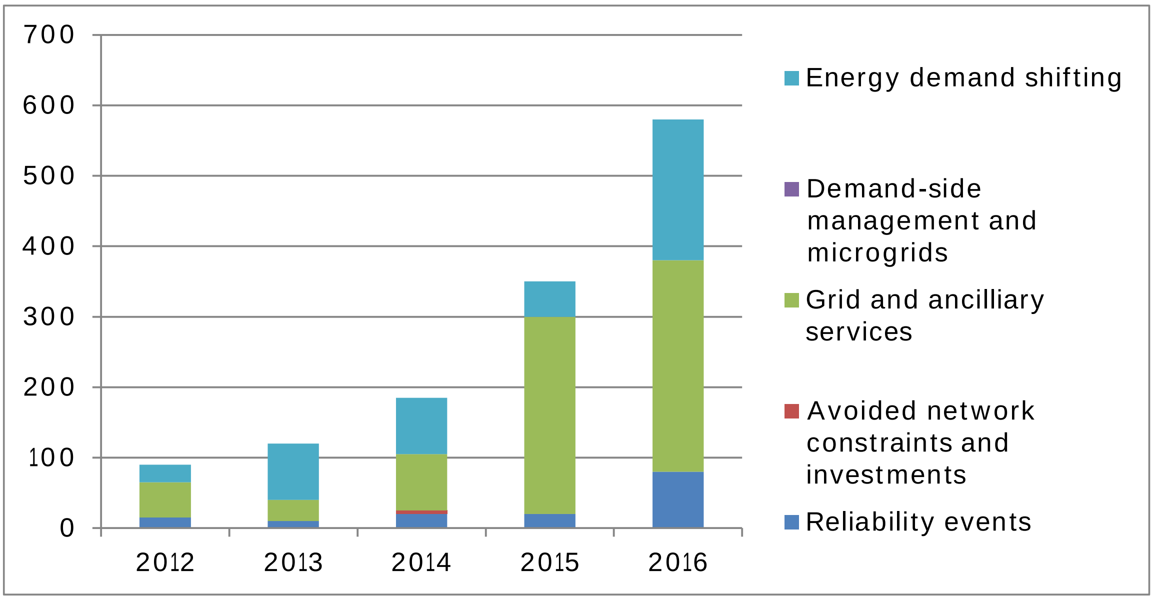
C.3.1. Energy storage

This subsection provides an update on the status of energy storage in the power sector (pumped hydro storage, thermal storage and applications) and includes deployment trends, particularly for battery storage. Potential future roles for energy storage, as well as regulatory aspects and business models, are illustrated through case studies and examples, ranging from the grid level to integrating VRE sources and deferring transmission investments, to supporting decentralised energy resources at the distribution level. The critical role of battery storage for electrifying transport and for demand response is also discussed.

As a share of power generation infrastructure, energy storage currently accounts for just below 3% of global capacity (or 160 GW) and is dominated by pumped storage hydropower (PSH). Vertically integrated, centralised utilities built most of this capacity to provide services to the system, to help manage peak demand and, especially, to allow for the continuous operation of inflexible nuclear plants. Within energy storage technologies, PSH plants still comprise the majority of planned deployments: 34 GW of pumped storage plants are expected to come online in the next ten years, with most of them concentrated in China and developing Asia. PSH deployment is, however, constrained by site availability issues.

Beyond pumped hydro, energy storage systems encompass a small but diverse and complex set of technologies, the potential role of which cannot be understood without taking a systems perspective. This set includes centralised and distributed technologies, which can store electricity, heat or chemical energy and are capable of providing a wide range of services across the energy system. Their applications (and their economic attractiveness compared with other options such as demand response, flexible generation or investment in networks) depend on how often the technologies are used (number of cycles), the volume of energy stored (storage duration), the power required and the location of the storage asset. Batteries, for instance, work better in distributed power applications in which the volume of energy stored and the number of cycles are low.

Figure 26. Use of energy storage

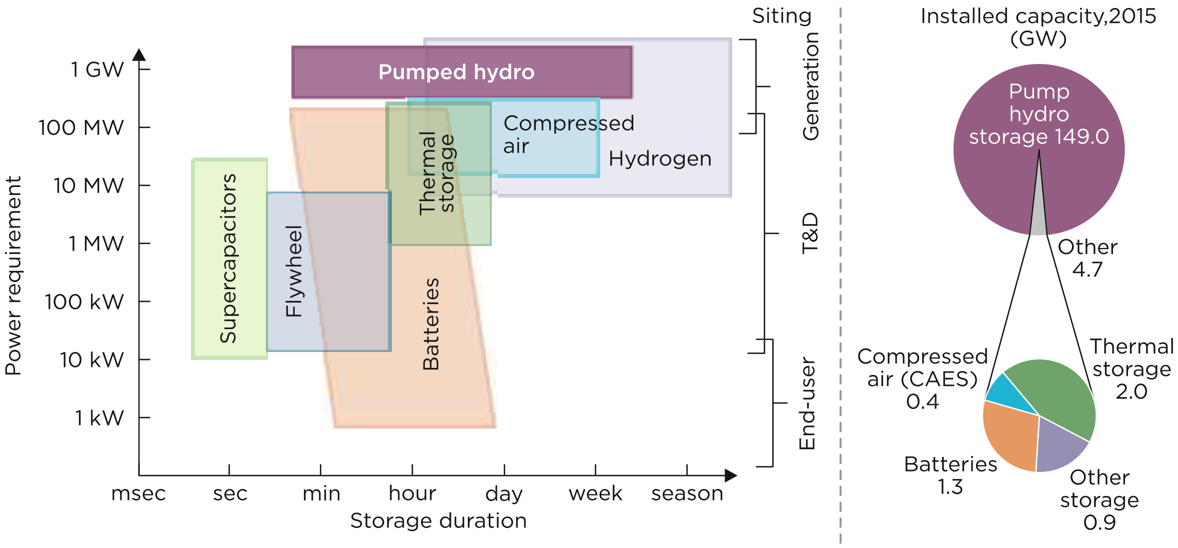


All power storage technologies beyond pumped hydro add up to just below 5 GW. Thermal storage is difficult to quantify due to its smaller scale and lack of visibility (the IEA estimated just over 2 GW at the end of 2015). Among all storage technologies, batteries are by far the fastest growing: the installed base expanded 2.5 times in less than three years, largely consisting of lithium ion batteries. Small-scale storage is also making advances in off-grid applications, owing especially to investments in 2017 to increase energy access for rural populations in Africa and South Asia.

The flexibility and modularity of storage systems can enable a wide range of services at all levels to support large-scale roll-outs of renewables: large-scale storage in transmission grids can hold surplus electricity produced when low-cost generation such as wind and solar exceeds demand, and release it to the grid when most needed; network operators can deploy storage to provide valuable system services; and small-scale storage coupled with rooftop solar PV can raise autogeneration, providing off-grid power solutions. Aggregating small-scale storage also enables system services, including firm capacity to meet peak demand.

In many of these applications, batteries stand out as an attractive storage technology to 2040 in a sustainable development scenario. Despite the costs of leading lithium-ion technology having dropped by 80% over the past eight years, further cost reductions are expected to come forward which will accelerate battery deployment. This declining cost trajectory results from consumer demand for small-scale storage systems for distributed generation in the residential and commercial sectors, as well as from off-grid applications; mostly, however, it is the result of technological advances that have come with the proliferation of EVs. Over 15 times more battery capacity is expected to be deployed for EVs than for all other applications combined.

Figure 27. Suitability of storage technologies in different applications (left), and installed capacity today (right)



Source: IEA (2017g), *Energy Technology Perspectives 2017*, www.iea.org/etp/.

Four regions – the United States, India, China and the European Union – are expected to account for nearly three-quarters of all battery storage deployment. The rate of battery cost decline is highly uncertain, but at current deployment and technical progress rates, the price of lithium-ion grid-scale batteries, designed for daily load-shifting, would be on a par with pumped hydro facilities before 2035 and with gas turbines, deployed to meet peak demand, by 2040.

As more variable renewables such as wind and solar are deployed, there will be a greater need for the grid services and storage can provide them. In these applications, however, storage will compete with other technologies such as flexible thermal generation, demand response or better grids, which, depending on the system, may be more desirable or cost-effective. As power systems decarbonise, regulatory equity for flexibility services is needed.

C.3.1.1. The need for regulatory innovation to accelerate storage uptake

Market and regulatory designs are critical to both support variable renewables and to accelerate deployment of system integration technologies such as storage. Pumped hydro plants are, for the most part, amortised assets; they mainly sell energy in wholesale markets, exploiting electricity price spreads for arbitrage opportunities. Building new storage for arbitrage is generally not attractive, particularly during a transition to higher shares of renewables, so business cases for storage rely instead on a range of revenues from different services and are complex – and are generally not viable under current market and regulatory conditions. Storage economics improve considerably, however, through 'benefits stacking' – bundling several power and energy applications together. Rewarding how fast or how often system assets respond (instead of rewarding power), or reducing regulatory barriers to allow storage to participate in ancillary services markets, could help developers monetise the value of storing electricity.

A key regulatory issue is ownership of storage. In many markets storage is considered a generation asset and system operators (transmission and distribution) are not allowed to own storage devices. This is a significant barrier for transmission and distribution deferral, which can be considered one of the highest-value applications for storage. A clear regulatory framework is therefore required to identify the services that can be provided by regulated transmission and distribution operators to avoid competition with power generators.

Although there are no market signals to support increase in storage at present, deployment in niche markets could facilitate cost reductions. In the short term, applications of storage duration of less than one hour (frequency regulation, load following), led by markets in Australia and by PJM and the California Independent System Operator Corporation (CAISO) in the United States, provide test beds for storage technologies. Together with further deployment of batteries in EVs and consumer electronics, these early applications could help drive costs down and provide new opportunities for battery storage in other markets. The long lead time required for storage technologies such as pumped hydro means that even though there are currently no investment signals for flexibility, it is critical to assess the national and regional trends of the power system in the longer term.

C.3.1.2. Thermal storage as a low-cost flexibility option

While electricity storage has received great interest, thermal storage system potential is significant in many countries. Demand-responsive distributed thermal (hot water or cooling) storage is a low-cost flexibility option for integrating variable renewables, to both reduce demand during periods of low renewables generation and to absorb surplus electricity from excess generation. In addition, more active demand-side participation could address concerns about current energy market design by dampening price volatility to make revenue streams more certain for all generators. Successful large-scale trials in Kitakyushu, Japan, the Nice Grid in southern France, and the Danish Cell Project have demonstrated the significance of the opportunity for decentralised smart demand response.

Its full potential is uncertain, however, and the market for such services is still immature. Enabling demand-side integration for smaller consumers requires communication infrastructure, market agents and new business models to aggregate large numbers of dispersed consumers. Even if data security and service quality concerns are addressed, consumers may be hesitant to adopt such technologies. As diffusion is likely to take time, demand response implementation should be assessed and initiated early to secure its contribution in the future.

The coupling of electricity with heating and cooling through larger-scale co-generation and/or district cooling and heating networks equipped with thermal energy storage is relatively simple to implement and can help considerably in managing structural VRE surpluses as well as shortfalls. When there is significant demand for cooling (air conditioning), the same principle can be applied as for heating, using cold storage and exploiting the seasonality of demand through underground or borehole thermal energy storage. Just over 100 megawatts (MW) of these systems exist around the world, half built since 2015.

C.3.1.3. Longer-duration storage – hydrogen

With higher penetrations of renewables, longer-duration storage technologies are critical to support the system during extended periods of abundant or scarce generation. In terms of R&D investment, flow batteries are the fastest-growing technology in many G20 countries. Even though they are only at the pre-commercial phase, they hold great promise for multi-hour storage. Hydrogen is also receiving increased interest, particularly in Japan, Australia and Europe (France, Germany, the Netherlands and the UK) with projects to either produce 'green' natural gas synthesised with CO_2 ('power-to-gas') or to provide an alternative transport fuel. Synthetic natural gas (SNG) can be stored inexpensively and avoids the need for hydrogen infrastructure, as it can be injected directly into gas grids.

However, costs are high, the technology is at an early stage of development with low round-trip efficiencies, and its potential depends on the availability of affordable CO_2.

Hydrogen is very energy-dense, and together with SNG may be one of few solutions for power system storage over long periods, which may be valuable in systems with a high penetration of variable renewables. However, the round-trip efficiency of hydrogen storage is still very low, costs are high and safety is an issue. There are also efforts to improve the viability of electrolysis; to assess the suitability of blending hydrogen with gas; to develop methods of using hydrogen to manufacture synthetic fuels; and to store hydrogen in the form of metal hydrides and in underground formations.

To date, hydrogen has been used in industry and refining as a by-product from industrial plants and as a product from the reforming of natural gas, liquefied petroleum gas and coal gasification. In the future, CCS and renewable electricity may be used to make hydrogen a completely CO_2-free energy source. In fuel cells, which are appreciated for their high part-load efficiency and the flexibility enabled by their modularity, hydrogen can be used in an electrochemical reaction with oxygen or another oxidising agent to convert the chemical energy from a fuel into electricity.

While some G20 members, companies and academics have implemented various projects towards realising a 'hydrogen-based society' in which hydrogen is used in daily life and in industrial activities, it will be imperative for all stakeholders to accelerate innovation in hydrogen and fuel cell technologies to advance growth.

It is indispensable to reduce hydrogen procurement and supply costs to facilitate its wider adoption. A basic approach is to combine fossil-based energy with CCS, or to procure considerable amounts of hydrogen from low-cost renewable electricity while establishing international supply chains through the development of storage and transportation infrastructure for hydrogen in one form or another (liquid, gaseous or bound to some chemical).

As variable renewable electricity (from solar and wind sources) expands globally, hydrogen remains an appealing option for its long-term storage due to its relatively high energy density. Storage batteries may play a key role in this function in the immediate future, but as renewable energy expands, large-scale and long-term power-to-gas systems using hydrogen in one or another storage form could be an option. It is also possible to produce hydrogen from dedicated assets and use it in gas turbines or fuels cells to balance power when the sun is not shining and the wind is not blowing.

Having features similar to natural gas, hydrogen power generation may become an alternative to reduce emissions in fossil fuel power generation if cost reductions can be achieved and if affordable, long-term storage options can be developed. Long-term electricity storage will be required so that large renewable energy oversupplies can be used without curtailment. To this end, hydrogen can be effective for storing energy on a large-scale, long-term basis over multiple seasons, either as a gas in salt caverns or chemically bound in other carriers such as ammonia. In this way hydrogen, along with renewable energy, is forecast to be a key contributor to electricity system emissions reductions. As with natural gas power generation, hydrogen generation is expected to provide value not only in electricity production, but as a source of flexibility and back-up capacity.

Beyond power, hydrogen is anticipated to help reduce carbon emissions from transport – from cars to large trucks and buses. Compared with lithium-ion and other storage batteries, hydrogen has more energy density per unit weight and, if sufficiently compressed or liquefied, more unit volume. For large, long-range transportation vehicles, therefore, fuel cell vehicles have comparative superiority over other zero-emission vehicles. Fuel cell efficiency and output density improvements are expected to further increase maximum driving distance and make fuel cells smaller.

Also in transport, hydrogen can be blended with gaseous fuels to reduce their carbon content, combined with other feedstocks to produce electrofuels, or used as a final energy carrier in combination with fuel cells. Using hydrogen as a feedstock in fuel production can make it possible to integrate a wider range of primary energy sources into the final energy mix. If produced from renewable electricity or fossil fuels with CCS, if combined with zero-emission feedstocks (such as nitrogen, to produce ammonia, or renewable carbon from air capture or biomass resources to produce synthetic hydrocarbons) or used directly with fuel cells, hydrogen is one of the few options that can enable zero-carbon transportation. Like the direct use of electricity in battery electric vehicles (BEVs), the direct use of hydrogen in fuel cell electric vehicles can enable zero tailpipe emissions.

Generally, it is not easy to significantly reduce CO_2 emissions from industrial processes. Resource efficiency and process integration, as well as best available technologies and shifts towards less carbon-intensive fuels can deliver CO_2 savings, but to further reduce industrial CO_2 emissions the industry sector will have to look for innovative process technologies that facilitate the integration of carbon capture for storage or use, low-carbon electricity and bio-based feedstocks. With the provision of cost-competitive renewable electricity, the use of electrolytic hydrogen could offer new options in this area, especially as a feedstock for the chemical production of ammonia or methanol, and as a reducing agent for steel production (provided adequate new production processes are demonstrated).

Fuel cells are one of the most important technologies for using hydrogen, as they use electrochemical reactions to generate electricity and heat, and they are small and have high power generation efficiency. Small, dispersed power systems that use fuel cells have greater power generation efficiency than large, fossil fuel power plants, and they do not require large-scale investment (if the simultaneous use of hydrogen in transport and industry brings down the cost of hydrogen transport and distribution infrastructure). Depending on the future investment environment for large-scale power sources, fuel cells may very well diffuse as dispersed power systems.

C.3.2. Nuclear energy

C.3.2.1. G20 status and recent trends

Nuclear power accounts for around 12% of total electricity generation in G20 countries. Of the 446 nuclear reactors operating worldwide, 89% are in G20 countries and represent 386.1 GW of installed capacity (94% of global capacity), illustrating the crucial role the G20 plays in nuclear energy development. All but five G20 countries have operating nuclear reactors; the United States has the largest capacity, followed by France and Japan. Of the five countries, one (Turkey) is in the advanced stages of beginning a nuclear programme and another (Saudi Arabia) is considering developing nuclear energy in the future.

China, with the fourth-largest nuclear energy capacity, has the most reactors under construction (18) and is expected to overtake Japan’s capacity by 2018 and France’s during 2022-25. Russia follows with seven reactors under construction, and India with six. Of the 59 reactors under construction globally, 47 are in G20 countries.

Recent global nuclear power developments have fluctuated widely: the highest capacity additions since 1990 were registered in 2016 (10 GW gross). In 2017, only 3.6 GW came online (3.3 GW in the G20) and new construction remained low at only 3.7 GW (2.5 GW in G20), down from a ten-year average of 8.5 GW. For the first time, in 2017 there were more reactors under permanent shutdown (seven) than there were connections to the grid (four), and capacity removed from the grid (5.5 GW globally) exceeded capacity additions.

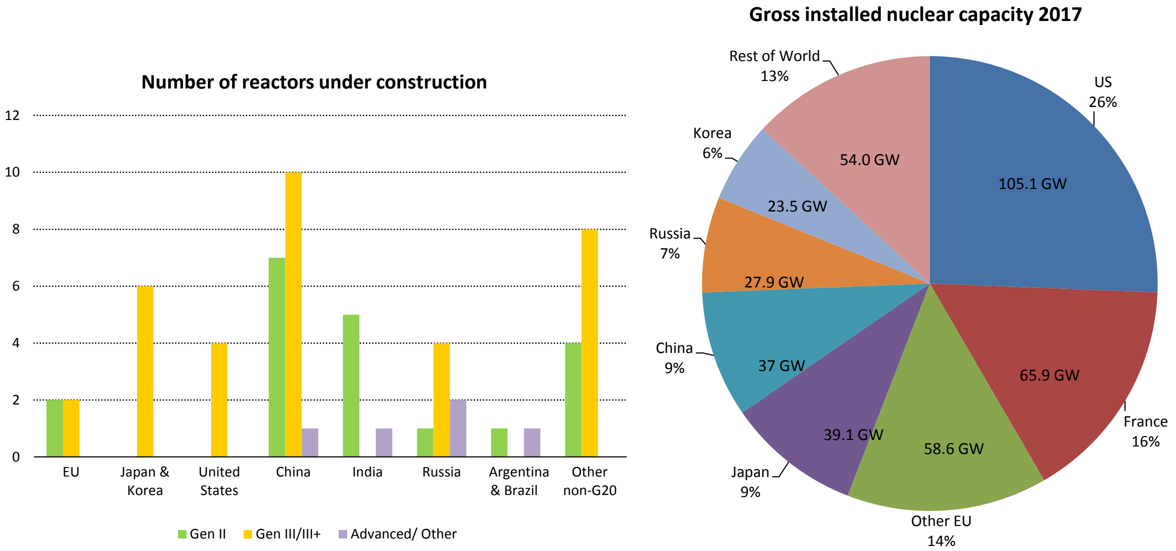
Premature closures of operational nuclear power plants for economic reasons, and the cost and timing of lifetime extensions of ageing fleets in some countries, are major challenges affecting the future of nuclear energy and requiring timely joint industry and government action. Several reactor operators in the United States have identified uncompetitive plants in markets dominated by record-low natural gas prices and growing renewable generation.

C.3.2.2. Outlook for nuclear energy and nuclear technology in the G20

A number of G20 countries, including China, India, the United States and Russia, have identified nuclear power as a key part of their energy transitions, and of the ten countries that explicitly included nuclear in their national strategies under the NDCs, five are G20 countries (Argentina, China, India, Japan and Turkey). Projected nuclear growth remains strongest in Asia, as China's 13th Five-Year Plan envisions doubling its 2015 capacity to 58 GW (net) by 2020. In China, a total of 33.4 GW (net) were in operation at the end of 2017 and 19.9 GW (net) under construction. Korea also projected considerable growth – from 23 GW in 2017 to 38 GW by 2029 – but the new government no longer supports additional construction beyond the four units already being built. Russia reduced its nuclear energy intentions in 2016, citing alignment with projections of reduced electricity demand as the reason. In the United Kingdom, final approvals were given for the Hinkley Point C Contract for Difference following a government review of the entire project, and EDF Energy made the final investment decision in July 2016. South Africa has deferred its nuclear programme (of up to 9.6 GW of new capacity) to the 2030s due to the country's financial situation, but it actively supports additional nuclear capacity.

In terms of technology, most reactors under construction today are Generation III/III+ designs. The first – APR1400 (Shin Kori 3 in Korea) and VVER1200 (Novovoronezh 2 in Russia) – were connected to the grid in 2016. Efforts to develop and deploy small modular reactor (SMR) designs continue, with Argentina's 25-megawatt electrical (MW_e) CAREM reactor under construction and Russia and China constructing floating nuclear power plants. In the United States, NuScale Power submitted the first-ever design certification application for an SMR to the US Nuclear Regulatory Commission. Canada received an overwhelming response to a Request for Expressions of Interest to construct an SMR at the Chalk River site.

Figure 28. Gross installed nuclear capacity, 2017 (left) and nuclear reactors under construction (right)



Source: OECD Nuclear Energy Agency (NEA), 2017.

Deploying additional nuclear capacity would capitalise on its recognised potential to contribute significantly to global decarbonisation. Recent experience shows consistent policy support for existing and new capacity is a success factor, including permitting and financial support such as long-term commitments from industrial users, clean-energy incentive schemes or tax incentives. Investment risks due to uncertainties must be reduced, for example through licensing and siting processes that have clear requirements and that do not demand significant capital expenditure prior to final approvals or decisions. The nuclear industry must do everything possible to reduce construction and financing costs to maintain economic competitiveness.

C.3.3. Carbon capture, utilisation and storage (CCUS)

CCUS can contribute to energy transitions around the globe when used to reduce emissions from industrial processes as well as from the numerous and relatively young coal- and gas-fired power generation units around the globe. CCUS technologies, including in combination with bioenergy, also provide the means to deliver ‘negative emissions’ to offset emissions from sectors in which direct abatement is not economically or technically feasible. These negative emissions are likely to be critical to meet the Paris Agreement goals of limiting temperature rise to “well below 2°C” and achieving net-zero emissions in the second half of the century.

The G20 Hamburg Climate and Energy Action Plan for Growth encouraged countries that opt for CCUS to continue undertaking R&D and to collaborate on large-scale demonstration projects.

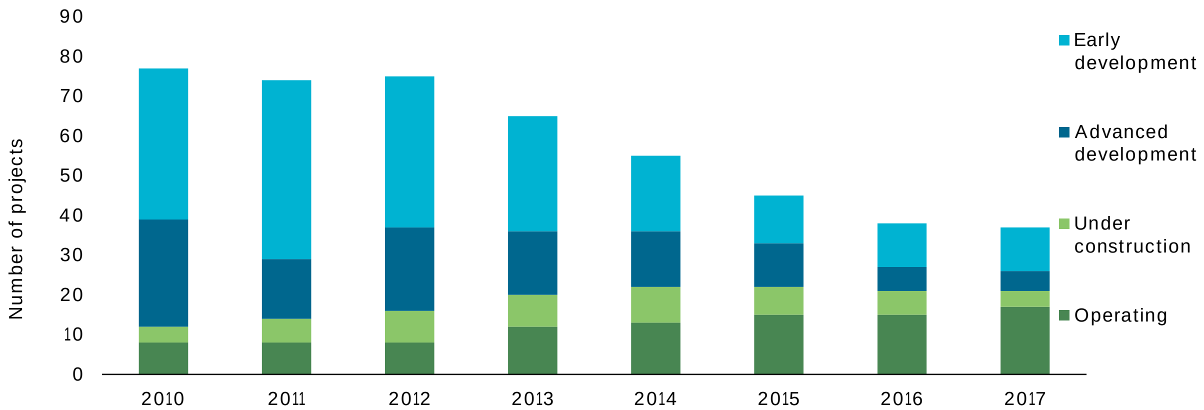
CCUS technologies are not new or untested. CO_2 capture and separation has been applied in industry for many decades, and the practice of injecting CO_2 for enhanced oil recovery (CO_2-EOR) first began in the 1970s. Today there are 21 large-scale, integrated projects operating or under construction throughout the world and across various applications, including coal-fired power generation, natural gas processing, steel manufacturing and oil sands upgrading (18 of these projects are in G20 countries). In addition to these large-scale projects, there are approximately 100 pilot plants around the globe and the impetus for R&D

is strong. This collective experience has brought CCUS to the stage at which the barriers to deployment are no longer technological but political and commercial.

While CCUS project deployment has made very encouraging progress in recent years, maintaining momentum is not assured (Figure 29). The total number of large-scale CCUS projects operating, under construction or in development has shrunk from a peak of 77 in 2010 to 37 today (GCCSI, 2018). There are now fewer projects in development than under construction and operational, and the future of several of these earlier-stage projects is uncertain without policy support. Since 2014, only one CCUS project in the world has taken a final investment decision: the Yanchang Integrated CCS project in China.

CCUS facilities accounted for around 0.1% of the USD 850 billion invested in low-carbon energy globally in 2016. To date, an estimated USD 10 billion in capital investments12 have been made in the large-scale CCUS projects operating or under construction globally. Around 80% of this investment is private capital, but public funds have been increasingly important in leveraging this investment in recent years (IEA, 2017l).

Figure 29. Decline in large-scale CCUS projects



Sources: IEA (2017l), "Five keys to unlock CCS investment"; data from GCCSI (2010-16), *Global Status of CCS (2010-2016)*.

The availability of a revenue stream from CO2-EOR has supported investment decisions in three-quarters of CCUS projects to date, the vast majority located in North America with strong commercial interest in the Middle East and China. For some early projects, the revenue from CO2-EOR was sufficient for commercial CCUS operation, but more recently EOR revenue, combined with capital grants, has helped to close the commercial gap and support investment in CCUS applied to coal-fired power generation. For example, the Petra Nova CCS project received USD 190 million in grant funding from the US Department of Energy and is now reportedly operating on commercial terms based on the additional oil revenue (Crooks, 2017). The US Budget Bill 2018 provides for the FUTURE Act, which extends the US tax credit for CCS and CCUS, allowing higher tax credits to EOR and storage. Beyond CO2-EOR, the conversion of CO2 into valuable and usable commercial products could create new revenue opportunities for CCUS facilities. Global demand for CO2 is around 200 Mt per year for such uses as urea production, carbonated drink manufacturing,

[12] This figure is an estimate due to incomplete or unavailable data for some operating CCUS projects. It does not include investments in large-scale projects that did not proceed to operation; it covers capital investments and excludes operational costs.

water treatment and pharmaceutical processes (IEA, 2017g). New or growth markets could include use of CO2 as a feedstock or as a working fluid in some processes (including in power generation), conversion to polymers or carbonates, concrete curing and mineral carbonation. Research is being conducted on the potential to turn CO2 into a transport fuel, but key questions are its potential for scalability and whether the CO2 will ultimately be re-released.
Several G20 and EU countries renewed their international commitment to CCUS deployment13 and recognised five key ways to unlock public and private investment: 1) focus on easily achievable targets first to build CCUS deployment experience; 2) tailor policies to guide CCUS through the early deployment phase; 3) target multiple pathways to reduce costs from technological innovation to progressive financing arrangements; 4) build CO2 networks and accelerate CO2 storage assessments in key regions; and 5) strengthen partnerships and co-operation between industry and governments, including through G20 initiatives, the CEM and Mission Innovation.

C.3.4. Investment in energy technology research, development and demonstration

Energy research, development and demonstration (RD&D) has been essential in providing today's technology options, especially in renewables and nuclear, and its importance will increase as societies strive to achieve affordable, secure and sustainable energy systems into the future. Global investment in clean energy RD&D is estimated to be at least USD 26 billion, but it is not yet rising enough to be on track for a sustainable energy transition. Despite favourable progress in wind and solar energy, energy storage and electric cars, broad-based energy innovation must be part of the energy transition. Innovation potential is high for heavy-duty transport, industrial energy use and seasonal electricity storage.

Reported RD&D spending on clean energy by IEA member governments doubled between 2000 and 2010 to around USD 15 billion (IEA, 2016a) – around 0.15% of their total budget expenses. This growth represents a fourfold increase if nuclear is excluded. Aggregated data from Mission Innovation submissions and national budgets and reports, shows that clean energy RD&D expenditure by non-IEA G20 economies[14] was around USD 4.5 billion in 2015, putting G20 public funding at USD 19 billion. This includes spending by major state-owned enterprises, which is a dominant source of publicly funded clean-energy RD&D in China.

However, spending on energy RD&D has stagnated since 2010, an observation that has underpinned the timely launch of Mission Innovation. This landmark intergovernmental initiative groups together 22 countries (17 of which are G20 members) and the European Commission to accelerate innovation for clean energy technologies, in part through doubling public funding for clean energy R&D over five years. Seven Innovation Challenges have been launched with the aim of catalysing research efforts to meet Mission Innovation goals of reducing GHG emissions, increasing energy security and creating new opportunities for clean economic growth.[15]

Collaboration takes place in various international forums – including the IEA's TCPs, IRENA and the CEM, the platform of 24 participating countries (most of them G20) and the

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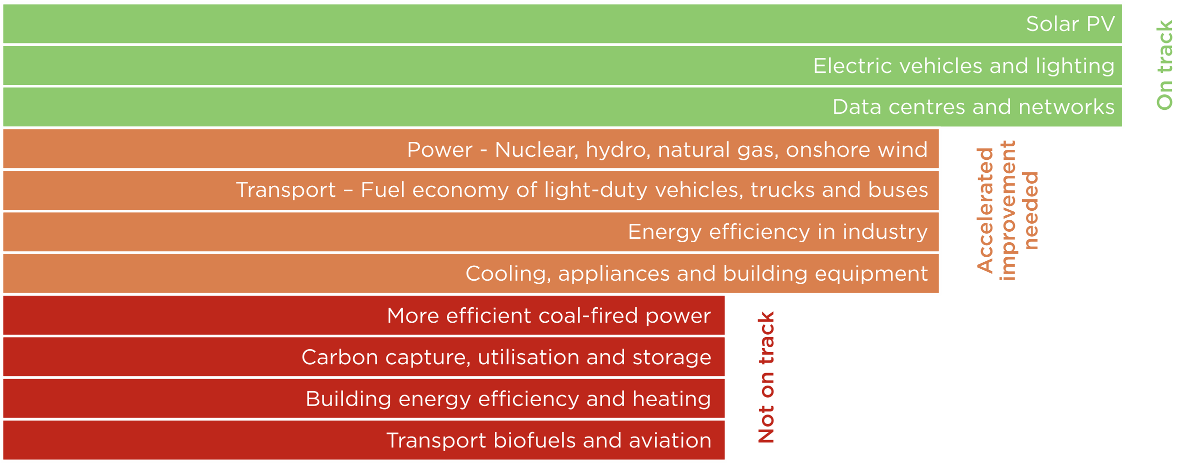
[13] Australia, Canada, Japan, Mexico, Poland, the Netherlands, the United Kingdom and the United States, together with Norway and the European Commission and CEOs from major energy companies held the CCUS Summit on 7 November 2017 at the margins of the IEA Ministerial meeting.
[14] Brazil, China, India, Indonesia, Mexico, Saudi Arabia, South Africa and the United Arab Emirates.
[15] These include smart grids, off-grid access to electricity, carbon capture, sustainable biofuels, converting sunlight, clean energy materials and affordable heating and cooling of buildings.

European Commission – to promote the advancement of clean energy with a focus on technology deployment and commercialisation.

Figure 30. Tracking clean energy technology progress



Sources: IEA (2018b), Tracking Clean Energy Technology.

D. Towards flexible energy systems and transparent markets

Energy security, as one of the G20 Principles on Energy Collaboration, is the focus of G20 leaders' discussions and declarations. As G20 countries proceed through their energy transitions, the importance of energy security has become more prominent, highlighting the need for regional collaboration and market integration to offer more flexible and transparent markets for energy commodities.

In 2017, the Hamburg G20 Leaders' Summit underlined the G20 Principles and energy security as crticial amid the energy system transformation: *"Recalling the G20 Principles on Energy Collaboration, we regard energy security as one of the guiding principles for the transformation of our energy systems, and we will continue to work on open, flexible, and transparent markets for energy commodities and technologies."*

Already in Beijing in 2016, the G20 Energy Ministers had underlined the need to safeguard energy security and sustainability: " *We emphasise the need for sustainable energy security and our commitment to the improvement and enhancement of energy security through cooperation and dialogue on issues such as emergency response measures. We stress the importance of diversification of energy sources and routes and of efficient, flexible and competitive markets. We stress that continued investment in energy projects remains critically important for ensuring future energy security and preventing economically destabilizing price spikes. We resolve to ensure those investments contribute to our sustainable energy security."*

This section therefore explores energy market trends in G20 countries to review progress towards more flexible and transparent energy systems. First to be examined are recent electricity market reforms, including the changing role of natural gas and coal, and opportunities to increase power system flexibility and diversification through dispatchable power plants, grid improvements, regional interconnection and integration as well as demand-side integration. Second, trends towards greater flexibility in natural gas markets are explored, as well as LNG challenges and opportunities, more regional market integration and the development of new gas supplies. This section concludes by outlining the main drivers of future flexibility needs and opportunities from sectoral coupling, notably through more energy storage and digitalisation of the power system.

D.1. Power markets in transition

The transition to cleaner power systems has altered power generation fuel mixes in many countries and has required that G20 governments and regulators carefully review whether the rules governing markets and the reliability and security of electricity supplies are adequate for the new technology and policy developments. This is true for both open, restructured markets and for those that remain fully regulated and vertically integrated.

D.1.1. The roles of coal and natural gas in the power sector transition

In 2016, coal was still the largest source of power generation in the world. It fueled 38% of global electricity production, although its share has been falling since 2013, when it was over 41%.

In the Middle East, where oil and gas resources are considerable, coal-fired power generation has been virtually nonexistent and natural gas dominates instead. In Latin America, with very few exceptions such as Chile, coal is not of great importance. By contrast, in EU-28 countries coal fuelled 40% of power generation in 1990 but now supplies less than 25%; many European countries have ended or announced the end of coal-fired power generation. There are several countries in which coal continues to represent a significant share of power supply, notably Poland and Germany. Weak power demand growth, renewables expansions (owing to policy support and declining costs) and environmental policies related to air pollution and climate change have made coal reductions possible.

In the United States, the share fell from 50% in 2006 to 31% in 2016 – the first year ever in which coal was not the largest source of US power generation, being replaced by natural gas. The shale gas revolution has been the main impetus for coal retreat, although weaker power demand growth and rising renewables also contributed. In China, the share of coal in the power mix has also declined, from roughly 80% in 2000 to less than 70% today – but power demand has quintupled since 2000, driven by the enormous growth of the Chinese economy. Two-thirds of the incremental growth in electricity generation, i.e. more than 3 200 TWh, has been supplied by coal. To put this in perspective, this is equivalent to total EU power generation. India, at a smaller scale, presents a similar case: coal supplies three-quarters of electricity, meaning more than 1 000 TWh of coal-fired generation. In Indonesia, coal-fired power generation began only in 1985, but today it supplies more than half of its electricity.

Overall, declining demand in Europe and the United States, and renewables expansions and increased gas use in some other countries, are reducing coal's share, but in 2017, there is no clear indication that global coal-fired power generation is about to drop.

Switching from subcritical to supercritical (SC) and ultra-supercritical (USC) technologies is being discussed for new constructions, but some subcritical units are still being built and this less-efficient technology accounts for the majority of installed capacity; a lack of financing and grid constraints are the main reasons for these constructions.

Air-polluting emissions (PM, NO_x and SO_2) from coal-fired power plants are a serious issue in many countries. Technologies to reduce non-CO_2 emissions to acceptable levels have been well proven, but capital expenditures and operating expenses are high, so regulations are needed to enforce compliance. Coal-fired power plants are responsible for 30% of energy-related CO_2 emissions, and while SC/USC plants can reduce CO_2 emissions from power generation by 20-30% compared with subcritical units, only CCS technologies can reduce them significantly. Progress in this area has been disappointing (see section C.3.3).

Looking ahead, two different energy transition approaches to coal-fired power plants have emerged. The Powering Past Coal Alliance, launched by United Kingdom and Canada and joined by over 20 countries and some states, cities and corporations, has committed to phasing out coal generation by 2030 at the latest. At the same time, the United States has announced plans to create an international Clean Coal Alliance to share the best emissions-reducing technologies.

D.1.2. Market reforms

Mexico continues to implement comprehensive power sector reforms, with clean energy at the centre of its model. In other countries, market reforms are at an earlier stage but are moving forward rapidly. China's ambitious power sector reforms will drastically alter generation patterns and simplify the integration of renewables. Japan has introduced retail competition and is currently implementing reforms that will open up the generation market as well, leaving behind the regional, vertically integrated utilities. Saudi Arabia has released a reform plan to modernise the power sector as part of its Vision 2030 programme. In restructured markets, the rising share of renewables has been a major driver to adjust power market design, notably in Germany as well as in the European Union with its new *Clean Energy for All* package of measures. Australia is also discussing power market design and is putting forward a transition mechanism to ensure both reliability and emissions reductions from the power sector.

In many jurisdictions, the combination of significantly higher renewable generation (subsidised by the public budget) and low coal/gas and carbon prices has led to a fall in wholesale electricity prices, putting power markets as well as system operation and dispatch under pressure. This trend is most conspicuous in Europe, but has also been a factor in the United States.

A critical question is whether current market and regulatory frameworks can incentivise sufficient investment to reduce GHG emissions from the power sector while maintaining satisfactory levels of electricity security and keeping final consumer costs manageable. An important debate is whether current market designs, created when VRE resources were an insignificant share of generation, can attract enough investment and retain sufficient supply flexibility to reliably meet future and peak electricity demand. Failure to account for this could lead to underinvestment in the electricity sector, which would at best undermine its economic performance and at worst compromise supply security.

This has led some markets to rely increasingly on scarcity pricing and intra-day short-term markets (Germany and the Nordic electricity market), while others have made wider use of capacity markets (France and the United Kingdom). The US Federal Energy Regulatory Commission (FERC) initiated regulatory proceedings to assess whether power system resilience is properly assured in the existing regulatory framework (FERC, 2018). Australia has recently established an Energy Security Board to co-ordinate the rule-making of electricity market bodies to guide the National Electricity Market's (NEM's) power market design transition.

Improving regulations governing the power sector so that it can decarbonise more easily and sustainably is not straightforward. Institutions are neded to objectively analyse the shortcomings of existing regulatory frameworks, propose balanced modifications, take an energy system perspective and properly consider legitimate stakeholders' interests.

Table 2. Key dimensions of power market frameworks for effective energy transitions

Source: (IEA, 2016a), *Repowering Markets*.

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

The IEA has argued that the power market designs best suited to the energy transition have to strike the balance of competitive markets and regulation (IEA, 2016a). The transition to a low-carbon power system requires the incorporation of carbon and technology support policies into a consistent electricity market framework. Competitive markets are an important tool and regulations must guide an effective transition to low-carbon power at least cost. Table 2 provides a high-level overview of a framework, outlining the role of competitive markets and rules set by governments and regulators.

Although the retirement of baseload generation is one of the most relevant topics that new policies and technologies call attention to, it is far from being the only or most challenging one from a regulatory point of view.

Cost reductions for distributed generation facilities, mainly solar PV, and for energy storage and EVs, must be subject to careful review of the distribution sector's regulatory environment. Some G20 countries are moving towards the concept of distribution system operators as neutral marketplace facilitators.

The smaller scale of distributed resources can be beneficial in terms of easier siting and reduced losses, but their low visibility and lack of system-operator control require that rules be adopted carefully to foster their efficient development. Because distributed resources can be deployed quickly and outside of utilities' investments, system impacts can be both rapid and unexpected.

In addition to distributed resources, storage and direct-current (DC) transmission facilities invested in on a merchant basis (i.e. by non-regulated market participants) demand that regulators be flexible and able to adapt the legal frameworks they create so that the power sector performs efficiently.

D.2. Power system flexibility

D.2.1. Demand-side flexibility

In addition to energy storage, explained in section C.3.1, a range of options exists to activate demand-side flexibility. Traditionally, electricity is generated in large power plants and delivered through networks to consumers in demand centres and consumption is inflexible.

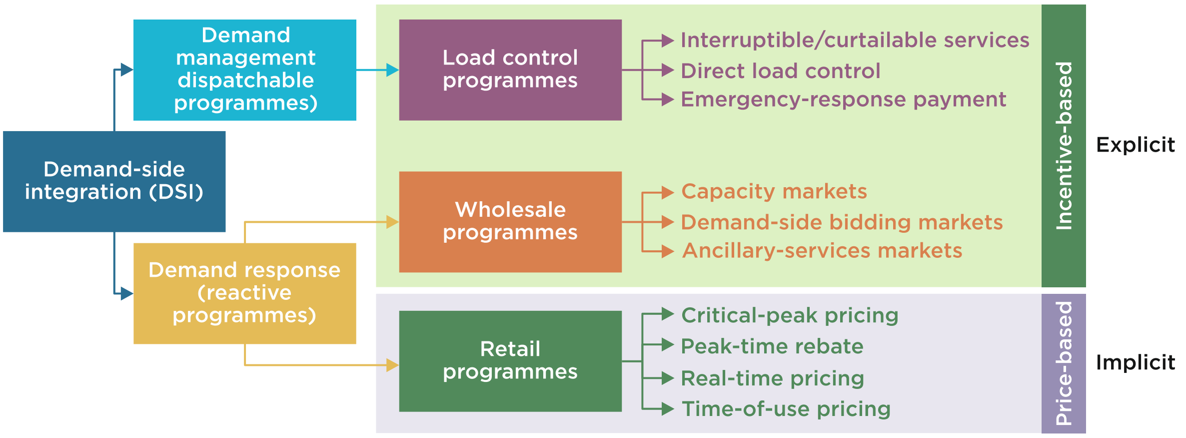
Programmes aimed at integrating the demand side into energy system operations, falling under the collective term 'demand-side integration' (DSI),[16] provide greater flexibility to electricity systems to accommodate higher shares of renewables, increase system efficiency and reduce costs.

During the hours when supply is scarce or electricity networks are congested, connected devices such as smart electric heaters and air conditioners, industrial boilers and smart home appliances can be switched off or run at lower load. These connected devices can reduce consumption or shift it to other periods when supply is abundant, for example when the sun is shining or the wind is blowing, or when there are no technical problems with the electricity grid. DSI can be implemented in a number of ways (Figure 31). Through tariff design and retail programmes, consumers can be exposed to price and other signals that allow them to adjust their consumption, also called 'implicit DSM'; conversely, wholesale and load control programmes, generally mediated by a demand aggregator, allow consumers to participate in operations in wholesale, capacity or ancillary service markets – also termed 'explicit DSM' or simply 'demand response'. Depending on their design and implementation, these programmes can defer or avoid costly investment in new power plants or in network infrastructure, save fuel costs and, during critical situations, avoid power outages, thereby improving the functioning of power markets, providing system services and shaping demand in a way that helps facilitate VRE integration.

Demand management has been used in some regions for many years, but has remained very limited in scale and has mainly been restricted to large industrial consumers. Today, only 1% of demand globally, or about 40 GW of capacity, can directly respond to shortages or excess supply. Generally, a small group of large consumers (typically energy-intensive industries) is offered financial incentives in return for accepting the chance that its supply will be interrupted at short notice when the grid operator deems it necessary to ensure the security of the electricity system. Only recently, in regions where governments have introduced capacity markets, has DSM been explicitly included as part of wholesale programmes.

[16] Demand-side management (DSM) programmes have been developed and co-ordinated by utilities, often supervised by regulators, to minimise the operating-cost base used to determine regulated tariffs for end users. Demand response differs from DSM in that it is the product of voluntary and independent decentralised decision making by suppliers and customers. The UK Department of Energy and Climate Change defined demand response as "all actions that reduce demand from the transmission system at a particular moment in time." It includes dispatchable distributed resources and storage. For further information see IEA, 2011.

Figure 31. Demand managment and demand response



There is, however, a broader range of energy technologies that – under the right regulations and market design – may be suitable for DSI purposes in the residential, commercial and industrial sectors. Shifting water or space heating or cooling demand in buildings has proven a low-cost option, with a larger potential that could be tapped with digital technology. Aluminium electrolysis, cement mills, wood pulp production, electric arc furnaces and chloralkali electrolysis, for example, are industrial activities suited for DSM. While current programmes are usually designed for large consumers, new business models for aggregators are emerging with digitalisation of the power sector.

If operated for a sufficient time and at a sufficient volume, DSI can help integrate renewables into an energy system by shifting demand away from periods of scarce renewable generation to periods of abundance, which can avoid curtailing excess output from renewables. DSM can help reduce the ramping up or down of conventional power plants to follow VRE fluctuations, and efficiency interventions, such as more efficient heating and cooling systems, building retrofits and industrial process improvements, can also improve system adequacy by reducing load at peak times. For these reasons, capacity markets in some parts of the United States enable energy efficiency providers to bid in their capacity auctions.

Digitalisation can further trigger the potential of DSM. The IEA estimates that 3 900 TWh of current global electricity consumption is technically available for digitally enabled demand response, and it is expected to almost double by 2040 to about 6 900 TWh, or nearly 20% of electricity consumption worldwide. Advanced metering is critical for any type of DSM, as it allows energy consumption to be charted in real time; traditional meters only register how much energy is consumed – not when. Advanced metering and other digitally enabled platforms reduce the burden on consumers and simplify demand-side activities, managing energy in response to real-time energy prices or other conditions specified by the user or the system by reducing unnecessary peak loads (e.g. shifting the time of use of a washing machine) or shedding loads (e.g. adjusting temperature settings to reduce energy demand at a particular time).

Greater automation, the diffusion of Internet of Things (IoT) devices in the residential and commercial sectors (e.g. smart thermostats directly connected to the power market and to weather forecast providers), and greater deployment of EVs and smart charging systems all require demand-response programmes enabled by digital infrastructure. In the longer term, big data analytics and control, or artificial intelligence (AI) applied to large numbers of consumers, could greatly enhance the efficiency and effectiveness of demand response.

D.2.2. Flexible supply from dispatchable power plants

Dispatchable generation provides the bulk of power generation in G20 power systems. This includes power from non-renewable sources such as coal and natural gas, and from firm renewable technologies (hydro as well as geothermal). As shares of variable renewable technologies grow, the role of dispatchable technologies is bound to change while they continue to provide valuable flexibility.

In systems with high VRE shares, dispatchable generation technologies need to be capable of rapid adjustment by shifting to very low operation levels or shutting down completely. They must also be able to ramp or start up in a short time to cover periods of low VRE availability.

Very flexible generators (e.g. some reservoir hydropower plants, aeroderivative gas turbines or banks of reciprocating engines) can come online fast and change their output on short notice, so are therefore suited to cope with combined generation and demand uncertainty.

In many power systems, however, current regulations, technical standards, market design or contractual arrangements inhibit the flexible operation of power plants, especially older ones. As a result, a large amount of technically available flexibility remains unexploited. Because very low or negative prices can force inflexible thermal power plants out of the spot market, failing to successfully integrate plant flexibility is a missed opportunity to reduce system costs at higher shares of VRE penetration.

Thermal generation, such as through flexible coal plants in Denmark and Germany, and natural gas plants in Spain and parts of the United States, now provide flexibility in leading energy transition countries.

The introduction of larger shares of VRE tends to displace generators with higher fuel costs first, but in many systems, plants with higher fuel costs are among the more flexible resources. The issue can be tackled in the domain of operational practices. There are numerous ways to increase power plant flexibility, and in many cases changing plant operations and installing relatively inexpensive monitoring and control equipment can significantly enhance operational performance. Several technical measures, which vary by plant design and fuel, can also be applied to reduce the inflexibility of thermal power plants.

A power market structure that rewards the capacity to change output on short notice (when needed) implicitly fosters dispatchable power plant flexibility: an example of market design that recognises and rewards power plant flexibility is Germany's intraday market. In this market, generators can make incremental adjustments to their energy schedules (resulting from the day-ahead market) to mitigate the potential inefficiency of day-ahead dispatch and to recover the balance between demand and supply if the VRE forecast changes. If wind availability drops substantially, for example, the price of energy exchanged in the intraday market would rise, rewarding those dispatchable operators able to intervene on short notice.

Even within a well-functioning market design, however, not all existing power plants will remain competitive. In fact, the exit of certain power plants from the market can help re-establish an optimal generation portfolio. Mature systems need to meet the twin challenge of scaling down those parts of the generation portfolio that are ill-adapted to high shares of VRE, while providing investment signals for scaling up flexible generation. However, existing power plants may also be valuable for VRE integration, as dynamic systems are advantageous. They can focus on building up flexible dispatchable generation along with VRE capacity, avoiding the challenges of an ill-adapted power plant mix.

While the Chinese electricity system benefits from hydropower and interconnections as its main sources of flexibility, the government of China has also recognised that increasing coal-fired power plant flexibility is an additional means to integrate increasing VRE shares to enable China to meet its long-term climate goals. It will develop new flexible plants (pumped hydro and natural gas), but actions to increase coal plant flexibility are considered critical. In its 13th Five-Year Plan, China commited to retrofitting 133 GW of CHP and 86 GW of condensing coal-fired plants – one-fifth of installed coal-fired capacity – to enhance their operational flexibility and environmental performance by 2020. China has prioritised lowering the minimum load as the first step in retrofits, the aim being to reduce minimum loads by roughly half. Other retrofits will increase ramping speeds and shorten start-up times. China is operating 22 demonstration plants to study the impact of technical retrofits on its power system.

D.2.3. Regional market integration

Cross-border integration of energy markets has been motivated primarily by a combination of improved economic efficiency and increased energy security. This has been the case for power systems that both expand across borders within countries (e.g. interstate/inter-provincial power system integration in Australia, Canada, India and the United States) and that expand between countries (e.g. the Association of Southeast Asian Nations [ASEAN] Power Grid, the European Union, the Gulf Cooperation Council and the Southern African Power Pool). More recently, VRE integration has also emerged as a driving force – and to some degree a challenge – for regional market integration.

Economic efficiency

The economic efficiency benefits of regional integration derive primarily from economies of scale and resource diversity. When power systems are integrated across borders, local resources gain access to a larger demand pool, making it possible to build larger power plants than would otherwise be justifiable and allowing developers to benefit from the economies of scale of larger projects. It also means that existing generators can run more often: variations in economic activity and weather patterns, among other factors, mean that demand patterns differ across geographies, so expanding market size allows generators to operate in periods when local demand is not sufficient. Depending on the resource mix, regional integration can also create more specific economic co-benefits, including environmental improvements (e.g. reduced pollution), expanded electricity access and improvements to government balance sheets (ESMAP, 2010).

Security

The security benefits of regional power system operations may be less obvious, as integrating across borders also means exposing the local power system to external risks. Integrating synchronous power systems, or power systems that operate at the same frequency, requires a significant degree of cross-border co-ordination, as deviations in operations in one part of the system can have ripple effects across the entire interconnected region. Prior research by the IEA found that lack of co-ordination is a primary cause for nearly all blackouts that extend across political borders (IEA, 2015).

Nevertheless, there are also significant security benefits to regional power system integration. Access to a larger pool of generators means there are more resources available should a single generator experience an outage. Greater resource diversity overall means that power systems are less exposed to events that impact a single type of generator, such as natural gas supply disruptions or extended periods of drought. The security benefits of system integration can therefore be significant. In its most recent medium-term resource adequacy assessment for Europe, the European Network of Transmission System Operators for Electricity (ENTSO-E) found that, without new transmission capacity, there would be more expected outages of at least 8 hours per year in 12 countries by 2025 (ENTSO-E, 2017).

Integrating renewable resources

Cross-border power system integration can make it easier to integrate larger shares of VRE resources. As a result, as VRE penetration in a power system increases, the pressure to extend the power system across borders also rises. The benefits of regional integration for VRE derive primarily from the ability to take advantage of a larger, more diverse resource base. These diversity benefits come from both natural differences in weather patterns and resource potential.

Extending power systems across borders also allows system operators to benefit from alternate technology mixes. Different policy choices can lead to different technology mixes between jurisdictions, such as high shares of nuclear in France and of wind in Denmark. Having a high number of interconnection is one of the main reasons Denmark has been able to integrate such a high share of wind – nearly 50% of generation in 2016. Despite having a significant quantity of flexible domestic generation (particularly natural gas-fired CCGTs), wind production in Denmark is balanced by imports or exports around 80% of the time (IEA, 2017m). This is primarily due to economics: it is less expensive to balance wind with external resources (e.g. hydropower from Norway) than with local resources.

At the same time, cross-border flows of VRE generation can create operational challenges. In Europe these challenges are most apparent in the ongoing issue of loop and transit flows, or unscheduled power flows that originate in one jurisdiction and pass through one or more neighbouring jurisdictions (IEA, 2016c).[17] These are especially challenging from an operational perspective because they are caused by events outside the control of the system operator, and can therefore be addressed only by using local resources. While such flows may occur between any interconnected power systems, high VRE shares can lead to a significant increase in their volume. Managing these requires increased co-ordination, both in long-term planning (e.g. to optimise VRE generation deployment and to develop sufficient transmission infrastructure) and in short-term operations (e.g. through sharing real-time system information and co-ordinated dispatch).

D.2.4. Principles of regional power system security

D.2.4.1. Regional planning and resource adequacy assessments

The efficient development of cross-border infrastructure requires active co-operation among all relevant system planners. It is natural that planners have significantly greater visibility in their own power systems than in those of their neighbours, yet development within neighbouring systems can have cross-border impacts even in the absence of cross-border infrastructure. Building a large natural-gas plant, for example, could have regional implications for fuel demand. A new hydroelectric plant can impact water flows for countries downstream of development.

Regional planning often starts, therefore, with a simple sharing of domestic plans. Countries that participate in the Greater Mekong Subregion Regional Power Trade Coordination Committee (GMS RPTCC), for example, gather on a regular basis to share grid plans (ADB,

[17] Loop flows differ from transit flows only in that they terminate in the jurisdiction from which they originated. Loop flows are only possible in mesh networks, or in networks that have more than one entry and exit point.

2018). Doing so does not obligate countries to develop cross-border infrastructure, but can allow them to identify areas of potential conflict or synergy.

The next step beyond sharing individual plans is integrating them into a common analysis. In the United States, the Eastern Interconnection Planning Collaborative (EIPC) took grid plans developed by local utilities and, taking into account potential state and federal policies, evaluated the potential regional impacts (EIPC, 2018). As with the RPTCC process, this did not obligate the parties to undertake any new interconnector developments, but it did have the potential to reveal areas in which further collaboration would yield benefits.

Although these methods can help identify areas in which additional infrastructure could yield economic advantages, they are less helpful in identifying potential security benefits. This is largely because when interconnectors are considered in local plannning, they tend to be viewed as a fixed quantity and not considered equivalent to local generation. Thailand's 2015 Power Development Plan (PDP2015) was constrained by a cap of 15% of generation on future imports (IEA, 2016d), and the European Union has set an interconnection target of 10% of domestic installed capacity by 2020 for member countries, but is proposing to increase it to 15% (EC, 2017).

Increasingly, however, policy makers, utilities and market participants are recognising the growing importance of regional resource adequacy – or ensuring that there are sufficient resources across an interconnected region to meet current and expected demand. To this end, a number of regions have begun to develop regional resource adequacy assessments. In Europe, for example, the Pentalateral Energy Forum – a collaborative body made up of seven countries in Central and Western Europe – organises regional resource adequacy assessments through its security-of-supply working group (PLEF, 2015). In the United States, CAISO is developing a draft framework for performing regional assessments with its neighbours (CAISO, 2018).

D.2.4.2. Developing interconnectors

Once the need for additional interconnectors has been established, developing them involves many of the same challenges as for developing local infrastructure. In both cases, permits must be granted, stakeholder approval must be sought and costs must be appropriately allocated.

Because interconnector development involves stakeholders from two or more jurisdictions, however, the process is more complex. Complicated siting processes often lead to project delays (Roland Berger, 2011), so developing cross-border infrastructure can be time-consuming. Simplifying permitting processes within jurisdictions can also benefit cross-border projects, since making it easier to resolve local issues frees up time to address cross-border ones, and harmonising permitting procedures across regions can help even further.

Even when planning and permitting issues have been addressed, however, cost allocation can remain a stumbling block. When a transmission line is developed within a service territory, the costs are generally recovered by the ratepayers in that area, at least to the extent that the regulatory authority allows them to be.[18]

D.2.4.3. The role of regional institutions

The regions that have been most successful in developing regional power systems are those that have established regional institutions to support integration. In Europe, both ENTSO-E and the Agency for the Cooperation of Energy Regulators (ACER) play key roles in

[18] This refers specifically to investments in regulated assets. Merchant investments, by contrast, are paid for by the investor, with costs generally recovered by charging for access.

supporting the development of new infrastructure and the harmonisation of regulations and technical standards. The North American Electric Reliability Corporation (NERC) develops reliability standards and assesses seasonal and long-term system adequacy for Canada, the United States and part of Mexico, and regional power system integration in Southern Africa is supported by the Southern African Power Pool (SAPP) and the Regulators Association of Southern Africa (RERA). In Central America, the *Comisión Regional de Interconexión Eléctrica* (CRIE) acts as regional regulator and the *Ente Operador Regional* (EOR) as regional system operator for the *Sistema de Interconexión Eléctrica de los Países de América Central* (SEIPAC).

Regional institutions have two primary roles. First, they aid in developing cross-border power infrastructure. They can play a particularly important role in supporting regional planning, both by acting as a platform for collaboration and by providing additional analytical capabilities to augment the capacity of local institutions. Second, they support harmonisation of regulations and policies. This second role is critical and challenging, especially in regions where the institutions are not backed by explicit regulatory authorities.

In Europe, for example, ENTSO-E and ACER have clear authorities and limits on those authorities. ENTSO-E can highlight the benefits of developing a particular transmission line, but cannot mandate that the line be developed. Instead, the European Union encourages development through financial incentives and grants. ACER acts essentially as a regulator of last resort, stepping in to resolve disagreements over cross-border infrastructure cost sharing arrangements only when the countries' regulators are unable to do so.

In North America, NERC's authority in Canada and the United States derives from different sources. In the United States, individual states are obligated under federal law to follow NERC standards, while in Canada each province can choose whether or not to do so. In practice, though, all provinces have recognised the benefits of having common standards across an interconnected power system, and so have chosen to adopt NERC standards as mandatory (NRCan, 2015).

D.2.4.4. Market and regulatory harmonisation

Divergent policies and regulations can be a significant obstacle to regional power system integration. Some degree of harmonisation is necessary. Technical standards for interconnecting generators, for example, must at minimum be shared across the entire interconnected region, and ideally should be uniformly applied, so that system operators know how generators will respond to different situations. This harmonisation, however, must be balanced with each jurisdiction's own preferences and autonomy.

In an ideal world, all energy policies would be harmonised across the interconnected region. For example, renewable support schemes could be co-ordinated to encourage deployment that is optimal from a regional perspective. In reality, though, different jurisdictions will always have different policy and regulatory mixes, and once power systems are interconnected, spillover effects are inevitable.

Lack of market harmonisation is not necessarily an obstacle to integration. Malaysia and Singapore have significantly different market structures – a single-buyer model in Malaysia, and a fully liberalised wholesale market in Singapore. The two countries maintain an interconnection the primary purpose of which is to ensure there is sufficient reserve power available in case of an emergency. Power is traded on a regular basis, but under non-economic terms – that is, all trades are netted out to zero over time, so no price needs to be applied and no money is ever exchanged.

Nevertheless, lack of harmonisation does place limits on integration potential. Some regions have addressed this by differentiating the regional power system from the local power system. The SIEPAC line in Central America, for example, functions as a backbone connecting all the participating countries, which may tap into it whenever they choose. SEIPAC has harmonised rules for access that necessarily require some harmonisation at the national level, but that still allow national power systems to maintain a different set of standards and regulations.

At the other extreme is, again, the example of the European Union. In implementing the EU Network Codes and Guidelines, EU member states are harmonising both technical standards (such as calculations of available cross-border transmission capacity) and market rules (for example, harmonised tariff structures) across the entire continent (IEA, 2016c). The end goal is a single market for energy in Europe – referred to as the “Energy Union”.

D.3. Flexibility from regionally interconnected and global gas markets

Natural gas demand has increased in most G20 countries, thanks to a surge in unconventional production, globalising gas trade, decisions to phase-out coal and regional market integration. This has led to a change in gas market structures from local bilateral links to interconnected regional commodity trading hubs, increasing competition among suppliers and enhancing transparency for market participants. In the next decades, natural gas is the only fossil fuel that has the potential to increase its share in the global energy mix.

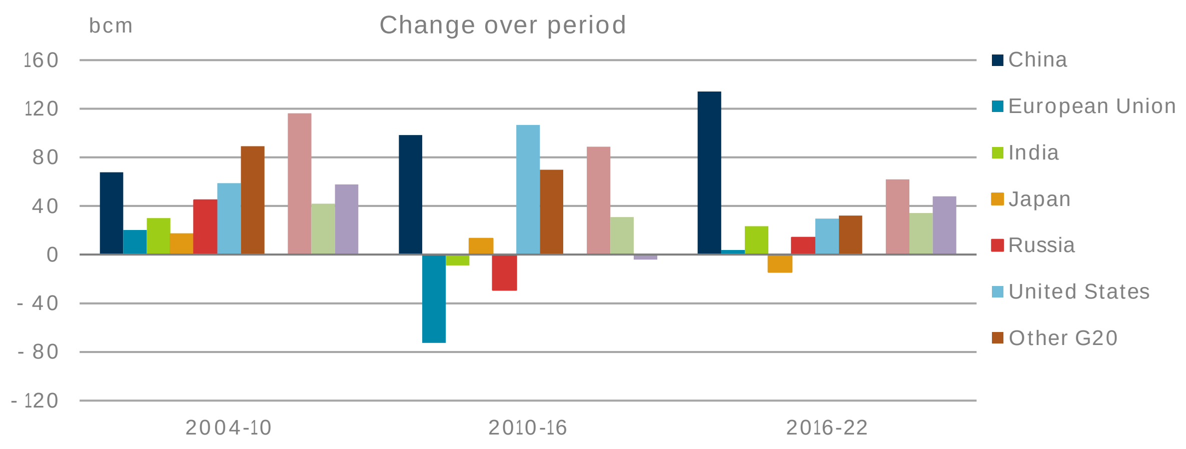
Much of the growth in natural gas consumption to 2030-40 is projected to take place in developing countries, led by China, India and other Asian countries. Much of the gas will have to be imported (at significant transportation costs); infrastructure is often not yet in place; and policy makers and consumers will be very sensitive to its affordability versus coal and ever-cheaper renewables – notably solar and wind. While the case for gas in resource-rich countries (e.g. the Middle East) is evident, in import-reliant countries the pure economic drivers are less compelling. In these cases, strategies favouring gas are typically required to ensure its growth – for example, China’s desire to improve air quality by switching away from coal for industrial and residential use. Argentina has the opportunity to develop the vast unconventional gas potential of its Vaca Muerta formation, one of the world's largest shale oil and gas resources, which would reduce Argentina’s import needs and make it a leading pipeline and LNG exporter. In Argentina, therefore, natural gas would do far more than provide flexibility: its significant substitution potential for power generation and for other uses would enable a faster transition to a cleaner energy system.

The largest increase in gas demand is expected to come from industry, especially where ample resources are available, impelled by strong demand for fertiliser production and chemical processing. Gas is expected to displace household coal consumption for heating and as a cooking fuel, and oil for transportation, especially for heavy-duty vehicles and maritime transport. Almost one-third of the incremental consumption of gas to 2040 is projected to come from gas-fired power plants. Where gas prices are very low (e.g. the United States, Russia and parts of the Middle East) it is commercially viable for gas plants to run at high utilisation rates and provide baseload power. In most gas-importing regions, however, the primary role of gas plants is to provide flexibility for mid-load and peak-load power, implying significantly lower utilisation rates and hence lower gas consumption, to complement rising shares of wind and solar power.

D.3.1. Natural gas supply and demand trends

Natural gas consumption grew at 1.7% per year on average over the past decade, even reaching 2.6% in 2016. Power generation has been the key driver in both mature markets and emerging economies, accounting for half of total demand increase. Growth in North America has been strong owing to abundant and affordable domestic shale resources, whereas in Asia it declined and even became negative in the European Union. Figures for 2004 to 2022 indicate positive natural gas demand development in Asia and the Middle East (Figure 32). China has one of the most dynamic natural gas markets, and it is expected to remain so into the near future. Domestic gas demand has been mainly policy-driven to improve air quality, through the coal-to-gas substitution programme for industry and residential customers, and China is expected to account for more than one-third of global natural gas demand growth to 2022. Gas demand is also developing in Latin America and Africa.

Figure 32. Natural gas demand by region, G20 and non-G20, 2004-22

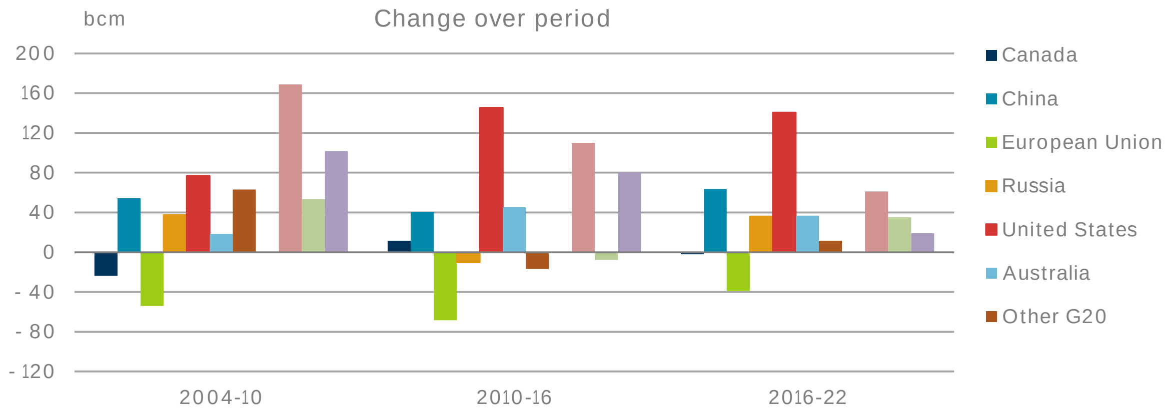


Source: IEA (2017n), *Gas 2017.*

At the same time, gas production increased following new gas developments in the Middle East in the early 2000s (Qatar, Oman and Abu Dhabi, for domestic markets in Iran and Saudi Arabia), and more recently with North American (United States) shale gas exploitation (Figure 33).

New sources of supply also emerged in other regions, serving expanding domestic market needs (China, Brazil and Argentina) and exports (Australia). Additional contributions from North America, Australia and the Middle East, and new capacity from Russia's Artic regions and sub-Saharan Africa (Mozambique) are expected to come online by the mid-2020s.

Figure 33. Natural gas production by region, G20 and non-G20, 2004-22



Note: bcm = billion cubic metres.
Source: IEA (2017n), *Gas 2017.*

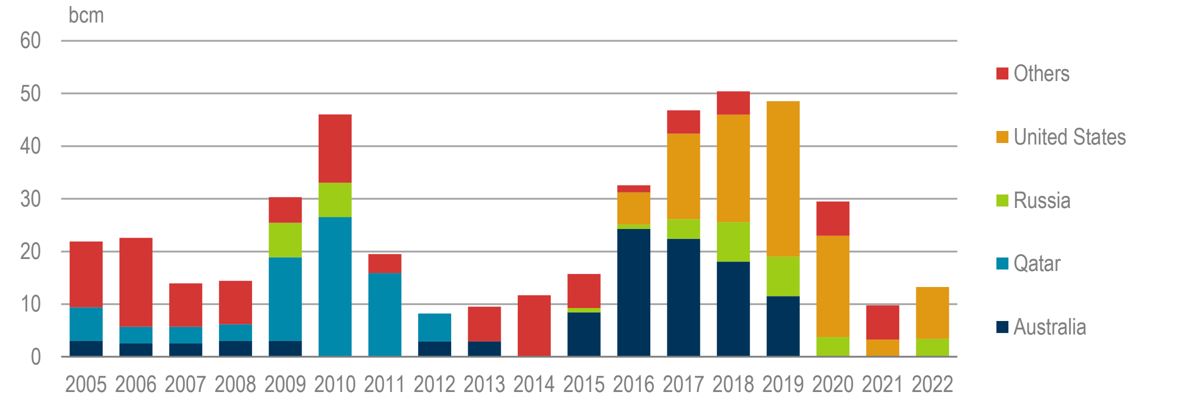
D.3.2. From regional gas markets to more flexible globalised LNG

In conjunction with production development and LNG export capacity expansions, local and regional market integration has been the third factor pushing natural gas market expansion and increasing flexibility and liquidity. International natural gas trade has grown by more than 60% since 2004, thanks to a doubling of LNG.

LNG market expansion in the past decade was driven by successive waves of investment in liquefaction capacity. The first wave, centered around Qatar, materialised in the late 2000s and led to the first supply glut (with US natural gas import needs curtailed by domestic shale gas development and Asian demand growth halted by the aftermath of the 2008 financial crisis). This overcapacity period was short-lived, however, as the Great East Japan Earthquake of 2011 resulted in a sharp and unexpected demand surge, prompting high LNG prices that in turn triggered a second wave of capacity investments – and subsequent oversupply. Nearly 200 bcm of additional liquefaction capacity is due to be added by 2022, led by the United States and Australia, countries which, with Qatar, will by then account for most LNG supply capacity (Figure 34).

The number of countries with LNG import facilities went from 14 in 2004 to 38 in 2016. The number of LNG importers increased rapidly as new buyers joined, attracted by the competitiveness of LNG, its flexibility and the lower-capital-cost import solutions provided by floating storage and regasification units (FSRUs). LNG trade is growing in volume, in suppliers (with the emergence of Australia and the United States) and in new markets, with 47 countries and territories expected to import LNG by 2022 compared with 38 in 2016.

Figure 34. Incremental liquefaction capacity, 2005-22



Source: IEA (2017n), *Gas 2017.*

Global LNG markets are well supplied; however, there are no new greenfield investments sanctioned after 2021 and market overcapacity is expected to be absorbed by LNG demand growth, especially in the Asia-Pacific region, where new investments in demand-side infrastructure, LNG terminals and domestic pipeline networks are needed by the mid-2020s. This underlines the importance of timely supply-side investment to ensure security of supply, as well as the need for LNG market flexibility, for instance through the elimination of competition-restraining clauses, notably destination clauses based on EU competition laws and the ruling of the Japan Fair Trade Commission in 2017. Timely new investment in supply capacity is also needed to avoid market tightening and volatility, as well as to meet gas demand growth.

In recent years, global contractual structures have shown a trend towards more flexibility and liquidity (IEA, 2017o). The share of flexible destination contracts out of total LNG contracts continues to increase (almost 42% of newly signed volumes in 2016). In parallel, average contract duration is decreasing for both fixed- and flexible-destination contracts, but the reduction is more important for fixed than for flexible, as the share of spot and short-term transactions is also rising.

If all things remain equal over the medium term,[19] the net share of contracts with fixed destination is expected to decrease – with some additions from new projects, but not sufficient to counter expiration of legacy contracts, which are counted as uncontracted (at least at present). Flexible contracted volumes are expected to double, mainly owing to the development of US exports, which are a major additional source of contractual flexibility. Currently uncontracted volumes would almost triple, cumulating the impacts of expiring legacy contracts, the sum of flexible tail-end liquefaction project capacity, and the currently open positions held by natural gas wholesalers (also known as portfolio players).

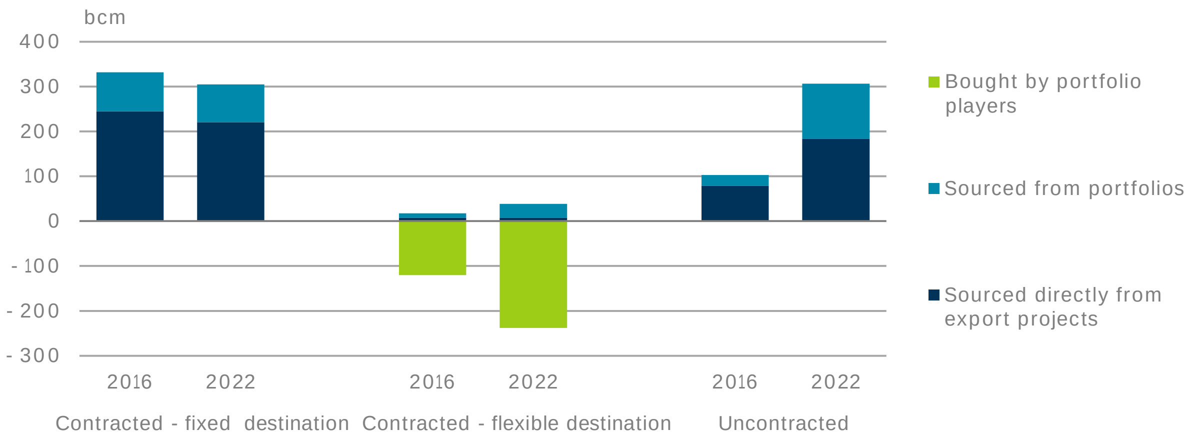
These portfolio players have a pivotal role in the evolution of LNG markets as important *de facto* providers of flexibility and security of supply (Figure 35). However, the cost of this is usually less destination flexibility, as portfolio players tend to buy flexible volumes from exporters and sell with fixed destination to their customers. Being the principal buyers of current and future US flexible LNG output, and faced with the prospect of more open

[19] Assuming that expiring contracts are not renewed by the time of construction, and no specific assumptions on contracts yet to be signed.

positions in a buyers' market structure in the near future, they will look even more actively for opportunities to secure long-term outlets.

The emergence of the United States as a major LNG exporter will impact both volume availability and access to flexibility. The sale of gas free-on-board, the absence of destination clauses, pricing formulas based on gas-to-gas competition, and the scalability of new investments in both liquefaction and regasification (with FSRUs) offer greater flexibility, which will drive improved global gas security. On the demand side, it is also expected that more flexibility will be sought because most of the newly added LNG importers are sensitive to prices. These new importers tend to consider LNG as an opportunity to diversify their natural gas or even global energy mix, provided it remains a flexible and price-competitive option.

Figure 35. LNG supply evolution per type of contract, 2016-22



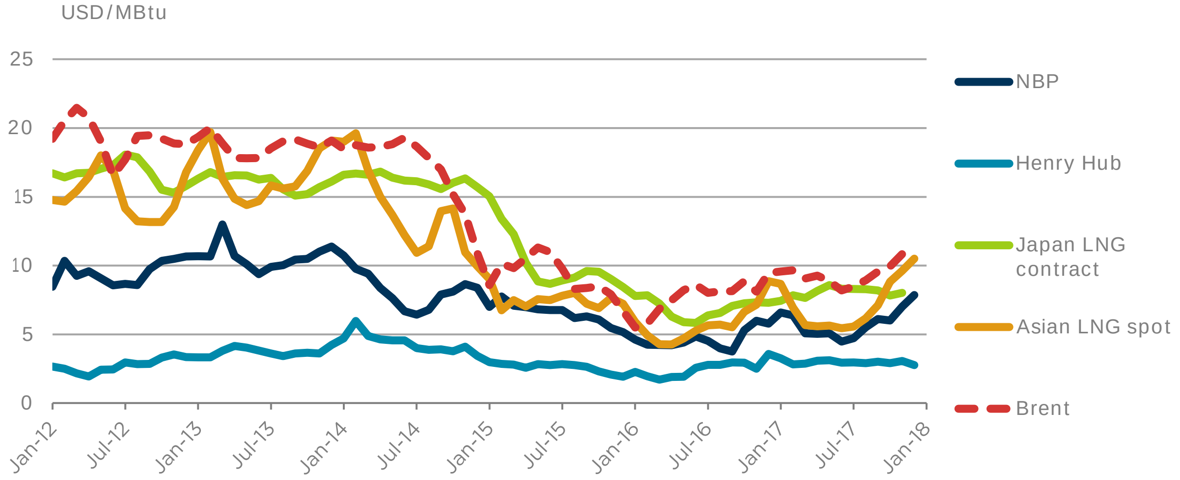
Source: IEA (2017o), *Global Gas Security Review 2017.*

D.3.3. Regional gas market integration

Regionally formed natural gas prices have converged since the end of 2014, as illustrated in Figure 36. This convergence results from numerous factors (tensions in the Asian LNG market following the 2011 Great East Japan Earthquake; the development of additional supply capacity throughout the world; and European renewables shifting natural gas consumption patterns for power generation) coinciding with the decrease in crude oil prices. Price spreads between European and Asian markets have since remained relatively low, as have absolute prices, resulting in greater convergence with US Henry Hub prices – although tensions mounted at the end of 2017 due to China's seasonal supply needs, prompting higher spot prices.

Among developing natural gas markets, Latin America, especially its southern region (Argentina, Brazil and Chile), already possesses some of the features required for greater market integration: significant resources, supply diversity, physically interconnected markets, a regulatory framework that enables access to infrastructure, processes for opening wholesale and retail markets, and developing trading markets. The emergence of new local sources of supply, along with progress towards more competitive markets and the need for emergency co-operation, can foster the development of a regional market and enhance flexibility and liquidity to the benefit of local consumers, reinforcing energy integration and supply security. Achieving regional integration requires that cross-border pipeline interconnections be built and that liquid, competitive markets (trading hubs) be developed to ensure that suppliers and customers are numerous and diverse. Integration processes, ranging from cross-border trade to full market coupling, are under way in several regions, although at various stages of maturity. Mature, strongly interconnected regions such as Europe and North America are the most advanced in market integration (the European Union's internal market is described in Box 2).

Figure 36. Natural gas price development, 2012-17



Notes: MBtu = million British thermal units; NBP = National Balancing Point (United Kingdom).

North America's gas market is strongly integrated, with pipelines running across borders. These strong cross-border integrated oil/gas/electricity networks and integrated oil/gas production chains offer energy security, reliability and affordability. Most US gas imports come from Canada, but they have been in decline since 2007 due to the shale gas revolution in the United States. Eastern Canada (Ontario and Quebec) now imports natural gas from the United States, and although gas production is expected to remain flat in Canada, it has to find new LNG markets because Canadian and US gas demand are also projected to remain flat. The importance of natural gas is expected to rise for oil sands production and in power generation as Canada phases out coal use by 2030.

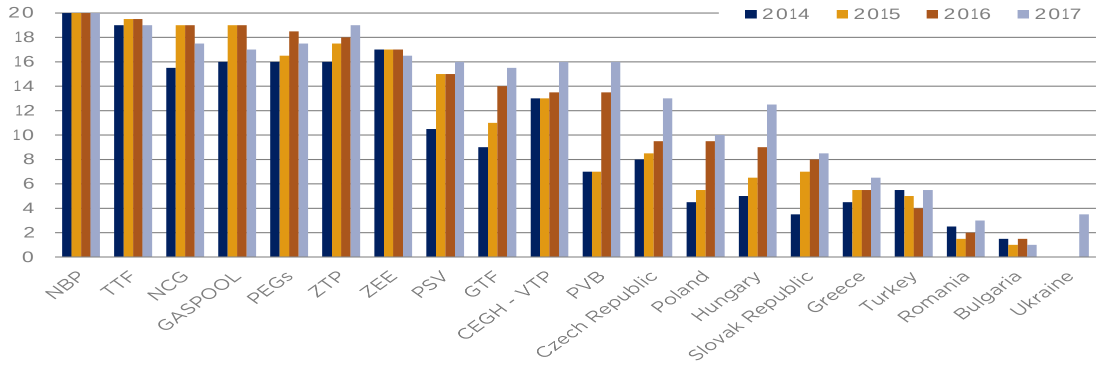
Box 2. Natural gas market integration in Europe

Natural gas hubs in Europe originated with the creation of the NBP in the United Kingdom in 1996, and started to evolve across Europe in the early 2000s. The United Kingdom began reforming its gas market in the 1980s, in conjunction with development of a competitive upstream supply from the North Sea, and it was fully liberalised in the 1990s.

The European Commission initiated the natural gas liberalisation process at the EU level in the late 1990s, with a regulatory framework established through successive liberalisation directives and energy packages (1998, 2003 and 2009) transposed into member states' legal systems to create a single EU integrated natural gas market. To establish this common market, the regulatory packages contained measures abolishing local monopolies and liberalising domestic wholesale and retail markets, and guaranteeing non-discriminatory access to natural gas infrastructure and cross-border networks, transparent access to market data and information, separation of commercial and infrastructure operation activities (unbundling), and independence of national regulators.

Several trading hubs developed across Europe, starting with the Zeebrugge hub in Belgium (the only physical hub in Europe), launched in 1998 after development of the Interconnector pipeline linking the United Kingdom to the continent. The European Union now has about twenty different natural gas hubs in Europe, at different stages of maturity (Figure 37). The European Federation of Energy Traders' (EFET) annual scorecard assessed the best practices among existing trading hubs, observing positive evolution over 2014-17 and highlighting the differences between the more mature markets in Northwest Europe and more recent ones in Southern and Eastern Europe. The two most successful and liquid trading hubs remain the United Kingdom's NBP and the Dutch TTF, which accounted for 43% and 46% of hub-traded volumes in the first nine months of 2017 (EC, 2017b). The Northwest European market is the most interconnected and liquid region (IGU, 2017). Oil indexation accounted for only 9% of natural gas consumption in Northwest Europe, compared with the EU average of 30%, and local ratios of 28% in the Nordic and Baltic regions, 28% in Central Europe, 32% in Southeast Europe, and 68% in the Mediterranean. Hub pricing accounted for 28% of consumption in Northwest Europe in 2005 when trading hubs and market integration rules were still in development.

Figure 37. European natural gas hubs scorecard, 2014-17



Notes: NBP = National Balancing Point (United Kingdom); TTF = Title Transfer Facility (the Netherlands); NCG = NetConnect Germany; GASPOOL (Germany); PEGs = Points d'Echange Gaz (France); ZTP = Zeebrugge Trading Point (Belgium); ZEE = Zeebrugge beach physical trading hub (Belgium); PSV = Punto di Scambio Virtuale (Italy); GTF = Gas Transfer Facility (Denmark); CEGH-VTP = Central European Gas Hub - Virtual Trading Point (Austria); PVB = Punto Virtual de Balance (Spain).
Source: EFET (2017), "2017 review of gas hub assessment", http://efet.org/Files/Documents/Gas%20Market/European%20Gas%20Hub%20Study/EFET%20Hub%20Scores%202017_Final.xlsx.

D.4. Digitalisation and the smart and flexible energy system

Digitalisation is the application of digital technologies across an economy, including in the energy sector. The trend towards greater digitalisation is being enabled by advances in data, analytics and connectivity: increasing volumes of data thanks to declining costs of sensors and data storage; rapid progress in advanced analytics, such as machine learning; and greater connectivity of people and devices as well as faster and more affordable data transmission.

While digital technologies have been helping to improve energy systems for decades, the pace of their adoption is accelerating. Advancing technology, falling costs, and ubiquitous connectivity are opening the door to new models of producing and consuming energy, putting energy on the cusp of a new digital era. The progressive electrification of the global economy makes electricity system transformation even more important and offers large opportunities to exploit new digital technologies. Electrification of end uses, such as EVs, heat pumps and electricity-based production of metals, can also provide means of decarbonising (to the extent that power is generated with low-carbon sources) and curbing local air pollution. Smart charging of EVs is one such opportunity[20] at the nexus of electrification, connectivity and decentralisation.

D.4.1. Transforming the electricity system

Digitalisation holds the potential to break down boundaries between energy sectors, increasing flexibility and enabling integration across entire systems. The electricity sector is at the heart of this digital transformation. Traditionally, electricity is generated in large power plants, transferred through transmission and distribution networks and delivered in one direction to end users in the residential, commercial, industry and transport sectors. Digitalisation is accelerating a shift towards a multi-directional, distributed energy system – one in which demand sources of any size actively participate in balancing supply at all scales.

By matching demand to the needs of the overall system in real time, digitalisation offers the opportunity for millions of consumers as well as producers to sell electricity or provide valuable services to the grid. Connectivity is the key enabler. It permits the linking, monitoring, aggregation and control of large numbers of individual energy-producing units and pieces of consuming equipment. These assets can be big or small, e.g. a rooftop solar PV system in a home, a boiler on an industrial site or an EV. As digitalisation advances, a highly interconnected system can emerge, blurring the distinction between traditional suppliers and consumers, with increasing opportunities for more local trade of energy and grid services. As this physical infrastructure evolves and stakeholders' roles change, centralised grids and the owners and operators of transmission networks will continue to provide the backbone that balances the overall electricity system.

Digitalisation is one part of the overall transformation of electricity systems. The continuing electrification of energy services across all end-use sectors, notably transport, and the growth of decentralised sources of power – which would happen even without digital technologies – are the other drivers.

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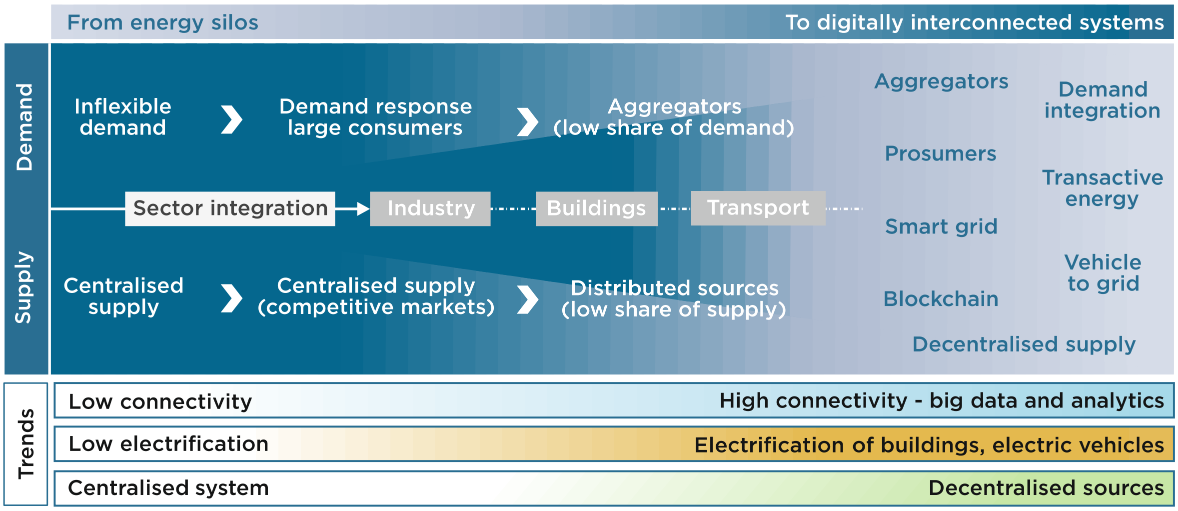
[20] Digitalisation can also enable smart demand response, help integrate greater shares of variable renewables, and facilitate the development of distributed energy resources. These opportunities are discussed in depth in Chapter 4 of the recent IEA publication *Digitalisation and Energy* (www.iea.org/digital).

Figure 38. Possible steps in the digital transformation of the electricity system



Source: IEA (2017q), *Digitalisation and Energy*.

But digitalisation – particularly the growth in connectivity among producers, grid operators and end users – is supporting these trends and helping to accelerate the transformation of the electricity system and the establishment of new business models. By allowing for the exchange of operational information in real time between equipment anywhere in the energy system, inefficiencies within each sector are removed, improving reliability and lowering costs, as consumers and producers respond instantaneously to changing market conditions (Figure 38).

D.4.2. Digitally enabled sector coupling: Smart charging of electric vehicles

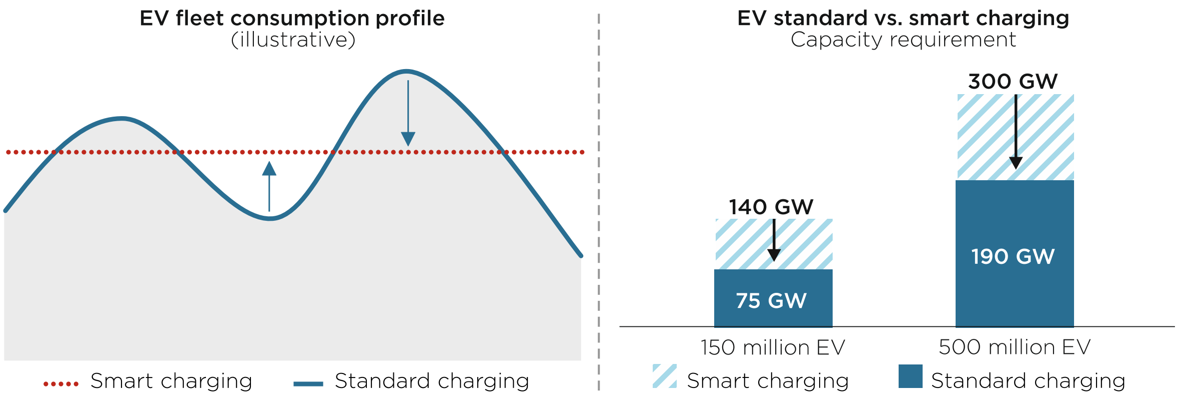
The deployment of EVs and the way in which EV charging infrastructure is deployed and used could significantly impact energy systems. Providing enough power to fully top up the battery of a typical EV in four hours would require nearly 9 kilowatts (kW) of capacity today – equivalent to the current peak demand of an average Californian household. Shifting the charging of EVs to times when demand is low and there is abundant low-cost generation (such as wind and solar power) could reduce the need for additional generation capacity to meet EV demand, delivering significant savings for the system.

The deployment of EVs requires new investments to build charging infrastructure and to improve distribution networks related to the charging facilities. EVs, which represent mobile electricity demand, can theoretically be charged at any point in the day, at low recharging rates at home or at the office, or via faster charging using public charging infrastructure. When and where they are charged, and how much power EVs draw from the grid, will vary significantly and will depend not only on drivers' behaviours, but on incentives and signals provided to consumers in the form of monetary savings, and to the entire system in the form of greater flexibility and reduced investment needs.

Co-ordination of charging strategies through digital technologies (smart charging) is needed to take full advantage of this opportunity. With smart charging, price and control signals provide incentives for connected EVs to charge when there is abundant production of low-cost, low-carbon electricity or to stand by when the network is congested. Smart charging requires digital infrastructure to enable communication between charging points and back-end systems, so that grid operators can send requests to increase or reduce demand at certain times.

The need for power capacity increase depends on the penetration of EVs. In a scenario in which 150 million EVs are deployed by 2040, capacity requirements for standard charging reach 140 GW. If smart charging were implemented, however, the required capacity would be 75 GW (i.e. 65 GW less) in 2040. In a more ambitious scenario in which the global EV fleet reaches 500 million by 2040, capacity savings increase to 110 GW. In the first scenario, the flexibility provided by smart charging avoids USD 100 billion of investment in electricity infrastructure (new power generation capacity and transmission and distribution) that would otherwise be required to cover the peak in electricity demand from EVs, and USD 280 billion is saved in the second scenario (Figure 39). The higher the penetration of EVs, the more significant the savings from deploying them using digitalised infrastructure. In the case of 500 million EVs, the savings are about two-thirds of the investment in all EV charging infrastructure to 2040. Smart charging can also provide services to the grid to enhance power quality and reliability, which further raises its value. Deeper flexibility can be unlocked through vehicle-to-grid (V2G) technologies that allow for bidirectional charging. While the benefits to the grid could be enormous, technological issues remain, mainly linked to EV batteries reaching the end of their lifetimes more quickly with the high number of charging-discharging cycles entailed in V2G technology.

Figure 39. Impact of smart versus standard charging of EVs



Sources: IEA (2017g), *Energy Technology Perspectives 2017*; IEA (2017q), *Digitalisation and Energy*.

Where and when EV charging occurs is also critical, especially for utilities and distributors. EVs can be charged ‘behind the meter’, whereby the additional load is met by rooftop PV systems and/or batteries, and the charging is optimised to occur either at home or at work during the day. Or, they can be charged on the distribution network at public charging stations, in which case the revenues of traditional utilities/grid operators would be higher and flexibility services from delayed charging would be more readily available.

D.4.3. Impacts on energy end-use sectors

Beyond the power sector, digital technologies are already widely used in the transport, industry, and buildings sectors, with the widespread deployment of potentially transformative technologies such as autonomous cars, 3D printing and machine learning on the horizon. While these technologies could improve efficiency, some could also induce rebound effects that will increase overall energy use.

Transport

In the transport sector, cars, trucks, planes, ships, trains and their supporting infrastructure are becoming smarter and more connected, improving safety and efficiency. Digitalisation could have the greatest impact on road transport, as connectivity and automation (alongside further electrification) could dramatically reshape mobility. However, the overall net energy and emissions impacts of automation and connectivity are highly uncertain, depending on the combined effects of changes in consumer behaviour, policy intervention, technological progress and vehicle technology.

Highly automated vehicles reduce driver stress and allow for more productive use of travel time, making private car travel more attractive. Automation will also make road freight transport more affordable. Both these factors could encourage more travel activity, resulting in increased congestion and energy demand; on the other hand, shared and autonomous transport could facilitate vehicle right-sizing and accelerate EV adoption, reducing energy use and emissions. High utilisation of automated and shared vehicles, spurring more rapid vehicle (and fleet) turnover, could favour and accelerate the uptake of highly efficient technologies including EVs, reducing the emissions intensity of travel. The successful integration of shared and automated mobility services with mass public transit, walking and cycling could also help reduce energy use. In cities with high population density and good public transport networks, digitalisation could contribute to a shift away from the traditional paradigm of vehicle ownership towards the provision of 'mobility as a service'.

Industry

In industry, many companies have a long history of using digital technologies to improve safety and increase production. Further cost-effective energy savings can be achieved through advanced process controls, and by coupling smart sensors with data analytics to predict equipment failure. 3D printing, machine learning and connectivity could have even greater impacts. For example, 3D printing can be used to make aircraft lighter, reducing both the materials to build the plane and the fuel to fly it.

The impact of digitalisation in industry is also moving 'beyond the plant fence'. Digitalisation offers a wide range of opportunities when connecting a particular industrial facility to its surroundings. Digitalisation can better connect producers along product value chains, thereby facilitating the reuse and recycling of materials. Cloud-based collaborative platforms exist to let manufacturers exchange information on available surplus raw materials, industrial by-products and waste. By connecting industrial equipment to the network, companies can benefit from identifying and providing real-time information on the availability of local waste streams, which can be captured and used. Examples include excess heat, organic waste and off-gases, which can be captured and used to produce heat or electricity, thereby reducing both the cost of purchasing other forms of energy and the environmental footprint of the plant.

Buildings

In buildings, digitalisation is bringing new energy services to consumers, such as smart thermostats, occupancy sensors, remote control and enhanced safety features. These technologies could cut energy use by about 10% by using real-time data. Smart thermostats can anticipate the behaviour of occupants and use real-time weather forecasts to predict heating and cooling needs. Smart lighting can provide more than just light when and where it is needed: light-emitting diodes (LEDs) can also be equipped with sensors linked to other systems, helping to tailor heating and cooling services. However, digitalisation also comes with an energy cost, in particular the greater use of network standby power, which could offset potential savings.

E. The role of G20 in fostering energy transitions

Group of Twenty (G20) members account for 85% of the global economy, 75% of world trade and two-thirds of the global population. While the energy mix in G20 economies varies considerably, most countries currently rely on a high share of fossil fuels in their total energy supply: in fact, G20 economies account for 82% of global energy-related carbon dioxide (CO_2) emissions and almost 80% of global energy consumption. At the same time, G20 economies have become leaders in fostering cleaner energy systems, holding a cumulative 81% share of global renewable power capacity.

Energy transitions in G20 economies will shape global energy markets and determine GHG emissions and sustainable development pathways worldwide.

E.1. Opportunities for G20 collaboration

On 1 December 2017, Argentina assumed the G20 presidency, marking the 10th anniversary of the first G20 Leaders' Summit in Washington, D.C., in 2008. Under the overarching presidency theme of "building consensus for fair and sustainable development", Argentina aims to ensure that "growth that is fair, as well as sustainable, is the pillar of development". To this end, the presidency is addressing three new themes: the future of work; infrastructure for development, with enhanced private sector engagement to reduce infrastructure deficit; and improved soils and increased productivity for a sustainable food future. Transitioning towards cleaner, more flexible and transparent energy systems is one of eight priority areas in which Argentina aims to continue promoting G20 collaboration and taking responsibility for climate change action.

Building on the Hamburg Update of the 2030 Agenda for Sustainable Development and the Addis Ababa Action Agenda on Financing for Development, the Argentine presidency's priorities for the G20 Climate Sustainability Working Group are to address climate sustainability, including adapting to climate change and extreme weather events with a focus on developing resilient infrastructure; identify and share long-term low-greenhouse gas development strategies; and align international climate financing with the effective implementation of Nationally Determined Contributions (NDCs) and long-term strategies.

Many G20 countries have adopted energy sector strategies that look ahead to 2030 and include energy sector reforms to transition to cleaner energy, and some have taken a longer-term perspective to 2050, as illustrated in the country profiles in Annex I. Given the growing importance of near- to medium-term challenges, and of the various pathways and possible outcomes, it is timely for the G20 as a whole to examine the real-world challenges of their energy transitions. Outside the G20 framework, energy transitions have been discussed in other settings, notably the Suzhou Forum on Energy Transitions and the Berlin Energy Transition Dialogue, involving G20 partners. Argentina's energy agenda is inclusive and builds on existing G20 commitments, G20 work on inefficient fossil fuel subsidies, natural gas, market transparency, sustainable development, energy efficiency and renewable energy – while placing the ongoing energy transitions of G20 economies at centre stage.

Under Germany's presidency, the G20 Hamburg Climate and Energy Action Plan for Growth was put forward; the People's Republic of China instituted the G20 Energy Efficiency Leading Programme and the Voluntary Action Plan on Renewable Energy; and Turkey's G20 presidency led to several action plans, notably the Action Plan on Energy Access and the

Voluntary Renewable Energy Toolkit. G20 leaders at their summit in Hamburg 2017 committed to "continue to work on open, flexible, and transparent markets for energy commodities and technologies" as well as to "transform and enhance their economies and energy systems consistent with the 2030 Agenda for Sustainable Development". They also acknowledged digital transformation as "a driving force of global, innovative, inclusive and sustainable growth."

E.2. Guidelines for G20 actions

- With the objective of building consensus for fair and sustainable development, G20 economies can build momentum to **engage in closer collaboration and exchange experiences on best practices in their energy transitions** with regard to energy planning, resilience and energy security, regional co-operation and market integration, the role of fossil fuels in the transition, energy efficiency indicators and renewable energy, energy market design and power system flexibility.
- To **foster investment from private and public sectors** across a broad mix of energy sources and technologies, G20 countries should support **stable and robust regulatory frameworks and transparent energy pricing structures** to facilitate private sector investment.
- To stimulate **innovative financing**, including through green bonds, the G20 collectively should aim to leverage support from Multilateral Development Banks (MDBs) and multilateral climate financing institutions to facilitate investment in key regions, including through the G20 Finance track.
- Accelerated innovation in the deployment of energy efficiency, renewable energy and a broad mix of cleaner energy technologies are necessary to foster energy transitions compatible with the objectives of the UN SDG goals. Building on the success of wind and solar PV, the G20 can bring down **technology costs by investing in the research and development of a broader range of critical clean energy technologies** and by **strengthening investment and efforts beyond the power sector.** The G20 can benefit from expanded collaboration through a variety of cooperative venues, such as CEM, MI, and TCPs, the Biofuture Platform, the International Solar Alliance, and others.
- To ensure cost-effective and secure energy transitions, G20 members aim to **accelerate the rate of energy intensity improvement**, collectively aiming to double the annual rate by 2030 by expanding sectoral coverage through minimum performance standards and related labelling programmes across industry, transport, buildings and appliances.
- To maximise benefits for air quality, energy access and climate change mitigation, G20 countries could aim to **triple the share of modern renewable electricity** and **double the share of renewable energy in total energy consumption by 2030** with accelerated deployment of renewables in **transport, heating and cooling, and industry,** which supports the greater electrification.
- Amid rising shares of variable renewable energy (VRE) and power system transformation through greater digitalisation and more decentralised energy in the medium term, the G20 should **foster collaboration on power system flexibility to put forward a G20 roadmap**, assessing contributions from flexible power grids and power plants, regional integration and interconnectivity, and energy storage and demand response, as well as greater electrification and digitalisation.

- G20 countries should underline **regional collaboration as a guiding principle of energy transitions** to ensure the secure and cost-effective transformation of energy systems, based on flexible, regionally integrated and transparent energy markets and systems. **Regional network planning, including interconnectors, and market harmonisation rules** can provide an institutional framework for both government and industry collaboration. Regional market integration and power and gas market interconnections are integral to cost-effective energy transitions.
- As many countries have identified **natural gas as a flexible and cleaner fossil fuel** for energy system transitions, the G20 should emphasise continued investment in gas supply infrastructure and greater regional integration, as well as flexible and diverse LNG contract terms to strengthen gas trade, supply security and resilience to market volatility.
- To track the energy transition across sectors and the economy as a whole, the G20 should take stronger action to **close energy data gaps**, especially on energy end-use data, public/private spending on energy R&D and digitalisation of the energy sector. Digitalisation is already transforming energy systems, breaking down boundaries between energy sectors, enabling integration across technologies and improving overall flexibility.
- As **technology innovation** is vital to enable and accelerate cost-effective energy transitions, the G20 recognises the need to boost global clean energy technology transfer and RD&D efforts as they bring economic and societal benefits, such as reducing GHG emissions and local pollution that are not yet sufficiently valued by markets. The G20 should commit to increased engagement in other multilateral efforts, including through a variety of co operative venues. The G20 as a whole should build an **energy innovation agenda** as part of the collaboration on energy transitions.

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