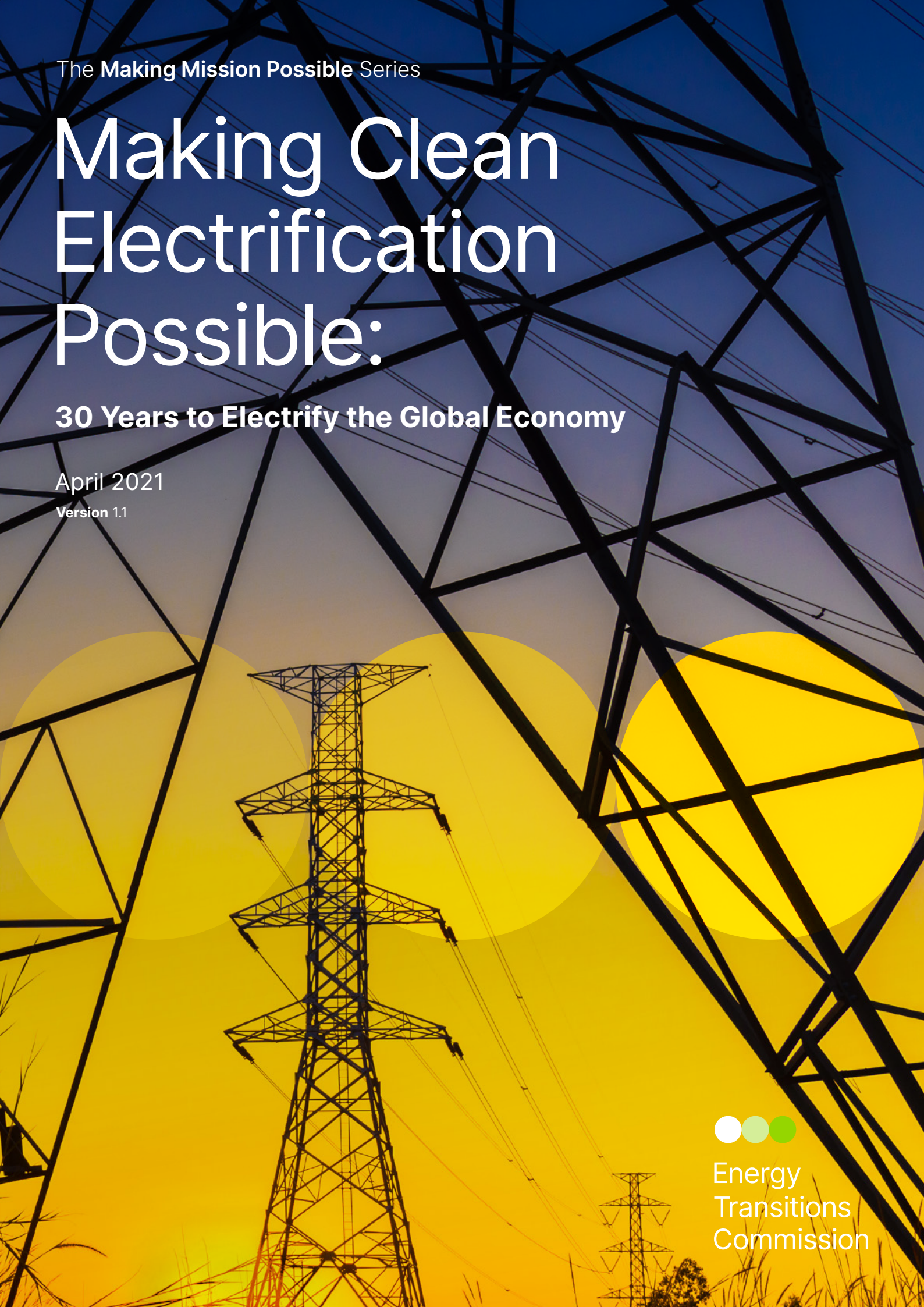
The **Making Mission Possible** Series

Making Clean Electrification Possible:

30 Years to Electrify the Global Economy

April 2021

Version 1.1



Energy Transitions Commission

Making Clean Electrification Possible

30 Years to Electrify the Global Economy

The Energy Transitions Commission (ETC) is a global coalition of leaders from across the energy landscape committed to achieving net-zero emissions by mid-century, in line with the Paris climate objective of limiting global warming to well below 2°C and ideally to 1.5°C.

Our Commissioners come from a range of organisations – energy producers, energy-intensive industries, technology providers, finance players and environmental NGOs – which operate across developed and developing countries and play different roles in the energy transition. This diversity of viewpoints informs our work: our analyses are developed with a systems perspective through extensive exchanges with experts and practitioners. The ETC is chaired by Lord Adair Turner who works with the ETC team, led by Faustine Delasalle. Our Commissioners are listed on the next page.

Making Clean Electrification Possible: 30 Years to Electrify the Global Economy and Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy were developed by the Commissioners with the support of the ETC Secretariat, provided by SYSTEMIQ. They bring together and build on past ETC publications, developed in close consultation with hundreds of experts from companies, industry initiatives, international organisations, non-governmental organisations and academia.

The reports draw upon analyses carried out by ETC knowledge partners SYSTEMIQ and BloombergNEF, alongside analyses developed by Climate Policy Initiative, Material Economics, McKinsey & Company, Rocky Mountain Institute, The Energy and Resources Institute, and Vivid Economics for and in partnership with the ETC in the past. We also reference analyses from the International Energy Agency and IRENA. We warmly thank our knowledge partners and contributors for their inputs.

This report constitutes a collective view of the Energy Transitions Commission. Members of the ETC endorse the general thrust of the arguments made in this report but should not be taken as agreeing with every finding or recommendation. The institutions with which the Commissioners are affiliated have not been asked to formally endorse the report.

The ETC Commissioners not only agree on the importance of reaching net-zero carbon emissions from the energy and industrial systems by mid-century, but also share a broad vision of how the transition can be achieved. The fact that this agreement is possible between leaders from companies and organisations with different perspectives on and interests in the energy system should give decision makers across the world confidence that it is possible simultaneously to grow the global economy and to limit global warming to well below 2˚C, and that many of the key actions to achieve these goals are clear and can be pursued without delay.

Learn more at:
www.energy-transitions.org
www.linkedin.com/company/energy-transitions-commission
www.twitter.com/ETC_energy

Our Commissioners

Mr. Marco Alvera,
Chief Executive Officer – SNAM

Mr. Thomas Thune Anderson,
Chairman of the Board – Ørsted

Mr. Manish Bapna,
Interim CEO & President - WRI

Mr. Spencer Dale,
Group Chief Economist – BP

Mr. Bradley Davey,
Chief Commercial Officer
– ArcelorMittal

Mr. Pierre-André de Chalendar,
Chairman and Chief Executive Officer
– Saint Gobain

Dr. Vibha Dhawan,
Director-General, The Energy and Resources Institute

Mr. Agustin Delgado,
Chief Innovation and Sustainability Officer – Iberdrola

Ms. Marisa Drew,
Chief Sustainability Officer & Global Head Sustainability Strategy, Advisory and Finance – Credit Suisse

Mr. Will Gardiner,
Chief Executive Officer – DRAX

Mr. John Holland-Kaye,
Chief Executive Officer
- Heathrow Airport

Mr. Chad Holliday,
Chairman – Royal Dutch Shell

Mr. Fred Hu,
Founder and Chairman
– Primavera Capital

Dr. Timothy Jarratt,
Chief of Staff - National Grid

Mr. Hubert Keller,
Managing Partner – Lombard Odier

Ms. Zoe Knight,
Managing Director and Group Head of the HSBC Centre of Sustainable Finance – HSBC

Mr. Jules Kortenhorst,
Chief Executive Officer
– Rocky Mountain Institute

Mr. Mark Laabs,
Managing Director – Modern Energy

Mr. Richard Lancaster,
Chief Executive Officer – CLP

Mr. Colin Le Duc,
Founding Partner – Generation IM

Mr. Li Zheng,
Executive Vice President – Institute of Climate Change and Sustainable Development, Tsinghua University

Mr. Li Zhenguo,
President – LONGi Solar

Mr. Martin Lindqvist,
Chief Executive Officer and President
– SSAB

Mr. Auke Lont,
Chief Executive Officer and President
– Statnett

Mr. Johan Lundén,
SVP Head of Project and Product Strategy Office – Volvo Group

Dr. María Mendiluce,
Chief Executive Officer – We Mean Business

Mr. Jon Moore,
Chief Executive Officer –
BloombergNEF

Mr. Julian Mylchreest,
Managing Director, Global Co-Head of Natural Resources (Energy, Power & Mining) – Bank of America

Ms. Damilola Ogunbiyi,
Chief Executive Officer
– Sustainable Energy For All

Mr. Paddy Padmanathan,
President and CEO – ACWA Power

Mr. Vinayak Pai,
Group President EMEA & APAC
– Worley

Ms. Nandita Parshad,
Managing Director,
Sustainable Infrastructure Group
– EBRD

Mr. Sanjiv Paul,
Vice President Safety Health and Sustainability – Tata Steel

Mr. Alistair Phillips-Davies,
CEO – SSE

Mr. Andreas Regnell,
Senior Vice President Strategic Development – Vattenfall

Mr. Siddharth Sharma,
Group Chief Sustainability Officer
– Tata Sons Private Limited

Mr. Mahendra Singhi,
Managing Director and CEO – Dalmia Cement (Bharat) Limited

Mr. Sumant Sinha,
Chairman and Managing Director
– Renew Power

Mr. Ian Simm,
Founder and Chief Executive Officer
– Impax

Lord Nicholas Stern,
IG Patel Professor of Economics and Government - Grantham Institute
- LSE

Dr. Günther Thallinger,
Member of the Board of Management
– Allianz

Mr. Simon Thompson,
Chairman – Rio Tinto

Dr. Robert Trezona,
Head of Cleantech – IP Group

Mr. Jean-Pascal Tricoire,
Chairman and Chief Executive Officer
– Schneider Electric

Ms. Laurence Tubiana,
Chief Executive Officer - European Climate Foundation

Lord Adair Turner,
Co-Chair – Energy Transitions Commission

Senator Timothy E. Wirth,
President Emeritus – United Nations Foundation

Mr. Zhang Lei,
Chief Executive Officer
– Envision Group

Dr. Zhao Changwen,
Director General Industrial Economy
– Development Research Center of the State Council

Ms. Cathy Zoi,
President – EVgo

Contents

The Energy Transitions Commission 2
Our Commissioners 3
Glossary 6
Introduction 10

Chapter 1 **14**

Massive electrification to deliver a zero-carbon economy

I. Massive growth in electricity and hydrogen demand 16
Road transport 16
Shipping and aviation 20
Commercial and residential buildings 20
Industry 21
Electricity for carbon removal 24
II. Electricity for green hydrogen production: the green versus blue question 24
III. Energy productivity improvements 24
IV. Regional and global ramp ups in demand 28

Chapter 2 **32**

Generating low-cost zero-carbon power

I. Declining costs of zero-carbon power 33
II. Balancing VRE based power systems – a vital but manageable challenge 39
Daily balancing – clearly cost-effective solutions 46
Seasonal balancing – more challenging but solvable 49
III. Total system generation costs – fully competitive with fossil fuels 53
IV. Additional costs in transmission and distribution 55
V. Phasing out unabated fossil fuel 58
The path to phase out – gas: decreasing utilisation and balancing role 61
Role of existing coal – transitional role in balancing 62
VI. Natural resource availability – clearly sufficient at global level 66
VII. Resource constrained countries – challenges and solutions: the role of long-distance transmission 68

Chapter 3 — 72

Building and financing zero-carbon power systems

I. Scale and speed of ramp up and investment needs 75
Installed renewable capacity 75
Pace of renewable installations 76
Financial investment implications 76
II. Policies and actions to support rapid ramp-up of zero-carbon electricity generation and system balancing capabilities 80
Power market design 82
Planning, permitting and land acquisition systems to support rapid development 89
Value chain development: identifying and resolving potential bottlenecks 91
III. Policies and actions to support investment in transmission and distribution infrastructure 92
IV. Overcoming financing challenges, in particular in some developing countries 94

Chapter 4 — 98

Critical priorities for the 2020s – Summary

I. The What: Massive clean electrification under way by 2030 99
Substantive phase out of coal and gas generation 100
Expansion of networks and enabling capabilities 100
Overcoming key innovation barriers 100
II. The How: 6 critical priorities for the 2020s 101
1. Clear medium-term targets embedded in a strategic vision for economy-wide decarbonisation 101
2. Appropriate incentives for clean electrification at scale, including power market design 101
3. Building the infrastructure and capabilities required for mass electrification and power system decarbonisation 102
4. Integrated power system vision, with appropriate planning and permitting to speed up implementation 102
5. Unlocking financial flows, especially for developing countries 103
6. Developing the technologies and business models of the future 103

Concluding remarks 105
Acknowledgements 106

Glossary

Abatement cost: The cost of reducing CO_2 emissions, usually expressed in US$ per tonne of CO_2.

Aggregators: New market players that can bundle the energy consumption or generation of several consumer-level electricity market actors (i.e. Distributed Energy Resources) to engage as a single entity – a virtual power plant (VPP) – and sell this flexibility (i.e. 'avoided' electricity consumption through temporary reduction in electricity consumption when there is high demand for electricity) or electricity (e.g. from behind-the-meter storage or distributed generation) in power or ancillary service markets.

Autothermal Reforming (ATR): A catalytic process in which natural gas reacts with oxygen to produce hydrogen and CO_2.

BECCS: A technology that combines bioenergy with carbon capture and storage to produce energy and net negative greenhouse gas emissions, i.e., removal of carbon dioxide from the atmosphere.

Behind-the-meter: A generation or storage system (e.g., rooftop solar PV, home batteries) which produces power on site at a commercial, residential, or industrial site, behind the utility meter.

BEV: Battery-electric vehicle.

Biomass or bio-feedstock: Organic matter, i.e. biological material, available on a renewable basis. Includes feedstock derived from animals or plants, such as wood and agricultural crops, organic waste from municipal and industrial sources, or algae.

Bioenergy: Renewable energy derived from biological sources, in the form of solid biomass, biogas or biofuels.

Capital expenditure (CAPEX): Monetary investments into physical assets (e.g., equipment, plants).

Carbon capture and storage or use (CCS/U): We use the term "carbon capture" to refer to the process of capturing CO_2 on the back of energy and industrial processes. Unless specified otherwise, we do not include direct air capture (DAC) when using this term. The term "carbon capture and storage" refers to the combination of carbon capture with underground carbon storage; while "carbon capture and use" refers to the use of carbon in carbon-based products in which CO_2 is sequestered over the long term (e.g., in concrete, aggregates, carbon fibre). Carbon-based products that only delay emissions in the short term (e.g., synfuels) are excluded when using this terminology.

Carbon emissions / CO_2 emissions: We use these terms interchangeably to describe anthropogenic emissions of carbon dioxide in the atmosphere.

Carbon offsets: Reductions in emissions of carbon dioxide (CO_2) or greenhouse gases made by a company, sector or economy to compensate for emissions made elsewhere in the economy.

Carbon price: A government-imposed pricing mechanism, the two main types being either a tax on products and services based on their carbon intensity, or a quota system setting a cap on permissible emissions in the country or region and allowing companies to trade the right to emit carbon (i.e. as allowances). This should be distinguished from some companies' use of what are sometimes called "internal" or "shadow" carbon prices, which are not prices or levies, but individual project screening values.

Circular economy models: Economic models that ensure the recirculation of resources and materials in the economy, by recycling a larger share of materials, reducing waste in production, light-weighting products and structures, extending the lifetimes of products, and deploying new business models based around sharing of cars, buildings, and more.

Combined cycle gas turbine (CCGT): An assembly of heat engines that work in tandem from the same source of heat to convert it into mechanical energy driving electric generators. Newer CCGT models can be compatible with a retrofitting process to enable the plant to switch from burning methane to burning hydrogen for power generation.

Contract for difference (CfD): A contract between a buyer and seller that stipulates that the buyer must pay the seller the difference between the current value of an asset (spot price) and a pre-determined fixed contract value (strike price). Where public actors act as the buyer this model can be used to cover the cost premium faced by green commodity producers deploying low-carbon technologies that are higher cost than traditional fossil technology. For example, CfDs have been used in the offshore wind industry where generators are reimbursed the difference between the fluctuating wholesale electricity prices and a fixed strike price, typically determined via a public auction. Under a 'two-way' CfD design, where the spot price rises above the strike price the winning bidder must pay back the differential.

Distributed Energy Resource (DER): Small and medium-sized power resources connected to the distribution network, including storage, distributed generation, demand response, EVs and their charging equipment.

Distribution System Operator (DSO): Emerging system operator capability to manage and optimise the transport of electrical power through the fixed infrastructure of a local distribution network. This includes procuring flexibility services from network users, managing local generation and network congestion, and managing flows of energy from and to the wider electricity grid, coordinating with the Transmission System Operator (TSO).

Decarbonisation solutions: We use the term "decarbonisation solutions" to describe technologies or business models that reduce anthropogenic carbon emissions by unit of product or service delivered though energy productivity improvement, fuel/feedstock switch, process change or carbon capture. This does not necessarily entail a complete elimination of CO_2 use, since (i) fossil fuels might still be used combined with CCS/U, (ii) the use of biomass or synthetic fuels can result in the release of CO_2, which would have been previously sequestered from the atmosphere though biomass growth or direct air capture, and (iii) CO_2 might still be embedded in the materials (eg, in plastics).

Direct air capture (DAC): The extraction of carbon dioxide from atmospheric air.

Direct reduced iron (DRI): Iron (so called "sponge iron") produced from iron ore utilising either natural gas or hydrogen. This DRI is then converted to steel in a second step called electric arc furnace (EAF). The DRI-EAF is an alternative primary steel production process enabling decarbonisation of the traditional coke-fired blast furnace/basic oxygen furnace (BF-BOF).

Electrolysis: A technique that uses electric current to drive an otherwise non-spontaneous chemical reaction. One form of electrolysis is the process that decomposes water into hydrogen and oxygen, taking place in an electrolyser and producing "green hydrogen". It can be zero-carbon if the electricity used is zero-carbon.

Embedded carbon emissions: Lifecycle carbon emissions from a product, including carbon emissions from the materials input production and manufacturing process.

Emissions from the energy and industrial system: All emissions arising either from the use of energy or from chemical reactions in industrial processes across the energy, industry, transport and buildings sectors. It excludes emissions from the agriculture sector and from land use changes.

Emissions from land use: All emissions arising from land use change, in particular deforestation, and from the management of forest, cropland and grazing land. The global land use system is currently emitting CO_2 as well as other greenhouse gases, but may in the future absorb more CO_2 than it emits.

Energy productivity: Energy use per unit of GDP.

Final energy consumption: All energy supplied to the final consumer for all energy uses.

Fuel cell electric vehicle (FCEV): Electric vehicle using a fuel cell generating electricity to power the motor, generally using oxygen from the air and compressed hydrogen.

Greenhouse gases (GHGs): Gases that trap heat in the atmosphere. Global GHG emission contributions by gas – CO_2 (76%), methane (16%), nitrous oxide (6%) and fluorinated gases (2%).

Heavy Goods Vehicles (HGV) or Heavy Duty Vehicle (HDV): Both terms are used interchangeably and refer to trucks ranging from 3.5 tonnes to over 50 tonnes.

High Voltage Direct Current (HVDC) transmission: A power transmission technology utilising direct current for the bulk transmission of electrical power. It is particularly useful for high capacities and longer distances due to minimal energy transmission losses compared to classical AC technology.

Hydrocarbons: An organic chemical compound composed exclusively of hydrogen and carbon atoms. Hydrocarbons are naturally occurring compounds and form the basis of crude oil, natural gas, coal and other important energy sources.

Internal combustion engine (ICE): A traditional engine, powered by gasoline, diesel, biofuels or natural gas. It is also possible to burn ammonia or hydrogen in an ICE.

Learning rate: The learning rate describes the cost decline for one unit (e.g., electrolyser) for each doubling of the total cumulative number of previously produced units.

Levelised cost of electricity (LCOE): A measure of the average net present cost of electricity generation for a generating plant over its lifetime. The LCOE is calculated as the ratio between all the discounted costs over the lifetime of an electricity-generating plant divided by a discounted sum of the actual energy amounts delivered.

Liquified Natural Gas (LNG): LNG is the clear and non-toxic liquid state of natural gas at temperatures below -162ºC. It enables the transport and storage of natural gas without pressurisation, especially over longer distances via ships.

Natural carbon sinks: Natural reservoirs storing more CO_2 than they emit. Forests, plants, soils and oceans are natural carbon sinks.

Nature-based solutions: Actions to protect, sustainably manage and restore natural or modified ecosystems which constitute natural carbon sinks, while simultaneously providing human, societal and biodiversity benefits.

Near-total-variable-renewable power system: We use this term to refer to a power system where 85-90% of power supply is provided by variable renewable energies (solar and wind), while 10-15% is provided by dispatchable/peaking capacity, which can be hydro, biomass plants or fossil fuels plants (combined with carbon capture to reach a zero-carbon power system).

Net-zero-carbon-emissions / Net-zero-carbon / Net-zero: We use these terms interchangeably to describe the situation in which the energy and industrial system as a whole or a specific economic sector releases no CO_2 emissions – either because it doesn't produce any or because it captures the CO_2 it produces to use or store. In this situation, the use of offsets from other sectors ("real net-zero") should be extremely limited and used only to compensate for residual emissions from imperfect levels of carbon capture, unavoidable end-of-life emissions, or remaining emissions from the agriculture sector.

Operating Expenditures (OPEX): Expenses incurred through normal business operations to ensure the day-to-day functioning of a business (e.g., labour costs, administrative expenses, utilities).

Partial Oxidation (POX): A non-catalytic chemical process to convert hydrocarbon residues or natural gas with oxygen to hydrogen and carbon dioxide.

Power Purchase Agreement (PPA): A PPA describes the contractual obligations between an electricity generator and buyer. Typically, these contracts are used to guarantee long-term offtake security for the supplier prior to the construction of a new generation asset.

Proton Exchange or Polymer Electrolyte Membrane (PEM) electrolyser: A specific water electrolysis technology which operates under acidic conditions using a polymer to separate the electrodes.

Primary energy consumption: Crude energy directly used at the source or supplied to users without transformation – that is, energy that has not been subjected to a conversion or transformation process.

Steam methane reforming (SMR): A process in which methane from natural gas is heated and reacts with steam to produce hydrogen.

SMR/ATR/POX with carbon capture and storage (SMR/ATR/POX + CCS): Hydrogen production from SMR/ATR/POX, where the carbon emitted from the combustion of natural gas is captured to be stored.

Sustainable biomass / bio-feedstock / bioenergy: In this report, the term 'sustainable biomass' is used to describe biomass that is produced without triggering any destructive land use change (in particular deforestation), is grown and harvested in a way that is mindful of ecological considerations (such as biodiversity and soil health), and has a lifecycle carbon footprint at least 50% lower than the fossil fuels alternative (considering the opportunity cost of the land, as well as the timing of carbon sequestration and carbon release specific to each form of bio-feedstock and use).

Synfuels: Hydrocarbon liquid fuels produced from hydrogen, carbon dioxide and electricity. They can be zero-carbon if the electricity input is zero-carbon and the CO_2 is from direct air capture. Also known as "synthetic fuels", "power-to-fuels" or "electro-fuels".

Technology Readiness Level (TRL): Describes the level of matureness a certain technology has reached from initial idea to large-scale, stable commercial operation. The IEA reference scale is used.

Transmission System Operator: Existing system operator capability responsible for managing flow of electricity through the electricity transmission system, ensuring its stable and secure operation and matching demand and supply in time and space.

Virtual Power Plants (VPP): Aggregation of many disperse Distributed Energy Resources (DERs) with the aim of enabling DERs to provide services to the grid. VPP operators aggregate DERs to behave similar to a conventional power plant, with features such as minimum / maximum capacity, ramp-up, ramp-down, etc. and to participate in markets to sell electricity or ancillary services.

Zero-carbon energy sources: Term used to refer to renewables (including solar, wind, hydro, geothermal energy), sustainable biomass, nuclear and fossil fuels if and when their use can be decarbonised through carbon capture.



Major ETC reports and working papers

Global reports



Better Energy, Greater Prosperity(2017) outlined four complementary decarbonisation strategies, positioning power decarbonisation and clean electrification as major complementary progress levers.



Mission Possible (2018) outlined pathways to reach net-zero emissions from the harder-to-abate sectors in heavy industry (cement, steel, plastics) and heavy-duty transport (trucking, shipping, aviation).



Making Mission Possible (2020) showed that a net-zero global economy is technically and economically possible by mid-century and will require a profound transformation of the global energy system.

Sectoral and cross-sectoral focuses



Sectoral focuses provided detailed decarbonisation analyses on each on the six harder-to-abate sectors after the publication of the Mission Possible report (2019). Our latest focus on building heating (2020) details decarbonisation pathways and costs for building heating, and implications for energy systems.

As a core partner of the Mission Possible Partnership, the ETC also completes analysis to support a range of sectoral decarbonisation initiatives:



In October 2020, the corporate members of the Clean Skies for Tomorrow initiative (CST) developed a **Joint Policy Proposal to Accelerate the Deployment of Sustainable Aviation Fuels in Europe**

Produced for the Getting to Zero Coalition, **"The First Wave – A blueprint for commercial-scale zero-emission shipping pilots"** highlights five key actions that first movers can take to make tangible progress towards zero emission pilots over the next three to four years.

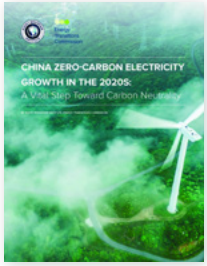
Geographical focuses

A series of reports on the Indian power system and outlining decarbonisation roadmaps for Indian industry (2019-2020) described how India could rapidly expand electricity supply without building more coal-fired power stations, and how India can industrialise whilst decarbonising heavy industry sectors.





China 2050: A Fully Developed Rich Zero-carbon Economy described the possible evolution of China's energy demand sector by sector, analysing energy sources, technologies and policy interventions required to reach net-zero carbon emissions by 2050.



China Zero Carbon Electricity Growth in the 2020s: A Vital Step Toward Carbon Neutrality (January 2021). Following the announcement of China's aim to achieve carbon neutrality before 2060 and peak emissions before 2030. This report examines what action is required by 2030 aligned with what is needed to fully decarbonise China's power sector by 2050.

Introduction

Stabilising the world's climate requires reducing net greenhouse gas emissions to zero by mid-century. An increasing number of countries have made commitments to reach this goal, and others will follow. The key question is how to achieve that objective. The first and most important step must be a massive shift to clean electricity as the basis of the global economy, with electricity applied to a far wider range of end applications and matched by an equally rapid decarbonisation of electricity supply. Alongside this, a range of complementary technologies, including clean hydrogen, carbon capture and storage or use (CCS/U) and sustainable bioenergy, will also need to be deployed.

Direct electrification will be the key to decarbonising many sectors of the economy, including road transport and building heating. Electrification will often be the most cost-competitive decarbonisation option. It will automatically produce major improvements in energy efficiency; and it will deliver large local environmental benefits with better air quality and reduced noise pollution. Hydrogen, produced via electricity, can provide a clean zero-carbon route to decarbonisation in harder-to-abate sectors such as steel and long-distance shipping. At the global level, electricity's share of final energy demand will likely grow from today's 20% to over 60% by mid-century with a further 15 to 20% accounted for by hydrogen produced primarily from electrolysis [Exhibit 0.1].

To enable the shift to an electrified economy, total global electricity supply must rise by around 3.5-5 times current levels in the next 30 years – from today's 27,000 terawatt hours (TWh) to as much as 130,000 TWh by 2050, including electricity use for the production of hydrogen.

Massive clean electrification is a significant challenge – growing electricity use must be matched by equally rapid decarbonisation of electricity supply. The good news is that the transition, managed properly, will pay for itself. Dramatic reductions in renewable electricity costs enable the decarbonisation of power systems while reducing total system generation costs. The opportunity is already clear: despite disruptions from the COVID crisis and in contrast to other generation sources, renewables capacity, including hydropower, increased by 7% in 2020, and captured 90% of new power capacity added.[1]

Globally, wind and solar generation still only account for 10% of electricity generation.[2] They will need to grow to around 40% of electricity generation by 2030 and over 75% by 2050, with parallel deployment of other zero-carbon generation, flexibility, storage and networks, to deliver zero-carbon power systems at scale.

Achieving early power decarbonisation – ahead of economy wide decarbonisation – must therefore be at the heart of all countries' paths to net-zero greenhouse gas emissions. The Energy Transitions Commission believes that:

All developed economies can and should commit to be net zero economies by 2050 and to achieve near total electricity decarbonisation by the **mid-2030s** (e.g. with grid emissions intensity targets of below 30gCO_2 per kWh), eliminating coal use almost immediately and with clear plans to phase out unabated gas. In these regions, total electricity use will typically grow 2-2.5 times by 2050.

Developing economies can and should commit to be net-zero economies by 2060 at the latest, and to achieve near total decarbonisation of power by the **mid-2040s**. Electricity use will often need to grow 5-6 times by 2050, with the growth in electricity generation being met almost entirely by zero-carbon sources, and a phase out of existing coal plants in the 2030s and 2040s.

Low-income economies (e.g. in Sub-Saharan Africa) can and should aim to "leap-frog" fossil fuels. They can massively expand electricity provision – to meet as much as a tenfold growth in electricity use by 2050 – by building zero-carbon power systems while never going through a fossil fuel phase.

1 IEA (2020), *Renewables 2020.*
2 IEA (2020), *World Energy Outlook.*

This scale of change will only occur at the pace required if countries set out strategic visions for the growth and decarbonisation of their power systems with clear medium-targets, supported by critical actions including appropriate power market design and network investment frameworks. Annual installations of zero-carbon power capacity (primarily wind and solar) must rise to over 10 times current levels: total global investments of over $2 trillion per annum will be needed in clean power generation and supporting transmission and distribution networks, compared with $1 trillion annual investment in fossil fuels and $1.9 trillion annual investments across the total energy sector today.[3] In some countries specific actions will also be needed to remove barriers to investment arising from planning and permitting processes, or to fast-track the availability of key skills and low-cost finance.

This report sets out why massive green electrification is essential, but also feasible and affordable. It identifies both potential barriers to success, and actions to overcome them. It covers in turn:

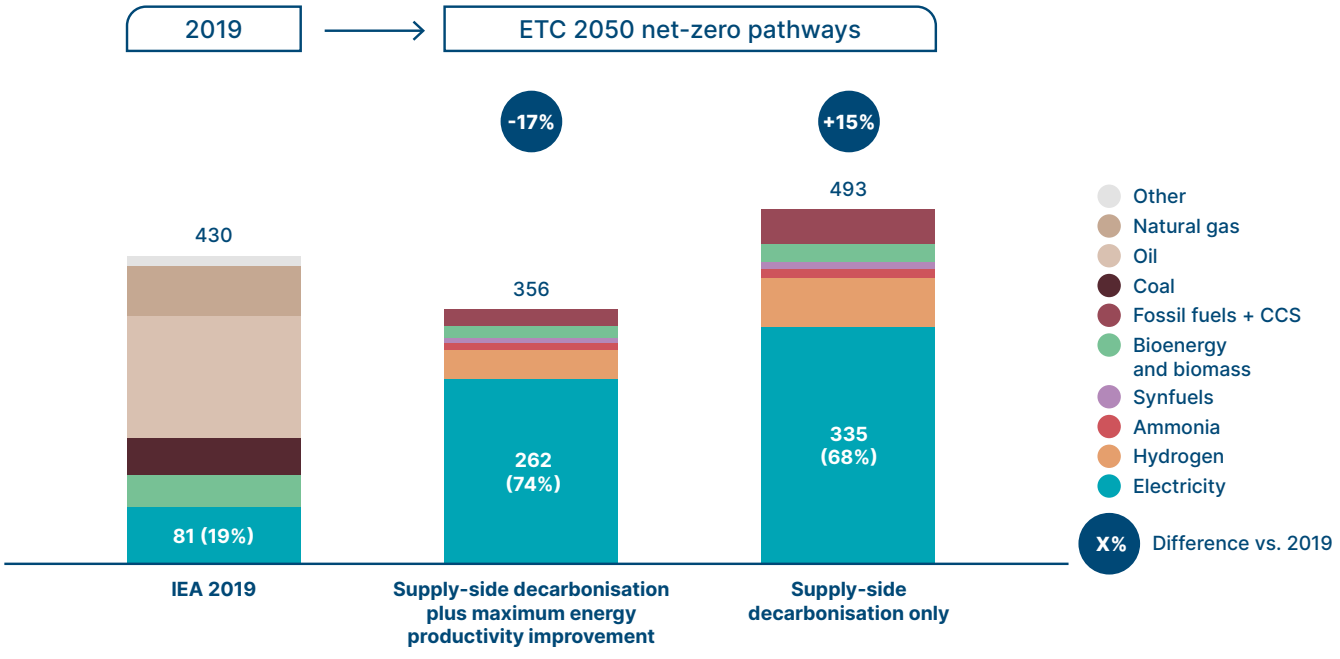
- Electrification plus hydrogen as key routes to decarbonisation;
- How to deliver zero-carbon electricity at low cost;
- How to build and finance zero carbon power systems;
- Summary of key actions required in the next decade.

The report covers challenges in both developed and developing countries, drawing for the latter on recent ETC reports on the decarbonisation of the Chinese and Indian power systems.[4] It also refers to the parallel ETC report, issued simultaneously, on the role which hydrogen must play in decarbonisation and the implications of hydrogen demand growth for electricity demand.[5] Forthcoming ETC reports will cover other key areas needed to build a zero-carbon economy, including sustainable supply and use of bioenergy and biomaterials, as well as the various technologies and applications which can capture CO_2, covering CCS/U, Direct Air Capture, bioenergy with carbon capture and storage (BECCS), and natural carbon sinks.

Exhibit 0.1

Indicative final energy mix in a zero-carbon economy

EJ/year



SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021); IEA (2020), *World Energy Outlook*

3 IEA (2020) *World Energy Outlook.*

4 See TERI/ETC India (2020), *Renewable Power Pathways: Modelling the Integration of Wind and Solar in India by 2030* and RMI/ETC China (2021), *China Zero-Carbon Electricity Growth in the 2020s: A Vital Step Towards Carbon Neutrality.*

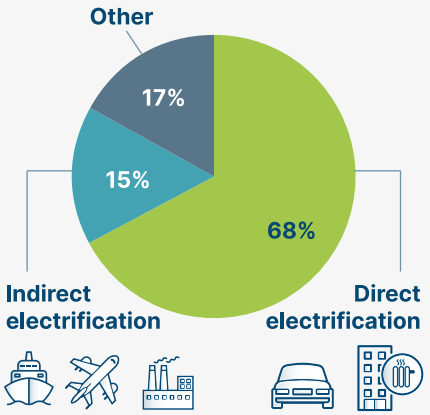
5 ETC (2021), *Making the Hydrogen Economy Possible: Accelerating clean hydrogen in an electrified economy*

Energy Transitions Commission

MAKING CLEAN ELECTRIFICATION POSSIBLE

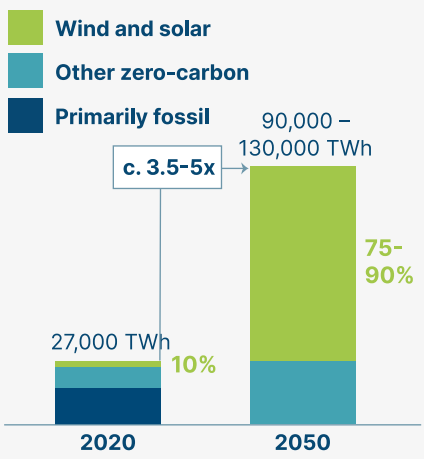
AN ELECTRIFIED ECONOMY

Final energy demand – ETC 2050 Indicative Scenario



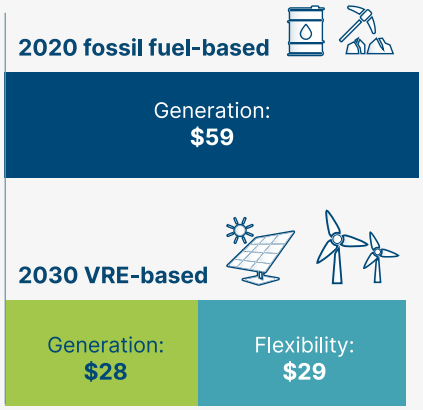
A MASSIVE INCREASE IN CLEAN POWER PROVISION

Power generation, TWh



AT NO EXTRA SYSTEM GENERATION COST

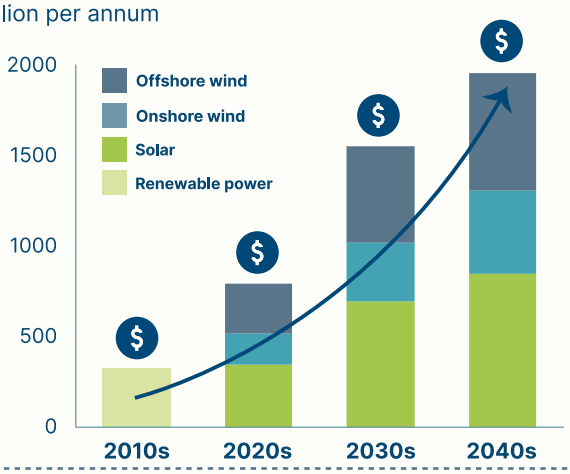
All-in generation cost, $/MWh



What will it take?

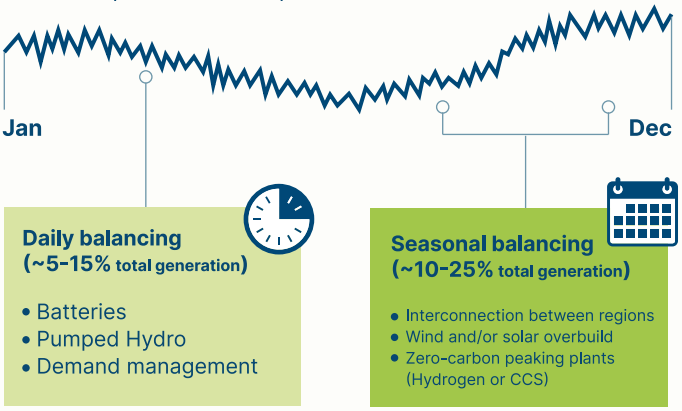
RAPID RAMP-UP IN WIND AND SOLAR INVESTMENT

$ billion per annum

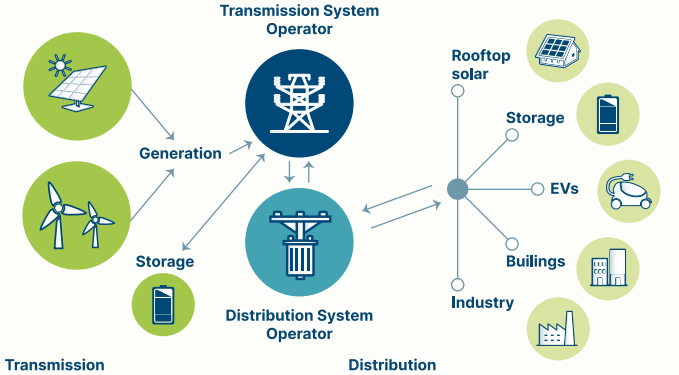


INCREASING FLEXIBILITY PROVISION

Indicative power demand profile



UPGRADING AND DIGITALISING T&D NETWORKS



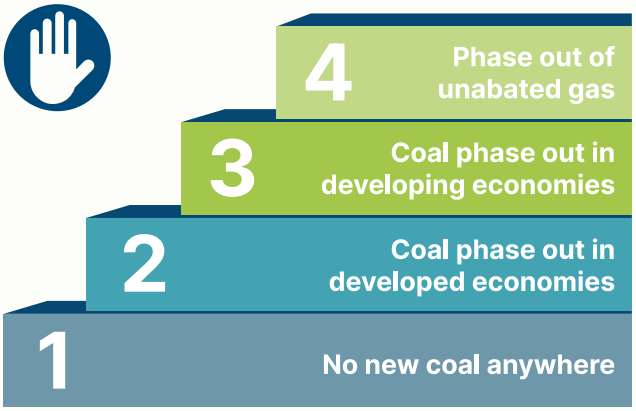
Transmission

Integrated across network vision
Connecting remote renewables
Employing new technical capabilities

Distribution

Digitalised
Connected to new infrastructure (e.g. EV charging)
Moving 2-way power flows

PHASE OUT OF UNABATED FOSSIL FUELS GENERATION







Chapter 1

Massive electrification to deliver a zero-carbon economy

All published scenarios defining a path to a low-carbon economy see a major role for clean electrification. Estimates of that role, and of resulting electricity generation requirements, have increased over the past few years. [Exhibit 1.1]. Increasing estimates for the role of electricity reflect a growing recognition that electricity (or hydrogen made from electricity) will be the most cost-effective decarbonisation path across multiple sectors, given the falling cost of electrification use cases, as well as of renewable electricity generation.

It is vital for companies, investors and policymakers to recognise that this required growth could be even higher than many projections still assume. Our ETC scenarios for net-zero greenhouse gas emissions by mid-century, reflecting latest available information on the likely cost-competitiveness of power-based decarbonisation solutions, suggest that total electricity use – for direct electrification as well as for the production of hydrogen via electrolysis – will need to rise from 27,000 TWh to between 90-130,000 TWh by 2050.[6] Rapid energy productivity improvement could reduce the scale of the challenge and should therefore be a key priority, but, even then, a three-fold increase in the size of the power system would still be required.

This chapter therefore describes the basis for our view of an electrified economy, covering in turn:

- Growing demand for electricity or hydrogen in both existing and new applications;
- Potential electricity demand for hydrogen production – the "green" versus "blue" choice;
- Improvements in energy efficiency and the impact on demand growth;
- Regional and global ramp ups in electricity demand.

External outlooks increasingly aligned to high electrification vision

Global electricity demand, TWh/year

Boxes indicate scenario ranges in a given year

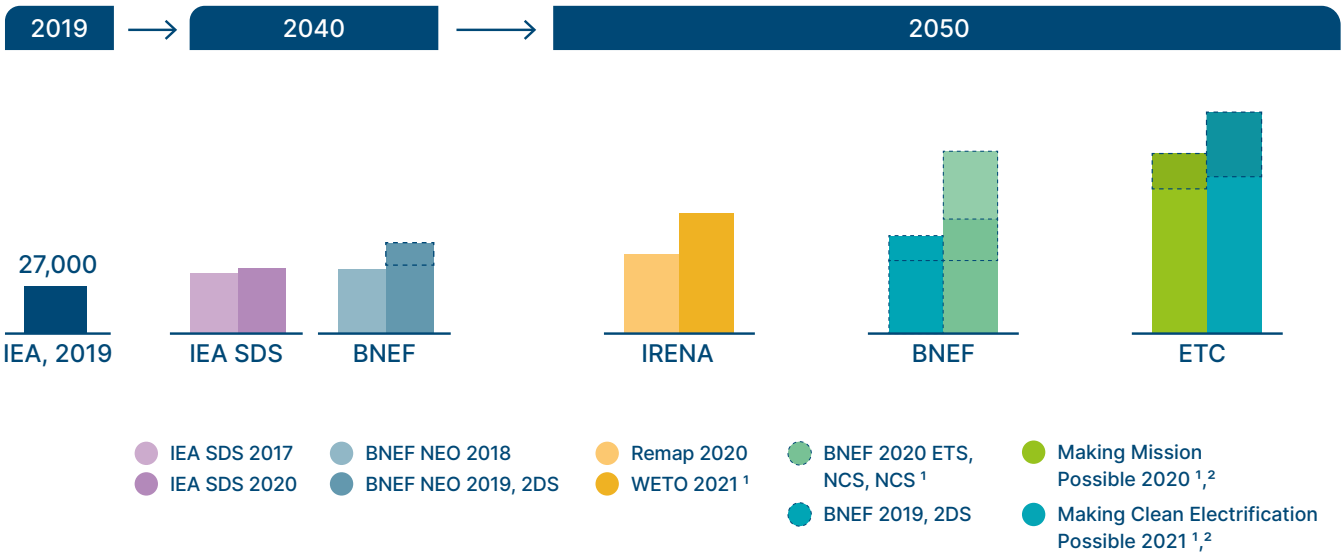


Exhibit 1.1

[1] Includes electricity demand from green hydrogen production. [2] Denotes range across supply-side decarbonization plus maximum energy productivity improvement and supply-side decarbonization only scenarios.

NOTES: IEA SDS is IEA Sustainable Development Scenario; BloombergNEF's NEO is New Energy Outlook, with the 2020 base case as the Economic Transitions Scenario (ETS) and the alternative, deep decarbonization scenario as the NEO-Climate Scenario (NCS). IRENA Remap is the Energy Transformation outlook to 2050, WETO is the 1.5DS in the World Energy Transitions Outlook.

SOURCE: IEA, IRENA, BloombergNEF, ETC

6 This view reflects a split of 85% of "green" hydrogen and 15% of "blue" hydrogen production in 2050. The actual balance between green and blue will reflect future trends in technology and cost and will vary in line with specific national and regional circumstances. ETC analysis for the parallel hydrogen report concludes that it is likely that green hydrogen will account for a large majority of total production by mid-century and become increasingly dominant in the late 2020s/early 2030s, given the long-term cost trends and prospects for rapid green hydrogen cost reductions in the 2020s

I. Massive growth in electricity and hydrogen demand

In a net-zero GHG emissions economy, electricity use will increase due to growth in existing electricity applications, as well as the emergence of new uses for electricity as the economy decarbonises and switches away from existing high-carbon technologies. Currently, electricity is used primarily in buildings (51%), in light industry (41%), and a minimal share in transport (2%).[7]

In many developing countries, electricity use in existing applications will be driven by economic growth and rising prosperity. Current electricity use per capita varies from less than 1,000 kWh in most of Africa to over 10,000 kWh in the US [Exhibit 1.2]. As incomes rise and societies urbanise, demand for applications such as air-conditioning, or the use of information technology, will inevitably increase.

In addition, new applications for electricity or hydrogen will be key to the decarbonisation of transport, buildings, and industry, which will drive electricity demand growth across both developed and developing countries. Some of these applications will also have implications for the timing and shape of electricity demand, and thus the challenges of balancing electricity systems.

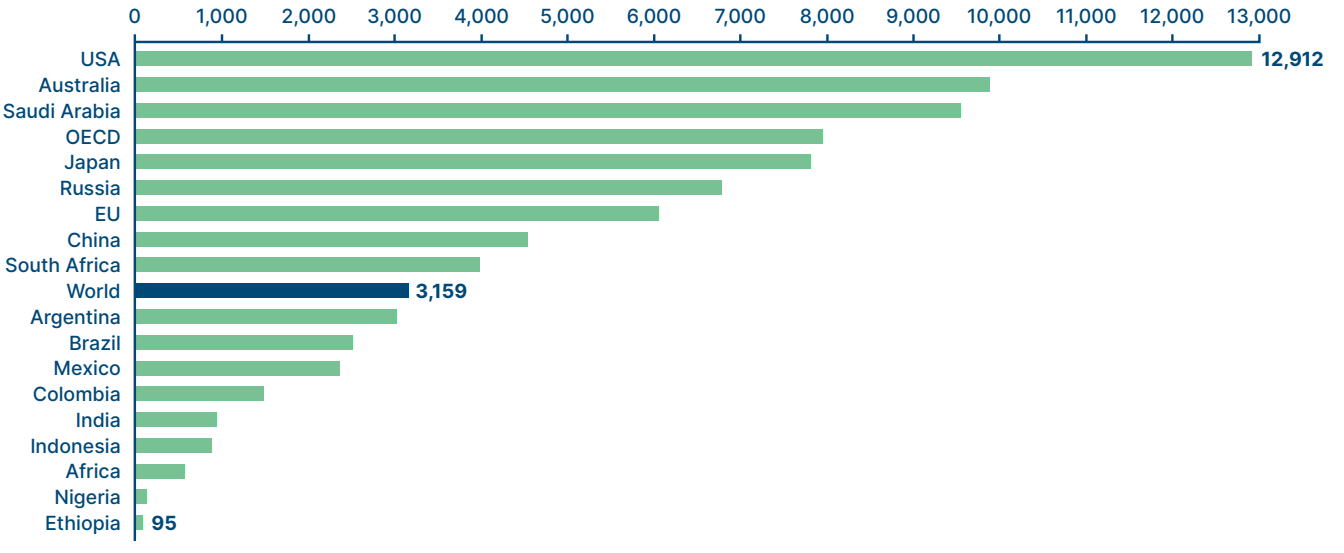
Road transport

Until a few years ago, many scenarios for road transport decarbonisation still assumed a major long-term role for biofuels. But it is now clear that battery electric vehicles (BEVs) will play a dominant role in road transport decarbonisation, eventually accounting for almost all light duty vehicle (LDV) kilometres travelled, and probably for the majority of heavy goods vehicles (HGV) kilometres, though with hydrogen fuel cell electric vehicles (FCEVs) also playing an important role for HGV.

Exhibit 1.2

Electricity use per capita varies greatly, reflecting living standard inequalities

Electricity consumption per capita
kWh per capita, 2018



SOURCE: IEA (2019), *World Energy Outlook*; IEA website

7 IEA (2019), *World Energy Outlook*

Light Duty Vehicles

In the LDV sector, including passenger cars as well as vans, BEVs will dominate in the long term, but the pace of electrification will depend crucially on public policy:

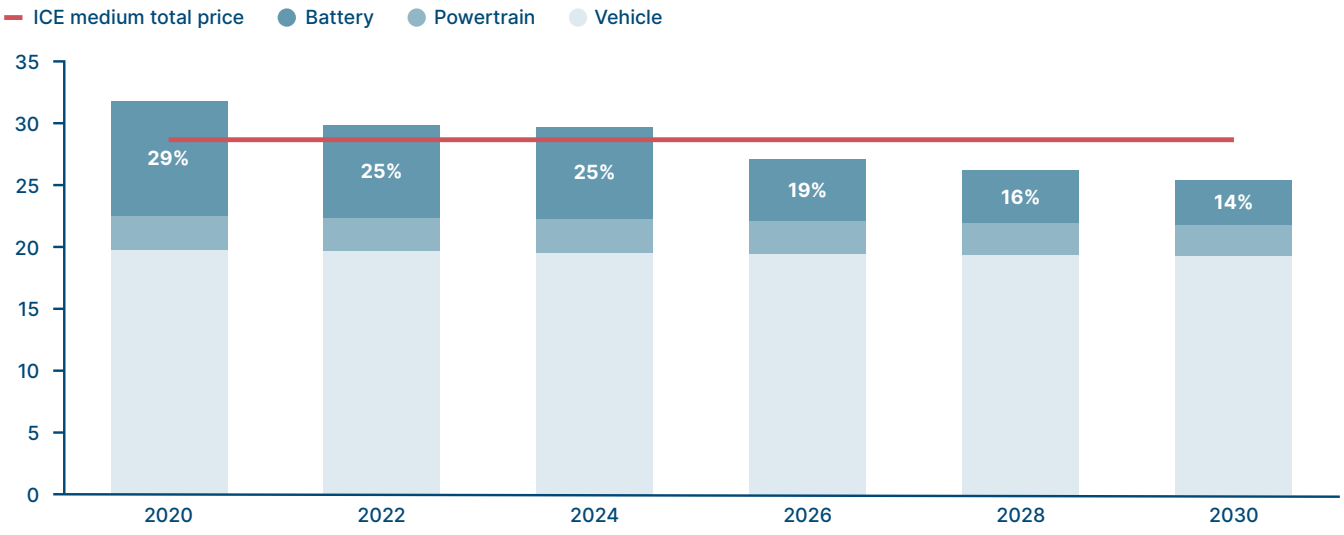
- Lithium-ion battery prices have fallen 85% in 10 years and are projected to fall below $100/kWh by 2024, reaching $60/kWh by 2030, and still lower in the 2030s.
- As a result, and given the lower cost of much simpler electric engines, the upfront cost of BEVs is likely to fall below that of ICEs during the 2020s (with BloombergNEF forecasting that this tipping point will be reached as early as 2024).[8] [Exhibit 1.3]
- Given the inherent energy efficiency advantage of BEVs versus ICEs (which typically turn about 60-80% of total energy input into waste heat), plus the lower maintenance costs resulting from simpler engines, the total ownership cost advantage of BEVs will occur ahead of upfront costs. The total cost of ownership (TCO) of EVs could fall below that of ICE as early as 2022 for China and 2025 for the United States, when comparing medium-sized cars.[9]
- With effective barriers to EV adoption being overcome (e.g. battery range improvements, companies introducing a wide range of new models across segments, including SUVs or pickup trucks), it is possible that battery electric LDV sales could take off far more rapidly than many current forecasts suggest, reaching over 80% of new sales by the mid-2030s. Further innovation, e.g. expanding the availability of rapid charging technology or further increases in range due to improved battery density, will accelerate adoption at scale.

However, despite improving economics leading to growing shares of BEVs in new sales, it will take many years for the fleet of LDVs to be largely electrified given typical vehicle turnovers of 12 years in developed economies, but much longer in some developing countries.

Exhibit 1.3

By the middle of the 2020s, the average BEV in the US and Europe will be cheaper than a comparable ICE

BEV and ICE pre-tax prices in the U.S and the share of battery costs in the vehicle price
Real thousand 2019$ and %, medium size car segment, 2020-2030



SOURCE: BloombergNEF (2020), *When Will EVs Be Cheaper Than Conventional Vehicles?*

8 Relative prices could be significantly different from relative costs during a significant transitional period. This is because i) auto companies will be seeking to recover initial investments in BEVs – as they face a seller's market for popular BEV models, they could be selling BEVs at undiscounted target prices to recover all costs; ii) auto companies have increasing overcapacity in ICE production, and would therefore be willing to sell some models at discount – an effect that is likely to become larger as ICE bans are announced. As a result, ICE model prices may stay below BEVs for most of the 2020s. However, in the long run, and certainly sometime in the 2030s, the cost advantages of BEVs in term of falling battery prices and cheaper electric engines will be reflected in prices as well as costs.

9 BloombergNEF (2020), *Long-term Electric Vehicle Outlook*. To be fully comparable, a total cost of ownership (TCO) calculation for BEVs and ICE should include no fuel tax.

It is therefore essential that public policy drives the economically feasible transition as rapidly as possible, with a short-term focus on charging infrastructure investment, the introduction of bans on new ICE sales from 2030 or soon thereafter, as well as stringent CO_2 emissions or fuel economy standards, and policies to encourage accelerated fleet renewal and early retirement of ICEs, for instance through purchase incentives for BEVs or prohibiting their use in major cities.

Heavy Goods Vehicles

In the HGV sector (encompassing trucks ranging from 3.5 tonnes to over 50 tonnes), there is higher uncertainty over the balance of technologies. Falling battery costs, increasing battery density, and improved potential charging speeds make it likely that BEVs will play a bigger role than until recently assumed. For many medium-weight local distribution trucks and urban buses, the total cost of ownership (TCO) for BEVs are likely to become increasingly competitive with ICEs during the 2020s. Globally, the increasing competitiveness of BEV trucks is reflected in the increasing flow of BEV model announcements, including from Volvo, Daimler, Scania, as well as Arrival, Rivian, Tesla and BYD.[10]

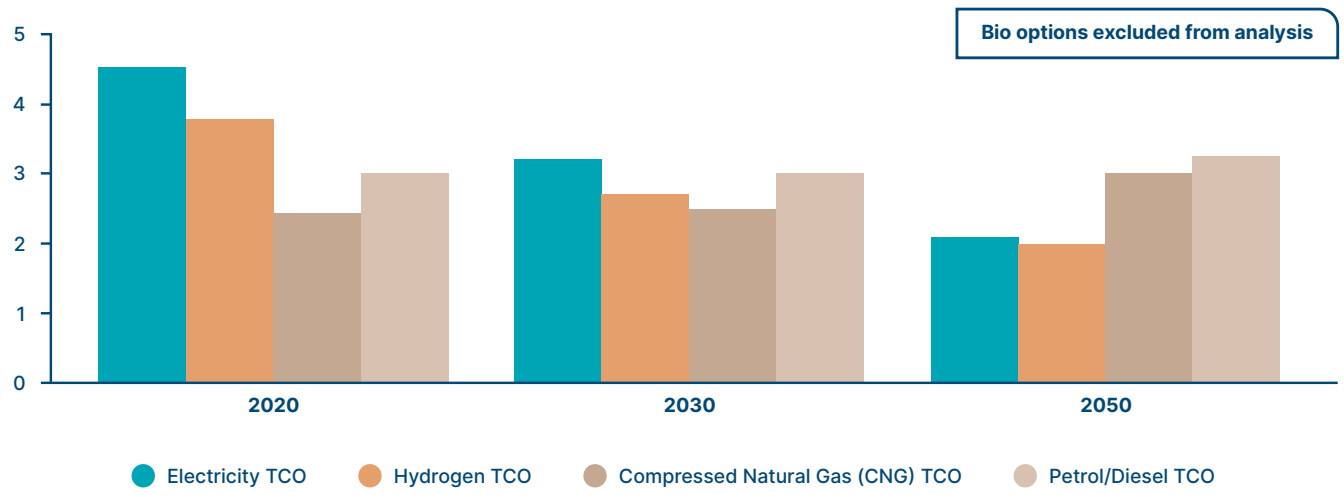
For very heavy trucks travelling long distances, hydrogen FCEVs may still play a significant role. Analysis on total cost of ownership in India shows that BEV and FCEV trucks will be the most cost-competitive options in 2050 on a ton-kilometer (tkm) basis, with broadly similar economics [Exhibit 1.4]. The precise balance between different vehicle types will depend on unpredictable future technology and cost developments (and in particular on how far and how fast battery energy density and charging speeds can be improved, with the battery weight being a significant consideration for BEVs), as well as the availability of charging infrastructure around long-distance routes. A reasonable scenario at a global level sees BEVs accounting for 80% of final energy demand in the heavy-duty transport sector in 2050, with FCEVs accounting for the other 20%.[11] By 2050, biofuels are not expected to be cost-competitive with non-bio, low-emissions alternatives for any road transport segment, with the possible exception of sustainably produced biofuels or synthetic fuels in ICE powertrains for ultra-long-distance and very heavy duty trucking (e.g., if BEV and FCEV infrastructure is not able to expand to more remote areas).[12]

Combining our scenarios for the LDV and HGV sectors, this could imply a demand for 12,000-18,000 TWh of electricity by 2050, of which 1,300-1,900 TWh used to produce green hydrogen.

Exhibit 1.4

India example, total cost of ownership (TCO) analysis for trucks shows BEV and FCEV most cost competitive in 2050

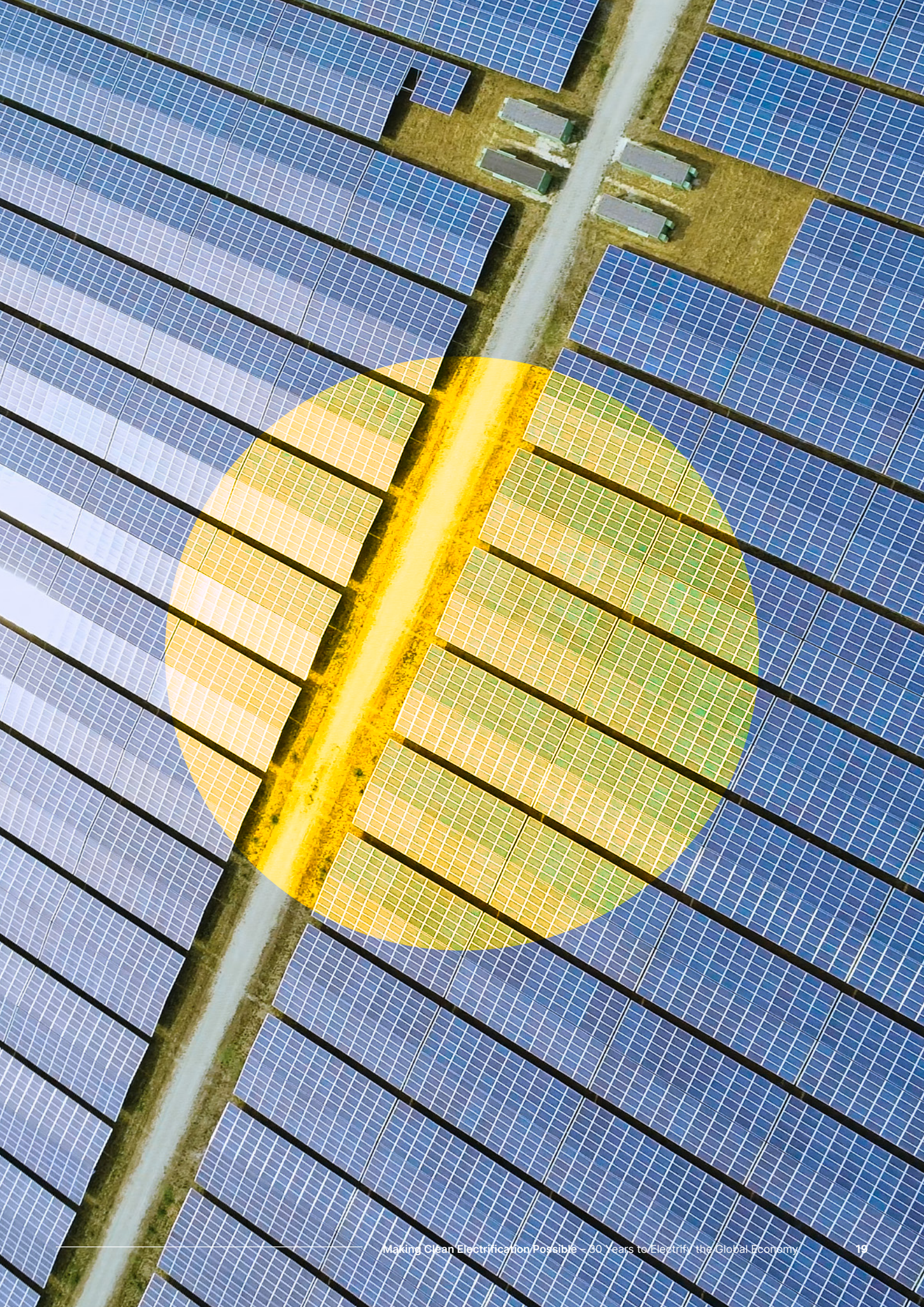
Modelled results for truck total cost of ownership (TCO) per ton-kilometre in India
₹/Tkm



NOTE: This analysis excludes a CO_2 price assumption. The metric represented is the total cost of ownership (TCO) / ton-kilometre (Tkm), where Tkm is the truck payload multiplied by the distance travelled. Modelled vehicle represents heavy-duty truck in the order of 25 tonnes.

SOURCE: TERI/ETC India (2020), *The Potential Role of Hydrogen in India*

10 *GreenBiz*, 19 January 2021, "2021 is the year for electric trucks"
11 ETC (2020), *Making Mission Possible*
12 Material Economics analysis



Overall, road transport would account for less than 20% of final electricity demand by 2050. However, the potential timing and shape of this demand – and the resulting implications for the challenge of balancing supply and demand in electricity systems based primarily on variable renewable supply – makes forward looking public policy and investment critical, particularly in relation to local distribution networks.

- If vehicle charging was concentrated at particular times of day, e.g. early evening when many workers return home, it could increase demand peaks and exacerbate the cost of system balance.

- But vehicle batteries could be a major flexibility and storage resource, significantly reducing the costs of balancing the system, either if charging is done at optimal times (e.g. overnight or when electricity is temporarily in surplus supply such as midday in sunny regions), or if vehicle batteries could store and discharge electricity into the grid (e.g. vehicle-to-building, vehicle-to-grid). Theoretically, if by 2050 there were 1.5 billion BEVs each with 60 kWh batteries, the resulting 90 TWh of battery storage would be sufficient to charge (and then discharge) eight hours of total global electricity supply in 2050. In practice, however, although vehicle-to-grid (V2G) is well positioned to play a meaningful role in grid balancing, this theoretical potential could be limited by consumer concerns over battery degradation, as well as the fact that V2G could be limited to a discharge capacity below that of the full battery capacity.

- Furthermore, the rapid adoption of battery electric vehicles will have strong localised effects on electricity demand, which requires forward planning to ensure that local distribution-level capabilities (e.g. charging stations, network capacity) are in place ahead of need.

It is therefore vital that public policy and investment decisions not only drive rapid road transport electrification, but proactively encourage flexibility and storage provision (including smart charging), including by rewarding flexibility in power markets through real-time pricing. Investment frameworks for distribution networks should also enable investments ahead of need to ensure timely reinforcements.

Shipping and aviation

Direct electrification will play a role in the decarbonisation of short-distance shipping and aviation. Local ferries and shorter distance cruise ships will likely move to electric engines powered by batteries or fuel cells. In the airline industry, players such as Airbus hope to be able to electrify flights of up to 1,500 km by the mid-2030s: if that is possible about 20% of all aviation jet fuel demand could be replaced with electricity, or by hybrid combinations of electricity and hydrogen.

But unless or until there are order of magnitude improvements in battery energy density, the primary path to decarbonisation of long-distance shipping and aviation will involve the use of liquid fuels burnt in largely unchanged engines. These could come from low-carbon sustainable bio-resources (converted into alcohols or biofuels) or from a power-to-liquid production route (ammonia in the case of shipping and synthetic jet fuel in the case of aviation).[13]

The total impact on electricity and hydrogen demand is inherently less certain than in the case of road transport, but could result in about 9,000-13,000 TWh of electricity demand, with 700-1,000 TWh from direct electrification of short-haul distances of shipping and aviation, and 8,000-12,000 TWh to produce 150-250 million tonnes of hydrogen for long-haul.

Commercial and residential buildings

Electricity use in commercial and residential buildings will in part be driven by existing applications – for electrical appliances, air conditioning (AC), and information technology equipment.

- Air-conditioning will be a major driver of demand growth in many developing economies, driven primarily by increasing living standards, as well as warming temperatures. Only 8% of the 2.8 billion people living in the world's hottest countries currently use AC, compared to 90% penetration in the US and Japan.[14] ETC estimates for India suggest potential demand growth from 140 TWh today to 900 TWh by 2050.[15] There is significant potential for AC efficiency improvement though that should be strongly incentivised via the introduction of standards. An RMI study found that total energy efficiency in AC could be improved by 5 times.[16]

13 For an overview of scenarios to reach zero-carbon in the aviation industry, see the ETC's Mission Possible Sectoral Annexes on Shipping and Aviation, and the Air Transport Action Group (ATAG)'s Waypoint 2050 report

14 IEA (2018), *The Future of Cooling: Opportunities for energy-efficient air conditioning*

15 Analysis in *TERI/ETC India (2020) The Potential Role of Hydrogen in India*

16 Electricity consumption of air conditioners could be reduced fivefold with existing technologies, while several emerging technologies (such as deep space radiative cooling, thermoelectric cooling, magnetocaloric cooling, etc) have shown potential in prototype stages for further efficiency gains at low cost. RMI (2018), *Solving the Global Cooling Challenge: How to Counter the Climate Threat from Room Air Conditioners*

- Information and communications technology (ICT) requirements already account for 200 TWh, or about 1% of global electricity. The effect of future growth will be particularly strong in smaller countries with expanding data markets such as Denmark or Ireland.[17]

In addition, electricity is almost certain to play a greatly expanded role in heating for commercial and residential buildings. Heating demand is concentrated in mid to high latitude countries, and, in some areas, electricity already plays a major role [Exhibit 1.5]. In others, however, gas is the primary heating source, while northern China is heavily dependent on coal-based distributed heating systems.

Multiple zero-carbon options are possible – including local renewable heat sources (solar thermal or geothermal), waste heat from industrial processes, bioenergy and hydrogen. District heat networks and heat storage systems – while not heat sources per se – can often be critical enablers to store production at favourable times in high-renewables systems.

But it is highly likely that electricity-based solutions will play a major role in decarbonising building heating, especially given the inherent efficiency advantage of heat pumps, which can reach over 300% (equal to 3 kWh of heat delivered per kilowatt-hour of electricity input) versus 100% for electric resistive heating, 90% from new gas boilers and 60% for some old boilers still in operation. Significant further improvements in heat pump efficiency are also technically possible, with many studies suggesting 500-600% efficiency is feasible.[18]

Strong policy will however be required to achieve the adoption of zero-carbon routes, given the significant upfront cost involved in replacing gas boilers with heat pumps and the investment in building insulation which will be needed in certain geographies. New builds should mandate electric heating and energy efficient building design, in addition to consumer incentives and information campaigns supporting retrofits. [19]

Current solutions to heating differ considerably by country

Fuel share (%) for residential and commercial heating demand in a number of OECD countries

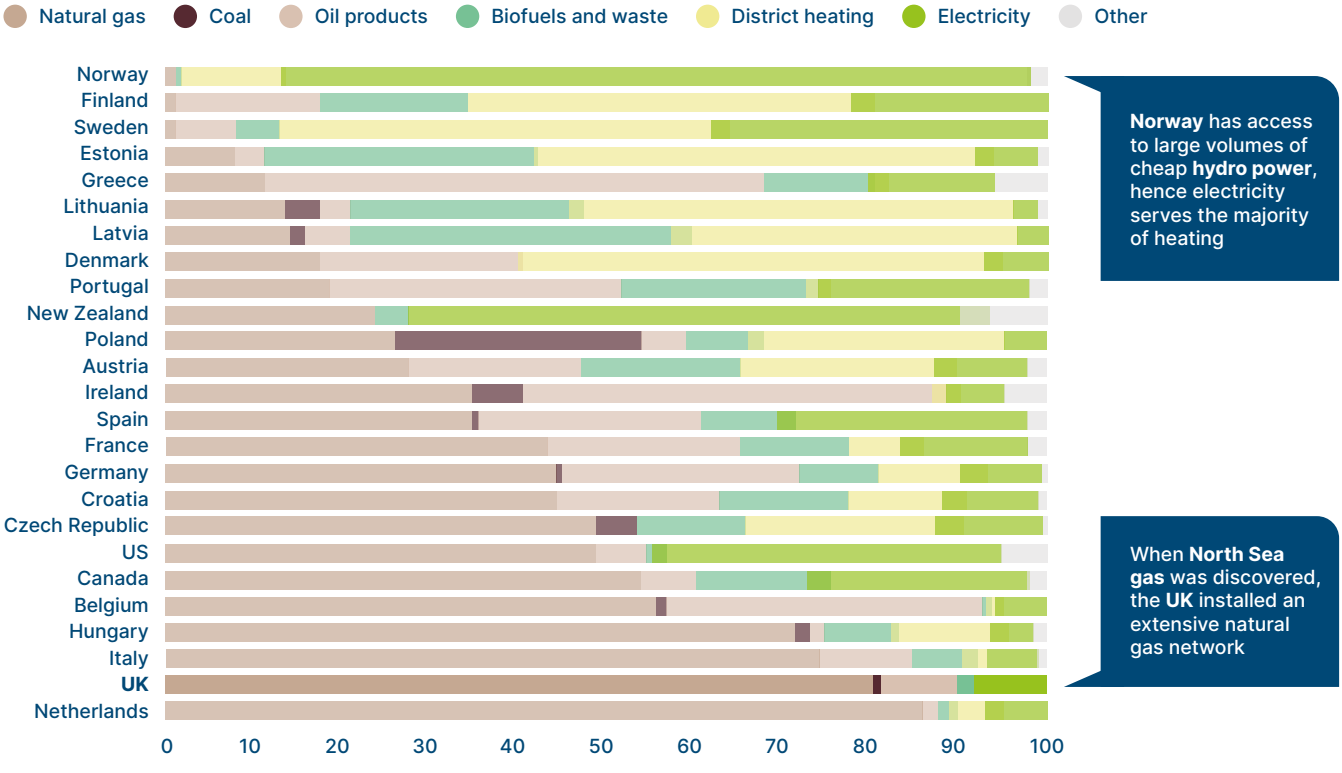


Exhibit 1.5

SOURCE: Vivid Economics for the Department for Business Energy and Industrial Strategy (2018)

17 One estimate for Denmark, for example, shows that data centre electricity consumption is project to grow from less than 1% today to 15% of total electricity consumption in 2030. IEA (2019), *Data centres and energy - from global headlines to local headaches?*

18 Fraunhofer IEE (2020), *Hydrogen in the Energy System of the Future: Focus on Heat in Buildings*

19 ETC (2019), *Mission Possible Sectoral Annex on Building Heating*

In total, electricity use in building heating could reach around 20,000-22,000 TWh by 2050, including up to 3,000TWh for hydrogen production. Electricity demand for building heating will represent an important share of total electricity use, though the share will be far higher in some colder climate countries, where building heating could account for around 40% of total electricity demand.

As in the road transport sector, these growing uses of electricity within commercial and residential buildings will have important implications for the timing and shape of electricity demand [Exhibit 1.6].

- In particular, if residential heating is electrified, this could significantly increase daily as well as seasonal demand peaks, which may not be matched by increasing VRE supply. From a seasonal perspective, in the UK for instance, peak electricity is about 60 GW, and electrifying heat could add between 50-80 GW to the peak (i.e. more than doubling the peak).[20] This will require the deployment of large-scale seasonal storage and balancing options.

- However, the deployment of flexibility and storage levers for electric heating, including pre-heating and hot water storage, could itself play a role in reducing the impact on peak demand over hours and days, offering flexibility services for the power sector similarly to EVs. Taken together, BloombergNEF estimates that flexibility and storage could reduce 'peak' demand by around 20-25%.[21]

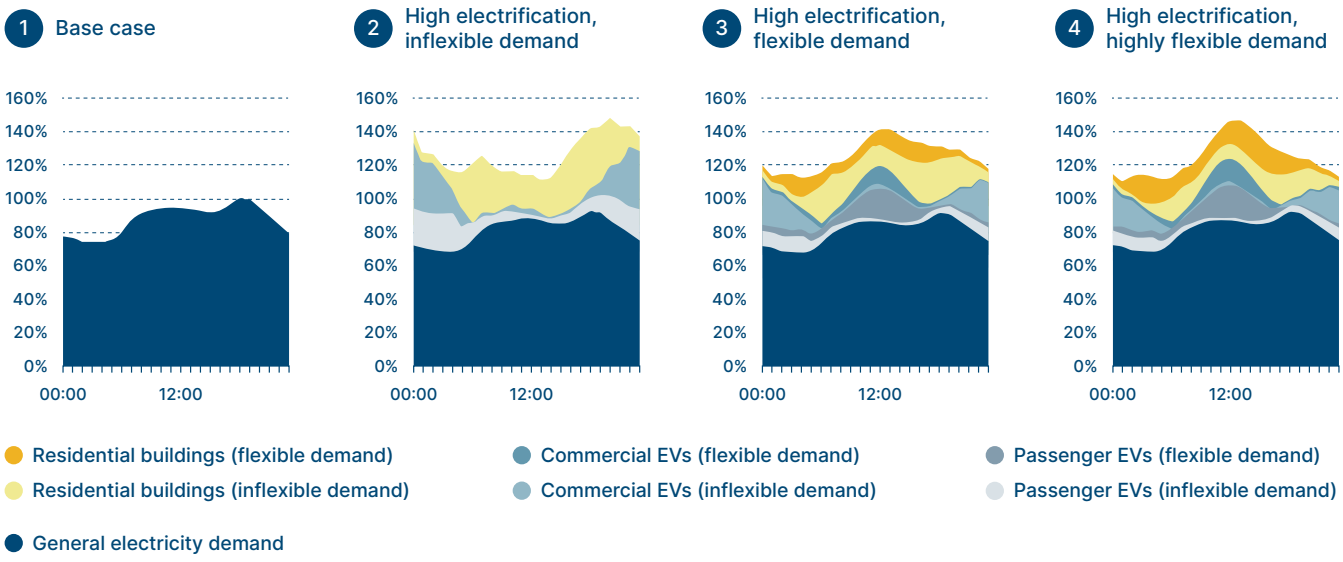
The growth of air conditioning, meanwhile, will generate significant daily demand peaks, including during evenings in countries with large reliance on daytime solar supply. Data centre demand growth will add to the peak at times of busy internet traffic, such as early evening at locations with hyperscale data centres.[22]

The suite of options to deal with these seasonal and daily balancing challenges faced by renewable-dominated power systems are discussed further in Chapter 2 Section 2.

Exhibit 1.6

New electrification demand could lead to higher demand peaks without enabling flexibility

Intraday example: demand profile for Northern European archetype across scenarios (typical winter day in 2050)
Normalised hourly load, %



SOURCE: Bloomberg NEF (2020), *Sector Coupling in Europe: Powering Decarbonisation*

20 BEIS (2018) *Clean Growth – Transforming Heating*, Energy Technologies Institute (2015), *Smart Systems and Heat: Decarbonising heat for UK homes*
21 BloombergNEF (2020), *Sector Coupling in Europe: Powering Decarbonisation.*
22 IEA (2019), *Data centres and energy - from global headlines to local headaches?*

Industry

Across most of the manufacturing industries, factory operations are already electrified, and future electricity demand will reflect the balance between economic growth and opportunities to improve energy efficiency.

Heavy industrial sectors – such as steel, cement, and petrochemicals – face a greater decarbonisation challenge, but as the ETC described in its *Mission Possible* report, all of these apparently "harder-to-abate" sectors can be decarbonised via a mix of direct electrification, use of hydrogen, carbon capture and storage or use (CCS/U), and limited use of sustainable low-carbon biomass.[23]

The most cost-effective option will vary by region based on local resource availability, and between brownfield and greenfield developments. Recent technological and cost developments (described in the parallel ETC report *Making the Hydrogen Economy Possible*) make it increasingly likely that hydrogen will play a very major role, with the relative role of hydrogen versus direct electrification of industrial heat among the remaining uncertainties.[24]

In total, industrial hydrogen demand could increase from 8 million tonnes today to around 150-300 million tonnes by mid-century, with a resulting electricity demand of 7,000-14,000 TWh of electricity required for this hydrogen production. Including direct electrification and already electrified uses, total electricity use for the heavy industrial sectors could reach between 8,000-16,000 TWh by 2050.

23 ETC (2018), *Mission Possible*
24 ETC (2021), *Making the Hydrogen Economy Possible – Accelerating clean hydrogen in an electrified economy*



Electricity for carbon removal

In addition to the end-use applications of electricity described above, significant volumes of electricity may eventually be required to power carbon removal technologies.

The ETC has so far focused primarily on the energy, building, industry, and transport (EBIT) sectors which we believe could get close to zero emissions by 2050, without relying by then on large-scale use of offsets. But even in these sectors, there will be some residual emissions (for instance arising from less than 100% efficient CCS processes). In addition, the pace of emissions reductions in the next decade may be insufficient to meet a climate target of 1.5°C temperature rise, and there are large emissions from the agriculture, food and land use sector (AFOLU), which must also be eliminated or offset. As a result, achieving a climate target of 1.5°C may require significant "carbon removals" (sometimes also called "negative emissions").

The ETC is now assessing the potential need for such carbon removals, including a comparative assessment of the different possible carbon removal mechanisms (e.g. nature-based solutions, BECCS and DACCS).

If DACCS were part of the solution mix and were used to achieve 5 Gt per annum of carbon removals, that would require an additional 14,000 TWh of zero-carbon electricity. We have not factored this potential need into our scenarios yet, but it reinforces the need to plan for massive electricity system expansion.[25]

II. Electricity for green hydrogen production: the green versus blue question

Growing global electricity use to 2050 will be driven by both direct and indirect electrification – e.g. electricity used for the production of hydrogen and other electricity-based fuels. The demand for 'indirect' electricity will depend not only on the scale of future demand for hydrogen, but on whether low/zero-carbon hydrogen is produced via a "blue" route (which combines gas-based Steam Methane Reforming (SMR) or Autothermal reforming (ATR) production technology with CCS) or a "green" route with hydrogen produced by electrolysis of water using zero-carbon electricity.

ETC analysis for the upcoming report *Making the Hydrogen Economy Possible* concludes that it is likely that green hydrogen will account for a large majority of total production by mid-century and become increasingly dominant in the late 2020s/early 2030s, given the prospects for rapid green hydrogen cost reductions in the 2020s and the longer-term cost trends.[26]

Our base case assumption is that electrolysis will account for 85% of total hydrogen production of around 500-800 million tonnes in 2050. Producing this would require almost 30,000 TWh of electricity, in addition to around 90,000 TWh of demand for direct electricity use by 2050.

III. Energy productivity improvements

Improving energy productivity could materially reduce final energy demand in a net-zero emissions economy, and thus materially reduce the necessary scale-up in zero-carbon power systems and associated investment (see Chapter 3 Section 1). Total future electricity demand depends not only on the quantity of each consumer product or service which is delivered through the use of electricity (e.g. kilometres of car travel, or the temperature within a house resulting from cooling or heating), but on the efficiency with which electricity is converted into those benefits. It is therefore essential to focus on the many opportunities to improve energy efficiency, including:

25 Assumes power requirement of 2.8 MWh/tCO_2 based on Kraan et al., An Energy Transition That Relies Only on Technology Leads to a Bet on Solar Fuels, *Joule* (2019).
26 ETC (2021), *Making the Hydrogen Economy Possible: Accelerating clean hydrogen in an electrified economy*

- Major opportunities to improve the thermal insulation of buildings, which reduce the required input of heat to deliver reasonable levels of warmth or cool. Best practices across physical and digital building upgrades could, for instance, increase energy efficiency by over 50% in UK buildings.[27]

- Still greater opportunities to improve heat pump/air-conditioner efficiency, where the coefficients of performance currently achieved (often around 3 to 4) are still far below absolute thermodynamic limits. As referenced previously, energy efficiency could be as high as 5 times current baselines for air conditioning with current technology [Exhibit 1.7].

- Significant opportunities to improve the efficiency of auto electric engines and car design, increasing kilometres per kilowatt hour.

- As the hydrogen economy grows, an opportunity to improve the efficiency of electrolysis, increasing the hydrogen produced for a given power input.[28]

In addition to energy efficiency improvement, the role of material and service efficiency is also critical to reduce energy demand:

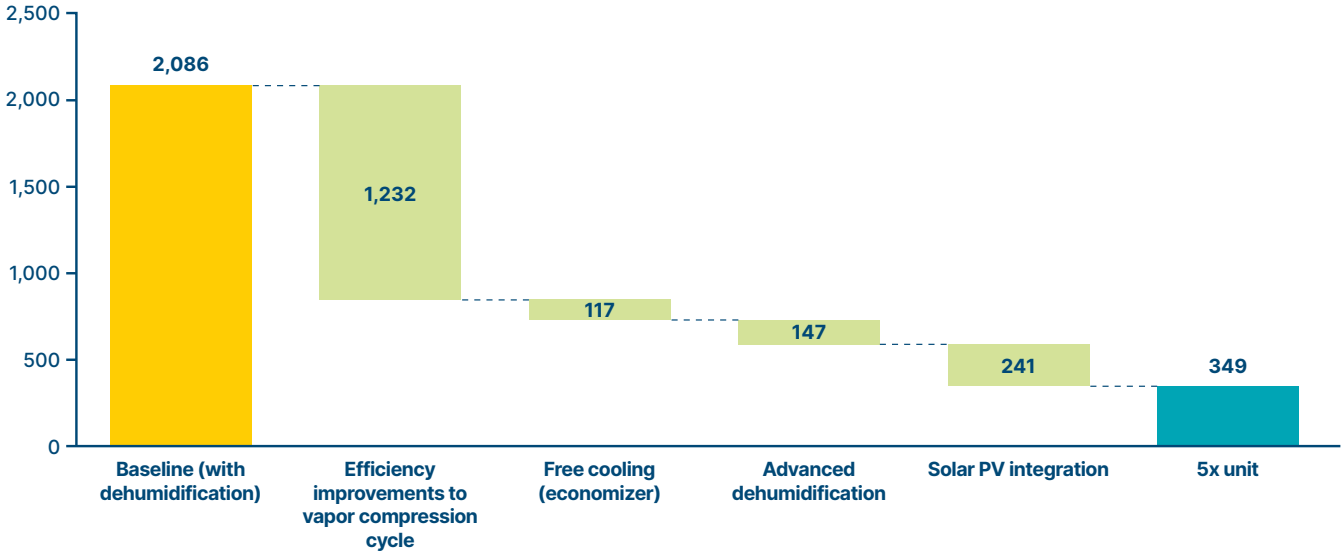
- Material efficiency gains could be achieved via improving material circularity (e.g. such as via higher recycling) as well as material-to-product efficiency. There are significant opportunities across energy-intensive materials, such as steel and cement. Analysis by Material Economics suggests that in theory, such measures could reduce global emissions from heavy industrial sectors by 40% below business-as-usual levels.[29]

- Service efficiency gains could be achieved via increasing product-to-service efficiency (e.g. via car-sharing) as well as via demand reduction and behavioural changes (e.g. via modal shift from more energy intensive road or aviation to more efficient mass transit and long-distance rail systems, as well as logistics and operational efficiency improvements, e.g. slower shipping speeds, or more efficient air traffic control). Here the potential depends more significantly on consumer behaviour changes and is therefore more speculative; but in principle, major reductions could also be achieved.

Exhibit 1.7

5x improvements in air-conditioning efficiency

Pathway for a 5X efficiency solution using conventional technologies
TWh



SOURCE: Rocky Mountain Institute (2018), *Solving the Global Cooling Challenge*

27 ETC (2019), *Mission Possible sectoral focus: Building heating*
28 ETC Hydrogen work assumes a linear increase from 63 to 69% in the 2020s. and then linear increase to 74% to 2050 based on BloombergNEF estimates.
29 *Material Economics* (2018) for the Energy Transitions Commission

It is important to recognise that even with maximum possible progress on each of these and other dimensions, electricity use is certain to be far higher in a zero-carbon economy than today. A reasonable set of assumptions suggest that maximum possible progress towards an energy-efficient economy could reduce total electricity use in 2050 from around 130,000 TWh to around 90,000 TWh, but with global electricity use still therefore increasing more than three times from today's level.

Furthermore, recent trends point to the difficulty in achieving energy productivity improvements. Since 2015, global improvements in energy efficiency have been declining. As a result of the Covid-19 crisis and continuing low energy prices, energy intensity is expected to improve by only 0.8% in 2020, roughly half the rates, corrected for weather, of 2019 (1.6%) and 2018 (1.5%).[30]

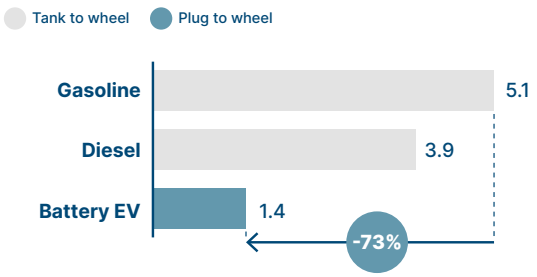
No amount of energy efficiency improvement will remove the need for huge increases in electricity supply. In terms of energy use, however, a deeply electrified economy will automatically be a far more efficient one, as Exhibit 0.1 shows.

- While global GDP is likely to grow about 3 times by mid-century, ETC indicative scenarios show that total final energy use may only increase by 15%, and might even fall by around 15%, if societies seized all opportunities for energy efficiency and productivity improvement.[31] This reflects the inherently far greater efficiency of an electrified economy – particularly in road transport and residential heat, where BEVs are 3 to 4 times more efficient than ICEs and heat pumps 3 to 4 times more efficient than the best gas boilers – and where further improvements in efficiency are feasible [Exhibit 1.8].

Radical energy efficiency improvement can be achieved through electrification

Transport example

BEVs consume one fourth the energy of gasoline cars
Liters of gasoline equivalent per 100 km



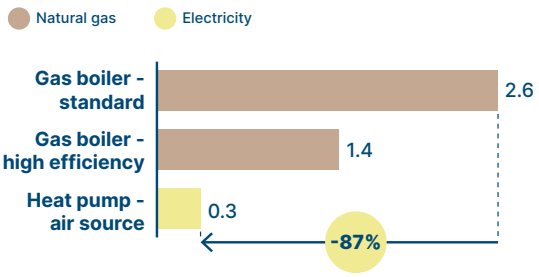
Assumptions

All vehicle efficiencies based on 200 km driven through New European Drive Cycle.

BEV assumes Li-ion battery with 95% roundtrip efficiency.

Building heating example

Electric heat pumps are ~90% more efficient than gas boilers
kWh final energy per kWh heat delivered



Assumptions

Standard gas boiler is 70% combustion efficient and 55% system efficient.

High-efficiency boiler is 90% combustion efficient and 80% system efficient.

Heat pumps have a coefficient of performance (COP) of 2.0-4.0 with average of 3.0 shown here.

Note: significant opportunities exist for further improvements in COPs beyond 3 or 4 since current COPs are still far below theoretical thermodynamic limits.

Exhibit 1.8

SOURCE: Energy Transitions Commission (2017), *Better Energy, Greater Prosperity*, based on Energy & Environmental Science (2015), *Well to wheel analysis of low carbon alternatives for road traffic*

30 IEA (2020), *Energy Efficiency 2020*

31 This is similarly reflected in IEA Scenarios. The IEA's 2020 Stated Policies Scenario shows total final energy demand potentially growing from 420 exajoules (EJ) in 2019 to 515 EJ in 2040, its Sustainable Development Scenario describes a feasible world in which final energy demand could fall by 7% to reach 390 EJ over the next 20 years.

- At the primary energy level, the improvement in energy efficiency is greater still, since producing electricity from solar, wind, hydro or nuclear sources eliminates the energy losses which inevitably result from fossil fuel extraction and thermal generation. Global primary energy demand in 2019 of 600 EJ could fall by over 30% in the ETC's high-efficiency indicative scenario. [Exhibit 1.9].

Indicative primary energy mix in a zero-carbon economy

EJ/year

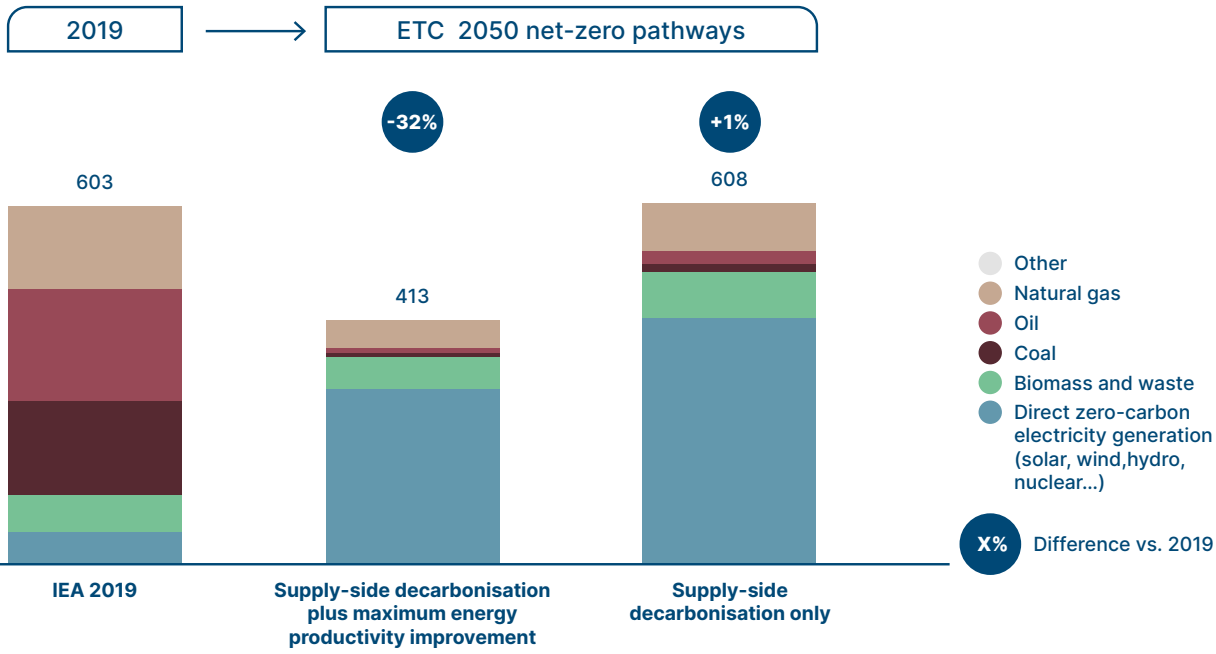
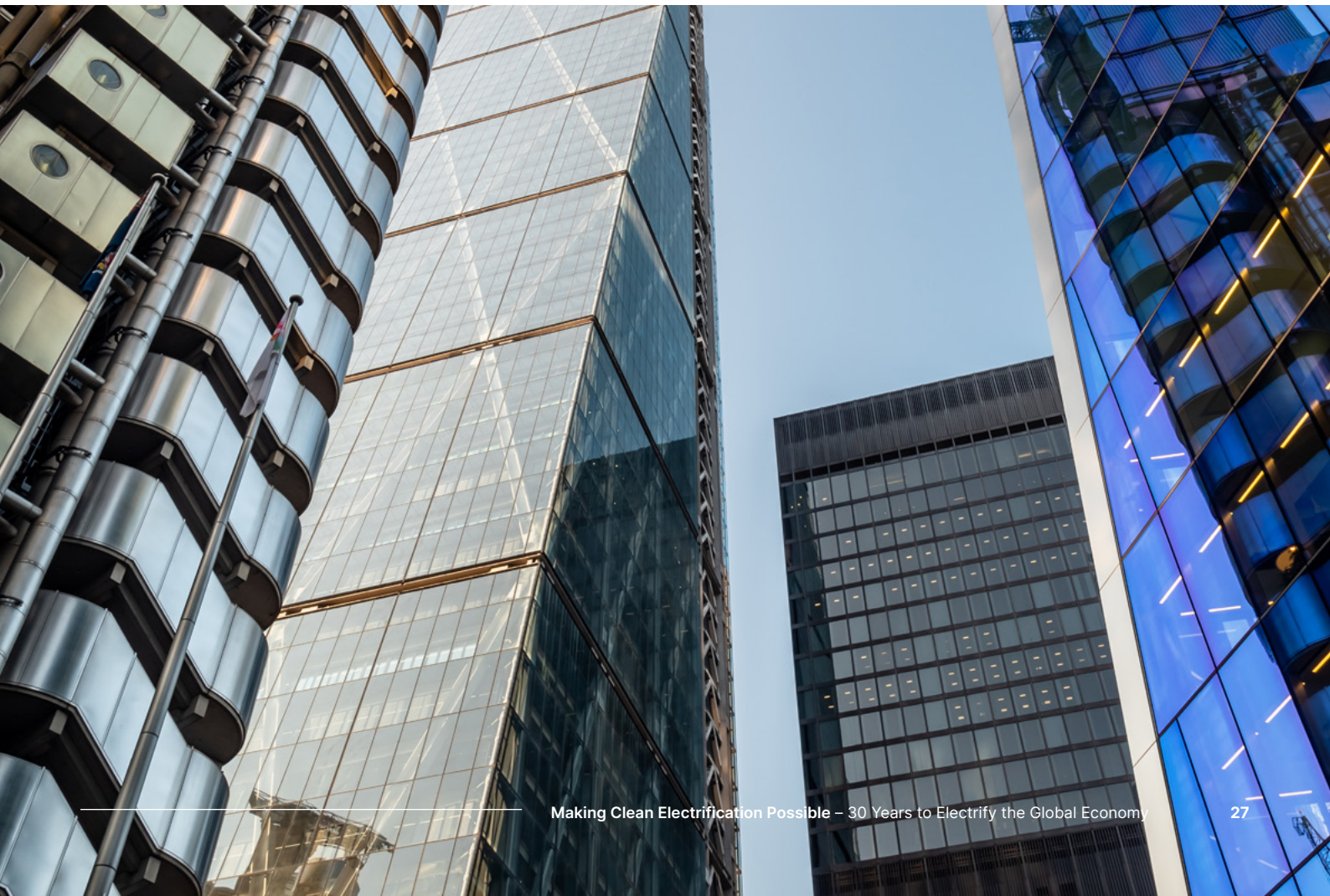


Exhibit 1.9

SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021); IEA (2020), *World Energy Outlook*



IV. Regional and global ramp ups in demand

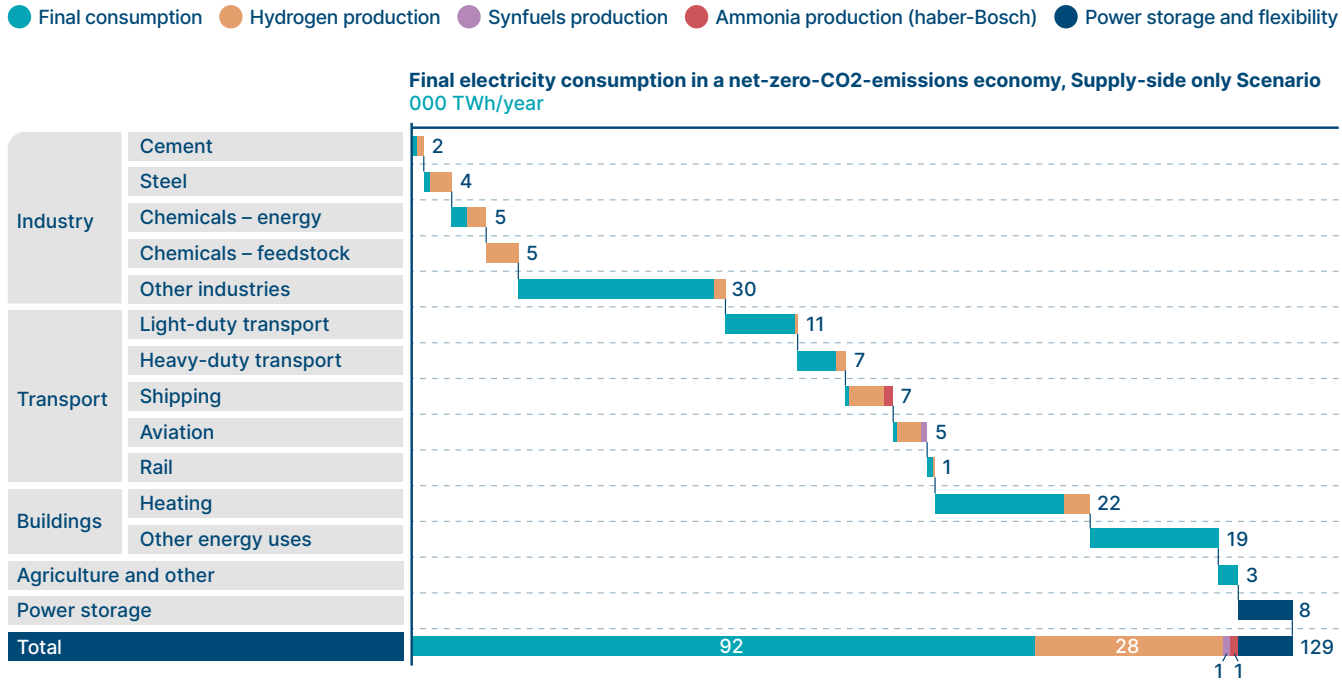
For some sectors, the path to decarbonisation is very clear – e.g. passenger road transport will be almost entirely electrified. For others, the balance between alternative routes is inherently less certain – e.g. currently unpredictable technological developments will determine the balance between electric planes, hybrid hydrogen-electric planes and conventional engine planes for different distances.

But in many cases these uncertainties relate to the balance between electricity directly used, and the use of hydrogen or ammonia/synfuels derived from hydrogen, which in turn are produced with electricity. As a result, overall projections of total electricity use in the economy are more certain than forecasts of precise decarbonisation routes by sector.

Our ETC scenarios suggest that total electricity use will need to rise from 27,000 TWh to between 90-130,000 TWh by 2050 [Exhibits 1.10-1.11]. This includes requirements to produce hydrogen that can be 'stored' for weeks or months before being burnt to generate power to meet long-term seasonal balancing and unpredictable week-by-week balancing needs, discussed further in Chapter 2, Section 2.[32]

Exhibit 1.10

Electricity will play a major role across sectors



SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission analysis (2021)

32 Hydrogen could also be re-converted to power in fuel cells.



Overall, the global ramp-up in electricity demand will require major increases in required electricity supply in almost all countries, but with the scale of increase, the mix of sectors, and the timing of ramp up differing significantly between different country groups [Exhibits 1.12-1.13].

Gross electricity generation will reach ~90,000 to ~130,000 TWh/year

Total electricity generated by 2050 in the ETC indicative pathways
000 TWh/year

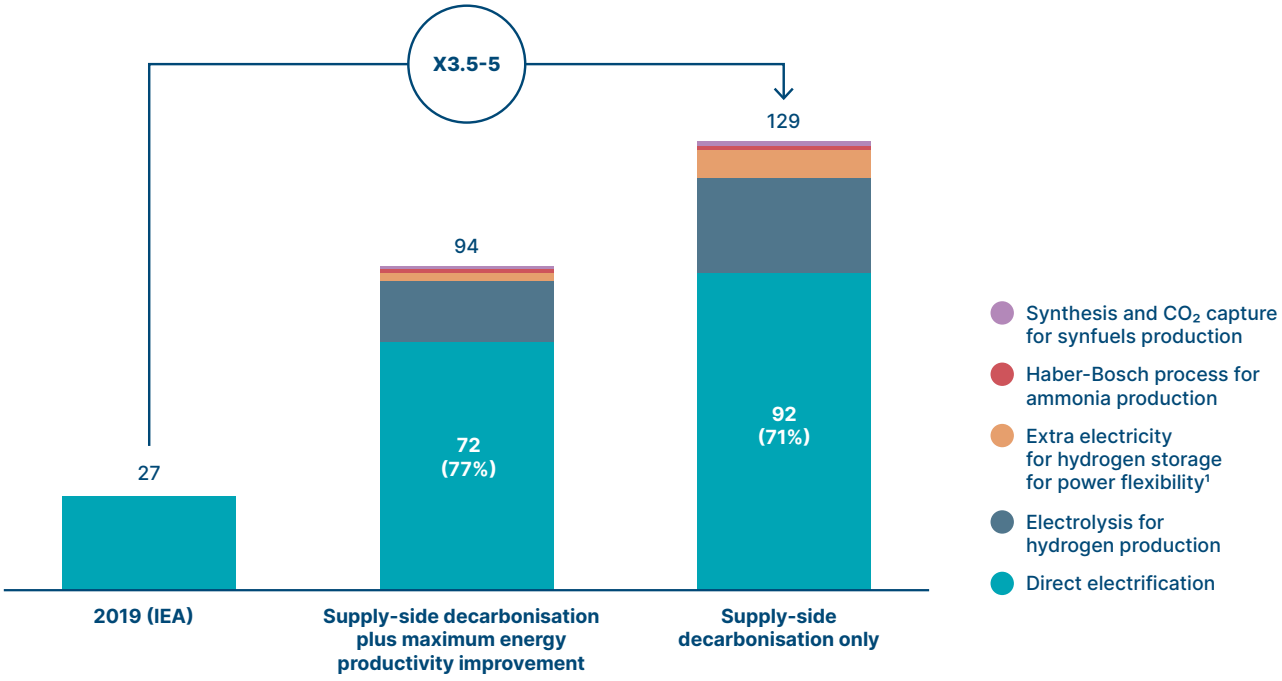


Exhibit 1.11

NOTE: Assumes 85% green hydrogen production in 2050.
[1] Extra electricity for hydrogen storage for power flexibility only covers the electricity loss due to the transformation into hydrogen and back to electricity.

SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021), IEA (2020), *World Energy Outlook*

Electricity use by sector varies across regions under high electrification scenarios

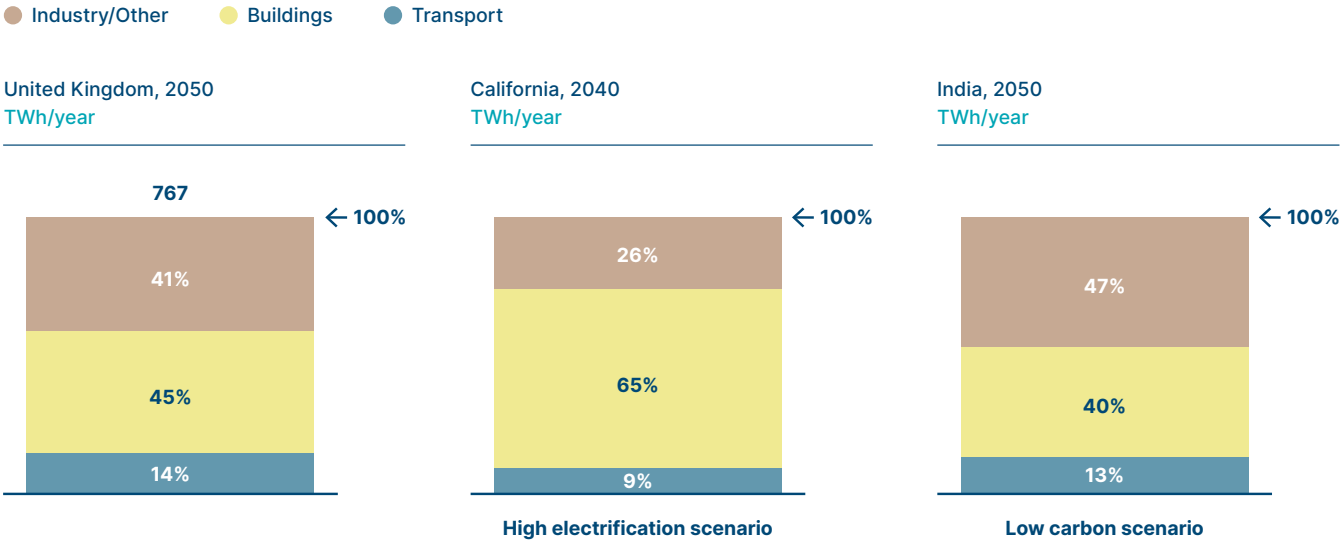


Exhibit 1.12

SOURCE: Climate Policy Initiative (2017), Imperial College London (2018), TERI analysis

- Already rich developed economies could see increases of electricity generation between 2-2.5 times by 2050. But with growth in these countries primarily arising from the new applications in road transport and electric heating, and subsequently from the production of hydrogen to meet new applications in the sectors such as shipping, steel and aviation, growth may be "S-shaped", fairly slow in the 2020s, but accelerating thereafter.

- China is likely to see similar total growth of 2-2.5 times by 2050 (from 7,000 TWh in 2020 to 15,000 TWh by 2050), but with economic growth still running at over 5% per annum, electricity use will grow strongly even in the 2020s.[33]

- In developing countries (e.g. India), economic growth and rising living standards will likely drive fairly rapid growth across the next three decades. Total electricity use could grow 5-6 times by 2050.[34]

- Low-income economies could see massive growth in electricity use, e.g. an increase of 10 times current levels by mid-century, with the profile over time determined by the success of economic growth strategies and the ability to expand energy access, including via the mobilisation of international financial flows to support investment.

The policies required to drive sufficiently rapid and cost-efficient electrification will reside primarily at national (or EU) level, and the different regional pictures are therefore more important than the global. But it is still useful to grasp the scale of the overall global ramp up [Exhibit 1.14], which determines the total global generation, flexibility and networks investments need, as well as associated resource requirements.

The ramp-up of electricity use to 2050 will vary across regions

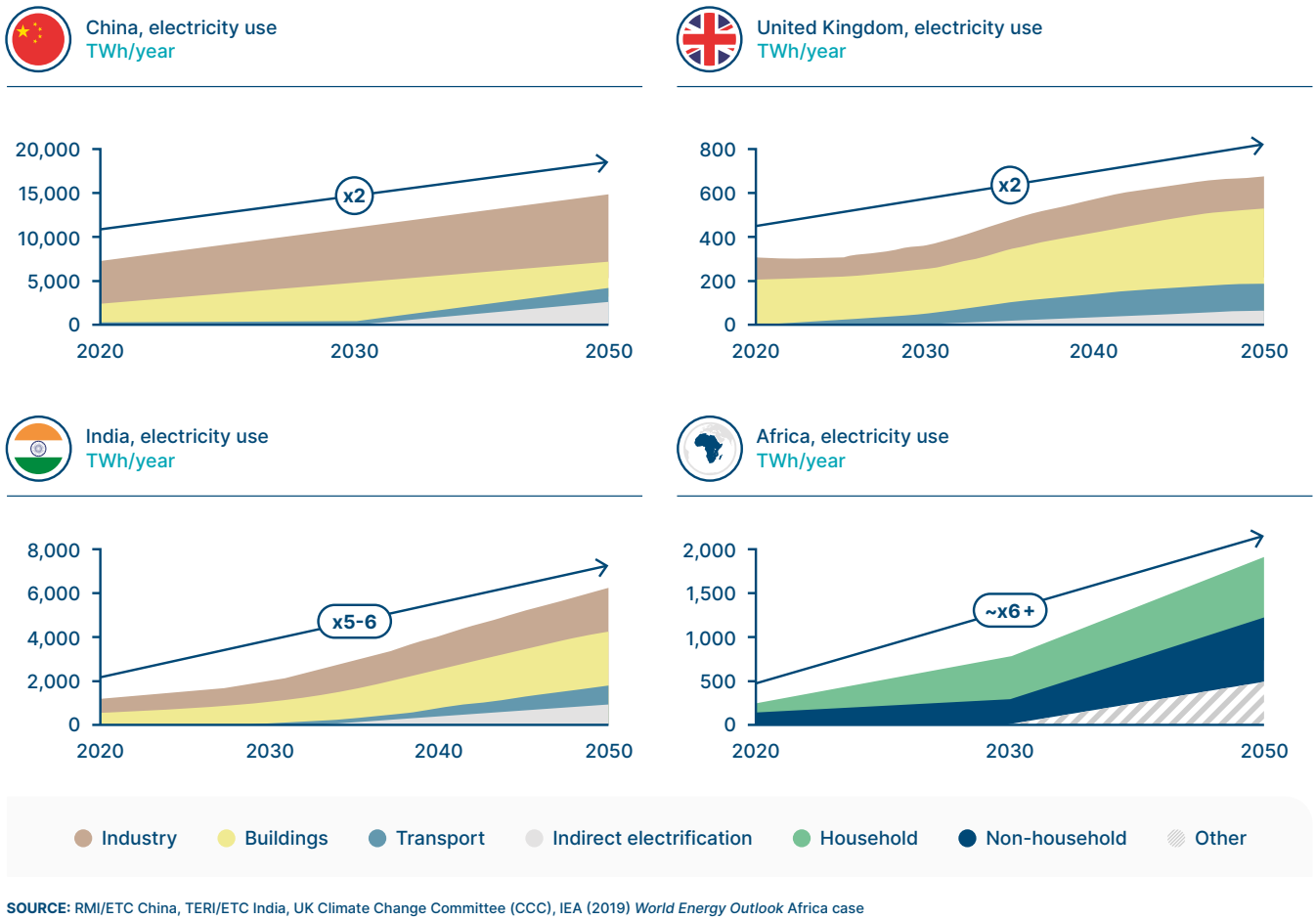


Exhibit 1.13

SOURCE: RMI/ETC China, TERI/ETC India, UK Climate Change Committee (CCC), IEA (2019) *World Energy Outlook* Africa case

33 RMI/ETC China (2019), *China 2050: A fully developed rich zero-carbon economy,* UK Climate Change Committee (2020), *Sixth Carbon Budget Report*
34 TERI/ETC India (2020) *The Potential Role of Hydrogen in India*

Cost-competitiveness and technology readiness across electricity end-uses differ, with implications for the timing and pace of electrification over the next 30 years. Beyond electricity growth in line with baseline economic, income and population growth, the expansion of new use cases is likely to occur under an 'S' shape.

- Globally, a ramp-up to ~110,000 TWh of power generation by 2050 (the mid-point of the two scenarios) is likely to see a step change in demand in 2030s, with faster growth rates as transport electrification and building heating build momentum. EV uptake under S-curve scenarios is likely to see the tipping point from the mid- to late-2020s, as EVs become more competitive than ICE vehicles. This will vary by geography, with Europe and China likely to hit the growth point sooner (around 2025). For building heating, the growth point of an S-curve uptake will be highly influenced by government policies to support the economics of heat pump adoption.

- High absolute annual electricity generation additions are likely to come in the 2040s, as a result of continued growth in direct electricity use (e.g. in vehicles and buildings, as well as direct electricity use in industrial applications, such as electric arc furnaces), alongside growing green hydrogen production for decarbonisation of the harder-to-abate sectors (e.g. for low-carbon steel production, long-haul shipping & aviation). Overall, the longer asset replacement and investment cycles for industry, as well as maturing technology readiness, will push significant additions of electricity use to the 2040s. Indirect electrification for hydrogen or electricity-based fuels is inherently less efficient than direct electrification. By 2050, indirect electricity use could make up around 25% of total electricity use.

- Demand for cooling and other already highly electrified industries will be more even over time, driven by underlying growth.[35]

- As power systems become increasingly decarbonised and the share of variable renewables increase, requirements to produce hydrogen that can be stored for weeks or months before being converted to generate power to meet balancing needs will grow. As we will see in Chapter 2 Section 2, the need to meet long-term seasonal balancing and unpredictable week-by-week variations will also increase as power systems move above 70% VRE shares. The uptake of hydrogen demand for power flexibility will therefore begin to take-off from the mid-2030s, as more power systems move into high-VRE states.

Feasible global electricity use ramp-up to 2050 reaching a mid-point of 110,000 TWh, fastest growth in the 2030s

Illustrative global scenario for electricity use, TWh

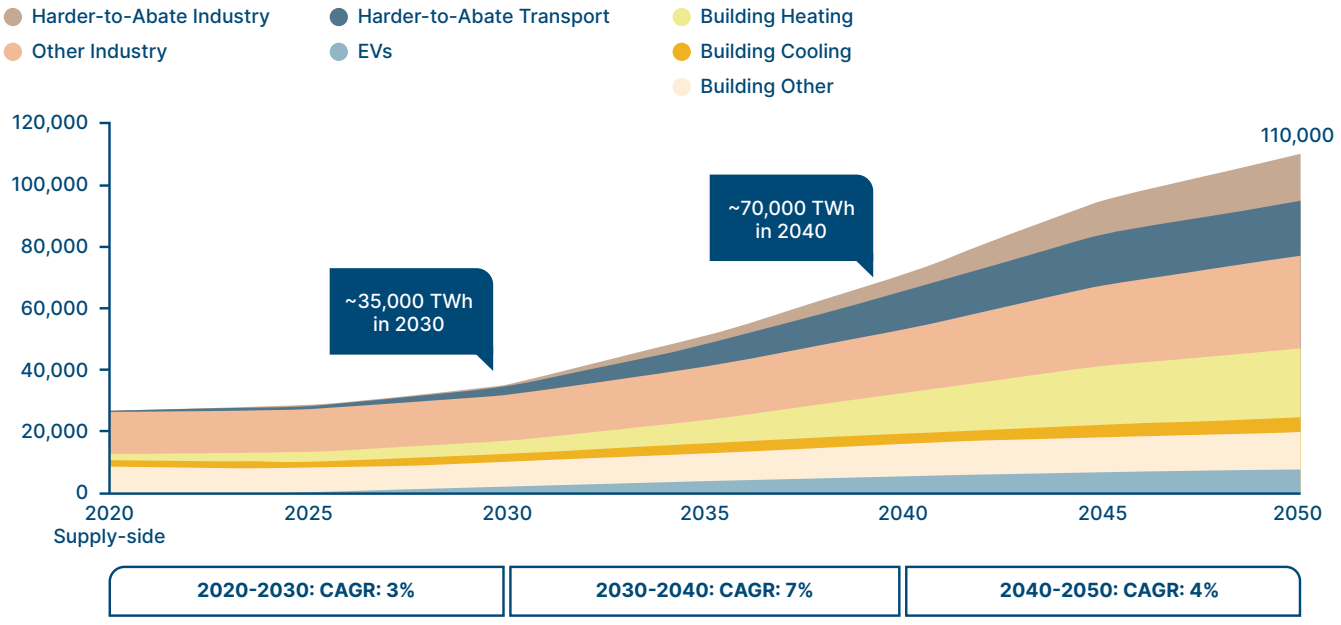
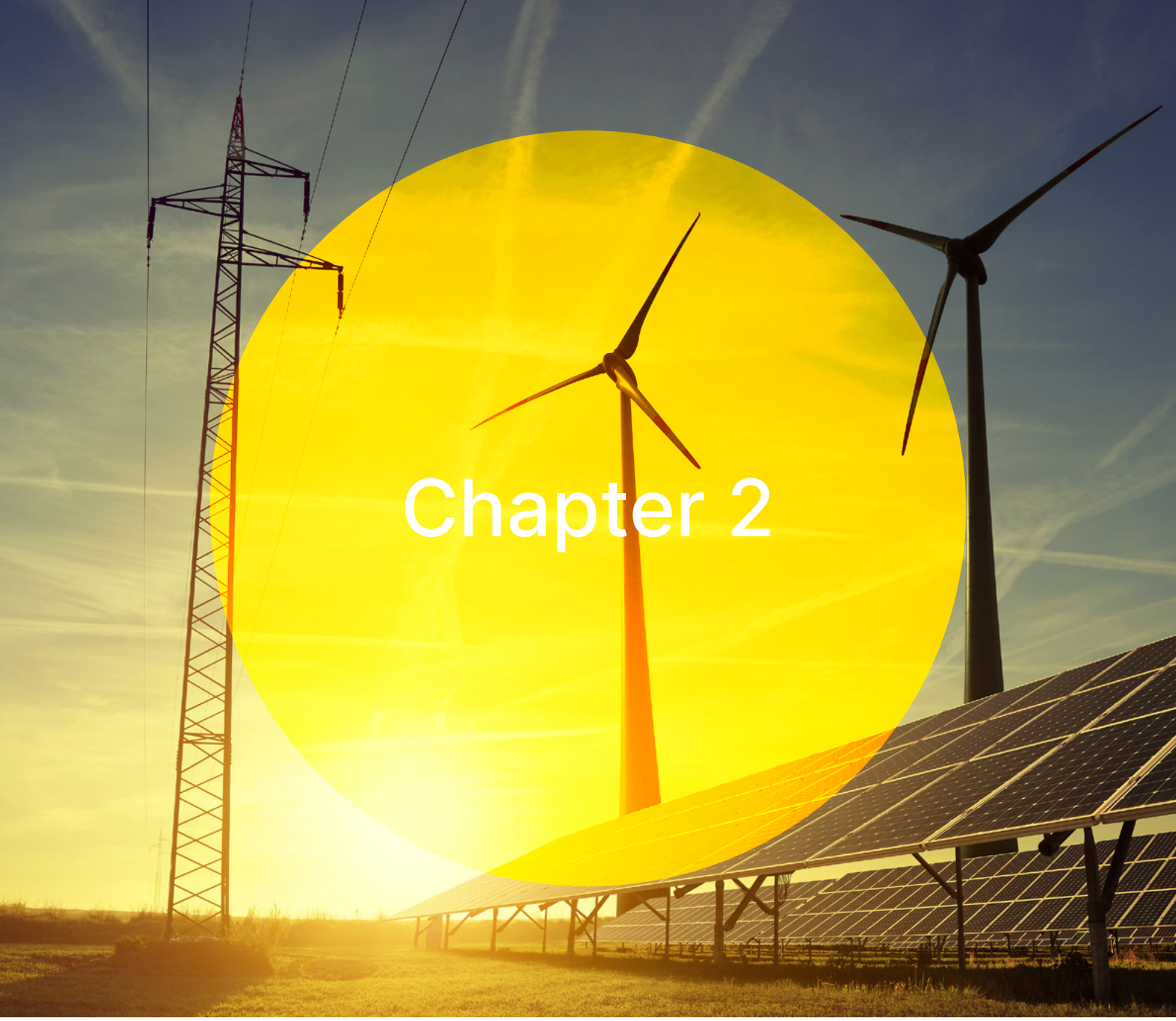


Exhibit 1.14

NOTE: Other industry includes Aluminium, Pulp& Paper, Other (incl. Mining, FMCG, Textiles, Metals, Electronics, Equipment, Construction).

SOURCE: IEA (2017), *Energy Technology Perspectives*, SYSTEMIQ analysis for the Energy Transitions Commission (2021)

35 Other industry includes aluminium, pulp & paper, and other sectors such as mining, fast-moving consumer goods (FMCG), textiles, metals, electronics, equipment, construction).



Generating low-cost zero-carbon power

Dramatic declines in the cost of renewable electricity and key storage technologies now make it possible to achieve power system decarbonisation at low-cost, while also supporting the massive growth in electricity supply required in a zero-carbon economy. But maximum feasible cost reductions will only be achieved if countries commit in advance to clear decarbonisation strategies.

All countries should therefore plan for the vast majority of growth in electricity to come from zero-carbon sources, and develop plans for the phase-out of unabated fossil fuel generation. This chapter describes why those strategies are now feasible and economic, and the key actions required to achieve them, describing in turn:

- Declining costs of zero carbon power – driven by huge scale development
- Balancing VRE-based power systems – a vital but manageable challenge
- Total system generation costs – fully competitive with fossil fuels
- Additional costs in transmission and distribution
- Phasing out unabated fossil fuel assets
- Natural resource availability – clearly sufficient at global level
- Resource constrained countries – challenges and solutions: the role of long-distance transmission

I. Declining costs of zero-carbon power

Dramatic declines in the cost of renewables have made them increasingly competitive with fossil fuel generation and rapid further declines will be driven by increasing scale and technological progress, spurred by ambitious deployment targets.

Over the last 10 years, the cost of renewable electricity has plummeted. [Exhibit 2.1]

- Estimates of solar PV levelized costs of electricity (LCOEs) have fallen by over 80% to reach $60 per MWh; but auction prices in favourable locations are far lower still, reaching below $20 per MWh in most favourable locations.
- Offshore and onshore wind power costs have also fallen by 55% since 2010, with auction prices for onshore wind approaching US$20 per MWh in some countries.

Wind and solar LCOE have dramatically decreased in the last 10 years with latest lowest auction prices for solar PV below $20/MWh

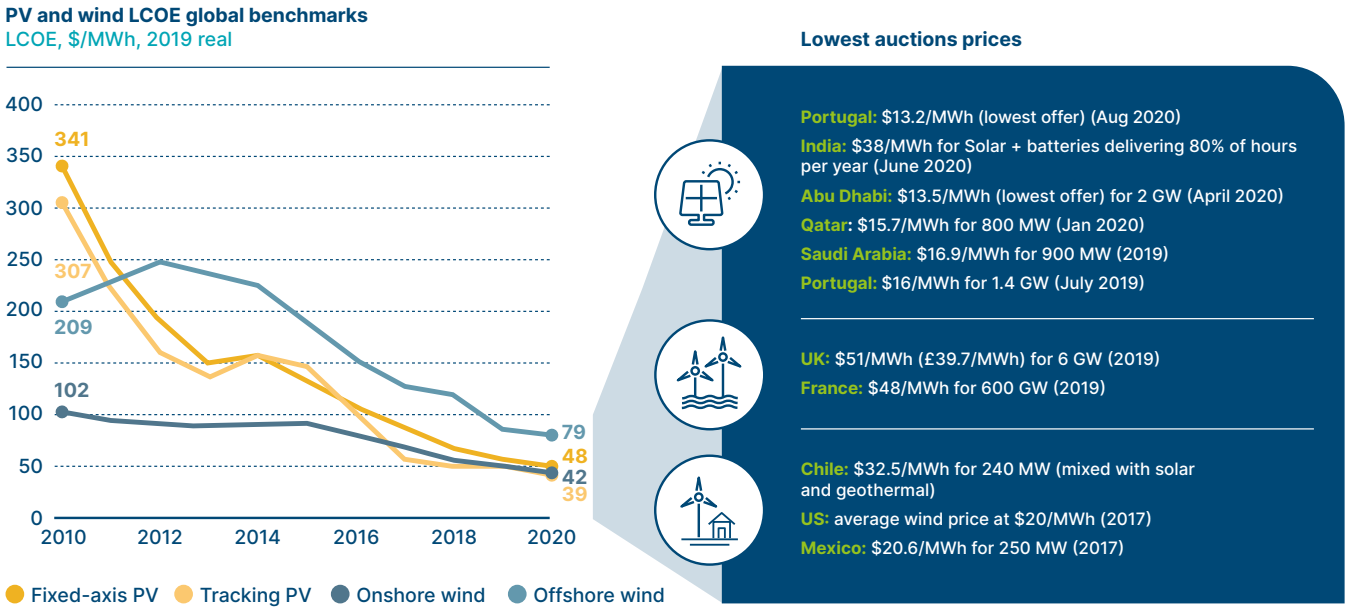


Exhibit 2.1

LEFT-HAND SIDE: the global benchmark is a country weighted-average using the latest annual capacity additions.
RIGHT-HAND SIDE: economics of auction prices may be favoured by local tax treatments and other implicit subsidies.

SOURCE: Press research, BloombergNEF (2020), *2H 2020 LCOE update*

Estimated LCOEs and achieved auction prices vary significantly by country and specific location. In its 2020 World Energy Outlook, the IEA concluded that solar projects with low financing costs now represent one of the cheapest sources of electricity generation in history.[36] Bloomberg NEF figures suggest a range of solar LCOEs from $26/MWh in India, $36/MWh in China, $42/MWh in the United States, and $114/MWh in Japan [Exhibit 2.2]. Some of these differences reflect factors such as the local cost of capital or the development of local supply chains which can and should be influenced by the effective public policies discussed in Chapters 3 and 4. But some reflect inherent resource differences deriving from geography and constraints to project sizes which drive up costs, for example in Japan due to high density and land availability restrictions.

LCOEs vary by geography

New bulk generation LCOE forecast in selected markets
$/MWh, 2019 real

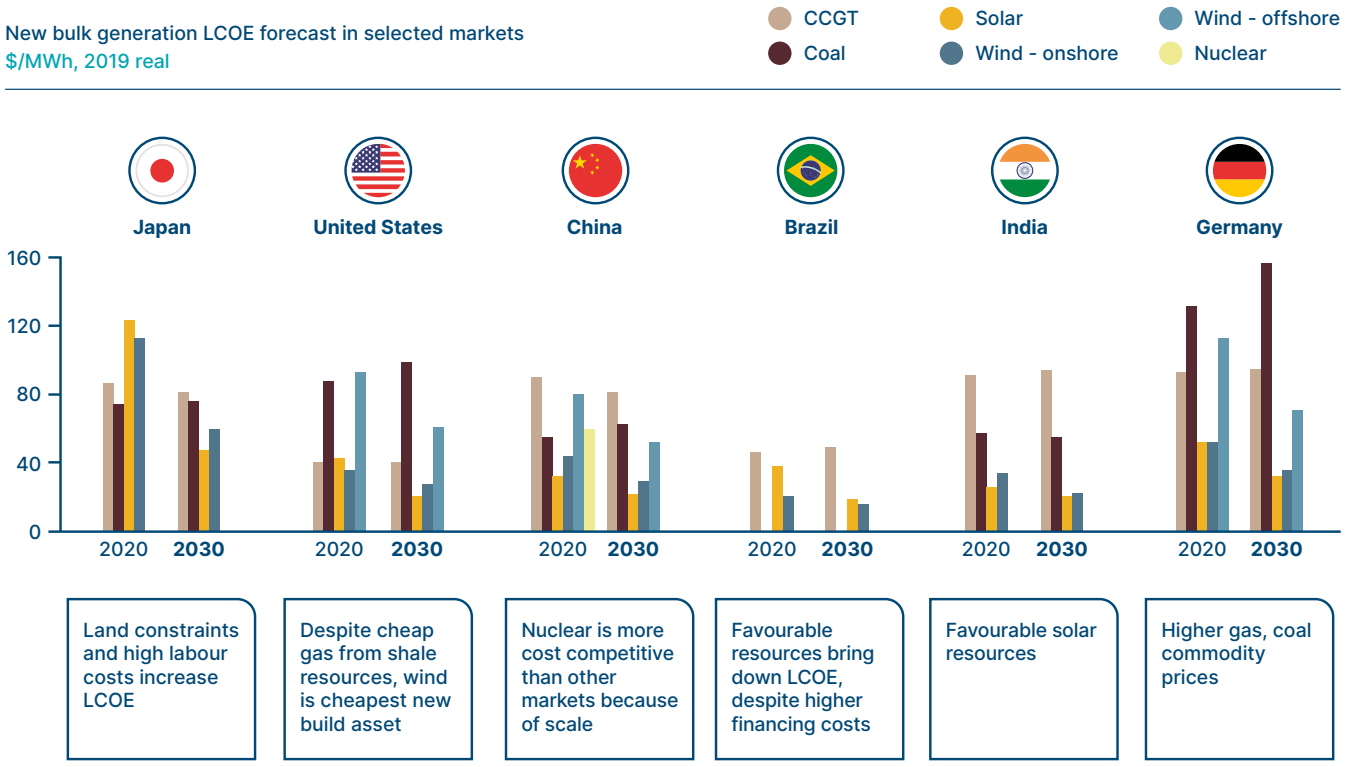


Exhibit 2.2

NOTE: Solar refers to fixed-axis PV. Values refer to the 'mid-case' LCOEs. All LCOE calculations are unsubsidized.

SOURCE: BloombergNEF (2020), *2H 2020 LCOE update*

Furthermore, we can have high confidence that renewables costs will continue to decline, and this is highlighted by major forecasts such as IRENA, BloombergNEF and IEA. Significant reductions are expected in both upfront capital costs (cost per MW) due to cheaper equipment and installation, and in total 'levelised' cost of electricity (LCOE) generation (costs per MWh) driven by increasing capacity factors alongside declining operational and financing costs.

- **For solar PV**, projections show that costs per MW could fall from today's $1 million to below $500,000 by 2050 and potentially below $200,000 [Exhibit 2.3].[37] Costs per panel will continue to fall due to manufacturing efficiency improvements and larger wafers, but improvements in power efficiency will be equally as important, with technologies such as by bifacial modules and perovskites promising to increase yields from today's 20% to over 30%.[38] Such improvements in efficiency (or "light to power" conversion) have a powerful impact on LCOE, since they also automatically reduce the cost per MW and per MWh of some key non-panel costs such as land acquisition and project planning expenses.

36 IEA (2020), *World Energy Outlook*
37 BloombergNEF (2020), *New Energy Outlook*, IRENA (2019) *Renewable Power Generation Costs*
38 BloombergNEF (2020), *New Energy Outlook*, IRENA (2019) *Renewable Power Generation Costs*

- Estimates for **onshore wind** suggest future falls of capex per MW between 30% and 60% because of economy of scale and learning effects as competitive global supply chains continue to grow.[39] In addition, cost per MWh will be driven down by increases in capacity factors.

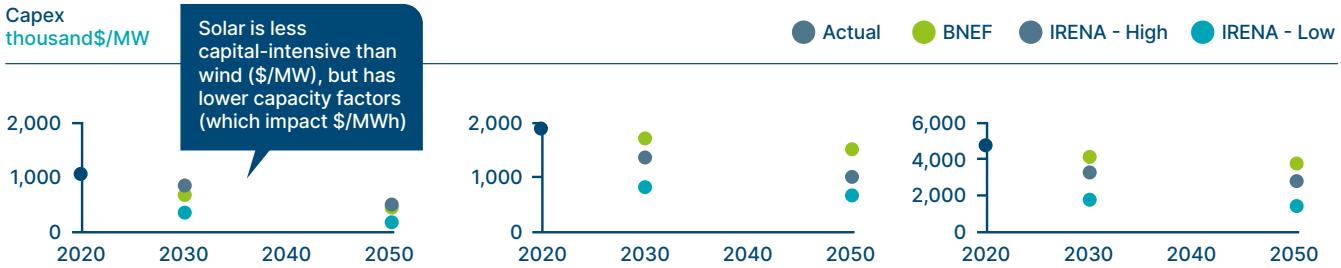
- **Offshore wind** costs could fall even more, with IRENA's low-cost estimate of capital costs suggesting a reduction of 80% by 2050 driven by larger turbine sizes, relentless incremental product improvement and economy of scale effects in an industry which could see growth of over 6 times in the next 20 years.[40] Technology and engineering developments will also expand the scale of exploitable resources, for example via the use of floating platforms which can operate at far deeper depths.

Declines in renewables Capex expected to continue, primarily driven by innovation, more competitive global supply chains and economies of scale

Solar capex cost declines driven primarily by innovation on efficiency

Onshore wind capex declines driven primarily by competitive supply chains

Offshore wind capex declines driven by economies of scale



- **Cost reduction via innovation which improve panel efficiency** (i.e., electricity output per solar energy that hits the panel) from c. 20% today to closer to 30% - without proportional cost increases[1], e.g. bifacial modules and larger wafers, perovskites
- Manufacturing efficiency improvements will continue to drive cost declines

- **Cost reductions in component parts driven by competitive global supply chains** and further economies of scale
- Technology innovation (e.g. higher hub-heights with larger swept blade areas) will improve capacity factors (e.g. from c.25% to c. 35%)[2], rather than reduce equipment investments

- **Prospect of increased gains from economies of scale** in manufacturing as EU / UK announce capacity targets for offshore wind
- Trend to larger turbines reducing costs of installations and foundations per MW
- Access to deeper waters and farther offshore impacts capacity factors

Exhibit 2.3

NOTES: [1] For example, bifacial modules can provide a 5% to 15% bonus in power output with only a 2% to 3% price premium. [2] Refers to global fleet-wide average improvement.

SOURCE: BloombergNEF *New Energy Outlook* (2020), IRENA Renewable Power Generation Costs (2019), WoodMackenzie "Solar technology got cheaper and better in the 2010s. Now what?", 18 December 2019

39 BloombergNEF (2020), *New Energy Outlook*, IRENA (2019) *Renewable Power Generation Costs*
40 BloombergNEF (2020), *New Energy Outlook*, IRENA (2019) *Renewable Power Generation Costs*



Renewables costs will also be reduced by improvements in operational efficiency (monitoring and maintenance), enabled significantly by digital solutions. Total costs would also fall significantly in some countries if costs of capital could be reduced.

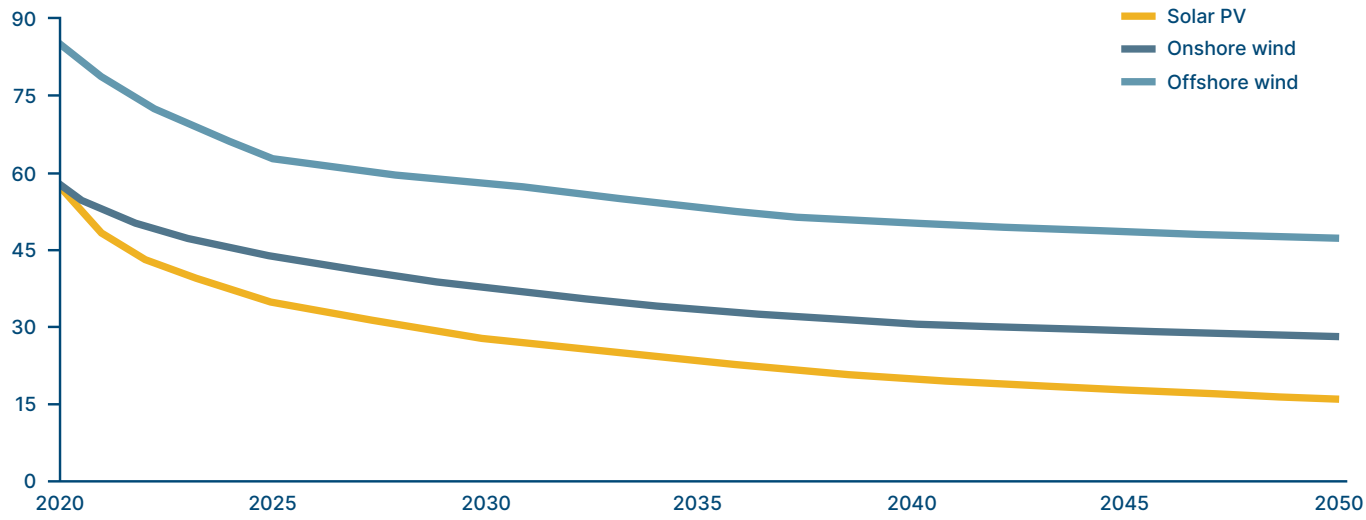
Overall, BloombergNEF forecasts suggest that average global LCOEs could fall by over 70% for solar, 50% for onshore wind and 45% for offshore by 2050 [Exhibit 2.4].[41] But it is important to note that:

- These forecasts imply a much lower pace of reduction than achieved in the last 10 years, for instance a 70% fall for solar over the next 30 years versus 80% in the last decade. Some experts believe that such forecasts still systematically underestimate the potential for continued rapid cost reduction.[42]
- The pace of reduction will itself be strongly influenced by public policy and by the overall scale of ambition, investor confidence in future revenues reducing cost of capital, and the detailed design of planning and approval processes and power market contractual structures.

Exhibit 2.4

Renewable LCOEs projected to fall further

Solar PV and wind LCOE forecasts (global average)
LCOE, $/MWh, 2020 real



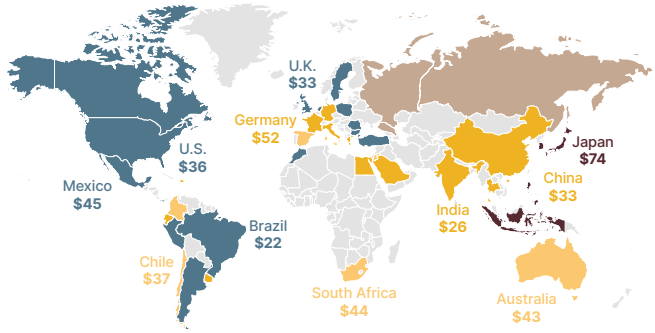
NOTE: Based on a simple average of global regions, and mid range LCOE forecast.
SOURCE: BloombergNEF (2020), *2H 2020 LCOE Update*

Even at current cost levels, new renewable electricity is cheaper than new coal or gas plants in countries representing 76% of GDP and 90% of current electricity generation[43] [Exhibit 2.5] and this advantage will increase and spread to other countries over the next decade. By 2025 or sooner, BloombergNEF expect that solar will outcompete coal in the Philippines, Vietnam, Malaysia and Indonesia.[44] In many countries, furthermore, new wind and solar is already cheaper than the marginal cost of running some existing coal or gas plants, and this advantage will also spread and grow over time.[45] In both India and China for instance, BloombergNEF shows that new build solar and wind are already in part competitive with some existing coal plants [Exhibit 2.6].

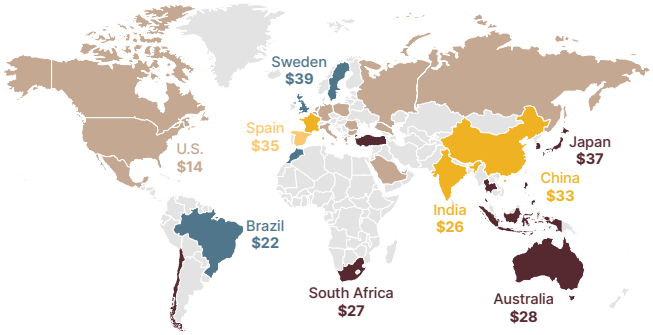
41 BloombergNEF (2020), *2H 2020 LCOE Update*
42 See for instance Ramez Naam (2020), "Solar's Future is Insanely Cheap", which suggests that solar PV generating costs could by 2050 be below 0.5 cents per kWh in most favourable locations, below 1 cent per kWh across most of the world and only 1.5 cents per kWh even in the highest cost countries.
43 BloombergNEF (2020), *2H 2020 LCOE Update*
44 BloombergNEF (2020), *2H 2020 LCOE Update*
45 This relatively will vary greatly between coal plants of different age and efficiency. In many countries VRE generation is already significantly cheaper than the marginal cost of running old inefficient units, but still appreciably above the marginal cost of recently built and highly efficient units.

VRE is increasingly cost-competitive against both new fossil and existing fossil

New-build VRE vs. new-build fossil
Cheapest source of bulk generation globally, 2020



New-build VRE vs. existing fossil
Cheapest source of bulk generation globally, 2020



Onshore wind · Offshore wind · Utility PV - fixed axis · Utility PV - tracking · Natural gas - CCGT · Coal · Not covered

VRE cheaper than new fossil in countries representing 2/3 of global population.

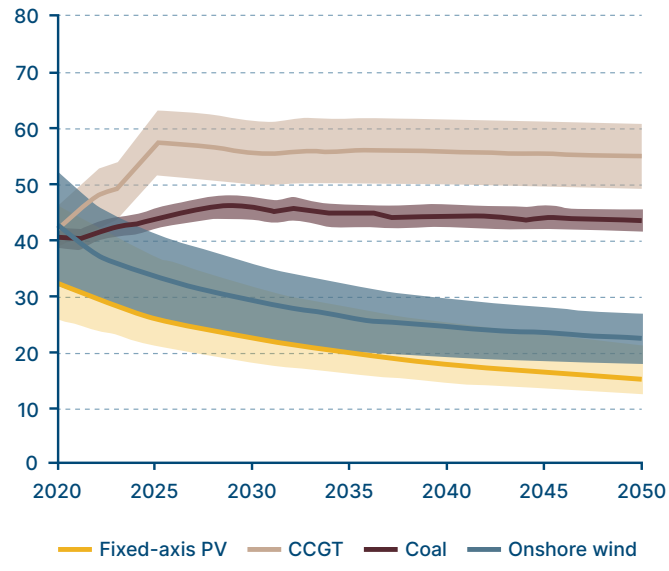
VRE cheaper than existing fossil in countries representing almost 1/2 of global population.

Exhibit 2.5

SOURCE: BloombergNEF (2020), *2H 2020 LCOE Update*

VRE increasingly cost-competitive with marginal cost of coal in China and India

Levelised cost of new PV and onshore wind vs. running costs of existing coal and gas: China
$/MWh, (2019 real)



Levelised cost of new PV and onshore wind vs. running costs of existing coal and gas: India
$/MWh, (2019 real)

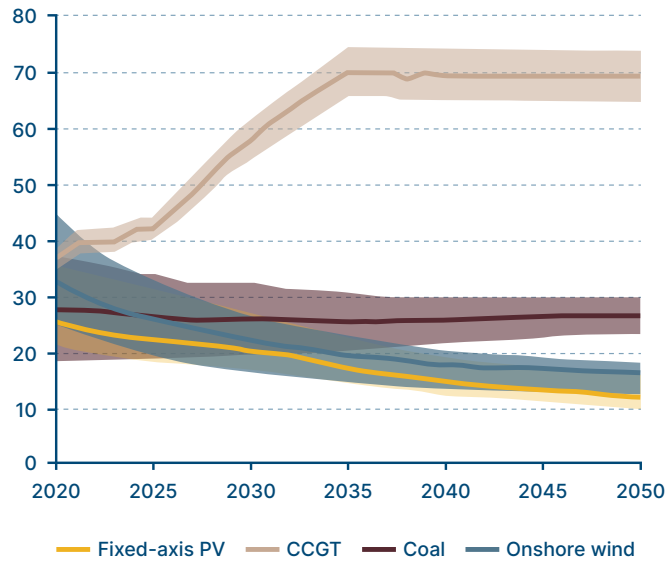


Exhibit 2.6

NOTE: Solar and wind LCOEs account for curtailment. Coal and gas running costs include a carbon price.

SOURCE: BloombergNEF (2020), *2H 2020 LCOE Update*

It is therefore clear that VRE can and should play a dominant role in electricity decarbonisation in almost all countries, and has the potential to deliver bulk electricity cheaper (and in some cases far cheaper) than current fossil fuel-based systems.

In addition, there can be a significant role for other zero-carbon sources including in particular:



Hydropower, which in many locations delivers power at costs as low as wind or solar, and can also be a dispatchable resource, is of great value within a VRE-dominated system. However, it is critical that any hydropower expansion – including increasing generation via modernisation of the existing fleet – should be sustainable, with no adverse effects on biodiversity and low project lifecycle carbon emissions (e.g. due to the high carbon footprint of reservoirs). Estimates show that across the world it may still be possible to increase hydropower capacity in a sustainable way by over 5,000 TWh, with opportunities broadly evenly distributed around the world. [46]



Nuclear can be relatively low cost in countries like China which commit to build multiple variants of one design, but is likely to be easily outcompeted by VRE in many others, unless developments in small modular reactors (SMR) can drive meaningful cost declines. Nuclear energy also faces major constraints including waste management concerns and costs, as well as local opposition.



Bioenergy with or without carbon capture and storage (CCS) may have a role to play in providing seasonal balancing, as well as when fitted with CCS (BECCS), achieving negative emissions. However, the use of bioenergy in power is likely to be constrained by multiple competing use cases for the limited sustainable supply of biomass with low lifecycle GHG emissions. This topic will be covered extensively in the upcoming ETC Bio-economy report.[47]

46 Some existing hydropower project proposals represent significant threats to nature and biodiversity, including via ecological impacts such as land flooding, freshwater habitat alteration, and water quality degradation. In addition, some hydropower generation cannot be considered low carbon where lifecycle emissions of hydropower plants are high due the carbon footprint of reservoirs. A 2018 study by the International Hydropower Association highlighted that the medium life-cycle carbon equivalent intensity of hydropower was around 18.5 gCO2e/kWh. The International Hydropower Association have developed set of guidelines and tools for assessing project performance against environmental, social and governance performance criteria. Estimates show that further technical potential of hydropower than meets ecological criteria is over 5,500 TWh, see Gernaat et al, (2017), Nature, "High-resolution assessment of global technical and economic hydropower potential".

47 ETC (upcoming, 2021) *Making a Sustainable Bio-economy Possible*

II. Balancing VRE based power systems – a vital but manageable challenge

As renewables get ever cheaper, the critical question is no longer the relative cost of renewable versus fossil fuel-based generation, but the feasibility and cost of running systems with an increasing percentage of VRE. Running such systems will require the application of new technologies and approaches to system operation, supported by appropriate power market design. Provided those enablers are in place, it will be feasible and cost-effective to run power systems with VRE penetration rates as high as 75% to 90%.

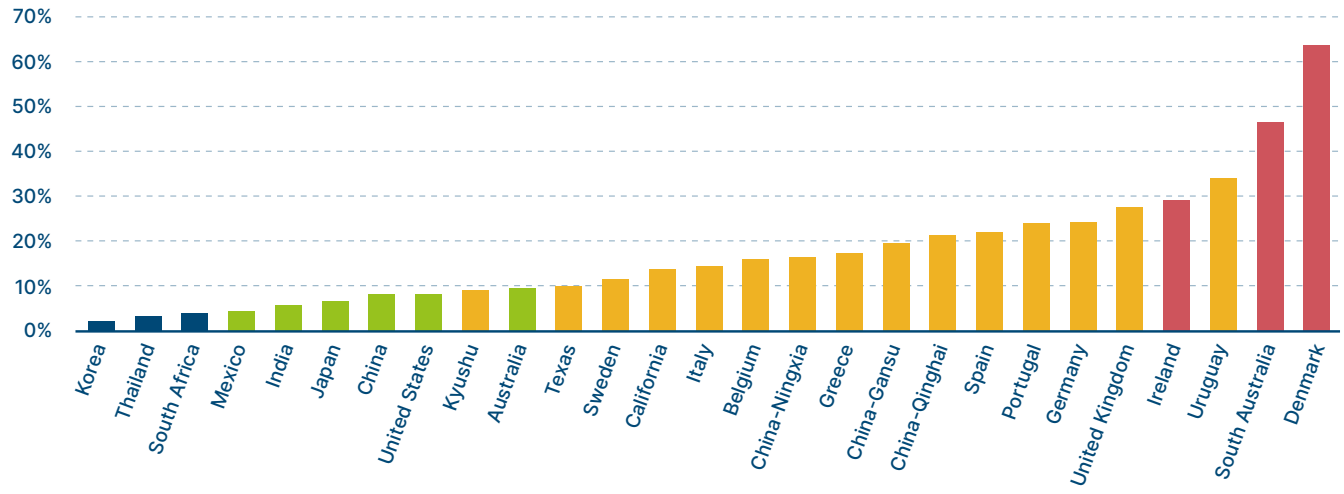
When VRE resources were first introduced into power systems, some experts believed that technical system management complexities (for example, the need for real-time frequency balance previously provided by rotating inertia) might limit feasible levels of VRE penetration below 50%. But as VRE shares have increased, technical solutions have been found.[48] As will be discussed in Chapter 3, market design will have to adapt to ensure procurement of newly unbundled ancillary services required in high-VRE systems.

Many countries already operate with average yearly VRE generation shares of 30% or more [Exhibit 2.7]. The Covid-19 crisis has also acted as a stress-test, with the share of renewables in electricity generation rapidly rising as a result of the demand shock from lockdown measures.[49] Several systems operate today with daily or hourly VRE percentages reaching 60% or more.[50]

- Across many countries, rising shares of VRE penetration have been easily managed by using thermal capacity more flexibly, exploiting dispatchable hydro resource where available, or increasing interconnectivity between different regions. In systems with large gas capacity, more flexible generation has proved straightforward.

Several markets already reaching VRE penetration of 30% or more

Annual VRE share and corresponding system integration phase in selected countries/regions
% VRE annual electricity generation, 2018



Phase 1 - No relevant impact on system
Phase 2 - Minor to moderate impact on system operation
Phase 3 - VRE determines the operation pattern of the system
Phase 4 - VRE makes up almost all generation in some periods

Exhibit 2.7

NOTE: Refers to VRE only (excluding bio-resources), share of generation, inclusion of distributed generation not specified.

SOURCE: IEA (2019) *Renewables 2019: Analysis and Forecasts to 2024*

48 There are clearly available solutions to four categories of technical challenge often mentioned as VRE penetration rises, including frequency control, voltage control, fault ride-through, and capacity utilisation of long-distance high-voltage direct current (HVDC) lines. For further details, see RMI/ETC China (2021), *China Zero-Carbon Electricity Growth in the 2020s – Vital Step Towards Carbon Neutrality.*

49 For example, see National Grid ESO, "2020 greenest year on record for Britain", 12th January 2021

50 In 2020, in the UK the record for the highest ever level of wind generation was broken several times during the year, and reached a new high when wind generation accounted for nearly 60% of total power supply on August 26, 2020. In Germany, renewables generated 77% of net power supply in a single day on April 22, 2019, with wind generating 40%, solar 20%, and others 17%. See National Grid ESO, RMI/ETC China (2021), *China Zero-Carbon Electricity Growth in the 2020s – Vital Step Towards Carbon Neutrality.*

- Even in countries currently dominated by coal generation, such as India or China, ETC analysis shows that it is easily possible to take the VRE share of generation from today's 10% to around 30%, by using already existing coal or hydro plants more flexibly [Box 1].

- Nevertheless, in some limited regions where existing thermal capacity is either insufficient or inflexible, additional zero-carbon balancing options – or, in some highly constrained cases, new gas, with plants that would make a shift to hydrogen possible during their lifetime – will be required (see Chapter 2 Section 5 for details).

As VRE penetration rates rise above 30% and still higher, and shares approach 100% at particular times, the system balance challenge will become more complex but still manageable. Systems will have to find solutions to three types of balancing challenge:

- **Daily balancing,** between hours and day to night, with for instance large daytime solar output but significant demands during the evening;

- **Predictable seasonal** month by month cycles in either demand or supply (e.g. winter demand peak for building heating in Northern latitude economies or wind generation peak in India during the monsoon season);

- **Unpredictable week-by-week** variations that cannot be forecast well in advance and which vary in importance each year (for example, extended weeks of 'wind droughts'/anticyclones). The frequency and duration of these vary by geographic region, and may be further influenced by climate change.[51]

51 In a typical Northwest European winter, for instance, anticyclonic wind droughts might usually last about a week and occur several times each winter but in extreme winters, they can last for several weeks, and are often accompanied with cold temperatures, increasing heating demand and decreasing heat pump efficiency. Similarly, there can be multi-day solar events where solar generation is significantly lower than average for multiple days in a row.



Sufficient flexibility within existing systems to integrate 30% of renewables
China and India case studies

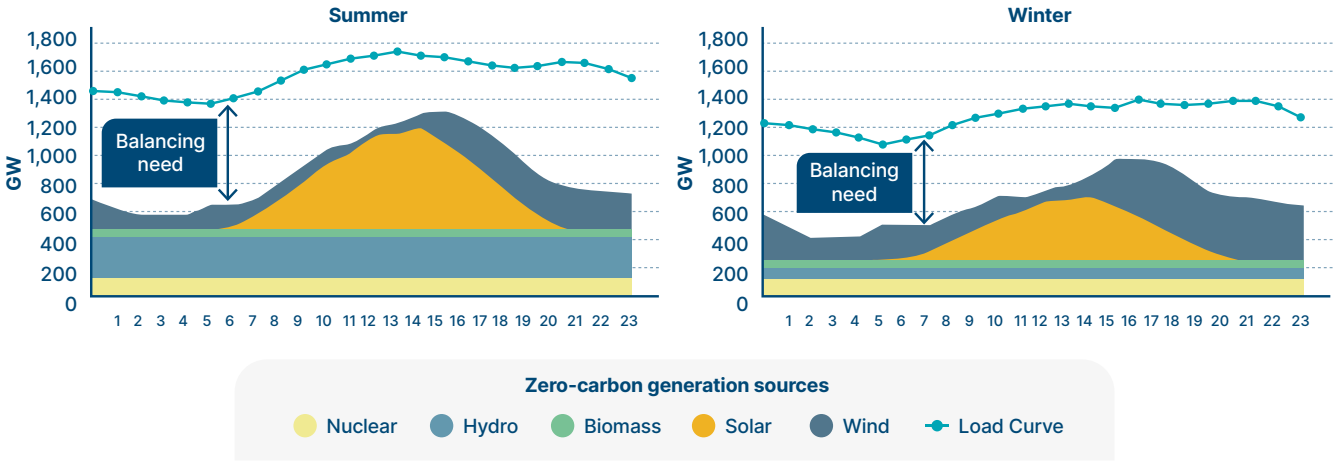
Many systems have sufficient capacity already in place to easily integrate 30% of VRE penetration, due to flexible thermal plants, hydro resource, and cross-region balancing. As other zero-carbon balancing scales up, existing capacity can provide a transitional balancing source for growing VRE in bulk generation.

In China, 2030 scenarios show that 28% VRE penetration can be absorbed without need for any new fossil additions due to existing thermal and hydro generation, with a minimal role for battery storage (2GW in 2030) and moderate role for pumped hydro storage (81GW). This is despite China's hydro capacity which is less flexible than that of other countries, reflecting both physical limits (e.g. more run-of-river hydro and fewer dams, lower reservoir capacity, and lower height drops) and rigid contractual mechanisms.

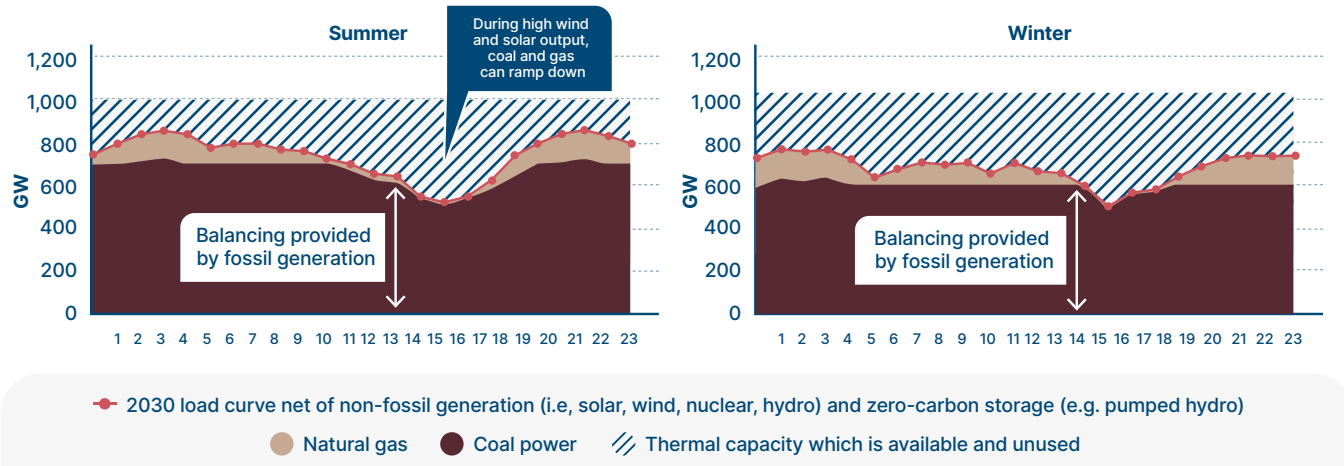
In India, scenarios show that reaching 32% VRE penetration by 2030 can be met principally with flexibility from conventional generators, in particular the coal and hydro fleet, with an increasing role for battery storage (60 GW in 2030). By varying output throughout the day, India's coal fleet could provide significant flexibility to integrate VRE. However, some modifications to the mode of operation need to be made to ensure the coal fleet can meet stringent ramping requirements, e.g. the ability to run in a stop/start manner to allow two-shifting. In the mid-term, battery storage and coal flexibility are complementary, with batteries reducing the operational stress of the coal fleet.

In the medium to long-term, thermal capacity should phase out, as other zero-carbon balancing options (e.g. hydrogen, CCS) will be able to provide long-term flexibility for high-VRE systems.

China, Simulated load curve and zero-carbon generation in typical winter and summer days in 2030



Estimated Flexibility of China's Coal fleets in Typical Winter and Summer Days in 2030



Box 1

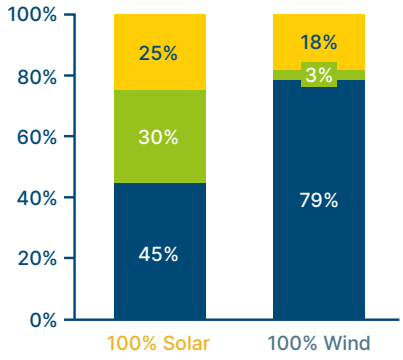
NOTE: The load profile and renewable profile are based on Reinventing Fire: China's model assumption.

SOURCE: Rocky Mountain Institute and Energy Transitions Commission (2021), *China Zero-Carbon Electricity Growth in the 2020s: a Vital Step Towards Carbon Neutrality*, TERI (2020) *Renewable Power Pathways Report*

Optimal mix of VRE resources can minimise balancing challenges

Exhibit 2.8

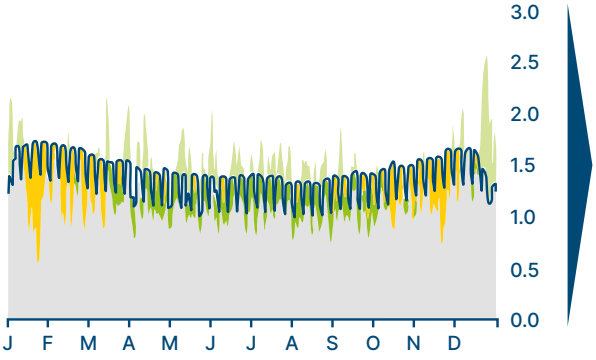
Germany storage 'gaps' – with 100% solar or wind



	100% Solar	100% Wind
Seasonal gap	25%	18%
Daily gap	30%	3%

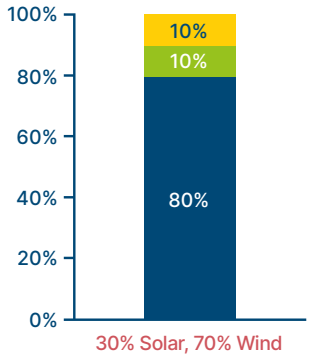
- Seasonal balancing
- Daily balancing
- Concomitant generation

German yearly power demand profile in a near 100% VRE system, Daily TWh



- Daily electricity demand
- Renewable energy generation used in the same hour it is produced
- Daily shortfall of renewable energy production, potentially met by daily shifting
- Daily surplus of renewable energy production that can be shifted
- Seasonal shortfall

Germany storage 'gap' with optimal mix



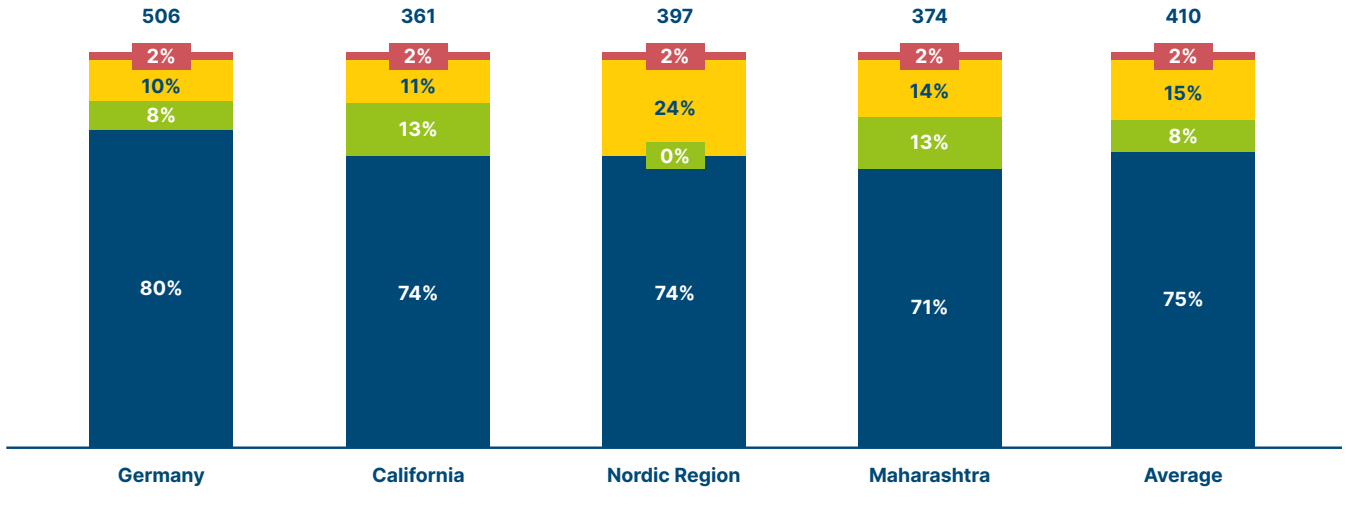
	30% Solar, 70% Wind
Seasonal gap	10%
Daily gap	10%

SOURCE: Adapted from Climate Policy Initiative for the Energy Transitions Commission (2017)

Scale of seasonal balancing needs differs across regions

Exhibit 2.9

Balancing variability across markets in a near 100% VRE system



- Week-by-week variation (unpredictable)
- Seasonal balancing (predicatable)
- Daily balancing
- Concomitant generation

NOTE: 2% week-by-week variation is approximate, and range will vary by market. Generation scaled up to meet 100% demand based on current VRE ratio: Wind (64%), solar (34%) and run of river hydro (2%).

SOURCE: Adapted from Climate Policy Initiative for the Energy Transitions Commission (2017)

The absolute and relative importance of balancing challenges will vary by region, and be significantly influenced by the mix of VRE selected. Analysis for Germany for instance, shows that an optimal 30%/70% mix of solar and wind generation can result in 80% "concomitant generation" (hours of VRE generation which occur at the same time as demand) leaving only 20% of hours where demand and supply must be matched either by storage or by some category of dispatchable generation, and solving to minimise the amount of seasonal balancing required [Exhibit 2.8].[52] Analysis for other countries/ regions suggest that the total need for storage / dispatchable plant might vary between 20 and 30%, but that in all cases the "unpredictable" element is only a limited number of total hours. [Exhibit 2.9]

These different challenges can be met through a combination of:

- Choosing the optimal scale, mix, and interconnectivity of VRE resources for a given geographical area:
  - Scale: "Overbuilding" VRE capacity to meet predictable seasonal peak demands even if this results in some curtailment at other times, for example overbuilding wind in the UK so wind generation is available to meet winter peak even if it gets curtailed in the summer.
  - Mix: Optimising the mix of wind and solar supply to optimise alignment of generation with demand profile, for example, 30% solar and 70% wind for Germany can reduce seasonal balancing needs (or "gap") to 10% of total load.[53]
  - Interconnectivity: Increasing the size of balancing areas via interconnectors with other regions which have a complementary renewables resource profile, likely over very long distances (for example, HVDC from Morocco to the UK).
- Deploying a range of dispatchable generation, energy storage and demand-side flexibility mechanisms [Exhibit 2.10]. Where available, hydro and, in some cases, nuclear generation can significantly reduce balancing challenges.

Exhibit 2.10

Range of dispatchable generation, energy storage, demand-side flexibility options

			Daily	Seasonal (predictable)	Week-by-week (unpredictable)
Dispatchable generation	Other zero carbon	Hydro, nuclear[1]	✓	✓	✓
	Fossil	Fossil (or bioenergy) + CCS	✓	✓	✓
		Fossil – very low utilisation	✓	✓	✓
Energy storage		Pumped hydro	✓	✓	✓
		Lithium ion battery[2]	✓		
		Emerging technologies	✓		
		Power-to-X-Power[3]	✓	✓	✓
Demand side flexibility		EV (smart charging, V2G)	✓		
		Heating load	✓		
		Industrial load[4]	✓	✓	

NOTES: [1] Limited nuclear capacity for flexible ramping. [2] Li-ion storage is utility-scale and behind-the-meter. [3] Examples of Power-to-X-Power include the production of hydrogen from electrolysis and re-conversion of hydrogen into power via gas turbines or fuel cells. [4] Including hydrogen electrolysis, where production can be shifted to optimal times.

SOURCE: Adapted from Climate Policy Initiative for the Energy Transitions Commission (2017), *Low-cost, low-carbon power systems*

52 Adapted from Climate Policy Initiative for the Energy Transitions Commission (2017), *Low-cost, low-carbon power systems*. Generation scaled up to meet 100% demand based on current VRE ratio Wind (64%), solar (34%) and run of river hydro (2%).
53 Climate Policy Initiative analysis (2017)

Which of these zero-carbon solutions is most cost-effective, and whether applying them will reduce or increase costs relative to unabated fossil will depend on several cost tipping points which become relevant as VRE penetration rises [Exhibit 2.11] Relative to unabated fossil, VRE and zero-carbon solutions will become economic if they hit the following cost tipping points:

- VRE vs new and existing fossil fuels. Increasing share of VRE in total generation will be cost-competitive if VRE LCOEs are not only below the cost of new fossil fuels, but also undercut the marginal cost of running existing fossil fuel plants (with new fossil fuel cost the relevant long-term comparator when existing fossil fuel plants are phased out at end of useful life). As referenced in Chapter 1 Section 1, these tipping points are well underway: new VRE is already undercutting the marginal cost of fossil generation in countries representing almost half of the global population.

- VRE + storage vs new and existing fossil fuels. Increasing VRE shares above around 30% of generation to around 70% of generation will become economic if VRE + storage becomes a competitive dispatchable solution, especially for daily balancing, with costs falling below the cost of first new then existing fossil generation. VRE + storage will become competitive if battery technology costs continue to decline, and further declines materialise in the storage costs of VRE power, e.g. due to technology improvements and increasing availability of low-cost (including curtailed) VRE electricity generation within the network.

- Hydro generation where available is likely to remain an economic seasonal balancing option. Beyond hydro, VRE overbuilding strategies to deal with predictable seasonal balancing could become more economic than dispatchable gas generation, if VRE LCOEs fall far below marginal cost of gas, or in later years, of gas with CCS.

- The optimal solution to unpredictable week-by-week variations may be driven by the relative price of 'stored' hydrogen burned in compatible CCGT versus gas plus CCS. The tipping point to shift to one of those solutions rather than unabated gas peaking is unlikely to be reached without a significant carbon price.

The critical priority in the 2020s is undoubtedly the massive deployment of cost-competitive renewables for bulk generation, increasing VREs penetration in networks across geographies to 30% and above.

As discussed in the following sections, in most countries, a mix of zero-carbon balancing tools will ensure relatively easy and cost-effective solutions to the short-term challenge of balancing supply and demand within each day. At the point where VRE shares increase significantly, e.g. rising to 70% and over, balancing between seasons and across weeks will in some countries be more challenging, but still manageable at reasonable cost.

The cost impact of increasing VRE penetration and optimal mix of balancing solutions deployed will be influenced by cost "tipping-points"

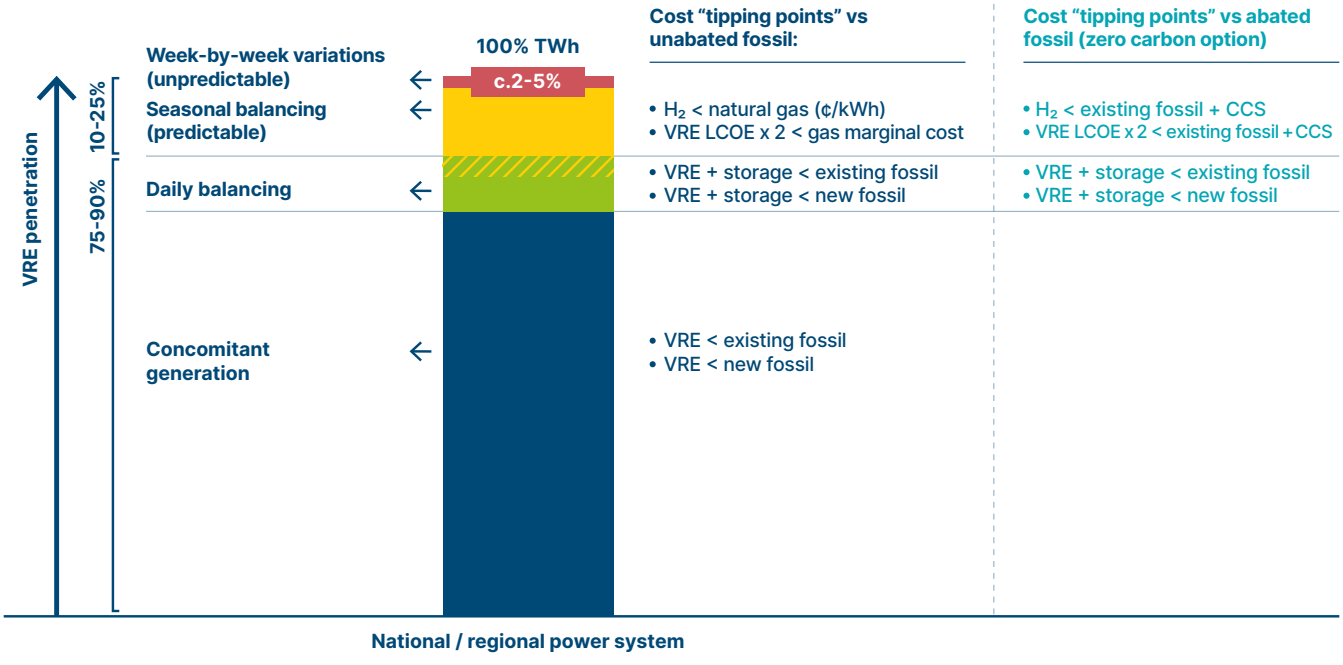


Exhibit 2.11

SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021)



Daily balancing – clearly cost-effective solutions

In many warmer-climate, lower-latitude countries – and therefore across much of the developing world – the main challenge in VRE-dominated systems will be to balance plentiful daytime solar supply with demand which extends into the evenings and overnight. Even in countries where this is not the most important challenge because of more evenly distributed VRE generation (which tends to be the case with wind generation), demand and supply must still be brought into balance on an hour-by-hour basis.

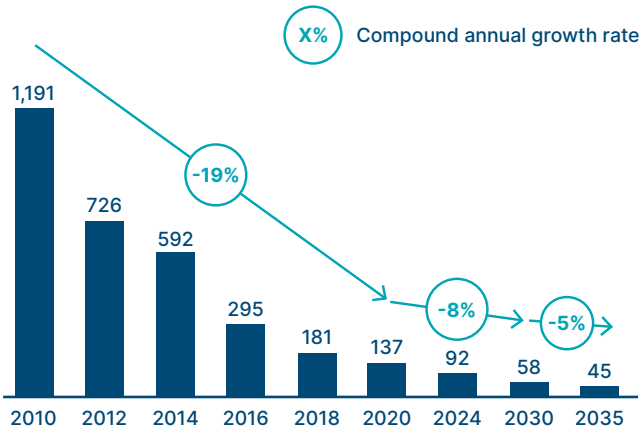
But it is increasingly certain that this challenge can be met at low cost by deploying a range of energy storage and demand management levers:

- **Lithium-ion battery pack** costs have fallen 85% in the last decade and are certain to fall still further as automotive demand drives economy of scale and learning curve effects. BloombergNEF suggests that by 2035, battery pack costs could fall a further 67% below current levels.[54] Technological progress towards high-nickel cathodes and solid-state chemistries could further improve performance and reduce costs. Even at current prices, batteries are increasingly being deployed within the grid to provide both frequency response and short-term energy balancing services. In the US, several gas turbine contracts have been cancelled in favour of VRE + batteries combinations.[55] Meanwhile, in May 2020, India ran a "round-the-clock" auction for 400 MW of renewable capacity with a winning bid price of $38/MWh – below current power offtakers' average cost of electricity purchase – illustrating that VRE + batteries will be increasingly competitive as a source of flexible power supply[56] [Exhibit 2.12].

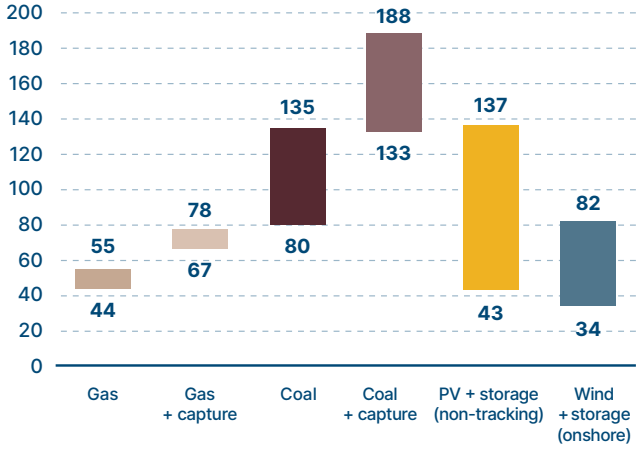
For daily balancing, lithium-ion batteries will be an increasingly cost effective solution

Exhibit 2.12

Battery prices – Observed and Outlook
Real 2020 $/kWh (historical, predicted)



Comparison of US LCOEs in 2023
$/MWh, (2018 real)



NOTE: on RHS, capture refers to post-combustion, liquid absorption of CO_2. LCOE forecasts use 4hr battery storage. LCOEs exclude subsidies, tax credits, and CO_2 transport and storage costs.
SOURCE: BloombergNEF (2020)

- **Other short-term and medium-term energy storage** solutions may also play a significant role. Pumped hydro storage – which can also provide dispatchable electricity for longer durations – represents the majority of grid-level storage today and is highly likely to be economic in many situations. Significant new capacity potential still exists.[57] Furthermore, alternative battery technologies to lithium-ion, such as flow batteries, may enable power storage to meet daily balancing needs, and a range of other heat or pressure-based storage technologies are being developed [Box 2].

54 These costs refer to lithium-ion battery pack prices. Grid lithium-ion battery storage face a higher cost premium on the battery pack compared with automotive end-users. See BloombergNEF (2020) *Lithium-ion Battery Price Survey*; versus 2020 average expected price of $137/kWh at the pack level, BloombergNEF base case scenario (based on learning curve assumptions) predicts $45/kWh by 2035.
55 BloombergNEF (2020), *1H 2020 LCOE Update*
56 The auction stipulated that the generator had to have availability 80% of the hours of the year (including overnight). Renew Power won the auction at a price of $38/MWh and is expected to meet the requirements through a mix of storage and also oversizing the solar/wind resource such that even when producing below max capacity (e.g., when cloudy for solar) the site will still meet the required output. The auction tariff was $38.29/MWh, 3% annual escalation for 15 years and fixed thereafter, levelized tariff is $47.65/MWh assuming a 9% discount rate. BloombergNEF, (2020), *Round-the-Clock Renewables Threaten Coal Power in India.*
57 See Australian National University, "ANU finds 530,000 potential pumped-hydro sites worldwide", 1 April 2019

Innovative energy storage technologies for balancing

Multiple energy storage technologies could provide solutions to daily and longer-term balancing challenges.

Emerging technologies vary across costs and technology readiness levels, e.g.:

- Flow batteries (rechargeable batteries where liquid electrolyte is stored in external tanks), e.g. vanadium-redox, increasingly targeting durations of around 6-8 hours of storage, and able to hold higher capacity compared to lithium-ion batteries.
- Compressed air energy storage (CAES), which requires large, high pressure underground salt caverns, and could provide high capacity energy storage across days. This is still early-stage at grid scale, though could provide higher round-trip conversion efficiency compared with hydrogen storage, for example.

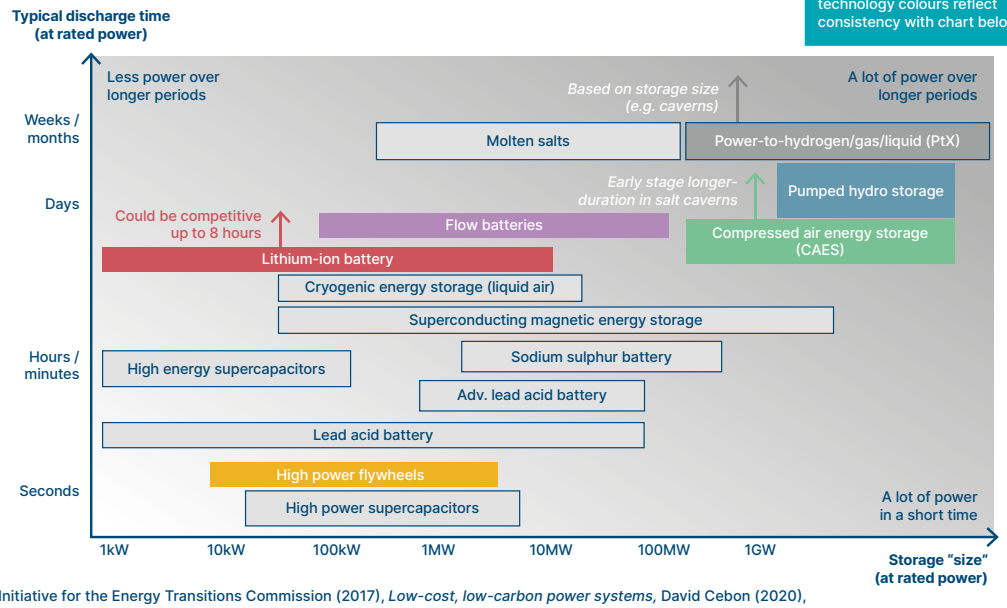
Energy storage solutions vary depending on storage size and discharge time performances

Discharge times are illustrative, based on typical applications; technology colours reflect consistency with chart below

Seasonal balancing
- Narrower range of technologies
- Complex and expensive challenge, with costs varying widely according to local conditions

Daily balancing
- Wide range of technologies
- Strong cost decrease (e.g. lithium ion batteries) making zero- or low-carbon storage solutions competitive with fossil fuel peak generation

Short-term reserves
- Well-known cheap technologies

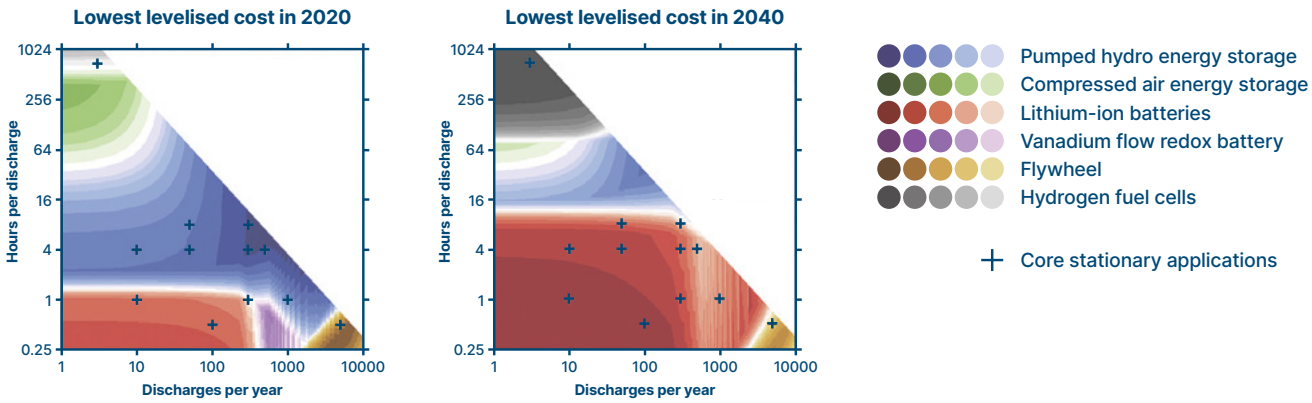


SOURCE: Adapted from Climate Policy Initiative for the Energy Transitions Commission (2017), *Low-cost, low-carbon power systems*, David Cebon (2020), The Centre for Sustainable Road Freight, *"Blog: Technologies for Large-Scale Electricity Storage"*

Assessment of costs across selected storage options suggests that Li-ion, pumped hydro and hydrogen storage could win out

Analysis by Imperial College highlights that today pumped hydro storage is the least cost storage option across the most storage durations (e.g. from 1-50+ hours) and discharge frequencies (e.g. from 1 to almost 10,000 times). By 2040, the balance of storage technologies might include a very significant role for lithium-ion across a large spectrum, a limited role for flywheels (for low-duration yet high discharge frequencies), a significant role for pumped hydro for energy storage between 16-60 hours, a role for compressed air-energy storage (CAES) for longer durations, and hydrogen in fuel cells playing the major role for long storage durations.

Levelised cost of storage analysis based on selected storage options



NOTE: Shading indicates how much higher the levelised cost of storage (LCOS) of the second most cost-efficient technology is, meaning lighter areas are contested between at least two technologies, while darker areas indicate a strong cost advantage of the prevalent technology.

SOURCE: O. Schmidt, S. Melchior, A. Hawkes, I. Staffell, (2019), *Joule*, "Projecting the Future Levelized Cost of Electricity Storage Technologies"

Box 2

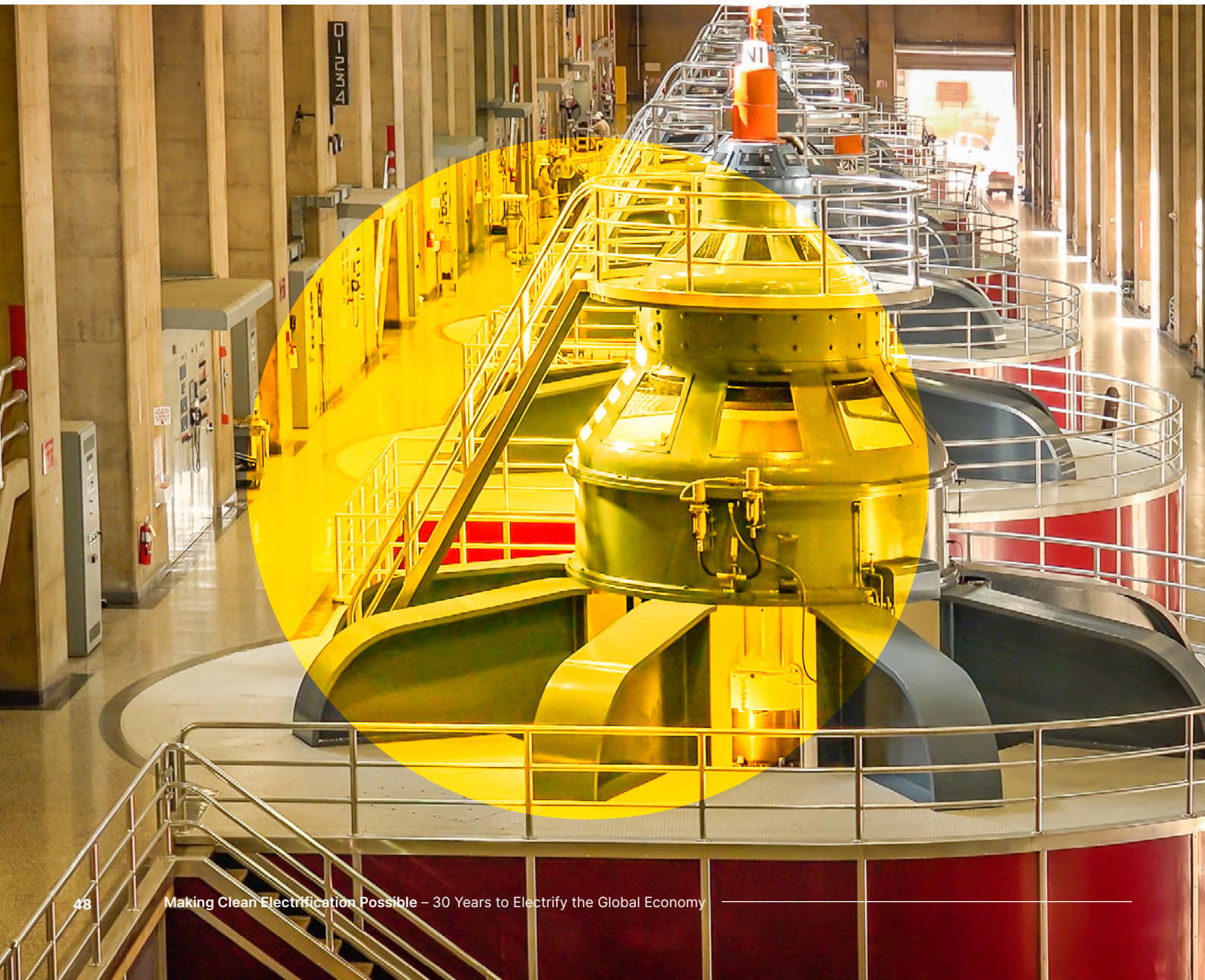
- The optimal mix of technologies remains uncertain and will differ across markets and by use case, but competition between these alternative options is highly likely to produce further reductions in the cost of flexibility provision. As will be discussed in Chapter 3, appropriate market design will be needed to ensure that zero-carbon storage solutions are properly incentivised.

Flexible demand response to available supply also has huge potential to meet the daily cycle. As Chapter 1 described, electrification of road transport and of residential heat, alongside increasing air conditioning demand, could exacerbate system balancing challenges by creating peak demand uncorrelated with fluctuations in VRE supply. But there are huge opportunities to make these and other categories of demand more responsive to supply:

- Large residential heating loads could be shifted by several hours if houses were adequately insulated to ensure high thermal inertia, domestic water heaters were installed, and micro heat storage technologies were deployed and developed.

- Electrification of road transport creates a major opportunity for flexible demand response. As described in Chapter 1, electric vehicles can provide both demand-side flexibility (via smart charging, at optimal times) and energy storage (via vehicle-to-grid), though the latter has higher implementation barriers. With well-designed incentives, the majority of the EV load could be highly flexible in response to changes in supply.

- In addition, many industrial and commercial electricity uses could vary demand in response to supply. These include multiple existing uses – such as commercial AC, or retailer chilling and freezing cabinets. But the biggest opportunity probably lies in hydrogen electrolysis. In the zero-carbon economy of 2050, almost 25% of total electricity supply could be used to produce around 400-700 million tonnes of hydrogen per annum. Electrolysers will be sufficiently cheap to run cost-effectively for only a small proportion of total yearly hours, with the ability to ramp up and down rapidly. This is a potentially significant flexible source of demand, with strong incentives to use electricity when it is cheapest.



However, to support development of these demand management options, it is critical for governments and electricity regulators to deploy a set of enablers. It will require rolling out appropriate incentives within power markets (in particular real-time pricing), as well as ensuring the mandatory installation of smart capabilities (e.g. smart chargers), ease of customer use, and the development of aggregator and virtual power plant (VPP) business models.[58] As discussed in Chapter 1 Section 1, the use of vehicle batteries for storage will also depend on addressing battery degradation concerns.

Seasonal balancing – more challenging but solvable

While daily balancing can be provided at low cost, challenges are more complex over longer durations. But here too there are a range of zero-carbon technologies which can address both the predictable seasonal and the unpredictable week-by-week challenge.

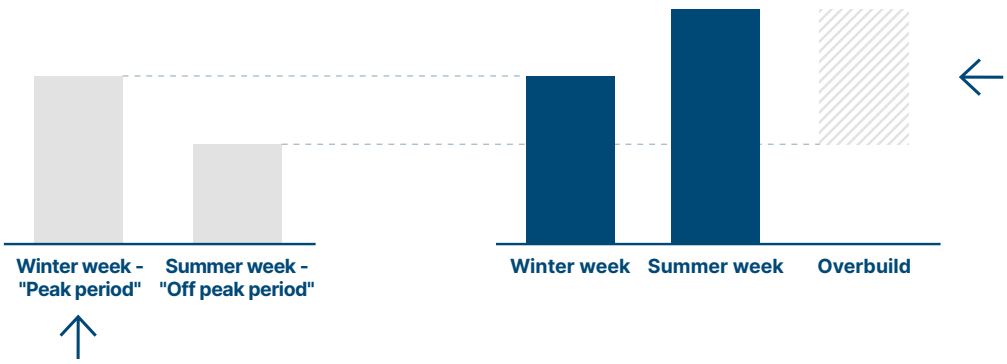
For **predictable seasonal** cycles, a range of solutions is available:

- Long-distance interconnection with other regions (both within and across countries) which have complementary renewable resources;
- The "overbuild" of VRE assets or building sufficient VRE capacity to meet the predictable seasonal peak even if that means curtailment in low demand periods [Exhibit 2.13];[59]
- Dispatchable generation, including hydro, nuclear, as well as other flexible emerging options for zero-carbon generation, including (a) hydrogen produced from electrolysis and burnt in compatible CCGTs when needed[60], (b) natural gas plus CCS, and/or (c) a constrained role for sustainable biomass (with or without CCS)

VRE 'overbuild' could provide low-cost option to meet seasonal balancing

Exhibit 2.13

Illustrative northern latitude archetype



Overbuild of solar or wind to meet winter peak demand, creates surplus generation in summer

This "surplus" electricity can either by curtailed – or provide very cheap/free electricity for e.g. seasonal green hydrogen production

Cost of procuring kWh of energy in winter period:

		China 2040	USA 2040
Solar	Projected Solar PV LCOE	$0.024/kWh	$0.015/kWh
	x2 ("oversizing" to ensure winter period production)	**$0.048/kWh**	**$0.030/kWh**
Gas	Projected marginal cost of gas CCGT	**$0.055/kWh**	**$0.032/kWh**

Installing additional renewables to meet seasonal demand peak cheaper than operating existing gas plants, rationale for VRE "overbuild" – where curtailment in the "low season" is the least-cost option to meet demand in the "high season"

NOTE: LCOE 2040 projection is based on BloombergNEF, and is the mid-range China and low-end for the United States.

SOURCE: BloombergNEF (2020)

58 Aggregators bundle Distributed Energy Resources (DERs) to engage as a single entity – a virtual power plant (VPP) – in power or service markets. Distributed energy resources (DERs) are small and medium-sized power resources connected to the distribution network, including storage, distributed generation, demand response, EVs and their charging equipment.

59 Curtailment will furthermore be reduced in a market that has facilitated storage and/or hydrogen production.

60 Hydrogen could also be reconverted to power via fuel cells, though this route faces lower technology readiness levels and higher costs compared with burning in compatible-CCGTs.

- Industrial demand management, with major energy users planning maintenance or other shutdowns for periods in which demand can be predicted to be high relative to supply, and thus electricity prices likely to be elevated.

For **unpredictable week-by-week** variations, overbuild does not provide a solution (since however much wind capacity is in place it may not be operating), and the role of interconnectors could be limited by security of supply concerns.[61] Lack of predictability is also likely to limit the industrial off-takers able to offer demand-side response solutions. Therefore, some category of firm dispatchable capacity is almost certain to be required, with the same list of options as described above for the predictable cases.

The optimum set of solutions to both these balancing challenges will vary according to local costs and availability:

- Dispatchable generation beyond hydro is likely to require low-utilisation capital assets, which run only a small number of hours per annum. However, the impact of this on total electricity costs will be very small. Generating electricity for just 10% of all hours per year using gas plus CCS (with CCS capex costs spread over a period of 20 years) could cost between $0.13-24 per kWh delivered [Exhibit 2.14], and therefore contribute $0.01-$0.02 cents per kWh to average total costs across the year. Furthermore, the impact of this increase on total system costs in a high-VRE system relative to today's costs could be offset by the low and falling cost of VRE generation.

- For predictable seasonal cycles, in addition to low-cost hydro in large reservoirs where this is available, the most cost-effective solutions are likely to involve both (i) long distance interconnection with complementary regions and (ii) the "overbuild" of VRE assets or building sufficient VRE capacity to meet the predictable seasonal peak even if that means curtailment in low demand periods. While this inevitably involves some "waste" of curtailed resources (which can face some level of political opposition) renewable generation gets ever cheaper, overbuild will in many locations be the least-cost solution, potentially delivering peak period electricity at costs below those of current unabated fossil fuel-based generation.

H_2 in CCGTs could be most cost-effective zero-carbon way to meet unpredictable week-by-week variations

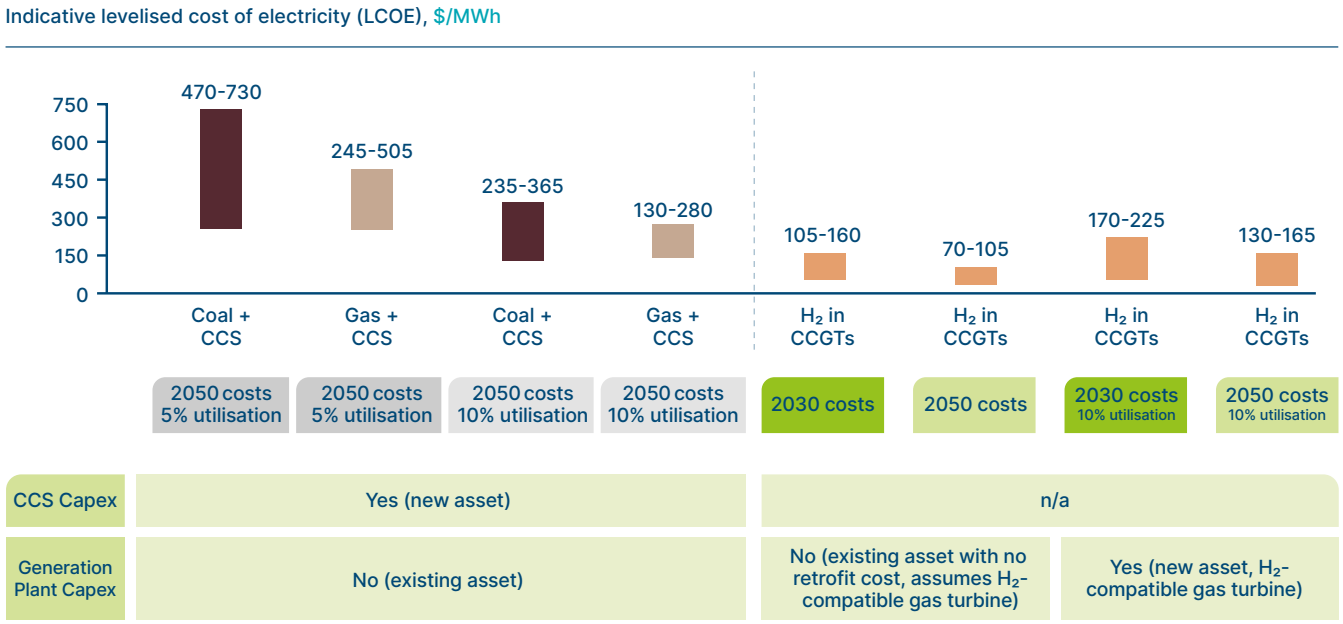


Exhibit 2.14

NOTES: High/Low ranges determined by CCS capex cost ($2490-4770/KW for coal CCS and $1620-3560/KW for gas), fuel costs ($2-7/MMBtu for gas, coal fuel costs assumed to be negligible in 2050), and costs of hydrogen production ($1.5-2.5/kg in 2030, and $0.9-1.5/kg in 2050). Hydrogen T&S cost assumed to be $0.2/kg. Assuming 50% conversion efficiency in CCGTs for hydrogen. Hydrogen-ready CCGT capex is assumed to be $1000/KW in 2050 and $1080/KW in 2030. Assumed 20-year asset lifetimes.

SOURCE: S. Budinis, S. Krevor et al, (2018), *Energy Strategy Reviews*, "An assessment of CCS costs, barriers and potential." BloombergNEF(2020), *Hydrogen: The Economics of Power Generation*, SYSTEMIQ analysis for the Energy Transitions Commission (2021).

61 In a regionally limited connected grid an unexpected resource shortfall for VRE production in one country could cut off exports and cause blackouts.

- Overall, at the system level, both balancing challenges must be met, and therefore the cost-optimal mix of zero-carbon solutions must optimise across both. For example, these challenges could be met by either i) the overbuild of VRE and the ultra-low-utilisation of zero-carbon dispatchable generation for the small number of hours associated with unpredictable week-by-week variations, or ii) higher utilisation zero-carbon dispatchable generation meeting both predictable and unpredictable variations. Given that the CAPEX investment required for zero carbon dispatchable generation must be made in both cases, relative costs will be determined by the price of fuel (e.g. natural gas or hydrogen) compared with the cost of electricity from renewable overbuild – if the LCOE for overbuild (taking into account underutilisation) was lower than the cost of fuel then overbuild of renewables would reduce total costs.[62]

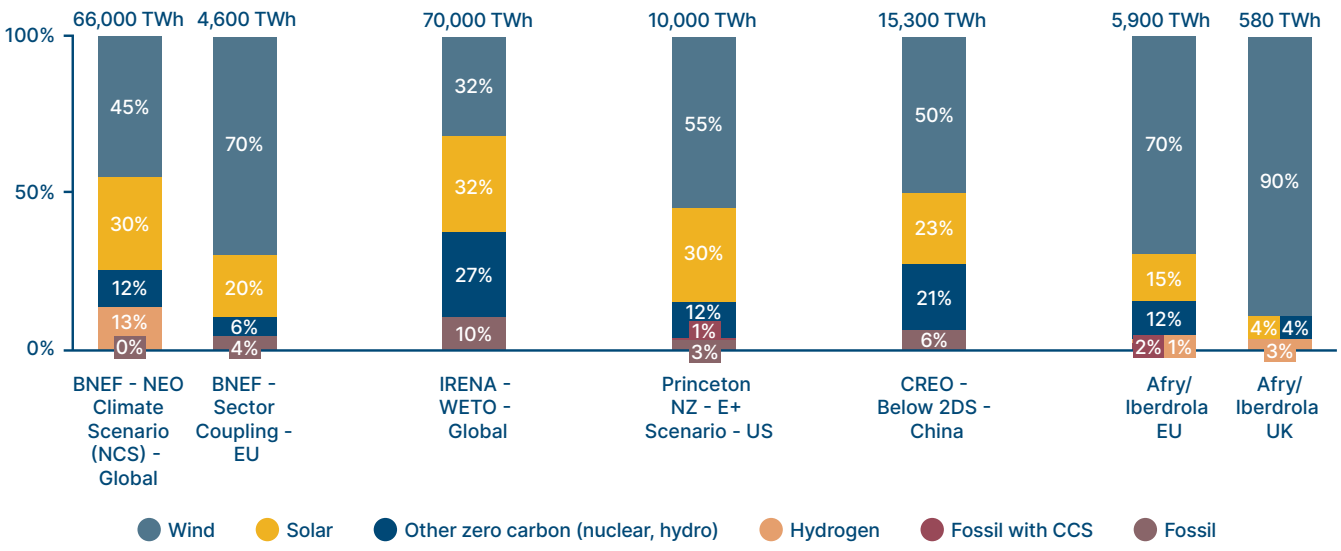
Given the potential solutions to both the daily and seasonal balancing challenges, estimates of the maximum potential electricity generation share that VRE can deliver have increased significantly in recent years. Multiple studies indicate results of VRE shares above 70%, with others as high as 90% [Exhibit 2.15]. Based on these conclusions, ETC illustrative scenarios considering 75% to 90% VRE penetration globally are developed in Chapter 3.

The optimal generation and flexibility mix will vary by country and should evolve over time in the light of the changing costs of different technologies, but it is clear that total power decarbonisation is feasible and that massive expansion of renewables capacity will play a central and cost-effective role in that decarbonisation.

Exhibit 2.15

Given emerging flexibility options, multiple studies suggest VRE could account for 60-90+% of electricity generation in highly decarbonised systems

Generation mix, 2050
Indicative shares (%)



NOTE: Power from discharge (e.g. battery) captured in relevant baseload generation (e.g. wind, solar).

SOURCE: Afry/Iberdrola (2020), BloombergNEF (2020), New Energy Outlook, IRENA (2021), World Energy Transitions Outlook, China Renewable Energy Outlook (CREO 2018) by CNREC

62 For example, if predictable seasonal balancing needs were ~10% annual hours, and unpredictable balancing ~5%, one option would be to use an existing gas CCGT retrofitted with CCS to provide zero-carbon dispatchable generation to meet all ~15% of hours. If the gas CCGT did not run outside of these period and local gas prices were ~$4/MMBtu, cost to meet these needs could be ~$151/MWh (or $22/MWh across all hours of the year). However, alternatively, if low-cost solar generation (~$15/MWh) was built with the expectation that ~50% of the electricity produced would be utilised with an effective cost of ~$30/MWh, and this overbuild could meet predictable seasonal balancing demand (e.g. 11% total hours), the total cost to meet this demand would be ~$146/MWh, even with the CCGT with CCS running for only ~4%. Sources (modelling inputs) US EIA, S. Budinis, S. Krevor et al, (2018), Energy Strategy Reviews, "An assessment of CCS costs, barriers and potential.", IEA (2019) *The Future of Hydrogen, BloombergNEF*

III. Total system generation costs – fully competitive with fossil fuels

Total system generation costs for zero-carbon power systems will in many countries be lower than the cost of today's fossil fuel-based system and in others be only very slightly higher. They will reflect a balance between (i) the fact that VRE generation will be cheaper than fossil fuel-based generation and (ii) the additional costs required to provide some aspects of zero-carbon flexibility as VRE penetration increases.



Overall, the evolution and the net result for countries setting out today to build zero-carbon power systems is shown in Exhibit 2.16.[63]

- At lower levels of VRE penetration (up to 30% and in some countries much higher), systems costs fall as the share of zero-carbon generation increases, since VRE generation is lower-cost than fossil generation.

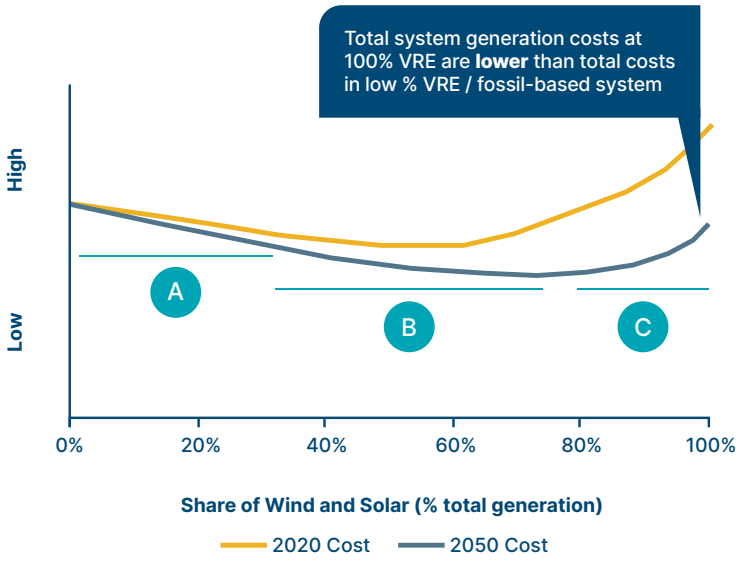
- However, beyond some level, balancing needs will cause total system costs to cease falling and start to rise, given additional costs of providing the "last 10%-20%" of supply in a zero-carbon fashion.

ETC analysis illustrates that in near-total-variable-renewable power systems, total system costs by 2035 (including generation costs and a conservative estimate of flexibility costs, but excluding network costs) would be cost-competitive or below those of current fossil-based power systems.[64] Overall, daily and seasonal balancing could add between $10-20 per MWh to the costs of bulk generation, a magnitude in line with the estimate of the additional costs for seasonal balancing from gas with CCS estimated in the previous section.[65] These costs could be significantly lower due to any breakthrough technology development not considered in this analysis. There will be meaningful variations by geography according to access to low-cost renewable generation and the nature and size of the local balancing challenge [Exhibit 2.17].

Many countries, however, will only reach VRE penetration rates above 50% in the 2030s, and even countries which reach that share earlier will need to build significant additional capacity (in both generation and flexibility provision) in the 2030s and 2040s. Total system generation costs faced in 2050 will therefore also reflect the benefit of the significant cost reductions certain to occur by then in both VRE generation and flexibility provision. The net result could in many countries be costs which even for very-high-VRE systems are below those of today's fossil fuel-based systems, even accounting for the rising costs from the "last mile" of decarbonisation.

Total system generation costs in zero-carbon power systems likely to be below those of fossil-based power systems

Total system generation costs as function of VRE penetration, $/MWh, 2020 and 2050 cost scenarios



A

0-30% VRE penetration

Declining system generation costs as cheaper renewables replace fossil in baseload generation; no balancing needs

B

30-80% VRE penetration

Further cost declines as renewables + storage increasingly cheaper than fossil for dispatchable generation

C

80-100% VRE penetration

Increase in total system generation costs as significant costs required to provide zero carbon answers to the "last 10%-20%" of generation

Exhibit 2.16

SOURCE: Adapted from TERI/ETC India (2020) *The Potential Role of Hydrogen in India*

63 In the case of those countries (primarily in the rich developed world) which began the shift to renewables before the costs collapsed, there is an additional "legacy" cost of subsidising initially expensive renewable deployment. This cost will continue until the subsidised contracts run off (typically over the next 20 years) and represented an investment in technology development which made possible the cost declines. Any changes to legacy contracts should be carefully managed to minimise disruption to the investor community which could slow down the pace of future investments.

64 This analysis refers to a system where 85-90% of power supply is provided by variable renewable energies (solar and wind), while 10-15% is provided by dispatchable/peaking capacity, which can be hydro, biomass plants or fossil fuels plants (combined with carbon capture to reach a zero-carbon power system). Adapted from the Climate Policy Initiative for the Energy Transitions Commission (2017), *Low cost low carbon power systems.* This analysis incorporates the following assumptions: power system delivering ~500TWh/year. In the baseline archetype, i) daily shifts represent 10% of total power demand, covered by batteries (66%) and CCGTs (34%), ii) interday/seasonal shifts represent 10% of total power demand, entirely covered by CCGTs.

65 While this represents average system costs, actual realised electricity prices will depend on the effective share that each of the baseload, daily, and seasonal balancing options makes up the marginal asset dispatched.

Actual cost implications will vary by country, but a range of estimates confirm that in many the impact of complete power system decarbonisation will be minimal or negative.

- The UK Climate Change Committee estimates suggests that total decarbonisation with VRE rising to 80% of generation will reduce UK electricity system costs in 2050 by an amount equal to 0.16% of GDP.[66]
- Estimates of total system cost in China made by the Energy Research Institute of the NDRC suggest that 2050 costs per MWh for a "below 2 degrees" trajectory with 73% VRE generation in 2050 will be 19% below today's level.[67]
- India estimates suggest that a 100% VRE power system could in 2050 deliver power at total system costs per MWh about 5% below today's level.[68]
- A study looking at reaching 90% clean electricity in the United States by 2035 concluded that electricity costs would fall to 4.6 cents per kWh under a base case, about 10% lower than the 5.1 cents per kWh in 2020.[69]

Fully decarbonised power systems are thus feasible and will be able to deliver electricity across the days, weeks and year at costs fully competitive with today's fossil fuel-based systems. Achieving them will however require large investments underpinned by a strategic vision which Chapter 3 will discuss.

Local cost of near-total-variable renewable power systems will vary depending on climate patterns, natural resources and existing power flexibility infra

Maximum all-in cost of power generation in a near-total-variable-renewable power system by 2035
$/MWh, breakdown by flexibility services

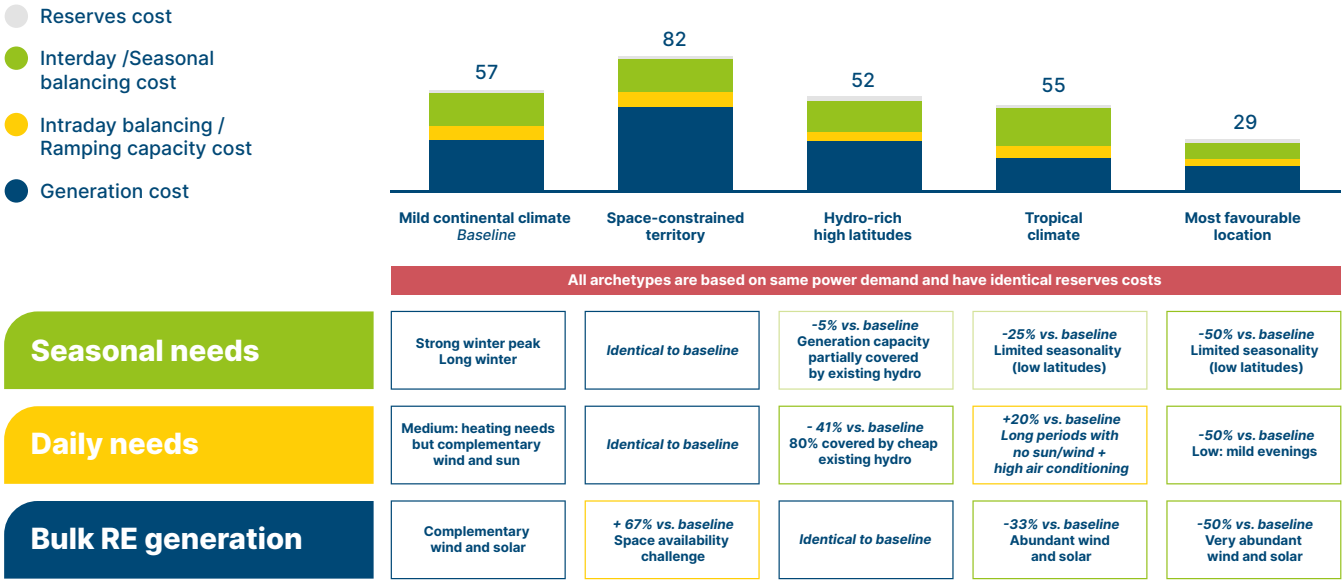


Exhibit 2.17

SOURCE: Adapted from Climate Policy Initiative for the Energy Transitions Commission (2017), *Low-cost, low-carbon power systems*

66 UK Climate Change Committee (2020), *Sixth Carbon Budget*
67 CNREC (2018), *China Renewable Energy Outlook (CREO 2018)*
68 TERI/ETC India (2020), *The Potential Role of Hydrogen in India*
69 Analysis includes the costs of generation plus incremental transmission investments. UC Berkeley, (2020), *2035: The Report*

IV. Additional costs in transmission and distribution

Massive clean electrification will require significant expansion and upgrade of transmission and distribution (T&D) networks. While a growing and decarbonised electricity system will require more networks, particularly at the distribution level, there is also a need for more digitalised, smarter grids.

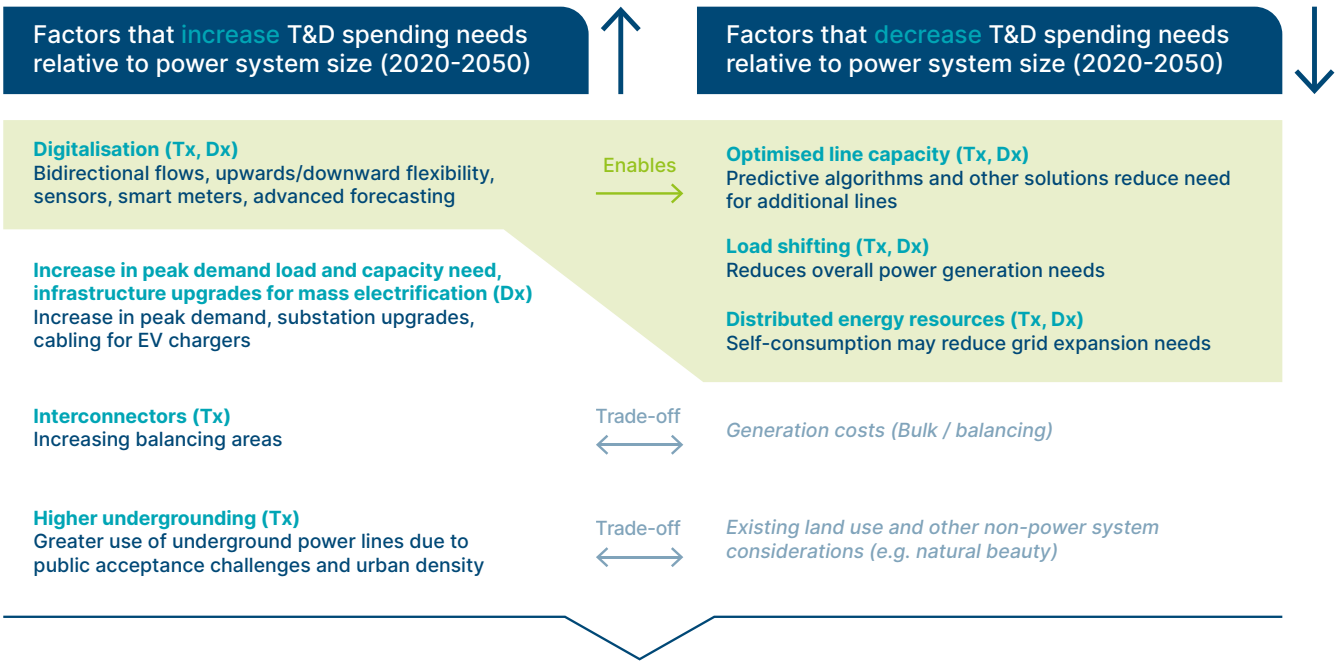
Transmission and distribution costs vary significantly by country, but on average account for about 40% of total power system costs, of which distribution is about two-thirds and transmission about one-third.[70] In absolute terms and in all countries, total T&D investments (discussed in Chapter 3) will need to rise sharply to support the massive increase in electricity supply required in a net-zero emissions economy.

There are several critical drivers of growing network needs, which go beyond rising shares of VRE. These include:

- **Enabling mass electrification**, including integrating new use cases (electric vehicles, heat pumps). This will drive the need for network expansion and upgrades, particularly on the distribution side. This includes the installation of EV charging points, local distribution (Dx) reinforcements and cables, as well as transmission (Tx) connections for larger public, depot, and workplace charging hubs.

- **Increasing variable renewable penetration**: The imperative to connect remote resources located away from demand centres (such as in the USA and China) as well as a need for greater balancing areas will drive the need for long-distance networks, including high-voltage direct current (HVDC) cables and interconnectors. Integrating non-synchronous generation via new capabilities will also demand grid services such as ability to regulate voltage, maintain system frequency, ride through disturbances. Furthermore, the smaller scale and distributed profile of some renewables generation will mean integrating more generation at the distribution level (for example, in Europe, power connections to distribution grid will rise from 23% today to 67% in 2050).[71]

T&D spending relative to size of power system impacted by competing trends



Competing trends weighted towards **increase in T&D investments relative to power system size**
In a period of rapid network growth T&D investments should be optimised accounting for whole system costs and future system needs

Exhibit 2.18

SOURCE: IEA (2020), *World Energy Outlook*, BloombergNEF (2020), *New Energy Outlook*, Literature review

70 IEA (2020), *World Energy Investment Outlook*; EIA (2020) *Annual Energy Outlook*
71 BloombergNEF *(2020)*, *New Energy Outlook*

- **Enabling flexibility**: Enabling flexibility (via distributed energy resources such as batteries, energy storage, demand management) will require new capabilities at the Dx level, including smart grids and bi-directional flows, as well as remote monitoring sensors in Dx to facilitate management of distributed resources.

- **Managing network threats**: Managing new network threats, increasing resilience to extreme weather events and cybersecurity risks, will require Tx and Dx fault isolation and service restoration tools.

Together, these trends will have important implications for the shape of T&D network costs, some potentially increasing cost per MWh but with other offsetting impacts [Exhibit 2.18]. The trajectory of costs per MWh will be affected by several main drivers:

- Requirements for transmission infrastructure to connect remotely located wind and solar resources to load centres could add to total system cost. A CSIRO study for Australia shows that increasing VRE penetration to 90% across the National Energy Market (NEM) would raise transmission costs by $4/MWh to connect remote resources and by $0.1-1.8/MWh for other transmission costs. However, in a 90% VRE system, these costs would account for only 8% of total system costs.[72]

- New electrified use-cases, such as road transport electrification, may impose additional, localised distribution costs to support infrastructure upgrades (e.g. EV charger cabling).

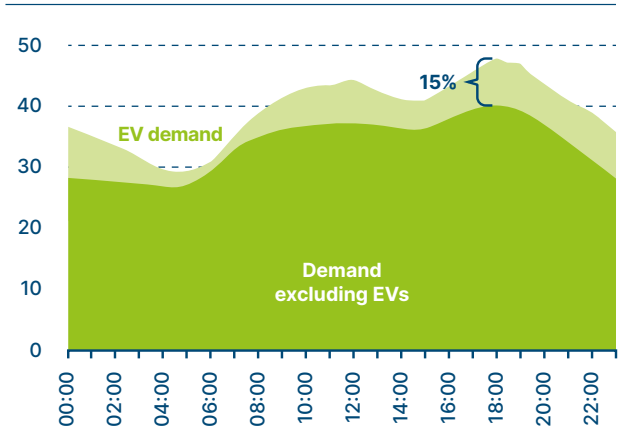
- Increase in peak demand load and needs for additional capacity, in particular at the distribution level (e.g. due to road transport electrification and the electrification of building heating), could also add to total system costs. In some areas, increase in peak demand at local distribution level will be significantly higher (30-40% increase) than the demand peak at national level (15% increase) [Exhibit 2.19].[73]

- Digitalisation upgrades may be required across distribution networks to enable efficient management of distributed energy resources.[74] This includes bringing on flexible demand management – via smart meters and applications – in addition to physical improvements to the distribution networks – such as bi-directional flows and remote sensors. While these upgrades could raise costs initially, in the long run these could be offset by the benefits of smarter and more digital networks, which would optimise grid capacity and reduce costs.

Peak demand at local level could be double that of national level, due to highly localised EV adoption

Illustrative examples

EV impact on U.K. national power demand at 50% EV adoption



EV impact on typical 11kW feeder in the U.K., with 50% of houses owning an EV

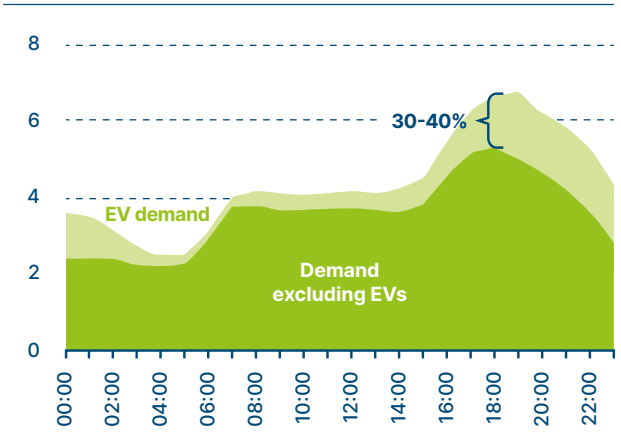


Exhibit 2.19

NOTE FOR LHS: EV charging curve = combination of passenger and commercial Evs. Note for RHS: Winter day. Assumes all Evs are BEVs charging at 7kW.

SOURCE: BloombergNEF (2020), *Sector Coupling in Europe: Powering Decarbonisation*

72 CSIRO (2020), *GenCost 2020-2021 Consultation Draft*. Total system costs include generation, storage, and transmission costs.
73 BloombergNEF (2020), *Sector Coupling in Europe: Powering Decarbonisation*.
74 Distributed Energy Resources (DERs) include storage, distributed generation, demand response, EVs and their charging equipment.

- Distributed generation – in particular co-located storage and small-scale solar – could reduce total required network investments and thus minimise costs, while sometimes posing difficult challenges for existing operators potentially facing revenue losses. Similarly, front-loaded energy efficiency gains would also reduce the needs for anticipated network investments.

The net impact of these different effects on total system cost per MWh will add to the total cost drivers discussed in Sections 2 and 3 above. It is therefore a critical priority to develop T&D networks as cost-effectively as possible. This will require:

- The development of an "active" distribution system operator (DSO) capability – as the electricity system moves to greater activity level at the distribution level, a DSO could optimise energy procurement and utilise the demand-side levers available in a smart grid, therefore reducing peak demand and enabling cost savings [Box 3].

- Investment strategies which anticipate future demand growth rather than responding to it, and which exploit opportunities for scale economies and innovative solutions, which we will return to in Chapter 3 Section 3.

- Planning and permitting processes and integrated siting strategies that can support rapid development while addressing legitimate local concerns and political opposition, which we will return to in Chapter 3 Section 3.

Creating a Distribution System Operator

Today distribution networks have a 'Distribution Network Operator'

- **'Passive'** role as network operator
- **High distribution network redundancy**, (e.g. oversizing of capacity relative to demand to ensure able to meet peak)
- **One-way** power flows

Massive clean electrification will need 'Distribution System Operator' capability, procuring and managing flexibility

- **More activity** at the distribution level, including from:
  - **Peak demand increases** due to transport and heating electrification
  - Higher deployment of **Distributed Energy Resources (DERs)**, including storage, distributed generation, demand response, EVs and their charging equipment
  - **Multi-directional** system
- Requires **'active'** coordinating role as system operator to reduce peak demand, manage demand side response and enable cost savings for grid operator[1]



Conventional role of DNO

- Connection and disconnection of DERs
- Planning, maintenenace and management of networks
- Management of supply outages
- Energy billing (only if vertically integrated)

Emerging role of DSO

- Peak load management through DERs
- Network congestion management
- Provide reactive power support to TSOs
- Procure voltage support
- Technical validation for power market

Box 3

NOTE: DER refers to Distributed Energy Resources.
[1] UK Power Networks reduced peak demand by 60 % by aggregating DERs through a virtual power plant; DSO innovations in the UK, such as smarter network and improvements in T&D processes related to connections of distributed generation, led cost savings for the grid operator of close to USD 1.32 billion.

SOURCE: IRENA, Future role of Distribution System Operators - Innovation landscape brief

V. Phasing out unabated fossil fuels

As Section 1 described, new VRE generation is now fully competitive with new fossil power generation in many locations, and this cost advantage will spread wider and grow larger over time. While existing thermal plants will need to play a flexible role in balancing systems in many geographies, almost all countries have sufficient capacity in place to play this role even in hugely expanded electricity systems. All countries should therefore commit to strategies in which the near totality of new growth of electricity capacity and generation is zero-carbon. No new coal capacity should be added, and the role of new gas should be limited to very specific circumstances where:

- Either there are limits to the speed with which new zero-carbon balancing capacity can be put in place, and technical limits to the use of existing thermal capacity for flexibility at low utilisation;
- Or countries have ageing existing gas plants approaching retirement, which will need to be replaced to provide thermal flexibility in a future VRE-dominated system.

Any such new gas investment should, however, be compatible with a transition to zero-carbon systems, for instance via the conversion potential of newly-built CCGTs to operate on fully decarbonised fuels (e.g. hydrogen), and must be accompanied by policies to ensure that methane leakages across the whole value chain are limited to very low levels (e.g. less than 0.05% by 2050). In addition, however, countries need to develop strategies for the eventual phase-out of large existing fossil fuel fleets, both coal and gas.

The scale of the challenge

Global installed **coal** capacity is 2,075 GW, used to generate about 9,000 TWh of electricity and producing about 9.5 Gt of CO_2 emissions [Exhibit 2.20].

- Of this, a smaller share is in developed countries (in particular USA, Europe, and Japan). In many of these countries, coal use is already declining rapidly as a percent of total generation, and across much of Europe clear end dates for

Coal: China, India account for over 60% of global coal capacity

Global coal capacity by region, GW

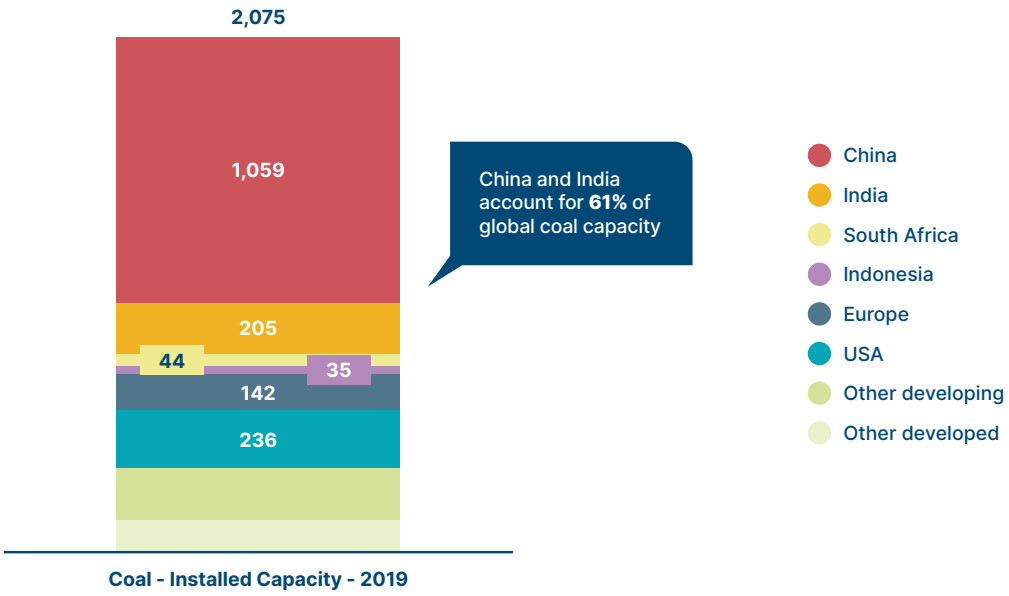


Exhibit 2.20

NOTE: Coal plant lifetimes can reach 40-50 years, so any plant built within the last 20 years could be at risk of operation until 2050.

SOURCE: BloombergNEF (2020), *New Energy Outlook*

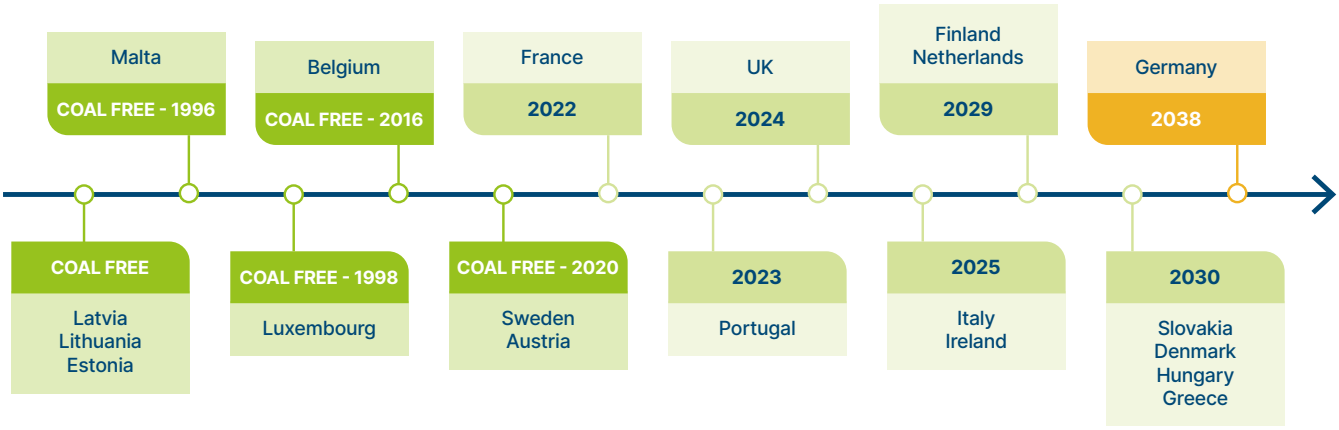


coal phase-out have been established. The Biden administration has committed to reaching 100% clean electricity by 2035, with an implicit phase-out target for unabated coal. Japan's significant coal fleet, however, is not yet subject to a coal phase-out plan [Exhibit 2.21]. Accelerating coal phase-out in developed countries – ideally with an end date of 2035 at the very latest – should be a high priority.

- The key challenge lies in developing countries, and in particular China and India. In both countries, coal currently accounts for over 60% of total generation, and the stock of plants is relatively new with 77% of China's 1,060 GW coal capacity and 85% of India's 205 GW capacity built in the last 15 years. Given potential coal plant lifetimes of 40-50 years, China could have over 800 GW of already existing coal capacity, and India over 170 GW still operating in 2050 [Exhibit 2.22].[75]

Exhibit 2.21

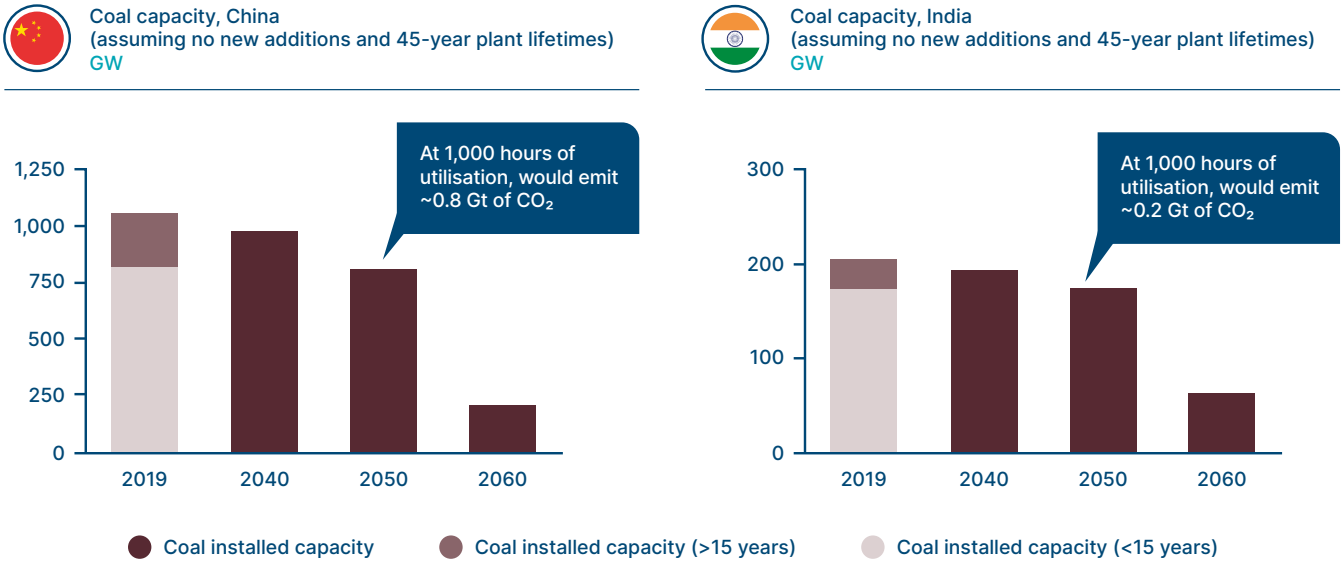
Coal increasingly subject to phase-out targets by 2030



SOURCE: Europe Beyond Coal, E3G (2021), *The rise and fall of coal: 2020 transition trends*

Exhibit 2.22

Even with no new additions, significant coal capacity left by mid-century in China and India



NOTE: Coal plant emissions intensity is assumed to be 342gCO_2/kWh with an efficiency rate of 34%.

SOURCE: Historical data from BloombergNEF (2020), *New Energy Outlook*

75 Assuming 45-year coal plant lifetime. BloombergNEF (2020), *New Energy Outlook*

For **gas**, total installed capacity is 1,715 GW of which 34% is in the US, with the rest spread across numerous countries with only 7% in China and India combined [Exhibit 2.23].[76] These gas plants currently account for 6,000 TWh of generation and 3 Gt of CO_2 emissions. While gas in power generation emits less CO_2 than coal, methane leakage throughout the natural gas value chain can have a disproportionate impact, with methane having a short-term climate impact that is 84 times more potent than CO_2.[77] IEA estimates for methane emissions from the oil and gas industry (with around 60% of those accounted for by gas operations), were over 80 Mt of CH_4 in 2019 – converted into CO_2 equivalent amounts, this is larger than the total energy-related CO_2 emissions of the European Union.[78]

The path to phase out – gas: decreasing utilisation and balancing role

Increasingly over time, the cost of VRE generation will fall below the marginal cost of many existing gas plants, and the role of gas in bulk generation will therefore decline, with capacity utilisation decreasing [Exhibit 2.24].[79]

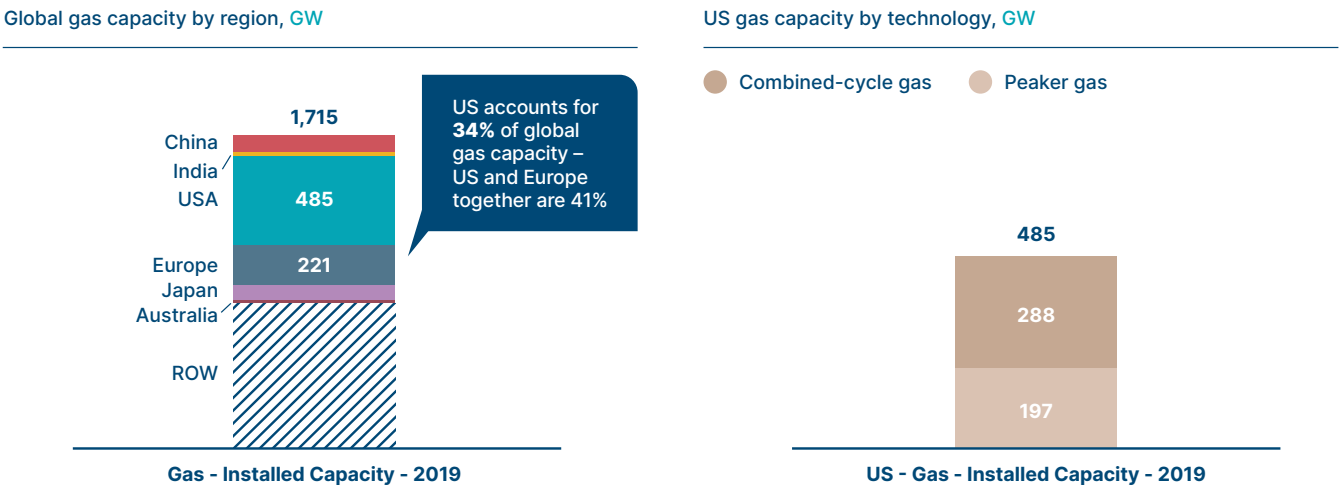
Existing gas capacity could play an important role to provide long-term balancing, especially for unpredictable week-by-week variations. Particularly during the transition, this could involve a role for very low utilisation of unabated gas plants producing minimal residual emissions, as well as partial blending of hydrogen with natural gas in compatible gas turbines.[80] In the long term, however, zero-carbon generation should be ensured via either:

- The addition of CCS to gas turbines;
- Other zero-carbon balancing options, which would include building new (or retrofitting, where possible) gas turbines to burn hydrogen, which may in the long term prove the most cost-effective option, as discussed in Section 2.

National decarbonisation strategies should therefore include clear plans for the future utilisation of existing gas fleets, including targets for the reduction and eventual elimination of unabated plants, and requirements for any new gas plants to be compatible with future conversion to CCS or hydrogen, supported by the establishment of carbon pricing.

Exhibit 2.23

Gas: the US accounts for 34% of global gas (combined-cycle and peaker) capacity, though high share of peaker gas



SOURCE: BloombergNEF (2020), *New Energy Outlook*

76 Includes both combined cycle generation (1,414 GW) and peaker gas (300 GW).
77 Over the first 20 years it reaches the atmosphere. Environmental Defense Fund, *Methane The other important greenhouse gas*
78 Assuming that one tonne of methane is equivalent to 30 tonnes of CO_2. IEA (2021), *Methane Tracker.*
79 In the United States, BloombergNEF analysis has shown that this tipping point has already been reached - when accounting for relevant tax credits, the costs of new VRE outcompetes the marginal cost of existing gas plants, even in a very low gas price environment, Source BloombergNEF (2020) *H1 2020 LCOE Update.*
80 Co-firing of hydrogen in gas turbines may be used as a transitional pathway. However, existing turbines are not able to burn high blends of hydrogen, newer existing turbines are able to blend up to around 30% of hydrogen. See Siemens (2021), Power-to-X: the crucial business on the way to a carbon-free world.

Role of existing coal – transitional role in balancing

In many locations, VRE generation will also soon fall below the marginal cost of running many existing coal plants, with estimates suggesting VRE costs are already below this threshold for older, less efficient coal units.

- In China, BloombergNEF projects that wind and solar generation costs could outcompete most of existing coal plants by the mid- to late-2020s as discussed in Section 1. In India, they expect cost parity may not occur till the late 2020s, except in the case of the oldest and least efficient units.

- Some estimates, however, suggest still earlier cost parity points. RMI estimate that 43% of China's coal fleet is already uncompetitive in 2020, rising to 70% in 2022 and 94% in 2025. In India, they estimate that 17% of the coal fleet is uncompetitive in 2020, rising to 50% in 2022 and 85% in 2025.[81] Robust carbon prices would further accelerate these trends.

This cost advantage of VRE will slowly erode coal's role in bulk generation and reduce utilisation rates. Over time, China and India's coal fleets will migrate to play a more flexible role as backup to increasingly VRE dominated power systems. As Section 2 described, in some countries, increasing flexibility of existing thermal generation can be the main system balancing resource as VRE grows to reach around 30% of generation in 2030, and will continue to be an important contributor to system balance in subsequent decades with increasing VRE shares.

Where possible and where this doesn't extend the asset life, increasing the flexibility of coal fleets to enable low utilisation for more flexible operation (e.g. cycling of the fleet) should be a priority. In the long term, however, the need for flexible coal supply capacity may decline as other balancing options become more cost-efficient. The phase-out of coal is therefore likely to occur across different stages:

- Given falling VRE costs relative to marginal coal costs, a first wave of phase-out of coal will occur economically, as the higher cost coal generation (the older, more inefficient plants) are pushed out of the supply mix on a cost basis by new VRE capacity. As long as no new coal capacity is built, it is therefore likely that operating coal capacity in 2050 will be significantly below the figures shown in Exhibit 2.25, and reductions in coal generation will be still more dramatic as utilisation rates decline.

- The second stage of phasing out, for the last portion of the coal fleet (the newer, more efficient plants), will likely entail a cost. The phase out plan should depend on the least-cost method among the following:

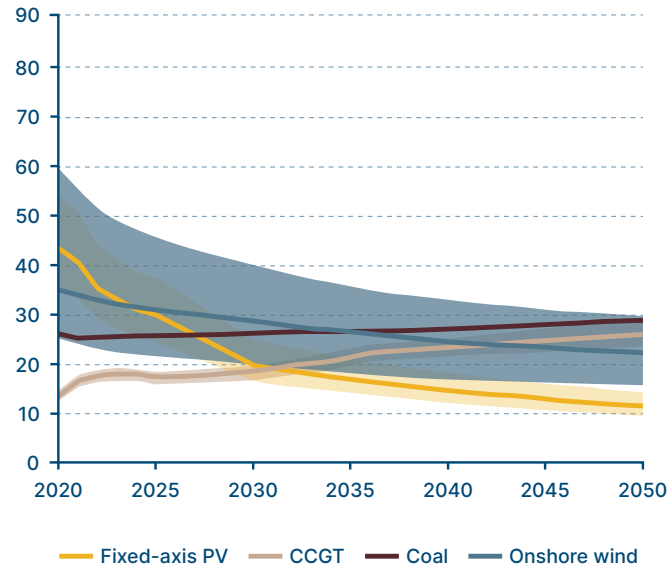
81 Uncompetitive coal describes assets for which the long-run cost to operate the plant exceeds the levelized cost to build and operate new solar or onshore wind plus storage. The coal costs are inclusive of any applicable carbon or emissions permits or taxes, but not of any unpriced health or environmental costs, while the renewable and storage costs include clean energy incentives.



- Transitional technologies such as co-firing green ammonia in coal plants, which is being piloted in Japan,[82] has the potential to reduce the carbon intensity of coal generation; but, on current assumptions, this will not provide a path to 100% clean generation.
- Fitting CCS to low-utilisation coal and running such plants as flexible assets for the grid to provide balancing is theoretically feasible, but at a higher cost than for gas plants as covered in Section 2.
- Closing down coal plants even if they have not reached end of technically feasible life could be the most cost-efficient option in a number of cases.

VRE increasingly competitive with marginal cost of gas in the US and Germany

Levelised cost of new PV and onshore wind vs. running costs of existing coal and gas: US
$/MWh, (2019 real)



Levelised cost of new PV and onshore wind vs. running costs of existing coal and gas: Germany
$/MWh, (2019 real)

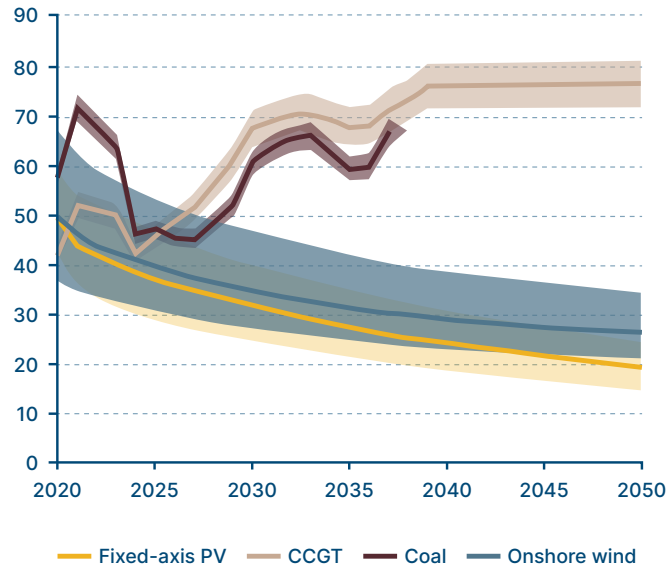


Exhibit 2.24

NOTE: Solar and wind LCOEs account for curtailment. Coal and gas running costs include a carbon price. For the US, data excludes the ITC and the PTC. PV refers to tracking PV.
SOURCE: : BloombergNEF (2020), *2H 2020 LCOE Update*

82 S&P Global Platts, "Japan moves to develop fuel ammonia supply chain with potential 20 mil mt/year demand", 27 October 2020



The most rational economic solutions will differ across geographies. Ongoing analysis within ETC Regional programmes is considering these pathways, including detailed modelling on India's power system to analyse the costs of these alternatives.

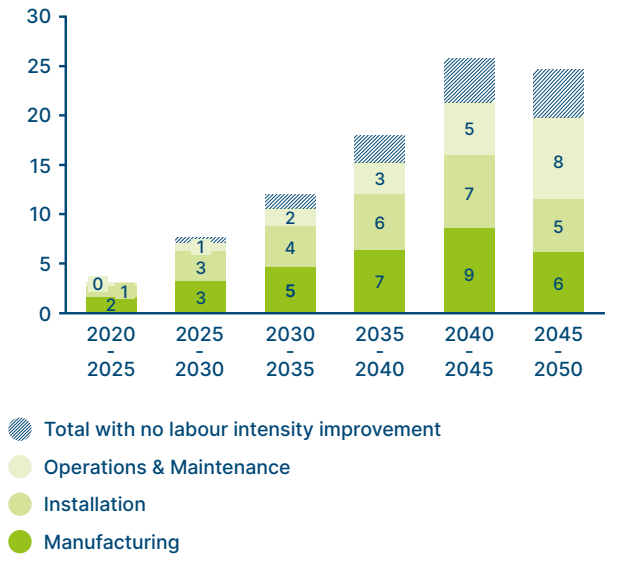
To enable these phase-out trajectories, it will be critical for developing countries as well as developed countries to set clear backstop dates for the complete elimination of unabated coal – such as 2045 in China and 2050 in India. Overall, the direct economic cost of such commitments is likely to be minimal. However, two factors may increase transitional costs and slow the onset of the transition:

- Firstly, existing coal plants sometimes enjoy long-term fixed price supply contracts in some cases lasting even decades into the future, which in many countries face limited possibilities to alter without penalties and/or legal costs.[83] As a result, uneconomic coal assets may not exit the system even when VRE costs fall below the marginal cost of operation, denying societies the benefit of cheaper electricity. Such contracts could significantly slow the pace of economically rational decarbonisation in the 2020s and 2030s. The constraints will vary by geography. In India, TERI analysis indicates that, by 2030, the optimal level of VRE penetration would be around 40%, even accounting for fixed take-or-pay payments that would have to be made under coal PPAs regardless of generation. However, long-term PPAs for coal will become more significant barriers once the more costly, inefficient coal plants are phased out.[84]

- Running down coal generation will have consequences for employment in coal mining. Estimates suggest, for instance, that while the Indian coal industry employs 355,000 workers, as many as 500,000 workers are directly or indirectly dependent on coal mining, with a strong geographical concentration in Bihar and Jharkhand.[85] In China, around 3 million workers gain employment from coal with a concentration in Shanxi and some other northern provinces, though it is noticeable that employment in the industry has already been reduced by 40% over the last seven years (from 5 million in 2013) due to the automation of operations, falling at a pace which will largely eliminate the employment challenge well before the 2040s.[86]

Solar PV will drive renewables job creation

Annual VRE jobs split by type based on 90% VRE Scenario (2020 – 2050), Millions/year



Annual VRE jobs split by technology based on 90% VRE Scenario (2020 – 2050), Millions/year

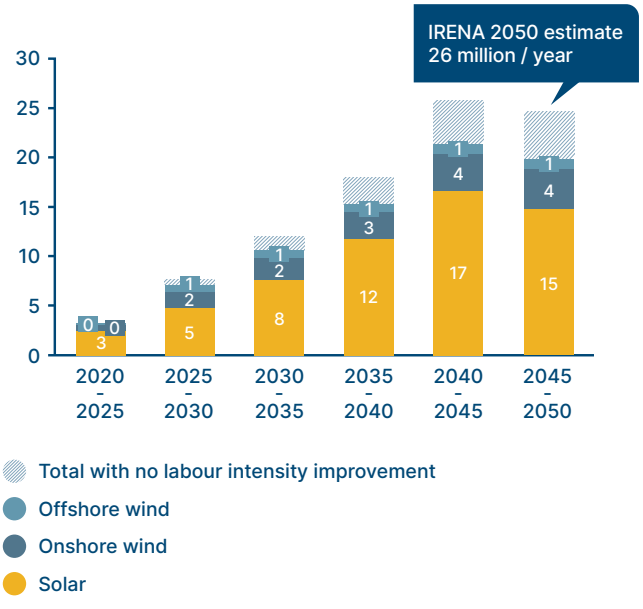


Exhibit 2.25

NOTE: : Manufacturing & installation jobs per MW assumed to decline over time in line with Capex, driven by higher efficiency in production.

SOURCE: Assumptions based on IRENA (2017), *Renewable Energy Benefits: Leveraging Local Capacity for Solar PV*; IRENA (2017), *Renewable Energy Benefits: Leveraging Local Capacity for Onshore W* IRENA (2018), *Renewable Energy Benefits: Leveraging Local Capacity for Offshore Wind*; IRENA (2020), *Measuring the Socio-economics of Transition: Focus on Jobs*

83 RMI (2020), *How to Retire Early*
84 TERI analysis
85 TERI (2018), *Coal Transition in India*
86 RMI/ETC China (2019), *China 2050: A fully developed rich zero-carbon economy*

At the national level, these employment effects will usually be more than offset by the extra jobs created by job creation in renewables, at least during the next 30 years of rapid capacity expansion. This could grow to reach 21 million jobs worldwide by 2045, with 9 million in panel and turbine manufacturing, 7 million in development and installation, and 5 million in ongoing operations [Exhibit 2.25].[87]

The regional concentration of coal mining, however, may still create important local transition challenges. Some countries may therefore need to include within their decarbonisation strategies policies to manage employment effects and ensure a just transition, as well as actions to subsidise changes to existing coal supply contracts [Box 4].

In situations where these costs are faced by low- and middle-income countries, and provided there are clear national commitments to no new coal investment, there may be a role for international climate finance flows to support these transitional expenditures.

Major financing mechanisms to phase out fossil fuels

CASE	Case 1	Case 2
	Running coal **more** expensive than new VRE Unsubsidised (no additional public funds required) E.g. Europe	Running coal **less** expensive than new VRE Subsidised (additional public funds required) E.g. SE Asia
TOOLS	**3 major tools to be used in combination** **Refinancing**, where coal plant owners obtain lower-cost finance (e.g. loan) to pay down closure of plant + any fuel supply agreements; new PPA/tariff structure to reflect loan costs + lower costs from VRE (different models possible - e.g., asset- backed securitization, ratepayer-backed bond, securitization, and green bonds) **Reinvesting** in clean energy to build new VRE and meet growth electricity demand, replacing returns from coal plants with returns from clean energy and reducing costs for customers Using some of low-cost loan raised through refinancing to **provide transition financing** to coal workers and communities, offering immediate resources to preserve livelihoods, protect benefits, and ensure that host communities can continue to thrive	**3 major tools** **Refinancing**... **Reinvesting** in clean energy... **Transition financing** to coal workers and communities... + **Concessional finance** instruments, e.g. **Carbon bonuses**, providing concessional payments per ton of emissions abated, therefore tilting the economics in favour of zero-carbon generation and reducing extra costs for consumers **Debt forgiveness via reverse auctions**, providing debt relief funding to incentivise coal plant closure, targeting highest-polluters
ACTORS	**Governments** **Public Finance institutions**	**Governments** **Public Finance Institutions** **Multilateral Development Banks**

Box 4

SOURCE: Rocky Mountain Institute (RMI) (2020), *How to retire early*

87 Based on ETC 90% VRE scenario developed in Chapter 3 and IRENA data. IRENA, *Renewable Energy Benefits: Leveraging Local Capacity for Solar PV* (2017); IRENA, *Renewable Energy Benefits: Leveraging Local Capacity for Onshore Wind* (2017); IRENA, *Renewable Energy Benefits: Leveraging Local Capacity for Offshore Wind* (2018); IRENA, *Measuring the Socio-economics of Transition: Focus on Jobs* (2020)

VI. Natural resource availability – clearly sufficient at global level

At the global level, there are easily sufficient natural resources to support required growth in zero-carbon electricity generation. Wind and solar resources are far more than sufficient to achieve the massive increase in clean power generation needed in a zero-carbon economy.

- If 100,000 TWh of annual electricity production were produced entirely from solar PV, only 1-1.2% of the land area of the world would have to be devoted to solar farms, and only 0.3-0.4% of the global surface would be required if it were possible to place solar panels above oceans.[88]

- IEA estimates of the total offshore wind resource show that it alone could generate more than 420,000 TWh per year – 4 times the expected annual power demand in 2050 described in Chapter 1.[89]

Published analysis of economically accessible resources, which include embedded assumptions about competition for land use, the economics of long-distance transmission and competition with other potential power sources, often suggest lower figures, but still confirm that there is more than twice the resource required to meet 2050 needs. They usefully illustrate, however, that resource availability relative to need varies by region, with some countries in South and Southeast Asia facing

88 Assuming 1.2-1.7ha/GWh/annum based on NREL (2018), *Land-use Requirements for Solar Power Plants in the United States. See ETC (2018), Mission Possible.* Some other analyses, e.g Solargis – suggest significantly lower area requirements e.g on average around 0.7 ha/GWh/annum, see Solargis data.
89 IEA (2019), *World Energy Outlook*



tighter constraints, while other regions could instead meet future power needs more easily with local resources[90]. A study for the United States found that the land area for renewables development under the highest VRE-based net-zero scenario would cover the size of West Virginia.[91] It is to be noted that, while solar PV technologies directly affect 90% of dedicated land area, wind farms can co-exist with grazing, farming and other land uses, thus affecting only 1% of total dedicated land area.[92]

There is also plentiful mineral resource to meet the battery and electricity needs of a deeply electrified economy.

- Total lithium stocks required to put 60 kWh batteries in 2 billion electric passenger cars, would for instance, require about 15 million tonnes of pure lithium, about 18% of total estimated resources. [93]

- Similar calculations suggest cumulative needs for cobalt and nickel might amount to 53% and 49% of current estimated resources.[94]

Nevertheless, supplies are likely to be far less tight than these estimates suggest since:

- Identified resource estimates are often revised upwards as new exploration for minerals increases. In 2018, the US Geological Survey identified 53 million tons of lithium resources, and this has now been revised upwards to 80 million tons.[95]

- Technology developments in battery chemistry may be able to reduce the need for specific metals in short supply. For instance, concerns about cobalt supply (primarily relating to political risk, child labour and local environmental damage rather than resource limits) have stimulated new battery developments which have dramatically reduced or even eliminated the need for cobalt.

- The development of circular value chains could enable the collection and recycling of key materials, including for instance battery materials, at end of life, reducing reliance on new mining supplies.

While significant, the local environmental effects of mineral mining can also be managed. Lithium mining in particular can have a significant local environmental impact, such as habitat destruction, chemical contamination, and noise pollution, and can demand significant water resources in water-constrained locations. These impacts need to be compared with the harmful effects arising from today's fossil fuel-based system: to build up the stock of 15 million tonnes of lithium required in a fully electrified light duty road transport system might require close to 700,000 tonnes per year mined (at the point of most rapid increase) compared with almost 8,000 million tonnes of coal mined and burnt each year.[96]

While mineral resources are sufficient, it is therefore vital to reduce any adverse impacts to a minimum by:

- Tight local regulation and clear international standards to monitor and mitigate local environmental impacts, which could include potential habitat destruction, chemical contamination, noise pollution, and high levels of water consumption, as well as any negative social impacts.[97]

- Making battery supply and use as circular as possible. This will require regulations and industry standards which ensure effective collection, repurposing and high-quality recycling with a specific focus on the end-of-life phase, in addition to measures to extend the service life of the battery through effective monitoring and maintenance.[98]

- Rapid decarbonisation of the industries – e.g. steel, aluminium and concrete – which will produce materials essential to the deployment of VRE on a massive scale.

Beyond minerals, the material and waste footprint from the growth in new power generation technologies should be optimised via proactive measures as well as regulation to improve circularity, including repair, reuse and recycling. This is critical to reducing both lifetime cost and environmental impact.[99] Such measures can also provide energy/materials security benefits by reducing concentrated supplies of critical inputs.

90 Deng et. Al., (2015), *Global Environmental Change*, "Quantifying a realistic, worldwide wind and solar electricity supply"
91 Princeton University (2020), *Net Zero America Interim Repor*t. E+RE+ Scenario has the following characteristics: i) Nearly full electrification of transport and buildings by 2050; ii) No fossil fuel use allowed by 2050; iii) No land-use change for biomass supply allowed; iv) No new nuclear power construction allowed, existing plants retired; v) No underground storage of CO_2 allowed
92 Princeton University (2020), *Net Zero America Interim Report*
93 SYSTEMIQ analysis for the Energy Transitions Commission (2021)
94 SYSTEMIQ analysis for the Energy Transitions Commission (2021)
95 United States Geological Survey, *Mineral Commodity Summaries*, Lithium
96 IEA (2020), *Coal 2020*
97 *The Guardian*, "The curse of 'white oil' electric vehicles' dirty secret, 8 December 2020
98 Circular Economy Initiative Deutschland (2020), *Circular Business Models – Overcoming Barriers, Unleashing Potentials*
99 IRENA estimates that recycling or repurposing solar PV panels at the end of their roughly 30-year lifetime can unlock an estimated stock of 78 million tonnes of raw materials and other valuable components (glass, aluminium, ethylene vinyl acetate, silicone metal, polyvinyl fluoride, silver, copper, polymers, tin, lead) globally by 2050. If fully injected back into the economy, the value of the recovered material could exceed USD 15 billion by 2050. IRENA (2016), *End-of-Life Management – Solar Photovoltaic Panels*

VII. Resource constrained countries – challenges and solutions: the role of long-distance transmission

While the world in total has plentiful wind and solar reserves to support massive electrification, some high population density countries may face local constraints on renewable and land resources relative to national demand. These include:

- Extreme examples, where high population density makes it impossible or extremely difficult to meet power generation needs fully with renewables due to shortage of land area available. China with a population density of 148 people per km² would only need to use about 1.7% of the land area of its five sparsely populated western provinces to meet its entire current electricity demand from solar power.100 On the other hand, Bangladesh, with a population density of 1,200 per km², would need to devote 6-8% of its entire land area to solar panels to deliver equivalent electricity use per capita, while almost all land is already intensively used to grow food. Singapore, with a population density of 8,000 people per km², could not meet its electricity demand from solar even if its entire surface area were covered with solar panels.[101]

- Moderate examples, where the challenge can in principle be met, but where national strategies need to be carefully designed to avoid constraints on the required pace of growth. While India has sufficient land to support a solar-led power system delivering 7,000 TWh by mid-century, renewable resource development could be constrained by barriers to land acquisition, local opposition, and land-use conflicts.[102]

- In addition, some other countries, such as China and the USA, have abundant land, solar and wind resources at national level, but much of the best resources are located at long distances from major load centres.

Solutions to these challenges include i) long distance energy transport, and ii) other zero-carbon generation options with lower land footprint, including nuclear generation, CCS, and new VRE technologies.

Long-distance energy transport from countries with abundant and cheap resources to land-constrained countries could be in the form of electricity transmission (the most efficient and cost-effective choice for direct electricity use) or hydrogen/ammonia carried in ships or pipelines. The cost of these options, and the relative cost of transport of electricity versus molecules, will vary greatly by specific location.[103] [Box 5] For instance, costs for undersea cabling or for overhead cabling in sparsely populated landscapes represent a small fraction of the cost of overhead cabling – and even more so of underground cabling – in densely populated countries. But in many cases long-distance transmission energy transport could be a solution.

- An undersea HVDC cable from Australia to Singapore (which is currently being proposed by the Australia ASEAN Powerlink Consortium), could add around $0.01/kWh to transmission costs, but with solar and wind costs in western and northern Australia likely to fall eventually to $0.02/kWh or below, the delivered price of electricity could still be cost-competitive with Singapore's current LNG-based supply.[104]

- Similarly, a few countries may have an energy deficit which forces them to import via alternative options to HVDC, beyond purely economic considerations. For example, it could be effective for Japan, which faces geographical and climatic constraints on local renewables production, to import green ammonia from Australia or from northern China.[105]

100 ETC (2018), *Mission Possible*
101 ETC (2018), *Mission Possible*
102 Analysis in TERI/ETC India (2020) *The Potential Role of Hydrogen in India*
103 See further discussion in ETC (2021), *Making the Hydrogen Economy Possible: Accelerating clean hydrogen in an electrified economy*
104 BloombergNEF (2020), *H2 LCOE Update*, Singapore Energy Market Authority (EMA)
105 ETC (2021), *Making the Hydrogen Economy Possible: Accelerating clean hydrogen in an electrified economy*



Transporting electrons

Long-distance electricity transmission could play an important in zero-carbon power systems.

The transport of electricity across long distances, primarily via high-voltage direct current (HVDC) lines, offers several potential use cases across zero-carbon power systems:

- To connect regions with abundant and cheap VRE resources far away from demand load centres (e.g. China, USA)
- To connect countries with abundant and cheap VRE resources to land constrained countries (e.g. Australia to Singapore)
- To connect countries with complementary VRE production profiles, to provide zero-carbon balancing (e.g. Morocco to UK)

There are several options for the long distance transport of clean energy beyond electricity transmission, including hydrogen via pipeline and ammonia via ship (explored in depth in the parallel ETC hydrogen report). Where energy is produced and used directly as electricity (and where laying cables is feasible), HVDC transmission will be preferred. This is due to:

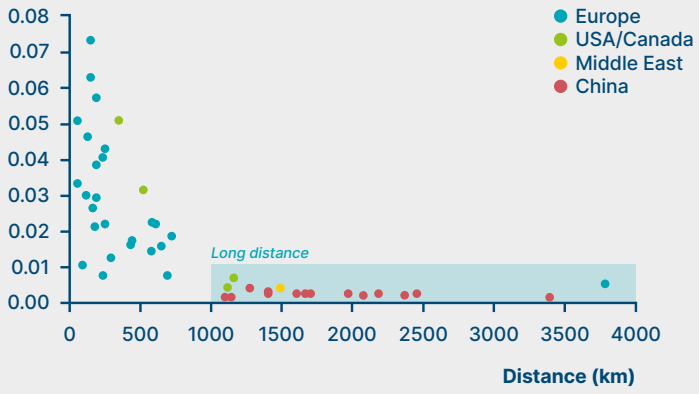
- Higher efficiency, due to lower conversion losses (e.g. avoiding energy losses across power-hydrogen-power conversion)
- Lower costs, avoiding costs required across transformation processes (e.g. electrolysis)

HVDC Capex declines with distance, as fixed costs are spread over longer distances

The competitiveness and feasibility of HVDC differs according to the geographic context. Key factors include the relative differential of renewables costs across regions, transport distance, form of transmission (e.g. overground vs underground vs subsea cables), and land acquisition costs.

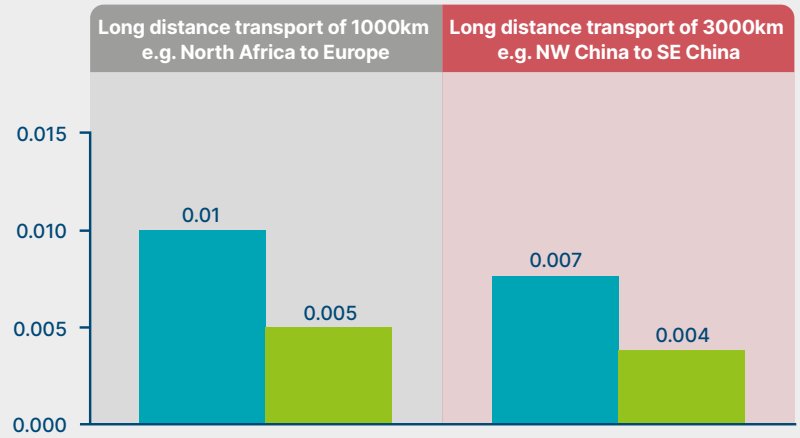
- HVDC transmission line costs ($/(kWh*1000km)) fall with distance, as high fixed costs (e.g. converter stations) are spread over a longer distance. Today, high capacity (c. 8 GW) and long distance (e.g. 2000 km+ distances) HVDC transmission lines are primarily found in China, to connect e.g. renewables resources in the North West with demand centres in the South West.
- Where cables pass over land, the costs vary greatly in line with population density, land costs, and degree of local opposition to development, and increase dramatically if undergrounding is required.

HVDC Capex cost of electricity transport (projects in development, excludes financing cost)[1]
$/(kWh*1000 km)



Range of HVDC cost estimates around $4-10/(MWh*1000km)

All-in indicative cost of HVDC electricity transmission across distances[2]
$/(kWh*1000 km)



High range Low range

Lower cost range:
Indicative costs for China, where multiple long distance and very high capacity (8GW) lines are being installed, with economies of scale from transmission line build out, as well as faster permitting processes, and lower land acquisition and installation costs

Higher cost range:
Indicative costs for Europe, where both distance and capacities tend to be lower (6GW), and where fewer long distance HVDCs lines are being installed. Therefore economies of scales typically lower, in addition to lengthier permitting processes, higher land acquisition and installation costs

[1] Excludes financing costs. Data is primarily from BNEF project database from 2016; represents data from all HVDC and UHVDC projects since 2005 (across all project stages, e.g. announced, commissioned, and permitted) evaluated with known project cost and length, assuming 50% utilisation, and project lifetime of 30 years.
[2] Financing cost assumed to be approximately 100% of Capex. For China, assumed c. 8GW capacity, for Europe/US c. 6GW capacity.

SOURCE: Industry interviews, BloombergNEF (2016), *Global HVDC and interconnector database and overview*

Box 5

Such international import strategies can raise concerns about either economic dependency or energy security. However, in most cases, the countries concerned are already dependent on other forms of energy import (whether coal, oil, or LNG), while many countries will benefit from high enough renewable resources to actually reduce their dependency to energy imports. There are significant differences between the import of electricity and the import of fossil fuels, though, including higher exposure to immediate cuts in supply (e.g. power cuts) from an unexpected shortfall, given the reduced ability for energy storage in the case of electricity. International frameworks should therefore be set up to provide greater certainty over arrangements in the case of disruptions.

With regards to alternative generation capacity, in addition to maximising all new potential for **sustainable hydro power**, **nuclear power** could also be deployed in space-constrained countries as a supplement to VRE, whether in conventional large fission form, using SMR, or by deploying nuclear fusion, which may become a technologically and economically feasible technology over the next two decades.

CCS on existing thermal plants may also play a greater role in space-constrained countries. Potential new forms of renewable technologies could also expand the range of possibilities:

- Floating offshore wind turbines has significant potential to transform offshore wind resources available to countries, such as Japan, which lack extensive shallow seabed, as well as capturing higher wind speeds. Floating offshore technology is rapidly scaling and could become commercial by the early 2030s. There is furthermore an emerging opportunity for offshore electrolysis.

- Airborne wind power generation through kites, rigid wings, or airborne rotors, may be able to generate power from low wind speeds at high altitudes, expanding the resource available.

- Floating solar deployment over lakes and reservoirs, can reduce land acquisition and site preparation costs, be complementary to hydropower, and help conserve water supplies through reduced evaporation.



Building and financing zero-carbon power systems

To deliver the clean electricity we need for a zero-carbon economy requires a massive increase in the deployment of and investment in renewables, other zero-carbon generation technologies, storage and flexibility options, and in electricity transmission and distribution networks. In particular, annual deployment of solar and wind must increase 10 to 15 times above current levels over the next two decades from 170 GW[106] to over 2,500 GW per year in 2040-2045.

Annual investment in zero-carbon power generation would as a result need to increase from today's $300 billion per annum[107] to a peak of around $2 trillion per annum in the early 2040s, with a similar scale of investment needed in transmission and distribution networks. In total, gross power system investments could amount to around $80 trillion over the next 30 years, equivalent to less than 1.5% of global GDP over that period. These power system investments are likely to account for about 80% of the investment required to build a zero-carbon system, which in gross terms could amount to over $100 trillion, or about 1.8% of GDP across the 30-year period.[108] This gross investment will be partly offset by a dramatic reduction in fossil fuel investments, which today amount to about $1 trillion per annum.[109] The required net increase in investment is likely to be around 1.3% of global GDP [Exhibit 3.1].

Exhibit 3.1

Power sector represents vast majority of total investments to reach net-zero across the energy sector

	2050 vision		Key investment needs	Total investment 2020-2050, US$bn	Total annualised investment, US$bn pa	Share of GDP %
Power	**Total power generation** 110,000 TWh / year **Total capacity required** 27-35 TW solar 14-16 TW wind 2-4 TW of hydro, nuclear, other zero-carbon	**Renewables & other zero-carbon**	26-34 TW solar 14-15 TW wind 3.5 TW other zero carbon	~46,000-47,000	~1,500-~1,600	~0.8%
		Transmission & Distribution	~50% of generation, front-weighted	~36,000	~1,100	~0.6%
		Battery storage	14 TWh per day (5% of daily generation)	~1,500	~50	~0.03%
		Seasonal storage: H_2 storage and/or CCS on thermal plants	4 TW thermal capacity equipped with CCS (5% of generation)	~3,800	~130	~0.07%
			1.5 TW electrolysis (2% power shifted)	~430	~15	~0.05%
Hydrogen in final use	800 Mt/year for final sectoral energy use	**Production**	7.6 TW electrolysis 0.7 TW blue hydrogen capacity	~1,200	~40	~0.02%
		Transport and storage	Salt caverns and other storage Gas pipeline retrofit	~1,100	~40	~0.03%
Industry	Steel, cement and petrochemicals industries achieve zero-carbon		CCS application to cement Hydrogen DRI or CCS for steel Multiple forms of changed chemical production process	~1,600	~50	~0.03%
Transport	**Road charging infrastructure**	Total decarbonisation road transport ~2bn electric cars and~200m electric trucks & buses	~1000bn slow residential, 200m moderate speed public and 10million superfast chargers, + truck and bus chargers	~2,000	~70	~0.04%
	Aviation and shipping	All long haul routes running with zero carbon fuels	Aviation and green shipping R&D, SAF plant investment and ship / fuel supply retrofit	~900	~30	~0.02%
Buildings Energy efficiency	IEA estimate of additional required investment in better insulation and more efficient lighting and HVAC systems			~12,000-15,000	~400-500	~0.2%
Total				**~106-110,000**	**~3,600-3,700**	**~1.8%**

NOTE: Wind and solar capacity for hydrogen production is included in renewables generation.

SOURCE: IEA (2020), SYSTEMIQ analysis for the Energy Transitions Commission (2021)

106 Average 2017-2019 annual additions, BloombergNEF (2020), *New Energy Outlook*
107 IEA (2020), *World Energy Outlook*
108 This includes generation capacity for direct and indirect electrification, e.g. renewable electricity provision for green hydrogen production
109 IEA (2020), *World Energy Outlook*

This investment is financially and physically feasible, but will only occur fast enough if governments create sufficient market certainty to attract large-scale private investment, by putting in place clear deployment objectives, supported by appropriate power market design, together with actions to identify and remove potential barriers to development. This Chapter therefore covers:

- Scale and speed of ramp-up and investment needs;
- Policies and actions to support ramp-up in zero-carbon generation and system balancing capabilities;
- Policies and actions to support investment in transmission and distribution infrastructure;
- Overcoming financing challenges, in particular in some developing countries.



I. Scale and speed of ramp up and investment needs

Chapter 1.4 illustrated the ramp-ups in total electricity use required for individual countries and at the global level. Delivering this in a zero-carbon fashion will require huge increases in renewable power capacity and other zero-carbon power sources, both to meet new demand and to progressively replace existing high-carbon generation, implying very large increases of annual investment opportunities.

The precise mix of capacity by different technologies (VRE, nuclear, hydro and thermal plant) will differ by country and evolve in light of changing relative costs. To illustrate the scale of capacity increase and investment, we have modelled two global scenarios – one with VRE increasing to 75% of total electricity generation, and a high VRE scenario in which the share reaches 90%. Other assumptions relating to the balance between wind and solar, and the evolution of capacity factors over time are described in a Technical Annex.

These assumptions would imply the following pace of ramp up:

Installed renewable capacity

Installed wind capacity would have to grow from today's 640 GW to between 14,000 and 16,000 GW by 2050, while solar capacity would have to increase from today's 650 GW to between 26,000 and 35,000 GW by 2050.[110] [Exhibit 3.2]. Net-zero aligned regional studies by the ETC and other organisations, reflecting bottom-up analysis of local needs and appropriate generation mixes, illustrate similarly dramatic increases. The UK Climate Change Committee illustrates the UK's offshore wind capacity growing from today's 10 GW to over 95 GW by 2050.[111] China will need to grow from today's 200 GW of wind and 200 GW of solar to about 2,500 GW of both wind and solar capacity by 2050.[112] High VRE scenarios for India show that VRE capacity will need to grow from 35 GW and 38 GW for solar and wind respectively to 230 GW and 170 GW by 2030.[113] The US will need to grow from 120 GW of wind and 90 GW of solar to 400 GW of wind and 390 GW of solar by 2050.[114] [Exhibit 3.3]

Wind and solar installed capacity must grow dramatically

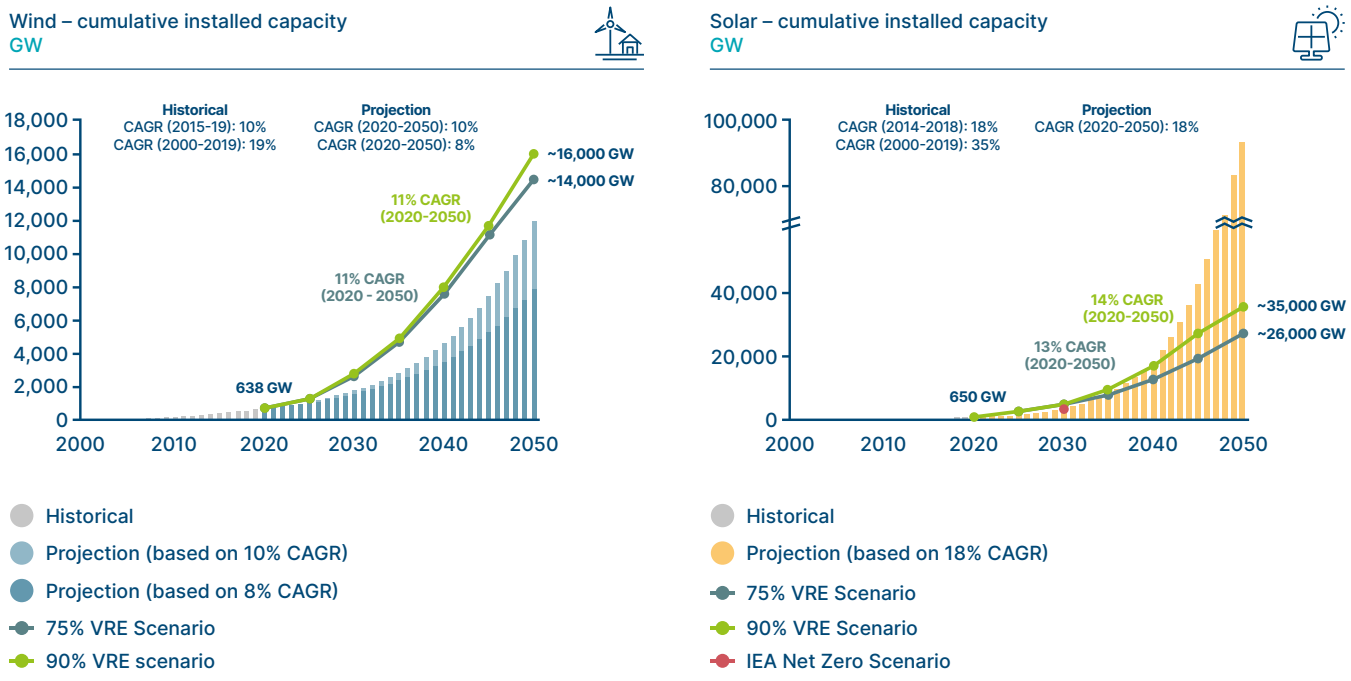


Exhibit 3.2

SOURCE: IRENA, IEA (2020) *World Energy Outlook*, SYSTEMIQ analysis for the Energy Transitions Commission (2021)

110 Historic data from BloombergNEF (2020), *New Energy Outlook*
111 UK Climate Change Committee (2020), *Sixth Carbon Budget Report*
112 RMI/ETC China (2019), *China 2050: A fully developed rich zero-carbon economy*
113 TERI/ETC India (2020), *Renewable Power Pathways: Modelling the Integration of Wind and Solar in India*
114 Princeton University (2020), *Net Zero America Interim Report*. Upper range of E+, E- and E-B+ pathways

At the global level, the installed capacity increases based on our illustrative scenarios imply average annual growth rates between 2020-2050 of about 11% for wind (more than maintaining the rate of growth of about 10% per annum seen over the last decade) and 13 to 14% for solar (allowing for some deceleration from recent high growth rates from a low installed base).

Pace of renewable installations

Achieving these huge increases in installed capacity will require a rapid ramp up in annual installations, beginning immediately in the 2020s when VREs will account for the vast majority of all new capacity added to global power systems. By 2030, new wind installations will need to grow by over 6 times from around 50 GW/year today to over 300 GW/year, and new solar installations 4 times from around 115 GW/year to over 500 GW/year. By 2040-45, when both direct and indirection electrification is firmly underway leading to higher annual electricity demand additions, the pace of new VRE installations will also peak, with annual solar installations growing to 1,400-2,000 GW/year (13-14 times today) and wind to 700-800 GW/year (12-18 times today) respectively. [Exhibit 3.4]

Financial investment implications

The implications for total investment in dollar terms will depend on the future capital and installation costs of renewable equipment. Using the midpoint of possible assumptions set out in Exhibit 2.3 would imply wind and solar generation investments for direct and indirect electrification rising from today's $300 billion per annum to a peak of about $1.6-2 trillion between 2040-2045 and an average of $1.2-1.4 trillion over the next three decades [Exhibit 3.5].

Regional scenarios show significant expansion of VRE capacity

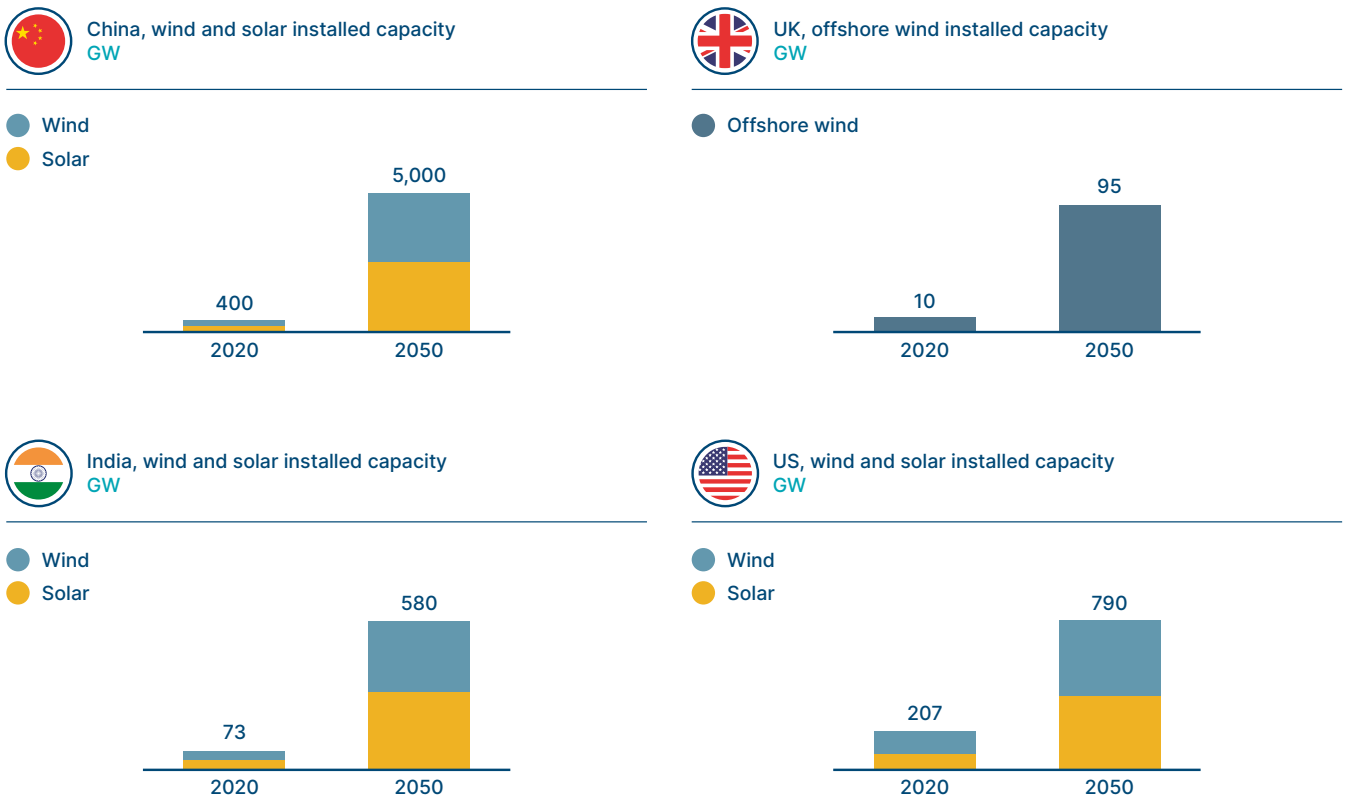


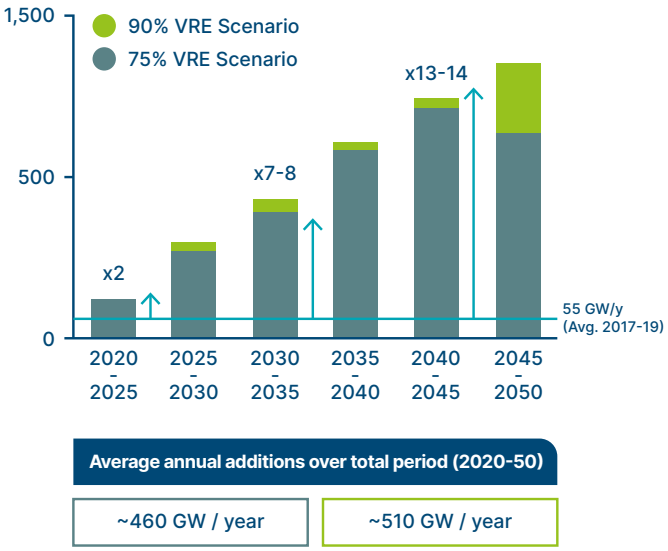
Exhibit 3.3

NOTE: UK data represents Balanced Pathways Scenario. US data represents upper range of E+, E- and E-B+ pathways.

SOURCE: TERI/ETC India (2020), *Renewable Power Pathways: Modelling the Integration of Wind and Solar in India by 2030*, RMI/ETC China (2019), *China 2050: A fully developed rich zero-carbon economy*, UK Climate Change Committee (2020), *Sixth Carbon Budget Report*, Princeton (2020) *Net-Zero America: Potential Pathways, Infrastructure, and Impacts Interim Report*

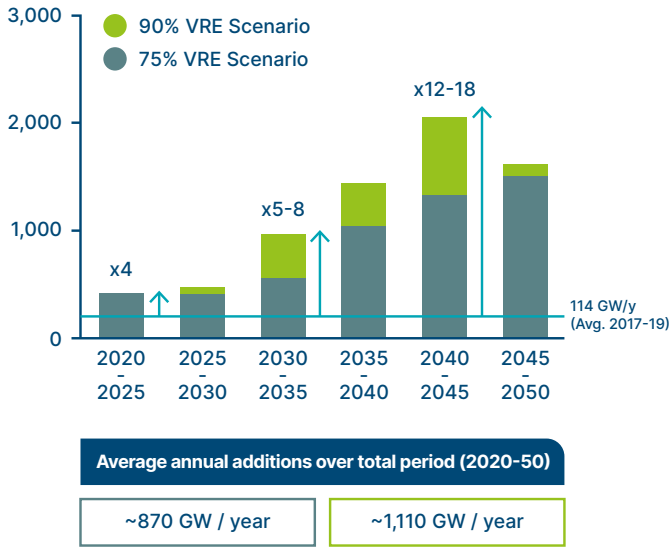
Rapid ramp-up in pace of new installations

Wind - annual installed capacity additions
GW / year (annual average over 5-year period)



Average annual additions over total period (2020-50)	
~460 GW / year	~510 GW / year

Solar - annual installed capacity additions
GW / year (annual average over 5-year period)



Average annual additions over total period (2020-50)	
~870 GW / year	~1,110 GW / year

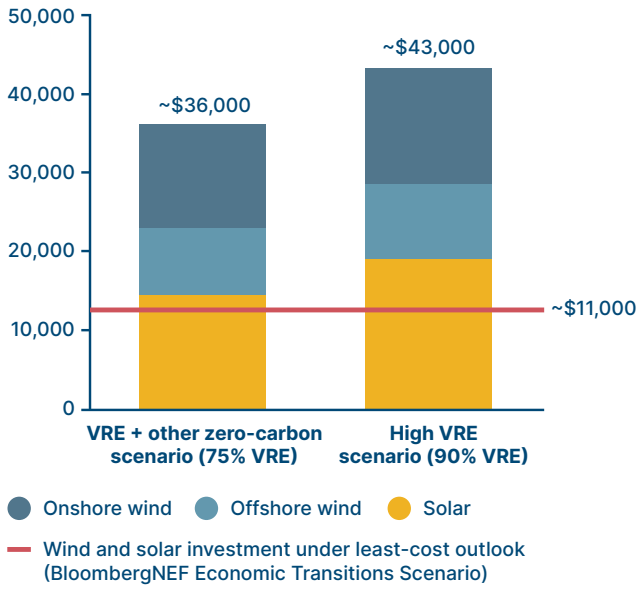
Exhibit 3.4

NOTE: 75% VRE scenario assumes 32% solar and 43% wind generation in 2050. 90% VRE scenario assumes 42% solar generation and 48% wind generation in 2050.

SOURCE: BloombergNEF (2020) *New Energy Outlook*, SYSTEMIQ analysis for the Energy Transitions Commission (2021).

Ramp-up requires significant investment in VRE generation over next 30 years

Capital investments 2020-2050 (wind and solar generation)
$ billion



Average annual capital investments in generation (wind and solar)
$ billion per year, average across 5-year period

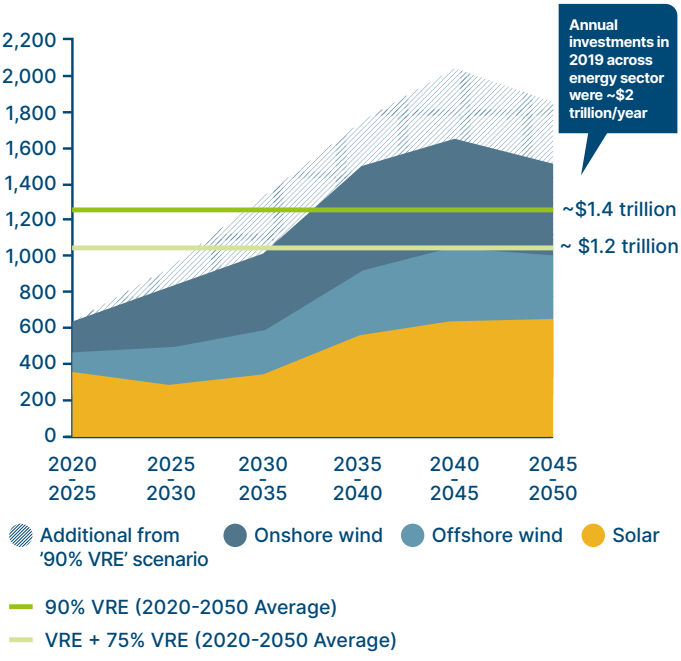


Exhibit 3.5

NOTE: Capex cost outlook to 2050 based on using the midpoint of possible assumptions between BloombergNEF, IRENA High and Low cases.

SOURCE: BloombergNEF (2020) *New Energy Outlook*, SYSTEMIQ analysis for the Energy Transitions Commission (2021)

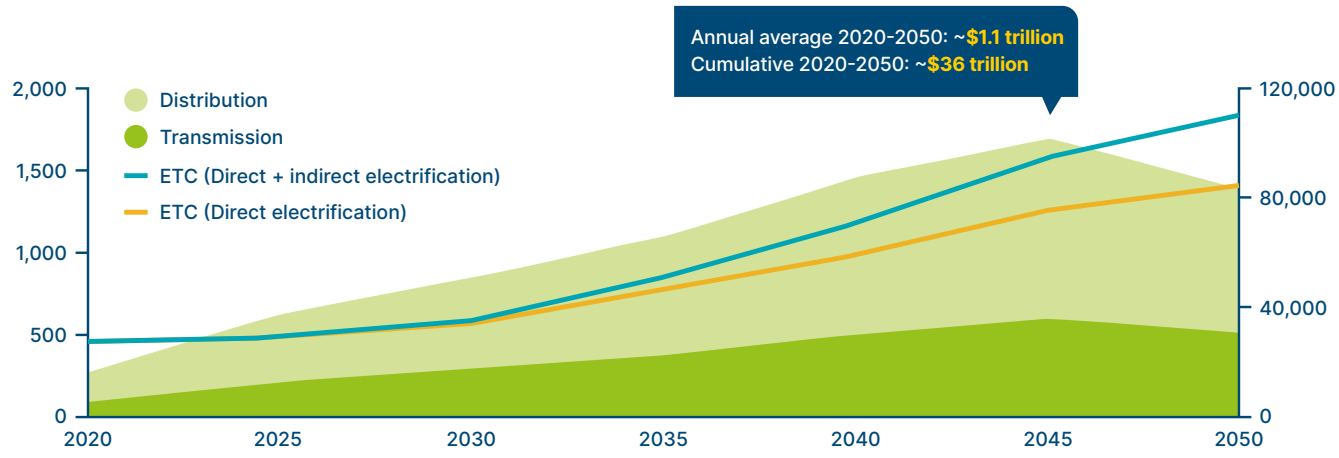
In addition, massive expansion of electricity demand, together with the changes in the demand patterns placed on transmission and distribution systems described in Chapter 2.4, will generate large investment opportunities within power networks. National requirements will vary greatly to reflect different increases in total electricity supply, existing assets and local choices and requirements, but at the global level, transmission and distribution (T&D) investments could add around another $1 trillion per annum, and $36 trillion cumulatively. T&D could therefore effectively double the investments required in the clean electricity system. The inclusion of network investments also front-weights the investment profile. T&D investment must indeed occur ahead of demand and generation, to enable new demand and generation capacity to come online with no bottlenecks[115] [Exhibit 3.6]. Estimating T&D investment is inherently complex. Local requirements and societal choices (e.g. to build transmission lines above or below the ground) could significantly increase the investment needed above these levels, while early investment in enablers of network cost reduction (e.g. network digitalisation, development of the DSO capability) could see them significantly reduced.

Overall, therefore total global investment needs to build a zero-carbon power system able to underpin a massively electrified global economy, including zero-carbon generation and networks, could amount to over $2.5 trillion dollars per annum, and over $80 trillion dollars overall, equal to less than 1.5% of global GDP over the next 30 years. Similar estimates of the order of magnitude have been developed by other studies.

- The UK CCC see for instance, estimates that building a UK zero-carbon electricity system which can deliver 2.5 times as much electricity as today could involve investments of about £15 to 20 billion per annum over the period 2020 to 2050, an amount equal to around 0.6% of possible UK GDP over that period.[116]

Network investment profile likely lumpy and front-weighted – in many areas early investment will be required to enable electrification ramp up

Total network investments and power generation
$billion (LHS), TWh (RHS)



Transmission and distribution needs are often front-loaded to avoid network infrastructure becoming a bottleneck to system growth:

Distribution investment required ahead of need (~5 years) to meet demands of rapid electrification: new use cases (e.g. EV charging infrastructure) & increasing distribution-level activity (e.g. smart meters and remote sensors to enable network digitalisation)

Transmission investment required ahead of need (~3-5 years) to connect remote VRE resources and strengthen key connections between VRE generation and load centres

Exhibit 3.6

SOURCE: BloombergNEF (2020), *New Energy Outlook*, Industry interviews, SYSTEMIQ analysis for the Energy Transitions Commission (2021)

115 Distribution investment in particular should be front-weighted for example in EVs, where substation upgrades and local network reinforcements must occur ahead of a critical mass of EV adoption in a local area, which is likely to follow an S-curve. Once this "tipping point" of EV charging is reached, existing distribution network infrastructure will be insufficient to meet demand if investment is not front-weighted

116 UK Climate Change Committee (2020), *Sixth Carbon Budget Report*

- Investments in developing countries facing still larger increases in electricity demand will be commensurately higher, though it is important to note that much of the investment would be required in any case to support economic growth and electricity demand growth, even if countries were not simultaneously decarbonising their economies.

In global and national macroeconomic terms, these levels of investment can easily be afforded and financed. Total global savings and investments are currently about 25% of global GDP, and increased investments in green electricity systems will be significantly offset by big decreases in investment in the fossil fuel system, which accounts for $1 trillion of annual investments today.[117] Meanwhile, historically low interest rates in advanced economies and some developing ones suggest plentiful investment demand for good investment opportunities.

In absolute terms, while the economic case for massive, clean electrification is growing ever more attractive, the challenges around faster deployment and investment are still huge. Clearly defined strategies and strong supporting policies will be required to create market certainty and send strong signals for developers and investors. Sections 2 and 3 describe the key actions required.

While capital is plentiful and relatively cheap in advanced economies and China, higher cost of capital could be an impediment to rapid investment growth in some developing countries. Section 4 describes responses to that challenge.

117 IEA (2020), *World Energy Outlook*



II. Policies and actions to support rapid ramp-up of zero-carbon electricity generation and system balancing capabilities

Developing the required ramp-up in clean power generation and in the forms of flexibility support needed to balance the electricity system described in Chapter 2 Section 2 will require significant investment.

The typical financing mix of renewables projects evolves across different stages of project development, progressing from a higher share of equity financing at the higher-risk pre-construction phase to a higher share of debt financing once the

Financing mix evolution across project stages

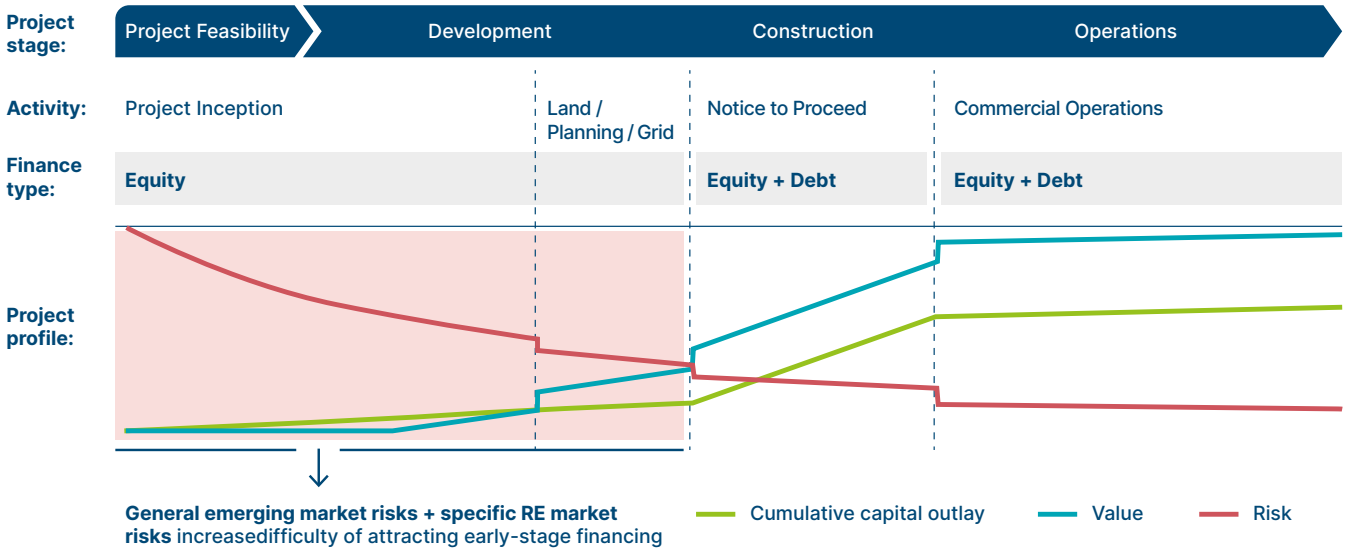
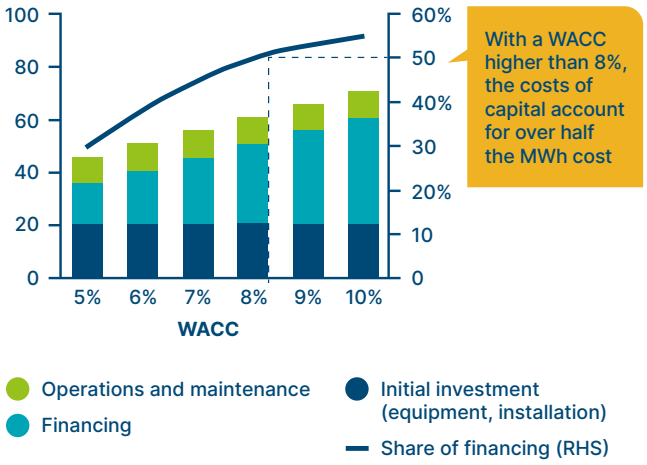


Exhibit 3.7

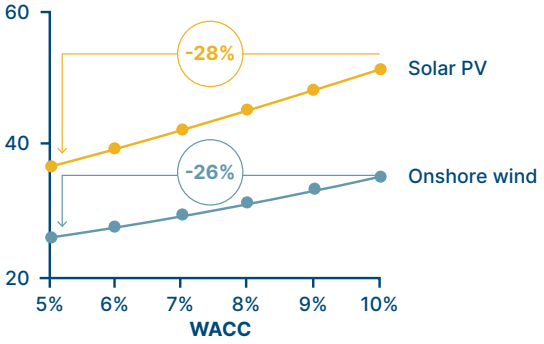
SOURCE: SYSTEMIQ analysis (2021)

Operational stage - a low cost of capital (WACC) will significantly reduce the cost of VREs build out, given VRE's high CAPEX, low OPEX cost profile

LCOE and share of financing costs, Solar PV, $/MWh, %



Illustrative LCOE, WACC for US wind and solar [1], $/MWh, %



Operations and maintenance
Financing
Initial investment (equipment, installation)
Share of financing (RHS)

Exhibit 3.8

NOTE: [1] illustrative example assuming project lifetimes of 20 years.

SOURCE: IEA (2019) *Solar Energy: Mapping the Road Ahead*, SYSTEMIQ analysis for the Energy Transitions Commission (2021)

project is operational [Exhibit 3.7]. Due to the high upfront capital costs of renewable projects, the cost of capital is a critical driver of the levelised cost of electricity (LCOE) of renewable generation. Indeed, once the project is operational, a decrease in the weighted average cost of capital (WACC) from 10% to 5% could decrease the associated LCOE by around 25-30% [Exhibit 3.8]. Lower financing costs have indeed been a significant contributor to the decline in the LCOE of solar over the past decade. The WACC in 2019 is now at 2.6-5% in Europe and the United States, 4.4-5.4% in China, and 8.8-10% in India.[118]

To enable massive investment in clean electricity generation and balancing at low cost, it is critical to reduce the risk – and therefore the cost of capital – across all project development stages by creating an optimal investment environment. The most important overarching policy requirement is for countries to set a clear strategic direction that will raise the confidence of investors in the scale and shape of future power markets, underpinned by clear medium-term quantitative targets for the pace of both power sector decarbonisation and mass electrification. These should include specific capacity and generation targets for zero-carbon sources over time, as well as clear end date targets (e.g. 2035 for developed countries and 2045 or 2050 for developing countries) for achieving near complete decarbonisation of power systems.

In addition, however, to rapidly scale investment and deployment, national strategies need to incorporate:

- Appropriate power market design to create incentives for rapid expansion of zero-carbon power and required system balancing capabilities;
- Planning, permitting and land acquisition systems which support large-scale and rapid development, including for transmission and distribution networks;
- Careful assessment of the ability of local and international value chains to deliver the necessary pace of investment, and the identification and resolution of any potential barriers.

Creating well-thought-out policies can reduce risks and increase investor certainty for developers and their financiers, thus enabling a rapid build-up at the lowest cost to the system. In this section we will discuss these areas in turn [Exhibit 3.9]

Critical areas to unlock project deployment and investment at scale

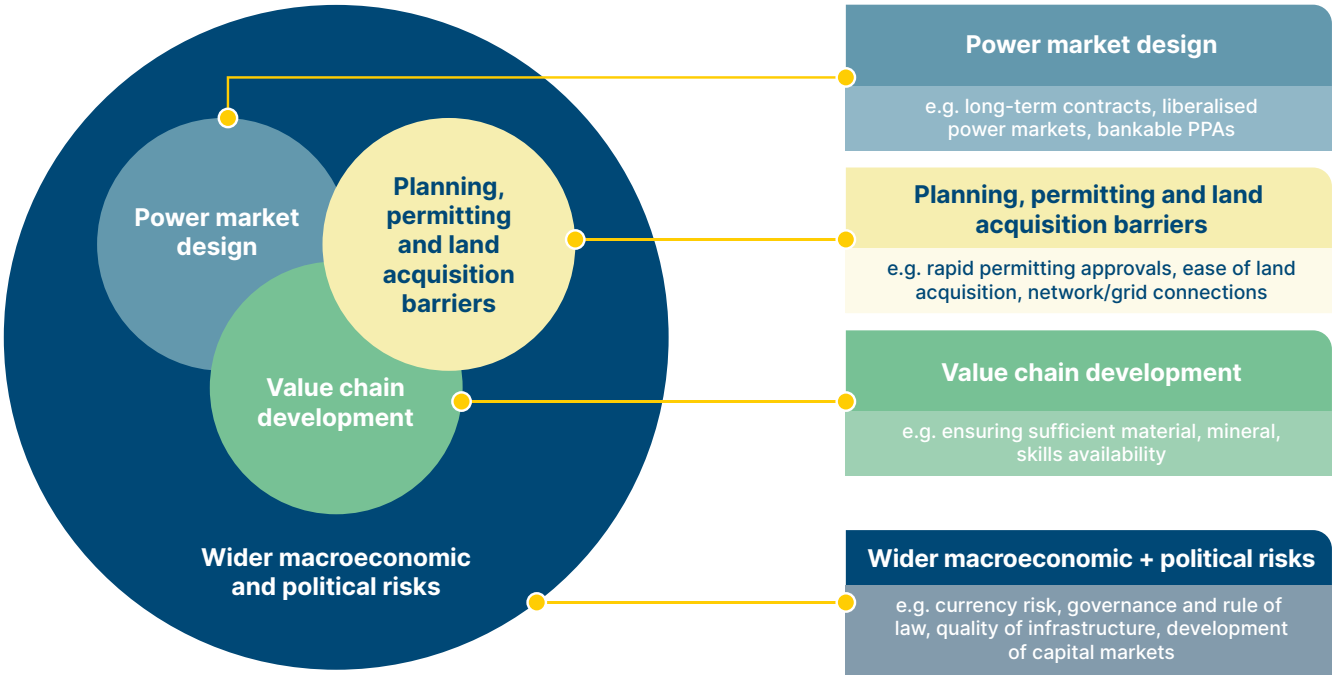


Exhibit 3.9

SOURCE: Industry interviews, SYSTEMIQ analysis for the Energy Transitions Commission (2021)

118 All in nominal terms after tax. IEA (2020) *World Energy Outlook*

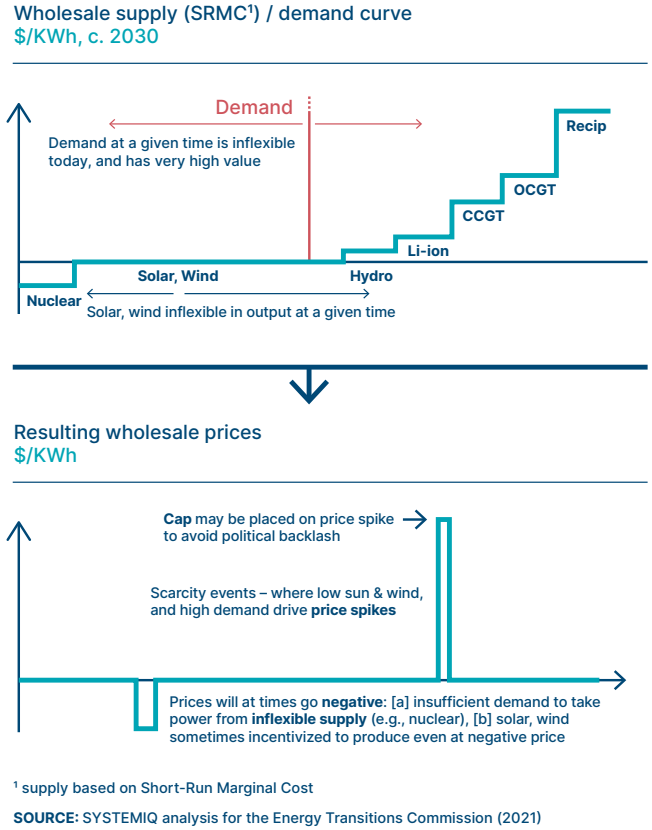
Power market design

Appropriate power market design will be essential to support rapid expansion of renewable capacity and required system balancing capabilities. To date, rapid growth in renewables in many markets has been driven by long-term contract structures – initially with set feed-in tariffs, and then via auctions to set feed-in premium levels. These structures have been enablers of significant declines in the cost of renewables, by providing both certainty over the future revenue streams which has lowered the cost of capital, and a mechanism for targeted subsidies for emerging renewables technologies.

With VRE generation costs now (or soon to be) below fossil fuel costs, the need for subsidy is disappearing. However, despite the falling costs of renewables, long-term contracts will continue to be required in the future to provide sufficient revenue certainty to attract low-cost, low-risk capital, able to provide financing for zero-carbon generation at the speed and scale required for the ramp-up in electrification to come.

While wholesale pricing based on short-run marginal cost leads to efficient dispatch, in a system increasingly dominated by renewables with zero marginal costs, the uncertainty over future wholesale prices makes short-term markets insufficient to incentivise required investment in new generation capacity. This is known as the "missing money problem". Wholesale pricing based on short-run marginal cost means that prices are set based on the 'marginal', or most expensive generator, required to be dispatched to meet demand at a given moment. Increasing the number of zero-marginal cost renewable generators on the system is likely to bring down wholesale prices for large periods of time, thus complicating the investment case for new generators. [Exhibit 3.10]. There is already evidence that wholesale power prices have fallen in some markets as VRE penetration has increased [Exhibit 3.11].[119]

Growing problem: Wholesale markets as sole revenue stream no longer provides a sufficient long-term generation investment signal



[1] supply based on Short-Run Marginal Cost

SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021)

Commentary

Higher share of capex in marginal generation (solar / wind @ 100% fixed costs)

Scarcity events no longer sufficient, exacerbated where price caps distort the market

In particular for solar / wind whose output is not likely to coincide with scarcity events

Forward-looking markets and price outcomes uncertain, e.g., tech advances, regulation changes

Raises investor cost of capital, which particularly impacts technologies which higher share of upfront costs, i.e., solar & wind

Even if scarcity events could be enough to incentivise new generation, investors would need to see many years of such events to have certainty before investing

→ creates a considerable time lag with underinvestment along the way, that lead to energy & capacity shortages

Exhibit 3.10

119 Note, this is not always the case as commodity price evolution and demand patterns also impact wholesale market prices. For instance, in 2018, increased gas prices drove increasing wholesale power prices in many geographies, even as share of renewable generation increased. In the UK in 2018, renewables penetration increased from 17% to 22% of generation but gas prices rose by 27%, with wholesale base power prices increasing by 29%.



- While 'scarcity events' will lead to high energy costs for certain time periods, these events are unlikely to be sufficient to incentivise new investment.[120] In practice, even if scarcity events could be enough to incentivise new generation, investors would need to see many years of such events to have certainty before investing. This would create a considerable time lag, with underinvestment along the way, which would undermine the ability to achieve clean electrification – and climate – targets.
- As discussed above, uncertain future prices for VRE supply would increase required investor returns, significantly increasing LCOE given the dominance of capital costs in VRE economics (as shown in Exhibit 3.7).

In many markets, long-term contracts will therefore still be required to mitigate the impact of growing future price uncertainty on pace and scale of investment during the incoming phase of rapid electrification and VRE capacity ramp-up.[121]

In addition to ensuring long-term revenue certainty, appropriate power market design should also aim to:

- Minimise distortion to short-term markets to allow them to continue to incentivise efficient dispatch and investment decisions,[122]
- Encourage flexibility onto the system,
- Provide sufficient locational signals in an increasing granular and distributed energy system.

In some markets, VRE penetration has been accompanied by decline in wholesale power prices

Wholesale base prices, VRE share of generation
% (LHS), $/MWh(RHS)

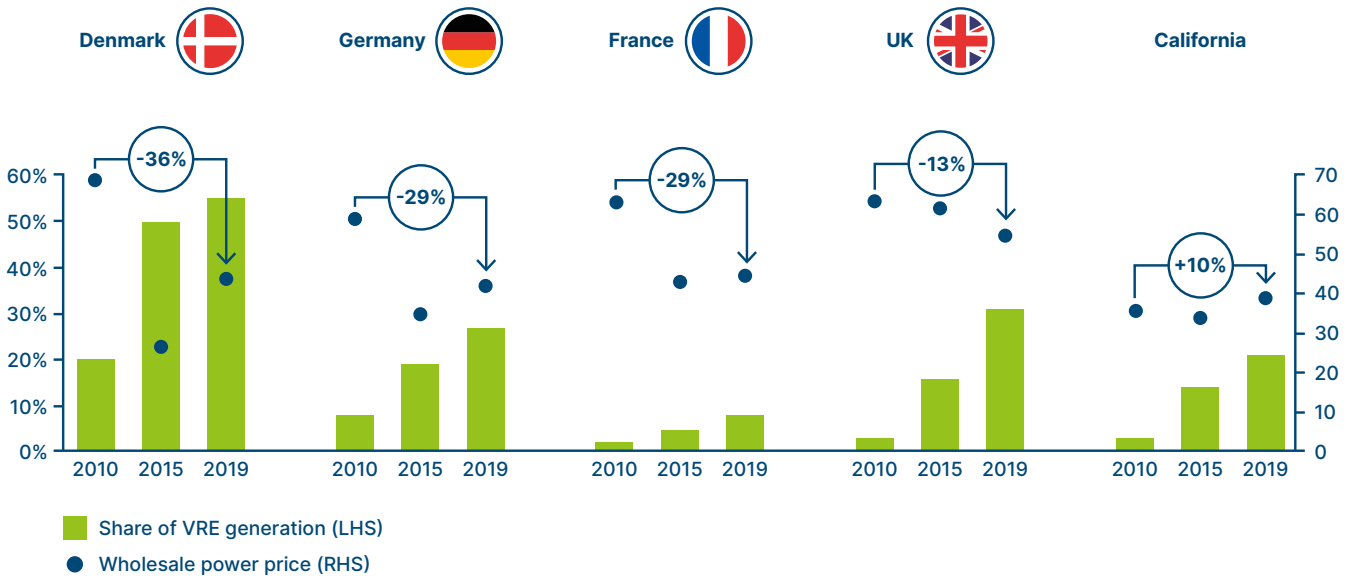


Exhibit 3.11

NOTE: VRE is wind and solar generation. Annual power prices are determined by many different factors, including weather events, commodity price spikes, and demand conditions. Prices are yearly averages. Wholesale prices for California are Intercontinental Exchange (ICE) reference prices for Southern California.

SOURCE: BloombergNEF (2020), Industry interviews, SYSTEMIQ analysis for the Energy Transitions Commission (2021)

120 Exacerbated where price caps, placed on price spike to avoid political backlash, distort the market.

121 In most markets, voluntary long-term contracting and other financial instruments (e.g. futures markets) will be insufficient to manage risks to incentivise new zero-carbon generation at the pace and scale required. However, in some advanced markets, an evolution to an integrated ownership structure where a utility can balance higher risks of wholesale price volatility via its storage and flexibility assets could enable new generation without centrally coordinated long-term contracts – i.e. effectively using the ownership of storage and flexibility assets to 'hedge' against increased price volatility and decreasing average wholesale prices.

122 Short-term markets are bound most tightly to the needs to the market (energy in a time & place).

Optimal long term energy contract structures to ensure sufficient revenue certainty

When organised at the market level long term energy contracts must balance

- Attracting **low-cost capital/WACC** by ensuring **sufficient revenue certainty** for investors
- Incentivising **supply aligned to market needs, minimising distortion of short-term markets**

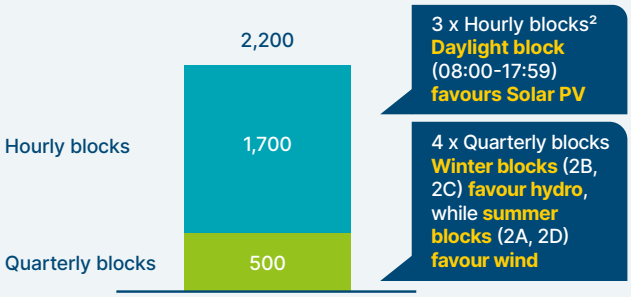
Production-based energy long-term contracts should include the following features

1 Competitive price-setting mechanisms	• Strike price set competitively via **auction, pay-as-bid** • **2- way contracts**. sharing risk across counterparties (i.e. generators reimburse any positive difference between strike price and wholesale reference price), or **1-way contracts** to optimise locational signals and drive lower auction bids
2 Ensure sufficient revenue certainty	• **Long term** contract (e.g. 15 years) • **Reference price based on technology-specific price** to minimise exposure to specifically low prices during times of VRE generation
3 Expose generators to wholesale market signals	• **Sliding premium with 'medium' settlement time**, e.g. daily, weekly or monthly, to incentivise producers to align generation with system needs based on wholesale pricing, and encourage the deployment of storage • Clause **against producing during negative wholesale prices**
4 Time of day / year / locational components	• **Multiple auctions with different time components (time of day, year) and / or locational components** - based on 4-6 year forecasts to reflect where / when energy shortages occur
5 Incentivise long-term use of existing assets	• **Market-wide contracts**, with existing and repowered generation able to bid into long-term production-based auctions once initial long-term energy contracts expires (e.g. after 15 years) for next auction period (esp. important for offshore wind)

Case study: Chile's technology-neutral auctions based on time-blocks incentivise the deployment of renewables

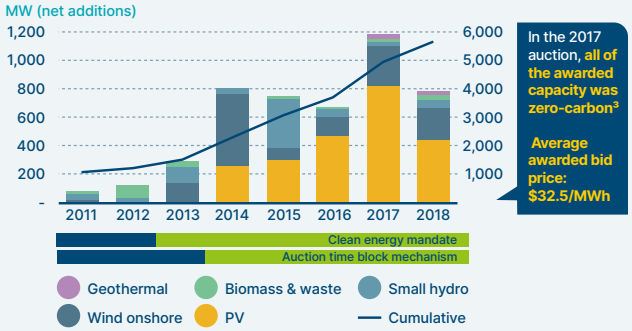
Technology-neutral, time-block auctions

Chile 2017 auction, total volume of the tender, GWh[1]



Net capacity additions favour VRE

Chile capacity additions, MW



NOTE: For counties which have retailer-only business models, these businesses may need additional support when long term energy contracts are introduced due to reduced hedging liquidity: Retail price should reflect wholesale price movements; retailers should be incentivised to bring on flexibility levers for short-term price hedging.

[1] Auction held in 2016 had continuous + hourly time blocks, auctioned 12,400 GWh;
[2] Hourly blocks are (1A) 00:00-7:59hrs and 23:00-23:59hrs, (1B) 08:00-17:59 hrs; (1C) 18:00hrs-22:59hrs; Quarterly blocks are (2A) 01 Jan – 31 Mar; (2B) 01 Apr – 30 Jun; (2C) 01 Jul – 30 Apr; (2D) 01 Oct – 31 Dec. Bidders can make offers in any number of combinations and for multiple blocks. Bids for hourly blocks can be transferred to quarterly blocks.
[3] 98% wind and solar, 2% geothermal.

SOURCE: BloombergNEF (2020) and CNE 2017 in AURES II, Auctions for the support of renewable energy in Chile, November 2019

Box 6

Five critical elements of power market design will achieve these objectives, although the precise mix of policies will be dependent on local market context. We provide an overview below:

1) Long-term energy contracts

As the energy system transitions, long-term energy contract structures should continue to play a role alongside short-term markets to bring sufficient zero-carbon generation, as well as storage, onto the system at low cost. There are two core options for such contracts:

- **Corporate PPAs or Virtual PPAs**, where a company contracts directly with an energy supplier for zero-carbon electricity, can play an important role in providing long-term revenue certainty for new generation.[123] Since 2008, over 50 GW of clean energy corporate PPAs have been signed globally (more than Vietnam's current total power generating capacity) – spearheaded in the United States by large technology players. Regulatory incentives for corporates to enter PPAs, as well as contracting public procurement via PPAs, should be encouraged. However, contracted volumes from voluntary PPAs alone will likely be insufficient to incentivise capacity at the pace and scale of additions required.

- **Long-term production-based energy contracts** organised at the market level will therefore be essential over the coming decades. Careful contract design is critical to provide sufficient revenue certainty to reduce the cost of capital, while also allowing some exposure to short-term market signals to minimise market distortions and support efficient, low-cost dispatch. Box 6 sets out a series of optimal design features for long-term production-based energy contracts for zero-carbon generation, recognising that optimum structures will vary by country and over time as technologies develop.[124] [Box 6]

123 Virtual PPAs are a financial contract between a corporate and a developer where the corporate does not consume actual power from a project, but it is delivered electricity from the grid – yet the agreement acts as a financial hedge to bring new renewable generation online.

124 For example, contracts should not remunerate generators for production during negative pricing times and should stipulate that generators reimburse any positive difference between the agreed price and the actual wholesale price.



2) Short-term markets, including ancillary services markets

Short-term markets aim to ensure efficient dispatch to balance electricity supply and demand, lowering overall system costs (and therefore consumer prices) through utilisation of lowest-cost generation at any given point in time. Short term markets must evolve to ensure a level-playing field across technologies, especially new zero-carbon generation and storage for which the market was not originally designed. Examples of features to adjust include:

- Ensuring time windows for bids are sufficiently granular (<15 mins) to allow all forms of generation to be competitive,
- Zonal or nodal pricing to ensure efficient locational signals for generation, and
- Creating new markets for ancillary services provision that was previously bundled with thermal generation (e.g. in the UK, National Grid ESO's Stability Pathfinder tenders for inertia provision).

3) Long-term peak capacity mechanisms

Energy markets must ensure system reliability (e.g. avoid black-outs). As VRE penetration increases within the power system, there is a growing risk that this reliability goal is not served from the short-term market as a result of the 'missing money problem' described above. While optimal capacity market mechanisms will vary based on specific market needs, overall, the development of peak capacity markets could be used to guarantee system reliability while ensuring access for all technologies on a level-playing field (e.g. ensuring that renewables, storage and demand-side response are allowed to bid into these markets with appropriate de-rating factors,[125] as well as setting out a market framework that accounts for the long lead times of pumped hydro development). Strategic reserves, which are formed of generation capacity that is not allowed to participate in the wholesale market, are an alternate form of system reliability mechanism. Beyond this, as capacity markets tend to favour dispatchable fossil generation, carbon intensity restrictions (e.g. a minimum gCO_2/kWh for bid) or bans on some unabated fossil fuel technologies could be used to ensure network decarbonisation, provided system reliability is not at risk.

125 For example, derating factors based on statistical review of technology performance in particular locations



4) Additional market and regulatory mechanisms to incentivise flexibility

In addition to short-term markets and long-term peak capacity markets, further steps should be taken to incentivise storage and flexibility in power systems. Market design should facilitate the development of interconnections between adjacent systems to expand the balancing areas, as highlighted by the energy crisis in Texas in February 2021, which lacks integration with other grids in the US. Market design should also act to incentivise flexibility from new sources of demand (electric vehicles, heat pumps). Key levers to accelerate this deployment include moving to real-time pricing, mandatory smart capabilities (e.g. smart chargers for EVs to enable smart charging and vehicle-to-grid), as well as joint procurement of VRE and storage.[126] It is important to note that the roll-out of real-time pricing has been a politically difficult reform to implement, given the impact that it could have in raising average electricity prices, especially for sectors with a limited ability to adapt consumption levels to price signals. However, the lower generation costs of high-renewables systems could now offset such an impact.

5) Market enablers

A set of market enablers are required to underpin smooth functioning and correct signals across the system. This includes System Operator capabilities to manage markets for grid services (e.g. ability to regulate voltage, maintain system frequency, ride through disturbances), as well as the incorporation of external environmental costs (e.g. via carbon pricing), and transparency over the decision-making process – for example, clarity over the auction pipeline and parameters for zero carbon generation contracts.

Considerations for developing countries

The principles outlined in this section are applicable across the world. In many countries, they represent the highest-priority actions to ensure sufficient generation and storage at scale and at low-cost. However, many developing countries face a different set of challenges and priorities for market design reform, while expanding energy access remains a top priority.

Some countries do not yet have fully liberalised electricity markets and have less advanced system operator capabilities. Key steps towards unbundling electricity markets may in themselves provide benefits for zero-carbon generation, including the introduction of economic dispatch where currently lowest-cost generation is not the first to be dispatched.[127]

Developing countries also face specific challenges such as lack of contract certainty and customer creditworthiness, which can be partially addressed by market design and governance reform. In India, potentially insolvent distribution companies (discoms) risk not paying developers as discoms themselves face payment arrears and electricity theft from their own consumers. In Vietnam, new renewable generation developments are stymied by 'unbankable' power purchase agreements (PPAs) due to the lack of creditworthiness of the utility offtaker for the project.

Additional market design priorities for emerging markets thus include:

- Ensuring grid connection access;
- Progressive evolution towards liberalised markets, though ensuring the role of long-term contracts to support renewable deployment;
- While politically sensitive, reforms to improve cost-recovery end-user tariffs and enable a transparent flow of funds from end-users to electricity generators, as well as government guarantees to improve rate recovery and utility creditworthiness;
- Harmonising frameworks between regions to ensure larger balancing area and power dispatch across entire countries (and even in some cases across neighbouring countries).

126 Note, this can include both physically co-located storage with VRE, as well as jointly procured but physically distant VRE + storage. Co-locating VRE and storage can be effective to rapidly increase storage capacity (e.g. due to shared project development costs). However, location of the storage may be suboptimal at the system level, as storage on remote VRE generation sites is often unable to access the highest discharge price signals typically found near load centres.

127 Some developed countries also have electricity markets that are vertically-integrated or "bundled", including parts of the United States (e.g. Florida).

Planning, permitting and land acquisition systems to support rapid development

Alleviating planning and permitting barriers for projects is critical to enabling build-up at pace, unlocking the project pipeline and investment. However, in many regions, current approval frameworks for new projects are often lengthy and complicated.

Two forces impact the speed and ease of permitting:

- Lengthy and complex rules and procedures are a challenge common across developed and developing countries. In Germany, for example, permitting processes that used to take just 10 months now take up to 2 years, and lack of staffing at the federal level has been one of the drivers, leading to undersubscription of some auctions.[128] [129]

- Increasing local opposition to the siting of large-scale renewables projects, and "Not in my back yard" (NIMBYism) sentiments, on the grounds of localised impact and noise pollution, also lead to delays. Protests and judicial actions from citizen groups to block developments have been an increasing factor of delays especially in the United States and Europe, including for instance in Hawaii and Germany.[130]

Barriers around land acquisition and ownership are another challenge, which is most pronounced in developing countries. In India, renewables projects often face challenges from land acquisition delays as well as land use conflicts. In many African countries, obtaining secure land rights is a key barrier for developers. For instance, in Kenya, developing greenfield projects is highly challenging due to regulations which limit foreign owning and leasing, as well as uncertainty over land titling.[131]

Box 7

Streamlining planning and permitting

UK offshore wind case study



Critical steps of the UK's successful regime for offshore wind permitting

1

Alignment across national and regional authorities

Designating offshore wind farms as nationally significant infrastructure projects within England and Wales. This allows all permitting of offshore (as well as onshore) infrastructure for the wind farm to be considered together at a national level, rather than having to go through both English and Welsh authorities.

2

Single regulatory body to provide approval – "One-stop shop"

In the UK, the approval process is managed by the Planning Inspectorate (PINS) which is part of central government.

3

Clear timelines

PINS commits to completing the approval process within 18 months of receiving the required supporting information. At the end of the period, PINS makes a recommendation to the Secretary of State, who has three months to decide. PINS' recommendations are typically accepted.

SOURCE: Adapted from Ocean Renewable Energy Action Coalition (2020), *The Power of Our Oceans*

128 *DW,* "German wind power blown off course", 21st November 2019

129 Bottlenecks caused by the permitting process in Germany have led recent auctions to be undersubscribed, with lack of participation in the rounds. Of over 1,350 MW offered by the government in 2019, only 746 MW were awarded. *DW,* "German wind power blown off course", 21st November 2019

130 *Financial Times,* "Germans fall out of love with wind power", 17th November 2019; *Star Advertiser,* "Wind farm opponents protest in Mayor Kirk Caldwell's office", 1st November 2019

131 Kent Kuran, (2016) "The Bright Continent – The Outlook for Utility-Scale and Commercial & Industrial Solar Projects in East Africa"

Addressing these challenges will be of critical importance to debottleneck new project development. Strategies include:

- Simplifying the permitting processes via coordination across different regulatory bodies (e.g. federal, state, and local) and providing a "one stop shop" for permitting that contains all required approvals. Regulators should set clear timelines and expectations for decision-making, and ensure appropriate civil service staffing and resources to manage fast-growing volume of approvals and interactions with local stakeholders. The UK's offshore wind planning and permitting regime represents a best-practice case study [Box 7].

- In parallel, a strategic approach to planning the siting of generation projects, which is coordinated with network design and anticipatory investments, is critical. System design should optimise to connect generation in favourable renewable regions, as well as for a mix of generation resources that will be optimal for the system. Projects could, for instance, be developed so as to more easily link to grid connections, allowing the same network infrastructure to serve a greater number of future projects.

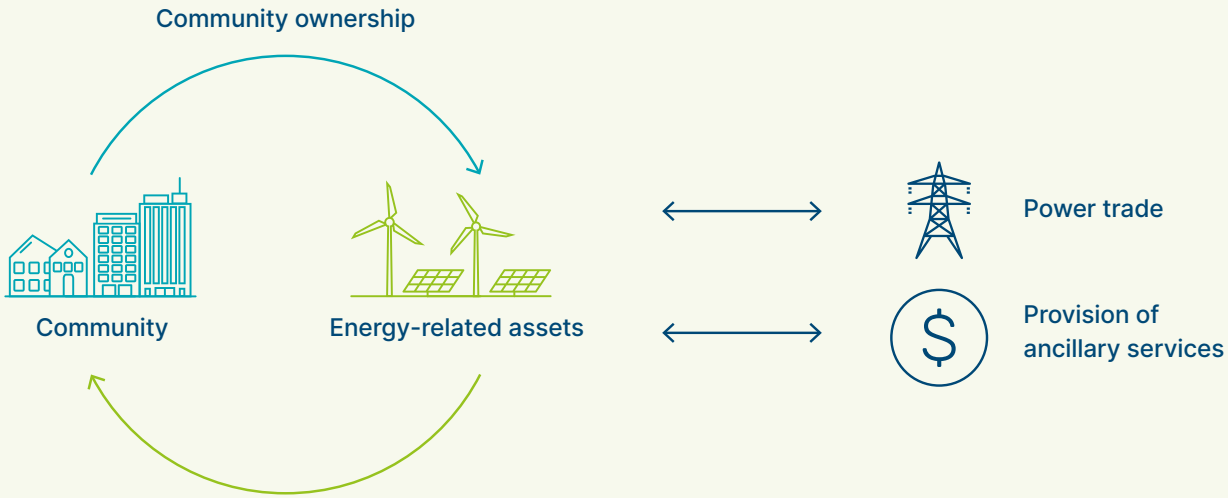
Role of community ownership for energy supply

Increasing the development of community-based models could play a role in reducing opposition to the build of renewables and "Not-in-my-Backyard" (NIMBY)-ism in areas where these are particularly strong, as well as to develop social responsibility around clean energy.

Community ownership structures refer to the collective ownership and management of energy-related assets, such as renewable generation, storage, or district cooling and heating systems. Projects are usually 5 KW to 5 MW in size. Local stakeholders own most of the project, and control rests with the community organisation. There are over 4,000 such community-based ownership models globally, with 1 GW (1% of installed capacity) in Germany run under these structures.

Such ownership structures have the advantage of directly generating benefits for the community by reducing energy costs, ensuring access to clean energy, financial profits as well as local jobs. Increasing distributed energy resources could also lower needs for transmission and distribution, which is also subject to increasing opposition.

Overview of community-based energy system



Socio-economic benefits to the community:

- Electricity generation, electricity storage, heating, cooling, etc.
- Community empowerment, energy security, energy independence, job creation, etc.

Box 8

SOURCE: Adapted from IRENA (2020), *Community-Ownership Models: Innovation landscape Brief*

- To address increasing local opposition, strategies could include further development of distributed generation to reduce the scale of generation plants, clear communication about the benefits of renewables, as well as some further development of community-ownership models for renewable power[132] [Box 8].

Planning and permitting bottlenecks are also a major issue for transmission and distribution build, which will be addressed in the next section.

Value chain development: identifying and resolving potential bottlenecks

Achieving the massive and rapid ramp up in clean power generation will require development of extensive supply chains for key materials and capabilities. As discussed in Chapter 2 Section 6, development of materials circularity represents a key lever to reduce reliance on primary resources. Overall key requirements for the transition will include:

- Greatly expanded solar PV and wind turbine production, including key components and materials – such as glass and electronic components for solar panels, and steel, rare-earth magnets, and precision ball-bearings for wind turbines;
- Large-scale installation capacity for both onshore and offshore wind, and for solar panels, which, together with manufacturing, will create the large-scale employment mentioned in Chapter 2.5 – as many as 21 million people potentially employed worldwide by 2045, but with specific skills and training therefore required[133];
- Huge growth in hydrogen electrolyser production, potentially growing from 1 GW of capacity per annum today to above 400 GW by 2040[134];
- Based on a rapid trajectory of EV growth highlighted in Chapter 1, battery production capacity potentially rising from around 100 GWh per annum today to over 5,000 GWh per annum by 2035, with proportional increases in key mineral supply[135].

All these developments are physically feasible within the required timescale. As Chapter 2, Section 6 described, sufficient mineral resources exist to meet demand. While material demands are significant, these are also manageable from a supply chain perspective. In the case of wind turbines, steel consumption over the next 30 years could average around 50 million tonnes per year, which is less than 5% of annual steel production in 2019.[136]

Overall, failure to plan in advance for the increases required could result in multiple bottlenecks, both locally and globally, which slow progress and increase costs. The most important public policy to avoid this danger is to set clear targets far in advance, including:

- Clear objectives for the pace of electrification supported by strong policy requirements (e.g. dates beyond which new ICE purchase will be banned);
- Quantitative targets for specific developments over the next 10 years e.g. India's commitment to build at least 450 GW of wind and solar by 2030, or the U.K.'s commitment to build 40 GW of offshore wind by that date;
- Firm dates for achieving power system decarbonisation (by the mid-2030s for developed countries and mid-2040s for developing countries).

In addition, governments and industry groups together should identify key capabilities and workforce skills, as well as components, materials and circularity strategies required to meet these targets, to anticipate any potential bottlenecks and specify the actions (including if necessary government support) to overcome them.

In some cases, policy and industry responses will not only ensure adequately fast decarbonisation, but also help national economies to develop significant local supply capability, rather than relying heavily on imported capabilities. Examples of this approach include those being developed by the European Battery Alliance, the European Union's green hydrogen strategy, and India's strategy to develop local solar PV manufacturing capabilities.[137]

132 C. Wilson, A. Grubler et al. (2020), *Science,* "Granular technologies to accelerate decarbonisation"
133 SYSTEMIQ analysis for the Energy Transitions Commission (2021)
134 ETC (2021), *Making the Hydrogen Economy Possible: Accelerating clean hydrogen in an electrified economy*
135 SYSTEMIQ analysis for the Energy Transitions Commission (2021)
136 SYSTEMIQ analysis for the Energy Transitions Commission (2021)
137 See European Commission, European Battery Alliance (EBA) and Hydrogen Strategy, TERI (2019), *Solar PV Manufacturing in India*

III. Policies and actions to support investment in transmission and distribution infrastructure

As already discussed in Chapter 2.4 and in 3.1, T&D networks typically account for around 40% of total power system costs, with two thirds of this cost resulting from distribution and one third from transmission. As discussed, while there are some factors which could reduce T&D costs per kilowatt-hour (such as increased line capacity and load shifting), others could increase it (such as long-distance transmission needs) (see Exhibit 2.20 in Chapter 2.4). Moreover, even where changes could lower long-term ongoing costs, large upfront investments will be required. As a result, T&D accounts for around 50% of the total estimated 30-year investment requirement described in Section 1 above.

Massive clean electrification will therefore depend crucially on adequate, appropriate and timely investment in T&D, and well-designed public policy must play a central role in making this possible. Network operator models in different countries range from private companies, to semi-public corporations, to outright public ownership, but regulators almost always play a key role in approving investment proposals and regulating returns, with a strong focus on fair consumer prices.

Four features of required T&D investment have important implications for optimal regulation:

- Investments are often "lumpy" in nature. In transmission, for instance, very large initial investments in long-distance lines – whether domestic or international interconnectors – can result in significant step changes in total asset bases and costs.

- Investments in both T&D often need to be made ahead of demand growth with an initial period of low utilisation before usage rises to fill the capacity and justify the investment. In distribution, for instance, investments in substation upgrades, local distribution cable reinforcement, and EV charging points will be needed to enable the take-off of electric vehicles and electrified heat which is likely to come rapidly from the late 2020s and 2030s. Similarly, investments in smart meters, remote monitoring sensors, and distribution grid digitalisation are needed to enable demand response as a key system balancing resource in parallel to the deployment of VRE.

- Some transmission investments in particular – such as long-distance links to cheap renewable supply – could add permanently to total T&D costs, but reduce total system generation costs, making it essential to have an integrated perspective which spans generation and T&D.

- Investment costs vary greatly according to the local environmental and aesthetic choices which societies choose to make. Estimated long-distance transmission costs can vary greatly between different countries and locations, with costs in high population-density developed countries increased by delays on development relating to land acquisition, planning and permitting, or by the need for underground cables to assuage local opposition.



Particularly in developed countries, existing regulatory approaches are often not well suited to addressing the challenges and needs of T&D investment, which is "lumpy", localised, and must occur ahead of need. Whereas developing country power systems have been growing to support economic growth even before the impact of wider electrification, many developed countries have faced slow-growing or flat electricity demand over the last few decades and have developed regulatory approaches which often combine:

- Relatively short-term planning horizons (e.g. five years);
- Long periods (e.g. 5 to 7 years) between identification of need and delivery of upgrades and additions;
- A strong focus on short-term cost minimisation for today's consumers, but potentially at the expense of investments required for long-term growth and cost minimisation.

To support rapid electrification and address changing T&D challenges, all countries will need regulatory and political strategies which include:

- Investment approval processes which support development well ahead of demand, i.e. "anticipatory investment". This approach will require a shift from an approach with ex-ante investment limits to one that includes (i) long-term planning horizons, (ii) acceptance that it may take several years before some strategically important assets are fully utilised, and (iii) the ability to take a "whole system" approach, e.g. allowing for future generation cost benefits when assessing the cost implications for consumers [Box 9].

- The ability to design, approve, and implement integrated visions for network development which can reduce future costs and support rapid renewable development. In the North Sea for instance, an integrated network including undersea links between different sectors, will be better designed to support rapid offshore wind developments, than the multiplication of individual connections from wind farm to shore approved on a case-by-case basis [Exhibit 3.12].

Anticipatory Investment Frameworks

Existing T&D investment approach is not suited to rapid scale-up in net-zero context

- **Short term planning horizons** (typically 1-2 years), with investment made only as need arises
- **Suboptimal choices made from long term system-perspective** (e.g. incremental decisions which only postpone more significant grid upgrades)
- **Limited pro-active investment** as costs typically charged to beneficiary or existing consumers

'Anticipatory investment' approach required to avoid network bottlenecks

- **Long term planning horizons**, investment anticipating needs before they arise and become bottlenecks
- Acceptance that it may take **several years before** some strategically important **assets are fully utilised**
- **"Whole system" approach** which includes assessment of generation cost trade-offs when assessing the cost implications for consumers

Case Study, National Grid Proposal (Business Plan 2021-2026):
Anticipatory investment mechanism that allows solutions to unlock rapid decarbonisation to net-zero 2050

"We are proposing a mechanism, involving a cross sector group of key stakeholders, policy-makers and regulators, that would consider the following factors for key strategic infrastructure solutions to net-zero challenges:

- **Criteria:** define when anticipatory investment is in consumers' interest.
- **Need case:** establish what circumstances trigger a pre-agreed investment approach.
- **Whole system outcomes:** stakeholder collaboration to ensure optimal, whole system outcomes are delivered.
- **Funding:** how companies can recover their efficiency costs.
- **Risk sharing:** appropriate customer user commitment, consumer protection and reward for value created.
- **Monitoring:** provisions to provide regulatory and stakeholder oversight of projects."

Box 9

SOURCE: National Grid, *Delivering your future electricity transmission system*, National Grid Electricity Transmission's business plan 2021–26, December 2019

- Planning and permitting processes which can support rapid development while addressing legitimate local concerns and political opposition, as discussed in the previous section on generation. This should also be complementary to strategic planning for siting generation. Optimum approaches need to combine:
  - Long-term planning which identifies needs far in advance (for example, Texas' 'Competitive Renewable Energy Zones');
  - Actions where possible to reduce local environmental impact via careful design and innovative approaches (e.g. by reducing the number of end individual connections as shown on Exhibit 3.10);
  - Designation of some projects as national infrastructure priorities, with special regulatory regimes to support rapid implementation, and "one stop shop" approval processes which ensure coordination across multiple layers of government and multiple regulators, as discussed in section 3.2;
  - Increased dialogue across stakeholders.
- Political leadership to argue for developments which are needed to deliver national emissions reductions, supported by willingness to approve and support additional costs (and potential implications for customer costs) to reduce environmental impacts (e.g. by undergrounding).
- The development at distribution level of the distribution system operator (DSO) capability described in Box 3, to actively manage increased activity at the distribution-level.
- Forward-looking supply chain planning as mentioned for generation.

For many developing countries, the required change in philosophy is less significant than in developed economies. ETC India work, for instance, has not identified long-distance transmission as a likely major barrier to VRE expansion, and, in China, approaches to planning and land acquisition support rapid implementation of required transmission investments. In sub-Saharan Africa, meanwhile, the low starting point of electricity connection and use creates an opportunity to develop local distributions in a new and innovative fashion, with a greater role for distributed energy resources (DER) and mini grids.

But in all countries, it is essential that plans for massive expansion of electricity use in VRE generation are combined with explicit analysis of the T&D challenges which will result, and the investments required.

Ensuring timely connections to remote VRE resources requires coordinated network planning

UK offshore wind network development models

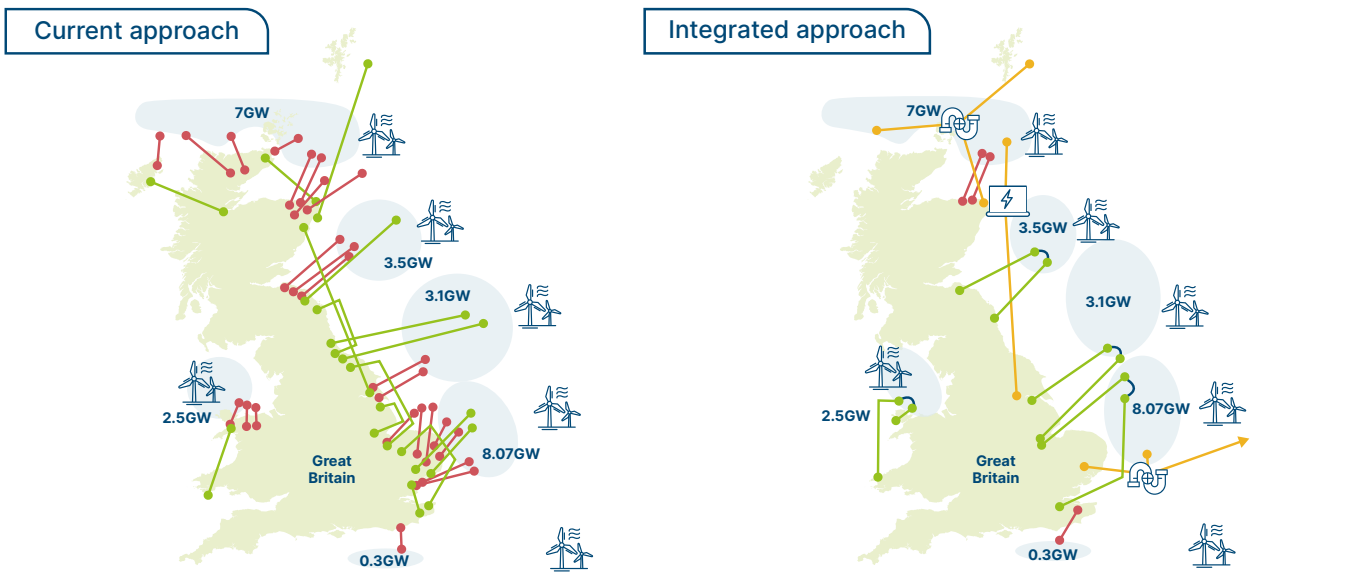


Exhibit 3.12

SOURCE: National Grid ESO

IV. Overcoming financing challenges, in particular in some developing countries

As sections 1 and 2 discussed, massive clean electrification will require huge investment. The cost of capital (the rate of return required by investors) is a key determinant of renewable generation costs – and therefore of the speed with which renewables can cost-effectively replace fossil in power generation – as well as of T&D costs.

Today, in most countries and at the global level, there is no shortage of potential capital. Renewable technology is considered more mature, risks are now easier to underwrite, and financing easier to obtain. Provided countries develop appropriate approaches to power market design and to the regulation and funding of T&D, finance will be available at adequately low cost in most developed economies to underpin large-scale investment. With appropriate structures, policy signals and market design principles, investments in the operational phase of a project can be sufficiently low risk to attract investors for returns of 5% real or below.[138]

In China too, specific features of the economic and financial system – which support aggregate national savings and investment rates of over 40% of GDP and where state-directed lending has focused on clean energy – will ensure that capital availability and cost is no impediment to rapid clean electrification.

But in some developing and emerging economies, the cost and availability of capital can be an important barrier to rapid transition. Thus:

- The cost of debt finance has a major impact on LCOEs in India. As an example, while Renew Power won India's May 2020 "round-the-clock renewables" auction with a bid price of ₹2.9/kWh ($0.04/kWh), estimates suggest that if it could access bank finance at the 4% interest rates available for Middle East projects, as against 10 to 11% in India, the bid price could have been a still lower ₹2.0/kWh ($0.03/kWh).[139]

- In many countries of sub-Saharan Africa costs are far higher, and there is effectively a quantitative shortage of capital relative to the opportunity, limiting Africa's ability to grasp its huge VRE potential. By 2019, sub-Saharan Africa had installed less solar capacity than the Netherlands.[140]

138 IEA *World Energy Outlook* (2020)
139 BloombergNEF (2020), *Round-the-Clock Renewables Threaten Coal Power in India; Times of India,* "Cleaner, and now cheaper solar power beats coal", 24th May 2020
140 IEA (2019), *World Energy Outlook*



As a result, while significant increases in power sector investment required over the next 30 years under regional net-zero trajectories developed for the US (about $10 trillion to 2050), Europe (about $10 trillion to 2050) and China (about $27 trillion to 2050) will almost certainly be available at reasonable cost, there is a danger that capital availability and cost will constrain rapid investment in Africa and other developing countries.[141] For Africa, a conservative estimate under the IEA's Africa Case, which is not a net-zero compliant scenario but is based on massively expanded energy access across the continent, sees investment in the power sector rising over 5 times, to more than $2 trillion to 2040 (2.7% of the regional GDP over the period), or over $100 billion per year.[142]

The causes of high cost of capital vary greatly by country. In many, they relate to the issues discussed in Section 2 – power market design and the creditworthiness of major power utilities and customers, lack of grid connection, permitting and land use issues, and the underdevelopment of local supply chains, including lack of project developers and technical know-how (in some instances exaggerated by local content requirements which has inhibited local industry development). All of these can affect the availability and cost of both the early project development stage as well as the later potentially lower-risk project operation stage described in Exhibit 3.6.

However, in some countries, there are also a wider set of macroeconomic and political factors which can restrict availability and increase the cost of capital across all sectors of the economy. This includes macroeconomic instability, perceived political and legal risks, currency risk, credit risks, as well as underdeveloped local capital markets. As one example, the cost of currency hedging to access dollar-denominated debt could add as much as 7% to the cost of financing in India. Overall, there is a wide variety of investment readiness levels across markets.

As a result, rapid development of projects in some developing and low-income economies is likely to depend on a large-scale role for multinational and national development banks, using the full range of development bank funding and risk mitigation approaches. These approaches can include blended finance vehicles, which combine public and private finance. Such measures should be targeted to de-risking the early project stages where risk is highest and allowing the creation of a project pipeline that can be more easily re-financed at lower-risk stages. Importantly, such vehicles can help mobilise financing ready to be deployed for aggregate pools of small- and medium-sized clean energy projects that fall out of scope of more traditional large-scale project and infrastructure finance.

Specific financing instruments include:

- Direct equity or debt investment at favourable rates, including via junior/subordinated capital, catalytic (or 'anchor') capital, loan syndication, and first-loss funding;
- Guarantees and insurance mechanisms, including loan guarantees, performance guarantees, and volume guarantees;
- Insurance against political instability and/or commercial and business insurance;
- Hedging facilities to manage currency risks and reduce costs;
- Grants, in particular for technical assistance facilities and project prep assistance;
- Securitisation, via the creation of new asset classes to transform illiquid assets into tradable financial instruments;
- Other contractual mechanisms, including off-taker agreements to support the development of bankable projects[143].

Clean power system development for developing and low-income economies should therefore be a priority focus for globally agreed flows of "climate finance" from developed economies. The policies which China applies in "Belt and Road" project will also have an important influence on capital provision. Total annual BRI investments in 2020 were around $57 billion, and $70 billion in 2019 – of which about 40% was in energy projects.[144] Ensuring that this investment supports green rather than dirty electrification is crucial.

The precise mix of actions and policies to crowd-in private capital in more challenging investment environments will depend on the market. Furthermore, these financing instruments must be deployed in addition to addressing the issues discussed earlier in this Chapter, in particular power market design reform priorities for developing countries.

141 US investment figures include renewable energy capacity and networks, referring to the E+RE+ Scenario from the Princeton University (2020), *Net Zero America Interim Report*. Europe investment figures are the total for the power sector, from McKinsey (2020), *How the European Union could achieve net-zero emissions at net-zero cost.* Chinese investment figures refer the IPCC's review of estimates of the additional investment required to achieve a 1.5°C climate objective, where by far the largest element within this is the capital expenditure to build massive amounts of renewable energy capacity. See RMI/ETC China (2019), *China 2050: A fully developed rich zero-carbon economy.*

142 IEA (2020), *World Energy Outlook*

143 Blended Finance Taskforce (2018), *Better Finance, Better World*

144 Green Belt and Road Initiative Centre, "Brief[illegible]nvestments in the Chinese Belt and Road Initiative (BRI) in 2020 during the Covid-19 pandemic", July 31st 2020





Critical priorities for the 2020s – Summary

This report concludes that it is undoubtedly technically feasible and economically affordable for the world to achieve massive electrification and near-total power sector decarbonisation by mid-century. Developed economies can and should meet the objective of a carbon intensity of power provision below 30gCO_2/kWh by the mid-2030s and all developing economies by the mid-2040s. The power sector represents a critical pillar – the single most important area – to reach the ETC's vision for economy-wide net-zero GHG emissions by mid-century, with all developed economies meeting that objective by 2050 at the latest and all developing economies within the following 10 years.

Laying out this vision is an important step. Companies and countries need to be confident that an end point of massive clean electrification can be reached in order to commit to achieving it and to drive the investments required to get there.

However, as this report has shown, achieving this will require a step change in the scale and pace of project deployment and investment. While in many geographies the power sector is ahead of the curve in decarbonisation compared to other sectors of the economy, decisive, continued action is required so as to meet fast-growing clean electricity needs over the next decades.

I. The What: Massive clean electrification under way by 2030

Reaching massive clean electrification by mid-century will require significant progress by 2030. Progress must occur along five critical dimensions:

1. Massive electrification under way, led by the transport sector,
2. Increasing deployment of zero-carbon power and storage;
3. Substantive phase out of coal and gas generation;
4. Expansion of networks and enabling capabilities;
5. Overcoming key innovation barriers.

Massive electrification under way, led by the transport sector

Demand for electricity use-cases must grow significantly:

- Global electricity use should grow 1.5 times (from 27,000 to around 40,000 TWh) with electrification of road transport and buildings leading the way in developed economies, and economic growth driving demand in developing countries;
- EVs should reach near 100% of new car sales in developed countries, and around 50% in developing countries;
- Heating should be increasingly electrified, with bans in place on fossil fuels in new builds, and building-retrofit programmes under way.

Increasing deployment of zero-carbon power and storage

VRE should increasingly dominate bulk electricity generation:

- Wind and solar should account for 40% of global generation by 2030, up from 10% today;
- 5-7x increase in annual wind and solar installations should take place compared with current levels, with wind and solar capacity growing from 1.3 TW to 7-8 TW;
- Storage and system flexibility should scale rapidly (e.g. grid battery storage, demand side response such as hot water storage in homes with heating, real-time pricing).

Substantive phase out of coal and gas generation

Power systems should push out coal and gas with grid emissions intensity progressively declining:

- Developed countries should reach below 80 gCO_2/kWh by 2030[145];
- Developing countries should indicatively reach below around 180 gCO_2/kWh by 2030.

Expansion of networks and enabling capabilities

Power networks must rapidly expand:

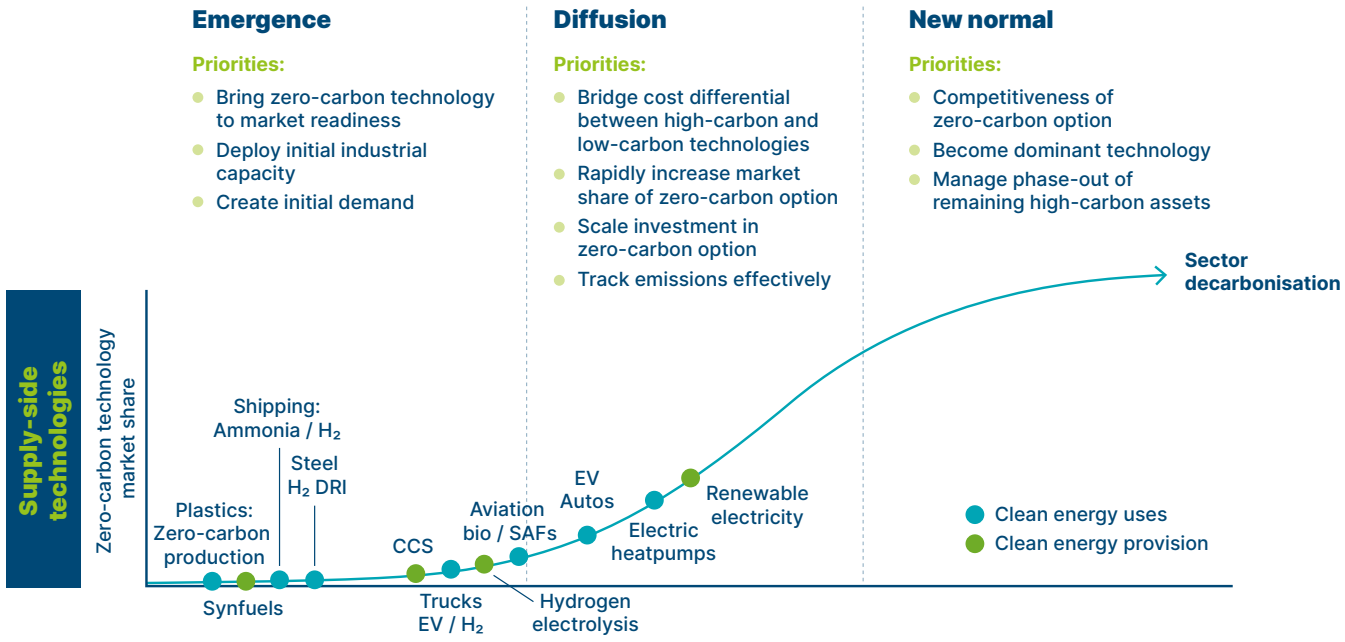
- National T&D forward-looking strategies should ensure rapid reinforcement, ahead of system growth;
- Annual investments in T&D networks should rise rapidly from $300 billion year to $700 billion per year;
- Networks should be able to manage high-VRE and higher activity at distribution level.

Overcoming key innovation barriers

Innovation will continue to play an important role. The technologies to enable massively electrified and zero-carbon power systems – whether focused on supply-side decarbonisation, electrification of new applications, or energy efficiency improvements – need to become widespread and embedded in the whole economy [Exhibit 4.1].

Exhibit 4.1

Deployment stages of technologies for massive clean electrification



SOURCE: SYSTEMIQ analysis for the Energy Transitions Commission (2021), based on Source: Victor, D., Geels, F., Sharpe, S., Energy Transitions Commission (2019), *Accelerating the low-carbon transition: The case for stronger, more targeted and coordinated international action*

145 Many developed countries should and will already be well below 80gCO2/kWh by 2030.

II. The How: 6 critical priorities for the 2020s

Meeting these objectives will require decisive, coordinated actions from policy makers, industry, finance, innovators and consumers.

There are 6 critical priorities for the 2020s:

1

Clear medium-term targets embedded in a strategic vision for economy-wide decarbonisation,

2

Appropriate incentives for clean technology deployment at scale, including power market design,

3

Building the infrastructure and capabilities required for both mass electrification and power system decarbonisation,

4

Integrated power system vision with appropriate planning and permitting to speed up implementation,

5

Unlocking financial flows, especially for developing countries,

6

Developing the technologies and business models of the future.

1. Clear medium-term targets embedded in a strategic vision for economy-wide decarbonisation

Massive clean electrification across the world as set out in this report cannot occur unless countries set out clear medium targets embedded in a strategic vision for the growth and decarbonisation of their power systems, providing a clear direction of travel and greater market certainty for developers and investors. These must be anchored to countries' net-zero commitments. Policymakers must:

- Set clear quantitative targets for zero-carbon electricity capacity (e.g. UK's commitment to 40 GW of offshore wind by 2030) or grid emissions intensity, and for the phase out of fossil fuels in power generation (including clear end dates), with firm, binding targets for 2030 to drive accelerated investment in the next decade, as well as indicative targets for 2050;
- Set clear 2030 and 2040 quantitative targets for electrification of new use cases, including bans for old technology (ICE sales bans, fossil heating bans in new buildings) and targets for the deployment of electrification technologies (e.g. EV sales target %);
- Set a substantive economy-wide carbon price to provide a common, long-term decarbonisation signal for both energy-using sectors and the power sector itself.

2. Appropriate incentives for clean electrification at scale, including power market design

Deployment of zero-carbon generation and electrification of end-uses at the pace and scale required must be supported by clear signals and incentives, aligning to decarbonisation objectives. Policymakers must:

- Remove all remaining fossil fuel subsidies (e.g. reduced tax rates on oil, coal, and gas);
- Introduce appropriate power market design to encourage rapid growth of zero carbon power systems. As discussed in Chapter 3 Section 2, there are five critical elements of power market design:
    a. Long-term energy contracts, for zero-carbon generation and storage (see Box 6);
    b. Short-term markets, including ancillary services markets;
    c. Long-term peak capacity mechanisms;
    d. Market and regulatory mechanisms to incentivise flexibility;
    e. Market enablers, including grid operation capabilities.

Additional specific market design priorities for emerging markets include ensuring grid connection access, a progressive evolution towards liberalised markets (though preserving the role of long-term contracts), reforms to improve cost-recovery end-user tariffs, to improve utility offtaker creditworthiness, and harmonising frameworks between regions to ensure larger balancing area and power dispatch across entire countries.

- Continue incentives and (where required) initial subsidies to enhance competitiveness of electrification versus fossil-based technologies in consumer and industrial uses (e.g. EV subsidies, ICE scrappage schemes, incentives to mitigate upfront cost of heat pump installation);
- Establish standards and regulations to improve energy efficiency and set targets for manufacturers (e.g. performance standards for AC units, EV sales quotas).

3. Building the infrastructure and capabilities required for mass electrification and power system decarbonisation

Supporting a low-cost and rapid build of an electrified global economy will require coordinated, decisive action across policymakers, system operators and regulators, industry and finance players to:

- Establish regulatory frameworks to enable anticipatory investment in power networks, enabling the build of networks ahead of need and reducing bottlenecks, as outlined in Box 9;
- Build expanded and digitalised network infrastructure to enable rapid electrification (e.g. transmission and distribution, EV charging, retrofit insulated buildings)
- Improve Transmission System Operator (TSO) technical capabilities to ensure smooth running high-VRE grid, e.g. ability to regulate voltage, system frequency, ride through disturbances;
- Develop new Distribution System Operator (DSO) capability to actively manage distribution activity, as outlined in Box 3;
- Build transparency into decision-making processes of system operators and policy makers;
- Develop clear plans for supply chain expansion, identifying key capabilities as well as materials and components required, anticipating any potential bottlenecks, and specifying the actions (including if necessary government support) to overcome them (e.g. EU Battery Alliance);
- Train workforce to develop appropriate technical expertise, e.g. for a less-centralised electricity system.

4. Integrated power system vision, with appropriate planning and permitting to speed up implementation

The speed of massive clean electrification laid out will require the implementation of a streamlined, clear regulatory approval process. Policymakers, system operators and regulators, and industry must work together to:

- Streamline planning, permitting, and land acquisition processes (e.g. creating a 'one stop shop', coordinating regulatory bodies, hiring more civil servants to manage a fast-growing number of requests), while addressing local concerns, as outlined in Box 7;

- Design and implement integrated visions for power system design, including the siting of generation and network build to ensure rapid development at lowest cost (e.g. generation sites connected to network build and siting plans).

5. Unlocking financial flows, especially for developing countries

Unlocking financial flows for zero-carbon electricity and electrification across the world will require policymakers and financial players to work to:

- Develop effective instruments and mechanisms to increase investment in developing countries, such as blended finance vehicles which de-risk early project stages (e.g. guarantees and concessional finance, asset securitization);

- Develop financing mechanisms to phase-out fossil fuels, including PPA modification and debt restructuring as outlined in Box 4;

- Establish a robust, simple, and standardised transition finance taxonomy to channel and focus capital flows on sustainability, supported by robust disclosure.

6. Developing the technologies and business models of the future

Supporting a low-cost and rapid transition will require the actions of industry, financial players, and policymakers to:

- Increase corporate commitments for uptake of zero-carbon power generation, electrification technologies, and energy efficiency measures, including for fleets, buildings, and industry, to accelerate deployment of those solutions and contribute to unlock cost reductions that would benefit the broader economy – these commitments could take the form of single company practices (e.g. automaker commitments to phasing out sales of new ICE vehicles) as well as multi-party campaigns (e.g. RE100 for renewables, EV100 for light-duty vehicles, EV100+ for trucking);

- Develop and deploy new consumer-friendly business models (e.g. easy-to-use smart capabilities for EV charging, aggregator and virtual power plants business models);

- Focus public and private R&D support on critical technology targets, to:

    i. Develop and scale solutions for long-term energy storage (e.g. hydrogen) as well as for medium-term storage (e.g. flow batteries, compressed air energy storage), to drive further cost declines and technology readiness;

    ii. Continue to drive VRE cost declines and efficiency improvements, including to reduce siting constraints (examples include high efficiency-solar innovation, such as perovskites, floating wind, airborne wind, floating solar);

    iii. Accelerate the readiness of other zero-carbon generation (e.g. small modular reactors (SMR), carbon capture use and storage (CCS/U));

    iv. Drive further EV battery cost declines and energy density improvements to increase range;

    v. Develop cheaper and higher performance heat pumps;

    vi. Support the development of direct electrification and use of clean hydrogen, including industrial uses (e.g. electric arc furnaces for cement and chemicals, electrochemical reduction of iron for steel production, electrochemical reduction of carbon dioxide into carbon-based materials) as well as transport uses (e.g. synfuels for aviation and green ammonia for shipping);

    vii. Improving line capacity and optimise existing T&D assets;

    viii. Commercialise power electronics for technical solutions for grid stability (e.g. synthetic inertia provision);

    ix. Develop material traceability, collection, sorting and recycling technologies.

Energy Transitions Commission

CLEAN ELECTRIFICATION IN THE 2020S



2030 TARGETS:

ELECTRIFICATION

Global electricity use up 1.5 times

- EVs near 100% of new car sales in developed countries, 50%+ in developing countries
- Heating increasingly electrified, building retrofits under way

WIND AND SOLAR DEPLOYMENT

Wind and solar ~40% global generation

- 5-7x increase in annual wind + solar installations
- Scaling storage and flexibility deployment

FOSSIL PHASE OUT

Grid emissions intensity

Developed countries	Developing countries
<80 gCO_2/kWh	<180 gCO2/kWh

- Immediate stop to new coal
- Meet all new electricity growth with wind and solar

6 CRITICAL ACTIONS

KEY EXAMPLES

1 TARGETS — Clear medium-term targets

- Clear quantitative targets for zero-carbon electricity (e.g. wind and solar capacity, grid emissions intensity) and electrification (e.g. EV sales)
- Future bans on fossil technology (e.g. ICE)

2 DEPLOYMENT — Incentives for clean electrification

- Remove all remaining fossil fuel subsidies
- Appropriate power market design (e.g. long-term contracts, appropriate short-term markets incl. ancillary services, long-term peak capacity mechanisms, flexibility enablers)
- Electrification incentives & subsidies (where required, e.g. heat pump incentives)
- Standards & regulations (e.g. AC min. efficiency standards)

3 NETWORKS & SKILLS — Infrastructure and capabilities

- Regulatory frameworks to enable anticipatory investment in power networks
- Network infrastructure (e.g. grids, EV charging, building retrofits)
- New Distribution System Operator capability to manage distribution network
- Clear plans for supply chain expansion and workforce training

4 PLANNING — Integrated vision, planning and permitting

- Integrated vision for power system and network design
- Streamlined planning, permitting, and land acquisition

5 FINANCING — Financing, mainly in developing countries

- Instruments to scale investment in developing countries, e.g. blended finance, concessional finance, asset securitization
- Fossil phase out mechanisms, e.g. PPA modification, debt restructuring

6 INNOVATION — Technologies and business models

- Long-term energy storage solutions (e.g. hydrogen)
- Continue VRE cost declines and increased range (e.g. floating wind)
- Aggregators and virtual power plants (VPPs)

Concluding remarks

The Energy Transitions Commission believes it is possible to reach net-zero carbon emissions by mid-century, significantly increasing the chance of limiting global warming to 1.5°C. Actions taken in the coming decade are critical to put the global economy on the right track to achieve this objective. Succeeding in that historic endeavour would not only limit the harmful impact of climate change, but also drive prosperity and better living standards, while delivering important local environment benefits. A net-zero GHG economy will be built on abundant, affordable zero-carbon electricity. Achieving massive electrification and early power decarbonisation – ahead of economy-wide decarbonisation - must be at the heart of all countries' paths to net zero. Policymakers, investors, innovators, producers, buyers, and more generally both public and private sectors have a major responsibility to collaborate and act now at the local, national, regional and global scales to undertake the 6 critical actions outlined in this document to drive massive clean electrification in the 2020s – overcoming the barriers to scaling and delivering the major step-change in the pace of renewables deployment required.



Acknowledgements

The team that developed this report comprised:
Lord Adair Turner (Chair), Faustine Delasalle (Director), Ita Kettleborough (Deputy-Director), Elena Pravettoni (Lead author), Mark Meldrum, Laetitia de Villepin, Meera Atreya, Alasdair Graham, Alex Hall, Lloyd Pinnell, Tommaso Mazzanti, Hettie Morrison, Aparajit Pandey, Francisco Pereira, Caroline Randle, Andreas Wagner (SYSTEMIQ).

This report builds on analyses developed by our knowledge partners, whom we would like to thank again for the quality of their inputs:
Albert Cheung, Logan Goldie-Scot, Seb Henbest, Benjamin Kafri, Tifenn Brandilly, Sanjeet Sanghera, Nikolas Soulopoulos, Emma Champion, Tara Narayanan, Brianna Lazerwitz (BloombergNEF); David Nelson, Felicity Carus and Brendan Pierpont (Climate Policy Initiative); Per Klevnäs, Anders Ahlen and Cornelia Jonsson (Material Economics); Arnout de Pee, Eveline Speelman, Hamilton Boggs, Cynthia Shih and Maaike Witteveen (McKinsey & Company); Elizabeth Hartman, Ji Chen, Yiyan Cao, Caroline Zhu, Bingqi Liu, Uday Varadarajan, Koben Calhoun (Rocky Mountain Institute); Thomas Spencer, Neshwin Nigel Rodrigues, Raghav Pachouri, G Renjith, A K Saxena (The Energy and Resources Institute).

The team would also like to thank the ETC members and experts for their active participation:
Rajit Nanda (ACWA Power); Elke Pfeiffer (Allianz); Javier Bonaplata, Nicola Davidson (ArcelorMittal); Abyd Karmali (Bank of America); Ian Luciani, William Zimmern (BP); Jeanne Ng (CLP); Cameron Butler, Rob Kelly, Wei Sue (Climateworks Australia); Dana Barsky (Credit Suisse); Bin Lyu (Development Research Center of the State Council); Rebecca Heaton, Richard Gow (DRAX); Adil Hanif (EBRD); Rebecca Collyer, Pete Harrison, Phillip Niessen (European Climate Foundation); Patrick Curran (Grantham Institute, London School of Economics); Matt Gorman (Heathrow Airport); Andrea Griffin (HSBC); Francisco Laveron Simavilla, Angel Landa Ugarte, Juan Rivier Abbad (Iberdrola); Chris Dodwell (Impax Asset Management); Ben Murphy (IP Group), Christopher Kaminker (Lombard Odier); (LONGi Solar); James Smith-Dingler, Elizabeth Watson (Modern Energy); Matt Hinde, Terry McCormick, Nick Saunders, Nicholas Young, Joseph Northwood, Tracey Walker, Mayoma Onwochei (National Grid); Jakob Askou Bøss, Anders Holst Nymark, Øyvind Vessia (Ørsted); Aditi Garg (ReNew Power); Xavier Chalbot, Jonathan Grant (Rio Tinto); Mallika Ishwaran, Charlotte Brookes (Royal Dutch Shell); Emmanuel Normant (Saint Gobain); Sandrine de Guio, Emmanuel Laguarrigue, Vincent Minier, Vincent Petit (Schneider Electric); Brian Dean (SE4All); Camilla Palladino, Xavier Lorenzo Rousseau (SNAM); Jesper Kansbod, Martin Pei (SSAB); Alistair McGirr, William Steggals, Matthew Pringle, Angus MacRae, Pavel Miller (SSE); Jan Braten, Kristian Marstrand Pladsen (Statnett); Brian Dean (Sustainable Energy For All); Abhishek Goyal (Tata Group); Madhulika Sharma (Tata Steel); Reid Detchon (United Nations Foundation); Mikael Nordlander (Vattenfall); Johan Engebratt and Niklas Gustafsson (Volvo Group); Rasmus Valanko (We Mean Business); Jennifer Layke, Asger Garnak, Karl Hausker (World Resources Institute), Paul Ebert, Phil O'Neill, Geeta Thakoral (Worley)

The team would also like to thank the ETC's broader network of experts for their input:
Alex Campbell (International Hydropower Association), David Nelson, Udetanshu (CPI); Paul Graham (CSIRO); Kash Burchett; Ben Dixon, Catharina Dyvik, Iman Effendi; Rafal Malinowski; Sanna O'Connor-Morberg, Guido Schmidt-Traub, Sophie Slot, Katherine Stodulka; Julia Turner (SYSTEMIQ); Mike Thompson, Owen Bellamy, David Joffe, Mike Hensley, Chloe Nemo (UK Climate Change Committee); Dolf Gielen, Francisco Boshell, Asami Miketa, Elena Ocenic, Arina Anisie, (IRENA); Karl Zammit-Maempel (Climate Champions); Constant Alarcon (C40); Chris Radojewski (Powering Past Coal Alliance)



www.energy-transitions.org

Energy
Transitions
Commission