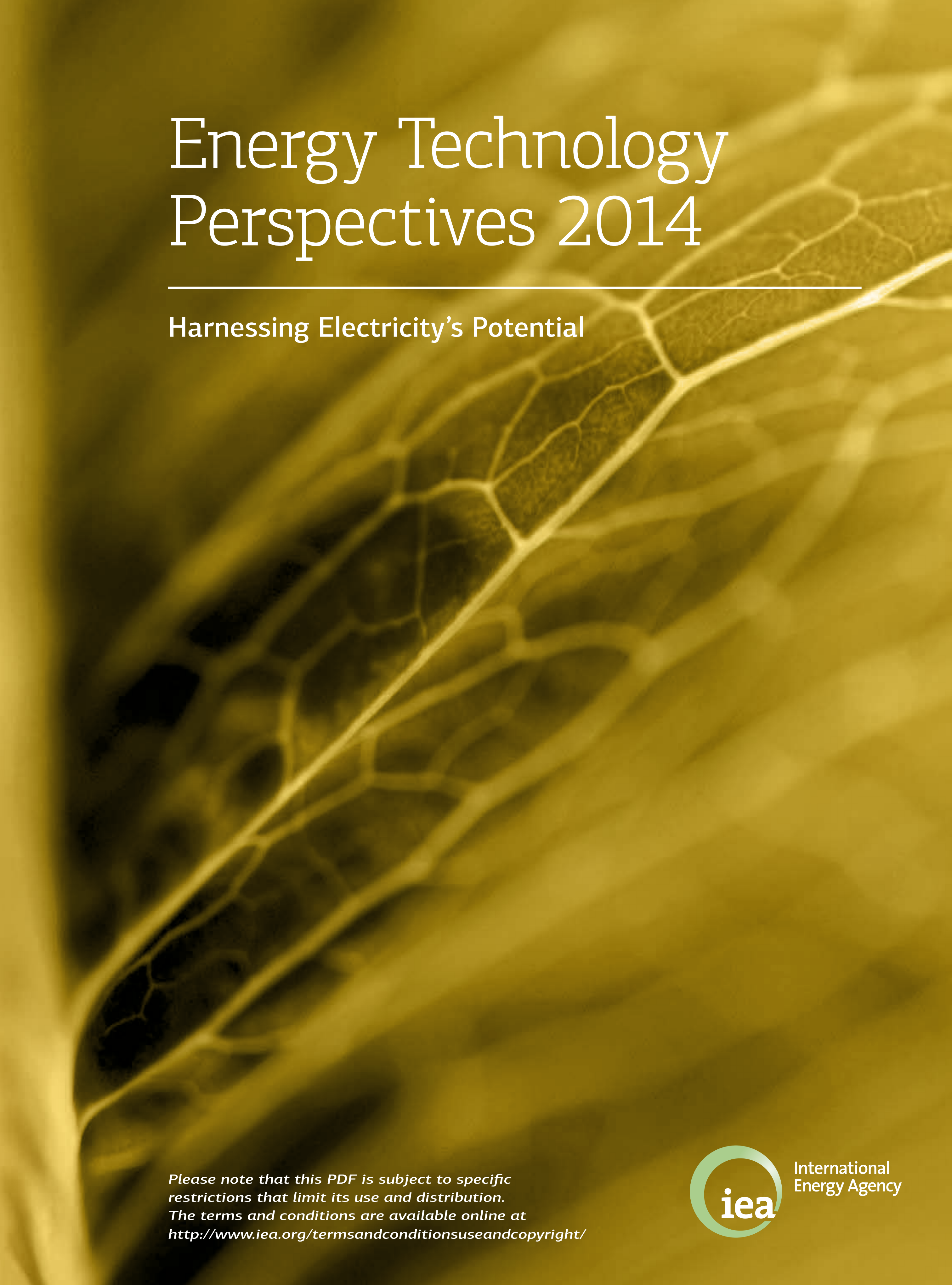

Energy Technology Perspectives 2014

Harnessing Electricity's Potential

International Energy Agency

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

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Table of Contents

Annexes 340

Foreword

The International Energy Agency (IEA) *Energy Technology Perspectives (ETP)* analysis offers a comprehensive, long-term view of energy system trends and technologies essential to meet goals for affordable, secure and low-carbon energy. This long-term view is regularly challenged by developments that have lasting and transformative impacts, such as the shale gas boom in North America, cost reductions in several renewable technologies and the uncertainty in nuclear power progress. These examples clearly show that technology, market developments and external events influence the evolution of energy systems.

These interactions draw attention to a troubling fact. In the face of rapidly growing demand and the increasingly urgent threat of climate change, we are continuing to respond to the energy system as it evolves rather than actively managing its transformation towards the aim of achieving a clean, secure and economic energy supply. A radical change of course is long overdue, and *ETP* shows the necessity of technology to obtain these goals.

Considering the links between effective short- and long-term development of energy systems, the IEA has taken a strategic decision to transition *ETP* to an annual publication in which each edition sharpens its focus to allow a "deep dive" into analysis of timely topics and trends. The *ETP* online presence has been expanded to deliver downloadable analysis updates, data visualisations and sector specific commentary, maintaining its comprehensive analysis, while increasing usability.

We also continue to monitor the status of global technology efforts to meet long term targets through "Tracking Clean Energy Progress", a key chapter in *ETP* and is the IEA fourth submission to the Clean Energy Ministerial on global clean energy technology development and deployment. We find growing evidence that a partial energy transition is under way – and that emerging economies have stepped into the lead, achieving the greatest gains in the past year. But it is clear that some of the encouraging trends observed in 2013 are in dire need of renewed support.

The theme of *ETP 2014*, Harnessing Electricity's Potential, reflects an opportunity arising from the convergence of two trends: rapidly rising global electricity demand and the evident need for increased system integration. Electricity production uses 40% of global primary energy and produces an equal share of energy-based carbon dioxide emissions today. However, cost-effective and practical solutions exist that can increase efficiency and reduce electricity demand as well as carbon emissions between now and 2050. Four key points emerge in this year's analysis:

- The unrelenting rise in coal use without deployment of carbon capture and storage is fundamentally incompatible with climate change objectives.
- Natural gas can, in the short term, play a dual role of replacing coal and supporting integration of variable renewable energy (VRE), in the medium to longer term, gas must be seen for what it is – a transitional fuel, not a low-carbon solution.
- Deployment of VRE technology is growing, and in some cases becoming competitive; experience now shows that balancing VRE supply and patterns of energy demand must – and can – be actively managed.
- Electricity storage can play multiple roles in an integrated system, as can other technologies with which it must compete. Contrary to many other voices, *ETP* analysis finds that electricity storage *alone* is not a necessary game-changer for the future energy system.

A new feature of each edition will be a country case study of particular relevance to the theme, with the inaugural example being India's tremendous challenge of expanding both capacity and generation of electricity to meet a doubling of demand in the next decade. A low-carbon, more integrated future will require strong policy action to manage the use of its substantial coal resources and to address the administrative hurdles that impede both innovation and investment.

The timescale for this publication is 40 years. As the IEA enters its 40th year, energy challenges are as daunting as they were in 1974. While energy security is still a concern, shifting the world to a sustainable energy path has become an additional urgent priority. Our efforts during the last four decades have not addressed this challenge. The greater focus of *ETP* and the associated series of publications further the IEA's underlying aim of providing truly transformative "calls to action" so that governments can take the steps necessary to move to a cleaner path. But we must start now; we cannot afford to wait another 40 years.

This publication is produced under my authority as Executive Director of the IEA.

Maria van der Hoeven
Executive Director
International Energy Agency

Executive Summary

Energy Technology Perspectives 2014 (ETP 2014) charts a course by which policy and technology together become driving forces – rather than reactionary tools – in transforming the energy sector over the next 40 years. Recent technology developments, markets and energy-related events have asserted their capacity to influence global energy systems. They have also reinforced the central role of policy in the increasingly urgent need to meet growing energy demand while addressing related concerns for energy security, costs and energy-related environmental impacts. Radical action is needed to actively transform energy supply and end use.

In addition to analysing the global outlook to 2050 under different scenarios, across the entire energy system for more than 500 technology options, *ETP 2014* explores pathways to a sustainable energy future in which policy support and technology choices are driven by economics, energy security and environmental factors. Starting from the premise that electricity will be an increasingly important vector in energy systems of the future, *ETP 2014* takes a deep dive into actions needed to support deployment of sustainable options for power generation, distribution and end-use consumption.

ETP 2014 analyses three possible energy futures to 2050:

- 6°C Scenario (6DS), where the world is now heading with potentially devastating results
- 4°C Scenario (4DS) reflects stated intentions by countries to cut emissions and boost energy efficiency
- 2°C Scenario (2DS) offers a vision of a sustainable energy system of reduced greenhouse gas and carbon dioxide (CO_2) emissions.

Status and recent trends are highlighted in *Tracking Clean Energy Progress*, providing a snapshot of advances or lack of progress in major low-carbon energy technologies. Collectively, *ETP 2014* lays out the wide range of necessary and achievable steps that can be taken in the near and medium terms to set the stage for long-term energy policy objectives, clearly identifying the roles of energy sector players, policy makers and industry.

Global energy trends show advances in decoupling demand from economic growth, but also reveal bottlenecks and uncertainties

***ETP 2014*'s 2DS confirms that global population and economic growth can be decoupled from energy demand, even for oil.** Extending recent trends to 2050 in the 6DS, global energy demand grows by 70% and emissions grow by more than 60% against 2011 levels. Under the same projections for population and gross domestic product, radical action in the 2DS dramatically improves energy efficiency to limit increases in demand by just over 25% while emissions are cut by more than 50%. One of the most notable differences between the two scenarios is this: in the 6DS, oil remains the most important primary energy carrier with demand increasing by 45%, while the policy and technology choices made under the 2DS deliver a 30% reduction in oil demand.

Solar, hydropower and onshore wind are presently forging ahead, while development is mixed for other clean energy supply. Policy certainty remains vital to a positive investment outlook for clean energy technologies. Cost per unit of energy generated by onshore wind and solar photovoltaic (PV) continued to fall in 2013, albeit at a slower rate than in previous years. Their cost-competitiveness is improving, in some countries, partly due to innovative market design. Despite their flexibility, concentrating solar power plants are being deployed much more slowly, with a slower decline in costs. Global nuclear capacity is stagnating at this time as a modest capacity increase from new reactors coming on line has been offset by the retirement of ageing or non-profitable plants in member countries of the Organisation for Economic Co-operation and Development (OECD). Looking at a midpoint to 2050 2DS targets, installed global nuclear capacity in 2025 will likely be 5% to 24% below needed levels, demonstrating significant uncertainty.

Emerging economies have stepped up their ambitions and become leaders in deploying low-carbon energy technologies. Emerging markets more than compensated for slowing or more volatile renewable power growth in Europe and the United States, with Asia deploying more than half of global solar PV additions in 2013. China's bold measures to support clean transport as a means of improving urban air quality has led to some 150 million electric 2-wheelers on the road and greater deployment of electric buses. Globally, sales of hybrid electric vehicles and electric vehicles (EVs) set new records in 2013, but still fall short of the 2DS trajectory.

Continued increase in coal use counteracts emissions reduction from recent progress in the deployment of renewables, underlining the need to improve coal plant efficiency and scale up carbon capture and storage (CCS). Growth in coal-fired generation since 2010 has been greater than that of all non-fossil sources combined, continuing a 20-year trend; 60% of new coal capacity built in the past decade was subcritical, the least efficient class of commercially available coal-fired generation technologies. The future of CCS is uncertain; at present, the technology is advancing slowly, due to high costs and lack of political and financial commitment. Near-term progress in CCS research, development and demonstration is needed to ensure long-term and cost-competitive deployment towards meeting climate goals.

Fossil fuel use decreases by 2050 in the 2DS, but its share of primary energy supply remains above 40%, reflecting its particularly important role for use in industry, transport and electricity generation. The ability of the different industrial sub-sectors to incorporate renewable energy sources into their processes varies greatly depending on the nature of the final product and diverse operational limitations. CCS is needed to capture both energy- and process-based emissions. In the transport sector, high energy density is an important characteristic of fuels. Apart from conventional fossil fuels, only biofuels and hydrogen show potential to support non-grid-connected, long-distance travel modes such as road freight, aviation and shipping (various battery and charging options can more easily support electric mobility in urban areas). Even in the 2DS, by 2050 the largely decarbonised electricity mix still depends on fossil fuels for 20% of electricity generation (down from 70% in 2011), most of which is combined with CCS.

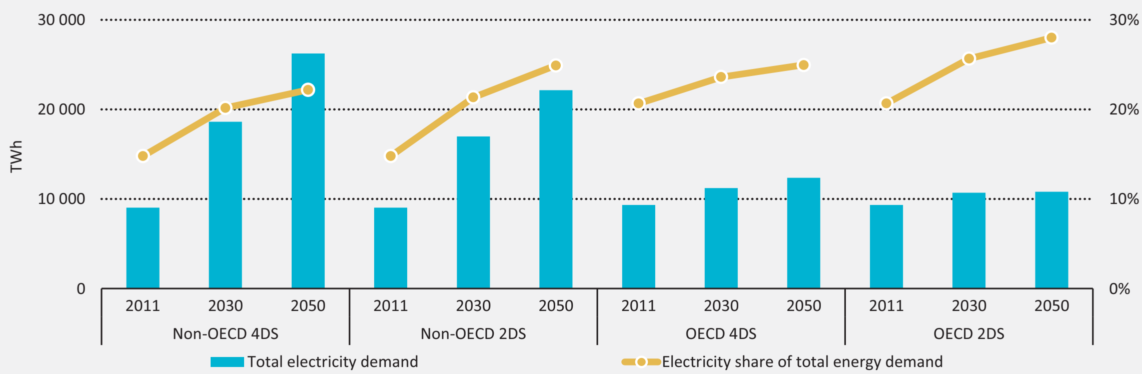
Energy efficiency makes the largest contribution to global emissions reduction in the 2DS, but needs to be combined with other technologies to meet long term targets. Between the 6DS and 2DS until 2050, energy efficiency accounts for 38% of cumulative emissions reductions, renewables account for 30%, and CCS accounts for 14% with fuel switching and nuclear making up the difference. The 2DS shows substantial efficiency gains in all end-use sectors. In transport, fuel economy of the whole vehicle fleet doubles over the projection period, keeping sectoral energy use flat while travel activity almost doubles. Industry, through adoption of best available technologies and greater penetration of less-energy intensive process routes related in some cases to the use of recycled materials, cuts energy use by 25%. Despite global floor area increasing by more than 70%, energy demand in buildings grows just 11%, without changing the comfort levels of buildings or requiring households and businesses to reduce their purchases of appliances and electronics equipment.

Increased electrification is a driving force across the global energy system

Globally, growth in electricity demand is outpacing all other final energy carriers; this creates potential for radically transforming both energy supply and end use. Since the 1970s, electricity's overall share of total energy demand has risen from 9% to over 17%. Across all scenarios globally, it climbs to 25%, while electricity demand grows by 80% in the 2DS and 130% in the 6DS by 2050. But regional growth rates in actual demand are vastly different: OECD countries remain almost flat with an average 16% demand growth; in non-OECD regions, growth skyrockets as high as 300%. *ETP 2014* investigates the potential for pushing the limits of electrification in supply and end use, analysing variants with increased deployment of renewable generation and increased electrification of transport and buildings.

The transition to electrification is not neutral: in fact, decarbonisation requires a massive reversal of recent trends that have shown continued reliance on unabated fossil fuels for generation. To meet 2DS targets, CO_2 emissions per unit of electricity must decrease by 90% by 2050. A continuation of current trends – which saw overall electricity emissions increase by 75% between 1990 and 2011, due to rising demand but little change in emissions intensity – would dangerously drive up electricity-related emissions. Ongoing use of imported fossil fuels in generation by some countries increases energy security risk and exposure to fuel supply volatility, creating competitiveness issues. By contrast, the 2DS demonstrates the opportunity to substantially reduce emissions intensity, reduce fuel imports and increase efficiency in end use to moderate growth of electricity demand.

Figure I.1 Electricity demand and share of electricity



Notes: TWh = terawatt hours. Unless otherwise indicated, all tables and figures in this report derive from IEA data and analysis.

Key point *Electricity demand growth differs between OECD and non-OECD countries, but the dominant trend is towards an increasing share of electricity in the overall energy mix.*

The potential of increased electrification requires drastic changes in supply and demand, facilitated by increased stakeholder co-ordination

Impressive deployment of renewable technologies is beginning to shape a substantially different future in supply. This is true even though fossil energy carriers still accounted, in 2011, for two-thirds of primary fuel in the global electricity mix and covered most of recent demand growth. Double-digit growth rates for wind and solar PV electricity generation over the last several years helped push the global share of renewables to 20% in 2011; the 2DS shows that renewables could reach 65% by 2050. In the 2DS-High Renewables Scenario (2DS hi-Ren), solar becomes the dominant electricity source by 2040, providing 26% of global generation by 2050.

Over the medium term, the 2DS sees strong interplay between variable renewables and the flexibility of natural gas to supply both base-load and balancing generation. Gas-fired generation supports two elements of a cleaner energy system: increasing integration of renewables and displacing coal-fired generation. Its evolving role in a given system will depend on the regional resource endowment and electricity generation mix. Shifting gas-fired generation towards flexible operation opens up competition among generation technologies: internal combustion engines, open-cycle gas turbines, combined-cycle gas turbines (CCGTs) and even fuel cells could become attractive. In regions with ambitious deployment plans for renewable electricity, part-load efficiency, ramp rate, turndown ratio and start-up times are more relevant for gas-fired plants than full-load efficiency. The outcome of competition between coal and gas depends more on the economics of CO_2 emissions and fuel prices than on technology improvements. If coal and CO_2 prices are low, unabated coal plants are sufficiently flexible and will remain profitable.

Natural gas should be seen only as a bridge to cleaner energy technologies unless CCS is deployed. After 2025 in the 2DS, emissions from gas-fired plants are higher than the average carbon intensity of the global electricity mix; natural gas loses its status as a low-carbon fuel. Recognising that base-load gas-fired plants will require CCS to meet 2DS targets, *ETP 2014* undertook a comparison of the costs and benefits of applying CCS to both coal- and gas-fired generation. Overall, the cost per tonne of CO_2 (tCO_2) is higher for gas than coal, but when comparing the cost of low-emissions electricity, gas is more attractive than coal-fired generation. At a carbon price of around USD 100/tCO_2 (and at reasonable gas and coal price assumptions), CCGT with CCS has a lower levellised cost of electricity (LCOE) than CCGT alone, and is less costly than supercritical pulverised coal with CCS.

Decarbonising the electricity sector can deliver the spillover effect of reducing emissions from end-use sectors, without needing further end-use investments. Yet to fully leverage the benefits of increased shares of decarbonised electricity, including reaching 2DS emissions targets, comprehensive approaches are needed to combine electrification with end-use initiatives. Improving the efficiency of consumption and applying demand-side management is vital to limiting the need for capacity expansion and reducing investment costs across the electricity chain.

Box I.1 *ETP 2014* Country case study: Electrifying India

With electricity demand in India expected to more than double in the next decade, the power sector faces two main challenges: adequately powering the projected economic growth and bringing electricity to the 300 million citizens who currently lack access.

Coal is India's most abundant primary energy resource: presently, 68% of electricity comes from coal. At 33.1%, the average efficiency of its coal-fired power plants is low and emissions (over 1 100 grammes of CO_2 per kilowatt hour [gCO_2/kWh]) are well above global state-of-the-art levels (750 gCO_2/kWh). Policies to halt construction of subcritical units and encourage more efficient technology are insufficient to achieve the CO_2 emissions reduction needed. Additionally, continued reliance on fossil fuels will require that India heavily supplement domestic supplies of coal and gas with imports.

India is to be commended for its ambitious plans to better exploit its abundant potential for generation from wind and solar, while also expanding geothermal, biomass and small hydropower. Expanding nuclear and large-scale hydropower capacity will assist in managing congested grids and integrating variable renewables capacity.

The projected demand growth should make India an attractive opportunity for energy sector investors. Addressing the complex administrative processes and investment risks is vital to bringing down the high cost of financing new projects.

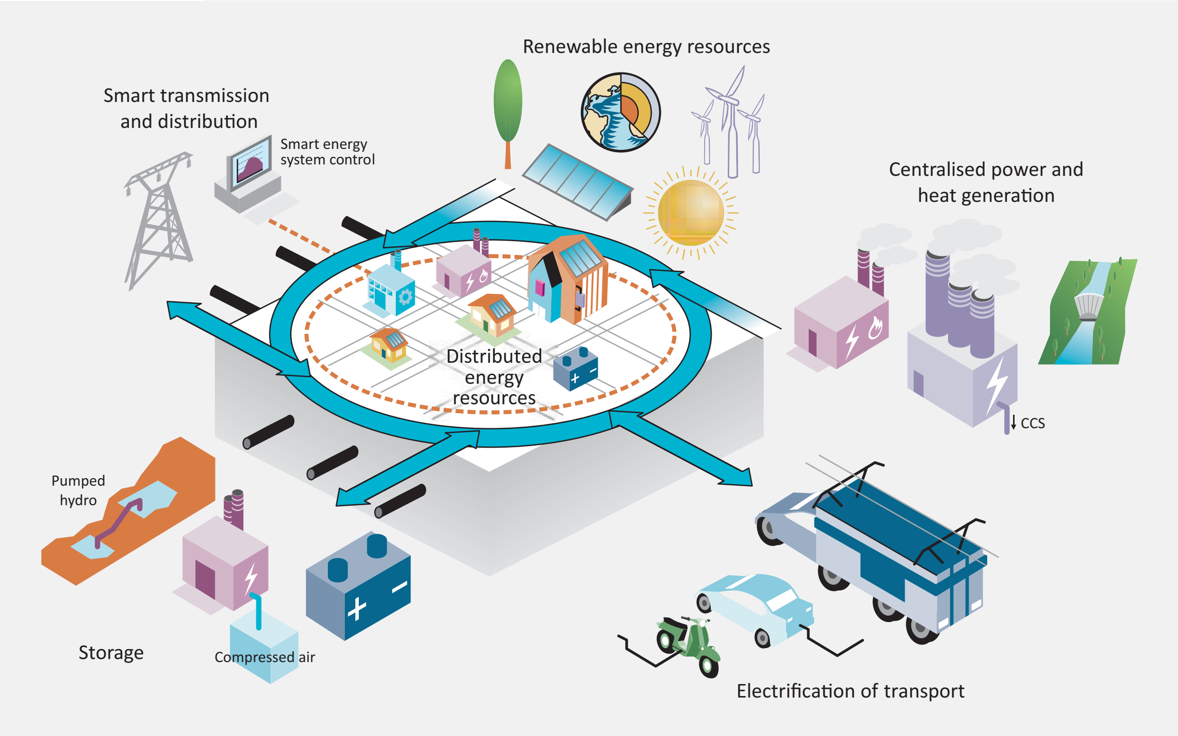
Increased electrification of buildings through the deployment of heat pumps as part of a comprehensive approach to improving buildings energy efficiency can significantly displace natural gas demand. Heat pumps for heating/cooling of space and water allow electricity to displace use of natural gas. The 2DS Electrified Buildings (2DS-EB) Scenario considers deployment of heat pumps beyond 2DS levels for both space and water heating applications, with a focus on the European Union and China. The EU gas share falls from 34% in 2011 to a 2050 level of 32% in the 2DS and even lower at 25% in the 2DS-EB. In 2011, China's share of natural gas in buildings was around 6%. In the 2DS, large expected economic growth and urbanisation drive up China's buildings energy consumption by 24% in 2050; increased demand for space and water heating drive the share of natural gas for those purposes to almost 20%. In the 2DS-EB, increased deployment of heat pump technology avoids most of this growth in natural gas demand while also moderating the overall change in electricity demand for buildings: the European Union sees a decrease of about 4% over the 2DS, while demand in China increases by only around 4%.

Electrification of transport, together with improved fuel economy, fuel switching and new vehicle technologies, substantially reduces transport sector oil use in the 2DS without considerably increasing overall electricity demand. The 2DS rapidly electrifies both personal and public passenger transport and extends electrification of rail freight. An "Electrified Transport" variant of the 2DS (2DS-ET) pushes the envelope by also putting in place the infrastructure needed to electrify heavy-duty vehicles, delivering a further 5% reduction in oil demand for a similar level of transport activity in 2050. Because transport is heavily oil-dependent, even incremental steps in electrification deliver substantial savings: although electricity makes up only 11% of total transport energy demand in 2050 in the 2DS, it accounts for approximately 50% of transport efficiency gains. Yet even with aggressive electrification, transport's share of electricity demand remains below 15%.

A framework of "systems thinking" can enable optimised cross-sector integration

The choice of technologies and their placement along the steps of generation, transmission and distribution (T&D) and consumption of electricity will play a critical role in the cost-effective development of integrated electricity systems. The energy community has largely recognised the need to integrate a broad range of technologies and policies across the supply, T&D, and demand sectors over the long term to establish a clean and resilient system that supports efficient, flexible, reliable and affordable operation (Figure I.2).

Figure I.2 The integrated and intelligent electricity system of the future



Key point *To better integrate all elements of electricity systems will increase complexity, but improve operations, efficiency and resilience while optimising energy resources and investments.*

"Systems thinking" is particularly important during the transition to optimise electricity system investments and ensure efficient management of future systems in which electricity from wind and solar dominate generation. This approach is also needed to prompt all stakeholders to optimise use of existing infrastructure and to direct research, development, demonstration and deployment towards integration.

Electricity storage can play multiple roles in integrated low-carbon electricity systems; *ETP 2014* analysis finds that storage, in itself, is unlikely to be a transformative force. The role of electricity storage in a given power system will depend on system-wide development. Pumped hydro storage (PHS) currently represents 99% of all deployed electricity storage, and remains well-suited for many storage applications. Although none have yet been deployed at a capacity scale comparable to PHS, a broad range of other technologies are emerging. The value of the flexibility that electricity storage technologies can provide will appreciate as the share of variable renewables in electricity systems increases. For these services, however, storage technologies will compete with other resources such as stronger internal grids, interconnection, demand-side integration and flexible generation. Under current market structures, cost is a major barrier to deployment of storage. Frequency regulation, load following and off-grid applications for electricity storage represent the most attractive deployment opportunities in the near to medium term, and could spur cost reductions; in most markets, however, storage will be deployed after more economic solutions have been maximised.

Smart coupling of the convergence of electricity generation from PV with rising demand from e-mobility would facilitate higher penetrations of both technologies; combining PV with electricity storage opens new possibilities. Effective management of increasing electricity demand arising from EVs and appliances can support integrated system operation by leveraging existing infrastructure and technology and optimising deployment of new options. While unmanaged charging of EVs would risk further increase in demand peaks, well-organised midday and off-peak charging could help flatten the net load curve and ease PV integration. In electrified areas, load management, interconnections, flexible generation and storage capabilities can all be used to integrate large shares of PV and will compete on cost and performance. Solar PV panels combined with small-scale electricity storage are suitable for off-grid applications and can provide access to electricity in remote areas.

Policy, finance and markets must be adapted to support active transformation of the global energy system

***ETP 2014* presents evidence that the USD 44 trillion[1] additional investment needed to decarbonise the energy system in line with the 2DS by 2050 is more than offset by over USD 115 trillion in fuel savings – resulting in net savings of USD 71 trillion.** Even with a 10% discount rate, the net savings are more than USD 5 trillion. To achieve the potential of integrated energy systems and unlock these savings, a coordinated policy approach must be used to actively transform both the energy system and the underlying markets. Acknowledging that the necessary financing has not yet been mobilised, *ETP 2014* examines how investors assess risk and return. Ultimately, the analysis shows a disconnect between the energy sector's use of LCOE and investor reliance on net present values.

1 Unless otherwise stated, all costs and prices are in real 2012 USD, i.e. excluding inflation.

Financing low-carbon power plants (renewables, nuclear, CCS) in a framework of competitive markets requires returns that compensate for the risks associated with potentially changing revenue streams from electricity generation, including unpredictable prices for carbon, gas and coal in the future.

Learning from the clean technologies now entering energy markets shows that regulation and market transformation can help or hinder the potential of individual technologies, including their competitiveness. To date, low-carbon investments have been driven by support schemes, including feed-in tariffs, output-based subsidies and quota systems. Governments need to assess whether these mechanisms remain relevant or need to be replaced with new options. Moving from a regulated environment with support mechanisms to a market-based approach considerably raises the risk to which investors are exposed. This increases the risk of uncertain carbon markets and wholesale electricity prices for technology investors, and may require different regulatory counterbalances. Innovative business models have, in some cases, proven an effective means by which emerging technologies can capture new niche markets. EVs, for example, account for more than 10% of car-sharing programmes recently launched around the world – compared with less than 1% market share of global vehicle sales. The car-sharing business model relieves users of the up-front costs and driving range concerns that undermine personal decisions to purchase EVs.

Without the stimulus of carbon pricing, alternative policy instruments will be necessary to trigger low-carbon investment in competitive markets. A high carbon price continues to show strong potential as a policy instrument by which governments can stimulate the low-carbon investment needed. In the absence of carbon markets, innovation in technology deployment, policy action and investments can enable progress. *ETP 2014* demonstrates, for example, that countries with a strong focus on low-carbon intensity and/or high shares of oil imports in transport can quickly reap significant benefits from massive deployment of e-mobility. The Low-Carbon Electric Transportation Maximisation Index (LETMIX) shows that, already today, more than 27% of the world's countries could obtain significant CO_2 savings from EVs, irrespective of mode. The LETMIX also identifies where and in what time frame electrifying transport can yield maximal benefits, although many transport technology solutions are mode-specific and require substantial build-up of infrastructure.

***ETP 2014* demonstrates that, as they mature, technologies can enable new and innovative options for policy, regulation and markets, complementing technology support mechanisms.** Smart-grid technologies will offer new options for technical operation of electricity systems and for evolving electricity markets, for example by enabling much more distributed generation and demand response. Broad based urban transport electrification can be part of integrated planning for land use, walking, biking, networked mobility and low-carbon electricity. Evaluating a range of possible technological options for more integrated energy systems will reveal an increased range of solutions that countries and regions can use to design, plan and operate energy systems in ways that best meet their respective needs. Technology can be used to actively support the adaptation of markets, regulation and policy that will truly transform global energy systems.

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The individuals and organisations that contributed to this study are not responsible for any opinions or judgements contained in this study. Any errors and omissions are solely the responsibility of the IEA.

Workshops

A number of workshops and meetings were held in the framework of this study and during the development of the technology roadmaps. The international experts participating in these workshops were able to provide valuable new insights, data and feedback for this analysis. The workshops covered various highly topical areas:

- Global Dispatch Model: "How to operate a low-carbon electricity system?", Energy Technology Perspectives 2014 and Storage Technology Roadmap Modelling Workshop: 23 January, 2013, Paris.
- Energy Storage Technology Roadmap Workshop: 23-24 September 2013, Paris.
- IEA Global Industry Dialogue and Expert Review Workshop: 7 October 2013, Paris.
- Future of Gas Power Technologies, IEA – ETN (European Turbine Network) Workshop, *Energy Technology Perspectives 2014*: 8 October 2013, City University London.
- Electric Vehicles Initiative (EVI) and International Smart Grid Action Network (ISGAN): Integrating EVs Into the Grid Workshop: 16 November, 2013, Barcelona.

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Setting the Scene

Part 1 sets out a vision for a sustainable energy system, and outlines the policies, technologies and financial capital needed to achieve it. Recent events, global energy trends and the three main scenarios of *Energy Technology Perspectives 2014 (ETP 2014)* are covered in Chapter 1, with commentary across the entire energy sector. Modelling to 2050 under different scenarios for more than 500 technology options, *ETP 2014* explores pathways to a sustainable energy future in which policy support and technology choices are driven by economics, energy security and environmental factors.

Against the backdrop of the urgent need to transform the way energy is supplied and used, Chapter 2 assesses recent progress on clean energy and is the International Energy Agency's fourth submission to the Clean Energy Ministerial. There is growing evidence that a partial energy transition is underway – with a need for accelerated efforts even as emerging economies step into the lead, having achieved the greatest gains in the past year.

Chapter 1

The Global Outlook

Technology developments and energy-related events have asserted their capacity to influence the global energy system. They have also reinforced the central role of policy in the increasingly urgent need to meet growing energy demand while addressing related concerns for energy security, costs and energy-related environmental impacts. The key message that emerges is the need for flexibility and adaptation within policy frameworks while maintaining and building stakeholder confidence.

Key findings

- **Carbon-intensity of the energy system has held steady – less than 1% change – for the past 40 years.** To meet long-term climate targets in the face of rapidly increasing energy demand, radical action is needed to decarbonise both generation and end-use.

- ***Energy Technology Perspectives 2014 (ETP 2014)* confirms that global population and economic growth can be decoupled from energy demand.** Under the same projections for population and gross domestic product (GDP), global energy demand grows by 70% in the 6°C Scenario (6DS) but by just over 25% in the 2°C Scenario (2DS).

- **Technology development and external events influence global energy system projections.** Slower progress in carbon capture and storage (CCS) and persistent increased costs of nuclear technology are decreasing deployments over the 2050 horizon compared with *Energy Technology Perspectives 2012 (ETP 2012)* analysis. Low costs in some regions are driving up near-term natural gas demand in both the 6DS and 4°C Scenario (4DS), but 2DS gas demand falls as renewable technologies quickly become more cost-competitive – especially in the power sector.

- **In the 2DS, the share of fossil fuels in global primary energy supply drops by almost half – from 80% in 2011 to just over 40% in 2050.** Because fossil fuel use remains sizable, CCS plays a significant role in limiting related emissions in the power sector; both transport and industry require significantly more decarbonisation beyond 2050.

- **Failure to implement "best-in-class" technologies for new coal electricity generation capacity is making it more difficult to meet 2DS targets.** In the past decade, 60% (434 gigawatts [GW] of 734 GW) of new coal capacity built uses the least efficient subcritical technology.

- **Energy efficiency renewables, and CCS make the largest contributions to global emissions reductions in the 2DS.** Respectively, they account for shares of 38%, 30% and 14% cumulative emissions reductions to 2050. Nuclear, end-use fuel switching, and efficiency and fuel switching for power generation remain essential to reach the 2DS target in the most cost-effective manner.
- **The USD 44 trillion[1] additional cost to decarbonise the energy system in the 2DS by 2050 is more than offset by over USD 115 trillion in fuel savings – resulting in net savings of USD 71 trillion.** Even with a 10% discount rate, the net savings are more than USD 5 trillion.
- **Industrial energy efficiency improvements will not suffice to decouple increasing materials demand and energy consumption.** Development and deployment of new low-carbon technologies such as enhanced performance catalysts and separation systems, technologies that can use low-quality raw materials with limited energy requirements, bio-based process routes, and CCS are also needed to meet 2DS targets.
- **Large energy saving potential that both is cost-effective and reduces emissions exists within the buildings sector and can provide net wealth to economies.** Difficult market conditions and non-technical barriers are stifling advancement. Unprecedented policy maker resolve and funding will be needed to overcome these first hurdles, after which realising these savings will become less policy-intense.
- **Improved fuel economy, advanced vehicles and fuels, and demand-side management strategies are critical to mitigating transport emissions.** Despite improving fuel economy (partially through hybridisation) of the passenger light-duty vehicle (PLDV) fleet and increasing deployment of electric vehicles (EVs), both are progressing too slowly to achieve 2DS.

Opportunities for policy action

- Systems – based energy system strategies are needed to take advantage of or hedge against unexpected technology developments or external events affecting the energy system.
- Innovation from research and development (R&D) through to deployment will be necessary to meet long-term energy goals for climate, security and cost. Additional support, while increasing efficacy through well-thought-out strategic frameworks throughout the innovation chain, will enable increased ambition to transform the energy system.
- Support programmes that effectively address barriers to the uptake of energy efficiency measures in industry should target areas such as the need for greater up-front capital investment, slow stock turnover, and mechanisms to enhance technology transfer and capacity building, among others. Promoting the adoption of best available technologies (BATs) on new capacity and simultaneously supporting research, development and demonstration (RD&D) on low-carbon process technologies will also be needed to achieve the 2DS targets.
- With enormous construction growth expected in emerging markets over the next few decades and given the long life of building stock, now is the time to aggressively pursue policy action. If a more sustainable future for buildings is not pursued, the opportunity will be lost to avoid a significant portion of irreversible climate change through measures that are highly economic and result in greater wealth, not cost, to an economy.
- Incorporating all three parts of an Avoid, Shift and Improve strategy into transport policy brings co-benefits otherwise not achieved and increases the overall impact, compared to an exclusively technological approach.

1 Unless otherwise stated, all costs and prices are in real 2012 USD, i.e. excluding inflation.

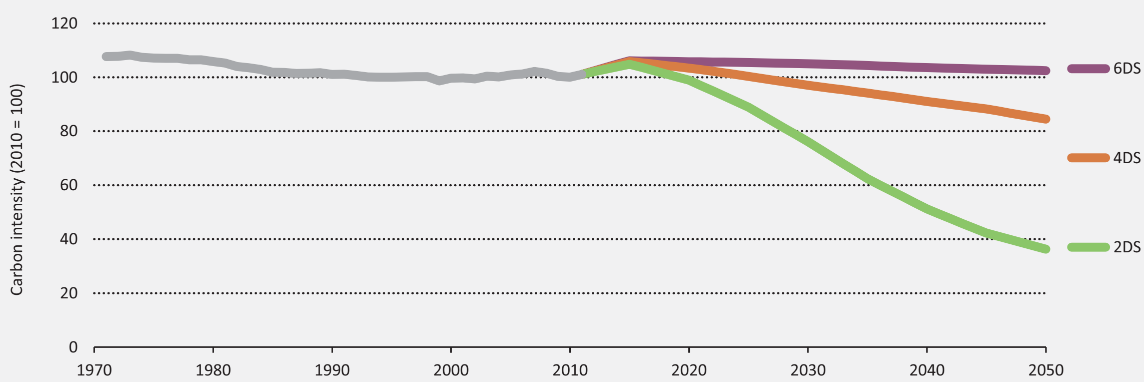
Despite a slight downturn due to the economic recession that emerged in 2009, global energy demand has continued to rise driven by population increase and rapid economic growth in some regions. National governments and international bodies continue to seek ways to curb demand growth by decoupling energy use and/or carbon dioxide (CO_2) emissions from economic development. To date, progress has been limited; thus, concerns associated with energy security and environmental impacts continue to become more pressing.

The expansion of shale gas in North America and the ongoing impacts of the Fukushima Daiichi nuclear accident have led to notable shifts in the energy sector since the publication of *ETP 2012*. This Global Outlook provides an informative overview of the current status of the energy system and of other technology developments and external events that have altered *ETP* scenario results. Several key sectors receive in-depth analysis in Part 2 of *ETP 2014*; others, including buildings and industry, are the focus of recent IEA publications and thus are summarised in this section. In-depth model results, additional sectoral discussion and all figures can be found at: www.iea.org/etp2014.

In exploring various scenarios, *ETP 2014* examines the potential, through large-scale action, to alter the carbon-intensity trend of the energy system and thereby achieve the interrelated goals of separating energy demand and economic development. This would enhance energy security and reduce environmental impacts – including, but not only, the projected scale of climate change.

Ongoing calls to reduce greenhouse-gas (GHG) emissions by decarbonising the energy system have had little effect, leading to a continuation of the 40-year trend of high carbon intensity across energy generation and end use. Despite progress in the deployment of renewables, continued dependence on fossil fuels (especially in the electricity and transport sectors) keeps the carbon intensity at a high level (Figure 1.1). As energy demand increases in the future, maintaining the status quo would ultimately lead to a global average temperature increase of

Figure 1.1 The Energy Sector Carbon Intensity Index (ESCII)



Notes: the ESCII illustrates the aggregate impact of technology shifts on carbon emissions in the energy sector. It measures how many tonnes of CO_2 are emitted for each unit of energy supplied. Under the ESCII, 100 represents CO_2 intensity in 2010, providing a base to measure progress. Unless otherwise indicated, all tables and figures in this chapter derive from International Energy Agency (IEA) data and analysis.

Key point *The carbon intensity of the global energy supply improved only slightly over the last 40 years, but with growing energy demand, annual emissions have increased by more than 17 gigatonnes (Gt) of CO_2 per year.*

at least 6°C, a future described in this publication as the 6DS (Box 1.1). The 6DS shows that unaltered emissions per unit of energy, coupled with rising demand, would drive up energy-related CO_2 emissions by over 60%.

The 4DS, which reflects actions that have been proposed but not yet implemented, shows some progress towards the goals described above. The 2DS uses modelling to demonstrate the action needed to achieve the ambitious target of limiting global temperature rise to 2°C. The technology and policy pathways set out in the 4DS and 2DS lead to dramatic reductions of the carbon-intensity index: by 15 points in the 4DS and by 64 points in the 2DS by 2050. These pathways focus on decarbonising energy supply and substantially increasing the efficiency of energy use. In Part 2, *ETP 2014* explores three scenario variants that consider different and more ambitious pathways in renewable electricity generation, electrified transport and increased electricity use in buildings (Box 1.1).

Box 1.1 Scenarios in *ETP 2014*

The **6DS** is largely an extension of current trends. By 2050, energy use grows by more than two-thirds (compared with 2011) and total GHG emissions rise even more. In the absence of efforts to stabilise atmospheric concentrations of GHGs, average global temperature rise is projected to be at least 6°C in the long term. The 6DS is broadly consistent with the *World Energy Outlook (WEO)* Current Policy Scenario through 2035.

The **4DS** takes into account recent pledges made by countries to limit emissions and step up efforts to improve energy efficiency. Projecting a long-term temperature rise of 4°C, the 4DS is broadly consistent with the *WEO* New Policies Scenario through 2035. In many respects, this is already an ambitious scenario that requires significant changes in policy and technologies compared with the 6DS. Capping the temperature increase at 4°C requires significant additional cuts in emissions in the period after 2050, yet still potentially brings forth drastic climate impacts.

The **2DS** is the main focus of *ETP 2014*. It describes an energy system consistent with an emissions trajectory that recent climate science research indicates would give at least a 50% chance of limiting average global temperature increase to 2°C. The 2DS also identifies changes that help ensure a secure and affordable energy system in the long run. It sets the target of cutting energy- and process-related CO_2 emissions by more than half in 2050 (compared with 2011) and ensuring that they continue to fall thereafter. Importantly, the 2DS acknowledges that transforming the energy sector is vital, but not the sole solution: the goal can be achieved only provided that CO_2 and GHG emissions in non-energy sectors are also reduced. The 2DS is broadly consistent with the *WEO* 450 Scenario through 2035.

The three thematic, electricity-based modelling variants used in Part 2 explore other paths to achieve the 2DS aims:

The **2DS-High Renewables (2DS hi-Ren)** variant illustrates an expanded role of renewables in the power sector, based on a decreased or delayed deployment of nuclear technologies and CCS.

The **2DS-Electrifying Transport (2DS-ET)** variant projects massive electrification of transport, deployed first in strategic regions to maximise CO_2 savings. While the 2DS is already ambitious in terms of transport electrification, especially for light-duty road passenger applications, the 2DS-ET aggressively pursues electrification of road freight vehicles, an area the IEA has not previously explored

The **2DS-Electrified Buildings (2DS-EB)** variant examines increased deployment of heat-pump technology for both space heating and potable water heating. While displacing the use of gas, and thereby reducing emissions, the variant would drive up electricity demand for heating and cooling.

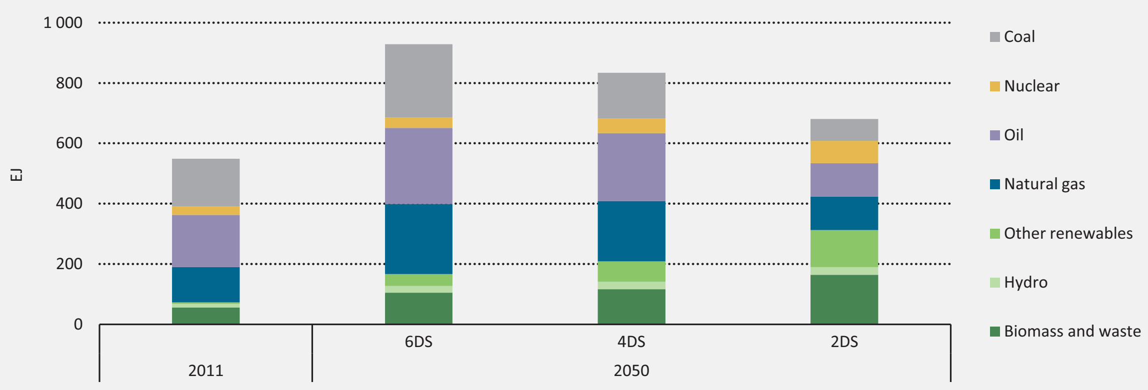
Notes: an extended summary can be found in Annex A. Full descriptions of the scenarios and extensive additional global and regional scenario results can be found online at: www.iea.org/etp2014.

This chapter will highlight a number of large trends in the global energy system, provide an overview of sector-specific modelling results and draw high-level conclusions for policy makers. The first section highlights global modelling results and describes changes within the energy system, recent and significant technology developments, and modelling framework enhancements that have led to updates in results compared with *ETP 2012*. The second section discusses sector-specific scenario results and system-wide technology and policy opportunities.

Global modelling results

Compared with the other *ETP* scenarios, the 6DS exhibits a lack of effort in developing, demonstrating and deploying clean energy technologies, and shows the least progress in cost and performance of climate-mitigating and efficiency technologies. By 2050, it shows almost 70% growth in primary energy supply, three quarters of which is provided by fossil fuels (Figure 1.2). The 4DS reflects the culmination of proposed efforts, yet its ambition falls short of the full level needed to meet global climate and energy security targets. Energy demand in the 4DS grows by over 50% and although use of renewables grows significantly, fossil fuels still make up almost 70% of primary energy demand (compared with 80% in 2011). With strategic policy action, the 2DS constrains energy demand growth to slightly over 25% (from 2011). By decoupling economic growth from energy consumption, the 2DS paves the way for renewables to provide a greater share than fossil fuels in 2050.

Figure 1.2 **Total primary energy supply**

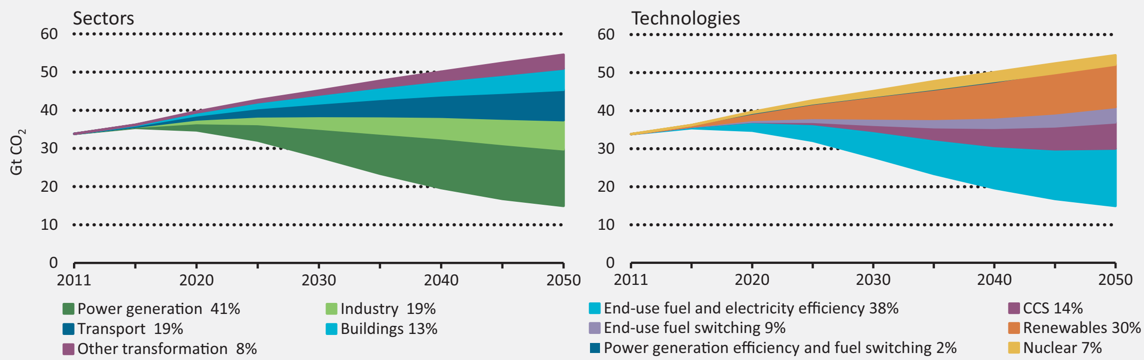


Note: EJ = exajoules.

Key point *The 2DS reflects a concerted effort to drastically reduce current dependency on fossil fuels, primarily through energy efficiency, renewables and nuclear energy.*

In 2011, the energy sector accounted for nearly 70% of GHG emissions. Strong will and practical efforts to decarbonise the energy system are needed across all sectors – particularly in the power sector, which in the 2DS is slated to deliver over 40% of the cumulative emissions reductions needed. As no single technology will be able to meet these targets, *ETP* modelling examines a portfolio of technologies that can meet them while maximising energy security and economic growth (Figure 1.3).

Figure 1.3 Contributions to annual emissions reductions between the 6DS and 2DS



Notes: $GtCO_2$ = gigatonnes of carbon dioxide. Percentage numbers represent cumulative contributions to emissions reductions relative to the 6DS. End-use fuel and electricity efficiency includes emissions reductions from efficiency improvements in the end-use sectors (buildings, industry and transport) in end-use fuels (including electricity). End-use fuel switching includes emissions reductions from changes in the fuel mix of the end-use sectors by switching from fossil end-use fuels to other end-use fuels (excluding renewables; fuel switching to renewables is balanced under the category "Renewables"). Renewables includes emissions reductions from increased use of renewable energy in all sectors (electricity, fuel transformation, end-use sectors). Power generation efficiency and fuel switching includes reductions from efficiency improvements in fossil electricity, co-generation and heat plants as well as from changes in the input fuel mix of the power sector from fossil fuels to less carbon-intensive fossil fuels (e.g. from coal to gas). Reductions from increased use of renewables or nuclear in the power sector are not included here, but accounted for under the corresponding categories. CCS includes emissions reductions from the use of CCS in electricity generation, fuel transformation and industry. Nuclear includes emissions reductions from increased use of nuclear energy in the power sector.

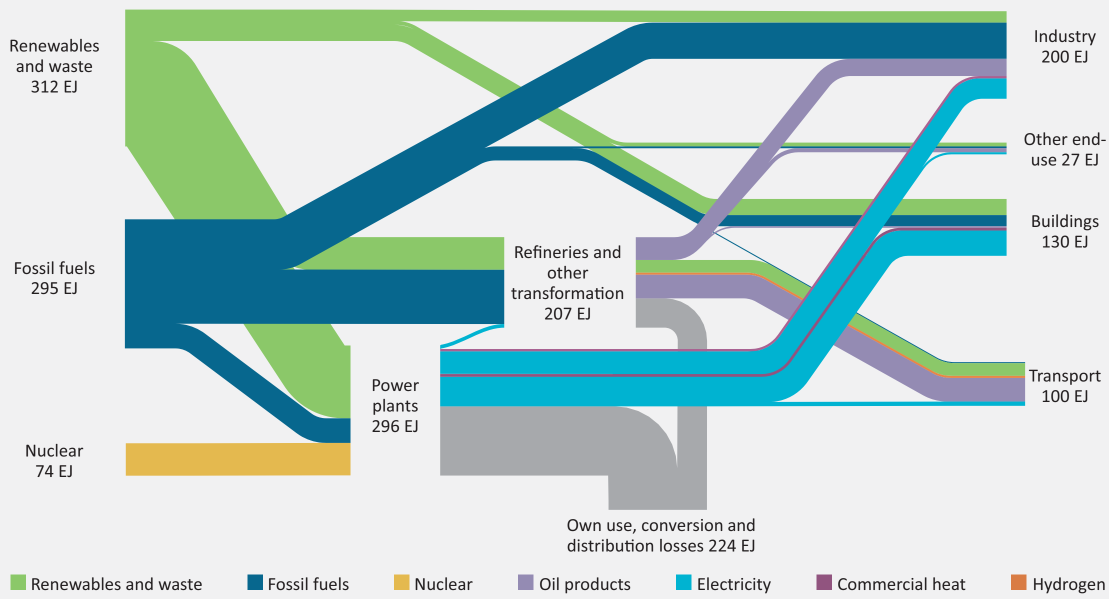
Key point *Achieving the 2DS will require contributions from all sectors and application of a portfolio of technologies.*

Although fossil fuel use decreases by 2050 in the 2DS, at a share of over 40% of primary energy supply, it retains an important role in an increasingly sustainable global energy system (Figure 1.4) – particularly for direct use in industry, transport and the power sector. The ability of the different industrial sub-sectors to incorporate renewable energy sources into their processes varies greatly depending on the nature of the final product and diverse operational limitations; in some cases, only fossil fuels deliver the necessary outcomes. In the chemicals and petrochemicals sector, the use of fossil fuels both for feedstock and as an energy source has resulted in process design that is difficult to modify. The scale of energy needed in some sectors will limit the transition to bio-based fuels (due to limited availability). Some industrial processes are constrained by the acceptable variability of the thermal properties of fuels used; new process designs would be needed to overcome these limitations.

In the transport sector, high energy density is an important characteristic of fuels, as space and desired efficiency constrain the volume and mass of energy sources that can be used. Apart from conventional fossil fuels, only biofuels and hydrogen may provide the characteristics needed for non-grid-connected, long-distance travel modes such as road freight, aviation and shipping. Under the 2050 time frame, limitations to sustainable biofuel availability and uncertainty around the development of hydrogen-based transport mean that fossil fuels will remain an important energy carrier in the transport sector. Hydrogen shows potential as a transport fuel, but hydrogen storage has not yet reached the energy density required to make it viable for long-range travel in shipping and aviation. Moreover, generation of low-carbon hydrogen is still costly.

Although the power sector is where the greatest share of renewables can be found, fossil fuels continue to play an important role, but unabated use is largely eliminated. In the 2DS,

Figure 1.4 The transformed energy system in the 2DS in 2050



Note: additional diagrams showing 2011 and 2050 4DS and 6DS can be found at: www.iea.org/etp2014.

Key point *The future energy system will need to use fossil fuels where essential or best suited, but will depend on increasing CCS, renewables and nuclear to meet long-term climate goals.*

electricity is largely decarbonised and use of fossil fuels is combined with CCS. In industry, CCS is also used to capture both energy- and process-based emissions.

Changes that alter previous energy projections

The long-term energy system projections in *ETP 2014* are influenced by ongoing trends and by unexpected events. Two major recent developments that influence current energy system operation – and therefore long-term projections – warrant initial analysis: the increased availability and low price of natural gas in North America, and reactions to nuclear power production following the Fukushima Daiichi accident. Additionally, recent decreases in renewable technology costs and slower development of other technologies are also changing the long-term modelling results. The *ETP* model frameworks have been improved and inputs have been updated to include recent developments – both cost and performance – in energy technologies[2] having varying effects on modelling, analysis and results.

2 In addition to recalibration to 2011 as the base year for analysis, and an update of technology and energy data, key changes to the modelling framework in *ETP 2014* include: refinement of chronological load curves and new linear dispatch model for storage analysis in the supply-side model; increased regional representation, and segregation of coal and petroleum into different fuel types in the industry model; and improved representation of bus fleet and better characterisation of trains in the transport model.

New gas resources alter prices and supply

The emergence of new supplies of unconventional natural gas, primarily shale gas, is transforming the energy sector in North America[3]. The shale gas boom is already providing the United States with an opportunity to increase the use of indigenous resources in its energy mix; in the medium to long term, it paves the way to becoming a gas exporter.

Increased supply, however, has created something of a glut, driving down natural gas prices and thus restraining US wholesale electricity prices to levels that make it challenging for any type of new "non-gas" generator to compete – even with incentives. To date, negative impacts on renewable energy have been minimal: environmental regulations are spurring early retirement of coal plants, which has led to natural gas displacing coal rather than renewables.

Up to a certain point, shale gas can support the fuel switch from coal to gas, delivering large CO_2 emissions reductions. If shale gas prices recover to a level closer to the economic cost of dry gas drilling, however, the use of coal may recover some of its lost ground. In fact, this may already be emerging: Henry Hub natural gas prices rose to USD 3.70 per million British thermal units (MBtu) from a low of USD 2.80/MBtu in 2013. Prices are expected to rise further in the medium term, and levels of USD 4/MBtu to USD 5/MBtu are often mentioned as a benchmark for healthy returns. With the economic recovery driving electricity demand, insufficient policies to constrain existing coal plant operations are leading to an increase of emissions in US power (IEA, 2013), but new investments in coal plants remain very risky.

Availability of cheaper natural gas has prompted a regional shift – towards North America – for production of high-value chemicals (HVCs),[4] even though the Middle East and the People's Republic of China remain the major global producers. It has also increased competitiveness of North America in markets for lighter feedstock-based process routes in the chemical and petrochemical industry.

Interestingly, low gas prices have also affected nuclear power production in the United States. Four reactors, all merchant plants, have shut down (Crystal River 3, Kewaunee and two units in San Onofre) mainly due to cost or issues with refurbishment and unfavourable economics compared with gas-fired generation. A handful of other US sites could also face early retirement for the same reasons.

Nevertheless, the deployment drivers of a portfolio of renewable sources remain robust in the United States. Strong state-level renewable mandates, along with federal tax incentives and very good renewable resources, continue to support deployment. Despite the competition with fossil fuels, the energy portfolio strategies of utilities and large corporate entities appear to see renewables as providing cost-effective hedges against the price volatility of fossil fuels and a way to meet corporate green power goals.

Globally, the development of unconventional gas is less intense, although many regions are expected to tap similar resources in the long term. Several regions are considering construction of liquefied natural gas terminals, which could change the near- to medium-term picture for global markets. Thus, the newfound resources in North America are expected to continue having a ripple effect for some years to come.

These developments in the price of natural gas, though not spread evenly across the global energy system, affect *ETP 2014* analysis compared with *ETP 2012*: the 6DS and 4DS results show increased primary energy demand of natural gas, but it declines in the 2DS. This reflects that fuel cost is a stronger driver in the 6DS and 4DS, while carbon prices mute this effect to a

3 Additional discussion on global gas markets can be found in the IEA *Medium-Term Gas Market Report*.
4 HVCs include ethylene, propylene and BTX (benzene, toluene and xylene).

large degree in the 2DS. Natural gas can, in the near term, contribute to carbon reductions when replacing coal use in power generation. Post-2030 in the 2DS, however, natural gas power generation increases average electricity system carbon intensity and is not in itself a long-term solution to meeting emissions reduction goals.[5] Natural gas generation without CCS decreases in the 2DS, but natural gas with CCS increases comparatively in 2014 analysis, demonstrating how fuel costs make natural gas generation with CCS roughly competitive with other low-carbon generation.

The Fukushima Daiichi nuclear accident: Three years after

The Great East Japan Earthquake and ensuing tsunami, which occurred on 11 March 2011, led to wide-scale flooding that resulted in a severe accident at Japan's Fukushima Daiichi nuclear power plant. All but one of the on-site emergency diesel generators failed, as did the pumps that provide cooling water from the ocean. Despite safety measures in place, hydrogen gas collected in the upper portion of the reactor buildings and then exploded through protective building materials. Large amounts of radioactive material were released into the environment.

One immediate reaction was that all the countries operating nuclear power plants requested safety evaluations under the supervision of national regulators and international peer reviews. Regulators determined that nearly all existing reactors (mostly Generation II reactors) could continue to operate with acceptable levels of safety, but upgrades were necessary to improve resistance to major earthquakes and flooding. Fewer changes were recommended for more recent Generation III reactors, which were designed to withstand the risk of severe accidents.

Three years out, the accident's impact on nuclear energy policies has been diverse. The accident accelerated the already-planned nuclear phase-out in Belgium and Germany, and led Switzerland to abandon any new projects. In contrast, China, India and the Russian Federation maintained ambitious development programmes, while the United States went ahead with construction of up to four new units at two different sites (the first US new-build projects in more than 30 years). The United Kingdom is considering the construction of several Generation III units to replace the country's ageing fleet. Finland has also confirmed plans to build up to two additional reactors, besides the Generation III reactor currently being completed. Newcomer countries have maintained their interest in developing nuclear energy as part of their electricity mix. Construction of several units is progressing well in the United Arab Emirates, and new projects continue to advance in Bangladesh, Poland, Saudi Arabia, Turkey and Viet Nam.

Two of the main nuclear countries in the Organisation for Economic Co-operation and Development (OECD) – France and Japan – have yet to clarify their future nuclear energy policies. France, with a 75% share of nuclear and 10% hydro in the electricity mix, has one of the lowest carbon intensities in the world. The French government aims to reduce nuclear's share to 50% by 2025, but is at the same time considering allowing operators to extend the amortisation period of its fleet up to 50 years. The decrease of nuclear power, even compensated in part by the growth of variable renewables, will lead to increasing CO_2 emissions as gas-fired power plants will need to be built to maintain back-up power. Japan has 50 operable reactors, but all remained closed at publication date (May 2014). The country has yet to finalise its new energy policy, but nuclear energy will still be a part of the mix, and a restart of some nuclear reactors is expected; what is uncertain is the target share of nuclear power in the long term. Mostly likely, it will decline from the pre-accident share of 30%. The

5 For additional discussion on emissions from natural gas generation, see Chapter 5.

Republic of Korea, which until recently had very ambitious nuclear development plans, has faced public opposition in the wake of scandals affecting its industry and the regulator. In December 2013, Korea revised its nuclear energy strategy to limit installed capacity to 29% by 2035, down from a previous goal of 41%.

After rising steadily since the 1970s, global nuclear electricity production dropped by 10% between 2010 and 2012, primarily due to the permanent shutdown of 8 reactors in Germany, and the temporary shutdown of Japan's 50 operable reactors. Additional safety measures increased the cost of nuclear electricity generation technology. Some positive developments are occurring, however: public acceptance, apart from Japan and Korea, is recovering from post-Fukushima lows, but is not yet leading to significant growth. These aspects, combined with cost reductions in other technologies (discussed below), are resulting in declining nuclear shares across all scenarios in *ETP 2014* analysis.

Recent technology developments that impact *ETP* results

Several technology developments – some positive, some negative – are worth noting due to their impacts on energy modelling, whether because of changed inputs at the beginning of the modelling horizon and/or effects on the expected development trajectory. Photovoltaic (PV) deployment has exceeded earlier modelling results and recent global forecasts, and system prices are as much as 40% lower at the beginning of the model horizon for *ETP 2014*,[6] compared with *ETP 2012*.

Bioenergy-based power generation increased continuously over the last decade, with an average annual growth rate of 10%. Electricity generation from bioenergy has the potential to scale up significantly over the coming years, especially in combination with the use of agricultural residues or renewable municipal waste. Co-generation, i.e. the combined generation of electricity and heat (or cooling), is an attractive option for using bioenergy because of its high overall efficiency. Its use, however, depends on the local heat demand in the buildings or industry sectors. Co-firing of solid biomass in coal power plants starts to play an important role in countries with large shares of coal-fired power generation.

Land-based wind technology is also progressing: global capacity has grown at an average rate of 25% per year over the last decade. Depending on the wind resource and the costs of conventional power generation, land-based wind generation can be competitive with newly built conventional plants. Investment costs for land-based wind turbines declined by 15% since 2010. Also, a new class of wind turbines appeared that can be sited in a broader range of places with lower speed winds, have a significantly higher capacity factor and deliver a more regular output.

CCS technology development has progressed slower than anticipated in terms of large-scale demonstration. As a consequence, the near-term deployment projection has been revised downwards: *ETP 2014* results for 2020 in the 2DS show 4 GW globally for fossil power plants equipped with CCS, compared with 16 GW in *ETP 2012*. Similarly, the near-term deployment of CCS in the industry and fuel transformation sectors has been revised downwards, resulting in an annual CO_2 volume of 33 Mt captured in 2020 in *ETP 2014*, which compares to 180 $MtCO_2$ in *ETP 2012*. Nevertheless, CCS still provides around 14% of the cumulative emissions reductions to 2050 needed to reach the 2DS (relative to the 6DS, [Figure 1.3]). The slower progress on demonstration and deployment results by 2050 in annual amounts of stored CO2 being around one fifth lower than in *ETP 2012*.

6 The base year for the model is 2011 for *ETP 2014*; in *ETP 2012* it was 2009.

Box 1.2 **How does the IEA model the energy technology future?**

Scenario modelling is the backbone of the *ETP* series of publications. The analysis is built on a combination of forecasting (which shows the end result from analysis of known trends) and back-casting (an approach that lays out plausible pathways to a desired end state), and assesses more than 500 technologies. The *ETP* series core scenario, the 2DS, starts from the globally agreed-upon target of limiting average global temperature increase to 2°C, taking into account rising global population and steady economic growth.

ETP modelling and analysis do not predict the future. Rather, the three *ETP* scenarios (6DS, 4DS and 2DS) reveal insights about the impacts of different technology and policy choices, thereby providing a quantitative approach to support decision making in the energy sector.

Several models are used in *ETP* analysis. The energy conversion module is a cost-optimisation model built on the TIMES framework. The demand-side modules are stock accounting simulation models. Consistency of supply, demand and price is ensured through an iterative process, as there is no hard link among the sector models. The *ETP* model works in five-year time steps.

Ultimately, the analysis explores pathways by which transformation of the global energy system can break the link among economic activity, energy demand and emissions – and aims to identify the path that is most economical. But many subtleties (political preferences, feasible ramp-up rates, capital constraints and public acceptance, for example) cannot be captured in a cost-optimisation framework. Also, for the end-use sectors (buildings, transport and industry), doing a pure least-cost analysis is difficult and not always suitable; decisions within those sectors are often not made considering minimum total ownership cost. By using differing modelling approaches that reflect the realities of the given sectors, together with extensive expert consultation, *ETP* obtains robust results and in-depth insights.

The shared modelling framework of TIMES offers *ETP 2014* an analytical approach that has been developed and used by hundreds of experts and more than 70 institutions to perform global and national energy system analyses. The *ETP* model does not answer all the questions one would like to ask about the energy system. It does, however, complement many other modelling approaches.

Because the IEA places high value on transparency and wishes to stimulate interaction and debate, *ETP 2014* detailed results are readily available online.

Note: an extended summary can be found in Annex A and a full description and model framework and assumptions can be found at: www.iea.org/etp2014.

Sector development in the future energy system

A key aspect of *ETP* modelling and analysis is that – as a primary goal – it integrates all that is known about current technologies and policies to identify the least-cost pathway to a clean energy system. The second strength is the ability to change virtually every parameter, which makes it possible to explore "what if" situations (found in Part 2). By carrying out the modelling on a regular basis, *ETP* can also accommodate the realities that occurred during the intervals – and how they influence the pathways and the interrelations of technologies and policies. *ETP 2014*, for example, accounts for the fact that CCS development and demonstration have been slower than expected, but PV deployment is ahead of targets. These two changes from *ETP 2012* affect the inputs from all other technologies and policies modelled, across all scenarios. The following text highlights sector development of the future energy system within the context of *ETP 2014* and its new scenario variants.[7]

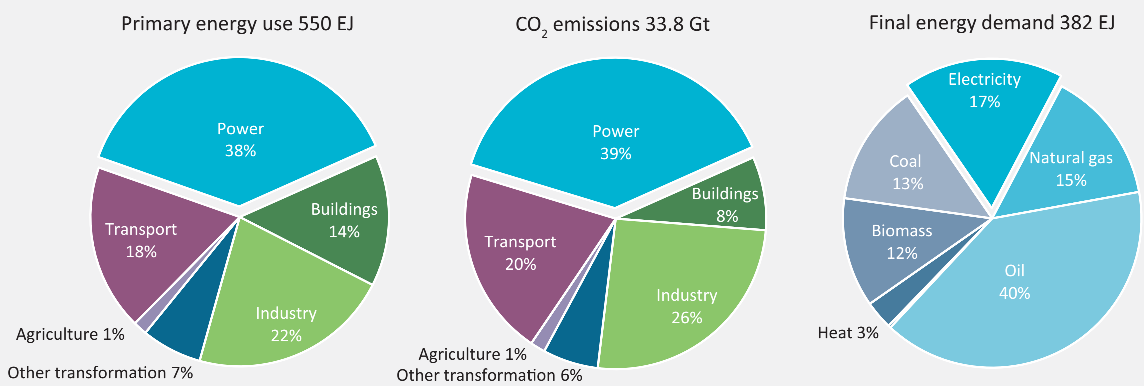
7 More extensive sectoral chapters and data can be found at: www.iea.org/etp2014.

The first sections focus on the supply sectors of electricity and fuel transformation. Following this, end-use sectors will be discussed, including transport, buildings and industry. Electricity will be discussed in detail in Part 2 of the publication and therefore only a short section will be included on electricity generation in this section, and across all the sectors focus will be more broadly given to non-electricity aspects of the energy system.

Electricity generation

Almost 40% of global primary energy is used to generate electricity, making electricity a core commodity in the energy system (Figure 1.5). But final energy demand exhibits a different trend: oil products continue to dominate, accounting globally for 40% of final energy demand in 2011 (particularly for transport). Electricity comes second with a share of just 17% in the final energy demand mix, but is rapidly increasing. Worldwide, electricity consumption per capita (/cap) more than doubled from 1 263 kilowatt hours/cap in 1974 to 2 933 kWh/cap in 2011.

Figure 1.5 **Primary energy use by sector, CO_2 emissions by sector, and final energy by fuel in 2011**



Key point *Conversion losses in thermal power plants explain why electricity generation currently accounts for 40% of primary energy use and CO_2 emissions, but for only 17% of all final energy needs.*

In recent years, most growth in electricity demand – in fact, 80% between 2001 and 2011 – has occurred in non-OECD countries. This is also reflected in the regional distribution of absolute electricity generation: with a share of 51% in 2011, generation from the block of non-OECD countries surpassed that of OECD countries for the first time. On a country level, China (with a 21% share) overtook the United States in 2011 to become the world's largest electricity producer.

Fossil energy carriers are still the primary fuel of choice to generate electricity, accounting for two-thirds in the global electricity mix. The power sector accounted for almost 40% of global energy-related CO_2 emissions in 2011, in part due to the relatively high conversion losses of fossil-based electricity generation (Figure 1.5). Despite advances in available coal- and gas-based power technologies, efficiency of fossil-based electricity generation in the past two decades has improved only marginally, in part because generation companies often choose less-efficient technologies for new plants. In the past decade, 60% (434 GW of 734 GW) of new coal capacity build was subcritical, the least efficient coal-fired power generation technology commercially available. In most cases, this is a straightforward question of short-term economic thinking. If coal prices are reasonably high, the more efficient supercritical and ultra-supercritical coal plants have lower overall costs across a plant's lifetime. Greater efficiency delivers more electricity per unit of fuel combusted, thereby reducing fuel costs. But the "best-in-class" plants can have up to 20% higher initial capital costs and often require more sophisticated maintenance procedures. Such factors help to explain why subcritical plants are still being favoured.

Impressive progress has been made in deploying renewable technologies for electricity generation, with annual capacity growth rates of 19% for wind and 42% for solar PV in 2012. Renewables reached, in 2011, a global share of around 20%. In absolute terms, however, electricity demand growth is largely covered by fossil fuels: between 2001 and 2011, coal accounted for 59% of the increase in electricity generation in non-OECD countries, whereas natural gas (86% share of growth) was the fuel of choice in OECD countries.

While these trends largely continue in the 6DS to 2050, the 2DS reflects the aim of an electricity sector that is largely decarbonised through a mix of technologies that includes renewables and CCS, but also increases energy efficiency to reduce overall demand. In the power sector, CCS provides around 14% of the cumulative reductions required between the 6DS and 2DS. Decarbonisation of the power sector can be achieved without CCS, but at 40% higher investment needs compared to having CCS available (IEA, 2012).

Radical transformation of the electricity sector and scenario results are explored in great detail in Part 2 of this publication.

Box 1.3 Utilisation of CO_2 captured in CCS applications

Utilisation of CO_2 can, in principal, be a substitute for geologic storage; however, utilisation options have to be carefully evaluated to ensure that they contribute to the goal of reducing emissions. Approximately 110 $MtCO_2$ per year are sold today for industrial use (ADEME, 2010) and around 20 $MtCO_2$ per year for enhanced oil recovery (EOR) (GCCSI, 2013). In comparison, the annual amount of CO_2 captured in the 2DS is greater than 1500 $MtCO_2$ in 2030 and 6300 $MtCO_2$ in 2050. While promising options are being investigated, it is unlikely that industrial use of CO_2 will achieve a level comparable to the storage needs in the 2DS. Furthermore, many of these applications (e.g. carbonated beverages, fertilizer and fuel production) result only in short-term storage (i.e. days to years) and result in difficult to quantify emissions reductions, if any. At the current time, CO_2 usage in EOR applications (CO_2-EOR) appears to be the only use of CO_2 that could grow to a relevant scale while permanently storing CO_2. Forthcoming IEA analysis shows that conventional CO_2-EOR has the technical potential to store around 60 $GtCO_2$ globally while producing 187 billion incremental barrels of oil, and that advanced approaches (e.g. where storage is maximized or coupled with storage in nearby geological formations) could dramatically increase the technical potential for both CO_2 storage and oil recovery. Use of CO_2 in EOR could be encouraged by increased availability of CO_2 at lower cost, which could result from a carbon price on CO_2 emissions (as under the 2DS), but achieving the full technical potential may require further policy action.

Fuel transformation

The fuel transformation sector comprises all separating and upgrading processes (other than electricity and heat generation) that convert primary energy into secondary energy carriers.[8] Refining of crude oil into various petroleum products for use in other energy sectors or as

8 Deviating from the IEA balances convention, the transformation sector in *ETP* analysis does not include blast furnaces, coke ovens and petrochemical plants, which *ETP* assigns to the industry sector. Energy commodities can be divided into primary energy commodities that are either extracted or captured directly from natural resources (such as crude oil) or secondary energy commodities, which are produced from primary commodities in transformation processes.

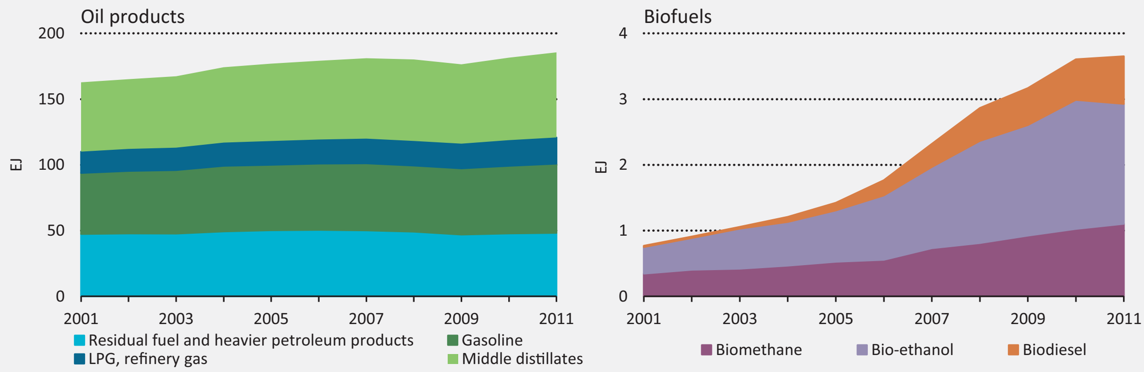
feedstock in the petrochemical industry dominates fuel transformation, covering 93% of global liquid fuel supply in 2011. But an increasing amount of liquid fuel supply is bypassing the refinery sector. Natural gas liquids, a by-product of natural gas production, are used in the chemical and petrochemical industry and accounted for 5% of liquid fuel supply in 2011. Liquid fuels can also be produced from coal (through coal-to-liquids [CTL]) and natural gas (through gas-to-liquids [GTL]) technologies. Biomass can also be converted, depending on the feedstock type, into various further biofuel products (e.g. biodiesel, bioethanol, biobutanol and biomethane). The contribution from CTL/GTL fuels and biofuels is, however, still small, representing a combined share of below 2% of fuel supply in 2011.

Current status

Fuel transformation has a conversion cost, though much lower than that of power generation: an average of 8% of the energy input into the global refining sector is lost, with variations ranging from 3% to 23%. The rate of loss depends on the crude oil type processed, the refinery configuration and age, and the desired product mix – and varies from country to country. The CO_2 intensity of refining declined only slightly over the last decade: from 192 grammes of carbon dioxide per gCO_2/tonne of crude oil processed in 2001 to 187 gCO_2/tonne of crude oil processed in 2011.

The transport sector accounted for around half of the petroleum demand in 2011 and has been second to industry in driving steady growth (1.3% annual growth, interrupted by a decline in oil demand in 2008/09). Demand for individual products is, however, shifting. In 2001, middle distillates (i.e. diesel, light fuels and kerosene) accounted for 32% of the petroleum demand. Their share grew to 35% by 2011 as they displaced heavy products (such as heavy fuel oil) and as demand increased for diesel for freight trucks (Figure 1.6), whereas growth in gasoline demand was dampened by increasing bio-ethanol supply and improved fuel economy of light-duty vehicles.

Figure 1.6 Oil products and biofuel demand



Note: LPG = liquified petrolum gas.

Key point *Petroleum demand grew steadily over the last decade with some shift to middle distillates in the mix. Biofuel production more than quadrupled, but from a low base.*

Global biofuel production more than quadrupled between 2001 and 2011, but from a low base, so that biofuels accounted for only 1.9% of the 2011 output of the fuel transformation sector (Figure 1.6), with fuel-specific shares as follows: bio-ethanol (50%), biogas (30%) and biodiesel (20%). The United States is the largest bio-ethanol producer with a share of 59% in 2011, followed by Brazil (26%). The European Union is the lead producer of biogas (39% of global share) and biodiesel (47%).

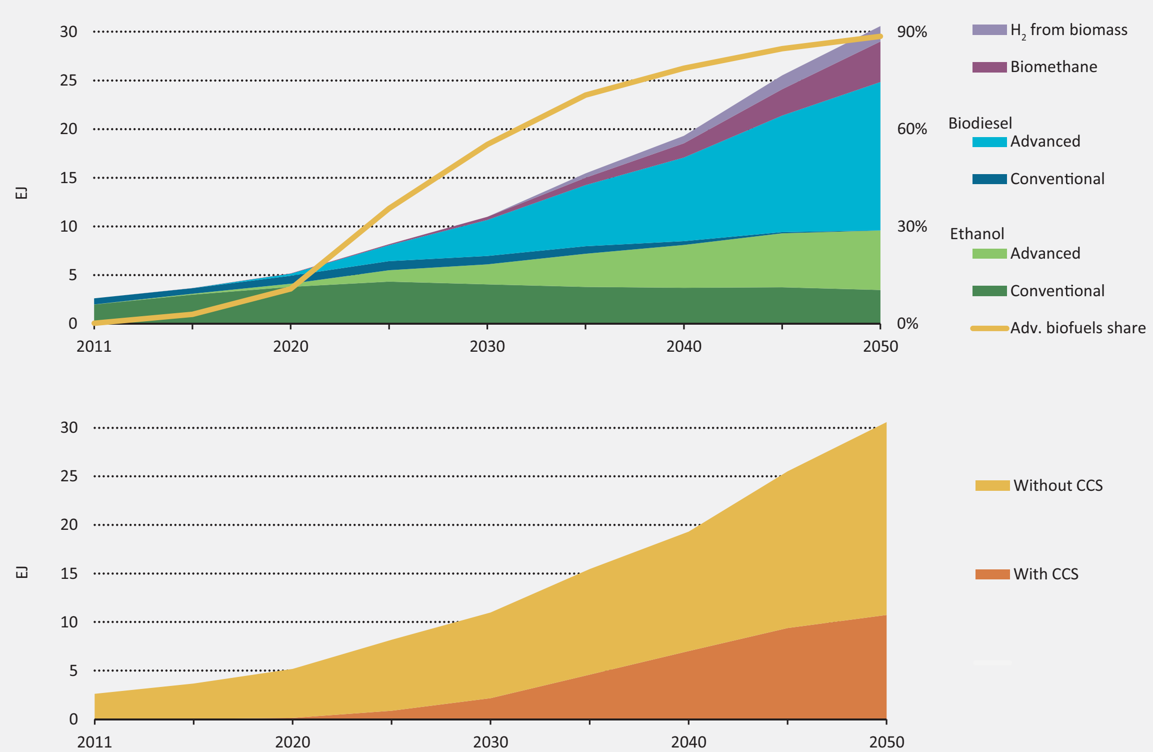
Scenario results

End-use demand for various products is the main driver of future developments in *ETP* scenarios for the fuel transformation sector. But projection trends are also influenced by policy constraints (such as carbon pricing) imposed on the sector itself, which affect the choice of technology and fuel to meet demand.

The most notable trend is in the 2DS: in contrast to a 40% increase in oil product demand in the 4DS by 2050, the 2DS delivers a 30% reduction. The transport sector accounts for almost 90% of this drop in oil product demand through improved fuel economy, fuel switching (e.g. increased use of biofuels in shipping and aviation) and new vehicle technologies (e.g. vehicles powered by alternative fuels or electricity). This overall decline in demand for petroleum products generates a 25% reduction in annual CO_2 emissions from refineries, which fall to 578 million tonnes of carbon dioxide ($MtCO_2$) in 2050 compared with 761 $MtCO_2$ in 2011.

Also dramatic in the 2DS is that biofuels, which currently play a minor role in covering liquid fuel needs, account for around 20% of demand in 2050. Advanced biofuel production technologies, which use ligno-cellulosic biomass feedstocks, dominate production of biodiesel and bio-ethanol by 2050 (Figure 1.7), replacing 25 EJ of oil products – the equivalent of total US transport oil demand in 2011.

Figure 1.7 **Biofuel production by technology type in the 2DS**



Key point *Advanced biofuel production accounts for almost 90% of global biofuel production by 2050 in the 2DS, of which more than one-third is equipped with CCS.*

Availability of biomass is a critical concern in this scenario. Taking into account also the biomass used for producing biomethane and hydrogen, by 2050 projected biofuel production in the 2DS would consume around 67 EJ of primary biomass. While this accounts for only 40% of total primary biomass use at that time, it exceeds current global biomass use. Sustainable biomass production, i.e. avoiding adverse side effects on food production and negative impacts on GHG emissions due to land-use change, is a precondition for any strategy of replacing oil by biofuels. Such switching should be monitored through certification schemes based on internationally agreed-upon criteria to ensure consistency and transparency.

Biofuel production processes, when coupled with CCS, can lead to so-called “negative” emissions as CCS effectively withdraws part of the carbon embedded in the biomass used from the natural carbon cycle. In the 2DS, CO_2 capture from biofuel production saves around 1 gigatonne of carbon dioxide ($GtCO_2$) per year, or 4% of the annual CO_2 reduction compared with the 4DS. Despite the attractiveness in terms of CO_2 mitigation, deployment of biofuel production plants is limited in the 2DS: plants need to be large enough for economies of scale, which has implications on the necessary biomass supply. Transporting the captured CO_2 to suitable storage sites poses another challenge to be taken into account in the planning process.

Hydrogen also has the potential to become a relevant end-use fuel in the 2DS, with almost 5 EJ being produced in 2050. Transport is the main application, where it accounts for 4% of final energy use. Importantly, the better fuel economy of fuel-cell vehicles, compared with combustion engines, allows 5 EJ of hydrogen to replace around 10 EJ of oil.

Transport

Current status

Transport remains the end-use sector most dependent on oil, which has high energy density, is easy to “carry” and remains cost-competitive compared with most alternative fuels. Even with rising oil prices, strong new policies are needed to change course; otherwise, transport oil demand will grow for the foreseeable future, exacerbating oil supply insecurity and environmental issues related to the extraction and combustion of oil.

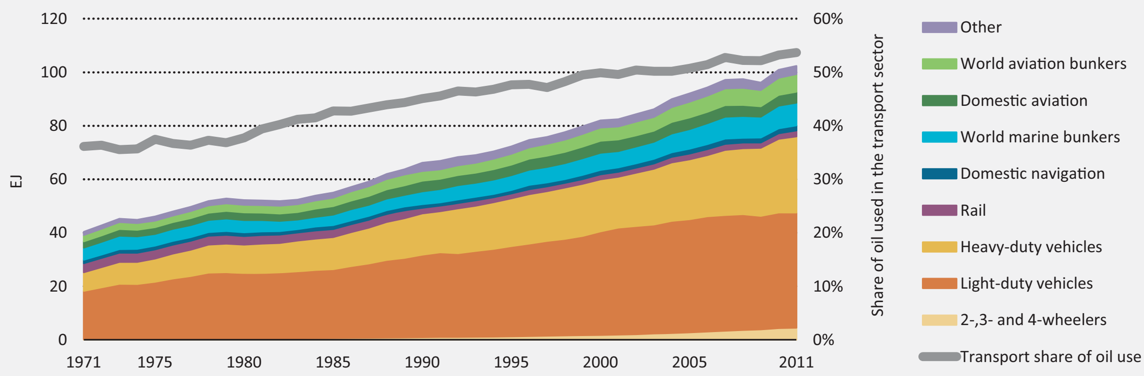
As oil use has declined in other sectors since the early 2000s, transport has come to represent the largest share of demand. Within transport, road vehicles have the largest share of energy use. Aviation has increased sharply in the last decade, as has the volume of light- and heavy-duty vehicles; in essence, the most oil-intensive transport modes have increased faster than the others (Figure 1.8).

Scenario results

The transport sector will evolve significantly by 2050, especially in non-OECD regions, where increasing wealth is driving parallel motorisation. To reach 2DS targets, an **Avoid/Shift/Improve** philosophy is needed. **Avoid** aims to slow individual travel growth via city planning and demand management while **Shift** enables people to shift some travel to more efficient modes, such as transit, walking and cycling, and prompts business to shift transport of goods from trucks to rail. **Improve** encourages the adoption of new technologies and fuels. All three approaches play critical roles in reducing both energy use and CO_2 emissions.

The 6DS models what is likely to happen if various policies currently under consideration are not implemented, including post-2015/16 fuel economy standards in the European Union and the United States, and no extensions are forthcoming for current national funding commitments for battery electric vehicle (BEV) and plug-in hybrid electric vehicle (HEV)

Figure 1.8 **Global energy consumption in transport by mode**



Note: light-duty vehicles are cars and light trucks (up to 3.5 tonnes); heavy-duty vehicles are trucks and buses.

Key point *The fastest-growing transport modes – light-duty vehicles, trucks and aviation – are also among the most energy-intensive.*

programmes (many of which are scheduled to end within one to two years). In the 6DS, electric mobility fails to significantly penetrate the mass market, and biofuels (especially second-generation biofuels) remain limited to niche markets.

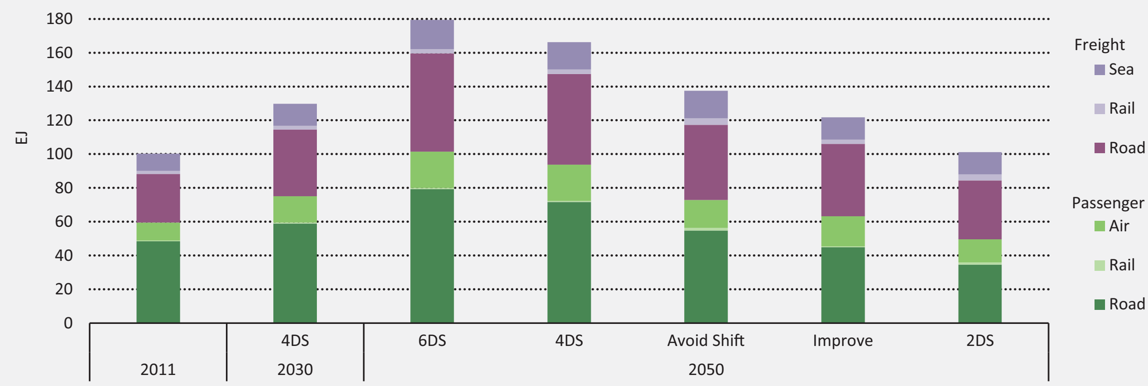
The 4DS for transport represents the trajectory that unfolds if some policy action is taken; if, for example, OECD countries continue to tighten fuel economy standards up to 2025 for both PLDVs and road-freight vehicles. The situation improves against the 6DS, but plug-in HEVs (PHEVs) and BEV market penetration is slow (similar to what happened with HEVs initially). The recent establishment of an Energy Efficiency Design Index[9] for new ships helps improve the energy efficiency of the shipping industry through a slow-starting but long-lasting effect. The European Union applies its Emissions Trading Scheme for aviation.

The 2DS capitalises on combining the **Avoid/Shift** and **Improve** cases to reach significant energy use and CO_2 abatement by 2050 (Figure 1.9). In the 2DS, the **Improve** case is especially pronounced, with almost half of all PLDVs being plug-in of some kind by 2050.

The CO_2 mitigation potential from transport in the 2DS is high, even though fossil fuels remain important for decades to come. Emissions in 2050 return to 2005 levels while travel activity almost doubles (Figure 1.10). These emissions are calculated on a well-to-wheel (WTW) basis,[10] and so include CO_2 emissions from associated sectors, such as power generation and oil refining.

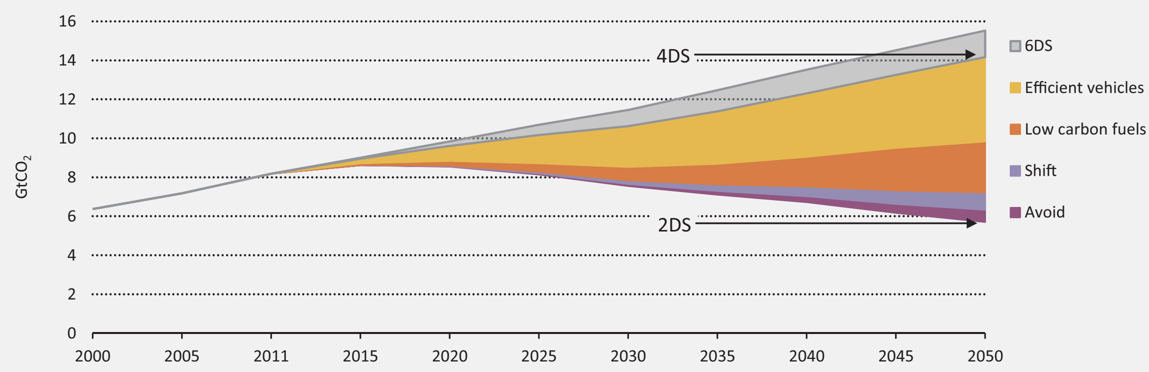
9 www.imo.org/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Technical-and-Operational-Measures.aspx
10 WTW includes all stages of production, taking into account environmental impacts; tank-to-wheel accounts only for environmental impacts as a result of emissions from the vehicle tank (i.e. not the related impacts of the fuel production upstream).

Figure 1.9 Global energy consumption in transport by scenario



Key point *The 2DS combines both "Avoid/Shift" changes for travel and "Improve" changes for vehicle efficiency to achieve maximum fuel savings.*

Figure 1.10 WTW emissions reductions from transport in 4DS and 2DS



Key point *The contribution of the Avoid/Shift case to lowering GHG emissions is modest when low-carbon technologies are implemented widely in transport.*

Progress and needed transport sector actions

Several new passenger vehicle technologies have become available in the past ten years, but the sector is decarbonising too slowly to reach the ambitious target of the 2DS. This analysis reveals two significant considerations. First is the importance of not focusing solely on one technology and instead pursuing a multi-pronged portfolio approach including modal Shift and Avoid strategies. The second consideration is the utility of a temporal perspective, which involves pursuing strategies simultaneously for both the near term (e.g. fuel economy improvement, modal shift, electric vehicles) and the longer term (e.g. advanced biofuels, fuel-cell vehicles).

Improving the fuel economy of current internal combustion engine (ICE) vehicles by using cost-effective technologies offers great potential. Much attention should be focused on this in the next decades, while also developing the market for zero-tailpipe emissions vehicles (e.g. electric vehicles, fuel-cell vehicles) and low-carbon transport fuels such as second-generation biofuels.

Advanced technologies, such as electric and fuel-cell vehicles, can be mainstreamed for less cost than is commonly believed. Deployment costs in the hundreds of billions or even a few trillion dollars between now and 2050 would represent only a small share of total societal expenditures on transport – likely to amount to several hundred trillion dollars over this time frame. Deployment of electric vehicles (both PHEVs and BEVs) continues, with major producers selling about 150 000 during 2013. The next few years will be critical to build markets and promote customer acceptance of this innovative technology, especially in regions that are heavily car-dependent.

Aviation and shipping often are left outside of climate negotiations, especially regarding trips having transnational origin and destination. Both international aviation and maritime nevertheless represent a growing share of energy use in the transport sector, and must be part of a global effort to cut energy use and GHG emissions in order to reach 2DS.

Applying more efficient technology and fuels is critical to 2DS targets, but may not be enough to deliver large CO_2 reductions over the next 10 to 20 years. Thus, it is imperative to investigate the potential for contributions from reducing the growth rate in travel demand and influencing the modes used. Growth in longer-distance travel can be cut somewhat by teleconferencing and by moderate shifts to more efficient modes (e.g. air to high-speed rail). For movement of goods, a greater reliance on rail can help, although it will require significant investment.

Even with these Avoid and Shift strategies, average travel per capita is expected to more than double over the next four decades. Consequently, the technology portfolio for the transport sector will need to evolve significantly in order to achieve the very low CO_2 targets set in 2DS for PLDVs globally. Across the different regions of the world, different technologies (e.g. BEVs, PHEVs, fuel-cell electric vehicles [FCEVs]) will compete, but each may also find niches and all may coexist. Biofuels will eventually provide near-zero GHG travel with liquid fuels in ICE vehicles.

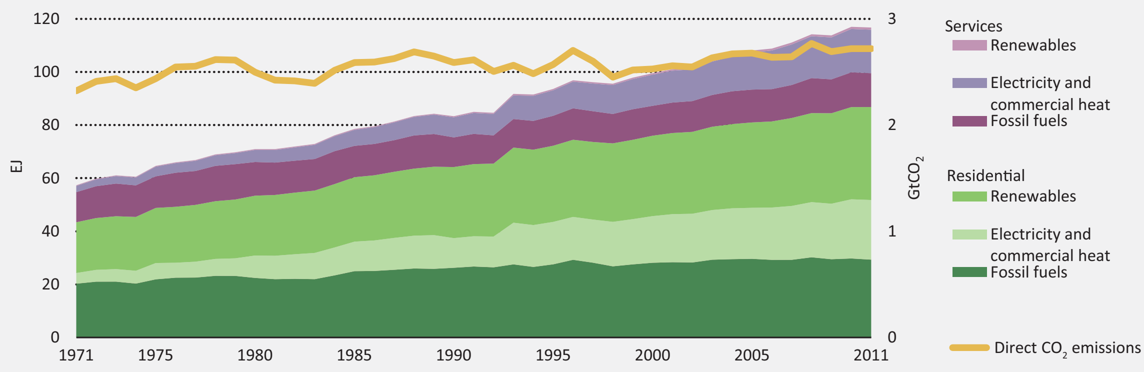
Buildings sector

Current status

The buildings sector, comprising both the residential and services sub-sectors, consumes 31% of global final energy use and accounts for about 8% of direct energy-related CO_2 emissions from final energy consumers (Figure 1.11). If indirect upstream emissions attributable to electricity and heat consumption are taken into account, the sector contributes about one-third of global CO_2 emissions. Despite significant policy effort to slow the energy demand growth in buildings, it has risen steadily for four decades.

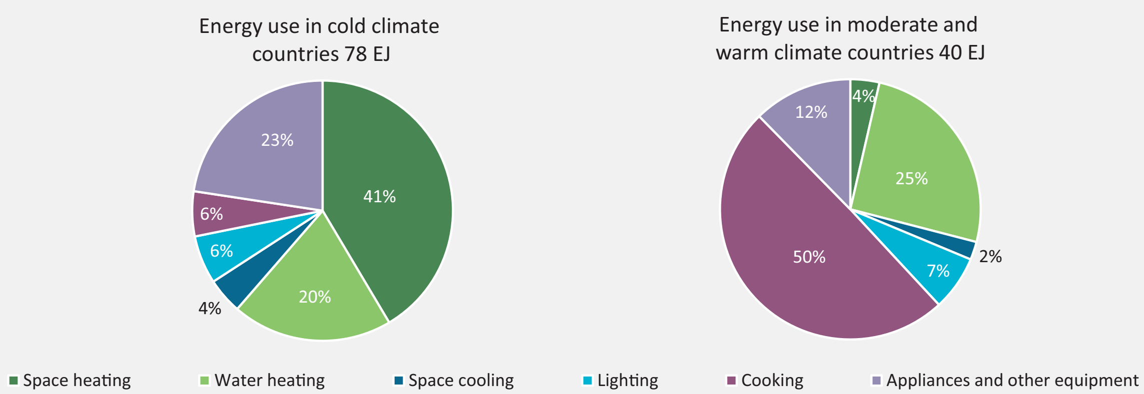
While all end-use impacts are important, space and water heating represent the largest portion of energy consumption in the buildings sector; the figure of 50% overall rises to more than 60% in cold climate countries (Figure 1.12). In many regions (some of which are located in more moderate and warm climate countries), lack of access to modern energy sources means traditional biomass for cooking continues to be a significant portion of residential consumption and can account for up to 80% of total final energy use.

Figure 1.11 Global energy consumption in buildings by sector and source



Key point *The residential sub-sector consumes about three-quarters of energy used in the buildings sector. Direct emissions have stabilised, but rising electricity demand will continue to drive an overall increase in total emissions, if not addressed.*

Figure 1.12 Buildings energy consumption by end-use, 2011



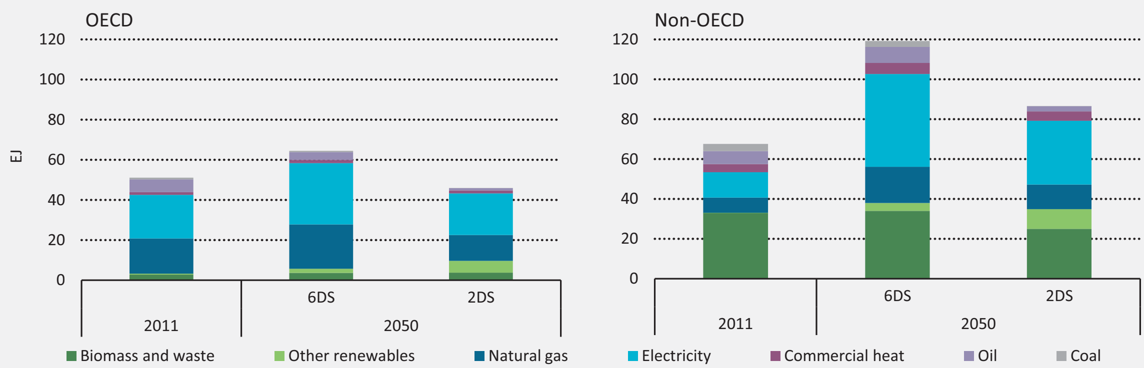
Notes: cold and warm climate countries are defined in Annex C. The fraction for space cooling is not truly representative because the largest economy for cooling, the United States, is treated as a cold climate due to its very large heating load, yet the figures do adequately illustrate broad trends.

Key point *Space and water heating dominate the energy consumption of buildings in cold climates; in moderate and warm climates, water heating and cooking are the largest end uses.*

Scenario results

If no action is taken to improve energy efficiency in the buildings sector, energy demand is expected to rise by 26% in the OECD region and 77% in non-OECD regions, for a total increase of 55% globally by 2050 (Figure 1.13). The main drivers of this rapid growth include corresponding increases in the number of households, residential and services floor area, higher ownership rates for existing electricity-consuming devices, and increasing demand for new products. Effective action as part of the 2DS could limit global growth to just over 11% without changing comfort levels or requiring households to reduce their purchases of appliances and other electronic equipment.

Figure 1.13 Global energy consumption in buildings by scenario



Key point *Despite the growing importance of electricity, biomass and waste remain key energy sources for non-OECD countries.*

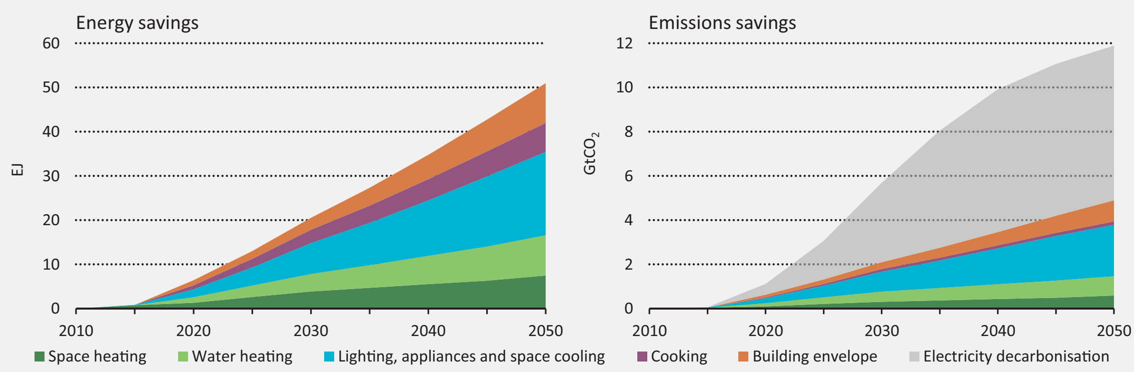
Electricity consumption in buildings represents 50% of global electricity demand, and is expected to grow rapidly in non-OECD countries (Figure 1.13). In the 2DS, a combination of efficiency standards, improved building envelopes, greater use of heat pumps and solar thermal, and co-generation with waste heat and renewables could reduce electricity demand to 16 000 terawatt hours in 2050 (27% less than the 6DS). This could significantly cut the need for investments in electricity system infrastructure. The overall switch from a high to a moderate level of fossil fuel use also contributes significantly to 2DS savings.

An estimated 50 EJ, equivalent to current energy use in buildings for China, France, Germany, Japan and the United States combined, could be saved in the buildings sector in 2050 through the wide deployment of advanced technologies and high-performance buildings (Figure 1.14). Examples include advanced envelopes (highly insulating windows, optimal levels of insulation, reflective surfaces and sealants, etc.), heat pumps, solar thermal heating, co-generation, energy efficient appliances and equipment, efficient cook stoves, and solid-state lighting (SSL), among others. Total direct and indirect emissions reductions are estimated at nearly 12 $GtCO_2$ in 2050.

Key actions needed for buildings

The buildings sector uses a wide array of technologies for diverse needs. Unprecedented levels of deployment of improved technologies will be essential to achieve the large savings potential available (Table 1.1). The recent IEA publication *Transition to Sustainable Buildings: Strategies and Opportunities to 2050* provides detailed analysis and extensive background to support recommendations for buildings policies (IEA, 2013a). Two complementary publications broaden the analysis to encompass comprehensive systems-level and individual component actions needed to transform the buildings sector by encouraging all stakeholders to embrace more value-added, high-performance construction methods that lead to very low energy buildings: *Policy Pathway: Modernising Building Energy Codes to Secure Our Global Energy Future* (IEA, 2013b) and *Technology Roadmap: Energy Efficient Building Envelopes* (IEA, 2013c).

Figure 1.14 Energy and emissions savings from buildings between the 6DS and 2DS



Key point *All end uses will be important to mitigate energy consumption in the buildings sector, with efforts to reduce electricity demand contributing the largest portion.*

Table 1.1 Policy areas for near- and long-term action

Policy action area	Near-term actions (through 2025)	Long-term actions (2025 to 2050)
Whole building systems	Promulgate enforceable building codes, striving for zero-energy buildings (ZEBs) in OECD. Implement policies to drive deep renovation to 2% per year or higher.	Promulgate enforceable building codes, striving for ZEBs all regions.
Building envelope	Promote very high performance envelopes. R&D: Highly insulating window (< 0.6 U-value watts per square metre per degree Kelvin [W/m^{2}K]) and super thin insulation.	Mandate minimum performance for world, double-glaze low-emissive windows (U-value ≤ 1.8 W/m^{2}K); cold climate, highly insulating (≤ 1.1 U-value W/m^{2}K) with climate-appropriate solar heat gain coefficients. Passivehaus[11] standard based on life-cycle cost.
Heating and cooling equipment	Greater promotion of heat-pump technology, with R&D for cold climates and gas thermal systems. Mandate use of gas condensing boilers.	Prohibit use of electric resistance heaters as main heating source. Regulations requiring heat pumps. Promotion/incentives for gas thermal heat pumps with COP > 1.2; mandate in some regions.
Water heating	Promotion/incentives for heat-pump water heaters and instantaneous gas condensing water heaters. R&D on low-cost solar thermal systems.	Mandate heat-pump water heaters with coefficient of performance of ≥ 1.5. Mandate instantaneous gas condensing water heaters unless solar thermal systems are installed and intended to provide expected demand ≥ 75% annual load.
Lighting	Ban all incandescent and halogen light bulbs, OECD. R&D and promotion of SSL and other innovated designs.	Ban all incandescent and halogen light bulbs, all countries. Performance criteria that require 50% of fixtures ≥ 100 lumens/watt.
Appliances and cooking	Implementation and active updating of minimum equipment standards. Promote efficient options and improved access to modern energy with least carbon footprint.	Establish performance metrics on total electricity use per square metre, with all loads considered. Incentives/high tariffs to promote progress and compliance.

Note: this summary is not exhaustive and does not provide details required to support specific policies. For example, the goal for ZEBs and definitions for site-energy and renewable grid power are further described in the referenced publications.

11 Passivhaus, an advanced residential building programme that calls for very high levels of building envelope performance, has gained significant momentum in Europe and is active globally (www.passiv.de/en/index.php).

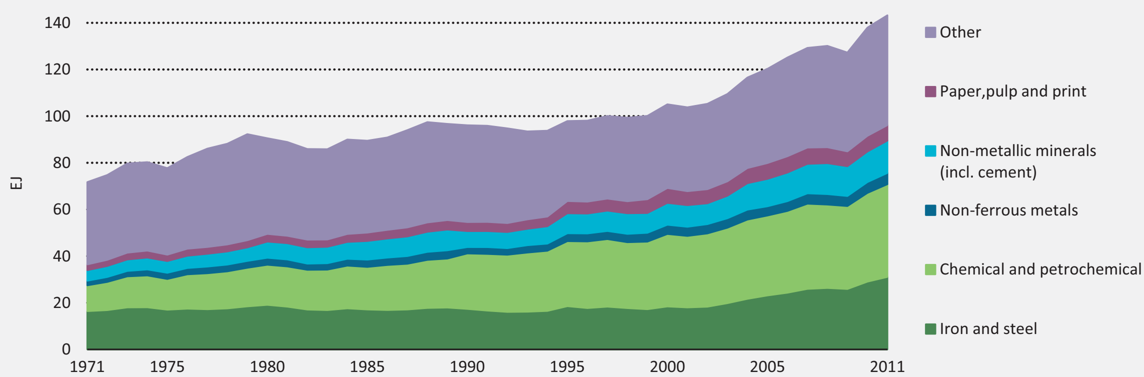
Industry

Current status

Industry accounts for 37% of total global final energy use and 26% of global direct CO_2 emissions. Global industrial energy consumption has doubled since 1971, with a 38% increase over the last decade. The energy-intensive sectors'[12] share of industrial energy use has grown from 57% to two-thirds since 1990 (Figure 1.15).

Industrial overall energy use and CO_2 emissions have been increasing in recent decades; significant progress in improving energy efficiency and reducing CO_2 intensity has been offset by the growth in materials demand. Substantial global efforts will be needed to reverse this upward trend in the sector's CO_2 emissions, particularly as demand for materials continues to rise.

Figure 1.15 **Global industrial energy consumption by sector**



Key point *The five most energy-intensive industrial sectors are gaining share in the overall industrial energy use.*

Scenario results

Due to the uncertainty of projecting long-term industrial materials production, *ETP 2014* considers two variants for each scenario: low-demand and high-demand[13] (Table 1.2). However, the direct CO_2 emissions reduction target is the same in both variants; thus, greater emissions reductions are needed in the high-demand variant. The industry scenarios make optimistic assumptions of technology development, considering that adoption of low-carbon technologies will be cost-effective and that additional barriers associated with regulatory frameworks and social acceptance will be overcome.

Reaching 2DS goals for industry will require global effort and co-ordination to overcome several challenges including: the effects of lower-quality feedstock on process technology energy intensity; public acceptance and environmental implications of using waste materials as fuel; and in some industries, limited availability of recycled materials. In the 2DS, China and India together contribute 41% of total direct CO_2 emissions reductions with respect to the 6DS

12 Industrial energy intensive sectors include iron and steel, chemicals and petrochemicals, non-metallic minerals (including cement), pulp and paper, and non-ferrous metals.
13 Globally, the difference between low- and high-demand variants of production projections for 2050 is in the range of 10% to 35%. Unless otherwise indicated, numbers refer to the low-demand variant.

Table 1.2 Global materials production

Mt	2011	2020 Low-demand	2020 High-demand	2030 Low-demand	2030 High-demand	2050 Low-demand	2050 High-demand
6DS							
Crude steel	1 518	1 840	1 988	2 023	2 216	2 295	2 568
HVC	320	437	461	552	609	780	872
Cement	3 635	4 394	4 556	4 359	4 991	4 475	5 549
Paper and paperboard	403	499	546	603	716	758	1 031
Aluminium	93	144	155	186	233	234	304
2DS							
Crude steel	1 518	1 840	1 988	2 023	2 216	2 295	2 568
HVC	320	433	452	529	546	692	635
Cement	3 635	4 394	4 556	4 359	4 991	4 475	5 549
Paper and paperboard	403	499	546	603	716	758	1 031
Aluminium	93	144	155	186	233	234	304

Notes: differences in HVC production values between 6DS and 2DS are due to increasing plastic recycling rates applied under 2DS, which results in lower demand for HVC (plastic precursors). Greater recycling of materials such as steel, aluminium and paper is embedded in 2DS resulting in a greater penetration of recycled or scrap-based production routes, which are typically less energy-intensive. The overall demand for these materials remains the same across the different scenarios.

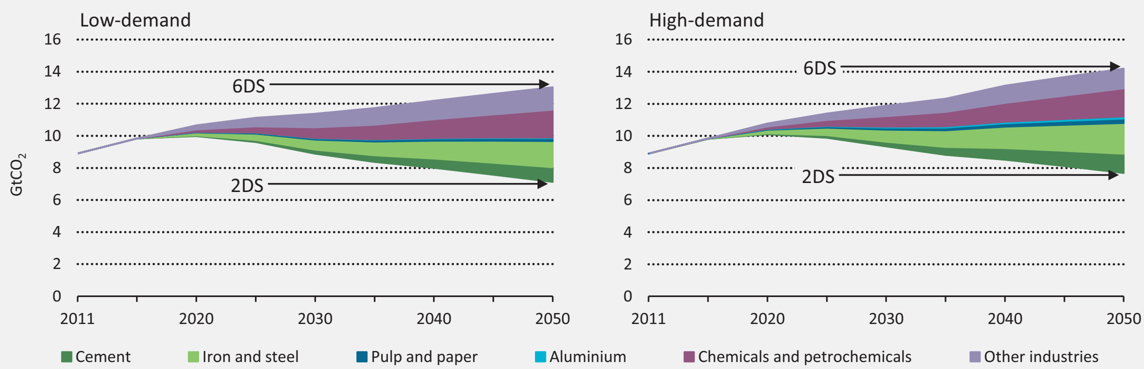
in industry in 2050, followed by the Middle East (11%), OECD Americas (10%), and Economies in Transition (EITs)[14] including Russia (9%). Each industrial sub-sector will need to meet CO_2 emissions reduction targets for the 2DS in 2050: 29% of industry emissions reductions will come from chemicals and petrochemicals,[15] 28% from iron and steel,[16] 15% from cement, 3.1% from pulp and paper, and 0.7% from aluminium.

The results reflect a need for near-term action to meet long-term energy savings and emissions reduction goals. Industry must reduce its direct CO_2 emissions in 2050 by 6 Gt (66% of current levels) and limit energy use to 200 EJ[17] (40% above current levels) to meet 2DS targets. CCS is crucial for realising deep emission cuts in the industrial sector, where CCS often is the only currently available technology to make deep reductions in process-related CO_2 emissions. In the industry sector, CCS provides around one quarter of the cumulative reductions needed to achieve 2DS goals.

In the iron and steel sector, a reduction of 1 633 $MtCO_2$ of direct emissions[18] is required to meet the 2DS targets in 2050, despite an expected increase of 51% in crude steel production. Energy efficiency improvements will play a major role, providing 42% of the total emissions reductions. The greatest potentials come from phasing out open-hearth furnaces in countries such as Ukraine and Russia, and from blast furnace improvements in India, China and Ukraine. CCS technologies will also be needed. In 2050 in the 2DS, the iron and steel sector captures 812 $MtCO_2$, or 40% of the sector's direct CO_2 emissions in that year. New, low-carbon

14 EITs refer to non-OECD Europe and Eurasia.
15 Including feedstock.
16 Including blast furnaces and coke ovens.
17 Including blast furnaces and coke ovens, as well as chemical and petrochemical feedstock.
18 Including blast furnaces and coke ovens.

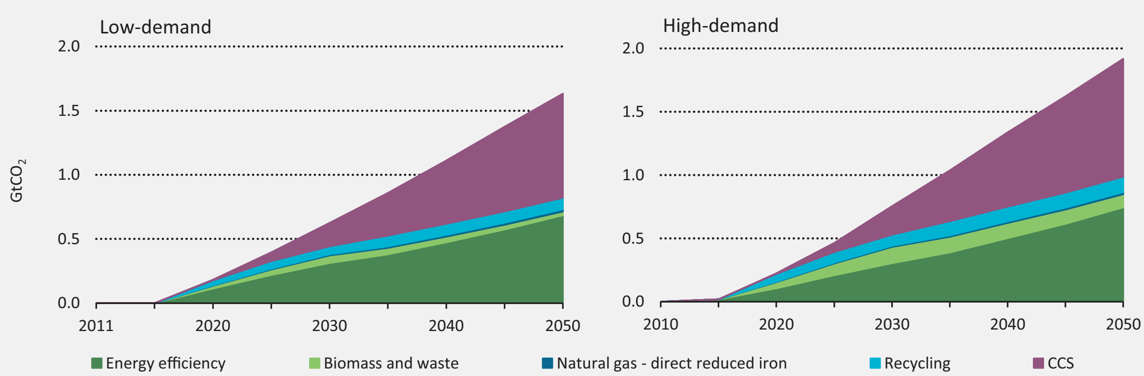
Figure 1.16 **Direct industrial emissions reductions between 6DS and 2DS**



Key point *CO_2 emissions peak in 2020 in the 2DS but continue to rise in the 6DS.*

technology options will also need to be developed and deployed to meet 2DS targets. R&D should focus on new technologies that can utilise low-quality ore and coal while limiting energy intensities. Among the different emissions reduction options, the best progress in recent years has been made in smelting.

Figure 1.17 **Direct emissions reductions in iron and steel between 6DS and 2DS**



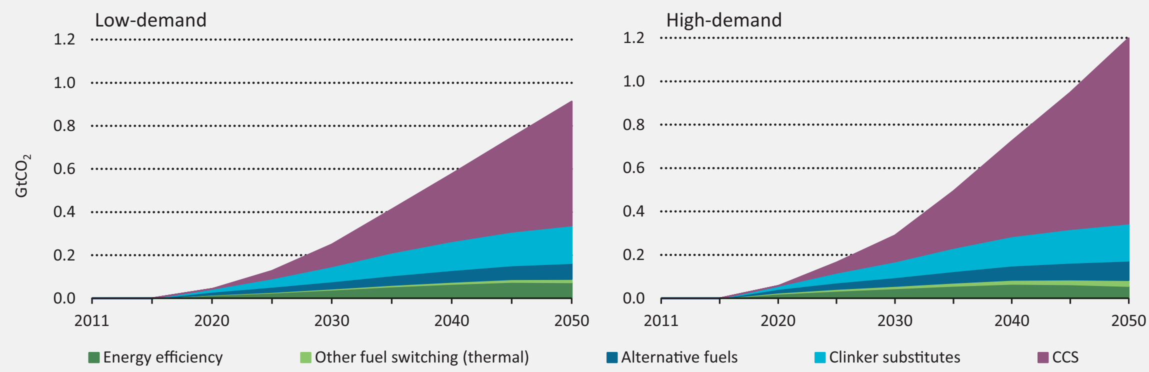
Key point *Nearly half of the CO_2 reductions in the iron and steel sector derive from energy efficiency improvements.*

The cement sector will need a reduction of 913 $MtCO_2$ in direct emissions to meet 2DS targets, though production is expected to increase 23% by 2050. Fuel switching and the use of clinker substitutes offer important and often cost-effective CO_2 mitigation options, and together could contribute 29% to 2DS targets for 2050.[19] Energy efficiency improvements

19 Technical potential, not necessarily economic potential.

have limited potential in this sector given the large share of process CO_2 emissions. This makes CCS essential to reaching the targets; in 2050, the cement sector will need to capture 575 $MtCO_2$ (34% of cement sector emissions).

Figure 1.18 **Direct emissions reductions in cement between 6DS and 2DS**



Key point *CCS deployment represents 63% of emissions reductions in the cement sector in 2050 in the 2DS.*

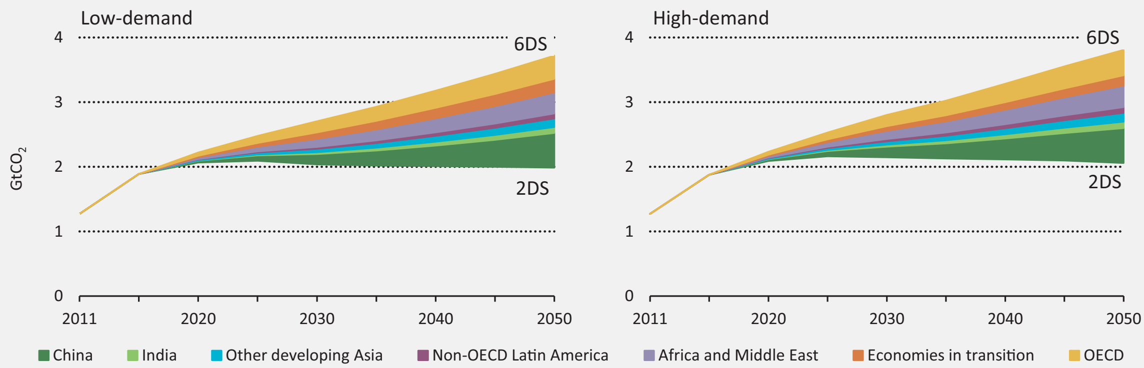
The chemical and petrochemical sector will need to achieve 1 732 $MtCO_2$ of direct emissions[20] reductions to meet its 2050 2DS target, despite significant growth in production. The largest CO_2 abatement contributions will come from China and the Middle East. Energy efficiency improvements can play a major role in this sector, with the greatest potentials related to maximising process integration, waste heat recovery and utilisation, adoption of efficient electrical equipment, and implementation of captive co-generation units. CCS deployment is necessary to meet the sector's targets: 551 $MtCO_2$ is captured in 2050 in the 2DS (28% of direct emissions in that year). Additional low-carbon technologies will be needed, including demonstration and deployment of large-scale, bio-based chemicals facilities, and improvement in the performance of catalysts and related process technologies. These technologies can help to further reduce the gap between actual and thermodynamic minimum energy use, develop less carbon-intensive process routes, and improve separation techniques.

Key actions

Across the industrial sector, policy support is crucial in the 2DS effort; the right policies can make energy efficiency upgrade projects attractive to investors, incentivise adoption of the most efficient technologies in new plants, and encourage RD&D of emerging technologies. Significant growth in the production of materials across all of the five most energy-intensive industries intensifies the challenge of achieving major emissions reductions to meet 2DS goals. Even after these reductions, industry will account for 7 123 $MtCO_2$ of direct emissions in 2050.

20 Including feedstock.

Figure 1.19 Direct emissions reductions in chemical and petrochemical sector between 6DS and 2DS



Key point *In 2050, China and the Middle East account for 48% of emissions reductions in the chemical and petrochemical sector.*

Table 1.3 Sector-specific direct CO_2 emissions by scenario

$MtCO_2$	2011	2050	
		6DS	2DS
Iron and steel	2 991	3 677	2 044
Chemicals and petrochemicals	1 273	3 720	1 988
Cement	2 163	2 605	1 692
Pulp and paper	237	345	164
Aluminium	150	375	333

Reaching these targets will require extensive deployment of BATs, switching to lower-carbon fuels and feedstocks, optimising the use of materials and increasing recycling, greater effort to develop, demonstrate and deploy emerging technologies in all industries, and rapid increases in CCS capacity.

Investment needs and fuel savings from transforming the energy system

The combination of reducing energy demand and decreasing reliance on fossil fuels in the 2DS offers security benefits to the energy system. Implementing energy efficiency measures is a key contributor: energy that is not consumed does not have to be produced, refined, transported or imported (IEA, 2012). Transitioning to a low-carbon energy system will lead to a sharp drop in spending for fuels and deliver other co-benefits such as improved health, fewer environmental impacts and new opportunities for employment. For countries that import oil and gas, this positively affects current account balances and frees up foreign reserves for other uses.

Significant investments in the power, buildings, industry and transport sectors will be needed to meet the 2DS: over the next 40 years, the total is over USD 160 trillion (compared with nearly USD 120 trillion for the 6DS).[21] This represents average annual investment requirements of USD 4 trillion (USD 3 trillion for the 6DS). The additional investments needed to decarbonise the energy system are estimated at USD 44 trillion, an increase of 37% over investment requirements in the 6DS.

Table 1.4 Cumulative investment requirements by sector, 6DS and 2DS

USD trillion	2011-50		Average annual Investments	
	6DS	2DS	6DS	2DS
Power	30.5	39.6	0.8	1
Buildings	17.9	29.3	0.4	0.7
Industry	11.3	13.1	0.3	0.3
Transport	58.8	80.2	1.5	2
Total investment	118.4	162.3	3	4.1

Investment requirements in the transport sector dominate both total investment needs and the additional investments needed to decarbonise the energy system (Figure 1.20). As advanced vehicles (including PHEVs, EVs and FCEVs) gain market share post-2020 and -2030, a sharp increase in investment is needed to cover the additional cost of these vehicles. In the power sector, investment needs to rise in both scenarios, reflecting the need for ongoing investments to keep up with increased electricity demand and replace ageing infrastructure. Investment requirements in the buildings sector are relatively stable over time, with an increase of approximately 50% under the 2DS to deploy more efficient appliances and equipment and for deep renovation of the building stock. Higher costs of CCS, increased recycling, fuel switching and more efficient equipment dominate the additional investment needs in industry

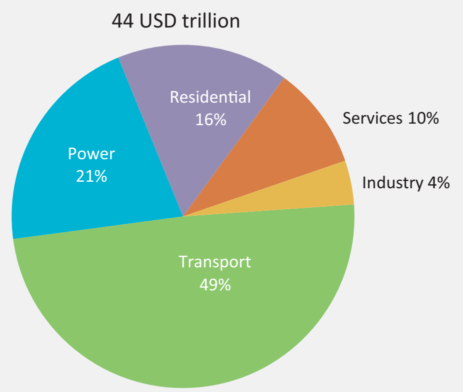
While investment requirements are substantial, the benefits of decarbonising the energy system are equally important. A key gain is significant savings in fossil fuel consumption. Total fuel savings, including higher spending on biomass, in the 2DS compared with the 6DS are USD 115 trillion over the period 2011 to 2050. Subtracting these undiscounted fuel savings from the undiscounted additional investments required yields a net savings of USD 71 trillion over the period to 2050.[22] Discounting the additional investment needs and the fuel savings, these investments generate net savings of USD 30 trillion at a 3% discount rate. At a 10% discount rate, net savings are USD 5 trillion (Figure 1.21), demonstrating that actively pursuing a low-carbon energy system is affordable.

ETP 2014 analysis demonstrates a compelling case for decarbonising the energy system, but this goal carries substantial challenges. The changes needed will not happen without deliberate efforts and, in many cases, direct interventions to influence a divergence from current trends. A rapid increase in near-term investments is needed to achieve savings over the long term, reflecting a shift to technologies that are more capital-intensive but have lower

21 Investment needs in power include investments in generation, transmission and distribution. In buildings, investment is needed for heating and cooling, other end-use technologies, and energy efficient building envelopes. Industry investments include only those needed in iron and steel, petrochemicals and chemicals, cement, pulp and paper, and aluminium. In transport, investments cover only the production cost for light- and heavy-duty vehicles, bus and rail networks, aircraft, and ships, which are expressed as powertrains (engines) only; investments in transport infrastructure for roads, rail and parking are not included.

22 If fuel savings calculation were based on 6DS and 2DS fuel prices for the relevant scenario, the total fuel savings would rise to USD 162 trillion. The net savings would rise to USD 118 trillion undiscounted.

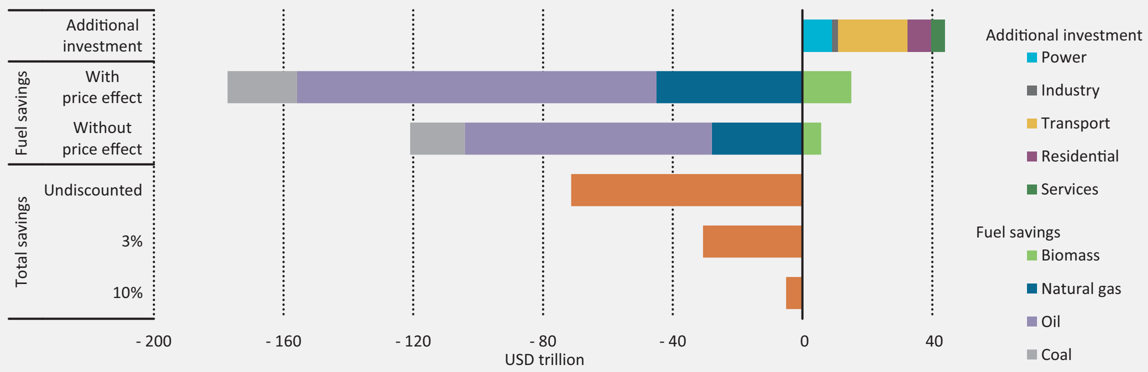
Figure 1.20 Additional global investment needs in the 2DS, 2011-50



Note: regional data can be found online at: www.iea.org/etp2014.

Key point *Transport dominates the additional investments needed to decarbonise the global energy system.*

Figure 1.21 Additional investment and fuel savings in the 2DS compared with 6DS, 2011-50



Key point *The USD 44 trillion additional cost of decarbonising the energy system is more than offset by over USD 115 trillion in fuel savings.*

operating costs. Additionally, including the price of emissions – whether through carbon markets, subsidies, regulation or other support mechanisms – will require long-term political will to meet long-term goals.

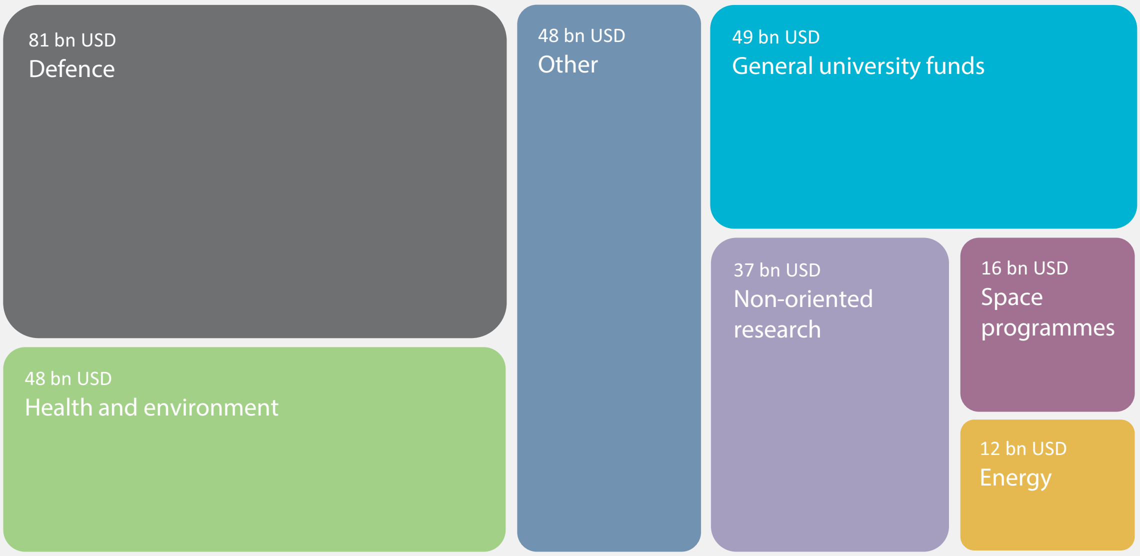
Policy action to lead the transition

In order to transition the global energy system to one based on more sustainable technologies, policy makers need to identify and understand the tools they can apply to successfully achieve both short- and long-term policy objectives. Considering the ambitious goals set out in the

2DS, they need to lead the way by taking informed, decisive action that builds confidence among the entire network of energy sector stakeholders.

Innovation is central to transforming any established system, whether through novel technical solutions or by adapting existing practices to meet new challenges or to work in different environments. Although absolute spending on energy related RD&D has increased, the share of energy RD&D is not keeping pace with the level of ambition needed to meet long term economic, security and climate goals. OECD countries' spending on energy RD&D has been generally decreasing as a share of total research budgets over the past 30 years, as governments have preferred other areas of research, such as health, space programmes and general university research.

Figure 1.22 Government R&D expenditure in OECD member countries in 2011



Source: OECD, 2014.

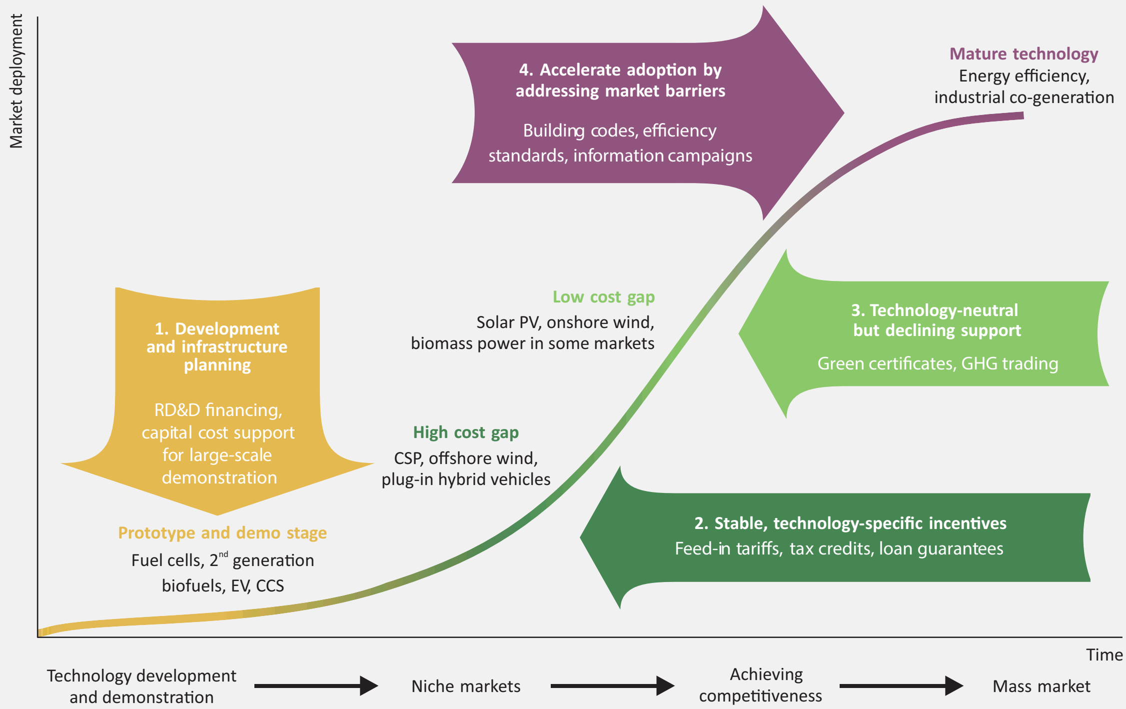
Key point *OECD member countries have increased absolute spending on energy related RD&D, but the overall share remains low.*

Despite the lessening emphasis on energy innovation, technological development is occurring in all sectors – with efforts towards incremental improvements and new breakthrough technologies.[23] With increased ambition, these developments could not only support, but also accelerate the changes needed to decouple social and economic growth from an energy dependence that negatively affects the global climate.

ETP analysis reasserts the IEA long-standing message on the importance of establishing the right framework conditions and incentives, including well-designed and predictable RD&D programmes, along with tailored, adaptable market instruments and innovative business models to support deployment (IEA, 2012; IEA, 2011). The ability to assess the effectiveness of policy measures along all the stages of the innovation process is particularly critical (Figure 1.23).

23 Recent technological developments in major energy sectors are captured in Chapter 2.

Figure 1.23 Tailoring support to meet needs along the innovation chain



Note: figure includes generalised technology classifications; in most cases, technologies will fall in more than one category. Many technologies will be cost competitive within niche applications, low and high cost gap categories are relative to mass market costs.

Key point *Innovation support measures need to be tailored to the maturity level of the technology.*

With its main objective of providing data and analysis that can inform policy and decision makers on technology's potential to contribute to policy and business objectives, the *ETP* series is an effective tool to highlight the increasingly urgent need for innovation, and the opportunities it offers. Greater visibility of innovation's potential to enable an economically viable, low-carbon energy system can provide more credible options to decision makers and more assurance in the feasibility of achieving emissions reduction targets that can meet global goals.

With the next round of the United Nations Framework Convention on Climate Change Conference of Parties negotiations scheduled for December 2015, the IEA proposes to dedicate *ETP 2015* to increasing policy-maker confidence in the ability of innovative solutions to facilitate the achievement of climate change mitigation targets. It will do that by providing better visibility of the potential impact of various forms of energy technology innovation. First and foremost, it will bring attention to tools that can spur innovation and identify mechanisms to evaluate the effectiveness of policy action. Japan's recent plan for low-carbon technology innovation is a strong example of a more assertive, strategic, integrated and collaborative approach (Box 1.4).

Efficient and appropriately scaled support mechanisms for all stages of the innovation chain will be important drivers for transforming the energy sector in support of 2DS targets. They hold the potential to unlock least-cost options across all sectors to achieve policy objectives,

Box 1.4 Japan's new low-carbon technology innovation plan

To address global issues of climate change and contribute to solving energy security and widespread environmental problems that hinder economic growth of developing countries, Japan formulated a Low Carbon Technology Plan in September 2013. This plan aims to steadily develop and diffuse technologies that will help meet the global goal of 50% GHG reduction by 2050. With a strategically incremental range of technologies and time frames, Japan is embracing a long-term plan with short-term solutions to facilitate achievement of clear future goals.

The plan articulates three steps to support this initiative:

1. Identify innovative technologies that best support the above goals to be developed over both the short to medium term and the medium to long term.

2. Strengthen policies that aim specifically at promoting identified technologies.

3. Identify opportunities for global collaboration in the diffusion of innovative technologies.

The plan highlights a range of technologies across the energy sector including supply, demand and system-based or integration technologies. In the short/medium term, the plan includes the development of technologies such as:

- supply: high-efficiency coal and natural gas, wind, and solar
- demand: next-generation automobiles, energy management and energy efficient buildings
- integration: high-performance electricity storage, heat storage and insulation technologies.

For medium/long-term development, the plan promotes CCS, artificial photosynthesis, biomass utilisation, and hydrogen production/transport/storage.

Strengthening policy that promotes technology development is established as a requirement to meet short-, medium- and long-term goals. Specifically, the plan aims to improve the investment environment for the private sector through utilisation and promotion of R&D tax systems, and to develop high-risk/high-return technologies under government leadership.

To support expansion and global co-operation, the plan promotes the development of a joint crediting mechanism, the development and utilisation of international standards, and co-ordinated R&D collaboration with other countries and international organisations.

while also creating opportunities to capture multiple side benefits such as energy security and economic growth. Ultimately, specific energy innovation choices will depend on many factors, such as regional existing energy systems, resource endowments, climate, culture, population and green growth perspectives. Action is needed now to materialise transforming technology while implementing best practices today to meet long-term goals, through both international collaboration and targeted national actions.

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Chapter 2

Tracking Clean Energy Progress

Deployment of solar photovoltaics (PV), onshore wind and electric vehicles (EVs) is still increasing rapidly, but their growth rates are slowing. Growth of coal-fired power generation exceeds that of all non-fossil fuels combined. Nuclear power generation is stagnating. Development of carbon capture and storage (CCS) remains too slow. These trends reflect inadequate political and financial commitment to long-term sustainability of the global energy system.

Key findings

- **Deployment of renewable power in Asia and emerging economies more than compensates for slow or volatile growth in Europe and the United States.** Asia as a whole deployed more than half of global solar PV additions in 2013, with China being the leader.
- **Sales of hybrid and electric vehicles set new records, but 2013 sales fall short of the 2°C Scenario (2DS) trajectory.** Eight out of ten manufacturers now offer EVs, and several launched high-profile models.
- **Global nuclear capacity is stagnating. Modest nuclear capacity increase from new reactors was offset by retirement of ageing or non-profitable plants in OECD countries.** Signs of renewed growth exist, as China and Russia push ahead with ambitious nuclear plans.
- **Efforts to curb coal demand and improve plant efficiency remain inadequate.** Since 2010, the growth in generation from coal has exceeded that of all non-fossil sources combined, continuing a 20-year trend. The 2DS trajectory requires a sharp decline in coal use in parallel with rapid development of CCS.
- **CCS is advancing slowly, due to high costs and lack of political and financial commitment.** Few major developments were seen in 2013, and policies necessary to facilitate the transition from demonstration to deployment are still largely missing.
- **Industry must cut energy use by 11% and direct CO_2 emissions by 14% by 2025 to meet 2DS targets.** Large economic values tied in existing plants slow the turnover of industrial equipment, even though IEA analysis shows that wide application of best available technologies (BATs) could technically slash energy use by 11% to 26% in iron and steel, chemicals, cement, pulp and paper, and aluminium.

Opportunities for policy action

- **Agreement on long-term energy policy goals, supported by stable and efficient policies, would accelerate clean energy technology deployment.** While clean energy technologies are increasingly competitive with conventional solutions, lack of long-term policy goals and abrupt policy changes have deteriorated the clean energy investment environment. Ongoing policy uncertainty remains one of the largest sources of risk for investment.
- **Policies that reduce capital risk are particularly important for clean energy technologies.** Several clean energy technologies offer low operating costs, but their high up-front capital costs create particular financing challenges, especially in liberalised markets. Market design will be central to meet environmental and energy security goals.
- **Actions to increase the uptake of energy management systems could unlock substantial energy efficiency potential in industry.** Where used, such systems and programmes are delivering impressive results. China's new mandates for large energy users is one example that is boosting policy attention.
- **Curbing escalating electricity demand from networked devices requires policy action.** As market drivers for energy efficiency in these globally traded devices remains weak, international policy and technology co-operation is vital.
- **Smart grid deployment would be accelerated by addressing regulatory barriers and enabling new business models.** Key policy goals should include leveraging existing infrastructure and engaging end users.
- **Energy performance of new buildings needs a higher priority in emerging and developing economies.** Adapting and widely deploying advanced building technologies and materials is essential.

Tracking Progress: How and Against What?

Technology penetration, market creation and technology developments are key measures of progress in clean energy deployment. *Tracking Clean Energy Progress (TCEP)* uses these criteria to probe whether current policy is effectively driving efforts to achieve a more sustainable and secure global energy system. What rates of deployment do recent trends demonstrate for key clean energy technologies? Are emerging technologies likely to be demonstrated and commercially available in time to fully contribute?

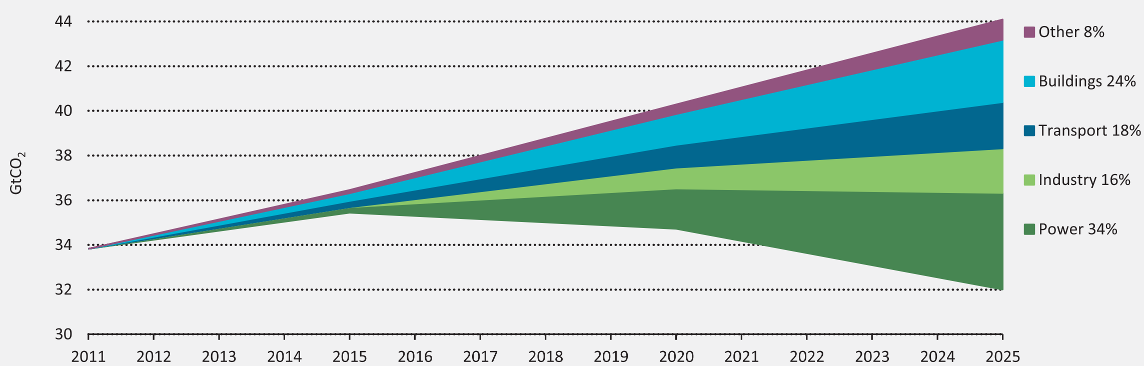
Tracking against near-term targets, while aiming for the long-term goal. This chapter uses interim 2025 benchmarks set out in the 2°C Scenario (2DS) to assess if technologies, energy savings and emissions reduction measures are on track to achieve 2DS objectives by 2050. The near-term focus shows where actions necessary for profound decarbonisation post-2025, across the energy sector, are progressing as required. It also uncovers areas that need additional stimulus.

Updated annually, the chapter highlights how the overall deployment picture evolves, year on year. Vitally, it highlights key policy and technology measures that energy ministers and their governments can take to scale up deployment for each technology and sector, while also demonstrating the relevant energy savings and emissions reduction potential. The chapter is structured by technology and sector, and uses graphical overviews[1] to summarise the data behind the key findings. This year's edition contains a special feature on energy use associated with devices that operate in network standby mode.

All three *TCEP* measures are essential to the success of individual technologies. The 2DS relies on development and deployment of lower-carbon and energy-efficient technologies across the power generation, industry, transport and buildings sectors (Figure 2.1). On the basis of available quantitative and qualitative data, this chapter assesses for each sector:

- **Technology penetration.** What is the current rate of technology deployment? What share of the overall energy mix does the technology represent? Is the technology being distributed or diffused globally at the rate required?
- **Market creation.** What mechanisms are in place to enable and encourage technology deployment, including government policies and regulations? What level of private sector investment can be observed? What efforts are being made to drive public understanding and acceptance of the technology? Are long-term deployment strategies in place?
- **Technology developments.** Are technology reliability, efficiency and cost evolving and if so, at what rate? What level of public investment is being made into technology RD&D?

Figure 2.1 Sector contributions to emissions reductions



Note: figures and data that appear in this chapter can be downloaded from www.iea.org/etp/tracking.
Source: unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *All sectors must contribute to achieve the 2DS goal of limiting global emissions across energy generation and use.*

1 Enhanced interactive data visualisations are available at: www.iea.org/etp/tracking.

Table 2.1 Summary of progress

On track?	Status against 2DS targets in 2025	Policy recommendations
Renewable power	Rapid progress, particularly in hydro, onshore wind and PV, on global scale; slightly slowing momentum in OECD. Offshore wind, bioenergy, concentrated solar power (CSP), ocean and geothermal technologies are lagging.	▪ Maintain a balance among sustainability, affordability and competitiveness while designing renewable power policies. ▪ For maturing markets, integrate renewables with greater exposure to market pricing and competition. ▪ Shift focus from high economic incentives to long-term policies that provide predictable and reliable market and regulatory frameworks offering a reasonable degree of certainty over remuneration. ▪ Reduce risks associated with policy uncertainty that ultimately drive up capital and project costs for capital-intensive renewable; avoid retroactive measures by all means.
Nuclear power	Installed capacity in 2025 likely 5% to 25% below 2DS target. Both new-build activity and long-term operation of existing reactors required.	▪ High capital and low running costs create need for policies that provide investor certainty, e.g. through more favourable market mechanisms and investment conditions. ▪ Implement safety upgrades in existing nuclear plants in a timely manner to ensure public confidence.
Gas-fired power	Decreasing power demand, overcapacity, the rise of renewable energy and low coal prices make the situation for gas power challenging, particularly in Europe.	▪ Carbon prices and other regulatory mandates needed to drive coal-to-gas switching outside the United States. ▪ Scaling up unconventional gas extraction requires careful regulation and monitoring to avoid adverse effects on the environment.
Coal-fired power	Current trends of increasing coal-fired power are incompatible with the 2DS. Accelerated development of carbon capture and storage (CCS) required.	▪ Policy incentives to drive emissions reductions, such as carbon pricing and regulation, are vital to control pollution and reduce generation from inefficient units. ▪ New coal power units should, at minimum, achieve the efficiency of supercritical units and be CCS-ready to have the potential to reduce even further the impact of coal use.
CCS	Global capacity of around 50 $MtCO_2$/yr in 2020 if projects in advanced stages reach operation. In the following decade, the rate of capture and storage must increase by two orders of magnitude.	▪ Demonstrate financial and policy commitment to CCS demonstration and deployment. ▪ Near-term policies should be supported by credible long-term climate change mitigation commitments. ▪ Recognise the large investments and long lead time required to discover and develop viable storage sites. ▪ Introduce CCS as a solution to address CO_2 emissions from industrial applications.
Buildings	Progress continues in most regions, but is insufficient. The 2DS target for 2025 constrains energy demand growth to 0.7%/yr from 2012; trend since 2000 is more than double at 1.5%/yr, throwing the sector off track.	▪ Promote deep energy renovation during normal refurbishment, and increase significantly the annual rate of renovation (to at least 2%). Pursue zero-energy building goals from 2020 onwards for all new construction, which will require significant effort now. ▪ Implement mandatory building codes that promote advanced building materials, integrated using a systems approach to reduce heating, cooling and lighting energy demand. Build capacity and infrastructure in emerging economies to promote building code development and compliance. ▪ Set MEPS to improve efficiency; continue and extend where possible. ▪ Apply labelling policies and standards to promote uptake of energy efficient models; develop measures to curtail increasing demand.

● Not on track ● Improvement, but more effort needed ● On track, but sustained deployment and policies required

Table 2.1 Summary of progress (continued)

On track?	Status against 2DS targets in 2025	Policy recommendations
Industry	Some progress in energy efficiency, but energy use must be cut by 25% and direct CO_2 emissions by 17% by 2025.	▪ Promote widespread application of best available technologies (BATs) to help overcome the challenges of slow capacity stock turnover, high abatement costs, fluctuation in raw material availability, carbon leakage and industrial competitiveness. ▪ Support RD&D programmes to bring to technical and commercial maturity new low-carbon technologies that enable the use of low-quality feedstocks; demonstrate and deploy emerging energy- and emissions-saving technologies, including CCS. ▪ Promote technology capacity building in emerging economies.
Transport	Although OECD recently shows high vehicle efficiency improvement rates for PLDVs, and despite recent progress in hybrid and EV deployment the sector is lagging.	▪ Implement fiscal policies that reflect actual costs, e.g. remove fuel subsidies to incentivise switching to fuel-efficient vehicles. ▪ Continuously adapt ongoing policies such as fuel economy and emission standards, feebate systems, or emission-based taxes for PLDVs; develop and implement fuel economy policies for HDVs. ▪ Use urban development strategies, access restriction and congestion charging to manage travel demand and influence modal choice, promoting shifts to collective transport modes and stimulating innovative vehicle technologies. ▪ Apply market-based instruments, such as emissions trading, to internalise GHG-related costs, and regulatory measures to foster the uptake of efficient technologies in the aviation and shipping sector.
Electric and hybrid electric vehicles	Slow growth compared with previous years; tracking indicator dipped from green (2013) to orange. Annual sales must increase substantially for both EVs (80%) and HEVS (50%) until 2020.	▪ Direct subsidies, tax exemptions, feebate schemes and favourable conditions in urban areas enhance cost-competitiveness of EVs/HEVs and boost manufacturer and consumer confidence. ▪ Extend policy measures and programmes to give industry confidence that market demand will continue to grow in the short term. ▪ Develop standards for charging stations and integrate EVs in city mobility programmes (e.g. car sharing) to underscore broader benefits, including reduced local air pollution.
Biofuels	Global production must triple; advanced biofuels capacity must increase 22-fold.	▪ Develop fiscal measures that reduce investment risk associated with first commercial-scale advanced biofuels projects, to achieve technology learning and cost reductions. ▪ Promote international harmonisation of sustainability certification schemes, without creating unwanted trade barriers. ▪ Create a long-term policy framework to ensure sustained investments in production and use of sustainable biofuels that perform well in terms of emissions reduction and land-use efficiency, as well as economic and social impact.
Co-generation and district heating and cooling	Slow progress despite their enhanced conversion efficiency; deployment of co-generation accounts for only 9% of global electricity, and penetration of efficient district heating and cooling (DHC) is limited.	▪ Make the efficiency and flexibility benefits of co-generation visible by creating market conditions that reflect the real cost of generation. Facilitate investments in modernisation and improvement of networks. ▪ Develop strategic local, regional and national heating and cooling planning to identify cost-effective opportunities to develop co-generation and expand DHC networks. ▪ Streamline grid interconnection standards to achieve the flexibility potential of co-generation technologies.
Smart grids	Steady growth, but available deployment data do not give a full picture; current rate of deployment is insufficient.	▪ Develop and demonstrate new electricity regulation that enables practical sharing of smart-grid costs and benefits. ▪ Support the development of international standards to accelerate RDD&D. ▪ Promote the development metrics, national data collection and international data co-ordination.

● Not on track ● Improvement, but more effort needed ● On track, but sustained deployment and policies required

Renewable Power

On track

Renewable power generation continues to progress quickly and is broadly on track to meet targets of the *Energy Technology Perspectives 2014 (ETP 2014)* 2°C Scenario (2DS). It grew 5.5% annually from 2006-13, up from 3% annually in 2000-06, and is expected to rise by around 40% between 2013 and 2018 (approximately 5.8% annually), to reach 6 850 terawatt hours (TWh). This compares well with the 2DS in terms of absolute generation but not in terms of renewables' target share in global power generation of over 35% by 2025. In addition, this expected growth of renewables is subject to strong regional differences, and depends on tackling policy uncertainty.

Technology penetration

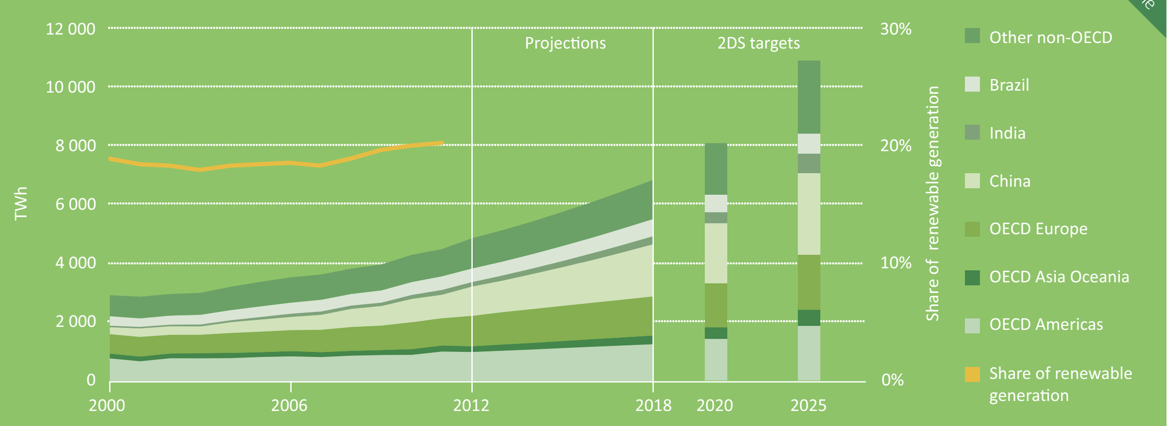
Growth is shifting beyond traditional markets mainly in Europe to an increasing number of non-OECD countries. In 2013, the number of countries with installed non-hydro renewable power cumulative capacity from onshore and offshore wind, bioenergy and solar photovoltaics (PV) above 100 megawatts (MW) rose significantly compared with 2006 levels. Led by China, India and Brazil, non-OECD countries now dominate global renewable power generation with around 54% of the total, up from 52% in 2012 (IEA, 2013a). This share is expected to further increase up to 58% in 2018. This trend is also in line with 2DS results, where the largest proportion of renewable electricity generation in 2025 would come from China (26%), followed by OECD Europe (17.3%), the United States (11%), Brazil (6.3%) and India (6.1%).

In 2013, installed cumulative capacity continued to grow strongly in both OECD and non-OECD countries. Solar PV grew by an estimated 37 gigawatts (GW) (+ 37%) and wind (onshore and offshore) by 35.5 GW (+ 12.5%). Asia, led by China and Japan, deployed more than half of global solar PV additions in 2013.

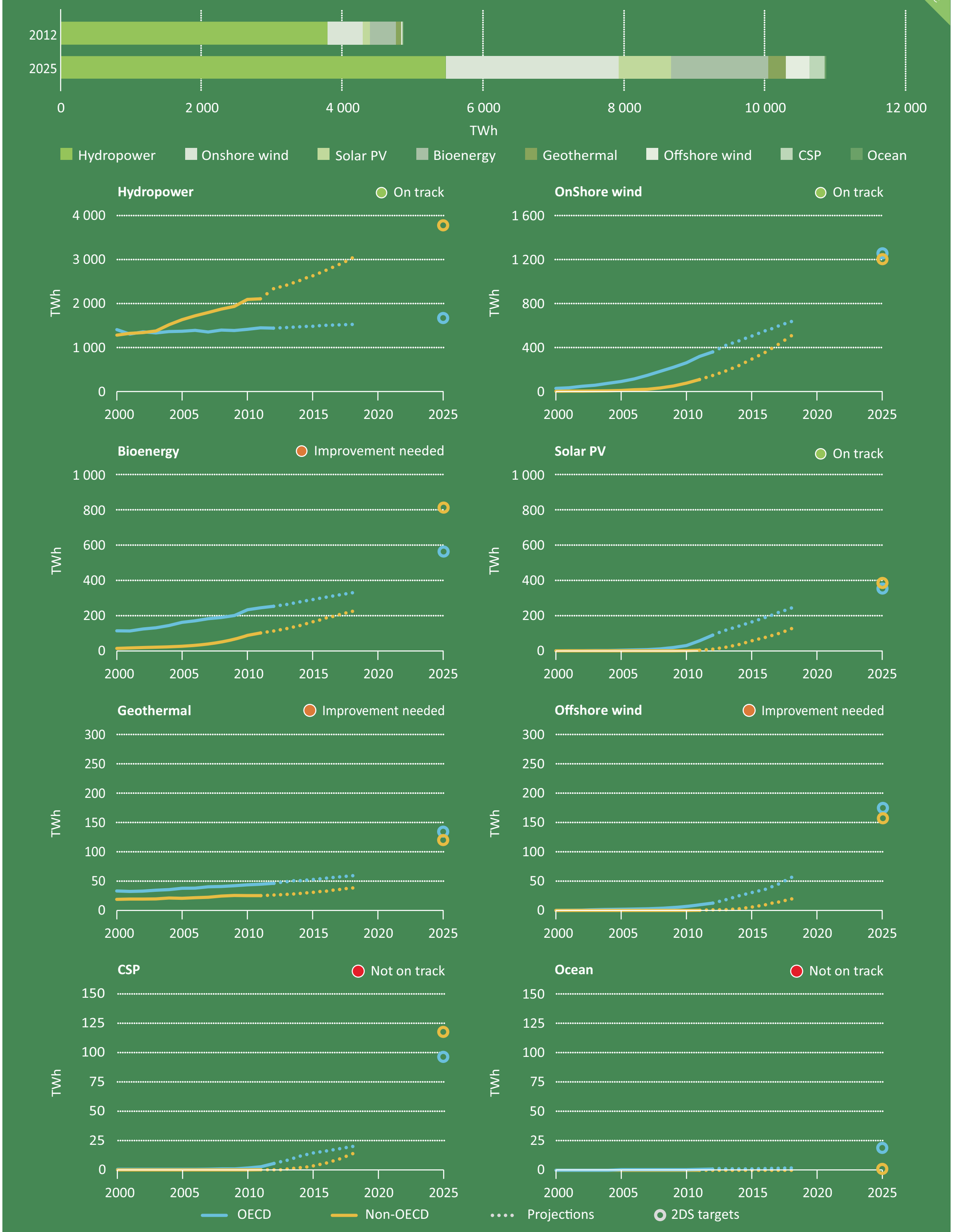
Certain technologies are doing better than others in terms of reaching 2DS targets. Hydropower continued its stable growth globally in 2013, and remained the largest generator of renewable electricity. Onshore wind is also on track to meet 2DS targets thanks to increasing deployment levels in non-OECD countries compensating for the slowing or more volatile growth in OECD Europe and Americas. Solar PV shows even stronger growth, and may exceed 2DS targets – with non-OECD cumulative capacity likely surpassing OECD before 2025.

In contrast, offshore wind, bioenergy, concentrated solar power (CSP), ocean and geothermal technologies are lagging behind. In order to reach the 2DS targets, these technologies need to achieve higher growth rates in coming years, which require further policy action to tackle technical and financing challenges that currently hinder deployment.

2.2 Renewable power generation by region



2.3 Renewable power generation by technology



For sources and notes see page 109

Market creation

By the end of 2013, over 100 countries had a renewable electricity support measure (e.g. targets, feed-in tariffs [FiTs], tenders, tax incentives). During 2013, new or revised policies supporting the deployment of renewable power were adopted in 16 countries.

A major policy challenge is to balance the affordability of support schemes with effectiveness and the need for investor certainty in order to drive deployment. In 2013, governments continued to be mindful of the affordability aspect of renewable energy deployment, allowing faster downward adjustment to cost changes.

In Germany, the revision of supported solar PV system categories and the monthly adjustment of solar FiTs have so far worked well. However, several countries made more drastic and even retroactive changes to renewable energy policies, which damaged investor confidence for future projects and affected the profitability of existing renewable energy assets in some markets. Onshore wind and solar PV have been affected, resulting in boom and bust investment cycles in some markets.

Installations of new wind capacity in the United States tumbled to 1 GW in 2013, a fraction of the record 13 GW in 2012. Developers rushed to finish projects before an expected expiration of the renewable electricity production tax credit (PTC) at the end of 2012, leaving an empty project pipeline for 2013. The situation is foreseen to partly recover since the PTC was extended in late 2012, with around 15 GW of new wind projects expected to come on line by 2015, but it has hurt the industry.

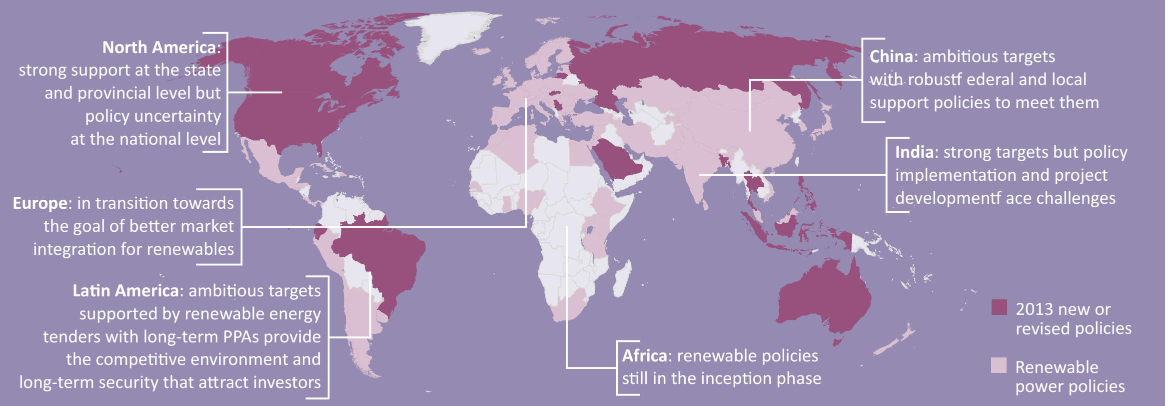
Greece experienced a solar PV boom in 2012 but introduced FiT cuts and retroactive taxes in 2013, which dramatically decreased investor interest in solar PV. The Romanian government has proposed suspending half of the wind certificates due under current incentive arrangements until 2018, applying retroactively to all projects started after 1 July 2013. In Spain, the 2013 electricity reform abandoned all FiTs and premiums provided to renewables retroactively by introducing a cap to limit projects' profits based on the average yield of Spanish government bonds. Also, the moratorium on renewable energy subsidies and the additional 7% tax for all power generators are still in place.

Inflexible and overly generous remuneration mechanisms may also be detrimental. Japan revised its PV FiT downward by only 10% in 2013, still maintaining tariff levels more than twice as high as Germany. This led to record deployment in 2013 but at a relatively high cost, and prompted questions over the financial sustainability of the FiT.

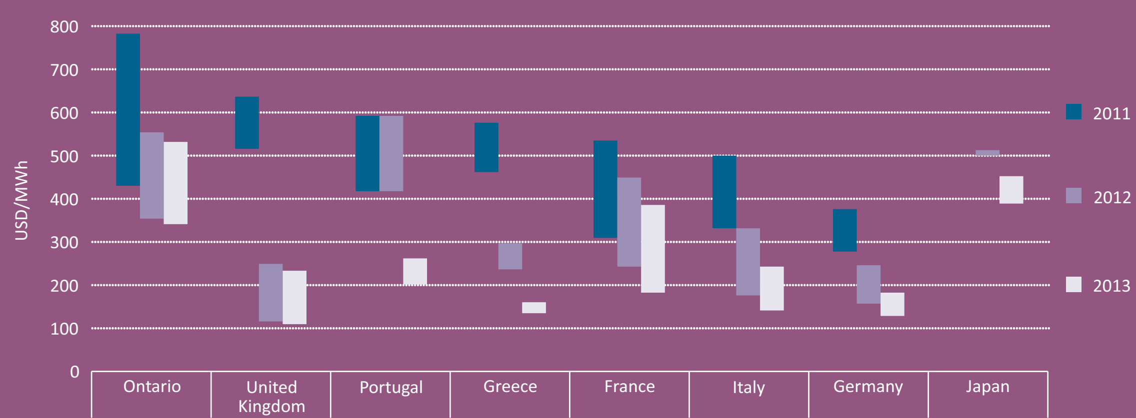
Stable policy can lead to lower cost of capital, which helps renewable technologies that have relatively high up-front costs. Long-term market power planning combined with competitive bidding (such as tenders and auctions for long-term power purchase agreements) has proved effective in triggering competitive deployment of renewables. In 2013, wind power won the majority of long-term contracts in Brazil in competition with other technologies, including natural gas. South Africa announced its third bid window for several renewable energy technologies with costs for onshore wind being around 30% lower than those for new coal plants. Saudi Arabia unveiled a white paper detailing the tender process for new solar PV and CSP plants.

Early estimates indicate that investment in renewable power was USD 211 billion in 2013, down 12% compared with 2012 and 22% lower than the record USD 270 billion in 2011, partly reflecting cost reductions but also due to uncertain policy and market frameworks.

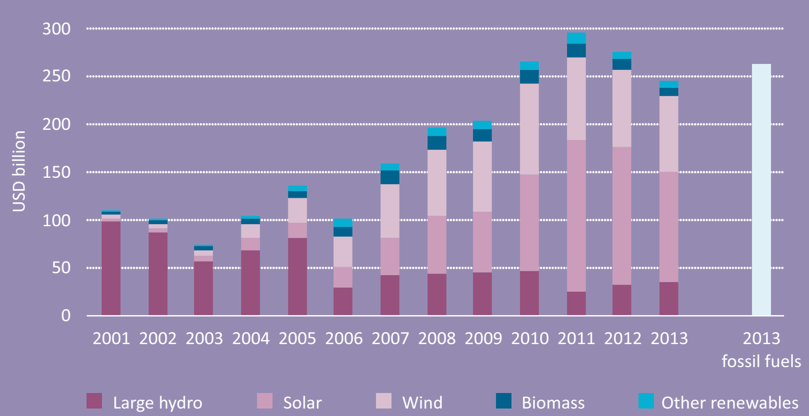
2.4 Renewable power policies



2.5 Solar PV feed-in tariffs



2.6 Capacity investment



55%

ASIA'S SHARE OF NEW SOLAR PV INSTALLATIONS IN 2013, LED BY CHINA AND JAPAN

For sources and notes see page 109

Technology developments

In 2013, price reductions of solar PV modules slowed considerably following a consolidation in the industry. Between 2008 and 2012, module prices decreased by around 80% from USD 3.98 per watt (W) to USD 0.79 per watt, while in 2013 prices remained more or less stable. The European Union and China agreed on a minimum export price (EUR 0.56/W) for Chinese solar panels in the EU, with imports at this price from China capped at 7 GW (a high import tariff is applied to additional imports from China).

Reductions in investment costs for CSP are expected to accelerate following the commissioning of large new projects in 2013 and early 2014. The United States commissioned the three largest CSP plants in the world: Ivanpah (391 MW tower with direct steam generation at an investment cost of USD 5 600 per kilowatt [kW]); Solana (280 MW with six-hour storage at USD 7 600/kW); and Crescent Dunes (110 MW with ten-hour storage at USD 9 000/kW). Offshore wind projects totalling 1.6 GW became operational in Denmark, Germany and the United Kingdom in 2013, but investment costs are expected to increase in coming years as projects will be installed farther from the coast.

Costs per kilowatt hour (kWh) of electricity can fall more quickly than costs per installed kW. Wind turbine manufacturers have focused on turbines that can harness more energy at equal capital costs, and on site-tailored overall project development and management. These are often low- and medium-wind turbines in the 2.0 MW to 2.5 MW capacity range. Similarly, higher efficiency of PV systems in areas with higher capacity factors led to increased average output per installed MW capacity in 2013. The world's first unsubsidised, utility-scale solar PV power plant was financed in Chile in 2013, and is to sell electricity to the wholesale market without a power purchase agreement. In Brazil, utility-scale solar PV was included for the first time in energy auctions, although no PV project was selected in the end. The government is now planning to open solar-only auctions.

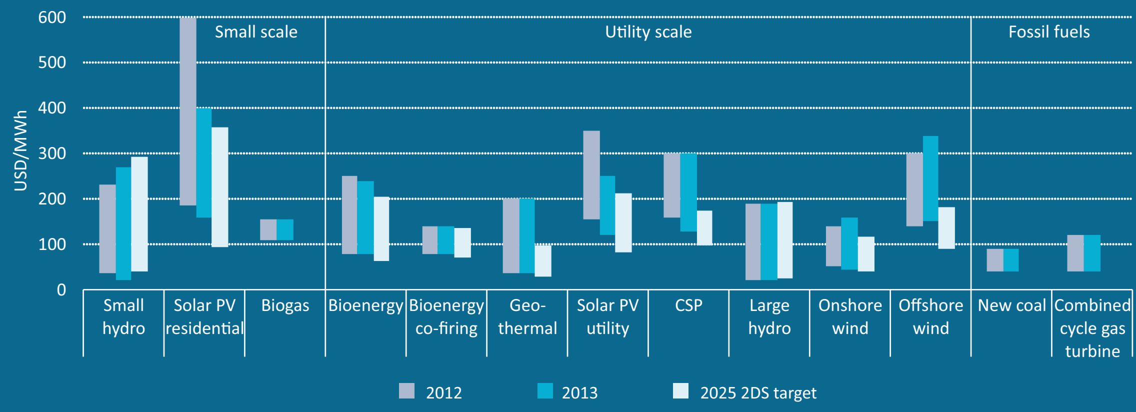
The falling costs of distributed solar PV systems are increasingly supporting deployment for self-consumption in markets such as Italy, Germany and California where costs for self-generation are on par with household electricity prices. Turkey's first commercial self-consumption solar PV plant was commissioned in 2013.

For geothermal, early-stage exploration and drilling risks remain a major deployment challenge. Technology development activities focus on enhanced geothermal systems, which can be used to upgrade existing wells or create geothermal reservoirs where none previously existed. Several testing activities are under way in the United States. Still, the degree to which commercial-scale deployment in existing plants or new projects will transpire over the next five years is uncertain.

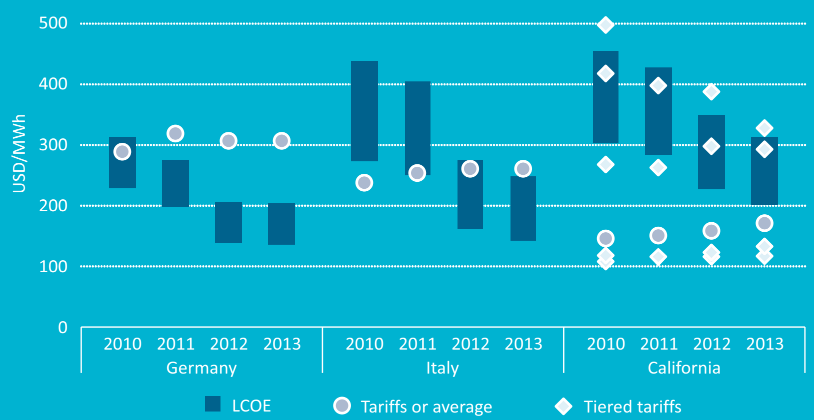
Ocean power technologies are still at the research and development (R&D) stage, and most remain relatively expensive. As of 2013, there were ten wave and tidal single-device test machines operational ranging from 250 kW to 1000 kW in the European Marine Energy Centre (EMEC), the largest ocean energy test centre in the world. The SeaGen tidal stream device in the United Kingdom, commissioned in 2008, remains the largest operational generating capacity.

Increased investment in research, development and demonstration (RD&D) in emerging technologies, particularly ocean and enhanced geothermal, is needed to enhance competitiveness. In 2012, public RD&D expenditure on fossil fuels and nuclear combined was 80% higher than on renewable technologies.

2.7 Levelised cost of electricity



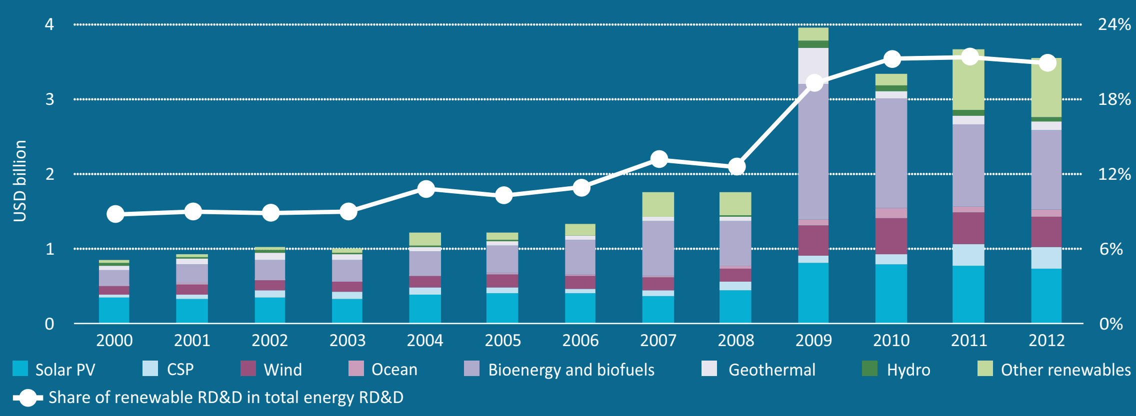
2.8 Residential solar PV LCOE and electricity prices



56%

IEA COUNTRIES PUBLIC RD&D EXPENDITURE ON RENEWABLE TECHNOLOGIES COMPARED TO FOSSIL FUELS AND NUCLEAR COMBINED IN 2012

2.9 IEA public RD&D spending



For sources and notes see page 109

Nuclear Power

Not on track

Global nuclear generation declined to around 2 350 TWh in 2012,[2] a 7% decrease from 2011 levels. Installed nuclear capacity remained virtually unchanged in 2013 at 393 GW (gross), yet 2013 also saw ten construction starts, representing some 11 GW, up from seven starts in 2012. A record 72 nuclear reactors were under construction at the end of 2013.

Technology penetration

Several new countries show interest in nuclear power: units are under construction in Belarus and the United Arab Emirates, and projects are well advanced in Turkey and Viet Nam, and under discussion in Bangladesh, Jordan, Poland and Saudi Arabia.

The transition to Generation III (Gen III) light-water reactors, which are designed to increase efficiency and reduce the likelihood and mitigate the consequences of severe accidents, is accelerating. Thirty of the reactors currently under construction are Gen III, and China has announced it will build only Gen III reactors. Construction spans of Nth of a Kind (NOAK) Gen III reactors in China seem close to 60 months, helped by established supply chains and workforces.

Still, installed capacity in 2025 will likely be 5% to 24% below the 2DS target. All of Japan's 50 reactors are now idle after the last two operational units were stopped in 2013. Four reactors were closed in the United States due to the cost of refurbishment and unfavourable economics compared to gas-fired generation.

Market creation

Nuclear energy policies have been debated in countries with mature nuclear industries, such as Japan, Korea and France. In February 2014 Korea set a target for the share of nuclear capacity to 29% by 2035 (down from the previous target of 41%), and Japan confirmed that nuclear energy will be part of its energy mix, though the level is yet unknown. A number of other countries have confirmed their desire to build new nuclear reactors.

The United Kingdom is pushing ahead with guaranteeing energy prices for low-carbon technologies including nuclear. For two new nuclear units, the government has proposed a guaranteed "strike price" of GBP 92.50 per megawatt hour over 35 years, meaning the government will top up the income to this level if wholesale prices are lower or recover the difference from the utility if prices are higher. This investment framework still has to be authorised by the European Commission.

Russia's "build, own, operate" model is attracting interest as it allows countries to transfer the high capital costs of nuclear investments to long-term guaranteed electricity prices paid by the customers. In addition, Russia is offering part-equity financing in a number of other countries.

Overall, financing of nuclear power, which has high capital costs and low running costs, is increasingly challenging – a problem shared with other low-carbon technologies such as carbon capture and storage (CCS) and offshore wind.

Technology developments

Following the Fukushima Daiichi accident, many existing Gen II plants are being equipped with additional emergency power supply systems and cooling capabilities, and other accident mitigation systems.

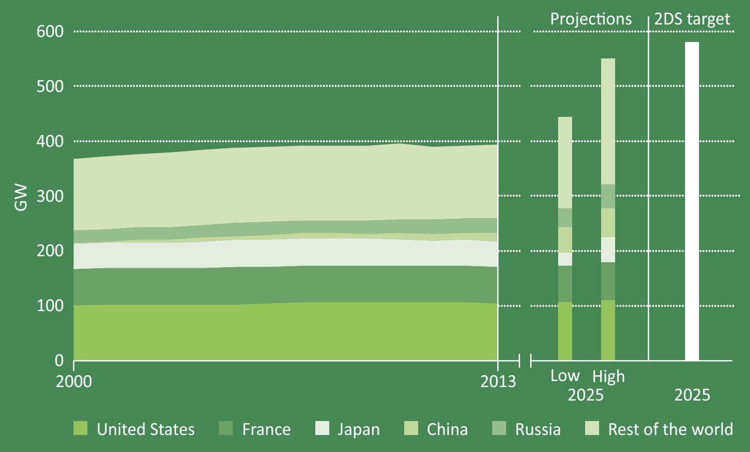
Development of small modular reactors has continued, with various levels of pre-licensing activity, especially in the United States, but only two construction projects have been launched (in Russia and recently in Argentina).

Some prototypes of advanced reactors with Gen IV type technologies are being built, but no industrial deployment is expected for several decades.

Projects for geological disposal of high-level waste made progress in Sweden, Finland and France. In the United States, the review of application to operate the Yucca Mountain site as a repository for high-level waste was resumed. The European Commission has required all European countries to submit their plans for disposal of radioactive waste by 2015.

2 Statistics in this section derive from the International Atomic Energy Agency (IAEA) Power Reactor Information System (PRIS) database.

2.10 Installed gross nuclear capacity



Recent developments

Japan confirmed that nuclear energy will be part of its energy mix, though the level is yet unknown

Korea lowered its target for the share of nuclear capacity to 29% by 2035

The UK government offered guaranteed price levels over 35 years to a new nuclear facility

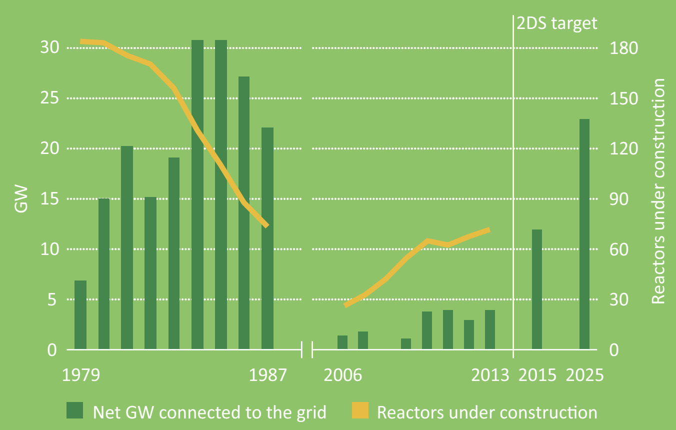
23

GW REQUIRED CAPACITY ADDITIONS YEARLY FROM 2020 TO 2030

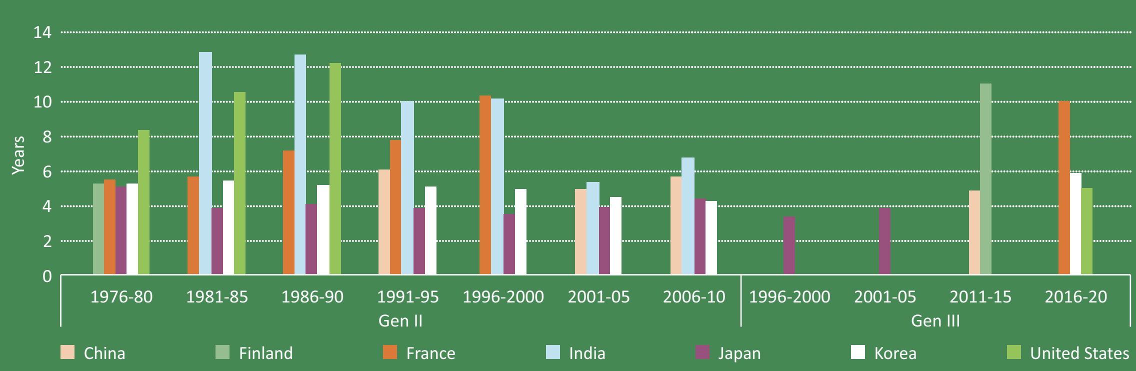
30

GW HISTORIC HIGH IN CAPACITY ADDITIONS

2.11 Capacity additions



2.12 Construction span for Gen II and Gen III reactors



For sources and notes see page 109

Natural Gas-Fired Power

Improvement needed

Natural gas lowers carbon dioxide (CO_2) emissions in two principal ways: directly by displacing coal and indirectly by providing flexible support for variable renewables. With a 1.5% increase over 2010, natural gas-fired power generation reached 4 850 TWh globally in 2011, 22% of total power generation.

Technology penetration

In the OECD region, growth is even quicker, 6% in 2012 compared with 2011. A five-year period of shift from coal to gas in the United States stalled in 2013 though, following a slight rebound in natural gas prices and a relatively cool summer.

Despite high prices, Japan increased its dependence on imported natural gas to ensure reliable electricity supply, following the shutdown of all nuclear reactors subsequent to the Fukushima Daiichi accident. The future of nuclear and the possibility of electricity system liberalisation will define the future of natural gas power. Natural gas remains the dominant fuel in ASEAN countries, but high natural gas prices and power demand growth double the global average make coal an increasingly attractive alternative.

In the European Union 20 GW of combined-cycle gas turbine (CCGT) plants were either mothballed in 2013 or are under threat of being so as utilisation rates fell below 25% for some units. In OECD Europe the share of natural gas in the power mix fell from 22% to 19% between 2011 and 2012. Decreasing power demand, overcapacity, the rise of renewable energy and low coal prices make the situation for natural gas power challenging.

Market creation

Development of natural gas trade capacity is accelerating, sparked by high price spreads among regions. Liquefaction capacity increased to roughly 400 billion cubic metres (bcm) globally, with an additional 140 bcm under construction (IEA, 2013b). As of end-2013, the United States had approved applications to build four terminals to export liquefied natural gas (LNG) to countries outside the US free trade agreements (non-FTA countries). China began the last phase to increase the capacity of a 5 000 km west-east pipeline that connects to the Central Asia pipeline system (completion in 2015).

Replication of the US shale gas boom in other regions seems unlikely in the short to mid term. Governments remain divided on exploration policy and geological uncertainty is high. In China, a number of appraisal wells have been drilled, but extraction is expected mainly after 2020: the official target is 6 bcm by 2015 and 100 bcm by 2020. The Indian government approved shale gas exploration. In Europe, a handful of countries have banned fracking while others issue exploration licenses. So far test drilling has shown less favourable conditions than in the United States and local opposition is strong in some places.

Technology developments

The focus of gas turbine design is shifting to flexibility performance as the role of natural gas evolves. High cycle efficiency that includes good ramping capabilities, quick start-up time, low turndown ratio and good part-load behaviour are now major design parameters. All major turbine manufacturers have released upgrades or new designs since 2012 to meet the power sector's need for flexibility.

In parallel, moderate full-load efficiency improvements continue. Top open-cycle gas turbine (OCGT) efficiency has risen to around 42% from around 35% in 1990. The best CCGT efficiency now exceeds 60%, up from about 55% in 1990.

Rising flexibility needs make internal combustion engines (ICEs) increasingly attractive for power, as single-unit plants (< 20 MW), stacked in so-called "bank" or "cascade" plants (20 MW to 200 MW), or operated with a combined steam cycle (> 250 MW). At 48% full-load efficiency, ICEs outperform OCGTs (< 42%) but fall short of CCGTs (< 61%), while having better flexibility and part-load efficiencies. Nine of the world's ten largest ICE-based power plants were to start between 2010 and 2014, all in developing countries.

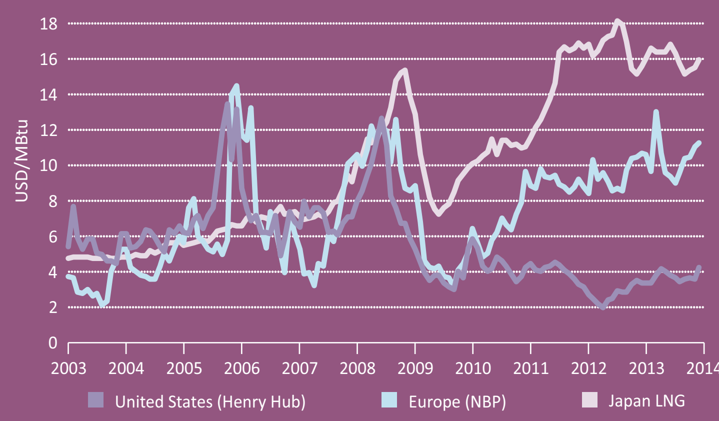
Coal-to-gas or gas-to-coal?

Regional market dynamics are producing divergent trends in coal to gas fuel switching

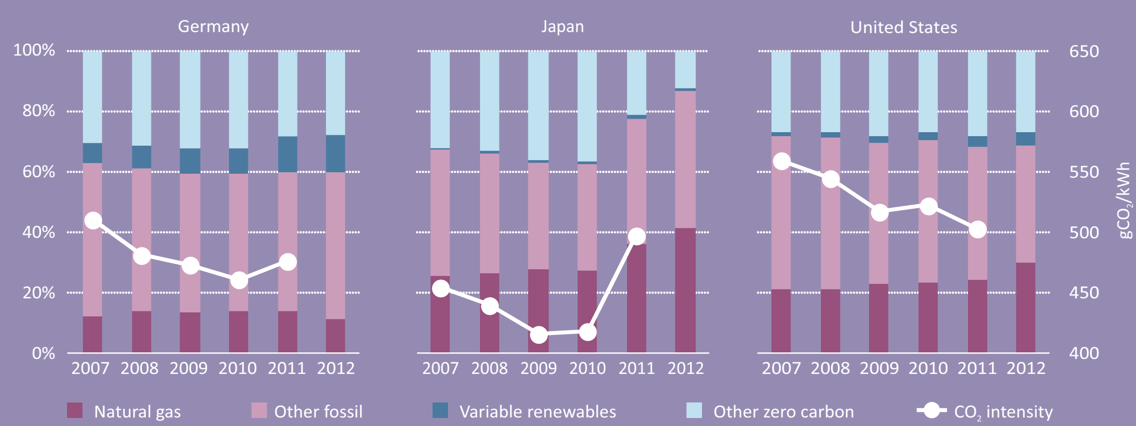
A replication of the United States shale gas boom in other regions seems unlikely in the short to mid-term

A five-year period of shift from coal to gas in the United States stalled in 2013

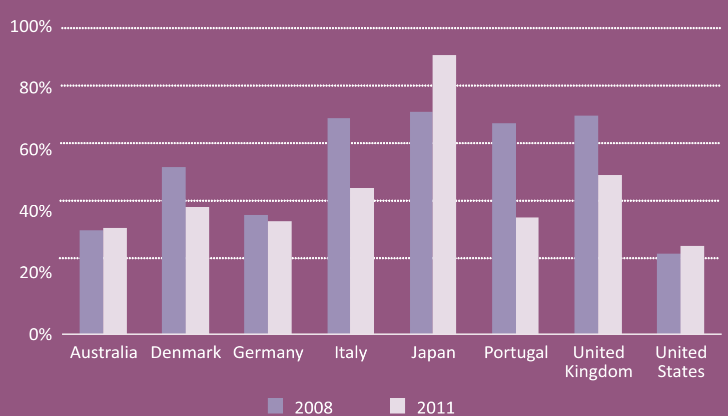
2.13 Natural gas spot prices



2.14 Power generation mix and related CO_2 intensity



2.15 Natural gas-fired power capacity factors



EU CO_2 PRICE

50 €/tCO_2

FOR SHORT-TERM COAL-TO-GAS GENERATION SWITCH

20 €/tCO_2

FOR LONG-TERM CAPACITY INVESTMENT SWITCH

For sources and notes see page 109

Coal-Fired Power

Not on track

Coal continues to dominate global power generation. In 2011, coal-fired electricity generation was over 9 100 TWh, a 52% increase over 2000 levels. At 41%, coal has the largest share in global generation by far. Driven by coal-to-gas switching in the United States, the share of coal in power generation fell to 32.1% in OECD in 2012, down from 33.4% in 2011.

Technology penetration

China and, to a lesser extent, India play key roles in driving this growth in demand. In 2012, China built 48 GW of new coal capacity and accounted for almost 50% (3 678 million tonnes [Mt]) of global coal consumption; India's share (753 Mt) was almost 10%. In Germany, 2.7 GW of lignite capacity became operational in 2012. Primary coal demand is estimated to increase from 158 exajoules (EJ) (7 697 Mt) in 2012 to 186 EJ (8 799 Mt) in 2018 (+ 2.3% per annum). These trends are not compatible with the 2DS.

The efficiency of generation is increasing. Globally, 64% of plants under construction are supercritical or ultra-supercritical, up from 50% in 2012. More than 60% of subcritical units under construction are in India. Between 2006 and 2010, China retired 77 GW of old inefficient plants, with a target to retire a further 20 GW by 2015. Having recently retired 1.4 GW, Germany plans to retire a further 1.5 GW by 2015. These essential trends to increase global generation efficiency must be combined with accelerated development of CCS if 2DS targets are to be reached.

Market creation

Policy offers routes to emissions reductions. China's recently released Air Pollution Action Plan aims to reduce the share of coal below 65% of total power generation by 2017 (from 79% in 2011). In September 2013, China announced that it will ban construction of new coal-fired power plants in the Beijing, Shanghai and Guangdong regions. Overall, the provinces around Beijing will reduce annual coal consumption by 73 Mt, around 10% of 2012 levels.

While Canada has already imposed emissions performance standards on its coal plants to become effective in 2015, the US Environmental Protection Agency's proposal to limit CO_2 emissions to 500 gCO_2 per kilowatt hour for new coal-fired plants, a level that cannot be achieved without CCS, was published in the Federal Register in January 2014. Furthermore, the EPA proposes to issue emissions standards for existing power plants by mid-2014, to be finalised by mid-2015.

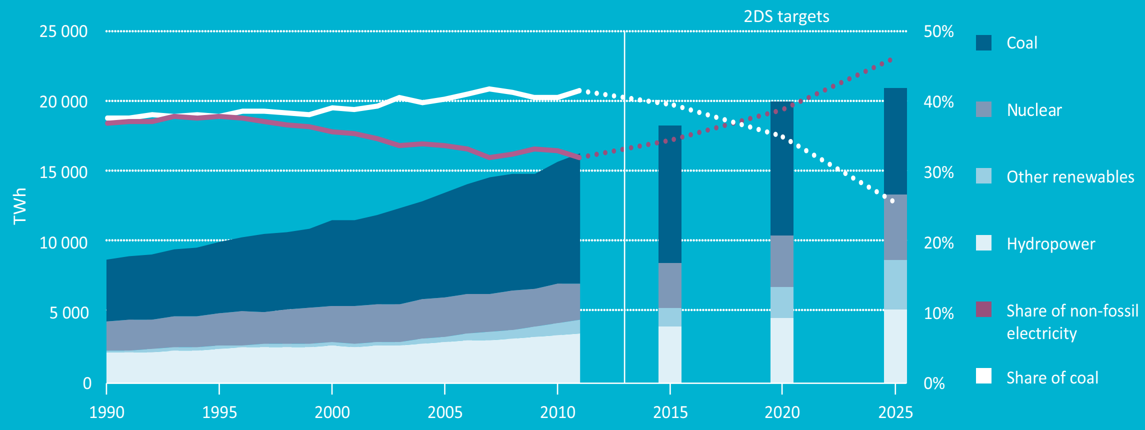
Cleaner use of coal can be achieved by strengthening bilateral or multilateral co-operation. China and the United States, the world's two largest coal users, emphasised in 2013 further co-operation in cleaner coal use, pollutant control in pulverised power generation plants, CCS, and selected CO_2 utilisation options.

Technology developments

The size of units is increasing, again, trends are most pronounced in China. The country has become a world leader both in number of installed units and in unit size. China installed the first 1 GW ultra-supercritical coal-fired unit in 2006, and by mid-2012, a further 46 units of this size were in operation. Japan's 600 MW Isogo Power Station Unit 2 possesses the world's most advanced environmental control system to minimise sulphur dioxide (SO_2) and nitrogen oxide (NO_X) emissions, as well as waste-water discharge. With a net efficiency of 45%, it emits over 25% less CO_2 than a plant operating with global average efficiency.

A major advantage of integrated gasification combined cycle (IGCC) plants is that they may reduce the cost of CO_2 capture. Climate change targets therefore offer the technology a second opportunity, after the cost of generation halted commercial interest after the first wave of IGCCs was commissioned in the 1990s. IGCC plants have recently been commissioned in China (GreenGen in Tianjin) and the United States (Edwardsport in Indiana), with further plants following closely behind in the United States (Kemper County, Hydrogen Energy California and Summit Texas Clean Energy) and in Japan (Osaki).

2.16 Coal and non-fossil power generation



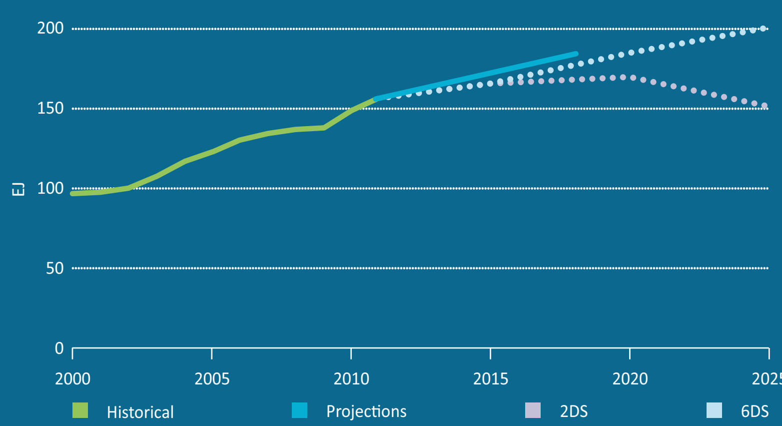
Key trends

Around half of new power plants in 2012 used inefficient subcritical technologies

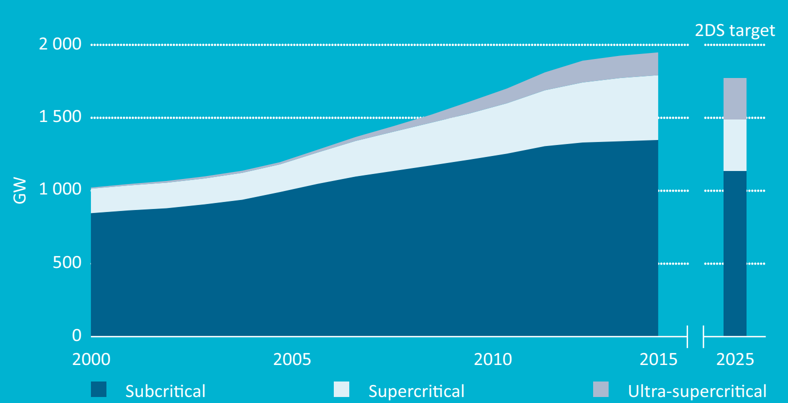
Decommissioning of old plants continues in China with close to 100 GW of inefficient plants taken offline since 2006

Proposed policies in the United States would prohibit construction of new coal plants without CCS

2.17 Global coal demand



2.18 Coal capacity deployment



33%

GLOBAL FLEET AVERAGE EFFICIENCY, COMPARED TO 46% WITH ULTRA-SUPERCRITICAL

For sources and notes see page 109

Carbon Capture and Storage

Not on track

Deployment of CCS in both power and industry is critical to address climate change. While progress is being made in demonstrating elements of capture, transport and storage the current pace of development must grow rapidly if CCS is to fulfil its potential.

Technology penetration

As of end-2013, four large-scale CCS projects are in operation and have captured and stored approximately 55 $MtCO_2$ in total. In addition, four large-scale enhanced oil recovery (EOR) projects that demonstrate elements of CO_2 capture, transport and storage entered operation in 2013, bringing the number of projects using anthropogenic CO_2 for EOR to eight.

Construction of nine large-scale projects with combined potential to capture and store an additional 14 $MtCO_2$ per year by 2016 is proceeding in Australia, Canada, Saudi Arabia, the United Arab Emirates, and the United States. Among these are two of the first projects built in the electricity sector. An additional 15 projects are in advanced stages of planning; if built, they could contribute an additional 29 $MtCO_2$ per year.

Of these 36 projects, 28 are in OECD countries. In the 2DS in 2025, OECD countries contribute only one-third of the CO_2 captured – additional demonstrations are thus needed in non-OECD countries. In the 2DS, 226 $MtCO_2$ per year are captured and stored by 2025, which means that the rate of capture and storage must increase by two orders of magnitude in the next decade to achieve 2DS targets.

Market creation

One CCS project took a positive final investment decision in 2013, and increasing the cumulative investment in CCS by USD 123 million to USD 10.5 billion. Up to six projects are expected to take final investment decisions in 2014.

OECD governments offered approximately USD 22 billion in direct financial support to large-scale CCS projects between 2008 and 2012. Most funded projects in North America are progressing, but few projects were funded in Europe and Australia, and many have since been cancelled or face serious delays.

Development of co-ordinated policy packages that address distinct market risks will be crucial in the coming years. In late 2013, the United Kingdom passed legislation that will allow the government to provide operating support to CCS projects. This mechanism will operate alongside a CO_2 price floor and emissions performance standard for new power generation. Carbon pricing is a critical long-term driver for CCS but is unlikely to stimulate deployment in the short term. In 2013, the US EPA proposed a rule that would require new coal-fired generation to be equipped with CCS. If this rule is adopted, the United States will join Canada and the United Kingdom in having regulations that effectively prohibit construction of new coal-fired generation without CCS. Moreover several international financing banks restricted funding for coal plants without CCS.

In the near term, utilisation of captured CO_2 (such as in EOR), will continue to drive interest in CCS, particularly from private investors: 24 large-scale projects are providing, or are expected to provide, CO_2 for EOR.

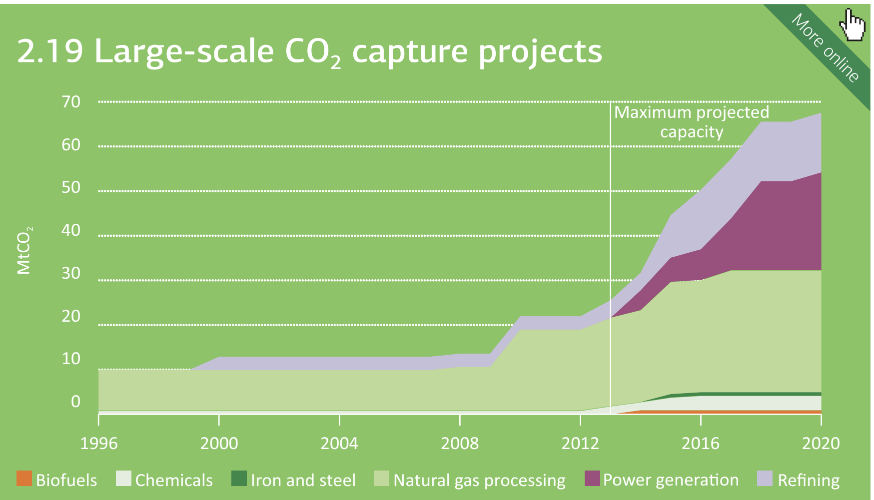
Technology developments

At least six CCS pilot projects began operation in 2013, and construction of several other projects has been announced, including a capture demonstration at a cement plant in Norway. This brings the total number of CCS pilot projects to approximately 60.[3]

IEA member governments spent an estimated USD 1.1 billion on RD&D for CCS in 2012, about 6.6% of their total energy RD&D expenditure, up 21% from 2011. The share of CCS in fossil fuel RD&D expenditure has increased significantly since 2008, from 22% to almost 54% in 2012. The number of new patent applications that relate to CCS continues to grow each year. Commercial interest in developing relevant technologies is still growing, but the level of patenting activity in 2012 may signal a slight softening of the exponential growth between 2006 and 2011.

3 Pilot projects are defined as those that test one or more elements of capture, transport or storage at a scale that is one or two orders of magnitude below that required for commercial use, in this case on the order of 10 kilotonnes of CO_2 per year. For information on storage projects, see GHG IA, 2013 for capture, see Aldous et al., 2013.

2.19 Large-scale CO_2 capture projects



55

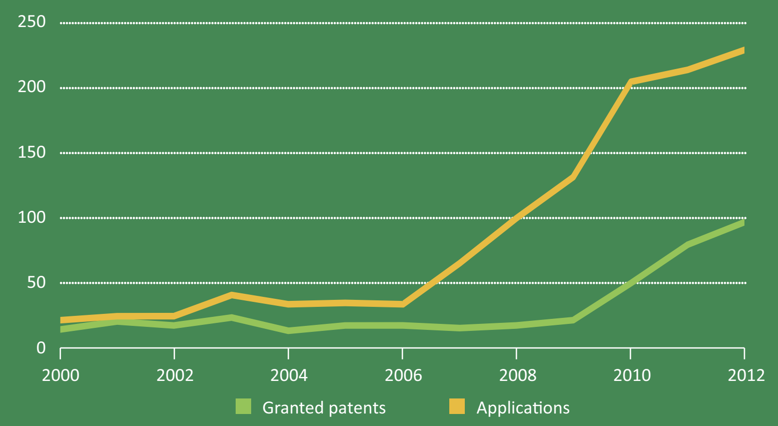
MILLION TONNES OF CO_2 STORED WITH MONITORING SO FAR

Key developments

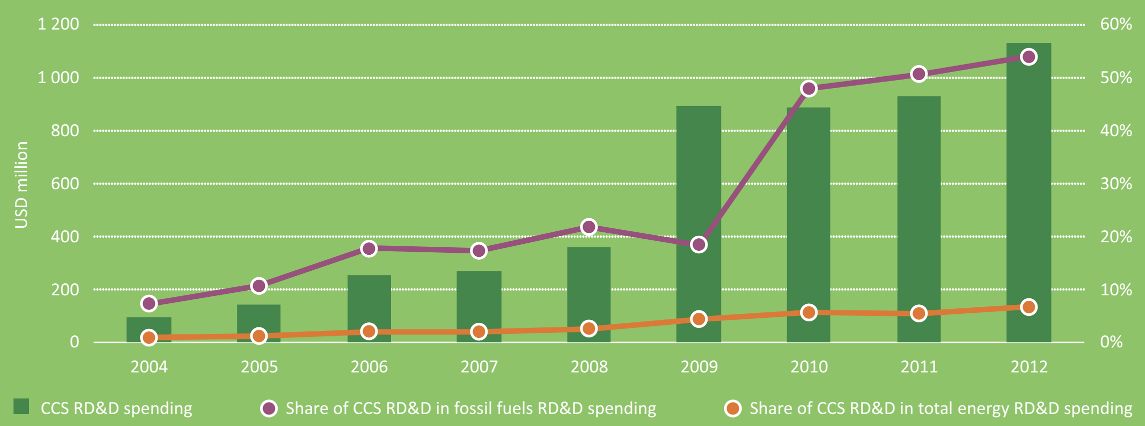
The first two coal-fired power plants to capture over 1 million tonnes of their CO_2 per year will start operation in 2014

Commercial CO_2 capture in the refining and gas processing sectors continues to provide CO_2 for EOR, increasing confidence in the technology

2.20 Patenting activity in CCS-related technologies



2.21 IEA public RD&D spending



For sources and notes see page 109

Industry

Improvement needed

Global industrial energy intensity has decreased 10% since 2000, mainly as a result of efficient capacity additions in emerging economies outweighing the upward effects of structural changes in the sector.[4] Despite this trend, industrial energy use and CO_2 emissions increased significantly.

Technology penetration

Industrial energy use reached 143 EJ[5] in 2011, up 36% since 2000. The increase is largely fuelled by rising materials demand in non-OECD countries, which now use 66% of industrial energy, up from 50% in 2000. Growth in industrial energy use must be cut to 1.7% per year in the period from 2011-25 compared with 3.3% per year in 2000-11. Similarly, trends in industrial CO_2 emissions must be reversed: from 2007 to 2011, emissions grew by 17%; by 2025, they must be reduced by 17% to meet 2DS targets.

Improvements in energy efficiency have offset the upward effect of structural changes in the industrial sector, such that overall industrial energy intensity is decreasing; in 2011 most regions were below a level of ten gigajoules (GJ) per thousand USD purchasing power parity (PPP) of industrial value added. China (2.4%) and India (1.9%) have had the highest annual reductions since 2000. Thanks to high shares of new capacity, China is now among the world's most energy-efficient primary aluminium producers.

Substantial potential to further improve energy efficiency exists. By applying current best available technologies (BATs), the technical potential to reduce energy use in the cement sector is 18%, 26% in pulp and paper, and 11% in aluminium. These potentials are unlikely to be fully tapped by 2025 due to slow turnover of capacity stock, high costs and fluctuation in raw material availability. Meeting 2DS targets will also require resolving challenges related to increased use of alternative fuels and clinker substitutes, and greater penetration of waste heat recovery (WHR)[6] in the cement sector, among others.

Market creation

Energy management systems (EnMS) can be effective tools to enable energy efficiency improvements, but in most countries they are still voluntary. In 2013, China mandated provincial-level implementation of energy management programmes in companies covered by the Top-10 000 Program, an energy conservation policy for large energy users. In the United States, pilot companies in the Superior Energy Performance programme on average improved their energy performance by 10% in 18 months. The Australian Energy Efficiency Opportunities programme, which is mandatory for large energy users, was estimated to have enabled 40% energy savings in participating firms. A growing number of industrial sites have certified EnMS (ISO 50001) in place: 6 750 in 70 countries in March 2014, up by more than 300% over the previous year (Peglau, 2014).

Technology developments

Innovative energy-saving technology developments have been relatively slow in energy-intensive industries over the last decade and need to accelerate: in the 2DS for instance, deployment of CCS starts before 2025. To stimulate investment in CCS, industry is investigating opportunities for CO_2 use in EOR and developing processes that use CO_2 as a feedstock (e.g. in polymer production).

In pulp and paper, the Confederation of European Paper Industries (CEPI) announced in 2013 promising lab-scale results of deep eutectic solvents (DES) allowing the production of pulp at low temperatures and atmospheric pressure. Applying DES-based pulp making throughout the sector could reduce CO_2 emissions by 20% from current levels by 2050 (CEPI, 2013).

4 Structural changes in the industrial sector refer to a shift in the share that energy-intensive industries represent in total industrial energy use. The energy-intensive sectors increased their share to 67% in 2011 from 57% in 1990.

5 Industry energy use data includes feedstock in the chemicals and petrochemicals sector, and coke ovens and blast furnaces in the iron and steel sector.

6 IEA analysis shows that 12% to 15% of the power consumption of a cement plant can be generated by WHR technologies.

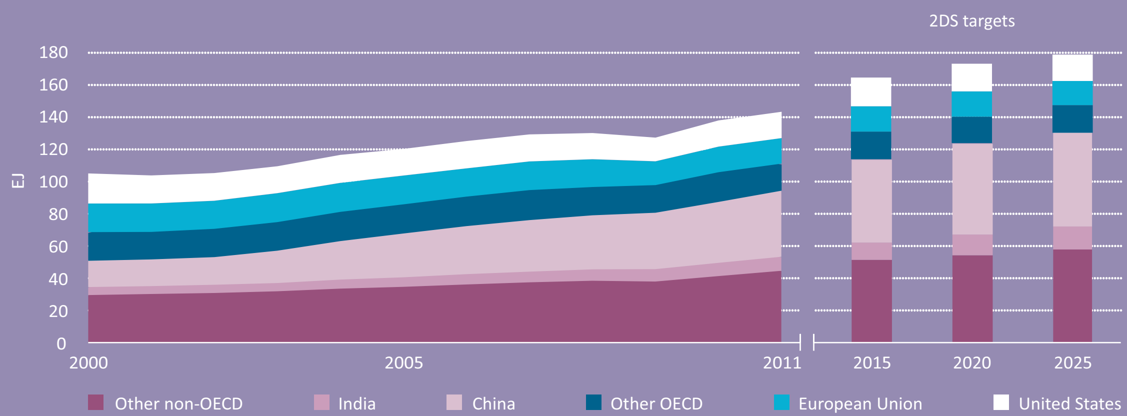
2.22 Energy intensity by product

	Current BAT	2011 World	2011 OECD	2011 Non-OECD	2025 2DS targets World	2025 2DS targets OECD	2025 2DS targets Non-OECD
Paper and paperboard (GJ/t)	n.a.	7.6	7.5	7.7	6.7	6.8	6.6
Clinker (GJ/t)	3.0	3.7	3.6	3.7	3.6	3.5	3.6
Primary aluminium (kWh/t)	13 611	14 788	15 587	14 509	13 383	14 833	13 141

26%

TECHNICAL POTENTIAL TO REDUCE ENERGY USE IN THE PULP AND PAPER SECTOR BY APPLYING BATS

2.23 Global industrial energy use

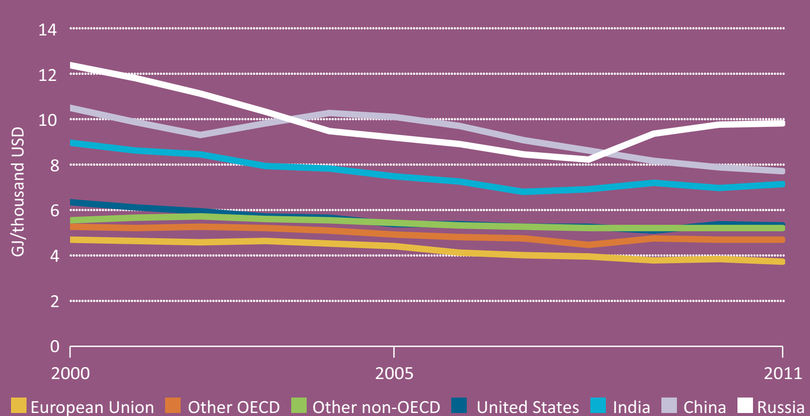


Key developments

12% to 15% of the power consumed in a cement plant can be generated through waste heat recovery

Energy management systems and programmes are receiving increasing policy attention

2.24 Aggregated industrial energy intensity



For sources and notes see page 109

Chemicals and Petrochemicals

Improvement needed

Accounting for 28% of total industrial energy use in 2011, the chemicals and petrochemicals sector is the largest industrial energy user. Energy use in the sector grew by 2.5% annually from 2000 to 2011. With demand for chemical and petrochemical materials projected to grow even faster in the coming years, the annual increase in energy use must be kept to 4.3% to meet 2DS targets; this will still result in a total increase of 60% in 2025 over 2011 levels. In parallel, CO_2 emissions must be cut by 30% compared with 2011. Both targets require significant improvements over current trends.

Technology penetration

In the 2DS, production of high-value chemicals (HVC)[7] is expected to grow from 320 Mt in 2011 to 485 Mt in 2025 (up 52% on 2011 levels), with notable production growth in ammonia (31%) and methanol (126%). The Middle East and China remain the major HVC producers and have the highest growth projections, even though the availability of cheap natural gas and natural gas liquid products from the exploitation of unconventional gas resources has driven a recent regional shift of production towards North America. Improvements in efficiency (based on increased levels of process integration driven by increasing energy prices), along with waste heat recovery and expansion of new, more efficient capacity, can help decouple materials demand growth from energy use.

Application of best practice technologies (BPTs) could save 24% of current energy use. This technical energy savings potential is unlikely to be fully tapped by 2025 due to dependency on existing production capacity stock turnover, demands for returns on investment for upgrades/refurbishment projects, fluctuation in raw material availability, etc. Reaching the 2DS targets requires that all new and refurbished plants adopt BPTs, switch to low-carbon fuels and increase recycling, and that emerging technologies start playing a role by 2020. Savings on process heat has the largest savings potential; the United States, a leading producer of chemicals and petrochemicals, has the largest savings potential of any country.

Market creation

No major new energy policy initiatives affecting the chemicals industry occurred in 2013; however, increased discussion between policy makers and industry was evident, particularly in Europe. The ongoing debate centres on how to reconcile sustainability and competitiveness (CEFIC, 2013).

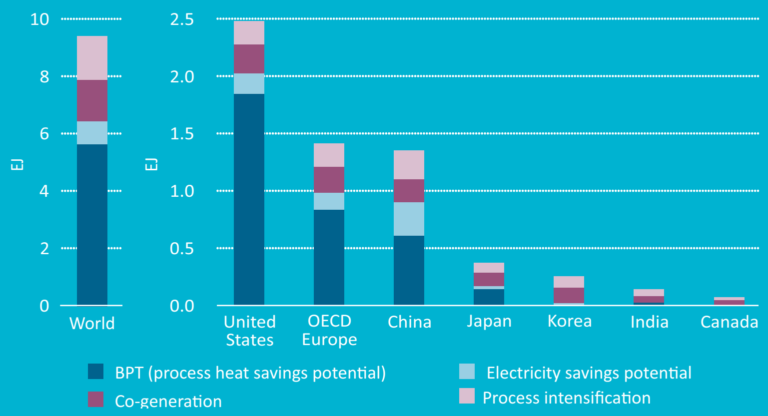
The IEA collaborated with the International Council of Chemical Associations (ICCA) and DECHEMA, the Society for Chemical Engineering and Biotechnology, to publish (in 2013) the *Technology Roadmap: Energy and GHG Reductions in the Chemical Industry via Catalytic Processes*. The roadmap also provides recommendations to policy makers and industry to enable implementation of identified savings potential (about 5 EJ by 2025,[8] or 13% of current sector energy use) (IEA, ICCA and DECHEMA, 2013).

Technology developments

Broad deployment of emerging technological improvements would be required to meet 2DS targets for the chemical industry. CCS applications should be successfully demonstrated by 2020 and should capture about 4% of the sector's CO_2 emissions by 2025. The methanol-to-olefins route, while more energy-intensive than steam cracking when the methanol production stage is included, allows for using biomass instead of fossil resources as feedstocks. Catalytic cracking can provide further energy efficiency benefits, using up to 20% less energy than steam cracking (Ren, Patel and Blok, 2006). This technology is currently at pilot scale.

7 HVCs include ethylene, propylene and BTX (benzene, toluene and xylene).
8 Energy savings resulting from comparing Business as Usual scenario and the Emerging Technologies scenario in 2025.

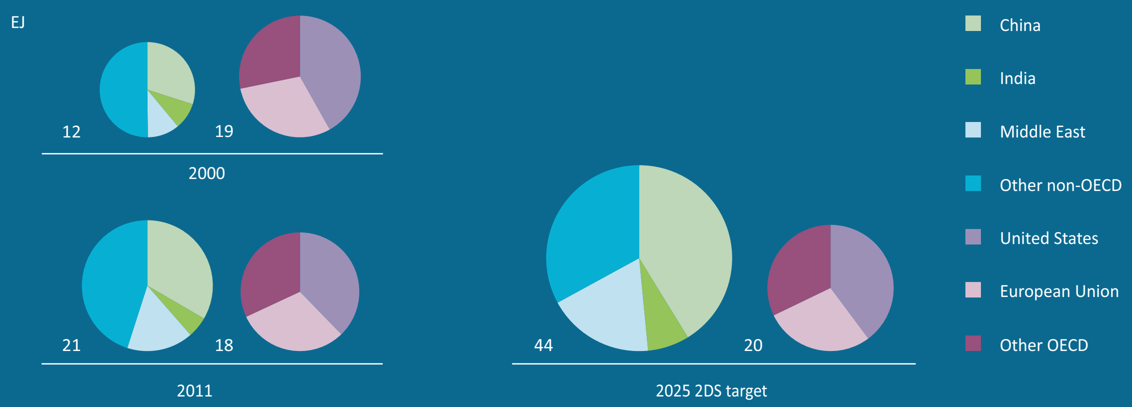
2.25 Energy savings potential in 2011



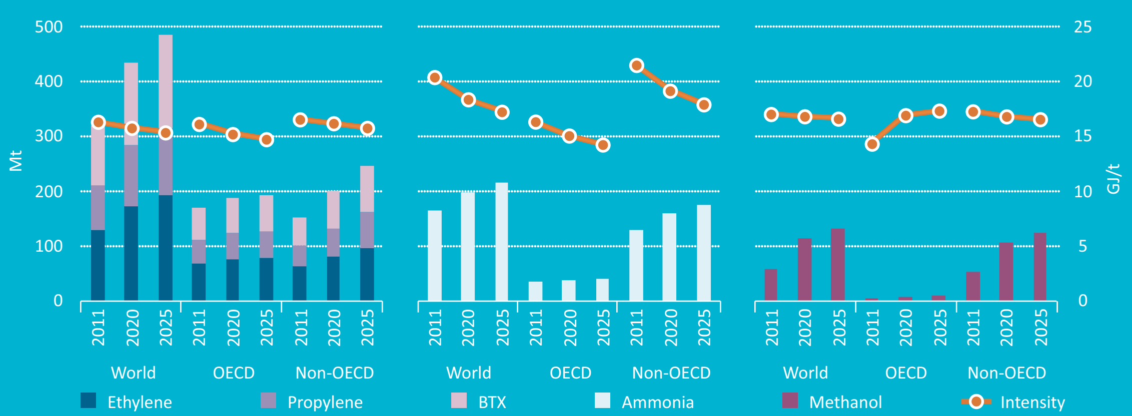
24%

OF ENERGY COULD BE SAVED WITH THE APPLICATION OF BEST PRACTICE TECHNOLOGIES IN THE SECTOR (6.6% OF INDUSTRIAL ENERGY)

2.26 Global energy consumption by region



2.27 Production and energy intensity



For sources and notes see page 109

Iron and Steel

Improvement needed

The iron and steel sector is the second-largest industrial energy consumer, accounting for 22% of total industrial energy use in 2011. The sector's energy use grew by 6.2% annually from 2000 to 2011, driven by increases in crude steel production (7.1% in 2011). In the 2DS, growth in annual energy use must be limited to 1.2% and CO_2 emissions must be 13% lower in 2025 compared with 2011 levels, even though crude steel production is expected to grow by 27%. Current trends run counter to this projection.

Technology penetration

Energy intensity is relatively stable in the steel industry: 20.7 GJ/t crude steel in 2011 versus 21.7 GJ/t crude steel in 2000. Positive effects of more efficient production capacity have been offset by a decline in recycling as a share of total crude steel production; from 47% in 2000 to 29% in 2011. Primary drivers include China's increased share of blast furnace/basic oxygen furnace technologies rather than scrap-intensive electric arc furnace (EAF) due to insufficient scrap availability, as well as the increasing amount of steel in products still in use. The overall share of EAF production from total crude steel must increase to 37% by 2025 to meet 2DS targets.

About 21% of energy use could be saved if current BATs were applied, but inertia in capacity stock turnover and high costs are slowing progress. Reaching 2DS targets requires that all new and refurbished plants adopt BATs, phase out open-hearth furnaces (OHFs) and limit coal-based direct reduced iron (DRI) production. Greater availability and use of scrap, as well as emerging technologies, must start playing a role by 2020. In total, global energy intensity must decrease to 18.9 GJ/t crude steel by 2025, down 10% compared with 2011.

Market creation

No major new policy developments specific to the iron and steel industry occurred in 2013, but dialogue regarding solutions for a low-carbon future has increased. To provide policy recommendations on the steel sector's contribution to decarbonisation, the European Commission published an *Action Plan for a Competitive and Sustainable Steel Industry in Europe*, and Eurofer (the European Steel Association) published a *Steel Roadmap for a Low Carbon Europe 2050*. The International Organization for Standardization (ISO) published a standardised method to calculate CO_2 emission intensity from iron and steel production (ISO, 2013).

Technology developments

Emerging technologies – such as CCS, smelting reduction and blast furnace with top-gas recycling – need to be deployed in order to reach 2DS targets. The Ultra-Low Carbon Dioxide Steelmaking (ULCOS) consortium, comprising 48 European companies and organisations, aims to dramatically reduce CO_2 emissions of the steelmaking process. But in late 2012, an ULCOS-supported demonstration plant with top-gas recycling was delayed due to technical and financial issues. Steel industry stakeholders are now pursuing the Low Impact Steel making project, which aims to demonstrate a commercial-scale blast furnace with CCS.

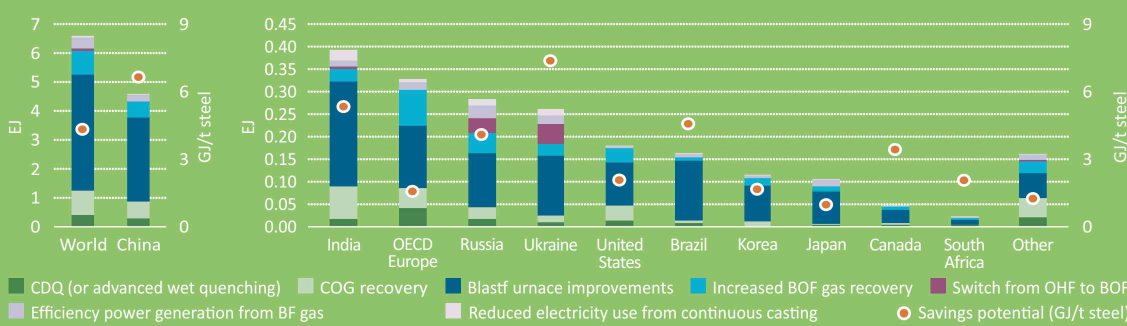
The COURSE50[9] program in Japan is a NEDO[10]-funded partnership with the Japanese steel industry that provided JPY 10 billion from 2008 to 2012 (Phase 1 Step 1). It seeks to develop technologies to reduce CO_2 emissions from steelmaking by 30%, including hydrogen reduction and capture and recovery of blast furnace gases. A trial hydrogen reduction operation was successfully completed in 2012, and the project aims to commercialise the technologies by 2050. Phase 1 Step 2 of this program is expected to be completed in 2017.

9 CO_2 Ultimate Reduction in Steelmaking Process by Innovative Technology for Cool Earth 50.
10 New Energy and Industrial Technology Development Organization.

2.28 Progress in emerging technologies

	Status	Description	Recent developments
HISmelt®	Commercial, not currently operational.	Direct smelting process producing pig iron directly from ore using a smelt reduction vessel. Eliminates need for traditional blast furnace and coking coal.	■ First plant relocated from Australia to China with planned operation in 2014 and 500 kt capacity. ■ 1 Mt to 1.2 Mt steelworks planned in India, to be operational in 2016.
HISarna®	Pilot stage, demonstration needed.	Iron-making process combining HISmelt® bath smelting process with a cyclone furnace, using thermal coal and fine iron ore to combine the coking and agglomeration. Allows more fuel flexibility, including hydrogen use.	■ Pilot project complete. ■ Commercial grade steel produced at pilot plant in 2013. ■ No large-scale demonstration currently planned.
COREX®	Commercial, not widely deployed.	Direct smelting process using non-coking coal as reducing agent and energy source with sinter, lump ore or pellets. Eliminates need for traditional blast furnace.	■ Commercialised in 1989. ■ Three plants currently in operation in India and South Africa.
FINEX®	Commercial, not widely deployed.	Direct smelting process using non-coking coal as reducing agent and energy source, with unagglomerated fine iron ore. Eliminates need for traditional blast furnace.	■ Commercialised in Korea in 2007. ■ 3 Mt integrated steelworks planned in China following feasibility study and Memorandum of Agreement.
Top-gas recycling blast furnace	Pilot stage, demonstration needed.	Separation of blast furnace off-gases into components for reuse in the furnace as reducing agents. Reduces coke needs and can facilitate CCS performance.	■ Full-scale demonstration was planned in France, but cancelled for technical and financial reasons. ■ No demonstration currently planned.

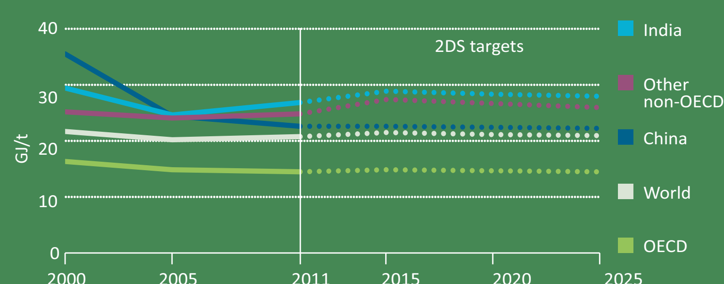
2.29 Energy savings potential in 2011



6.6

EJ COULD BE SAVED IF BEST AVAILABLE TECHNOLOGIESWERE APPLIED (4.6% OF INDUSTRIAL ENERGY)

2.30 Aggregate energy intensity



For sources and notes see page 109

Transport

Improvement needed

Energy consumption in transport reached 102 EJ in 2011, a 25% increase from 2000 (2% per year), with road transport taking the largest share (76 EJ). Passenger light-duty vehicles consume slightly more than 40% of total transport energy demand and cover half of global passenger mobility (expressed in passenger-kilometres). Road freight accounts for nearly 30% of energy use and about half of inland tonnage (tonne-kilometres). Shipping and air take up 10% of demand; 7% is needed for buses and trains. All transport accounted for 22% of global CO_2 emissions in 2011.

Technology penetration

Recent progress in hybrid electric vehicles and electric vehicles (HEVs and EVs) delivered important fuel economy improvements for road transport (see separate section). Renewed interest in diversifying energy sources is influencing vehicle technology, especially in areas where natural gas prices have decoupled from oil (EUNGVA, 2013). Bus rapid transit (BRT) systems are gaining ground as a means to shift passenger travel to more sustainable modes. By 2013, more than 200 cities in 48 countries had BRT (EMBARQ, 2014).

Various measures bring aviation close to the 2DS trajectory. Per-tonne fuel efficiency has improved by 1.2% per year since 2005 (IATA, 2013); the industry aims for 1.5% per year to 2025 (ATAG, 2013).

Market creation

Fiscal policies on fuels affect transport activity, modal choice and vehicle technology. Fuel taxation should ensure that driving costs reflect actual costs; dropping fuel subsidies (as Indonesia did in 2013) is one way to prompt switching to fuel-efficient vehicles.

Access restriction and congestion charging can rationalise travel choices, shift travel to collective transport modes and stimulate innovative vehicle technologies.

Fuel economy policies for new light- and heavy-duty vehicles, coupled with consumer information schemes, are important market drivers for energy efficient transport. Fuel economy standards for light vehicles are in place in Australia, Canada, China, the European Union, Japan, Korea, Mexico and the United States; Brazil recently undertook policy action in this area. Only Japan, China and the United States have fuel economy standards for heavy road transport. The European Union plans to implement such standards by 2015; Korea, Canada and Mexico are developing policy proposals.

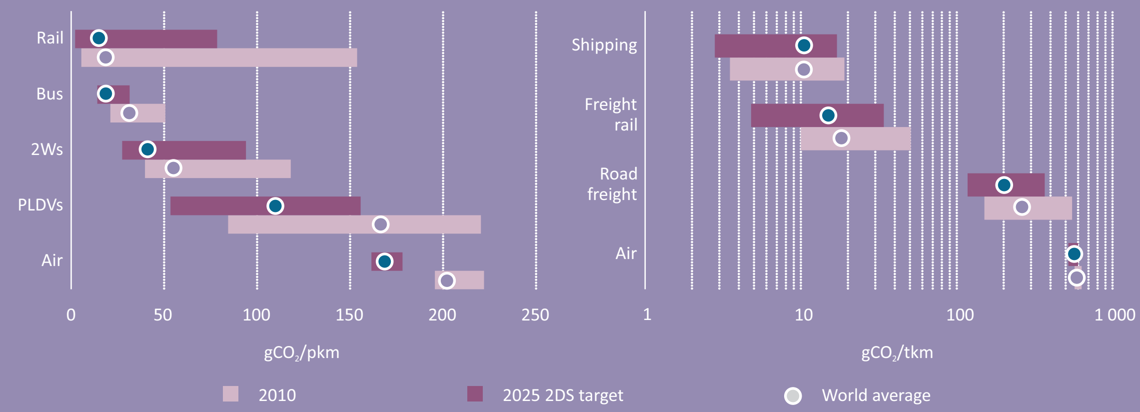
In October 2013, the International Civil Aviation Organization (ICAO) set a framework for carbon-neutral growth starting in 2020, supported by market-based mechanisms. ICAO member states also adopted aspirational goals to 2020, with a declared aim of improving efficiency by 2% per year until 2020 (ICAO, 2013).

Technology developments

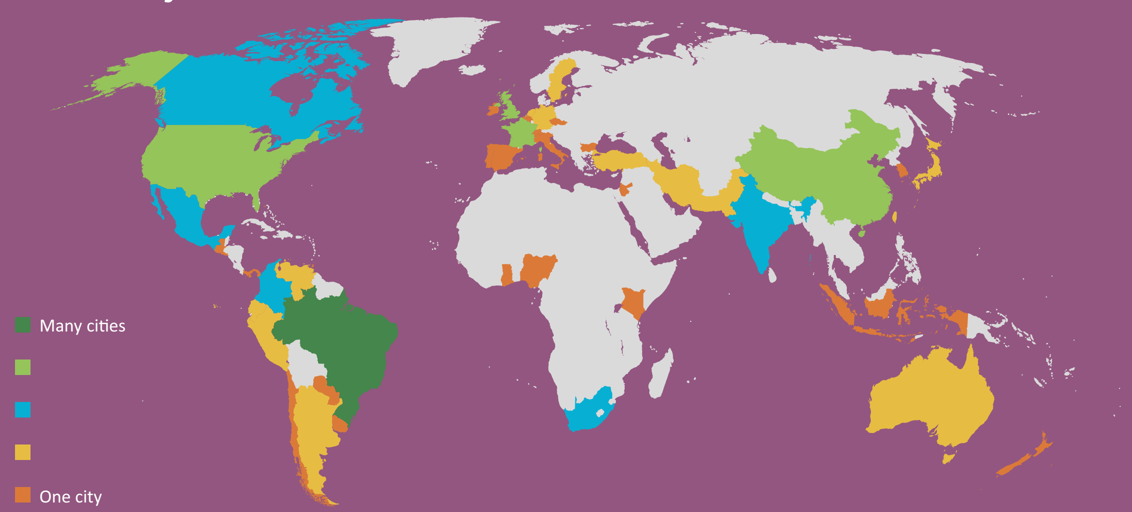
Fuel economy solutions on ICEs can deliver the largest fuel savings in the short term. Hybridisation could deliver the savings required by fuel economy improvement policies. HEVs are seen as a bridging solution towards massive deployment of EVs and plug-in HEVs (PHEVs). Electric motors, coupled with fuel cells, open the possibility of using hydrogen for transportation (IEA, 2014). While some production and distribution barriers remain for using natural gas and/or electricity for cars, hydrogen deployment faces substantial challenges,

Newer aircraft have more electrified systems to improve overall energy efficiency; installation of carbon fibre parts is helping to lighten the body and save fuel.

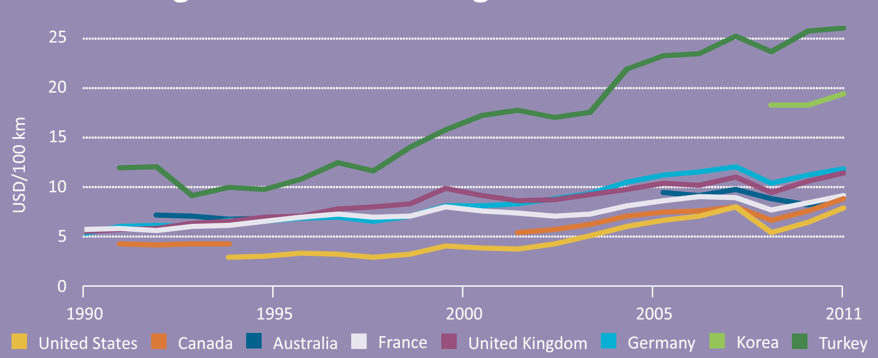
2.31 Well-to-wheel CO_2 intensity



2.32 BRT systems



2.33 Average new vehicle driving cost in selected countries



3

COUNTRIES HAVE FUEL ECONOMY STANDARDS FOR HEAVY ROAD TRANSPORT

For sources and notes see page 109

Electric and Hybrid Electric Vehicles

Improvement needed

Sales of EVs grew 50% from 2012 to 2013, reaching 170 000; sales of non-plug-in HEVs remained stable at 1.3 million. This is encouraging, but it falls below the levels needed to meet the ambitious 2DS targets, as in 2025 EV and HEV sales should grow 80% and 50% per year respectively.

Technology penetration

With almost 100 000 vehicles sold, the United States had the biggest increase and almost matched global EV sales in 2012 (115 000).

The global EV stock reached 350 000 vehicles at the end of 2013, still far from the 2DS target of 1 million in 2015 and the extremely ambitious target of 80 million EVs by 2025. In the Netherlands, Norway and the United States, among other countries, EVs now account for over 1% of sales.

Sales of non-plug-in HEVs reached 1.6% of global market share in 2013, with 52% of sales in Japan and 39% in the United States. The 2DS sees annual HEV sales at 17 million in 2025 (15% market share).

Growth of electric bikes is also significant. China has the biggest fleet, with more than 150 million battery-electric 2-wheelers on the road (over 50% of the 2-wheelers stock). The 2 600 plants in China that manufacture 36 million e-bikes annually will drive the stock increase in all of Asia.

Market creation

Early estimates [11] show that the EV charging infrastructure has continued to expand rapidly, with 12 500 (+ 27%) slow and 1 300 (+ 67%) fast chargers installed in 2013.

Governments participating in the Clean Energy Ministerial (CEM) Electric Vehicles Initiative (EVI) continued putting in place policy measures such as rebates or tax credits on vehicles, purchase subsidies, or exemption from vehicle registration taxes or license fees. Policy measures and programmes should have longer time frames and create favourable conditions in urban areas subject to access restriction and congestion charging to boost industry confidence that market demand will continue to grow over the short term and beyond.

Car sharing of EVs is growing in popularity and accounts for 10% of global vehicles in such schemes. Renting or leasing EVs helps to mitigate some consumer concern about battery life and range.

A five-year Clean Air Action Plan (2013-17) for Beijing rules that of 600 000 new vehicles to be allowed in the city in the next four years, 170 000 should be EVs, PHEVs or fuel-cell vehicles. In 2014, a quota of 20 000 new car registrations will be given to such vehicles.

HEVs failed to expand beyond core markets in Japan and the United States (91% of global sales in 2013). Japan's initial subsidies for HEVs were discontinued at the end of September 2012, with no further incentives envisioned. A tax reduction still exists for HEVs, PHEVs, battery-electric vehicles (BEVs) and clean diesel vehicles. The United States has no subsidies at the federal level, although HEVs qualify within vehicle acquisition laws that promote alternative fuel vehicles in government fleets. Several state incentives exist, both financial and non-financial (e.g. priority access on highways).

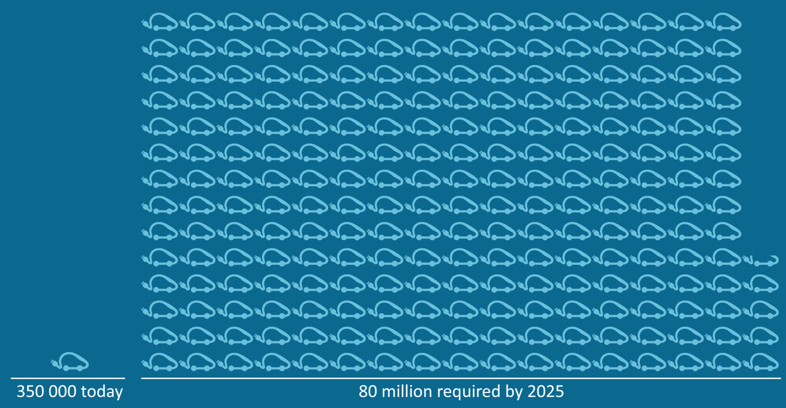
Technology developments

Batteries remain the most costly component of EVs. Encouraging signals are emerging from research laboratories, [12] with costs moving towards the target of USD 300/kWh by 2020 (from the 485 USD/kWh estimate of 2012), which should make EVs competitive with ICEs.

11 Data only available for six countries until end of September 2013.

12 According to the US Department of Energy (personal communication), battery cost is based on development efforts costing USD 400/kWh of usable energy at the end of 2013. Costs do not include warranty costs or profit, and are based on a production volume of at least 100 000 batteries per year.

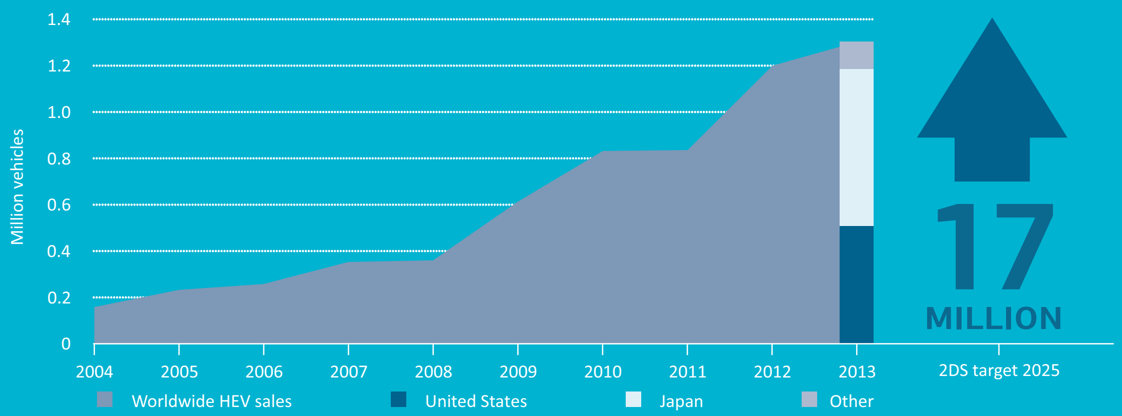
2.34 Global electric vehicles stock



10%

OF VEHICLES IN CAR-SHARING PROGRAMS AROUND THE WORLD ARE EVS

2.35 Global hybrid electric vehicle sales



REQUIRED ANNUAL SALES GROWTH RATE TO 2025

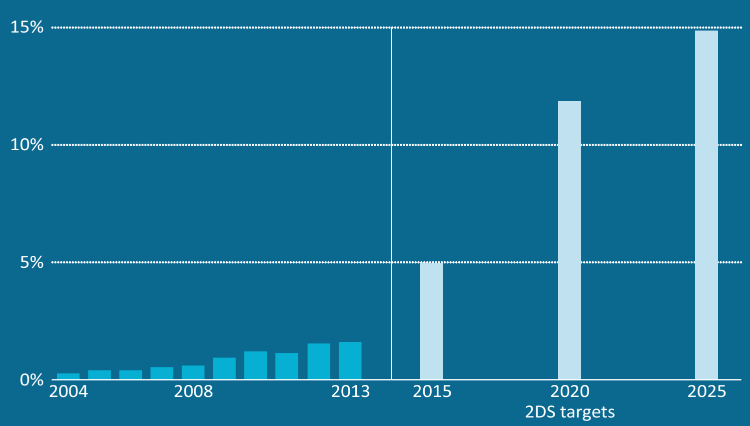
50%

FOR HEVs

80%

FOR EVs

2.36 Global hybrid electric vehicle market share



For sources and notes see page 109

Biofuels

Not on track

Biofuel production increased to 113 billion litres in 2013, buoyed by higher ethanol output in Brazil due to improved economics and the readjustment of the domestic ethanol mandate to 25%. High feedstock prices in the United States and European Union (among others) in the first half of the year reduced output there. Global biofuel production should reach 140 billion litres in 2018, undershooting the volumes required to reach 2DS targets.

Technology penetration

Advanced biofuels,[13] produced from lignocellulosic biomass, algae and other innovative feedstocks, have progressed more slowly than expected in recent years. Production capacity in 2013 increased by around one-third from 2012 levels, but will need to grow 22-fold to reach 2DS targets in 2025. This will require dedicated policy support for advanced biofuels and increased government funding for research and market creation.

Globally, operating of advanced biofuels capacity was 5.4 billion litres in 2013, an increase of over 1 billion litres compared to 2012. Looking forward, global advanced biofuel capacity could reach 8.7 billion litres in 2018, less than 10% needed to meet the 2025 2DS target.

Market creation

Over 50 countries worldwide have implemented biofuel blending mandates and targets, often accompanied by financial support measures such as tax incentives. These measures have been effective in driving biofuel production in general, but do not necessarily promote technologies that perform best in terms of land use, greenhouse-gas reductions, and social and economic impacts. Despite international efforts to establish sound sustainability criteria and certification schemes, only the European Union and the United States have set sustainability requirements for fuels that count towards biofuel targets. Also, requirements in these two regions are not currently aligned: EU standards consider a broader and more detailed set of criteria.

Most current blending mandates for biofuels do not specifically support advanced biofuels. Only the United States (dedicated blending quota for cellulosic biofuels) and the European Union (advanced biofuels based on waste, and cellulosic biomass, are counted twice towards the 10% renewable energy target in transport in 2020) have policies targeting advanced biofuels. But time horizons are limited to 2020 for the European Union and 2022 in the United States.

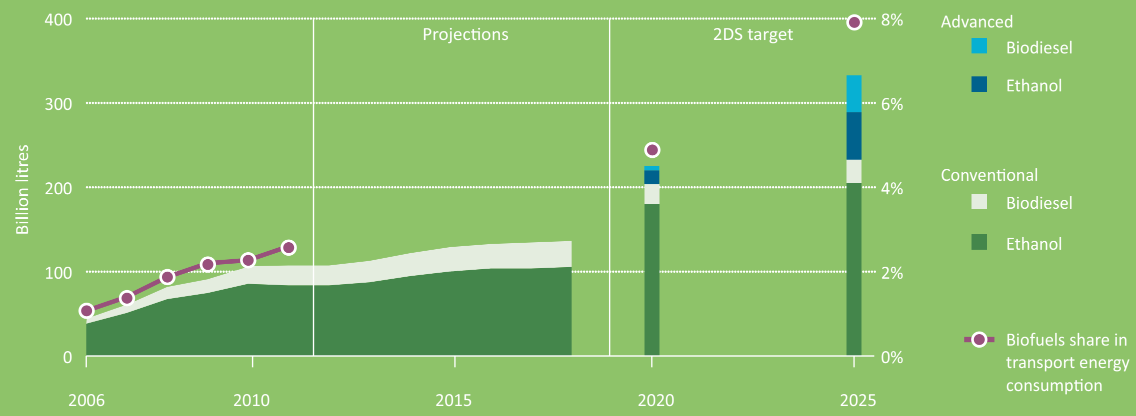
Long-term, stable policy frameworks that reduce the risks associated with advanced biofuels projects are needed to trigger further investments into commercial-scale advanced biofuel plants. This can be, for instance, in the form of a dedicated advanced biofuel quota or a premium paid for each litre of advanced biofuel blended to the fuel pool.

Technology developments

More than 100 advanced biofuel pilot and demonstration plants were established over the last decade. The recent opening of the first commercial-scale production units (such as the Beta Renewables 60 million-litres-per-year cellulosic-ethanol plant in Italy) as well as a number of plants scheduled to come online in the United States, Europe and Brazil in 2014 indicate substantial progress in technology development. But the units are relatively small, and several other projects were cancelled. More commercial-scale plants are needed to reach economy of scale and bring down costs.

13 Conventional biofuels (commonly referred to as first generation biofuels) include sugar- and starch-based ethanol, oil crop-based biodiesel, and straight vegetable oil, as well as biogas derived through anaerobic digestion. Advanced biofuels (commonly referred to as second generation) are conversion technologies that are still in the R&D, pilot or demonstration phase. This category includes hydrotreated vegetable oil, which is based on animal fat and plant oil, as well as biofuels based on lignocellulosic biomass, such as cellulosic-ethanol, biomass-to-liquids-diesel and bio-synthetic gas. Furthermore novel technologies such as algae-based biofuels and the conversion of sugar into diesel-type biofuels using biological or chemical catalysts are included.

2.37 Global biofuels production

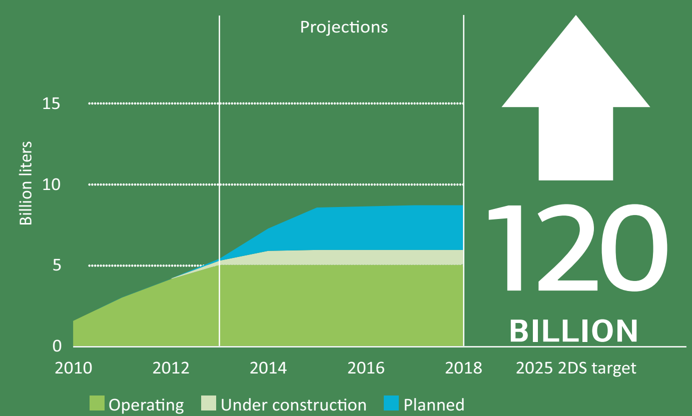


Recent developments

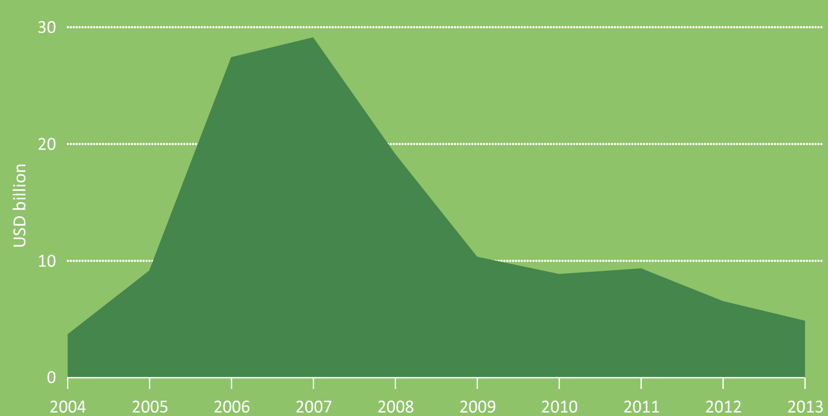
In 2013 two commercial-scale advanced biofuel production units opened in the United States and one in Europe

Over 50 countries have biofuel blending mandates and targets but only the United States and the European Union have policies targeting advanced biofuels

2.38 Global advanced biofuel capacity



2.39 Production capacity investment



1.4

USD BILLION SPENT ON BIOFUELS R&D IN 2013, 40% FROM PRIVATE INVESTORS

For sources and notes see page 109

Buildings Energy Efficiency

Not on track

Buildings are the largest energy-consuming sector, accounting for 31% of final energy consumption globally, and a substantial source of CO_2 emissions: 2.9 gigatonnes (Gt) from direct emissions and 3.8 Gt from indirect emissions due to electricity in 2011. Final energy use increased by 19% between 2000 and 2011, to 119 EJ. The trend is expected to continue, driven by rising population (1 billion people by 2025) and increasing wealth in some regions.

Technology penetration

Despite the recent global economic stagnation, which led to severe retraction in the buildings sector in several countries, global buildings energy consumption continues to rise. Concerns over the continuation of this trend have increased the call for further efforts to improve buildings energy efficiency. In 2013, *Transition to Sustainable Buildings: Strategies and Opportunities to 2050* was published to highlight the path to an alternative future (IEA, 2013c).

Heating per unit of floor area, the largest end-use, is becoming more efficient. Continued growth in floor area per capita in residential buildings across all regions, however, is driving up overall demand. The 2DS target for 2025 allows for energy demand growth of 0.7% per year from 2012; the trend over the last decade, 1.5% per year, throws the sector off track. Disaggregation of builders, coupled with varying levels of building stock, makes implementing energy efficiency improvements particularly challenging.

Market creation

Current policies are insufficient to make the construction of high-performance buildings routine, even though near-zero-energy, zero-energy and energy-plus buildings are being pursued around the world.[14] Some European countries have adopted zero-energy goals[15] for new residential construction around the 2020 time frame, even though debate continues on the specific performance criteria for the underlying EU Directive.[16] To achieve 2DS, deep energy renovation will need to become common practice during normal building refurbishment, with the current rate of renovation at least being doubled. Europe is leading this effort with a co-ordinated group of advocates and businesses through Renovate Europe and through the EU Directive to refurbish 3% of public buildings per year. This Directive, however, should be reviewed to include public and non-public housing stock.

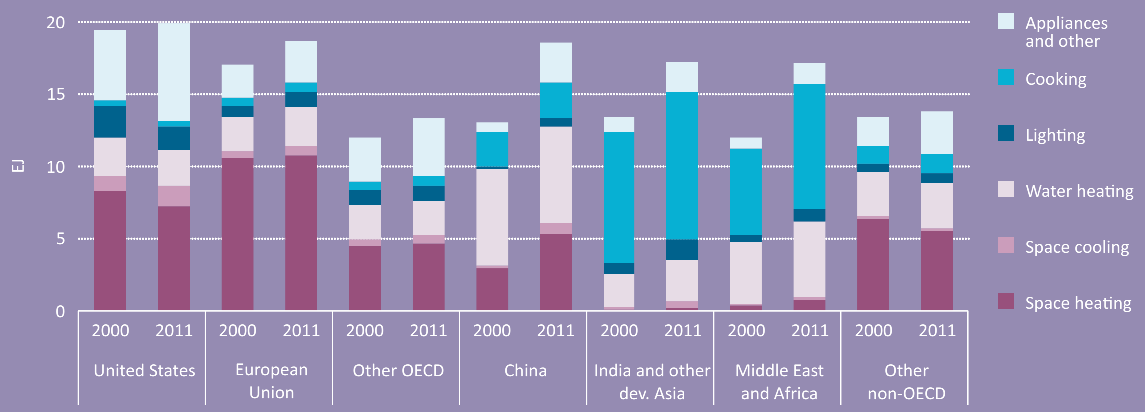
Sustainable building practices are growing through voluntary programmes such as the UK BREEAM and US Green Building Council LEED programmes. Russia recently introduced a new building energy efficiency label in association with the European Bank for Reconstruction and Development. Deep renovation could be significantly accelerated through financial incentives and policies that target stringent energy performance criteria. California recently launched a new approach, called CO_2 to EE, to enhance building renovation financing from climate change policy, which may be an effective way to stimulate the existing building market.

Technology developments

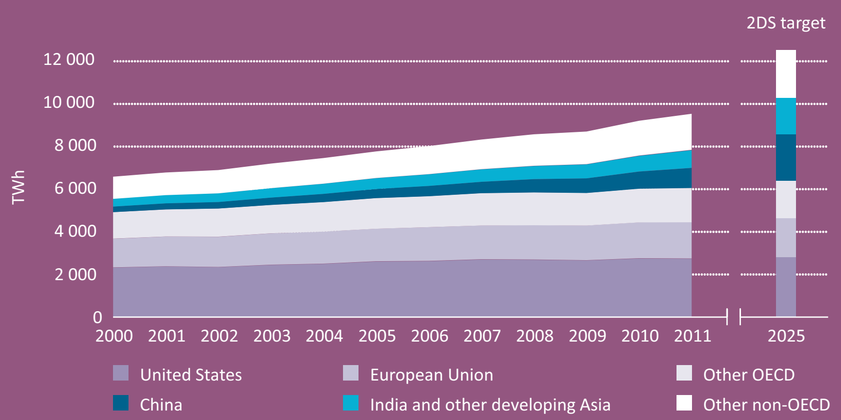
Systems-level research that promotes integrated solutions can significantly reduce the overall cost of building upgrades while maximising energy savings. R&D can lead to higher performing products and more favourable investment opportunities with more cost-effective applications. The core technology development need, however, centres on building equipment and envelope materials (see following sections).

14 China has adopted a National Green Building Action Plan with a goal of 1 billion square metres (m^2) of green buildings by 2015.
15 Zero-energy goals for all residential construction go beyond the EU Directive for near-zero-energy.
16 Data for annual progress are not available, but see www.buildup.eu/news/33980 for more information.

2.40 Buildings energy consumption by end use



2.41 Buildings electricity consumption



Key trends

Residential consumption has been relatively static since 1990, despite energy efficiency improvements

The current rate of renovation should at least double to meet 2DS targets

2.42 Floor area by sub-sector

For sources and notes see page 109

Building Envelope

Not on track

The thermal performance of the building envelope determines energy requirements for heating and cooling, and can reduce artificial lighting requirements. A systems approach for new construction and deep renovation is essential, as are advanced building materials that enable the construction of high-performance buildings.

Technology penetration

With space heating and cooling accounting for one-third of all energy consumed in buildings – and the figure rising to 60% in residential buildings in cold climates – building envelopes have a significant impact on global energy consumption. Global residential heating represents the largest end use; overall growth was low (0.1% per year from 2000) despite China's average growth being over 5.4%. Cooling demand increased dramatically since 2000 (4.5% per year), with developing countries being the largest driver and high US growth (2.8% per year) playing a role.

Market creation

Mandatory building codes are the most effective policy to reduce heating and cooling demand; progress continues in most regions, but not aggressively enough to reach 2DS targets. The United States recently implemented its most stringent energy-saving building code, which includes mandatory daylighting and automated lighting controls. Future stringency to achieve near-zero energy performance is unlikely. In 2013, Viet Nam implemented a new building code that was significantly influenced by previous policy action within the Asia-Pacific Economic Cooperation (APEC),[17] and progress continued on a regional building material testing and rating centre in Thailand.

The *IEA Technology Roadmap for Energy Efficient Building Envelopes* includes a market assessment of high-priority building envelope components. From a technological perspective, insulation and low-emissivity (low-e) windows have been the most successful measures; from a regional perspective, Canada, the European Union and the United States have been the most successful. Highly insulated windows have achieved 54% market share in a few European countries, but remain very low in other parts of the world. More programmes are required to promote and mandate advanced building materials such as double-glazed, low-e windows for the world and highly insulated windows (triple-pane low-e windows with low conductive frames) for cold climates.

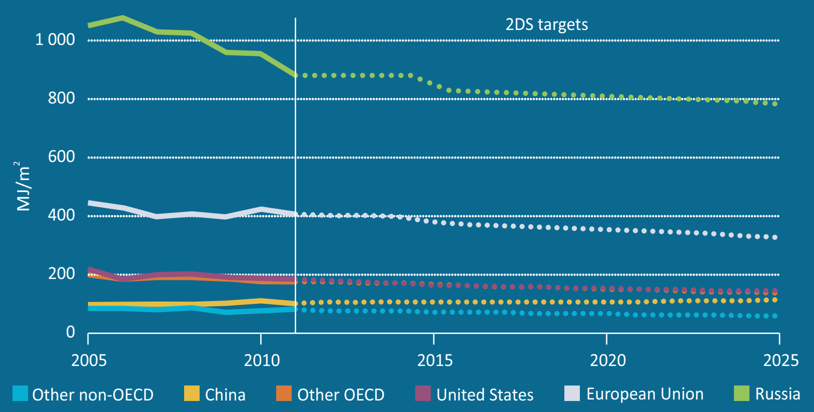
The Cool Roofs and Pavements Working Group of the Global Superior Energy Performance Partnership (GSEP), an initiative of CEM and the International Partnership for Energy Efficiency Co-operation (IPEEC), continues to pursue policies to adopt reflective surfaces that provide building energy efficiency and reduce urban heat islands while increasing global cooling benefits. The group's recent analysis showed that switching to cool roofs could reduce Mexico's cooling load by 22%; now Mexico preferential green mortgages can be used to install cool roofs.

Technology developments

Significant progress has been made in dynamic glazings that can improve passive heating benefits, reduce lighting loads (up to 60%), reduce cooling loads (up to 20%) and lower peak electricity demand (up to 25%). More R&D and economy of scale are needed to improve market viability, which is also true for automated solar control shading for regions that cannot eliminate cooling equipment due to severe climatic conditions. R&D continues on advanced insulation, such as aerogel and vacuum-insulated panels, and is needed to pursue lower cost validated air sealing techniques, reflective materials and the development of highly insulated windows for zero-energy buildings (U-values[18] $\leq$ 0.6 W/m^{2}k while the typical best practice U-value is 1.8W/m^{2}K) (IEA, 2013d).

17 For example, APEC's effort on Cooperative Energy Efficient Design for Sustainability effort on building codes.
18 Thermal transmittance is a term to describe heat transfer across a material or assembly over a specified difference in temperature, the most common descriptor being a U-value.

2.43 Residential heating per square metre



32%

SHARE OF SPACE HEATING AND COOLING IN BUILDINGS ENERGY CONSUMPTION (AROUND 60% IN COLD CLIMATES)

2.44 Market maturity for high-priority building envelope components

	ASEAN	Brazil	China	European Union	India	Japan/Korea	Mexico	Middle East	Australia/ New Zealand	Russia	South Africa	United States/ Canada
Double-glazed low-e glass	●	▲	▲	★	▲	●	●	▲	●	●	●	★
Window films	▲	▲	▲	●	▲	●	▲	▲	●	▲	▲	●
Window attachments (e.g. shutters, shades, storm panels)	●	▲	●	★	▲	●	▲	●	●	▲	●	●
Highly insulating windows (e.g. triple-glazed)		▲	▲	●		▲		▲	▲	▲	▲	▲
Typical insulation	★	●	★	★	●	★	●	★	★	★	●	★
Exterior insulation	●	▲	●	★	●	●	▲	●		▲	▲	★
Advanced insulation (e.g. aerogel, VIPs)				▲		▲				▲	▲	▲
Air sealing	●	▲	▲	★	▲	●		▲	▲	▲		●
Cool roofs	▲	▲	▲	●	▲	▲	▲	▲	▲			★
BIPV/ advanced roofs	▲	▲		▲	▲	▲			▲	▲	▲	▲

★ Mature market ● Established market ▲ Initial market

For sources and notes see page 109

Appliances and Equipment

Improvement needed

Improved energy efficiency of appliances and equipment can moderate demand in energy without sacrificing features. Labelling and standards programmes have been very effective when pursued aggressively and should be expanded further to reach 2DS targets.

Technology penetration

Extensive evaluations show that voluntary and mandatory policies have underpinned significant progress towards more efficient appliances and equipment in developed regions. Savings achieved, however, have in many cases been eroded by increased "productivity" such as larger dwellings, larger refrigerators, brighter spaces and improved comfort.

Average growth of electricity in the buildings sector was 3.4% per year[19] from 2000 through 2011, driven by the demand of appliances and electronics reaching 34 EJ. To achieve 2DS targets, this figure must be reduced to 2% per year through 2025. Space cooling, which increased by 4.5% per year, needs to be reduced to 1.8% per year. The more modest growth of water heating (0.9% per year) still needs to be halved, to 0.5% per year through 2025. More effort is needed to develop new programmes where they do not exist, and to expand the scope, stringency and compliance of existing programmes.

Market creation

Mandatory requirements for condensing boilers in the United Kingdom, and a similar requirement for new construction in France, have helped to temper residential heating, which represents the largest end use in buildings.

Improved lighting deployment continues to grow thanks to efforts such as the United Nations Environment Programme (UNEP) Global Environment Facility (GEF) en.lighten initiative's Global Efficient Lighting Partnership Programme, which supports 55 countries in following an integrated approach to implement policies and measures to accelerate the market transformation to efficient lighting technologies by 2016 (27 countries will complete the transition by 2014). Many countries now ban inefficient incandescent lamps (IIL), although some still allow "halogen" (which use around 80% the energy of a typical IIL). Current compact fluorescent lamps (CFLs) and light-emitting diode (LED) technologies use one-third to a fifth of the energy of IILs. With potential to become twice as efficient as CFLs, LEDs are growing in market share: global sales were about USD 24 billion in 2012, and are expected to reach USD 57 billion by 2018. In the United States, LEDs saved 75 petajoules (PJ) of primary energy in 2012 of an annual savings potential of 4 086 PJ.

Voluntary (ENERGY STAR) and mandatory (minimum energy performance standards) programmes enabled New Zealand to reduce total electricity demand for buildings by 4% in 2012. China recently introduced ten new efficiency standards. Japan expanded its Top Runner programme in 2013, and is developing improved energy performance ratings to ensure they reflect real-world conditions. The European Union issued several new directives, including one to improve the labelling and promotion of heat pump water heaters and solar thermal systems. The CEM-IPEEC Super-Efficient Appliance and Equipment Deployment (SEAD) initiative pursued several lighting, air conditioning and electronic efforts to reduce energy use.

Technology developments

Development of cold climate and gas thermal heat pumps[20] within the IEA Technology Network, continues but with a limited number of country participants. Japan has seen significant growth in sales of heat pump water heaters (500 000 sold in 2012) while high cost and market barriers limit EU sales (58 000 sold in 2012, mostly in France, Denmark and Poland) and the United States (26 000). With millions of electric resistance water heaters being sold annually around the world, more R&D and economies of scale to drive lower cost of heat pump water heaters is a priority.

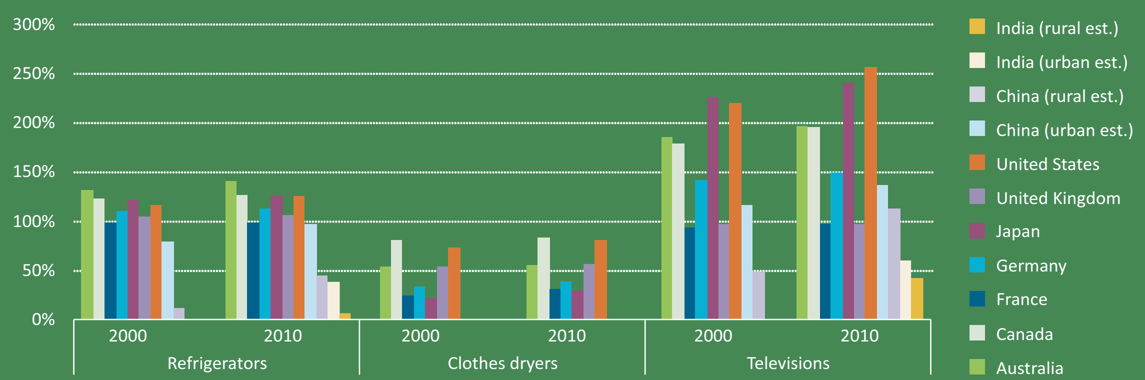
19 Significant variation exists, with the United States growing at 1.5% per year whereas China grew at 12.2% per year.
20 Current performance of heat pumps in cold climates is severely degraded and the most efficient source of gas heating is condensing boilers at around 95%; gas thermal heat pumps can improve that by around 25% (IEA, 2013d).

2.45 Labelling and standards programmes within the SEAD initiative

	Australia	Canada	European Union	India	Japan	Korea	Mexico	South Africa	United States
Phase-out of conventional incandescent light bulb	Mandatory standard	Mandatory standard; Mandatory	Mandatory standard; Mandatory			Mandatory standard; Mandatory	Mandatory standard		Mandatory standard; Mandatory
Clothes washers	Mandatory	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Voluntary		Mandatory standard; Mandatory	Mandatory standard; Mandatory		Mandatory standard; Mandatory
Residential refrigeration	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Mandatory	Mandatory standard; Mandatory
Commercial refrigeration	Mandatory standard	Mandatory standard			Mandatory standard	Mandatory standard; Mandatory	Mandatory standard; Mandatory		Mandatory standard
Computers	Mandatory standard		Mandatory standard		Mandatory standard; Voluntary	Voluntary			Voluntary
Distribution transformers	Mandatory standard	Mandatory standard		Mandatory	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Mandatory standard		Mandatory standard
Fans		Mandatory standard	Mandatory standard	Voluntary		Mandatory standard; Mandatory			Mandatory standard; Mandatory
Motors	Mandatory standard	Mandatory standard	Mandatory standard	Voluntary		Mandatory standard; Mandatory	Mandatory standard; Mandatory		Mandatory standard
Room air conditioners	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Mandatory standard; Mandatory	Mandatory standard; Mandatory		Mandatory standard; Mandatory
Standby power		Mandatory standard	Mandatory standard			Voluntary			
Televisions	Mandatory standard; Mandatory	Mandatory standard	Mandatory standard; Mandatory	Voluntary	Mandatory standard; Mandatory	Mandatory standard; Mandatory			Mandatory

● Mandatory standard Comparative label: ● Mandatory ● Voluntary

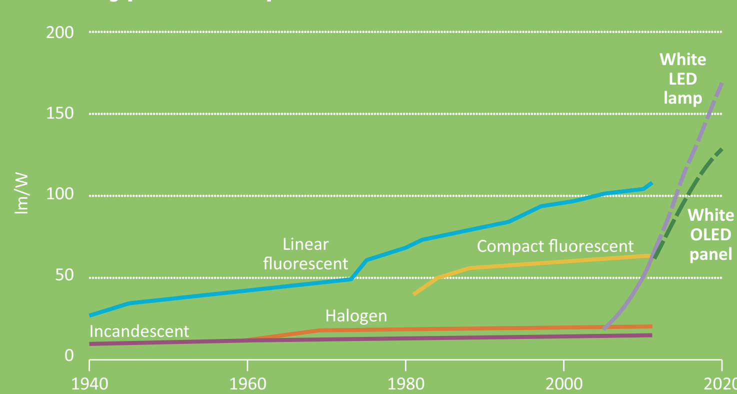
2.46 Selected appliance ownership



166

lm/W, MINIMUM TARGET EFFICIENCY OF LED SYSTEMS BY 2020 IN THE US (12 lm/W, COMMON INCANDESCENT LAMP EFFICIENCY)

2.47 Typical lamp efficacies



For sources and notes see page 109

Co-generation and DHC

Improvement needed

Global electricity generation from co-generation technologies remained stagnant at around 10% over the last decade, and deployment of efficient district heating and cooling (DHC) systems has also been limited, despite their significant potential for efficiency gains, emissions reductions and enhanced flexibility.

Technology penetration

With a global average efficiency of 58% in 2011, co-generation of heat and power is much more efficient than conventional thermal power plants (37%)[21] In fact, state-of-the-art plants can reach efficiencies of up to 90% (IEA, 2011). When coupled with DHC, the system-wide benefits of co-generation increase further. Yet global penetration of co-generation technologies is low and progress is sluggish; co-generation produced only 9% of global power in 2011, of which 26% was in industrial facilities.

Penetration and performance of DHC vary by region. Highly efficient district heating (DH) serves 61% of Denmark while emitting only 26 tonnes of CO_2 per terajoule. China and Russia have the world's largest networks but with lower efficiencies and higher emissions. China is the fastest-growing region expanding its DH network (trench length of DH pipeline doubled in the period 2005-11). The United States has the greatest reported DC sales (24.7 TWh) and DC capacity in Korea more than tripled in the period 2009-11 (Euroheat&Power, 2013).

Micro co-generation technologies, such as gas engines and fuel cells, are gaining wider deployment in some countries, such as Japan and Korea.

Market creation

Co-generation faces several deployment barriers, such as higher up-front capital investment needs, often grid access limitations, limited demand for local heat and in some cases failure of local markets to reward energy efficiency.

Strategic and integrated planning is key for co-generation and DHC since assets are long-lived and future improvements costly. Lack of data (especially heat-related) makes it difficult to assess existing potential for cost-effective deployment. In 2012, EU countries were mandated to map national heating and cooling demand and generation to establish the base for a cost-benefit assessment of the application of these technologies (EU, 2012). Korea designated urban areas that must include a heat supply network connecting buildings, and introduced policies to improve efficiency and fuel diversification of district energy (Third Basic Supply Plan of District Energy). Japan released a national co-generation roadmap that calls for a 250% increase in capacity (to 22 GW) by 2030. The United States bolstered efforts on industrial co-generation, including a focus on deployment with technical assistance, best practice guidance, increased co-ordination across agencies and new funding opportunities (US, 2012). Russia has implemented market reforms to reward energy efficiency, and although more is needed these will incentivise network improvements and more efficient use of heat by consumers.

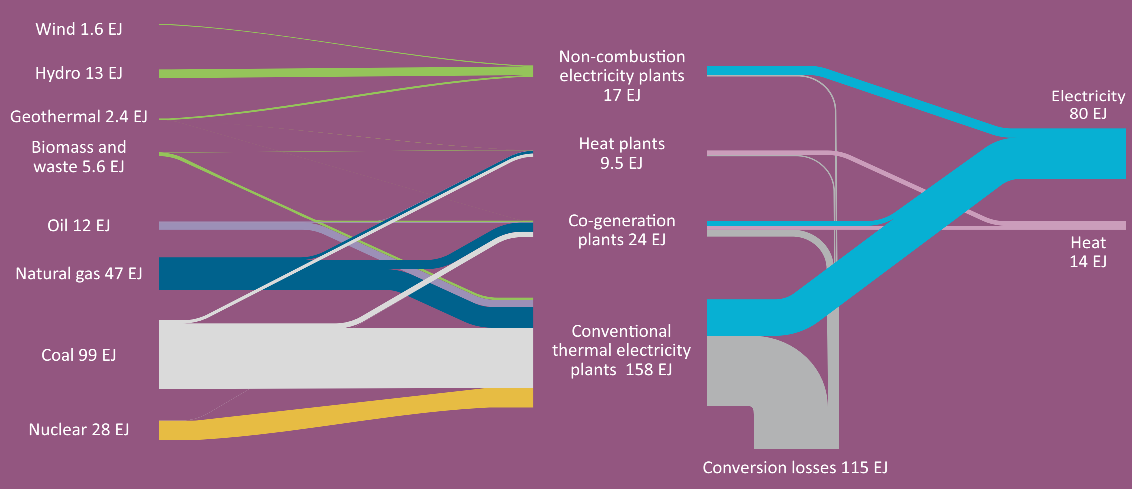
The IEA CHP/DHC Collaborative published country scorecards for Finland, Japan and Korea in 2013, and will release additional reports in 2014.

Technology developments

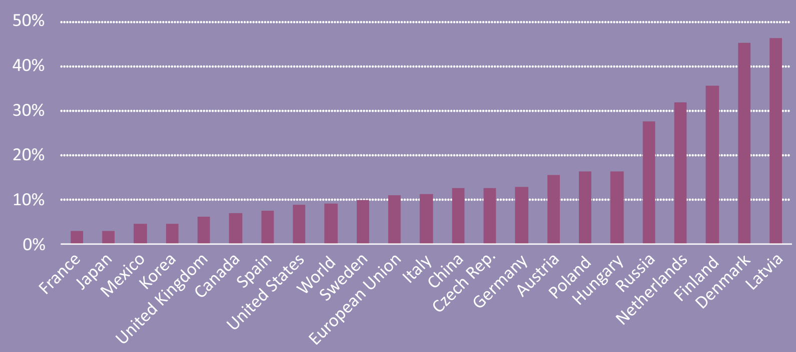
DHC networks with low supply and return temperature have been demonstrated, and could provide significant energy savings, as could improved control systems and insulation materials. Similarly, demonstration projects show the feasibility of very low-carbon DHC networks that integrate different energy sources including renewables, energy storage and heat pumps to enhance flexibility. These networks are already used commercially in Denmark. The 2DS envisions a decarbonisation of DH with the average CO_2 intensity peaking in 2020 before falling to 70% of current levels.

21 According to IEA energy balance conventions, for auto-producer co-generation plants, only heat generation and fuel input for heat sold are considered, whereas the fuel input for heat used within the auto-producer's establishment in not included, but accounted for in the final energy demand in the appropriate consuming sector. Transmission and distribution losses are not included.

2.48 Global power and heat generation energy flows, 2011



2.49 Co-generation share of power production in 2011



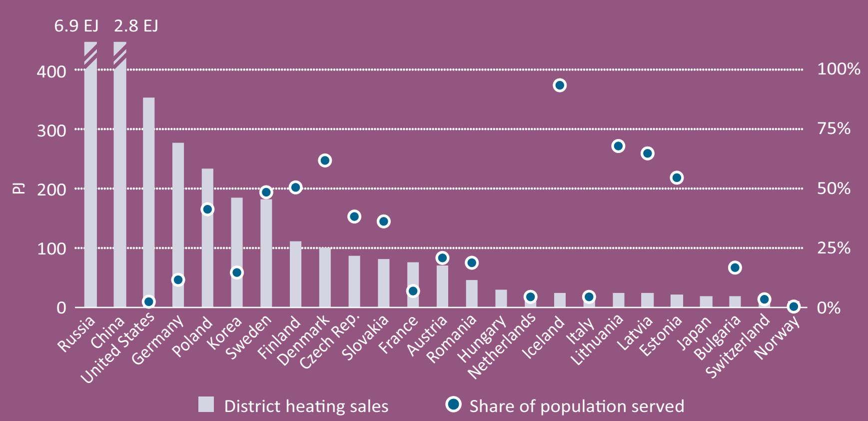
58%

GLOBAL EFFICIENCY OF CO-GENERATION SYSTEMS (37% IN THERMAL POWER PLANTS)

Key point

Fast-growing regions open a big opportunity for efficient DHC deployment; China doubled its DH trench length from 2005 to 2011. At this fast pace, energy infrastructure strategic planning becomes even more important.

2.50 District heat sales and share of population served, 2011



For sources and notes see page 109

Smart Grids

Improvement needed

Improved efficiency, ability to integrate renewable energy and EVs, and enabling customer involvement in shifting electricity consumption: smart grids are vital to transforming electricity grids into systems that can support the transition to the 2DS. Electricity will exceed a 20% share of overall energy demand in the 2DS by 2025, with variable renewable capacities growing from less than 6% of overall electricity generation capacity in 2011 to over 21% by 2025.

Technology penetration

Data are limited on smart-grid pilots and technology deployments globally. Improved effort is needed to develop effective indicators and collect data to track progress and impacts on the electricity system. At present, consensus is lacking as to which technologies can be considered authoritative indicators of the smartening of grids, though there are several agreed-upon groups emerging from the debate.

Global penetration of smart meters reached 20% in 2013, and is projected to achieve 55% by 2020 (Navigant Research, 2013a). Phasor measurement units (PMUs), as part of high-voltage wide-area monitoring, protection and control (WAMPAC) of the power systems, grew from almost zero to 5 356 units between 2002 and 2013 (ISGAN, 2013). Although smart-grid systems are growing steadily in many technology applications, the current rate of deployment does not appear sufficient to adequately support 2DS goals.

Market creation

Global smart-grid technology investments reached USD 45 billion in 2013, up from USD 33 billion in 2012, covering five main applications: transmission upgrades, substation automation, distribution automation, smart-grid information and operations technology, and smart meters. Investments are expected to reach over USD 70 billion by 2020 (Navigant Research, 2013b).

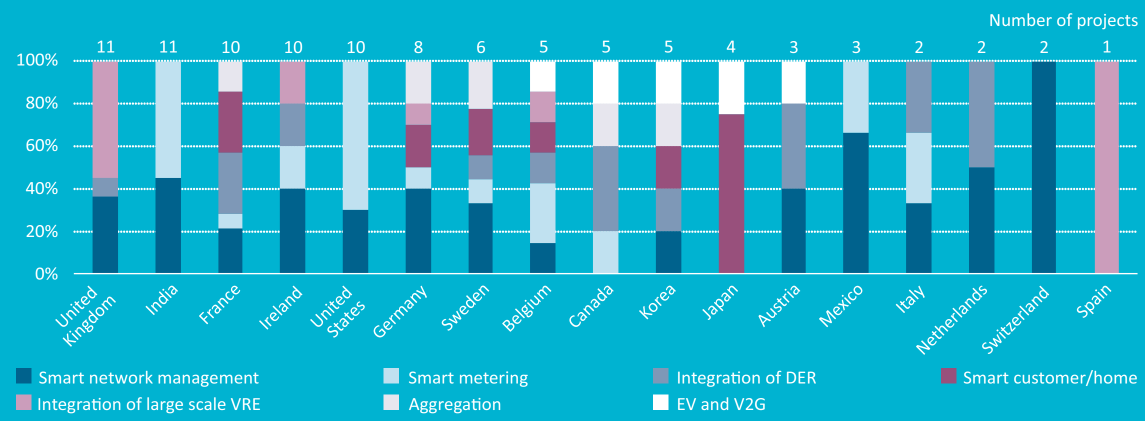
Development of international standards for interoperability stimulates market creation by increasing efficiency for manufacturers, encouraging supplier competition, and facilitating cost savings that benefit both utilities and consumers. European standardisation organisations are employing Mandate M/490 with the Smart Grid Coordination Group to tackle the challenge of interoperability within Europe. In North America, the Smart Grid Interoperability Panel provides a framework for co-ordinating stakeholder efforts to accelerate standards harmonisation.

The smart-grid market is expanding, but deployment slowed in some regions because of uncertainty over roles and responsibilities in some applications, and the need to share costs and benefits among different stakeholders. Cost reductions enabled by smart grids do not necessarily accrue in the same sectors in which investments are made. This creates the need for clear regulation and business models that manage cross-sectoral cost recovery such as: appointing a distribution system operator as a neutral market facilitator; demand-response programmes and aggregation models; and enabling net metering on solar energy projects.

Technology developments

The need to integrate diverse technologies is the greatest barrier in developing and deploying smart grids. The Smart Grid International Research Facility Network (SIRFN), part of the International Smart Grid Action Network (ISGAN), is a newly co-ordinated network of smart-grid research test-bed facilities that determines how new technologies, services and demonstrations can be reliably incorporated in different utility systems.

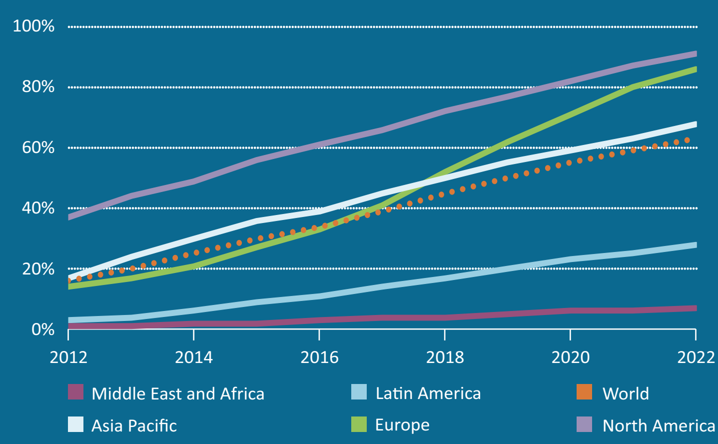
2.51 Sample smart-grid projects by application



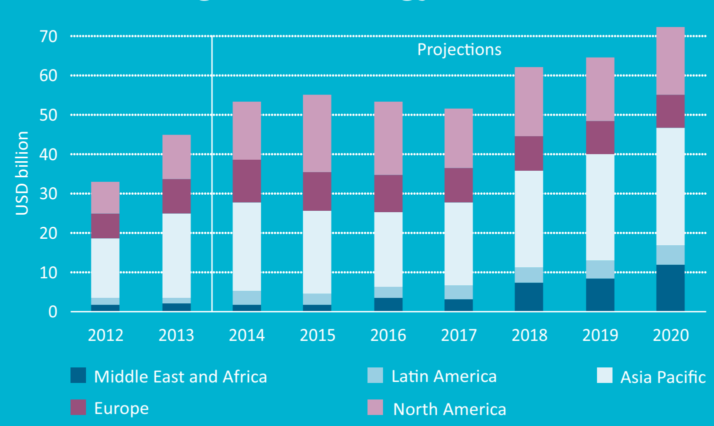
5 356

PHASOR MEASUREMENT UNITS DEPLOYED IN THE WORLD, 56% IN CHINA AND 31% IN NORTH AMERICA

2.52 Smart meter penetration



2.53 Smart-grid technology investments



Key points

Clear regulations and business plans are needed to define stakeholders' roles and responsibilities in sharing costs and benefits

Widespread research collection and sharing will accelerate development and deployment

Market penetration continues to grow, though metrics for tracking progress remain uncertain

For sources and notes see page 109

Getting "Smart" about Staying on Line

More people on line, more devices connected to networks, more data transferred: these characteristics define the future, as a vast array of devices become "smart" and interconnected. Today, over 14 billion of these devices outnumber people on the planet by a ratio of 2:1; by 2030, the device population may grow to 500 billion. Left unchecked, corresponding energy demand would soar to 1 140 terawatt hours (TWh) per year by 2025 compared to 615 TWh today – most of it consumed when devices are in standby, i.e. "ready and waiting", but not performing their main function.

Key findings

- Energy demand from information and communication technology (ICT) is on the increase, largely driven by the massive deployment of network-enabled devices in homes and offices.
- The electricity demand of network-enabled devices is expected to almost double between 2013 and 2025; as these devices spend most of their time in "standby mode", up to 80% of their electricity consumption is just to maintain connection to the network.
- Implementing best available technologies (BATs) and solutions could reduce this demand by up to 65%.
- High-efficiency mobile devices can maintain a network connection at 50 milliwatts (mW).

Opportunities for policy action

- There are no technical barriers impeding the potential to integrate the energy efficiency and power management solutions in mobile devices into other network-enabled devices. What's lacking are market drivers to achieve the same level of efficiency, creating a strong case for policy intervention.
- Policy options proven to be effective in tackling the issue of energy demand from network standby include minimum energy performance requirements or standards, voluntary agreements with industry, and consumer awareness campaigns.
- A few governing bodies have started to develop and implement network standby policies, notably the European Union, Korea, Switzerland and the United States. As network-enabled devices are traded globally, international policy co-ordination and co-operation provides the most efficient means to initiate action and ensure that efforts contribute to shared goals.
- To stimulate international dialogue and policy co-operation, the International Energy Agency (IEA) has developed a digital energy efficiency plan outlining how diverse measures can unlock vast energy savings – without compromising the quality of services delivered by network-enabled devices.

The ability to be "on line all the time" relies on two things: a complex infrastructure of network equipment and the ability of "edge devices" (computers, smartphones, etc.) to connect. A largely invisible aspect of our increasingly networked society is a rapid surge in energy demand to power an increasingly broad array of network-enabled devices. The ICT sector, which comprises end-use devices, network equipment and network infrastructure, accounted for more than 8% of total final global electricity consumption in 2013 (IEA and 4E IA, 2014 forthcoming).

To participate in a network, edge devices such as set-top boxes and smart TVs are "on" or "almost on" 24 hours a day, seven days a week, the end result being that two-thirds or more of their electricity consumption occurs when they are not actually in use (NRDC, 2010). For some device categories the situation is even more extreme: some games consoles use 80% or more of their electricity not to provide entertainment but just to maintain a network connection (Hittinger, 2011; NRDC, 2013).

At present, some 14 billion network-enabled devices have been deployed globally. The vast majority, irrespective of whether they are in "active" or "standby" mode, draw energy as though they were constantly in use. In reality, a very large proportion of this energy demand is simply wasted – as much as 80% in some cases. The underlying default is the inability of network-enabled devices to power down to low-power modes at times of low usage.

Lack of technical solutions is not the barrier: rather, with rapid response being the prime selling feature and low consumer awareness of energy draw, there is little market incentive to embed technologies that could change the equation. Analysis shows that – with existing solutions – energy consumption of network-enabled devices could be slashed by 65% (Bio Intelligence Service, 2013; IEA and 4E IA, 2014 forthcoming). The current situation creates a strong case for policies to support the development and implementation of energy efficient solutions to tackle network standby.

The European Union, Korea, Switzerland and the United States are front runners in developing policies that cover diverse aspects of standby in network-enabled devices using varied approaches. As network-enabled devices evolve rapidly and are traded globally, a strong case can be made for the need to develop international policies and standards: co-operation by all stakeholders can ensure resource efficiency and enable rapid and well-targeted policy responses in a complex technology environment. Political leadership is vital to enable this high level of co-operation.

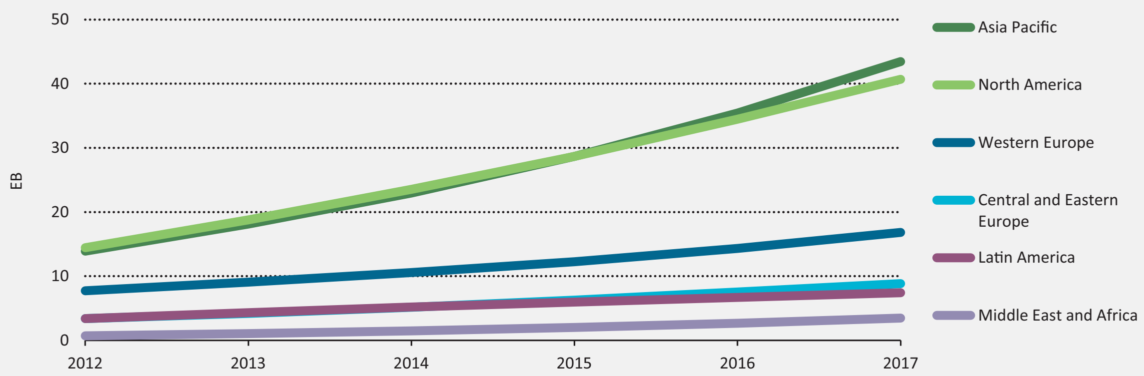
The importance of network standby as an increasingly urgent issue has prompted the IEA together with the Implementing Agreement for a Co-operative Programme on Energy Efficient End-Use Equipment (4E IA) to publish a book that provides an overview of trends, technology and technical solutions, and policy initiatives. *More Data, Less Energy: Making Network Standby More Efficient in Billions of Connected Devices*, scheduled for release in mid-2014, provides actionable policy guidance and outlines a work plan for action (IEA and 4E IA, 2014 forthcoming).

Everyone and Everything is Becoming Connected

More people are going online, in more ways. From 1990 to 2013, Internet users increased from 3 million to 2.7 billion. Today, they use many more types of devices to take advantage of diverse on-line technologies such as broadband connectivity, wireless mobility, cloud computing, e-commerce, social media and sensors. Already, more than 4.3 billion video-enabled devices – such as tablets, smart TVs, games consoles, smartphones, set-top boxes and Blu-ray players – are connected to the Internet. This is expected to almost double to 8.2 billion units by 2017 (IHS, 2013), as nearly all electronic and electrical technologies will become networked in the near future.

Internet traffic is growing at an exponential rate. During 2000-10, global Internet traffic grew more than 100-fold, yet in some regions access is still very low: future growth will continue a steep upward curve. In 2012, 74% of Internet protocol (IP) traffic and 94% of consumer Internet traffic originated from personal computers (PCs). By 2017, analysts estimate that 49% of IP traffic and 39% of consumer Internet traffic will originate from devices such as smart TVs.

Figure 2.54 Projected growth of monthly IP traffic by region



Notes: The byte is a unit of digital information in computing and telecommunications. One exabyte (EB) corresponds to 1 billion gigabytes (GB).
Source: adapted from Cisco, 2013.

Key point *IP traffic is expected to grow rapidly in all regions; particularly strong growth is expected in emerging and developing economies.*

Homes and offices are becoming increasingly networked with "smart" devices and "smart" systems, driven by consumer demand for new services, applications and functionalities and by business incentives such as demand-side management and deployment of "smart" meters and monitoring systems.

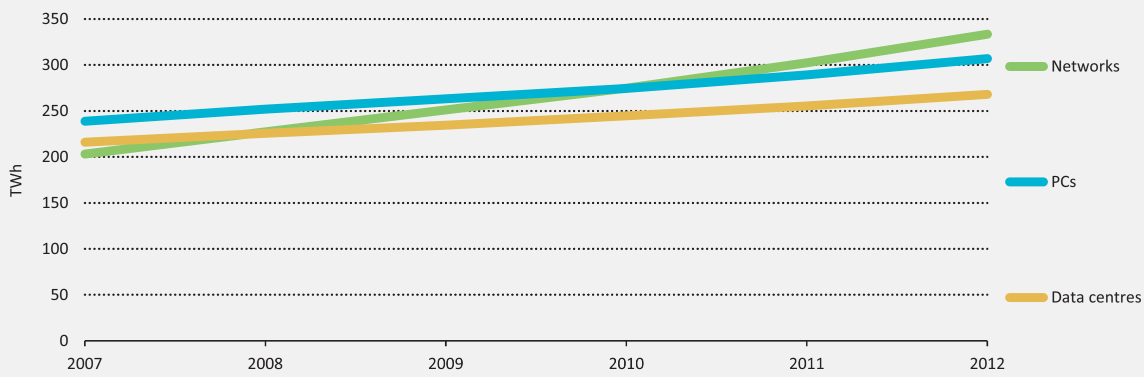
Network-enabled devices are forecast to increase fivefold by 2020 (World Economic Forum and INSEAD, 2012) and industry experts project an uptake of 50 billion network-enabled devices by 2020, reaching towards 500 billion over the coming decades (OECD, 2012). Globally, there were already more than 14 billion networked devices in 2012 – two per capita. Projections indicate that globally there will be nearly three networked devices per capita in 2017 (Cisco, 2013).

Manufacturers are already building "smart" home appliances that can interact with their owners and with one another, connect to smartphones, call a repairman when something goes wrong – even negotiate energy rates with the power company. Additionally, network equipment is needed to create the infrastructure for passing data among the networked devices and to connect to the Internet. More electronic devices are getting network connectivity, notably audio/video devices, and many non-electronic devices are beginning to acquire it, such as kitchen and laundry appliances; heating, ventilation and air-conditioning (HVAC) systems; lighting; and other end uses.

Rapidly Expanding Digital Economy Carries an Energy Cost

ICT energy demand is growing faster than all other energy end uses as appliances and equipment are increasingly network-connected, and networks and infrastructure are expanding to support growing communication traffic volumes. Worldwide electricity use is increasing at a compound annual growth rate (CAGR) of less than 3%; by contrast, the electricity to fuel networks is increasing at a CAGR of more than 10%, PC electricity demand at more than 5%[22] and data centre electricity demand at more than 4% (Van Heddeghem et al., 2014 forthcoming).

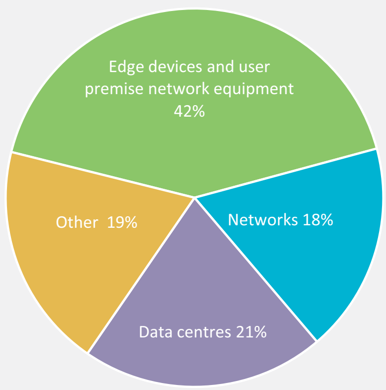
Figure 2.55 Global electricity consumption of networks, PCs and data centres



Note: does not include other network-enabled devices apart from PCs (PCs include desktop computers and laptops).
Source: Van Heddeghem et al., 2014 forthcoming.

Key point *Global energy demand of networks is growing at more than triple the rate of overall energy demand.*

Figure 2.56 Share of ICT electricity demand by ICT sub-segment in 2013



Key point *Edge devices and user premise network equipment account for the bulk of current ICT electricity demand.*

22 The energy performance of personal computers is improving. For example, the average performance of notebooks appears to be steadily improving with data showing a 10% decrease in average annual consumption for 2007 to 2008; consumption of the best-performing notebooks in the United States and European Union fell by 8% per year from 2008 to 2011 (4E IA, 2012a). Increases in energy demand are due to increased deployment and changes in usage patterns.

Edge devices (such as set-top boxes, games consoles and printers) and user premise network equipment (such as modems and routers), i.e. the aggregate of electronics located in homes and offices, constitute more than 40% of ICT electricity demand.

A single network-enabled games console continuously drawing up to 190 watts (W) per hour may not seem like much to worry about, but the scale of deployment for network-enabled devices makes the cumulative effect quite staggering. By 2013, the global population of network-enabled devices had already reached 14 billion – two for every person on the planet. In 2013, network-enabled devices used more than 615 TWh – surpassing the electricity production of Germany (611 TWh in 2012).

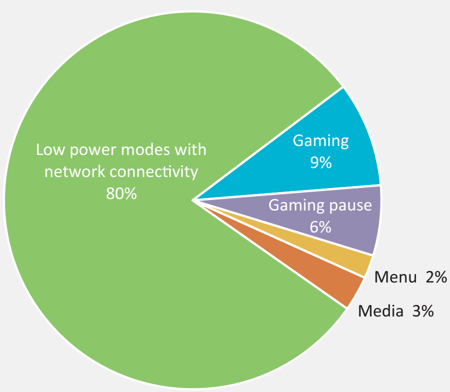
With a projected increase to 50 billion devices by 2020 (OECD, 2012), the amount of wasted energy becomes substantial. By 2025, without any radical efforts to improve energy efficiency, these devices are projected to consume close to 1 140 TWh, surpassing the current electricity production of Russia and accounting for 6% of total final global electricity consumption.

Energy Efficiency Opportunities

The savings potentials from mainstreaming energy efficiency solutions across all components of ICT-based systems – network-enabled devices, networking equipment, and network infrastructure – are considerable and grow as these systems expand and connectivity spreads.

The solution is not to pull the plug on connectivity. Some devices, particularly network equipment that has the primary function of transmitting data, need to be on continuously. The challenge is more about ensuring that network-enabled devices do not use excessive amounts of energy unnecessarily.

Figure 2.57 Example of annual energy consumption using a typical duty cycle of a 2010 games console model



Note: a 2010 games console model with a low-power active mode in which the console appears to be in standby but remains connected. The console uses 10 W of power per hour in standby mode, which accounts for 80% of the annual energy consumption using a typical duty cycle.
Source: NRDC, 2013.

Key point *Some network-enabled devices are using up to 80% of their electricity demand to maintain connectivity.*

Technologies and solutions: powering down and power scaling

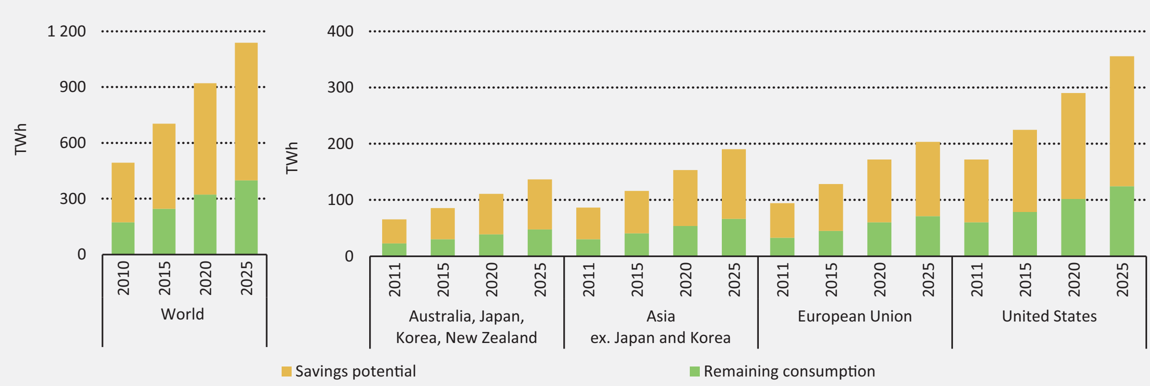
The ICT sector is designed to be on all the time, operating with maximum capacity and speed: no break time, and no loss of service; electricity demand does not change with changes in traffic volumes (Auer et al., 2011). This design principle is crucial for the core components of networks. But a large number of devices that are becoming network-enabled – for example, those offering entertainment or comfort features – do not need to be on all the time. In fact, global electricity demand of network-enabled edge devices and network equipment could be slashed by 65% by implementing BATs – resulting in savings of almost 740 TWh per year by 2025 and corresponding to 4% of current global total final electricity consumption.

Solutions already exist that enable such devices to maintain connectivity when needed but to "power down" (i.e. reduce their energy draw) when not in use or not engaged in sending or receiving important messages. Other solutions ensure that devices can stay connected continuously, but with far lower energy consumption. This can be done by, for example, shutting down those parts of the device not needed when the equipment is not communicating.

Even devices that need to be connected all the time can be designed to maintain connectivity for less energy. The principle of power scaling is to match the energy demand of such devices to the actual work performed; rather than needing to draw large quantities of power just to maintain capacity, they would have the capacity to use less power when less data is being transmitted. One option is to reduce the processing rate of a device when its workload is low.

Some solutions can be embedded in devices; others require changes in how networks or other devices on the network function. While some solutions incur extra costs, many just require use of technology standards that enable power management and more energy efficient device behaviour.

Figure 2.58 **Global network-enabled device electricity consumption and savings potential**



Notes: domestically and professionally used network-enabled equipment, connected to external or internal networks. Savings potential estimated on the difference between the BAT and the average device on the market.
Source: Bio Intelligence Service, 2013.

Key point *Early action to improve energy efficiency of devices leads to greater savings over time, even as the number of devices in use rises steeply.*

Mainstreaming energy efficiency in the ICT sector is not a one-off activity – it requires sustained effort by multiple stakeholders. Policy makers play an important role in facilitating the development and uptake of solutions, and in creating market demand for more efficient devices and systems.

Market Creation

While energy efficiency in ICTs and networks is gaining attention, some areas require policies to accelerate progress and create a demand for energy efficient solutions.

Where energy efficiency contributes to an improved bottom line, industry itself often drives the development and implementation of energy efficient solutions. This is true, for example, in optimising energy use in data centres. For portable devices that rely on batteries, strong consumer demand for lightweight devices with long battery life encourages manufacturers to incorporate design criteria that support energy efficiency.

Box 2.1 From standby to network standby

Standby power refers to the electricity consumed by appliances while not performing their primary functions. There are two general types of secondary functions for stand-alone devices (i.e. not network connected) that use energy in low power modes:

- the ability to be activated via a remote control and quicker start-up;
- features provided for convenience such as a clock display.

The issue of standby energy consumption is aptly illustrated by the case of the microwave oven. Heating food (the primary function) requires 100 times more power than running the clock displayed on most microwave ovens. But most microwave ovens are in standby mode(s) more than 99% of the time; over their life cycle, more energy is used to run the clock display than to cook food.

Standby power was first recognised as an area of significant energy waste in 1986. Experts estimate that standby energy now accounts for 1% to 2% of global electricity consumption and approximately 10% of residential electricity use (Energy Efficient Strategies, 2011). In 1999, the IEA proposed that all countries harmonise energy policies to reduce standby power use to no more than 1 W per hour. Widespread uptake of this initiative has had a clear impact in driving down energy consumption of televisions (other appliances show similar trends).

Figure 2.59 Average standby power of TVs

Notes: EU 13 includes data from Austria, Belgium, the Czech Republic, Denmark, France, Germany, Greece, Hungary, Italy, Latvia, Portugal, Romania and the United Kingdom. TVs covered include: cathode ray tube, liquid crystal display and plasma.
Source: 4E IA, 2012b.

Key point *In a relatively short time, policy intervention has been instrumental in pushing standby power of TVs to 1 W or less in multiple countries and regions.*

In fact, portable devices by far surpass devices that are mains-connected (i.e. devices that need to be plugged into electricity sockets) in terms of energy efficiency, including standby power consumption. High-efficiency mobile devices can maintain a network connection at 50 mW, whereas some set-top boxes use up to 40 W for that purpose. There are no technical barriers to implementing a similar emphasis on integrated energy efficiency and power management solutions in other network-enabled devices. What is lacking is the same level of drivers for efficiency.

This creates a strong case for policy intervention to support and foster the development and implementation of energy efficient solutions for the mains-connected devices that account for a large share of this energy demand. Concerted, international efforts such as those that were initiated as part of the IEA 1-Watt Plan of 1999 are needed, with recognition that technologies have advanced rapidly and tackling network standby will be more complex.

To date, policy initiatives for low-power modes for network standby have been limited, but progress is under way. Both Korea and the European Union have established minimum energy performance requirements to reduce standby energy consumption in network-enabled devices. The European policy (the most far-reaching to date) is estimated to achieve savings of approximately 49 TWh per year by 2025 (European Commission, 2013).

Voluntary endorsement programmes, such as ENERGY STAR and industry-led initiatives, also play an important role in fostering the uptake of energy efficient solutions. Rule-making to consider efficiency standards for set-top boxes spurred the US set-top industry to launch its voluntary agreement in 2013. The agreement engaged 15 industry-leading, multi-channel video providers and device manufacturers that deliver service to more than 90 million US households and is expected to result in annual residential electricity savings of USD 1.5 billion. Rule-making considerations have also promoted focus on energy efficiency in games consoles.

In May 2013, the Swiss Federal Office of Energy, together with leading service providers, launched a large awareness campaign on how customers can optimise the energy performance of modems, routers and set-top boxes (the country has more than 3 million modems and 2 million set-top boxes). The initiative aims to slash annual energy consumption of these devices from 500 gigawatt hours (GWh) per year to 320 GWh per year. The resulting savings of 180 GWh represents enough electricity supply to power 40 000 households (Brüniger, 2013).

These examples should spur other countries to follow suit and start addressing energy wasted by network-enabled devices. Without policy interventions, it is expected that:

- Energy efficiency will continue to be a low priority in device design.
- The value chain will lack incentives to develop energy-saving solutions.
- The rate of energy efficiency improvements will be slow.

Where policies and implementation vary considerably among countries, there is a risk that devices that do not comply with legislation in one jurisdiction will be sold in countries lacking legislation or with weaker requirements – i.e. inefficient devices will dominate in markets lacking interventions.

The Way Forward

International dialogue and alignment in this area will reduce the resources needed to develop policy responses. Ultimately, aligned approaches will reduce costs and unnecessary constraints on industry by avoiding situations in which globally traded devices must comply with a multitude of diverse regulatory approaches and procedures.

Building on the success of the 1-Watt Standby Plan, the IEA proposes a Digital Energy Efficiency Plan. This plan aims to initiate an ongoing process to enable the necessary research, stakeholder dialogue and information sharing that will enable policy makers to ensure that energy efficiency considerations are a core consideration in moving towards increasingly digitalised societies.

The IEA has developed a set of Guiding Principles to ensure that networks and network-enabled devices are designed with energy efficiency in mind. Leading industry associations have already adopted elements of the IEA guidelines, but further work is needed to mainstream energy efficiency in the design of ICT systems and devices.

Box 2.2 IEA Guiding Principles for energy efficient networks and network-enabled devices

The IEA Guiding Principles for Energy Efficient Networks and Network-Enabled Devices (IEA, 2007) sets out broad principles that support low(er) energy consumption in networks and network-enabled systems, focusing on both hardware and technology and on policy.

Five principles for hardware and technology design:

- Devices should support effective power management.
- A network function should not stop power management internally.
- A network function should not stop power management in other devices on the network.
- Devices should cope with legacy equipment on the network (that may have poor behaviour or lack suitable energy management features).
- Devices should scale power requirements in proportion to the service being provided.

Four principles for energy policy:

- Require power management to automatically enter low-power modes.
- Put reasonable power limits on low-power modes.
- Encourage network-enabled devices to minimise their total energy consumption, using industry-wide protocols for power management in networks.
- Keep performance requirements generic; require specific hardware or software technologies only after careful consideration (adapted from IEA, 2007).

As part of the Digital Energy Efficiency Plan, the IEA recommends that governments take three broad steps to stimulate implementation of the IEA Guiding Principles.

- Develop policies with clear and measurable energy efficiency objectives to promote power management in network-enabled devices.
- Intensify international co-operation to develop technical foundations for policy making, including the development of energy efficiency metrics and test procedures.
- Work towards establishing or supporting international initiatives to promote energy efficiency in the broader context of digital economies.

Considering the rapidly growing share of network power consumption, energy efficiency in a digital context needs to become an integrated part of the agenda of IEA member countries as well as key international initiative such as the Clean Energy Ministerial (CEM) and the G20.

CEM ministers are encouraged to enable and endorse a collective global approach to addressing network standby, by expanding the activities of the Super Efficient Appliance Deployment (SEAD) and related initiatives and adding their respective country's expertise and effort to international co-operation on network power energy efficiency solutions.

Technology Overview Notes

Figures and data that appear in this chapter can be downloaded from www.iea.org/etp/tracking. Enhanced interactive data visualisations are also available for the figures marked with the “more online” ribbon.

Unless otherwise noted, data in this chapter derives from IEA statistics and analysis. The notes below provide additional sources and details related to data and methodologies.

Renewable Power (page 64)

Figures 2.2, 2.3: Source: data for 2000-2018 from IEA (2013), *Medium Term Renewable Energy Market Report*, OECD/IEA, Paris.

Figure 2.6: Source: Bloomberg New Energy Finance database, 2014.

Figure 2.9: data in USD 2012 prices and PPP. Bioenergy and biofuels includes solid biofuels used for heat and power and liquid biofuels used for transport. Other renewables refers to techniques, processes, equipment, and systems related to renewable energy and not limited to a specific technology or fuel source as well as technologies used for monitoring and measuring renewable energy.

Nuclear Power (page 70)

Figure 2.10: Source: historic data from IAEA, PRIS Database. Projections from Nuclear Energy Agency (2012), *The Role of Nuclear Energy in a Low-Carbon Energy Future*, OECD/NEA, Paris.

Figure 2.11: 2DS numbers are required average yearly capacity additions: 12 GW/year in the decade to 2020, and 23 GW/year between 2020 and 2030.
Sources: historic data from IAEA, PRIS Database.

Figure 2.12: construction span from first concrete to grid connection. Gen III construction spans starting in 2011 are estimated. Grid connection for projects under construction is estimated based on recent public information.
Sources: realised grid connection data from IAEA PRIS database; OECD/NEA.

Natural Gas-Fired Power (page 72)

Figure 2.13: NBP = National Balancing Point (United Kingdom), representative of European gas prices.
Sources: Henry Hub: Intercontinental Exchange; NBP: GasTerra; Japan LNG: Japan Customs.

Figure 2.14: oil-fired power generation is negligible in Germany and the United States (<1%), but represents 15% in Japan (2011).

Figure 2.15: the capacity factor represents the full load hours a plant was operated as a percentage over a whole year (8 760 hours).

Coal-Fired Power (page 74)

Figure 2.16: other renewables includes geothermal, solar, wind, ocean, biofuels and waste.

Figure 2.17: Source: 2011-2018 projections from IEA (2013), *Medium Term Coal Market Report*, OECD/IEA, Paris.

Figure 2.18: Source: Platts database.

Carbon Capture and Storage (page 76)

Figure 2.19: large-scale projects are defined in accordance with the definitions of the Global CCS Institute: projects involving the capture, transport and storage of CO_2 at a scale of at least 800 000 tonnes of CO_2 annually for a coal-based power plant, or at least 400 000 tonnes of CO_2 annually for other emission-intensive industrial facilities (including natural gas-based power generation). Advanced stage of planning has been defined as projects that have reached at least the Define stage in accordance with the Global CCS Institute's Asset Lifecycle Model. Projects which do not have sufficient clarity at the end of 2013 over the support needed to become operational by 2020 have not been included. Projects included are those undertaking monitoring sufficient to provide confidence that injected CO_2 is permanently contained, which is assumed to be the case for all projects becoming operational after 2014.
Sources: GCCSI (2014), *The global status of CCS: February 2014*, Global CCS Institute, Melbourne, Australia; IEA analysis.

Figure 2.20: the CCS patent database was constructed using a combination of keywords and patent classification codes to retrieve CCS-related patents in the United States, European and Japanese patent offices. Patents were sought for their pertinence to a range of practices including inter alia CO_2 capture from flue gases, CO_2 capture from industrial processes, natural gas clean-up, CO_2 enhanced oil recovery, CO_2 storage site management, CO_2 stream clean-up and oxyfuel power generation. The results were examined by subject matter experts to remove as many irrelevant patents as possible. Duplicates and triplicates (i.e., patents appearing in more than one patent office) were consolidated into single patents for the computation of these statistics.
Source: Science-Metrix Inc.

Figure 2.21: data in USD 2012 prices and PPP.

Industry (page 78)

Figure 2.22: the paper and paperboard category includes a wide variety of products with a range of BAT energy intensity values. Because of this variety, no overall energy intensity related to BAT is included.
Sources: IEA (2009), *Energy Technology Transitions for Industry*, IEA/OECD, Paris; Worrell, E., L. Price, M. Neelis, C. Galitsky and Z. Nan (2008), *World Best Practice Energy Intensity Values for Selected Industrial Sectors*, Lawrence Berkeley National Laboratory.

Figure 2.24: industrial energy use per unit of industrial value added in USD 2005 prices and PPP.

Chemicals and Petrochemicals (page 80)

Figure 2.27: 2025 data are 2DS targets. BPT values: steam cracking, naphtha based = 12.0 GJ/t; ammonia, coal based = 19.7 GJ/t; ammonia, oil based = 15.1 GJ/t; ammonia, gas based =7.3 GJ/t; methanol, coal based = 12.8 GJ/t; methanol, gas based = 8.5 GJ/t. All energy intensities exclude energy associated with feedstocks (Source: IEA (2009), *Energy Technology Transitions for Industry*, IEA/OECD, Paris). Methanol production is mainly based on gas in OECD-member countries. A shift toward biomass-based methanol increases the level of energy intensity while reducing CO_2 footprint.

Iron and Steel (page 82)

Figure 2.29: depending on the specific status of the relevant process or plant, not all the indicated energy savings potentials may be relevant or able to be cumulatively tapped. "Other" refers to all countries and regions not included individually. BF = blast furnace; OHF =

open-hearth furnace; BOF = basic oxygen furnace; COG = coke oven gas; CDQ = coke-dry quenching (also includes advanced dry quenching).

Figure 2.30: aggregated energy intensity includes energy use in blast furnaces and coke ovens. Comparisons of this indicator among countries and regions are limited, as there are considerable differences in the iron and steel sector, specifically structure and quality of iron ore. Global overall crude steel energy intensity increases slightly in the short-term (2015) driven by fast capacity growth in some regions, with local scrap availability being unable to follow that increase. BAT values: coke oven net energy use = 3.7 GJ/t coke; blast furnace net energy use = 10.4 GJ/t hot metal; DRI gas = 10.4 GJ/t DRI; DRI coal = 20.0 GJ/tDRI; scrap-based EAF = 350 kWh to 370 kWh (1.3 GJ/t steel).
Sources: IEA (2007), *Tracking Industrial Energy Efficiency and CO_2 Emissions*, IEA/OECD, Paris.

Transport (page 84)

Figure 2.31: Well-to-wheel refers to the energy use and GHG emissions in the production of a fuel and its use in a vehicle. Well-to-wheel energy use and GHG emission estimates exclude the production and end of life disposal of the vehicle and fuel production/distribution facilities. As such, they provide a partial view of energy use and emissions resulting from a Life Cycle Assessment (LCA) of fuel and vehicle production, use and disposal. LCA is a broader concept, requiring more information that the well-to-wheel energy and GHG emissions estimates. LCA is used to account for all the environmental impact (not only energy and GHG, but also many kinds of pollutants and water requirements) resulting from the consumption of all the materials needed for the production process.

Figure 2.32: Source: BRT Centre of Excellence, EMBARQ, IEA and SIBRT. Global BRTdata database www.brtdata.org

Figure 2.33: data calculated by multiplying average fuel price in a country with the average new vehicle fuel economy. Sources: IEA (2013), *Energy Prices and Taxes database*, OECD/IEA, Paris; Cuenot and Körner (2011), *International comparison of light-duty vehicle fuel economy: an update using 2010 and 2011 new registration data*, GFEI IEA Working Paper 8.

Electric and Hybrid Electric Vehicles (page 86)

Figure 2.34: Source: Electric Vehicles Initiative and MarkLines Database.

Figure 2.35: Source: MarkLines Database.

Figure 2.36: Source: MarkLines Database.

Biofuels (page 88)

Figure 2.37: an 85% capacity utilisation is assumed to derive the capacity requirements for the 2DS. Utilisation rates of new projects can lie well below this level in the first year of production. Projections from IEA (2013), *Medium Term Oil Market Report*, OECD/IEA, Paris.

Figure 2.38: projections from IEA (2013), *Medium Term Oil Market Report*, OECD/IEA, Paris.

Figure 2.39: source for figure and textbox: Bloomberg New Energy Finance database, 2014.

Appliances and Equipment (page 94)

Figure 2.45: Source: Super-Efficient Equipment and Appliance Deployment (SEAD) initiative, 2014.

Figure 2.46: ownership levels above 100% indicate more than one unit per household. For instance, 150% television ownership indicates an average of 1.5 televisions per household.

Missing bars do not indicate 0%; rather, data were not available for those indicators. Japan refrigerator data has not been updated since 2004.

Figure 2.47: Source: adapted from US DOE (2012), *Solid-State Lighting Research and Development: Multi-Year Program Plan*, prepared for Lighting Research and Development Building Technologies Program, Office of Energy Efficiency & Renewable Energy, Washington, DC.

Co-generation and District Heating and Cooling (page 96)

Figure 2.48: According to IEA energy balance conventions, for auto-producer co-generation plants, only heat generation and fuel input for heat sold are considered, whereas the fuel input for heat used within the auto-producer's establishment is not included, but accounted for in the final energy demand in the appropriate consuming sector. Transmission and distribution losses are not included.

Figure 2.49: Sources: Euroheat & Power (2013), *District Heating and Cooling: Country by country 2013 survey*, Euroheat & Power, Brussels.

Figure 2.50: Russian data is from 2007.
Source: Euroheat & Power (2013), *District Heating and Cooling: Country by country 2013 survey*, Euroheat & Power, Brussels.

Smart Grids (page 98)

Figure 2.51: Source: ISGAN (2014), "ISGAN Inventory Report, Annex 1, Task 2", *Smart Grid Project Catalogue: Part 1 by Project Main Application,* United States.

Figure 2.52: Source: Navigant Research (2013), "Executive Summary: Smart Meters", *Smart Electric Meters, Advanced Metering Infrastructure, and meter Communications: Global Market Analysis and Forecasts*, United States.
Textbox source: ISGAN (2013), "ISGAN Annex 6 Discussion Paper", *Smarter & Stronger Power Transmission: Review of Feasible Technologies for Enhanced Capacity and Flexibility,* updates through professional correspondence; Swedish Transmission Institute, Sweden; Department of Electric Power Engineering, Norway.

Figure 2.53: investment includes transmission upgrades, substation automation, distribution automation, smart grid information and operations technology, and smart metering. Data are based on the best estimates available at the time of calculation. Annual revenues, shipments, and sales are based on end-of-year figures unless otherwise noted. All values are expressed in 2013 USD.
Source: Navigant Research (2013), "Executive Summary: Smart Grid Technologies", *Transmission upgrades, Substation Automation, Distribution Automation, Smart grid information technology and Smart Metering: Global market Analysis and Forecasts,* United States.

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Part 2

Harnessing Electricity's Potential

Starting from the premise that electricity will be an increasingly important vector in energy systems of the future, Part 2 takes a deep dive into actions needed to support deployment of sustainable options for generation, distribution and end-use.

Three additional scenario variants included focus on more ambitious renewables in power generation and electric use in mobility and buildings.

Additionally, as the rise in energy demand will be highest in emerging economies, *ETP 2014* includes the first review of the energy future of one of the IEA key partner countries: India.

Chapter 3

Electrification of the Energy System

Decarbonising supply and shifting end-use applications towards electricity as the prime fuel source: the global energy system is undergoing transformation on two levels. Rapid evolution in the character of supply, coupled with the fact that growth in electricity demand is outpacing all other final energy carriers, requires increasingly strategic approaches of how to balance supply and demand. These conditions are challenging policy and changing markets; but also offer prospects to optimise investments and system costs.

Key findings

- **By 2050, electricity overtakes the use of oil products to become the dominant final energy carrier.** This is the trajectory in the 2°C Scenario (2DS) in *Energy Technology Perspectives 2014 (ETP 2014)*, as the share of electricity rises to between 23% and 26% of overall energy demand. This reflects an acceleration of a 40-year growth trend that has seen electricity's overall share rise from 9% to over 17%.

- **The actual share of electricity in total energy demand progresses towards 30% across all regions, but growth rates to 2050 are vastly different.** In the 2DS, countries belonging to the Organisation for Economic Co-operation and Development (OECD) show an average 16% demand growth; in non-OECD regions, growth skyrockets as high as 300%.

- **Carbon dioxide (CO_2) emissions per unit of electricity must decrease by 90% by 2050 to meet 2DS targets.** This is a massive reversal of recent trends, which saw overall emissions from the electricity sector increase by almost 75% between 1990 and 2011, due to rising demand but little change in emissions intensity.

- **Shares of fossil fuels and renewables reverse in the 2DS.** In 2011, fossil fuels constituted over 65% of global generation capacity while all renewables combined made up 25%; the opposite share breakdown will be needed by 2050, with renewables surpassing 70% and fossils dropping to just over 20%, while nuclear maintains a 7% share.

- **Decarbonising the electricity sector can deliver the spillover effect of reducing emissions from end-use sectors, without needing further end-use investments.** If the electricity sector remains fossil fuel dependent, electrification of end-use sectors is unlikely to achieve the CO_2 emissions reductions needed.

- **"Systems thinking" is needed in the transition to a future system in which electricity from renewable generation is the dominant energy carrier – without creating the need for disproportionate investment.** A more systemic approach is required to better integrate all aspects of the electricity system and prompt all stakeholders to optimise use of existing infrastructure.

Opportunities for policy action

- Many current energy market structures do not yet function adequately with high shares of variable renewables, resulting in negative impacts on all generation technologies. Continued evolution of regulation, markets and system operations need to proceed in parallel with increased deployment of variable renewables.
- To optimise the development of a smart, integrated electricity system, technologies and market mechanisms need to be developed jointly. Smart-grid technologies will offer more choices for operation and market design, and provide opportunity for increased engagement by all electricity system stakeholders.
- In the highly regulated electricity industry, adaptable regulation is needed to support research, development, demonstration and deployment (RDD&D) in real-world situations. Such approaches are needed to fully explore and exploit the new opportunities provided by new technologies.
- Targeted RDD&D should focus on technologies that can provide system-wide benefits to enable more optimal electricity system development.

Electricity is already at the core of the global energy system and is projected to play an increasing role. Almost 40% of global primary energy is currently used to generate electricity, yet electricity covers on average only 17% of all global final energy needs. Among all final energy carriers,[1] per capita growth of electricity has been the strongest, more than doubling from 1 263 kilowatt hours per capita (kWh/cap) in 1974 to 2 933 kWh/cap in 2011. This trend is expected to continue to 2050 under all scenarios in *ETP 2014*. Generation from wind and solar technologies has grown annually at double-digit rates over the last ten years, but fossil fuels account for over 75% of net new electricity generation during the same time period (of which 50% is due to coal-based power generation in the People's Republic of China).

In this context, it is imperative that development of the electricity system is given due attention. These changes carry inherent challenges relative to energy security, economics and climate change. This increase in electricity demand is happening at a time when the energy sector has faced difficulty in meeting targets to reduce CO_2: electricity production contributed nearly 40% of all energy-related emissions in 2011. Growth in electricity demand has been uneven across regions, in part reflecting the global economic recession or a shift away from increasing industrial development to a more service-oriented economy. Electricity system reliability has been questioned due to ageing infrastructure while also put to the test by deployment of renewables and increased intense weather patterns.

ETP 2014 will focus on three key areas in the electricity system that show interesting developments, such as decreasing costs, changing roles, strong deployment progress and increased technology-specific interest:

- **Supply:** solar and base-load natural gas electricity generation technologies and financing of low-carbon generation.

1 Energy used in agriculture, buildings and transport and for industrial production processes.

- **Demand:** transportation and buildings.[2]
- **Integration:** electricity storage and flexible natural gas generation.

  Additionally, as the rise in energy demand will be highest in emerging economies, *ETP 2014* includes the first review of the energy future of one of the IEA key partner countries.

- **Country focus:** India.

  Throughout Part 2 of *ETP 2014*, discussion of modelling results will highlight the 2DS, with reference to the 4°C Scenario (4DS) and the 6°C Scenario (6DS) as needed; three additional variants are included in some of the topical analyses. While the 2DS offers the least-cost pathway to decarbonisation, the energy system does not always develop in line with optimum approaches and technology development may not roll out as hoped or expected. These variants demonstrate other pathways that could meet – or possibly exceed – the long-term benefits achieved in the 2DS. By exploring "what if?", the variants provide insights that might emerge if the energy system develops differently and electricity is used to a greater degree. Variants included focus on more ambitious renewables in power generation, and electric use in mobility and buildings (Box 3.1).

Box 3.1 Analytical variants in *ETP 2014*

The **2DS High Renewables (2DS hi-Ren)** variant illustrates an expanded role of renewables in the power sector that counterbalances a decreased deployment of nuclear technologies and carbon capture and storage (CCS). Faster deployment of renewable technologies in this variant results in lower technology costs due to learning effects.

The **2DS Electrifying Transport (2DS-ET)** variant projects massive electrification of transport, deployed first in strategic regions to maximise CO_2 savings. While the 2DS is already ambitious in terms of transport electrification, especially for light-duty road passenger applications, the 2DS-ET aggressively pursues electrification of road freight vehicles, in part counterbalancing the possibility that second-generation biofuels and hydrogen are not cost-effectively developed and deployed as anticipated.

The **2DS Electrified Buildings (2DS-EB)** variant examines two regions for increased demand for electricity in buildings due to higher deployment of heat-pump technology for both space heating and domestic water heating. The increased use of electricity for these applications displaces the use of natural gas. This approach could accelerate reductions in building-based carbon emissions, decrease dependency on non-indigenous fuels for certain regions and increase energy savings.

Note: for a full description of *ETP* scenarios, see Chapter 1: The Global Outlook.

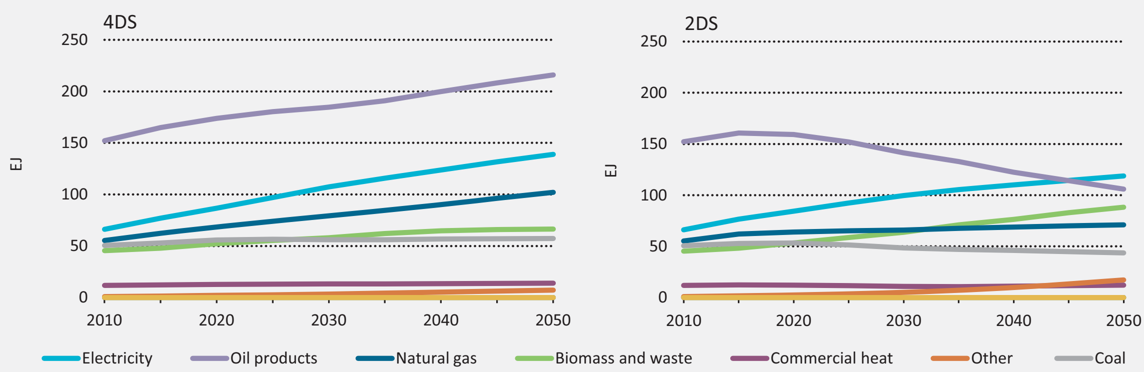
This chapter does not aim to provide a comprehensive discussion of all pertinent electricity system topics but rather to illustrate the importance of some of the aspects of the foreseen electricity system transition and its impact on the entire energy system. It is clear that electricity is a key resource for all countries; meeting the goals of an economic, secure and clean electricity system globally presents huge challenges, but the chapters will also highlight opportunities and benefits. Ultimately, it demands an approach to system development that leverages the most appropriate technology – which often implies policy intervention to support both finance and RDD&D.

2 Only a concise discussion of electricity use in buildings will be included in *ETP 2014* since the comprehensive publication *Transition to Sustainable Buildings: Strategies and Opportunities to 2050* (www.iea.org/etp/buildings/) was released in mid-2013.

The increasingly essential and evolving role of electricity

By 2050, global electricity demand is expected to increase in all *ETP* scenarios, rising to between 23% and 26% of global final energy demand. In fact, growth in demand for electricity will outpace overall final energy demand growth (Figure 3.1). Globally, electricity demand to 2050 grows by 110% in the 4DS and 80% in the 2DS (from 2011 levels). Electricity demand is over 30% higher in the 4DS than in the 2DS, as less progress in energy efficiency compounds the increased share of electricity.

Figure 3.1 Global final energy demand by fuel



	4DS				2DS			
TWh	*2011*	*2030*	*2050*	*CAGR*	*2011*	*2030*	*2050*	*CAGR*
Electricity demand	66 137	107 388	138 988	1.92%	66 137	99 664	118 725	1.51%
Total final energy demand	382 623	501 940	602 048	1.17%	382 623	456 664	435 029	0.45%

Notes: EJ = exajoules. TWh = terawatt hours. CAGR = compound annual growth rate.
Source: unless otherwise indicated, all tables and figures in this chapter derive from International Energy Agency (IEA) data and analysis. Figures and data that appear in this report can be downloaded from www.iea.org/etp2014.

Key point *By 2050, in the 2DS, electricity overtakes oil-based products as the largest end-use fuel for meeting the needs of the global energy system.*

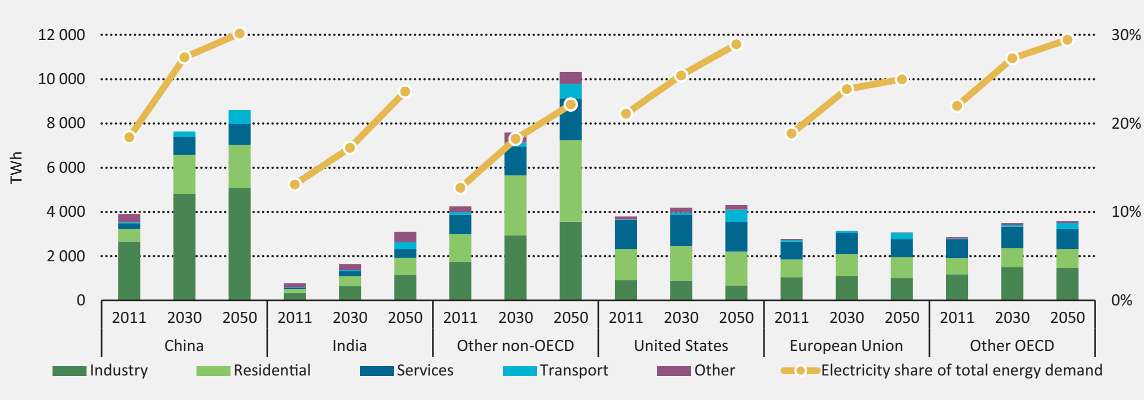
In 2011, oil products represented 40% of global final energy demand, with other energy carriers at shares below 17%. Projecting into the future shows diverging paths among the scenarios for the shares mix. In the 4DS, the shares of oil products, coal and biomass change by only small amounts (between 1% and 4% of total share) while overall demand for energy rises. Oil remains dominant even as electricity's net share grows to 23%. In the 2DS, which sees lower final energy demand compared with the 4DS, oil products and electricity switch positions: oil drops to below 25% of overall share and electricity increases to above 25%, becoming the largest final energy carrier in the energy system.

Investments needed in the power sector range from USD 30 trillion to USD 40 trillion to 2050 across the three scenarios, with the 2DS requiring the highest investments. Compared to the 6DS, a larger share of the investment in the 2DS is needed for low-carbon generation technologies, which are typically characterised by higher capital costs; less investment is required for transmission and distribution (T&D) networks due to increased electric efficiency in the end-use sectors, resulting in an overall lower electricity demand. The increased investment needs in the 2DS are offset by reduced fossil fuel costs, caused to some extent by a lower electricity demand, but especially by the increasing deployment of non-fossil fuel based electricity technologies, such as renewable and nuclear. The 4DS and 6DS exhibit the opposite trend compared to the 2DS: investment in deployment of fossil, often also less capital-intensive, technologies continues and results in higher fossil fuel costs. Higher electricity demand is a further factor increasing not only the generation investments in these scenarios, but also driving up investment needs in the T&D system.

The meaning of electrification differs depending on whether a region's electricity system can be characterised as stable or dynamic. In stable systems, electrification refers to increasing shares of electricity in the energy system and a growth in electricity demand in given sectors such as transport or buildings. Overall growth in electricity demand is modest. In this context, electrification demonstrates a shift towards greater use of electricity to displace other energy carriers, offering an opportunity to shift a country's primary fuel demand and exploit end-use efficiency benefits typically provided by using electricity. In dynamic systems, electrification is much more focused on providing access to electricity to society and industries in general, as an enabler of economic growth. High growth rates for electricity are seen in all sectors, with a similar fundamental shift from oil to electricity as the primary fuel for transport.

In many OECD countries, where systems are largely stable or mature, demand for electricity has been flat for several years. This trend of modest electricity demand growth continues under the 2DS, averaging 16% between 2011 and 2050. Without increased demand for electricity by electric vehicles (EVs), growth would be even lower (Figure 3.2). In contrast, demand in non-OECD countries and regions grows substantially – averaging 145% and as high as 300% – over the same period, reflecting highly dynamic systems. Since the 2DS reflects substantial energy efficiency improvements that moderate growth in energy demand, other scenarios show greater increases in actual demand.

Figure 3.2 **Sectoral electricity demand and share of electricity in total energy demand in the 2DS**



Key point *Electricity demand growth differs between industrialised and industrialising countries, but an increasing share of electricity in the overall energy mix follows similar trends.*

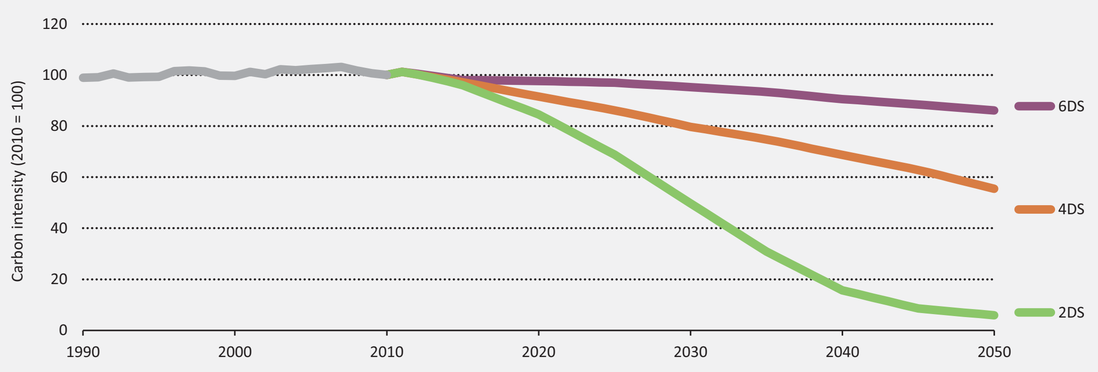
Despite differences in the growth rates, the share of electricity in total energy demand grows to between 20% and 30% by 2050 in both OECD and non-OECD countries, indicating an overall rise in the importance of electricity. In examining the roles of specific technologies in decarbonising the electricity system, the following chapters analyse how technology is deployed globally while considering variations across regions, as well as demonstrating similarities and differences.

In a new feature, *ETP 2014* explores the potential to transform India's power generation sector. Very few countries have been faced with challenges of the magnitude that confront India in its quest to maintain strong economic growth while providing electricity to its 288 million citizens who currently lack access. In addition, energy demand is projected to increase by 50% over the next ten years, and by a factor of three over the next 30 years – all energy sources and technologies will need to be exploited. This exceptionally large and challenging need for expansion of capacity creates an opportunity for true transformation of the Indian power generation sector.

Implications for environment, security and economy

In the 2DS, the character of electricity supply changes radically by 2050: in parallel with moderate growth in demand, supply shifts away from heavy dependence on fossil fuels in 2011 to an even higher reliance on renewables. The 4DS and 6DS show fewer changes in the share of various generation technologies but higher increases in demand. All parts of the electricity system must be transformed to accommodate a shift in and/or increased demand for electricity (depending on region) in order to meet long-term environmental, security and economic goals.[3]

Figure 3.3 Electricity Generation Sector Carbon Intensity Index (EGSCII)



Note: regional content is available online at: www.iea.org/etp2014.

Key point *The stable level of carbon intensity must be dramatically reduced to decarbonise the electricity system in the context of increasing demand.*

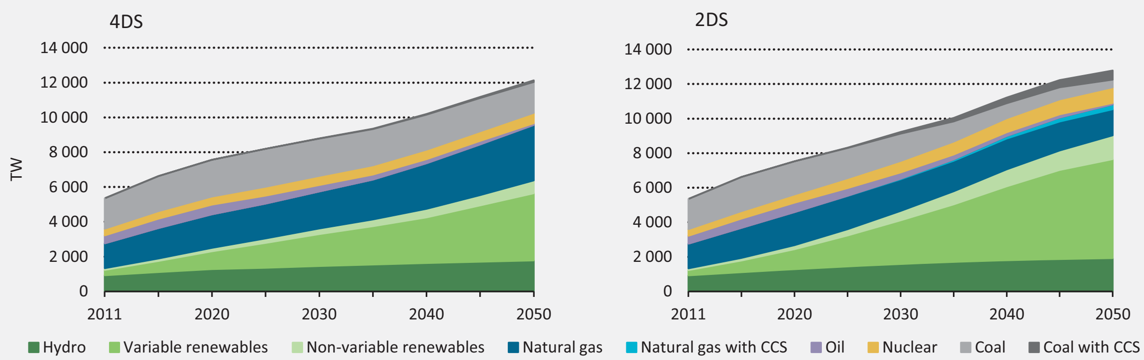
3 The discussion of economic impacts of electricity use focuses on two main aspects: the price of electricity and the respective impact on end users; and the importance of operating an electricity system in an economically sound manner that ensures reliable operation. Reliable and affordable electricity is believed to have broad-based macroeconomic benefits, but limited robust data are available to quantify this.

Electricity supply

The intensity of emissions from electricity generation has been stable over the last 20 years (Figure 3.3); as electricity production increased, overall electricity sector[4] emissions rose by almost 75% between 1990 and 2011. Despite significant growth in their deployment, the positive effects of low-carbon generation technologies have been muted by the fact that fossil fuels (especially coal power generation) have accounted for the majority of new generation capacity. To reach 2DS targets by 2050, CO_2 emissions per unit of electricity generation must be reduced by 90% while electricity generation increases by 80% from 2011 levels.

Achieving the 2DS targets by 2050 requires – on a capacity basis – a reversal in the share of fossil versus renewable generation. Whereas fossil fuels constituted over 65% of global generation capacity in 2011 and all renewables combined made up 25%, the opposite share breakdown will be needed in the 2DS by 2050 where renewables surpass 70% and fossils reach just over 20%, coupled with nuclear maintaining its current share (7%) (Figure 3.4). Some emissions reduction is seen in the 4DS, largely due to efficiency improvements in fossil generation, fuel switching from coal to gas and some renewables becoming increasingly competitive in good locations. The average CO_2 intensity in the 4DS in 2050, however, is only slightly lower than a very efficient gas plant by current standards – i.e. insufficient to meet long-term climate goals.

Figure 3.4 Global electricity generation capacity by technology



Note: TW = terawatts.

Key point *A dramatic increase in variable renewables capacity in the 2DS – rising to over 40% of total generation capacity by 2050 – requires altered planning and operation of electricity systems.*

Globally, variable renewables[5] are nearly 45% of total generation capacity by 2050 in the 2DS (30% in the 4DS) with some regions exceeding this level by a significant amount. Power generation shares are somewhat lower (17% and 29% in the 4DS and 2DS respectively) due to lower capacity factors inherent with variable renewables. The benefits and challenges associated with increased deployment of variable renewable technology will depend on the

4 CO_2 emissions of the electricity sector include the emissions from electricity generation and heat generation at co-generation and heat plants.

5 Variable renewable generation includes: wind, solar photovoltaic (PV), and ocean and tidal. Non-variable renewables include: biomass- and biofuel-based generation, geothermal, and concentrating solar. Hydro-based generation, as an additional renewable technology, is categorised individually due to its current and future scale of deployment.

context. In some regions that import fossil fuels, shifting to higher shares of indigenous renewables will reduce import dependence, and lessen exposure to fluctuating global markets or fossil fuel disruptions, thereby improving fuel security.

Box 3.2 What is electricity system security?

Power system security is a very broad notion and is built around loads, generation and networks. The IEA defines electricity system security as the ability of the value chain to deliver electricity to all connected users, within acceptable standards and in the amounts desired – which implies three fundamental requirements.

Fuel security: the ability to maintain access to reliable fuel supplies for power generation, even in the context of changing international commodity markets, upstream developments, and security of existing and new supply routes.

Adequacy: the capability of the power system to meet changes to aggregate power requirements in the present and future, using existing and new resources, through timely investment and operational and end-use responses.

System security: the capability of the power system, using existing resources, to maintain reliable supplies in the face of unexpected shocks and sudden disruptions, e.g. the unanticipated loss of key generation or network components, or rapid changes in demand or generation.

These three fundamental requirements are interrelated. System security policies and practices help to establish an effective "adequacy envelope" of existing generation and network infrastructure. In the long term, efficient, timely and well-located investment is needed to maintain power system adequacy, and provide the resources needed to maintain system security. Access to reliable fuel supplies and their efficient use are required to ensure that generation equipment operates reliably and predictably from a short-term electricity system security perspective, while ensuring that generation infrastructure is able to meet both present and future demand and adequacy requirements. Governance and market arrangements establish incentives for efficient, flexible, timely and innovative responses to maintain power system security and adequacy in the present and over time (IEA, 2013a).

Note: the IEA work on electricity security provides a fuller definition as part of the Electricity Security Action plan. This section has been adapted from the report *Secure and Efficient Electricity Supply* at: www.iea.org/publications/freepublications/publication/SecureandEfficientElectricitySupply.pdf.

The increased deployment of renewables significantly changes electricity systems, creating challenges for maintaining adequacy and system security. Three main actions are needed for a successful transformation to higher shares of variable renewables: improved system operation; deployment of variable renewables to directly support integration; and investment in additional flexible resources. Tackling the first two actions is a priority wherever and whenever variable renewables are deployed. Investment in flexible resources will differ depending on system context. In stable systems, operators can exploit the existing generation base and reach high shares of variable renewables by optimising flexibility through improved operations.

There is some risk that rapid addition of new generation capacity and the more flexible operating pattern can put legacy generation assets under economic stress. While this does not pose any short-term threat to generation adequacy in stable systems, it can lead to stranded assets and raise concerns regarding the future investment climate. By contrast, dynamic systems cannot rely on legacy assets to integrate variable renewables to the same extent. While economic stress on the legacy system will be less of a problem, dynamic systems need to develop a strategy for additional flexibility already at lower variable renewable shares (IEA, 2014).

Currently, the cost of producing electricity from solar and wind (the two fastest-growing renewable technology deployments) is higher than from conventional technologies such as gas and coal. Support schemes for these technologies have an economic cost – either to the general tax revenue fund or by increases in electricity tariffs – especially for residential consumers.[6] At times, these costs have been higher than expected due to higher than necessary support. In some cases, policy makers have been slow to reduce support scheme levels as technology prices decline or to link effectively to other mechanisms (such as carbon prices). Extensive learning has been acquired over the last 20 years in developing well-functioning support schemes; it is essential to deploy best practices, especially as technology development and cost reductions have been occurring very rapidly in recent years.

As technology develops and stakeholders gain experience in deployment, a greater range of low-carbon generation technologies are expected to become competitive with conventional technology. Low short-run costs and high up-front capital costs associated with many of these technologies, including nuclear, will require a different investment strategy and revised market mechanisms than are currently in place.

ETP 2014 includes three chapters that focus on key aspects of electricity supply: solar generation, natural gas generation and the challenge of financing low-carbon supply. The chapter on solar power will examine recent technology developments and cost reductions for PV, considering grid parity, self-consumption and grid integration. Discussion of advances in concentrating solar power (despite its slower uptake) highlights how the emergence of its complementarity to PV boosts expectations of increased long-term deployment. The 2DS hi-Ren explores implications of greater solar deployment than is considered in the 2DS.

The evolving role of gas generation technology looks at two possible future paths, providing either base-load generation (when coupled with CCS in the long term) or flexible generation to support high penetration of variable renewables. The challenge here is that gas technology needs to develop in two directions, which may create competition for development resources for conflicting innovations needed depending on the role played.

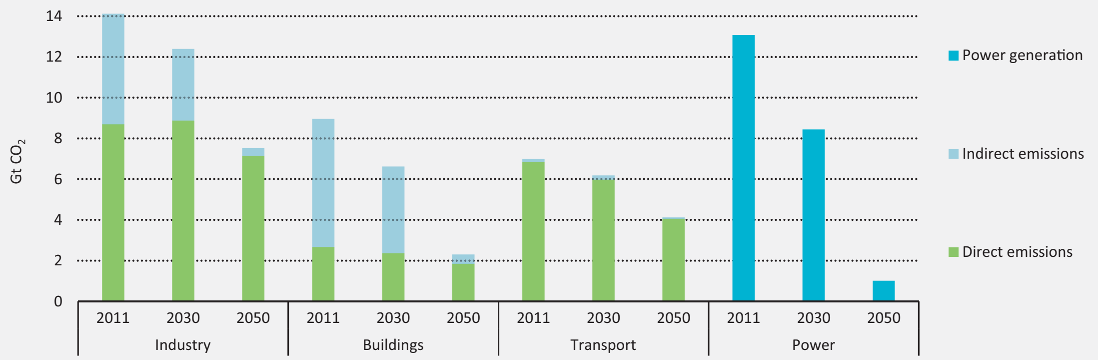
With a strong focus on understanding risk and return from the investor perspective, the chapter on financing low-carbon technology considers what actions are needed to mobilise sufficient financial flows to support the high up-front capital requirements typical to many low-carbon generation technologies. This is in addition to the evolving risks in financing in the context of uncertain climate mitigation ambitions.

Electricity demand

Decarbonisation of the electricity system can have a significant spillover effect in decarbonising end-use sectors. Direct emissions refer to those counted at the point of creation: e.g. at a coal-fired plant or from the tailpipe of a vehicle running on fossil fuels. Since the use of electricity produces no emissions at the point of consumption, direct electricity generation emissions can be attributed to the sector where the electricity is consumed. When accounted for in this manner, the importance of decarbonising the electricity sector becomes clear (Figure 3.5). Unless electricity supply is decarbonised, electrification of end-use sectors offers little opportunity to reduce CO_2 emissions (other than potentially some savings due to efficiency gains). But as electricity generation is decarbonised, sectors using electricity are automatically decarbonised without needing further end-use investments. Examination of the three largest energy-consuming sectors – industry, buildings and transport – shows broad variation in the impact of current and future electricity-based emissions.

6 Support schemes designed to make renewables more economically competitive often shield industrial customers from tariff increases.

Figure 3.5 2DS emissions reduction to 2050



Notes: $GtCO_2$ = gigatonne of carbon dioxide. Indirect emissions in the end-use sectors are due to electricity use and associated direct emissions from power generation. Direct emissions are those emissions released from stationary or mobile fuel combustion processes (i.e. from a vehicle or a power plant) or at industrial production sites (i.e. a cement plant). *ETP* includes also process-related CO_2 emissions in industry and refining, such as emissions in processes where the primary purpose is a chemical conversion (i.e. using carbon in coal as reducing agent during pig iron production).

Key point *The allocation of electricity-based emissions to end-use sectors demonstrates the importance of electricity decarbonisation to support total end-use emission reductions.*

In industry, electricity-based emissions account for 38% of total sector emissions in 2011; in the 2DS, this drops off to 5% in 2050 (demonstrating the spillover effect of decarbonised electricity effectively decarbonising industry). Direct use of fossil fuels and process-based emissions result in large point-source emissions; fully decarbonising this energy-intensive sector will require additional mitigation technologies (such as industrial CCS).

At present, direct emissions in the transport sector far outstrip indirect CO_2 emissions due to electricity use. Fossil fuels will continue to dominate the sector to 2050 in all scenarios, but improved vehicle efficiency, alternative fuels and advanced vehicles are together the three pillars key to decarbonising the sector. Electrification of transport delivers substantial benefits. For example, although electricity makes up only 10% of total transport energy demand by 2050 in the 2DS, it accounts for approximately 50% of transport efficiency gains.

Considering only direct emissions, the buildings sector is a minor contributor – accounting for only 8% – to global energy-related emissions. When allocating emissions from power generation based on the buildings sector's share of electricity use, this figure rises dramatically to over 25% – exceeding transport-based emissions. Decarbonising electricity as in the 2DS would substantially reduce the buildings sector's share of emissions by 2050.

In both buildings and transport, increased electricity use also reduces the multitude of small point-source emissions and is an effective way to improve urban air quality. Electrifying vehicles also substantially reduces noise in the transport sector. These are just two examples of co-benefits of electrification.

But substantial challenges must not be overlooked. The shift to electricity in end-use sectors will drive up base-load and peak demand, potentially stressing existing infrastructure. Additional peak demand could strain the financial sustainability of electricity systems, since added investment costs may not be adequately recovered by additional revenue from annual demand. In urban settings, expanding or upgrading both generation and network capacity to ensure adequacy can be complicated due to space constraints or may negatively affect busy urban centres during implementation. Smart grids, distributed generation and other advanced technologies can offer technical and market-based solutions to these issues.

Recent efforts to electrify passenger vehicles have led to deployments and growth rates largely in line with meeting 2DS targets. The payback period to recoup the additional up-front cost of e-mobility is a key metric for considering investment across all transport modes. The 2DS-ET examines the impacts of increased electrification of freight modes, including light-duty commercial vehicles and heavy-freight trucks, on the transport sector and on the overall energy system.

Box 3.3 **The impact of electricity prices on businesses, individuals and system operation**

Disparities in electricity prices among countries and regions have widened significantly in recent years. For industries with high electricity demand, electricity costs can have direct impacts on the price of products and seriously affect international or regional competitiveness, which can be said of high energy costs in general (IEA, 2013b).

If prices rise in one region but not in others, it may create motivation to relocate production (including direct and indirect jobs) to lower or least-cost locations. Within a given region, increased energy costs will often impact businesses uniformly. Typically, the solution is to pass the extra cost on to customers in a way that does not competitively disadvantage individual businesses, but goods and services become more expensive to customers.

For individuals with high levels of disposable income, electricity costs may be an insignificant part of overall expenditures and price increases are of little impact. In contrast, for those with lower incomes, electricity cost increases can have a significant effect on lifestyle. In severe cases, the term "fuel poverty" is used to describe a person or family for whom electricity (or energy) prices impose difficult choices on basic needs expenditures (i.e. whether to "heat or eat").

Retail electricity pricing is under increasing scrutiny in several countries and regions, with significant practical and political implications. The value of electricity is very high to the economy and society, and tariffs and market structures must be set to provide sufficient revenues to operate and maintain systems in a financially viable manner. If the price is too low, it can promote inefficient use of electricity. If the price is too high, it can have negative impacts on vulnerable populations. The energy sector must seek to strike a balance – by providing an overall structure that promotes efficient use and makes information accessible to enable consumers to make choices about how to use electricity, without overburdening those with lower incomes.

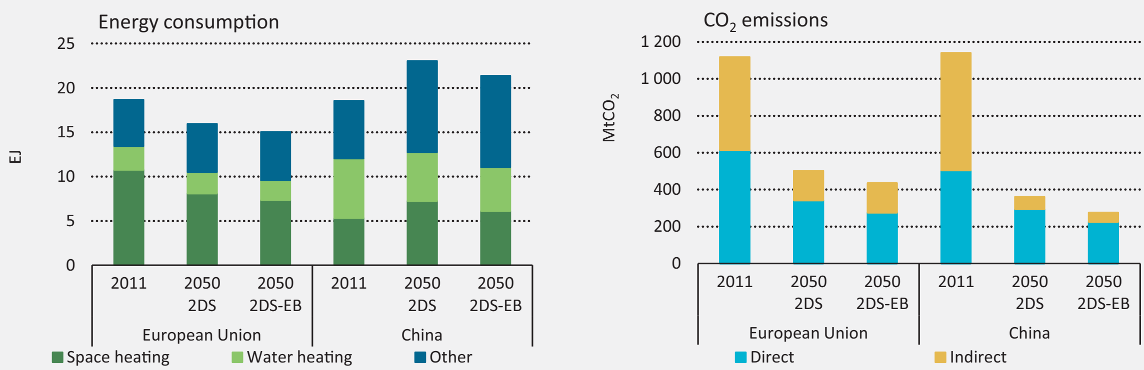
Beyond the 2DS in buildings: high electrification in the European Union and China

ETP 2014 carried out modelling beyond the 2DS to assess the feasibility of realising greater CO_2 emissions reductions in the buildings sector by increasing electrification in concert with fuel switching from natural gas to decarbonised electricity. The 2DS-EB considers increased deployment of heat pumps for both space and water heating applications, with a narrow focus on the European Union and China, both of which have fairly large thermal loads due to their cold climates but do not have large domestic resources of natural gas (unlike Russia, Canada and the United States).

In 2011, the European Union had fairly high natural gas fuel shares in the buildings sector (around 34%), mostly imported. By 2050, it sees nearly a 10% decline in energy consumption across the entire buildings sector in the 2DS, while the fuel share for natural gas falls to around 32% in 2050. In the 2DS-EB for the European Union, the fuel shares for natural gas decline even further to 27%. In 2011, China's fuel share of natural gas is around 6% in the buildings sector. Even in the 2DS, China's large expected economic growth and urbanisation drive up buildings energy consumption by 24% in 2050, while using more natural gas to meet demand for space and water heating, resulting in almost 20% fuel share in 2050. To avoid most of this growth in natural gas demand, the 2DS-EB switches to electricity through heat pump technology.

Advanced heat pump technology clearly delivers. In the European Union, the lower gas demand of the 2DS-EB leads to significant (67 million tonnes of carbon dioxide [$MtCO_2$]) additional emissions reduction in 2050, approximately 13% below the 2DS (Figure 3.6). China, despite more rapid demand growth, shows higher (85 $MtCO_2$) emissions reduction, an almost 24% drop from the 2DS. The European Union's 2DS-EB results show a further reduction of around 6% for the buildings sector energy consumption compared with the 2DS, whereas China results in around 7% reduction.

Figure 3.6 **Buildings sector emissions reductions and energy savings in the 2DS-EB, European Union and China**



Key point *Higher electrification in the European Union and China through the 2DS-EB results in further energy savings and emissions reduction beyond the 2DS.*

The overall change in electricity demand for the buildings sector in the 2DS-EB compared to 2DS is modest. Although aggressive increases in market share for heat pump technology increase the share of electricity use while displacing gas demand, heat pumps also displace existing electrical heating and cooling appliances beyond the 2DS, therefore moderating overall growth in demand. In the European Union, electricity demand decreases by around 4%; whereas it increases in China by around 4%. The 2DS-EB results in reductions of total primary gas consumption: in the European Union by almost 10% in 2050 compared to the 6DS and by 18% in China, reducing reliance on imported natural gas.

The viability of the additional emission reductions in the 2DS-EB in the European Union and China depends strongly on decarbonisation of the electricity sector; without decarbonisation, energy savings are possible, but the extent of emissions reductions compared with 2011 levels would be significantly less.

The policies required to implement higher rates of heat pump technology for space and water heating in buildings are plausible but will depend strongly on the political will of policy makers. As water heaters have a service life of around 15 years, most water heaters in the existing building stock will be replaced at least two or three times between now and 2050. Space heating is somewhat more challenging because many gas boilers are in service for 20 to 25 years. Based on these service life figures, if not pursued soon, the opportunity to implement the 2DS-EB and advanced technology will be reduced under the 2050 time frame.

Implementing the 2DS-EB would require the full complement of policies for RDD&D, voluntary market conditioning and mandatory standards. [For extensive information on building policies, see IEA (2013c) *Transition to Sustainable Buildings: Strategies and Opportunities to 2050 OECD/IEA, Paris*]. Most importantly, the 2DS-EB would require assertive policy to stimulate commercialisation of affordable, high-performance heat pump technology for both space and water heating. Currently, water heating heat pump technology has been successful in Japan with sales of over 500 000 units per year. Large-scale global adoption is still lacking, despite some recent success in the United States with the commercialisation of an affordable product (around USD 999) with a payback period of less than five years for many households.[7] Heat pump technology for space heating is widely available in many regions of the world; air-source heat pumps, which have lower initial capital costs, are predominantly used in moderate climates, whereas more expensive ground-source units are used in all climates. Research and development (R&D) continues to explore ways to reduce the installed cost of ground-source heat pumps. The IEA Implementing Agreement for the Heat Pump Technology Programme is exploring the development of air-source heat pumps that can maintain high performance in cold climates.

Systems approaches to electricity production and use

The need for "systems thinking" should be considered as a technology field in the same way as supply and demand. The energy community has largely realised the need to integrate a broad range of technologies and policies across the supply, T&D, and demand sectors over the long term to establish a clean and resilient system that supports efficient, flexible, reliable and affordable operation.

In the future, generation plants (both fossil-based and renewable) will be installed in an increasingly distributed fashion,[8] requiring a fundamental change in traditional mechanisms for supply and demand in electricity systems. The past unidirectional system will not be "smart" enough to function with high shares of distributed supply; the future system will need to have all electricity system components operating together to facilitate the "exchange" of resources and services among all stakeholders to support system operation (Figure 3.7).

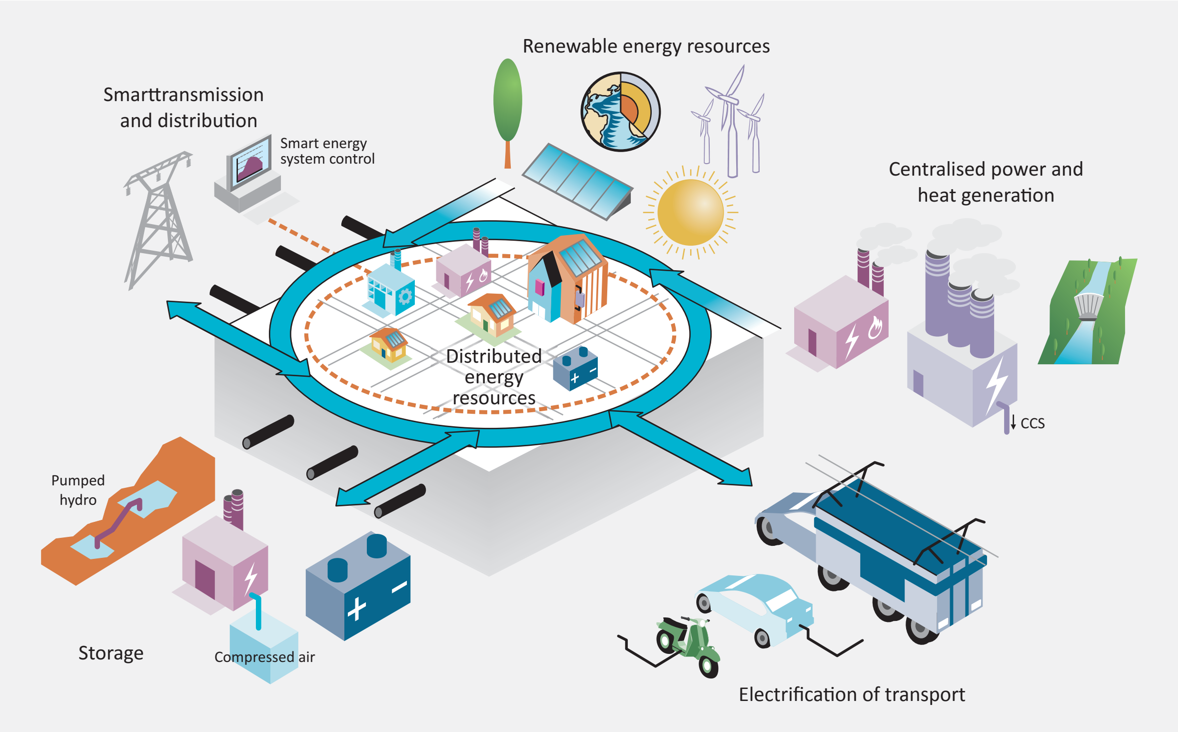
The anticipated scale of distributed generation is a significant departure from the historical model of large-scale centralised electricity production and operation. While centralised production will remain an important part of the electricity system, growth in distributed generation will require changes to the design, planning, and operation of electricity systems in all regions. Consumer engagement will also change, as many will become small-scale electricity producers through the addition of solar panels on homes, for example. The term "prosumers" has recently emerged to describe customers who consume and produce electricity, and may provide energy services. Demand-side management and demand response will also increase the role of the consumer to not only use electricity, but also support system operation.

Such integration is not without challenges. The growth in the number of generation plants, varying in size from a few kilowatts to the multi-megawatt scale, will need to be incorporated into the planning and operation processes for electricity systems. Highly sophisticated

7 Payback is variable and highly dependent upon hot water usage, ground water temperatures, climate, energy prices and many other factors.

8 The exact size and definition of distributed generation is not fully agreed upon in the literature but generally refers to plants installed on the distribution network. The *ETP* modelling framework only allows to a limited extent a differentiation between centralised and distributed generation (by distinguishing different voltage levels and a simplified representation of the T&D system), but the trend is being seen in practice.

Figure 3.7 The integrated and intelligent electricity system of the future



Key point *The aim for the future is to better integrate all elements of electricity systems to optimise investment and operation; this will increase complexity, but also improve efficiency and resilience while optimising use of energy resources.*

operational hardware and software already exists to manage such systems, and the increased deployment of smart-grid technologies will enhance information, thereby enabling greater control by system operators and other stakeholders. The inherent changes in the distribution systems will require increased interaction between transmission system operators and distribution system operators. Stakeholders also need to take seriously the reality that introducing more information and communication technology can potentially raise the risk of new security threats, such as hacking of systems and cyber attacks.

Integration aspects will be explored in all individual chapters, demonstrating the cross-cutting nature and importance of systems thinking. The future role of storage in electricity systems is currently attracting significant hype and expectation: it is often viewed as the singular technology that will allow large-scale deployment of variable renewables into global electricity systems. Recognising that an overriding challenge – i.e. storage must compete with existing technologies that deliver the balancing role at lower cost – has not yet been fully explored, *ETP 2014* includes a chapter that evaluates potential storage technologies and applications while also benchmarking cost and performance against competing technologies. Similarly, the chapter on natural gas electricity generation evaluates the ability for flexible operation while contrasting technology advances needed to improve flexible versus base-load performance.

Box 3.4 **Advanced technologies enable systems approaches in the electricity system**

A number of rapidly evolving or state-of-the-art technologies are providing increased capabilities to deploy systems-based solutions in the electricity sector.

High temperature superconductor (HTS): although still quite newly developed, HTS technologies are moving from R&D to demonstration and are being used in some niche commercial applications. HTS cable can support very high current ratings in very compact cables, providing an effective means of meeting increasing electricity demand in highly populated areas where space constraints are an obstacle for larger conductors. The increased current-carrying capability can enable more compact and lighter generator, motor, and transformer designs, thus allowing larger scale but still reducing other balance-of-system or support structures, resulting in improved cost performance. HTS fault current limiters can protect both ageing and new equipment, thereby increasing the service life of the infrastructure (HTS IA, 2013).

Storage: electricity is typically stored by converting it to a different form of energy (mechanical, electrical, chemical, kinetic, potential, and thermal) and then reverting back into electricity for use at a later stage. Power-to-heat or power-to-fuels storage interlinks the electricity system with heat and fuel systems, thereby avoiding the need for reconversion, i.e. the outflow of the storage is heat or chemical fuels. Thermal energy storage, for example, retains electricity as heat (i.e. latent and phase-change) that is eventually used for the purpose of heating.

Demand-side integration: demand-side response and management actively shifts end-use energy consumption and power loads across time, and can be considered as a virtual storage. As the electricity system is transformed, different levels of demand-side integration are emerging. The biggest change is the level that integrates the consumer as an active part of the electricity system through real-time participation that can schedule consumption, distributed generation assets and even storage assets.

Smart grids are electricity networks that use a multitude of digital technologies in a co-ordinated fashion to monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end users. Such grids will be able to co-ordinate the needs and capabilities of all generators, grid operators, end users and electricity market stakeholders in such a way as to optimise asset utilisation and operation. In the process, smart grids minimise costs and environmental impacts while maintaining system reliability, resilience and stability (IEA, 2010).

Smart-grid technologies will be a key enabler in integrating all of the above technologies (including also distributed generation, such as wind, PV and co-generation), with a view to enhancing energy efficiency and reducing CO_2 emissions.

Recommended actions for the near term

Whether operated in vertically integrated or liberalised markets, the electricity sector is highly regulated and governed. This creates both opportunities and challenges in pursuing the goal of decarbonisation while enhancing system security, economical operation and environmental stewardship. Interventions in market and regulatory frameworks can be used to influence development, but care must be taken to avoid unforeseen, negative consequences. Effort should be taken to minimise market impacts or distortions, and ensure that support mechanisms strike the balance of providing policy stability while adapting to rapidly developing technologies.

As deployment of variable renewable technologies has become significant in several regions, the importance of managing electricity security during the transition to a low-carbon energy system has become clear. Experience shows that variable renewables with low short-run marginal costs affect other generation technologies in terms of both load factors and revenues. As such learning will continue during the coming decades, sharing of best practices is vital to establishing regulation that can be more easily adapted as the electricity system continues to evolve.

In the near term, the policy focus should be directed towards support and guidance for RDD&D, with the aim of finding both medium- and long-term technology, regulatory and market solutions that enable an optimised, reliable and integrated electricity system. Critically, the regulatory framework must ensure that markets do not hinder technology development and deployment. In many cases regulation will need to underwrite the piloting and demonstration of new technology to determine actual costs and benefits.

Some new technologies will offer new options for technical operation of the electricity system and for market development. Increased deployment of smart grids, for example, can enable much more demand response to reduce peak demand, increase system flexibility and support higher shares of variable renewables. Countries and regions will be able to design, plan and operate their respective electricity systems and markets in ways that best meet their needs. The potential paradigm shift in the information and abilities that technology can provide to electricity system stakeholders (from generators and network operators through to consumers) will support more active participation that can optimise performance and cost of operation and planning.

In the following chapters, *ETP 2014* highlights some of the most interesting trends in the ongoing evolution of electricity systems – all of which will be essential to understand, monitor and indeed influence. Ultimately, successful decarbonisation of the electricity sector requires that the right planning take place to maximise opportunities and reduce risks, and to enable management that maintains system security while optimising costs.

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Chapter 4

Solar Power: Possibly the Dominant Source by 2050

Proving to be faster off the starting block than expected, solar power is now clearly in the race – and already competitive in some electricity markets. Photovoltaics (PV) have sprinted ahead offering easy scalability; solar thermal electricity (STE) delivers power after the sun goes down, but is behind in deployment numbers. The advantages of STE accelerate use in the *Energy Technology Perspectives 2014 (ETP 2014)* 2°C Scenario (2DS). The high renewable scenario (2DS hi-Ren) probes solar energy to supply the largest share of global electricity by 2040.

Key findings

- **Combined shares of PV (10%) and STE (7%) put solar fourth in global electricity supply by 2050 in the 2DS, after wind, hydro and nuclear.** Solar surpasses both natural gas and bioenergy-based power.

- **In the 2DS hi-Ren, solar becomes the first electricity source by 2040, and provides 27% of global generation by 2050.** Separately, PV (16%) and STE (11%) rank third and fourth after wind and hydro.

- **With an installation rate of 100 megawatts (MW) per day, global PV reached an annual deployment rate of 36 gigawatts (GW) in 2013.** Rapid growth has driven down costs of modules and systems, making PV cost-competitive in some markets.

- **STE from concentrating solar power (CSP) plants have built-in thermal storage capability, which reduces the cost of electricity and increases its value.** Where the direct radiation is strong enough, such plants can generate electricity at will, notably when/where demand peaks after sunset. However, CSP plants are being deployed much more slowly than solar PV, with a slower decline in costs.

- **Load management, interconnections, flexible generation and storage capabilities are needed to integrate cost-effectively large shares of PV into electricity systems.** Together, these options create technical and economic flexibility throughout the system.

- **Smart coupling of solar electricity with electric mobility could facilitate PV penetration in the electricity mix.** While unmanaged charging of electric vehicles would risk further increase in demand peaks, well-organised mid-day charging could help flatten the net load curve and ease PV integration.

Opportunities for policy action

- Non-market barriers should be addressed and retroactive changes avoided, as they undermine the confidence of potential investors.
- Regulatory frameworks and market designs that include and reward the provision of flexibility levels in the electricity system would help support the integration of variable PV output.
- Remuneration schemes should encourage self-consumption and local consumption of decentralised PV electricity generation, while ensuring cost recovery of the transmission and distribution (T&D) grid in a fair and efficient manner.
- Time-of-delivery (TOD) remuneration structures could be used to promote management of electricity injected into the grid by solar technologies; time-of-use (TOU) pricing could incentivise load management and storage.
- As solar power technologies are capital-intensive and have low marginal running costs, wholesale electricity markets may not provide enough remuneration. Long-term power purchase agreements, already in use in various areas, figure among the options to consider.
- When solar heat is used in hybrid fossil plants, incentives should apply only to solar shares; refraining from imposing arbitrary thresholds to shares for fossil and solar inputs will ensure effective use of support towards clean energy supply.
- Public research, development and demonstration support for solar technologies, in particular for solar chemistry and fuel technologies that still require significant development, can contribute to future cost reductions.
- Specific support or guarantees for innovative concepts and "first-of-kind" demonstration projects is needed to alleviate the risks for investors. Without this support, these projects have the potential to be severely delayed or may not be deployed.

Solar energy accounts for less than 0.5% of global primary energy use today. But with accelerating technology improvements, the costs of deploying this resource are rapidly decreasing, and solar energy will play an important role if the future energy system is to be largely decarbonised. Harnessing the potential will require an integrated approach to make the most appropriate use of the range of solar technologies, which may differ from place to place according to local resource (Box 4.1) and needs. Implementation efforts will also need to address the daily and seasonal variations in solar energy supply.

PV is the dominant solar electricity technology due to its rapid expansion and decreasing costs. Other solar electricity technologies have not succeeded to the same extent, but analysis suggests they all have important roles to play in the future. CSP plants can provide firm electricity, even when the sun does not shine. Solar heating and cooling can reduce the need for clean electricity and reduce direct fossil fuel use in buildings, industry and services. In the long term, solar fuels can help store solar energy from sunny seasons to colder ones, transport it from sunny countries to areas with lower solar resources, and use it for transportation.

This chapter, focusing on solar electricity technologies, briefly reviews existing technologies and discusses their recent and forthcoming evolution. It reflects on the best way to enlarge solar energy shares in current and future electricity systems, examines issues this resource raises and identifies how these issues can be resolved.

Box 4.1 One sun, various metrics

The solar radiation reaching the earth's surface is about one kilowatt per square metre (kW/m^2) in clear conditions when the sun is near the zenith. It has two components: direct or "beam" radiation, which comes directly from the sun's disk; and diffuse radiation, which comes indirectly after being scattered in all directions by the atmosphere. Direct radiation creates shadows; diffuse does not. Direct radiation is experienced as "sunshine", a combination of bright light and radiant heat. Diffuse irradiance is experienced as "daylight". Global solar radiation is the sum of the direct and diffuse components.

The global horizontal irradiance (GHI) is the measure of the density of the available solar resource per surface area. Irradiance on a fixed-tilted surface is a useful metric for PV. The global normal irradiance (GNI) and the direct normal irradiance (DNI) are measured on two-axis tracking surfaces "normal" (i.e. perpendicular) to the direct sunbeam. The GNI is relevant for sun-tracking PV devices. DNI is the only relevant metric for devices that use lenses or mirrors to concentrate the sunrays on smaller receiving surfaces, whether "concentrating photovoltaics" (CPV) or so-called CSP, also known as STE.

All places on earth have the same 4 380 daylight hours per year – i.e. half the total duration of a year. Different areas, however, receive uneven yearly average amounts of energy from the sun. When the sun is lower in the sky, its energy is spread over a larger area, and is therefore weaker per horizontal surface area. Tropical zones receive more radiation per land area on a yearly average than places north of the Tropic of Cancer or south of the Tropic of Capricorn. In humid equatorial places, however, the atmosphere scatters the sunrays. High DNI is found in hot and dry regions with clear skies.

The average energy received in Europe, measured in GHI, is about 1 200 kilowatt hours per square metre (kWh/m^2) per year. This amount compares with 1 800 kWh/m^2 to 2 300 kWh/m^2 per year in the Middle East. The United States, Africa, most of Latin America, Australia, most of India, and parts of the People's Republic of China and other Asian countries also have good-to-excellent solar resource, although only a subset is good enough for concentrating technologies. Alaska, Northern Europe, Canada, Russia and Southeast China are somewhat less favoured.

Importantly to the 2DS and the aim of a decarbonised global energy system, the most favoured regions are broadly those where much of the increase in energy demand is expected to take place in the coming decades.

Solar technologies in the electricity system: Recent trends

Solar photovoltaics

PV cells are semiconductor devices that generate direct current (DC) electricity. The cells are interconnected to form modules, which are then combined to form arrays and systems. PV can be used for on-grid and off-grid applications of capacities ranging from less than one watt (W) to hundreds of megawatts. Grid-tied systems, the dominant form, require inverters to transform DC power into alternating current (AC). The balance of system (BOS) includes inverters, transformers, wiring and monitoring equipment, as well as structural components for installing modules, whether on building rooftops or facades, above parking lots, or on the ground. Installations can be horizontal, fix-tilted or tracking the sun on one axis (for non- or low-concentrating systems) or two axes (for high-concentrating systems).

PV output per watt installed depends on system orientation and the quality of the solar resource, not on efficiency. The efficiency only determines the panel area per watt installed. High-efficiency PV modules might cost more than lower-efficiency PV modules on a per watt basis, but their higher efficiency might reduce non-module costs, such as land, wiring, support and other BOS costs proportionate to panel area. Various pathways (e.g. low-cost, low-efficiency modules versus higher-cost, high-efficiency modules) can lead to lower installed PV system prices, although systems based on highly efficient modules currently cost more than others in both residential and commercial markets.

Crystalline silicon (c-Si) modules, whether single- (sc-Si) or multi-crystalline (mc-Si), largely dominate the PV market. Cells are usually sliced from ingots or castings of highly purified silicon. The manufacturing process creates a potential junction, deposits an anti-reflective coating and adds metal contacts. Cells are then grouped into modules, with a transparent glass for the front, a weatherproof material for the back and often a frame around. Modules are usually guaranteed for a lifetime of 20 years at minimum 80% of their rated output, and sometimes for 30 years at 70%. Most commercial silicon modules have efficiencies around 16%, although some offer efficiencies above 21%; laboratory versions have achieved significantly greater efficiencies.

Two main alternative solar cell commercial technologies exist: thin films, based on either amorphous silicon (a-Si), cadmium-telluride (CdTe), copper-indium-(di)selenide (CIS), copper -indium-gallium-(di)selenide (CIGS) or copper-zinc-tin-sulfide; and multi-junction cells, used in CPV. Some manufacturers also sell hybrid PV-thermal panels that deliver heat and electricity all together.

Market deployment

Since 2010, the world has added more PV capacity than it had in the previous four decades. New PV systems are currently being installed at a rate of 100 MW per day – with 36 GW installed globally in 2013, further accelerating in early 2014. Asian markets, with China and Japan in first and second place, are overtaking the slowing European market, where most installations took place in 2003-12. The trend towards installation of solar systems in sunnier regions will likely accelerate as the market becomes truly global. Roughly 40% of new PV capacity installed in 2012 was in centralised plants, and 60% in decentralised, grid-connected facilities (PVPS IA, 2013).

The goal envisioned in the *IEA Technology Roadmap* (IEA, 2010a) of 210 GW cumulative PV capacity installed by 2020 now appears too low, and will likely be achieved in 2016 (IEA, 2013a). The latest projections put global PV capacity by 2020 at 354 GW (2DS and 2DS hi-Ren), 40% above earlier expectations.

PV module and system costs

The emergence of the global PV market has stimulated rapid cost reductions of modules and systems. In the last few years, intense competition and global overcapacities led many PV cell and module manufacturers to price their products at a level too low to allow for investment cost recovery, and several companies failed. The underlying cost trend, proven over decades of development and deployment, still remains that of a progress ratio of 80% – that is, each doubling of cumulative production leads to a 20% cost decrease.

PV production in China stimulated competition and cost reductions. However, in the United States, the installed price of Chinese versus non-Chinese modules was roughly the same for any given module efficiency (Barbose et al., 2013).

Prices for PV systems are more diversified than for cells and modules, which tend to be global commodities. Small systems, such as rooftop, are more expensive than larger ones, especially ground-based, utility-scale systems. Prices vary significantly among countries for similar system types (Table 4.1). Most of the gap comes from differences in "soft costs", which include customer acquisition;[1] permitting, inspection and interconnection; installation labour; and financing costs, especially for small systems (Seel et al., 2013). The generosity of incentive frameworks in some countries is another factor which may keep prices higher than raw costs plus reasonable margin. Even greater differences are evident in the costs of commercial PV systems from country to country; such systems are more than twice as expensive in the United States as in Germany.

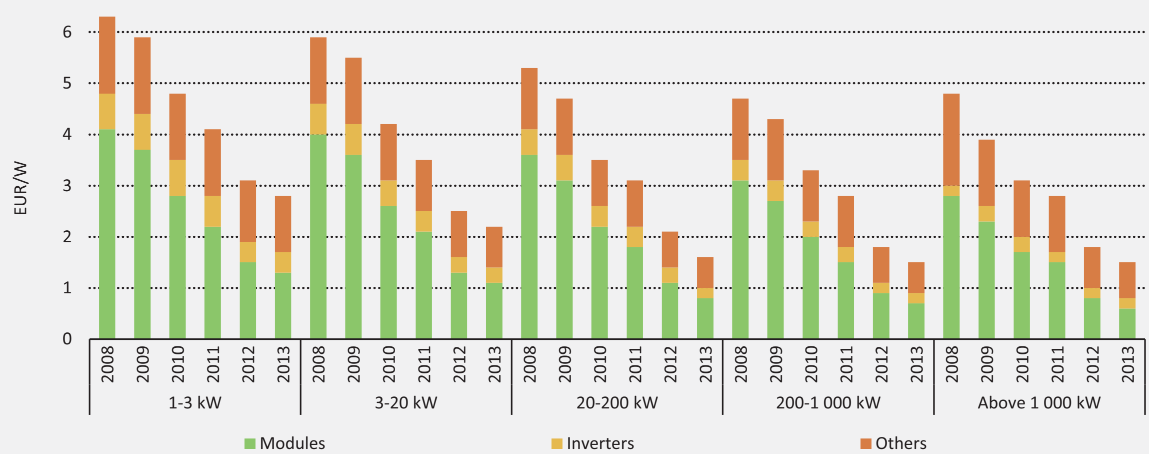
Table 4.1 PV system prices in 2012 in selected countries

USD/W	France	Germany	Italy	Japan	United States	Texas	New Jersey	California	Wisconsin
Residential	4.8	2.3	3.1	5.9	5.2	3.9	4.6	5.7	5.9
Commercial						4.5			
Utility-scale		1.9				3.3			

Note: unless otherwise stated, all costs and prices are in real 2012 USD, i.e. excluding inflation.
Source: Bolinger and Weaver, 2013.

Large cost reductions for PV systems occurred over the last six years in some markets. In Italy (Figure 4.1), prices for non-module components of PV systems dropped significantly; in other markets such as in the United States, those component costs have remained almost unchanged since 2005 (Barbose et al., 2013).

Figure 4.1 PV system costs in Italy by size



Note: analysis relative to crystalline PV modules; investment costs are considered overnight costs; values are VAT excluded. Figures and data that appear in this report can be downloaded from www.iea.org/etp2014.
Source: GSE, 2014.

Key point *In 2013 PV systems in Italy cost 30% to 44% what they cost in 2008.*

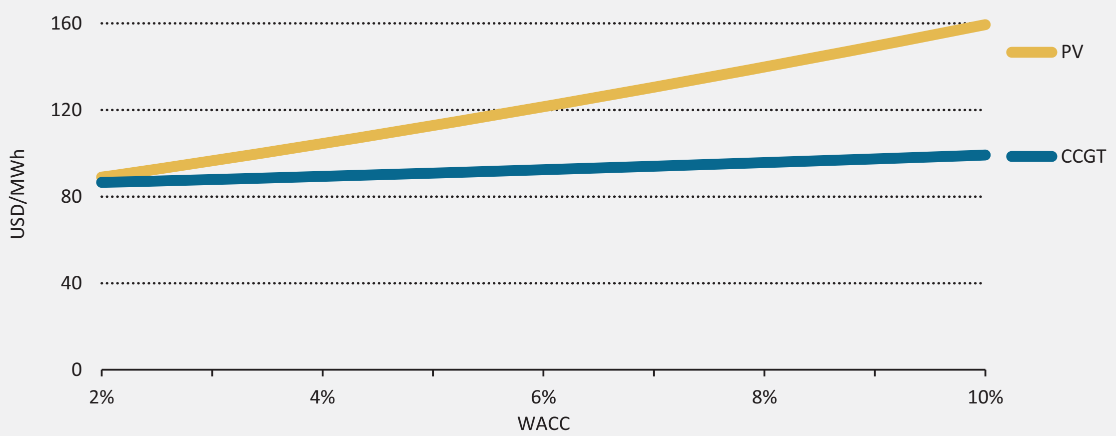
1 Customer acquisition cost is the resource a business needs to allocate in order to acquire an additional customer. In the case of PV systems it usually includes the cost of designing specific systems.

The learning experience for complete PV systems is usually considered slower than that for modules; this is a local or national phenomenon, rather than a global one. In emerging markets, non-module costs often shrink rapidly as installers gain experience – and also as project density increases, saving significant travel times for sales and marketing staff and skilled workers.

In 2013, large-scale ground-mounted PV systems could cost less than USD 1.50/W, a value that most market analysts expected, just two years ago, to apply in 2019 or 2017 at the earliest. Although module prices seem to have stabilised in 2013, system costs continued to decline, with cost reductions in California, for example, ranging from 10% to 15% depending on system size in the first half of 2013 (Barbose et al. 2013). Both the investment cost difference and the output gap between fixed-tilted PV systems and one-axis sun-tracking systems have narrowed in the last few years.

The levelised cost of energy (LCOE) of PV depends on several factors, notably the solar resource (the primary determinant of capacity factors), the system costs in various markets and the cost of capital. Figure 4.2 compares the importance of the cost of capital for PV, which is capital-intensive, and for combined-cycle gas turbines (CCGT), which are not. Current generation costs range from USD 100/MWh to USD 250/MWh for large-scale systems and USD 180/MWh to USD 400/MWh for small-scale installations. The lowest system prices and lowest financing costs today are in Germany, while sunnier areas exhibit higher system costs and/or higher financing costs.

Figure 4.2 **Influence of weighted average capital costs (WACC) on the LCOE of PV and CCGT**



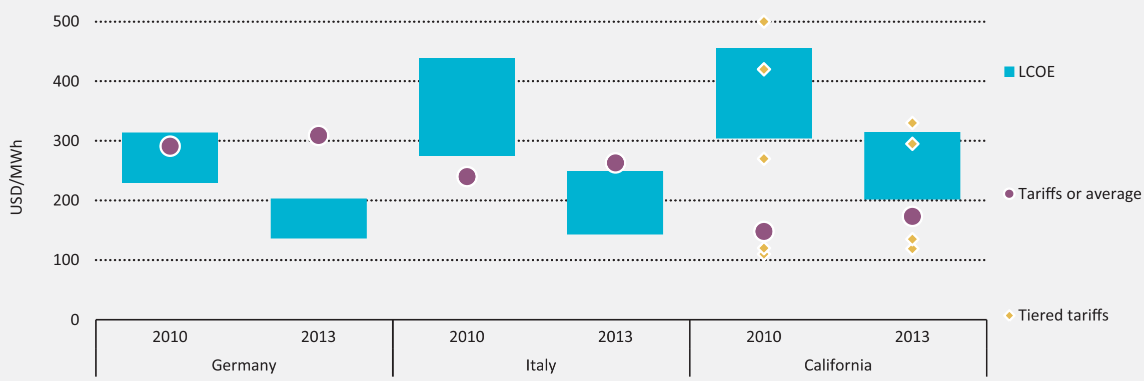
Notes: system costs of USD 1700/kW and output of 1360 kWh/kW (e.g. south of France) are assumed for PV; investment costs of USD 900/kW, output of 4 000 kWh/kW, fuel costs of USD 12/Mbtu are assumed for CCGT.
Source: unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *The LCOE of solar PV is heavily dependent on the cost of capital.*

Decentralised generation and grid parity

One particular strength of PV is its ability to be built and operate in millions of small, decentralised systems, often characterised as "rooftop". When the LCOE of decentralised solar PV systems becomes lower than the variable portion of the retail electricity price (i.e. per kWh) (Figure 4.3), the situation is known as "grid parity" or "socket parity" (Box 4.2). Grid parity provides an incentive to electricity customers to build a PV system and consume part of the electricity they generate – or to generate part of the electricity they consume. In virtually all power systems, the variable portion of retail prices covers energy costs, most T&D costs, utility or grid operator margins, and various fees and taxes.

Figure 4.3 **Estimated residential solar PV LCOE versus the variable portion of average retail power prices**



Notes: examples correspond to markets in Southern Germany, Italy and California. Household electricity tariffs exclude fixed charges. LCOEs are calculated using average residential system costs (including value-added tax and sales tax in California and Italy where applicable, and investment tax credit in California, but no other financial incentives); ranges mostly reflect differences in financing costs. The tiered tariffs in California are those of Pacific Gas and Electric. Tiers 3 to 4 or 5 are tariffs paid on monthly consumption when it exceeds given percentages of a set baseline.

Key point *Grid parity underpins PV self-consumption in Germany, and net-metering in California.*

This phenomenon of grid parity already drives part of the PV deployment in several countries, such as Germany as shown in Table 4.2. In the *ETP* model, the electricity from rooftop PV systems has to compete with bulk power costs from competitors, which is augmented by the T&D costs. Rooftop PV represents 47% of all PV systems in the 2DS, and 50% in the 2DS hi-Ren.

Table 4.2 **Expected self-consumption from new-built PV systems in Germany, 2014-18**

%	< 10 kW	10 to 40 kW	40 kW to 1 MW	> 1 MW
Share of new capacities	20	20	30	30
Share of installations with self-consumption	95	85	70	2
Average share of self-consumed electricity	27	27	38	20

Note: average share is only among the installations that self-consume.
Source: r2b energy consulting, 2013.

Box 4.2 **Decentralised PV generation and grid cost issues**

For efficiency and equity motives, utilities usually recover fixed grid costs, especially from households, mostly through variable, per kilowatt hour payments. Households with PV, now often referred to as "prosumers" as they can proactively participate in generation, tend to consume less electricity overall. But during peak periods, many call for access to similar capacity as they had in the past. In effect, by generating some of their own power, they pay less for their electricity bills while being responsible for similar grid costs. This raises concerns about grid cost recovery and allocation among customers.

Such issues must be analysed case by case, however. In temperate countries, peak demand occurs at dark in winter, when PV generation falls to zero. But PV injections into the same grid at times of low loads – sunny, summer Sundays – may overwhelm low-voltage distribution grids and require power management, power curtailment or grid strengthening. In sunnier countries, PV better matches peak or mid-peak demand, so it would allow grid-tied prosumers to reduce their capacity needs. With reduced grid losses, important at peak times, PV in such areas is more likely to reduce grid and other system costs, not increase them.

In all areas, problems linked to excess injection in distribution grids can be alleviated by setting a maximum input as a percentage of rated AC capacities for PV systems that cannot be curtailed remotely (the rest being either self-consumed or curtailed). Germany has set such a cap at 70%. Curtailing some quantities of PV electricity makes sense when the investment costs for transport exceed the benefits of so doing.

Reduced consumption from grid-tied PV prosumers may call for progressive rate adjustments (SEPA, 2013). Introducing TOU pricing seems an interesting option because it would incentivise load management and storage. Raising fixed payments could have similar effects if directly linked to subscribed capacity ("capacity charges"), but it risks incentivising consumption.

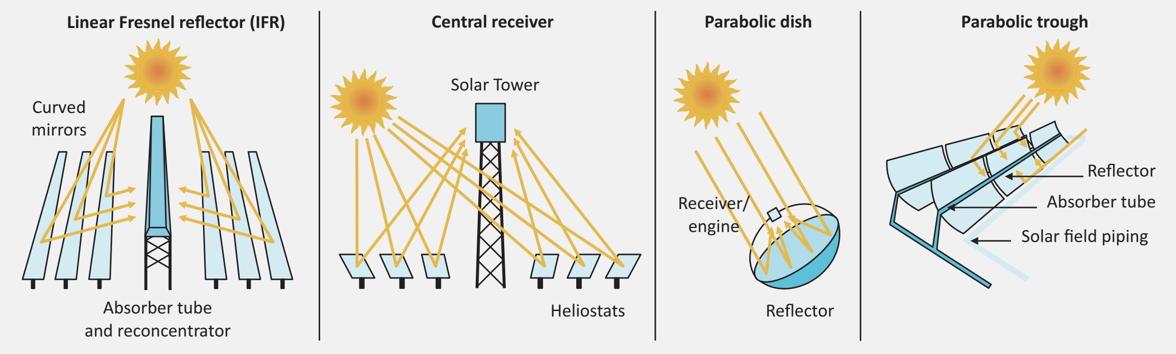
Solar thermal electricity

CSP plants concentrate solar rays to heat a fluid, which then directly or indirectly runs a turbine and an electricity generator. Concentrating the sun's rays allows for the fluid to reach working temperatures high enough to ensure fair efficiency in turning the heat into electricity, while limiting heat losses in the receiver. The three predominant CSP technologies are parabolic troughs, Linear Fresnel Reflectors (LFRs) and towers. A fourth type of CSP plant is a parabolic dish supporting an engine at its focus. These technologies differ with respect to optical design, shape of receiver, nature of the transfer fluid and capability to store heat before it is turned into electricity (Figure 4.4).

Most installed capacities today replicate the design of the first commercial plants built in California in the 1980s: long parabolic troughs tracking the sun on one axis, concentrating the solar rays on linear receiver tubes isolated in a glass envelope, heating oil up to 390°C, then transferring this heat to the steam generator (a water-steam cycle). Far behind PV in overall capacities, STE is gaining ground with CSP plants synced to the grid in Spain and the United States, and others under construction or planning in Africa. LFRs will soon see their first large plants connected as well, notably in India. Despite having the best efficiency, dishes supporting individual engines at focus points have not proven able to reduce higher technology costs and risks, or to accommodate heat storage. In fact, this technology has almost disappeared from the energy landscape.

Built-in thermal storage is the distinct advantage of STE. The standard technology in CSP plants is sensible heat storage in molten salts using two tanks. Some towers use molten salts as both heat transfer fluid and storage medium while others, and all LFR plants, directly generate steam in the receiver. Direct steam generation (DSG) makes storage more complex and less effective.

Figure 4.4 Main CSP technologies



Key point *Most current CSP plants are based on trough technology, but tower technology installations are increasing.*

Market deployment and costs

While the early CSP plants built in California in the 1980s are still operating, since 2006, CSP has experienced a renaissance in Spain and the United States, and is now expanding to many other countries. Still, deployment lags behind expectations. The goal envisioned in the IEA *Technology Roadmap: Concentrating Solar Power* (IEA, 2010b) of having 147 GW installed by 2020 now appears overly optimistic: only one-fifth to one-tenth of this amount will be achieved – between 18 GW in the 2DS and 33 GW in the 2DS hi-Ren. Spain has put new projects on hold, largely due to the economic crisis. But several countries are joining the United States in building large CSP plants, including Chile, China, India, Israel, Morocco, Saudi Arabia, South Africa and the United Arab Emirates. Other countries are beginning with smaller plants.

Competition from solar PV has played an important role in the sluggish CSP deployment, as witnessed by the conversion of some large CSP projects in the United States into PV projects. The financial and economic crisis has strongly affected the prospects for future deployment in one of the leading countries, Spain. Political turmoil has put the development of other projects on hold in some Arab countries.

Investment costs have remained high, in the range of USD 4 000/kW to 8 000/kW, depending on the "solar multiple" – i.e. the ratio of the actual size of the solar field to the size that would deliver the rated capacity under the best conditions of the year. This ratio is always greater than 1 for ensuring sufficient capacity factor, but can extend to 3 or even more for plants with storage. Under similar sunshine conditions, larger solar fields and storage capabilities for a given turbine size lead to greater annual electrical output.

The expected cost decrease as CSP deployment progresses, following a progress ratio estimated around 90% (i.e. 10% cost reduction for each cumulative capacity doubling), has taken a long time to materialise. This anomaly can be explained by an increase in the cost of materials, particularly affecting the most mature parts of the plants, the power block and balance of plant (BOP). Other causes are the dominance of a single technology (trough plants with oil as heat transfer fluid) and a regulatory limit of a sub-optimal 50 MW of power output per plant in Spain, where most of the deployment occurred after 2006. In the last few years, however, a broader set of plant technologies and designs (troughs, DSG towers, molten-salt towers and LFR), including larger plants (up to 250 MW), have been built in a greater number of markets.

A niche market for CSP plants involves integrating solar fields into existing or greenfield fossil fuel (gas or coal) or biomass-fired plants. The economics are better than those of stand-alone CSP plants, because power blocks and BOP – roughly half the investment cost of CSP plants – are already paid for. Solar fields bring mid-temperature heat into coal plants, which spares high-temperature heat from being distracted from the turbine, thus operating with higher efficiency (Siros et al., 2012). Such hybridisation could be a step towards bringing down the costs of solar technologies with larger deployment numbers and related learning effects. Potentials in the tens of gigawatts have been identified in Australia, Chile, China, India, Morocco, South Africa and the United States.

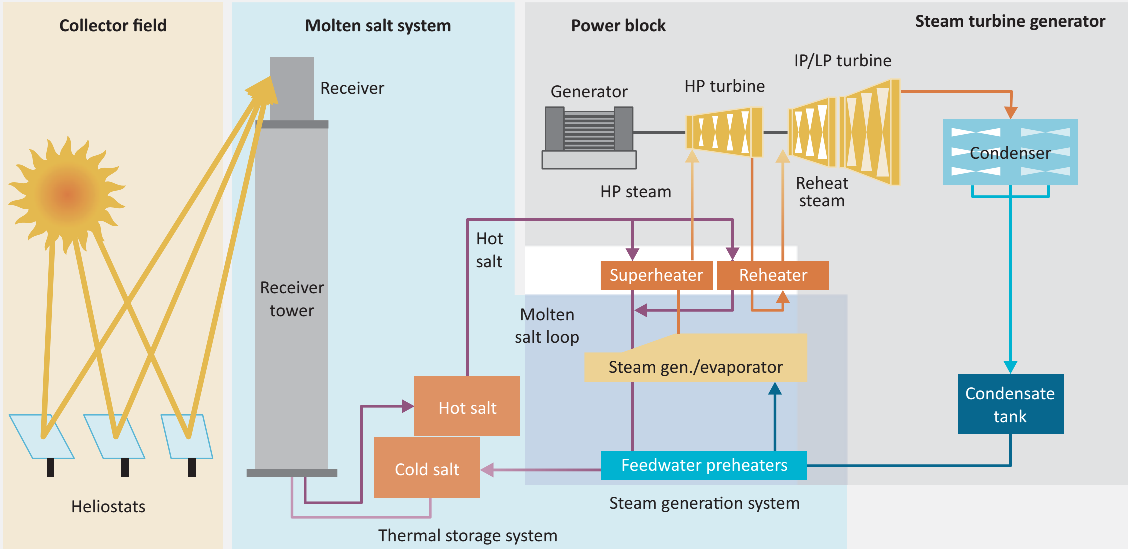
CSP plants can be sited only in areas with adequate solar resources. The economics of the technology are even more dependent than PV on the quality of the resource for various reasons. First, the direct irradiance, which governs the output of a CSP plant, is more affected by clouds and atmospheric humidity than the global irradiance, which governs the output of non-concentrating PV. Second, the thermal losses of a CSP plant's receiver and the parasitic consumption of the electric auxiliaries are essentially constant, regardless of the incoming solar flux (IEA, 2010b). The most favourable areas for CSP are arid, and thus lack water for condenser cooling. Dry-cooling technologies for steam turbines are available and can be further improved, so water scarcity is not an insurmountable barrier, but an efficiency penalty and an additional cost. Wet-dry hybrid cooling can significantly improve performance with limited water consumption.

LCOEs of STE vary widely with the resource, design and intended use of plants. Spanish plants benefitted from feed-in tariffs (FiTs) near EUR 300/MWh (USD 400/MWh), and 40% of them have seven-hour storage – i.e. the capacity to generate full-load electricity just from the storage during seven hours. Recent power purchase agreements (PPAs) in sunnier countries are at half that level or below. One widely quoted figure is of the PPA of the first phase of the Ouarzazate CSP plant in Morocco, at MAD 1.62/kWh (USD 0.19/kWh) for a 160 MW trough plant with three-hour storage. Recent CSP plants in the United States secured PPAs at USD 0.135/kWh, but taking investment tax credit into account sets the cost of electricity at about USD 0.19/kWh.

In trough plants, the storage for six or seven hours can cost about 12% of the overall plant. Thanks to higher temperature differences between hot and cold salts, molten-salt towers (Figure 4.5) need three times fewer salts than trough plants for the same storage capacity, thus lowering the storage system cost. Also, the "return efficiency" of thermal storage, at about 93% with indirect storage (in which heat exchangers reduce the working temperature), is increased to 98% with direct storage.

The main motive for storage may be to shift large amounts of electricity to demand peaks after sunset and significantly increase the value of STE. But increasing solar field sizes and extending load factors of the turbine, generator, BOP and connecting lines also reduces the cost of STE. By contrast, any actual electricity storage technology (as defined in Chapter 7) that first takes electricity from the grid always increases the LCOE of the electricity shifted in time. Built-in storage in CSP plants compares to reservoir hydropower, rather than to pump-storage plants or other electricity storage options.

Figure 4.5 Working scheme of a molten-salt tower



Note: the turbine has high pressure (HP), intermediate pressure (IP) and low-pressure (LP) sections.
Source: SolarReserve, 2011.

Key point *Molten-salt towers currently offer the best commercial option for STE with large storage.*

Future role of solar in the global electricity system

Envisioning a high-solar electricity future

The 2030 and 2050 outcomes for solar electricity deployment have been projected for four scenarios: the 6°C Scenario (6DS), the 4°C Scenario (4DS), and the 2DS and its 2DS hi-Ren variant (Table 4.3). In the 6DS, solar electricity provides only 2.6% of global electricity by 2050 (1.9% is PV, 0.7% is STE). This projection is the result of narrow economics: the main competitor for solar in this scenario is coal, the cheapest fuel for generating electricity (except for some hydropower). Unlimited coal development, if not linked to carbon capture and storage (CCS) technologies, is not only the worst scenario from a climate change perspective, it is also somewhat unlikely as governments strive to diversify the energy mix and reduce impacts of electricity generation on air quality.

In the 4DS, solar electricity reaches 7.4% of global electricity by 2050 (5.6% from PV, 1.8% from STE), while in the 2DS it reaches 17% of global electricity by the same date, with 10% (3 824 TWh) from PV and 7% (2 835 TWh) from STE (Figure 4.6). These data suggest that under stricter carbon dioxide (CO_2) constraints, more solar electricity is needed to displace fossil fuels, and STE progressively benefits more from its greater dispatchability. Solar electricity remains lower than hydropower (18%), wind power (18%) and nuclear (17%) in the 2DS, but surpasses natural gas with or without carbon capture and storage (CCS), bio-power, and other renewables. It contributes to decarbonisation of the power sector significantly, while

Table 4.3 Selected results relative to solar electricity from the main scenarios

Scenario	6DS		4DS		2DS		2DS hi-Ren	
	2030	2050	2030	2050	2030	2050	2030	2050
PV generation (TWh)	588	937	805	2 523	1 141	3 824	2 609	6 250
PV generation (%)	1.6	1.9	2.3	5.6	3.5	9.5	8	16
PV capacity (GW)	451	663	602	1 813	841	2 785	1 927	4 626
STE generation (TWh)	92	359	147	796	554	2 835	986	4 186
STE generation (%)	0.3	0.7	0.4	1.8	1.7	7.1	3	11
STE capacity (GW)	26	98	40	185	155	646	252	954

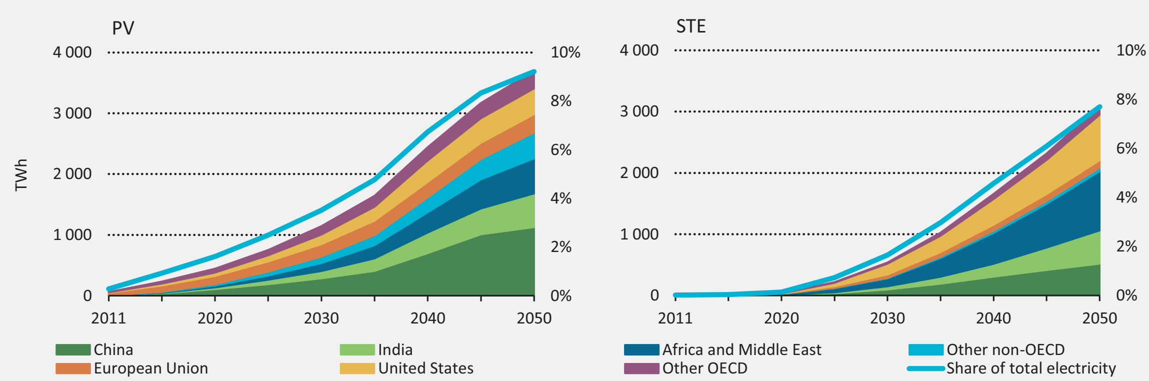
electricity consumption progresses more rapidly than in other scenarios and reaches 26% of final energy demand. Ultimately, through the electricity carrier, renewable energy displaces not only fossil fuel use in electricity generation but also direct fossil fuel use in end-use sectors.

Box 4.3 2DS hi-Ren scenario

While the 2DS offers the least-cost pathway, the energy system does not always develop according to optimum approaches or technology development may not occur as hoped or expected. Variants introduced in *ETP 2014* demonstrate other pathways that are possible to meet or possibly exceed long-term carbon reduction goals and provide insights into "what if" the energy system develops differently.

The 2DS hi-Ren variant illustrates an expanded role of renewables in the power sector based on a decreased or delayed deployment of nuclear technologies and CCS. Increased deployments of renewable technologies results in accelerated reductions of their costs.

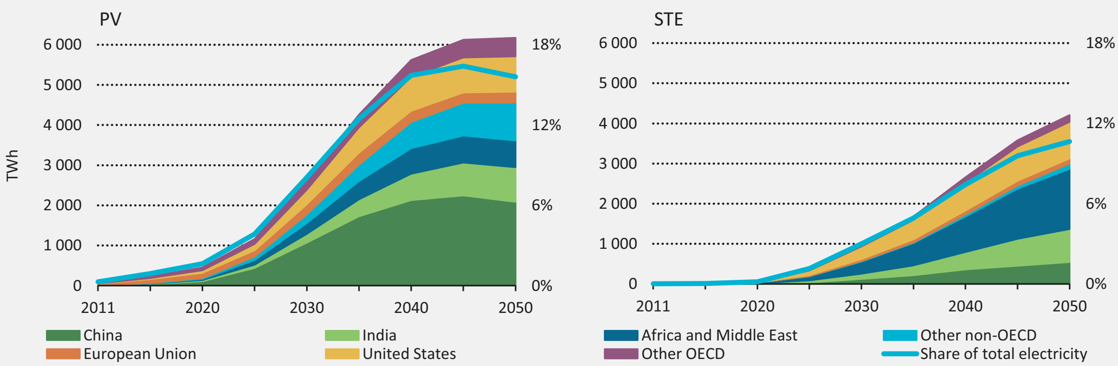
Figure 4.6 PV and STE generation in the 2DS



Key point *In the 2DS, STE growth lags ten years behind PV.*

In the 2DS hi-Ren scenario (Box 4.3), the CO_2 constraint is met in 2050 with less support from nuclear, at 8.5% of global electricity generation by 2050, and from CCS, at 3.7%. Solar electricity is the renewable energy technology that benefits the most from these assumptions (Figure 4.7). It reaches 27% of total electricity (16% PV and 11% STE), above its renewable competitors such as wind (21%), hydro (19%) and biomass (8%). Solar electricity already overtakes wind and hydropower around 2040 in the 2DS hi-Ren.

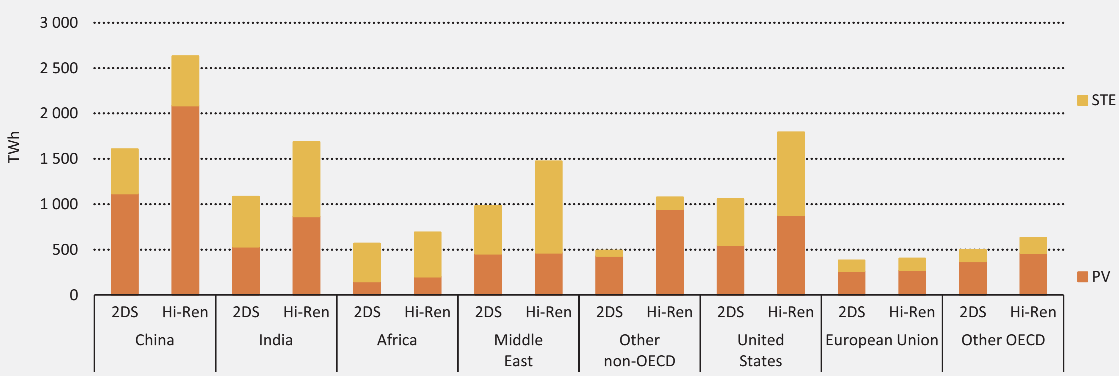
Figure 4.7 PV and STE generation in the 2DS hi-Ren



Key point *In the 2DS hi-Ren, both PV and STE increase by about 50% over the 2DS.*

All regions are not equal with respect to solar resources. In the 2DS hi-Ren, solar electricity provides 36% of power in the United States, 42% in India, 50% in South Africa and almost 60% in the Middle East by 2050. Only regions with good DNI have STE. In the most favoured ones – Africa, Australia, Chile, Mexico and the Middle East – STE dominates the solar electricity contribution by 2050 in both the 2DS and the 2DS hi-Ren, while both technologies provide about the same amounts of electricity in the United States, and PV generation dominates in all other regions (Figure 4.8).

Figure 4.8 Solar electricity generation by 2050 by region in the 2DS and 2DS hi-Ren



Key point *In areas with excellent DNI, STE eventually dominates over PV.*

By capacity, PV systems dominate over CSP plants for both scenarios in all regions because PV has significantly lower capacity factors. China leads in PV with 38% of global capacities, and the United States leads in STE with 25% of CSP plants. CSP plants built in North Africa or even the Middle East could export part of their output to Europe. The difference in resource (namely DNI) and greater land availability, together with firm and flexible solar power on demand, could more than offset the cost of transporting solar (and possibly wind) electricity across the Mediterranean Sea. Other exchanges could also take place between Mexico and the United States, some central Asian countries and Russia, or Australia and Indonesia (IEA, 2010b).

In the 2DS, installed PV capacity grows on average 67 GW per year, and CSP plants 20 GW per year. In the 2DS hi-Ren, the PV capacity increases on average 119 GW per year and reaches a 15-year peak above 200 GW per year between 2025 and 2040 before levelling off. CSP deployment averages 28 GW per year with a five-year peak at 43 GW from 2040 to 2045.

The 2DS hi-Ren requires additional, cumulative investments of USD 4.5 trillion for power generation compared to the 2DS. The lower consumption of fossil fuels in this variant, corresponding to fuel cost savings of USD 2.6 trillion, however, partly offsets the additional investment needs, so that overall the 2DS hi-Ren variant results in additional costs of USD 1.9 trillion. This represents a 3% increase of the total cumulative costs for power generation compared to the 2DS.[2]

Key factors influencing the prospects for solar PV

In the future, several factors will critically influence the role of PV. The investment costs of PV systems are of primary importance, but financing costs also matter. The real challenge for PV systems is to generate electricity at the right time, in the right place. Load management, storage and possibly further electrification of end-use sectors will contribute to the growth of PV. The policy framework also remains critical, and is examined in the last section of this chapter.

Continued cost reductions

The major cost factor in PV cells is that of pure polysilicon, which dropped from USD 67 per kilogram (/kg) in 2010 to USD 20/kg in 2012. Continued progress in the production, and reduction in the use of consumables, will bring it to less than USD 20/kg in the next few years. Cost of ingot growth, wafer (cell precursors) sawing and cleaning will also improve. Efforts to reduce the amount of purified silicon in cells, now at 5 grams (g) per watt, will continue towards 3 g/W or less, with thinner wafers. Manufacturers are also striving to lighten the amount of silver and other expensive materials (maybe replacing silver with copper) while maintaining or even extending the technical life of cells and modules. Manufacturing automation is progressing for both cells and modules. For the latter, higher throughput can be achieved for the interconnection and encapsulation processes (ITRPV, 2012). Energy savings over the whole manufacturing process are being sought. "Mono-like" mc-Si ingots, and reusable ingot moulds, could bring sc-Si performances at mc-Si costs.

Combining learning and economies of scale, the experience curve of PV witnessed over decades can be extended in the future; industry and the research community have already identified many of the required improvements in manufacturing process and in product design and performance. These improvements would bring the cost of Si modules to about (constant) USD 0.40/W or even less – about half of the current "sustainable" levels (once market prices

2 Noting that the spatial resolution of the model does not allow for an assessment of the possible changes in transmission and distribution (T&D) costs among both variants of the 2DS.

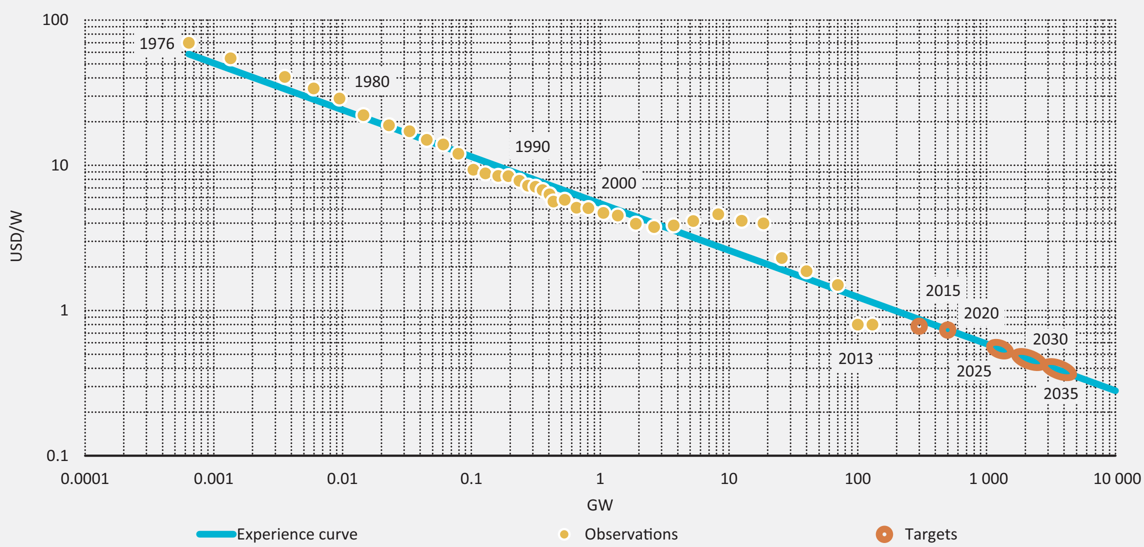
are corrected from the effects of the overcapacity) (Figure 4.9). The foreseeable PV future largely belongs to silicon, which has a virtually limitless material resource, even if alternative technologies are also improving (Box 4.4).

Box 4.4 Thin film and concentrating PV technologies

A few years ago alternative technologies such as thin films were projected to take a growing share of the PV market. This has not happened, and the share of thin films, which had grown from 5% in 2005 to over 15% in 2009, is now less than 10% and still decreasing. The price gap between c-Si modules and formerly cheaper thin-film devices has narrowed considerably. Thin films have their own resilient markets, though, due to their particular qualities, including extreme flexibility for CIS and CIGS, and exceptional resistance to heat stress for CdTe. More importantly perhaps, assembling c-Si and thin-film technologies in high-efficiency sandwiches for non-concentrating PV systems could possibly represent a very cost-effective long-term combination.

CPV, already based on (expensive) multi-layer cells, still has to prove that it can compete with PV on a pure cost basis. Unlike dispatchable STE, its output does not differ much from that of any other sun-tracking PV system. Quantum dots, organic cells and thermoelectric devices hold great promises for the future, but breakthroughs are needed for these technologies to materialise.

Figure 4.9 Experience curve for PV modules and extension to 2035 in the 2DS and the 2DS hi-Ren

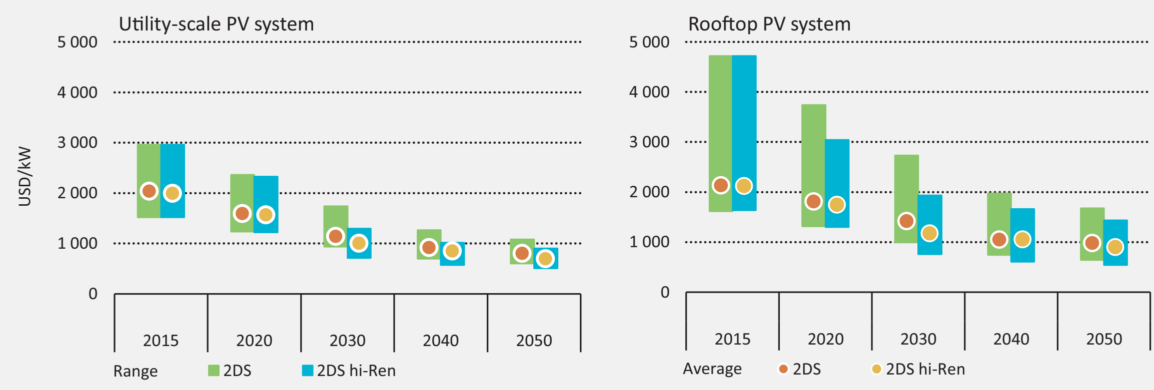


Note: yellow dots indicate past module prices; orange dots are expectations. The oval dots correspond to the deployment starting in 2025, comparing the 2DS (left end of oval) and 2DS hi-Ren (right end).

Key point *Based on proven progress ratio, the cost of PV modules could be further reduced by 50% or more by 2035.*

When local markets develop, system costs will likely converge towards the lowest values, except for some local specificities regarding, in particular, permitting and other soft costs. Costs will be further driven down as a result of technology improvements. Cost reductions are expected for both utility-scale and rooftop PV systems (Figure 4.10). By 2050, the minimum cost for utility-scale systems in the 2DS is USD 618/kW, the maximum for rooftop PV systems USD 1 724/kW. In the 2DS hi-Ren, these figures fall to USD 507/W (utility-scale) and USD 1 394/W (rooftop). This does not represent a change in assumptions, but instead the result of a more rapid deployment as the CO_2 emissions constraint must be met while other technologies experience greater difficulties scaling up.

Figure 4.10 Investment costs of utility-scale and rooftop PV systems in the 2DS and the 2DS hi-Ren



Key point *As markets mature and incentives are reduced, costs converge towards those of the least-expensive installations.*

The LCOE is the usual metric for assessing the cost of electricity-generating technologies (Table 4.4). It must be looked at as a starting point: it provides useful information, but is not sufficient to assess the actual performance of variable renewable energy technologies, which also depend on the actual availability of their output in place and time (IEA, 2014). Globally averaged LCOE plummet faster as installations move towards sunnier areas. LCOE in the 2DS hi-Ren are only marginally different from assumptions in the 2DS, as a result of a more rapid decrease in investment cost.

Table 4.4 Evolution of the LCOE for new-built PV systems in the 2DS

USD/MWh		2015	2020	2025	2030	2035	2040	2045	2050
Rooftop	Min	135	108	94	83	72	62	58	53
	Max	539	427	359	312	265	225	208	191
	Avg	202	165	146	128	110	98	93	93
Utility-scale	Min	119	97	83	73	63	55	51	47
	Max	318	254	214	187	159	136	126	116
	Avg	181	137	113	97	91	79	71	71

Note: Avg stands for the weighted-averaged LCOE of new-built systems.

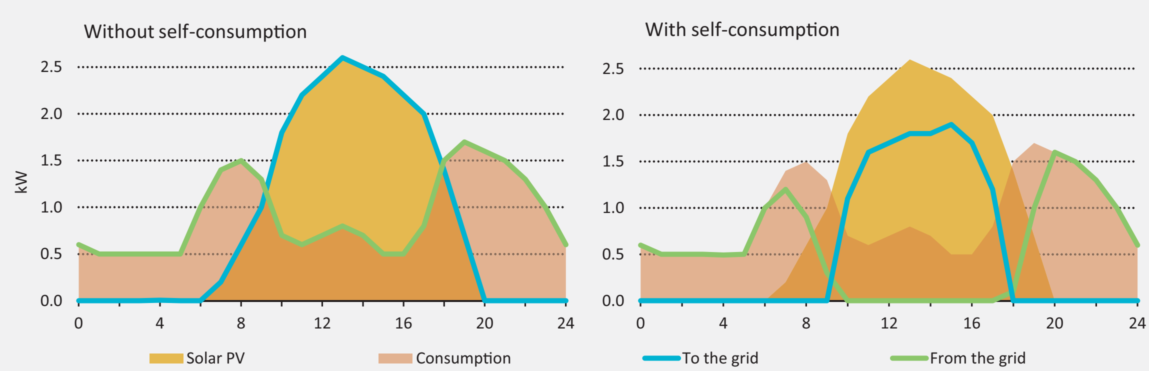
In most cases, despite recent and large cost reductions, solar PV electricity remains more expensive than most competing technologies, including amortised nuclear power plants, average coal plants and natural gas in various markets, as well as hydropower and land-based wind power. It can, however, already compete with diesel generator sets, oil-fired turbines and offshore wind power, and is approaching competitiveness with new combined-cycle gas turbine plants or even new coal plants that satisfy strict environmental criteria (apart with respect to CO_2 emissions). PV provides a hedge against the risk of price increases in fossil fuels, allowing energy companies to compile more robust energy portfolios at the same return rates (Awerbuch and Berger, 2003).

If available at peak times, PV also has a significant capacity value, though it arguably decreases with large PV shares (IEA, 2014). Its ability to be developed close to consumption centres, and even directly on consumption sites, allows for reducing grid losses and grid investments in some but not all cases. In other places, some "hotspots" may require grid strengthening. By 2025, PV electricity would be competitive in a wide number of markets and applications in both 2DS hi-Ren and 2DS, and to a lesser extent in the other scenarios.

Future of decentralised PV generation

Grid parity holds potential but may also create illusions and raise concerns. The variability of the solar resource, together with the variability of electricity demand, limits actual self-consumption and its related benefits for electricity consumers that are also PV producers (i.e. the prosumers), especially in the residential sector. In winter, most PV electricity will be self-consumed, but the bulk of electricity consumption will still be drawn from the grid. On sunny summer days, the opposite holds true: less than half of PV electricity is self-consumed, but some electricity must still be drawn from the grid, especially during the evening peak (Figure 4.11).

Figure 4.11 Self-consumption of stylised household and rooftop PV system during a sunny day

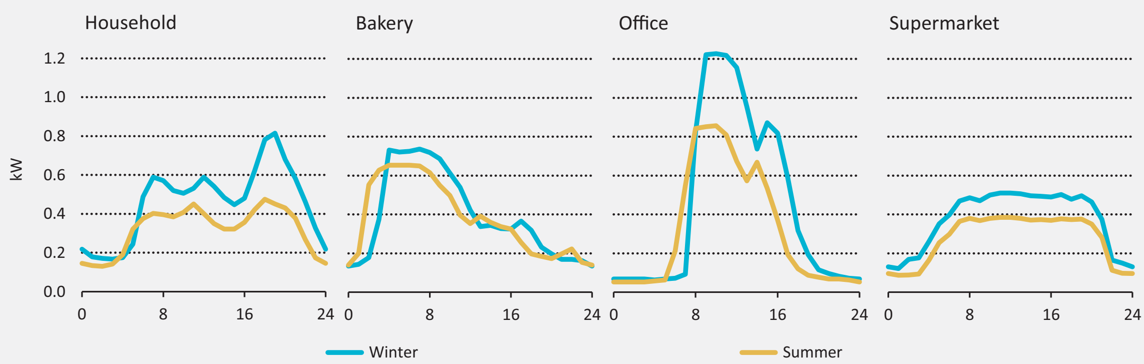


Key point *Variability of both solar power and electricity demand limit self-consumption.*

The prospects for self-consumption are higher in sunnier countries, where consumption is partly driven by air-cooling loads, and for buildings other than residential (the 40 kW to 1 MW range on Table 4.2). The load profile of office buildings or supermarkets suggests a better match with the solar resource, which reaches its maximum in the middle of the day (Figure 4.12).

Load management offers a significant opportunity to increase self-consumption – simply by shifting the use of some devices to hours of high solar generation. Chilled water, ice and other frozen media can be produced during the sunniest hours, and cheaply stored for hours to provide air conditioning, or cold for food and beverage storage and display. Decentralised battery storage could further increase self-consumption, but its exact role in the span of the scenarios depends on cost reductions that remain uncertain. This is not a go or no-go issue, though. As battery costs decline with mass production and experience, progressively greater storage capacities will find their business model, as the value of each marginal kWh of storage capacity decreases with its utilisation rate. Building on the PV output and load profiles of Figure 4.11, Figure 4.13 illustrates how load management and small storage could each increase self-consumption by ten percentage points (relative to the daily demand). Partial or total electrification of homeowner vehicles offers additional possibilities, as discussed below in the section on "Integrating variable PV output".

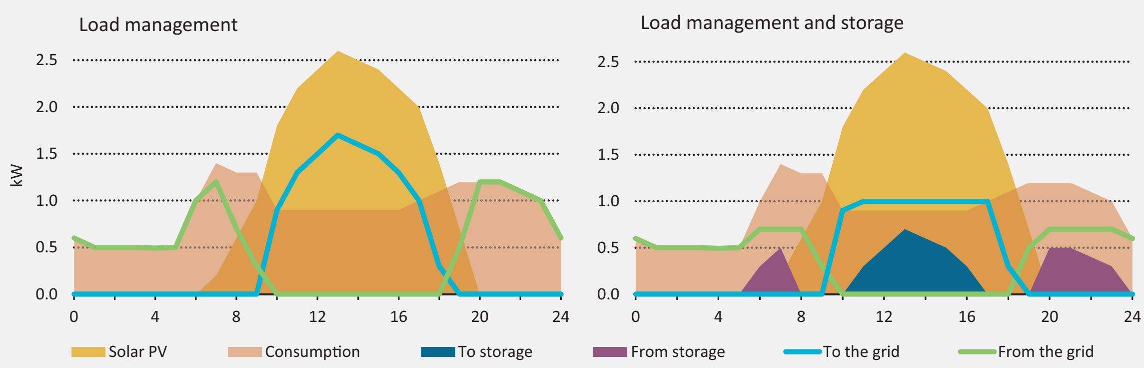
Figure 4.12 Hourly electricity consumption profiles for different building types in Germany



Note: the reported annual consumption of these buildings spans three orders of magnitude. To allow for an easy comparison of load profiles, these curves have been scaled down with respect to the annual consumption of a typical German household (3 500 kWh per year).

Key point *Many buildings other than residential offer better prospects for self-consumption.*

Figure 4.13 Increasing self-consumption with load management (+ 10%) and small storage (+ 10%)



Key point *Load management and decentralised storage can increase self-consumption.*

Decentralised PV generation, partly driven by self-consumption, constitutes almost half of global PV capacities by 2050 in the 2DS and the 2DS hi-Ren. The *ETP* model compares the LCOE from rooftop PV systems to that of all competing electricity-generating technologies plus T&D costs (but not the retail electricity prices). This projection is partly independent from the remuneration schemes such as FiTs, "net-metering" or "value-based" schemes (Box 4.5). For individual homes, however, if the electricity injected into the grid were not remunerated at all, only small PV systems (e.g. of about 1 kW in Germany for a single-family household) would be economically justified on the basis of self-consumption alone.

For apartment buildings in an urban environment, small PV systems might be close to what is possible given the available space, especially if limited to roofs. A five-storey building housing ten families, with an average apartment surface of 85 m^2, will likely have a roof surface of about 170 m^2. Assuming that only one-quarter is free for PV systems with acceptable tilt and orientation, and assuming by 2030 an efficiency of 20% (already exceeded by the best commercial modules), the maximum power from a rooftop system would be about 8.5 kW – less than 1 kW per family. Neither the small capacity nor the small available surface area in urban environments should thus be considered obstacles; on the contrary, they fit very well with each other to support PV self-production and self-consumption. By 2050, one-third of 3 billion families with a 1 kW system would represent 1 000 GW, one-third of the global PV capacity in the 2DS and almost one-fifth in the 2DS hi-Ren.

Box 4.5 Net-metering and the value of PV electricity

In 43 US states, as well as several Australian states and territories, Italy and other countries, the owners or users of PV systems who self-consume part of its electricity can "net" the electricity they inject into the grid against the amount they withdraw from the grid to cover their own needs. This "net-metering" extends over long periods of time (typically one billing period), and often includes the opportunity to report excess as credits to the next period. Net-metering is attractive, and easy to understand and administer.

However, net-metering raises growing concerns, particularly as it remunerates the injected electricity at a cost equivalent to the retail electricity price. Some utilities say the practice is inefficient and unfair: inefficient because utilities could buy electricity from other sources at a lower cost than the retail prices, which include T&D grid costs as well as various taxes and charges; and unfair, as the increase in costs resulting from inefficiency would be borne by other customers.

When the cost of PV electricity is close to this retail price (i.e. grid parity), net-metering appears neither better nor worse than alternative systems to remunerate the electricity of PV systems – if one accepts that nascent PV technologies and markets require support at the beginning, until they reach full competitiveness. Alternative systems, such as FiTs, would also have other customers pay some surcharge to cover these higher PV costs. In general, such approaches make policy costs more transparent than with net-metering.

When PV costs come to levels significantly lower than retail prices, net-metering provides excessive remuneration levels, i.e. entailing higher returns on investments than required for a smooth deployment. The risk is then of too-rapid and uncontrolled deployment at too-high costs. At some point, the remuneration of PV electricity must be distinguished from the retail electricity price. Over time, the remuneration should first fall on the level of the PV electricity cost plus normal return on investment, and eventually on its value for the system, which is higher where and when the PV electricity matches the demand. Exactly as TOU pricing could be used to incentivise load management, TOD pricing could be used to incentivise the management of injected power (SEPA, 2013).

Integrating the variable PV output

As with self-generation, the value and competitive position of PV electricity injected into the grid depend on the place and, more importantly, the time of injection. This is not only an issue of grid costs: it is the most important issue associated with PV – that it generates most of its electricity from mid-morning to mid-afternoon, while consumption varies throughout day and night.

The output of solar PV also depends on the weather, notably the cloud cover, which is only partially predictable on a small area. For large shares of PV, the systems may require more reserves than would be developed on the basis of the unpredictability of the variable electricity demand and the risks of failures of some generating plants or connecting lines. The possibility of relatively long periods with little solar resource – more frequent in winter – calls for adequate firm capacities.

A better match between supply and demand can come from changes in PV system design. PV developers can opt for sun-tracking systems. An alternative option, which the recent cost cuts have brought about, is to design fixed-tilted PV systems with a greater DC/AC ratio – i.e. increased total capacity of modules (generating DC current) with respect to the capacity of the inverters (delivering AC current to the grid). Modules would not all face the equator; some would face east and others west, thus delivering a more regular output throughout the day (although with steeper ramps at sunrise and sunset), and increased capacity factors for the same rated AC capacities.[3]

Eventually, integrating large shares of PV electricity requires technical and economic flexibility from the rest of the system (IEA, 2014). Such flexibility has four main pillars: load management, interconnections, flexible generation and storage.

Load management, including electricity savings and load shifting, offers the cheapest option for integrating variable PV output. This strategy has great potential, but is not infinite – people will always need light at night. Electricity savings, especially targeting nocturnal peak consumption, would help integrate more PV in the mix. Load management would not only reduce the annual electricity demand that PV cannot supply, but also reduce the minimum load level, during daytime, of the conventional plants required to cover the peak at night. Savings on lighting is the obvious example, and its potential remains important (IEA, 2006). The significant possibilities from load shifting have been mentioned above with respect to self-consumption. They could be incentivised for all customers, not only prosumers.

Interconnections are important, because they allow smoothing out the variability of PV plants over large areas and enable sharing flexible generation and storage. Integration with other energy forms and energy networks, such as district heating or gas networks through hydrolysis and methanation in the future, could also help increase PV shares in the electricity mix. Hence the PV industry, PV developers and PV system owners need to strike compromises with utilities and system operators relative to the recovery of grid costs as the current business model for grid expansion, maintenance and operation might be threatened by expansion of decentralised PV and self-consumption.

The flexibility of electricity-generating plants other than PV and wind has two aspects that are interlinked but distinct: one is purely technical, the other economical. Conventional thermal plants take time to start or stop; not all can change pace quickly. Cold starts, in particular, take a long time, especially for nuclear and coal plants. Economically, some technologies represent high investments, and their business models are based on continuous running; other plants are cheaper to build but usually burn more expensive fuels, and are preferably used as "peaking" or "mid-merit" plants. The business model takes into account that they will operate with fewer full-load hours. Many plants would run more economically at minimum load than if stopped for a few hours. Dispatchable renewables, such as reservoir hydropower and STE, where available, offer better prospects for shouldering PV generation, because their electrical capacity can be adjusted by design, for a given energy input (solar or water inflows) to be run as mid-merit or peaking capacities.

3 Wind power technology is following the same path at the same time, with higher hubs and greater swept area/rated capacity ratios (IEA, 2013b).

Storage would be needed to shift more PV electricity to other consumption times. Decentralised battery storage may be more competitive with retail electricity prices. However, 99% of grid-tied electricity storage capabilities today are pumped hydro storage (PHS) plants, with 140 GW in service worldwide and another 50 GW under construction or in development. Global storage capacities are estimated to reach 400 GW in the 2DS by 2050 and climb to more than 600 GW in the 2DS hi-Ren, with PHS providing most of the growth. PHS will, in particular, be developed in areas with large penetration of wind power and little room for CSP plants, such as temperate regions. The potential for PHS is significant, because these plants do not require the large surface areas that characterise reservoir hydropower plants (IEA, 2012; JRC, 2013). Storage at intermediate voltage levels (i.e. not decentralised to the level of individual PV systems, but not as remote as most PHS plants) can help address "hotspot" and grid congestion issues – providing the issues occur frequently enough to make sufficient use of the storage capacities. Almost inevitably, storage capacity optimisation will let some PV curtailment happen, if on rare occasions (see Chapter 7).

Further electrification of transport could also play a role in integrating variable PV output, because it offers storage and a potential means to reduce peak load (see Chapter 6). The external surface area of passenger cars and freight trucks is too small for embedded PV systems to provide a significant energy contribution. At present, these vehicles remain dependent on oil, a primary source of greenhouse gas (GHG) and other polluting emissions. Electric vehicles (EVs), whether partially electrified like plug-in hybrids or full-fledged battery electric vehicles, are major options to reduce both oil dependence and environmental impacts. The 2DS assumes that 17% of passenger cars and 50% of 2-wheelers are EVs by 2050. Its variant, the 2DS Electrified Transport (2DS-ET), aggressively pursues additional modes, such that 26% of light commercial vehicles and medium freight trucks become electrified by 2050. These vehicles offer electricity storage as an "absorbing capacity", in what is termed the grid-to-vehicle (G2V) configuration. Essentially, while not operating, they store electricity that the grid can draw on as needed. Provided charging can take place in the middle of the day, G2V could help flatten the net load curve, i.e. the load curve minus PV. Otherwise, the risk is that uncontrolled EV charging may take place during evening peaks and increase the crest factor (i.e. the ratio of peak over average load) of the net load curve (Figure 4.14).

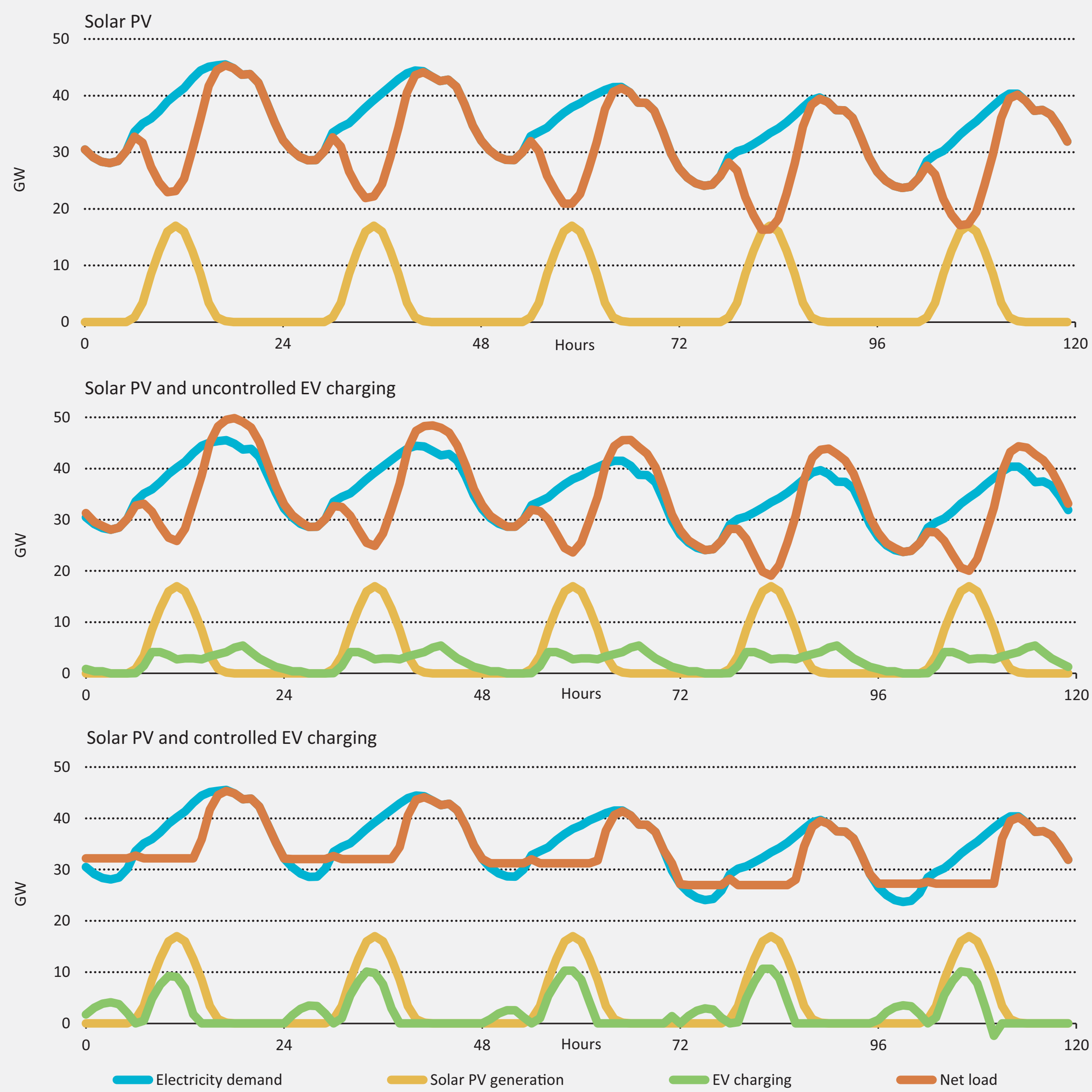
EV charging can increase PV self-consumption. Experiments in the southeast of France have shown that PV systems installed over the parking space for one car could produce enough electricity to run a four-passenger car over 10 000 kilometres (km) per year. Midday charging is more likely to happen at offices and other work sites using PV charging stations. This contribution would benefit from any form of on-the-move charging, such as induction (see Chapter 6).

Regional considerations in the 2DS and the 2DS hi-Ren

PV deployment is partly contingent on the structure of the electricity system and its evolution over time as ageing capacities are retired and new ones built (in various proportions depending on the growth of the electricity demand on various markets). Integrating PV (and wind) will be easier in countries with a large proportion of hydropower in the mix than in those dominated by coal or nuclear power. PV deployment will be an important factor driving that evolution. The other dominant factors are the match, or mismatch, between PV generation and demand, and the capacity to modify the demand profile.

Shares of PV will be significantly lower in temperate countries than in hot countries. In temperate countries, unless hydropower heavily dominates the mix, conventional generators will need to be able to cover peak demand at dark, and might need to run at partial load during the sunniest hours. As a result, PV cannot saturate demand at noon, and its contribution might

Figure 4.14 Controlled versus uncontrolled EV charging effects on load net of PV



Note: stylised electricity system for a five-day period with PV generation (top figure), with additional uncontrolled PV charging (middle figure) and controlled charging (lower figure).

Key point *Controlled charging of electric vehicles would facilitate the integration of solar PV.*

be limited to 5% to 10% of annual generation, unless extensive load management and storage are available, or extensive noon curtailment becomes economically acceptable.

In the 2DS hi-Ren, PV by 2050 reaches only 7.5% (and STE 3.6%) in the European Union, far behind wind power (over one-third), compared with 16% on global average, 18% in the Middle East and the United States, 21% in China and India. In sunnier countries, PV generation matches better with peak or mid-peak demand in the afternoon, making it easier to achieve penetration of up to 20%.

Key factors influencing the prospects for STE

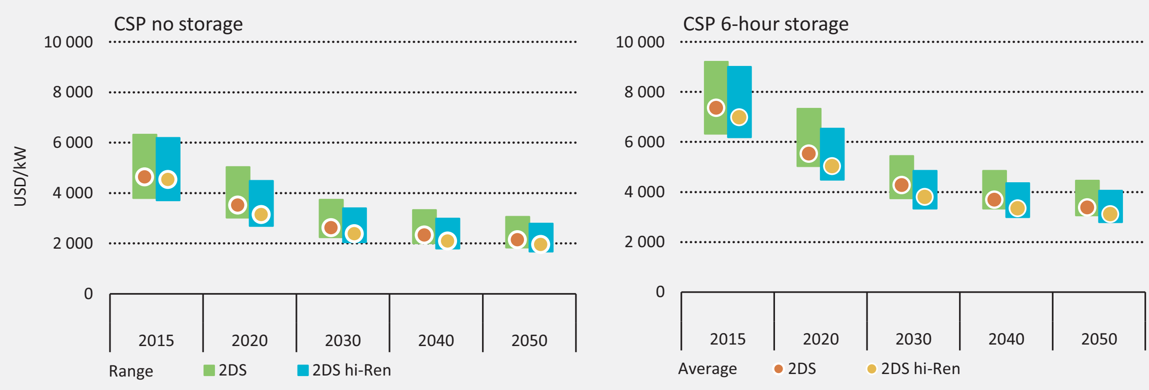
Continued cost reductions

For all three predominant types of CSP technologies – parabolic troughs, LFRs and towers – novel optic designs are being considered, as well as new mirror materials and receiver designs. Tower designers are also exploring choices relative to the type of receivers (cavity or external), the number and size of heliostats, the number of towers associated with each turbine, and the size and shape of solar fields.

Two paths exist to reduce costs. Some companies are developing low-tech solutions (typically LFR) with a higher local manpower content. Others seek to increase the electric conversion efficiency (mainly through higher temperatures) in order to downsize the solar field, which accounts for roughly half of the investment cost. This requires replacing the current heat transfer fluid of troughs (synthetic oil) with DSG or molten salts. The growing relevance of thermal storage favours using molten salts as both the heat transfer fluid and the storage medium (termed "direct storage"). Molten-salt towers are currently in operation in Spain and in the United States. Several companies are now developing the use of molten salts as a heat transfer fluid in linear systems, and have built or are building experimental or demonstration devices. One challenge is to reduce the parasitic loads required to keep the salts warm enough in long tubes at all times, including at night. Addressing this challenge is easier in towers because the central receiver is compact and can be drained by gravity; also, it is easier to keep salts hot in tanks.

Investments costs would follow a 90% progress ratio (i.e. diminish by 10% for each doubling of cumulative capacities), and in the 2DS fall by 2050 in the range of USD 3 060/kW to USD 3 600/kW for a plant with six-hour storage – allowing for up to 4 500 full-load hours versus 1 650 for solar PV (Figure 4.15). In the 2DS hi-Ren, the highest investment costs fall below USD 3 300/kW.

Figure 4.15 Investment costs of CSP plants with and without storage in the 2DS and 2DS hi-Ren scenario



Key point *Significant cost reductions are expected in the next few years as new CSP designs move into markets.*

LCOE and value

STE from CSP plants costs more than PV electricity (Table 4.5), but has higher value. Even in areas where afternoon peak time matches well with PV output, CSP plants offer a variety of additional ancillary services that are increasingly valuable as shares of PV and wind (both variable renewables) increase in the electricity mix. Denholm et al. (2013) have studied the role of CSP plants in a 33% renewable electricity mix for California, identifying a capacity value (similar to that of a conventional dispatchable resource) and a value for providing reserves. The incremental value of STE in their study was USD 30/MWh to USD 51/MWh compared with a base-load resource, and USD 32/MWh to USD 40/MWh compared with PV electricity.

Table 4.5 Evolution of the LCOE for new-built CSP plants with and without storage in the 2DS

USD/MWh		2015	2020	2025	2030	2035	2040	2045	2050
Without storage	Min	158	126	105	93	88	83	80	76
	Max	263	209	175	156	147	139	133	127
	Avg	191	149	132	115	109	104	100	97
With 6-hour storage	Min	146	116	97	86	82	77	74	71
	Max	213	169	142	126	119	112	108	103
	Avg	168	130	117	103	97	91	88	85

Note: Avg stand for the weighted average LCOE of new-built systems.

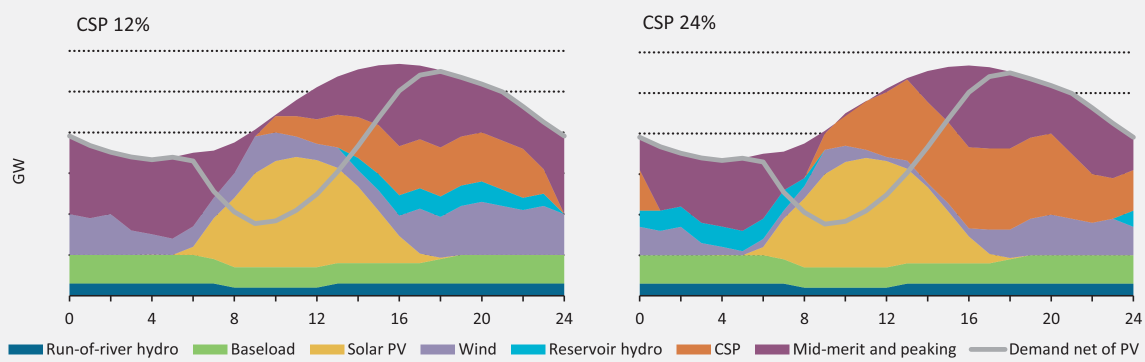
Thermal inertia and relatively small storage capacities are likely to be sufficient for CSP plants to provide these services. To some extent, these added values are able to compensate for higher costs. Utilities in the American Southwest that are choosing CSP plants to comply with renewable energy portfolio standards appear to be aware of these advantages of STE – and adverse to the potential risks arising from the variable output of PV systems that have been deployed too rapidly.

CSP can also generate electricity when PV cannot, in the absence of affordable electricity storage capacities. The built-in storage capability of CSP is cheaper and more effective (with over 95% return efficiency, versus about 80% for most competing technologies) than battery storage and PHS. Storage allows separating the collection of the heat (during the day) and the generation of electricity (at will). This capability has immediate value in countries having significant increase in power demand when the sun sets, in part driven by lighting requirements. In many such countries, the electricity mix, which during daytime is often dominated by coal, becomes dominated by peaking technologies, often based on natural gas or oil products. In developing economies often having very tight electric capacity, peaks stretch the electric system to its limits. At such times, the marginal value of electricity can skyrocket – often to twice the normal high as during daytime.

In countries with demand peaks during the afternoon and early evenings, the largest share might be accessible to PV. After some PV deployment has taken place, however, the load curve net of PV becomes more favourable to CSP, when evening peaks increase. CSP is well placed to respond to these evolutions (Figure 4.16).

This potential explains the growing interest for CSP in countries such as China, India, Morocco, Saudi Arabia and South Africa. The ability of CSP plants to deliver electricity at will also helps to explain, together with current higher costs, why in long-term scenarios, notably 2DS and 2DS hi-Ren, CSP electricity initially lags behind PV electricity but eventually gains shares as PV capacities level off. Although both technology families compete on some markets today, in the

Figure 4.16 Daily dispatch for a stylised system with annual PV electricity share of 18% and various CSP shares



Key point *CSP plants would generate electricity for peak and mid-peak demand; after sunset, their capacity complements PV generation from earlier in the day.*

longer term the synergies prevail. The greatest possible expansion of PV, which implies its dominance over all other sources during a significant part of the day, creates difficult technical and economic challenges to low-carbon base-load technologies such as nuclear power and fossil fuel with CCS. Natural gas is more suited to daily "stop-and-go" with rapid ramps up and down, and is more economic for mid-merit operations (fewer than 4 000 full-load hours). But as the CO_2 constraints grow stricter and the carbon price rises, the share of natural gas must progressively recede. In hot and dry regions, PV deployment thus paves the way for CSP expansion, not only in leaving untouched or aggravating demand peaks at dark, but also in dismissing other climate-friendly technology options.

Several recent examples highlight ways that CSP could be used to support electricity system operation and planning. In Morocco, the CSP plants being built to run mostly during daytime will require continuous support from the government, despite low financing costs provided by multilateral and bilateral development banks. Yet a mix of CSP mostly used after sunset and PV used during daytime would save the government money; these technologies are less costly than the marginal cost of alternatives currently forecast – natural gas during daytime and diesel oil after sunset.

In South Africa, while base-load electricity is generated from inexpensive coal, growing demand peaks call for the deployment of additional peaking capacities. To this end, building 5 GW of new open-cycle gas turbines (OCGT) to be run on diesel oil is currently planned, while gas is not available. This offers significant opportunities for CSP plants with storage, which could deliver 80% of the electricity at peak times, with the OCGT producing the remaining 20% (Silinga and Gauché, 2013).

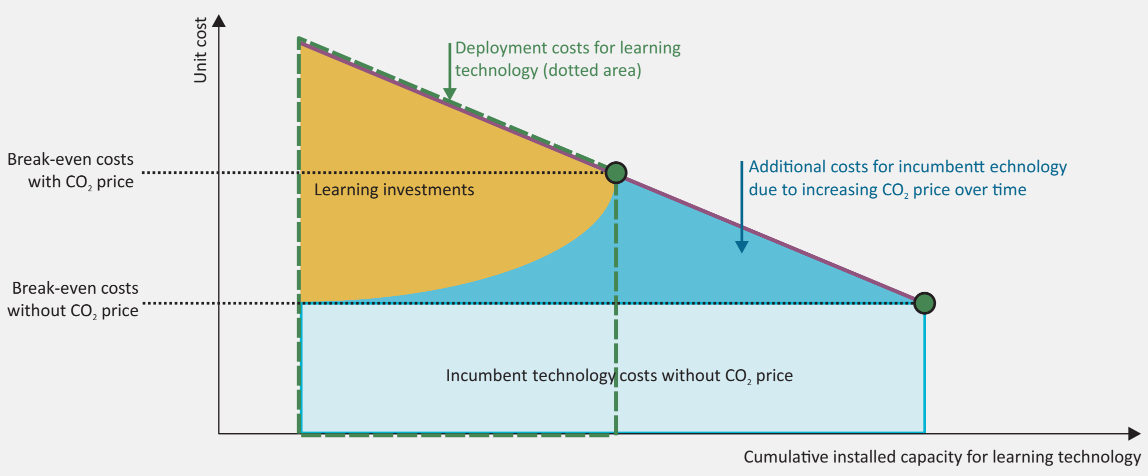
The South African Department of Energy (DoE) offers an excellent policy example on how to encourage CSP with storage to generate energy during peak time. The DoE recently introduced a TOD tariff in the third round of procurement for renewable capacities. A base tariff applies during the day, and a higher tariff – the base tariff multiplied by 2.7 – will be appied for supplying energy during peak time between 16 h 30 and 21 h 30. Competitors need only bid for one price – the price during peak hours being the simple product of the bidding price by the multiplier. Thus, this TOD keeps a simple process for selecting the best bids.

Recommended actions for the near term

Despite the recent cost reductions for PV systems, financial incentives are still needed in most markets to support the deployment of solar power technologies, but at significantly lower level than just a few years ago: as the costs of systems plummet, the gap between market prices and LCOE of PV shrinks even faster. The aim of these measures is to bring down further the technology costs through greater experience in production and use. The incentives can close the cost disadvantage to incumbent technologies and to provide investment security for these capital-intensive technologies. The inclusion of solar energy technologies in the energy mix provides a hedge to end users of electricity against volatility of fossil fuel prices. These end users ultimately shoulder that risk themselves, because fuel prices set the market price of electricity, and fossil-fuelled generating technologies can typically pass on the fuel costs to customers.

From the concept of technology learning curves it is possible to derive learning investments, which represent the amount of investment needed until solar PV and CSP technologies become cost-competitive with the incumbent technology (or mix of technologies) in the various scenarios (Figure 4.17). The learning investments describe the difference in costs between the learning technology and the incumbent technology. Factors affecting the incumbent technology, such as fuel or CO_2 prices, influence the learning investments. Furthermore, the deployment can be more or less directed towards markets where solar energy is more competitive. Hence, the learning investment costs depend on the localisation of solar assets and the costs of competing technologies.

Figure 4.17 Schematic representation of deployment costs and learning investments



Key point *A CO_2 price for the incumbent technology reduces the learning investments needed for the learning technology to become cost-competitive.*

PV deployment in the long term will be determined less by costs, especially if energy security and environmental externalities are duly priced, and more by issues of integration and PV's capacity to respond to the demand. Interconnections will allow smoothing variability over large areas and sharing other means of flexibility. But the potential of load management, the level of flexibility offered by other generators, and ultimately storage costs will determine the pace and extent of solar PV deployment. In sunny but wet regions, the perfect partner for PV would be hydropower; in sunny and dry regions, it is likely to be STE, as is considered below (IEA, 2011).

A recent IEA publication, *The Power of Transformation: Wind, Sun and the Economics of Power Systems* (IEA, 2014), investigates in detail the economics of large shares of variable renewables such as wind power and solar PV in power systems. It shows that with timely re-optimisation of power systems, less inflexible base-load power, and more flexible mid-merit and peaking generation, total electricity costs at 45% of variable renewables would be increased by about 10% to 15% with current wind and PV technology costs.

STE offers no significant superiority over PV with respect to the inter-seasonal variability, except that it is usually located in places where such variability is less pronounced than in regions of higher latitudes. Inter-seasonal storage hardly appears to be an economical option, unless very high shares of renewables are sought in the overall energy mix, and could be made to take the form of solar fuels manufactured in concentrating solar devices. At present, however, a portfolio of solar and wind resources appears more robust, since in winter, when the solar resource is low, the wind resource is usually at its greatest. While in sunniest places the portfolio is heavily favourable to solar, in temperate areas wind is more likely to dominate. For example, in the 2DS hi-Ren, in OECD Europe, solar electricity (PV plus STE) reaches 11% of annual electricity generation by 2050 but wind power reaches 35% – three times more.

Another issue for both technologies in liberalised markets may call for a new, imaginative solution. Highly capital-intensive solar technologies, which have low running costs, can experience difficulties in getting sufficient reward through spot markets where the marginal running cost of the last unit called to fulfil the demand drives the price for all generators. As the share of renewables in the mix grows over time, the most expensive peaking options will be solicited less often and spot market prices will plummet, especially for solar PV when the sun shines (or for wind when the wind blows). While progressively greater market exposure of renewables would be useful to drive investment and operations of variable renewables in a more system-friendly manner, there is a need to supplement wholesale markets with mechanisms to provide fair risk-return, attract financing and ensure sufficient investment (see Chapter 8).

Due to its built-in storage capability, STE is more likely to get its fair remuneration through markets, although the problem may remain. In contrast, PV systems and wind turbines face the challenge that if they are sufficient to respond to demand, their remuneration through spot markets may not provide enough payment for an acceptable return on investment. Whether requested by utilities, regulators, distributors or final customers, long-term contracts may represent an important aspect of future electricity systems if these systems are to support the expansion of solar and other renewable electricity technologies needed for decarbonisation.

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Chapter 5

Natural Gas in Low-Carbon Electricity Systems

Natural gas has two important roles in the transition to low-carbon electricity generation presented by the *Energy Technology Perspectives 2014 (ETP)* 2°C Scenario (2DS): reducing emissions by displacing coal-fired base load generation; and complementing deployment of renewables by increasing the flexibility of the overall system. Moreover, if later equipped with carbon capture and storage (CCS) technology, gas-fired generation has strong potential to compete with other dispatchable, low-carbon generation technologies (e.g. nuclear, hydro and coal with CCS). The evolution of both technology and markets will determine the extent to which gas-fired generation fulfils these two roles.

Key findings

- **Composition of the regional electricity generation mix will determine whether gas-fired generation is better placed to displace coal or improve system flexibility in the near term.** Regional resource endowments and carbon dioxide (CO_2) targets will be pivotal factors.
- **Displacement of coal by natural gas in power generation is not a foregone conclusion.** The outcome of competition between coal and natural gas depends more on the economics of CO_2 emissions and fuel prices than on technology improvements. If coal and carbon prices are low, coal plants are sufficiently flexible and can be profitable.
- **Base-load gas-fired plants will require CCS to meet 2DS targets.** This emphasises the need for technological learning from large-scale demonstration and capital cost reductions through research and development (R&D). Electricity from gas-fired plants with CCS is likely to be cost-competitive against coal plants with CCS.
- **Flexible operation creates additional maintenance costs for thermal generators.** Combined with low capacity factors, this could undermine the profitability of gas-fired generation investments.
- **Key performance indicators for gas-fired plants will depend on the role they play in specific electricity markets.** In regions with ambitious deployment plans for renewable electricity, part-load efficiency, ramp rate, turndown ratio and start-up times are more relevant than full-load efficiency.

- **Shifting gas-fired generation away from base-load operation – and towards flexibility – opens up competition among generation technologies.** Internal combustion engines (ICEs), open cycle natural gas turbines (OCGTs), combined-cycle natural gas turbines (CCGTs) and even fuel cells could be attractive depending on system characteristics and variability in natural gas composition.
- **Technically, a trade-off exists between efficiency and flexibility; this could create competition for R&D resources.** If the market up to 2030 is driven by capacity expansions in the People's Republic of China, the Middle East and the United States (as indicated in the 2DS), technology suppliers may focus on efficiency for base load at the expense of flexibility.

Opportunities for policy action

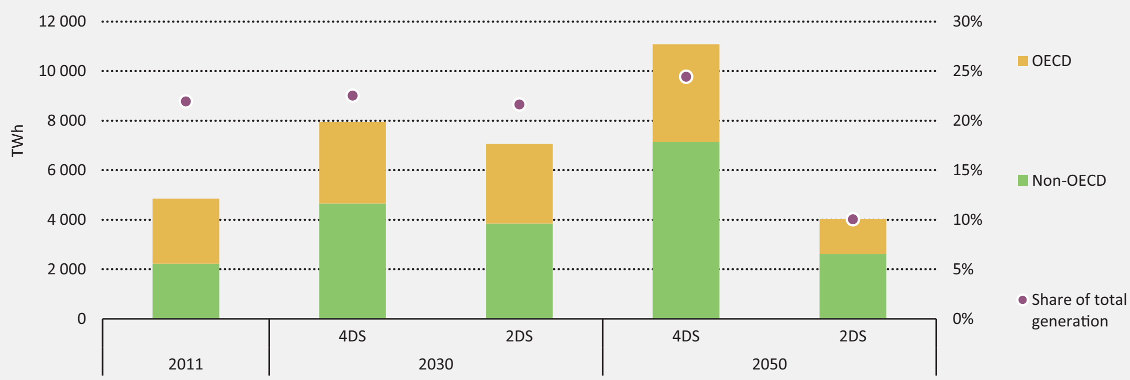
- Renewables, flexible gas-fired generation, and CCS each deliver different, but complementary benefits. Differentiated policies and market reforms will be required to encourage investment in each technology.
- Integrated electricity system planning can better capture the system synergies emerging from technical and economic complementarities among gas-fired and renewable electricity generators. Importantly, it can also avoid potential competition and conflicts.
- Rewarding ancillary services provided by flexible plants could help gas-fired generation to support capital-intensive capacity such as renewables and CCS.
- Depending on fuel prices, gas-fired generation with CCS can be cheaper, less polluting and less capital-intensive than coal-fired generation with CCS. Despite this, CCS development has focused almost exclusively on coal because it has a lower CO_2 avoidance cost. Policy can remedy this through more inclusive demonstration programmes and by targeting electricity price instruments to support early deployment.
- R&D is likely to be particularly important in two areas, towards which both private and public research objectives should be steered: reducing the capital requirements of gas-fired plants without compromising minimum flexibility or efficiency; and demonstrating and improving CCS for gas-fired power generation.

Natural gas in the *ETP 2014* scenarios: A summary

The two main scenarios considered by *ETP 2014* present different roles for natural gas in electricity generation.

In the 4°C Scenario (4DS), which reflects current policy commitments but would not prevent the worst impacts of climate change, natural gas-fired electricity (i.e. gas-fired) generation maintains its share of around 20% of electricity generation to 2050. The outlook for gas-fired generation in the 4DS is very positive. In absolute terms, gas-fired generation increases by 130% between 2015 and 2050, reaching over 11 000 terawatt hours (TWh) in 2050, and natural gas input to electricity plants and heat generation rises 58% to over 74 exajoules (EJ) in 2050. The growth is almost entirely located in non-member countries of the Organisation for Economic Co-operation and Development (OECD) (Figure 5.1), where demand for electricity increases by 175% over the period and where using natural gas instead of coal can have a pronounced impact on reducing pollution, including CO_2, in line with existing goals. Because the climate mitigation ambitions underpinning the 4DS are only modest, they can be met without fully decarbonising electricity generation or industry; just 0.3% of all gas-fired generation is from plants that use CCS to avoid CO_2 emissions in this scenario.

Figure 5.1 Gas-fired generation in the 4DS and 2DS



Note: includes generation from gas-fired plants equipped with CCS.
Source: unless otherwise noted, all tables and figures in this chapter derive from International Energy Agency (IEA) data and analysis. Figures and data that appear in this report can be downloaded from www.iea.org/etp2014.

Key point *Gas-fired generation in both the 2DS and 4DS continues to expand in absolute terms up to 2030, with all of the increase in non-OECD countries. In the 2DS, both gas-fired generation and its share of total generation decline by 2050, with most of the reduction in OECD countries.*

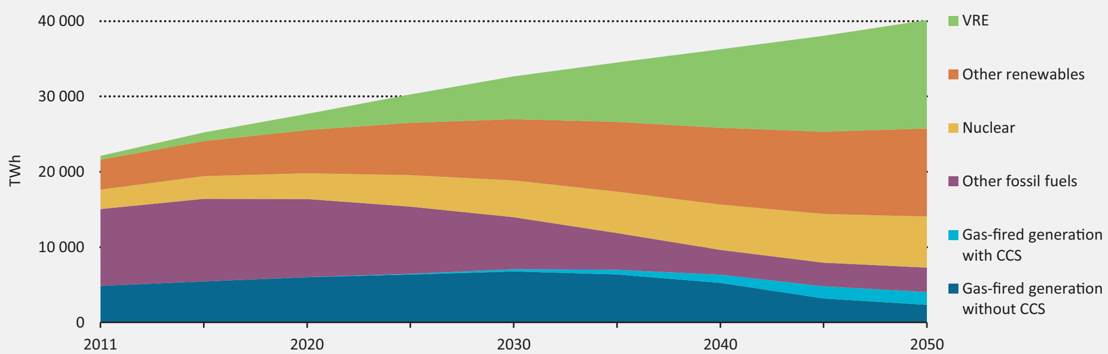
In the 2DS, the global share of gas-fired generation in total electricity generation falls by 50% after 2030 to just over 10% in 2050 (Figure 5.1). The absolute quantity of natural gas used as a fuel for electricity and heat production declines 41% to 27 EJ over the same period. In addition, the global average capacity factor[1] of natural gas-fired power (i.e. gas-fired) plants begins to fall after 2030. This squeeze on operating hours results from increasing generation costs from gas-fired plants without CCS due to rising carbon prices and, the penetration of variable renewable energy (VRE) that has lower marginal costs and is therefore more competitive in energy-only electricity markets. Thus, gas-fired generation becomes increasingly relegated to a flexible backup for renewables in many regions.

In the 2DS, on aggregate, almost all the growth in electricity demand globally is met by growth in VRE (Figure 5.2). Due to ambitious decarbonisation objectives, 42% of electricity generated from natural gas in 2050 is from plants equipped with CCS.

In a world that limits emissions in accordance with a 2°C target, gas-fired plants with high capacity factors and without CCS (i.e. unabated plants) will generally have only a couple of decades remaining. Natural gas is often promoted as a "clean" energy source; however, it is only "cleaner" relative to other fossil fuels. Gas-fired plants emit fewer pollutants than coal- or oil-fired plants, but they are not without environmental impacts. A modern CCGT has an

1 Capacity factor is the ratio of effective energy generation to maximum potential output over a given year.

Figure 5.2 Global gas-fired generation compared with other sources in the 2DS



Key point *In the 2DS, total generation from natural gas remains relatively steady only by use of CCS to cut emissions; globally, it does not maintain overall market share despite playing a key role in balancing supply and demand.*

efficiency of around 60% (lower heating value [LHV] basis), and emits around 350 kilogrammes of CO_2 ($kgCO_2$) per megawatt hour (MWh) when operating at full load. Under the same operating conditions, emissions are much higher from a modern supercritical (810 $kgCO_2$/MWh) or ultra-supercritical (730 $kgCO_2$/MWh) plant fuelled by hard coal.[2]

As decarbonisation of the electricity system progresses, the relative "cleanliness" of gas-fired generation declines in comparison to the system average. Today's best-performing gas-fired plants would exceed the average CO_2 intensities seen in the 2DS not long after 2025 (Figure 5.3). Each additional kilowatt hour generated at unabated gas-fired plants would therefore raise, not lower, the average emissions of the electricity system. Against other sources, unabated gas-fired plants will become too carbon-intensive to power a significant proportion of the global economy and still meet the emissions reduction targets set out in the 2DS. Thus, CCS will be a necessity for not only coal-fired plants, but also gas-fired plants.

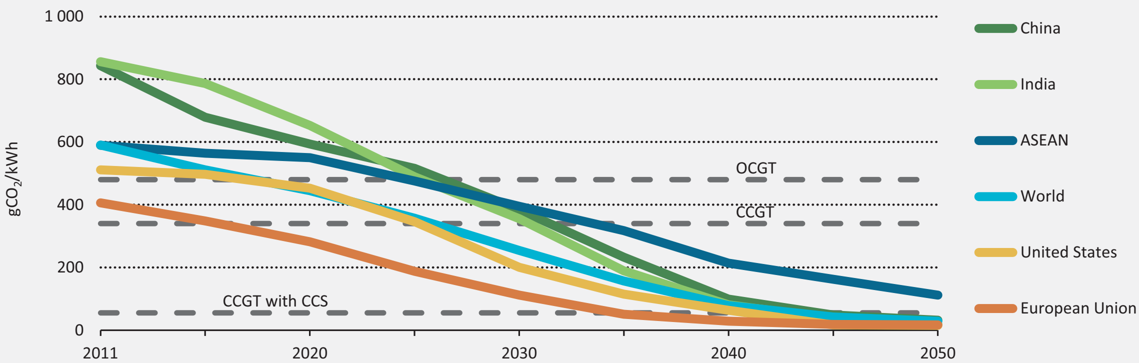
These results show that gas-fired generation is substantially challenged in the 2DS. Much of the unabated capacity currently operating or planned in the coming years remains in the electricity mix after 2025, but is used less and less from an operating perspective. In addition, carbon pricing increases the costs of fossil fuel-based electricity. Nonetheless, gas-fired generation is dispatchable and can act as a complement to the variability of renewables such as wind and solar, and provide important ancillary services.[3] The challenge will be to determine how gas-fired generation capacity can be maintained in the system – and provide valuable ancillary services – when its profitability could be diminished due to increased costs and reduced operating hours.

The two roles for gas-fired generation

Natural gas offers two benefits in the 2DS: i) per unit of electricity generated, it has half the CO_2 emissions of coal; and ii) gas-fired generation technologies can support the integration of

2 The equivalent plants burning lignite have higher emissions rates of around 830 $kgCO_2$/MWh and 910 $kgCO_2$/MWh, and many older coal-fired plants have considerably higher emissions rates than this.
3 Also referred to as network services, see IEA, 2013d and *ETP 2014* Chapter 7.

Figure 5.3 **Carbon intensity of electricity generation in the 2DS compared with gas-fired generation technologies**



Notes: gCO_2/kWh = grams of carbon dioxide per kilowatt hour. Emissions intensities are estimated for new build plants in 2015. ASEAN = Association of Southeast Asian Nations.

Key point *After 2025 in the 2DS, emissions from gas-fired plants are higher than the average carbon intensity of the electricity mix; natural gas loses its status as a low-carbon fuel.*

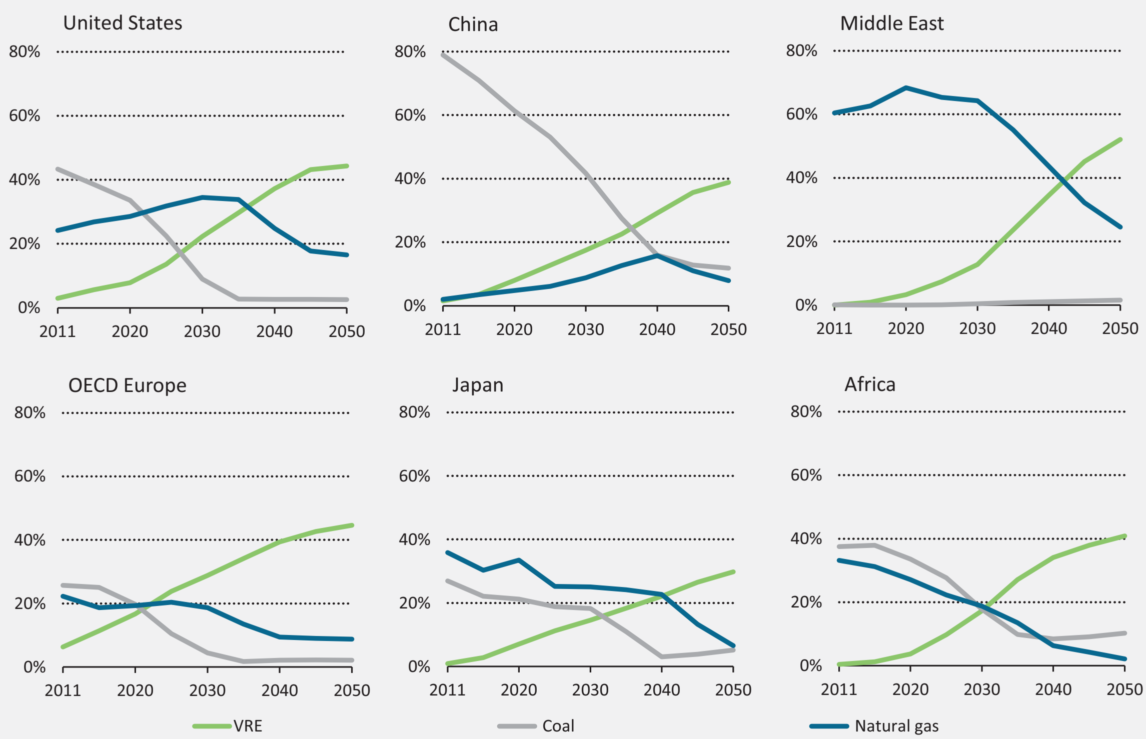
VRE. These benefits relate to the chemical and physical properties of the fuel itself. In relation to other fossil fuels, natural gas has fewer carbon atoms per unit of chemical energy and thus emits less CO_2 per megawatt hour when burned. In relation to other forms of electricity generation, gaseous fuels are most compatible with the more flexible technologies, such as combustion turbines. This chapter focuses on these two roles in order to examine how new and better technologies can help meet the 2DS challenges.

Globally, fuel switching from coal to gas in the 2DS delivers 4.5 gigatonnes of CO_2 of emissions reductions in the period up to 2030 (relative to the 6DS). Thereafter, CCS is the predominant technology for further emissions reduction from gas-fired generation to 2050 and beyond in most regions.

Regionally, whether the primary decarbonisation benefit of gas-fired generation is to displace coal or to support renewables depends on a number of factors. These include a country's existing electricity mix, its relative prices of coal and natural gas, its penetration of VRE, its regulation of CO_2 emissions, and the availability of competing technologies for low-carbon dispatchable electricity. Because these factors vary between regions, the evolution of gas-fired generation and other sources of electricity follow different patterns in the 2DS (Figure 5.4).

In terms of timing, gas-fired generation is already performing both roles in different parts of the world. In the near term in the 2DS, increasing use of natural gas rather than coal to provide base-load generation is the major role. As the period evolves, the second role becomes more important as renewable electricity is deployed at substantial scales in all regions. In theory, given the abatement costs involved, these roles would be sequential. In practice, the relative importance of these roles depends on the initial share of coal-fired generation and the availability of other flexible, low-carbon generation options.

Figure 5.4 **Evolution of the share of generation from natural gas, coal and VRE for six regions in the 2DS**



Notes: natural gas and coal include generation from plants equipped with CCS. VRE includes wind, solar and ocean.

Key point *In the 2DS, the Middle East and the United States increase their shares of gas-fired generation in the medium term; Europe, Japan and Africa reduce their shares of gas-fired generation while increasing the share of generation from variable renewables.*

Competing gas-fired generation technologies

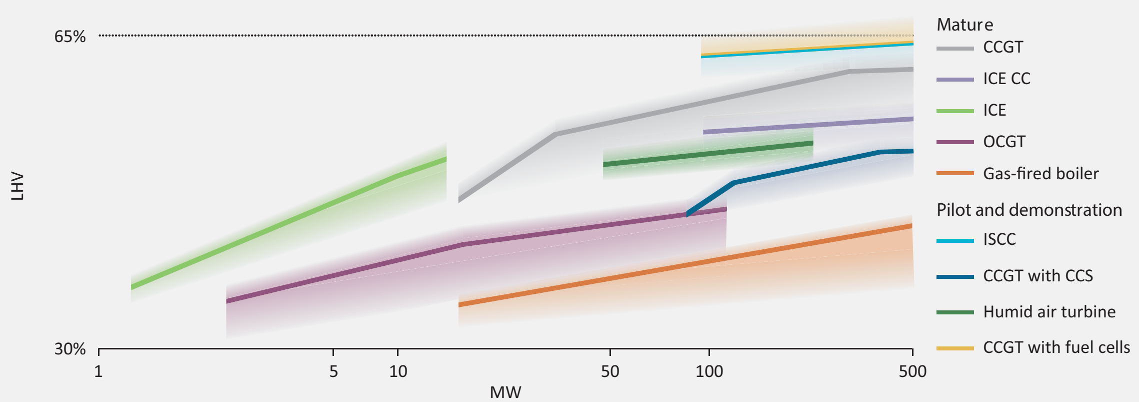
Historically, a major driver of technology development for gas-fired generation has been the quest for increased efficiency. However, raising efficiency cannot be the only technical objective in the future. Other criteria, such as part-load efficiency, ramp rate, turndown ratio and start-up times, are coming to the fore. A wide range of natural gas electricity generation technologies, designed for diverse system needs, are at different levels of maturity (Table 5.1).

The importance of matching technology to needs, and indeed adapting existing technologies to future needs, is the central theme of this chapter. One example is unit size, for which a counter-intuitive relationship with efficiency can exist. Smaller unit sizes can be attractive in smaller electricity grids, where larger units are difficult to finance and for providing ancillary services. Internal combustion engine (ICE) plants, although less efficient than CCGTs for large units, can offer higher efficiencies at small scales (Figure 5.5) and also higher efficiencies than a large CCGT operating at part load.

Table 5.1 Technical options for gas-fired generation

	Maturity	Strengths	Weaknesses	Potential improvements
CCGT	Mature	High efficiency; relatively low specific capital cost	Efficiency reduced at part-load or smaller plants	Improved heat recovery steam generation; inlet pre-heaters; variable pitch to improve flexibility; advanced materials
CCGT with CCS	Pilot/ demonstration scale	Lowest CO_2 emissions	Increases fuel consumption and capital expenditures; potentially reduces flexibility; requires available CO_2 storage	As above; reduced capital and operational costs; optimisation of value chain
OCGT	Mature	Rapid start-up; small footprint	Lower efficiency than CCGT	Improved efficiency at smaller scales
Gas-fired boiler	Mature	Few strengths over other options	Slower start-up than OCGT; lower efficiency than OCGT and CCGT	Only minor incremental improvements expected
ICE	Mature	Relatively high efficiency at small scale; modular; rapid start-up; lower capital cost than OCGT; tolerant of different fuel qualities	Lower efficiency than CCGT at larger scales	Some improvements expected through operation at 100 megawatt (MW) scales and above
Humid air turbine combined-cycle	Pilot scale	Higher efficiency than CCGT; faster start-up time and lower stable minimum load	Higher efficiencies require larger scale plants	Proof of concept at large scale and reduction of cost
Solid oxide fuel cell (SOFC) plus CCGT	Pilot scale	High efficiency	Currently high cost; higher efficiencies require large-scale plants	Proof of high-pressure operation; improved flexibility
Integrated solar plus CCGT	Demonstration scale	Reduced CO_2 emissions without increased fuel use	Low-carbon operation dependent on solar radiation; higher efficiencies require large-scale plants	Improve temperature stability

Figure 5.5 Selected gas-fired generation technologies by efficiency and unit size



Notes: technologies will be discussed further throughout the chapter. CCGT with CCS is the cleanest technology, but the additional energy requirement to capture CO_2 reduces the efficiency compared with CCGT. Technologies at pilot and demonstration stage vary widely in technical maturity, from an ISCC, which is commercially available, to fuel cells, which are available only at pilot scales.

Key point *CCGT plants are the most efficient large-scale gas-fired plants, but banks of several less efficient ICE plants can offer higher efficiencies than smaller sizes of CCGTs.*

Traditionally, CCGTs have been associated with load-following applications (or base load, where cost-effective), while OCGTs have provided flexible response and peaking electricity. ICEs have traditionally been employed in smaller electricity systems, where fuel flexibility is important and where short lead times are desirable. These decisions have frequently been taken in regulated electricity markets and generally on the basis of long-run marginal costs (Box 5.1). Looking ahead, market structures, financing concerns and even alternatives to new capacity additions (e.g. demand-side management and storage technologies) will play a larger role in determining the optimal choice for investments. Consequently, measures of long-run marginal costs, e.g. levelised cost of electricity (LCOE), will be less suited to decision making in liberalised markets (Joskow, 2011). Measures of short-run marginal costs, i.e. variable operating costs, and the ability to capture revenues from provision of ancillary services are of growing importance. Thus, these technologies may be attractive in new contexts and the selective pressures of the marketplace will result in different outcomes.

Box 5.1 Long-run and short-run marginal costs

Long-run marginal costs (LRMC), generally presented as the LCOE, are often quoted in literature that compares electricity generation options. However, for installed capacity, it is short-run marginal costs (SRMC) that determine whether a plant operates and the revenue it receives.

SRMC is the change in total cost resulting from a one-unit change in the output of an existing production facility. It ignores adjustments in the capital stock, and includes only fuel costs and variable operating and maintenance costs (O&M). Theoretically, in energy-only markets, plants with the lowest SRMC are dispatched first and all generators receive the price paid to the dispatched plant that is last in the merit order (i.e. with the highest SRMC). Operators seek to cover the variable costs of producing an extra unit. Renewable generators have no fuel costs; their remuneration and profitability therefore depend on the SRMC of the last plant in the merit order, often a CCGT.

LRMC is a measure of the marginal cost of electricity over the economic life of the facility, including capital and fixed and variable operating costs. It is generally used when evaluating new capacity to be added to an electricity grid, especially in markets with regulated prices. In competitive markets, however, if the market-clearing price is consistently below the SRMC, a plant with a lower LRMC may be less profitable than a plant with a lower SRMC and investments may be recovered more slowly than envisaged.

SRMCs are necessary to explain recent coal-to-natural-gas fuel switching in the United States and why existing coal plants often operate more hours than gas-fired plants, despite having higher capital intensity and higher LCOE.

Other system-wide issues

In addition to electricity generation technologies, achieving the 2DS hinges partly on changes to how natural gas is used throughout the global economy. Four specific issues that are not considered in depth in *ETP 2014* are:

- **Direct use of natural gas in end-use applications.** Natural gas can be used without conversion to electricity in many end-use applications (e.g. transport, industry, buildings), including heating, fleet vehicles and off-grid electricity generation. Among these are applications in which an initial conversion of natural gas to electricity may reduce life cycle efficiency and increase emissions, depending on the efficiency of the end-use technology. Increasing electrification in both the 2DS and 4DS would require parallel deployment of efficient end-use electrical equipment. Examples include heat pumps for heating, solid-state lighting and advanced motors for vehicles and industry.[4]

4 More information available from the Implementing Agreement for a Programme of Research, Development, Demonstration and Promotion of Heat Pumping Technologies (HPT IA) and the Implementing Agreement for a Co-operative Programme on Energy Efficient End-Use Equipment (4E IA).

- **Upstream emissions from gas supply.** While these numbers reflect the state of the art for the downstream stages of fuel transformation, they do not account for upstream emissions, and the overall emissions benefits will depend critically on any leakage of natural gas to the atmosphere during extraction and transport to the electricity plant. It has been estimated that 80 to 90 million metric tonnes of methane are released from oil and gas supply and distribution each year (IEA, 2012a; US EPA, 2012). One US estimate places the contribution from methane emissions prior to electricity generation from Barnett Shale gas at 7% to 15% of life-cycle greenhouse gas emissions for gas-fired generation (NREL, 2012b). In this study, the contribution of combustion emissions during gas supply and distribution was found to be approximately equal to that from methane leakage. Typical natural gas system leakage rates have been found unlikely to negate the benefits of coal-to-gas fuel switching on a century timescale, however (Brandt et al., 2014).
- **Decarbonisation of gaseous fuel supplies.** To minimise life-cycle emissions associated with gas-fired generation, natural gas in the distribution system can be fully or partly replaced by other gaseous fuels that have lower carbon contents. Examples include hydrogen produced from coal with CCS, hydrogen produced by electrolysis with low-carbon energy, or biogas.
- **Fuel composition.** In recent years, gas itself has become a more diverse fuel due to increasing regional pipeline interconnections, growing liquefied natural gas (LNG) trade, unconventional gas production and use of landfill gas, biogas and synthetic natural gas. In fact, energy policy often promotes increasing the role of these fuels to improve competiveness, energy security or sustainability. These gases can have varying compositions. Pipeline specifications and gas-fired plants are designed for a range of fuel compositions, with CCGT and OCGT power plants generally being less tolerant to different fuels. The introduction of more fuels with different specifications into gas supplies will have cost implications if gas upgrading (or downgrading) is required before pipeline transport or if power plants require more dynamic control of combustion. It will also influence technology choices, especially for distributed gas plants that are not integrated into a gas network. ICE plants generally have the highest tolerance to fuel variability.

Present status

In OECD countries in 2012, gas-fired generation provided 26% of total electricity generation, an increase of 48% compared with 2002 and 156% compared with 1990. Only VRE (primarily wind and solar) grew more quickly in percentage terms, but started from much lower bases. In the decade from 2002 to 2012, 340 gigawatts (GW) of gas-fired capacity was added in the OECD, compared to 530 GW during the preceding 50 years. Globally, between 1990 and 2011, gas-fired generation increased its share of total electricity generation in all regions, with the exception of non-OECD Europe and Eurasia where it remained stable (Figure 5.6). The following sections expand on some of the key developments during this period.

Growth of CCGT capacity, 1990-2005

The proportion of gas-fired generation in the electricity mixes of all regions has grown since 1990, most notably between 1990 and 2005. Numerous factors contributed to a rapid deployment during this period, including the development of high-efficiency CCGT plants: a decline in wholesale natural gas prices relative to coal; market liberalisation in some countries or higher interest rates that favoured lower-capital-intensity plants; and the repeal of prohibitions on the use of natural gas for electricity generation (Box 5.2).[5]

5 Such repeals occurred in the United States (Title II of the Powerplant and Industrial Fuel Use Act of 1978 was repealed in 1987) and the European Union (European Directive 75/404/EEC on the restriction of the use of natural gas in power stations, which prohibited the use of gas for new power plants in the absence of exceptional technical or economic circumstances, was revoked in 1991).

Box 5.2 The dash for natural gas in the United States and the impact of shale gas

Gas-fired generation capacity boomed in the United States between 1990 and 2010 with 312 GW added, including 41 GW of CCGTs and 20 GW of OCGTs added in 2002 alone (Platts, 2013). Over 20 years, gas-fired generation tripled.

Several factors coincided to deliver this rapid expansion. In 1987, the government repealed a prohibition on use of natural gas for electric generation. CCGT technology became mature around the same time, and market liberalisation made its lower capital costs attractive. Furthermore, gas-fired plants (e.g. OCGT) set the market price in peak demand periods, resulting in a strong correlation between natural gas and electricity prices that meant that gas-fired plants were effectively "self-hedged".

During this period prices for both coal and natural gas fell. Gas plants did not replace coal but supplied much of the increase in electricity demand, until demand began to decline around 2008. Some observers argue that too much capacity was built: as of 2011, capacity utilisation of US CCGT plants was approximately 46%, compared with 62% for non-lignite coal.

Expansion of tight gas production triggered a substantial price drop in Henry Hub (HH) natural gas prices to below USD 4 per million British thermal units (MBtu) in 2009-11, then dipping to below USD 3/MBtu for the first nine months of 2012 in nominal terms. CCGT generation costs fell and, as a result, the IEA estimates that around 20% of coal-fired generation was displaced by gas-fired generation between October 2011 and October 2012 compared with the previous 12 months. This fuel switching had a significant impact on US CO_2 emissions.

The rate of switching might have been higher – especially considering the overcapacity of CCGTs. There are a number of reasons why switching was limited: many US CCGTs were not efficient enough to beat generation costs of some higher-efficiency coal plants; 93% of coal contracts are long-term and often "take-or-pay", which makes it unattractive to substantially reduce these coal-fired plants' generation; while gas prices fell, coal prices are fixed and are also very low in some states; preference to run CCGTs as balancing capacity over coal-fired plants, which are relatively less flexible; regulated electricity markets put less pressure on minimising SRMC; and the lack of flexibility in natural gas supply contracts and the physical limitations of the gas pipeline network.

The future of US gas prices is uncertain. Recent natural gas prices have approached USD 4/MBtu and the expectation is that prices will stabilise at a higher level, at which the advantage of CCGTs over coal-fired plants will be lessened. Future gas prices will depend, among other things, on expansion of US LNG exports and US domestic market responses to this period of low pricing. In 2013 coal won back market share from natural gas for power generation, providing 39% of electricity generation (compared with 37% in 2012) against 27% from natural gas (compared with 30% in 2012), a balance that is expected to persist through 2015 (EIA, 2014); nevertheless, the expectation is that US gas-fired generation will continue to increase over the long term.

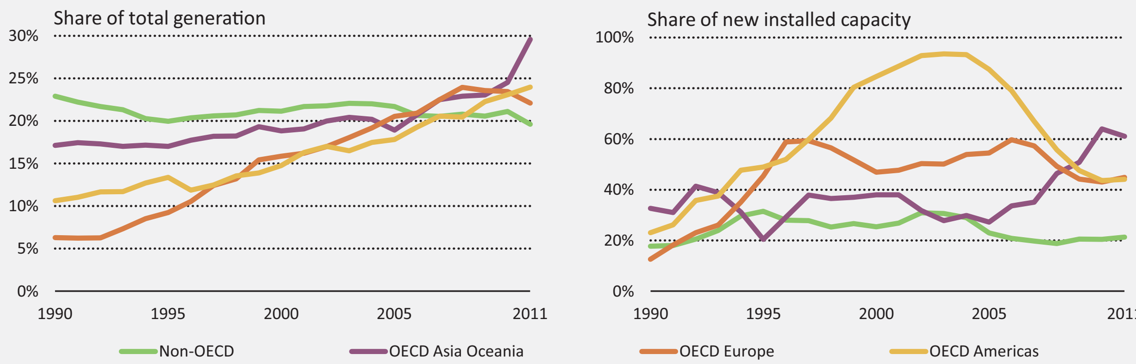
The role of coal-to-gas fuel switching in the United States in the near to medium term may be influenced just as strongly by environmental regulation of coal-fired plants as by natural gas prices.

Source: IEA, 2013a.

Divergent prices at a regional level since 2008

Regional natural gas prices have diverged in the last five years (Figure 5.7). Unlike in the United States, natural gas prices in Europe and Asia rose strongly following the global financial crisis in 2008. In Asia, heavy dependence on imports of LNG and increasing competition for LNG cargoes in the region have led to the highest natural gas prices in the world. In particular, the phaseout of nuclear reactors after the Fukushima Daiichi accident in Japan pushed up local natural gas demand and regional prices.

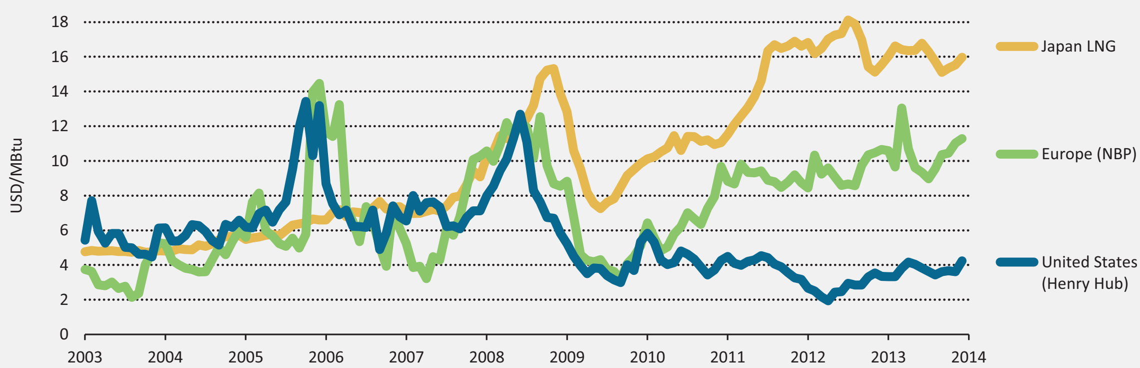
Figure 5.6 Natural gas-fired generation as a proportion of total generation and capacity additions (three-year moving average)



Sources: IEA analysis (left) and Platts (2013) (right).

Key point *Between 1990 and 2010, gas-fired generation displaced other forms of generation in all OECD regions, even though in recent years its share of total generation has declined somewhat in OECD Europe. This reflects construction rates that increased compared to other electricity generation sources over the period. Both generation and construction have maintained their shares in non-OECD regions.*

Figure 5.7 Natural gas pricing at different global trading hubs



Notes: NBP = UK National Balance Point. Nominal prices.
Source: IEA, 2013b.

Key point *Natural gas prices, which were largely convergent until 2010, are now diverging. US prices have dropped well below those in other regions due to the abundant production of shale natural gas.*

Following the global financial crisis in 2008, US gas prices fell to below USD 4/MBtu in nominal terms; they have remained around (or even below) this up to the end of 2013. These low prices are, in large part, due to booming US domestic production of tight gas. However, these low prices are not viewed as sustainable for producers: either exploration for and production of tight gas will slow, or demand will increase, possibly due to growth in LNG exports.

Replication of the US shale gas boom in other regions seems unlikely in the short to medium term. In China, several appraisal wells have been drilled, but production is not expected until 2020: the official target is 6 billion cubic metres (bcm) by 2015 and 100 bcm by 2020. The Indian government has approved shale gas exploration. In Europe, a handful of countries have banned hydraulic fracturing required for production of shale gas, while others have issued exploration licences. So far, test drilling in Europe has shown less favourable conditions than in the United States, and local opposition is strong in some places. Outside North America, production developments in the near term will focus mostly on coalbed methane and tight gas, not on shale gas.

Prices in Europe and Asia are expected to remain significantly above North America. In the near term, LNG markets are expected to be tight, and oil-indexed LNG contracts seem to be a persistent feature of the market. In the medium term, LNG trade is expected to grow dramatically. Nonetheless, even if HH-indexed (or other gas marker price) contracts were to become commonplace, the significant cost of liquefaction and transport means the gap between Asian and North American prices would not likely be smaller than USD 5/MBtu.

Other factors impacting gas-fired generation

Divergent natural gas prices are only one factor in the diverse outlooks for gas-fired generation in different regions. In Europe, rapid expansion of renewables, low coal prices, and relatively high gas prices have led to the mothballing of some CCGTs, a situation that would have been almost unthinkable several years previously (Box 5.3). In OECD Asia Oceania, growth in gas-fired generation since 2010 has had multiple drivers: gas-fired plants in Japan and South Korea were used to compensate for the shutdown of nuclear generation following the Fukushima Daiichi accident; in Australia, a combination of the impact of the carbon pricing mechanism, the mandatory renewable target and the increase in peak-load demand led an increase in gas-fired generation while coal-fired generation remained flat in 2012.

Box 5.3 A challenging environment for Europe's gas-fired plants

In OECD Europe, gas-fired generation declined by 181 TWh (21%) between 2010 and 2012 – and three factors have combined to worsen the immediate outlook. First, the financial crisis and energy efficiency measures have reduced the growth in electricity demand, leading to overcapacity. Second, energy policies have supported the sustained growth of renewable energy sources and their priority dispatch, which has led to thermal generation being pushed down the merit order, reducing its operating hours. Third, the relative prices of coal, natural gas and CO_2 have tipped in favour of coal, partly due to temporary increased exports of US coal that have depressed international coal market prices.

While European LNG imports are increasing, much of the natural gas is supplied through long-term take-or-pay contracts. The challenging outlook for the profitability of gas-fired plants has created some opportunities for the renegotiation of contracts. However, LNG import prices have not fallen in line with US internal natural gas prices due to US export constraints, the costs of liquefaction and delivery, and competition in global LNG markets.

In some European countries, relatively new gas-fired plants that were operating at less than 25% capacity factors were judged unprofitable and mothballed, even though European electricity systems rely on thermal (especially gas-fired) plants to ensure grid stability and reliability. Across Europe, 4.5 GW of gas-fired generation under 30 years old was mothballed or decommissioned between March 2012 and December 2013 and over 8 GW could face the same fate in 2014 (Caldecott and McDaniels, 2014). Some public intervention has prevented the closure of newly unprofitable plants. Germany's grid operator (Tennet GmbH) estimated that, even though it was barely operating 2 000 hours per year, the Irsching

CCGT was critical to balancing the system and financially compensated the plant owner to keep it on line.

Some older, coal-based capacity is expected to be decommissioned in the near term, and carbon prices may rise, which would improve the position of gas-fired plants in the merit order. Continued expansion of renewables and low carbon prices could, however, undermine the investment case for new CCGTs under existing market structures.

In non-OECD, coal-dependent countries, natural gas continues to gain importance, but shares in electricity generation remain low – e.g. 2% of total generation in China and 10% in India in 2011 (IEA, 2013c). For China, the increasing importance of natural gas is driven by the government's goal of doubling its share in the nation's primary energy consumption by 2015 as part of the 12th Five-Year Plan (2011 to 2015). Natural gas remains a substantial contributor to power generation in most of the Middle East (60%), Russia (50%) and Latin America (23%).

Enabling gas-fired generation technologies to displace coal

Recent history has shown significant expansion of gas-fired generation in several regions. At a global level, however, natural gas has not yet made major inroads into the displacement of coal-fired generation.[6] To follow the emissions reduction trajectory set by the 2DS, coal-to-natural gas switching will be a necessary feature of electricity generation in the near term. In the longer term, CCS on gas-fired (and coal-fired) plants will be needed to meet the ambitious goals of the 2DS. This section examines the technologies and conditions that could enable these developments.

Gas-fired generation technologies to enable fuel switching

In regions and situations where gas-fired plants are able to operate at full load, maximising efficiency provides a clear advantage. In the 2DS, this includes China and ASEAN countries, and also North America, the Middle East and countries of the Former Soviet Union, where base-load gas-fired generation continues to play a significant role. Higher efficiency lowers fuel costs, reduces CO_2 emissions and raises competitiveness. Customers drive manufacturers of gas-fired plants to optimise efficiency, as a function of cost, and significant R&D resources are currently directed towards improving efficiency across various gas-fired generation technologies.

As introduced previously (Table 1), there are multiple technologies that could support high-efficiency electricity generation from natural gas that are at different stages of development.

- **CCGT** is a mature technology, and only incremental full-load efficiency improvements are expected through 2050. Manufacturers aim to bring CCGT full-load efficiency towards 65% (LHV basis) by 2020 (from around 60% today) through materials improvements, and also through combustion and compression processes. The efficiency of a gas turbine may be

6 Gas-based electricity generation increased by 5% each year between 1990 and 2005 on average, and also by 5% between 2006 and 2011, moving from 15% to 22% of global electricity output. While some of this was at the expense of coal, coal-fired electricity generation itself grew by 3% each year between 1990 and 2005, in line with total demand growth, and grew at 5% per year between 2006 and 2011, overtaking total demand growth. Coal increased its share of global electricity output from 37% to 41% between 1990 and 2011.

improved by increasing its turbine inlet temperature. Using a 1 700°C-class gas turbine on a CCGT could raise its efficiency to around 63%. The Japanese government is supporting development of pilot plants with higher turbine inlet temperatures, which they aim to have in operation from 2016. A higher turbine inlet temperature, however, leads to increased nitrous oxide (NO_x) production and to a higher risk of high-temperature degradation of turbine components. Improved dry-low NO_x combustion systems, and advances in catalytic combustors with the potential to combat this increase in NO_x emissions, are being developed. Materials resistant to high temperature and corrosion, as well as cooling techniques and ceramic thermal barrier coatings, are also being developed to protect blades and other internal turbine components.

Water withdrawal and consumption of a CCGT with a wet cooling tower is around 780 L per MWh; dry cooling can reduce water use by two orders of magnitude, but adds a cost and efficiency penalty (Macknick et al., 2012).

- **Co-generation** technologies raise the useful energy output from natural gas by combining electricity generation with provision of heat. Typically, co-generation plants capture exhaust heat from the electricity generation cycle that would otherwise have been lost to the environment and use it to satisfy demand for heating or cooling at industrial sites and/or commercial and residential networks (e.g. district heating). Co-generation is technically and economically attractive in specific cases where there is local demand for both heat and power (Box 5.4). The overall system efficiency of electricity and heat provision is raised when other heating and cooling supplies, that use dedicated fuel inputs, are substituted. Waste heat can be recovered from most gas-fired generation technologies, including OCGTs, CCGTs and ICEs. These are technically mature but the potential for widespread integration of co-generation plants in smart electricity and heating networks remains unexploited. Within the 2DS time frame, medium-sized and micro co-generation, including turbines, fuel cells or engines, may be effective and more decentralised options.
- **Humid air turbine** systems are at an early stage of development, with small-scale pilots tested. The regenerative gas turbine cycle uses humid air as the working fluid and could achieve, in simple cycle operation, the same electrical output and efficiency as a combined-cycle system. A major technical challenge, however, is to develop the mechanism to inject moisture into the compressor. Some concepts add water at the compressor exit, which will result in higher water content and thus higher efficiency (e.g. evaporative gas turbine cycles) (Thern, Lindquist and Torisson, 2007). The moisture injection system could be simplified using an advanced water-atomising cooling system; this technology is anticipated to enter practical application as the advanced humid air turbine and a 40 MW pilot facility has been finalised in Japan (Hitachi, 2013).

  A humid air turbine may offer flexibility advantages. Particular features of the system are its simple plant configuration (potentially translating into lower capital costs) and its ease of operation and control, combined with lower NO_x emissions from the combustor. The use of humidified air makes the stable minimum load lower than that of a CCGT. Having no steam turbine, the start-up time is shorter and the ramp rate higher than for a CCGT. However, the integration of a humid air turbine in a combined cycle could raise the efficiency beyond that of a conventional CCGT.

  Humid air turbines may face siting challenges due to their potentially high water consumption relative to alternative gas-fired generating technologies.

Box 5.4 Co-generation

Co-generation technologies enable the simultaneous generation of heat and electricity. This increases the overall energy efficiency of fuel use in comparison with conventional thermal generation technologies for electricity or heat only. This is achieved by partially recovering heat produced during electricity generation to make it available for end-use applications.

Four favourable preconditions are generally required to maximise the benefits of co-generation:

1. Simultaneous demand for electricity and heat. Typical heat-to-power ratio ranges are 0.5 to 1.5 for ICEs, 1 to 10 for OCGTs and 3 to 20 for gas-fired steam cycles. Heating needs from processes operating at temperatures below 400°C can technically be supplied by co-generation technologies.

2. Heat demand for industrial processes or district heating needs to be local as transporting heat over long distances is ineffective.

3. Access to the electricity grid, to increase asset utilisation by feeding excess electricity to the grid (e.g. when heat is not required or if capacity is in excess of local electricity requirements).

4. Revenues that provide a return on the greater capital investments compared to electricity generation alone. Plants can choose to follow heat demand, limiting control over electricity sales, or maximise electricity generation during periods when electricity prices are more attractive (if the steam condenser is adequately sized, electricity-only generation is possible). The interplay between contracts and revenues for heat and electricity generation can in some situations be complex and needs to be well understood.

Maximising the economic benefits and emission reductions from co-generation in the 2DS is likely to require smart solutions for managing heat and electricity demand and supply. In electricity markets that reward greater flexibility and availability of spinning reserves, or have high penetrations of VRE, gas-fired plants could benefit from heating and cooling demand from thermal networks (e.g. via thermal storage) when demand for electricity is low. Equally, integration with heating and cooling networks could provide additional demand for electricity from the grid via heat pumps in order to utilise VRE generation and balance any reduction in heat output from co-generation plants. Additional gas-fired co-generation plants could thus offer emissions reductions even if their CO_2 intensity on an electricity-only basis is above the grid average.

Co-generation represents a considerable share of electricity generation in some countries (e.g. over 60% in Denmark) but only 9% of global electricity generation, and growth has been stagnant over the last decade. A 2012 United States Executive Order aims to achieve 40 GW of industrial co-generation by 2020, China has indicated that it will reach 50 GW of gas-fired co-generation by 2020 Japan's roadmap targets a five-fold increase in co-generation based electricity by 2030. These initiatives support the need for continued R&D efforts for enhanced energy efficiency and further reductions in costs.

Source: IEA, 2014a.

- **Integrated solar combined-cycle (ISCC)** integrates a CCGT plant with concentrating solar power (CSP). As with other thermal generation technologies, CSP works by generating steam that drives a turbine; when combined with a CCGT plant, this steam can be used to reduce the amount natural gas required for a unit of electricity. Combining these two technologies can extend the operating hours possible from a CSP plant alone, primarily by generating during periods of lower solar radiation and after dark, and reduce the efficiency losses associated with daily cycling of the steam turbine that would occur in a traditional CSP plant. Efficiencies are also gained through sharing of plant equipment, infrastructure and grid access. An ISCC plant could also be designed so that the solar energy could be used to increase the overall output of the combined system. However, in this case, the steam turbine will often operate at part load and must be designed to minimise efficiency losses. The principle economic benefits of an ISCC are reduced LCOE for solar power relative to that from a CSP alone and lower marginal costs for a unit of electricity than for a CCGT. ISCC plants are operating today or in development in Algeria, Egypt, India, Mexico, Morocco, Iran, Italy, Tunisia and the United States – i.e. regions with favourable insolation profiles. Plant capacities range from a few megawatts to more than 500 MW. For comparison with other gas-fired plants efficiencies are estimated to lie between 61% and 70% (LHV) on the basis of natural gas input per MWh generated (US DOE, 2011).

- **Oxyfuel combustion** would eliminate the need for costly CO_2 separation processes when CO_2 capture is desired. In oxyfuel-based cycles, gas is combusted in an atmosphere of oxygen and recycled flue gases, and the working fluid is generally a mixture of CO_2 and water. While there have been many cycles proposed, only a few have reached the pilot stage of development, most notably the Clean Energy Systems (CES) Water Cycle and the Allam Cycle (Aldous et al., 2013). In the CES Water Cycle, the working fluid is predominantly (i.e. 80%) water, while in the Allam Cycle, the working fluid is predominantly (i.e. 80%) CO_2. In both cycles, the working fluid is expanded across one or more turbines – with or without reheat – and a portion of the produced water or CO_2 are recycled. Both cycles share the benefits of having being net producers of water, and show promise of efficiencies comparable to current CCGTs (without CO_2 capture) at similar capital costs. The main drawback of these and other oxyfuel cycles is that they require large amounts of relatively high purity oxygen and advances in materials and turbine design to achieve promised efficiencies.

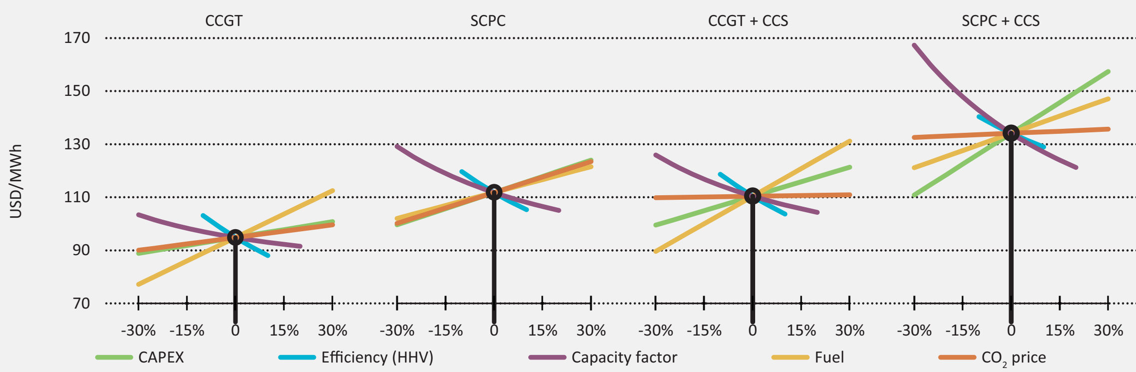
- **SOFCs** are also at an early stage of development. Thanks to their high operating temperatures, SOFCs are potential candidates for pairing with gas turbines in a hybrid configuration. A fuel cell hybrid CCGT could reach an efficiency of 70% (LHV) when coupled with turbines of 800 MW to 1 200 MW capacity by "cascading" the energy potential of natural gas from an SOFC to a CCGT (MHI, 2011). At present, the process control of this system presents a major challenge and, in heavy-duty use, the operation of the SOFC at high pressure needs to be confirmed.

Economics of fuel switching from coal to gas

Thermal electricity generation technologies have traditionally been compared on an LCOE basis. For base-load electricity generation, efficiency is a key factor in determining LCOE (Figure 5.8). Full-load efficiency for CCGTs has improved from 55% in 1990 to over 60% in 2013 (on an LHV basis) (IEA, 2013e). Technology improvements will continue to play a key role, just as the development of the efficient CCGTs allowed gas-fired plants to compete with coal for base-load generation in the 1990s. The average efficiency of gas-fired generation (including OCGTs and CCGTs) in the OECD is 49% compared with 40% in non-OECD in 2011. While full-load efficiency can be an important metric for the purposes of technology comparisons, the relevant efficiency metric for more representative LCOE calculations is the average efficiency over the life of the plant.

Over the 2DS period, assuming that a plant will operate at base load over its operational life may not be a good assumption. Base-load thermal generation plants are typically operated 70% to 80% of the time. However, CCGTs are often not used as base load, which is reflected in their historically lower capacity factors. For example, in the United States in 2011, during a period of relatively low natural gas prices, US CCGTs had average capacity factors of 46%. In the 2DS, average capacity factors decline in most regions; for example, full-load hours fall well below 2 000 hours for gas-fired plants without CCS in the United States. Reducing the capacity factor of a CCGT by 30% can increase LCOE by 13% (Figure 5.8). Lower capacity factors may also be correlated with more frequent on-off cycling of the plant, which also has associated fuel and maintenance costs (see section: Impact of cycling on operation and maintenance, and on plant lifetime).

Figure 5.8 LCOE sensitivity to changes in key factors for CCGTs and SCPCs with and without CCS



Notes: SCPC = supercritical pulverized coal. Natural gas = USD 10/MBtu, hard coal price = USD 4/MBtu, carbon price = USD 46/tCO_2 (consistent with 2DS in 2020). Capacity factor of 75% for all technologies with 2020 *ETP* cost and performance assumptions. Unless otherwise stated, all costs and prices are in real 2012 USD, i.e. excluding inflation.

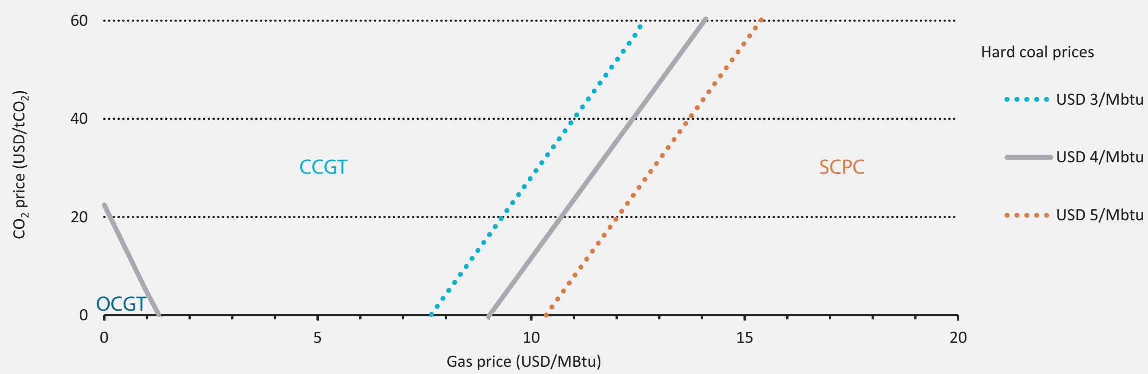
Key point *The LCOE of electricity from a CCGT plant is less sensitive to changes in capital cost, capacity factors, and carbon prices than a SCPC electricity plant; however, it is more sensitive to changes in fuel prices.*

Uncertainty around capacity factors will increase risk for investors in gas-fired plants, and investors may demand higher risk premiums. Lowering capital costs could help investments in gas-fired generation to remain attractive, all other things being equal. However, in comparison to a coal-fired plant, the LCOE of a CCGT is less sensitive to changes in capital cost and carbon prices, and more sensitive to changes in fuel prices (Figure 5.8). This is due to the much lower overnight cost (i.e. USD per kW of installed capacity) of CCGTs relative to coal-fired plants, the lower carbon content of natural gas per unit of energy and the higher price of natural gas relative to coal.

Because fuel prices vary widely between regions and across time (e.g. Figure 5.7), the lowest LCOE option differs. For gas prices around USD 9/MBtu and below, the LCOE from gas-fired power generation is lower than that from an SCPC plant (Figure 5.9). A USD 1 change in coal prices from the baseline of USD 4/MBtu shown in Figure 5.9 will lower or raise the breakeven gas price by USD 1.4/MBtu and the breakeven LCOE by USD 8/MWh. At the same time, increasing carbon prices will expand the range of natural gas prices for which CCGTs hold an advantage over coal-fired plants (Figure 5.9). For example, at recent European gas prices of USD 10/MBtu to USD 11/MBtu, a long-term carbon price of USD 10/tCO_2 to USD 30/tCO_2 would be sufficient to shift investment towards gas-fired power generation.

This discussion has focused on LCOE, which is a metric that can be used to inform investment decisions and is based on long-term expectations of coal and gas prices. However, relatively low gas prices can easily drive *short-term* changes in the merit order, leading to higher utilisation of existing gas-fired generation capacity at the expense of coal. In the United States, this has been observed in recent years (Box 5.2). Investors would need to expect that natural gas prices would remain low relative to coal prices over the long term to prefer gas- over coal-fired plants. In the long term, the relatively vast coal and natural gas reserves result in very flat supply cost curves with natural gas prices under USD 11/MBtu and coal prices below USD 5/MBtu for 90% of all technically recoverable reserves (IEA, 2013f). Interestingly,

Figure 5.9 Lowest LCOE generating technologies as a function of natural gas and carbon prices, at three different coal prices



Notes: the comparison on an LCOE basis does not necessarily reflect the competitiveness of existing plants, which compete on the basis of SRMC. Capacity factor of 75% for all technologies with 2020 2DS US cost and performance assumptions.

Key point *For base-load operation, CCGT plants generate electricity at lower costs than SCPC plants at gas prices around or below USD 9/MBtu (depending on coal prices); as carbon prices increase, the range of natural gas prices over which CCGT plants are viable grows.*

given current technologies and these long-term fuel prices, LCOEs for gas- and coal-fired generation would be approximately equal in the absence of carbon prices (Figure 5.9).

It is important to note, however, that the choice of generating technology will not be solely driven by the cost and performance of generating technologies and relative fuel prices: they will also be influenced by a host of other factors.

Other factors that will influence fuel switching from coal to gas

The emissions rate advantage of gas-fired compared with coal-fired plants will translate in fuel switching only if several non-technical factors combine to incentivise operation of and investments in gas-fired plants. Four of these factors are:

- **Regulation or pricing of pollutants.** Gas-fired generation has lower associated emissions rates of most pollutants, including CO_2, in comparison with coal-fired generation. Thus, any regulation or pricing of pollutants will likely favour gas-fired generation, particularly in liberalised markets. However, any CO_2 emissions reduction policy will lead to fuel switching only if the combination of the CO_2 penalty for coal and the relative fuel prices results in cheaper marginal generation costs for gas-fired generation.

  Short-term price differentials can alter capacity utilisation, but as long as coal capacity remains on the system, a reversal in carbon price could prompt a backwards switch. Recent experience in OECD countries shows that stable long-term policies are needed to deliver enduring emissions reductions (IEA, 2013g). Imposing legislation or regulation, e.g. bringing in emissions performance standards, carbon taxes or carbon price floors, is likely to be perceived as having greater permanence and being a safer bet for investment decisions.

  CO_2 emissions can also be regulated through performance standards, which have been proposed or implemented for new thermal electricity plants in countries including Canada, the United Kingdom and the United States. These have generally been set at levels that prevent the construction of new coal plants without CCS, and, given technology costs and fuel prices in these countries, are driving fuel switching.

Gas-fired generation requires fewer control measures than coal for local air pollutants, such as NO_x, particulate matter and sulphur dioxide (SO_2). These pollutants are of particular concern due to their health impacts in urban areas. For example, China is investing to expand access to gas, including natural gas imports and production of synthetic natural gas from coal in remote northern provinces, to support coal-to-gas fuel switching close to urban centres. In the particular case of synthetic gas from coal without CCS, however, CO_2 emissions would increase, as synthetic gas production is a more energy-intensive process compared with direct use of coal.

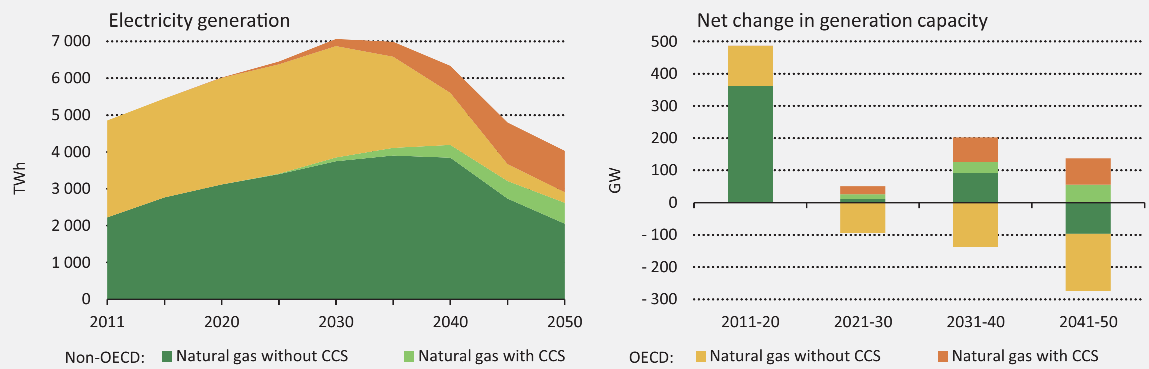
- **Planning for water constraints.** Per unit of electricity generated, gas-fired plants have lower water withdrawal than coal (by as much as 50%) and nuclear (by as much as 70%) for plants with cooling towers (Mackinick et al., 2012). Life cycle water requirements for electricity from synthetic gases based on coal or even CO_2 are generally significantly higher than for natural gas. Water constraints are a regional issue, however, and will not influence electricity capacity planning in all countries or regions.
- **Liberalisation of electricity markets.** CCGTs have been perceived as a relatively low-risk investment that yields a high rate of return in liberalised markets. CCGTs are quick and low cost to build: at USD 1 100/kW, specific investment costs for CCGTs are less than half that of coal plants (USD 2 000/kW to USD 2 600/kW depending on technology). Private investors are attracted to shorter payback periods and the prospect that CCGT flexibility creates the opportunity to follow peak demand and sell electricity when prices are high (Roques, 2007). In addition, new natural gas plants are typically less affected by the siting and licensing difficulties often faced by proposed coal, nuclear and wind plants.
- **Local fuel supply considerations.** Despite its high CO_2 emissions, the abundance of coal means that use of coal can have benefits in terms of security of supply. While energy security is a much more complex notion than simply the relative volumes of fossil fuels in place, coal remains attractive in many parts of the world where other fuels are not readily available, where there is a local mining infrastructure already in place, where the termination of coal mining would entail social costs and consequences, or where fuel imports of other energy sources represent a perceived geopolitical risk. In the United States, the extent of coal-to-gas fuel switching has been limited by the favourable economics of coal-fired power plants that are vertically integrated with local mines, inflexible long-term coal contracts or the limited extent or capacity of natural gas infrastructure. Many coal-fired power generators pay prices much lower than those in Figure 5.9. These fuel supply issues could prove a hindrance to fuel switching.

Fuel switching is not a universal opportunity, even where fuel prices are attractive and climate policy is supportive. Countries lacking an extensive natural gas supply infrastructure face a substantial challenge as the up-front investment needed for networks and terminals counters the eventual benefits. On the other hand, there are additional factors that could incentivise the switching, including the availability of indigenous natural gas resources, the benefits of diversifying the fuel mix, lower investment requirements, shorter lead times for plant construction and a small land footprint.

Achieving even lower emissions from gas-fired generation through CCS

CCGT plants built in this decade may not reach the end of their technical lifetimes without either reducing their operating hours due to CO_2 emissions limits or adding the capacity to capture and store most of the CO_2 they produce. In the 2DS, nearly half of the electricity generated from natural gas would be from CCS-equipped plants by 2050 (Figure 5.10). While the installed capacity of such plants grows after 2020, that of unabated gas-fired plants falls. In non-OECD countries the replacement rate approximately balances the retirement rate, and total installed gas-fired capacity remains almost constant after 2030, despite declining generation output.

Figure 5.10 **Gas-fired generation and capacity with and without CCS in the 2DS**



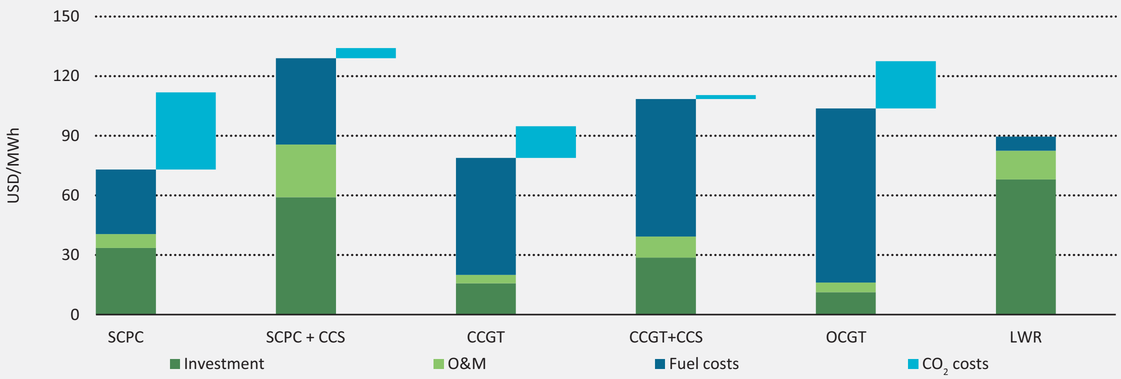
Key point *In the 2DS, generation from gas-fired plants peaks before 2020; by 2050, nearly half of gas-fired generation is from plants equipped with CCS.*

Gas-fired power generation using CCS has generally received less attention from analysts and policy makers than the use of CCS with coal-fired generation. Because coal-fired generation is more CO_2-intensive per megawatt hour than gas, the emissions avoided are larger for the application of CCS to coal-fired generation assuming that the relevant alternative is an unabated coal plant. Furthermore, it also costs less to capture and store a tonne of CO_2 from coal-fired generation than from gas-fired generation: CO_2 concentrations in flue gas are higher from a coal-fired plant (13% to 14%) than from a CCGT (3% to 4%), which means that the capture system for a CCGT needs to process more flue gas to capture each tonne of CO_2. Thus, for a coal-fired plant, the cost of avoiding the emission of a tonne of CO_2 is lower. Consequently, if coal is to continue to be used in power generation, CCS for coal-fired generation appears sensible.

However, it is the cost of electricity that is the primary determinant of investment decisions in electricity generation capacity, not the cost of CO_2 avoided *per se*. This does not only depend on how much it costs to capture and store each tonne of CO_2, but also how many tonnes need to be captured per megawatt hour. On this basis, gas-fired generation can appear very competitive.

Per megawatt hour, gas-fired plants produce over 50% less CO_2 than coal plants. Thus, to generate a megawatt hour of low-carbon power from natural gas with CCS, only half as much CO_2 needs to be captured compared with coal, and per tonne capture costs are generally not twice as high – although this depends on fuel prices. The LCOE of low-carbon gas-fired generation is not necessarily higher than that from coal-fired generation (IEA, 2011a). Furthermore, depending on fuel prices, gas-fired power with CCS compares well with other sources of low-carbon dispatchable power generation (Figure 5.11).

Figure 5.11 **LCOE of dispatchable power generation technologies in the 2DS, 2020**



Notes: LWR = light water nuclear reactor. Technology costs are representative 2DS costs for the United States in 2020. Total costs of SCPC coal + CCS are comparable to those of integrated gasification combined-cycle (IGCC) coal + CCS and oxyfuel coal + CCS. CO_2 = USD 46/tCO_2, hard coal = USD 4/MBtu; gas = USD 10/MBtu; load factor = 75%.

Key point *CCGT with or without CCS can be more attractive than coal-fired generation at reasonable coal and gas price assumptions, regardless of CO_2 pricing. At a carbon price of around USD 100/tCO_2, CCGT with CCS has a lower LCOE than CCGT and, is less costly than SCPC with CCS.*

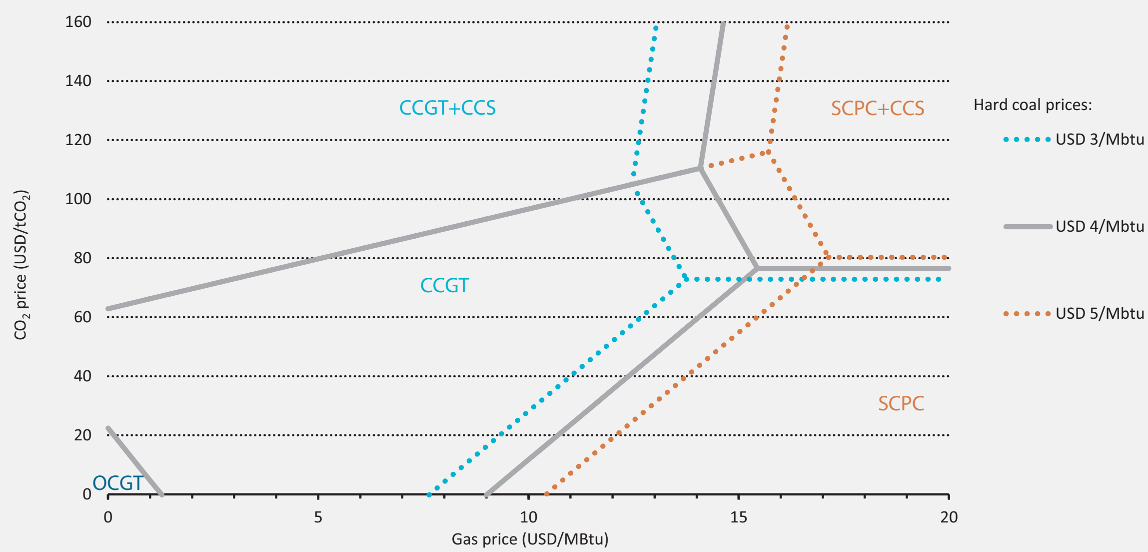
As with coal-to-gas fuel switching, the choice of technology is determined by relative fuel and CO_2 costs. At carbon prices above about USD 100/tCO_2 both gas- and coal-fired generation with CCS become attractive on an LCOE basis, but their relative appeal depends heavily on fuel prices (Figure 5.12). At natural gas prices below USD 7.3/MBtu, gas-fired generation is a lower cost option than SCPC generation (with or without CCS) regardless of the carbon price, and even if coal is priced as low as USD 3/MBtu.

At natural gas prices between USD 10/MBtu and USD 14/MBtu – typical of recent prices in Europe – the fuel choice depends on the carbon price: below 60 USD/tCO_2, both CCGT and SCPC are viable; at carbon prices between USD 60/tCO_2 and USD 110/tCO_2 CCGT is the lowest cost option; and at prices above 110 t/CO_2, CCGT with CCS is the lowest cost option. Only at gas prices above USD 15.5/MBtu does coal become a better option across the entire range of carbon prices in the 2DS through 2050. Lower coal prices shrink the price ranges at which gas-fired generation is preferred, but only slightly reduce the carbon price at which SCPC+CCS would outcompete CCGT+CCS. In the 2DS, carbon prices reach around USD 90/tCO_2 by 2030, making investments in CCGTs a much more attractive proposition than SCPCs in many regions.

LCOE figures indicate that new gas-fired generation with CCS should be at least as economic as coal-fired generation with CCS in many regions, and it is therefore sensible to develop and deploy gas-fired generation in parallel.[7] In addition, CCGT with CCS also has a lower capital

7 A qualification to this statement relates to the retrofitting of existing coal or gas plants with CCS, which may be important in some regions. The investment driver for retrofitting of depreciated assets is largely related to SRMC, rather than LCOE. In this context, retrofitting can reduce SRMC relative to competitor plants that have a higher CO_2 price burden in liberalised markets with carbon pricing. Where retrofitting takes place, the greater "bang for the buck" in climate terms will be CCS on coal if both the coal and gas plants would otherwise continue to supply the same amount of electricity to the grid without CCS.

Figure 5.12 **Lowest LCOE generating technologies, including CCS, as a function of natural gas and carbon prices, at three different coal prices**



Notes: the comparison on an LCOE basis does not necessarily reflect the competitiveness of existing plants, which compete on the basis of SRMC. Capacity factor of 75% for all technologies with 2020 2DS United States cost and performance assumptions.

Key point *At typical recent North American gas prices (i.e. around USD 4/MBtu), CCGT with CCS has a lower LCOE than both CCGT and SCPC if carbon prices are above USD 80/tCO_2; for European prices (i.e. around USD 10/MBtu), carbon prices need to approach USD 100/tCO_2 to drive adoption of CCS.*

cost than a coal-fired plant with CCS, making it potentially more attractive in liberalised electricity markets. Furthermore, coal-fired generation with CCS faces a higher exposure to the carbon price per megawatt than gas-fired generation with CCS in that, even after the capture process, both plant types still emit approximately 10% of the combustion CO_2; the absolute amount of CO_2 emitted per megawatt would be over 50% less from gas-fired generation with CCS than from coal-fired generation with CCS.

Enabling this deployment of CCS remains a challenge, however. Avoiding at least 85% of the emissions from a CCGT is technically possible and proven, but there is a dearth of plants that currently operate CCS on gas-fired plants. The largest operating CO_2 capture system on a CCGT is the 25 MW (0.05 million tonnes of CO_2 [MtCO_2] per year) Mongstad plant in Norway. For comparison, the largest coal plant with CCS under construction is expected to capture 3.5 MtCO_2 per year. None of the 33 large-scale projects at advanced stages of development in 2013 were on gas-fired generation (GCCSI, 2013).[8]

Existing projects use the most mature CO_2 capture method – flue gas scrubbing using a chemical solvent and then using steam taken from the generation cycle to strip CO_2 from the

8 Thirty-three projects are in the operate, execute or define stages as defined by the GCCSI, none of which are gas-fired. However, there are three projects in earlier stages of development that may demonstrate CCS on gas-fired plants. If UK government support is secured, the Peterhead gas plant in Scotland could be fitted with 340 MW (1 MtCO_2 per year) of integrated CCS by 2019.

solvent. Capturing CO_2 from a CCGT would reduce the net efficiency of electricity generation from around 57% to 48%. About 60% of this energy penalty is related to the stripping of CO_2 from the solvent using steam that is taken from the power generation cycle. New solvents and better heat integration will deliver lower energy requirements. Other technologies under development that may come into use for CCS on gas-fired generation during the period to 2050 include oxy-firing, chemical looping, and reforming of natural gas into hydrogen and CO_2 before electricity generation (pre-combustion) (IEA, 2013h).

Projects that aim to demonstrate CCS on gas-fired generation have been disadvantaged in government demonstration funding programmes, which have tended to favour projects with lowest cost per tonne CO_2 stored.[9] Yet, as illustrated above, when considering the costs of securing low-carbon electricity, there is no reason to favour coal- over gas-fired generation. In fact, seeking to store the most CO_2 for the lowest price is unlikely to be an overriding objective for governments unless the focus is strictly on retrofitting existing fossil fuel plants that would otherwise be retired. The deployment of CCS will rather depend on how climate regulation enables companies to collect revenue from products that are made and sold from CCS-equipped facilities. In the electricity sector, firms will seek to minimise the costs of electricity generation, and gas-fired generation with CCS may provide lower cost electricity, lower capital intensity and the possibility of smaller unit sizes than coal with CCS.

Finally, while CCS on CCGTs may have lower capital costs compared to coal plants with CCS, the addition of CCS does nevertheless increase the capital cost of a CCGT. As discussed later in this chapter, capital costs are likely to become a key determinant of the ability of gas-fired generation to compete in a low-carbon world. If CCS-equipped electricity plants need to operate at high capacity factors to recover their capital costs, their contribution to an electricity system with high penetration of variable renewables may be compromised. Unless the cost of capital for gas-fired plants with CCS can be reduced and the full CCS value chain can be operated flexibly, CCGTs with CCS are likely to have the greatest role to play in regions where they can operate under base-load conditions. The research agenda for CCS on gas-fired generation should focus on reducing CO_2 capture costs and, in particular capital requirements, while policy will be required to support the flexible operation of CO_2 capture plants.[10]

Flexible gas-fired generation to support VRE generation

Most existing CCGT plants were built to operate for more than 2 000 full-load hours per year as mid-merit or base-load plants. Low-capital cost, relatively inefficient thermal generation, such as OCGTs, are generally used to meet demand fluctuations and are referred to as "peaking plants". The increasing penetration of VRE in some countries has begun to change this traditional generation split. In the 2DS, VRE generating capacity increases year-on-year through 2050 and becomes more widely distributed around the world. The electrical output from VRE generation is not constant due to the inherent variability of renewable resources (e.g. wind speed and solar irradiation) or certain because wind and solar forecasts are subject to error. Electricity supply and demand must balance at every instant and, therefore, electricity systems will increasingly require technologies that can provide electrical energy and other ancillary services that can respond to changes in VRE generation. Thermal generators will be increasingly called upon to operate more flexibly.

9 The European Commission's NER 300 competition is one example.
10 More information on research and policy priorities for CCS can be found in the 2013 IEA Technology Roadmap: Carbon Capture and Storage (IEA, 2013h).

In this section, the potential of gas-fired generation to ease the integration of VRE by contributing to increased flexibility of the electricity system is discussed. Adapting the thermal generating fleet to the requirements of flexible electricity systems will contribute to the successful transition to the low-carbon electricity system described in the 2DS. A low-carbon electricity system, i.e. one that has average emissions rates of less than 100 kilogrammes of CO_2 (kgCO_2) per MWh, is a critical component of the 2DS and is achieved through adding renewable generation, balanced by dispatchable power with the lowest possible emissions. In terms of gas-fired generation technologies, incumbent OCGT and CCGT plants may be able to adapt to this new role, but could also be challenged by other mature technologies (e.g. ICEs) and new developing technologies (e.g. humid air turbines) that do not yet play a substantial role in the sector.

What is flexibility?

Flexibility describes the extent to which an electricity system can adapt the pattern of electricity generation and consumption in order to balance supply and demand. Mismatches between supply and demand affect system voltage and frequency, both of which need to be maintained within a narrow target band to ensure reliable electricity supply.

Electricity system flexibility has four main sources (IEA, 2011b): generation (dispatchable plant); electricity storage; interconnection with other electrical systems; and demand response, which aims to either reduce or increase the load. Curtailment of VRE generation can also help to ensure system stability if supply strongly exceeds demand, but to maximise CO_2 reductions from VRE generation it is likely to remain an exceptional measure.

Generation flexibility refers to the extent to which generators across a given system can respond to the variability (expected or otherwise) in the residual load[11] on a timescale of a few minutes to several hours. Electricity demand is inherently variable, cannot be fully predicted and can occasionally exhibit large, rapid fluctuations. Operators have traditionally relied on dispatchable plants (including reservoir hydro plants[12] and gas- and coal-fired peaking plants[13]) to match supply to demand at every instant. Generation flexibility has traditionally been the dominant source of system flexibility. In the short to medium term, generation flexibility is likely to remain the critical resource to deliver flexibility: it is less limited in capacity and geography compared with interconnection, and more mature than demand response and storage.

While electricity systems have always required flexibility to respond to unforeseen outages, increasing amounts of VRE bring additional complexity to electricity systems. Wind and solar generation increase the variability and reduce the predictability of supply to different extents; while solar is in general more predictable, when it goes offline in the evening the grid balancing needs can be very abrupt. Benefiting from free renewable resources, wind and solar photovoltaic (PV) generation plants have close to zero marginal costs and are dispatched first, pushing out of mid-merit the thermal generators that have higher SRMC due to fuel costs (IEA, 2014). To favour its deployment, some countries (e.g. Germany) have even established obligations to dispatch VRE ahead of other generation.

The need for flexibility can be somewhat mitigated by improving forecasting of demand and supply. Forecasting output of VRE will continue to improve with better measurement-based data, improved forecast methodologies and increased computational power of weather

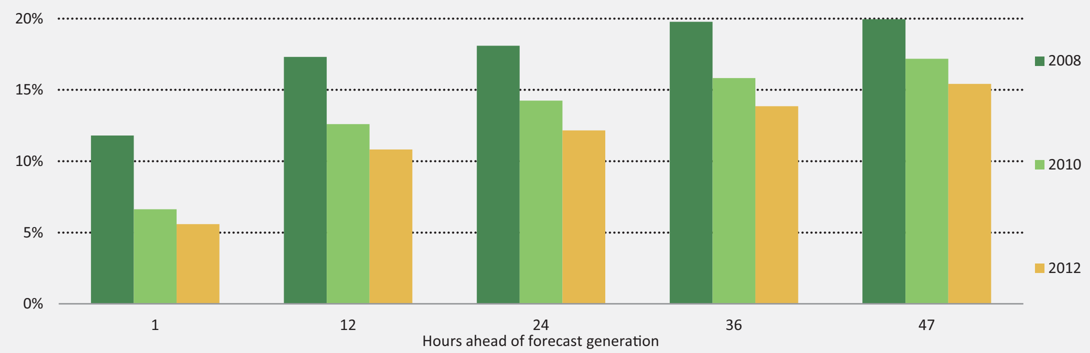
11 Residual load is used here to denote the level of electricity demand that must be met by dispatchable generation technologies. It is the load on the system net of generation from VRE.

12 See Chapter 7.

13 Thermal generation that was not designed to operate as peaking capacity, including many CCGTs, coal-fired plants, CCS-equipped power plants and nuclear plants, can technically provide some flexibility, but due to the higher capital costs, they generally need to be operated more hours than those for which peaking plants are required.

simulation models (Figure 5.13). As forecasting improves, the requirements placed on dispatchable generation to respond at short notice will be moderated. Electricity systems will nevertheless continue to require flexibility to cope with unforeseen outages and maintenance of voltage and frequency (ancillary services).

Figure 5.13 **Mean absolute forecast error as a proportion of average actual wind generation in Spain for a range of forecast lead times**



Sources: IEA, 2013i; Red Electrica, 2013.

Key point *Day-ahead errors in Spain have been reduced by one-third since 2008.*

Improving the technical ability of gas-fired generation to provide flexibility

The operational demands placed on a plant determine how frequently it starts up, ramps up or down, and shuts down. These patterns of operation are commonly referred to as cycles. All generating plants are cycled, but the nature of these cycles depends on their position in the merit order and the dynamics of the overall power system (i.e. residual load profile, topology of the transmission system and characteristics of other generators). The ability of a plant to cycle is determined by its technical characteristics and its operator's willingness to cycle, which will depend on the revenues that the plant can capture by providing electricity and ancillary services. However, continuous changes in output levels versus binary changes in plant operation (i.e. start-up and shutdown) impose different stresses on a plant and therefore costs.

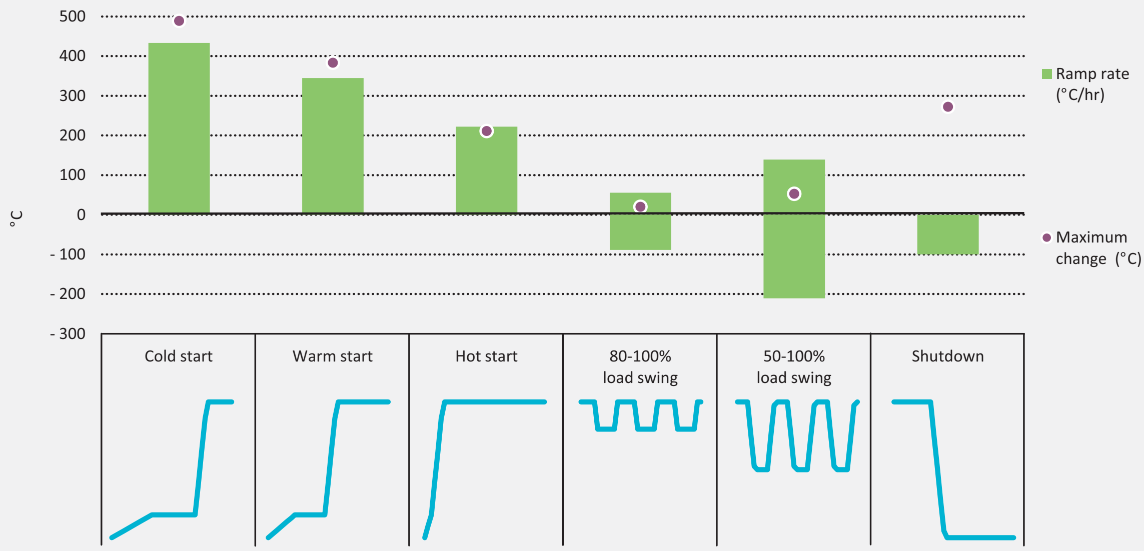
Impact of cycling on operation and maintenance, and on plant lifetime

This growing need for more cyclic operation was not foreseen when many existing CCGT plants were designed and installed. It is now clear that such operation reduces material lifetime, which increases outage rate and fault risk and, consequently, drives up operating costs. The type of cycling (load-following, hot start, warm start or cold start) influences the temperature variations experienced by materials and hence the extent of damage incurred. The extremes of going from cold start to operation are the most damaging cycles for a plant (Figure 5.14).

How is the flexibility of generating technologies measured?

While full-load efficiency has traditionally been used as the main performance metric for assessing new gas-fired plants, with the exception of peaking plants, other attributes are becoming increasingly important for all gas-fired generation in systems with high penetrations of VRE. In the 2000s, all major original equipment manufacturers competed to

Figure 5.14 Temperature changes as an indicator of damage for different CCGT operating conditions



Sources: NREL, 2012a; Lefton, Besuner and Grimsrud, 1997; IEA analysis.

Key point *Cold start is the most damaging operating condition due to large temperature changes imposed on equipment and materials.*

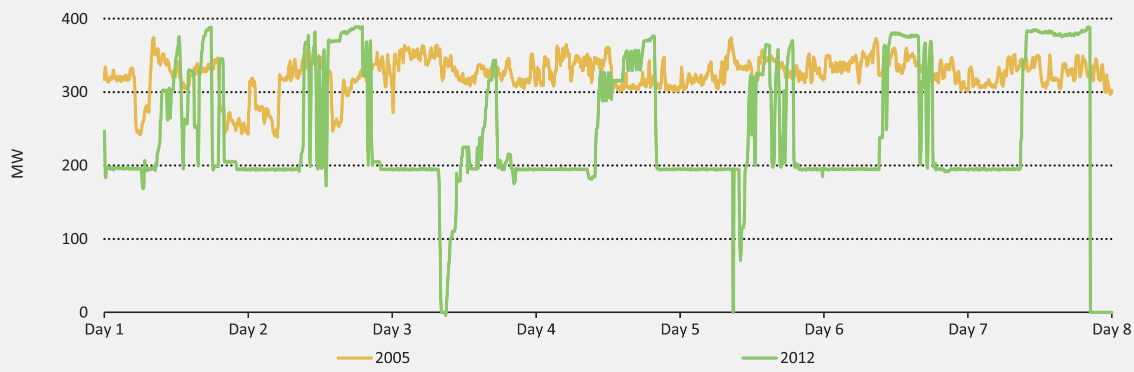
boost the base-load efficiency for CCGTs to a record 61% (on an LHV basis). Since then, the focus of R&D has shifted. As some CCGTs are already not operating consistently at full load (Figure 5.15) and need to provide high efficiency over a variety of operating conditions or load cycles, the full-cycle efficiency of the thermal plant over each year is probably a more important indicator than its base-load (i.e. peak) efficiency.

Load cycle performance is difficult to compare across different manufacturers, in part because no uniform load test cycle for gas turbines exists. While power plant developers are highly informed and specialised consumers, having manufacturers report efficiency based on more realistic operational cycles could be helpful to policy makers and technologists.

The other factors that are of growing importance to all gas-fired generation and have a strong impact on generation flexibility are part-load efficiency, start-up time, ramping capability and turndown ratio. All are commonly used metrics in the industry, but they need to be considered more widely because they determine the ability of the thermal generation fleet to integrate VRE and are, thus, important to R&D policy.

Part-load efficiency improvements reduce the SRMC for electricity, which increases the potential to be dispatched and generate revenue. A plant with higher part-load efficiency could offer a cost advantage over competing units (e.g. CCGTs with lower part-load efficiency and smaller OCGT plants operating at full load), which would improve profitability. From a system-wide perspective, only a small number of plants operate at part load, so the associated increase in CO_2 emissions tends to be negligible (NREL, 2013). Even though CCGTs experience a high-efficiency penalty (e.g. twenty percentage point efficiency reduction at 50% turndown ratio) in part-load operation, they remain the most efficient thermal technology at high load (Figure 5.16).

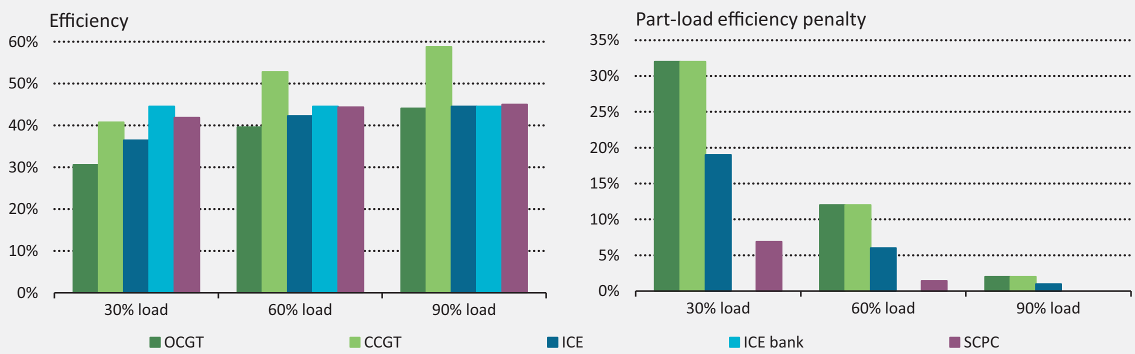
Figure 5.15 Operation of a CCGT in a European electricity system



Notes: day 1 2005 is 2 June 2005. Day 1 2012 is 5 May 2012.
Source: Pasini, 2012.

Key point *Between 2005 and 2012 CCGT requirements in Europe have become more susceptible to sharp and large swings in load and hence more rapid changes between full-load and part-load operation.*

Figure 5.16 Efficiency versus load for different gas-fired generation technologies

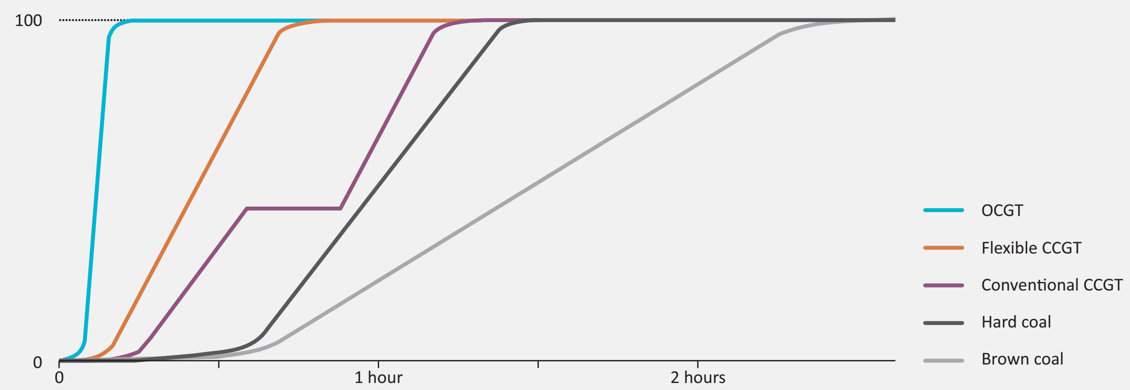


Notes: OCGT (approx. 100 MW). CCGT (120 MW), ICE (20 MW), ICE bank (6x20 MW), SCPC (1 GW).
Sources: Vuorinen, 2009; Linnenberg, Oexmann and Kather, 2009; US EPA, 2008; IEA analysis.

Key point *CCGTs have the highest part-load penalty even at 30% load, but when comparing similar capacity sizes, a bank of ICE plants has a lower efficiency penalty when reducing absolute output to 30% of full-load due to its modularity.*

Start-up time is defined as the operating period before the plant reaches stable combustion conditions. Short start-up times allow plants to be called upon closer to actual dispatch, which avoids unnecessary spinning to provide reserve capabilities. More generally, reducing start-up times increases the electricity-generating capacity available on demand within a given time window. Depending on the preceding shutdown duration, start-up can be loosely classified as hot (within 8 hours), warm (8 to 60 hours) and cold (more than 60 hours). CCGTs can be started up roughly twice as fast as coal-fired electricity plants (Figure 5.17). The limiting factor for a CCGT is the thermal stress on the heat recovery steam generator (HRSG), particularly when compared with OCGTs and ICEs, which have quicker start-up times. The prices on offer for provision of electricity at the last minute are often very high, but CCGTs face additional costs in order to be able to generate at short notice (e.g. the additional fuel costs of spinning reserve and part-load operation, and additional CO_2 emissions). To overcome this, is it possible for CCGTs to decouple the steam cycle and operate more like an OCGT, which can make generation on a short notice profitable (Troy, 2011).

Figure 5.17 **Start-up times for different gas-fired generation technologies, hot start**



Source: VDE, 2012.

Key point *Start-up times are fastest for OCGTs, followed by CCGTs and coal-fired generation.*

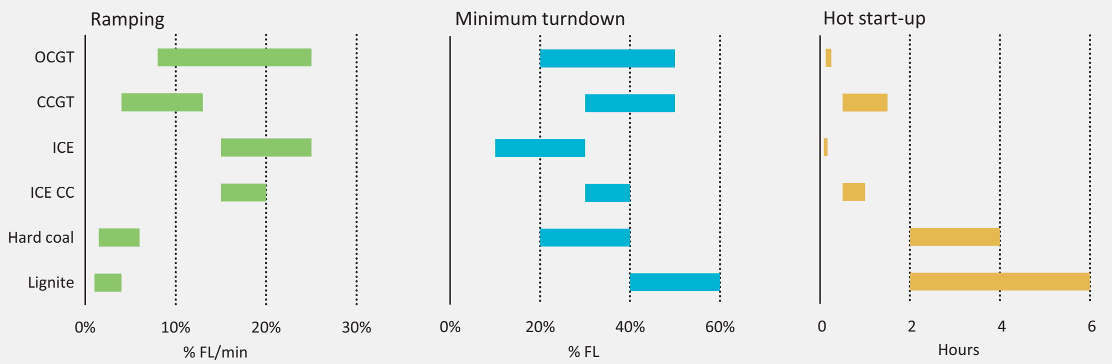
Ramping capability describes a plant's ability to respond to changes in demand, either by ramping up to meet demand during higher net loads or ramping down to support grid stability when net loads decrease. Ramping of some technologies will have impacts for CO_2 and local pollutant emissions that need to be managed (Katzenstein and Apt, 2009). ICE and OCGT plants have the best performance (Figure 5.18).

Turndown ratio represents the minimum stable operational load and is expressed as a percentage of full load. Reducing turndown ratio expands its operational range and allows it to offer more generating capacity to the grid. The main challenge is to keep all emissions within allowable range (Katzenstein and Apt, 2009). Efforts are under way to develop an "overnight parking mode" for CCGTs to keep plants warm during the night at minimum fuel use (to reduce CO_2) while also minimising start-up cost the next day. Reducing turndown ratio could, however, also result in increased fuel use and CO_2 emissions if the costs of running the plant at minimum load are lower than those incurred by cycling the plant. Minimum turndown ratios for CCGTs are similar to those of other thermal plants, in particular coal-fired plants; all have equal opportunity to participate in competitive markets (Figure 5.18; Box 5.5).

New technology and upgrades to improve flexibility of gas-fired generation

New large CCGT offerings from major manufacturers reflect a shift in industry priorities from increasing full-load efficiency towards flexible operation at the maximum possible efficiency. In flexible designs, efficiency penalties are modest while capital costs remain roughly identical.

Figure 5.18 **Ranges of flexibility parameters for thermal electricity generation technologies**



Notes: FL = full load. Typical plant size (MW) is as follows: Black coal = 500-1 000; lignite = 500-1 000; CCGT = 300-500; GT = 50-200; ICE = 20-200; and ICE CC (ICE operated with a combined steam cycle) = 250-450. If included, nuclear plants. would show lower performance against all parameters. Top ends of ranges indicate estimated potentials.
Sources: DIW, 2013; VDE, 2012; IEA analysis.

Key point *Among thermal generation plants, gas-fired plants perform better than coal-fired plants in terms of key flexibility parameters, with OCGTs and ICEs performing best.*

The following technical improvements, some of which could be retrofitted to existing plants, can increase flexibility:

- **Variable-pitch guide vanes and inlet pre-heaters improve combustion for part-load and minimum load performance.** Introducing variable-pitch guide vanes at the inlet of the gas turbine compressor allows better control of airflow through the turbine. In fact, airflow can be optimised to match the fuel input at any given load. The vanes minimise the reduction in combustion kinetics at part load and increase reactivity, leading to lower specific fuel consumption and emissions (in particular NO_x).

  An air inlet pre-heater, placed in front of the compressor, improves part-load efficiency and lowers the minimum load. Pre-heating the air via the steam cycle reduces the mass flow of air through the turbine, thereby imposing a load reduction without throttling the turbine and incurring throttle losses. Using this method, CCGT part-load efficiency can be raised by 0.8 percentage points above the equivalent value for a CCGT without air inlet pre-heating (Pickard and Meinecke, 2011).

- **Improved HRSG design increases ramping capability and reduces start-up times.** The thermal inertia and high-pressure cycle of existing HRSGs (designed using thick-walled components) limit CCGT ramping capabilities, and start-up and shutdown times. The main challenge is the need to gradually warm material to avoid thermal stress. Simply bypassing the steam cycle using an exhaust valve placed after the turbine could provide CCGT plants with the option to deliver quicker response services and steeper ramp rates without impacting the HRSG. CCGTs could effectively fulfil the role of fast-responding OCGT plants (Troy, 2011).

  Sealing the HRSG to minimise heat losses during shutdowns could also reduce the time for warm and especially hot start-ups. This solution can be integrated into existing plants.

- **Advanced new materials and sensing to reduce cycling impact.** Use of advanced materials that are less heat-sensitive can alleviate the impact of cyclic operation. Additionally, technologies to enhance sensing, on-line diagnosis and control provide better ability to monitor the condition of components and materials. With these tools, maintenance can be planned in the most efficient way; not too early and not too late, but just before critical components reach a breaking point.

- **Modular design provides a technology hedge against market and policy uncertainty.** In the 2DS, the role of gas-fired generation evolves substantially over the normal lifetime of the generation fleet. Building a high degree of modularity into the gas turbine platform could enable components to be exchanged relatively quickly if the market conditions require different technology characteristics. Modularity can be built into both hardware and software, e.g. controls. Such an approach could provide investors and operators with "option value" on new plants and a partial hedge against policy and market uncertainty. Upgrading existing gas-fired plants to improve performance has potentially valuable precedent in the conversion of obsolete steam cycle plants to CCGTs to raise efficiency while retaining as much of the existing infrastructure as possible.

These technology developments highlight options for increasing the flexibility of new or existing gas turbine-based plants. It is noteworthy that nearly all of these R&D projects were led by the private sector and commercialised quickly, demonstrating industry desire to anticipate and react aggressively to market changes. Governments should recognise that targeted research to respond to short-term market needs is often well-addressed by industry in this area, and that publicly funded R&D projects can take a longer-term view of the system and generating flexibility requirements of the 2DS.

Increasingly flexible operation of gas-fired plants will impact profitability

As the previous section demonstrates, providing flexible, dispatchable capacity to complement the increasing flexibility needs of the future 2DS power system is technically possible; however, it could be economically challenging. Cost impacts of flexible operation, competing sources for flexibility and pricing of flexibility have the potential to seriously affect profitability of gas-fired plants, and therefore investment, under liberalised market conditions.

Cycling of natural gas plants increases variable costs

Operating thermal power plants to vary the output adds costs to electricity plant operators due to increased deterioration, maintenance and fuel costs of starting up and shutting down. The less stable the operating conditions, the greater the increased cost: estimates suggest 2% to 5% cost increases on average for fossil-fuelled plants when levels of up to 33% VRE generation are added to the electricity grid (NREL, 2013). This is significant but in the range of fuel price fluctuations. Costs and impacts on maintenance are estimated to be higher for coal-fired plants than for gas-fired plants, which are more technically suited to ramping up and down and operation at part load (NREL, 2012a).

Operators of plants near the end of their lives are likely to accept more rapid deterioration of the plant in return for increased operating hours and revenue in the short term. For younger plants, the increased costs would be tolerated if flexible operation enabled the plant to collect revenues that offset the costs of increased maintenance. If fuel costs are low, some of these costs could be avoided by continuing to run the plant at minimum fuel consumption even when disconnected from the grid, but CO_2 emissions would be increased.

These plant-level considerations need to be reconciled with system-wide perspectives. The additional costs of cycling are likely to be lower than the benefits of reduced CO_2 emissions and reduced fuel costs associated with variable renewables (NREL, 2013). Increased costs of cyclic operation could become an unavoidable cost of operating gas-fired plants on grids with

Box 5.5 ICEs: Comeback of a well-known technology?

ICEs are a very mature technology used in many sectors including transport, industry and services. Until recently, the electricity industry paid little attention to ICEs, since utilities traditionally deployed large centralised plants (e.g. 300 MW to 500 MW) such as hydro, coal, nuclear and CCGTs, rather than distributed assets, to realise economies of scale in terms of efficiency and costs. This apparent disinterest in ICEs appears to have changed in recent years as the industry looks more closely at tools to help manage distributed generation. The technology portfolio of many major thermal electricity generation manufacturers for small-mid-size plants (< 200 MW) demonstrates growing interest in both ICEs and gas turbine products.

Growth in ICE plants actually exceeds that of turbine-based technologies, even though the installed capacities are still very low (Figure 5.19).

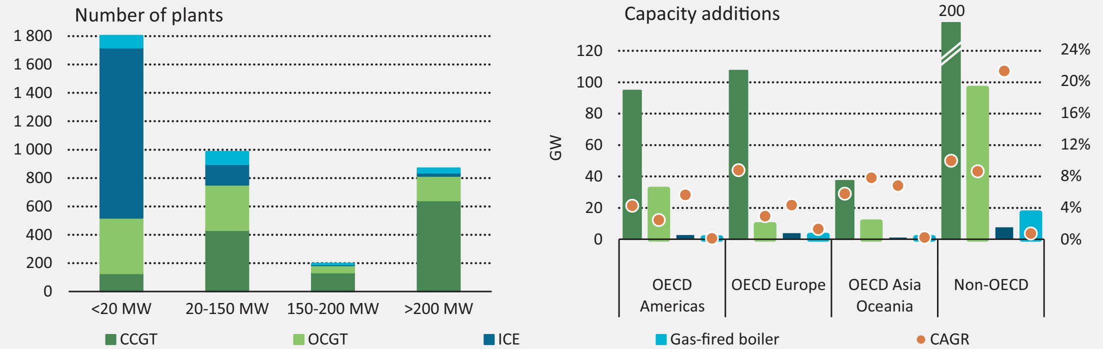
From a macro perspective, ICEs are cost-competitive with OCGTs. The ultimate investment decision is very sensitive to specific project conditions, but the following drivers explain why ICEs could become increasingly attractive in future electricity systems.

Modularity. ICEs can be used as single-unit plants (< 20 MW), stacked in so-called "bank" or "cascade" electricity plants (20 MW to 200 MW), or operated with a combined steam cycle (> 250 MW). In island systems or weakly interconnected electricity systems, the modularity of natural gas engine-based cascade plants allows a more cost-effective management of the "N-1" reliability criterion compared with large-scale turbine-based plants. Electricity systems are usually oversized to ensure that they can reliably serve demand even if one unit fails. Of the ten largest ICE electricity plants (outputs higher than 250 MW), nine have entered operation since 2010 – all in developing countries.

Efficiency at part load. Large natural gas engines have efficiencies of up to 48%. A key benefit of cascade ICE plants is that they can operate at part load by using only a portion of the engines at full load; as a whole, the plant operates at part-load efficiency while individual engines operate efficiently at close to full load.

Start-up time and ramping capabilities. ICEs can execute a cold start in under 15 minutes and ramp from 80% to 100% within seconds, features that make natural gas engine-based electricity plants a strong flexibility resource (Figure 5.18). Large electricity systems may not require such

Figure 5.19 Gas-fired capacity additions by size, technology and region, 2004-13



Note: CAGR = compound annual growth rate of installed capacity.
Sources: Platts, 2013; IEA analysis.

Key point *Gas-fired ICEs dominate the market of small-size plants (< 20 MW) and are growing rapidly, especially in non-OECD countries.*

performance for integration of VRE, but plant operators can improve profitability by benefiting from ancillary service markets.

Fuel compatibility. Natural gas ICEs can burn a broad range of gaseous fuels (pipeline quality and synthetic natural gas, landfill gas, and biogas) as well as other oil petroleum-based fuels. Multi-fuel engines provide additional fuel security; in the case of disruptions in the supply of natural gas, they can easily switch to liquid petroleum-based fuels that can be stored locally and have high energy density. Increased use of unprocessed biogas, which tends to have very low Wobbe numbers, would also favour the use of fuel-tolerant ICEs.

Temperature and altitude sensitivity. As noted earlier, gas-fired plant efficiency is sensitive to the condition of air inlet. The impact on ICE efficiency of different air inlet temperatures and pressures is less important than for gas turbine-based plants.

Construction time. As long as no manufacturing bottleneck exists, ICE plants can be built in less than one year; all components are pre-assembled in factories and can be installed directly on the construction site.

Gas turbines have their own benefits and are likely to remain leaders in the following characteristics:

Footprint. Gas turbines can deliver more energy per unit of land, an important factor in suburban and urban environments with high property prices and strong public opposition to energy infrastructure. This also makes gas turbines the technology of choice for oil and gas production operations.

Noise levels. Gas turbines have considerably lower operating noise levels than gas engines. Intake and exhaust silencers for ICEs can reduce the noise levels considerably.

Full-load efficiency. For large electricity plants (> 200 MW), CCGTs deliver higher full- and part-load efficiency (up to 50% to 60% turndown ratio) than ICE plants, even in combination with a steam cycle.

Technical considerations aside, a main factor in selecting gas turbines over ICEs may be the human resources available to electricity utilities. Many utilities have rich in-house expertise with gas turbines and may perceive a switch to use of more ICEs as a risk to be avoided – unless the investment opportunity is considerable.

high variable renewables penetration. From a system management standpoint, the challenge will be to share the benefits of renewables in a manner that covers the costs of supporting them.

Technical flexibility does not necessarily translate into economic flexibility

As described earlier, plant dispatch generally depends on SRMC. If VRE output is sufficiently predictable in systems with high penetration of VRE generation, capacity that can respond to the residual load profile need not be the most technically flexible. If multiple different generating technologies can provide sufficient flexibility, the technology with the lowest SRMC will win.[14] In this regard, gas plants have competitors.

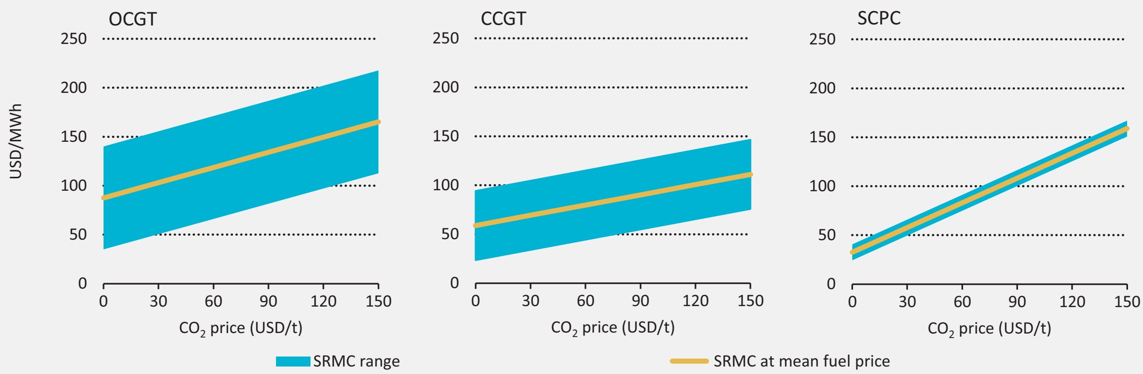
First, coal plants can be operated relatively flexibly. If coal prices are relatively low, coal plants can be ramped up and down relatively slowly or kept spinning so they are ready to connect to the grid. This will, however, increase fuel consumption and CO_2 emissions. Coal plants nearing retirement may be operated more flexibly if any associated deterioration can be tolerated before decommissioning. The high day-ahead predictability of solar has provided enough lead time for coal to serve as the least-expensive balancing fuel in certain cases in the United States and Europe; the combination of coal and solar PV in Germany, where much of the coal capacity is depreciated, is a good example. In coming decades, responding to the needs of

14 However, it may not always be the case that revenues from electricity sales cover the additional costs of providing flexibility, which may disincentivise flexible operation in the absence of additional compensation.

variable renewables may actually become less technically demanding at plant level as predictability of wind and solar output improves.

To avoid incentivising coal-fired plants to provide flexibility at the cost of higher CO_2 emissions, the variable costs of coal- and gas-fired generation would need to be adjusted. A carbon price of USD 50/tCO_2 would balance SRMC if natural gas prices were USD 10/MBtu and coal prices were USD 4/MBtu (Figure 5.20). Higher carbon prices would be needed to compensate for higher natural gas prices.

Figure 5.20 SRMC of gas- and coal-fired plants with increasing carbon prices



Notes: natural gas prices range from USD 4/Mbtu to USD 16/Mbtu; coal prices from USD 3/MBtu to USD 5/MBtu. Technology assumptions are consistent with the 2DS in 2020.

Key point *The choice of coal or natural gas dispatch is very sensitive to both fuel and carbon prices.*

Demand response, electricity storage, curtailment of renewable generation[15] and increased interconnections also compete with gas-fired plants to provide grid flexibility. Demand response can have very low SRMC and very rapid response times. Opportunities for electricity consumers to reduce their electricity bills by varying their demand in response to price signals are increasing in many electricity markets. The 2DS shows increased scope for storing electricity produced at times when low-cost supply exceeds normal demand (see Chapter 7). Storage has in the past been more expensive than gas-fired electricity generation, but technological improvements and the penetration of renewables with low SRMC may change the equation in some regions. Gas-fired plant profitability will depend on being able to compete with these alternatives for flexible generation and reserve capacity.

Reduced operating hours and reduced marginal costs

High penetration of VRE generation in the 2DS leads to reduced operational hours for thermal plants, including those that operate flexibly – which translates to fewer hours of operation during which a return on investment could be made. As an indication, decreasing the capacity factor of a CCGT from 90% to 30% raises the LCOE by over 55%. CCGTs, being less capital intense, suffer proportionately less than coal or nuclear plants from reduced capacity factors.

15 Note that curtailment of wind generation can be a solution if wind output increases sharply, but not if it drops off sharply. Likewise, some modes of demand response, such as interrupting industrial production or consumer demand, are suitable only for times when renewables supply drops; others, such as thermal storage, are suitable only for times of excess supply.

Longer payback times for investments in generation will make it difficult to attract the investment needed in the 2DS.

High levels of variable renewables could also drive down the price received for electricity generated. As SRMC of wind and solar power are very low, generators on the grid that have traditionally been high in the merit order (i.e. low SRMC) could be pushed to become the marginal plant and thus dictate market-clearing prices. All generators would receive less revenue per unit generated, which could further increase payback periods, unless higher prices can be secured at times of peak demand or rapid response.

Overcoming economic challenges: Reward the benefits of flexible generation and penalise emissions

While technology can enable more flexible operation of gas-fired power plants, there is no guarantee of increased profitability for operators in liberalised markets. Thus, the incentives for operators to adopt the technologies are missing. Moreover, since gas-fired generation will compete with other flexible resources, it is far from clear which gas-fired generation will be the preferred provider of flexibility. Creating market mechanisms that reward flexibility and penalise CO_2 emissions can help to address these challenges.

Liberalised markets can and do reward ancillary services that ensure system stability (e.g. PJM Interconnection wholesale electricity market in the United States). While the needs for these services are very market-specific, they can be broadly categorised under normal and contingency conditions. Services under normal conditions (e.g. frequency regulation and voltage control) are often mandatory for all connected generators and rewarded at lower rates, if at all. Contingency services (spinning and non-spinning reserves, black start) often receive higher reward through markets that require specific technical characteristics (e.g. quick start-up times). Such markets and the expected increasing market price due to VRE deployment are, at present, incentivising the use of gas-fired generation over coal.

Prices or limits on CO_2 emissions can also address the economic challenge. In the 2DS, carbon pricing is an essential driver of both decarbonisation of electric supply and growth in VRE generation deployment. Renewable support schemes (e.g. feed-in tariffs, renewables obligations) commonly used today to encourage VRE generation are principally suited to facilitate deployment of relatively new, commercially immature technologies. As such technologies become commercially mature, the need for support schemes decreases and carbon pricing (or emissions limits) will become the main driver of deployment. If implemented effectively, carbon pricing could incentivise deployment of gas-fired generation that is more flexible than the coal-fired alternatives in many regions. Carbon pricing may also tend to push investment into complementary technologies.

Recommended actions for the near term

This chapter has illustrated that there are two main roles for gas-fired generation in the 2DS and they will emerge to different extents in different regions, and at different times. This evolutionary perspective emphasises that technologies may face different market pressures during their 25- to 30-year economic lifetimes.

With respect to coal-to-gas fuel switching, policy action that tightens environmental regulation of local pollutants, together with carbon pricing, favours gas-fired generation over coal-fired generation. In the European Union, a strengthening of the carbon price could favour natural gas over coal. In the United States, the revised proposal for Clean Air Act emissions standards will make it nearly impossible for a new coal-fired plant to be built without CCS.

Coal-to-gas switching remains very sensitive to fuel prices, however, as the growth of US coal-fired generation in 2013 demonstrates. Increased efficiency has been the key factor in making CCGTs competitive with coal-fired plants in the past, and marginal improvements, and even alternative cycles, could gradually improve gas-fired plant efficiency. In the 2DS, it is expected that the market for those plants will be limited to countries where gas-fired generation can be operated at high capacity factors for most of their lifetimes. Due to the emissions intensity of gas-fired generation without CCS, coal-to-gas fuel switching at a global level has only a limited impact after 2025 in the 2DS.

Bringing new low-carbon technologies, such as CCS, to market will require stable, long-term policy frameworks that support the technology from R&D to commercial-scale demonstration and then to deployment (IEA, 2012b). CCS for gas-fired generation is currently in need of two specific types of policy support: public capital or guaranteed revenue to generate vital knowledge from first-of-a-kind demonstration projects; and a framework for reducing the financial risks associated with early deployment of CCS. Measures that could provide revenue for early deployment of CCS on gas-fired generation could reward the value of "clean" electricity generated. Instruments such as the contracts-for-difference feed-in tariff structure in the United Kingdom and the certificate system in Illinois, which are similar to the support schemes for renewable energy, can incentivise private sector investment in capital-intensive projects by reducing operational risks. Instruments that reward the generation of low-carbon electricity (as opposed to rewarding quantities of CO_2 captured and stored) will provide greater parity between coal- and gas-fired plants with CCS. There is also an important role for R&D to continue to focus on improved efficiency for gas-fired plants with CCS to reduce total costs of the 2DS.

Drive or load cycle efficiency matters over a variety of operational conditions and is essential in electricity systems where gas-fired plants are operated in a cyclic manner, such as in electricity systems with high shares of VRE. Policy and technology decision making would benefit from comparable reporting of efficiencies for a wider range of operational cycles and patterns for different technology options.

Policy plans and targets for flexible designs and upgrades for CCGTs need to acknowledge the rapid technology R&D progress in recent years and should focus on supporting deployment of flexible solutions. R&D measures focused on adaptations for existing plants, rather than new plants per se, will also be important so that the existing fleet of gas-fired plants can deliver upon increasing demands for flexibility. Modular technology, including hardware and software, could help facilitate cost-effective adaptation of the electricity plant to changing system needs.

In some regions, governments face the risk that existing gas-fired plants (CCGTs but also some OCGTs), which are needed to balance the variability of renewables, will be driven out of the market. Cyclic operation results in low capacity factors and creates additional maintenance costs for thermal generators, thus undermining investments in new projects. Three actions could help flexible gas-fired generation remain competitive and thus support capital-intensive capacity such as renewables (but also nuclear and CCS-equipped power plants): reduce capital costs; improve cycling efficiencies; and reward system services provided by flexible plants. In addition, as coal-fired generation can also be operated flexibly in many circumstances, the flexible gas-fired electricity generation envisaged by the 2DS appears unlikely to materialise without CO_2 emissions pricing or regulation.

Natural gas is a key transition fuel in the 2DS pathway to a low-carbon electricity system. It can play two roles in the transition and, in some regions, its role in coal-to-gas fuel switching will need to evolve into a role as a provider of system flexibility. These two roles are complementary and will depend on regional contexts, but technology will need the right characteristics to play these roles in the most efficient and cost-effective manner. In addition, this chapter affirms that VRE generation, which is essential to a low-carbon electricity future, is not in competition with gas-fired power but can be, to a large extent, enabled by it. A large part of the policy challenge will relate to securing the right markets as well as the right technologies.

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Chapter 6

Electrifying Transport: How Can E-Mobility Replace Oil?

With oil accounting for more than 90% of its primary energy, transport remains the end-use sector most dependent on fossil fuels. The electrification of transport offers great opportunities to foster fuel diversification, carbon dioxide (CO_2) mitigation, and increased energy efficiency while contributing to other sustainable transport goals. Combining technological and economic analysis, this chapter explores the possibility to radically transform transport through increased electrification, mapping out which modes could first be electrified and which regions are best positioned to be front-runners.

Key findings

- **Already today, more than 27% of the world's countries could obtain significant CO_2 savings from EVs, irrespective of mode.** Savings are highly influenced by the carbon intensity of the electricity mix, but electric 2-wheelers offer carbon savings in all electricity systems. The Low-Carbon Electric Transport Maximisation IndeX (LETMIX) shows where and in what time frame electrifying the transport sector can yield maximal benefits.
- **Cost-effective electricity supply infrastructure and storage for vehicles still represent the main challenges for the widespread use of e-mobility technologies.** Solutions include combining batteries and internal combustion engines (ICEs), as in plug-in hybrid electric vehicles (PHEVs). Catenary lines can also provide electricity directly to moving vehicles. Specific business models have the capacity to optimise the use of charging infrastructure. Reducing electricity storage costs is needed to enable a large-scale deployment of battery electric vehicles (BEVs).
- **Combined with smart grid technologies, electric vehicles (EVs) can support increased energy system integration.** A significant EV fleet can offer services to the electric grid rather than being a burden. Effective charging strategies can enable EVs to provide electricity storage and flexibility to the grid. Even at very high EV penetration, e-mobility accounts for below 15% of the total electricity demand across 2DS pathways in *Energy Technology Perspectives (ETP 2014)*.

- **In the 2DS Electrified Transport (2DS-ET) scenario, targeted development of long-haul e-mobility delivers substantial CO_2 savings.** Road freight traffic is highly concentrated on national road networks, presenting a large opportunity for economies of scale and the application of overhead lines for electricity supply. Care must be taken to maintain the access flexibility provided by road vehicles, either through hybrid/dual powertrains or intermodal terminals (and related logistic arrangements).
- **Rail stock is already 40% electrified, but substantial potential exists in non-urban areas.** Targeting passenger and freight rail network segments with the highest usage rates is the most cost-effective way to transform remaining shares. The electric infrastructure and rolling stock is less costly to run for high-traffic and/or high-frequency corridors and requires less maintenance compared with diesel-powered locomotives.
- **Buses have the widest range of electrification options available.** Mature projects are already in place across all four technologies (battery swapping, overhead lines, induction and stationary battery charging). Electrification of urban buses is expanding rapidly, as municipalities value the zero local emissions and low noise levels.

Opportunities for policy action

- Stimulating electrification of transport supports diversification of the fuel mix away from oil, enabling enhanced energy security. As most current alternative fuels policies target light-duty vehicles, promoting early investment in long-haul e-mobility could offset future refinery investments needed to supply higher diesel shares in the transport fuel mix.
- Transport policies should recognise the full social costs of fossil fuels use to effectively contribute to shorter payback periods for e-mobility options, adding to the improved efficiency and lower operational cost of EVs. Monetising the additional opportunity to leverage a range of primary energy sources for electricity generation, as well as the superior performance of EVs in reducing local air pollution and noise, could also help address the significant change to governmental revenues (e.g. from reduced fuel taxation).
- Policy action to stimulate the uptake of transport electrification should aim to use pre-existing electrical infrastructure in cost-optimal ways. Government and industry need to secure up-front investments to develop electricity supply and charging infrastructure to overcome the "chicken-and-egg" problem characterising many alternative transportation technologies. These investments need to be subject to a thorough business case analysis to ensure sustainable, long-term operation.
- Governments need to support research to make sure that EV batteries meet the principles of efficient use of resources (reduce, reuse, recycle), favouring high recyclability targets and confirming the resale value of EV batteries, which weigh heavily in the cost and payback calculation of purchasers (including fleets).
- Targeted deployment of EVs in urban areas can effectively address multiple policy goals across different sectors. Urban transport electrification should be part of integrated planning for land-use, walking, biking, networked mobility and low-carbon electricity.

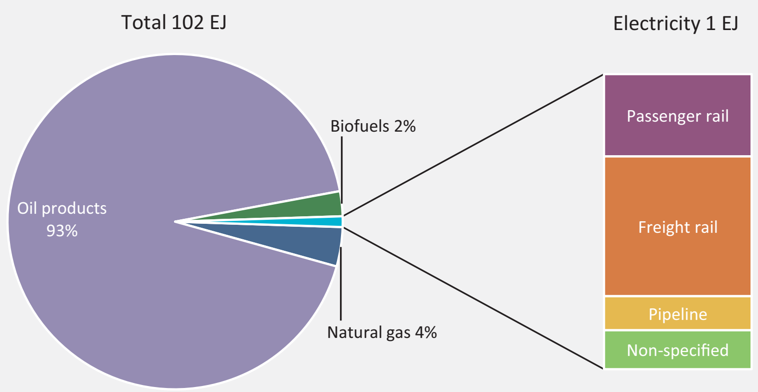
Energy use in the transportation sector is diffuse: almost 1 billion independent vehicles and other carriers are on the move daily for both passenger and freight transport. A key challenge is the need for substantial infrastructure to support easy refuelling. As capturing CO_2 emissions at these point sources (the vehicles) is currently considered unrealistic, the sole means of eliminating greenhouse gas (GHG) emissions from transport is to move to decarbonised vehicle and fuel systems. Electricity shows strong potential as a sustainable fuel, but only if the carbon content of the electricity mix is lower than other fuel options, conventional and otherwise.

Despite efforts to diversify primary energy supply, the transport sector remains heavily reliant on oil. Anticipated growth in transport demand represents increased GHG emissions, and poses energy security issues in many countries that struggle to secure long-term supply of oil and/or refined products at affordable prices. Energy source diversification is key to long-term sustainability of transport, and the way forward to start its decarbonisation.

Electricity's share in transport has been flat at around 1% since the early 1970s (IEA, 2013a); it is used mainly in rail transport and for pipeline transport (Figure 6.1).

EVs, in the context of *ETP 2014*, are defined as those that directly interact with the electricity grid. Thus, non-plug-in (autonomous) hybrids and fuel cell (powered by hydrogen) vehicles are not included in the analysis.

Figure 6.1 **Global energy use in the transport sector in 2011**



Notes: EJ = exajoules. Figures and data that appear in this report can be downloaded from www.iea.org/etp2014.
Source: unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *Electricity represents only 1% of energy use in transport. Electric freight rail represents a small share of total transport energy use, yet thanks to its efficiency represents 3.7% of total freight tonne kilometres (tkm).*

With vehicles lasting between 10 and 30 years (e.g. passenger cars and heavy freight trucks, 8 to 10 years; trains and 747s, 25 to 30 years), e-mobility can allow for vehicles to emit less CO_2 as the electricity generation gets decarbonised. Unlike conventional vehicles without retrofits, and excluding flex-fuel vehicles, a purchased EV has the promise to be an investment that becomes "cleaner" over time, while also conferring the instant benefit of reducing local air pollution, especially in high exposure areas such as cities. This is an important opportunity to avoid the lock-in inherent in other powertrain options or in other sectors, where near-term technologies will become increasingly "dirty" relative to newer, cleaner technologies.

This chapter maintains a narrow focus on electricity as a substitution "fuel" for the transport sector. Other fuels, including second-generation biofuels, hydrogen and natural gas, which also hold potential to decarbonise the transport sector to varying degrees, are summarised in Chapter 1: The Global Outlook. Fuel cell vehicles and hydrogen storage will be examined in more detail in a forthcoming separate International Energy Agency (IEA) roadmap *(Hydrogen Technology Roadmap)*.

Box 6.1 **Energy density and the challenge of electrifying transport**

Liquid fuels have a distinct advantage for energy that supports motion: per unit of volume and weight, they hold or store large amounts of energy that is available on demand. This high energy density is a key obstacle to fuel switching. Today's most efficient batteries are much less energy- and power-dense than fossil fuel, which has impacts for both speed and distance of travel.

Electricity is increasingly present within all transport modes, primarily as the means of powering auxiliary electronic and electric devices, such as on-board computers, global positioning systems (GPS), air conditioning, lighting and entertainment devices. With increased load demands for auxiliary functions, competition for electricity demand is increasing inside the vehicle. EVs have the added challenge that, lacking an engine block, they produce no waste heat to transfer to the interior.

Use of electricity for propulsion remains quite rare in the global vehicle fleet (besides rail). Most transport requires that vehicles provide versatility during the journey; on-board energy storage is the sole means of ensuring flexibility to cope with users' needs. Utilising external energy supply without on-board energy storage currently works only for vehicles that travel the same routes, such as trolley buses and rail.

Electrifying transport modes: Technologies, time frames and opportunities

ETP analysis, coupled with research from other sources, assesses what can be done to use electricity as a fuel in each transport mode while several case studies highlight successful deployment. Two main avenues exist for boosting the role of electricity in the transport sector:

- **Reduce oil use** by using electricity within the vehicle to increase overall energy efficiency (hybridisation, electrifying auxiliaries, etc.).
- **Displace oil use** by fuelling vehicles with electricity.

Fuel switching to displace oil use is the main focus of this chapter; however, improving energy efficiency through increased internal use of electricity will be briefly covered for those commercial modes (e.g. aviation and shipping) in which electricity cannot be used as the main propulsion fuel. Transitional opportunities will also be explored, such as how non-plug-in hybrid electric 2-wheelers or passenger cars can increase energy efficiency to reduce oil use while further effort is needed to achieve the goal of electricity displacing oil.

Supplying electrification for transport can be achieved through four configurations:

- **Conductive battery charging** (slow and fast) involves plugging the vehicle into power supply infrastructure than can be situated in residential, retail, work and public spaces.
- **Battery swapping** relies on creating mechanisms by which operators of a uniform vehicle can swap a depleted battery for a recharged one of the same type.
- **Overhead (catenary)** power lines are already used for light rail and buses in several cities, but could have potential for broader use on highways by trucks.

- **Induction charging** uses electromagnetic fields without contact to charge a battery or to interact with copper coils on vehicles for propulsion, and can be static (stationary charging) or dynamic (charge is transferred as the vehicle passes over the field).

This chapter uses investment calculations (Box 6.2) to determine payback periods and the most logical roll-out of transport electrification to provide attractive return on the substantial investments needed. Modes are categorised by passenger light-duty vehicle (PLDV) applications, using battery storage to a great extent, and heavy-duty applications (including non-road such as rail) predominantly using on-the-go power supplies such as overhead lines. Global numbers demonstrate various degrees of viability according to mode and configuration, while also attempting to capture the differing perspectives of private consumers and fleet operators, as well as municipalities and national governments.

Box 6.2 Methodology: Payback periods and sensitivity analysis

Payback period analysis is used to understand how long it takes to recuperate, usually through lower operational costs, the higher up-front capital cost of an investment compared with a reference purchase of a similar item. In the case of vehicles, with no discounting applied, the economic potential of electrification includes additional up-front investment against total fuel and maintenance cost savings over the vehicle's lifetime.

By varying the key parameters behind the payback period analysis, it is possible to determine a range of results and analyse how "sensitive" the result is to a given change. Sensitivity analysis examines how different sources of uncertainty in inputs affect the overall payback period result. This can be used to assess both expected returns given variations in data and future evolutions of key parameters, thereby allowing for a better understanding of related uncertainty and risks involved when making investment decisions.

Some modes were excluded from the analysis due to insufficient cost data or a lack of on-the-ground experience, including shipping, aviation, battery-swapping buses (despite growth in China), battery-electric heavy freight vehicles and dynamic induction (despite a recent demonstration project in South Korea, the analysis focused on static induction due to its current edge in cost-effectiveness).

Key parameters tested for sensitivity analysis (varied by + 40%/- 40%) included battery cost, oil price, annual mileage and infrastructure cost. Each parameter is more or less relevant depending on the model. Additionally, because travel frequency plays a key role for transit modes, they are assessed differently than individual transport. If a municipality invests in a bus system with overhead lines, for example, the payback period changes greatly depending on the frequency of transit travel. By contrast, the purchase of an EV by one buyer does not affect the cost of another EV (not counting economies of scale in manufacturing).

Electricity cost was analysed, but ultimately not considered a key parameter as it did not greatly affect the payback period results. Infrastructure lifetime and maintenance* are not considered integral for calculations but rather used to compare against results.

While useful, payback period and concomitant sensitivity analysis have some drawbacks. The most important in the case of transport is that if the lifetime of an investment (vehicle or infrastructure) is longer than the payback period, it is not possible to capture the overall lifetime profitability. For this reason, *ETP 2014* also uses savings per kilometre to comparatively assess cost results.

A payback period shorter than the lifetime of a vehicle provides a net economic gain; if payback is achieved in 5 years, but the vehicle lasts 12 years, the result is 7 years of net economic gain. Taking into account the ownership period might change the equation: if the owner sells the same vehicle after four years, the owner is subject to one year of economic loss.

* Unless otherwise indicated, maintenance refers to both vehicle and infrastructure maintenance.

Current technological maturity and technological potential are important factors when assessing available configurations for electrification (Table 6.1). Battery charging is, at present, the most mature option in the roadway sector and shows strong potential across many applications. The potential for others may grow as technology matures. Induction could offer the best "complementarity," in that it can be used to charge a variety of vehicle configurations. Any technology that can attract a wider variety of users will have a stronger chance of building a strong business case.

Table 6.1 **Overview of technological potential and maturity of vehicle electrification**

	Motorcycles		Passenger cars			Buses			Trucks		Rail		
	Lead acid	Li-ion	PHEV	Small BEV	Large BEV	Urban	Rural	LCV	MFT	HFT	Passenger Urban	Passenger Intercity	Freight
Battery charging	+ (developed)	+ (developed)	+ (developed)	+ (developed)	+ (developed)	+ (developed)	+ (moderate)	+ (developed)	+ (moderate)	− (nascent)	− (nascent)	− (nascent)	− (nascent)
Swapping	+ (developed)	− (nascent)	− (nascent)	− (moderate)	+ (moderate)	+ (moderate)	+ (moderate)	+ (nascent)	− (nascent)	− (nascent)	n.a.	n.a.	n.a.
Static induction	− (nascent)	− (nascent)	+ (moderate)	+ (moderate)	+ (moderate)	+ (moderate)	+ (nascent)	+ (moderate)	+ (nascent)	+ (nascent)	+ (moderate)	− (nascent)	− (nascent)
Dynamic induction	− (nascent)	− (nascent)	+ (nascent)	+ (nascent)	+ (nascent)	+ (nascent)	+ (nascent)	+ (nascent)	+ (nascent)	+ (nascent)	+ (nascent)	− (nascent)	− (nascent)
Catenary	n.a.	n.a.	n.a.	n.a.	n.a.	+ (developed)	− (developed)	− (moderate)	− (moderate)	+ (moderate)	+ (developed)	+ (developed)	+ (developed)

Economic potential: + positive; − negative

Technological maturity: ● developed; ● moderate; ● nascent

Notes: it is not only the vehicle itself that determines the potential/maturity, but also the application in which it is used. Bicycles, for example, have different results if considered individually or within the context of bike sharing. Abbreviations: Li-ion = lithium ion battery. PHEV = Plug-in hybrid electric vehicle. LCV = Light commercial vehicle. MFT = Medium freight truck. HFT = Heavy freight truck. n.a. = not available.

Overall, light-duty applications (including 2- and 3-wheelers) show higher potential for electrification than heavy-duty applications. This reflects the inherent physical relationship between energy density and weight, which implies that heavy-duty applications require larger and more powerful energy supplies. Batteries will be shown to be viable for certain heavy-duty applications; in other cases, overhead lines can be a conduit to electrification.

Light-duty applications

In general, light-duty applications are split into two categories: powered 2- and 3-wheelers, and passenger cars. Electrification of both vehicle types has been under way for some time, but much potential remains. Although 2-wheelers are more popular for passenger transport, in many regions, China and the ASEAN[1] in particular, 2- and 3-wheelers serve both passenger and freight functions. Building on more detailed previous analysis of technical aspects of passenger EVs (IEA, 2013a), *ETP 2014* focuses on considerations such as vehicle sharing and infrastructure.

1 Association of Southeast Asian Nations.

Powered 2- and 3-wheelers

Gasoline-powered scooters, which may have two or three wheels, have gained popularity in city centres worldwide and as a mainstream mode in low- to middle-income countries with growing demand for individual motorised modes of transportation. Asian (Box 6.3) and more recently Latin American countries have experienced robust growth of sales of powered 2-wheelers; the Latin American fleet grew by 336% between 2000 (7 million) and 2010 (24 million).

Electric scooters (e-scooters) are now available on the market, as an alternative to low-powered scooters (with ICEs of 50 cc to 125 cc) and to higher-powered scooters (usually fitted with a 300 cc to 500 cc ICE). In addition to decreasing reliance on gasoline and exposure to its price volatility, electrified 2-wheelers inherently deliver two significant co-benefits. E-scooters produce no direct emissions, a substantial advance against the fact that exhaust treatment is not yet compulsory in many places and motorcycles create air quality issues in densely populated city centres. E-scooters also reduce noise pollution, which is laxly regulated on scooters in many countries and rarely enforced.

Box 6.3 Electric 2-wheelers in China: Rapid creation of an e-mobility market

With more than 150 million battery-electric 2- and 3-wheelers on the road, China now has the biggest fleet worldwide. Moreover, China has developed 2 600 domestic plants that manufacture 36 million e-bikes annually.

Low purchase cost is the main driver for most users, together with high versatility in congested environments. Some large cities have been very aggressive in promoting the use of electric bikes – even to the point of banning gasoline-powered motorcycles.

In 2009, electric 2-wheelers represented more than half of the powered 2-wheelers on the road in China.

For transporting goods, variations of the e-bikes are in use, including electric 3-wheelers or e-trikes. These are also being used as taxis in some places, such as Manila, Philippines.

More recently, pedelecs (electric motor-assisted bicycles) that combine human and electric power have become a popular alternative to small motorcycles and regular bicycles, particularly in city centres. In Europe, the market for both e-bikes and pedelecs grew from 300 000 units in 2008 to approximately 1.76 million in 2013. In Japan, demand for pedelecs overtook motorcycles in 2008 and remains in front.

Being significantly lighter than 50 cc motorcycles, pedelecs deliver far better efficiency. While acceleration and comfort favour e-scooters, pedelecs offer a comparable range and speed. At present, e-scooters and pedelecs are more expensive to purchase (higher up-front cost) than the traditional alternatives of motorcycles and pedal bicycles (Table 6.2). Payback period analysis shows that, depending on energy prices, it still takes more than five years for savings on gasoline to recuperate the premium cost of an e-scooter versus a motorcycle with similar specifications. If battery prices decreased and gasoline prices increased, the payback period could be shortened significantly, and fall more in line with consumer perceptions of an acceptable payback time (less than three years in most cases).

Passenger cars

Passenger cars have been the focal point of transport electrification analysis in recent years (IEA, 2011a) with encouraging progress in technological advances for hybrid electric vehicles (HEVs), PHEVs and BEVs (IEA, 2013b). The market remains unsettled, however, and many challenges still have to be solved to support wide penetration of EVs into the mainstream

Table 6.2 Payback period when switching to electric 2- and 3-wheelers

	Baseline vehicle		Electric alternative			
Vehicle type	Energy cost (USD/km)	Vehicle cost (USD)	Vehicle type	Battery type	Vehicle cost (USD)	Investment payback (years)
50 cc scooter	0.03	1 400	E-scooter	Lead acid	3 000	3-5
				Li-ion	3 800	4-8
300 cc motorcycle	0.07	10 000	E-bike	Li-ion	1 500-13 700	5-8

Notes: km = kilometre. Battery cost assumed at USD 500 per kilowatt hour (kWh) for Li-ion and USD 100/kWh for lead acid batteries. Electricity cost assumed at USD 0.17 kWh. Unless otherwise indicated, all material in figures and tables derive from IEA data and analysis. Unless otherwise stated, all costs and prices are in real 2012 USD, i.e. excluding inflation.

market. Despite lower battery costs and increased range, for example, EVs still suffer from high up-front costs (more than half of which is for batteries alone) and so-called range anxiety (i.e. concern that distance capacity is insufficient to meet trip requirements) (Figure 6.2) (IEA, 2013c).

EVs are well suited for urban and suburban areas where drivers need to cover relatively short distances. Currently, few BEVs have the capacity desired for intercity travel on a single charge, though several projects are trying to solve this problem by installing fast-charging infrastructure along highways (EC, 2013).

Efforts to lighten weight are especially important for EVs so that less battery power is needed to meet range requirements. As always, there are trade-offs as light-weighting can be more costly, but it remains a sound policy for increasing vehicle range while lowering costs through avoided batteries. In other words, less can be more.

With the technology well advanced but high up-front costs and the limited range continuing to act as barriers to uptake of BEVs, analytical focus of the nascent market has been shifting to more sociological and policy aspects, such as a lack of consumer education and misperception. This section will examine innovative business models that position BEVs in the context of new mobility paradigms through e-car sharing schemes, and on the infrastructure and business models needed to deliver sufficient profitability to support BEV recharging for both urban and intercity travel.

E-car sharing schemes

Many municipalities or governments around the world are taking steps to address the high cost of purchase for BEVs through e-car sharing schemes, which have the valuable by-product of enhancing familiarity and knowledge of EVs. The high up-front cost for the fleet owner is spread across many vehicle users (thereby avoiding high individual up-front costs), while each user benefits from the low cost of use and pays only for the actual hours of use. As long as use is frequent enough, the fleet owner can realise a satisfactory payback period. When making vehicle purchasing decisions, the owners of car-sharing fleets tend to better manage the benefits of higher capital investments with lower operation and maintenance costs compared with individual buyers (e.g. fleet owners buying HEVs, EVs, etc.).

Globally, approximately 50 000 car-share vehicles are reported, with 1.8 million car-sharing members. Around 10% of the car-sharing fleet is electric (about 5 000 EVs). The number of car-sharing members is projected to reach approximately 12 million by 2020 (Navigant Research, 2013). Car manufacturers are likely to adapt their product fleets and business models in their business as EVs gain market share and car sharing expands further.

Box 6.4 Olympus: The Flemish Living Lab on networked and shared mobility

Olympus is an e-mobility initiative led by the Belgian railway operator (NMBS-SNCB) and starting up in four cities: Antwerp, Ghent, Hasselt and Leuven. The programme makes available Blue-bike bike-sharing and Cambio car-sharing vehicles (both conventional and electric) in urban centres and at train stations. The cities of Ghent and Hasselt are also investing in automatic rental and charging stations for e-bikes. In addition, NMBS-SNCB is providing charging infrastructure for EVs, e-scooters and e-bikes at its 34 largest train stations.

This case study, followed by the Implementing Agreement for Co-operation on Hybrid and Electric Vehicle Technologies and Programmes (HEV IA), is examining the role of EVs within the evolving trend of networked and shared mobility. Via an open-service platform, the project is gathering data about vehicles, charging infrastructure, power consumption, payments and traffic. Relevant mobility service providers (public transport, car- and bike-sharing, parking, charging infrastructure, etc.) connect to this central platform. For a seamless user experience, a smart app "MoveFree" has been developed as a user-friendly interface to all mobility services in the open-service platform.

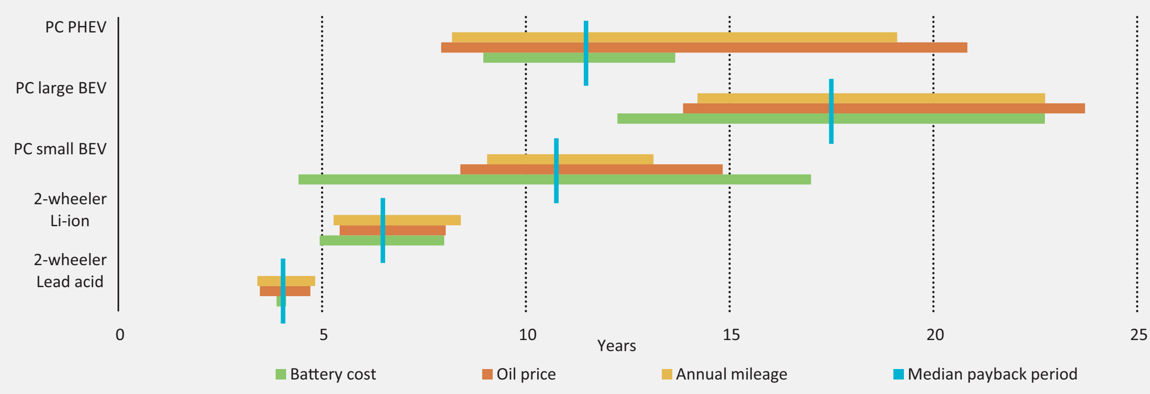
Sources: www.proeftuin-olympus.be and www.ieahev.org.

Vehicle costs

ETP 2014 analysis for PLDVs shows that 2-wheelers are the first, best investment with the fastest payback period, particularly in the urban context (Figure 6.2). Passenger EVs, especially larger BEVs, have a longer payback period but are well suited for urban driving and car sharing. PHEVs are the best fit for longer distances, including intercity travel.

The importance of battery costs, oil price and annual mileage are especially pronounced for BEVs. Infrastructure is not separated out as a parameter for sensitivity analysis for light-duty applications as it plays a relatively small part in the overall payback period calculation.

Figure 6.2 Light-duty applications: Sensitivity analysis (+/- 40%) for key parameters on payback period



Notes: PC = passenger car. Battery cost assumed at USD 500/kWh for Li-ion and USD 100/kWh for lead acid batteries. Gasoline/diesel tax assumed at 40% throughout report. No electricity tax assumed.

Key point *2-wheelers have a shorter payback period than most passenger cars, largely due to the smaller battery needed.*

Heavy-duty applications

The potential for heavy-duty electrification, whether for passenger mass transportation, road freight, aviation or shipping, has been the focus of much debate. Detractors argue that the energy densities needed to sustain the high energy requirements of these modes will never be attained through electricity storage (as in batteries for passenger EVs). Advocates are looking at alternative ways to supply electricity to heavy-duty on-road vehicles, notably by emulating the case of rail electrification.

In any case, heavy-duty electrification applications face substantial infrastructure challenges. But this does not rule out a large potential; rather, it forces the question of which option best fits the vehicle type and usage – overhead lines (trolleybuses), induction (dynamic or static), battery swapping or stationary conductive battery charging?

Road freight is quite complex. Provided that a number of prerequisites are fulfilled (such as the presence of intermodal goods centres on the edges of cities), and notwithstanding the need for policy support, urban freight deliveries can be made electric, especially given short distance requirements. A side benefit would be substantial noise reduction. Heavier, long-distance road freight would require installation of overhead lines along highways and pantographs on the trucks themselves. Operation could be entirely electric or with diesel-hybrid trucks. One first step should be to connect trucks to the grid at rest areas along highways to reduce use of fossil fuel while idling – a move that would be especially important for refrigeration trucks.

Rail and buses are the primary methods for passenger mass transportation via heavy-duty applications. The market for rail is familiar thanks to more than a century of electrification, yet only one-quarter of existing rail lines are currently electrified. Buses have several electrification possibilities, which will be explored below.

Shipping and aviation show the lowest potential for electrification, though some niche applications are viable.

Road freight

Delivery of goods by road is complex, with products – and thus vehicles – following very specific routines. Many road freight vehicles belong to fleet owners, and are administered via vehicle pools. As pool vehicles usually refuel at dedicated stations, deployment of alternative refuelling infrastructure is easier than for independently owned vehicles: less infrastructure is needed and that installed covers a larger number of vehicles (all vehicles in the fleet).

Urban delivery vans typically cover a large distance per day in metropolitan areas compared with cars. Equipping such vehicles with battery-electricity storage would allow the performance of typical daily missions without needing to recharge, which could be done overnight at the fleet headquarters. As these vehicles are used frequently, the payback time will be short (Table 6.3) and allow for a win-win situation: the fleet owners would save significant fuel costs and the city environment benefits from zeroing tailpipe emissions and reducing noise (the latter being especially important for vehicles operating at unusual times). In fact, reduced noise might make it possible for delivery and refuse vehicles to extend their hours of operation into nights, thereby gaining efficiency and improving profitability.

Long-haul truck transport needs a lot of energy to cover long distances, ideally with limited time lost for refuelling (depending on local legislation mandating stopping periods). Storing electricity on board is not realistic for such journeys; the huge battery capacity needed would alter the cost of the vehicle and its loading capacity, and would still require many recharging stops.

ETP 2014 analysis examined payback periods for multiple technologies that could be applied to trucking: BEV LCVs, BEV MFTs and catenary HFTs (Table 6.3). If looking only at the vehicle, the BEV MFT has the best median payback period (6.3 years), closely followed by BEV LCV (7.0 years). The difference reflects higher mileage of an MFT versus an LCV, which allows for more rapid recuperation of the initial investment. The payback period for catenary HFT (vehicle only) is just 1.6 years, due to the highest cost being the infrastructure rather than the battery, which the catenary HFT does not have.

For HFTs, a diesel-electric hybrid vehicle is foreseen as the best option in the early deployment phase, as trucks will need to run on non-electrified infrastructure for the first and last miles, until reaching the electrified infrastructure. Fitting lines first along high-traffic corridors would provide the next shortest payback time on the necessary investment.

These results, which stem from using oil prices and mileage by weight class, demonstrate the importance of parameter selection. For all trucks, a low oil price (and thus diesel price) undermines the cost advantage of electricity, thereby lengthening the payback period. Depending on key parameters, the prospect of electrifying heavier modes can quickly lose its appeal, with annual distance being the more important variable. The savings per kilometre is highest for HFTs, but due to high infrastructure costs, the payback period is likely the longest (not to be confused with lifetime economic profitability).

Table 6.3 Payback time of electrified trucks

Vehicle type		Energy price (USD/km)	Vehicle cost (USD)	Investment payback (vehicle only) (years)
LCV	Baseline (diesel)	0.07	22 000	n.a.
	Battery electric	0.03	29 000	4-7
MFT	Baseline (diesel)	0.25	66 000	n.a.
	Battery electric	0.16	127 000	4-13
HFT	Baseline (diesel)	0.46	101 000	n.a.
	Battery electric (Catenary)	0.25	178 000	1-3

Notes: throughout report, catenary numbers refer to both sides of the road and should not be double-counted. Diesel infrastructure cost assumed as 0. Lifetimes assumed as follows: LCV = 8 years; MFTs = 9 years; HFT = 10 years. Payback is compared with diesel reference vehicles. Charging point cost assumed for LCV and MFT BEVs at USD 13 000.

Another way to show the economic viability of an investment is to amortise it over the course of its lifetime. Unless otherwise noted, throughout the chapter a global societal perspective (rather than consumer, fleet operator or government) has been used, but this hides the detail of discount and interest rates.

Using the catenary HFT as an example, a payback calculation could be done from the vehicle or the infrastructure perspective, or from both. For electrified road freight, both have been used since the vehicle and infrastructure are highly integrated; this amplifies the importance of frequency (i.e. usage of infrastructure).

Using the same assumptions from Table 6.3, another calculation framework highlights the differences in perspective. Using a USD 2.5 million/km infrastructure cost assumption for catenary HFT, a government might invest, looking to cover only capital costs. Assuming an infrastructure lifetime of 35 years, an equal lifetime for vehicles, and a real interest rate on government loans of 6% (conservative assumption), an annuity is needed of USD 170 000/km. Assuming a daily total traffic of 4 400 trucks, this equals about 1 600 000 trucks per year. If each truck pays a fee of USD 0.11/km, this would cover the annuity. Higher frequency would lead to lower fees.

From a vehicle payback perspective this means the following:

- diesel fuel cost = USD 0.47/km
- electricity cost = USD 0.24/km
- electricity cost plus infrastructure fee = USD 0.35/km
- the net saving per travelled kilometre thus = USD 0.12/km.

Assuming that a HFT has an annual mileage of 140 000 km per year, this delivers savings of USD 16 800 per year. Adding in the lower maintenance cost (diesel maintenance cost – electric maintenance cost = USD 13 572 – USD 3 878 = USD 9 694) yields a total annual saving of USD 26 494 per travelled kilometre.

In this case, the approximately USD 70 000 (USD 2.5 million per km/35 years of lifetime) additional cost of a catenary HFT compared with a reference diesel vehicle can be paid back in about 2.5 years.

Each method highlights different results – and each has drawbacks. Typically, the method used depends on which perspective is considered most important (the consumer, the fleet operator or the government), and whether the analysis considers the vehicle and infrastructure separately or together. *ETP 2014* uses a global societal (versus consumer or business perspective) analysis to highlight the importance of frequency for corridor electrification projects.

Passenger mass transportation

For buses, *ETP 2014* considers two categories: intercity buses and urban buses (some publications further separate urban minibuses). Their specifications, both technical and logistical, are very different and need to be addressed separately.

Intercity buses (commonly known as coaches) perform a variety of long-distance journeys. At present, a lack of data makes it hard to characterise their trip profiles. Theoretically, in the long term once the technology cost declines, such coaches could be fitted with pantographs to use the overhead lines developed for long-haul trucking. Having multiple users would spread the up-front cost of infrastructure.

Electrification of **urban buses** is expanding rapidly, as municipalities value them for their zero local emissions and low noise levels. With low-carbon electricity, electric buses deliver even more significant well-to-wheel (WTW)[2] CO_2 emissions reductions. Although more expensive to purchase than conventional buses, electric buses are approaching cost-effectiveness thanks to the high degree of utilisation and low operating costs, and to declining battery costs.

In urban areas around the world (especially in Eastern Europe), trolleybuses are a popular alternative to buses running on diesel or compressed natural gas both for lower emissions and reduced noise. The electrical traction of a trolleybus gets its energy from overhead electrical lines. While braking, the electrical driveline can recuperate energy back to the lines or use it on board for heating, air conditioning, etc. The recuperation depends on the topography and the characteristics of a line but is normally between 15% and 35%. Among available technologies, trolleybuses offer lower total cost of ownership (USD 0.68/km) than baseline diesel buses (USD 0.96/km), making them competitive on high-frequency corridors.

2 WTW includes all stages of production taking into account environmental impacts, whereas tank-to-wheel accounts only for environmental impacts as a result of emissions from the vehicle's tank (i.e. not the related impacts of the fuel production upstream).

Box 6.5 Preparing for electrified feeder traffic

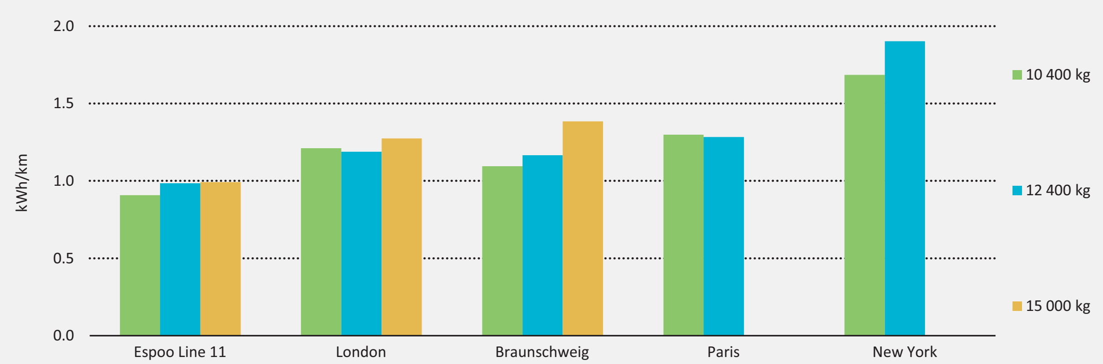
Mass transport stakeholders in the Helsinki region are building a new westbound metro line into the city of Espoo. When the new line begins service in 2015/16, the western bus services will change from longer regional lines to feeder-type (versus primary, trunk) service. With the aim of maximising electrification, Helsinki Region Transport is looking at the option of using battery-electric buses for feeder services in several cities.

The Finnish project is unique in that it builds on:

- involvement of all key actors
- a systemic approach, covering grid, infrastructure, vehicles, operation and planning of electrified operations
- benchmarking of technology from several suppliers
- detailed performance evaluation through on-board and chassis dynamometer measurements
- challenging operation conditions, such as temperatures ranging from - 25°C to + 35°C, humid autumn/pre-winter conditions, and snow and ice in the winter.

The heavy-duty vehicle test facility at the VTT Technical Research Centre of Finland has been updated to enable measurements of total energy use as well as efficiency measurements, component by component. Total energy consumption (energy supplied to the vehicle) for an electric bus varies according to vehicle weight and driving cycle (Figure 6.3). Rounded off, 10 000 kilogrammes (kg) corresponds to a vehicle with moderate battery capacity and moderate passenger load; 15 000 kg to a full-size battery and higher passenger load. Total energy consumption varies from 0.9 kWh/km to 1.9 kWh/km. Corresponding values (as heating value in diesel fuel) for a typical diesel bus are 3.2 kWh/km to 9.5 kWh/km; for a hybrid bus, the values decline to 2.6 kWh/km to 5.8 kWh/km (Nylund and Koponen, 2012).

Figure 6.3 Bus energy consumption in five cities



Source: Erkkilä et al., 2013.

Key point *Across weights and locations, energy consumption for an electric bus was on average 75% less than a conventional diesel bus, and 65% less than a hybrid electric bus.*

Germany, the United States and Korea are testing dynamic induction charging wherein induction plates installed in roadways interact with copper coils on buses to generate electricity while the vehicle drives over the plate (i.e. without the need to stop). This greatly reduces the need for on-board battery storage capacity. Induction has the benefit of complementarity in that multiple vehicle types could potentially use the same power source. Lack of consistent data and the multiplicity of possible configurations, however, made it difficult to include dynamic induction in the sensitivity analysis.

Payback period and sensitivity analysis for passenger mass transportation shows wide variability for static induction, trolley and battery charging in buses. Battery-electric buses have shorter and more stable payback periods compared with diesel buses, largely due to lower infrastructure costs and reduced dependence on oil price variability. EVs have lower maintenance costs because electric power trains need less service than conventional technologies, and the wear on the brakes is reduced since part of the braking is done electrically. Overall, results point towards the most cost-effective solution being options such as bus rapid transit (BRT) for high-frequency routes (Trigg and Fulton, 2012).

Though most vehicles types discussed above come at a higher cost than the USD 300 000 of a diesel bus, across all technological configurations they deliver a lower energy cost per kilometre (Nylund and Koponen, 2012). The infrastructure cost (including maintenance) is hard to calculate, though USD 40 000 is assumed for a charging point, USD 630 000/km for overhead catenary and USD 260 000/km for static induction (using an estimated average number of stopping plates needed to satisfy a bus driving cycle).

Overall, the payback periods for the vehicles range between:

- four to nine years for battery-electric buses
- three to eight years for trolleybuses
- one to five years for induction buses.

All show high sensitivity to oil prices. Payback periods for dynamic induction and battery swapping are difficult to define due to the high uncertainty of infrastructure costs. Including infrastructure into the calculation for trolley and induction buses is similarly difficult to define due to high variability in cost estimates and uncertain frequency estimates.

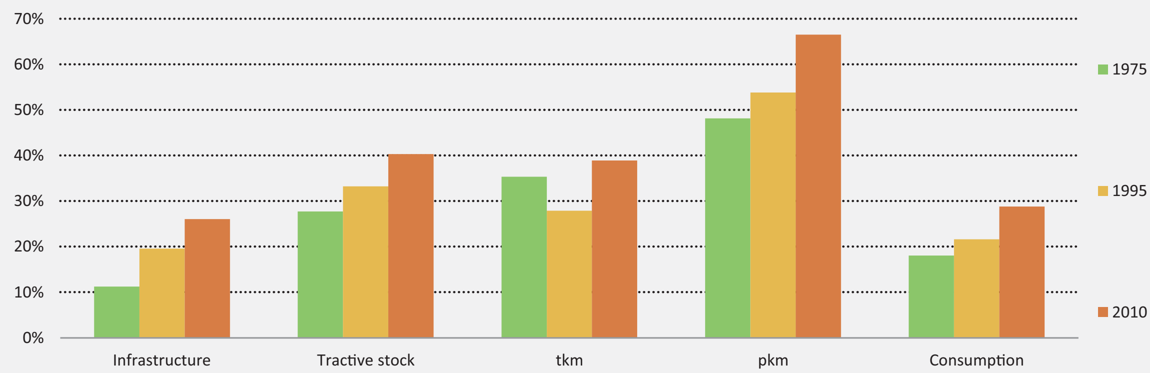
Rail

Rail is the transport mode with the highest share of electrification; in fact, electricity accounts for one-third of energy now used in the rail sector. More than one-quarter of the rail infrastructure is electrified worldwide (UIC/IEA, 2013), with almost 40% of the powered railway stock being electric locomotives (Figure 6.4). Rail electrification is increasing across five key metrics, including infrastructure, tractive stock, freight tonne kilometres (tkm), passenger kilometres (pkm) and final energy consumption. Freight goods movement (tkm) shows the slowest progress, which is understandable given the average long distances freight trains travel compared with passenger trains as well as low electrification rates in the United States and Russia, which account for a large portion of the total tkm.

The electric infrastructure and rolling stock is proving to be more reliable as less maintenance is required and is less costly to run for high-traffic and/or high-frequency corridors compared with diesel-powered locomotives (Table 6.4). Most non-electric trains run on diesel-powered engines coupled to the electric motor, where the powertrain arrangement is often very similar to that of a hybrid road vehicle, as well as diesel-mechanic and diesel-hydraulic transmissions.

Urban rail systems are today all electrified, whether on-the-ground tramways, overhead light rail applications or underground metro applications. Electric rail urban systems are well-proven as a mass transport solution with high capacity that offers numerous benefits to communities such as being relatively quiet and pollution free at the point of use with high frequency and reliability along fixed routes.

Figure 6.4 Electrification evolution of the worldwide railway sector



Notes: pkm = passenger kilometres; tkm = freight tonne kilometres. Consumption refers to percentage of exajoules that are electric of final energy consumption.

Key point *Rail electrification is moving forward across all five metrics listed above, with more relative progress seen for passenger rail than for freight rail.*

Switching the focus to intercity rail (diesel and electric), one must first acknowledge that freight and passenger trains have different characteristics, and so need to be assessed separately. Freight trains pull very heavy loads that need more energy, but usually operate less frequently than passenger trains that run more often with lighter loads.

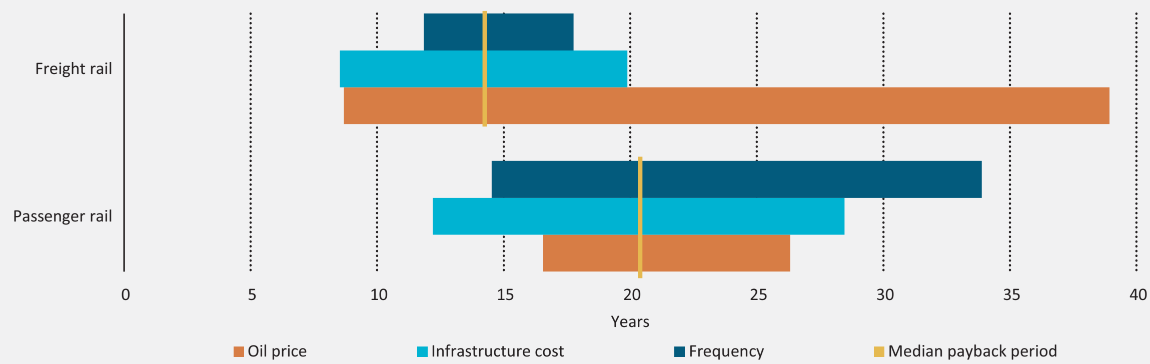
Table 6.4 Train running costs by energy source

		Energy cost (USD/kWh)	Efficiency (kWh/vkm)	Maintenance (USD/vkm)	Loco lease (USD/vkm)	Total running cost (USD/vkm)	Overhead line cost (USD/track km)
Passenger	Electric	0.17	14	0.6	1.0	**3.8**	1 000 000
	Diesel	0.14	33	0.8	1.4	**7.0**	0
Freight	Electric	0.17	70	1.1	2.7	**16.0**	1 000 000
	Diesel	0.14	140	1.6	4.0	**25.8**	0

Notes: vkm = vehicle-kilometre. Maintenance costs include locomotive and infrastructure maintenance costs. Load factor for freight assumed as 2 000 tonnes per train.
Source: NetworkRail, 2013.

Depending on cost assumptions and train frequency, the payback time for installation of overhead lines is generally shorter than the expected lifetime of the lines, especially when train frequency is above five trains per hour (Figure 6.5). Freight train payback time is shorter than for passenger trains, largely due to the efficiency differences compared with a reference diesel train, though this is highly sensitive to oil price fluctuations.

Figure 6.5 Rail applications: Sensitivity analysis (+/- 40%) for key parameters on payback period



Key point *Payback periods for rail vary by oil price in particular, with low oil prices making it especially hard for freight rail to recuperate the up-front investment in electrification.*

Shipping

Little short-term opportunity is seen in electrifying long-haul shipping. But limited savings can be realised by electrifying marine vessel operation when at port, so that engines can be turned off to reduce fuel use, thereby saving costs and reducing local air pollution (Box 6.6).

Some trials are under way to run electric ferries for island countries and river crossings. Norway is assessing the potential of battery swapping for a full electric ferry with recharging of less than ten minutes (Barry, 2013a). As demonstrated in Denmark, the potential for hybridisation is high for frequent ferries with payback periods of four years (Barry, 2013b). The value proposition for ferry electrification increases as the annual distance increases, and may be most interesting for short-distance, high-frequency ferry routes found on the west coast of North America, parts of Scandinavia and elsewhere.

Leisure boats could also be partially electrified. Recently, a 31 metre (m) yacht covered with 500 m^2 of photovoltaic (PV) cells successfully circumnavigated the globe to showcase the technology's viability (MS Tûranor PlanetSolar). Despite increased interest, with the exception of ferries, any mainstream commercial applications for electrification of shipping are unlikely before 2030, after which point maritime electrification could become more widespread.

Aviation

Aircraft electrification, as for marine vessels, would allow fuel saving but is unlikely to become a primary energy source. Aircraft manufacturers increasingly use electric devices to replace components that were previously hydraulic or pneumatic. As the resulting efficiency supports significant fuel savings, the electrification trend is expected to carry on (Table 6.5), but full fuel switching is unlikely except for small, very light-body aircraft.

Israel's El Al airline has converted 20 of its Boeing 737s so that they use hybrid electric power while on the ground. According to El Al, using the auxiliary power unit instead of the primary engines to operate on the tarmac (taxiing and idling) can reduce fuel use by 85% while grounded. A NASA/Boeing report suggests that plug-in aircraft could hit the market at the 2040 horizon. Similarly, the SUGAR Volt project involves a plug-in hybrid aircraft with an

Box 6.6 Nascent niche applications: Electrifying the operations of ports and airports

When at halt, aircraft and marine vessels become the focal point of many related activities. Many support vehicles circulate at airports and port facilities, mostly relying on fossil energy that is attributed to the service sector (rather than to transport, even though most of the vehicles used are similar to those driving on open roads). As they operate on predictable paths and are always close to their base of operations, these vehicles are strong candidates for electrification.

The ports of Los Angeles, Rotterdam and Houston are leading the way with hybrid and plug-in hybrid yard hostlers. Marine vessels can now plug into shore power to avoid using diesel during lengthy docking procedures (including loading and unloading). The Port of Los Angeles (the biggest in the United States) is looking at powering trucks with overhead wires, as well as fuel cell electric trucks, for drayage operations. In 2009, the Port of Los Angeles took delivery of 25 heavy-duty, all-electric drayage trucks, which can pull a 27 000-pound cargo container at a top speed of 64 km per hour and have a range of 48 km to 97 km per charge. Similarly, rail is being considered to avoid using trucks, further electrifying ports around the world.

In Canada, four ports or organisations have invested in shore power: Port Metro Vancouver (cruise ships); Prince Rupert (container ships); Halifax (cruise ships); and Seaspan (ferries). The Halifax port is the largest investment with a total project cost of USD 10 million, and is estimated to provide annual reductions in fuel use of 123 000 litres and 370 000 kg of GHGs. These installations were partially funded under Transport Canada's Shore Power Technology for Ports programme and its predecessor, the Marine Shore Power Program.

Table 6.5 Stages of electrification by type of aircraft

<table>
<tr><th>Function/control</th><th>Conventional aircrafts</th><th>More electric aircrafts (B787)</th><th>All-electric aircrafts</th></tr>
<tr><td>Taxiing</td><td>Thrust</td><td>Thrust</td><td rowspan="10">Electric system</td></tr>
<tr><td>Flight control actuator</td><td rowspan="3">Hydraulic system</td><td rowspan="3">Hydraulic system</td></tr>
<tr><td>Landing gear</td></tr>
<tr><td>Utility actuator</td></tr>
<tr><td>De-ice</td><td rowspan="2">Pneumatic system</td><td rowspan="6">Electric system</td></tr>
<tr><td>Environmental control</td></tr>
<tr><td>Motor</td><td rowspan="4">Electric system</td></tr>
<tr><td>Lighting service</td></tr>
<tr><td>Heating service</td></tr>
<tr><td>Avionics and subsystem controllers</td></tr>
</table>

Source: Mehta, 2013.

on-board battery for regional short-haul flights (Bradley and Droney, 2011). If the hybrid electric motors or batteries are excessively heavy, such initiatives could become cost-negative. Weight is crucial when making the calculation for any innovation in aviation.

Aircraft, as for marine vessels, have a significant area directly exposed to sunlight, and can benefit from high irradiance[3] when flying above the clouds. Fitting aircraft with PV cells could power a tiny share of the engine (less than 1%) and electricity needs while cruising, reducing

3 Irradiance is the power of electromagnetic radiation per unit area (radiative flux) incident on a surface.

fuel consumption by more than 100 kg on daytime flights (Mehta, 2013). In the long term, fitting aircraft bodywork and wings with solar panels can help reduce the fuel needed on board and allow for more load (cargo or passengers), thereby increasing flight revenue. As the cost and weight of solar panels decrease, the case for capturing solar radiance while in flight will increase. It is unrealistic to think, however, that solar energy could propel aircraft with more than 20 passengers.[4]

Summary of vehicle electrification payback periods and sensitivity analysis

ETP 2014 analysis shows that cost-effectiveness of electrifying transport is inconsistent across modes, and that payback period can differ substantially depending on the mode, the electrification technology and the parameters selected. The cost of oil, and of the electric storage/supply devices chosen, both significantly influence the final cost-effectiveness and payback periods of electrification in transport. With electric propulsion being so efficient, electricity price is not a key parameter to consider; rather, fossil fuel prices, annual mileage and battery/overhead line costs are of primary importance for an acceptable payback time.

The demand profile for electric freight/public transport services using overhead/induction is much easier to manage from the operator's point of view (much flatter), so on-board storage is less necessary. In general, there is less need for any demand-side management (DSM). Electricity storage can be made at a larger scale, for example through pumped hydraulic storage or compressed air electricity storage, so that those modes can also rely heavily on renewable electricity. Vehicle-to-grid technology is less important than managing the charging demand. Some manner of smart charging should be more cost-effective than most alternatives for DSM at the distribution level (see Chapter 7).

Since electrical vehicles tend to have lower operating costs than fossil-fuelled alternatives, payback is often achieved before the lifetime of the vehicle and/or infrastructure. The challenge lies in aligning public and private stakeholders to set the conditions for achieving this payback as quickly and broadly as feasible. The vehicle service (passenger or freight) plays a large role as the relevant buyers differ in their risk tolerance in relation to payback periods. Similarly, the risk profile differs greatly in relation to the vehicle versus the related infrastructure.

The LETMIX

As evidenced, electrifying the transport sector has significant benefits and – from a societal perspective – can be cost-effective in the near term for certain applications. This section focuses on how switching to e-mobility can maximise CO_2 emissions reduction, based on a new modelling tool developed by the IEA. The LETMIX identifies countries that have a strong focus on low-carbon intensity and/or high shares of oil imports in transport, and can thus maximise the benefits from a massive deployment of e-mobility. In total, the model analyses six criteria:

- the country's current **electricity carbon intensity**
- threat to energy security from **oil imports**
- country plans to **decarbonise electricity supply**

4 Internal estimate.

- the current **share of electricity** use in the transport sector
- country plans to **develop e-mobility**
- convenience of **e-mobility deployment**.

LETMIX relies on a quantified scoring system to rank countries based on their performance in each of these criteria. Higher scores indicate which countries are most ready to benefit; minimum scores represent countries least ready (Table 6.6).

Table 6.6 Scoring system for the LETMIX

Criteria / Score	2011			2050	
	Electricity carbon intensity (gCO_2/kWh)	% of oil imported	% of electricity as transport fuel	4DS electricity carbon intensity (gCO_2/kWh)	Plans to deploy e-mobility (subjective scale)
0	> 900	< 10	0-0.8	> 450	no incentive to deploy e-mobility
1	800-900	10-19	0.8-1.5	400-450	
2	700-800	20-29	1.5-2.3	350-400	
3	600-700	30-39	2.3-3.0	300-350	
4	500-600	40-49	3.0-3.8	250-300	
5	400-500	50-59	3.8-4.6	200-250	
6	300-400	60-69	4.6-5.3	150-200	
7	200-300	70-79	5.3-6.1	100-150	many incentives in place to promote e-mobility
8	100-200	80-89	6.1-6.8	50-100	
9	50-100	90-99	6.8-7.6	0-50	
10	< 50	100	> 7.6	< 0	

Note: gCO_2 = grams of carbon dioxide.

LETMIX aims to highlight countries where clean electrification of transport is most advanced, while also providing insights of where it is most desirable. Thus, the index could help provide a metric for national policy makers seeking to establish a lower-carbon transport sector and benefit from an energy security perspective by taking into account the share of oil imports.

A country's power generation sector plays a key role in readiness for low-carbon electrification of transport. The lower the carbon intensity of the electricity, the larger the CO_2 emissions reduction possible when migrating away from vehicles that rely on fossil energy.

Based on the efficiency difference between an EV and its ICE equivalent, it is possible to calculate a "CO_2 from power generation threshold" to identify the point at which the EV becomes the less CO_2-intensive option (Table 6.7). This threshold differs slightly, depending on modes and fuel considered as a reference. For most modes, CO_2 savings can be achieved by switching to electric propulsion when electricity carbon intensity is below 700 gCO_2/kWh (the emissions rate of a typical, state-of-the-art coal power plant).

The one notable exception is powered 2-wheelers; because they are dramatically more efficient when running on electricity, CO_2 reduction can be achieved even when electricity generation is carbon-intense. As the final column in Table 6.7 shows, based on the national average carbon intensity (which differs by region), for all modes more than 27% of the countries could benefit from deploying EVs to save CO_2, and all would gain from deploying electric 2-wheelers.

Table 6.7 Typical power carbon intensity threshold to allow for CO_2 savings when electrifying transport

Mode	Typical efficiency		Efficiency difference (%)	Threshold below which CO_2 is saved (gCO_2/kWh)	% of countries in which mode would reduce CO_2
	ICE (Wh/vkm)	Electric (Wh/vkm)			
2-wheelers	349	29	92	3 065	100
Cars	372	170	54	559	33
Vans	493	200	59	628	27
Medium trucks	1 674	930	44	459	46
Heavy trucks	3 256	1 395	57	594	30
Passenger trains	33	14	58	601	29
Freight trains	140	70	50	510	39

Note: Wh = watt hours.

In a 2DS future, electricity becomes significantly decarbonised to a worldwide average of just 37 gCO_2/kWh by 2050 (compared with 529 gCO_2/kWh in 2013). Most countries will be well below each modal threshold shown above. To take into account current country/region plans to decarbonise electricity – and thereby better reflect the electricity mix and carbon content most likely in the coming decades – LETMIX uses the 4°C Scenario (4DS) carbon intensity in 2050 for the power sector.

Few energy pathways allow for ongoing CO_2 emissions reduction without any need for retrofits to the energy-consuming devices. During the lifetime of an EV, its CO_2 emissions will vary as the carbon electricity of the power system evolves. Hydrogen, drop-in biofuels (to a certain extent) and biogases all have the same potential benefit with no need to change anything on the vehicle. Once bought, these vehicles have the potential to become cleaner over time. In a power sector that decarbonises quickly, as in the 2DS, this leads to significant economic savings and increases the cost-effectiveness of electrifying the transport sector. Countries that deploy EVs (or the other technologies) early on are in a better position to maximise the gains of an e-mobility strategy.

Overall, electricity represents a small share of energy used in the transport sector (Figure 6.1), but shares vary considerably from country to country. Ergo, the starting point for decarbonisation differs: some countries will be able to react faster when an electrification strategy is to be adopted. Many governments have announced ambitious plans to deploy EVs in their national fleet. The IEA-led Electric Vehicles Initiative (EVI) is tracking such announcements to use as a basis to attribute part of future LETMIX scores to countries that have ambitious EV deployment targets (IEA, 2013a).

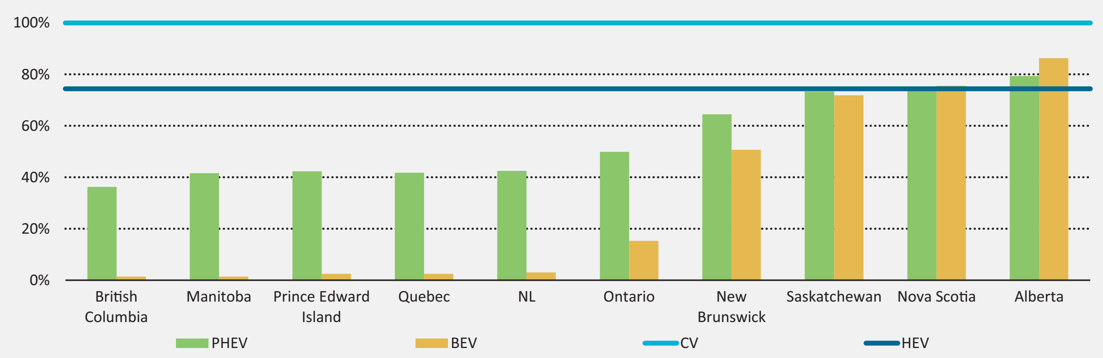
The last criterion, related to the convenience of e-mobility deployment to maximise CO_2 emissions reduction, is more subjective and thus given a lighter weight when using LETMIX to rank countries, with only five bonus points given where applicable. It reflects country characteristics such as topography, size, population density and grid inter-connectivity. In places such as small isolated islands, deploying e-mobility would seem more relevant, as vehicles are not driven for long periods or far from their charging point. Moreover, having no interaction with other grids, island communities can better control their electricity mix.

Box 6.7 Optimum emissions reduction solutions strongly depend on local conditions and time

Being a large country with diverse geography, Canada draws upon a large variety of primary sources and technologies to generate electricity. Some provinces mainly use hydropower; others rely heavily on fossil fuels. Thus, using electricity to replace gasoline in transport will have varying impacts on GHG emissions. Provinces with clean electricity can drastically reduce GHG emissions by using PHEVs and especially BEVs to replace ICE vehicles in their light-duty fleets. The emissions reduction opportunity is lower in provinces using mainly coal for power production. In some of these provinces, HEVs provide cleaner transportation than PHEVs or BEVs (Figure 6.6).

Importantly, one study revealed that long-term solutions may differ significantly from options that maximise emissions reduction in the short to medium term. As HEVs were introduced into the market first, their share of the provincial fleets in 2030 is expected to be higher than those of PHEVs and BEVs. Although HEVs generally have lower emissions reduction on a per-vehicle basis, an aggregate effect is evident. In the provinces with fossil-fuelled based generation, the larger number of HEVs will deliver larger total GHG reduction than the smaller numbers of PHEVs or BEVs. In the longer term, with anticipated further greening of electricity generation after 2030, PHEVs and BEVs also become the preferred options for these provinces.

Figure 6.6 GHG emissions of advanced vehicles as a percentage relative to average conventional vehicle (CV), by Canadian province in 2030

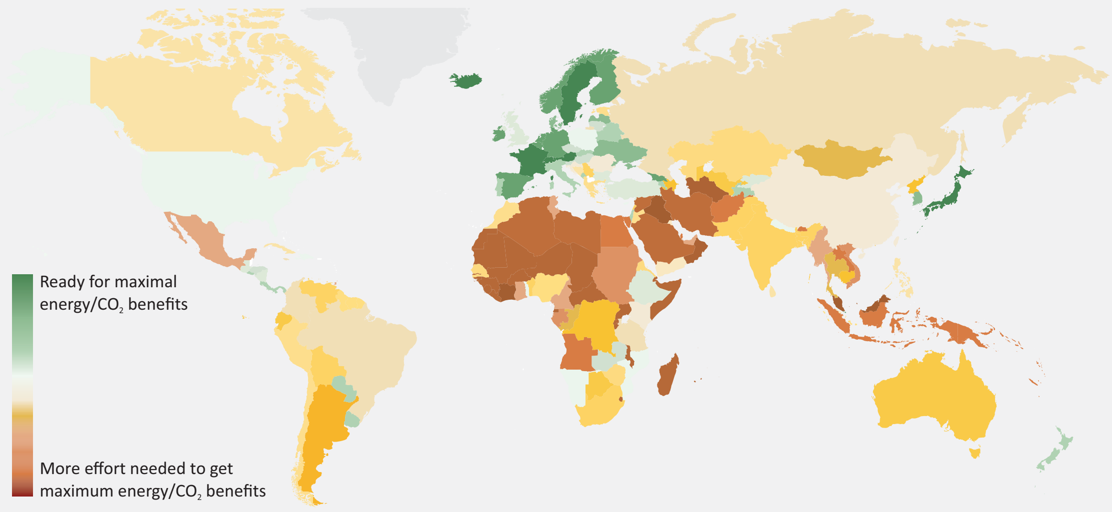


Notes: NL = Newfoundland and Labrador. PEV-CIM, the Plug-in Electric Vehicle – Charge Impact Model, is a software tool to evaluate the impact of EVs on the electricity grid, on emissions and on fuel costs. PEV-CIM can be downloaded freely from the software tools section on www.nrcan.gc.ca/energy/resources.
Source: NRCAN, 2014a. © Her Majesty the Queen in Right of Canada, as represented by the Minister of Natural Resources, 2014.

Key point *The GHG emissions intensity of the local electricity grid greatly influences which vehicle technology has the lowest emissions.*

While LETMIX shows that countries are at different stages in low-carbon power supply and electric transport deployment, it also drives home the point that all can do more. Countries that have a high score can and should go further into a transport electrification strategy; countries with a low score should undertake requisite steps to support massive deployment of electric transport modes (Figure 6.7). Countries starting from scratch will need to tackle EV deployment and low-carbon electricity in parallel.

Figure 6.7 LETMIX



Note: this map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Key point *Scandinavia and Japan are in good position to maximise the CO_2 and energy security benefits from an electrification strategy.*

Mapping the LETMIX results shows that the Scandinavian region is in the best position to forge ahead with electrifying transport, with low-carbon electricity already available and e-mobility plans under way. Boosting efforts would bring the region significant CO_2 cuts, and contribute to its ambitious GHG mitigation plans (IEA, 2013d). Norway has a high share of EVs – about 6% of new vehicles sales in 2012.

Switzerland, France, and Japan are also in the lead group, both with high shares of electrified rail in the current mode mix. Former Soviet Union countries have high scores, mainly because electricity use is already quite common in the transport sector, though long-term plans to further electrify lack ambition. China is very proactive in deploying e-mobility but further work is needed on decarbonising the power sector to bring CO_2 saving benefits in the mid- to long term. High reliance on coal-fired power undermines the potential CO_2 savings and must be addressed together with EV deployment.

Electricity use in transport is almost non-existent throughout the Middle East and in the ASEAN region. The Middle East needs more effort on power sector decarbonisation to support low-carbon e-mobility. Recent analysis in the *World Energy Outlook 2013* shows that at current oil prices, almost all technology options (including solar) would be competitive with oil-fired generation, but deployment is hampered by substantial oil product subsidies (IEA, 2013c). Saudi Arabia has shown interest in high-speed trains powered by overhead lines, which would help increase to some extent the regional share of electricity in transport. With many areas still lacking any electricity access, Africa has limited potential to electrify transport in the coming decades.

The Americas show diverse scores that reflect local and national circumstances, with the evolution of electricity carbon content to 2050 playing a large role. At present, current and future e-mobility plans are rather limited and focused only on selected modes, such as e-BRT in Colombia and passenger car BEVs and PHEVs in the United States. Brazil shows good potential, as its electricity is hydro-based and almost carbon-free, and is likely to remain so in the future.

The *ETP 2014* 2DS and 2DS-ET variant

By 2050, the 2DS already includes a significant share of electric mobility, especially for cars and powered 2-wheelers, where deployment efforts have already started (see Chapter 1: The Global Outlook). The 2DS power sector is close to being zero-carbon emissions in 2050.

Most battery-powered vehicles (especially commercial ones for LCVs and MFTs) are assumed to plug in to the grid once the working hours are over and charge overnight when overall electricity demand is lower. Trolley vehicles continue to need immediate supply of power, and the power needed for freight applications (electric trains, trolley trucks) is assumed to be distributed throughout the day and night. Demand for passenger applications (urban buses, trains) will be concentrated during the day. The mix of vehicles that store electricity on board versus those drawing electricity from the grid will have a significant impact on the grid and its development.

Before 2030, e-mobility is expected to have a limited impact on the grid. Even in countries where rail is fully electrified and has an important modal share (e.g. Switzerland), transport demand currently represents only 5% of total electricity consumption. Only in Russia does transport exceed 10% of electricity consumption, but this share appears to be decreasing as private car ownership rises.

In all regions, it will be important to ensure that transport-related electricity demand will not drive up peak electricity demand, requiring not only extra power supply facilities, but also a smarter grid and DSM.

After using the weighted preferences of LETMIX as an input to define regional information on *where* e-mobility should be deployed first, *ETP 2014* used these regional results to model a scenario that pushes the limits of electrification in transport, with the aim of showing the long-term benefits of such an aggressive strategy.

The *ETP* 2DS-ET variant

The 2DS-Electrifying Transport (2DS-ET) scenario models massive electrification of transport, first in regions with high LETMIX scores, to maximise CO_2 savings. It aggressively pursues electrification of road freight vehicles (LCVs, MFTs and HFTs), which is largely unexploited at present and insubstantial in the 2DS. As the 2DS is already ambitious in terms of electrifying light-duty road passenger applications (IEA, 2012), the number of passenger EVs does not rise substantially in the 2DS-ET.

Electric transport is the dominant technical pathway in 2DS-ET variant. Having much higher shares, it displaces not only fossil fuels but also alternatives such as hydrogen and natural gas, which come to play only minor roles. In the 2DS-ET, plug-in hybrids are considered only as a bridge technology that facilitates the transition from ICEs to EVs. Dynamic induction is not considered in 2DS, but is considered in 2DS-ET for wide-scale implementation only after 2040; it does not become a dominant technology option before 2050.

Increased electrification in the 2DS-ET also aims to address other aspects of transport that are more challenging to decarbonise than previously expected. Recent challenges in biofuels deployment, for example, raise the question of whether their supply will be limited in the long term and should thus be targeted to long-haul modes that cannot refuel en route, such as aviation or shipping.

Overall, 2DS-ET pushes e-mobility further, especially on-road freight application, where penetration shares were low or non-existent in 4DS and 2DS (Table 6.8).

Table 6.8 Key assumptions for vehicles technology penetration rate

Mode	Dominant electric powertrain type	Stock share in the fleet (%) 2030 2DS-ET	2030 2DS	2030 4DS	2050 2DS-ET	2050 2DS	2050 4DS
Passenger							
2-wheelers	BEV	50	40	28	70	50	27
Cars	BEV	4	4	< 1	17	17	2
Urban minibus	BEV	8	< 1	< 1	30	< 1	< 1
Urban bus	Trolley electric	7	< 1	< 1	27	< 1	< 1
Intercity bus	Diesel hybrid with pantograph	1	0	0	8	0	0
Freight							
LCVs	BEV	5	1	< 1	26	1	< 1
MFTs	BEV	5	1	< 1	27	1	< 1
HFTs	Diesel hybrid with pantograph	2	0	0	15	0	0
Rail	Electric with pantograph	55	51	45	71	61	50

Electrifying road freight

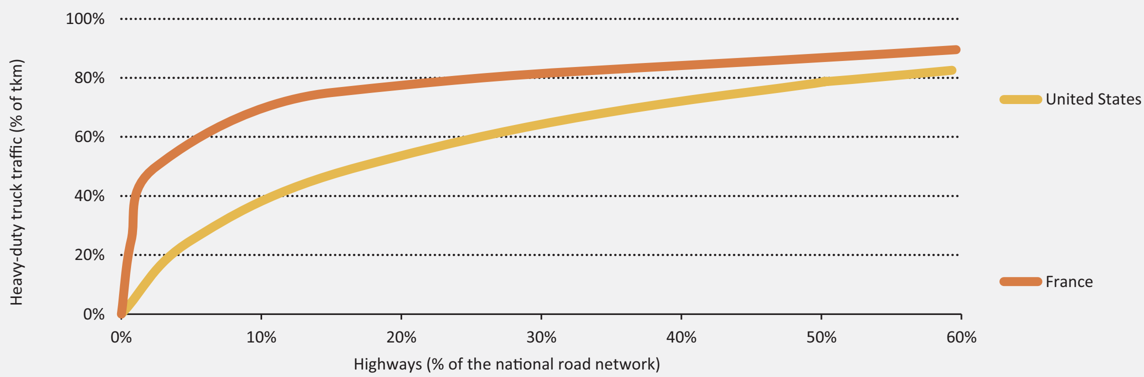
The 2DS-ET focuses on freight electrification potential for urban deliveries and long distance, both for road and rail applications, based on the evidence shown earlier that overhead electrification of trains and heavy-duty trucks could be cost-effective – particularly if frequency is high.

To grasp the scale of the potential in the 2DS-ET, it is helpful to understand the present situation. In many member countries of the Organisation for Economic Co-operation and Development (OECD), long-haul truck traffic is concentrated on main corridors. In France, more than half of long-haul trucking activity occurs on 2.5% of the motorway infrastructure (Figure 6.8). In the United States, 50% of the tonnes carried use only 17% of the interstate network (US DOT, 2011). Even a limited overhead infrastructure deployment would displace a significant amount of the fuel currently used by long-distance truck operators.

In urban areas, hybridisation would improve efficiency significantly, as loads and speeds often vary.

On long trips, of 800 km distance or more, mode switching could be encouraged – including transporting containers on specific trains on new dedicated railways – and trucking could be discouraged. For middle distances, trucks could be fed with electricity through induction or from overhead wires trough trolley poles while travelling on highways. In Europe, almost half the total tonne kilometres are in these middle-distance trips (500 km), with a significant share of these distances run on highways. The savings potential could exceed 40% of oil consumption and CO_2 emissions of current road freight – depending on the share of trips over 500 km that can be transferred to rail (IEA, 2011b).

Figure 6.8 Truck traffic concentration, United States and France, 2011



Source: IEA analysis based on URF, 2013 and US DOT, 2011.

Key point *The concentration of heavy-duty traffic is an opportunity for electrification.*

2DS versus 2DS-ET impacts on energy and CO_2

Thanks to the higher efficiency of electric powertrains compared to ICEs, by 2050 global transport energy use in 2DS-ET is 5% lower than in the 2DS, for a similar level of transport demand activity (Figure 6.9). Moreover, diesel demand drops by 10% to 25 EJ for the whole transport sector. With electric infrastructure (whether recharging stations, overhead lines or induction) and vehicle deployment for long-haul travel ramping up after 2035, electricity not only displaces fossil fuel use but also decreases the need for other low-carbon fuels such as hydrogen or biofuels. As a result, hydrogen use drops from 4.4 EJ in 2DS to 2.6 EJ in 2DS-ET in 2050.

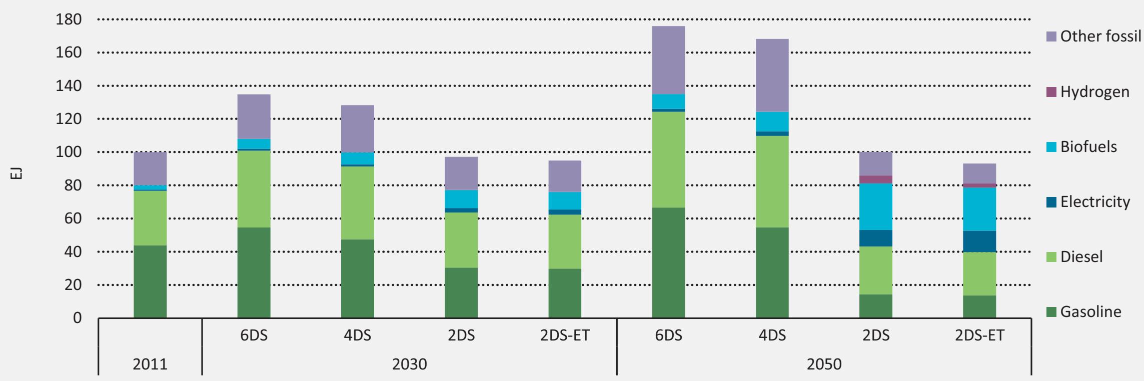
When pushing electrification to its maximum in the 2DS-ET, the extra electricity demand is almost entirely offset by a drop in demand from reduced hydrogen demand, due to high losses in converting electricity to hydrogen.

As in the 2DS, transport demand remains below 15% of global electricity demand. Electricity's share in transport energy use rises from 1% in 2013 to 13% in 2DS-ET in 2050, compared with 11% in 2DS. Realistically, with massive deployment starting in the mid-2030s, most benefits of the 2DS-ET are expected to come after 2050; the scenario strongly contributes to a fully decarbonised transport sector by 2075 and beyond (IEA, 2012).

The extra electricity demand in the 2DS compared with the 4DS is mainly from light-duty BEVs. In the 2DS-ET, demand for instantaneous power from overhead lines increases. Overhead applications are used today by train operators that run predetermined routes on pre-planned schedules, which allow electricity network operators to plan for the demand in advance. Massive deployment of long-haul trolley trucks is likely to make the prediction for the instantaneous demand more complex; for example, sub-stations along the lines would need to be scaled appropriately. Grid operators could provide incentives to encourage freight companies to move their wares during off-peak periods (e.g. at night), thereby shifting demand.

The means of large-scale BEV charging reflected in the 2DS-ET is still unknown (e.g. slow/fast and home/public), and might pose substantial challenges to grid operators. Demand-response management will have to evolve alongside BEV deployment, probably using electricity pricing as a lever to shift recharging demand to off-peak times.

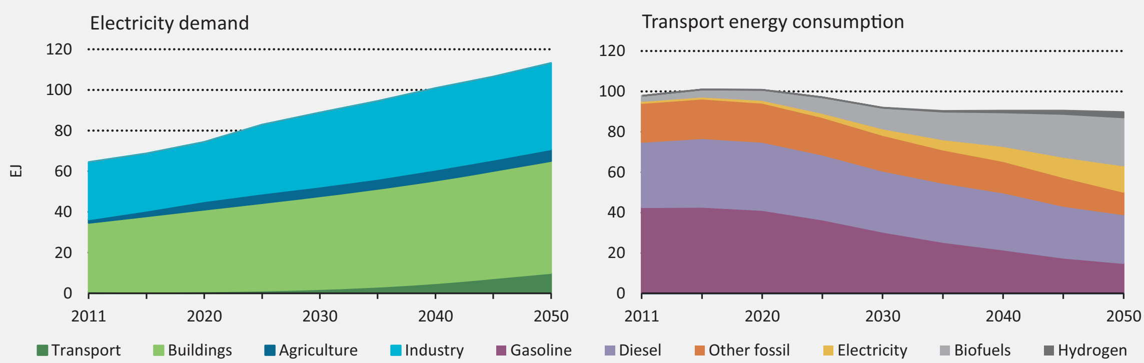
Figure 6.9 Final energy use of the transport sector



Key point *High efficiency of electric motors provides significant energy savings in both 2DS and 2DS-ET.*

Overall, transport in the 2DS-ET requires 3 EJ of extra electricity supply in 2050 compared with the 2DS. This transport demand tops out at 118 EJ in 2050, which still represents a modest share of total electricity demand among all end-use sectors (Figure 6.10).

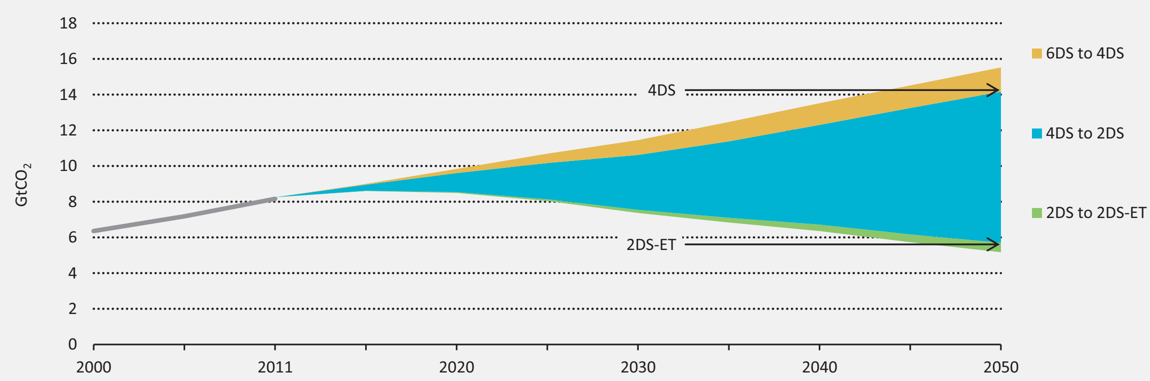
Figure 6.10 Transport energy demand by fuel type and electricity use by sector, 2DS-ET



Key point *In 2050, electricity for transport demand accounts for just 13% of total electricity demand, despite electrifying over half of the passenger vehicle fleet.*

The CO_2 emissions reduction prospects in the 2DS-ET exceed those of the 2DS; by 2050, a strongly decarbonised power sector reduces overall WTW CO_2 emissions by about 10% more than the 2DS (Figure 6.11). Cumulated over the decades leading up to 2050, the additional savings in the 2DS-ET is almost 7 $GtCO_2$. Although modest compared with the 1 000 $GtCO_2$ likely to be emitted over the same period under the 2DS, it still supports the way towards a carbon-free transport sector later in the century as the power sector continues to decarbonise. Once the energy supply and infrastructure hurdles are surpassed, EVs become cleaner over time.

Figure 6.11 Impact of transport sector electrification on CO_2 emissions



Key point *The most dramatic CO_2 emissions savings are from 4DS to 2DS, with 2DS-ET providing slightly more.*

Impacts of an electrification strategy on refining

With transport electrification, the 2DS and 2DS-ET will alter demand for fossil fuels, effectively forcing an evolution of the output mix of refineries. In the 2DS, gasoline fuel demand is greatly reduced by substantial fuel economy improvement of ICEs, by hybridisation and by EVs replacing mainly gasoline light-duty vehicles. Higher drop-in share of biofuel in the gasoline mix also reduces demand for gasoline from oil. In total, fossil gasoline demand drops by 70% in the 2DS, from 43 EJ in 2011 to 13 EJ in 2050. Diesel demand falls by 20% in the same period (from 32 EJ to 26 EJ), mainly through fuel economy improvements. These substantial drops occur even while truck traffic doubles between 2011 and 2050 in 2DS.

The evolution of transport will also affect demand for middle distillates. Shipping will require larger quantities to reduce sulphur from marine vessels. Electrifying the freight sector as in 2DS-ET would displace larger quantities of middle distillates, permitting refinery capacity to evolve more slowly and giving lead time to adapt to the distillate type demand switch (Figure 6.12).

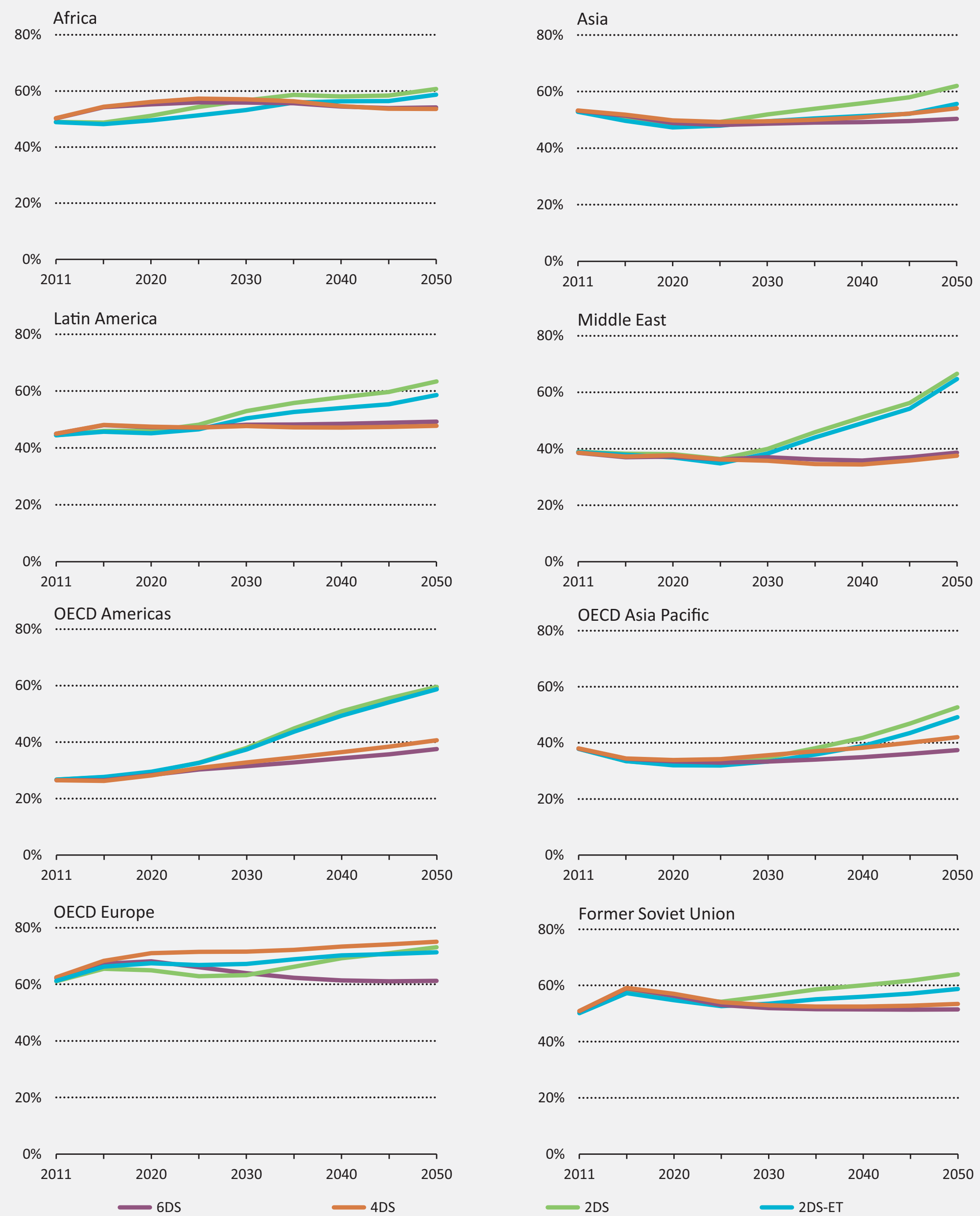
In some countries, final product shortages have already created price tension for such products, which could be considered as a threat to energy supply and energy security. Europe has a long history of diesel imports due to the high share of diesel in the vehicle fleet. Electrifying transport as done in 2DS-ET could dampen the potential final product price volatility, and therefore be seen as an energy security benefit.

The diesel share of the gasoline-diesel mix rises significantly over time in 2DS, from 42% in 2011 to 63% in 2050. In the 2DS-ET, the share of diesel climbs to only 58% (Figure 6.12).

Recommended actions for the near term

Electrification should be seen as an opportunity that brings significant benefits to the transport sector. Diversifying transport away from oil dominance enhances energy security by weakening certain import dependencies. It also ensures that governments have more fuel options at their disposal, including electricity.

Figure 6.12 Diesel share of gasoline/diesel mix



Key point *As diesel share will rise significantly in the 2DS, some regions are likely to struggle providing supply; slightly lower demand in the 2DS-ET relieves the pressure somewhat for certain regions.*

CO_2 emissions reduction, zero tailpipe emissions, reduced noise (especially at low speeds) and improved energy security all contribute to a more sustainable transport system. Deployment of certain e-mobility options (e.g. electric 2-wheelers in China, car sharing of BEVs in France, catenary buses in Austria) was already cost-effective in 2013 taking a societal point of view without discounting, and can already save CO_2 emissions in many countries and regions.

The social value proposition of an EV is higher than that of a conventional vehicle. But concerted efforts from all stakeholders will be needed to realise this proposition, including enabling of smart grids, energy storage, lower CO_2 WTW emissions, lower noise and lower local air pollution.

Networked and shared mobility represents an optimal combination of cost savings and CO_2 reductions; such innovative business models to enhance e-mobility can also reduce investment costs.

Substantial up-front investment in vehicles and infrastructure is needed to make e-mobility a widespread, viable alternative to conventional transport technologies. Governments would be wise to invest in e-mobility, but must also back their investment with pricing policies (financial and non-financial support) that encourage massive adoption of e-mobility worldwide.

Battery charging appears suitable for lighter vehicles, whereas battery swapping is appropriate for fleets (multiple vehicle operators), though a stock of batteries is necessary, which is rather costly in terms of capital expenditure. Catenary lines and induction are best suited for predictable lines with high vehicle frequency; the increased utilisation factor spreads the overall investment over a greater number of potential ratepayers.

E-mobility along pathways (e.g. highways) could concentrate road freight traffic and allow for substantial CO_2 savings, as can other alternative fuel infrastructure deployment. In fact, new infrastructure should be deployed where it will be amortised the fastest, on busiest corridors.

Developing a wider portfolio of fuel pathways for most modes will require political vision that has so far been lacking. As currently organised in many countries, national government often shies away from long-term investment, preferring to wait for the most competitive alternative fuel to gain significant market share. Without policies to promote deployment, it could be delayed for decades. Strong commitments to reduce CO_2 emissions and to improve national energy security are important first steps to move away from fossil fuel in the transport sector.

Most governments raise a significant share of their national budget through fuel taxes – and do not want to see that contribution decline as fuel use decreases. To maintain revenues, they will need to create alternative streams: a combination of CO_2-tax and road pricing, for example, could stimulate contributions from the transport system to sustain revenues at the state level.

The LETMIX developed by the IEA shows that deploying e-mobility right now and at the same pace everywhere will not maximise CO_2 and other benefits. Those countries most ready should aggressively pursue a CO_2-efficient EV deployment strategy; others need to set solid foundations prior to fully committing to strong e-mobility deployment while pursuing strong CO_2 emissions reduction through other means.

Switching massively to e-mobility, taking full advantage of the high efficiency of electric motors and of a very low-carbon power supply by 2050, as in the 2DS-ET, will boost energy and CO_2 savings above levels possible in the 2DS. This will nonetheless require heavy extra investments that would require vision and relevant policies to engage the private sector into adopting e-mobility. The likely initial resistance could be overcome once benefits overshadow up-front capital investments.

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Chapter 7

Electricity Storage: Costs, Value and Competitiveness

Energy Technology Perspectives 2014 (ETP 2014) analysis casts doubt on recent claims that electricity storage will be a game changer, yet confirms its widespread value as a versatile tool. As a flexibility resource, storage can support grid balancing and facilitate access to electricity using renewable energy. But currently, the high cost of many technologies for high-power and high-energy applications undermine the conceptual flexibility potential of storage compared with competing options. Storage is uniquely capable of delivering modularity, controllability and responsiveness.

Key findings

- **Electricity storage is expected to play multiple roles in future energy systems, but is unlikely in itself be a transformative force.** At current costs and performance levels, particularly for high-power and high-energy applications, it falls short of delivering the conceptual flexibility potential when compared with competing options.
- **The role of electricity storage in a given power system will depend on system-wide development.** Storage competitors are at different levels of maturity and cost-competitiveness: thermal dispatchable generation is the incumbent technology; demand response can provide excellent reserve capacity at minimal cost; and although less mature, smart-grids provide increased interconnectivity to shift loads in time and space.
- **The true asset of battery electric storage for power systems might lie in the modularity, controllability and responsiveness.** No other asset in the power sector can combine these characteristics.
- **Arbitrage opportunities have driven most global electricity storage deployments over the last 40 years.** Current drivers for electricity storage, including variable renewable integration, operational support, system planning and end-use applications, are highly system-specific and complex and will likely require changes to regulatory and market frameworks.
- **Pumped hydro storage (PHS) currently represents 99% of all deployed electricity storage, and remains well-suited for many storage applications.** Although a broad range of other technologies exist at varying stages of development, none have yet been deployed at a significant scale compared to existing capacity of PHS.
- **Frequency regulation, load following and off-grid applications represent the most attractive deployment opportunities for electricity storage in the short to medium term.** Being the applications with the highest value, there is more latitude for the high cost of electricity storage to be competitive.

- **Solar photovoltaic (PV) panels combined with small-scale electricity storage are a powerful resource for off-grid applications and can provide access to electricity in remote areas.** Due to the low energy and power requirements, the lessons learned from battery technology in electronic devices and electric vehicles (EVs) are useful to these applications.
- **Energy systems integration that strategically positions energy storage can create an economic, flexible and resilient low-carbon energy system.** Diverse system-wide opportunities exist, such as power-to-heat, power-to-gas or co-generation[1] with thermal storage.

Opportunities for policy action

- Establishing international and national data co-operation is an important means to foster electricity storage research and development (R&D), monitor progress and assess the bottlenecks. Major discrepancies about current and future storage technology costs and methodologies attest to the uncertainty around storage R&D and to the need for industry involvement to capture rapid technology development.
- Governments should develop policy measures to support application-driven R&D strategies for grid balancing, including electricity storage and other flexibility resources that contribute to delivering a low-cost trajectory to low-carbon power systems.
- At present, who should have ownership of storage assets remains an open question. Governments should assess regulatory options concerning ownership and control of storage assets to ensure support for policy goals while also providing a competitive framework.
- All energy stakeholders should encourage and engage in "systems thinking" that capitalises on synergies among thermal, electrical and fuel pathways within the energy system.

Appeal of storing electricity

Electricity is fundamentally different from most commodities in the energy sector. With oil, gas and coal, storage is an integral part of the supply chain that provides a buffer to facilitate balancing supply and demand over time frames of a few days, weeks, months or even a year. Except for PHS plants, there is no mechanism by which to economically store large quantities of electricity for later use. The use of PHS, which creates the opportunity to – on demand – release water from a higher reservoir to generate electricity, is limited by geographical constraints, such as water availability, topology, and distance between resource and demand.

This absence of storage capability in electricity systems requires that supply be instantaneously (e.g. microseconds to seconds) balanced to match demand. Despite this constant balancing challenge, most power systems in member countries of the Organisation for Economic Co-operation and Development (OECD) operate at very high reliability and availability. By contrast, the inability to balance systems in many non-OECD countries commonly results in power shortages and load shedding.[2]

1 Co-generation refers to the combined production of heat and power.
2 Load shedding is an intentional "last resort" strategy to decouple certain distribution regions from the grid in periods where short supply threatens the integrity of the grid.

This need to balance supply and demand carries a certain cost. To secure reliability, the power system needs to be "over-designed" and "overbuilt" to meet the highest annual load, i.e. annual peak load that occurs on relatively rare occasions. This leaves at least some portion of the system underutilised for the vast majority of the time: in Ireland or France, for example, 10% of the generation capacity operates only 5% of the time (ENTSOE, 2013). The electricity system, which is capital-intensive to build, has lower utilisation rates than other energy or infrastructure systems. In the context of electrification, this creates additional challenges for investment.

The increasing penetration of the variable renewable energy (VRE) supply is expected to further complicate the balancing challenge by adding more variability to the supply side. Experience has confirmed the potential of wind and solar PV to deliver energy over the course of a year, but both resources vary (sometimes widely) even from one hour to the next and do not provide "firm" capacity. Capacity factors[3] for wind and solar power depend strongly on local resource endowment (e.g. wind speed and solar irradiation) but usually remain below 40% in nearly all regions. In Germany, capacity factors for wind in 2012 were 19% and for solar 10% (BMU, 2013). System operators face two different situations: when demand exceeds total system supply, they can use backup capacity or reduce some demand; when the output of VRE generation exceeds the immediate demand, they can curtail input from VRE or look for ways to increase demand.

In recent debate, the concept of electricity storage technology (Box 7.1) is often referred to as the "game changer" (Box 7.2) that could ensure increased utilisation of power system assets and fully unleash the potential of VRE. This chapter explores the degree to which diverse electricity storage technologies have been developed and their potential to become game changers. However, alternative methods to integrate new supply-and-demand technologies into the power system and provide flexibility[4] are also available or developing. To evaluate its true potential, storage must be measured – in terms of performance and cost – against dispatchable thermal power plants, demand response, and power grid interconnections and modernisation.

Box 7.1 Definition of energy storage in the power sector

This chapter differentiates two different concepts of energy storage in the power sector:

- Electricity storage or "power-to-power" storage refers to technologies in which electricity is an energy form that flows into and out of a given storage asset. Electricity is typically stored by converting it to a different form of energy (mechanical, electrical, chemical, kinetic, potential, thermal) and then causing it to revert back into electricity at a later stage. Competing options for electricity storage include dispatchable thermal power plants, demand response, and power grid interconnections and modernisation. Reservoir hydro (without pumping mode) is not considered as electricity storage but rather dispatchable power generation.
- "Power-to-heat" or "power-to-fuels" storage interlinks the electricity system with heat and/or fuel systems. There is no reconversion back into electricity, i.e. the outflow of the storage is heat or chemical fuels. Thermal energy storage, for example, retains electricity as heat (latent, phase-change, etc.) that is eventually used for the purpose of heating.

3 Capacity factor of a power plant is the ratio of its real output during a certain time (usually a year) compared with the potential output if the plant were operated at maximum capacity during that time.
4 Flexibility describes the extent to which an electricity system can adapt the pattern of electricity generation and consumption in order to balance supply and demand.

Energy R&D strategies and policies often consider electricity storage as an important priority to deliver clean, reliable power systems and to develop a technology leadership role either nationally or regionally. Recognising the need for innovation in electricity storage, it is useful to set out the parameters by which the scale of innovation is typically measured (Box 7.2).

Box 7.2 Degrees of innovation and breakthrough technology

Energy technology innovation is often pursued in response to societal needs, and can be spurred by clearly defined policy goals and supporting science, research and innovation. Such innovation is unpredictable, but its impacts can be broadly classified as follows:

Incremental: reflecting small, gradual developments.

Semi-radical: involving the innovative use of an existing technology.

Disruptive or radical innovation: often associated with a "game-changer" solution that cannot be compared with past technologies and leads to paradigm shift in the sector.

Successful market penetration of small, low-power batteries, particularly lithium ion (Li-ion) technology, in portable electronic devices has created ease of use for consumers and helped draw public attention towards the potential of batteries for large-scale electricity storage. In the transport sector, improved battery life has helped to increase sales of EVs, even though high battery costs and limited range remain hurdles for broader deployment (see Chapter 6). Lessons learned from technology and manufacturing in these sectors could benefit grid-scale batteries. In off-grid power applications, storage devices facilitate access to electricity and reduce costly grid extensions to remote, small communities and can play a role in international efforts to bring modern energy to every human on the planet.

To date, the performance of storage technology is too low and electricity storage costs too high for successful large-scale introduction in the power sector, whereas shares of VRE in power systems have increased dramatically in some countries. Without considerable improvement in these areas, it may remain more cost-effective to use traditional or other developing alternatives for balancing and flexibility, such as thermal generation, thermal storage, transmission and distribution (T&D) grid development, or demand response, than to implement storage technologies.

Ultimately, a radical innovation in storage technology development makes it possible to envision more cost-effective and better performing electricity systems with abundant renewable energy supply. *ETP 2014* explores four aspects of the outlook for electricity storage to assess if and how they could facilitate the achievement of 2°C Scenario (2DS) goals and accelerate progress towards a clean, secure and economical power system:

- **identify technology, policy and market drivers** that could radically change the role of electricity storage
- **understand the value of power and energy applications** for electricity storage at different locations along the electricity value chain
- **identify the role of electricity storage** in the 2DS, estimating the global storage requirement and pushing the limits of technology development to explore the game-changing potential of electricity storage technologies
- **explore potential of electricity storage compared with competing technologies:** thermal generation, thermal energy storage, power grid development (including interconnections) and demand response – all of which support power system integration.

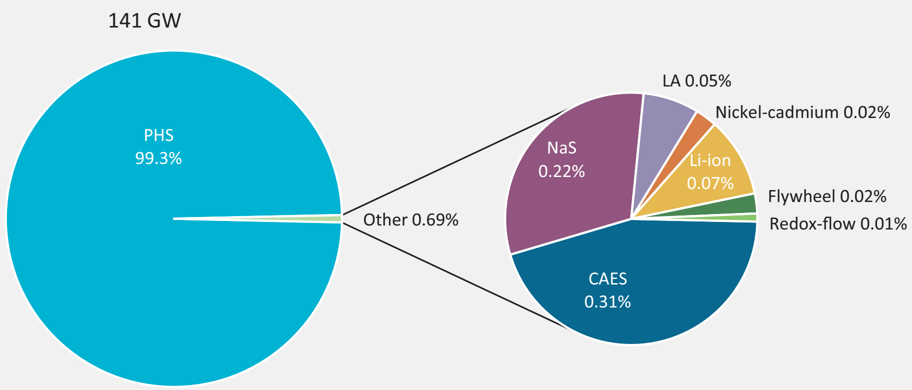
Ultimately, the role of storage will also be defined by its strengths and uniqueness compared with its competitors.

ETP develops the vision for energy storage in the power sector under the 2DS and sets the target for the International Energy Agency's (IEA) *Technology Roadmap: Energy Storage*. It covers the power sector and heat applications including: in-depth coverage of a deployment pathway and policy milestones; detailed technology reviews and case studies; and assessment of market and regulatory barriers. The *Technology Roadmap: Hydrogen* (forthcoming) will further assess the potential for hydrogen to act as an energy storage medium.

First deployment wave of energy storage

Installed electricity storage capacity today represents a small portion (< 3%) of the 5 250 gigawatts (GW) of global electricity generation capacity and mature PHS represents 99% of all installed electricity storage. More recently developed storage technologies have not yet penetrated the power system to significant levels: the remaining 1% comprises mainly compressed air energy storage (CAES) and batteries using sodium sulphur (NaS) or Li-ion technology (Figure 7.1).

Figure 7.1 **Globally installed electricity storage**



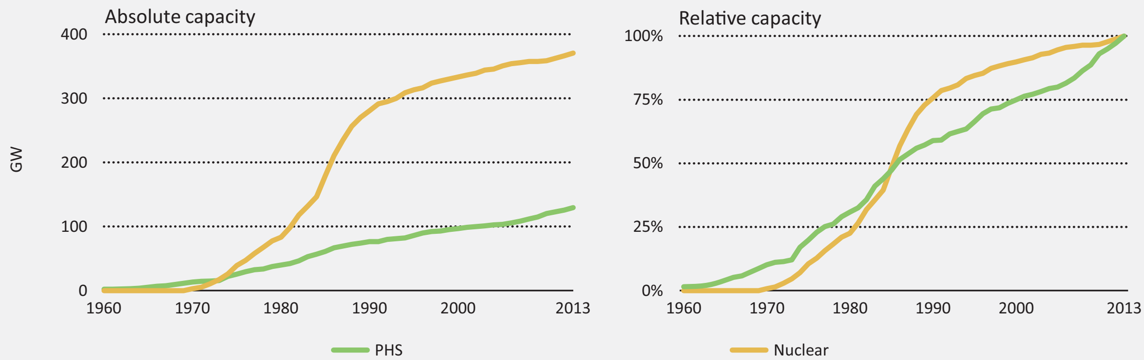
Notes: unit = megawatts (MW). LA = lead acid. Figures and data that appear in this report can be downloaded from www.iea.org/etp2014.
Sources: IEA analysis; EPRI 2010.

Key point *Electricity storage represents 3% of globally installed power capacity, but this is nearly exclusively PHS.*

Most of the PHS storage capacity has been built since the 1970s (Figure 7.2), often in parallel with deployment of nuclear energy to meet the need for daily (diurnal) arbitrage between expensive peak electricity power and less costly off-peak base-load power. As nuclear is capital-intensive, many nuclear power companies also developed PHS to store their excess electricity generation during periods of low demand (e.g. overnight) for later sale during peak times when prices were highest (a practice known as "price arbitrage"). This was a way to offset the reality that nuclear power plants were very inflexible and could not be easily ramped up or down as demand changed.

Especially for integrated energy monopolies, price arbitrage using PHS was an effective business model. But generation unbundling during market liberalisation made this integrated planning more complex and even risky. After 1990, increased penetration of combined-cycle

Figure 7.2 Nuclear and PHS capacity deployment globally



Sources: Platts, 2013; IAEA PRIS, 2013.

Key point *Nuclear power deployment created price arbitrage opportunities that favoured PHS projects.*

gas turbine (CCGT) technology in OECD Americas and Europe offered a flexible mid-merit[5] option. By the early 2000s, shares of VRE generation entered the markets, with a very low short-run marginal cost (SRMC) and often supported by policy for priority dispatch. These factors drove down the demand for base-load generation, ultimately reducing wholesale electricity prices and hence the price gap between base and peak load. VRE, in particular, pushed plants with higher SRMCs out of the merit order, reducing the opportunity for price arbitrage. In some power markets, solar PV generation during peak price periods has reduced the peak price and consequently the arbitrage opportunity. In this context, market liberalisation undermined sustained growth in storage capacity: increased long-term uncertainty or diminishing market opportunities negatively affected the interest of investors.

Under the same application, CAES represents most of the remainder of installed energy storage, even though only two large-scale plants are operational. A first 321 MW plant was built in Huntorf, Germany, in 1978, and a second 110 MW plant in McIntosh, Alabama, in the United States, in 1991. Both plants are diabatic, meaning that heat produced during the air compression process is lost and efficiencies are only 42% to 54%. After years of preparation, the construction of a third 290 MW plant in Iowa, in the United States, was cancelled in 2011 (Box 7.3).

A second storage deployment wave on the horizon

Storage applications and their deployment are influenced by the evolution of the whole energy system. In the same way that price arbitrage triggered PHS deployment, other additional storage applications may trigger a new deployment wave of storage technologies as well as additional PHS and CAES. In recent years, major PHS plants have been built – and are operating successfully – in most countries and regions: the People's Republic of China (17 projects), Europe (10), Japan (8), India (4), Russia (1), the United States (1) and South Africa (1). At least in Europe, these projects were motivated by the need to integrate VRE. New commercial non-PHS projects, however, are struggling for diverse reasons (see Box 7.3).

5 Mid-merit plants are dispatched between peak-load and base-load power plants and have roughly 2 000-4 000 full-load operation hours per year.

Box 7.3 **The story of two storage project failures**

First-of-kind projects always face high risk, particularly as they enter the market competing against mature, widely deployed technologies. An analysis of two major US storage projects that have failed since 2011 can provide invaluable "lessons learned".

After eight years of development, a long-planned CAES plant in Iowa was dropped in 2011 by private investors, mainly because the geology analysis and site selection turned out to be very complicated for a greenfield aquifer CAES project. The large-scale 270 MW plant for bulk storage was designed to operate only 12 to 16 hours per day, and therefore would have been unable to offer more beneficial secondary applications, particularly reserve capacity. Also, even though the CAES plant would have reduced wind curtailment in the region, the CAES plant investors would have been unable to capture the benefits under the existing regulatory framework, since they did not own the wind turbine assets (Sandia, 2011).

The Stephenstown, New York, flywheel project, supported by a loan from the US Department of Energy, was commissioned in 2011. The rapid response time of the flywheel was considered ideal to provide short but rapid grid-balancing services, specifically frequency regulation. The project developers could not have anticipated that implementation of a new rule by the Federal Energy Regulatory Commission (FERC) – which would have forced grid operators to pay higher compensation for rapid power supply to the grid – would be delayed by six months. Additionally, the US shale gas revolution led to a thermal overcapacity, especially coal generation, in the region, which drove down market prices for frequency regulation and reserve capacity. These unforeseeable events forced the flywheel manufacturer and owner, Beacon Power, to declare bankruptcy in 2011. Subsequently, the company was revived and a new 20 MW flywheel project will open in 2014 in Hazle, Pennsylvania (US DOE, 2013).

These two examples demonstrate that energy storage projects, even if the technology is mature, are dependent on system-wide conditions and on the regulatory framework.

By its very nature, storage does not operate in isolation; its true value is as an integrative technology that interacts with the electricity system to define deployment opportunities. A few particular power system trends are once again making deployment of storage attractive; storage research, development and demonstration could accelerate the progress of these and other technologies in the electricity system.

- **Large-scale remote and distributed VRE.** Solar PV and wind power generation grew quickly in the last few years; in the 2DS, they provide 28% of global electricity generation by 2050. The fact that both are inherently variable (the wind does not always blow; the sun does not always shine) is redefining power systems operations and planning. While system operators have decades of experience in managing demand-side variability, VRE deployment introduces supply-side variability – thereby increasing the complexity of balancing demand and supply. Electricity storage creates the opportunity to "hold" excess renewable energy generated for later discharge when VRE generation is lower. In effect, storage could make VRE dispatchable – more easily managed and more effective. It would also reduce VRE curtailment at periods of low demand, thereby increasing the capacity factors of VRE assets and also reducing overall system carbon dioxide (CO_2) emissions. Yet countries that lead in VRE integration (e.g. Denmark, Ireland and Germany) continue to increase VRE shares without building electricity storage for integration purposes, often relying instead on other flexibility resources that were deployed before VRE.
- **Increased use of electric demand technologies.** Electricity has been the quickest growing end-use fuel in the last decades in OECD countries. Several factors explain the attractiveness of electricity to consumers: electricity offers a variety of services (from

mechanical power to light), produces no waste or local emissions at end-use location, and does not require stocking fuel. The 2DS focus on electrification strengthens this trend; by 2050, shares in final energy demand rise in the buildings sector (from 28% to 44%), in transport (1% to 10%) and in industry (from 24% to 32%). In particular, electricity demand for transport (EVs) and heat (electric heat pumps) is dependent on consumer behaviour and could increase the gap between base and peak load and drive up the need for peak-load management. Storage could allow electricity produced during low demand periods to be used during peak demand, as well as alleviate congested portions of the system to improve electricity flow to meet demand.

- **Smart-grid deployment.** Growing deployment of information and communication technologies (ICTs), including sensing equipment and controls, in the electricity grid is creating systems with greater intelligence and capacity for control of both demand and supply. Increased integration of new technologies, such as smart meters, provides all grid participants, including the consumer, with near real-time information on system status and can therefore inform decisions about use and operations. So far, only limited information on the electricity grid is captured – especially at the distribution level. The number of smart meters is expected to increase twenty-fold between 2008 and 2018 to 1 billion installed meters (IEA, 2013a). The data acquired by smart-grids could enable storage technology integration into the electricity system, and could play a role in identifying appropriate technologies and locations for installation.
- **Self-consumption increase through on-site generation.** In some regions, end users or communities are seeking to increase energy independence for security of supply, due to discontent with larger utility or government strategies, or to take advantage of technologies as they approach cost parity. PV, wind and other technologies enable on-site, decentralised generation. To ensure reliability of these local, off-grid systems and maximise their capacity to utilise renewable generation, small-scale storage will be needed. Storage could also help to increase self-consumption or maximise savings or revenues for grid-connected users; excess generation can be stored when demand or prices are low, and consumed or sent to the grid when demand or prices increase.
- **Electrification of off-grid areas, particularly in developing countries.** Globally, it is estimated that 1.3 billion people still lack access to electricity (IEA, 2013b), which undermines economic development and has negative personal impacts. The use of inefficient and polluting end-use equipment (such as petrol lanterns) exposes the poorest to health hazards and high costs. The most aggressive and successful electrification campaigns, in China and Brazil, have largely focused on providing grid access to poor populations. If some industrial load is in the same geographic area, such electrification projects can be very cost-effective. However, the lack of capital in less developed countries, the low level of demand from poor populations and the sparse population density in rural regions make it difficult to replicate the grid electrification strategy in other regions. Small-scale electricity storage embedded in devices, home systems, micro-grids and mini-grids – charged by renewable energy – can help to deliver electricity to the poorest in a more cost-efficient manner. Different projects based on battery-powered lanterns demonstrate how electrification can be promoted without access to the grid.

Applications for electricity storage

A wide range of electricity storage technologies can satisfy diverse applications across electricity systems – in generation, system operation, T&D and end use. In fact, because the use of storage technologies is application- or opportunity-driven, it is important to understand

and assess the different applications. Two additional factors enter the equation: electricity systems operate under technical and regulatory frameworks that differ from region to region, and many systems are already equipped with other, competing flexibility options that work within these frameworks.[6] For easy comparison, storage roles are examined according to location in the grid.

Generation

- **Seasonal storage** may be required to achieve very deep decarbonisation of the power sector in climates where a given renewable resource is not available constantly throughout the year (as with solar in most OECD countries). In Northern Europe, for example, where most of the hydropower potential has already been tapped, wind and solar PV are required in the 2DS. However, solar irradiance peaks and electricity demand are uncorrelated over seasons: solar irradiation is highest in late spring and early summer, when the electricity demand is often lowest (longer and warmer days require less electricity). Solar is scarce in winter when consumption might be higher for lighting and heating.
- **Inter-seasonal or weekly storage.** Storing electricity during a couple of days or weeks can be required to compensate for the loss of an interconnection or for a longer-term supply disruption (e.g. extended wind or solar recession or a fossil fuel disruption). This application is currently provided by strategic fossil fuel reserves and large-scale reservoir hydro.
- **Arbitrage.** Storing low-priced, base-load power for later sale at higher peak price is very important in systems with inflexible base-load power plants. Apart from PHS, peak generation is usually provided by open cycle gas turbines (OCGTs) and, in some countries, oil-fired generation.
- **Large-scale wind and centralised PV grid integration.** Although wind and solar are distributed resources, like most conventional generators, they are usually connected to the high-voltage transmission grid (as entire solar or wind farm). Storage can smooth and optimise the output from intermittent sources to increase quality and value. In the absence of on-site storage, grid integration of wind and solar PV increases the need for balancing services (the characteristics of wind and solar PV require different balancing services) and should be considered part of the system balancing challenge (discussed below). Unless explicitly mentioned, hereafter wind and solar PV are discussed as part of system operation.

System operation

The ancillary services described below are used to balance supply and demand in real time, thereby supporting the reliable operation of power systems. Costs for these services are covered by vertically integrated utilities or by specific players in unbundled electricity markets. Ancillary services are generally market- or system-specific, but can be categorised according to different storage applications.

- **Area or frequency regulation** continuously balances the minute-by-minute fluctuations of demand and supply within a control area under *normal conditions*, to maintain the system within the strict limits required to avoid instabilities. To cope effectively with the rapidly changing conditions, all assets providing this service (such as running generators, storage or interruptible loads) are usually automated. Thermal generators commonly provide this grid service and are equipped with automatic generation control to meet the rapid changes.
- **Load following**, the second continuous balancing mechanism for *normal conditions*, is slower than regulation in that it manages system fluctuations on a timescale of 15 minutes up to a

6 This is not to say that if regulation is a barrier, it cannot be changed. Rather, such regulatory changes will need to occur if storage technologies offer a compelling benefit compared with other available solutions.

few hours. The power plants providing this service can therefore be controlled manually. Load following services could also be supplied by storage technologies that can both absorb power (when generation exceeds demand) or produce power (during a deficit).

- **Reserve capacity** for electricity supply is typically called upon as a *system contingency*[7] to compensate for a rapid loss (such as an unplanned plant outage or feeder failure) and keep the system balanced. Depending on the response time, reserve capacity is further classified as spinning (< 15 minutes response time) and non-spinning (> 15 minutes). Different thermal plants provide reserve services: spinning reserves are more costly since they consume more fuel and could thus provide higher financial incentive for storage.
- **Voltage-support** is the injection or absorption of reactive power to maintain T&D voltages within required ranges under *normal conditions*. It can be provided by thermal generators or by specific T&D equipment (e.g. capacitors, inductors and transformer tap changes). Since reactive power losses tend to exceed real-power and contingency losses (i.e. the three previous applications), voltage-support needs are very location-specific and distributed across the power system. Even in unbundled systems, voltage-support is mostly provided through long-term contracts rather than on competitive markets (the dispersion of voltage-support resources makes it difficult to stimulate competition). If grid operators do not directly provide voltage-support, operators typically mandate that generators provide the service as a pre-condition for grid connection.
- **Black start.** In the very rare situation that a power system collapses and all the above ancillary mechanisms have failed, electricity supply that has self-starting capacity (i.e. start capacity without grid support)[8] is required to energise – step by step – the grid and other generators. Since this event is so rare in power systems, the asset utilisation is extremely low. It is very unlikely that a storage asset would be built exclusively for this application, unless at a very high cost. If, however, a storage device could guarantee that a minimum electricity reserve is available at any time, black start capabilities could be an excellent secondary application. Location of such a black start generator close to essential assets of the re-energisation procedure is important.

Electricity T&D

- **T&D congestion management and investment deferral.** A specific location in the T&D grid can become the physical connection bottleneck between two parts of the power system. To relieve the system, a generator or a grid line can be added or storage can be placed at the congested point. Compared with the lumpiness of large power infrastructure projects, the modularity of the storage device allows for gradual expansion. Ultimately, storage could make the construction of certain T&D lines redundant and thus defer grid investments. Compared with grid capacity expansion, storage projects could require less permitting and right-of-way procedure, which is especially important in more densely populated or environmentally sensitive areas.

End use

- **Small-scale PV grid integration and increased self-consumption by end users.** PV panels are often installed today at the end-user side and connected to the distribution grid. Integration of small-scale PV, like large-scale VRE, is an additional challenge for grid balancing

7 A contingency is the sudden, unexpected loss of a generator or transmission element. Slower events, such as load being higher than forecasted, are not contingencies.

8 Synchronous generators, which make up the majority of generators on large-scale grids, typically have limited ability to start up in the absence of an existing energised grid. A modest amount of generation capability is required throughout the grid to restart the grid in the event of a large-scale outage.

and requires the different ancillary services listed previously. The economics of storage to support self-consumption are often favourable, as it allows savings on electricity bills which are based on retail electricity prices. In following sections, storage applications for all PV grid integration will be discussed under the different system operation applications listed above. Additional discussion of storage for end-use PV applications can be found in Chapter 4.

- **Off-grid.** At present, off-grid electricity consumers typically rely on diesel, gasoline or natural gas generators. PV is a cost-effective and clean alternative. Since some demand, such as for lighting, are required when there is no sunlight, compact storage is necessary to ensure reliable power supply over each 24-hour period and over the whole year. For small-scale users, the storage requirement is small; technologies used in electric devices and EVs could enter the power sector through this application. At larger utility scale (often referred to as mini- or micro-grid), low-cost solar PV coupled with low-cost electricity storage could become competitive without policy support as a grid-level electricity supply mechanism. Such integrated systems could ultimately become the standard electricity generation source in regions with high solar resources.[9]

Storage applications can be defined by four important characteristics: power (watts [W]), discharge duration (hours [h]), full charge-discharge cycles during a day or a year, and response time (Table 7.1). In operation, storage technologies need to provide very different characteristics at very different scales.

Table 7.1 Key characteristics of different storage applications

	Size (MW)	Discharge duration	Cycles	Response time
Seasonal storage	> 500	Weeks-months	1/year	Days
Inter-seasonal storage	500-1 000	3-10 days	1-5/year	Day
Arbitrage	100-1 000	8-24 hours	0.28-1/day	> 1 hour
Wind grid integration	100-400	1-60 min	0.5-2/day	
Frequency regulation	1-40	1-15 min	20-40/day	1 min
Load following	10-100	15-120 min	1-4/day	10-15 min
Spinning reserve	10-100	15-120 min	0.5-2/day	< 15 min
Non-spinning reserve	10-100	15-120 min	0.5-2/day	> 15 min
Voltage-support	1-40	1-60 sec	10-100/day	msec-sec
Black start	0.1-400	1-4 hours	< 1/year	Minute
T&D congestion relief	10-500	2-4 hours	0.14-1.25/day	> 1 hour
T&D investment deferral	1-500	2-4 hours	0.75-1.25/day	> 1 hour
PV grid integration	0.01-1	1-60 min	0.5-2/day	
Off-grid	0.001-0.01	3-5 hours	0.75-1.5/day	> 1 hour
Off-grid utility scale	1-100	4-8 hours	0.75-1.5/day	1 hour

Note: MW = megawatt.
Sources: IEA analysis; Battke, 2013; EPRI, 2010; Sandia, 2010.

9 It should be noted that fossil-based backup would still likely be included in the system design to ensure reliability, but adequate design using PV and storage would limit its actual use.

Box 7.4 Energy storage for the Scottish Isle of Gigha

In March 2013, blizzards raged across Scotland and its surrounding isles. The Isle of Gigha suffered a five-day power outage that caused significant disruption to the community. It also brought to light that the status of the current electricity system may be more of a problem than anticipated.

Under the present "passive" network-operating arrangements, voltage constraint restricts the connection of further generation capacity, which prevents installation of renewable energy such as additional wind turbines, PV panels and tidal-stream generators.

Irish company REDTenergy won a contract from the UK government's Department of Energy and Climate Change (DECC) to demonstrate a vanadium redox flow battery energy storage system (ESS) as the means of solving network constraint for the Isle of Gigha. Though other alternatives, including demand-side management (DSM) and active network management (ANM), were noted, planners ultimately chose ESS as it seems to have the greatest potential to benefit the community. Moreover, it leaves open the possibility to upgrade with DSM or ANM in the future, with continued benefits from ESS. A primary goal of this project is to maximise the isle's renewable energy yield by reducing curtailment of an additional (fourth) wind turbine.

Supported by the Irish Government and an example of its policy of developing and investing in smart-grid technology and infrastructure, REDTenergy is leading the development of ESS and at the forefront of the micro-grid movement in Ireland. A number of similar projects are planned for deployment in Ireland in 2014 to further demonstrate the potential of ESS and its role in micro-grids.

With the ability to provide both load and generation capacity, energy storage can be controlled to provide exactly the demand necessary to eliminate constraint on Gigha's fourth turbine, and to maximise revenues from the export of power. The constraint applies specifically to the generation site, whereas the ESS can be located anywhere between the turbine and its 11 kV connection point, using locally-measured power to dispatch its charge and discharge functions. In addition to the benefits identified, the ESS can generate revenue, for example by selling wind energy to the market during peak times and price spikes; providing local backup power in the event of network faults; and replacing diesel generators with an uninterruptible power supply deriving from the ESS.

Source: Wilson, 2013.

Value of power system applications for storage

All storage applications have a certain value for the power system. These values help to assess the R&D priorities for electricity storage technology, determine which application will be deployed first, and define a cost target for different applications. Yet the value of a given application will largely depend on the regulatory framework, the policy support and specific conditions of the power system, such as grid architecture, demand profiles, weather conditions and power generation mix. The values are therefore difficult to quantify and even more difficult to generalise, especially since the interactions with other parts of the system are complex to assess (as for every system integration technology).

The cost of the incumbent technology or, if available, market prices for specific services, can indicate the value of different applications. These values will largely differ across regions depending on the existing electricity system; the values would also dynamically evolve during the transition towards the 2DS. As an example, the increased share of VRE in the 2DS would drive up demand for grid balancing; if balancing supply does not expand in parallel, its market value would rise. A first assessment of storage application values indicates that off-grid applications seem to represent the highest value, since incumbent technology (diesel generators) has a very high levelised cost of energy (LCOE) (Table 7.2). Lessons learned from quickly progressing battery technology in electronic devices and EVs could probably be applied to this application, since it is the storage application with the lowest energy and power requirements (Table 7.1). For electrification of poor or remote communities, combining PV with storage deployment may be an effective approach, especially due to the low power demand for initially relatively simple services (e.g. lighting).

In countries with extensive grids (i.e. most OECD countries), end-use storage applications provide more interesting economics since the end user can save money on retail electricity prices, which provide larger benefits compared with the lower wholesale price. Policy support for end-use storage should be considered carefully if end users are not mandated to have a grid connection. Otherwise, policy support could incentivise grid users to go offline and save the grid tariffs, which would reduce revenue for the power grid and could eventually degrade the quality of a strategic public asset. Germany has put in place (since the beginning of 2013) an incentive scheme for grid-connected end-use storage to support PV integration. California's Self Generation Incentive Program offers incentives for a wide array of customer-sited energy technology, including energy storage. In 2013, California also introduced a storage mandate that required the three main Californian utilities to install 200 MW by the end of 2014, expanding to 1.3 GW by 2020.

Load following has a higher value than frequency regulation. Since generators are often mandated to provide a certain amount of frequency regulation, the cost is embedded in the provision of power, reducing the need and the value of acquiring the service from other providers. Spinning and non-spinning reserves are used as needed during contingency situations; the costs and value can be very high if alternatives are limited. Since reserve capacity is not needed under normal conditions, providing these services is often considered a secondary income application.

Voltage-support has a relatively low value. It can be provided by the grid operator and is often mandatory for synchronous generators. Since it is also a very local problem, operators usually provide small-scale solutions across the grid.

Seasonal storage, arbitrage and T&D investment deferral can be provided by any dispatchable thermal generators; thus, their value will largely depend on the overall use of the generation fleet. As a benchmark for the value, the LCOE for a generator using gas as fuel and providing only these applications is used.

Table 7.2 Estimated storage value by application

	Price setter	Value (USD/MWh)
Seasonal and inter-seasonal storage	LCOE natural gas CCGT	70-105
Arbitrage	LCOE natural gas CCGT	70-91
Frequency regulation	Market	45-51
Load following	LCOE natural gas OCGT	99-193
Spinning reserve	Market	8-22
Non-spinning reserve	Market	4-8
Voltage-support	Long-term contracts	2-6
T&D investment deferral	LCOE natural gas OCGT	89-105
Off-grid	LCOE diesel generator	250-420

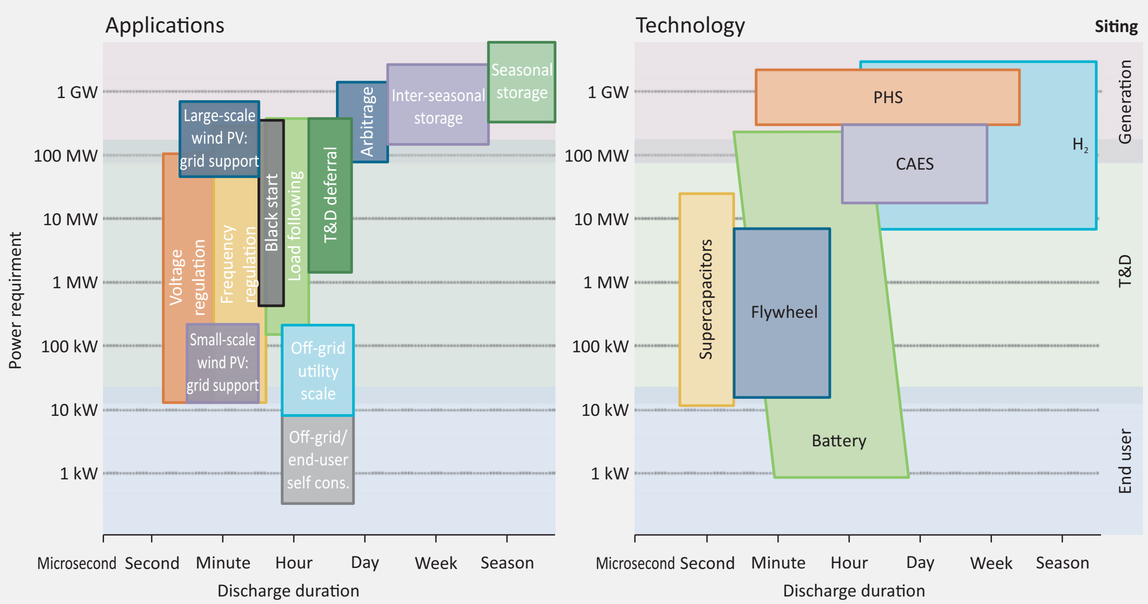
Notes: MWh = megawatt hour. Range of natural gas LCOE reflects different full-load hours. Gas prices for LCOE range from USD 4 per million British thermal units (MBtu) to USD 10/MBtu. Market prices are approximate ranges in USD/MWh for 2005 and include US power grids in California, ERCOT and New York. Unless otherwise stated, all costs and prices are in real 2012 USD, i.e. excluding inflation.
Source: IEA analysis; Kirby, 2007.

Performance and costs of electricity storage technology

Not all storage technologies will be able to provide the very diverse requirements for the different applications. To better understand the potential applications and the associated challenges, it is vital to compare both performance and cost of technologies that represent different attributes: PHS, hydrogen storage (H_2), CAES, flywheels, supercapacitors, superconducting magnet energy storage (SMES); and several battery technologies: LA, Li-ion, vanadium redox flow battery (VRB), NaS and Zebra batteries. In a quickly evolving sector such as electricity storage, technologies are developing continuously. As is expected with most new technologies, the risk and uncertainty factors remain large, and the learning effect needs to be considered as an important process of R&D.

Different storage applications and technologies can be mapped according to their key characteristics: power capacity and discharge duration (Figure 7.3). Discharge duration also represents the energy capacity of the storage device: energy (watt hours [Wh]) = power (W) x discharge time (h). A PHS plant can illustrate both characteristics: the height of the waterfall determines potential power while the size of the smallest of the upper and lower reservoirs determines the time that the waterfall can provide a certain power – in other words, the energy capacity.

Figure 7.3 Energy storage applications and technologies



Sources: IEA analysis; Battke, 2013; EPRI, 2010; ETSAP IA and IRENA, 2013; Sandia, 2010.

Key point *Different applications require different storage technologies.*

PHS, CAES and hydrogen are well-suited for longer-term storage (hours to weeks); flywheels and supercapacitors for short-term storage (seconds to minutes); and batteries can be used for applications that fall between the two extremes (minutes to hours).

Electricity storage technologies have very diverse technical characteristics that are mostly still developing (Table 7.3). Most storage technologies (more limited for PHS and CAES) can be deployed in a modular approach over time to gradually expand the storage device in pace with increasing demand. This modularity together with the high controllability and responsiveness are major advantages of using storage for all applications as opposed to other competing technologies such as peaking power plants, demand-side response and thermal storage. Battery-based systems can be dismantled and relocated if required, adding operational and financial flexibility to the asset owner and system operator.

Table 7.3 **Technical performance of different electricity storage technologies**

Type	Maturity stage	Typical power output (MW)	Response time	Efficiency (%)	Lifetime years	Lifetime cycles
Pumped hydro	Mature	100-5 000	sec-min	70-85	30-50	20 000-50 000
Hydrogen	Demonstration	100-500	min	< 40	10-30	n.a.
CAES	Deployed	100-300	min	50-75	30-40	10 000-25 000
Flywheel	Deployed	0.001-20	< sec-min	85-95	20-30	> 50 000
Li-ion battery	Deployed	0.001-5	sec	80-90	10-15	5 000-10 000
NaS battery	Deployed	1-200	sec	75-85	10-15	2 000-5 000
LA battery	Deployed	0.001-200	sec	65-85	5-15	2 500-10 000
VRB	Deployed	0.001-5	sec	65-85	5-20	> 10 000
SMES	Demonstration	< 10	< sec	90-95	20	> 30 000
Supercapacitors	Demonstration	< 1	< sec	85-98	20-30	> 10 000

Note: n.a. = not available.
Sources: Black & Veatch, 2012; Bradbury, 2010; EPRI, 2010; ETSAP IA and IRENA, 2013; Fraunhofer ISI, 2010; JRC, 2011; PNNL, 2010; Sandia, 2011; ZfES, 2012.

Applications for electricity storage technologies

The cost structure of electricity storage technologies also comes into play when considering that different technologies provide different applications. Costs of storage devices are determined by two main factors: energy storage capacity cost, proportional to energy storage volume (kWh); and power conversion equipment, proportional to the power rating of the system (kW). A complete assessment of storage technology cost is calculated by adding the power and energy capacity costs. Generally, a technology will either have low energy (or storage volume) costs or low power costs, but not both. Those with low energy or storage volume costs (USD/kWh), such as PHS and CAES, are better suited for large-scale, bulk storage; those with low electric capacity costs (USD/kW) are better suited for short-term power applications (Table 7.4). As demonstrated by the wide ranges in most cost numbers, such assessments are extremely difficult to carry out, as this level of data is mainly available only in scientific research projects and in manufacturer data. International and national data co-operation will be key to foster electricity storage research, monitor progress, and assess the R&D bottlenecks.

Centralised grid storage

PHS plants comprise a lower and higher water reservoir. Water is pumped using electricity up to the higher reservoir, thus converting the electrical energy into potential energy. The stored energy can be transformed back into electricity by letting the water fall from the higher reservoir to drive a turbine. PHS is a mature technology that has been used widely on large scales at a commercial level; the largest PHS plant (3 GW) is in Virginia, in the United States. Existing PHS plants can often be expanded and hydro reservoir plants can be technically

Table 7.4 Specific costs of different electricity storage technologies

Type	Investment cost Power (USD/kW)	Investment cost Energy (USD/kWh)	O&M costs per year (% of investment cost)	Discharge time
Pumped hydro	500-4 600	30-200	1	hours
CAES	500-1 500	10-150	4-5	hours
Hydrogen	600-1500 (electrolyser) and 800-1200 (CCGT)	10-150	5	min
Li-ion battery	900-3 500	500-2 300	3	min-hours
NaS battery	300-2 500	275-550	5	hours
LA battery	250-840	60-300	5	hours
VRB	1 000-4 000	350-800	3	hours
Flywheels	130-500	1 000-4 500	n/a	min
SMES	130-515	900-9 000	n/a	min
Supercapacitors	130-515	380-5 200	n/a	sec-min

Notes: O&M = operating and maintenance. As all costs will be highly influenced by actual operation, technology costs differ depending on applications. For example, a high-energy battery has different specific costs than a high-power battery. Reliable cost data for Zebra batteries were not available.
Sources: IEA analysis; Black & Veatch, 2012; Bradbury, 2010; EPRI, 2010; ETSAP IA and IRENA, 2013; Fraunhofer ISI, 2010; JRC, 2011; PNNL, 2010; Sandia, 2011; ZfES, 2012.

upgraded to include storage aspects. Topology is the main limitation for new-build, expansion or reservoir hydro upgrades. Costs also vary widely, depending on the specific location. Civil engineering costs of a PHS project (17%) are higher than for any other storage technology (Black & Veatch, 2012). They can be operated very flexibly, and PHS can provide a variety of applications (see IEA's *Technology Roadmap: Hydropower*). Since variable-speed, pump-turbine groups are now also used for pumping mode, recent PHS plants allow for fine voltage modulation in withdrawals from the grid, which was previously only possible for grid feed-in.

- **Advantages:** mature large-scale technology, simple mechanical process with long lifetime, high power and energy capacity.
- **Disadvantages:** very site-specific requirements (e.g. topology, water, distance to demand).
- **Game-changer potential:** Since it can provide a variety of applications, PHS could play an increased role in providing grid services in future low-carbon power systems. PHS is not a game changer; performance and cost are unlikely to improve and could even increase since the technology depends on several site-specific conditions and the best sites have already been used in some regions.

CAES involves compressing and storing air, either in geological underground voids (e.g. salt caverns) or in designated above-ground vessels. Electricity is transformed into thermal and mechanical energy as hot pressurised air. Later, the compressed air is heated by burning natural gas and then expanded in a gas turbine to generate electricity. The process of compressing air for storage generates heat. In the two installed diabatic[10] CAES plants, the generated heat is dissipated as waste to the atmosphere. These CAES installations have thermal efficiencies 50% to 60% lower than or at best similar to those of CCGT plants. Research is being performed into the use of adiabatic[11] CAES, in which the heat generated during the gas compression is stored and used for heating the compressed air before it enters

10 In a diabatic process, temperature changes occur due to an external heating source.
11 In an adiabatic process, temperature changes occur without exchange of heat with the surroundings.

the expansion turbine. This heating effect could drastically reduce or even eliminate the requirement for fuel. Germany is currently planning a new pilot plant (ADELE) using an adiabatic process. Isothermal CAES is another emerging technology (SustainX, Lightsail Energy, General Compression) that uses several heat exchangers to limit the air temperature increase during compression/expansion. A 2 MW pilot plant was commissioned at the end of 2012 in Gaines, Texas, in the United States. Underground pipes or above-ground storage vessels could make CAES projects independent of geology, but additional costs and potential pressure losses would need to be managed.

- **Advantages:** simple mechanical process (long lifetime), low energy- and power-specific costs, high power and energy capacity.
- **Disadvantages:** mostly site-specific (for diabatic and adiabatic CAES), requires natural gas and emits CO_2, low efficiency (for diabatic CAES).
- **Game-changer potential:** CAES could make a significant impact if adiabatic or isothermal zero-emission CAES could become available at the cost of diabatic CAES, and if smaller modular units are developed, the need for large underground storage could be avoided, making CAES less site-specific.

Hydrogen is the storage medium with the highest energy density if compressed or liquefied (1 200 Wh per cubic metre [m^3] to 2 400 kWh/m^3). Electricity is stored as hydrogen by driving an electrolyser that produces hydrogen from air and water. Hydrogen can consequently power a fuel cell or combustion turbine and thus be reconverted into electricity. A key conceptual difference is that charging (in the electrolyser) and discharging (e.g. in a gas turbine or fuel cell) can occur at different locations; the hydrogen itself can be transported in between by truck or pipeline. Total cycle efficiency is low due to the many conversion steps: multiplying all conversion step efficiencies – electrolyser (efficiency 60%), hydrogen storage (90%) and CCGT (60%) – the final efficiency is less than 32%. In the case of large quantities of excess electricity – through the avoidance of excessive curtailment of renewable power for example- the concern over low conversion efficiency is less important. Still, use of hydrogen beyond the power sector could be more promising since end-use fuels, especially for the transport sector, have higher prices than electricity from the grid.

- **Advantages:** large energy volumes due to high-energy density, only technology suited for seasonal applications.
- **Disadvantages:** very low round-trip efficiency, very high costs, and little experience in electrolyser and fuel cell technology.
- **Game-changer potential:** cost and performance of hydrogen remain main obstacles to making a large impact within the power sector but are coming close to PHS and CAES in the medium term. For seasonal storage hydrogen might be the only suitable storage option since low energy density of PHS and CAES lead to prohibitive costs at low cycling rates and high-energy capacities. R&D needs to focus on mainly improving the cost of the electrolyser and on improving cost and efficiency of the fuel cell. For both, electrolyser and fuel cells, the lifetime needs to be enhanced. Power-to-gas applications can widely increase the level of integration in the energy system by connecting the power with the gas grid, thus making use of the already existing storage potential of the natural gas infrastructure.

Grid power-support

Flywheels are powered by electricity and can store electrical energy as rotating inertia. The discharging process transforms the flywheel movement back into electricity through a generator. Air friction is commonly reduced by putting the flywheel inside a vacuum and rotating friction minimised by using magnetically levitated bearings, leading to high efficiencies (90% to 95%). The energy output tends to be small, so flywheels are limited to short-time applications such as area regulation or load following. The rapid response time, low maintenance requirements and very high cycle life (i.e. can undergo a large number of charging and discharging cycles) are also important characteristics for short-term applications to maintain power quality. Also, flywheel storage can provide both up and down regulation during the same time period (although not simultaneously).

- **Advantages:** high cycle life, high power capacity, quick response time.
- **Disadvantages:** limited to very short-term applications (limited energy density).
- **Game-changer potential:** flywheels can provide only short-term grid services; they will not conceptually change the power system.

SMES stores energy in a magnetic field generated by a coil with many windings. An SMES operates at very low temperature (- 270°C) to minimise resistance. Since the power is available nearly instantaneously but only limited amounts of energy can be stored, SMES (like flywheels) is most suitable for short-term applications. In the United States, roughly 30 SMES installations with a combined 50 MW capacity are used for frequency regulation.

- **Advantages:** high cycle life, high power capacity, very quick response time.
- **Disadvantages:** cooling losses and costs of superconducting magnet, limited to very short-term applications (limited energy density).
- **Game-changer potential:** SMES can provide only short-term power services; it cannot store considerable energy quantities, so will not conceptually impact the power system.

Supercapacitors store small electricity quantities in an electric field between two capacitor plates. Supercapacitors use double-layer capacitors to improve the energy storage performance of conventional capacitors, but can still be used only for short-term applications. At present, only limited grid installations exist, for example a 500 kW supercapacitor in Big Island, Hawaii (United States).

- **Advantages:** high cycle life, high power capacity, quick response time.
- **Disadvantages:** limited to very short-term applications (limited energy density).
- **Game-changer potential or grid integrator:** supercapacitors can provide only short-term power services, but not store considerable energy quantities; they will not conceptually impact the power system.

Distributed grid and off-grid

Batteries can store electricity in the form of electrochemical energy through redox reactions. A battery is composed of a conductive electrolyte and two electrodes: one that attracts negative charged ion (anions) and one that attracts positive charge ions (cations). During charging, the electrons are added to the cathode and removed from the anode, creating a voltage difference between the two electrodes. During discharging, the reverse reaction occurs. The amount of energy that can be stored in a battery cell is determined by the volume of active ions in the electrolyte. The amount of power is determined by the surface area of the electrodes, i.e. greater surface means more material for redox reactions.

Thanks to their modular design, batteries can be dimensioned exactly for a particular application. They can be manufactured mostly from widely available resources or, if the materials are rare, recycling processes promote effective end-of-life management. A diverse set of electrodes and electrolytes can be configured into different battery technologies. The high reliability of batteries improves energy security.

LA batteries are a mature technology, used mainly as starters in automobiles, and are the current leader in the industrial battery sector (e.g. uninterruptable power source and off-grid). The innovation potential is relatively small: limited lifetime and low energy density are major drawbacks. Electrolyte stratification, an issue for most "flooded" batteries, is more severe for LA: as the battery is deeply charged and discharged, the ion concentration in the electrolyte can get higher in certain locations and lower in others. The high concentration accelerates corrosion in associated areas while the low concentration reduces capacity; overall performance decreases and the lifetime is shortened. Various maintenance approaches or smaller discharge cycles (i.e. smaller depth of discharge [DoD]) can reduce this effect.

- **Advantages:** mature (manufacturing experience and recycling infrastructure), lowest battery costs.
- **Disadvantages:** low energy density, sensitive to high DoD, large quantities of toxic lead and dangerous sulphuric acid, build-up of lead sulphate on electrode, lead electrode corrosion (to lead oxide).
- **Game-changer potential:** LA batteries are currently the leading battery technology in the power sector, but considering the limited innovation potential, their role may decrease.

NaS batteries are most suited for daily operation. They need to be kept at high operational temperature (250°C to 350°C), which can be maintained from the heat released by chemical reactions combined with efficient cell isolation. The initial warm-up time makes NaS batteries incompatible for transport or black start applications. A group of NaS batteries delivering in total 34 MW at the Rokkasho-Futamata Wind Farm in Japan provides load following services. Japan is the only country using this technology, through a joint initiative of TEPCO and a private company called NGK. The technology market for NaS batteries is therefore very uncompetitive. Apart from improvement of ceramic separators, little innovation potential seems to exist. Sodium nickel chloride or **Zebra** batteries, another molten salt battery that operates at higher temperatures than the NaS battery, are available from two manufacturers: FIAMM Sonick and GE Durathon.

- **Advantages:** relatively high-energy density, efficient in charge-discharge cycles, long life cycle (depending on DoD), low-cost materials.
- **Disadvantages:** heating required, highly corrosive nature of the sodium polysulphides (supported by high temperatures).
- **Game-changer potential:** the use of NaS and Zebra batteries will remain limited to continuous operating power applications, such as area regulation and load following, but their importance could grow if technology and cost improvements are achieved.

Flow batteries are a unique category of batteries, composed of two electrolytes separated by an ion-selective membrane that allows only specific ions to pass during the charging or discharging process. The electrolyte can be stored in separate tanks and pumped into the battery as needed. Energy and power components are separated and facilitate scaling: larger storage tanks increase energy storage capacity. Several chemistries can be used, but VRB appear the most mature.

- **Advantages:** less sensitive to higher DoD, long life cycle, unlimited energy capacity.
- **Disadvantages:** low energy density, not commercially mature.
- **Game-changer potential:** flow batteries appear to be a very interesting alternative to provide power applications, and could also provide reserve capacity and black start capabilities.

Li-ion batteries, due to their high-energy density, are already used for many small power stationary applications. In the power sector, they could provide load following and similar applications, especially since spillover effects from the transport sector could occur. In 2011, just three countries (Japan, Korea and China) produced about 95% of all Li-ion batteries (DG ENER, 2012). AES Westover (Johnson City, New York, USA) is a 20 MW advanced Li-ion storage facility that provides regulation services. Li-ion will likely remain the most mature lithium-based battery over the next 20 years; research in the post Li-ion era is already under way with new systems such as lithium-sulphur, lithium-air and sodium-ion batteries.

- **Advantages:** high-energy density, highest cycle life, effective manufacturing process for small scale.
- **Disadvantages:** cost, electrolyte used in some is toxic (battery management recycling needed).
- **Game-changer potential:** Li-ion batteries appear to be an interesting alternative to provide power applications and could also provide reserve capacity and black start capabilities. The technology could see considerable progress, if deployment in transport proves successful and the lessons learned from it can be scaled up for grid applications.

Maturity of different electricity storage technologies differs considerably (Table 7.3). The technology risks and capital requirements – and thus eventually the policy support needed – are very different: some will require loans or loan guaranties for pilot and demonstration projects; others would benefit more from subsidies or tax credit to support deployment. Since no technology clearly emerges as the strongest, policy support should remain technology-neutral and be application-specific to spur competition and innovation.

The large variety of R&D players in the sector, from small venture capitalist firms to large multi-nationals, indicates a high level of innovation in the sector. The drive for innovation is expected to remain high or even strengthen over time, as the need for storage to balance power grids increases as a result of growing electricity demand from new technologies (e.g. heat pumps, EVs) and deeper penetration of VRE.

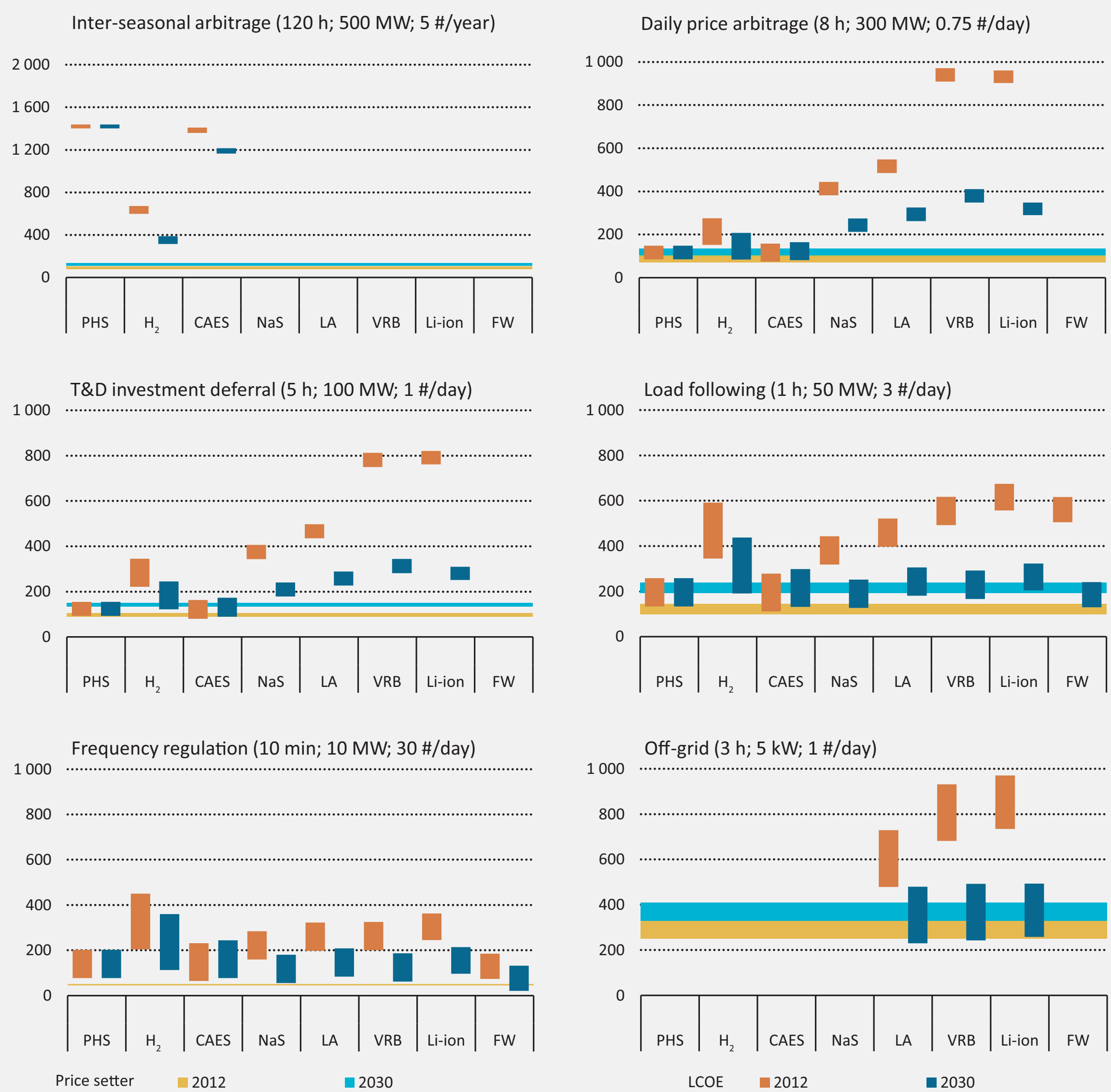
Cost of storing electricity

As market design and regulatory frameworks are specific to a given region or power system, a particular storage technology may be profitable in one situation but not in another. Additionally, some of the strengths of storage (controllability, modularity, etc.) over other application-specific solutions may provide increased value in some situations.

Cost for storing electricity can be estimated using the LCOE methodology, commonly used for electricity generation technologies. In the case of storage, LCOE represents the total cost of the energy storage asset – including capital, O&M, and electricity charging costs – per unit of energy quantity discharged to the grid. Both technology- and application-specific characteristics drive the storage LCOE calculation. From a technology perspective, cost, lifetime and efficiency are important. From an application perspective, the storage duration, number of charging-discharging cycles and price of the electricity for charging have the largest impact. The cost calculation does not include full life-cycle costs, mainly due to lack of data: costs covering aspects such as decommissioning, recycling and scrapping of waste need to be better quantified, especially when comparing technologies with long lifetimes against those of a relatively short lifetime.

The analysis carried out for *ETP* is by no means a complete cost-benefit assessment; rather, it aims to provide a general understanding of the factors that impact storage cost and also quantify the challenge of making storage cost-competitive. In Figure 7.4, the LCOE of respective storage technologies is graphed against the blue line, which represents the value of

Figure 7.4 Levelised cost of electricity for storage technologies by application, with associated price setter



Notes: FW = Flywheel. Electricity prices differ for storage applications and range from minimum USD 0/MWh for charging to maximums of USD 30/MWh for seasonal storage and USD 200/MWh for off-grid applications. For each application, only technologies judged compatible are represented. Cost performances of SMES and supercapacitors are not shown, but are similar to flywheels. The value of frequency regulation application was not adapted for 2030, but kept at 2012 estimates.

Sources: IEA analysis; Black & Veatch, 2012; Bradbury, 2010; EPRI, 2010; ETSAP IA and IRENA, 2013; Fraunhofer ISI, 2010; JRC, 2001; PNNL, 2010; Sandia, 2011; ZfEs, 2012.

Key point *The cost of storing electricity strongly depends on the applications and the characteristics of the technology. Not all technologies are suited for all applications.*

different applications or the current price-setting technology and market for given applications (Table 7.2). The figure represents current technology costs and those projected in 2030 to capture R&D progress and consequent cost reductions. As suggested in previous sections, the value of different applications is likely to increase under the 2DS. While this is not explicitly modelled here, the price-setting technologies in 2030 include – where relevant – the *ETP* CO_2 and gas price developments. The 2030 values should not be attached too closely to that date, but rather taken to reflect general trends projected over the next 10 to 20 years. Also, new technologies not shown are likely to emerge from the very active storage R&D sector. The technologies used here provide a diverse group of characteristics, so that new technologies could be associated with existing technologies as a first assessment.

This analysis of cost for different applications reveals that storage for inter-seasonal applications remains uncompetitive if compared to a stand-alone open cycle gas turbine with moderate annual load (Figure 7.4). For inter-seasonal storage, hydrogen is the only option getting closer to the order of magnitude of LCOE of the benchmarking technology. For arbitrage applications, PHS and CAES remain the most competitive technologies and hydrogen becomes close to competitive at the most positive projection levels. Still, the cost target in the power sector for hydrogen is so low that it is more interesting to use the hydrogen in other sectors showing higher value, particularly in transport (see IEA *Technology Roadmap: Hydrogen*). Hydrogen becomes more attractive in the future for a range of applications, but the levelised cost represented here does not include hydrogen transport (by truck or pipeline). The shorter the storage duration, the more battery and short-term storage technology costs come down, but they remain more expensive than PHS and CAES. In the future, especially for load following and area regulation applications, non-PHS and non-CAES storage will become increasingly competitive.

One main advantage of storage is the potential for "benefit stacking"; i.e. many of the technologies can provide several applications, which improves their business case (but is not represented in the preceding figure) (see IEA *Technology Roadmap: Storage*). Provision of reserve capacity and black start capabilities could, for example, be complementary to other applications. Further analysis and testing are required to determine which applications can be technically provided from one device.

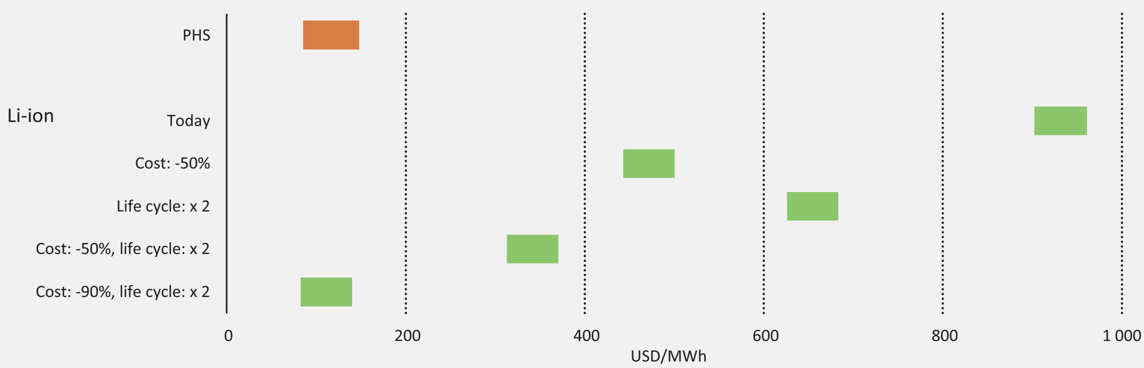
Storage technologies could see dramatic cost reductions and have a stronger contribution if major technology breakthroughs are achieved in three key areas:

- **Number of discharge cycles.** Battery technologies currently have limited capacity to withstand discharge cycles compared with the more mature mechanical storage technologies (PHS, CAES). In the case of batteries, repeated discharge cycles lead to a shorter lifetime and additional replacement costs.
- **Depth of discharge.** The number of discharge cycles a battery can withstand is also a function of the DoD, which complicates optimisation of battery dimensioning. The less the battery is discharged, the more life cycles it can undergo, but this implies scaling up to a larger (and thus more expensive) battery. The trade-off is this: increasing battery capacity drives up the initial capital costs but reduces the DoD requirements and extends the life cycle, thus reducing interim capital costs.
- **Economies of scale of production.** Mass production delivers economies of scale that can dramatically bring down the cost of a technology. This could considerably change the role for modular, small-scale storage. Spillover effects from other sectors could also lead to price reductions. Li-ion batteries, for example, appear to be the current technology of choice for EVs; successful deployment in transport could support the development of a large-scale manufacturing process, ultimately altering the cost equation for electricity storage in the power sector.

The scale of cost performance improvement needed

For applications with longer discharge durations, the challenge for battery technology to compete with PHS remains immense – even with very aggressive assumptions (Figure 7.5). As a reference example, Li-ion is shown at 2012 prices, and then with significant price reductions and performance improvements. For Li-ion batteries to compete with PHS, battery costs would need, for instance, to be reduced by 90% and lifetimes doubled at the same time. This highlights that within the *ETP* time horizon, battery technologies are unlikely to store electricity over several hours daily and largely impact the power sector in the longer discharge duration applications.

Figure 7.5 **Influence of cost reductions and performance improvements of Li-ion compared with PHS**



Notes: application characteristics assumed for arbitrage: 300 MW, eight-hour storage; 365 cycles per year. The values depend on the electricity price and range from minimum USD 0/MWh to a maximum of USD 50/MWh.
Source: unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *Initial analysis suggests that extremely large cost reductions are needed to make Li-ion competitive with PHS for price arbitrage.*

Overall, electricity storage is currently uncompetitive in many applications and therefore will not strongly influence power systems at this time. Its future role could be different, but the scale of cost reduction and performance improvement is very large for many technologies in given applications. The exceptions are PHS and CAES, which are both cost-competitive for most applications, but their use remains limited to a few specific sites. Development of small-scale, isothermal CAES could expand the role of this technology by providing a much more diverse set of applications that are not site-dependent. Batteries, flywheels, SMES and supercapacitors should be considered first for power applications such as frequency regulation and load following since they are closer to competiveness already. Regardless of these challenges – there is a wide range of versatile storage technologies that can provide several grid services, which may accelerate its adoption.

Importance of regulatory frameworks on storage deployment

Market and regulatory frameworks will strongly influence deployment of storage assets. Some countries, mostly in OECD regions, have liberalised electricity markets in which the value chain is unbundled. In many others, the power system remains monopolistic. In both frameworks, several attributes minimise the investment risk: scalability (deployment at several grid voltage levels possible), modularity (investment can be matched to demand), rapid construction, and provision of multiple applications or benefit stacking.

In liberalised electricity markets, ownership and control of storage assets is a key regulatory question that needs to be addressed, since it will define the financial attractiveness of storage investments. Two broad regulatory approaches can be differentiated: storage can be considered as a market participant (much the same as generation) or it could be considered as a regulated asset (such as the electricity grid). Competition and therefore technology innovation would be higher if storage were considered a market participant. Regulated markets have a low appetite for technology risk, preferring to invest in mature options with proven economic returns. However, system-wide benefit would be captured best if storage were considered a regulated asset under the control of the system operator. Owning storage, however, could also provide the grid operator with the power to intervene and influence the market, in which case a market participant status may be more appropriate. The regulatory framework therefore strongly impacts the business model and opportunities for electricity storage and, from a policy perspective, is thought a key priority to support successful and efficient deployment of storage technologies.

Monopolistic electricity systems have even greater disincentive for innovation and are often considered even less likely to deploy new storage technologies. Monopolistic companies, however, should more easily derive the greatest benefit from the system-wide deployment of electricity storage.

Competition against other technologies

Electricity storage can provide a range of applications in the power sector, but is not the unique technology for these applications (Table 7.1). Electricity storage is competing against other technology options, proven and at R&D stage (Table 7.5), including thermal dispatchable generation, demand response and advanced electricity grids (including interconnections). As a system technology, the role and success of electricity storage technologies will depend on system-wide development, including the development of other technologies that can provide the same application.

Table 7.5 Suitability of other flexibility options to provide electricity storage applications

	Electricity storage	Thermal generator	Electricity grids	Demand response
Seasonal storage	Suited	Suited	Limited	Incompatible
Arbitrage	Suited	Suited	Suited	Incompatible
Frequency regulation	Suited	Suited	Limited	Limited
Load following	Suited	Suited	Limited	Limited
Reserve capacity	Suited	Suited	Limited	Suited
Voltage-support	Suited	Suited	Suited	Suited
T&D investment deferral	Suited	Suited	Suited	Incompatible
Off-grid	Suited	Suited	Incompatible	Incompatible

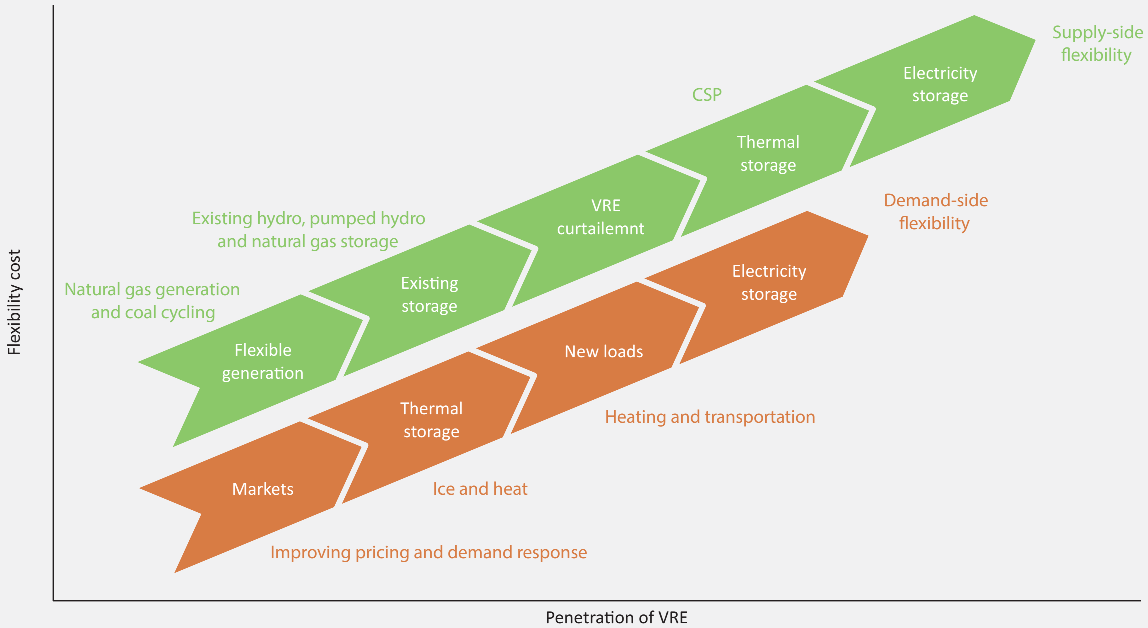
Incompatible / Limited / Suited

Note: wind and PV integration are part of different grid-balancing services (regulation, load following, reserve capacity and voltage-support).

As previously discussed (Figure 7.4), the cost for storing electricity remains a main barrier to large-scale deployment of electricity storage technologies. Compared with its competing options, electricity storage is often considered as the last, or most expensive, resource –

especially for grid flexibility (Figure 7.6). The wide range of technologies available, including storage and competing technologies, reinforces that successful R&D strategies should be application-driven to ensure inclusion of the most competitive technology.

Figure 7.6 **Conceptual merit order for flexibility options**



Note: the relative order of flexibility options is conceptual only.
Source: Denholm, 2013.

Key point *Due to the high technology cost, storage appears to be the last flexibility resource to be utilised in managing the deployment of variable renewable generation technologies.*

Dispatchable thermal generation

Thermal generation is commonly used to balance power systems. The combustion fuel, brought on as needed, can be described as energy storage. Nuclear, coal and gas can all provide firm dispatchable reserve capacity to the grid. Gas electricity generation is technically the best-performing thermal technology to provide backup capacity and is commonly used to provide peak load (see Chapter 5). The CO_2 emissions from gas generation are an important downside, however, which could be addressed through the use of renewable fuels such as biogas. From a technology perspective, storage technologies generally outperform gas with respect to their very quick start-up and ramping capabilities. Electricity storage does not emit any direct emissions and the indirect emissions strongly depend on the emission content of the charging electricity (i.e. whether the electricity generation is from fossil fuel or renewables). Being the incumbent backup technology, gas-fired generation can serve as the benchmark to assess at which price storage can enter the market.

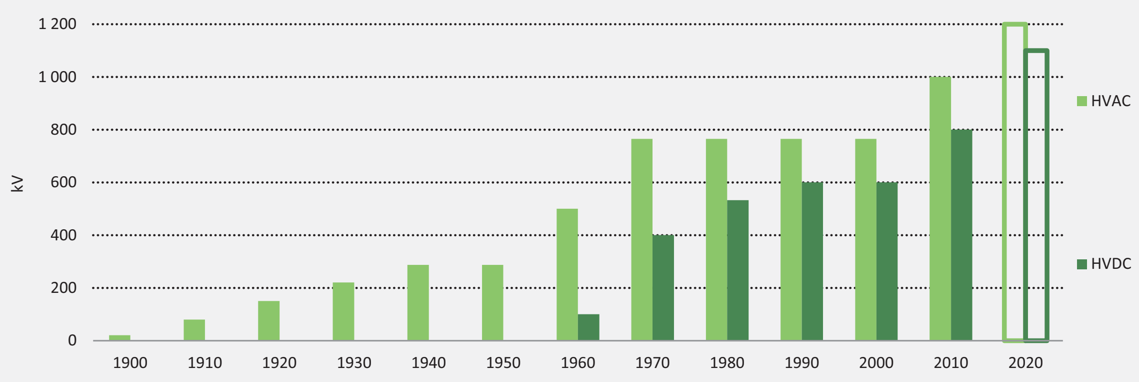
Electricity networks

Advanced power grids can facilitate grid balancing and thus reduce the need for electricity storage. Two key trends are already changing the traditional passive role of grids: development of high-voltage transmission supergrids and development of smart distribution grids.

Development of high-voltage transmission supergrids. Far-reaching, interconnected networks can support connecting and matching supply and demand from different locations. Interconnections among two different zones can enable the development of better renewable resources at farther distances from load centres, and capitalise on complementarities between two zones and provide similar services to storage; i.e. balancing fluctuations whether of short duration or associated with seasonal change. Remote regions endowed with wind, hydro or solar resources need be connected to load centres through high-voltage alternating current (HVAC) and direct current (HVDC) transmission lines. By reducing the current for a given voltage, high-voltage lines minimise the losses induced by currents. Over the last decade, however, so-called "ultra"-high-voltage solutions have been deployed to support the high efficiencies needed by transmission projects over very long distances (Figure 7.7). China is currently installing ultra-high-voltage transmission networks that include 1 000 kilovolts (kV) AC and 800 kV DC transmission lines and interconnects remote, resource-rich provinces in the west with demand centres on the east coast.

Apart from reducing losses, advanced transmission technologies enhance controllability and support the installation of more compact lines. Increased power flow controllability using flexible AC transmission systems (FACTS) and HVDC technology improves system flexibility and increases utilisation of the transmission infrastructure, which can then effectively increase utilisation of remote renewable energy resources while containing grid connection costs. FACTS technology compensates reactive power and controllability of HVAC lines to improve overall power quality. HVDC provides black start capability and already plays an important role in connecting offshore wind to AC grids (multi-point DC terminals). A major R&D breakthrough for DC grids would be the commercialisation of HVDC circuit breakers that would enable using DC grids not just for point-to-point transmission, but also for interconnected DC networks. ABB claimed in 2012 to have developed the first DC circuit breaker.

Figure 7.7 Voltage level increase for best available DC and AC transmission lines

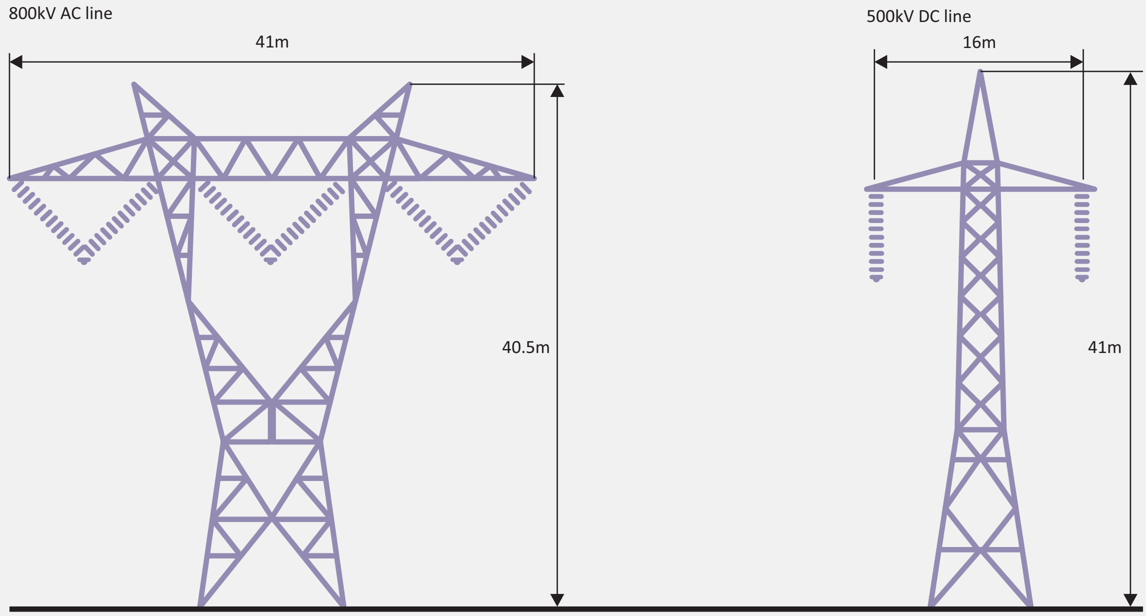


Notes: the 2020 estimates project that technology currently under development reaches market maturity by 2020. For HVDC, the numbers represent ± kV.
Source: ISGAN, 2013.

Key point *Higher voltage levels for electricity transmission increase efficiency of transport over long distances.*

Permitting and right-of-way are, in many countries, the main obstacles for transmission extension. Growing public opposition and political involvement in long-term infrastructure planning decisions could limit the build-up of electricity transmission lines, especially in densely populated areas. This could completely block any new projects or capacity increase and thus potentially favour deployment of storage technology, or could favour the transmission technology with lower land-use requirements. For example, to transport 3 000 MW, the DC (500 kV, bipolar) would require only half the size of transmission corridor compared with an AC line (800 kV) (Figure 7.8).

Figure 7.8 **Land requirement for 800 kV AC line and 500 kV DC line for 3 000 MW transmission capacity**



Source: FOSG, 2013.

Key point *To transport the same amount of electricity, the transmission corridor for DC lines is only half that required for AC lines.*

HVDC offers the important advantage of being suitable for long-distance land and marine cable connections. The major cost for new DC transmission interconnections is the converter stations that currently render the technology economical only for a point-to-point connection over 500 kilometres (km). HVDC will not replace HVAC as main electricity carrier, but the future HV network will increasingly become a hybrid AC-DC network. Quick progress in high-voltage transmission deployment, both DC and AC, could reduce the role of long-term storage, but increasing public opposition against network projects could also favour a larger role for storage.

Development of smart distribution networks. Distribution networks have typically been built to "fit and forget"; grid operators make little effort to gather information on power flows or quality. Smart-grids use ICTs to build sensing and control capabilities into the distribution grid, thus allowing active management of demand and supply. An active distribution network enables demand-response participation while also increasing penetration of distributed generation and distributed storage. Smart distribution networks serve as a platform that improves understanding of the demand side and allows data-based competition in this part of the system. Smart-grids are capable of quantifying the multiple benefits of storage and potentially supporting its integration in a strategic manner.

Demand-side response and management actively shifts end-use energy consumption and power loads across time, and can be considered as a virtual storage. Different levels of demand-side integration need to be distinguished. The ultimate level integrates the consumer as an active, real-time participant in the electricity system who can manage consumption, distributed generation assets, and even storage assets. Such a system would require an extensive refurbishment of current distribution lines, substations, transformers and protection equipment to enable increased control and bi-directional flow.

A first level of demand-side response would be to provide the grid operator or aggregator with some control over end-use loads or even enable end users to offer their loads on markets. Such a demand response programme requires only additional communication and management system, but no radically new infrastructure – making it more cost-attractive. The load control variant of demand response is particularly relevant in the buildings sector, where a large portion of heating and cooling loads can be shifted without impacting the resident. Integration of water heaters for demand-side response, for example, is used in many countries (Table 7.6) and accounts for around 20% of total residential water heating usage in EU countries and the United States. Enabling all residential heaters to provide demand response would be a major flexibility asset for power grids at low cost.

Table 7.6 Residential electric water heating in a selection of OECD countries

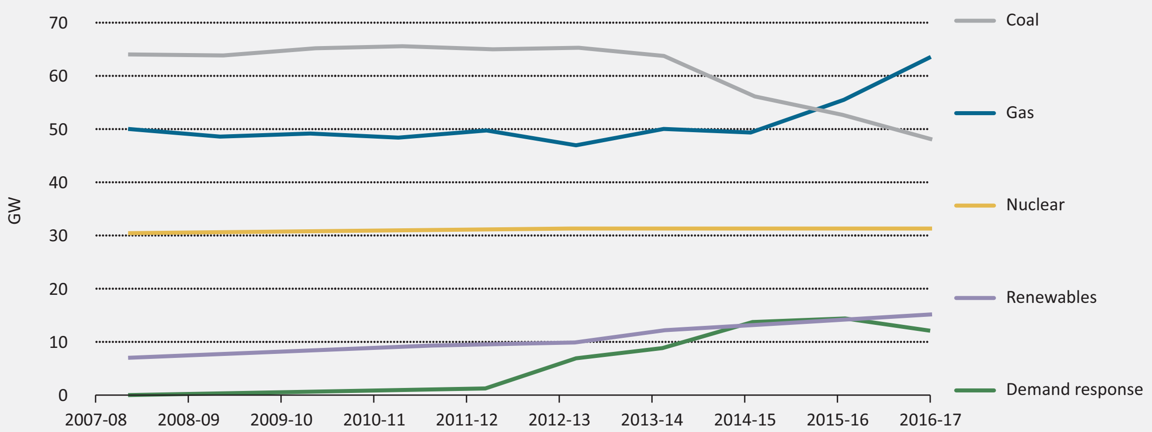
	Electricity demand (TWh)	Share in total residential water heating (%)
Australia	28	41
Canada	63	23
France	51	40
Germany	84	27
Ireland	6	32
Italy	29	26
Japan	161	14
Netherlands	17	13
Spain	48	10
United Kingdom	80	9
United States	542	23

Notes: TWh = terawatt hours. Additional data available online at www.iea.org/etp2014.

The boilers of non-electric natural gas heating systems can also be adapted to provide additional flexibility, simply by adding an electric coil to create a dual fuel (gas-electricity) mechanism to heat water. The cost of such an upgrade (inserting coil and controller) to provide demand response through smart meters and smart-grids is low – about USD 30 for a boiler controller and USD 100 for a smart meter.

Electricity market design can stimulate electricity users, especially large industrial consumers, to participate in demand response by bidding-in their demand capacity for various applications. Such schemes require relatively simple communication equipment to remotely reduce a load. Successful introduction of demand response into electricity markets, such as in the PJM[12] market in the United States (Figure 7.9), demonstrates that consumers do respond to market signals. The role of demand response to support grid balancing in power systems is increasing since it offers a cost-effective solution to reduce annual peak load. Storage and demand response could complement each other in power systems, as is seen in the PJM market, where batteries are tested in parallel to demand-response deployment to provide system regulation.

Figure 7.9 Cleared installed capacity in PJM market



Source: Helm, 2013.

Key point *When accompanied by market incentives, demand response has taken off rapidly to provide annual peak load.*

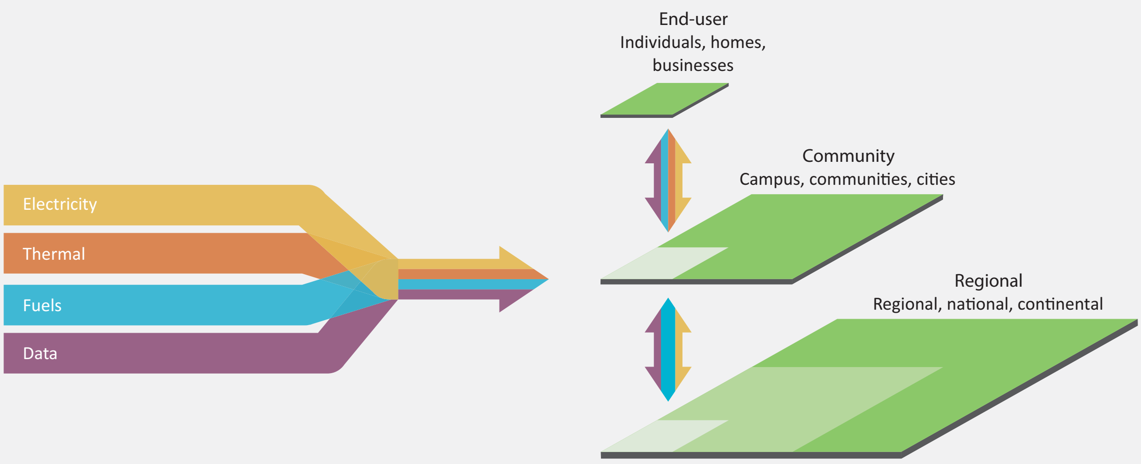
Energy storage for system integration

Traditionally, three main "pathways" have underpinned energy systems: electrical, thermal and fuel. More recently, data have become a fourth means of managing energy resources (NREL, 2012). An increasing convergence of those pathways defines new energy system integration opportunities at all scales – from end user to regional energy infrastructure (Figure 7.10). The increase in natural gas electricity generation since the 1990s has interconnected the natural gas and electricity systems. The continuous electrification of heat and transport is increasing the interface with electricity systems. Systems thinking could stimulate complementarities across different energy pathways and increase efficiency, resilience and economics of the whole energy infrastructure.

Whereas electricity (or power-to-power) storage is limited to the power system, other forms of storage could expand the nexus with the thermal and fuel systems. Power-to-fuels and power-to-heat storage are system-wide approaches to enhance power system flexibility while also benefiting from cost efficiencies available in other energy pathways: fuels are often higher-priced than electricity, and heat can be stored more cost-efficiently then electricity.

12 PJM is a large transmission system and market operator in the northeastern United States.

Figure 7.10 Energy systems integration



Source: Denholm, 2013.

Key point *Storage can support integration among power, heat and fuel systems.*

Power-to-heat or thermal storage

Power-to-heat or thermal energy storage does not enable use of electricity at a later time; rather, it stores electricity for thermal use and thus increases flexibility for thermal electric demand. The earlier example of using hot water storage systems for demand response is a form of thermal storage.

In fact, heat (thermal energy) can be stored at a variety of temperatures (from - 40°C to 400°C) and in different forms: as sensible heat in a given storage medium (often water); as latent heat in phase-change materials (PCM); and as chemical energy using thermo-chemical heat (TCM). Sensible heat – based systems are widely available commercially. More advanced TCM- and PCM-based systems are still under development and demonstration, but have a higher storage capacity per unit volume than water storage. This makes it possible to produce thermal storage devices that are more compact (Figure 7.11).

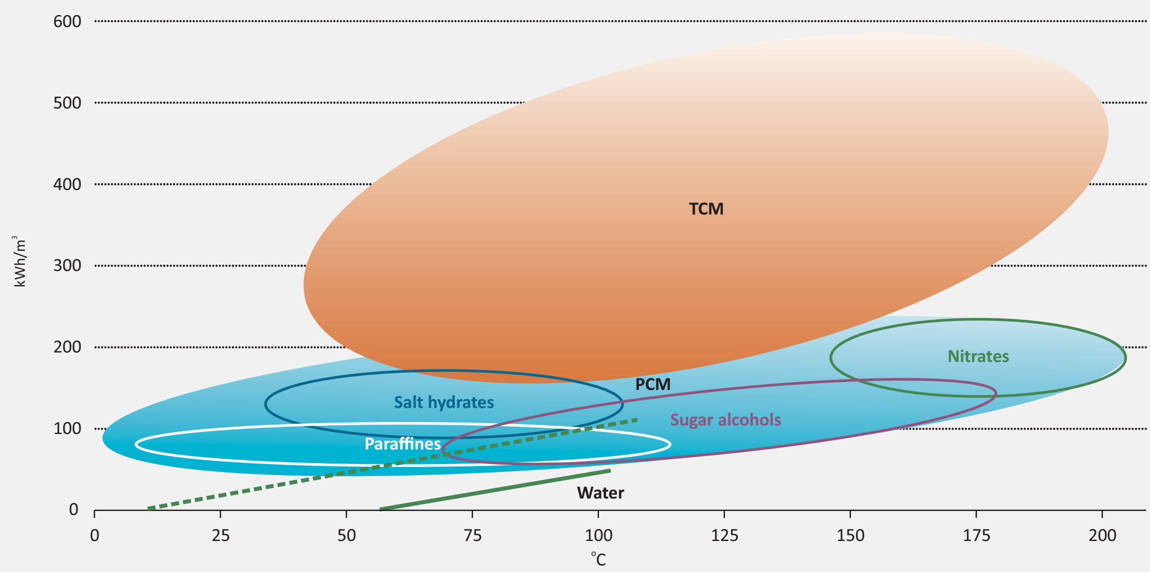
Thermal storage technology is more mature and shown as being more cost-effective (Table 7.7); it may therefore outperform electricity storage, especially for long-term or seasonal storage applications. Systems thinking offers an enhanced system solution that requires co-ordination among an larger number of stakeholders, which is a major challenge.

Table 7.7 Typical parameters of thermal energy storage systems

	System capacity (kWh/t)	Power (MW)	Efficiency (%)	Storage period	Cost (USD/kWh)
Sensible (hot water)	10-50	0.001-10	50-90	Day to month	0.1-13
PCM	50-150	0.001-1	75-90	Hours to months	13-64
TCM	120-250	0.01-1	75-100	Hours to day	10-129

Note: t = tonne.
Source: ETSAP IA and IRENA, 2013.

Figure 7.11 **Thermal energy storage technologies and their storage capacity versus temperature**



Source: ETSAP IA and IRENA, 2013.

Key point *PCM and TCM could increase the volumetric density of thermal storage by a factor of 100 compared with water.*

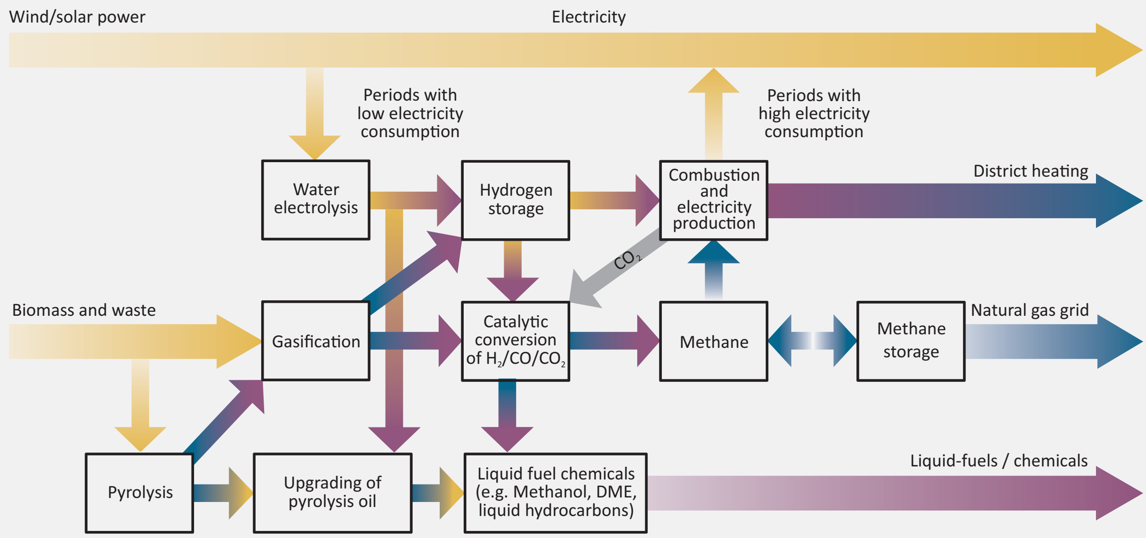
Co-generation plants (see Box 5.4, Chapter 5) already combine electrical, thermal and fuel pathways; integration of a thermal storage technology could further increase system flexibility. Denmark, one of the leading countries in terms of VRE integration with minimum curtailment, benefits from many distributed co-generation plants equipped with water heaters and a large district heating network. In the absence of district heating and cooling networks, which can be considered as heat transport infrastructure, thermal storage will need to be located close to the demand.

Power-to-gas

Excess VRE, as previously discussed, could power an electrolyser and generate zero-carbon hydrogen. The generated hydrogen could be either blended in the natural gas grid or transformed into synthetic natural gas in a further transformation step (Figure 7.12). Blending hydrogen into the natural gas grid can be a cost-effective means of reducing CO_2 emissions by integrating excess or very low cost electricity at higher natural gas prices and under future technology assumptions. But hydrogen could potentially have higher value and therefore be competitive at higher prices as a fuel in the transport sector or as a feedstock in the industry sector.

In Germany, a first pilot plant trying to integrate renewable hydrogen into the transport sector was opened in 2013 (in Wertle) with support of industry and government. The "windgas" concept includes the further transformation of hydrogen into synthetic methane, the main component of natural gas, by capturing CO_2 in a Sabatier process. The resulting CO_2-neutral gas can be injected into the natural gas grid. The additional transformation step, however, further degrades the total cycle efficiency to less than 10%: electrolyser (efficiency 60%), methanisation (75%), gas storage (95%) and natural gas combustion engine (20%).

Figure 7.12 System integration with growing hydrogen production and biomass gasification



Note: CO = carbon monoxide.
Source: DTU International, 2013.

Key point *Storage of renewable energy could bring system-wide benefits through integration with biomass and hydrogen conversion process.*

Systems integration enables delivery of hydrogen to systems that offer higher prices, thereby increasing its competitiveness. The use of power-to-fuels could significantly increase interactions between the gas and power system, which is currently limited to gas electricity generation. Biomass gasification could also help to decarbonise the gas grid, creating a very flexible, interlinked and low-carbon energy system based on gas and electricity networks.

Grid storage requirements in the 2DS

Estimating grid storage requirements remains challenging mainly because it depends completely on system-wide development, which itself is difficult to predict. Since storage applications span diverse timescales – from milliseconds to months – and are very location-specific, the modelling requirements are quite complex. For accuracy, it is necessary to combine a unit commitment and infrastructure planning model with some degree of spatial resolution, which is challenging over large regions. The *ETP* long-term modelling framework therefore estimates the storage needs towards 2050 only for arbitrage applications. Higher value applications, such as load following, are not captured due to modelling limitations.

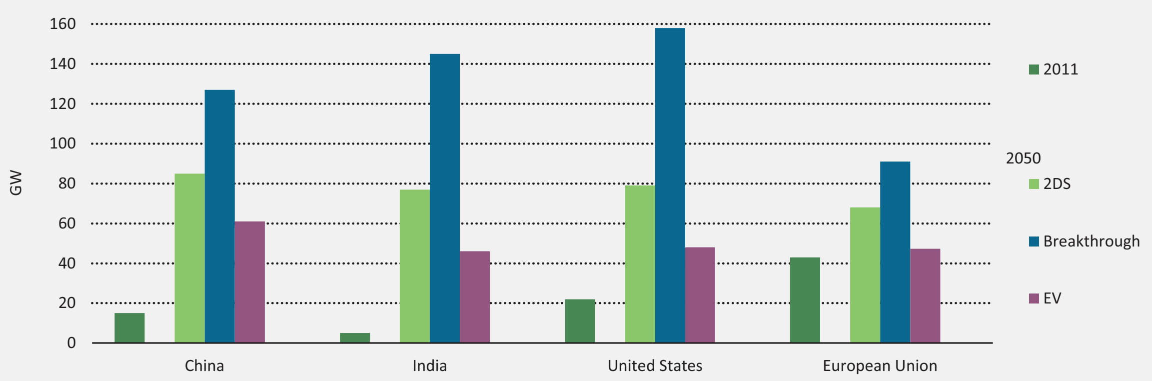
The *ETP* 2DS projects the capacity expansion of power generation technologies from now to 2050 to meet low-carbon objectives. The resulting system is then explored further using a linear model in which the cost of operating the electricity system is minimised by determining the dispatch of generation and storage technologies during every hour in a given year. This provides a detailed assessment of flexibility within the 2DS power generation fleet under a range of conditions for storage and technologies competing to provide the same services (full detail on the modelling and scenario assumptions can be found in the Annex A). The future role of daily electricity storage technologies is analysed under a range of sensitivities regarding future costs and performance of storage, and in light of competing technologies including dispatchable thermal generation and demand response. Three of these variants are reproduced here:

- the 2DS
- a "breakthrough" scenario, with aggressive cost reductions in storage technologies
- an "EV" scenario, in which demand response from "smart" charging of the EV fleet in the 2DS provides additional flexibility to the system.

The 2DS assumes that the cost of technologies providing daily storage needs in 2050 will be that of the lowest-cost technology, which under current assumptions is PHS. In the "breakthrough" scenario, aggressive reductions in storage costs of specific energy (per megawatt hour) and power capacity (per megawatt) drive increased deployment of storage. Finally, the EV scenario employs charging strategies to provide system flexibility, reducing the need for additional large-scale storage in the six-to-eight-hour-duration range.

Depending on the different storage scenario assumptions, the capacity of storage deployed in 2050 varies by a factor of up to 4 across some regions (Figure 7.13). Storage deployments grow between 2 and 15 times from 2011 to 2050 in the 2DS across the regions analysed. The difference in growth between the regions reflects differences in the flexibility options available to the respective systems, the structure of electricity demand and the level of VRE deployments. New deployment is highest in China and India, consistent with the large-scale build-up of electricity infrastructure required by a tripling of electricity generation in the 2DS while achieving a high share of variable renewables.

Figure 7.13 Storage capacity in the 2DS and storage variants



Key point *The impact of a technology breakthrough varies greatly across regions, but demand response provided by EVs consistently reduces storage needs in electricity systems.*

Impact of a "breakthrough"

The "breakthrough" scenario aims to estimate the highest penetration of daily electricity storage in the 2DS. Aggressive cost reductions make storage technologies providing daily storage services competitive with the "price setter", which for arbitrage/load-levelling applications is represented by a CCGT with a 60% load factor. While storage penetration in this scenario increases in all regions, the results again highlight how system-specific the deployment of storage is. In India, where PV achieves a high penetration in the 2DS, lower cost daily storage allows for increased load-shifting of solar electricity. In Europe, the existing PHS capacity, and the relatively high shares of gas plant available for flexibility, dampen the impact of a breakthrough in daily storage technologies.

Such cost reductions are, however, highly ambitious. For PHS and CAES, civil engineering costs account for nearly half of the initial capital investment; improvements in the technology itself would have a relatively low overall impact. For other technologies the cost targets are very ambitious: for batteries a ten-fold energy-specific cost reduction and a tripling of battery life would be required.

Integration of EVs

The cost of batteries for EVs is primarily paid by the buyer in return for acquiring mobility. In reality, most passenger EVs will be parked for most of the time (95%) and will spend much of that time connected to the grid. EVs can therefore provide flexibility to the grid through effective charging strategies. The cost for the EV storage asset, from a grid perspective, can be assumed to be relatively low since it is primarily paid for by the owner for car propulsion. By 2050, widespread system integration with EVs reduces the total storage need by roughly half.

Two main restrictions need to be overcome for this potential to be realised. First, power grids and EVs need to be upgraded in terms of technology and software to enable controlled charging. Second, the battery owner may need to be compensated for degradation of the EV battery due to additional charging cycles.

System integration of other clean energy technologies, in particular heat pumps equipped with water storage tanks, can potentially also provide similar system-wide benefits through demand response.

Recommended actions for the near term

The role of storage is projected to be among a range of grid integration technologies – including thermal dispatchable generation, advanced grids (including interconnection) and demand response – to support the operation of low-carbon electricity systems. The true benefit of battery electric storage for power systems might lie in the modularity, controllability and responsiveness. At present, no other asset in the power sector can combine these characteristics. Current electricity storage technology development levels and the associated high costs for high-power and high-energy applications currently fall short of delivering the conceptual flexibility potential compared with competing options, with the exception of PHS and CAES.

R&D strategies for power systems should be application-driven, i.e. focused on solving problems through a wide set of technologies that includes electricity storage and its competitors. Applications have very diverse characteristics in terms of location, power size, energy requirements and response time; no single technology can deliver all of these needs. The system perspective aims to identify the most promising technology for each application and thus fosters R&D in specific applications.

For longer-duration applications, electricity storage other than PHS and CAES remains largely uncompetitive, even in the long term under aggressive R&D assumptions. The high cost and low energy density of electricity storage technologies make thermal power generation more cost-effective. Hydrogen appears to be the only technology that can provide seasonal storage, although power-to-fuels might be more valuable since price goals in the power sector seem very low.

Frequency regulation and load following appear to be the best-suited applications for deployment of battery and short-term storage (e.g. flywheels, SMES and supercapacitors) in the long-term. If technology costs continue to drop through learning and progress, these modular storage assets could take up additional roles in future power systems.

In addition to technology development, it will be essential that regulation and markets be evaluated and adjusted to enable storage to competitively participate in electricity system operations. Regulatory and market frameworks will influence the role of storage for all grid applications. In liberalised markets, the ownership question needs to be addressed to define under which conditions grid storage should participate in markets (such as generation) or be considered a regulated asset (such as electricity grids).

Electricity storage combined with solar PV can be a powerful technology for off-grid applications, since it can replace or reduce the run time of costly diesel generators. The initial low power and energy requirements could also scale-up progress in battery technology from non-power sector applications, and will increasingly become a main focus of the battery industry. In regions without access to electricity, especially in poor communities, small-scale battery services (e.g. for lighting) help eradicate energy poverty and are already a cost-effective alternative to grid extension.

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Chapter 8

Attracting Finance for Low-Carbon Generation

Attracting private investment in low-carbon electricity generation requires that governments learn to think like investors – who expect a return on capital that appropriately reflects the risks they perceive such projects represent. Currently, uncertainty regarding future energy and carbon prices seriously undermines investor confidence. To reassure investors, governments may need to spread related risks and associated costs to taxpayers and consumers. Governments need to become more transparent when using such support mechanisms.

Key findings

- **It will be necessary to assess whether current low-carbon support mechanisms continue to be the best options or if new mechanisms are needed.** To date, low-carbon investments have been driven by support schemes, including feed-in tariffs (FiTs), output-based subsidies and quota systems. The aim of wind and solar power deployment is to reduce their costs down to a point where low-carbon technologies are competitive on electricity markets.

- **Moving from a regulated environment with support mechanisms to a market-based approach considerably raise the risk to which investors are exposed.** This increases the risk of uncertain carbon market and wholesale electricity prices for technology investors.

- **Mobilising finance to decarbonise the electricity sector requires an understanding of how investment decisions are made.** The investor community's approach to evaluating risk, however, is not always well understood. Financing low-carbon power plants (renewables, nuclear, carbon capture and storage [CCS]) in a framework of competitive electricity markets requires returns to compensate for the risks of revenue streams from electricity generation, stemming from potentially low prices for carbon, gas and coal in the future.

- **A high carbon price could stimulate low-carbon investments, but is insufficient on its own given the potential downside risks of carbon pricing policy.** Moreover, carbon pricing is unlikely to be put in place in a foreseeable future in many regions with competitive electricity markets.

- **The low variable costs that characterise low-carbon technologies will influence electricity prices.** The 2°C Scenario (2DS) target implies that average wholesale electricity market prices will decline closer to 2050. As a result, market revenues alone might not be sufficient to cover up-front investment costs.

- **Without the stimulus of carbon pricing, it will be necessary to trigger low-carbon investment needed in the 2DS.** Governments will have to continue providing policy solutions that improve the net present value of low-carbon investments and mitigate the market risks for project developers and financial investors.
- **Governments are uniquely positioned to stimulate the investment needed.** Options available include shifting the carbon and fossil fuel price risk away from generators, and transferring it to consumers and taxpayers. Governments must make this allocation more transparent to all stakeholders.

Opportunities for policy action

- Supplementing wholesale power markets with low-carbon support schemes can stimulate investments; to do so, measures must provide a fair risk-return ratio to attract financing, most notably where a carbon price is absent, too low or too uncertain. A strategic international agreement on carbon pricing would make investment more attractive.
- Transparency in costing can enable better cost comparison of specific low-carbon solutions against the end goal of CO_2 emissions reduction. This should reflect the total cost to society, including the cost of the solutions themselves and potential costs from the transfer of the risks to consumers or taxpayers (e.g. subsidies, quotas, FiTs, auctions and regulated assets).
- Public policy instruments should be designed so as to supplement electricity markets while seeking to minimise distortions, and should rely on market mechanisms for mature technologies while also minimising costs through timely technology deployment.

To close the financing of any project, a project developer needs to convince financial investors of one thing: that they will be able repay the debt and the interest on the debt while also remunerating shareholders for the capital mobilised. If the expected cash flows generated by a project lack sufficient certainty, the financial investors simply will not release the cash needed to pay the up-front investment cost.

The same holds true when financing a power plant. Over many decades, investors have established metrics by which they calculate risk and return to make decisions about investing in the power sector – in part based on the fact that most conventional power plants are costly to build, but generate revenue over long lifespans (40 to 100 years).

From the financial investor perspective, financing low-carbon projects is relatively new territory, fraught with uncertainty. One common feature of most low-carbon technologies is the high investment cost per kilowatt (/kW) of installed capacity. In *ETP* scenarios, the cost of major technologies in 2013 ranges broadly, for example onshore wind costs USD[1] 1 600/kW and nuclear USD 5 000/kW.

From 2004-13, global investment in renewable energy, excluding large hydropower, exceeded USD 1 500 billion (BNEF in IEA, 2013a). While not insubstantial, this is grossly insufficient in comparison with the USD 27 trillion of generation investments needed to transition to low-carbon electricity by 2050 in the 2DS. Although recent investments represent only a small fraction of capital available globally, to attract low-carbon financing, governments have had to

1 Unless otherwise stated, all costs and prices are in real 2012 USD, i.e. excluding inflation.

rely on support instruments including a carbon price, quotas, capital subsidies, technology-specific support instruments and economic regulation of individual projects.

The way these instruments improve the risk-return ratio for investors is by increasing revenues and allocating risks more widely – usually among investors, taxpayers and consumers. In competitive electricity markets, however low-carbon technologies remain more expensive and have not yet provided the rate of return that investors see as commensurate with the associated risks (with a few exceptions). The expected average electricity prices are too low compared with initial investment costs, and the market risk is perceived to be too high.

In short, the need to stimulate low-carbon investment means first finding ways to increase returns and reduce risks to investors. During the transition, governments' ability to choose the right mix of instruments and execute policies efficiently is the key success factor in achieving the decarbonisation objective. This chapter provides an analytical framework for governments determined to reduce CO_2 emissions in the electricity sector. The chapter opens with a brief description of how private investors make investment decisions and the potential role of a carbon price, then moves on to present the costs and risk profiles of different technologies. After recapping the historical investment framework of regulated utilities, the text examines the prospect for low-carbon investments in competitive electricity markets. Finally, the last section reviews the instruments available by which governments can supplement competitive markets to incentivise low-carbon investments. The aim here is not to make *ETP* readers into investment bankers, but rather to give non-finance readers a sense of what matters to attract financing.

Attracting financing resources

Traditionally, governments have used a specific metric, called levelised cost of electricity[2] (LCOE), to assess the cost-competitiveness of generation technologies (Figure 8.1). Under a regulated framework, this metric can still be useful to help governments select base-load generation technologies. LCOE is not, however, particularly well-suited to assessing the competitiveness of variable renewable energy supplies. Indeed, LCOE does not capture the market value of some variable renewable technologies, which depends on electricity prices at the time of generation. More to the point, LCOE does not reflect the way private investors make their investment decisions.

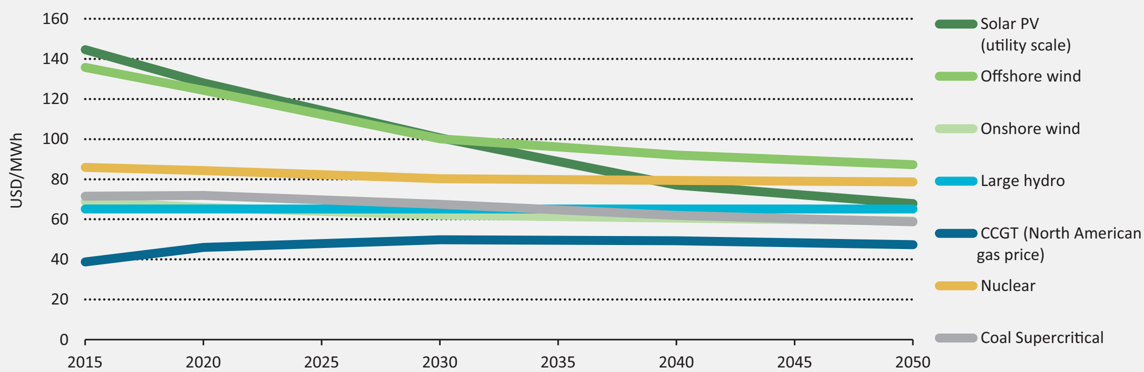
To assess whether the cash flows of a new project are sufficient to reimburse the investment and capital costs used to finance a project, investors calculate the net present value[3] (NPV). NPV calculations are based on expected electricity prices and take into account their variation and uncertainty over time. A negative NPV implies that the project will not deliver sufficient return, and thus is unlikely to proceed; a positive NPV is a necessary condition for being financed, but even this is not sufficient. Investors also appraise projects with other financial ratios, such as the internal rate of return, the payback period or debt coverage ratio under stress conditions to capture other dimensions of financial viability, and to inform investment decisions.

Ultimately, the key dimension of investment decisions remains the trade-off between the risks of a project and the return on investment. Many investors have a low risk appetite, such as

2 Detailed approach can be found in the study *Projected Cost of Generating Electricity* (IEA and NEA, 2010). The LCOE is a useful tool for comparing the unit costs of different technologies over their economic life. It corresponds to the cost assuming the certainty of production costs and the stability of electricity prices. The LCOE is equal to the constant price for electricity that would lead to a zero net present value (IEA and NEA, 2010).

3 In finance, the NPV of a time series of cash flows, both incoming and outgoing, is defined as the sum of the present values of the individual cash flows. NPV is a central tool in discounted cash flow analysis, and is a standard method for using the time value of money to appraise long-term projects. Used for capital budgeting, and widely throughout economics, finance and accounting, it measures the excess or shortfall of cash flows, in present-value terms, once financing charges are met (www.princeton.edu/~achaney/tmve/wiki100k/docs/Net_present_value.html).

Figure 8.1 *ETP*'s LCOE excluding a carbon price



Notes: unless otherwise noted, material in all figures and graphs in this chapter derive from IEA data and analysis. PV = photovoltaic. CCGT = combined-cycle gas turbine. MWh = megawatt hour. Figures and data that appear in this report can be downloaded from www.iea.org/etp2014.

Key point *Based on LCOE, low-carbon technologies remain more expensive than generation from fossil fuels over the transition period to the 2DS.*

banks lending money or pension funds, and are unlikely to invest in risky projects. In any case, when making a final investment decision, investors will need to feel assured that a project with higher perceived risk is going to deliver a higher rate of return.

Low-carbon investments, whether large and financed by sophisticated large utilities or small-scale and financed by households, cannot escape this financing constraint. Before deciding to spend USD 10 000 for a rooftop solar PV or USD 5 billion to USD 10 billion for a nuclear power plant, investors will seek to assess whether they will be able to get their money back and get a return.

A discussion of financing must therefore assess for potential investors the risk profile and profitability of low-carbon investments. Capital markets allocate financing resources according to the expected risk/return profiles of these industries and projects, not on the basis of the government objectives.

Using a carbon price to stimulate low-carbon investments

Many argue that an explicit carbon price is needed to correct for the fact that fossil fuel emissions are driving climate change (i.e. the climate externality) and to send the price signals needed to trigger low-carbon investment. The *ETP* 2DS assumes a global and uniform carbon price of USD 90 per tonne of CO_2 (tCO_2) by 2030, which would drive up the cost of gas-fired generation by around USD 30/MWh. Internalising the climate change and environmental impacts of gas-fired electricity would drive up the price, putting it on par with low-carbon technologies that now seem expensive. The competitive price would likely incentivise some investors towards low-carbon options.

From an economic point of view, uniform carbon pricing is essential, but not sufficient, for the profitability of low-carbon investments based on market prices. Progress has been made in many countries to establish a carbon price, either via a tax system or a cap-and-trade system. The European Union launched in 2005 the largest carbon market covering more than 11 000 power stations and industrial plants in 31 countries. Several regional carbon markets exist in North America, for example in California and in states that joined the Regional Greenhouse

Gas Initiative. Many other countries are in the process of introducing a carbon price, including the People's Republic of China, Korea and South Africa.[4]

Unlike the gas price, which has a physical market, a carbon price is a public policy construct. As a result, carbon pricing has been a source of uncertainty – particularly as it leaves investors exposed to significant risks of future policy changes over the lifetime of new low-carbon generation investments. Moreover, the prices predicted to date, on which investors calculated their returns, have not materialised. When the EU Emissions Trading Scheme (EU ETS) was introduced, the carbon price was projected to remain at EUR 20/tCO_2 by 2020 (EU, 2006); it was close to EUR 4/tCO_2 at the end of 2013. This low price is mainly due to overly optimistic economic growth forecasts and over-allocation of emissions allowances. The eligibility of international offset credits in the EU ETS, along with the implementation of energy efficiency and renewable policies, have reduced CO_2 emissions but without any adjustment of the cap on emissions. These factors also played a role in the weakness of carbon prices.

To date, carbon pricing constructs have not been credible enough for investors. In the current context of growing political uncertainty surrounding a global climate agreement, business plans of new projects are likely to discount the long-term carbon prices, reducing its long-term value to zero or close to zero. Investment decisions tend to neglect the price of carbon, even if a non-zero carbon price is viewed as a possible upside.

Less well known but equally important, consumers are also exposed to the carbon price risk and more generally to the carbon policy uncertainties. If, after setting ambitious low-carbon policies, governments delay or weaken decarbonisation objectives (for any reason such as economic crisis or the failure to reach a global agreement), consumers may have to pay higher electricity bills to compensate for previous low-carbon investments that are no longer valued by society. Shifting the carbon price risk away from investors does not necessarily mean that the risk disappears.

Low carbon remains expensive and capital-intensive

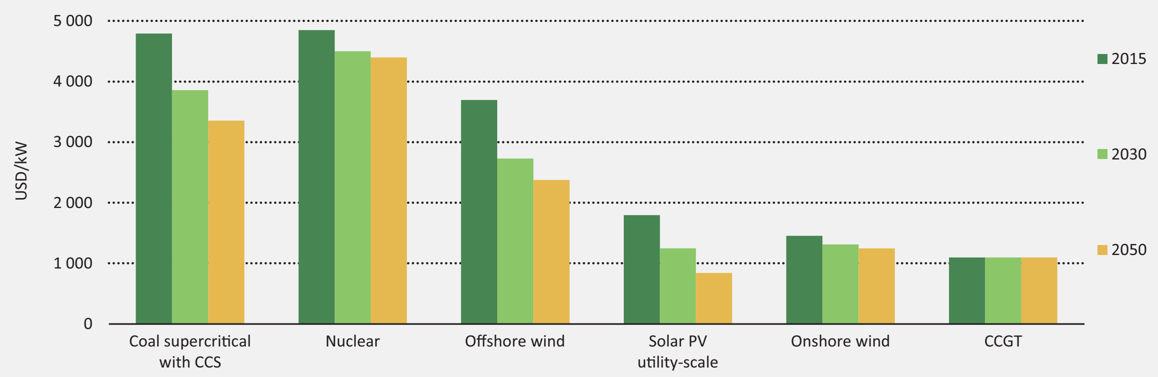
One frequent feature of low-carbon generation technologies is that the up-front investment cost per kilowatt (kW) of installed capacity is usually two to five times higher than for gas-fired power plants (Figure 8.2). Over time, the lower fuel costs (except for CCS and biomass) partly compensate for the higher capital cost, but variable renewable technologies generate only when the wind is blowing or the sun is shining. Thus, their capacity utilisation factor (or load factor) is relatively low, from around 12% for solar PV to 37% to 40% for offshore wind parks. As discussed later, high up-front investment costs have important consequences on the risk profile of low-carbon investments under different market arrangements.

Low-carbon investment projects differ in size and maturity. Large hydropower and nuclear power plants are large-scale projects that have developed over the past 50 to 100 years, and are well understood by many electric utilities. Solar PV and onshore wind are more recent technologies, but are now mature in a growing number of markets with a good track record of many installations, albeit their costs remain generally higher than conventional technologies. Offshore wind and coal with CCS are less mature, large-scale projects that still present technology risks.

Despite massive cost reductions, most low-carbon technologies are still more expensive; some could remain so during the transition to low-carbon electricity systems. The competitiveness of low-carbon technologies depends on many factors. Initial learning effects are driving cost-competitiveness in some markets where sun and wind resources are good. Onshore wind

4 https://icapcarbonaction.com/.

Figure 8.2 *ETP* **assumptions on investment cost per kW of installed capacity, United States**



Key point *The up-front investment costs of low-carbon technologies are higher than gas.*

for instance is reported to have already been tendered at a price of around USD 50/MWh in Brazil and in the United States (NREL, 2013). But low fossil fuel prices, particularly current gas prices in North America, reduce the likelihood of low-carbon technologies reaching competitiveness without a price on CO_2 emissions. A high explicit carbon price would improve the prospect for market-based investments but will remain difficult to implement. Most investments in low-carbon technologies will require out-of-market support.

Risks also have to be factored in

If costs remain certainly the first element to assess, the next step for an investor is to carefully analyse the risks facing a project. Before taking an irreversible investment decision that requires huge up-front payments, an investor will seek to assess the likelihood of its future returns. Whereas past low-carbon investments have benefitted from public support schemes that provided attractive returns, market-based investment is the long-term objective – and should be considered as the default option. Therefore, this section discusses the perspective of an investor facing all the risks associated with a project.

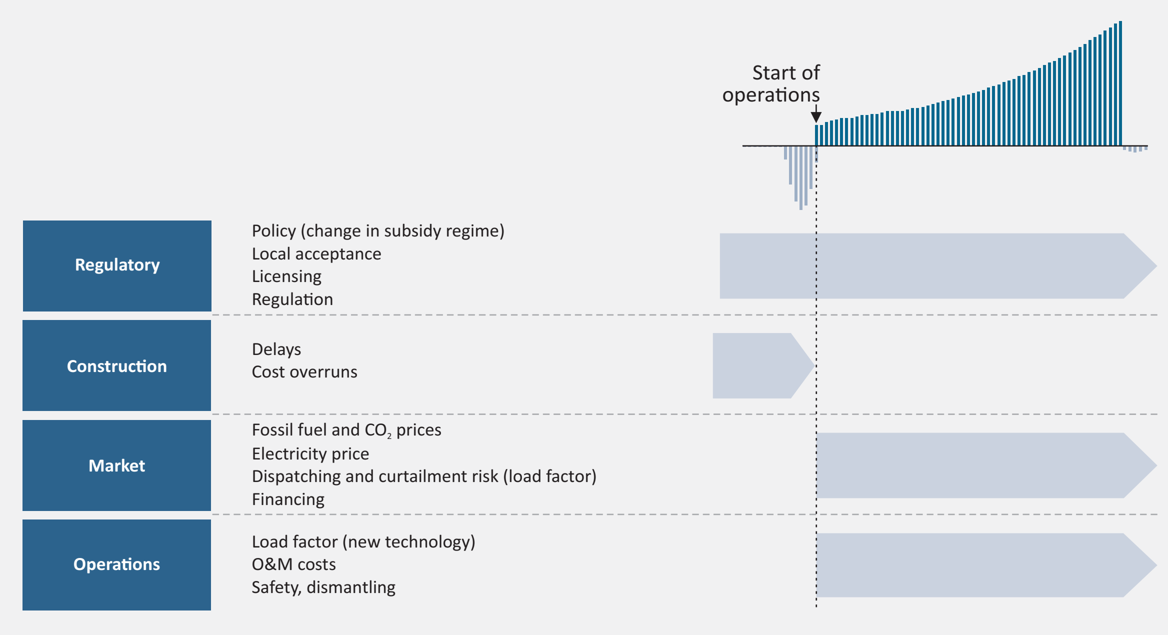
In briefly reviewing the main risks assessed by investors considering an investment in a power plant, this section also examines an important task of project management: to identify these risks, to evaluate their probability and potential impact, and to define risk mitigation actions and execute them as needed.

Overall, project risks affect the cash flows of generation projects at different phases of development (Figure 8.3). The rate of return that investors seek increases with the perceived risks; they want to secure a minimum return on capital if the risk materialises. Depending on the risk profile, the risk-adjusted cost of capital is usually higher at the construction phase, reflecting the risk of cost overruns or delay. For projects with good track records, the risks then decrease during the operation phase, reducing the cost of capital.

Risks associated with regulation, markets and operations are ongoing over the lifetime of the power plant.

As with any investment, low-carbon power plants are exposed to regulatory risks such as licensing delays, problems of public acceptance or changes in support schemes. But the

Figure 8.3 Cash flow profile of a low-carbon power plant, and associated risks



Key point *The value of low-carbon investment projects is exposed to regulatory, construction, market and operations risks.*

magnitude of these risks can be particularly important for many low-carbon technologies. Some of these risks, such as the licensing risk, can be better mitigated by government entities. To reduce the risk of construction delay due to licensing problems, for example, the Energy Policy Act of 2005 in the United States introduced a new licensing regime for nuclear that provides "standby support" or regulatory risk insurance.

Power plant projects, like any other large projects, face the risk of construction delays and cost overruns. This dimension is particularly important for low-carbon power plants based on capital-intensive technologies. Mega-projects (such as nuclear) are notorious for being exposed to such risks. Smaller projects (such as wind and solar) are modular and can rely on a track record of thousands of projects to more accurately predict construction costs and schedule. Construction risks can be better mitigated by creating incentives that encourage technology suppliers to devote more resources and managerial attention to building on cost and on time. A power plant investor has to be held financially responsible in the case of poor technology choice.

Market risk covers several dimensions. First, low-carbon technologies provide a hedge against high fossil fuel prices, most notably gas. This is absolutely true for the system, but not for an individual investor that sells low-carbon generation at market price. The returns on low-carbon assets exposed to electricity price risk are hence exposed to the fossil fuel and carbon price risks. Indeed, when the price of gas reached USD 12 per million British thermal units (MBtu) in 2008, low-carbon generation was an increasingly competitive solution. Conversely, in a scenario of low gas prices, low-carbon technologies are relatively more expensive. This is precisely what is happening in the United States, where the price of gas was only USD 3/MBtu at the end of 2013 – a price that was largely unexpected only a few years ago when some low-carbon investment decisions were made.

Low-carbon projects also face carbon price uncertainty. If any, a carbon price increases wholesale electricity prices, thereby increasing the profitability of non-emitting power plants and providing incentives for their construction. Renewable projects have the added risk of uncertain load factor, resulting from possible curtailment of their output due to grid integration challenges and in the situation of excess generation.

Finally, operational risks can be a significant dimension for private investors. For new technologies, accurate O&M costs can be known only once operations are under way; some installations of a given technology type can prove to be less reliable and with a lower availability factor than others. For wind and solar power, initial estimates of the quality of the resource can also be a source of risk; for example, if the wind or solar resource turns out to be not as good as expected. In addition, yearly weather variability can be a significant source of cash flow variability.

Risks affect the value of different technologies

Different low-carbon technologies differ in the degree to which they are exposed to these risks. Clearly, a detailed analysis of all the risks of low-carbon investments is project-specific and far beyond the scope of this chapter. The risks also differ by country, depending on their level of development and experience with the technologies: building the 25 000th land-based wind turbine in Germany is not the same as installing the very first megawatts (MW) in Ethiopia.[5] But it remains useful to compare the risk profile of different low-carbon technologies against that of fossil-fired power plants, the benchmark investment in many markets.

Sensitivity analysis is an effective means of presenting the variation of the NPV metric (Figure 8.4). The calculation assumes that the reference is a wholesale electricity price of USD 100/MWh by 2030, consistent with a European price based on CCGT costs with a gas price of USD 10/MBtu plus a carbon price of USD 90/tCO_2. The NPV is calculated for different assumptions concerning electricity prices, load factor, construction costs and construction duration. The parameters tested here are ranked by decreasing sensitivity for most power plants, considering reasonable assumption on the range of values: variations in electricity prices (capturing both fuel and carbon price risks); the operational load factor; and the risk of cost overruns and delays in construction. To be able to compare the risk profiles of these technologies, the same installed capacity of one gigawatt (GW) is considered in each case.

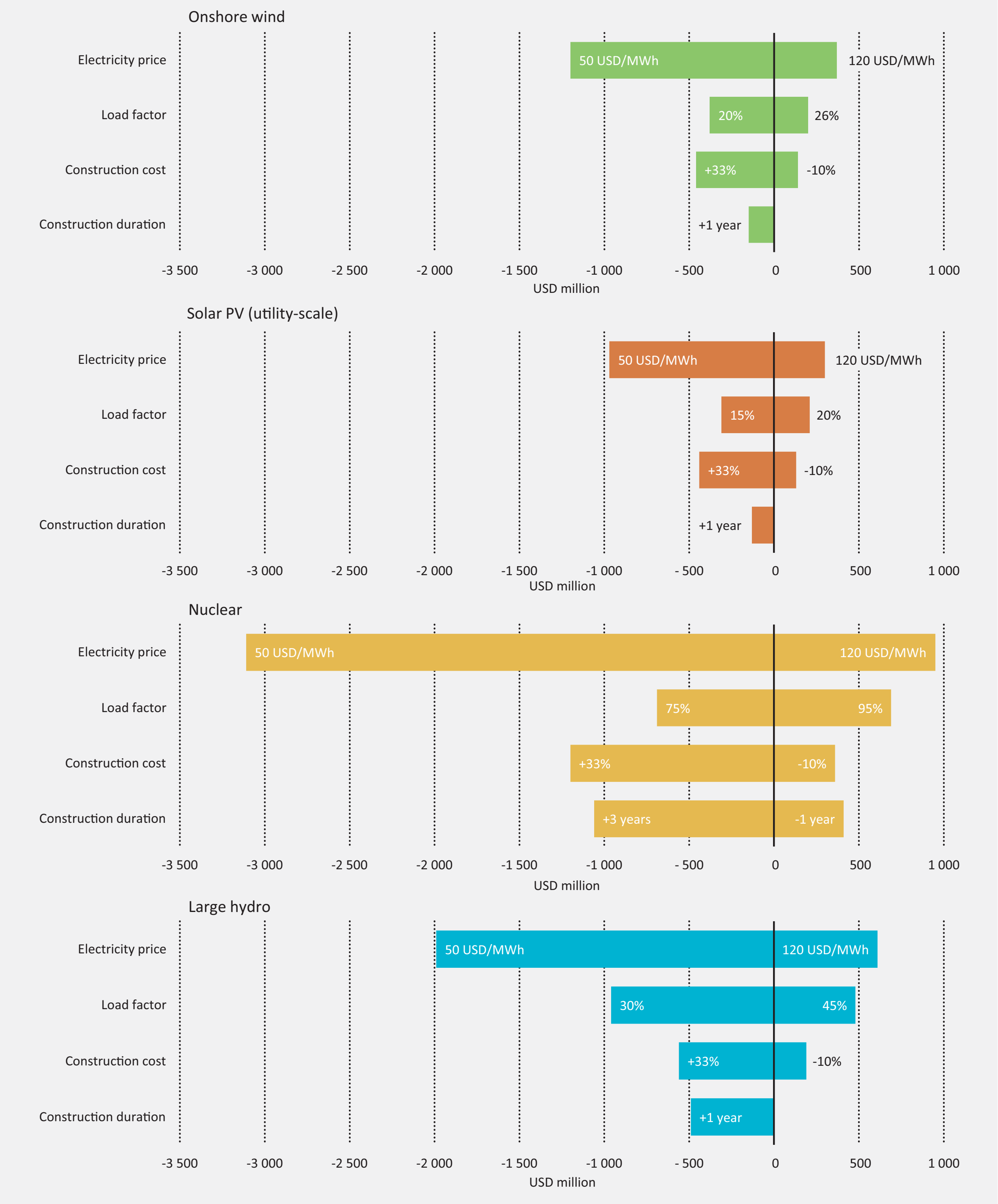
- **Onshore wind** power plants are mature technologies. Being modular and having short lead time, the construction risk is modest in member countries of the Organisation for Economic Co-operation and Development (OECD). If exposed to market price, wind generation revenues would depend on gas and carbon prices (Figure 8.4). As long as the electricity price is positive, wind turbines will continue to produce, but the lower price reduces the value of the 1 GW project by almost USD 1 billion.

  At high penetration level, wind generation can depress wholesale prices and reduce revenues. Furthermore, curtailment of the output of wind turbines for network security or network congestion reasons can increase the risk associated with the energy actually generated and the load factor of the investment.

- **Solar power** is similar to onshore wind for many dimensions of risk. While the price of solar panels is relatively certain and they are quick to install, civil works needed for the installation can present some construction risk. In addition, while large-scale solar farms could be exposed to wholesale market prices, rooftop solar PV reflects the retail price, which is much less volatile (Box 8.1).

5 The 120 MW Ashegoda Wind Farm in Ethiopia suffered a two-year delay due to logistical constraints, www.aljazeera.com/news/africa/2013/10/africa-biggest-wind-farm-opens-ethiopia-201310271316584314 7.html.

Figure 8.4 Sensitivity analysis of the NPV of 1 GW of capacity in 2030



Key point *The net present value of low-carbon technologies critically depends on electricity prices and construction risks.*

Box 8.1 Rooftop solar PV

Rooftop solar PV is quick to install and, with millions of systems already in place, the solar panel itself is a well-known technology and the estimates for installation costs are usually accurate. In case of congestion on the distribution network, rooftop solar PV might also face a load factor risk through curtailment, but this is likely to be rare with limited impact on the overall output.

Rooftop PV revenues depend on retail price rather than wholesale electricity price. This technology is developing rapidly in many countries where net metering allows owners to deduct the generation from these solar panels from their electricity consumption.

In many jurisdictions, electricity bills are entirely or predominantly based on the kilowatt hour (kWh) consumption, which covers not only generation costs but also network costs as well as taxes, including surcharges to finance low-carbon support schemes. Where such variable retail prices exceed a certain level (in the range USD 0.15/kWh to USD 0.20/kWh depending on sun conditions), households find it attractive to invest in rooftop solar PV to reduce their electricity bills. Net metering extends this trend by allowing the entire PV generation, whether self-consumed or injected into the grid, to be deducted from the electricity bills.

Despite being lauded as an achievement for solar PV, many utilities and regulators view this development as unsustainable. In effect, self-consumption reduces the billing base over which they are able to spread network costs and taxes needed to support large-scale renewables. If this retail price evasion becomes too substantial, governments and regulators may have to introduce fixed payments to recover network costs and, in parallel, reduce taxes on electricity.

Changing taxation schemes and moving to a fixed payment for network costs could impact the bills of many consumers. Such measures might take more time to implement than the duration needed to install solar PV, but it seems necessary to better reflect network fixed costs and limit distortions of the taxation system. This eventual possibility, however, presents a risk for households considering installing solar PV, having the similar effects as a retroactive change in the regulatory framework.

- **Nuclear power plants** are highly exposed to construction risk, as illustrated in ongoing projects in OECD countries. A 33% cost overrun or a three-year delay would cut the value of a 1 GW nuclear project by around USD 1 billion. Still, the electricity price risk is the most important dimension of nuclear power economics. A market price of USD 50/MWh would reduce the NPV by USD 3 billion – more than half of the initial investment costs. Acceptability and political risk during the regulatory phase are also important considerations in certain countries. As a result, nuclear projects are very large, multibillion-dollar investments, sometimes referred to as "bet the company" propositions from the perspective of investors.
- **Hydropower** has a risk profile similar to that of nuclear. While the technology is proven, the construction phase can experience significant delays and cost overruns. Run-of-river hydro is exposed to market price risk. Reservoir hydro is flexible and can be dispatched according to market conditions.
- **Offshore wind** is a less mature technology. Like nuclear, its up-front investment cost is very high in part because the marine environment presents substantial construction risks. Furthermore, little track record exists for availability and O&M costs. Should its electricity sell at wholesale prices, offshore wind would be exposed to significant market risk.
- **CCS** is not yet commercial but its cost structure will make it similar to nuclear in terms of construction risk and acceptability. Because it burns coal or gas, CCS will also be exposed to fuel price risk. CCS plants are likely to have expensive marginal costs. In practice, it would likely be economical to dispatch them only during high-demand conditions, which introduces uncertainty concerning the number of operating hours and load factor.

- **Other technologies**, including biomass power plants, are also mature technologies. They have specific risk profiles mainly due to the fuel costs, which depend on specific cases.

In terms of NPV, the risk profiles of these technologies differ substantially, which helps explain why gas is the technology of choice for market-based investments. CCGT is not immune to risks, as illustrated by the financial losses of gas power plants in Europe in 2013.

A project with cost overruns and delays requires more resources, even if project developers or investors are insulated from these risks. Similarly, if the load factor is lower than anticipated, the end result is that resources devoted to electricity could have been better used elsewhere; the investment can be said to be "inefficient".

Concerning fuel cost, the question of risk is more subtle. One argument in favour of renewables is that their cost is stable, and does not expose consumers to high gas price risk (i.e. a high gas price is a downside risk for consumers). But most consumers would be happy to benefit from a low gas price, as is currently the case in the United States with shale gas. If consumers have to guarantee the revenues of low-carbon power plants, they would not benefit from the low cost of gas (or would benefit less). Exposure to the risk of a low price for fossil fuel is positive from the perspective of the cost to society but negative for merchant low-carbon investors. Choosing the most efficient mix of technologies will depend on the expected fossil fuel price risks as well as the risk profile of different technologies.

To sum up this analysis, it is important to grasp that investors balance expected returns with the risk profile of different technologies. A simplified comparison of the risks of different technologies (Table 8.1) shows that most low-carbon technologies are exposed to high market risk, because their costs are up-front investment costs while their revenues depend on prices over their operating lifetime. Some of the technologies also currently face high construction risk (offshore wind and nuclear), which may be reduced as and if more units are built.

In practice, the regulatory framework and market environment determine to a large extent how the risks are allocated to different stakeholders.

Table 8.1 Risk profile of different technologies

	Regulatory	Construction	Market	Operations
CCGT	Low	Low	Medium	Low
Onshore wind	Low	Low	High	Low
Solar PV	Low	Low	High	Low
Offshore wind	Medium	High	High	Medium
Nuclear	Medium	High	High	Low
Large hydro	Medium	Medium	Medium	Low

Low Medium High

Attracting finance involves a transfer of risks to consumers and taxpayers

All the options described involve a transfer of risk away from investors and towards consumers, albeit to different degrees. Investors will always regard the removal of risks as a favourable factor in easing the financing of low-carbon investments and reducing financing costs. In reality, the risks do not vanish but become less transparent as they are passed on to consumers (or taxpayers) in various ways. Taking the downside risk of a low wholesale electricity price away from investors can result in higher prices on future consumer bills.

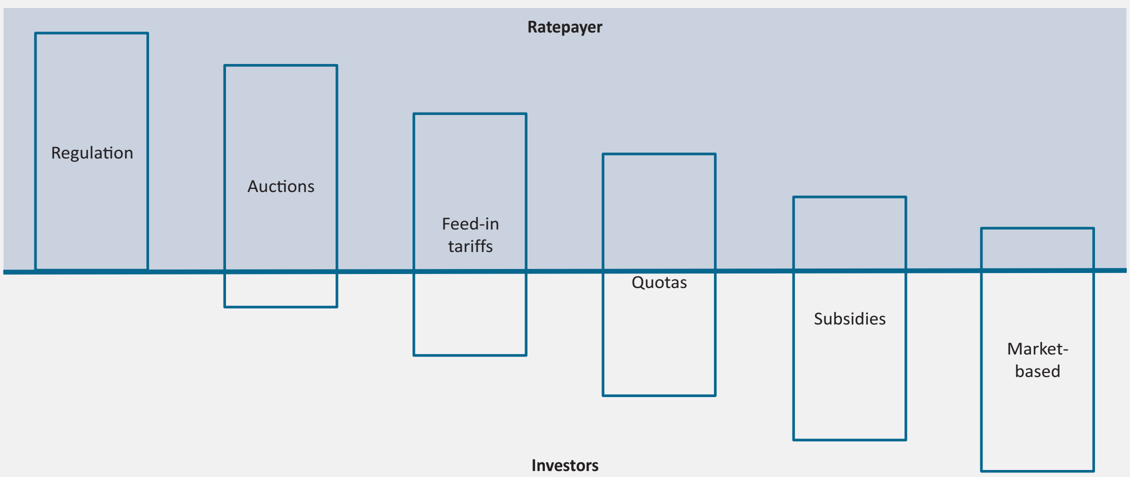
Governments are making a key trade-off decision in this practice, essentially asking: "Who is best equipped to face the uncertainties associated with fossil fuel prices and carbon policies in the long run? Taxpayers, consumers or shareholders?"

Under a framework of cost-of-service regulation, all the risks (regulatory, construction, market and operations) are borne by rate payers who have to pay the regulated rates covering all the costs (first bar in Figure 8.5). At the other extreme of the spectrum, a market framework transfers all the risks to investors, except to a certain extent the fossil fuel price risk, which depends on the marginal cost of the marginal units.

Between these two extremes, a range of different risk allocation exists, depending on the specificity of the instruments used in practice.

- Technology-specific regulations, in which governments pick technology winners, insulate investors from the risk of making the wrong technology choice. As that risk is limited to the choice of the equipment manufacturer, investors face only the construction and operation risks.
- With a technology-neutral tax credit or quota, investors can choose among several technologies (nuclear, CCS, solar, biomass or wind) to achieve the stated objective and may not be exposed to the market risk.

Figure 8.5 **Allocation of risks for different support schemes**

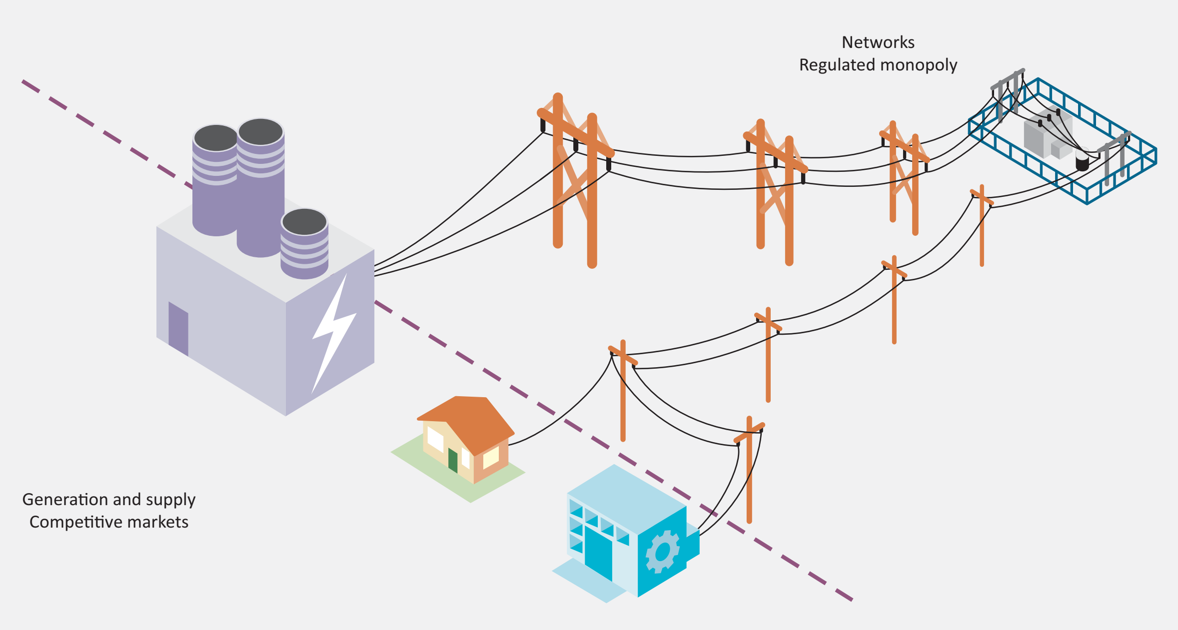


Key point *Policy options used by the government to foster low-carbon investments usually involve a transfer of risks from investors to rate payers.*

The two extremes: Regulated utilities and competitive markets

For about 25 years, market liberalisation has been a central policy path in electricity policy. Chile in the 1980s and England and Wales in the early 1990s pioneered the first electricity market liberalisation, leading the way for many other countries. While networks usually remain operated by a monopoly and subject to economic regulation, the generation segment of the industry is open to competition for the supply of electricity to final consumers (Figure 8.6). Electricity restructuring and liberalisation stalled in the aftermath of the crisis and market breakdown that hit California in 2001. In the past ten years, the rise of low-carbon policies has been another major new trend affecting electricity markets.

Figure 8.6 **Electricity market restructuring**



Key point *As they would be too costly to duplicate, network activities remain regulated monopolies. But liberalised markets now comprise hundreds or thousands of generating plants that compete to supply electricity to final consumers.*

Moving from a regulated to a market environment considerably changed the risks to which energy investors are exposed. While the initial renewable investments were triggered by different support schemes, the ultimate target is to create the conditions for market-based investments in low-carbon generation. Given the risk profiles of low-carbon technologies presented in the previous section, one key challenge will be to attract financing of low-carbon projects that are exposed to uncertainty in electricity market price.

Regulated utilities

Many national or state governments continue to regulate electric utilities, operating as monopolies over a specified geographic area. This is the dominant industrial organisation in non-OECD countries. In India, state electricity boards own and operate most of the generation assets. In China, the largest consumer of electricity in the world, five major state-owned companies each own 20% of the electricity system. ESKOM, in South Africa, is a vertically integrated regulated entity. Vertically integrated, regulated utilities still remain in some OECD countries. KEPCO, in Korea, retains the same structure. In North America, many electric utilities continue to be regulated by a public utilities regulatory commission, including subsidiaries of some of the major investor-owned utilities such as Southern Company, Entergy, Florida Power & Light, and HydroQuebec. Together, regulated utilities represent 40% of US consumption.

Securing the financing of capital-intensive investments is relatively straightforward in a regulated framework. Regulators approve investments and can endorse government decisions to develop low-carbon power generation. Where applicable, the corresponding low-carbon assets are added to the regulatory assets base. The regulator then sets electricity tariffs that, on average, have to cover fuel costs, O&M costs, depreciation, debt repayment and a return on the capital invested.

The financing community is confident that regulated companies will be able to repay a high level of debt. Thanks to economic regulation, return on invested capital is largely insulated from the variations of the overall economic activity; as a result, the cost of debt and remuneration of shareholders can remain at the lower range, improving the economics of large capital-intensive projects. This does not mean, however, that risks have vanished. Rather, they are passed to consumers who pay the regulated tariffs. Regulated tariffs are simply increased in case of cost overruns or project delays, or if expensive technologies or equipment are built.

The choice of the generation mix is another concern associated with regulated utilities. In some countries, they might have a tendency to over-invest (creating excess capacity). While the choice of generation mix remains largely under the responsibility of regulators, regulation can protect past investments that could have discouraged the adoption of more efficient technologies (such as, for instance, CCGTs).

Potential bias in investment decisions is particularly concerning for new low-carbon generation technologies. Many renewable technologies, such as wind, solar power, small hydro and biomass, tend to be smaller and decentralised. They can be operated by small or medium-sized companies and connected to the distribution network, whereas the business model of traditional utilities is focused on large-scale and centrally-managed technologies.

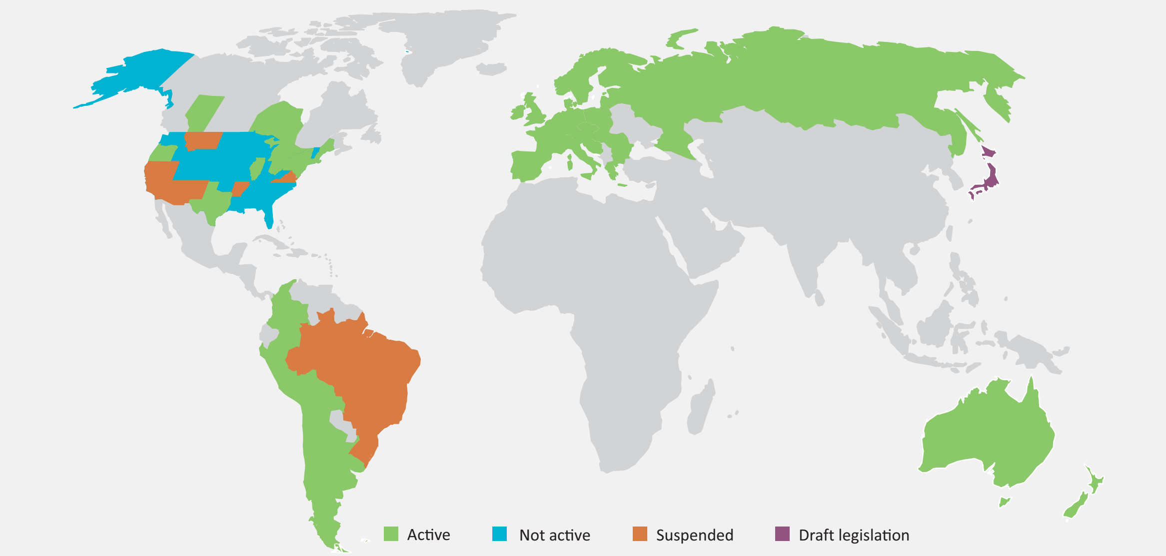
With all of these issues in mind, the traditional framework of utilities' regulation should not be viewed as a benchmark for low-carbon investments. More basically, with a typical investment decision usually representing less than 1% of peak demand in most member countries of the International Energy Agency (IEA) (e.g. 400 MW out of 40 GW), the generation segment of the electricity sector no longer needs to be legally granted the right to operate as a single entity over a geographic area. Instead, several firms can compete to generate electricity.

Liberalised markets

Shifting the risk of inefficient investment and operation decisions away from rate payers was the single most important driver of liberalisation of the power market (Figure 8.7). Creating free markets for electricity generation radically changes the risk profile of investments in new generation capacity compared with regulated utilities. In competitive markets, electricity producers are required to take investment decisions based on electricity price expectations, rather than on regulatory approval. The producers, not the regulators, bear the construction and policy risks, as well as the gas and coal price risks passed on through the power price risk.

Initially, the move to competitive electricity markets triggered a wave of investment that saluted technology progress. New CCGTs, with an efficiency of 50% to 55%, could generate base-load electricity at lower cost than older units with 40% to 45% efficiency. As electricity wholesale prices are usually set by the less-efficient units (Figure 8.8), the margin on electricity was expected to be sufficient to cover project debts and deliver a return on investment in CCGTs. In the United States, 185 GW representing 17% of 2011 installed capacity was built between 2000 and 2011. Likewise, 114 GW of CCGT was installed in the European Union from 2000 to 2011. As a result, electricity markets delivered investments in more efficient power stations, meeting increasing demand while decreasing the cost of generating electricity and ensuring security of electricity supply.

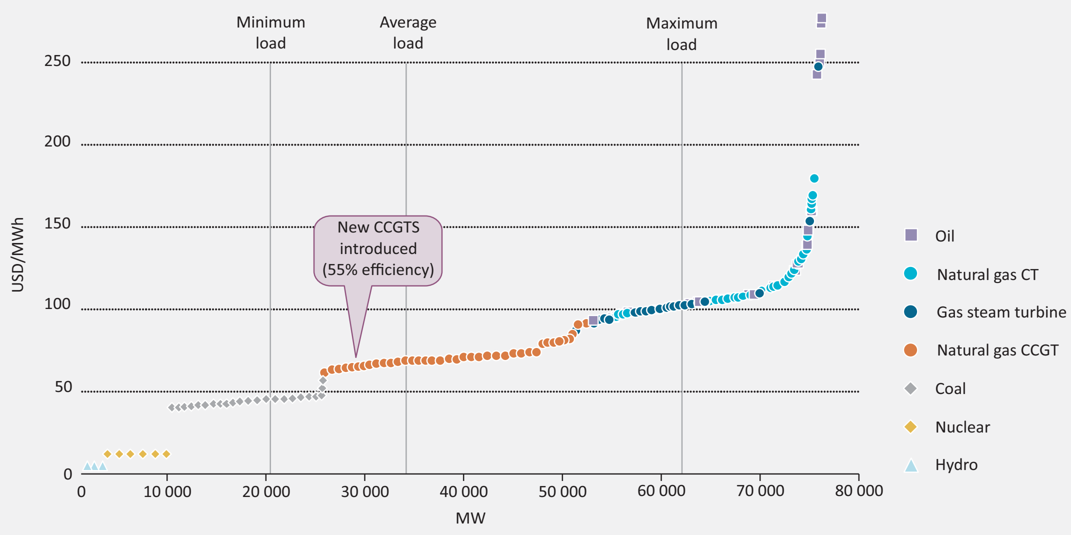
Figure 8.7 Status of liberalisation in selected countries



Note: this map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Key point *While the majority of OECD countries have liberalised their power sectors, most emerging economies maintain regulated electric utilities.*

Figure 8.8 Dynamics of investments in increasingly efficient gas turbines (illustrative)



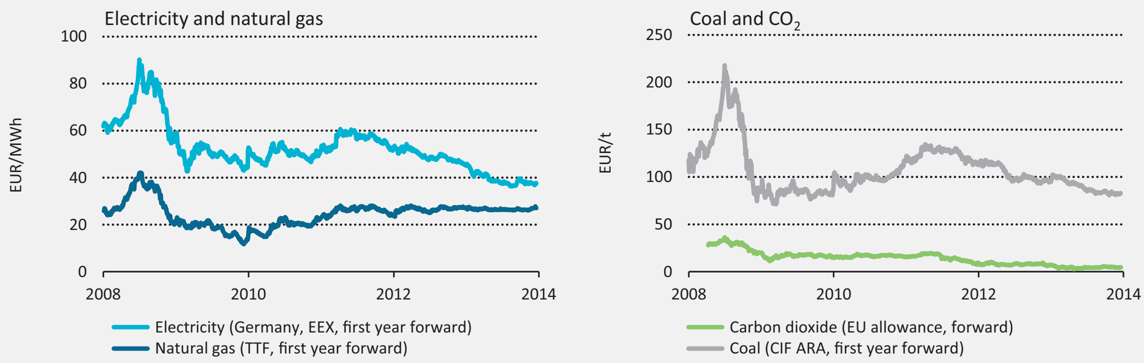
Key point *New CCGT can operate for a relatively low cost at base load, and sell power at a price set by more expensive units.*

Some low-carbon investments could, in principle, be delivered under a similar market framework. Hydropower, wind, solar power and nuclear can generate electricity at low fuel costs and can sell electricity at the market price set by older units. As already discussed, a high carbon price could incentivise some low-carbon investments. Indeed, a carbon price of USD 90/tCO_2 would increase the cost of generating electricity from gas by around USD 30/MWh by 2030. If such a high carbon price is credible, this could be sufficient to meet the 2030-35 renewable deployment envisioned in most European countries (Poyry, 2013).

Experience outside the electricity sector clearly shows that it is possible to invest in low-carbon projects without knowing the future selling price of electricity. Indeed, investments in large, capital-intensive projects in many other industries are exposed to fuel price risk. Major oil companies, for instance, spend billions of dollars on offshore platforms and sell oil at market price, which varied from USD 20 per barrel (bbl) to more than USD 100/bbl over the past 20 years. Yet the profitability of oil investments reflects the risks of such projects. This is similar to low-carbon technologies. Investors could, in principle, invest even if there is a price uncertainty, but are likely to require a very high expected electricity price to compensate for the price uncertainty.

To assess the extent to which generation investments can happen in electricity markets, it is useful to examine the signals sent by electricity prices on wholesale electricity markets. Wholesale spot electricity prices can vary from a factor of 10 to 100 within one year, one month or even one day, reflecting the volatility of demand and cost differences in technologies used to meet this demand.[6] In the long term, these price variations are compounded with the uncertainty of coal, gas and carbon price scenarios (Figure 8.9). To convince bankers that a project is viable, a project developer has to assess the quantity of energy the plant will actually sell over several decades and estimate the electricity selling price over the plant's lifetime.

Figure 8.9 **Forward prices for electricity, coal, gas and carbon in Europe**



Notes: EEX: European Energy Exchange. TTF: Title Transfer Facility. CIF: Cost Insurance Freight. ARA: Amsterdam/Rotterdam/Antwerp.
Source: Bloomberg, 2014.

Key point *Wholesale electricity prices reflect uncertain coal, gas and CO_2 prices.*

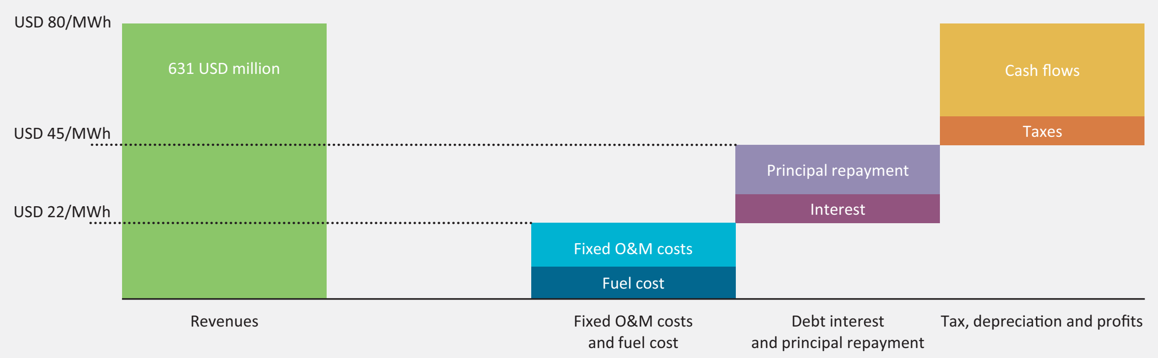
Not surprisingly, the risk/reward profile for low-carbon technologies under market conditions is not very appealing. Despite the low energy costs of low-carbon technologies, it is difficult for

6 As electricity cannot be stored, it has to be produced in real time to balance demand, which is itself extremely volatile. Some power plants are producing less costly, base-load electricity while the more expensive plants run only during periods of peak demand and high wholesale price. Understanding electricity price formation in liberalised electricity markets is of key importance for investors considering new power plants.

wholesale markets to support their development due to the high up-front nature of the investment, compounded by the electricity market price risk. In principle, the construction risks could be balanced by a high return, but the absolute level of electricity prices is currently too low to make this happen. Essentially, investing in a low-carbon technology would be a "bet" that gas and possibly carbon prices will recover the highs of 2007-08 and maintain those levels over the coming decades. Few investors are willing to take this risk.

Indeed, price certainty is an essential factor of investment decisions, and this is especially the case for low-carbon technologies. Expected electricity prices lower than USD 50/MWh are just not high enough to recoup the investment and financing costs. As shown in Figure 8.10, for the cash flows of an illustrative nuclear power plant, the first USD 22/MWh covers the fuel cost and fixed O&M cost. Assuming that a price of USD 45/MWh has enough certainty, this would provide resources to repay the principal of a debt of only about USD 2 billion and to cover the interest. But it is not enough to finance a new nuclear unit. The rest would have to be financed with equity, and the equity investors would want to be confident that the price would reach or exceed USD 80/MWh to recover and get a satisfactory return on their investment. If there is a chance that the price will never exceed USD 45/MWh, it will be hard to convince an investor to spend USD 3 billion that could be lost. Needless to say, the financing community has little appetite for such risky investment strategies.

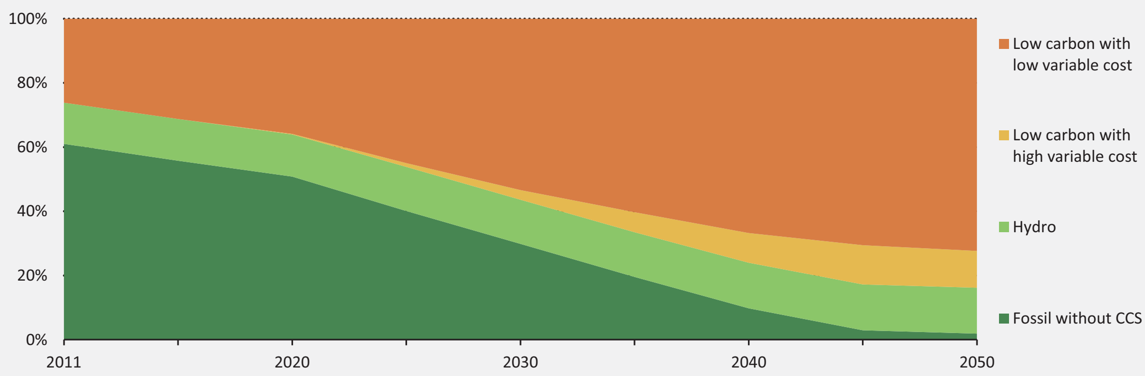
Figure 8.10 Impact of electricity price on cash flows of a 1 000 MW nuclear power project



Key point *Electricity price risk constrains the amount of project-specific debt and equity investors are willing to take on.*

Looking forward, another difficulty is that wholesale electricity market prices are unlikely to be high enough to reach the 2050 renewable deployment levels envisioned in *ETP*. These ambitious targets (Figure 8.11) imply that variable renewables would generate power volumes that exceed actual demand during some generating hours. From a technical perspective, electricity can to a certain extent be stored and/or exported, provided appropriate transmission capacity exists. But from a market perspective, the value of this excess output is likely to be very low, if not negative. Under the wholesale energy market arrangement based on marginal prices, the renewable power plants would generate most of the time but would receive low revenues; the opportunity to collect higher revenues would be limited to only a few hours when coal with CCS, biomass or gas plants with high marginal costs are setting prices. This raises many issues concerning the ability of renewable plants to recoup their costs under existing market designs.

Figure 8.11 Share of generation by technology group in the OECD, 2DS



Key point *After 2030, low-carbon technologies with low marginal cost generate more than 50% of electricity.*

Yet another consequence of policy-driven renewable deployment is the increased risk of investing in conventional power plants in order to meet demand not covered by wind and solar output. Mandating the deployment of wind and solar power has had the effect of cutting down the call on dispatchable generation more quickly than anticipated by utilities or investors, who have also been confronted with sluggish demand growth and low or nonexistent carbon prices. This raises a concern for the profitability of power plants in the short term and that these assets could become stranded (i.e. retired early) before investors are able to realise the return on investment they calculated. Governments are increasingly concerned with the ability of markets to deliver the medium-term investments to complement wind and solar power output. While *ETP 2014* focuses on low-carbon investments, other IEA publications analyse the issues associated with investment in conventional power plants (IEA, 2012; IEA, 2013b).

Box 8.2 Utilities strategies to manage risks in liberalised markets

Liberalised electricity markets expose electric companies to risks, including market price volatility, the evolution of their market share and the construction risk for new projects. Some independent power producers were successful in investing on a project-finance basis (merchant investments, with non-recourse financing), mainly in North America. Another solution taken up is to sign long-term power purchase agreements at a predefined price.

Instead, most utilities (only electricity in the United States; both electricity and gas in Europe) have developed strategies – either in day-to-day operations or in corporate strategy – to mitigate the risks encountered in liberalised markets.

- Operational risks can be managed through arbitrage on day-ahead, intra-day, balancing and operating reserves markets, by scheduling maintenance according to market conditions, or by negotiating long-term contracts or financial hedging contracts.
- Market risks can be mitigated by diversifying the portfolio of technologies (nuclear, gas, coal and renewables) and through co-investments in mega-projects (nuclear in Finland, France and the United Kingdom).
- Corporate diversification is applied and may include strategies such as establishing an international presence, integrating generation and supply, investing in upstream gas (physical hedge), pursuing activities in regulated and non-regulated segments, and creation of conglomerates (gas-electric utilities or energy service companies).

Intermediate solutions to promote low-carbon investments

Current conditions suggest that it may be necessary to continue supplementing competitive markets to secure the low-carbon investments needed to decarbonise the electricity sector by 2050. Governments have at their disposal a combination of economic instruments that have proven effective in this area, including measures such as carbon pricing, subsidies, tax credits, quotas and certificates, FiTs, auctions, and new forms of economic regulation. Other administrative tools include emissions performance standards on generation units. These regulations have the effect of prohibiting investments in fossil fuel plants (particularly coal without CCS) and are currently being implemented in the United States and the United Kingdom. Such measures do not address the issue of attracting new investments and are not analysed further here.

This section provides an overview of the main economic tools used to make low-carbon bankable. Importantly, as these measures influence risk allocation, the text also examines how these measures might impact taxpayers and consumers.

The possible solutions to promote low-carbon investments can be illustrated in principle with the probability distribution of the net present value of a project. Given the costs and risks discussed previously, the range of NPV outcomes can vary substantially, depending on assumptions on electricity prices, load factor, construction cost and construction duration. For low-carbon projects and in the absence of a carbon price, the NPV is likely to be negative in most cases, as reflected qualitatively in the illustrative probability distribution (left probability distribution in Figure 8.12), which is always below zero.

The various approaches to promote low-carbon investments may have one of the following effects:

- Increase the NPV of the project without mitigating risks for investors (1, wide probability distribution of NPV in Figure 8.12); this effect is typically seen with carbon pricing, capital subsidies and quota systems.
- Mitigate risks for investors (2, narrow probability distribution of NPV in Figure 8.12); this effect is seen with long-term power purchase agreements, such as FiTs or auctioning mechanisms.

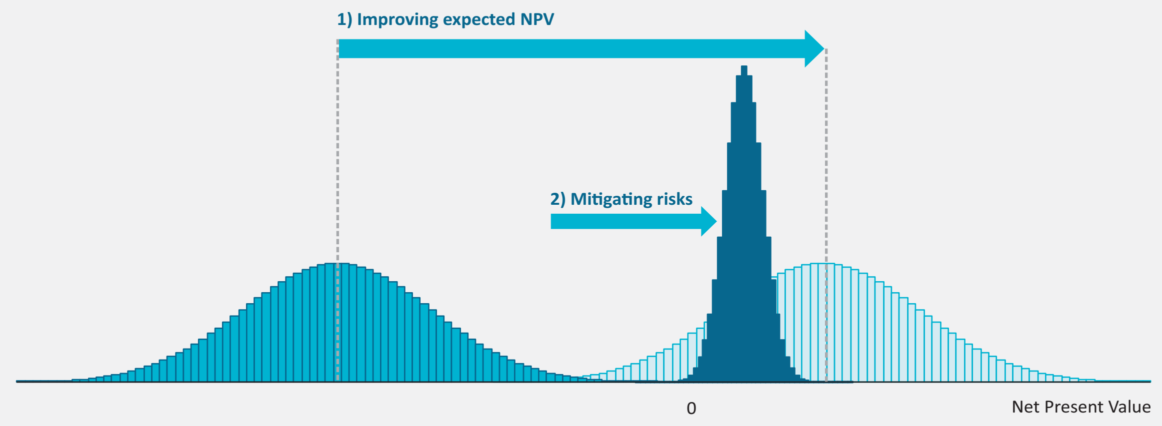
Some of the low-carbon support instruments (Table 8.2) supplement competitive electricity markets; others substitute the market and effectively transfer the risks to consumers or taxpayers.

Carbon price

As already discussed, using a carbon price to correct the climate externality has the effect of increasing both wholesale electricity prices and the NPV of the low-carbon project. But this approach hardly changes the risk of NPV distribution of low-carbon investments. On the contrary, it could be argued that quota systems, such as emissions trading schemes, expose market participants to another source of risk resulting from carbon pricing policy.

Despite the recent failed attempts to introduce or strengthen emissions trading schemes, carbon value remains the central pillar of any low-carbon policy. Governments use other instruments to supplement a carbon price, but it is the social cost of carbon that constitutes the reference against which all other policies must be appraised (OECD, 2013).

Figure 8.12 NPV impact of strategies to attract new low-carbon investments



Key point *Attracting financing must consider two dimensions: improving the expected NPV and mitigating risks.*

Capital subsidies

Direct capital subsidies include investment subsidies or investment tax credits; loan guarantees provided to some projects can also fall in this category. Subsidies are already commonly used to finance research, development and demonstration (RD&D) projects but can also be considered to remedy the absence or weakness of a carbon price. The use of public funding to de-risk investment is a common instrument used in developing countries. One advantage of direct investment subsidies is that they are effective in supplementing competitive electricity markets: by reducing the investment cost, they increase the NPV of projects without changing the incentives to bid their short-run marginal costs, avoiding distortions of wholesale electricity market prices.

There are, of course, some risks associated with subsidies, including the stimulation of intense lobbying activity from technology providers and project developers to be eligible for subsidies. If set too high, direct subsidies can lead to poor investment decisions in unproductive projects (take the money and run), and there is always a risk that subsidies will be used to support failing companies.

Compared with a carbon price, however, subsidies avoid increases of wholesale electricity prices, and thus are less likely to raise opposition from consumers. The associated drawback is that prices do not reflect the full cost and therefore do not play their role to promote the right level of consumption (for example, to stimulate energy efficiency). But governments are increasingly under pressure to reduce public debt, and direct capital subsidies are strictly controlled by competition authorities. In many jurisdictions, subsidies would need to benefit from an exemption to general competition rules.

Quotas with tradable certificates

Quota systems are used to promote renewable electricity in Sweden and Norway. The United Kingdom uses tradable certificates, as do some of the 29 US states that have implemented Renewable Portfolio Standards (RPS). Similar approaches are used in other jurisdictions. Under this approach, renewable energy generators receive certificates, and sell them to electricity

Table 8.2 Examples of solutions already implemented to attract finance for low-carbon generation

Technology	Market-based	Capital subsidies	Quotas with tradable certificates	Feed-in premium	FiTs	Auctions or public procurement	Regulated plants
Onshore wind	New Zealand	United States (investment tax credit)	United States (RPS), Nordic countries		Austria, Finland, Netherlands, Germany, other	Brazil	–
Solar PV (utility-scale)	–	United States (investment tax credit)	Korea	United States (production tax credit)	Many European Union countries, Japan	Indonesia	–
Offshore wind	–	–	United Kingdom (ROCs)		Germany, United Kingdom (future)	France	–
Nuclear	Finland (long-term contract)	–	–		United Kingdom, Hinkley Point	–	China, United States (Vogtle project)
CCS	–	Several countries (RD&D)	–		–	–	
Hydro	Switzerland	–	Chile		Switzerland, Germany (small scale)	Brazil	China

Notes: RPS: Renewable Portfolio Standards. ROCs: Renewable Obligation Certificates.
Source: IEA Policy and Measures database, www.iea.org/policiesandmeasures/.

suppliers that are mandated to meet specific requirements (the quotas) in terms of green energy. If the quota is not fulfilled, the supplier has to pay a penalty. The certificate price creates an extra revenue stream for generators, essentially a premium on top of the electricity sold; this increases the expected NPV of renewable projects.

In terms of risk, low-carbon investors bear all the risks: construction, electricity market price risk and certificate market price risk. The expected NPV value increases but remains within a large range (Arrow 1 in Figure 8.12). The expected prices of certificates and power have to be high enough to compensate investor risks.

Quotas have the potential to supplement competitive electricity markets with limited distortions of wholesale market prices. If quantitative, low-carbon objectives are predictable (in energy or share of supply), then the conventional segment of the market can better anticipate market developments and adjust investments accordingly. A quota-based system could be an efficient instrument for massive deployment, once technologies are considered mature.

Feed-in premium and production tax subsidies

Feed-in premiums and production tax subsidies are two forms of payment that low-carbon producers receive in addition to the wholesale price of electricity they generate. Production tax subsidies have been used in the United States and contributed to the deployment of wind and solar power, along with the RPS introduced in some states. Germany introduced market premium payment in 2012, opening the possibility for wind and solar generators to sell directly on the market.

In terms of risks, these payments increase the NPV of low-carbon projects but the probability distribution can remain large, depending on the wholesale price (Arrow 1 in Figure 8.12). The subsidy resulting from the premium or the tax credit is known in advance and has to be high enough to compensate investor risks.

Feed-in premiums and production tax subsidies have the potential to supplement competitive electricity markets with limited distortions of wholesale market prices. As low-carbon generators have to sell their output, they participate on electricity markets. They could bid, however, a price that reflects the subsidy they receive, not the short-run production costs. That being the case, this introduces a price distortion on wholesale markets during hours of low demand and high renewable output.

Feed-in tariffs

FiTs are long-term contracts that governments offer to low-carbon producers, at a predefined price. Governments then oblige local utilities to buy the wind or solar power generated at this FiT, which is above wholesale prices. FiTs have been very effective in promoting the deployment of wind and solar power. Germany has deployed 65 GW of wind and solar capacity on the basis of FiTs. Ultimately, governments need to reimburse the extra cost to utilities, usually through revenues collected on final electricity consumers (similar to a tax). Examples of such revenue collection schemes include the *Erneuerbare-Energien-Gesetz* (EEG) surcharge in Germany or the *Contribution au service public de l'electricité* in France.

In terms of risks, FiTs insulate investors from the electricity market price risk (cf. narrow probability distribution in Figure 8.12). When governments have granted them priority dispatch, renewables are also protected from the risk of being curtailed in case of excess generation, which is a market load factor risk. Being insulated from market risk provides financial certainty to investors, thereby reducing financing costs and improving the attractiveness of capital-intensive technologies. From an investor perspective, it can be argued that FiTs are more cost-effective than other support schemes.

Still, electricity consumers have to pay for the higher costs of wind and solar power, even when the wholesale electricity price is low. This is precisely what happened in Germany in 2013. The wholesale electricity price declined from EUR 80/MWh in 2008 to EUR 45/MWh in 2013, due to the economic crisis, low fuel and carbon prices, and deployment of renewables. Consequently, the EEG surcharge paid by consumers mechanically increased to guarantee the FiT payments and provide price certainty to renewables investors.

In a dynamic environment with very heterogeneous projects and rapidly declining costs, governments have also found it difficult to set the right level of FiT. For solar PV, some governments failed to keep pace in adjusting solar FiTs to rapidly declining solar PV costs. This created an investment bubble in solar PV and put a heavy burden on electricity consumers, though this policy lesson has largely been learned. Another pitfall is that a uniform FiT can also generate significant rents for the most efficient projects. Indeed, if the same FiT is available over large areas, the projects located where natural resources are the best may receive a rent leading to return on investment too high for low-risk investments. Increasing retail electricity prices to serve two-digit returns to investors might not be politically sustainable.

Equally important, FiTs can distort wholesale electricity market prices. With priority dispatch for renewables, generators (or system operators on their behalf) see incentive to bid at any price – including negative prices on markets – to be sure to be keep at least part of the production subsidy (the situation is the same with production tax credits). This behaviour can result in negative prices during hours of excess renewable supply; in this case, FiTs are inefficient because they do not reflect the marginal cost of variable renewables, which is close to zero.

In conclusion, FiTs are an interesting instrument to kick-start and accelerate the deployment of promising specific technologies, particularly for distributed generation at the early stage of deployment. The industry they help to create should be prepared to change its business model and take more risk as these technologies become mature and represent a significant proportion of the generation mix.

Auctions or public procurement

Tendering processes, such as auctions for the procurement of new capacity, present interesting features to deploy low-carbon technologies – most notably for larger renewable projects such as utility-scale wind and solar farms or hydro projects. Most public entities are already using competitive tendering in public procurements.

The most popular example of large-scale auctions in the electricity sector is the Brazilian model, introduced in 2004 after the country experienced a shortage of electricity. In Brazil, a federal entity, *Empresa de Pesquisa Energetica*, now centralises electricity requirements on a forward basis and organises an auction to fulfil these new requirements a few years in advance. Brazil succeeded in achieving very competitive electricity prices with auctions. While auction entails the centralisation and planning of electricity needs, well-designed auctioning systems have the potential to be very cost-effective as they can extract the rents resulting from different natural resources endowments. This was an important objective in Brazil, which has a hydro-based electricity system. Whether this model can be efficiently applied in other systems less dominated by hydropower deserves further analysis.

In terms of risks, auctions usually provide a predefined payment to winners, effectively insulating them from the market risk. So they present the same drawbacks as FiTs discussed previously: risk of picking inefficient technology when the auctions are technology-specific, and possible distortion of energy bids.

More sophisticated auction designs might also be less distortive of competitive wholesale electricity markets. An auction on a per kilowatt capacity payment, for example, rather than a per kilowatt hour energy payment, would prompt generators to bid into markets based on their marginal cost, avoiding market distortions. Auctioning systems are a market-based instrument and have the potential to trigger low-carbon investment on a large-scale basis. Governments could consider this option more often during the transition to low-carbon electricity systems, and devote more resources to design and implement auctions.

Regulated plant

None of the above solutions could be suited to have enough competition for the development of lumpy and large projects such as nuclear and some large offshore wind parks. If governments wish to include these technologies in their generation mix, a form of regulation might have to be introduced for assets. Instead of regulating a company with a portfolio of assets, a specific power plant or asset is regulated.

There are three reasons government may have to accept to regulate individual plants. First, the plants cannot be built without an extremely high and credible carbon price over decades. Second, lack of competition during the licensing phase cannot yield a competitive outcome: several projects can be developed by several companies but with different timings, which limits the scope for competition. Third, governments and companies might not be willing to commit to a predefined price that would carry the risk of creating excessive returns at the expense of future consumers, which would not be politically sustainable.

The construction cost of a nuclear power plant in the United Kingdom is expected to be GBP 14 billion and provides a good example of the challenges associated with large projects (Box 8.3). Electricité de France (EDF) and the UK government agreed to a power purchase contract at a predetermined price (the FiT with a CfD) of GBP 89.50/MWh. But a discovery mechanism for competitive prices was unachievable.

Box 8.3 Attracting nuclear investment in the United Kingdom

The UK government decided to reform the domestic electricity market to attract the investment needed to replace ageing energy infrastructure and meet the projected demand increases from the electrification of sectors such as transport and heat.

On 29 November 2012, the secretary of state for energy and climate change introduced the Energy Bill into Parliament, which implements the main aspects of electricity market reform (EMR). One key element of the EMR is a mechanism to support investment in low-carbon generation: the FiTs with Contracts for Difference (CfD).

On 21 October 2013, the UK Government and EDF Group reached commercial agreement on the key terms of a proposed investment contract for the Hinkley Point C nuclear power station. This paves the way for construction of the UK's first new nuclear power station in a generation, beginning the process of replacing the existing fleet, most of which are due to close in the 2020s.

The commercial agreement was reached on six key terms:

- A "Strike Price" of GBP 89.50/MWh, fully indexed to the consumer price index. (If EDF does not take a final investment decision on Sizewell C, the Strike Price for Hinkley will be GBP 92.50/MWh.)
- A contract difference payment duration of 35 years. Under investment contracts (and CfDs), if the Strike Price is above the reference price, the generator would receive the difference between the two. If the reference price is above the Strike Price, however, the generator would have to pay the difference to the counterparty.
- Gain share arrangements through which savings made on the construction of Hinkley Point C, or on refinancing or equity sales that increase investors' realised equity returns beyond a certain point, would be shared.
- Arrangements, at certain fixed points, whereby the Strike Price could be adjusted, upwards or downwards, in relation to operational and certain other costs (including balancing and transmission charges and business rates) and in relation to certain future changes in law (including in respect of specific nuclear taxes, or of uranium and generation taxes).
- Arrangements whereby Hinkley Point C would be protected from being curtailed without appropriate compensation.
- Compensation to the Hinkley Point C investors for their expected equity return would be payable in the event of a government-directed shutdown of Hinkley Point C, other than for reasons of health, safety, security, environmental, transport or safeguards concerns. In the event of a shutdown covered by these provisions, the arrangements include the right to transfer to government the project company that owns Hinkley Point C, and for government to call for this transfer. The compensation arrangements would be supported by an agreement between the secretary of state for energy and climate change and the investors.

Source: DECC and Prime Minister's Office, 2013.

Asset regulation would be a return to a form of regulation, albeit limited to certain power plants rather than for all the generation assets in the portfolio of a utility. Governments that wish to develop nuclear, large offshore wind farms or CCS projects might have to consider this as the most viable financing mechanism. Regulators have made progress in introducing incentive schemes for regulated companies, allowing them to retain part of the cost reduction and exposing them to the construction risks of new projects in order to keep costs under control. A regulated asset is likely to suffer from the same drawback as traditional utility regulation in terms of weak incentives to control costs, construction duration, technology choice, and operational efficiency.

Potential inefficiencies

None of these options should be regarded as the perfect solution. Rather, governments should carefully apply the best option from their "basket" of instruments. Some are better for the uptake of technologies, but need to be replaced as technology matures or if progress is made on implementing carbon prices. Other options fit well for distributed generation that can be installed quickly, while large and long-term low-carbon projects may need long-term commitment by governments.

Caveats exist for all the options available to supplement markets. They can have different implied costs of avoided CO_2 emissions. Most of the options are technology-specific, yet inefficiencies can arise when governments pick the winners. Promoting too-expensive technologies too early may be unsustainable in the long run and may increase the cost of climate change mitigation. Evidence confirms that the costs of some low-carbon policies are very high compared against their emissions benefits (OECD, 2013). Quantifying the implicit cost of avoided carbon would also shed some light on the costs associated with industrial and job dimensions embedded in these policies.

All the options can have distortive effects on wholesale electricity markets, again to different degrees. These solutions also distort long-term investment signals for conventional generation investments that will be needed to complement variable renewables during the transition to low-carbon systems. Retaining the benefits that liberalised electricity markets bring in terms of least-cost dispatch over wide geographic areas and with an increasing number of market participants should be a primary objective, even through the transition period.

This chapter assumes that governments must find ways to deliver the low-carbon investments trajectory resulting from *ETP* modelling, and explains why it is unlikely that liberalised electricity markets will deliver these scenarios (which *ETP* modelling takes as given). An alternative approach could be to correct the market framework, particularly in terms of carbon pricing, and let the market determine the most efficient low-carbon investment trajectory.

Recommended actions for the near term

Financing low-carbon investments is mostly a question of balancing and allocating risks and returns on investments under different market and regulatory arrangements. A carbon price should be the cornerstone of low-carbon policies, and should serve as the reference against which all other options are assessed. But the conditions are not yet met to have a uniform carbon price across the global economy that reflects the high social cost of CO_2 emissions.

Meanwhile, other options should be pursued to promote low-carbon investments. This does not mean abandoning competitive electricity markets and coming back to regulated utilities. Absent a carbon price, many available options have already been used successfully to supplement markets such that some degree of decarbonisation will be delivered over the coming decades during the transition to a 2DS.

Regarding the long-term decarbonisation target by 2050, *ETP* scenarios envision a share of zero or low marginal cost electricity of more than 80%. The current design of wholesale electricity markets might not provide the signals needed to trigger such investments. In the next four decades, technological breakthroughs such as inexpensive electricity storage, low-cost distributed generation and efficient demand response have the potential to change the economics of electricity markets. Continued monitoring of technical developments is essential to ensure the adaptation of the regulatory and market arrangements and prompt low-carbon generation investments.

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Chapter 9

Power Generation in India

Very few countries have been faced with challenges of the magnitude that confront India in its quest to maintain strong economic growth while providing electricity to its 300 million citizens who currently lack access. All energy sources and technologies will be needed to meet the scale of energy demand projected over the next few decades. In establishing the framework for its low-carbon growth strategy, and with fossil fuels currently providing more than three-quarters of electricity generated, India will need to be mindful of environmental and social factors.

Key findings

- **India is increasing both power capacity and generation.** Progress is being made to address the institutional and structural barriers that continue to hamper the much-needed expansion of the power sector.
- **68% of India's electricity comes from coal.** As India pursues a low-carbon growth strategy in the power sector, this share is expected to fall. Coal capacity, however, will continue to rise.
- **At 33.1%, the average efficiency of India's coal-fired power plants is low.** Specific emissions from its coal fleet, at over 1 100 gCO_2/kWh, are well above the global state-of-the-art level of around 750 gCO_2/kWh. Policies in place to eventually halt the construction of subcritical units and encourage construction of more efficient technology will gradually bring down its specific CO_2 emissions.
- **Continued reliance on fossil fuels for a large share of generation will require that India heavily supplement domestic supplies of coal and gas with imports.** This will impact on power plant design, technology and operation, and will require that issues such as the regulation of power tariffs are addressed.
- **Expanding nuclear and large-scale hydropower capacity is increasing the share of non-fossil generation.** More large-scale hydropower will assist in managing congested grids and integrating the growing variable renewable generation capacity. While nuclear provides just 3% of power generation, India has long declared an ambition for its share of nuclear generation to increase.
- **India is abundantly endowed with potential for generation from other renewable sources, including wind, solar, geothermal, biomass and small hydropower.** Wind power capacity additions, for example, have exceeded targets.
- **The high cost of financing new projects and complex bureaucratic processes result in high perceived risks that could slow India's ambitious plans in solar and wind power.**

Opportunities for policy action

- To facilitate capacity expansion, more effective procedures must be developed to resolve in a timely manner issues related to land acquisition and building on or near protected areas.
- Further expansion of the transmission and distribution system and effective operation of the newly created national grid will be important to enhance the efficiency of delivering power to the consumer and the potential to expand generation.
- Power tariffs could be set at levels that prompt utilities to improve the performance of power generation plants while also allowing for reasonable profits on generation. The practice of providing free or heavily subsidised electricity can lead to wasteful use of energy and should be reviewed.
- The average efficiency of the coal-fired fleet must increase. Though policies are in place to eventually halt the construction of subcritical units and to encourage construction of more efficient technology, more could be done. Stringent regulation on pollutant emissions would lead to a more efficient coal fleet.
- From a low-carbon emissions perspective, natural gas offers benefits while it can also complement the growth in variable renewable generation capacity. Extending the potential for gas imports by constructing further liquefied natural gas terminals and establishing competitive pricing policies will be key.
- Greater emphasis placed on increasing generation from renewable sources and putting the infrastructure in place to distribute the electricity generated would allow an expanded renewables portfolio to contribute more effectively to satisfying India's power demand.
- Industry accounts for just under half of total electricity use in India, with a significant share of that power produced on site. Wider implementation of co-generation technologies could further improve efficiency while making use of waste heat in industrial sectors. The greatest potential is to be found in the chemicals, pulp and paper, textile, and food and beverage industries, where significant heat and electricity loads exist. Moreover, allowing captive power plants to compete in the broader market could provide a much-needed source of additional power.

India's low-carbon growth strategy

India's primary energy goal is to supply secure, affordable, clean electricity to its growing population, while ensuring that its economic growth maintains a strong upward trajectory. In the Indian context, the nexus between human development and energy access is significant: a per capita electricity consumption of 673 kilowatt hours (kWh) in 2011 was less than one-quarter of the world average, and almost one-quarter of its population has no access to electricity. Raising per capita consumption and reducing the numbers with no electricity access, while at the same time powering a rapidly growing economy, present significant challenges.

In its efforts to achieve sustainable development, India is pursuing a low-carbon growth strategy. However, mitigating climate change is a global endeavour, and the development of the Indian energy system is indelibly linked with that of the rest of the world. The International Energy Agency (IEA), in its *ETP 2014* analysis and modelling, compares possible global CO_2 emissions pathways to 2050.[1]

1 The *Energy Technology Perspectives 2014 (ETP 2014)* 2°C Scenario (2DS) projections describe a global energy system consistent with an emissions trajectory that recent climate science research indicates would give at least a 50% chance of limiting global temperature increase to 2°C. The 4°C Scenario (4DS) takes into account recent pledges by countries to limit emissions and step up efforts to improve energy efficiency.

The 2DS and 4DS for India are elements of *ETP 2014* global scenarios based on global least-cost mitigation, where CO_2 emissions are priced uniformly around the globe. Projections from the scenario should not to be confused with predictions or forecasts, or even a recommendation that India could or should commit to follow such a path.

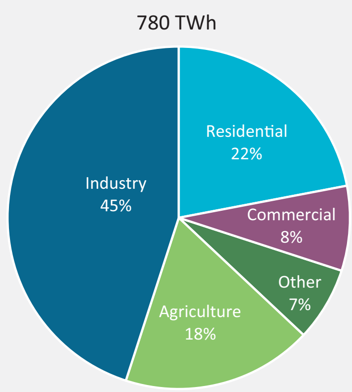
What emissions trajectory will India find itself on as it tackles the building of new infrastructure; the production and delivery of fuel; the efficient distribution and utilisation of electricity; and continued investment in more effective, more environmentally benign operations and equipment? How India meets its short-term objectives while developing its energy sources and infrastructure will determine whether its path forward can be truly sustainable and low-carbon. Decisions taken now will have far-reaching implications. In this sense, with its economy growing rapidly, events and achievements over the next two decades will be absolutely crucial, which is why the content of this chapter focuses predominantly on the 2030 time horizon. Projections from *ETP 2014* scenarios are included where they inform discussion.

The Indian power sector today

Access to electricity is critical for India's economic growth and development. It improves quality of life and helps meet basic lighting, cooking, transport and telecommunication needs. From 818 million in 2011, India will still have a projected 730 million people without clean cooking facilities in 2030, equivalent to 60% of its population (IEA, 2013a). A quarter of all households remain without access to electricity. Nearly 93% of these households are in rural areas, with most depending on kerosene to satisfy their basic lighting needs.

Compared with more industrialised or service economies, electricity demand in India is more evenly spread across diverse sectors (Figure 9.1).

Figure 9.1 **Sector-wise consumption of electricity from utilities in 2011**



Notes: unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis. Figures and data that appear in this report can be downloaded from www.iea.org/etp2014.
Source: Central Statistics Office, 2013.

Key point *Electricity consumption is spread across several sectors, but industry dominates.*

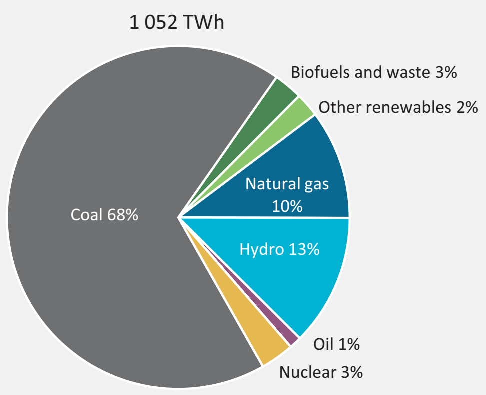
To satisfy increasing demand, India must substantially expand its power generation capacity, and must exploit all available options (PC, 2006). India has extensive reserves of coal and moderate amounts of natural gas. Its waterways provide a high potential for hydropower[2] and it is well placed to tap into renewable energy resources based on wind, solar, geothermal,

2 Unless stated otherwise, Indian convention is followed in the treatment of sources of electricity in the chapter. Rather than discussing renewable energy technologies, the category is divided into a discussion of large-scale hydropower (> 25 megawatts [MW]) and "other renewable technologies", where the latter includes small-scale hydropower (≤ 25 MW).

biomass and small hydropower. India has modest deposits of uranium for existing nuclear plants and abundant quantities of thorium for future technologies. But India faces significant challenges in expanding power generation capacity. For starters, its energy resources are unevenly dispersed geographically and often located long distances from consumption centres.

India has increased generation rapidly in recent years, from less than 200 terawatt hours (TWh) in 1990 to over 1 000 TWh[3] in 2011 (Figure 9.2). Coal is the mainstay of electricity generation, providing 68% of generation in 2011. Although hydropower dominates in some regions, nationally it represented just 12% of generation, on a par with gas at 10%. Other renewable energy technologies contributed 5% and nuclear technologies 3% (IEA, 2013a). If socio-economic conditions for India's growing population are to improve, capacity additions must accelerate side by side with a growing contribution from non-fossil technologies, the potential of which has largely remained untapped.

Figure 9.2 **Electricity generated by fuel in 2011**



Key point *Coal dominates – by far – electricity generation in India; together, fossil fuels account for four-fifths of the total.*

As would be expected in an economy so dependent on fossil fuels, India's carbon dioxide (CO_2) emissions from energy use are growing, currently standing at 1.9 gigatonnes (Gt) – 5.6% of the world's total. However, the context here is fundamental: per capita emissions from electricity generation are one-quarter of the world average. Nonetheless, India is pursuing a low-carbon growth strategy for its power sector, and its Planning Commission claims that aggressive action could reduce the emission intensity of gross domestic product (GDP) by as much as 35% by 2020 (compared with the level in 2005).

To quantify its socio-economic aspirations, India's central government, through the Planning Commission, produces Five-Year Plans[4] (FYPs) that include strategic goals for energy (as well as the economy, health, agriculture and industry). FYPs include measures to improve energy efficiency and increase domestic supply by embracing renewables and nuclear energy. A core challenge is that while the FYPs provide a framework, neither the central government nor the

3 Includes generation from utility-based capacity and captive power capacity.
4 Periods for the three most recently completed FYPs: 9th Five-Year Plan = 1 April 1997-31 March 2002; 10th Five-Year Plan = 1 April 2002-31 March 2007; 11th Five-Year Plan = 1 April 2007-31 March 2012.

Planning Commission itself is in a position to ensure that the stated targets are met. In practice, due to India's federal structure, much of the actual work involved is delegated downwards to individual states, with direct engagement and support from central government.

This arrangement reflects the historical reality that power generation in India was the joint preserve of central and state governments. In 1990, just 4% of capacity was owned by the private sector. By May 2013, with a total installed capacity of 225 gigawatts (GW)[5], the private sector's share had grown to 31%; state governments owned the highest share (40%), followed by central government (29%). In today's power sector, a plethora of players from each group are involved throughout all stages – from setting policy through regulation, generation, transmission and distribution. Progress often becomes mired in bureaucracy, which can be both costly and time-consuming.

While some states are able to balance energy supply and demand reasonably well, nationally India has been in a power deficit for many years. The 11th FYP achieved a degree of success, bringing the deficit down from 9.6% (in FY2006/07) to 8.7% (April to December 2012) but, overall, generation has failed to keep pace with rapidly growing demand – further exacerbated at peak, where the deficit April to December 2012 stood at 9% (MoF, 2013).

To manage the power deficit, distribution companies often resort to load shedding, i.e. simply cutting power to one part of a system to avoid complete system failure. While measures are taken to limit the impact, e.g. by scheduling the load shedding so consumers can plan ahead, they are particularly prevalent between 17h00 and 23h00 – the peak period nationally. Clearly, load shedding does not occur in all regions and, in FY2012/13, several states received a 24-hour supply throughout the year. Shortages, as well as the substandard quality and security of supply, stifle economic growth by disrupting industry, agriculture, education and health. One-third of India's businesses cite expensive and unreliable power as one of their main business constraints (World Bank, 2012). Some have opted to find their own solutions, often by constructing and operating their own power generation plants, known as "captive power plants" (Box 9.1).

Events in 2012 and 2013 illustrate the scope of India's power challenges. In terms of geographic coverage and population affected, the two blackouts that occurred in late July 2012 were among the largest ever experienced anywhere in the world. From a numbers perspective, with 206 GW installed, India had sufficient generation capacity to meet the peak electricity demand of 128 GW (CEA, 2012a). While such incidents usually result from a complex sequence of events, the root cause of these exceptional episodes was essentially a combination of underutilised generation assets and transmission bottlenecks.

State distribution companies (DISCOMS)[6] cannot afford to buy costly electricity from coal and gas-fired power plants that must then be fed to consumers at subsidised rates. Consequently, many of these plants were (and are) failing to recover their operating costs. During the first half of 2013, output of India's thermal plants dropped to the lowest level in more than two decades. Load factors for coal plants dipped to 64% in June 2013 (cf. an average of 79% in FY2007/08); gas-based power projects operated at just 29% of their capacity during the first quarter of 2013.

Recent trends suggest the situation in India is improving: generation of electricity increased by nearly 6% over the first six months of FY2013/14, while the peak deficit decreased (CEA 2013a).

5 Gigawatts (GW) refer to gigawatts of electrical output, also often referred to as gigawatts-electric (GW_e).
6 DISCOMS are the state distribution companies. They are responsible for the distribution of electricity in India and for collecting the tariffs from electricity customers.

Box 9.1 Captive power plants

According to India's Electricity Act 2003, a "captive generating plant" is a power plant set up by any person to generate electricity primarily for his own use and includes a power plant set up by any co-operative society or association of persons for generating electricity primarily for use of members of such co-operative society or association.

Captive power, following logically, refers to power generated from a captive generating plant, usually from a unit set up by industry or a commercial establishment for its own consumption. There may also be some mutually beneficial dependencies between the captive power plant and the commercial process it serves, e.g. fly ash produced from a captive coal-fired plant can be used in cement manufacture and bagasse produced during sugar production can be used as fuel in a captive power plant.

The concept of captive power plants is something of an anomaly: in an effective electricity market (whether regulated or liberalised) industry should be able to rely on the power sector for secure supply. In India, captive plants are prevalent in energy-intense process industries such as sugar, cement, chemicals, fertilisers and textiles, where such plants provide power, heat and steam, so-called co-generation [7] plants.

For many companies, this is the only means of being certain of a high-quality, continuous supply of electricity. The industrial sector, the largest user of electricity in India, accounting for just under half of total electricity use, relies heavily on captive power plants: for example, the Indian cement industry produces 60% of its own power requirement.

Construction of captive power plants has been growing at an aggressive pace, with units varying in technology and capacity. Of almost 22.5 GW installed in March 2012 (end of 11th FYP), 14 GW had been added in the previous five years; by March 2017, a further 13 GW are anticipated. While clearly necessary, captive plants present multiple challenges.

In FY2009/10, coal fuelled 55% of captive power units (TERI, 2013), most of which are smaller and less efficient than newer, utility-sized power generation units. A further 44% are powered by many smaller diesel and gas units. Overall, captive power plants are highly carbon-intensive. A second shortcoming is that captive power capacity is often underutilised; many companies need less electricity than their captive plants can produce. Because they operate at part load, the plants are less efficient and deliver less power than they are capable of.

Opportunity to address these integrated challenges exists. Increasing the share of captive power based on hydropower and other renewable energy technologies could reduce emissions; replacing older units and increasing unit sizes could improve efficiencies, as could greater application of co-generation plants in locations with local heat or steam demand. The greatest potential is likely to be in the chemicals, pulp and paper, textile, and food and beverage industries, where significant heat and electricity loads exist.

Importantly, as most captive power plants are connected to the grid, the opportunity exists for owners to operate at higher loads (more efficiently) and sell surplus power to distributors – thereby increasing their own revenues while also improving grid security and helping to reduce the power supply deficit. India's Electricity Act 2003 made provision for such sales, but implementation has been ineffective: for example, to feed power to the grid, captive plant owners are required to predict a day ahead the precise sequencing of power availability, and prices received for power are unrelated to generating costs.

The government is taking steps to resolve these issues and pursuing policies to better utilise the potential of captive power to benefit owners, the states and the country as a whole. As the installed capacity of captive power plants increases, suitable policy frameworks could make industry a key player in improving access to energy, boosting efficiency and reducing emissions from the country's power plants.

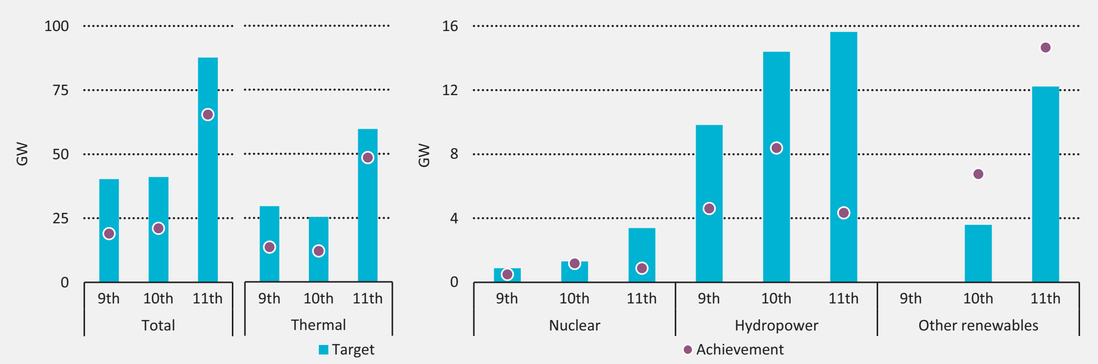
7 Co-generation is the process whereby a single fuel source, such as coal or natural gas, is used to produce both electrical and thermal energy. A co-generation plant is more efficient than a utility-operated central power plant since thermal energy that would otherwise be wasted is captured for use at the facility. The result is a much more efficient use of fuel.

Capacity expansion

India has made substantial progress over recent years in increasing both capacity and generation. Over the three FYPs to March 2012, utility-based capacity increased from 86 GW to 200 GW and generation from 395 TWh to 922 TWh. In the 15 years prior to April 2012, around 65% of the target for construction of new power plant was achieved.

Targets set in the 12th and the nascent targets for the 13th FYPs should be seen in the context of steady progress: for each successive plan, capacity addition against targets has improved (Figure 9.3). Greater additions were achieved during the 11th FYP than during the preceding two FYPs combined. Notably, targets for wind and solar capacity addition in recent years were surpassed.

Figure 9.3 **Performance against targets: Capacity additions, April 1997-March 2012**



Sources: CEA, 2013b; CEA, 2012b; Deloitte, 2013; PC, 2013; PC, 2008; PC, 2002; Saxena, 2009.

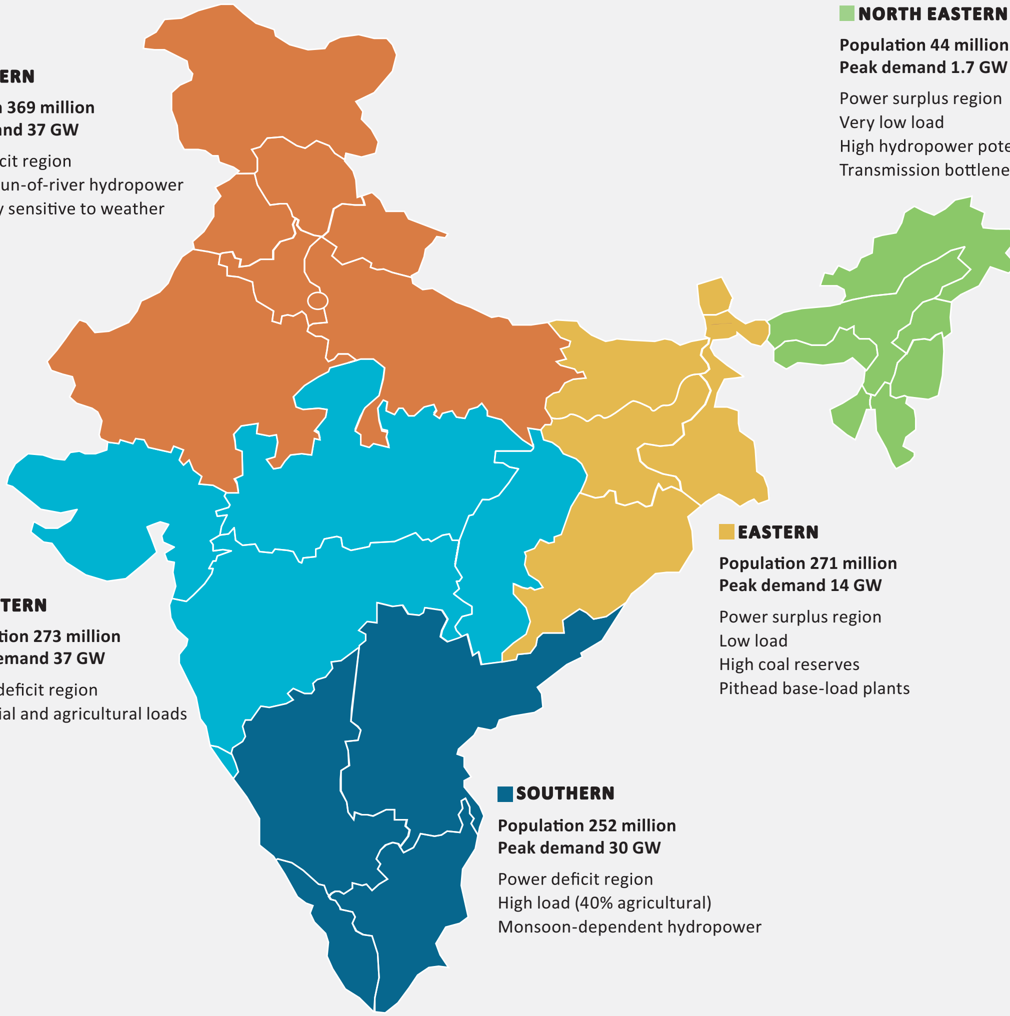
Key point *While India has outperformed its "other renewables" 10th and 11th FYP targets, it has underperformed relative to its targets for other technologies. Nonetheless, improvements in meeting total FYP targets and expanding total capacity are evident.*

While some barriers to achievement are technology-related, others are not. For example, some are related to the shortcomings of the transmission and distribution (T&D) infrastructure; others to land acquisition. On the financing side, the fact that electricity prices for some consumer categories are too low undermines investment in upstream technologies to improve fuel access and fuel quality. Non-technology barriers may be easy to articulate, but they are far more complex to address, particularly as many are entrenched in India's political and institutional framework. In recent years, the Government of India has taken steps to address many of these issues; progress has been made. Until further corrective measures are put in place, however, non-technical barriers will continue to inhibit progress.

Electricity networks

India's transmission network has a two-tier structure. The interstate grids belong to the state-owned POWERGRID, while private investment is permitted and is slowly emerging. Both intra-state and local grids are managed by State Transmission Utilities. Five regional grids – Northern, Western, Southern, Eastern and North Eastern – have varied levels of installed capacity and fuel mix. All five were interconnected as of December 2013 (Figure 9.4). Flow stabilisation in the recently connected Southern grid is likely to take a few months, following which India will have a fully functioning national grid.

Figure 9.4 Power grid regions



Note: this map is without prejudice to the status of a sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

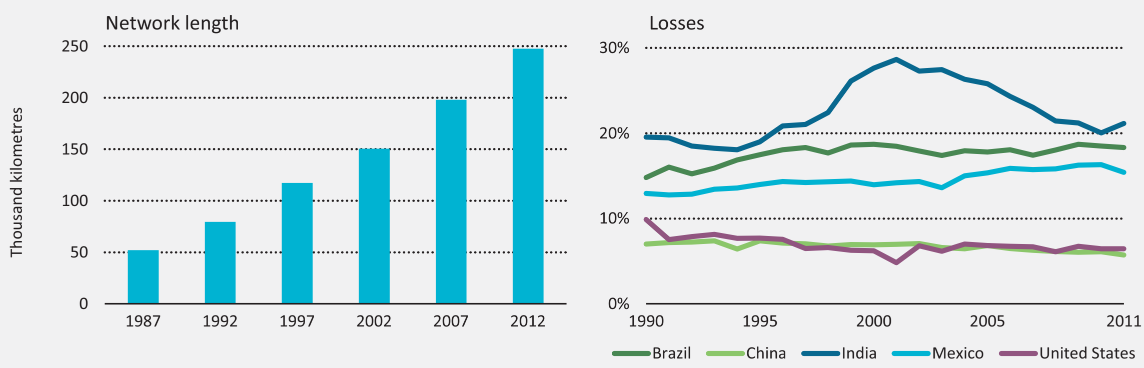
Key point *Full connectivity of the regional grids by mid-2014 will provide India with a single, national grid network.*

Despite the substantial achievement of establishing a national grid, India has not yet completely overcome its transmission challenges. The large increase expected in electricity production and consumption requires significant expansion and strengthening of the existing network. This task is made more difficult by the fact that India's resources for power generation are diverse and well-dispersed geographically: solar in the west (Gujarat and Rajasthan); wind in the southeast (Tamil Nadu and Andhra Pradesh) and west (Gujarat); coal in the central states of Jharkhand, Odisha and Chhattisgarh; nuclear (with modest uranium resources in the southern states of Karnataka and Andhra Pradesh, and in the north in Jharkhand and Meghalaya); and hydropower in the northeast (including Sikkim).

A well-integrated national transmission network is essential to move towards parity of demand and supply within and among regions, to optimise utilisation of national generation resources, and to manage peak demand. Transmission capacity has failed to keep pace with the increase in generation capacity (FICCI, 2013), however, creating transmission constraints that significantly undermine India's inability to match demand with supply. Ambitions to raise the transmission capacity have faced many challenges, including delays in acquiring land/rights-of-way; delays in project delivery, from inception to commissioning; general lack of application of best practice in all aspects of project execution; and insufficient private sector engagement in the process.

Furthermore, India experiences high T&D losses (Figure 9.5). While the World Bank puts losses at 21% (World Bank, 2013a), some other estimates place them at 28% to 30% nationally, and as high as 67% in some states (TERI, 2013). While grid losses have declined over the past decade, they are, for example, still more than three times higher than losses in the People's Republic of China and the United States.

Figure 9.5 T&D network, physical expansion and electricity losses



Sources: FICCI, 2013 (left); IEA data and analysis (right).

Key point *India's grid losses have decreased since 2002, but still stand at three times Chinese and US levels.*

Grid losses are partly technical and partly commercial. Technical losses are primarily due to inadequate investment on maintenance and upgrading, which has resulted in ad hoc extensions of distribution lines, overloading of transformers and conductors, and lack of adequate reactive power support. Commercial losses largely result from theft; from defective meters, errors in meter reading and in estimating unmetered supply of energy; and from overconsumption by those receiving free or heavily subsidised electricity (e.g. agricultural sector).

While the largest current impact is on economic growth from the inability to meet rapidly increasing demand, T&D issues will also affect the extent to which India can rely on renewable energy sources in the future. Capacity expansions in wind and solar generally occur over a shorter time frame than the expansion or reinforcement of T&D grids, so new capacity is not well integrated. Slow grid connection processes and poor grid management have hampered growth in key wind farm projects and present barriers for the further adoption of distributed photovoltaic (PV) power. In the long term, expanding and reinforcing T&D grids will be essential for India to accommodate the variable renewables additions envisioned in its FYPs.

India is making great strides in addressing these issues. The introduction of Renewable Energy Management Centres should support the expansion of variable renewable energies through improved forecasting, scheduling and grid operations. And there are already plans to double India's inter-regional transfer capacity. A programme exists to increase high-voltage direct current (HVDC) transmission capacity, which will lower land footprint and reduce rights-of-way issues, while also affording better control of power flows during transient conditions.

The potential of smart grids to more effectively accommodate the increasing variable renewable capacity planned is being investigated. In theory, smart grids should enable better planning and operation of the electricity system, and better deployment and use of infrastructure to meet actual needs. In August 2012, India's Ministry of Power approved 14 smart-grid projects across the country for immediate execution.

The Ministry of Power has also initiated its Restructured Accelerated Power Development and Reforms Programme (R-APDRP) with the aim of modernising electricity distribution management systems and introducing control and data acquisition systems. Apart from improving reliability and minimising distribution losses, these measures are an important step towards smart-grid implementation.

A programme has also been initiated to have separate electricity infrastructure for rural agricultural and non-agricultural power consumers (i.e. rural feeder segregation). Experience to date indicates that the scheme is improving both the availability and the quality of power supply in rural areas and has led to better load management and increased power supply for rural households and small industries. An analysis of the scheme made two key findings: i) custom solutions are needed from state to state, given the wide variety of local contexts and challenges; and ii) all feeder segregation proposals should be evaluated as part of a larger strategic programme to improve rural power supply (World Bank, 2013b).

Cross-border energy trade with neighbouring countries represents a promising opportunity for India to advance energy security and reduce its dependence on indigenous, coal-derived electricity. Harmonised regional energy policies can facilitate transmission interconnections with countries such as Nepal and Bhutan to allow India to access their abundant hydropower resources. Of particular interest is the integration of hydropower potential in the North Eastern Region, i.e. Sikkim and across the border with Bhutan, where untapped hydropower potential has been estimated at between 36 GW and 58 GW. In this case, hybrid high-voltage direct current/ alternating current (HVDC/AC) connections would be suitable to accommodate seasonal variability with lowest impact. Significant opportunities for cross-border electricity also exist between India and Bangladesh (coal), India and Myanmar (hydropower), and India and Sri Lanka via undersea transmission connections. India and Bangladesh began trading electricity in 2013; future opportunities may also exist with Pakistan.

Statutory clearances

Compliance with statutory clearances is the greatest barrier to the development of India's electricity infrastructure. These have been put in place to recognise the critical importance of community rights, environmental protection and sustainable development in India's growing economy. Sensitivity to the environment requires compliance with all forest and environment regulations; "rehabilitation and resettlement" and "land acquisition" address fair compensation when private land is acquired for public use. Whether it is to site a new wind farm, build a thermal power plant, establish a new coal or uranium mine, or extend a railway line, dealing with these issues in India is a complex operation, and often a socially and politically charged issue. In recent times, formal appeals and public protests have prevented many infrastructural projects from proceeding. However, in September 2013, the Indian Parliament passed the

"Right to Fair Compensation and Transparency in Land Acquisition, Rehabilitation and Resettlement Bill, 2013", which introduced a framework for land acquisitions and provided for a transparent compensation and rehabilitation mechanism.

It is important to note that around 70% of Indians still live off the land. As farm productivity and revenues have been declining for many years, the security of the rural population is linked strongly to the amount of land they have available for productive use. Some rural communities believe the drawbacks of releasing land for power infrastructure outweigh the benefits.

There is also the environmental dimension. Forest cover and biodiversity across states in India have yet to be fully recorded. The lack of a comprehensive database to map areas as ecologically sensitive or fragile is a prime reason for delays in environmental clearances for power projects, mining projects and other infrastructure.

Air quality and the sustainable use of water (Box 9.2) are also issues that can impact on land acquisition. Air quality in India is particularly poor (Yale, 2014). While a major culprit was the growing number of vehicles in India, issues relating to power generation were also cited, such as mining of coal and uranium, transport of coal and gas, and pollution arising from coal-fired power generation.

Cognisant of these matters, the environmental lobby in India is active and, in many circumstances, slows down the acquisition of land and is also known to protest strongly at various other stages of the power chain.

Box 9.2

Sustainable water use: Power sector

India has 17% of the world's population and only 4% of its usable fresh water supply. Utilisable water estimates range between 1 123 billion cubic metres (bcm) per year to 1 464 bcm per year, while current use is 634 bcm per year – i.e. almost half. Nearly two-thirds of India's cities already suffer from daily water shortages, yet aggregate demand is set to nearly double by 2030 (to 900 bcm per year to 1 200 bcm per year).

Without effective action, India is heading towards a serious water crisis. The situation reflects, in part, India's erratic distribution of rainfall and its extreme monsoon events, which lead to frequent flooding and periods of drought in various areas. Climate change effects could worsen the situation.

Groundwater extraction is unregulated, with wells being exhausted much more quickly than they can be recharged. Surface water is becoming increasingly polluted: uncontrolled discharge of untreated domestic/municipal wastewater has contaminated 75% of all surface water across India (MoUD, 2008). Safe drinking water is becoming scarce, and water service delivery suffers from inadequate institutional reforms and ineffective distribution of existing provisions.

Power generation competes for water demand with households, industry and agriculture, with regulations giving priority to drinking water and irrigation. In a bid to attract generators, Indian states with large coal reserves have underpriced access to water, exacerbating the local water crisis; severe water shortages have led to a growing number of conflicts.

Thermal power plants – coal, nuclear, geothermal and solar thermal electric plants, as well as many natural gas power plants – have a heavy demand for water. Coal-fired power plants, for example, require substantial water volumes for generating steam and for ash and process cooling. Almost two-thirds of India's thermal power plants are located in water-scarce or water-stressed areas, and nearly 80% of planned plants will be located in such areas (InfraInsights Research, 2013). Effective measurement and monitoring of water usage, along with recycling of plant waste water can minimise net withdrawal. Technical measures for reducing water consumption may include using more efficient technologies (such as supercritical rather than subcritical), dry cooling, dry bottom ash handling, alternative emissions control technologies and, where possible, water recovery from plant operations. In addition, generators may be encouraged to create large reservoirs and to adopt coastal siting of power plants where possible.

Structural and political constraints

The Indian power sector is highly regulated. It is endeavouring to establish an independent regulatory regime to enhance investor confidence. While many reforms have been implemented, they have failed to keep pace in a country where power generation capacity has more than doubled since the year 2000.

Each state is responsible for the generation, distribution and pricing of electricity for its residents, and has authority over policy decisions governing how energy is produced, moved and consumed within its borders. Each of these operations presents its own challenges. Together with a multiplicity of other federal and state institutions with responsibilities for generation, transmission and distribution, decision making in the power sector can be a complicated process.

The pricing of electricity is complex in India, following three main pricing mechanisms. First, state generation utilities sell electricity to the DISCOMS based on long-term contracts at the prices largely controlled by the State Electricity Regulatory Commissions (SERCs). This pricing is generally based on a cost-plus principle. A cross-subsidy structure is then applied in which surcharges are levied on industrial consumers to subsidise other consumers, particularly between, say, agriculture and households on the one hand and industry on the other. Secondly, short-term bilateral contracts are used by traders for interstate or inter-regional power purchase through open access. The third mechanism follows the Electricity Act 2003, through which India developed a spot market that has been in operation since the opening of two power exchanges in 2008. Power purchases are made through a bidding process. The exchanges provide a spot market for electricity, mainly on a day-ahead basis, which matches demand and supply for each time block. The spot market covers a much smaller portion of the overall market compared with the first two mechanisms.

Power sold between states is subject to federal oversight and regulation via the Central Electricity Regulatory Commission (CERC), which sets the tariff framework. End-user tariffs are then set by the CERC and the SERCs. While efforts are made to relate tariffs to the fuel price, in practice, political sensitivity often prevents the tariff from being increased too frequently or too steeply, even if there has been a hike in the cost of fuel. As a result, average electricity tariffs are generally lower than the costs of power generation, which tends to encourage inefficient use of electricity in the subsidised sectors. The mismatch between generation costs and tariffs is significant and, together with the high T&D losses, have placed the DISCOMS in financial difficulties. At the same time, the cross-subsidy structure burdens industrial users with high electricity tariffs to subsidise agricultural and other consumers. Any further price increases for industry could trigger a switch to captive production, leaving the DISCOMS with an even greater share of subsidised users.

Underpayment (or even non-payment) to generators creates immediate supply problems and, in the longer term, threatens critical investment in more efficient generation technology and in upstream exploration and production. The financial difficulties faced by the DISCOMS are exacerbated by theft incurred by illegal tapping of transmission lines or tampering/damage of meters; non/under-billing, where distribution companies fail to correctly bill consumers; non-payment, where consumers fail to pay; and misclassification of consumers, such that they are inadvertently classified as subsidised users.

In FY2011/12, the combined financial losses of DISCOMS were of the order of USD 35 billion[8], prompting the central government to announce (October 2012) a bailout – the second in a decade. Recognising the need for reform to ensure commercial viability of the power sector, the central government also initiated strong measures (legal, regulatory and technical) to

8 Unless otherwise stated, all costs and prices are in real 2012 USD, i.e. excluding inflation.

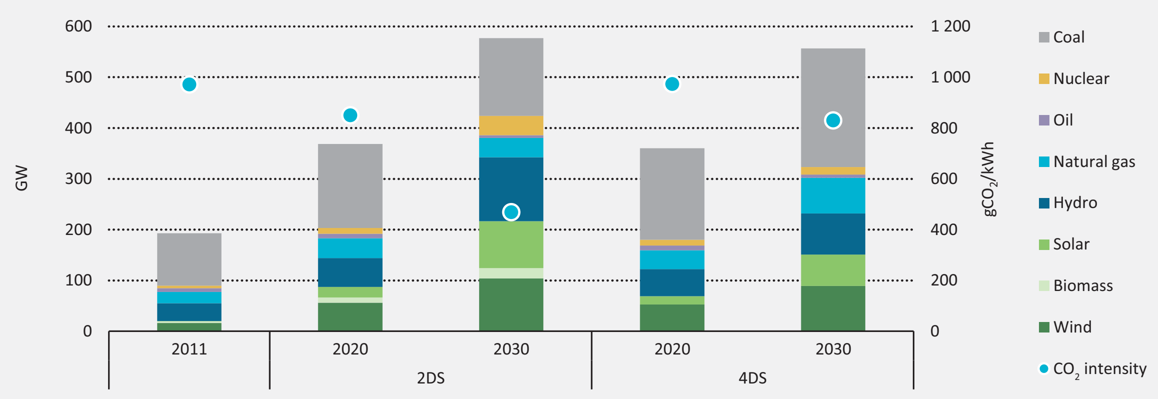
address persistent problems. DISCOMS have implemented the new package with positive results, including raising tariffs. Prices are now approved by the regulators, with any losses (owing to subsidy) experienced by the DISCOMS made good by the state.

Mid-term goals for the power sector

India's current FYP (its 12th), which covers the period from 1 April 2012 to 31 March 2017, has demanding targets. The utility-based installed capacity of 200 GW at the end of the 11th FYP (31 March 2012) is targeted to increase by 60% to 318 GW. Renewables are targeted to more than double, from 25 GW to 55 GW. Recent experience suggests that achieving the FYP targets will be challenging; reaching FYP goals requires a strategic vision for the power sector, one that considers all options in a holistic manner. But progress is being made, and new policies implemented in India are beginning to have a positive impact.

The IEA, in *ETP 2014*, has carried out its own, very different exercise using modelling techniques to analyse and compare possible energy futures, where two main global scenarios are presented – the 2DS and the 4DS. The 2DS and 4DS for India are elements of these global scenarios based on global least-cost mitigation, where CO_2 emissions are priced uniformly around the globe. As indicated earlier, projections from the scenario should not to be confused with predictions or forecasts, or even a recommendation that India could or should commit to follow such a path. An equitable burden-sharing of the efforts to mitigate climate change is unlikely to be similar to a cost-effective distribution of efforts. *ETP 2014*, in its 2DS, sets an ambitious target for India, with capacity projections rising to 369 GW by 2020 (Figure 9.6).

Figure 9.6 **Installed capacity and CO_2 intensity of power generation**



Key point *The path followed by the power sector is expected to demonstrate the ambition of India's low-carbon growth strategy.*

In the 2DS, generation in India is projected to increase fourfold to 2050, with the contribution from fossil fuels falling from 80% to 25%. The share from coal plummets to less than 20%, with around half fitted with carbon capture and storage (CCS); the share of gas falls to less than 3%. Shares of nuclear (15%) and hydropower (17%) both rise, and the contribution from renewables steps up markedly, reaching 40%. The 4DS also projects a fourfold increase in generation to 2050, but the contribution from fossil fuels – at around 65% – remains high. *ETP 2014* analysis shows that, unless a stringent low-carbon growth strategy was implemented, CO_2 emissions from power generation could rise by 45% over the next decade and by a factor of three by 2050.

For each technology, the key issues, challenges and opportunities for implementation differ greatly and must be appraised individually.

Coal

More than two-thirds of India's electricity derives from coal. From 2002 to 2012, almost 50 GW of new coal-fired capacity was added, raising the total to 112 GW or 56% of total generating capacity. India has ambitions to reduce the share of electricity from coal in the long term, but under the target set out in the 12th FYP, coal capacity would rise by 70 GW by April 2017.

12th FYP targets broadly align with *ETP 2014* projections. In the longer term *ETP 2014* projections see coal capacity increasing right through to 2050 in the 4DS but peaking by 2030 in the 2DS with subsequent decline. In both *ETP 2014* scenarios, the share of total generation from coal decreases continuously to 2050.

Supply and transport of coal

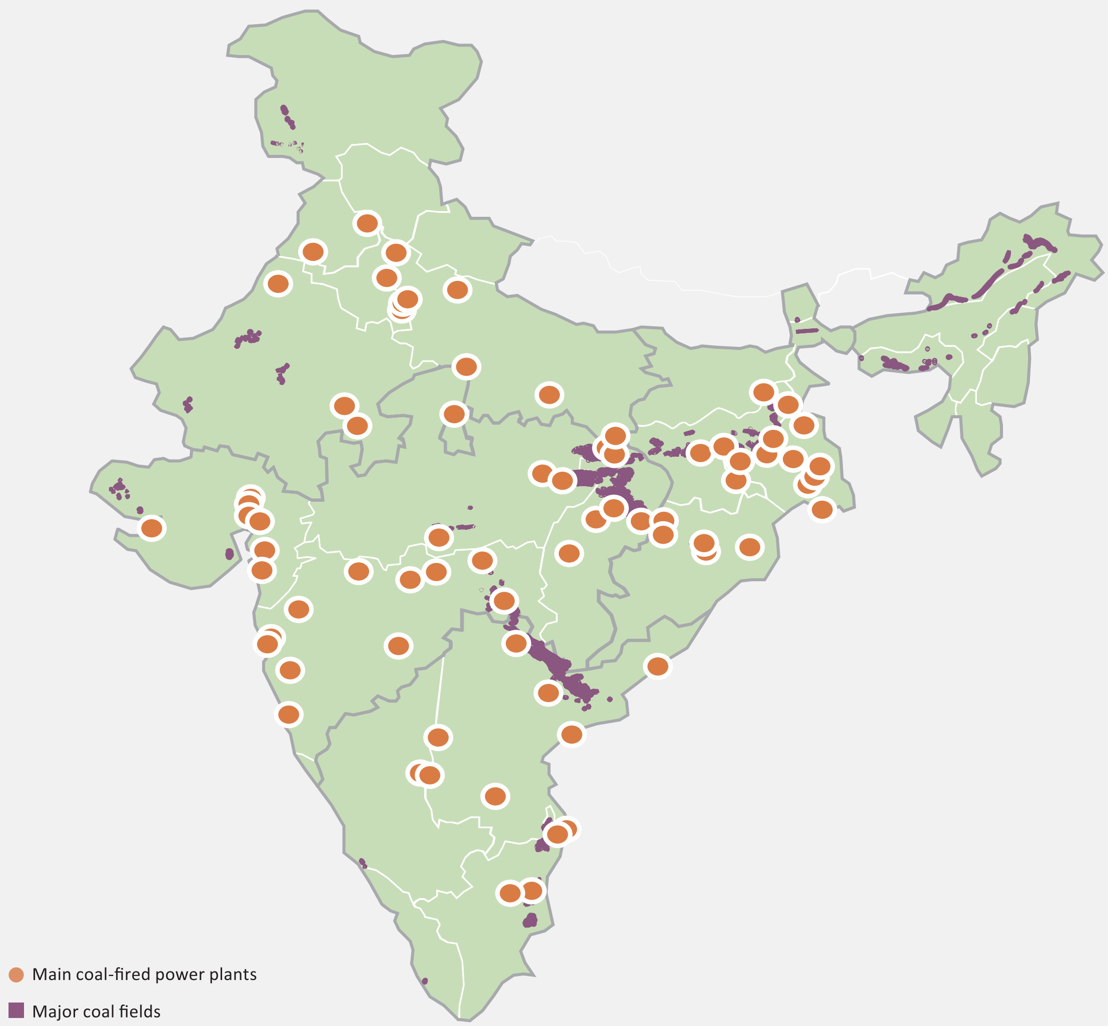
As of April 2012, India had 118 billion tonnes of proven hard coal reserves; it was the world's third-largest coal producer (552 million tonnes [Mt] hard coal and 44 Mt lignite) and, at 160 Mt, the third-largest hard coal importer (IEA, 2013b). Most coal (as well as oil and gas) reserves are located in areas where they are geologically and technically difficult to extract, in environmentally sensitive forested or protected areas, or far from demand centres (Figure 9.7). This reality has numerous impacts on production, transport and pricing.

Currently, the government holds a monopoly: over 90% of coal production comes from government-controlled mines. The monopoly was loosened somewhat in 1993 with the introduction of a policy to support captive mining, which allowed the private sector to bid (through auction) for coal blocks for own-use in the power sector, for the iron and steel industry, or for the cement industry. In reality, little progress towards private investment has been made.

Since 1993, 218 coal blocks, totalling approximately 50 billion tonnes in resources, have been allocated, including 106 to private companies. Of the 178 blocks allocated by 2012 (40 have been de-allocated), for various reasons only 34 blocks had commenced production. Their combined production was a mere 36 Mt in FY2011/12 against a target of 105 Mt. While there are many reasons for this underperformance, difficulties in obtaining the necessary environmental permits (such as forestry clearance), land acquisition and availability of geological data are most frequently cited. Removing the own-use constraint from captive coal mines could be beneficial for greater flexibility of the entire power supply, though many captive coal blocks also suffer from unfavourable geological conditions. Currently, further coal block auction has been proposed and a detailed mechanism is being formulated for transparent and efficient processing.

The geographic location of reserves means domestic coal must be transported long distances by train, or first converted to electricity, then transmitted via the grid (coal-by-wire). Both are costly, incur losses and drive up emissions. The average cost for transporting coal between the coal-bearing areas in the east and the electricity loads of Delhi, Mumbai or Chennai (around 1 500 km) is between USD 17/tonne and USD 19/tonne of coal – up to twice the cost of an equivalent distance in the United States. Moreover, relative to imported coal, domestic coals are of poorer quality and have lower heat content; on an energy basis, the cost of transporting domestic coal is around 15% to 30% higher.

Figure 9.7 Coal resources and major plant locations



Note: this map is without prejudice to the status of a sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

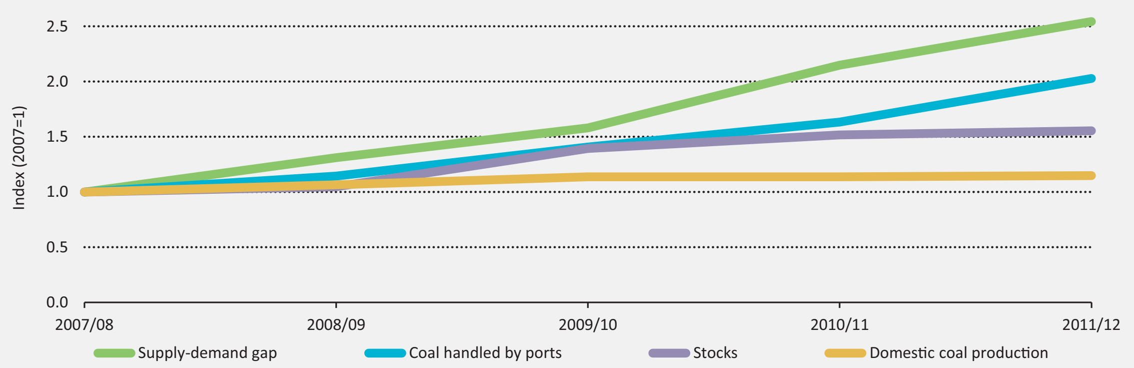
Key point *An important domestic energy resource, coal plays a vital role in the generation of electricity in India.*

With modernisation of the rail system, rail transport of coal has increased at an average annual rate of 6.4% in recent years – with a steep increase (11%) seen in the past two years. Imported coal is more attractive along India's western and southern coasts and has reached cost parity with domestic coal for inland locations; farther east, domestic coal is the more attractive.

In recent years, poor road-rail connectivity, slow permitting and other regulatory barriers on transport companies have caused a build-up of coal stockpiles at the pithead. Yet at the same time, stocks at 60% of coal power plants are sufficient for perhaps only seven days' worth of generation; at many plants, the stock is sufficient for only one day. So while large amounts of coal await transport, many power plants lack coal in sufficient quantities to efficiently and effectively deliver the electricity they are capable of.

Despite having the fifth-largest coal reserves in the world, India is not able to meet its domestic demand. Domestic production of hard coal rose from around 430 Mt in FY2006/07 to 540 Mt in FY2011/12 (an increase of 24%). Coal demand in the past decade grew at a compound annual growth rate (CAGR) of more than 7%, reaching around 635 Mt. While imports, which stood at around 138 Mt at the end of FY2012/13, are rising, they do not entirely compensate for the supply-demand gap. Many issues relating to transport, to coal quality, to mining constraints, to particular rules and regulations, come together to prevent coal-fired power plants from receiving enough coal to optimise generation.

Figure 9.8 **Coal demand and supply trends**



Source: TERI, 2013.

Key point *As demand for coal has increased, domestic production and transport has not kept pace, leading to an increasing supply-demand gap.*

To compensate for domestic production and transport constraints, and to raise (through blending) the quality of the coal used, India's coal imports grew at a CAGR of 15% between FY2004/05 and FY2010/11. During the same period, thermal coal imports grew at a CAGR of around 25%. According to projections, India's coal import requirements will be more than 200 Mt by the end of the 12th FYP.

Power stations are designed for a particular coal specification. When coal of that specification is no longer available or is available in insufficient quantities, operators may opt to blend two or more coals. The properties of blends, however, are difficult to predict and can result in a deterioration in thermal efficiency as well as decreasing plant availability (CEA, 2012c). To optimise performance, it is important to understand the composition of the blended coals, to investigate the slagging and fouling characteristics, and to know the emissions characteristics relating particularly to nitrogen oxides (NO_X), sulphur dioxide (SO_2) and particulates.

Coal pricing schemes, as is the case across India's energy sector, raise additional challenges. Price subsidies keep power tariffs artificially low and fail to send effective pricing signals to those who could adjust consumption to use electricity more efficiently. Pithead domestic coal prices in 2012 were less than a half to one-third the cheapest imported coal. Historically poor financial returns are a disincentive to private sector investment, so India's mining sector and generators do not benefit from best available technology. Pricing mechanisms need to be rationalised to reflect the changing costs of electricity and to provide sufficient incentives to investors to enter India's power business.

Coal-fired power generation

At 33.1% (HHV, gross)[9] in FY2011/12 (CEA, 2013c), the average efficiency of India's coal-fired power fleet remained substantially lower than fleets in China and the United States. A number of factors contribute to this lower efficiency.

Coal mined in India typically has low to medium calorific value, with net calorific value ranges from 2 500 kilocalories per kilogram[10] (kcal/kg) to 5 000 kcal/kg. It has a high ash content (35% to 50%), moderate moisture content (4% to 20%) and low sulphur (0.2% to 0.7%). Around 90% of Indian coal is mined in open-cast operations, the remainder underground. Silica in the ash renders it highly erosive. High ambient temperatures and relative humidity in India lead to power generation efficiency losses.

The heat content of Indian coal has been declining steadily over several decades, from typical values of 5 900 kcal/kg in the 1960s, to 4 200 kcal/kg in the 1980s, to 3 500 kcal/kg in the 2000s. The lower heat content requires that more coal is burnt for the same electrical output, leading to an increase in specific local emissions of SO_2, NO_X and particulates.

The high ash content of Indian coal gives rise to several problems: transportation costs per unit energy content are higher as ash (which has no useful heating value) is transported together with coal; power plant efficiency is lower as ash hampers heat transmission; plant operation and maintenance are generally more difficult due to corrosion, and fly and bottom ash removal; higher ash content leads to higher pollutant emissions, while lower efficiencies lead to higher CO_2 emissions; end users require coal of a certain quality, with consistency of quality as important as quality itself – though coal washing would help in this regard, most Indian coal used at the power stations is not washed (Box 9.3).

The efficiency of a coal-fired power generation unit is broadly proportional to the temperature difference between the internal heat source and the external environment. Consequently, the relatively high temperatures in India are not consistent with the very high efficiencies that can be achieved in, say, parts of Europe. Many power plants have higher net output in winter than summer due to differences in cooling water temperature.

For a number of reasons, primarily the poor quality of coal and the supply shortage, unexpected and unscheduled maintenance outages, and longer commissioning periods for new units, India's coal-fired plants are also prone to low plant load factors. After increasing steadily through the 1990s and early 2000s to load factors over 78%, by 2012 a drop to 73% was reported. Low load factors reduce the volume of electricity generated and thus undermine the financial performance of generating companies.

Most Indian coal units have been in operation for less than 30 years, making the average age significantly lower than fleets in the United States and the European Union (Figure 9.9). Some 20% of operational thermal power units are more than 25 years old; another 40% are older than 15 years (but less than 25).

Having a young fleet, however, does not give India an edge on efficiency. India only commissioned its first supercritical 660 MW power plant, up to 40% (HHV, gross) efficient, in December 2010. Slightly more than 90% of India's coal-fired power plants are based on subcritical technology, and the fleet's average efficiency is relatively low at 33.1%. Generally, India's older units are small and many operate at efficiencies significantly less that 30%.

9 Efficiency value is reported on the basis of the fuel's higher heating value (HHV) and gross electricity output (gross), i.e. before deduction of electricity for plant's own-use.
10 1 000 kcal/kg = 4.187 MJ/kg.

Box 9.3

Washing Indian coals

A major part of the ash in Indian coals is finely distributed within the coal's structure, so-called inherent ash; washing such coal to reduce ash content can be only partially successful. After washing, two fractions result, one with a higher calorific value than the original coal and one with a lower value. Unless a nearby power plant is able to burn the rejected fraction, part of the energy contained in the original coal is lost – typically 5% to 20%. If not burnt in a power plant, the rejected fraction must be disposed of in an environmentally friendly manner, which may be difficult to achieve and leads to a loss of energy in a country with a shortage.

Increasingly rigorous washing may reduce the energy content of the primary fraction, but is beneficial in other ways. At present, most domestic coal is not washed; where washing is practiced, much of the equipment used is suboptimal. Modern washeries are more flexible, with more washing stages and less coal lost in the reject fraction. Furthermore, burning the rejected fraction in a fluidised bed combustor could recover some of the energy that would otherwise be lost.

Reducing ash content through washing can also reduce the concentration of other pollutants, such as sulphur and heavy metals. Today, only coal transported over 1 000 km is required to have less than 34% ash. Coal washing improves coal quality, and hence coal prices. It saves money in coal transportation. It only marginally increases the cost of electricity while the environmental benefits and the benefits to power companies can be substantial. Theoretically, washing should be driven by the market, but a market failure makes it unprofitable to do so.

India has been slower than other countries to implement coal washing due to a lack of emissions standards and a misperception that it adds to the cost of electricity generation. A policy or regulatory framework that makes it obligatory to internalise externalities (such as emissions) would help promote the use of cleaner coal, with positive impacts on plant efficiencies, emissions and the environment.

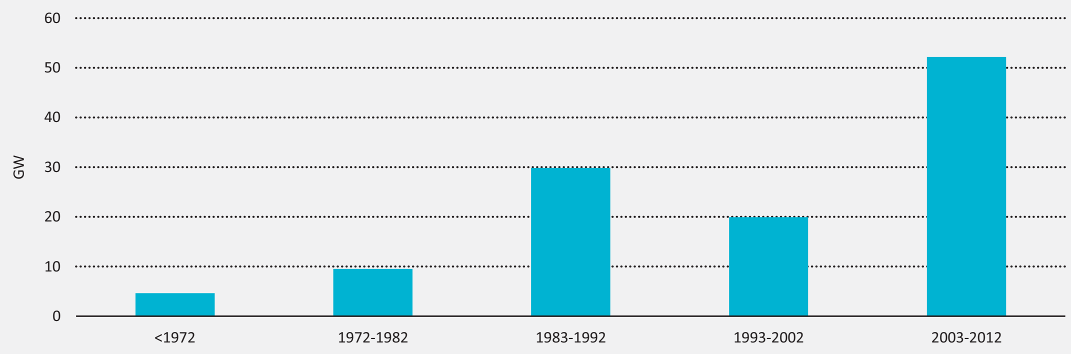
Without washing, the high ash content of Indian coal requires that boilers provide additional residence time for the carbon to burn out, and must be around 20% larger compared with boilers sized for imported, lower-ash coal (CEA, 2012c). The gross calorific value of coal considered for the design of boilers using domestic coal is about 3 300 kcal/kg, with performance guarantees based on the design coal. Boilers supplied by Bharat Heavy Electricals Limited (BHEL) can provide the rated output with a coal quality variation of about 1 000 kcal/kg (e.g. from 3 000 kcal/kg to 4 000 kcal/kg), thus offering some flexibility (CEA, 2012c).

The combination of high dependence on coal and inefficient generation means that India's power generation is highly carbon-intensive. In 2011, its CO_2 intensity of coal-fired power generation was 1 171 grammes of carbon dioxide per kilowatt hour (gCO_2/kWh), compared with 915 gCO_2/kWh in the United States (IEA, 2013a). Increasing the average efficiency of its coal fleet will help to gradually reduce India's CO_2 intensity. In the longer term, should India decide it needs to make deeper cuts in CO_2 emissions from the power sector, it will need to deploy CCS (Box 9.4).

At present, India's emissions regulations apply only to particulates. The ash properties of domestic coal are a particular challenge: the electrostatic precipitators used to remove particulates are often undersized and, hence, operate with reduced removal efficiency – with the net result that emissions are high (CPCB, 2007). Adding bag filters may be a method to improve particulate removal. Only the National Thermal Power Corporation (NTPC) monitors particulate emissions from its plants.

India has not yet set emissions limits for NO_X or SO_2 from coal-fired power plants, which have increased markedly in recent years (Lu and Streets, 2010), particularly with increased use of domestic coal, which has low heat content. Imported coal is likely to have a higher sulphur

Figure 9.9 Age of coal-fired power generation plant



Source: Platts, 2013.

Key point *The majority of the coal power fleet has been built in the last 30 years.*

Box 9.4 Carbon capture and storage

China and India are the main drivers behind the growing demand for coal; despite growing shares of renewables in both countries, coal and other fossil fuels will play a role for many decades to come. While improving the efficiency of existing processes and switching to lower-carbon technologies can reduce CO_2 intensity, CCS is the only technological means to achieve deep cuts in CO_2 emissions.

The rate and timing of CCS deployment differs widely around the world. In India, the priority to provide affordable power to residents with poor or no access to electricity is paramount and informs many policy decisions. While India is committed to pursuing a low-carbon growth strategy for its power sector, CCS technology is too costly to yet have a role, and substantial effort (also at high cost) would be required to assess India's long-term usable CO_2 storage potential.

Ultimately, CCS deployment in India would depend on successful demonstration and subsequent implementation elsewhere and on international co-operation and technology transfer. The 2DS projects that member countries of the Organisation for Economic Co-operation and Development (OECD) would have nearly 13 GW of CCS by 2020, with a smaller amount in China. India would adopt the technology later, with rapid growth to 2050 (when growth in OECD countries and China had flattened). More international co-operation is needed as pointed out at the Carbon Sequestration Leadership Forum (CSLF) Ministerial meeting in November 2013.

Significantly, industrial applications of CCS are more important in India than power sector applications, reflecting high CO_2 emissions that are an unavoidable by-product of processes to produce steel, cement and some chemicals (IEA, 2013c). Fortunately, in many of these processes, the CO_2 is relatively pure and easy to capture.

content than domestic coal, so increasing its use could also drive up SO_2 emissions. Regulation is important, but must be supported by effective monitoring and mandatory compliance. In addition, coal plants must be designed such that pollution reduction equipment can be retrofitted once legislation enters into force.

As India's coal-fired fleet continues to expand, its average age is declining; the country is in a prime position to migrate towards a fleet of highly efficient, low-emission units. This opportunity is not yet being adequately grasped: many subcritical units are still being constructed with no plans for future addition of pollution control equipment. Globally, the share of subcritical units under construction is coming down, from around 50% in 2010 to 36% in 2012. India accounts for more than 60% of subcritical units under construction, but progress is evident.

The 12th FYP targets about 60% of new coal power plants using supercritical technology and mandates that ultra-mega power plants (UMPPs) adopt supercritical technology to improve fuel efficiency. Launched in 2005, the UMPP programme aims to accelerate expansion of power capacity with around 12 UMPPs envisaged, each with a minimum capacity of 4 GW. The first UMPP (in Mundra, Gujurat) comprises five 800 MW units and was designed to operate on imported coal. Successful operation has been hampered by rising costs of imported coal and Tata Power, its owner, has applied for a higher electricity tariff to compensate. From April 2017, the 13th FYP targets supercritical technology for all new units.

Gas

Gas has two major advantages over coal: its potential to complement growth in generation from variable renewable energy sources is greater and its specific emissions of CO_2 are substantially lower. However, India's moderate reserves, together with the high cost of imported gas, have so far prevented it from being the game changer that it might otherwise be. Installed capacity of around 20 GW in May 2013 puts gas plants at just 9% of India's total installed capacity of 225 GW. Just over 5 GW of gas capacity was added during the 11th FYP.

At the end of 2011, natural gas reserves were estimated at 1.15 trillion cubic metres (tcm) (WEC, 2013). India was self-sufficient in natural gas until 2004. From FY2004/05 to FY2008/09, domestic production was flat, at around 30 bcm to 32 bcm. Output rose to 46.5 bcm in FY2009/10, and to 51.2 bcm in FY2010/11 before falling back to 46.4 bcm in FY2011/12 and a provisional 39.8 bcm in FY2012/13 (MPNG, 2013).

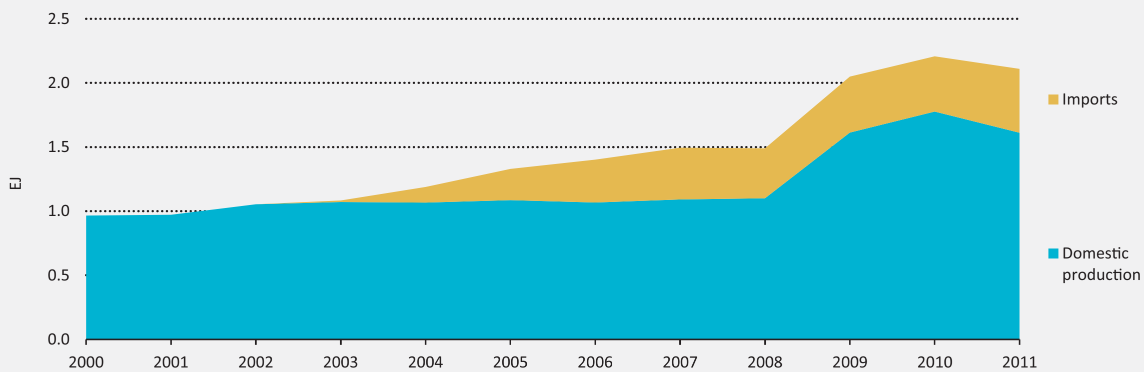
The upstream natural gas sector has experienced a number of recent challenges. On top of unexpected geological challenges, clearance delays on the part of various authorities have prevented the development of new blocks, pricing has lacked clarity and pipeline development has been delayed. These issues have, together, contributed to a decline in output from both onshore fields (mainly in Gujarat, Assam and Andhra Pradesh) and offshore fields (in the Bay of Bengal).

To compensate for the decline in domestic natural gas production, India steadily increased imports – from 3.5 bcm in FY2004/05 to 13.2 bcm in FY2011/12 (MPNG, 2012). As India has no international pipeline connections, all imported gas currently enters the country as liquefied natural gas (LNG), with the limitation that all operational LNG import regasification facilities are located on the west coast. Two fully operational terminals are located in Gujarat, with a combined capacity of 18.2 bcm (13.5 million tonnes per annum [mtpa]). Partially operating facilities are located at Ratnagari in Maharasthra (planned capacity 6.8 bcm or 5 mtpa) and Kochi in Kerala (3.4 bcm or 2.5 mtpa).

Recent supply challenges have driven down gas-fired plant load factors, from an average of 66% in FY2010/11 to 60% in FY2011/12. The combined effect of declining gas production coupled with increasing gas-fired power capacity pushed load factors down even further in 2013, forcing plant owners to choose between closing facilities or buying more expensive gas from overseas.

By May 2013, against the 85 million standard cubic metres (mscm) per day required for a 90% gas plant load factor, just 30 mscm per day was being supplied. With the prospect of leaving stranded the further 7.8 GW gas capacity that was ready for commissioning, the situation threatened to worsen substantially unless domestic production stepped up or imports increased, despite the substantial price challenge (Figure 9.10).

Figure 9.10 Natural gas production and consumption



Note: EJ = Exajoules.

Key point *Imported gas will be required to fill the growing supply-demand gap.*

In 2008, in view of scarcity of domestic natural gas, the Indian government introduced new market guidelines relating to gas produced by the national oil companies and produced from fields set up under the New Exploration and Licensing Policy. Under the Gas Utilisation Policy, the government established priority sectors for allocation rather than allowing gas producers to sell on the open market. Existing users for fertiliser production, petrochemicals and power plants were set as "category one" customers, to be supplied at the lowest rate, which is set by the government. Other industrial users interested in switching to gas would not have access to these low-priced gas resources; instead, they would have to pay higher prices to private companies and LNG importers. India is presently revisiting this policy to increase allocations to power generators.

With India's gas-fired power stations currently underutilised, plans to further increase capacity will depend on future gas availability – whether through increased domestic production (requiring investment in domestic exploration and production) or higher imports (implying the construction of additional LNG regasification terminals and pipelines, and ensuring last-mile connectivity). Current gas pricing formulas used by domestic producers offer little incentive to invest in further exploration or in technology and practices to improve production. To spur investment, the Indian government passed a resolution to allow producers to raise gas prices from 1 April 2014. The price is expected to rise to from USD 4.20 per million British thermal units (MBtu) to around USD 8 MBtu. As most new gas prospects are in deep water, however, the technology needs will be great and the investment required very high.

Potential sources of unconventional gas for India are discussed in Box 9.5.

Box 9.5

Unconventional gas: Coalbed methane, shale gas and underground coal gasification

The depletion of conventional resources and increasing demand for clean energy has led India to consider the role of unconventional gas resources, which are profoundly affecting supplies and markets in other places, such as Australia and the United States.

The potential of unconventional gas resources, particularly of coalbed methane (CBM) and shale gas, is widely recognised. Gas hydrates are also being investigated, but without a technology breakthrough are unlikely to achieve commercial production for some decades.

India formally recognised the potential of CBM in a new policy in 1997, after which the government began offering (in 2001) 33 blocks in four rounds of bidding. Projected CBM resources are estimated at 4.6 tcm (DGH, 2014). The first block commenced commercial production in 2007; two others are at advanced stage. CBM activities in India are regulated by the Director General of Hydrocarbons.

Progress to date has been stymied by a challenging paradox: while domestic companies lack the expertise and technology to develop the resources, foreign companies have been deterred by regulatory uncertainties and a difficult market. The government is relaxing its policies to attract investment.

Given the way shale gas production in the United States has driven down prices while enhancing energy security, it is no surprise that India is among the many countries exploring their own shale gas potential. In fact, many Indian oil and gas companies have invested in shale gas plays in the United States; while not the primary motive, they will gain valuable experience in technology and operations. The Ministry of Petroleum and Natural Gas has identified six basins in India with potential resources of shale gas. It announced its shale gas and oil policy in late 2013, to be followed by an auction of shale gas development blocks.

Underground coal gasification (UCG) could prove to be a valuable technology addition, as India has very large deposits of coal and lignite that are difficult to extract by conventional mining methods. In UCG, coal is converted *in situ* into synthesis gas (syngas – primarily a mix of carbon monoxide, hydrogen and methane) by reaction with air/oxygen and steam at elevated temperatures. India has not yet taken steps to pursue UCG, but is watching pilot projects already being rolled out in Australia, Canada, China, New Zealand and South Africa. Water consumption and CO_2 emissions would be of concern in India, but recent evidence shows that a dry-cooled UCG-IGCC unit[11] requires far less water consumption than an equivalently sized conventional dry-cooled, subcritical pulverised coal plant with flue gas desulphurisation (Eskom, 2014). In the future, UCG-IGCC could also support addition of CCS.

Rules and regulations for exploration and exploitation of coal and gas are governed by different ministries in India, which can lead to conflicts of interest when developers may wish to compare the relative merits of pursuing coal mining, CBM and UCG for a particular block. At present, no mechanism exists to resolve these conflicts.

Nuclear

India has long associated nuclear energy with energy security. In 1948, shortly after independence, it established the Atomic Energy Commission and then, in 1954, the Department of Atomic Energy. Prior to 2008, however, India was excluded from access to fuel and technology within the international nuclear market.[12] Consequently, over several decades,

11 In a UCG-IGCC unit, synthetic gas (syngas) from a UCG operation is fed into an integrated gasification combined cycle (IGCC) unit to generate electricity.

12 The origin of this exclusion goes back to when India conducted its first nuclear weapon test in 1974, resulting in the country remaining outside of the Non-Proliferation Treaty (NPT). In 2008, however, the Nuclear Suppliers Group (NSG) granted a waiver to India, allowing it access to civilian nuclear technology and nuclear fuel from other countries. Subsequently, the US-India Civil Nuclear Agreement 2008 was ratified in the United States, and this was followed by a number of other bilateral cooperation agreements, e.g. between India and France (2006), Russia (2010) and the United Kingdom (2010) (DAE, 2014).

India developed a strong domestic capability covering the complete process chain, from uranium exploration and mining to generation, reprocessing and waste management. This resulted in domestic design, construction, operation and maintenance of several 220 MW pressurised heavy water reactors (PHWRs), two 540 MW PHWRs and, more recently, a 1 000 GW pressurised water reactor (PWR).

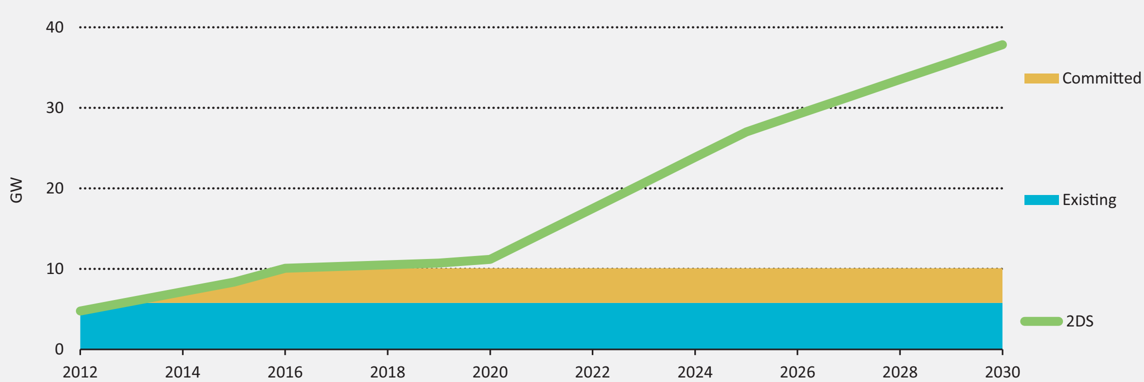
Despite growing public opposition, strong support for nuclear power is evident at the highest levels of government. Along with other countries, India prudently ordered a comprehensive review of nuclear safety and security measures in the wake of the 2011 Fukushima-Daiichi accident in Japan. In the context of maintaining strong economic growth, nuclear power could make a robust contribution to meeting India's rising energy demand while at the same time mitigating carbon emissions.

Nuclear power generation

At 5.8 GW, India's nuclear power capacity remains relatively small, ranking 13th in the world and accounting for only 3% of Indian generation in 2011. The first Indian power stations, two 160 megawatts electrical capacity (MW) boiling water reactors, entered commercial operation in Maharashtra at the end of the 1960s. Numbers expanded in subsequent decades with the construction of PHWRs and, in early 2014, a PWR. The reactors are located at seven sites, strategically positioned close to areas of high population density. Nuclear power is well established for meeting base-load electricity demand in India (Figure 9.11).

The 2DS projects the share of generation to rise to 5% by 2025 (based on 11 GW capacity) and to 15% by 2050 (80 GW). India's government has much more ambitious capacity targets in its FYPs, planning an increase to 10 GW by March 2017 and to 28 GW by March 2022.

Figure 9.11 Nuclear capacity



Source: WNA, 2014.

Key point *While generation from nuclear is modest at present, ambitions are to significantly increase its share of total generation.*

Several new nuclear units are under construction, with others in the pipeline. By the end of the 12th FYP, a further 4.3 GW capacity should be in operation. The newly constructed 1 GW unit, Kudankulam Unit 1 in Tamil Nadu, began operation in February 2014, with the second unit to be commissioned later in the year. Following legal challenges and public unrest, the Supreme Court of India stressed that the reactor was safe and was necessary for economic growth.

Nuclear generation data show that prior to FY2010/11, shortage of fuel led to low plant load factors. With greatly improved access to uranium after 2008, plant load factors and output rose markedly in FY2010/11 and even more so in FY2011/12 (Figure 9.12). The average plant load factor of 80% is still relatively low, particularly as nuclear is usually considered as base-load capacity.

Tellingly, nuclear plants running on imported fuel typically have much higher plant load factors (95%) than those operating on domestic fuel (67%) (DAE, 2012). This is mostly attributed to delays with uranium mining projects and labour disputes – both matters (among others) will need to be addressed to improve utilisation of existing nuclear capacity.

Figure 9.12 Power generation from nuclear plants

Key point *Participation in global markets for uranium led to increased access to fuel and reversed the trend for plant load factors.*

India has only modest resources of uranium, but abundant resources of thorium. Using thorium for nuclear power generation, however, requires a more complex chain of nuclear technologies. Since 1958, India has been engaged in a three-stage nuclear programme to exploit these resources:

- First stage: to develop and put into operation PHWRs, fuelled by natural uranium.
- Second stage: to develop and put into operation pressurised fast breeder reactors (PFBRs) backed by reprocessing plants and plutonium-based fuel fabrication plants, fuelled by mixed oxides of uranium-238 and plutonium-239. With a sufficient inventory of plutonium, thorium can be converted to the fissile isotope uranium-233 (U-233).
- Third stage: to develop and put into operation a thorium-generated U-233 cycle using advanced heavy water reactors (AHWRs).

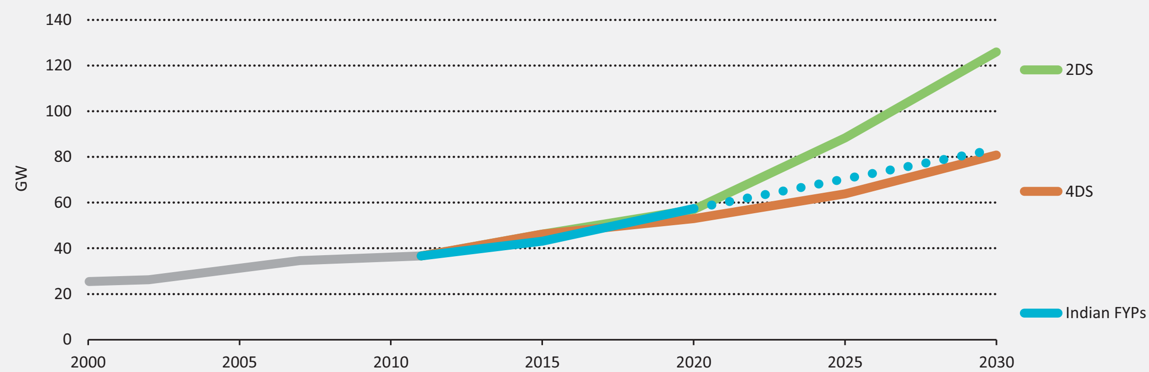
With the first stage completed, the second stage is under way. After a substantial cost overrun and much later than originally planned, the 500 MW Kalpakkam PFBR is expected to commence commercial operation in 2014. India aims to have a full prototype thorium-based AHWR in operation during the 2020s.

Hydropower

Hydropower represents less than 20% of installed capacity in India, and around 12% of generation. As gas turbines are also able to provide peaking power, the onus on hydropower is less demanding, but nonetheless, it remains important as a major source of renewable, clean power.

In 1987, India assessed its scope for hydropower development at 148 701 MW (145 320 MW above 25 MW)[13] from a total of 845 schemes – which corresponds to 84 044 MW at 60% load factor (CEA, 2008). By the end of the 11th FYP, only 38 748 MW had been developed, implying substantial future potential (Figure 9.13).

Figure 9.13 Hydropower capacity



Note: blue dotted line shows *ETP 2014* extrapolation of India's previous FYP.
Sources: PC, 2013; CEA, 2013d; IEA data and analysis.

Key point *Hydropower is crucial for securing power supply and enabling variable renewable deployment.*

Although they generally have low operational costs and long, productive lives, hydropower projects are notoriously difficult to finance because of the large up-front capital required. Nonetheless, some 12 372 MW of hydropower plants were under construction at the end of June 2013 but, for various reasons, several were unlikely to proceed to completion due to technical difficulties or because of controversy relating to their environmental impact. To reduce the risk of non-completion, individual sites must be fully characterised to understand, e.g. the potential impact on the water consumption needs of households, industry and agriculture; the land-use issues that may require forestry clearance, resettlement or interstate agreement; and the potential for sedimentation, which is particularly problematic for Himalayan water courses. If sedimentation is not well-managed, it can be a costly issue. Most rivers originating in the high Himalayas have excessive silt in the river water, particularly during the rainy season from June to October. This silt, if not removed, will damage run-of-river hydropower plants by, e.g. erosion of the turbine blades and other steel structures. Only when sites are developed in compliance with the prevailing laws and regulations, and in accordance with good environmental and social practices, can hydropower fulfil its potential.

13 Below 25 MW is classified as "small hydropower".

Hydropower plants offer excellent operational characteristics and can also provide social benefits. They can start up and shut down quickly and economically, providing the flexibility to respond to wide fluctuations in demand. This flexibility is particularly important in a highly populated country like India, where household electricity demand is a significant portion of total demand – a situation that will be exacerbated by 2030. The current peak power shortfall typically occurs between 17h00 and 23h00; to meet peak demand during this period, households often turn on small petrol or diesel generators, which are polluting and a serious health hazard in congested areas.

A large portion of India's hydropower resources is located in some of its least-developed regions. If designed appropriately, with social and environmental concerns addressed to the satisfaction of all stakeholders, the plants offer significant potential for regional development and poverty alleviation. Projects can provide employment opportunities and improve significantly the quality of life in local communities. While run-of-river hydropower plants are subject to daily and seasonal variations in water flows, which can affect their electricity output, they are not affected by the fluctuations in fuel costs that trouble coal or gas plants.

If water storage facilities are built in, hydropower plants can also help manage critical water resources in an integrated manner by serving as flood controllers, as well as sources of irrigation and much-needed drinking water. The Tehri Dam in Uttarakhand, for instance, which was commissioned in 2006, today provides one-third of the drinking water needs of Delhi, India's capital (World Bank, 2012).

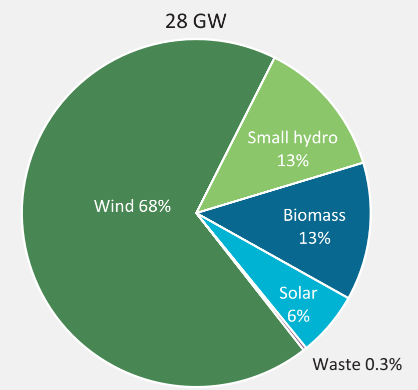
Other renewable energy technologies

India has extensive potential for other renewable energy technologies, including wind, solar, geothermal, biomass and small hydropower. By 31 March 2013, capacity had reached 28.1 GW (Figure 9.14). Wind power represents more than two-thirds of renewable installed capacity, with load factors currently at 17.65%, comparable to those of Germany. Biomass power generation is dominated by industrial co-generation, fuelled mainly from agricultural residues. Solar power, while currently accounting for only 7% of installed renewable capacity, has huge potential and features prominently in India's FYPs and the more aggressive ambitions represented in *ETP 2014* scenarios.

India aims to increase installed capacity of other renewables from about 30 GW at the end of 2013 to around 90 GW by the end of the 13th FYP (Figure 9.15). While the current FYP rate of deployment would roughly correspond to the 4DS, investment in other renewable technologies would have to increase dramatically to maintain this trajectory.

The bid to install more renewable energy technologies is likely to encounter the same institutional and structural challenges faced by all projects to develop India's power generation infrastructure. Electricity needs to be transmitted and distributed in an effective and efficient manner to meet demand; land to locate the equipment must be acquired; and the power needs to be affordable to consumers. With renewable energy sources playing an increasingly important role in India, the effective integration of renewable energy power plants into the electricity grid is critical to ensure a more sustainable energy supply. In 2012, in its report entitled "Green Energy Corridors", the POWERGRID Corporation of India put forward its views on the transmission infrastructure and other related services required to integrate large-scale renewable capacity into the grid (PGCIL, 2012). In 2013, the Ministry of New and Renewable Energy (MNRE) firmed up international co-operation agreements with Germany and United States to put the comprehensive transmission plan underway.

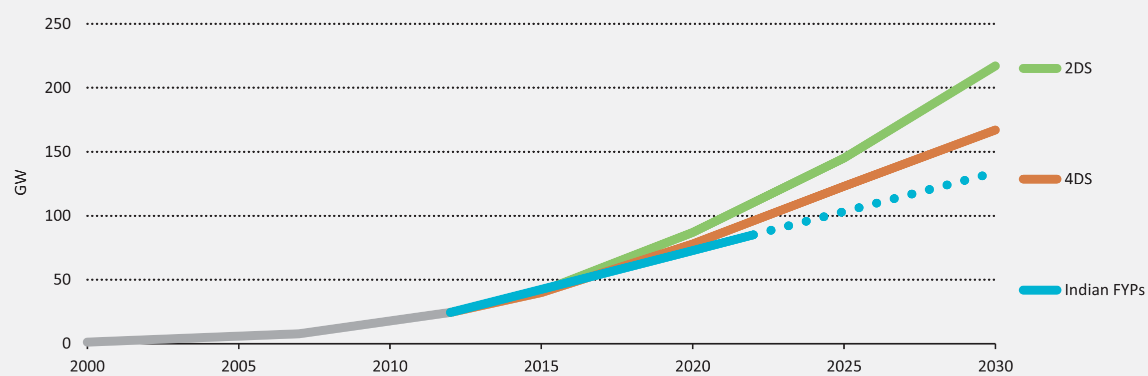
Figure 9.14 Capacity of other renewable energy technologies, 2013



Source: EY, 2013.

Key point *India's other renewable energy mix is dominated by wind, but solar power is growing at an accelerated rate.*

Figure 9.15 Other renewable capacity



Note: blue dotted line shows *ETP 2014* extrapolation of India's previous FYP.
Sources: PC, 2013; PC, 2012; IEA data and analysis.

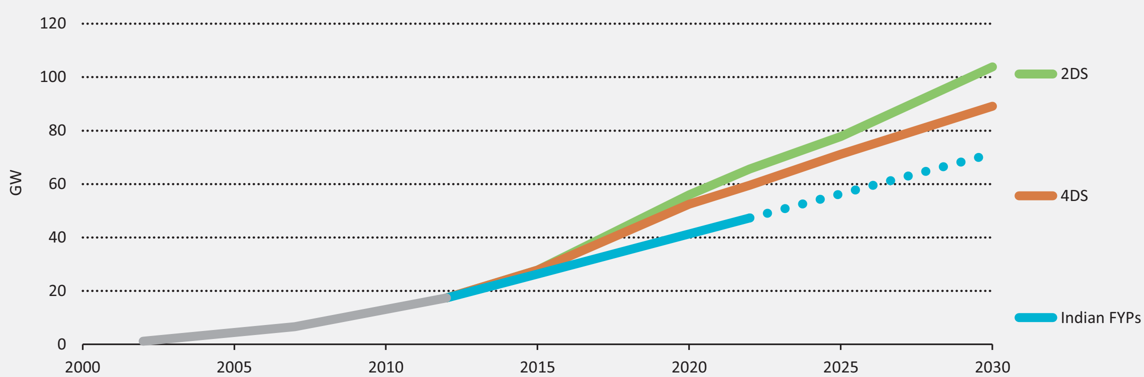
Key point *Renewables, led by wind and solar, have potential to make a fundamental contribution to India's long-term, low-carbon growth strategy.*

Wind

With 20 GW installed capacity by the end of 2013, India ranks fifth globally in terms of onshore wind power deployment. The wind power programme was initiated in FY1983/84, towards the end of the 6th FYP. Current estimates for onshore wind potential vary greatly. Previous government analysis showed a maximum of 102 GW, but recent work using geographical assessments of land availability and wind resource put the number much higher – at between 543 GW and 3 121 GW depending on the specific technology deployed and the quality of the sites developed (Phadke, Bharvikar and Khangura, 2012). Wind potential is concentrated in the west and south, with 95% of it found in five states: Karnataka, Tamil Nadu, Maharashtra, Gujarat and Andhra Pradesh. Developing the best-quality sites in Tamil Nadu alone (which already hosts 38% of all wind capacity in India at 7.2 GW) would yield an additional 58 GW, exceeding the 2DS projections for the next ten years.

At 1.8 GW per year, wind power capacity additions during the 11th FYP exceeded by 13% the targeted 9 GW. The 12th FYP calls for around 2 GW annual capacity additions, a rate the wind industry is currently meeting. Decarbonisation efforts projected in the *ETP 2014* 4DS and 2DS, however, would require increased and sustained acceleration. In the period covered by the 12th FYP, wind power capacity would have to grow at an annual rate of 4 GW to 4.3 GW to stay on pace for decarbonisation by 2050 (Figure 9.16). Industry analysts consider this rate achievable under a combination of favourable conditions (IEA, 2013d), including enhanced policy design and the implementation, and acceleration of grid development.

Figure 9.16 Wind capacity



Note: blue dotted line shows *ETP 2014* extrapolation of India's previous FYP.
Sources: PC, 2013; CEA, 2012b; IEA data and analysis.

Key point *Wind power capacity additions have exceeded FYP targets; continued overperformance would be required for deployment to remain in line with ETP 2014 projections.*

Asset financing for new wind power installations in India slowed to USD 3.1 billion in 2012, down from USD 5.9 billion in 2011. Stop-and-go policy making and policy uncertainty in FY2012/13 was one contributor to the decline. Previously, wind power installations benefitted from a generation-based incentive (GBI) and an accelerated depreciation provision, both of which expired in 2012. The GBI has since been reinstated, but only after a period of uncertainty that may have delayed some investment decisions. Indian wind farms also benefit from the Renewable Purchase Obligation, which obliges suppliers to produce electricity from renewable sources while generating additional revenue in the form of tradable certificates. Weak enforcement of the obligation by some states and an oversupply of certificates reduced non-solar certificate prices to floor levels (INR 1 500 per megawatt hour [MWh], or about USD 25/MWh) during 2012 and 2013, adversely affecting investor confidence. Some state governments are beginning to step up enforcement efforts on local power distributors, which is stimulating greater certificate demand. Coupled with recent upward revisions in state-level feed-in tariffs, these measures may augment the impact of the wind policy support framework.

A second, related issue is the high cost of financing new wind power developments. This reflects the prevailing high interest rate environment, as well as a lack of familiarity of banks with renewable energy, and increased project risk from the existing market and regulatory environment. The short-term impact is that high financing costs increase the levelised cost of electricity by an estimated 22% relative to US projects. The shortage of debt could have higher consequences in the medium term (i.e. for the 13th FYP): as projects are financed with greater equity shares, overall available equity is reduced, undermining the sustainability of growth in the sector. Financing structures in other emerging economies, such as the Brazilian Development Bank, have successfully reduced financing costs and provided long-term debt vehicles (Nelson et al., 2012). Crucially for India's low-carbon development, however, in many states, wind power is already competitive with new-build coal power plants, which reduces the need for new incentives. The challenge will be to maintain a stable policy environment that provides predictable and reliable market and regulatory frameworks to accelerate investment.

The increased growth for wind set out in the next two FYPs, and in the 2DS and 4DS, hinge on a stable policy environment, commensurate grid capacity expansion and interconnection, and progressive reduction of financing costs. The recent announcement of a National Wind Energy Mission to facilitate investment is a positive development (full details are yet to be finalised). Further development of interstate systems should be continued to sustain growth in renewables, which could put India on a similar track to the 2DS projections to 2050.

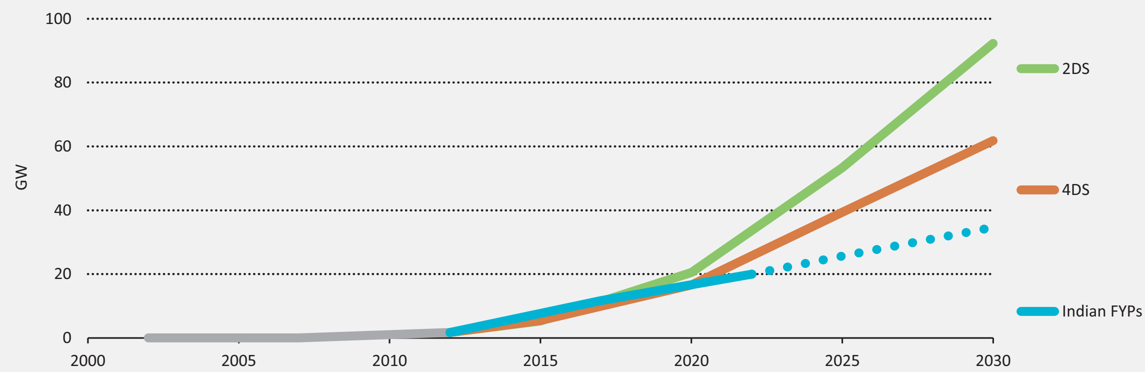
Solar

Solar programmes will be central to achieving the low-carbon growth ambition in the Indian power sector. The flagship stimulus policy, the Jawaharlal Nehru National Solar Mission (JNNSM) (implementation commenced in January 2010) aims to create the enabling policy framework to reach 20 000 MW of grid-connected solar power by 2022 (Figure 9.17). The mission delivered on its first target: by the deadline of March 2013, installed capacity reached 1 686 MW (surpassing the 1 000 MW target) with a further expansion to 2 080 MW as of September 2013. The second phase of the mission has not yet taken off, but aims to achieve almost 4 000 MW of solar power project installations under the central scheme and 6 000 MW under state schemes. Of these, 3 600 MW of installations were targeted for FY2013/14 and FY2014/15.

From the start, the JNNSM included a local content requirement (LCR), whereby first modules (for projects selected in FY2010/11), and then both cells and modules (FY2011/12) would have to be manufactured in India. The LCR requirement, however, applied only to crystalline silicon technologies while thin-film PV was exempt; this resulted in thin-film PV imports taking up a market share of 50%, in contrast with a global market penetration of around 10%. Structural changes in the global PV market then created further difficulties for Indian manufacturers, who were forced to adapt to new local markets. Both effects combined to leave the local crystalline PV manufacturing industry greatly disadvantaged (Johnson, 2013).

While estimates vary, local manufacturing capacity appears to have increased to 848 MW for cells and 1 932 MW for modules. Assuming an 80% utilisation rate, and that all manufacturing serves the local market, Indian manufacturing capacity would need to increase by a factor of three to sustain the JNNSM objectives, and a factor of four when considering 2DS projections. The LCR has now been revised to allow 50% of solar capacity to be built using imported equipment, a more balanced approach that sends a strong signal that the Indian government will support local industry and should help foster further growth.

Figure 9.17 Solar capacity



Note: blue dotted line shows *ETP 2014* extrapolation of India's previous FYP.
Sources: MNRE, 2010; IEA data and analysis.

Key point *Declining costs of solar technology and India's significant resource endowment would continue to make solar attractive after the end of the stimulus policy.*

Rooftop solar panels also contribute to total solar capacity, and are emerging as a major component of the Indian solar industry. The central government is actively encouraging rooftop solar and states are developing net metering frameworks. In this sense, distributed generation can have positive co-benefits for transmission grids. For rural electrification needs, it is often neither desirable nor feasible to build new power lines. In these cases, small-scale solar PV – but also biomass and biogas development – can economically contribute to crucial off-grid or mini-grid solutions. For solar PV self-consumption, where the consuming entity exhibits a good match between consumption and the solar PV output (see discussion on captive power, Box 9.1), integration costs can be more than offset by reducing losses and congestion.

Concentrated solar power (CSP) is a promising technology for India; a total of 470 MW were awarded under the first phase of the JNNSM. These early plants faced some setbacks, however. Due to a lack of on-the-ground measurements, satellite solar irradiance data was used to scope sites, which later led to a downgrading of the solar resource for CSP plants in many areas. Four of the five plants have not met the commissioning deadlines, but were awarded extensions. This suggests that development may proceed incrementally over the medium term. Nevertheless, as CSP scales up and if costs come down, the value of CSP with storage to meet evening peak demand could make it a very attractive power source for India in the long run. Despite the challenges, the IEA expects India to deploy around 600 MW before 2018, which would represent significant growth on the global scale (IEA, 2013d).

Beyond progress in the JNNSM, recent activity indicates that states will take an increasing role in delivering solar energy targets. Up to 2012, the state of Gujarat, aided by preferential energy tariffs for solar (with no LCR), had come to account for two-thirds of nationwide installed PV capacity. Other states have adopted obligations for solar energy supply or for net metering. The role of the states, however, needs to be strengthened and is not without caveats: state electricity board (SEB) finances are in widely differing financial health, with average losses increasing in the last FYP to around USD 32 billion. Power purchase agreements between solar developers and some SEBs will have continuing difficulty in reaching viability and obtaining finance.

Geothermal

From the several states that have geothermal resources, it has been estimated that India has the potential to produce 10 600 MW of power (Chandrasekharam, 2000). Though India has been exploiting these resources since the 1970s for direct uses (e.g. drying and space heating), at present it has no operational geothermal power generation plants.

In 2013, it was proposed to establish India's first geothermal power project in Chhattisgarh, under a partnership between the Chhattisgarh Renewable Energy Development Agency (CREDA) and NTPC. CREDA would be responsible for procuring permits for implementation and operation, while NTPC would be responsible for funding. Project activities are anticipated to begin by 2016, following completion of the detailed project report.

While up-front investment may be high, e.g. for exploration and drilling, operational costs for geothermal power generation are generally quite low.

Biomass

In 2013, biomass-fired power capacity in India stood at 3.8 GW, fired predominantly by bagasse (a fibrous residue from the production of sugar). The majority of capacity was captive power, generating power for industry. While estimates can vary greatly, with some much higher, the MNRE puts the potential capacity of surplus biomass at around 23 GW. The potential capacity of remaining biomass is variously estimated as between 19 GW and 100 GW.

Official estimates suggest that by 2032, mill residues (including bagasses) could support around 5 GW, wastes 7 GW, and agricultural and forestry residues a further 61 GW (MoP, 2014). *ETP 2014* scenario projections, on the other hand, are a little less ambitious, with the installed capacity of biomass and waste at 16 GW (4DS) and 20 GW (2DS) by 2030.

Compared with other fuels, biomass is relatively uniformly available in India. However, land availability, as always, is critical to the expansion of biomass. Current understanding is that no extra land would be sought for cultivation of biomass for power. Consequently, biomass availability becomes important. Substantial biomass power remains untapped but the short supply of land for tree-based farming or energy crops (e.g. sorghum or jatropha), coupled with India's land allocation policies, greatly limits its potential. Tree-based farming on the peripheries of farms or off-season cultivation of short-cycle energy crops could provide additional opportunities.

Small hydropower

As India has experienced difficulties in developing capital-intensive, large-scale hydropower projects, attention has turned to small hydropower capacity, i.e. with outputs of less than 25 MW. The MNRE estimates the potential for power generation from such plants at more than 15 GW. As small-scale hydropower projects are usually developed in remote and inaccessible areas, they can bring a huge improvement to the quality of life in rural communities.

Recognising its important role, India plans to raise the installed capacity of small hydropower to around 7 GW by the end of the 12th FYP. A capacity of 1 419 MW was added during the 11th FYP compared with 536 MW during the 10th FYP. By the end of April 2013, 3 632 MW had been installed and a further 1 061 MW was under construction.

The MNRE is providing central financial assistance to both the public and private sectors to set up small hydropower projects, while state governments are also providing financial support to identify potential sites to renovate and modernise old projects. In FY2012/13, the central government released USD 28 million under the Small Hydro Power Programme, with the largest amounts going to states in the north and northeast. The programme focuses mainly on reducing the environmental impact, lowering the cost of equipment, increasing reliability and setting up projects in areas that provide maximum capacity utilisation.

Recommended actions for the near term

To continue its current trajectory of economic growth, to provide electricity to all and to support increased per capita energy consumption, India must continue to expand both its power capacity and its generation. Since the Electricity Act 2003 came into effect, the Indian power sector has undergone a number of transformations towards setting up an effective system. However, it is not there yet: parts of the country still face power shortages that stifle progress; the generation mix remains heavily dependent on coal; and there are several challenges to overcome – both non-technical and technology-related – that impede the construction of new low-carbon capacity.

Rectifying these issues has been central to India's FYPs, and steady improvement has been made on multiple fronts. Yet several critical institutional and structural barriers to progress need to be addressed. The respective responsibilities of central government and the states are complex, and require extensive and lengthy co-ordination across all phases of infrastructure development and implementation. The regulatory environment is highly complex, frequently resulting in delays with implementation of both public and private sector projects. A thorough review of existing policies – with a view to simplify the planning, development and implementation process – would be a critical action to meet expected demand growth in the power sector. Reaching its FYP goals requires India to develop a strategic vision of the power sector, one that considers all options in a holistic manner. For each technology, however, the key issues, challenges and opportunities for implementation differ greatly and must be appraised individually.

India needs to expand all aspects of its power infrastructure: from exploration, through generation, to transmission and distribution. In so doing, it must ensure that its future development follows a sustainable, environmentally responsible trajectory. Very few countries have been faced with undertaking implementation of such magnitude. At present, satisfying statutory clearances is a particularly time-consuming activity. While it is absolutely essential to respect the environment, effective oversight is important to ensure that progress is not unnecessarily hampered. Appropriate procedures must be developed to resolve in a more timely manner issues related to land acquisition and building on or near protected areas, so as to avoid tying up potential investments from being made or diverted elsewhere.

Production and delivery of domestic coal and gas falls well short of the quantities needed to satisfy demand. Imports are crucial and are likely to increase in the future, but India will need to find a way to reconcile the costs of imported fuels with its power demands. Power tariffs will need to reflect actual fuel costs. The need for investment in infrastructure and operational practices must also be recognised. Greater efficiencies from these fuels must be pursued, and where possible, coal and gas generation units should be located close to industry to promote use of heat and steam to raise overall fuel efficiency.

Policies in place to phase out the construction of subcritical units by April 2017 and to encourage construction of more efficient technology will help bring the average efficiency of the coal-fired fleet more in line with international standards. Retiring older, less-efficient units could be accelerated, with a proposal to expand the programme to cover a greater share of subcritical units considered. Plans should be put in place to introduce CCS in the 2020s. Gas-fired generation offers lower emissions and can complement growing generation from wind and solar, but again requires resolution of issues relating to domestic production and the higher costs of imported gas.

Expanding nuclear capacity will be essential for India to achieve a low-carbon growth scenario. Efforts in this area should accelerate more quickly now that India has greater access to fuel and technology, yet India must overcome remaining obstacles, pick up the pace of construction and complete its domestic programme to construct units based on thorium. A clear demonstration of intent would be to meet its 13th FYP target of reaching 28 GW by April 2022.

Of a potential capacity estimated at around 150 GW, India today has less than 40 GW of hydropower capacity in operation. Given its obvious operational and low-carbon attributes, overcoming the few technical and non-technical challenges to hasten expansion should be a priority. Tapping into the vast potential of renewable energy technologies (wind, solar, geothermal, biomass and small hydropower) is equally vital to successful expansion of India's generation capacity. Again, the challenges include financing, T&D, land availability and the effective use of electricity generated from these sources.

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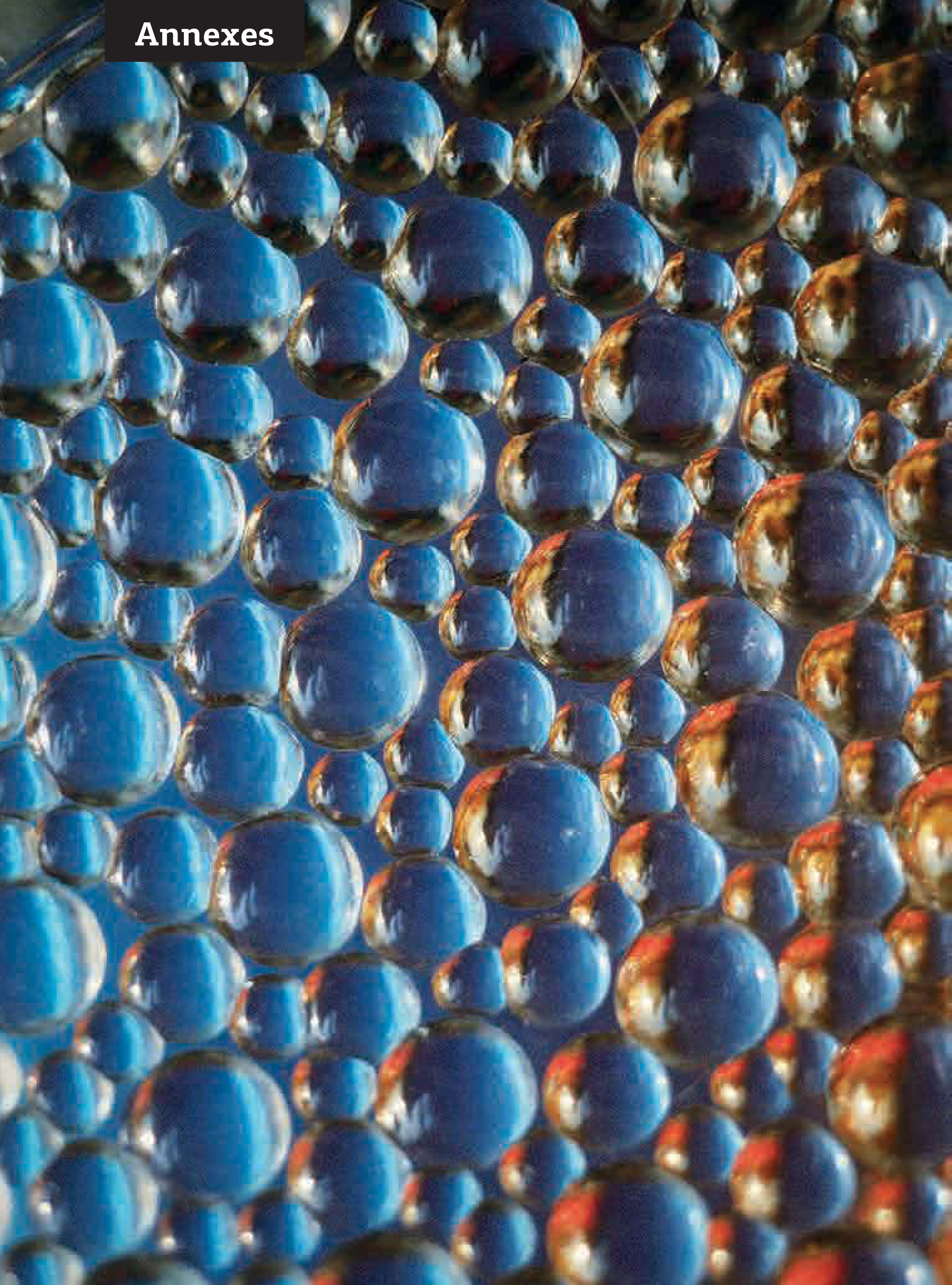
Annexes



Analytical Approach

Energy Technology Perspectives 2014 (ETP 2014) applies a combination of back casting and forecasting over three scenarios from now to 2050. Back casting lays out plausible pathways to a desired end state. It makes it easier to identify milestones that need to be reached, or trends that need to change promptly, in order for the end goal to be achieved. The advantage of forecasting, where the end state is a result of the analysis, is that it allows greater considerations of short-term constraints.

The analysis and modelling aim to identify the most economical way for society to reach the desired outcome, but for a variety of reasons the scenario results do not necessarily reflect the least-cost ideal. Many subtleties cannot be captured in a cost optimisation framework: political preferences, feasible ramp-up rates, capital constraints and public acceptance. For the end-use sectors (buildings, transport and industry), doing a pure least-cost analysis is difficult and not always suitable. Long-term projections inevitably contain significant uncertainties, and many of the assumptions underlying the analysis will likely turn out to be inaccurate. Another important caveat to the analysis is that it does not account for secondary effects resulting from climate change, such as adaptation costs. By combining differing modelling approaches that reflect the realities of the given sectors, together with extensive expert consultation, ETP analysis obtains robust results and in-depth insights.

Achieving the *ETP 2014* 2°C Scenario (2DS) does not depend on the appearance of breakthrough technologies. All technology options introduced in *ETP 2014* are already commercially available or at a stage of development that makes commercial-scale deployment possible within the scenario period. Costs for many of these technologies are expected to fall over time, making a low-carbon future economically feasible.

The ETP analysis acknowledges those policies that are already implemented or committed. In the short term, this means that deployment pathways may differ from what would be most cost-effective. In the longer term, the analysis emphasises a normative approach, and fewer constraints governed by current political objectives apply in the modelling. The objective of this methodology is to provide a model for a cost-effective transition to a sustainable energy system.

To make the results more robust, the analysis pursues a portfolio of technologies within a framework of cost minimisation. This offers a hedge against the real risks associated with the pathways: if one technology or fuel fails to fulfil its expected potential, it can more easily be compensated by another if its share in the overall energy mix is low. The tendency of the energy system to comprise a portfolio of technologies becomes more pronounced as carbon emissions are reduced, since the technology options for emissions reductions and their potentials typically depend on the local conditions in a country. At the same time, uncertainties may become larger, depending on the technologies' maturity levels and the risks of not reaching expected technological development targets.

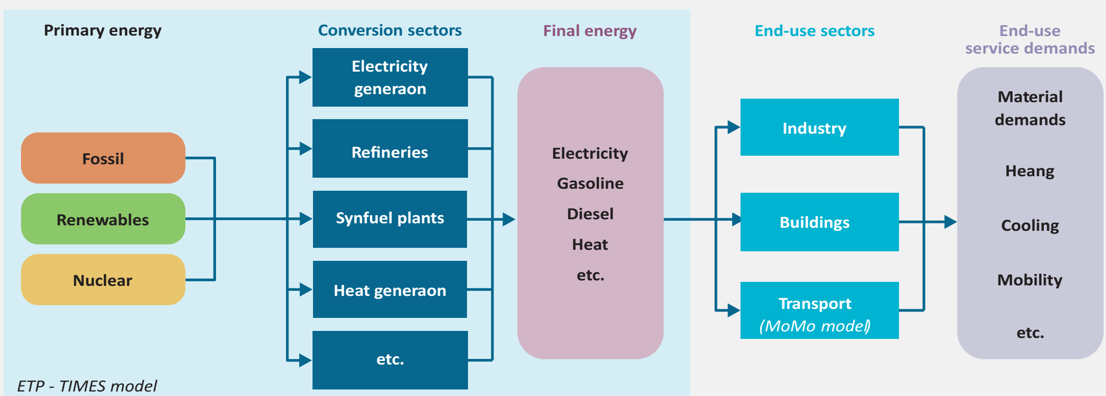
ETP model combines analysis of energy supply and demand

The ETP model, which is the primary analytical tool used in *ETP 2014*, supports integration and manipulation of data from four soft-linked models:

- energy conversion
- industry
- transport
- buildings (residential and commercial/services).

It is possible to explore outcomes that reflect variables in energy supply using the energy conversion model and in the three sectors that have the largest demand (and hence the largest emissions) using models for industry, transport and buildings. The following schematic illustrates the interplay of these elements in the processes by which primary energy is converted to the final energy that is useful to these demand-side sectors (Figure A.1).

Figure A.1 Structure of the ETP model



Notes: TIMES = The Integrated MARKAL-EFOM System; MoMo = Mobility Model.

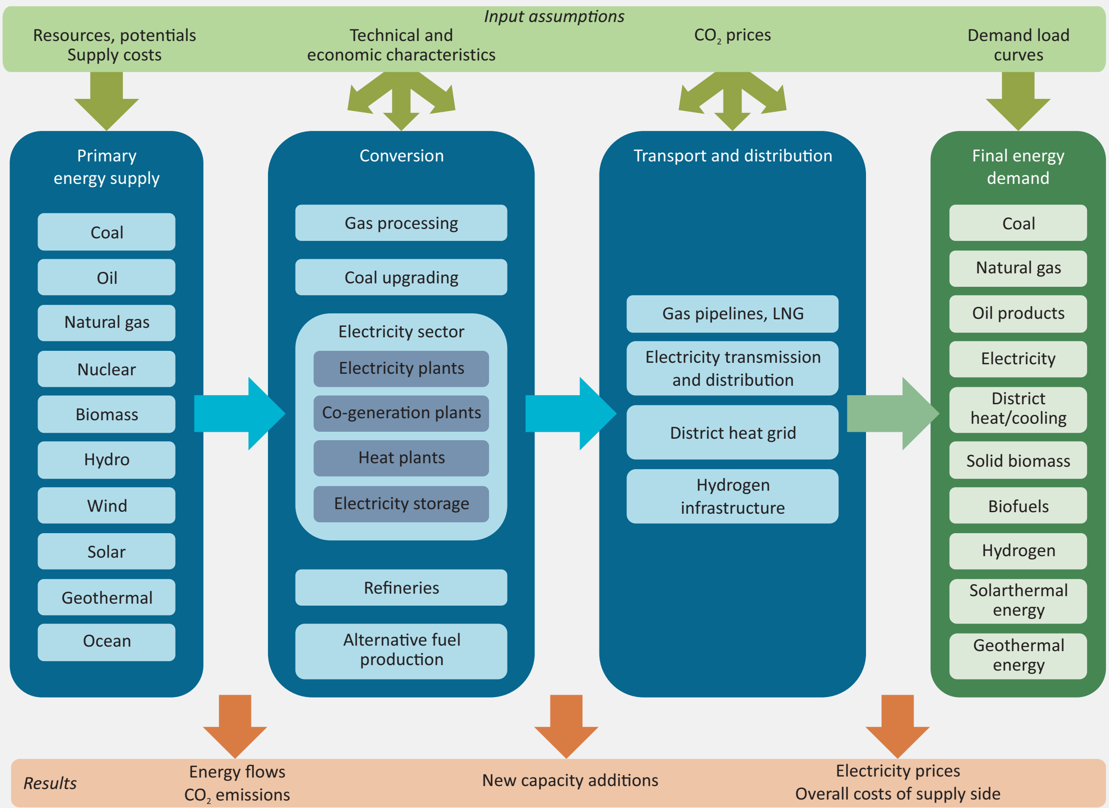
Key point *The ETP model enables a technology-rich, bottom-up analysis of the global energy system.*

ETP-TIMES model for the energy conversion sector

The global ETP-TIMES model is a bottom-up, technology-rich model that covers 28 regions and depicts a technologically detailed supply side of the energy system. It models from primary energy supply and conversion to final energy demand up to 2075. The model is based on the TIMES (The Integrated MARKAL EFOM System) model generator, which has been developed by the Energy Technology Systems Analysis Programme (ETSAP) implementing agreement of the International Energy Agency (IEA) and allows an economic representation of local, national and multi-regional energy systems on a technology-rich basis (Loulou et al., 2005).

Starting from the current situation in the conversion sectors (e.g. existing capacity stock, operating costs and conversion efficiencies), the model integrates the technical and economic characteristics of existing technologies that can be added to the energy system. The model can then determine the least-cost technology mix needed to meet the final energy demand calculated in the ETP end-use sector models for industry, transport and buildings (Figure A.2).

Figure A.2 Structure of the ETP-TIMES model for the conversion sector



Notes: CO_2 = carbon dioxide; LNG = liquefied natural gas; co-generation refers to the combined production of heat and power.

Key point *ETP-TIMES determines the least-cost strategy in terms of supply-side technologies and fuels to cover the final energy demand vector from the end-use sector models.*

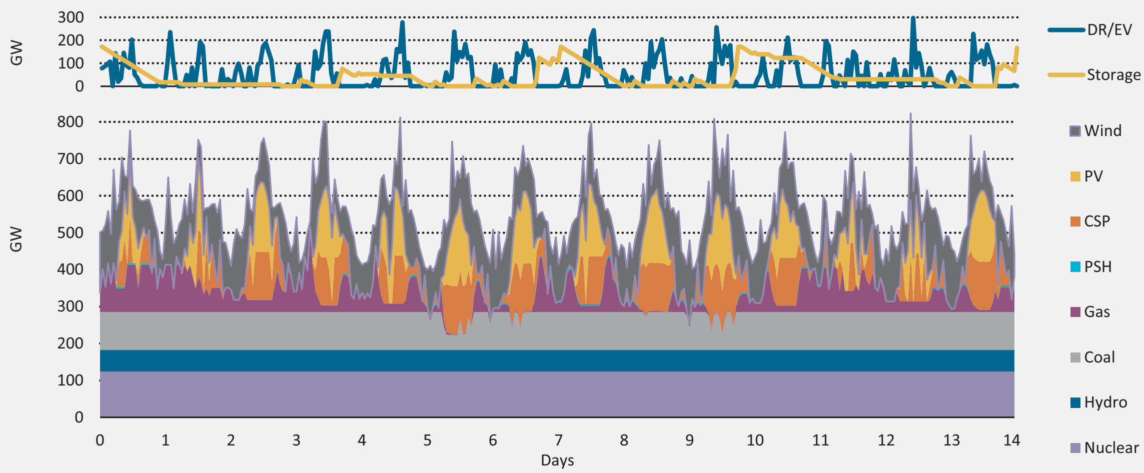
Technologies are described by their technical and economic parameters, such as conversion efficiencies or specific investment costs. Learning curves are used for new technologies to link future cost developments with cumulative capacity deployment.

The ETP-TIMES model also takes into account additional constraints in the energy system (such as fossil fuel resource constraints or emissions reduction goals) and provides detailed information on future energy flows and their related emissions impacts, required technology additions and the overall cost of the supply-side sector.

To capture the impact of variations in electricity and heat demand, as well as in the generation from some renewable technologies on investment decisions, a year is divided into four seasons, with each season being represented by a typical day, which again is divided into eight daily load segments of three hours' duration.

For a more detailed analysis of the operational aspects in the electricity sector, the long-term ETP-TIMES model has been supplemented with a **linear dispatch model**. This model uses the outputs of the ETP-TIMES model for the 2050 electricity capacity mix for a specific model region and analyses an entire year with one-hour time resolution using datasets for wind production, solar photovoltaic production, and hourly electricity demand for a year. Given the hourly demand curve and a set of technology-specific operational constraints, the model determines the optimal hourly generation profile, as illustrated in Figure A.3 for the 2DS in 2050 over a two-week period. To increase the flexibility of the electricity system, the linear dispatch model can invest in electricity storage or additional flexible generation technologies (gas turbines). Demand response by modifying the charging profile of electric vehicles (EV) is a further option depicted in the model in order to provide flexibility to the electricity system.

Figure A.3 Electricity dispatch in the United States over a two-week period in 2050 in the 2DS



Notes: PV = photovoltaics; CSP = concentrated solar power; CCS = carbon capture and storage; DR = demand response; EV = electric vehicle.

Key point *The linear dispatch model analyses the role of electricity storage, flexible generation and demand response.*

This linear dispatch model represents storage in terms of three steps: charge, store, discharge. The major operational constraints included in the model are minimum generation levels and time, ramp-up and -down, minimum downtime hours, annualised plant availability, cost considerations associated with start-up and partial-load efficiency penalties, and maximum storage reservoir capacity in terms of energy (megawatt hours [MWh]).

Model limitations include challenges due to a lack of comprehensive data with respect to storage volume (MWh) for some countries and regions. Electricity networks are not explicitly modelled, which precludes the study of the impacts of spatially dependent factors such as the aggregation of variable renewable outputs with better interconnection. Further, it is assumed that future demand curves will have the same shape as current curves. A bottom-up approach starting from individual energy service demand curves by end-use technology would be useful in refining this assumption, but is a very data-intensive undertaking that faces the challenge of a lack of comprehensive data.

Industry sector model

Industry is modelled using a stock accounting simulation model that covers five energy-intensive sectors: iron and steel, cement, chemicals and petrochemicals, pulp and paper, and aluminium. The model is structured in five sub-models that characterise the energy performance of process technologies from each of the energy-intensive sub-sectors, and it includes 39 countries and regions. Typically, raw materials production is not included within the boundaries of the model, with the exception of the iron and steel sector in which energy use for coke ovens and blast furnaces is covered. Due to the complexity of the chemicals and petrochemicals sector, the model focuses on five products that represent about 47% of the energy use of the sector: ethylene, propylene, BTX[1], ammonia and methanol.

Demand of materials is estimated based on country- or regional-level data for gross domestic product (GDP), disposable income, short-term industry capacity, current materials consumption, regional demand saturation levels derived from historical demand intensity curves, and resource endowments (Figure A.4). Total production is simulated by factors such as process, age structure (vintage) of plants and stock turnover rates. Overall production is similar across scenarios, but means of production differ considerably. For example, the same level of crude steel production is expected in both the 6°C Scenario (6DS) and the 2DS, but the 2DS reflects a much higher use of scrap (which is less energy-intensive than production from conventional raw materials).

Each industry sub-model is designed to account for sector-specific production routes for which relevant process technologies are modelled. Industrial energy use and technology portfolio for each country or region are characterised in the base year based on relevant energy use and material production statistics for each industrial energy-intensive sub-sector. Changes in the technology and fuel mix as well as efficiency improvements are driven by exogenous assumptions on penetration and energy performance of best available technologies (BATs), and constraints on the availability of raw materials. Thus, the results are sensitive to assumptions on how quickly physical capital is turned over and on how effective incentives are for the use of BATs for new capacity.

The industry model allows analysis of different technology and fuel switching pathways in the sector to meet projected material demands within a given related CO_2 emissions envelope in the modelling horizon.

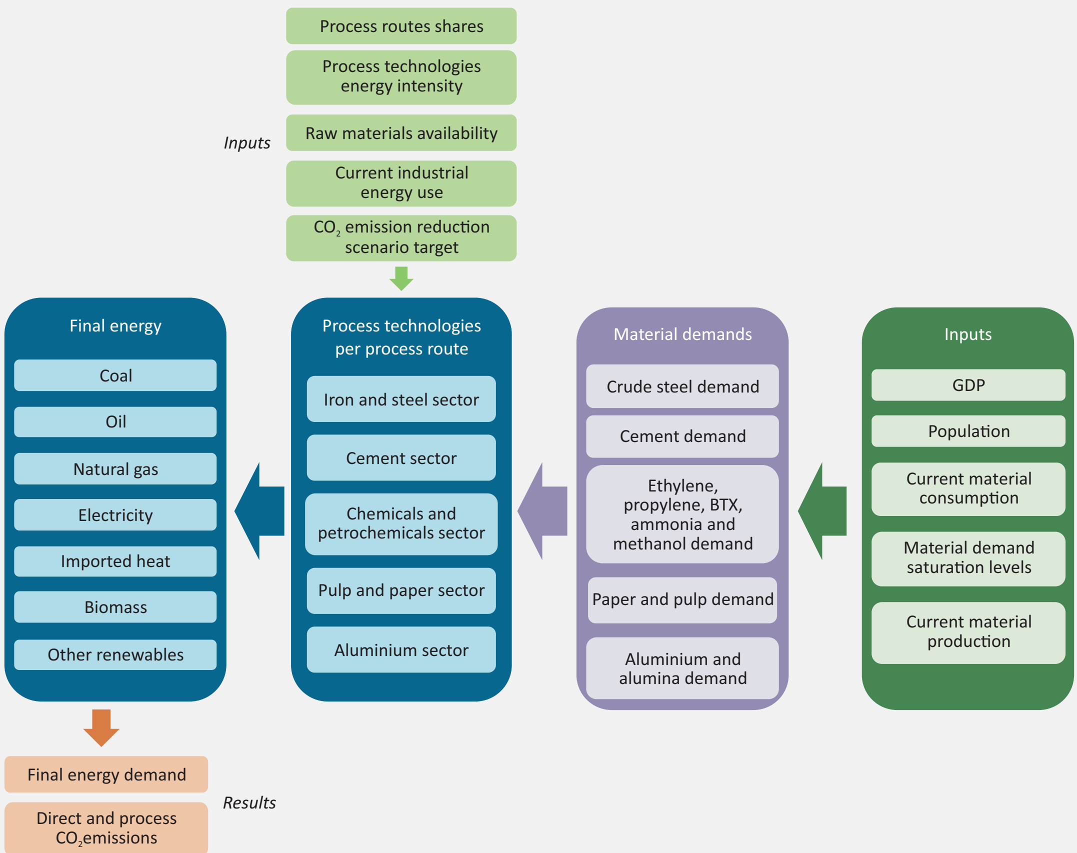
Mobility Model (MoMo) for the transport sector

MoMo is a technical-economic spreadsheet model that allows detailed projections of transport activity, vehicle activity, energy demand, as wells as CO_2 and pollutant emissions in different policy scenarios to 2050. The mobility model currently covers:

- 29 countries and regions
- passenger and freight services
- all transport modes except pipelines (road, rail, shipping and air)
- several road vehicle types (2- and 3-wheelers, passenger cars, light trucks, medium and heavy freight trucks, buses)
- a wide number of powertrain technologies (internal combustion engines, and hybrid electric, plug-in hybrid electric, electric and fuel cell powertrains)
- related fuel supply options (petroleum gasoline and diesel, biofuel and synthetic fuel alternatives to liquid fuels, gaseous fuels including natural gas and hydrogen, and electricity).

1 BTX includes benzene, toluene and xylene.

Figure A.4 Structure of the industry model



Key point *Based on socio-economic assumptions and statistical information, the industry model projects material demands, which then determine the final energy consumption of the sector depending on the energy performance of process technologies within each of the available production routes.*

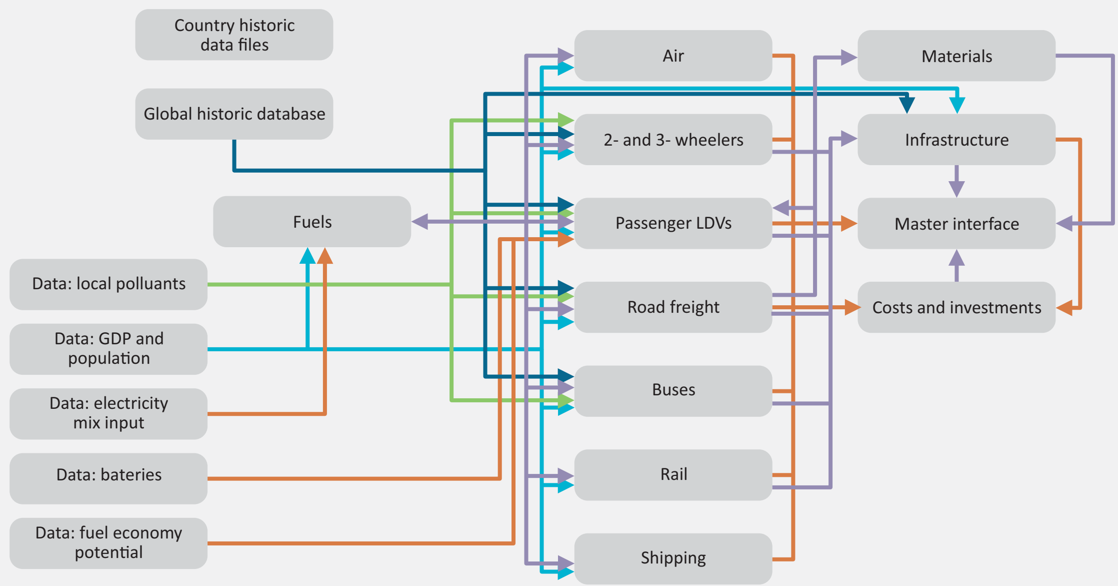
MoMo also takes into account of the cost of vehicles, fuels and transport infrastructure, as well as material required for the construction of vehicles, related energy needs, and CO_2 and pollutant emissions.

To ease the manipulation and implementation of the modelling process, MoMo is split into several modules that can be updated independently. Figure A.5 provides a representation of how the modules are organised and how they communicate.

Integrating assumptions on technology availability and cost at different points in the future, the model reveals, for example, how costs could drop if technologies were deployed at a commercial scale and allows fairly detailed bottom-up "what-if" modelling, especially for passenger light-duty vehicles and trucks (Fulton, Cazzola and Cuenot, 2009).

To ensure consistency among the vehicles, energy use is estimated based on stocks (via scrappage functions), utilisation (travel per vehicle), consumption (energy use per vehicle, i.e.

Figure A.5 MoMo structure



Note: LDV = light-duty vehicle.

Key point *MoMo covers all transport modes and includes modules on local air pollutants and on the costs of fuels, vehicles and infrastructure as well as analysis on the material needs for new vehicles.*

fuel economy) and emissions (via fuel emission factors for CO_2 and pollutants on a vehicle and well-to-wheel basis) for all modes.

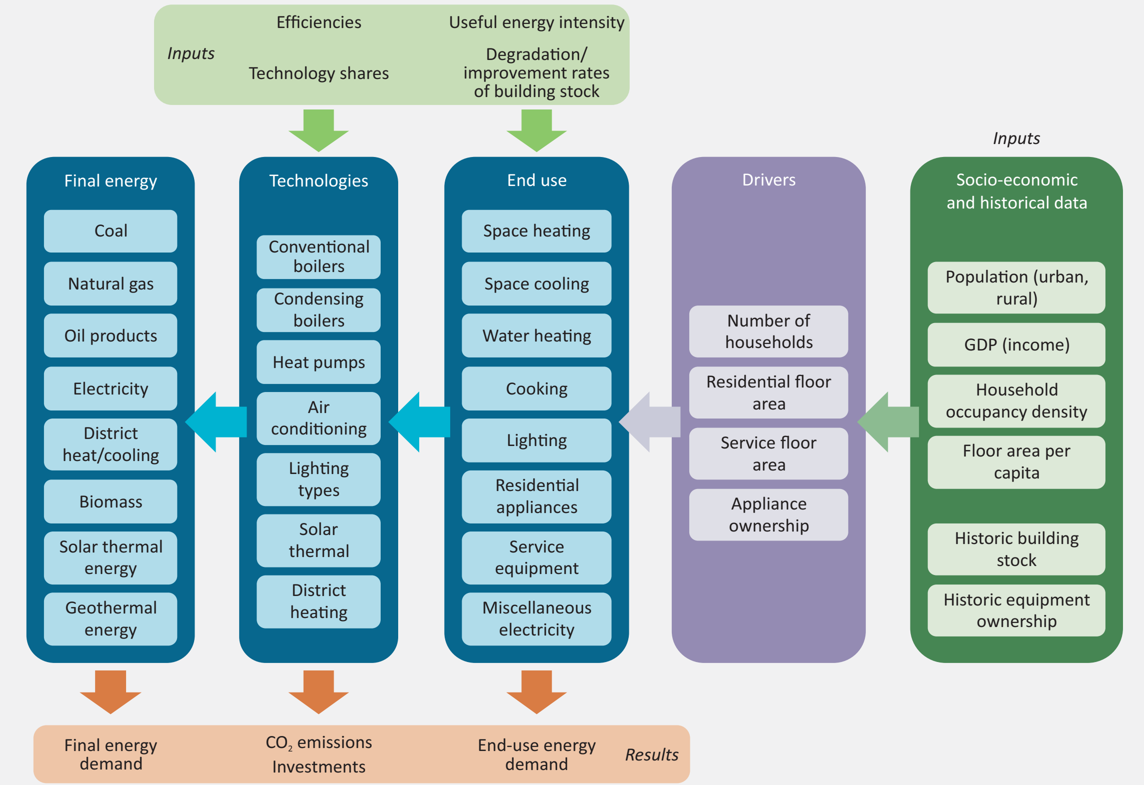
For each scenario, this model supports a comparison of marginal costs of technologies and aggregates to total cost across all modes and regions.

The primary drivers of technological change in transport are assumptions on the cost evolution of the technology, and the policy framework incentivising adoption of the technology. Oil prices and the set of policies assumed can significantly alter technology penetration patterns.

Buildings sector model

The buildings sector is modelled using a global simulation stock accounting model, split into residential and services sub-sectors and applied across 31 countries or regions (Figure A.6). The residential sub-sector includes those activities related to individual dwellings. It covers all energy-using activities in apartments and houses, including space and water heating, cooling, lighting, and the use of appliances and electronics. The services sub-sector includes activities related to trade, finance, real estate, public administration, health, food and lodging, education, and commercial services. This is also referred to as the commercial and public service sector. It covers energy used for space heating, cooling and ventilation, water heating, lighting, and a number of other miscellaneous energy-using equipment, such as commercial appliances and cooking devices or office equipment.

Figure A.6 Structure of the buildings model



Key point *Starting from socio-economic assumptions, the buildings sector model determines first demand drivers and the related useful energy demands, which allows one to derive the final energy consumption depending on the characteristics of the technology options.*

For both sub-sectors, the model uses socio-economic drivers, such as income and population, to project floor space per capita and appliance ownership. As far as possible country statistics are used for floor area and appliance ownership rates in the base year. But especially for non-member countries of the Organisation for Economic Co-operation and Development (OECD), these data are more difficult to obtain, so in several cases these parameters have been estimated for the base year. The buildings floor area is differentiated by vintage, approximations based on other indicators (e.g. historical population) are used to estimate the vintage distributions if no statistical data are available for a country or region.

Based on the projections for floor area and appliance ownership, the model determines the useful energy demands, such as space or water heating, applying useful energy intensities, which take into account the vintage of the buildings as well as the ageing or refurbishment of the buildings through corresponding degradation and improvement rates for the useful energy intensities.

For each of these derived useful energy demands (e.g. space heating), a suite of different technology and fuel options are represented in the model, reflecting their current techno-economic characteristics (e.g. efficiencies) as well as their future improvement potential. Depending on the current technology stock as well as assumptions on the penetration and market shares of new technologies, the buildings sector model allows exploration of strategies for different useful energy demands and the quantification of the resulting developments for final energy consumption and related CO_2 emissions.

Framework assumptions

Economic activity (Table A.1) and population (Table A.2) are the two fundamental drivers of demand for energy services in ETP scenarios. These are kept constant across all scenarios as a means of providing a starting point for the analysis, and facilitating the interpretation of the results. Under the ETP assumptions, global GDP will more than triple between 2011 and 2050; uncertainty around GDP growth across the scenarios is significant, however. The climate change rate in the 6DS, and even in the 4°C Scenario (4DS), is likely to have profound negative impacts on the potential for economic growth. These impacts are not captured by ETP analysis. Moreover, the structure of the economy is likely to have non-marginal differences across scenarios, suggesting that GDP growth is unlikely to be identical even without considering secondary climate impacts. The redistribution of financial, human and physical capital will affect the growth potential both globally and on a regional scale.

Energy prices, including those of fossil fuels, are a central variable in the ETP analysis (Table A.3). The continuous increase in global energy demand is translated into higher prices of energy and fuels. Unless current demand trends are broken, rising prices are a likely consequence. However, the technologies and policies to reduce CO_2 emissions in the *ETP 2014* scenarios will have a considerable impact on energy demand, particularly for fossil fuels. Lower demand for oil in the 4DS and the 2DS means there is less need to produce oil from costly

Table A.1 Real GDP growth projections in *ETP 2014*

CAAGR (%)	2011-20	2020-30	2030-50	2011-50
World	4.0	3.4	2.7	**3.2**
OECD	2.2	2.1	1.7	**1.9**
Non-OECD	5.8	4.5	3.2	**4.2**
ASEAN	5.5	4.2	3.5	**4.1**
Brazil	3.6	3.8	2.7	**3.2**
China	8.1	4.9	2.9	**4.6**
European Union	1.3	1.8	1.5	**1.5**
India	6.4	6.5	5.1	**5.7**
Mexico	3.4	3.1	2.3	**2.8**
Russia	3.6	3.2	1.7	**2.5**
South Africa	3.0	2.6	2.2	**2.5**
United States	2.8	2.2	1.9	**2.2**

Notes: CAAGR = compounded average annual growth rate; ASEAN = Association of Southeast Asian Nations; growth rates based on GDP in 2012 USD using purchasing power parity terms. Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.
Source: IMF, 2013; IEA analysis.

Table A.2 Population projections used in *ETP 2014*

Country/Region	2011	2020	2030	2040	2050
World	6 986	7 701	8 406	9 016	9 524
OECD	1 254	1 317	1 366	1 407	1 430
Non-OECD	5 732	6 385	7 035	7 609	8 095
ASEAN	603	665	721	762	785
Brazil	197	211	223	229	231
China	1 376	1 440	1 461	1 444	1 393
European Union	507	516	518	517	512
India	1 221	1 353	1 476	1 566	1 620
Mexico	119	132	144	152	156
Russia	143	140	134	127	121
South Africa	52	55	58	61	63
United States	319	342	367	387	405

Note: numbers in millions.
Source: UNDESA, 2013.

Table A.3 Fossil fuel prices by scenario

		2012	2020	2025	2030	2035	2040	2045	2050
IEA crude oil import price (2012 USD/bbl)									
	2DS	109	110	107	104	100	97	94	92
	4DS	109	113	116	121	128	133	136	139
	6DS	109	120	127	136	145	152	158	163
OECD steam coal import price (2012 USD/t)									
	2DS	99	101	95	86	75	67	61	56
	4DS	99	106	109	110	110	110	110	110
	6DS	99	112	116	118	120	122	124	126
Gas (2012 USD/MBtu)									
US import price	2DS	2.7	4.8	5.4	5.7	5.9	5.7	5.6	5.4
	4DS	2.7	5.1	5.6	6.0	6.8	7.1	7.2	7.4
	6DS	2.7	5.2	5.8	6.2	6.9	7.2	7.5	7.7
Europe import price	2DS	11.7	11.5	11.0	10.2	9.5	9.2	9.0	8.8
	4DS	11.7	11.9	12.0	12.3	12.7	13.2	13.5	13.8
	6DS	11.7	12.4	12.9	1.4	14.0	14.7	15.3	15.7
Japan import price	2DS	16.9	13.4	12.8	12.2	11.7	11.3	11.0	10.8
	4DS	16.9	14.2	14.2	14.4	14.9	15.5	15.9	16.1
	6DS	16.9	14.7	15.2	15.9	16.7	17.5	18.2	18.7

Notes: bbl = barrel; t = tonne; MBtu = million British thermal units.

fields higher up the supply curve, particularly in non-members of the Organization of the Petroleum Exporting Countries (OPEC). As a result, oil prices in the 4DS and 2DS are lower than in the 6DS. In the 2DS, oil prices even fall after 2030.

Prices for natural gas will also be affected, directly through downward pressure on demand, and indirectly through the link to oil prices that often exists in long-term gas supply contracts.[2] Finally, coal prices are also substantially lower owing to the large shift away from coal in the 2DS.

The global marginal abatement costs for CO_2 to reach the reduction targets of the 4DS and 2DS are shown in Table A.4. These values represent the costs associated with the abatement measures to mitigate the last tonne of CO_2 emissions to reach the annual emissions target in a specific year. The global marginal abatement costs can be regarded as a benchmark CO_2 price allowing the comparison of the cost-effectiveness of mitigating options across technologies, sectors and regions. For the 2DS, with costs of up to USD 170 per tonne of CO_2 (t/CO_2) in 2050, it is more cost-effective to implement all mitigation measures up to that cost level rather than emitting the CO_2. In the 4DS, the less ambitious CO_2 reduction target results in significantly lower marginal abatement costs of up to USD 60/tCO_2. The costs shown for the 6DS reflect only the carbon price in the EU Emissions Trading Scheme (ETS) for electricity generation, industry and international aviation, which has been assumed to be continued after 2020.

Table A.4 Global marginal abatement costs by scenario

(USD/tCO_2)	2020	2030	2040	2050
2DS	30-50	80-100	120-140	140-170
4DS	10-30	20-40	30-50	40-60
6DS	30	40	50	60

Note: 6DS only assumes carbon pricing in the EU for the sectors currently included in the ETS (electricity generation, industry and aviation).

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2 This link is assumed to become weaker over time in the ETP analysis, as the price indexation business model is gradually phased out in international markets.

Abbreviations and Acronyms

2DS	*ETP2014* 2°C Scenario
4DS	*ETP2012* 4°C Scenario
6DS	*ETP2012* 6°C Scenario
AC	alternating current
ADELE	adiabatic compressed-air energy storage (CAES) for electricity supply
AHWR	advanced heavy water reactors
ANM	active network management
APEC	Asia Pacific Economic Cooperation
ASEAN	Association of Southeast Asian Nations
BAT	best available technologies
BEV	battery electric vehicle
BF	blast furnace
BOF	basic oxygen furnace
BOP	balance of plant
BOS	balance of system
BPT	best practice technologies
BRT	bus rapid transit
CAAGR	compounded average annual growth rate
CAES	compressed air energy storage
CAGR	compound annual growth rate
CBM	coalbed methane
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CDQ	coke-dry quenching
CdTe	cadmium-telluride
CEM	Clean Energy Ministerial
CERC	Central Electricity Regulatory Commission
CES	clean energy systems
CfD	Contracts for Difference
CFL	compact fluorescent lamp
CIF	cost insurance freight
CIGS	copper-indium-gallium-(di)selenide

CIS	copper-indium-(di)selenide
COG	coke oven gas
CPV	concentrating photovoltaics
C-Si	crystalline silicon
CSLF	Carbon Sequestration Leadership Forum
CSP	concentrated solar power
CV	conventional vehicle
DC	direct current
DES	deep eutectic solvents
DH	district heating
DHC	district heating and cooling
DISCOMS	state distribution companies
DNI	direct normal irradiance
DoD	depth of discharge
DRI	direct reduced iron
DSG	direct steam generation
DSM	demand-side management
EAF	electric arc furnace
EEG	Erneuerbare-Energien-Gesetz, German Renewable Energy Act
EEX	European Energy Exchange
EIT	economies in transition
EMR	electricity market reform
EMS	energy management systems
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ESCII	Energy Sector Carbon Intensity Index
ESS	energy storage system
ETN	European Turbine Network
ETP	Energy Technology Perspectives
EV	electric vehicle
EVI	Electric Vehicles Initiative
FACTS	flexible AC transmission systems
FCEV	fuel-cell electric vehicles
FiT	feed-in tariffs
FYP	Five-Year Plans

GBI	generation-based incentive
GCCSI	Global CCS Institute
GDP	gross domestic product
GEF	Global Environment Facility
GHG	greenhouse gas
GHI	global horizontal irradiance
GNI	global normal irradiance
GPS	global positioning systems
HDV	heavy-duty vehicle
HEV	hybrid electric vehicle
HFT	heavy freight truck
HH	Henry Hub
HP	high pressure
HRSG	heat recovery steam generator
HTS	high-temperature superconductors
HV	high-voltage
HVAC	heating, ventilation and air-conditioning
HVAC	high-voltage alternating current
HVC	high-value chemicals
HVDC	high-voltage direct current
ICE	internal combustion engine
ICT	information and communication technologies
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IIL	inefficient incandescent lamps
IPEEC	International Partnership for Energy Efficiency Co-operation
IRENA	International Renewable Energy Agency
ISCC	integrated solar combined cycle
ISGAN	International Smart Grid Action Network
ISO	International Organisation for Standardisation
LCOE	levelised cost of electricity
LCR	local content requirement
LCV	light commercial vehicle
LED	light-emitting diode
LEED	Leadership in Energy and Environmental Design
LETMIX	Low-Carbon Electric Transport Maximisation Index

LFR	linear fresnel reflectors
LHV	lower heating value
LIS	Low Impact Steel
LNG	liquefied natural gas
low-e	low-emissivity
LP	low-pressure
LRMC	long-run marginal costs
mc-Si	multi-crystalline silicon
MEPS	minimum energy performance standards
MFT	medium freight truck
MNRE	Ministry of New and Renewable Energy, India
MoMo	mobility model
NaS	sodium sulphur
NEA	Nuclear Energy Agency
NGCC	natural gas combined-cycle
NOAK	Nth of a Kind
NO_X	nitrogen oxide
NPT	Non-Proliferation Treaty
NPV	net present value
NSG	Nuclear Suppliers Group
O&M	operating and maintenance
OCGT	open-cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
OHF	open-hearth furnaces
PCM	phase-change materials
PFBR	pressurised fast breeder reactors
PHEV	plug-in hybrid-electric vehicle
PHS	pumped hydro storage
PHWR	pressurised heavy water reactors
PLDV	passenger light-duty vehicle
PMU	phasor measurement units
PPA	power purchase agreements
PPP	purchasing power parity
PTC	production tax credit
PV	photovoltaic
PWR	pressurised water reactor

R&D	research and development
RD&D	research, development and demonstration
RDD&D	research, development, demonstration and deployment
RPS	renewable portfolio standards
SCPC	supercritical pulverized coal
Sc-Si	single-crystalline silicon
SEAD	Super-Efficient Appliance and Equipment Deployment
SEB	state electricity board
SERC	State Electricity Regulatory Commissions
SIRFN	Smart Grid International Research Facility Network
SMES	superconducting magnet energy storage
SMRC	short-run marginal cost
SOFC	solid oxide fuel cell
SSL	solid-state lighting
STE	solar thermal electricity
SUGAR	SUGAR Volt Project, Hybrid aircraft concept proposed by a team led by Boeing Research & Technology, a division of Boeing
T&D	transmission and distribution
TCEP	Tracking Clean Energy Progress
TCM	thermo-chemical heat
TIMES	The Integrated MARKAL-EFOM System
TOD	time-of-delivery
TOU	time-of-use
TTF	title transfer facility
UCG	underground coal gasification
ULCOS	ultra-low carbon dioxide steelmaking
UMPP	ultra-mega power plants
VRB	vanadium redox flow battery
VRE	variable renewable energy
WACC	weighted average capital costs
WAMPAC	wide-area monitoring, protection and control
WEO	World Energy Outlook
WEPP	World Electric Power Plants Data Base
WHR	waste heat recovery
WTW	well-to-wheel
ZEB	zero-energy buildings

Definitions, Regional and Country Groupings and Units

This annex provides information on Definitions, Regional and Country Groupings and Units used throughout this publication.

Definitions

	2-, 3- and 4-wheelers	This vehicle category includes motorised vehicles having two, three or four wheels. 4-wheelers are not homologated to drive on motorways, such as all terrain vehicles.
A	Advanced biofuels	Advanced biofuels comprise different emerging and novel conversion technologies that are currently in the research and development, pilot or demonstration phase. This definition differs from the one used for "Advanced Biofuels" in the US legislation, which is based on a minimum 50% lifecycle greenhouse gas (GHG) reduction and which, therefore, includes sugar cane ethanol.
	Aquifer	A porous, water saturated body of rock or unconsolidated sediments, the permeability of which allows water to be produced (or fluids injected). If the water contains a high concentration of salts, it is a saline aquifer.
B	Bayer process	Process for the production of alumina from bauxite ore.
	Biodiesel	Biodiesel is a diesel-equivalent, processed fuel made from the transesterification (a chemical process which removes the glycerine from the oil) of both vegetable oils and animal fats.
	Biofuels	Biofuels are fuels derived from biomass or waste feedstocks and include ethanol and biodiesel. They can be classified as conventional and advanced biofuels according to the technologies used to produce them and their respective maturity.
	Biogas	Biogas is a mixture of methane and CO_2 produced by bacterial degradation of organic matter and used as a fuel.
	Biomass	Biological material that can be used as fuel or for industrial production. Includes solid biomass such as wood, plant and animal products, gases and liquids derived from biomass, industrial waste and municipal waste.
	Biomass and waste	Biomass and waste includes solid biomass, gas and liquids derived from biomass, industrial waste and the renewable part of municipal waste. Includes both traditional and modern biomass.

Biomass-to-liquids (BTL)	BTL refers to a process that features biomass gasification into syngas (a mixture of hydrogen and carbon monoxide) followed by synthesis of liquid products (such as diesel, naphtha or gasoline) from the syngas using Fischer-Tropsch catalytic synthesis or a methanol-to-gasoline reaction path. The process is similar to those used in coal-to-liquids or gas-to-liquids.
BIO-SNG	Bio-synthetic natural gas (BIO-SNG) is biomethane derived from biomass via thermal processes.
Black liquor	A by-product from chemical pulping processes, which consists of lignin residue combined with water and the chemicals used for the extraction of the lignin.
Bond market/bonds	Bond is a formal contract to repay borrowed money with interest at fixed intervals.
Buses and minibuses	Passenger motorised vehicles with more than nine seats.

C

Capacity credit	Capacity credit refers to the proportion of capacity that can be reliably expected to generate electricity during times of peak demand in the grid to which it is connected.
Capacity (electricity)	Measured in megawatts (MW) capacity (electricity), is the instantaneous amount of power produced, transmitted, distributed or used at a given instant.
Carbon Capture and Storage	An integrated process in which CO_2 is separated from a mixture of gases (e.g. the flue gases from a power station or a stream of CO_2-rich natural gas), compressed to a liquid or liquid-like state, then transported to a suitable storage site and injected into a deep geologic formation.
Clean coal technologies (CCTs)	CCTs are designed to enhance the efficiency and the environmental acceptability of coal extraction, preparation and use.
Clinker	Clinker is a core component of cement made by heating ground limestone and clay at a temperature of about 1 400°C to 1 500°C.
Coal	Coal includes both primary coal (including hard coal and brown coal) and derived fuels (including patent fuel, brown-coal briquettes, coke-oven coke, gas coke, gas-works gas, coke-oven gas, blast-furnace gas and oxygen steel furnace gas). Peat is also included.
Coefficient of performance	Coefficient of performance is the ratio of heat output to work supplied, generally applied to heat pumps as a measure of their efficiency.
Co-generation	Co-generation refers to the combined production of heat and power.
Coal-to-liquids (CTL)	CTL refers to the transformation of coal into liquid hydrocarbons. It can be achieved through either coal gasification into syngas (a mixture of hydrogen and carbon monoxide), combined with Fischer-Tropsch or methanol-to-gasoline synthesis to produce liquid fuels, or through the less developed direct-coal liquefaction technologies in which coal is directly reacted with hydrogen.

Conventional biofuels	Conventional biofuels include well-established technologies that are producing biofuels on a commercial scale today. These biofuels are commonly referred to as first-generation and include sugar cane ethanol, starch-based ethanol, biodiesel, Fatty Acid Methyl Esther (FAME) and Straight Vegetable Oil (SVO). Typical feedstocks used in these mature processes include sugar cane and sugar beet, starch bearing grains, like corn and wheat, and oil crops, like canola and palm, and in some cases animal fats.
Corex	A smelting-reduction process developed by Siemens VAI for manufacture of hot metal from iron ore and coal in which the iron ore is pre-reduced in a reduction shaft using offgas from the melter-gasifier before being introduced into the melter-gasifier.

D

Demand response	Demand response is a mechanism by which the demand side of the electricity system shifts electricity demand over given time periods in response to price changes or other incentives, but does not necessarily reduce overall electrical energy consumption. This can be used to reduce peak demand and provide electricity system flexibility.
Direct equity investment	Direct equity investments refer to the acquisition of equity (or shares) in a company.
Distribution	Electricity distribution systems transport electricity from the transmission system to end users.

E

Electrical energy	Measured in megawatt hours (MWh) or kilowatt hours (kWh), indicates the net amount of electricity generated, transmitted, distributed or used over a given time period.
Electricity generation	Electricity generation is defined as the total amount of electricity generated by power only or combined heat and power plants including generation required for own use. This is also referred to as gross generation.
Energy intensity	A measure where energy is divided by a physical or economic denominator, e.g. energy use per unit value added or energy use per tonne of cement.
Enhanced oil recovery (EOR)	EOR is a process that modifies the properties of oil in a reservoir to increase recovery of oil, examples of which include: surfactant injection, steam injection, hydrocarbon injection, and CO_2 flooding. These processes are typically used following primary recovery (oil produced by the natural pressure in the reservoir) and secondary recovery (using water injection), but can be used at other times during the life of an oilfield.
Ethanol	Although ethanol can be produced from a variety of fuels, in this book, ethanol refers to bio-ethanol only. Ethanol is produced from fermenting any biomass high in carbohydrates. Today, ethanol is made from starches and sugars, but second generation technologies will allow it to be made from cellulose and hemicellulose, the fibrous material that makes up the bulk of most plant matter.

F

FINEX	A smelting-reduction process developed by Pohang Iron and Steel Company (POSCO) in collaboration with Siemens VAI, where iron ore fines are pre-reduced in a series of fluidised bed reactors before being introduced to the melter-gasifier.

	Fischer-Tropsch (FT) synthesis	Catalytic production process for the production of synthetic fuels. Natural gas, coal and biomass feedstocks can be used.
	Flexibility	Power system flexibility expresses the extent to which a power system can modify electricity production or consumption in response to variability, expected or otherwise. In other words, it expresses the capability of a power system to maintain reliable supply in the face of rapid and large imbalances, whatever the cause. It is measured in terms of the MW available for ramping up and down, over time (±MW/time).
	Fuel cell	A device that can be used to convert hydrogen or natural gas into electricity. Various types exist that can be operated at temperatures ranging from 80°C to 1 000°C. Their efficiency ranges from 40% to 60%. For the time being, their application is limited to niche markets and demonstration projects due to their high cost and the immature status of the technology, but their use is growing fast.
G	Gas	Gas includes natural gas, both associated and non-associated with petroleum deposits, but excludes natural gas liquids.
	Gas-to-liquids (GTL)	GTL refers to a process featuring reaction of methane with oxygen or steam to produce syngas (a mixture of hydrogen and carbon monoxide) followed by synthesis of liquid products (such as diesel and naphtha) from the syngas using Fischer-Tropsch catalytic synthesis. The process is similar to those used in coal-to-liquids or biomass-to-liquids.
H	Heat	Heat is obtained from the combustion of fuels, nuclear reactors, geothermal reservoirs, capture of sunlight, exothermic chemical processes and heat pumps which can extract it from ambient air and liquids. It may be used for domestic hot water, space heating or cooling, or industrial process heat. In IEA statistics, heat refers to heat produced for sale only. Most heat included in this category comes from the combustion of fuels in co-generation installations, although some small amounts are produced from geothermal sources, electrically powered heat pumps and boilers. Heat produced for own use, for example in buildings and industry processes, is not included in IEA statistics, although frequently discussed in this book.
	HIsmelt	A direct smelting process, licensed by HIsmelt Corporation, where iron ore is reduced in a molten metal bath.
	HIsarna	A smelting reduction process being developed by the European Ultra-Low Carbon Dioxide Steelmaking (ULCOS) programme, which combines the HIsmelt process with an advanced Corus cyclone converter furnace. All process steps are directly hot-coupled, avoiding energy losses from intermediate treatment of materials and process gases.
	Hydropower	Hydropower refers the energy content of the electricity produced in hydropower plants, assuming 100% efficiency. It excludes output from pumped storage and marine (tide and wave) plants.
I	Integrated gasification combined-cycle (IGCC)	IGCC is a technology in which a solid or liquid fuel (coal, heavy oil or biomass) is gasified, followed by use for electricity generation in a combined-cycle power plant. It is considered a promising electricity generation technology, due to its potential to achieve high efficiencies and low emissions.

	Isarna	The former name for the HIsarna process, which is a smelting reduction process being developed by the European Ultra-Low Carbon Dioxide Steelmaking (ULCOS) programme, which combines the HIsmelt process with an advanced Corus cyclone converter furnace. All process steps are directly hot-coupled, avoiding energy losses from intermediate treatment of materials and process gases.
L	Liquidity	Liquidity is the ability to sell assets without significant movement in the price and with minimum loss of value.
	Low-carbon energy technologies	Lower CO_2 emissions, higher-efficiency energy technologies from all sectors (buildings, industry, power and transport) that are being pursued in an effort to mitigate climate change.
M	Markets	Markets are structures which allow buyers and sellers to exchange any type of goods, services and information.
	Middle distillates	Middle distillates include jet fuel, diesel and heating oil.
	Modern biomass	Modern biomass includes all biomass with the exception of traditional biomass.
N	Non-energy use	Non-energy use refers to fuels used for chemical feedstocks and non-energy products. Examples of non-energy products include lubricants, paraffin waxes, coal tars and oils as timber preservatives.
	Nuclear	Nuclear refers to the primary heat equivalent of the electricity produced by a nuclear plant with an average thermal efficiency of 33%.
O	Oil	Oil includes crude oil, condensates, natural gas liquids, refinery feedstocks and additives, other hydrocarbons (including emulsified oils, synthetic crude oil, mineral oils extracted from bituminous minerals such as oil shale, bituminous sand and oils from coal liquefaction) and petroleum products (refinery gas, ethane, LPG, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, bitumen, paraffin waxes and petroleum coke).
	Options	Options are instruments that convey the rights, but not the obligation to engage in a future transaction on an underlying security or in a future contract.
P	Passenger Light Duty Vehicles	This vehicle category includes all four-wheels vehicle aimed at the mobility of persons on all types of roads, up to nine persons per vehicle and 3.5t of gross vehicle weight.
	Private equity	Private equity is money invested in companies that are not publicly traded on a stock exchange or invested as part of buyouts of publicly traded companies in order to make them private companies.
	Project finance	Project finance is the financing of long-term infrastructure, industrial projects and public services, based upon a non-recourse or limited recourse financial structure where project debt and equity used to finance the project are paid back from the cash flow generated by the project.
	Purchasing power parity (PPP)	PPP is the rate of currency conversion that equalises the purchasing power of different currencies. It makes allowance for the differences in price levels and spending patterns between different countries.

R	Renewables	Renewable includes biomass and waste, geothermal, hydropower, solar photovoltaic, concentrating solar power, wind and marine (tide and wave) energy for electricity and heat generation.
	Road Mass Transport	See buses and minibuses.
S	Smart Grids	A smart grid is an electricity network that uses digital and other advanced technologies to monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end-users. Smart grids co-ordinate the needs and capabilities of all generators, grid operators, end-users and electricity market stakeholders to operate all parts of the system as efficiently as possible, minimising costs and environmental impacts while maximising system reliability, resilience and stability.
	Steam coal	All other hard coal that is not classified as coking coal. Also included are recovered slurries, middlings and other low-grade coal products not further classified by type. Coal of this quality is also commonly known as thermal coal.
	Synthetic fuels	Synthetic fuel or synfuel is any liquid fuel obtained from coal, natural gas or biomass. The best known process is the Fischer-Tropsch synthesis. An intermediate step in the production of synthetic fuel is often syngas, a mixture of carbon monoxide and hydrogen produced from coal which is sometimes directly used as an industrial fuel.
T	Total final consumption (TFC)	TFC is the sum of consumption by the different end-use sectors, it excludes conversion losses from the transformation sector (power plants, oil refineries, etc.), energy industry own energy use and other losses. TFC is broken down into energy demand in the following sectors: industry (including manufacturing and mining), transport, buildings (including residential and services) and other (including agriculture and non-energy use). The final consumption of the transport sector includes international marine and aviation bunkers.
	Total primary energy demand (TPED)	TPED represents domestic demand only and is broken down into power generation, other energy sector and total final consumption.
	Total primary energy supply (TPES)	TPES is the total amount of energy supplied to the energy system, at the domestic level it is equivalent to total primary energy demand. Total primary energy supply is made up of primary energy production + imports – exports ± stock changes. Stock changes reflect the difference between opening stock levels on the first day of the year and closing levels on the last day of the year of stocks on national territory. A stock build is a negative number, and a stock draw is a positive number.
	Traditional biomass	Traditional biomass refers to the use of fuel wood, charcoal, animal dung and agricultural residues in stoves with very low efficiencies.
	Transmission	Electricity transmission systems transfer electricity from generation (from all types, such as variable and large-scale centralised generation, and large-scale hydro with storage) to distribution systems (including small and large consumers) or to other electricity systems.
V	Venture capital	Venture capital is a form of private capital typically provided for early stage, high potential growth companies.

Sector definitions

Buildings	Buildings includes energy used in residential, commercial and institutional buildings. Building energy use includes space heating and cooling, water heating, lighting, appliances, cooking and miscellaneous equipment (such as office equipments and other small plug loads in the residential and service sectors).
Energy industry own use	Energy industry own use covers energy used in coal mines, in oil and gas extraction and in electricity and heat production. Transfers and statistical differences as well as pipeline transport are also included in this category.
Fuel transformation	Fuel transformation covers the use of energy by transformation industries and the energy losses in converting primary energy into a form that can be used in the final consuming sectors. It includes losses by gas works, petroleum refineries, coal and gas transformation and liquefaction as well as biofuel and hydrogen production. Energy use in blast furnaces, coke ovens and petrochemical plants is not included, but accounted for in Industry.
Industry	Industry includes fuel used within the manufacturing and construction industries. Fuel used as petrochemical feedstock and in coke ovens and blast furnaces is also included. Key industry sectors include iron and steel, chemical and petrochemical, non-metallic minerals, and pulp and paper. Use by industries for the transformation of energy into another form or for the production of fuels is excluded and reported separately under fuel transformation. Consumption of fuels for the transport of goods is reported as part of the transport sector.
Other end-uses	Other end-uses refer to final energy used in agriculture, forestry and fishing as well as other non-specified consumption.
Power generation	Power generation refers to fuel use in electricity plants, heat plants and co-generation plants. Both main activity producer plants and so-called autoproducer plants that produce electricity or heat for their own use are included.
Transport	Transport includes all the energy used once transformed (tank-to-wheel); international marine and aviation bunkers is shared among countries based on the statistics available. Energy use and emissions related to pipeline transport are accounted for under Energy industry own use.

Regional and country groupings

Africa	Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan,[1] United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries and territories.[2]
ASEAN (Association of Southeast Asian Nations)	Brunei Darussalam, Cambodia, Indonesia, Lao People's Democratic Republic, Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam.
Asia	Bangladesh, Brunei Darussalam, Cambodia, China, India, Indonesia, Japan, Korea, Democratic People's Republic of Korea, Malaysia, Mongolia, Myanmar, Nepal, Pakistan, Philippines, Singapore, Sri Lanka, Chinese Taipei, Thailand, Viet Nam and other Asian countries and territories.[3]
China	Refers to the People's Republic of China, including Hong Kong.
Economies in Transition (EITs)	Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[4] Former Yugoslav Republic of Macedonia, Georgia, Gibraltar, Kazakhstan, Republic of Kosovo, Kyrgyz Republic, Latvia, Lithuania, Moldova, Montenegro, Romania, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.
European Union	Austria, Belgium, Bulgaria, Croatia, Cyprus,[5] Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain, Sweden and United Kingdom.
Latin America	Argentina, Bolivia, Brazil, Colombia, Costa Rica, Cuba, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other Latin American countries and territories.[6]
Middle East	Bahrain, the Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, United Arab Emirates and Yemen. It includes the neutral zone between Saudi Arabia and Iraq.
OECD	Includes OECD Europe, OECD Americas and OECD Asia Oceania regional groupings.
OECD Americas	Canada, Chile, Mexico and United States.

1 Because only aggregated data were available until 2011, the data for Sudan also include South Sudan.
2 Individual data is not available for: Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland, Uganda and Western Sahara. Data is estimated in aggregate for these regions.
3 Individual data is not available for: Afghanistan, Bhutan, Cook Islands, East Timor, Fiji, French Polynesia, Kiribati, Lao PDR, Macau, Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Tonga and Vanuatu. Data is estimated in aggregate for these regions.
4 Footnote by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".
Footnote by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.
5 See note 4.
6 Individual data is not available for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St.Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands. Data is estimated in aggregate for these regions.

OECD Asia Oceania	Includes OECD Asia (comprising Japan, Korea and Israel)[7] and OECD Oceania (comprising Australia and New Zealand).
OECD Europe	Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.
Asia excluding China, India, Japan, Korea	Non-OECD Asia regional grouping excluding China and India.
Deviating regional definition only used for Figure 2.51 and 2.52	**Asia Pacific:** Afghanistan, American Samoa, Armenia, Australia, Azerbaijan, Bangladesh, Bhutan, British Indian Ocean Territory, Brunei Darussalam, Cambodia, People's Republic of China, Christmas Island (Indian Ocean), Cocos (Keeling) Islands, Comoros, Cook Islands, Fiji, French Polynesia, Guam, Heard and McDonald Islands, Hong Kong (China), India, Indonesia, Japan, Kazakhstan, Kiribati, Korea, the Democratic People's Republic of Korea, Kyrgyzstan, Lao People's Democratic Republic, Malaysia, Maldives, Marshall Islands, Mayotte, Federated States of Micronesia, Midway Islands, Mongolia, Myanmar, Nauru, Nepal, New Caledonia, New Zealand, Niue, Norfolk Island, Northern Mariana Islands, Pakistan, Palau, Papua New Guinea, Paracel Islands, Philippines, Pitcairn, Samoa, Seychelles, Singapore, Solomon Islands, Spratly Island, Sri Lanka, Chinese Taipei, Tajikistan, Thailand, Tokelau, Tonga, Turkmenistan, Tuvalu, Uzbekistan, Vanuatu, Viet Nam, Wake Island, Wallis and Futuna Islands. **Europe:** Albania, Andorra, Austria, Belarus, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[8] Czech Republic, Denmark, Estonia, Faroe Islands, Finland, Former Yugoslav Republic of Macedonia, France, Georgia, Germany, Gibraltar, Greece, Guernsey, Hungary, Iceland, Ireland, Isle of Man, Italy, Jersey, Republic of Kosovo, Latvia, Liechtenstein, Lithuania, Luxembourg, Malta, Moldova, Monaco, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Russian Federation, San Marino, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom. **Latin America:** Anguilla, Antigua and Barbuda, Argentina, Aruba, Bahamas, Barbados, Belize, Bermuda Islands, Bolivia, Bouvet Island, Brazil, British Virgin Islands, Cape Verde, Cayman Islands, Chile, Colombia, Costa Rica, Cuba, Dominica, Dominican Republic, Ecuador, El Salvador, Falkland Islands (Malvinas), French Guiana, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Mexico, Montserrat, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Puerto Rico, Saint Helena, St. Kitts-Nevis, Saint Lucia, Saint Pierre and Miquelon, St. Vincent and the Grenadines, South Georgia and the South Sandwich Islands, Suriname, Trinidad and Tobago, Turks and Caicos Islands, Uruguay, Venezuela, Virgin Islands of the United States, West Indies. **Middle East/Africa:** Algeria, Angola, Bahrain, Botswana, Burkina Faso, Burundi, Cameroon, Central African Public, Chad, Congo, Democratic Republic of the Congo, Cote d'Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, the Islamic Republic of Iran, Iraq, Israel, Jordan, Kenya, Kuwait, Lebanon, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Morocco, Mozambique, Namibia, Niger, Nigeria, Oman, Palestinian Authority, Qatar, Réunion, Rwanda, Sao Tome and Principe, Saudi Arabia, Senegal, Sierra Leone, Somalia, South Africa, Sudan, Syrian Arab Republic, United Republic of Tanzania, Togo, Tunisia, Turkey, Uganda, United Arab Emirates, Western Sahara, Yemen, Zambia, Zimbabwe. **North America:** Canada, Greenland, United States

7 The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

8 See note 4.

Units of measure

Unit prefix

E	exa (10^{18}, quintillion)
P	peta (10^{15}, quadrillion)
T	tera (10^{12}, trillion)
G	giga (10^{9}, billion)
M	mega (10^{6}, million)
k	kilo (10^{3}, thousand)
c	centi (10^{-2}, hundredth)
m	milli (10^{-3}, thousandth)
μ	micro (10^{-6}, millionth)

Area

Ha	hectare
m^2	square metre

Emissions

CO_2-eq	carbon-dioxide equivalent
g CO_2/km	gramme of carbon dioxide per kilometre
g CO_2/kWh	gramme of carbon dioxide per kilowatt-hour
g CO_2-eq	gramme of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases)
g/Nm^3	gramme per normal cubic metre
ppm	parts per million (by volume)
t CO_2-eq	tonne of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases)

Energy

boe	barrel of oil equivalent
Btu	British thermal units
Cal	calorie
EJ	exajoule
GJ	gigajoule
GW	gigawatt
J	joule
J/Nm^3	joule per normal cubic metre
kW	kilowatt
kWh	kilowatt-hour
kWh/m^2	kilowatt-hour per square meter
MW	megawatt
PJ	petajoule
TWh	terawatt-hour
tce	tonne of coal equivalent (equals 0.7 toe)
toe	tonne of oil equivalent
Wh	watt-hour

Mass

g	gramme
kg	kilogramme
t	tonne

Monetary

USD million	1 US dollar x 10^6
USD billion	1 US dollar x 10^9
USD trillion	1 US dollar x 10^{12}

Pressure

bar	bar
Pa	pascal

Temperature

^oC	degree Celsius

Volume

m^3	cubic metre

Sector-specific units

bcm	billion cubic metres
EB	exabyte

Gas

Btu	British thermal unit
tcm	trillion cubic metres
bbl	barrel

Oil

mb/d	million barrels per day
Btu	British thermal unit

Power

W	watt (1 joule per second)
W_e	watt electrical
W_{th}	watt thermal
km	kilometre

Transport

km/hr	kilometre per hour
lge	litre gasoline equivalent
mpg	mile per gallon
pkm	passenger kilometre
tkm	tonne kilometre
vkm	vehicle kilometre

List of Figures

Part 2 Harnessing Electricity's Potential 116

List of Tables

List of Boxes

Explore the data behind
Energy Technology Perspectives 2014

www.iea.org/etp2014

The IEA is expanding the availability of data used to create the *Energy Technology Perspectives* publication. Please visit the restricted area of the ETP website, www.iea.org/etp2014. There you will find many of the figures, graphs and tables in this book available for download, along with much more material. The website is evolving and will be continuously updated. Your username is “etp2014” and password “harnessingelectricity54”.

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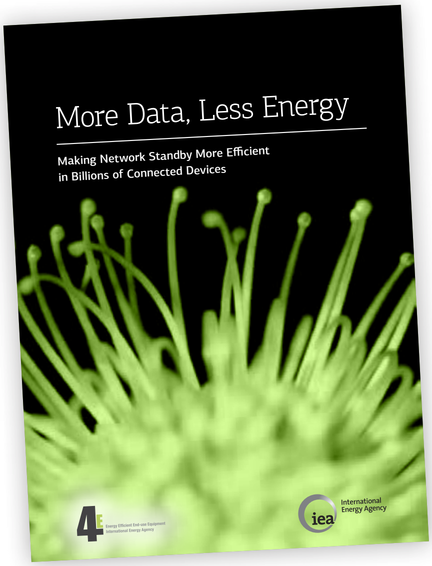

More Data, Less Energy (free for download in mid 2014). The growing energy demand of billions of networked devices such as smart phones, tablets and set-top boxes is a great cause of concern. In 2013, such devices consumed 616 terawatt hours (TWh) of electricity. The International Energy Agency uses this publication to set the stage for tackling the challenge of network standby. In exploring policy and technology solutions, the book charts a path forward and identifies which stakeholders should take the lead in particular areas. www.iea.org/etp/networkstandby

Recently released

Resources to Reserves (released in May 2013). There is no shortage of oil, gas and coal in the ground, but quenching the world's thirst for them in a sustainable manner will call for major investment in modern technologies. The publication reviews recent and anticipated future technological developments in the production of oil, gas and coal and their impact on future supplies of hydrocarbons. www.iea.org/etp/resourcestoreserves

Technology Transition for Buildings: Strategies and Opportunities to 2050 (released in June 2013) addresses building energy trends and technologies in both the residential and services sectors and necessary technology pathways to achieve objectives identified in *Energy Technology Perspectives 2012*. www.iea.org/etp/buildings

The Technology Roadmaps are free publications that identify priority actions for governments, industry, financial partners and civil society that could advance technology developments described in the *ETP* 2DS. As of May 2014, 20 global roadmaps have been published, covering a wide range of energy demand and supply technologies including solar photovoltaic energy, electric vehicles, carbon capture and storage, hydropower, energy storage and energy efficient buildings: heating and cooling equipment. More will follow in 2014. www.iea.org/roadmaps

For more information, please visit www.iea.org/etp

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Energy Technology Perspectives 2014

Harnessing Electricity's Potential

Starting from the premise that electricity will be an increasingly important vector in energy systems of the future, *Energy Technology Perspectives 2014* (*ETP 2014*) takes a deep dive into actions needed to support deployment of sustainable options for generation, distribution and consumption. In addition to modelling the global outlook to 2050 under different scenarios for more than 500 technology options, *ETP 2014* explores the possibility of "pushing the limits" in six key areas:

- Solar Power: Possibly the Dominant Source by 2050
- Natural Gas in Low-Carbon Electricity Systems
- Electrifying Transport: How Can E-mobility Replace Oil?
- Electricity Storage: Costs, Value and Competitiveness
- Attracting Finance for Low-Carbon Generation
- Power Generation in India

Since it was first published in 2006, *ETP* has evolved into a suite of publications that sets out pathways to a sustainable energy future in which optimal policy support and technology choices are driven by economics, energy security and environmental factors.

- Topic-specific books and papers explore particularly timely subjects or cross-cutting challenges.
- ***Tracking Clean Energy Progress*** provides a yearly snapshot of advances in diverse areas, while also showing the interplay among technologies.
- Supported by the *ETP* analysis, IEA ***Technology Roadmaps*** assess the potential for transformation across various technology areas, and outline actions and milestones for deployment.

Collectively, this series lays out the wide range of necessary and achievable steps that can be taken in the near and medium terms to set the stage for long-term energy policy objectives, clearly identifying the roles of energy sector players, policy makers and industry. Next editions will examine the role of technology innovation to meet climate goals (2015) and urban energy systems (2016).

Who will benefit from using *ETP 2014?* Past experience shows that *ETP* publications attract wide and varied audiences, including experts in the energy field (e.g. technology analysts and academics), policy makers and heads of governments, as well as business leaders and investors. This reflects the value of the series' detailed and transparent quantitative modelling analysis and well–rounded commentary, which ultimately support high-level policy messages.

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