Energy Technology Perspectives 2012

Pathways to a Clean Energy System

International Energy Agency

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Energy Technology Perspectives (*ETP*) is the International Energy Agency's most ambitious publication on energy technology. It demonstrates how technologies – from electric vehicles to smart grids – can make a decisive difference in limiting climate change and enhancing energy security.

ETP 2012 presents detailed scenarios and strategies to 2050. It is an indispensible guide for decision makers on energy trends and what needs to be done to build a clean, secure and competitive energy future.

ETP 2012 shows:

- current **progress on clean energy** deployment, and what can be done to accelerate it;
- how **energy security and low carbon energy** are linked;
- **how energy systems** will become more complex in the future, why systems integration is beneficial and how it can be achieved;
- how demand for **heating and cooling will evolve dramatically** and which solutions will satisfy it;
- why **flexible electricity systems are increasingly important**, and how a system with smarter grids, energy storage and flexible generation can work;
- why **hydrogen could play a big role in the energy system of the future**;
- why **fossil fuels will not disappear but will see their roles change**, and what it means for the energy system as a whole;
- what is needed to **realise the potential of carbon capture and storage** (CCS);
- whether available technologies can allow the world to have **zero energy related emissions by 2075** – which seems a necessary condition for the world to meet the 2°C target.

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Explore the data behind ETP

For the first time ever, the IEA is making available the data used to create the *Energy Technology Perspectives* publication. Please visit the restricted area of the ETP website, www.iea.org/etp. 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 “etp2012” and password “cleanenergypathways21”.

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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Foreword

We must seize the opportunity for a clean energy future.

Let me be straight: our ongoing failure to realise the full potential of clean energy technology is alarming. Midway through 2012, energy demand and prices are rising steadily, energy security concerns are at the forefront of the political agenda, and energy-related carbon dioxide (CO_2) emissions have reached historic highs. Under current policies, both energy demand and emissions are likely to double by 2050.

To turn the tide, common energy goals supported by predictable and consistent policies are needed across the world. But governments cannot do this alone; industry and citizens must be on board. The public needs to understand the challenges ahead, and give the necessary support and mandate for policy action and infrastructure development. Only decisive, effective and efficient policies can create the investment climate that is ultimately needed to put the world on a sustainable path.

The good news is that technology, together with changed behaviour, offers the prospect of reaching the international goal of limiting the long-term increase of the global mean temperature to 2°C. By reducing both energy demand and related greenhouse-gas (GHG) emissions, strategic application of clean energy technologies would deliver benefits of enhanced energy security and sustainable economic development, while also reducing human impact on the environment.

Knowing what we do about the link between GHG emissions and climate change, it is disturbing to see that investments in fossil-fuel technologies continue to outpace investments in best available clean energy technologies. Or, that governments and private enterprises continue to build energy capacity that will have detrimental effects on people and the planet for decades to come. Continued heavy reliance on a narrow set of technologies and fossil fuels is a significant threat to energy security, stable economic growth and global welfare, as well as to the environment.

Too little is currently being spent on every element of the clean energy transformation pathway. As a result, clean energy technology infrastructure is being rolled out too slowly. Yet, with each year that passes, we get a clearer sense of the high costs associated with energy systems driven by the combustion of fossil fuels. I am not talking only about future costs, but those we are paying today: economic, environmental and political.

Energy Technology Perspectives 2012 (ETP 2012) is the guidebook for a very specific group: policy makers and energy sector players. In examining the interplay among technology, policy and pricing, it clearly maps out a viable and affordable pathway to a low-carbon future. *ETP 2012* demonstrates that it is both possible and economically feasible to meet future energy demand under a completely transformed system.

Policies can drive technological innovation by stimulating investment in research, development, demonstration and deployment. Policies can create market frameworks that give these new technologies a fair chance to compete against mature options. In short, policy can unleash the potential of technology to ensure a sustainable energy future for our planet.

Maria van der Hoeven, Executive Director

Executive Summary

A sustainable energy system is still within reach and can bring broad benefits

Technologies can and must play an integral role in transforming the energy system. The 2012 edition of *Energy Technology Perspectives* (*ETP 2012*) shows clearly that a technological transformation of the energy system is still possible, despite current trends. The integrated use of key existing technologies would make it possible to reduce dependency on imported fossil fuels or on limited domestic resources, decarbonise electricity, enhance energy efficiency and reduce emissions in the industry, transport and buildings sectors. This would dampen surging energy demand, reduce imports, strengthen domestic economies, and over time dramatically reduce greenhouse-gas (GHG) emissions. The *ETP 2012* 2°C Scenario (2DS) explores the technology options needed to realise a sustainable future based on greater energy efficiency and a more balanced energy system, featuring renewable energy sources and lower emissions. Its emissions trajectory is consistent with the IEA *World Energy Outlook*'s 450 scenario through 2035. The 2DS identifies the technology options and policy pathways that ensure an 80% chance of limiting long-term global temperature increase to 2°C - provided that non-energy related CO_2 emissions, as well as other greenhouse gases, are also reduced.

Investing in clean energy makes economic sense – every additional dollar invested can generate three dollars in future fuel savings by 2050. Investments in clean energy need to double by 2020 (Chapter 4). Achieving the 2DS would require USD 36 trillion (35%) more in investments from today to 2050 than under a scenario in which controlling carbon emissions is not a priority. That is the equivalent of an extra USD 130 per person every year. However, investing is not the same as spending: by 2025, the fuel savings realised would outweigh the investments; by 2050, the fuel savings amount to more than USD 100 trillion. Even if these potential future savings are discounted at 10%, there would be a USD 5 trillion net saving between now and 2050. If cautious assumptions of how lower demand for fossil fuels can impact prices are applied, the projected fuel savings jump to USD 150 trillion.

Energy security and climate change mitigation are allies. The 2DS demonstrates how energy efficiency and accelerated deployment of low-carbon technologies can help cut government expenditure, reduce energy import dependency and lower emissions (Chapter 1). Renewable energy resources and significant potentials for energy efficiency exist virtually everywhere, in contrast to other energy sources, which are concentrated in a limited number of countries. Reduced energy intensity, as well as geographical and technological diversification of energy sources, would result in far-reaching energy security and economic benefits. In the 2DS, as a result of energy savings and the use of alternative energy sources, countries would save a total of 450 exajoules (EJ) in fossil fuel purchases by 2020. This equates to the last six years of total fossil fuel imports among OECD countries. By 2050, the cumulative fossil fuel savings in the 2DS are almost 9 000 EJ – the equivalent of more than 15 years of current world energy primary demand.

Despite technology's potential, progress in clean energy is too slow

Nine out of ten technologies that hold potential for energy and CO_2 emissions savings are failing to meet the deployment objectives needed to achieve the necessary transition to a low-carbon future. Some of the technologies with the largest potential are showing the least progress. The *ETP* analysis of current progress in clean energy (Chapter 2) produces a bleak picture. Only a portfolio of more mature renewable energy technologies – including hydro, biomass, onshore wind and solar photovoltaic (PV) – are making sufficient progress. Other key technologies for energy and CO_2 emission savings are lagging behind. Particularly worrisome is the slow uptake of energy efficiency technologies, the lack of progress in carbon capture and storage (CCS) and, to a lesser extent, of offshore wind and concentrated solar power (CSP). The scale-up of projects using these technologies over the next decade is critical. CCS could account for up to 20% of cumulative CO_2 reductions in the 2DS by 2050. This requires rapid deployment of CCS and is a significant challenge since there are no large-scale CCS demonstrations in electricity generation and few in industry. Committed government funds are inadequate and are not being allocated to projects at the rates required. In transport, government targets for electric vehicles are set at 20 million vehicles on the roads in 2020. These targets are encouraging, but are more than twice the current industry planned capacity so may be challenging to achieve, in particular given the relative short-term nature of current government support schemes.

The share of energy-related investment in public research, development and demonstration (RD&D) has fallen by two-thirds since the 1980s. Government support for technology RD&D is critical and offers opportunities to stimulate economic growth and reduce costs for low-carbon technologies. Promising renewable energy technologies (such as offshore wind and CSP) and capital-intensive technologies (such as CCS and integrated gasification combined cycle [IGCC]), have significant potential but still face technology and cost challenges, particularly in the demonstration phase. Renewable energy technology patents increased fourfold from 1999 to 2008, led by solar PV and wind (Chapter 3). While these two technologies have successfully taken off, patent development has failed to translate into sufficient commercial applications of other technologies (such as enhanced geothermal and marine energy production). Against this background, it is worrying that the share of energy-related public RD&D has fallen to under 4% in 2010, down from a global average of 12% and an IEA member country average of more than 20% in 1980. This trend of declining public support to RD&D needs to be reversed. Moreover, RD&D policies need to be better aligned with measures to support market deployment. Expectations of new markets are a key factor in triggering additional private investment in RD&D and technological innovation.

Fossil fuels remain dominant and demand continues to grow, locking in high-carbon infrastructure. The *World Energy Outlook 2011* showed how the window of opportunity is closing rapidly on achieving the 2DS target. *ETP 2012* reinforces this message: the investments made today will determine the energy system that is in place in 2050; therefore, the lack of progress in clean energy is alarming.

Energy policy must address the entire energy system

Energy technologies interact and must be developed and deployed together. A low-carbon energy system will feature more diverse energy sources. This will provide a better balance than today's system, but it also means that the new system must be more integrated and complex, and will rely more heavily on distributed generation. This would entail increased efficiency, decreased system costs and a broader range of technologies and fuels. Success, however, will critically depend on the overall functioning of the energy system, not just on individual technologies. The most important challenge for policy makers over the next decade will likely be the shift away from a supply-driven perspective, to one that recognises the need for systems integration. Roles in the energy markets will change. Current consumers of energy will act as energy generators through distributed generation from solar PV or waste heat recovery. Consumers will also contribute to a smoother operation of the electricity system through demand response and energy storage. Enabling and encouraging technologies and behaviour that optimise the entire energy system, rather than only individual parts of it, can unlock tremendous economic benefits.

Investment in stronger and smarter infrastructure is needed. An efficient and low-carbon energy system will require investments in infrastructure beyond power generation facilities. Already, there are bottlenecks in electricity transmission capacity in important markets (such as Germany and China) that threaten to limit the future expansion of low-carbon technologies. Systems also need to be operated more intelligently. Better operation of existing heating technologies could save up to 25% of peak electricity demand from heating in 2050, reducing the need for expensive peak generating capacity (Chapter 5). Stronger and smarter electricity grids can enable more efficient operation of the electricity system through a greater degree of demand response (Chapter 6). In fact, demand response can technically provide all of the regulation and load-following flexibility needed to 2050, depending on the region. Investments in smart grids can also be very cost effective: *ETP* analysis shows that their deployment could generate up to USD 4 trillion in savings to 2050 in Europe alone, reflecting a 4:1 return on investment. A majority of these savings come from a reduction in investment needed for new generation capacity.

Low-carbon electricity is at the core of a sustainable energy system. Low-carbon electricity has system-wide benefits that go beyond the electricity sector: it can also enable deep reductions of CO_2 emissions in the industry, transport and buildings sectors. *ETP* analysis shows how emissions per kilowatt-hour can be reduced by 80% by 2050, through deployment of low-carbon technologies. Renewable energy technologies play a crucial role in this respect. In the 2DS, their share of total average world electricity generation increases from 19% currently to 57% by 2050, a sixfold increase in absolute terms. In fact, low-carbon electricity generation is already competitive in many markets and will take an increasing share of generation in coming years. Integrating a much higher share of variable generation, such as wind power and solar PV, is possible. In 2050, variable generation accounts for 20% to 60% of total electricity capacity in the 2DS, depending on the region.

Energy efficiency must achieve its potential. It is difficult to overstate the importance of energy efficiency, which is nearly always cost effective in the long run, helps cut emissions and enhances energy security. Energy efficiency must help reduce the energy intensity (measured as energy input per unit of gross domestic product [GDP]) of the global economy by two-thirds by 2050; annual improvements in energy intensity must double, from 1.2% over the last 40 years to 2.4 % in the coming four decades. Yet, a lack of incentives and a number of non-economic barriers continue to block broader uptake. Application of more stringent performance standards and codes will be necessary, particularly in the buildings and transport sectors. In this regard, information and energy management are proven and effective ways to encourage energy efficiency measures in industry. Economic incentives will be essential to unlock the energy efficiency potential and scale up private finance, but non-economic barriers must also be overcome.

Energy use becomes more balanced; fossil fuels will not disappear, but their roles will change

Reducing coal use and improving the efficiency of coal-fired generation are important first steps. To halve CO_2 emissions by 2050, coal demand in the 2DS would need to fall by 45% compared to 2009 (Chapter 8), and even further by 2075 (Chapter 16). Against that background, the current increase in the use of coal for electricity generation is the single most problematic trend in the relationship between energy and climate change. Nonetheless, given the dependency on coal in many regions, coal-fired power generation will remain substantial; increasing the efficiency of existing and new plants will be essential over the next 10 to 15 years. The potential for improvement is significant. Operations with higher steam temperatures will be capable of reducing CO_2 emissions from power generation plants to around 670 grams per kilowatt-hour, a 30% improvement over current global averages.

Natural gas and oil will remain important to the global energy system for decades. As emissions targets tighten, the share of natural gas will initially increase, particularly for base-load power plants, displacing both coal (in many regions) and some growth in nuclear (in fewer areas). Post-2030, as CO_2 reductions deepen in the 2DS, gas-powered generation increasingly takes the role of providing the flexibility to complement variable renewable energies and serves as peak-load power to balance generation and demand fluctuations (Chapter 9). Natural gas will remain an important fuel in all sectors in 2050, and demand is still 10% higher in absolute terms in 2050 compared to 2009. The specific emissions from a gas-fired power plant will be higher than average global CO_2 intensity in electricity generation by 2025, raising questions around the long-term viability of some gas infrastructure investment if climate change objectives are to be met. If near-term infrastructure development does not sufficiently consider technical flexibility, future adaptation to lower-carbon fuels and technologies will be more difficult to achieve. *ETP 2012* does not have a chapter dedicated to oil, as oil extraction has not seen the same technological revolution as natural gas. Even though global oil use falls by more than 50% by 2050 in the 2DS, oil will remain an important energy carrier in transport and as a feedstock in industry.

Carbon capture and storage remains critical in the long term. CCS is the only technology on the horizon today that would allow industrial sectors (such as iron and steel, cement and natural gas processing) to meet deep emissions reduction goals. Abandoning CCS as a mitigation option would significantly increase the cost of achieving the 2DS (Chapter 10). The additional investment needs in electricity that are required to meet the 2DS would increase by a further 40% if CCS is not available, with a total extra cost of USD 2 trillion over 40 years. Without CCS, the pressure on other emissions reduction options would also be higher. Some CO_2 capture technologies are commercially available today and the majority can be applied across different sectors, although storage issues remain to be resolved. While most remain capital-intensive and costly, they can be competitive with other low-carbon options. Challenges lie in integrating these technologies into large-scale projects.

Governments must play a decisive role in encouraging the shift to efficient and low-carbon technologies

Strong government policy action can help key technologies become truly competitive and widely used. The main barrier to achieving a low-carbon future is the unequal distribution – in time, across sectors and among countries – of the costs and benefits associated with transforming the global energy system. Governments need to take strong and collaborative action to balance, for all, the costs and benefits of achieving a low-carbon future. They should encourage national clean energy technology goals and escalate the ambition of international collaboration. Governments must seize the opportunity provided by the potential of technology and create the right framework to encourage its development and deployment, taking into account the driving interests of all involved (industry, finance, consumers, etc.). Broader perspectives will ensure that the combined benefits of technologies are maximised.

But governments alone cannot achieve the transition – clear incentives are needed for consumers, companies and investors. Governments need to set stringent and credible clean energy targets. Policies underpinning the targets must be transparent and predictable in order to adequately address and alleviate the financial risks associated with new technologies. Strong policies and markets that encourage flexibility and mitigate risks for investors in these technologies are vital. Ensuring that the true price of energy – including costs and benefits – is reflected in what consumers pay must be a top priority for achieving a low-carbon future at the lowest possible cost. Putting a meaningful price on carbon would send a vital price signal to consumers and technology developers. Phasing out fossil fuel subsidies – which in 2011 were almost seven times higher than the support for renewable energy – is critical to level the playing field across all fuels and technologies. Temporary transitional economic incentives can help to create markets, attract investments and trigger deployment. They will be even more effective if combined with other measures to overcome non-economic barriers, such as access to networks, permitting, and social acceptance issues. Finally, promoting social acceptance of new infrastructure development should be a priority.

Real-world examples demonstrate that decisive policy action is a catalyst for progress. The success of some renewable energy technologies provides evidence that new, emerging technologies can break into and successfully compete in the market place. Solar PV has averaged 42% annual growth globally over the last decade; onshore wind has averaged 27%. As a result of strategic and sustained policy support of early stage research, development, demonstration and market deployment, these technologies have reached a stage where the private sector can play a bigger role, allowing subsidies to be scaled back. In Chapters 2 and 11, *ETP 2012* highlights the dramatic cost reductions that are possible. For example, system costs for solar PV have fallen by 75% in only three years in some countries. Policy makers must learn from these examples, as well as from the failures in other technologies, as they debate future energy policies.

Governments need to act early to stimulate development of new, breakthrough technologies. Strategic and substantial support for RD&D will be essential. The technologies set in place by 2050 in the 2DS may be insufficient to deliver the CO_2 cuts required to reach zero emissions further into the future**.** *ETP 2012* provides the first quantitative analysis by the IEA of how emissions from energy-related activities could be eliminated completely by 2075, consistent with climate science estimates of what will be necessary to achieve the 2DS target (Chapter 16). The analysis reveals certain considerations for policy makers today. Breakthrough technologies are likely to be needed to help further cut energy demand, and expand the long-term opportunities for electricity and hydrogen, in part to help limit excessive reliance on biomass to reach zero emissions. RD&D efforts that aim to develop such options must start (or be intensified) long before 2050.

Recommendations to energy ministers

Each chapter of ETP 2012 *provides policy recommendations specific to individual sectors or challenge areas. Four high-level recommendations required to set the stage for a low-carbon future were identified across all areas:*

- ***Create an investment climate that builds confidence in the long-term potential of clean energy technologies.*** *Industry is key to the transition. Common goals supported by stringent and predictable policies are essential to establish the necessary credibility within the investment community.*
- ***Level the playing field for clean energy technologies.*** *Governments should commit to, and report on, progress on national actions that aim to appropriately reflect the true cost of energy production and consumption. Pricing carbon emissions and phasing out of inefficient fossil fuel subsidies, while ensuring access to affordable energy for all citizens, are central goals.*
- ***Scale up efforts to unlock the potential of energy efficiency.*** *The IEA has developed 25 energy efficiency recommendations to help governments achieve the full potential of energy efficiency improvements across all energy-consuming sectors. Committing to application of these recommendations would form a good basis for action and accelerate results.*
- ***Accelerate energy innovation and public research, development and demonstration.*** *Governments should develop and implement strategic energy research plans, backed by enhanced and sustained financial support. Additionally, governments should consider joint RD&D efforts to co-ordinate action, avoid duplication, and improve the performance and reduce the costs of technologies at the early innovation phase, including sharing lessons learned on innovative RD&D models.*

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Workshops

A number of workshops and meetings were held in the framework of this study and the development of the technology roadmaps. The workshop participants have contributed valuable new insights, data and feedback for this analysis:

Energy Storage: Issues and Opportunities. 15 February 2011, Paris.

Gas Beyond 2020 – Implications for Technology Policies and Scenarios. 8 June 2011, Dublin.

Industry expert review workshop, 5 October 2011, Paris.

IEA CERT-ETP 2012 Energy Systems Workshop: Integrated energy systems of the future, 78 November 2011, Paris.

Developing Metrics and Assessing Progress Towards a Clean Energy Economy, EGRD workshop, 16 17 November 2011, Paris.

Mobility Model annual partners' meeting, 25 November 2011, OECD, Paris.

ETP 2012 Finance Seminar: Missing an opportunity? Linking energy to growth, 15 December 2011, London.

India *Energy Technology Perspective 2012* Expert Group Workshop. 19 January 2012, Central Energy Authority, New Dehli.

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.

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Part 1

Vision, Status and Tools for the Transition

Part 1 sets out a vision of a sustainable energy system, and outlines the policies, technologies and financial capital needed to achieve it. Current energy trends and the three main scenarios of Energy Technology Perspectives 2012 (ETP 2012) are covered in Chapter 1, along with an analysis of the close links between climate change mitigation and energy security.

Against the backdrop of the urgent need to transform the way energy is generated and used, Chapter 2 assesses recent progress on clean energy. Chapter 3 provides insights on how policy can accelerate progress and innovation, emphasising the importance of packages of policy instruments (rather than just one type). Part 1 concludes in Chapter 4 with an assessment of the financial needs and implications of the transition to a low-carbon energy system.

Chapter 1

The Global Outlook

A low-carbon energy system is achievable and could be surprisingly affordable by 2050. But the world is currently failing to tap technology's potential to create a clean energy future. We need vision, goals and policies to nurture the technologies we can least afford to neglect. It is not too late to change course.

Key findings

- ***Energy use and CO_2 emissions will almost double by 2050 if current trends persist. This would put the world on the path towards a 6°C rise in average global temperature.*** *The energy technologies exist to stave off that threat. The current relationship between economic growth, energy demand and emissions is unsustainable.*
- **ETP 2012** ***unveils three dramatically different energy futures:*** *the 2°C Scenario, a vision of a sustainable energy system; the 4°C Scenario, an assessment of what announced policies can deliver; and the 6°C Scenario, which is where the world is now heading, with potentially devastating results.*
- ***Progress in rolling out clean technologies has been too slow and piecemeal.*** *Too little is being spent on clean energy technology. Investment in fossil fuel technologies is still outpacing low-carbon alternatives.*
- ***A low-carbon energy system is likely to provide a higher level of energy security,*** *primarily through reduced dependency on energy, greater diversity of energy sources and technologies, and lower risks related to climate change.*
- ***The cost of creating low-carbon energy systems now will be outweighed by the potential fuel savings enjoyed by future generations.*** *A sustainable energy system will require USD 140 trillion in investments to 2050 but would generate undiscounted net savings of more than USD 60 trillion.*
- ***The biggest challenge to a low-carbon future is agreement on how to share the uneven costs and benefits of clean technology across generations and countries,*** *not the absolute cost or technological constraints. Governments must address these distributional issues.*
- ***Substantial opportunity exists to increase energy savings, efficiency and know-how across sectors and technologies,*** *such as those between heat and electricity, or among transport and industry applications.*
- ***A sustainable energy system is a smarter, more unified energy system. Complex and diverse individual technologies will need to work as one.*** *Technologies must be deployed together rather than in isolation. Policies should address the energy system as a whole, rather than individual technologies.*

Opportunities for policy action

- ***Governments must outline a coherent vision for a clean energy future, backed by clear goals and credible policies.*** *This is vital to establish the necessary investment climate for clean energy to thrive and to stimulate the development of breakthrough, low-carbon technologies. Ensuring that the true cost of energy is reflected in consumer prices, that non-economic barriers for energy efficiency are removed, and that clean energy research, development and deployment is accelerated are three key steps for governments to take.*
- ***Governments must collaborate to achieve a low-carbon future.*** *Governments need to show determination and courage to transform the energy system by making the right choices. Cooperation and collaboration at home and abroad will be vital to achieve this.*

The global economy runs on energy: virtually all goods and services require an input of energy. As consumer demand for more goods and services grows, energy demand also increases. Continuing to supply energy by today's means is unsustainable: surging demand will translate into higher energy prices and aggravated energy security concerns, and experts predict the resulting greenhouse-gas (GHG) emissions (including carbon dioxide [CO_2] emissions) would increase average global temperatures by 6°C in the long term. This would have disastrous impacts on the Earth and its inhabitants.

The clear correlations between economic growth, energy demand, CO_2 emissions and energy prices must be seen not as an insurmountable obstacle but rather as the starting point for a clean energy future. Strategic policy actions have the potential to break – and eventually reverse – past trends.

Energy Technology Perspectives 2012 (*ETP 2012*) starts from the globally agreed-upon target of limiting average global temperature increase to 2°C. The analysis identifies a pathway in which the link between economic activity, energy demand and emissions can be broken through a transformation of the global energy system and its technologies. To demonstrate the feasibility of this transformation, *ETP 2012* uses modelling techniques[1] to analyse and compare three possible futures, all of which take into account rising global population and steady economic growth (Box 1.1).

Global energy demand has nearly doubled since 1980 (Figure 1.1). If current trends continue unabated, it will rise another 85% by 2050. While efficiency measures have achieved some reduction in global energy intensity, the rate of improvement has slowed in recent years, which is worrisome. The virtually unbroken trend of increasing energy demand over the last 30 years has driven up energy-related CO_2 emissions (Figure 1.1). As energy-related CO_2 emissions make up two-thirds of total global GHG emissions (Figure 1.2), this trend must be reversed in order to address concerns over climate change and long-term energy security.

1 Annex A contains a description of the analytical approach and methodology of *ETP 2012*.

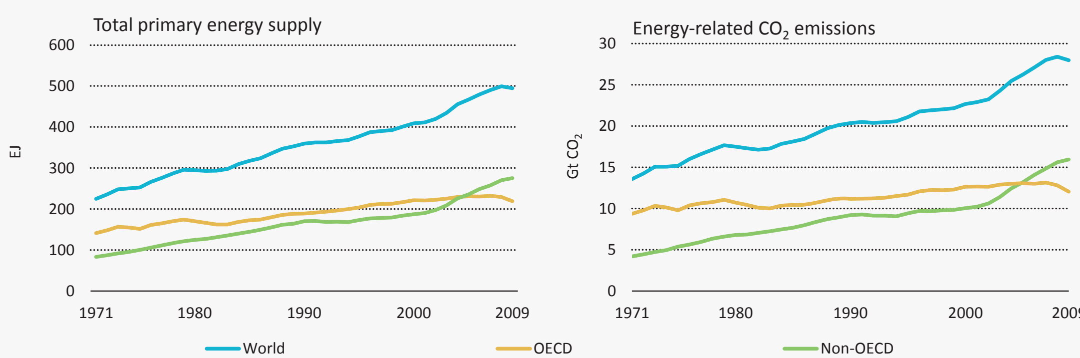
Box 1.1 ETP 2012 Scenarios

The **6°C Scenario (6DS)** is largely an extension of current trends. By 2050, energy use almost doubles (compared with 2009) 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* Current Policy Scenario through 2035.

The **4°C Scenario (4DS)** takes into account recent pledges made by countries to limit emissions and step up efforts to improve energy efficiency. It serves as the primary benchmark in *ETP 2012* when comparisons are made between scenarios. Projecting a long-term temperature rise of 4°C, the 4DS is broadly consistent with the *World Energy Outlook* New Policies Scenario through 2035 (IEA, 2011). In many respects, this is already an ambitious scenario that requires significant changes in policy and technologies. Moreover, capping the temperature increase at 4°C requires significant additional cuts in emissions in the period after 2050.

The **2°C Scenario (2DS)** is the focus of ***ETP 2012*.** The 2DS describes an energy system consistent with an emissions trajectory that recent climate science research indicates would give an 80% chance of limiting average global temperature increase to 2°C. It sets the target of cutting energy-related CO_2 emissions by more than half in 2050 (compared with 2009) 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 only be achieved provided that CO_2 and GHG emissions in non-energy sectors are also reduced. The 2DS is broadly consistent with the *World Energy Outlook* 450 Scenario through 2035.

Figure 1.1 Total primary energy supply and CO_2 emissions

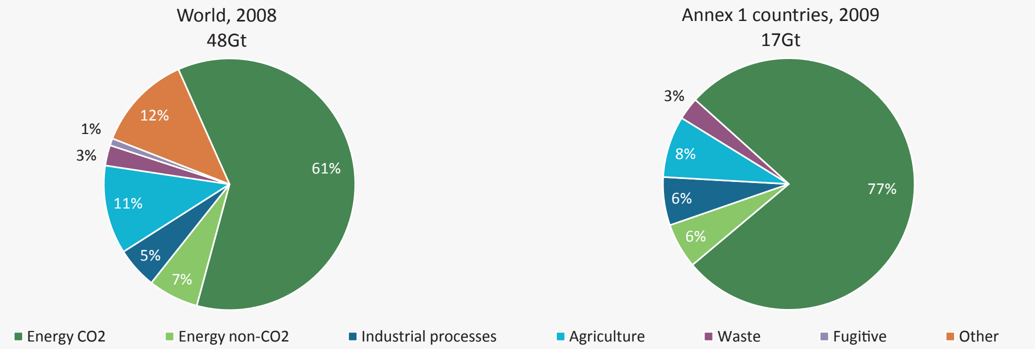


Notes: The apparent decline in 2009 reflects reduced energy demand due to the economic recession. Figure does not include industrial process emissions which were 1.53 gigatonnes (Gt) in 2008 and are estimated to be 1.44 Gt in 2009.
Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *Since 2003, energy demand has stabilised in OECD regions but grown rapidly in non-OECD countries, reflecting higher rates of economic development and population growth. If current trends persist, global CO_2 emissions will double by 2050, resulting in a projected average temperature increase of 6°C in the long term.*[2]

2 Temperature rise in 2100 is projected to approximately 4°C.

Figure 1.2 Global greenhouse gas emissions by sector



Notes: World GHG emissions calculated based on IEA sectoral approach for CO_2 emissions from fuel combustion; EDGAR 4 database for other emissions. In general, estimates for emissions other than CO_2 from fuel combustion are subject to significantly larger uncertainties.
Annex I countries as defined by the United Nations Framework Convention on Climate Change (UNFCCC). Emissions for Annex I do not include land use, land use change and forestry (LULUCF). Solvent use is included in industrial processes and 'other' is included in waste.

Key point *In 2009, the energy sector accounted for 68% of global GHG emissions; in Annex 1 countries alone, the energy share jumps to 83%.*

Continuous increase in energy demand has also translated into higher prices for energy and fuels. The doubling of global oil prices in less than a decade is the most visible example, but concerns over constrained short- to mid-term supply capacity and decreasing discovery rates are likely to push oil prices even higher in the future. For natural gas, technological breakthroughs that enable extraction of unconventional sources (*e.g.* shale gas, coalbed methane and tight gas) have put downward pressure on prices (in some regions, significantly so) and altered trade patterns. In the longer term, improvements in extraction and conversion technologies are unlikely to offset the increasing demand, resulting in a continued rise in fossil fuel prices.

ETP 2012 devotes an entire chapter to tracking recent progress towards a clean energy system: it is clear that few clean energy technologies are currently on track to meet climate change objectives. The technologies with great potential for energy and CO_2 emissions savings are making the slowest progress: carbon capture and storage (CCS) full-scale demonstration projects are not receiving necessary rates of investment; about half of new coal-fired power plants are still built with inefficient technology; vehicle fuel-efficiency improvement is too slow; and offshore wind and concentrated solar power (CSP) are not penetrating the market at the rates required. Progress on energy efficiency is also slow, with significant untapped potential remaining in the buildings and industry sectors.

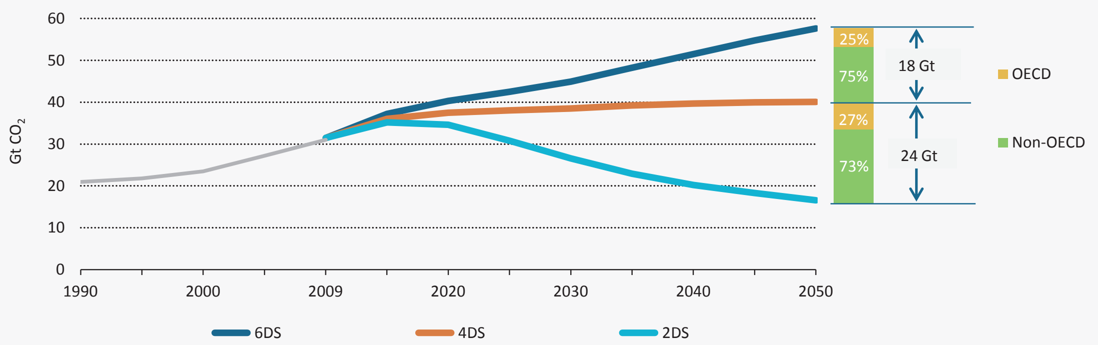
Encouraging signs are also evident, however. Onshore wind has grown at an annual rate of 27% over the last decade, and solar photovoltaic (PV) has registered 42% annual growth over the same period. Impressive cost reductions for solar PV – up to 75% over the last three years in some regions – are both a cause and effect of this growth. Government targets for electric vehicles (20 million by 2020) are ambitious, as are continued government nuclear expansion plans in many countries. In both cases, significant public and private sector efforts will be necessary to translate plans into reality. Companies around the world are building highly efficient plants and investing in best available technologies (BATs) relevant to their sectors. Others are incorporating BATs during the refurbishment of old plants. On average, facilities in OECD countries are more efficient than in the past, but the most striking development is in non-OECD regions, where many new plants are being built to the highest international standards. The resulting convergence of efficiency levels in OECD and non-OECD countries is a marked shift from the situation 20 years ago.

Assessing both technical and economic factors, *ETP 2012* sets a feasible path to the future that governments around the world have repeatedly committed themselves to – one in which a low-carbon energy system underpins economic development, enhances energy security and reduces environmental impacts. Within and across all energy sectors, this book outlines the actions and investments needed to achieve that outcome.

Choosing the future: scenarios in *ETP 2012*

ETP 2012 presents three possible energy futures, the boundaries of which are set by total energy-related CO_2 emissions (Figure 1.3). The message is clear: different energy systems deliver very different futures. Governments must choose what future they want and start building the appropriate energy system now if that future is to be realised.

Figure 1.3 *ETP 2012* **scenario CO_2 emissions pathways**



Key point *Global energy-related CO_2 emissions in 2050 must be half of current levels to limit the global temperature increase to 2°C.*

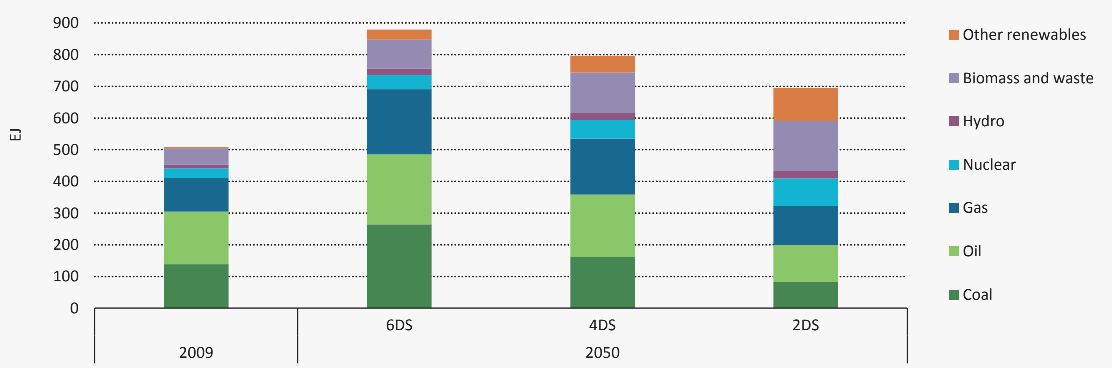
The focus of *ETP 2012* is on the 2DS as the desirable target; the 6DS and 4DS are explored in less detail, primarily to better understand and illustrate the transitions required to realise the 2DS. Modelling was also carried out to explore several scenario variants that analyse specific issues in more detail, such as impacts of slower progress in CCS, different demand developments in industry and alternative pathways for hydrogen use (see Chapters 9, 10, 11 and 12).

On a global basis, total primary energy supply (TPES) will grow in all scenarios (Figure 1.4). In the 2DS, TPES increases by some 35% in the period 2009 to 2050. This is significantly lower than the 85% rise seen in the 6DS and the 65% increase in the 4DS.

But large regional differences are evident within these numbers. In the OECD, TPES is projected to stay almost constant in the 2DS and increase only moderately in the 6DS and 4DS. The outlook for non-OECD countries is very different: even in the 2DS, primary energy supply is projected to rise by some 70% in 2050 compared to 2009. In the 4DS, non-OECD TPES will approximately double, while the 6DS sees a rise of 130%.

These basic differences have important implications for how – and in what time frame – a transformation of the energy system can be achieved. In the OECD, much of the focus will be on replacing ageing infrastructure: the turnover of the capital stock will determine how quickly a transformation can take place. In non-OECD countries, the rapid expansion of new infrastructure presents both an opportunity and a risk. The opportunity is to invest wisely in BATs and avoid sinking investments into old and inefficient technologies. But weak investment in BAT is a major threat: given the long lifespan of energy infrastructure, near-term investments in inefficient technologies increase the risk of further locking the world into a high-emissions trajectory.

Figure 1.4 Total primary energy supply

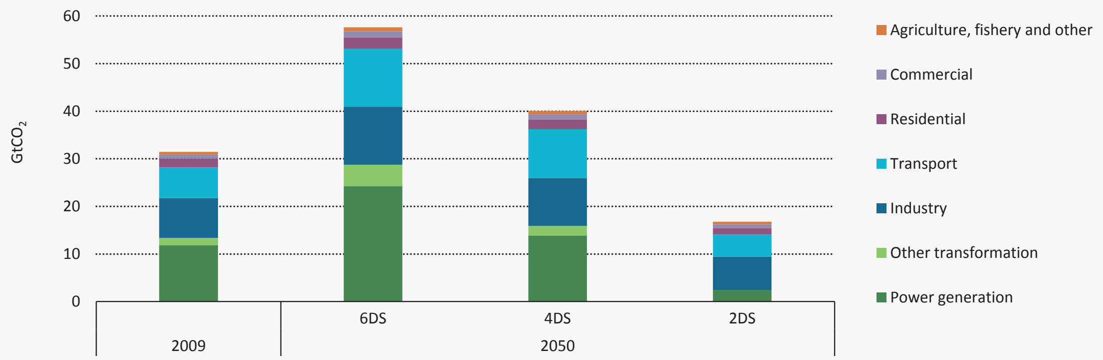


Key point *The 2DS reflects a concerted effort to reduce overall consumption and replace fossil fuels with a mix of renewable and nuclear energy sources.*

Lower energy demand in the 2DS (compared to the 4DS and the 6DS) is coupled with a transformation in the *composition* of energy demand: demand for fossil fuels falls significantly as a concerted effort is made to increase the use of electricity as a main fuel while also decarbonising its production. In fact, fossil fuel use in OECD countries in 2050 would drop by over 60% in both electricity generation and in transport compared to 2009 under the 2DS.

The distribution of emissions among sectors changes significantly in the 2DS (Figure 1.5). Emissions from electricity generation are almost eliminated by 2050, while those from transport and industry remain significant. This reflects the reality that transport and industry emissions are the most difficult to mitigate, but also has important implications for the long-term prospects of keeping the global temperature rise to below 2°C. These two sectors will not be decarbonised by 2050, and additional mitigation strategies will need to be carried forward after 2050 (see Chapter 16 for an exploration of the longer-term implications).

Figure 1.5 Global CO_2 emissions by sector and scenario



Note: CO_2 emissions in this graph are accounted for in the sector, where the CO_2 is physically emitted.

Key point *Decarbonising electricity is critical, but all sectors must contribute to emissions reduction.*

The *ETP 2012* 6°C Scenario

The 6DS assumes no new policy action is taken to address climate change and energy security concerns. The energy system remains heavily dependent on fossil fuels, which meet a majority of the additional demand. By 2050, fossil fuel use and CO_2 emissions are almost double compared to 2009; this scenario is clearly unsustainable in the long term.

At the sectoral level, the 6DS is similar to the current system, but increasing demand for energy compounds climate change concerns. Coal use for electricity generation more than doubles compared to 2009, and CCS is not deployed. The share of renewable energy sources for electricity increases from 19% to 24%.

Transport remains based almost exclusively on fossil fuels. Fuel economy improves slowly, but final energy use in the sector almost doubles by 2050. There is little penetration of plug-in electric vehicles and other alternative technologies and fuels.

Energy efficiency in the industry and buildings sectors improves at approximately 1% per year, in line with the rate from 1971 to 2009. A large share of heating is provided by individual boilers fired by fossil fuels. District heating remains an important technology, particularly in the Nordic countries and Russia, but remains fired primarily by fossil fuels. Co-generation[3] plays a minor role.

Energy system investments in the 6DS are very high, with a large portion directed towards new coal-fired electricity generation.

In part due to strongly rising demand, energy prices increase significantly, including electricity. Most notably, oil prices continue to rise throughout the period, approaching USD 150/barrel in 2050. It seems unlikely that a shortage of fossil fuel reserves would constrain this growing demand; it is less clear that the necessary investment will occur in time to exploit those reserves (IEA, 2011).

3 Co-generation refers to the combined production of heat and power (CHP).

The *ETP 2012* 4°C Scenario

The 4DS represents a concerted effort to move away from current trends and technologies, with the goal of reducing both energy demand and emissions vis-à-vis the 6DS. It extends to 2050 the trends in energy efficiency and carbon intensity in the *World Energy Outlook* New Policy Scenario (IEA, 2011). IEA analysis indicates that this scenario is plausible given recent developments, but it is clear that governments must play a lead role by implementing and delivering on policy commitments already made to combat climate change and improve energy security if the 4DS is to be realised.

Policies required to achieve the 4DS include targets and support programmes to boost the use of renewable energy and to improve energy efficiency. This reflects national pledges to reduce GHG emissions under the UNFCCC process, and the initiatives taken by the G-20 and the Asia-Pacific Economic Cooperation (APEC) to phase out inefficient fossil fuel subsidies that encourage wasteful consumption.

Annual energy-related CO_2 emissions in the 4DS rise by 27% compared to 2009, to 40 gigatonnes (Gt) (Figure 1.3), despite strong policy action to shift away from fossil fuel dependency in meeting the increasing demand for energy services. Fossil fuels still represent two-thirds of TPES in 2050, and renewable sources represent 35% of total electricity generation. This scenario also includes some deployment of CCS, although only 2% of total electricity capacity would be equipped with this technology in 2050.

Decarbonisation of electricity generation is starting in the 4DS but the transition is slow, with renewable sources accounting for 35% of generation in 2050.

In transport, implementation of tighter fuel economy standards in all major economies, as already planned in the European Union and United States post-2015/16, results in average fuel economy in passenger light-duty vehicles (passenger LDVs) improving by 30% over 2009. However, policies to encourage the adoption of new fuels are weak, and penetration of alternative-fuel vehicle technologies (*e.g.* plug-in hybrid electric and battery electric vehicles [BEVs]) is slow. The only new alternative technology that gains significant market share is gasoline hybrid vehicles, reaching some 25% of sales in 2050.

Energy efficiency in industry and buildings improves through an increased adoption of BATs in new construction and retrofits, stimulated by policies such as carbon pricing and improved building codes. Still, CO_2 emissions from industry increase by 20% to 35% under the 4DS. Energy demand from the buildings sector would increase from 115 EJ in 2009 to 185 EJ in 2050. Although solar energy grows at an average rate of 8% per year to 2050, it represents only 0.3% of the sector's energy consumption in 2050.

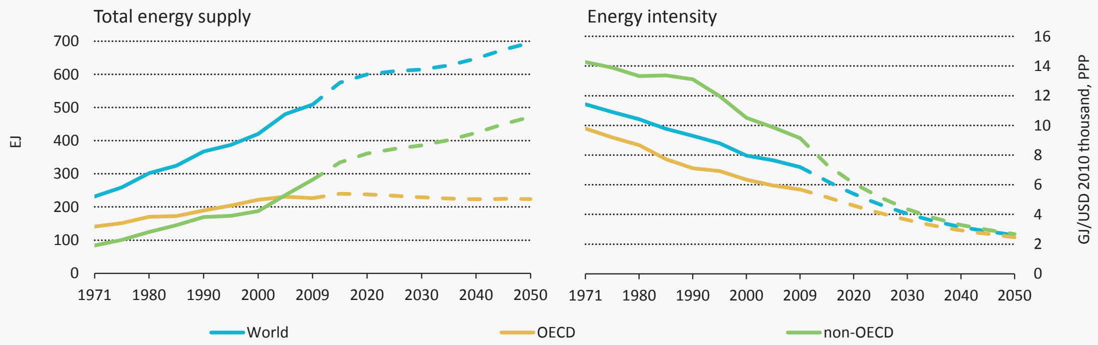
The *ETP 2012* 2°C Scenario

The 2DS is the primary focus of *ETP 2012*. It presents a vision of a sustainable energy system. However, attaining it will require extensive transformation of the energy system, cutting energy-related CO_2 emissions in half by 2050 compared to 2009. Success will depend on a significant decoupling of energy use from economic activity, which requires changes in technology development, in economic structure and in individual behaviour. In the 2DS, the energy intensity of the global economy falls significantly, and demand for physical goods and energy decreases over time (Figure 1.6, Figure 1.7). Without this decoupling, achieving the 2DS becomes very costly, if not impossible.

ETP 2012 focuses on the technology component of decoupling, but also explores some aspects of behavioural change, including modal shifts in the transport sector and the link between income and larger houses in the buildings sector.

The importance of structural changes in industry and in energy infrastructure are further highlighted in scenario variants that reflect different demand patterns, motivated primarily by potential saturation of demand at certain levels (*e.g.* in car ownership and residential floor area), physical constraints in supply of materials, and assumptions on consumption of services substituting for consumption of physical goods as relative prices change.

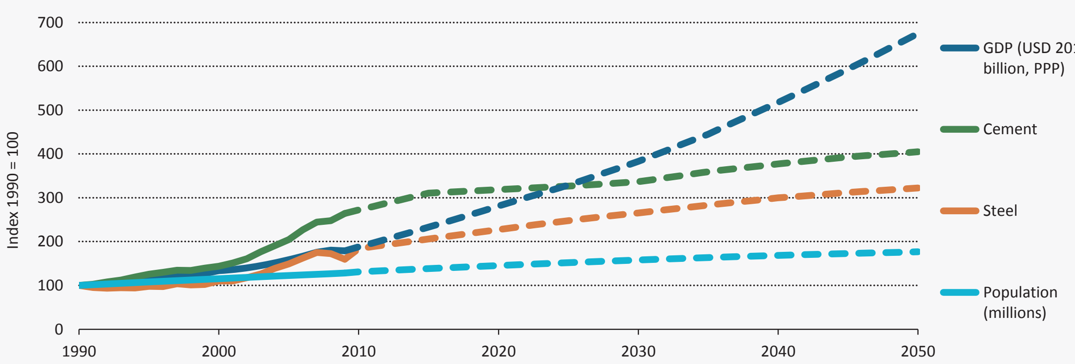
Figure 1.6 Total energy supply and energy intensity in the 2DS



Note: GDP = gross domestic product

Key point *Reducing the energy intensity of the economy is vital to achieving the 2DS.*

Figure 1.7 GDP, population and global demand for steel and cement in the 2DS



Note: 1990 index = 100

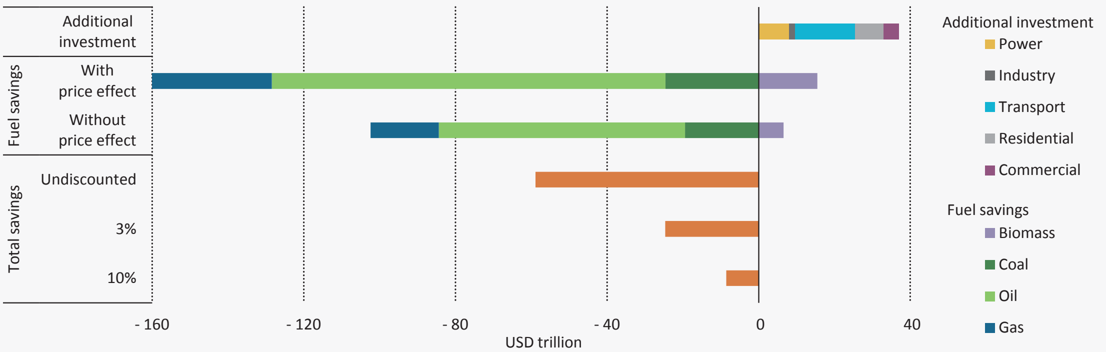
Key point *Steel and cement production must be decoupled from population rise and economic growth in the 2DS. Saturation of demand and substitution by other materials are the two primary drivers.*

Box 1.2 Does the 2DS make economic sense?

One of the most striking findings of *ETP 2012* is that future savings from the 2DS outweigh the up-front investment costs – *even without taking into account the value of avoiding potential damages from climate change* (Figure 1.8). Investing in a low-carbon energy system appears likely to generate a net economic surplus at the global level, due to the enormous value of fuel savings, estimated at USD 100 trillion between 2010 and 2050. This represant undiscounted net savings of USD 60 trillion or an average of USD 1.5 trillion annually. Using a 10% discount rate still shows net savings of USD 5 trillion and high-lights the affordability of moving to a low-carbon energy sector.

This does not mean that there will be only winners; some regions and sectors will undoubtedly come out worse from an economic standpoint in the 2DS, but the overall picture looks surprisingly good.

Figure 1.8 Investments and savings in the 2DS



Note: Numbers are relative to the 6DS.

Key point *Future fuel savings more than offset investment costs in the 2DS.*

What is behind this result? Projected increases in fossil fuel prices (particularly for oil in the 6DS) make reducing demand for these fuels even more valuable than today. A secondary effect that may add further savings is the potential dampening of fossil fuel price increases in the 2DS due to lower demand. With cautious assumptions on how lower demand may impact fossil fuel prices, undiscounted savings jump to over USD 150 trillion (the top fuel savings bar in Figure 1.8).

Many low-carbon technologies are characterised by high initial investment costs, but lower operations and maintenance costs. A good example is a hydroelectric dam, which may require several hundred million USD in initial investment, but has very low generation costs. The sums are smaller for technologies for distributed generation (such as wind and solar), but the general characteristic remains the same.

The implications for financing the transformation of the energy system in deregulated markets are great. Availability and cost of capital will be critical, as well as the investment horizons applied by investors. For some technologies, such as CCS and some renewables, it seems likely that governments will have to play a dominant role in financing for at least another decade. Relying solely on market-based policies (*e.g.* carbon pricing) to induce these investments is unlikely to achieve the levels required (Chapter 3 provides more analysis on this topic).

The cost-benefit estimates in *ETP 2012* are sensitive to many factors that are uncertain or contentious, such as cost and performance of emerging technologies, future fuel prices, cost of capital and discounting of future savings. Chapter 4 presents a more detailed analysis of investment needs and potential sources of capital.

Large efficiency gains can stem from system-wide changes and better integration of technologies, while some individual technologies can deliver important improvements by themselves. Increased electrification of end-use sectors, coupled with decarbonisation of electricity generation and energy efficiency improvements, are the most important transformations. Energy generation will become more distributed and will make use of smart electricity grid technologies. Additional benefits, although to a lesser extent, will come from the use of gaseous fuels.

Fossil fuel use will only drop by some 20% in 2050 compared to 2009 levels, but this represents a 60% reduction in the use of fossil-based fuels in 2050 in the 2DS compared to the 6DS. In transport, oil is replaced by a portfolio of three alternative fuels (or energy carriers): electricity, hydrogen and biofuels. These will require a revolution in vehicle propulsion systems, particularly the electrification of LDVs. Improved vehicle fuel efficiency also plays a major role. Still, emissions in transport will be approximately 5 Gt in 2050 (down 25% compared to 2009), mainly due to the rapid increase in the number of cars in emerging economies.

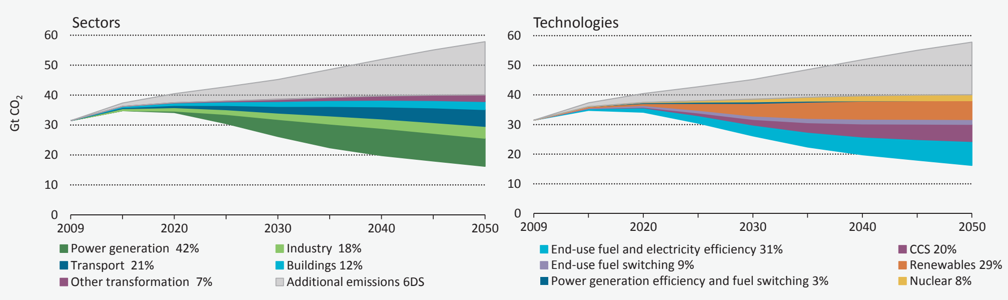
Energy efficiency will play a major role in industry, driven by deployment of new technologies, better system integration and closed-loop processes. Renewable energy sources replace fossil fuels in almost all direct uses. Emissions of CO_2 from industry fall to approximately 6.5 Gt by 2050, a 20% reduction compared to 2009. This is lower than average across the economy as a whole, due to very costly abatement options in some industrial processes such as cement and steel production.

In buildings, better building shells will improve energy efficiency and reduce energy demand, as will more efficient heating and cooling systems. This entails a substantial increase in the use of heat pumps, expanded use of district heating (where advantageous), and deployment of technologies such as solar heating and cooling. All new construction would have to meet high performance standards, particularly in non-OECD countries where most new construction will take place. OECD countries will need to focus on refurbishing the existing building stock; financing of such measures, however, is expected to be a central challenge.

Technologies needed to achieve the 2DS

Achieving the 2DS requires a collective effort in every aspect: no single fuel, technology or sector can deliver a dominant proportion of the necessary emissions reduction – all are necessary to varying degrees (Figure 1.9).

Figure 1.9 **Contributions to emissions reductions in the 2DS**



Note: Percentage numbers represent cumulative contributions to emissions reductions relative to the 4DS.

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

The following section focuses first on the need to establish smarter and more flexible energy systems, transform electricity generation and use (including increased electrification), and improve energy efficiency. It then explores new technologies (such as CCS) before examining key factors such as the crucial role of pricing energy services and the economic and energy security benefits that arise from investing in a low-carbon energy future. As demonstrated, diversifying the energy portfolio is of vital importance to reducing risk to energy disruptions, as is building resilience into energy systems – especially electricity grids – to accommodate higher levels of renewable energy sources (particularly those that are variable).

Smarter energy systems are decentralised but highly integrated

Many existing energy systems are made up of large facilities (power plants, oil refineries, etc.) that are widely dispersed across a given country. As a result, transporting and distributing energy to users is a significant challenge, as is maintaining a steady supply of high-quality energy.

Today's information and communication technologies (ICTs), coupled with a more diverse range of energy-producing methods, make it not only possible but also highly practical to produce a large proportion of energy closer to the point of use while also improving the ability to deliver energy to areas in which local production is currently lacking. Increasing the flexibility of energy systems is a central objective to improving the ability to respond rapidly to variations in both demand and supply.

Decentralising energy systems can be achieved through a range of technologies that vary in scale and meet the needs of different types, sizes and densities of human settlements. Relatively large-scale co-generation plants and district heating technologies can deliver energy in a more efficient manner in areas where users are concentrated and demand is high. Solar PV and wind offer the possibility of providing electricity in close proximity to smaller or isolated communities as well as to denser populations via larger facilities such as wind farms. On-site heat pumps and biogas systems can also deliver energy conversion near the point of use. Micro off-grid generation will be important in niche markets and far from the grid. As this is common in some developing countries, improved technologies for decentralised generation will also help fulfil the objective of access to modern energy for all.

Importantly, the capacity now exists to integrate such dispersed and diverse components into energy systems in a way that ensures the available technologies respond in the most efficient manner to differences in demand patterns, thereby smoothing out overall load. Charging of electric vehicles, for example, can be automated to take place during off-peak load when other power demands are low. In Chapter 5, analysis of heating and cooling shows how better operation of heating systems can save up to one-quarter of peak electricity demand in 2050. Improving incentives – and practical possibilities – for consumers to manage their demand is, overall, a central component of a smarter energy system. Moreover, increasing the integration of transmission and distribution aspects of electricity networks supports market liberalisation and harmonisation – both of which are stepping stones for real-cost pricing that facilitates effective demand response.

Thus, as the analysis in Chapter 6 shows, a smarter, more decentralised and integrated energy system would make a vital difference in realising the 2DS. Smart systems may significantly reduce both total and peak demand, leading to substantial savings in upstream capacity investment. Managing such systems requires more information, however, as well as increased capacity to handle the information flow.

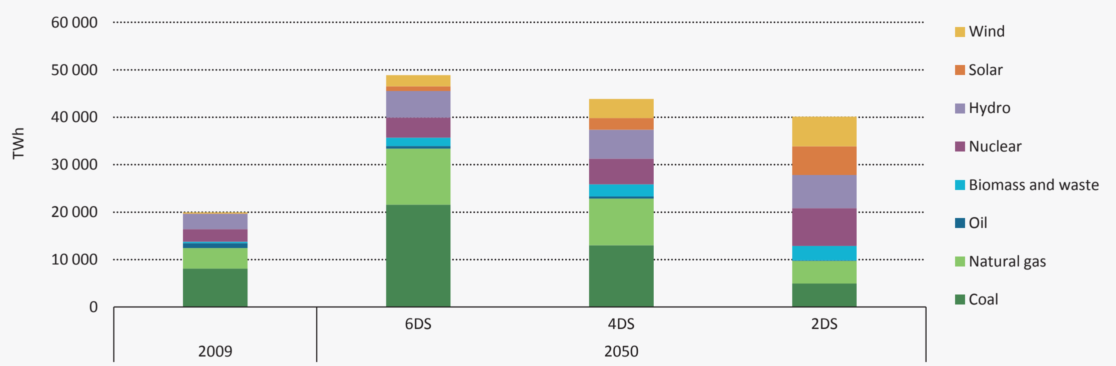
Transforming electricity systems

Decarbonising electricity generation is the most important system-wide change in the 2DS (Figure 1.10). In 2009, fossil fuels generated 67% of global electricity. Policies that stimulate increased deployment of conventional clean technologies (*e.g.* hydropower, onshore wind and nuclear), as well as rapid expansion of emerging technologies (*e.g.* solar, offshore wind and geothermal) bring the share of fossil fuels down to less than 25% in 2050. Together with the application of CCS, these efforts result in the CO_2 intensity of electricity generation in the 2DS falling by 80%: from just under 600 grams of carbon dioxide per kilowatt-hour (gCO_2/kWh) in 2009 to 60 gCO_2/kWh in 2050.

The pathway to decarbonisation is described in detail in Chapter 11. In the short to medium term, decarbonisation will require a substantial switch from coal to natural gas in many regions, with coal use falling rapidly after 2020. The use of natural gas will follow a similar decline after 2030 (the role of natural gas is explored further in Chapter 9). Use of solar and wind rise substantially over this same period, becoming almost as important to electricity generation as hydro and nuclear in the 2DS in 2050. Hydro will continue to play a central role in absolute terms, but its growth is less pronounced.

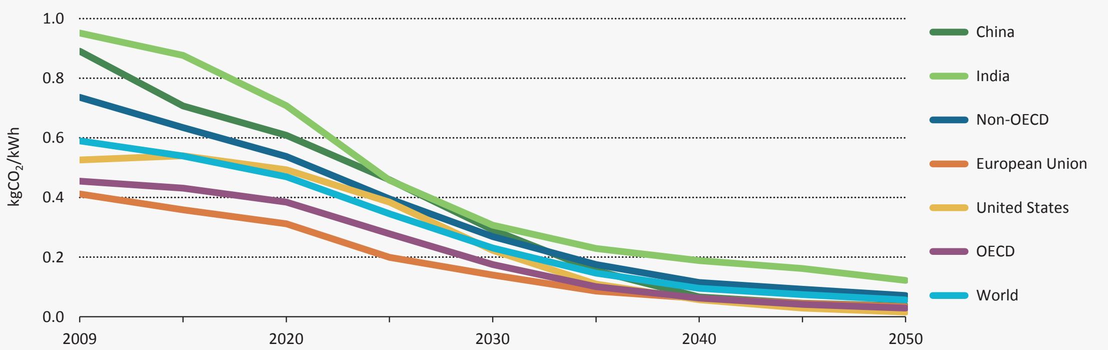
Electricity as a power source offers a key advantage: it can be precisely targeted to provide the right amount of energy at the right time to any end use. Because electricity is used extensively in all sectors, the characteristics of electricity generation have important implications for the entire economy. Tremendous potential exists to increase the use of electricity for heat generation for industrial processes, for more efficient regulation of electric motors in industry, to power heat pumps for heating and cooling in buildings and industry, and to support deployment of electric vehicles in transport. Clearly, promoting greater use of electricity in such applications will increase demand for electricity. The amount of resulting CO_2 emissions will depend on the fuel and technology mix used to generate that electricity.

Figure 1.10 Fuel mix in electricity generation, by scenario



Key point *Diversification of fuels and increased use of low-carbon sources in the 2DS achieves a high degree of decarbonisation in electricity generation by 2050.*

Figure 1.11 CO_2 intensity in electricity generation in the 2DS



Key point *Starting from diverse levels of CO_2 intensity, different regions and countries will need to apply different levels of effort to achieve a global conversion of less than 60 gCO_2/kWh.*

Electrification should not, however, be perceived as a universal solution to energy challenges: it has drawbacks that need to be managed and that may sometimes make it less preferable to other options (see Chapters 5 and 6).

The average cost of generating electricity will rise by 40% to 50% in all *ETP 2012* scenarios between today and 2050. But the cost differences between scenarios will be modest, with an average increase of 10% at the global level in the 2DS in 2050 compared to the 4DS. In the short term, increases will be greater in the 2DS, but in the mid to long term, as costs of renewable technologies continue to fall, average costs converge. Reduced demand, lower technology costs and lower fossil fuel prices are the three most important parameters that keep electricity costs from rising at a much faster rate in the 2DS. Estimating the market price for electricity, which in competitive markets is set by the marginal cost of electricity generation, requires a more detailed analysis than *ETP 2012* provides. Factors such as market organisation and level of competition will be at least as important for price developments as the fuel and technology mix, in particular in the short term. However, the ETP analysis is useful to get a broad understanding of potential long-term differences between scenarios.

Carbon capture and storage, which involves technologies that capture CO_2 emissions at the source (*e.g.* at a coal-fired power plant), transport them to storage sites and then sequester them permanently deep underground, is a key component in the 2DS. By 2050, the 2DS requires that more than 60% of coal-fired generating capacity should be equipped with CCS. CCS is also important in industry because it is the only technology that can prevent substantial emissions from being released into the atmosphere in some heavy industries (*e.g.* iron and steel, and cement). About half of the total volume of carbon captured comes from the industry and transformation sectors. Starting around 2025 and at an accelerated pace after 2035, CCS is added to biofuels production, which could result in a net removal of CO_2 from the atmosphere.

For the first time, *ETP 2012* dedicates an entire chapter (Chapter 10) to CCS, motivated by the substantial uncertainties that continue to cloud its future. Deployment has been slower than anticipated in *ETP 2010* and is further delayed in the *ETP 2012* scenarios. Problems associated with attracting financing and obtaining permits for full-scale demonstration plants are particularly worrisome. In Chapter 11, a scenario with significantly less CCS deployed compared to the main 2DS is analysed. The conclusion is that, from a technical standpoint, it is possible to achieve the 2DS without CCS. But doing so becomes more costly and would increase the pressure on land resources.

Energy efficiency is critical

Energy that is not consumed does not have to be produced, refined, transported or imported; and, of course, it produces no emissions. Reducing global energy consumption reduces vulnerability to all the things that might go wrong across the value chain and also contributes to achieving climate change goals.

A dramatic improvement in energy efficiency will be central to achieving the 2DS. A higher degree of electrification, as discussed above, offers great potential for more efficient energy use but is not enough, by itself, to reach the 2DS goals. Myriad technological improvements, some large and some small, are needed to improve efficiency in both energy generation and in end-use sectors. Potential efficiency gains are evident in all sectors. In some instances, it is largely a matter of using the same technology in a more efficient manner, thereby avoiding excessive peak loads, for example.

Co-generation of heat and power is the most important aim in combustion technologies for electricity generation. It shows potential to deliver generation efficiencies reaching 90%, compared to only 45% achieved by today's best coal-fired plants. While the emerging technologies of solar and wind draw upon enormous resources, additional effort is needed to improve efficiency in capturing these sources and delivering their energy to the consumer.

Buildings are an important target for increasing efficiency in end use, but two diverse challenges come into play. Many non-OECD countries will pursue rapid expansion of their building stock in the next 50 years; as such, they can play a lead role in constructing highly efficient buildings. Conversely, should they miss this opportunity to innovate, there is a serious risk of "lock-in" of inefficient buildings that will stand for decades. Such lock-in is already evident in OECD countries, where the building stock is growing slowly and the potential to increase overall efficiency by constructing more efficient buildings is very limited. In these regions, the focus must be on undertaking major renovations to improve the efficiency of existing buildings.

The combination of buildings designed to have lower energy demand per square metre of floor space and ready access to a supply of decarbonised electricity opens up the potential to install much more efficient systems for heating and cooling based mainly on heat pumps. In densely populated areas, district heating systems based on co-generation can further reduce energy demands.

In industry, motors are used extensively in all sectors; applications include industrial blowers, fans, pumps and machine tools. Electric motors, particularly if they are run efficiently, offer major efficiency advantages over traditional mechanical drives. But many electric motors are currently quite inefficient; they lack, for instance, even basic efficiency enhancing features such as variable speeds. Optimising a motor and its related drive system can typically increase its efficiency by 20% to 25%. Given the ubiquitous use of motors, this could translate into savings of as much as 7% of global electricity demand (IEA, 2009).

In the transport sector, improved fuel economy of today's internal combustion engine (ICE) in cars and trucks (and efficiency improvements in other transport modes) can deliver the largest fuel savings and CO_2 emissions reduction in the short term. After 2030, the increased share of electric and plug-in hybrid electric vehicles (PHEVs) becomes increasingly important for cars and light-duty trucks, reaching 50% of vehicle sales in the 2DS in 2050. The success of hydrogen fuel-cell vehicles depends on the wider use of hydrogen in the economy, as well as on the development of sustainable production methods, the efficiency of hydrogen as a storage medium (compared to competing solutions) and the capacity to finance the necessary infrastructure deployment. Under favourable conditions, fuel-cell vehicles could represent close to 20% of annual vehicle sales in 2050. Biofuels will play an increasingly important role in decarbonising remaining ICE cars and trucks, as well as ships and aircraft, since liquid fuels used by these modes will represent over 75% of energy used in transport in 2050.

All else being equal, higher efficiency is, of course, positive. Yet the gains from pursuing higher efficiencies must be weighed against the higher costs of implementation. In electricity generation, for example, the higher cost of more efficient solar cells must be justified against the savings on land use, grid connections, etc. In laboratory settings, solar PV cells now reach efficiencies of 40% but current economics limits their application to niche markets. Looking ahead, the PV market will likely comprise a mix of high-efficiency, high-cost and low-efficiency, low-cost PV systems and applications that target different market segments. Similarly, in the buildings sector, dramatically improving the efficiency levels in existing buildings is possible through extensive but very costly refurbishments. These costs should be weighed against, for example, increasing the possibilities to use inexpensive waste heat through district heating.

Policies needed to achieve the 2DS

Although *ETP 2012* analysis indicates that the 2DS can be achieved at a net economic saving to society, the transformation will not happen without significant government and public support. Transforming the energy system is an enormous financial challenge, and cost-effective policies should be a priority – particularly as low-cost abatement options are exhausted and the cost of additional reductions rises. Using market mechanisms, such as taxation or emissions trading to allocate abatement efforts and resources where they are most effective, should be the guiding principle for policy design. Incentives at the individual and company level are often not aligned with those of society as a whole. Governments have a critical role to play in correcting this.

First and foremost, the true cost of energy, including effects on the environment, should be visible and passed on to consumers. This is currently not often the case.

Inefficient subsidies that encourage wasteful consumption of energy and fossil fuels must be phased out: such measures are estimated to reduce growth in energy demand by some 4%, even by 2020 (IEA, 2011). In 2010, fossil fuel subsidies were estimated at USD 409 billion (up more than 37% since 2009), against USD 66 billion for renewable energy.

Ideally, a carbon price should equal the net cost to society caused by an additional tonne of emissions. If applied across the entire economy, pricing will in theory deliver an efficient outcome since all sectors would face equal marginal abatement costs. Marginal abatement costs in *ETP 2012* are discussed further in a section below.

Carbon pricing is necessary to incentivise action, but also to safeguard against rebound effects. Even though the prices charged by suppliers of fossil fuels may fall if demand drops in the 2DS, the consumer will continue to see high fossil fuel prices even in the low-carbon scenarios, due to higher carbon prices. If these are implemented in the form of taxes or auctioned emissions allowances, the revenues can be recycled into the economy to help reduce other negative distortions.

Efforts to promote research and development (R&D) to improve the performance and reduce the cost of new, efficient low-carbon technologies need to be stepped up (see Chapter 3). There are important reasons to consider the entire innovation system when designing energy policy and there are limitations to what a carbon price can achieve. Under certain conditions, there is a strong rationale for support for R&D and even for direct technology subsidies. Such policies should be designed to evolve, initially emphasising measures that push technologies into the market (for instance through research, development and demonstration [RD&D] support), then shifting to those aimed at increasing demand (such as fuel economy standards and carbon pricing) as the technologies mature.

Removing non-economic barriers can be as important as introducing pure economic incentives, particularly in regards to energy efficiency. Efficiency improvements often pay back their capital costs via fuel savings over the life of the equipment and provide positive net present value when considered using a societal discount rate. However, many businesses and especially end-use consumers typically exhibit much higher private discount rates and demand much faster payback times. The difference represents a key barrier to investment in energy efficiency, so policies must be used to close this gap and raise efficiency-technology adoption rates to capture their full societal benefits. Part of removing investment barriers is to internalise their non-economic benefits such as CO_2 reductions. Other market failures such as information failures (*i.e.*, cost-benefits are not apparent at the time of investment) are also important to address.

Incremental improvements in energy efficiency are evident globally, but its large potential has yet to be fully tapped. In the buildings sector, improving the efficiency of the building shell will have the largest impact on energy savings. This can be achieved through the stringent application of integrated minimum energy performance codes and standards for new and existing buildings in order to deploy available energy efficient technologies in new constructions and in retrofitting current building stock. For industry, major potential still remains for energy and economic savings through the use of BATs and adoption of energy management systems. In transport, improving fuel economy is the primary action that will help reduce CO_2 emissions within the next decade.

Governments can also act to reduce the cost of capital and to mitigate the risk to investors in clean energy. Capital costs can be brought down by leveraging the governments' cost of capital advantage, or through instruments such as tax credits. Risk can be reduced through support for operating cash flow, for example in the form of feed-in tariffs.[4] Loan guarantees, underwriting of liability risk and public-private partnership are other important policy instruments.

Governments need to develop policies that establish a systems perspective for the energy sector (as shown in Chapters 5 through 7). Segmented approaches to energy policy can rationalise the need for targeted initiatives, but often overlook the potential for true optimisation. Increasing deployment of variable renewables, greater use of electricity for electric vehicles and heating applications, and rising peak and global electricity consumption – all changes in the electricity sector itself – urgently require new policies that allow and provide incentives for smarter energy delivery and consumption. The policy needs are diverse: incentives for construction of new transmission and distribution infrastructure, creation of capacity markets for utilities, and policies to address privacy concerns associated with energy monitoring all fall into this category. How to best encourage investors and utilities to be more flexible will be a central policy challenge.

4 Carbon pricing is also an effective support for operating cash flow, as are specific emissions targets or mandatory performance standards.

Better understanding of energy production, delivery and use from an integrated systems perspective will also help leverage investments across sectors. This will require policy makers to understand new technologies and to work with stakeholders who have not been traditionally involved in the energy sector.

Box 1.3 Carbon market prospects in 2012

Carbon pricing is at the core of an effective long-term strategy to address the climate change challenge. Carbon taxes have been implemented in a number of developed countries and are a topic of policy discussion in others such as China. Carbon market instruments are gaining the favour of governments for the regulation of large emissions sources.

Yet in 2012, the carbon market presents a mixed picture. The European Union Emissions Trading System (EU ETS), the largest of such instruments to date, is hampered by a large surplus of emission allowances, the result of both the economic crisis and an over-allocation to industrial sources early on. While the integrity of the emissions cap remains secure, a price lower than EUR 10/ tCO_2 is not enough to put gas ahead of coal in power generation in Europe, and provides only limited incentives to renewables and nuclear (which are actively supported through other means at present). Low demand in the EU ETS also undermines the development of new projects in developing countries under the Clean Development Mechanism (CDM). Launched under the Kyoto Protocol, and extended beyond 2012 at COP 17 in Durban, the CDM is the only standing carbon market programme to foster GHG emissions reductions in the developing world.

Encouraging developments are now evident outside of Europe; if all these efforts come to fruition, carbon pricing could become the norm rather than the exception. In OECD countries, an ETS has been in operation in New Zealand since 2009; Australia confirmed the implementation of its carbon pricing law, with a carbon tax evolving into a full-blown emissions trading system by 2015; in the United States, California's system is to start in 2013 (with discussions on linking it to similar initiatives in the Canadian province of Quebec); and the North Eastern States' Regional Greenhouse Gas Initiative has been in operation since 2009, albeit with low prices at present. In Canada, the province of Alberta also has a carbon price system in place, with revenues to fund innovative GHG mitigation. South Korea recently approved a law to implement an ETS by 2015.

Of even more significance from an international climate policy perspective, China has launched six carbon market pilots, covering four cities (Beijing, Chongqing, Tianjin and Shanghai) and two provinces (Guangdong and Hubei). The city of Shenzhen recently joined the initiative. If successful, these pilots will pave the way for a nationwide system by 2015. Other developing countries have also expressed interest in developing various types of carbon market mechanisms, as part of the World Bank's Partnership for Market Readiness; partner countries include all four BASIC countries (Brazil, China, India, South Africa) but also Chile, Colombia, Costa Rica, Indonesia, Jordan, Mexico, Morocco, Thailand, Turkey, Ukraine and Vietnam.

Finally, countries agreed at COP 17 in Durban to establish a new market mechanism, of broader reach than the project-based CDM, to support mitigation action in developing countries. Taken together, without underestimating the implementation challenges of carbon market mechanisms, the prospects for carbon pricing are positive.

Finally, a clear message arising from the analysis is that without a genuinely global policy commitment, the 2DS is unachievable. This is true from a purely physical perspective: if only half of the world's countries decarbonise, emissions from the remaining half will likely be higher than the total in the 2DS. Global co-ordination is also necessary from technological, economic and political standpoints. Global deployment of technologies will drive down technology costs, but without comparable policy efforts, the resulting economic distortions would quickly erode political support for stringent domestic policies. International collaboration should therefore be a priority. Countries must act together to establish a common vision for the future energy system, a vision that can be translated into specific goals and policies at the regional and domestic levels.

Marginal abatement costs and carbon pricing in the 2DS

Marginal abatement costs represent the estimated cost for the last tonne of CO_2 emissions eliminated via abatement measures. They are often used as a reference for what carbon price is needed to trigger this abatement, by making the cost of emitting higher than the cost of avoidance. In practice, however, a given carbon price may not trigger all abatement opportunities at that cost level if there are any of a range of market failures at play.

In the 2DS, global CO_2 prices in line with the marginal costs in Table 1.1 have been applied. Overall, estimated marginal abatement costs in *ETP 2012* are slightly lower than in *ETP 2010*. This is an important finding, as marginal abatement costs are a central aspect in policy design. Higher estimates of future prices of fossil fuels (making fuel savings and fuel switching options relatively cheaper) and slightly more optimistic forecasts on cost reductions in important low-carbon technologies (such as solar PV and electric vehicles) are the two main factors behind the lower abatement costs in *ETP 2012*.

Table 1.1 Global marginal abatement costs and example marginal abatement options in the 2DS

	2020	2030	2040	2050
Marginal cost (USD/tCO_2)	30-50	80-100	110-130	130-160
Energy conversion	Onshore wind Rooftop PV Coal w CCS	Utility scale PV Offshore wind Solar CSP Natural gas w CCS Enhanced geothermal systems	Same as for 2030, but scaled up deployment in broader markets	Biomass with CCS Ocean energy
Industry	Application of BAT in all sectors Top-gas recycling blast furnace Improve catalytic process performance CCS in ammonia and HVC	Bio-based chemicals and plastics Black liquor gasification	Novel membrane separation technologies Inert anodes and carbothermic reduction CCS in cement	Hydrogen smelting and molten oxide electrolysis in iron and steel New cement types CCS in aluminium
Transport	Diesel ICE HEV PHEV	HEV PHEV BEV Advanced biofuels	Same as for 2030, but wider deployment and to all modes	FCEV New aircraft concepts
Buildings	Solar thermal space and water heating Improved building shells	Stability of organic LED System integration and optimisation with geothermal heat-pumps	Solar thermal space cooling	Novel buildings materials; development of “smart buildings” Fuel cells co-generation

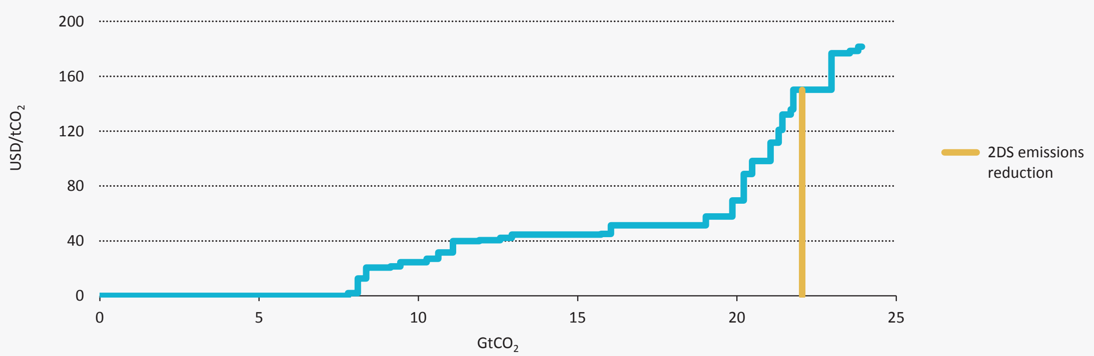
Notes: HVC = high-value chemicals, FCEV = fuel-cell electric vehicle, LED = light emitting diode.

However, there are limitations and methodological challenges in the estimation and application of marginal costs that affect their usefulness in policy design. As described in Chapter 4, in some cases early deployment of technologies with high marginal abatement costs can be cost-effective in the longer term, if their costs come down via increasing scales and through learning. On the other hand, technologies may be limited in application for reasons other than pure cost; two examples include biofuels (which may be limited by land availability) and nuclear (which may be limited by public acceptance).

ETP 2012 analysis follows the general principle of applying less costly technologies before more expensive ones, and also the principle that at the margin (*i.e.* the most expensive) abatement costs should be roughly equal across sectors and regions. But it may be difficult to achieve such alignment in practice; apart from basic cost uncertainties and imperfect information, trade barriers, different political priorities, distributional considerations, etc., all have strong influences on which measures can be implemented in different regions.

The numbers in Table 1.1 represent the cost of the most expensive option applied to mitigate carbon emissions in the 2020 to 2050 time period. Before these last abatement measures, many other measures have been implemented. The impact of these measures can be represented in a marginal abatement cost curve. Typically, marginal cost curves have an exponential (concave upward) shape, as shown for electricity generation (Figure 1.12).

Figure 1.12 Marginal abatement cost curve in electricity generation, 2050



Key point *Marginal abatement costs reach USD 150 in 2050 and increase rapidly as reductions get deeper.*

Inevitably, uncertainty surrounds each individual cost estimate, increasing as the date of the projection reaches further into the future. Small changes in assumptions can result in large changes in estimated net cost per tonne of CO_2 avoided (Box 1.4). Moreover, there is not one unique reference setting in which to determine emissions reductions, and options also interact. The benefits of electrifying industry processes, for instance, will hinge on what measures have been taken to decarbonise electricity. Transaction costs and the cost of addressing non-economic barriers are important, particularly to energy efficiency, and are difficult to assess. Costs of stimulating behavioural change (*e.g.* modal shift) are hard to quantify. Long-term welfare effects of infrastructure development can be very important but are not included in *ETP 2012* analysis.

Marginal abatement costs are dynamic by nature: they both evolve over time and exert influence on each other. Two principal processes work in opposite directions: everything else being equal, costs increase as emissions reductions get deeper. However, as more clean energy technologies are deployed, the cost of using each technology may also decline as a result of learning. The combined effect – and whether marginal abatement costs will rise or fall over time – hinges on whether learning outpaces the move up along the cost curve.[5] This effect is shown more clearly for transport in Box 1.4.

This does not imply that policy makers should not pay attention to marginal costs: they absolutely should. But they need to be aware of the difficulty in estimating future costs and an efficient technology mix. This creates a strong argument in favour of market-based instruments such as taxes or emissions trading, which do not require governments to determine the technologies that should be used to meet a given target. Those choices are left to the market and strategies can be adapted as technologies develop.

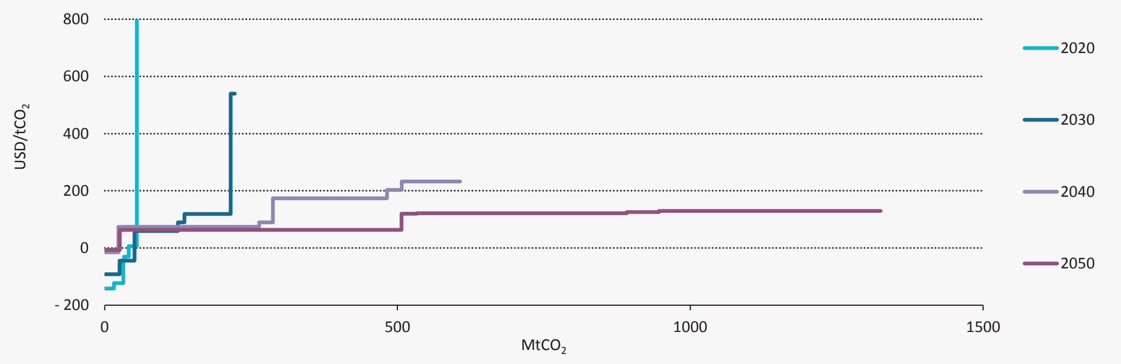
Politicians and policy makers need to formulate a vision of how the future energy system should function. *ETP 2012* provides one such vision and a plausible pathway to get there. Marginal cost curves can be very useful in policy design and evaluation, but to rely too heavily on them to determine the optimal policy mix would be a mistake.

Box 1.4 The dynamics of CO_2 abatement cost: the case of transport technologies

For transport, *ETP 2012* considers a range of efficiency and technology options; those for light-duty vehicles (LDVs) are summarised in Figure 1.13. Costs are estimated for improved gasoline vehicle fuel economy, shifts to advanced diesel vehicles, hybrid vehicles, plug-in hybrids, battery electric vehicles and fuel-cell vehicles.

The figure shows how the total tonnes of reduction (horizontal axis) can be achieved at a given abatement cost per tonne (vertical axis), and how this changes over time. The potential reductions rise over time mainly because it takes time to roll out the improvements, and increase the use of specific technologies over the entire stock of vehicles. Fuel cell vehicle-related reductions, for example, only begin to show up by 2040 and become much more significant by 2050.

Figure 1.13 Passenger LDV marginal abatement cost curves by year, 2DS



Key point *Marginal abatement costs evolve over time, and in transport there is a clear lowering of these costs as a result of learning outpacing the move up the cost curve.*

5 There are many other things that also have an impact on marginal costs, so the description here is stylised.

The other very important effect of time is abatement cost reduction. The base 2DS results show fairly strong cost reductions for key technologies such as batteries and fuel cell systems. Abatement cost reductions also result from rising fuel prices, such that fuel savings become more valuable over time. The net effects reflect the fact that the cost per tonne of avoided CO_2 is highly sensitive to relatively modest changes in technology and fuel costs.

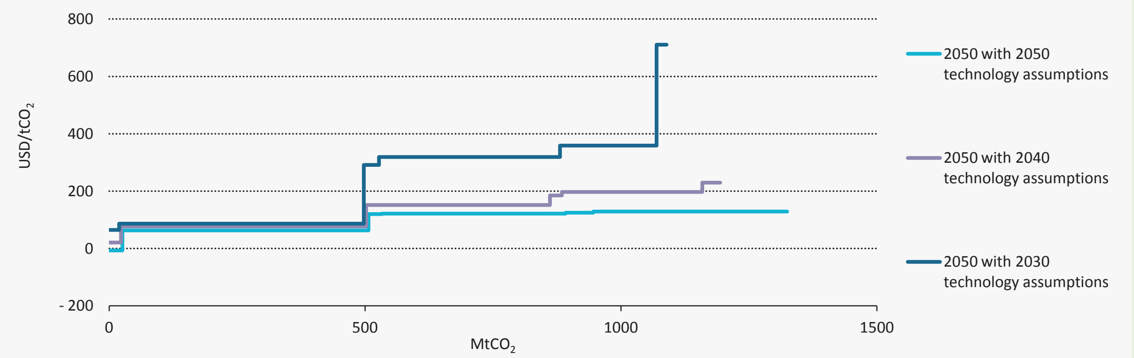
Overall, most of the cost reductions in 2020 (mainly fuel economy improvements) can be achieved at below USD 0 per tonne. Above zero, the costs quickly become very high, rising to USD 500/tCO_2 but the amount of CO_2 reduction achieved is quite low. This reflects the period required to reduce the costs of electric vehicles and plug-in hybrids through policy support, which would not be of interest (from a societal perspective) if there weren't strong reason to believe that the costs will come down over time as cumulative production provides learning effects. It should be noted as well that, since these are societal cost calculations, even costs below zero might not be taken up by the market. This could be the case if, for example, personal discount rates are much higher than societal ones, and the payback time for investments is longer than people are willing to tolerate.

Over time, the cost of new technologies such as EVs, PHEVs and FCEVs declines as the numbers of these vehicles rise, which (along with fuel prices rising over time) has the effect that cost per tonne drops rapidly in concert with increasing production rates of vehicles. By the time very large volumes of each type of vehicle are being produced, the cost per tonne is well below USD 100 and in some cases has dropped below zero. The implication is that while one must be careful not to be too optimistic on cost reduction, one also must not reject technologies simply because of a high cost per tonne in the early years, when very few vehicles are being produced anyway.

Cost sensitivity

A sensitivity analysis of the results with respect to variations in technology cost shows how important assumptions on learning are (Figure 1.14). The 2DS 2050 cost curve is presented along with cases where we see the 2050 cost curves if technology costs are assumed to stay constant after 2020 or 2030. Though these cases are not explicitly modelled in *ETP 2012*, the curves show that with 2030 cost levels, the marginal transport costs (from hydrogen/fuel-cell vehicles) is about USD 125/tCO_2. This would rise to over USD 700/tCO_2 with 2020 costs; as such a case is not cost-effective, it is unlikely that FCEVs would be included in a scenario with those input assumptions.

Figure 1.14 **Passenger LDV marginal abatement cost curves in the 2DS in 2050 under different assumptions on learning**



Key point *Estimates of future marginal abatement costs are very sensitive to input assumptions.*

Linking energy security and low-carbon energy

Energy security refers to the ability of a given country to obtain uninterrupted availability of its main energy sources at an affordable price. In the short term, energy security is the ability of a given energy system to react promptly to sudden changes in supply and demand, maintaining the availability, affordability, accessibility and quality of energy. Long-term energy security is linked mainly to making timely investments to ensure that the future supply of affordable energy will support economic development and environmental goals.

Ultimately, the long-term strategy has consequences for the short-term delivery of energy security, particularly in the current context: the energy sector is evolving rapidly, yet many components in a given energy system have long life spans (40 to 100 years). Just as today's energy systems reflect investments and policy decisions made from the mid-1900s onwards, choices made in the coming years and decades will either support or constrain future energy supplies.

In the past, many energy strategies had a strong focus on mitigating the risks of energy supply disruptions, particularly within oil markets. For the IEA, oil supply disruptions are historically an important threat to energy security, and it has started to identify and assess the severity of other risks given the recent evolution of energy supply and demand. It also emphasises that avoiding risks is only part of the energy security equation: another important characteristic is resilience – the ability of energy systems to mitigate or withstand disruptions.

In the 6DS, the world's TPES would increase by approximately 80% in 2050 compared to 2009; the 2DS estimates an increase of some 35%. Implementing the energy efficiency measures needed for the 2DS, and thereby reducing energy consumption, contributes to short-term energy security: energy that is not consumed does not have to be produced, refined, transported or imported, so the dependence on a sometimes fragile value chain will fall. A substantial increase in energy consumption will further stretch already tight supply chains and bring into question the availability of supply itself. In addition, these scenarios represent two diverse energy systems, with different basic requirements for energy security. Some broad assumptions about how each scenario could influence energy security can be made by examining changes to the energy mix as well as the energy security profiles of individual fuels. In this section an explanation is given of how to measure risk and resilience and the benefits of diversified energy portfolios. The section concludes with an examination of energy security under the 6DS and the 2DS – *i.e.* in the wake of climate change or within the context of a low-carbon economy.

Measuring risk and resilience

Historically, energy security was primarily associated with oil supply. While oil supply remains a key issue, the increasing complexity of energy systems requires systematic and rigorous understanding of a wider range of vulnerabilities. Disruptions can affect other fuel sources, infrastructure or end-use sectors. Thus, analysis of oil supply security alone is no longer sufficient for understanding a country's energy security situation as a whole.

The IEA has responded to this challenge by developing a comprehensive tool to measure energy security. The Model of Short-term Energy Security (MOSES) examines both risks and resilience factors associated with short-term physical disruptions of energy supply that can last for days or weeks. MOSES extends beyond oil to monitor and analyse several important energy sources, as well as the non-energy components (such as infrastructure) that comprise an energy system. Analysis of vulnerability for fossil fuel disruptions, for example, is based on risk factors such as net-import dependence and the political stability of suppliers. Resilience factors include the number of entry points for a country (*e.g.* ports and pipelines), the level of stocks and the diversity of suppliers. For hydropower, MOSES uses annual volatility of production as a risk indicator (calculated by the standard deviation of full load hours divided by the average of full load hours) and water reservoirs as a resilience factor. Nuclear energy carries predominantly domestic risks, associated with the unplanned outage rate and average age of nuclear power plants; these risks can be compensated for (resilience) by the number of nuclear plants in place and the diversity of reactor models.

Box 1.5 IEA model of short-term energy security

The IEA MOSES aims to help IEA countries understand their energy security profiles in order to identify energy policy priorities. MOSES identifies a set of indicators for external risks (from energy imports) and for domestic risks (from transformation and distribution) as well as for resilience. The current version of MOSES (Primary Energy Sources and Secondary Fuels) covers seven primary sources (crude oil, natural gas, coal, biomass and waste, hydropower, geothermal energy and nuclear power) and two sets of secondary fuels (oil products and liquid biofuels). The IEA is working to extend the analysis to power generation and end uses of energy, which will be reflected in subsequent versions of MOSES.

MOSES addresses four dimensions of energy security: external and domestic risk, and external and domestic resilience (Table 1.2).

Table 1.2 Dimensions of energy security addressed in MOSES

	Risk	Resilience
External	***External risks:*** risks associated with potential disruptions of energy imports.	***External resilience:*** ability to respond to disruptions of energy imports by substituting with other suppliers and supply routes.
Domestic	***Domestic risks:*** risks arising in connection with domestic production and transformation of energy.	***Domestic resilience:*** domestic ability to respond to disruptions in energy supply such as fuel stocks.

MOSES highlights vulnerabilities of energy systems and can be used to track the evolution of a country's energy security profile. Policy makers and analysts can use MOSES to identify energy policy priorities by assessing the effects of different policies on a country's energy security.

The current version of MOSES focuses on security of supply of primary energy and secondary fuels; it does not assess the security of solar, wind and ocean energy. As such energies are primarily used to produce electricity, the security of their supply is closely linked to the risk and resilience profile of electricity systems.

Diversification of energy sources

Promoting the diversification of sources in an energy portfolio is one way to mitigate the potential impact of an interruption of any given energy source. Diversification can therefore be seen as a resilience factor for national energy security.

Energy independence (reduced need to import fuels) is sometimes also seen as an indicator for national energy security. While such a policy reduces the risks that can come with long transportation routes, one has to caution that domestic production and distribution have their own risks too, as explained below.

The following analysis uses the Herfindahl-Hirschman Index (HH-index)[6] to measure diversification in the energy portfolios in the three scenarios for different countries and regions. A lower HH-index score indicates a higher level of diversity in the energy mix, assuring greater energy security. The *ETP 2012* scenarios distinguish seven energy sources: coal, oil, gas, nuclear, hydropower, biomass and waste, and other renewables. The HH-index can thus range from 0.143 (each fuel accounts for one-seventh of TPES for perfect diversity) to 1.0 (only one fuel source, or no diversity of supply). Applying the HH-index across different regions and countries within the context of each scenario[7] shows levels of security change in different patterns, but diversification in 2050 is consistently higher in the 2DS than in the 6DS (Table 1.3).

Table 1.3 HH-index for measurement of diversification of energy portfolio

	in 2009	in 2050		
		6DS	4DS	2DS
World	0.240	0.232	0.193	0.164
OECD	0.259	0.204	0.194	0.171
United States	0.265	0.205	0.208	0.174
OECD Europe	0.246	0.209	0.194	0.175
OECD Asia Oceania	0.283	0.225	0.204	0.193
Non-OECD	0.249	0.253	0.204	0.166
Russia	0.361	0.275	0.268	0.215
China	0.481	0.368	0.260	0.171
India	0.299	0.332	0.260	0.170
ASEAN	0.264	0.254	0.210	0.194

The 2DS would be achieved when the fossil fuels share in TPES significantly decreases and is compensated for by nuclear and renewable energy. Deployment of non-carbon fuels and consequent diversification of the energy portfolio are beneficial for enhancing energy security, reducing dependence on fossil fuels. It should also be noted that most non-fossil fuels are produced domestically, which makes them less vulnerable than fossil fuels that have to be imported in most countries, sometimes over long distances and from countries with political instability. For measuring the vulnerability for fossil fuels, the MOSES model

6 The Herfindahl-Hirschman Index is a well-established tool, commonly used by governments to measure market concentration – and therefore market power – of companies. It is equal to the sum of the square of the individual market shares of all the participants. In this ETP analysis of the most important countries and regions in energy projections, the market participants are considered to be the seven fuels, and the calculations are made according to the share of each fuel in TPES in each of the scenarios.

7 In MOSES, the HH-index is also used to calculate the diversity of suppliers of fossil fuels and the diversity of nuclear reactor models, as it is a useful tool for measuring concentration or diversity.

uses import dependence and political stability of suppliers as external risk indicators, as well as volatility of production and share of offshore production as domestic risk indicators. Reduction of dependency on fossil fuels can contribute to mitigating both the external and domestic risks of fossil fuels.

China shows the greatest potential to benefit from diversification. In 2050, its HH-index falls from 0.368 in the 6DS to 0.171 in the 2DS, largely reflecting a dramatic drop in the share of coal (from over 50% in the 6DS to less than 30% in the 2DS). The significant decrease of coal's share could also reduce import dependency and the proportion of underground mining, which in MOSES are labelled as risk indicators for coal.

In India, diversification in 2050 improves by over 0.15 points in the 2DS compared to the 6DS. This is based on the reduced share of coal in TPES (from close to 50% in the 6DS to less than 25% in the 2DS), and on the rising share of nuclear (from below 2% in the 6DS to over 10% in the 2DS) and renewables (from around 10% to some 35%). India can also mitigate the current vulnerability deriving from coal dependency.

ASEAN has well-diversified energy sources even in 2009, as shown by its relatively low HH-index, reflecting a higher share of biomass and waste due to traditional use of biomass energy. Broader introduction of renewables, including through deployment of modern biomass energy technologies (as envisioned in the 2DS), could further improve its energy portfolio.

Energy security in the 6DS

On the current course, which is the trajectory followed by the 6DS, energy security is likely to become a more urgent challenge. Worsening rates of global climate change will have severe impacts on the natural environment, including rising sea levels, changing rainfall patterns, and increasing incidences of droughts, floods and heat waves – all of which will severely affect ecosystems, food production and water resources. These impacts will alter the global economy and affect the well-being of citizens.

Such threats will also influence energy balances and energy security, leading to an elevation in supply risks for both fossil and non-fossil fuels.

On the fossil fuel side, these reserves are not unlimited and the costs of producing the marginal barrel, cubic metre or tonne will rise over time. While fossil fuel demand in OECD countries will rise by some 10%, in non-OECD countries demand for fossil fuels will more than double in 2050 compared to 2009 in the 6DS; these countries will need more resilience factors (such as expensive emergency stocks) to ensure their energy security. Exceptional natural disasters could delay the exploration of offshore oil and natural gas fields, and more hurricanes could force the shut-down of oil refineries in the affected regions. Furthermore, an increasing share of oil and gas production will come from unconventional sources and production methods that have higher production costs and leave greater environmental footprints than conventional methods.

Non-fossil fuels will also face new risks. Electricity grids and wind farms may need to be better protected against increased random events like hurricanes; solar technologies (including PV, heating and cooling) could be negatively affected by longer periods of cloudy weather.

More systematically, five additional risks for energy security can be identified as a result of climate change: altered demand patterns; different infrastructure needs; water scarcity; productivity of arable land; and human migration.

Energy demand patterns are region-specific. As temperatures rise, electricity consumption in some areas would inevitably increase due to the use of air conditioning. But heating demand could decrease in other regions as winters become milder. On balance, energy demand will not only increase, but will also be distributed differently across regions and seasons.

Risks to the energy infrastructure are diverse. Rising sea levels put at risk both coastal refineries and offshore/coastal oil storage facilities. Oil and gas pipelines might also be more vulnerable because of an increase in unanticipated soil falls due to heavier rainstorms. If warmer temperatures melt permafrost, pipeline infrastructures (*e.g.* the Trans-Alaska Pipeline System) might also be affected.

Increased water scarcity creates risks for hydro power, fracking and enhanced oil and gas recovery, as well as for the cooling opportunities of thermal and nuclear power plants. By regulation in many countries, seas and rivers are not allowed to be used for cooling if the water temperature is above a certain level.

Productivity of arable land is likely to be affected by abnormal weather patterns and desertification may have negative impacts such as lower production of biofuels.

Finally, deterioration of local environments may accelerate mass migration of human populations. This would most certainly affect energy demand trends, but could also threaten energy security due to increasing political instability.

On a global level, energy efficiency and energy security go together in tackling climate change. Considering the trends in total energy supply in the scenarios, it is clear that OECD and non-OECD countries alike can enhance their energy security by making efforts to slow down their rising energy demand. Ultimately, achieving the 2DS is pivotal to reducing energy demand, improving diversification of the energy portfolio and mitigating risks resulting from climate change itself.

Energy security in the 2DS

The 2DS is significantly different from the other scenarios when examined from the energy security perspective. Total energy demand is substantially lower than in the 4DS and the 6DS, and the sources and technologies employed to meet that demand are radically different. In fact, fossil fuel use will decrease by close to 50% in both electricity generation and transport in the OECD.

This has implications for the effectiveness of certain current measures for the security of the energy supply. For example, fuel switching, which assures the energy supply for heat or power generation by substituting one energy source for another, currently functions mainly on the substitution possibilities between oil and gas. Existing policies are unlikely to be effective in an energy system in which the shares of variable renewables outstrip those of fossil fuels. Clearly, a low-carbon energy system creates a new set of challenges for short-term energy security. The role of low-carbon technologies needs to be appraised based on their influence on the overall risk portfolio.

Because electricity will account for a larger share of final energy demand in the 2DS, its security is of high importance. In all regions, promoting timely decarbonisation of electricity supplies must be coupled with efforts to ensure continuing reliability of electricity systems.

In the electricity sector, flexibility is the term used to describe the extent to which a power system can rapidly ramp up (or down) the actual output in response to unexpected fluctuations in either supply or demand. Flexibility is traditionally associated with generators that can be dispatched quickly (such as open-cycle gas turbines and reservoir hydropower), but the definition can be widened to encompass how the system transports, stores, trades and consumes electricity. Assessment of flexibility should reflect the full capability of a power system to maintain reliable supply in the face of rapid and large imbalances, for whatever reason.

In the case that electricity generated by large-scale solar and wind power plants can be traded beyond the producing region, electricity import dependency might pose risks similar to those currently associated with imported fossil fuels. If interregional electricity import becomes more common, measures will be needed to tackle electricity disruptions beyond regions, possibly through mechanisms much like the emergency oil stock, fuel switching and demand restraint strategies now in place to reduce the impact of oil supply disruptions.

Recommended actions for the near term

The world's energy system needs to be transformed. The current path is unsustainable from an environmental standpoint, and threatens long-term economic growth and energy security. There are encouraging signs in some areas, but the overall rate of progress towards a future sustainable energy system is too slow.

Political leaders need to set a clear vision for a clean energy future, backed by credible targets and decisive policy action. Only then will it shape the decisions made in research, industry and by investors today, that are necessary to achieve a sustainable energy system in the longer term.

As *ETP 2012* shows, a low-carbon energy system will look different across regions. Existing infrastructure, domestic energy resources and the structure of national economies dictate which policies are appropriate and most effective in a regional context. However, a level playing field for all energy resources and technologies should be a priority in all countries.

Ensure that prices reflect the full scope of costs and benefits. Without correct price signals, the transformation towards a clean energy future will be more costly and garner less support among political leaders and citizens. Removing non-economic barriers is also important, particularly to unlock the large, near-term potential for energy efficiency improvements.

Increase international collaboration. While policy choices will be governed by domestic priorities and will differ among countries, a shared vision of a clean energy future is vital. Action must be taken in all regions if the goals outlined in the 2DS are to be achieved. Continued dialogue and multilateral co-operation, and efforts to develop common goals, are critical.

Increase efforts to reduce energy dependence. Diversifying the portfolio of energy technologies and resources will strengthen energy security. Policy choices made in the coming years will be crucial for mitigating the risks and strengthening resilience to energy supply disruptions in 2050. Considering the substantial investment required in order to provide secure energy, system investors and operators look to governments to create policies that provide a clear, long-term energy strategy, and support a reasonable return on investment.

Accelerate energy innovation. As the results from RD&D can take years to fully materialise, it is imperative that efforts in this area are made in the near term. Investing in the development of new technologies may seem costly from the outset, but the advantages to be gleaned in the longer term prove to be a far greater benefit.

Ultimately, the future energy system is contingent on short term decisions. These must be guided by long-term visions, goals and strong, definitive policies.

Chapter 2

Tracking Clean Energy Progress

While many clean energy technologies are available, few are being developed and deployed at the rates required to meet the *ETP 2012* 2°C Scenario objectives. Getting back on track will require timely and significant policy action.

Key findings

- ***Onshore wind has seen 27% average annual growth over the past decade, and solar photovoltaic (PV) has grown at 42%, albeit from a small base****. Costs have fallen dramatically, with a 75% reduction in solar PV system costs in as little as three years in some countries. This is positive, but maintaining these high rates of deployment will be challenging.*
- ***The technologies with great potential for energy and carbon dioxide (CO_2) emissions savings are making the slowest progress****. Carbon capture and storage (CCS) is not seeing the necessary rates of investment to develop full-scale demonstration projects, and nearly half of new coal-fired power plants are still being built with inefficient technology. Improvement of vehicle fuel efficiency is slow, and significant untapped potential for energy efficiency remains in the buildings and industry sectors.*
- ***In addition, while government targets for electric vehicle stock (20 million by 2020) are ambitious, as are continued government nuclear expansion plans in many countries, translating plans into reality will not be easy****. Manufacturers' production targets for EVs after 2014 are highly uncertain, and rising public opposition to nuclear power is proving challenging to address.*

Opportunities for policy action

- *Government support for technology research, development and demonstration (RD&D) is critical. Promising renewable energy technologies (such as offshore wind and concentrated solar power) and capital-intensive technologies, such as CCS and integrated gasification combined cycle (IGCC), have significant potential but still face technology and cost challenges that require enhanced RD&D.*
- *Broad policy action to level the playing field for mature clean energy technologies is necessary. This can be enabled, for example, by ending inefficient fossil-fuel subsidies and ensuring that energy prices appropriately reflect the "true cost" of energy (e.g. through carbon pricing) so that the positive and negative impacts of energy production and consumption are fully taken into account.*

- *Targeted deployment policy support to foster continued learning and cost reductions will also help available technologies penetrate the market faster. While some renewable technologies are beginning to compete under the right market and resource conditions, most clean energy technologies still cost more than incumbent fossil fuel technologies.*
- *Energy efficiency improvements must be prioritised. In the buildings sector, improvements in the efficiency of the building shell will have the largest impact on energy savings. This can be achieved through the stringent application of integrated minimum energy performance codes and standards for new and existing buildings, retrofitting the current building stock, and deploying available energy efficient technologies. In industry, major potential remains for energy and economic savings through the use of best available technologies (BAT) and adoption of energy management practices and systems. In transport, improving fuel economy is the number one action that will help reduce CO_2 emissions within the next decade.*

Recent environmental, economic and energy security trends point to major challenges: energy-related CO_2 emissions are at a historic high, the global economy remains in a fragile state, and energy demand continues to rise. The past two years (2010 and 2011) also saw the Deepwater Horizon oil spill off the Gulf of Mexico, the Fukushima nuclear disaster in Japan and the Arab Spring, which led to oil supply disruptions from North Africa. Taken together, these trends and events emphasise the need to reshape the global energy system. Whether the priority is to ensure energy security, rebuild national and regional economies, or address climate change and local pollution, the accelerated transition towards a lower-carbon energy system offers opportunities in all of these areas.

Energy Technology Perspectives 2012 (ETP 2012) demonstrates that achieving this transition is technically feasible – and outlines the most cost-effective combination of technology options to limit global temperature rise by 2050 to 2°C above pre-industrial levels. While possible, it will not be easy. Governments must enact ambitious policies that prioritise the development and deployment of cleaner energy technologies at a scale and pace never seen before. Based on recent trends, are clean energy technologies being deployed quickly enough to achieve this objective? Are emerging technologies making the necessary progress to play an important role in the future energy mix? And if not, which technologies require the biggest push?

Answering these questions requires looking across different technology developments simultaneously, as technology transition requires changes throughout the entire socio-technical system. This includes the technological system, its actors (government, individuals, business and regulators), institutions, and economic and political frameworks (Neij and Astrand, 2006). The success of individual technologies depends on a number of conditions: the technology itself must evolve and become cost-competitive; policies and regulations must enable deployment; markets must develop to a sufficient scale to support uptake; and the public must embrace new technologies and adopt new behaviours (Table 2.1).

Table 2.1 Factors that influence development and deployment progress of clean energy technology

Technological progress	Technical efficiency improvements Competitive cost of technologies
Market development	Creation of technology markets through enabling policies Knowledge and competencies of market analysts and private-sector investors Parity of energy and electricity prices Manufacturing capacity and supply chain development Skills and competencies to build and operate new technologies
Institutional, regulatory and legal frameworks	Changes to institutions and processes to support adoption of new technologies Legal and regulatory frameworks to enable technology deployment
Acceptance by social frameworks	Knowledge and education Acceptance of new technologies

Using available quantitative and qualitative data, this chapter tracks progress in the development and deployment of clean energy[1] and energy efficient technologies in the power generation, industry, buildings and transport sectors, given their essential contributions to the objectives of the *ETP 2012* 2°C Scenario (2DS) (Figure 2.1). Technology progress is evaluated by analysing three main areas:

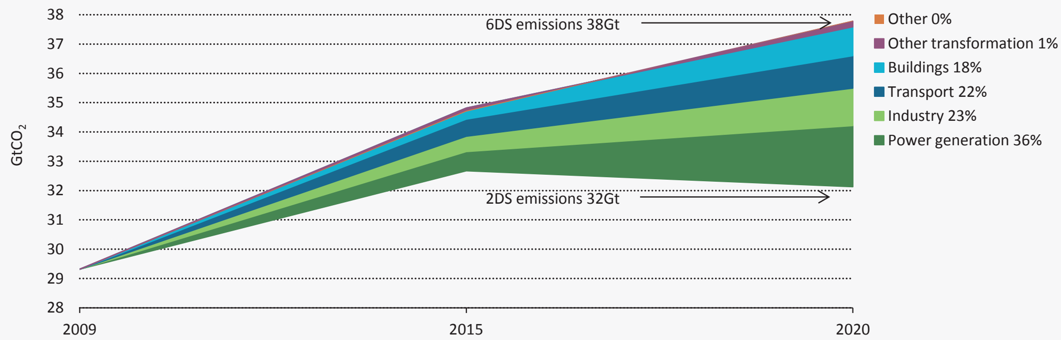
- **Technological progress,** using data on technology performance, technology cost and public spending on RD&D.
- **Market creation,** using data on government policies and targets, and private investment.
- **Technology penetration,** using data on technology deployment rates, share in the overall energy mix and global distribution of technologies.

Assessing these elements together provides an overview of whether technologies are, or are not, likely to achieve the 2DS objectives by 2050, using 2020 deployment milestones as interim evaluation benchmarks. The short-term focus (present to 2020) emphasises actions over the next decade that are required both to capture available energy savings opportunities and to set the course for technologies that will play a larger role in post-2020 decarbonisation, such as CCS and electric vehicles.

Importantly, the analysis in this chapter also identifies major bottlenecks and enablers for scaling up the spread of each clean energy technology.

1 "Clean energy" here includes those technologies outlined as necessary and playing a major role in reducing CO_2 emissions under the *ETP 2012* 2°C Scenario (2DS), and for which sufficient data were available to undertake analysis. Natural gas technologies and recent developments are not included in this analysis, but are discussed in detail in the Gas chapter.

Figure 2.1 Key sector contributions to world CO_2 emissions reductions



Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *All major sectors must contribute to achieve the 2DS by 2020.*

While this report assesses progress and makes recommendations in individual technology areas, it should be emphasised that to effectively plan for a clean energy future, governments should ideally approach the transition holistically. The success of individual technologies does not necessarily translate into a successful transition. Much more important is the appropriate combination of technologies integrated within fully flexible energy production and delivery systems. Enabling technologies, such as smart grids and energy storage, are equally vital and should be prioritised as part of national energy strategies.

Box 2.1 Quality and availability of progress-tracking data

Data included in this analysis are drawn from IEA statistics, country submissions through the Clean Energy Ministerial (CEM) and G20 processes, publicly available data sources and select purchased data sets. Significant improvements to data quality and completeness would benefit future progress-tracking efforts.

- Major progress in deployment of clean energy technology has been driven by countries outside the OECD, but gaps exist in non-OECD country data.
- While public RD&D data are included in this report, private RD&D data are not. While efforts have been made to assess the possibility of enhancing private RD&D data collection, major barriers remain, including lack of appropriate frameworks for industry to confidentially report data, and a general lack of incentive for industry to report these data. Private RD&D is, however, estimated to represent a large share of RD&D spending in some technology areas. Better information on private RD&D spending would help governments prioritise allocation of public RD&D funds.
- Significant scope remains for the collection of data related to energy efficiency technologies, including data on appliance efficiencies, sales and market share. In addition, better and more complete data on buildings and industry energy efficiency are necessary, particularly given their large-scale potential.
- Collection of data for assessing the smartness of electricity grids is under way and will complement this analysis in the future.

Table 2.2 Summary of clean energy technology progress towards the 2DS

CO_2 reduction share by 2020*	On track?	Technology	Status against 2DS objectives	Key policy priorities
36%		HELE coal power	Efficient coal technologies are being deployed, but almost 50% of new plants in 2010 used inefficient technology.	CO_2 emissions, pollution and coal efficiency policies required so that all new plants use best technology and coal demand slows.
		Nuclear power	Most countries have not changed their nuclear ambitions. However, 2025 capacity projections are 15% below pre-Fukushima expectations.	Transparent safety protocols and plans; address increasing public opposition to nuclear power.
		Renewable power	More mature renewables are nearing competitiveness in a broader set of circumstances. Progress in hydropower, onshore wind, bioenergy and solar PV are broadly on track with 2DS objectives.	Continued policy support needed to bring down costs to competitive levels and to prompt deployment to more countries with high natural resource potential is required.
			Less mature renewables (advanced geothermal, concentrated solar power [CSP], offshore wind) not making necessary progress.	Large-scale RD&D efforts to advance less mature technologies with high potential.
		CCS in power	No large-scale integrated projects in place against the 38 required by 2020 to achieve the 2DS.	Announced CCS demonstration funds must be allocated. CO_2 emissions reduction policy, and long-term government frameworks that provide investment certainty will be necessary to promote investment in CCS technology.
23%		CCS in industry	Four large-scale integrated projects in place, against 82 required by 2020 to achieve the 2DS; 52 of which are needed in the chemicals, cement and iron and steel sectors.	
		Industry	Improvements achieved in industry energy efficiency, but significant potential remains untapped.	New plants must use best available technologies; energy management policies required; switch to lower-carbon fuels and materials, driven by incentives linked to CO_2 emissions reduction policy.
18%		Buildings	Huge potential remains untapped. Few countries have policies to enhance the energy performance of buildings; some progress in deployment of efficient end-use technologies.	In OECD, retrofit policies to improve efficiency of existing building shell. Globally, comprehensive minimum energy performance codes and standards for new and existing buildings. Deployment of efficient appliance and building technologies required.
22%		Fuel economy	1.7% average annual fuel economy improvement in LDV efficiency, against 2.7% required to achieve 2DS objectives.	All countries to implement stringent fuel economy standards, and policies to drive consumers towards more efficient vehicles.
		Electric vehicles	Ambitious combined national targets of 20 million EVs on the road by 2020, but significant action required to achieve this objective.	RD&D and deployment policies to: reduce battery costs; increase consumer confidence in EVs; incentivise manufacturers to expand production and model choice; develop recharging infrastructure.
		Biofuels for transport	Total biofuel production needs to double, with advanced biofuel production expanding four-fold over currently announced capacity, to achieve 2DS objectives in 2020.	Policies to support development of advanced biofuels industry; address sustainability concerns related to production and use of biofuels.

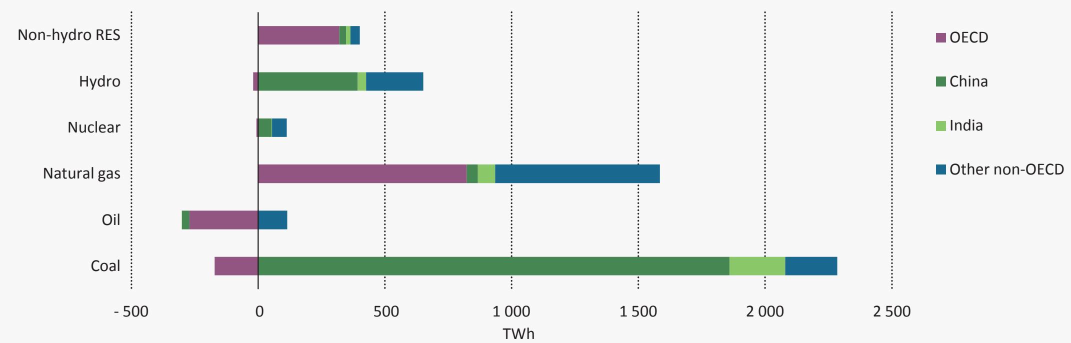
Note: HELE= high efficiency, low-emissions *Does not add up to 100% as 'other transformation' represents 1% of CO_2 emission reduction to 2020; = Not on track; = Improvements but more effort needed; = On track but sustained support and deployment required to maintain progress.

Power generation

The power generation sector is expected to contribute more than one-third of potential CO_2 emissions reduction worldwide by 2020 under the 2DS, and almost 40% of 2050 emissions savings. Enhanced power generation efficiency, a switch to lower-carbon fossil fuels, increased use of renewables and nuclear power, and the introduction of CCS are all required to achieve this objective. Over the past decade, however, close to 50% of new global electricity demand was met by coal (Figure 2.2). This trend must be reversed quickly to successfully reduce CO_2 emissions in the power sector and have any chance of meeting the 2DS objectives.

This section focuses on progress in the development and deployment of higher-efficiency, lower- emissions (HELE) coal technology, nuclear power and renewable power.

Figure 2.2 Changes in sources of electricity supply, 2000-09



Note: Non-hydro RES = renewable energy sources other than hydropower. TWh = terawatt hours.

Key point *Coal remains the largest source for global power generation and supplied the largest share of additional electricity demand worldwide over the past decade. The share of natural gas is also increasing, particularly in some OECD economies.*

Higher-efficiency and lower-emissions coal

Progress assessment

Coal is a low-cost, available and reliable resource, which is why it is widely used in power generation throughout the world. It continues to play a significant role in the 2DS, although its share of electricity generation is expected to decline from 40% in 2009 to 35% in 2020, and its use becomes increasingly efficient and less carbon-intensive. Higher-efficiency, lower-emissions coal technologies – including supercritical (SC) pulverised coal combustion, ultra-supercritical (USC) pulverised coal combustion and IGCC – must be deployed. Given that CCS technologies are not being developed or deployed quickly, the importance of deploying HELE technology to reduce emissions from coal-fired power plants is even greater in the medium term.

From a positive perspective, HELE coal technologies increased from approximately one-quarter of coal capacity additions in 2000 to just under half of new additions in 2011.

By 2014, global SC and USC capacity will account for 28% of total installed capacity, an increase from 20% in 2008. Given their rapid expansion, China and India will account for more than one-half of combined SC and USC capacity. Nonetheless, it is of concern that in 2010, almost one-half of new coal-fired power plants were still being built with subcritical technology (Figure 2.6).

IGCC technology, in the long term, offers greater efficiency and greater reductions in CO_2 emissions, but very few IGCC plants are under construction or currently planned because costs remain high (Figure 2.4). Recent demonstration plants in the United States had cost overruns that soared far beyond expectations. For example, costs of the US Duke Energy 618 megawatt (MW) IGCC plant (in Edwardsport, IN) increased from an original estimate of USD 3 400 per kilowatt (kW) in 2007 to more than USD 5 600/kW in 2011 (Russell, 2011).

Significant variation persists in achieved efficiencies of installed coal power-plant technologies, but the gap between designed and actual operational efficiency is closing. Based on a sample of plant estimates, the efficiency of India's installed subcritical plants stood at 25% in the 1970s, while those installed in 2011 achieve efficiencies up to about 35%; efficiency of the SC and USC among OECD member countries improved from about 38% to close to 45% over the same period (Figure 2.3). Poor-quality coal resources and inefficient operational and maintenance practices often result in lower operational efficiency. Given the long life span of existing coal infrastructure, a focus on improving operational efficiency of existing plants offers obvious energy and cost savings opportunities without requiring additional capital investments.

In summary, although the rising share of more efficient coal technologies is positive, if the 2DS objectives are to be achieved, policies must be put in place to stop deployment of subcritical coal technologies, curtail increased coal demand and further reduce associated CO_2 emissions.

Recent developments

From 2009 to 2011, demand for coal has continued to shift to non-OECD Asia, particularly China and India (Figure 2.7). Since 2000, China has more than trebled its installed capacity of coal, while India's capacity has increased by 50%. On an optimistic note, in 2011 China built more SC and USC capacity (40 gigawatt [GW]) than subcritical capacity (23 GW), and its growth in power capacity from coal has slowed slightly, as its policy of diversification to nuclear and renewable sources takes effect.

As of 2009, 25% of India's population still had no access to electricity. To meet this large latent demand, India is rapidly increasing construction of new coal-fired power plants, with 35 GW of additional capacity in 2011 (a threefold increase over 2010 additions). Until 2010, all new plants in India were built with subcritical technology, but from 2010 to 2011, preliminary estimates suggest that 8.5 GW of SC capacity was installed, compared with 36 GW of new subcritical capacity.

Global coal prices increased significantly, which if sustained may provide greater impetus to build high-efficiency plants and operate existing plants more efficiently. However, in cases where power prices have continued to be kept low, the additional capital investments required for higher-efficiency plants (Figure 2.5) may prove challenging as profit margins are squeezed or losses incurred.

- Steam coal import prices among OECD member countries – a proxy for international coal prices – rose sharply from just over USD 40 per tonne (t) in 2004 to more than USD 100/t in 2011 (Figure 2.5).

Higher-efficiency and lower-emission coal overview

More advanced coal technologies are being deployed, but inefficient coal technologies still account for almost half of new coal-fired power plants being built. Unless growth in coal-fired power generation and subcritical coal development is curtailed, it will be impossible to achieve the 2DS objectives.

Technology developments

Recent technology developments

Despite an increasing coal price, it remains among the cheapest power generation sources

IGCC offers the highest efficiency potential, but still requires dramatic cost reductions to take off

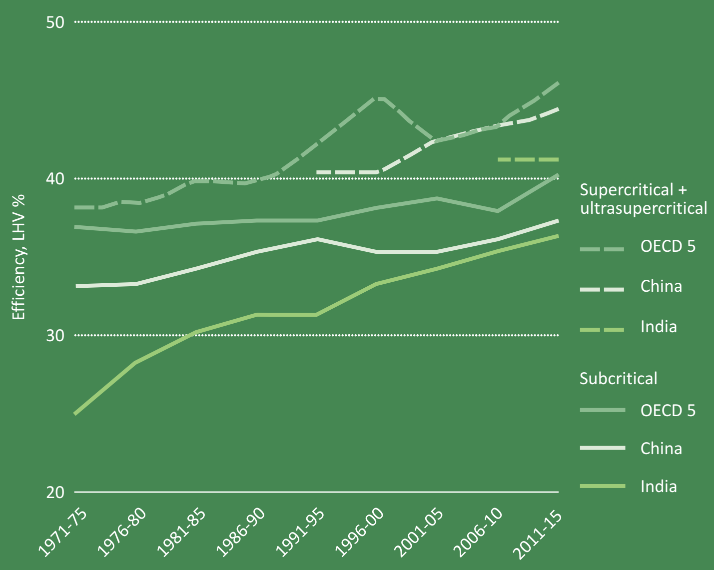
Achieved operational efficiency of coal technologies is improving, but potential for improvement remains

RD&D spending has remained relatively constant over the past decade

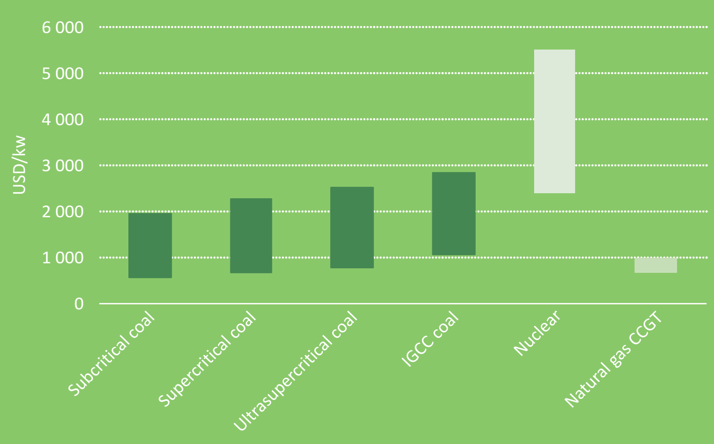
50%

IGCC EFFICIENCY POTENTIAL, BUT SIGNIFICANT COST REDUCTIONS STILL REQUIRED

2.3: Efficiency of coal-fired power plants

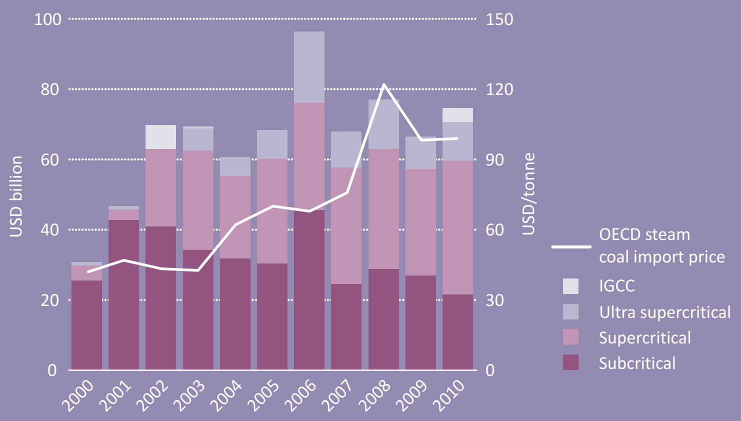


2.4: Investment cost of fossil and nuclear power



Market creation

2.5: Annual capacity investment and coal price



Key trends

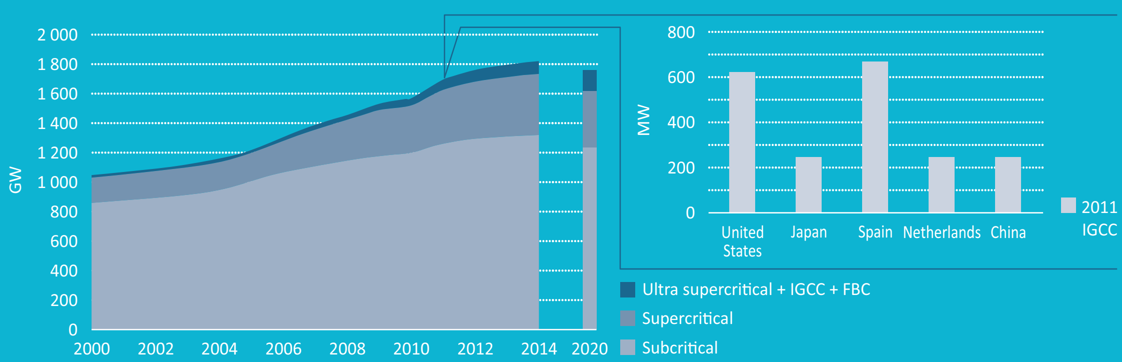
In much of Europe and the United States, natural gas is being favoured over coal for new power generation

Sustained coal price increases may favour more efficient coal technology investment and operation

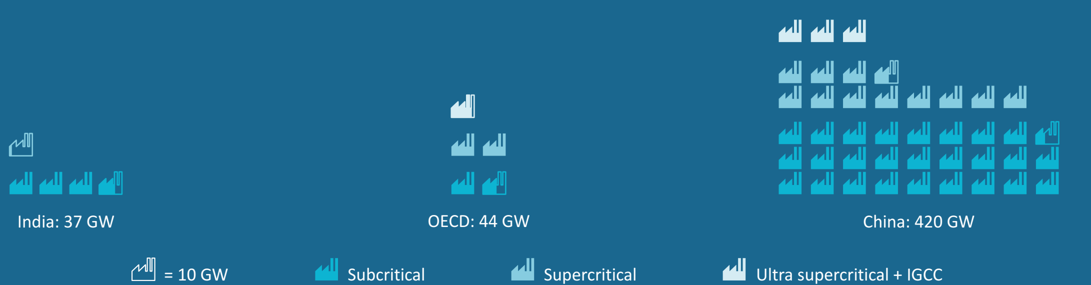
India's next five-year plan will aim for 50% to 60% of new coal plants to be supercritical

Technology penetration

2.6: Coal technology deployment by technology (2000-14) and *ETP* 2DS



2.7: Capacity additions in major regions by technology (2000-10)



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- Since 2006, coal prices in China have been fully subject to market pricing, and domestic coal prices rose by more than 50% from 2006 to 2008 (China Electricity Council, 2010). The continued policy of keeping power prices relatively low meant that China's top five state-owned power generating groups incurred losses of USD one billion in the first six months of 2011. This was despite an increase in power prices, making future investments in higher-cost coal technologies a potential challenge (China Electricity Council, 2011).
- In October 2011, Indonesia adopted a new price-indexing policy, which prompted a sudden hike in export prices that increased coal costs for countries, such as India, importing large amounts of Indonesian coal.

A number of OECD member country economies are starting to shift away from coal to gas, due to lower natural gas prices, emerging pollution control rules (particularly in the United States) and greater deployment of variable renewables (in Europe).

Scaling up deployment

A combination of CO_2 emissions reduction policies, pollution control measures and policies to halt the deployment of inefficient plants is essential to slow coal demand and limit emissions from coal-fired power generation. Governments are starting to adopt such policies, but should accelerate implementation to avoid a "locking in" of inefficient coal infrastructure (Table 2.3).

Table 2.3 Key policies that influence coal plant efficiency in select countries

Country or region	Policy	Impacts and goals of policy
China	Its 11th Five-Year Plan mandated closure of small, inefficient coal-fired power generation. In the 12th Five-Year Plan, coal production is capped at 3.8 billion tonnes by 2015; all plants of 600 MW or more must be SC or USC technology.	By 2010, 77 GW of small, inefficient coal-fired power generation was shut down; in 2011, 8 GW closed. 17% reduction in carbon intensity targeted by 2015; and 40% to 45% reduction by 2020.
India	The 12th Five-Year Plan (2012 to 2017) states 50% to 60% of new coal-fired capacity added should be SC. In the 13th Five-Year Plan (2017 to 2022), all new coal plants should be at least SC; energy audits at coal-fired power plants must monitor and improve energy efficiency.	The 12th and future Five-Year Plans will feature large increases in construction of SC and USC capacity.
Indonesia	Began indexing Indonesian coal prices to international market rates (2011); put emissions monitoring system in place.	Likely to increase coal prices paid by large importers of Indonesian coal.
European Union	Power generation covered by the EU ETS. The first two phases saw over 90% of emissions credits "grandfathered" or allocated to power producers without cost, based on historical emissions. Beginning with Phase 3 in 2013, 100% of credits will be auctioned.	GHG emissions reduction of 21% compared to 2005 levels under the EU ETS. Credit auctioning will provide further incentive to coal plants to cut emissions.
United States	The US EPA's GHG rule recommends use of "maximum available control technology".	New plants are all likely to have SC or USC technology, although pending EPA regulation, combined with low natural gas prices, suggest limited coal capacity additions in the future.
Australia	Generator efficiency standards defined best-practice efficiency guidelines for new plants: black coal (42%) and brown coal (31%). Both have higher heating value net output. Emissions trading is under consideration for 2013.	New plants will likely be SC or USC technology.

- China's 12th Five-Year Plan (2011 to 2015) explicitly calls for the retirement of small, ageing and inefficient coal plants and sends a strong message about the introduction of a national carbon trading scheme after 2020. In 2011, six provinces and cities were given a mandate to pilot test a carbon pricing system, which may go into effect as early as 2013. A shadow carbon price is likely to be implicit in investment calculations made by power providers.
- India's 12th Five-Year Plan (2012 to 2017) contains a target that 50% to 60% of coal plants use SC technology. Early indications of India's longer-term policy direction suggest that the 13th Five-Year Plan (2017 to 2022) will stipulate that all new coal-fired plants constructed be at least SC.
- In Europe, the European Union Emissions Trading Scheme (EU ETS) and increasing government support for renewable sources of power have largely eliminated the construction of new coal plants.
- In the United States, if the Environmental Protection Agency's (EPA) proposed coal emissions regulation is adopted and the country's continued shift to natural gas for power is sustained, construction of new coal power plants will be limited.

Nuclear power

Progress assessment

The nearly 440 nuclear reactors in operation across the world remained constant over the last decade, with 32 reactors shut down and the same number connected to the grid. Overall, nuclear capacity increased by more than 6%, due to installation of larger reactors and power uprates[2] in existing reactors.

In 2010, nuclear energy was increasingly favoured as an important part of the energy mix – subject to plant life extensions, power uprates and new construction – given its competitiveness (especially in the case of carbon pricing) as an energy source that is almost emissions-free. Ground was broken on 16 new reactors, the most since 1985, mainly in non-OECD countries (Figure 2.10); in 2011, 67 reactors were under construction, 26 in China alone (Figure 2.12). The cost and length of time of construction for nuclear power plants vary significantly by region and reactor type. Average overnight costs of generation III/III+ reactors range from about USD 1 560/kW to USD 3 000/kW in Asia and from about USD 3 900/kW to 5 900/kW in Europe (NEA, 2010). In terms of construction time, some are built in as little as four years, whereas in rare cases, it has taken as long as 20 to 27 years to complete construction (*e.g.* Romania, Ukraine).

Recent developments

Since 2011, the earthquake and tsunami damage to the Fukushima Daiichi nuclear power plant in Japan has cast some uncertainty over the future of nuclear power. Some countries are choosing to phase out nuclear reactors (*e.g.* Belgium, Germany, Switzerland); most confirmed that they are keeping nuclear in their energy mix or will develop it further, albeit at a less ambitious rate than previously anticipated (Figure 2.9; Table 2.4). In addition, countries planning to introduce nuclear power for the first time (*e.g.* Indonesia, Thailand, Malaysia and the Philippines) are delaying, and in some cases revising, their plans.

Following the Fukushima damage, all countries operating nuclear reactors have carried out stress tests to assess plant safety in the event of extreme natural events (*e.g.* earthquakes and flooding). The results, currently under review by regulatory bodies, are expected to increase the stringency of safety standards and thus require more investment in safety

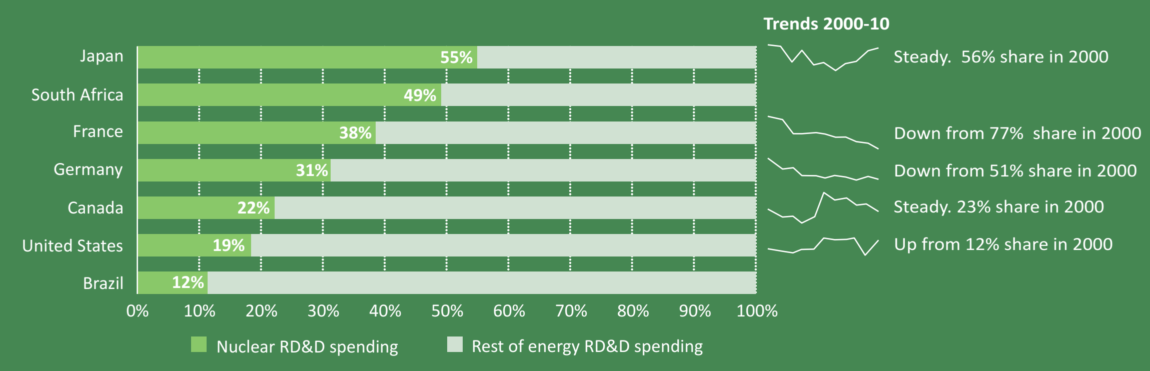
2 A power uprate is defined as the process of increasing the maximum licensed power level at which a commercial nuclear power plant may operate.

Nuclear power overview

The vast majority of countries with nuclear power remain committed to its use despite the Great East Japan Earthquake, but projections suggest that nuclear deployment by 2025 will be below levels required to achieve the 2DS objectives. In addition, increasing public opposition could make government ambitions for nuclear power's contribution to their energy supply harder to achieve.

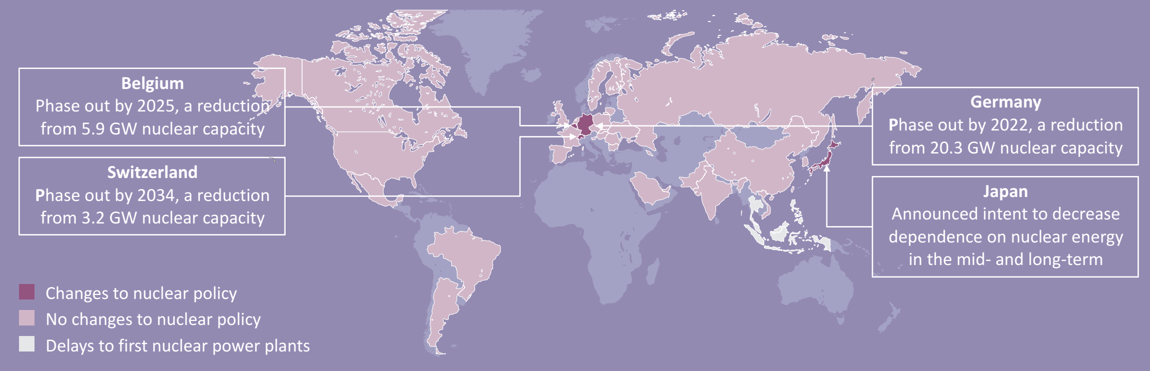
Technology developments

2.8: Share of nuclear in government energy RD&D spending, 2010

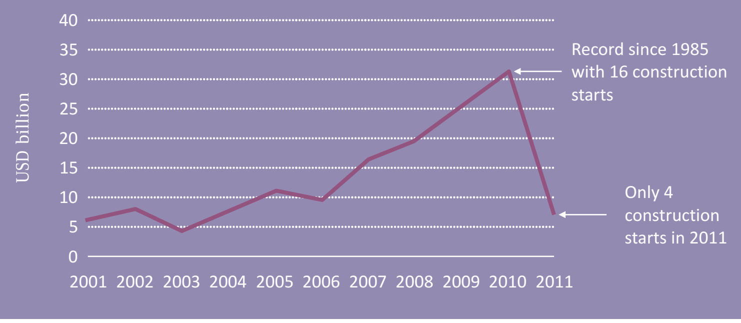


Market creation

2.9: Nuclear policy post-Fukushima



2.10: Annual nuclear capacity investment

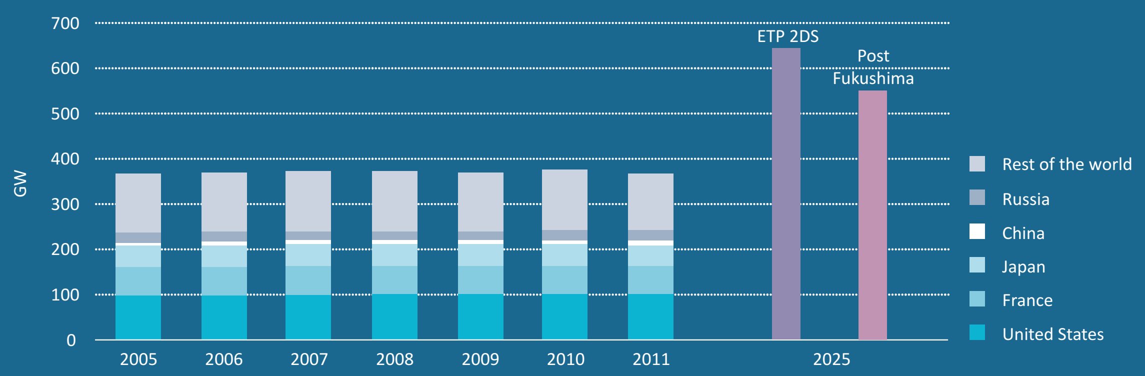


80

USD BILLION AVERAGE ANNUAL NEEDED TO 2025 TO ACHIEVE 2DS NUCLEAR OBJECTIVES

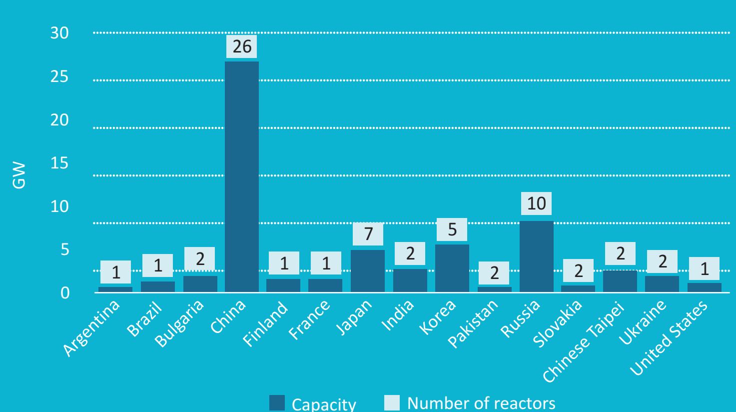
Technology penetration

2.11: Installed nuclear capacity and 2DS objectives



Source: IAEA

2.12: Reactors under construction, end 2011



Source: IAEA

Key developments

Stringent safety and risk-management protocols, enhanced transparency in management and decision making, and major public engagement efforts are necessary to achieve planned nuclear deployment goals

China is currently building the most reactors globally; their reactor construction times have decreased impressively, and are likely to become the fastest in the world

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upgrades, especially for older plants. Overall, the outcome of the stress tests may speed up the rate at which older plants are shut down (making approval of reactor life extensions more difficult to obtain); slow the start of new reactor projects (with siting and licensing expected to take more time); and negatively affect public acceptance of nuclear energy. In 2011, construction began on only four new nuclear reactors, a significant drop from 2010 (Figure 2.10).

Taking into account the nuclear phase-outs in Germany, Switzerland and Belgium, potentially shorter reactor life spans, and longer planning and permitting procedures, nuclear energy deployment is projected to be about 100 GW below the level required to achieve the 2DS objectives by 2025.[3] This represents a drop of about 15% against capacity projections before the Fukushima accident (Figure 2.11). At this rate, it is unlikely that nuclear deployment levels under the 2DS will be achieved.

Table 2.4 Nuclear policies, post-Fukushima

Status	Countries	Summary and implications
No changes to nuclear targets as a result of Fukushima accident	Argentina, Armenia, Bulgaria, Brazil, Canada, China*, Czech Republic, Finland, France, Hungary, India, Korea, Lithuania, Mexico**, Netherlands, Pakistan, Poland, Romania, Russia, Slovak Republic, Slovenia, Spain, Sweden, Taiwan, Ukraine, United Kingdom, United States.	Most countries have not changed their plans for nuclear energy as a result of the Great East Japan Earthquake. It is, however, expected that the execution and cost of projects will take longer than previously planned, given potential additional safety requirements, siting and permitting restrictions, and possible public opposition.
Changes to nuclear targets post-Fukushima	Belgium	Will phase out nuclear power by 2025, a reduction of 5.9 GW from nuclear capacity.
	Germany	Plans to phase out nuclear power use for commercial power generation by 2022, a reduction of 20.3 GW from nuclear capacity.
	Japan	Announced intent to decrease dependence on nuclear energy in the mid- and long-term.
	Switzerland	Will phase out nuclear power by 2034, a reduction of 3.2 GW from nuclear capacity.
Delays or changes to first nuclear power plant introductions	Thailand, Malaysia, Philippines, Indonesia.	Further assessments to planned introductions of nuclear power, resulting in delays or modifications to plans.

* After Fukushima, China froze the approval process for new plants, pending lessons learned from the damage, especially with respect to siting. The currently ambitious new building programme is under revision and may result in a decrease of 10 GW compared to 90 GW initially planned by 2020.
** Mexico recently declared that it was abandoning plans to build 10 reactors in the next 15 years and will instead develop gas-fired generation capacities. The decision is not the result of the accident following the Great East Japan Earthquake.

Interest in small modular reactors (SMRs) may revive, given their suitability for use in small electric grids. Their modularity and scalability, with more efficient transport and construction, should lead to shorter construction duration and lower cost and overall investment. Large-scale nuclear plants, however, are still more competitive than SMRs in

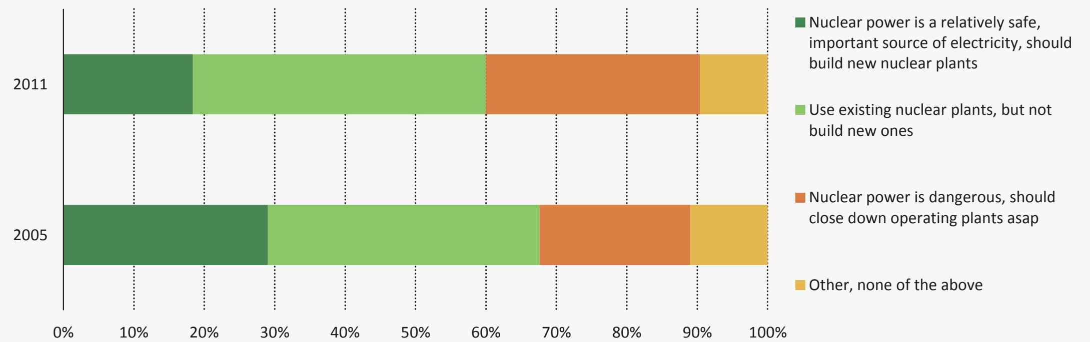
3 2025 selected to highlight full impact of major plans to phase out nuclear energy.

terms of cost of kWh produced. The United States is licensing some of the more mature SMR designs, but it is unlikely at this point (given post-Fukushima re-analysis and low natural gas prices in the United States) that many SMR projects will launch before 2020.

Scaling up deployment

In the post-Fukushima era, scaling-up nuclear power faces increasing challenges. A 2011 survey compared public opinion of nuclear power before and after the Great East Japan Earthquake, finding that public opinion in favour of closing existing nuclear power plants rose from 21% to 30%, and opinion against building new nuclear plants rose from 39% to 42%. While these findings reflect the results of one survey and should therefore be interpreted with caution, they highlight an important message.

Figure 2.13 Public opinion of nuclear energy



Note: Countries included in survey data are France, Germany, India, Indonesia, Japan, Mexico, Russia, the United Kingdom and the United States.
Source: GlobalScan, 2011.

Key point *A 2011 survey found that between 2005 and 2011, an increasing share of citizens responded that nuclear power was dangerous, and all operating plants should be shut down.*

To reach nuclear goals, countries need to make significant efforts to convince an increasingly sceptical public that nuclear power should continue to be part of the future energy mix. In addition, rising costs associated with enhanced safety measures, difficulty in extending reactor life spans, and longer and more stringent processes for siting and licensing of new plants must be overcome. Governments and plant operators also need to increase transparency in their decision-making processes and implement updated safety and risk-management protocols. Strong, independent nuclear regulatory bodies are required for industry oversight.

Renewable power

Progress assessment

Renewable power (including hydropower, solar, wind, biomass, geothermal and ocean) progressed positively (posting 13% average annual growth in installed capacity) in the last 10 years. While starting from a small base, non-hydro renewables have been growing more rapidly, with generation doubling over the past five years (Figure 2.17). In 2010, their share of total electricity production remained stable at about 3%.

While the portfolio of renewable technologies is becoming increasingly competitive, given the right resource and market conditions, many renewables are still more expensive than fossil fuel-based power technologies (Figure 2.15). Costs of some renewables have dropped impressively over the past decade: in particular, solar photovoltaic (PV) has seen systems costs decrease by as much as 75% in some countries in just three years.

Box 2.2 Achieving competitiveness through well-designed policy support

The competitive position that onshore wind technologies enjoy today is the result of a technology push driven by Denmark in the 1980s. Strong RD&D funding and programme support, coupled with the creation of sufficient industrial capacity and deployment of effective policy frameworks, is a powerful example of how governments can foster technology progress and create markets.

From 2000 to 2011, driven by strong policy support, **solar PV** was the fastest-growing renewable energy technology worldwide with an average annual growth above 40%. Growth, however, was concentrated in only a few markets (Germany, Italy, the United States and Japan). Regions with good solar potential (*e.g.* Africa and parts of Asia) need to add significant solar capacity to meet the technology contribution share in the 2DS.

Progress in **concentrated solar power** (CSP) has been less impressive. The first commercial plants, built in the 1980s in the United States, are still in operation, but further project development lagged in the 1980s and 1990s. Today, the industry has hundreds of megawatts under construction and thousands under development worldwide. Spain has taken over as the world leader in CSP and, together with the United States, accounted for 90% of the market in 2011. Algeria, Morocco and Italy also have operational plants, while Australia, China, Egypt, India, Iran, Israel, Jordan, Mexico, South Africa and the United Arab Emirates are finalising or considering projects. While the project pipeline is impressive, the economic recession and lower PV costs show evidence of diverting and slowing CSP projects (*e.g.* the United States converted a number of planned CSP projects to PV).

Onshore wind is on pace to achieve the 2DS objectives by 2020 if its current rate of growth continues (27% average annual growth over the past decade). It is among the most cost-competitive renewable energy sources and can now compete without special support in electricity markets endowed with steady winds and supportive regulatory frameworks (*e.g.* New Zealand and Brazil). China, the United States, Germany and Spain built the majority of the new power capacity and generation from wind in the past decade.

Offshore wind is an emerging technology and requires further RD&D to enhance technology components (*e.g.* offshore wind platforms and large wind turbines) and bring down technology costs. Several governments have recently invested substantial amounts in large-scale demonstration activities. For example, in May 2011, the United Kingdom committed more than GBP 200 million (USD 317 million) to establish a network of technology and innovation centres, including the Offshore Renewable Energy and Technology Innovation Centre. China and Germany, as well as other governments, are making offshore wind a policy priority. The next few years will determine the future success of this technology.

Average annual growth in **geothermal** electricity generation reached 3% between 2000 and 2010. Geothermal electricity provides a significant share of total electricity demand in

Iceland (25%), El Salvador (22%), Kenya (17%), the Philippines (17%) and Costa Rica (13%). In absolute terms, in 2010, the United States produced the most geothermal electricity, at 17 TWh.

Where an accessible high-temperature geothermal resource exists, generation costs are competitive with other power generation alternatives. Despite this, geothermal electricity generation has not reached its full potential and is falling behind the deployment levels required to achieve the 2DS objectives by 2020. Given the unique nature of geothermal resources, the technology is still considered relatively risky and is exploited in only a limited number of countries.

Electricity from **solid biomass, biogas, renewable municipal waste and liquid biofuels** has been steadily increasing since 2000, at an average of 8% annual growth. This progress is broadly on track with the 2DS objectives. But future progress will depend heavily on the cost and availability of biomass.

Hydropower provided about 82% of all electricity from renewable energy sources in 2010, increasing at an average rate of about 3% per year between 2000 and 2010. China, Brazil, Canada, the United States and Russia are the world leaders in hydropower. In Brazil (80%) and Canada (60%), hydropower provides the largest share of power generation.

In the next decade, the installed capacity of hydropower will increase by approximately 180 GW, if projects currently under construction proceed as planned (a 25% increase of current installed capacity). One-third of this increase will be in China and Brazil; India also has a large capacity under construction (IEA, 2011c). Delivering these projects on time and in a sustainable way is essential to achieve the 2DS goal, and additional projects should be identified and developed to offset any delays or cancellations.

Recent developments

2011 was an active year for renewable energy markets. For the first time, global investment in new renewable power plants, which reached USD 240 billion (Figure 2.16), surpassed investment in fossil-fuel power plants, which stood at USD 219 billion (BNEF, 2011; IEA[4]). However, several factors point to a potentially turbulent 2012. Rapid reductions in costs of technology will stimulate deployment, but industry consolidation is looming as a number of smaller and higher-cost manufacturers become uncompetitive, in particular for PV and wind. The slow economic recovery across Europe and parts of North America will likely have different impacts from country to country: in those countries where long-term, effective and cost-efficient policies are implemented, renewables will be relatively sheltered from the crisis. On the contrary, in countries where governments are rethinking policy schemes, investor confidence may decline. In general, the costs of financing are increasing, and developers may struggle to raise capital for renewable projects that require intensive up-front capital investments.

A number of market developments offer useful insights. In 2010, China became the world leader in total installed capacity of wind, ahead of the United States, which had a difficult year. 2011 saw China keeping its lead, while the United States market continued to grow compared with 2010. In China, however, out of the 63 GW of cumulative installed onshore wind capacity, only 47 GW were grid-connected at the end of 2011. The government has taken steps to remedy this situation. In general, the overall trend is clear: the centre of gravity for wind energy markets has begun to shift from OECD regions to Asia, namely China (IEA, 2011c).

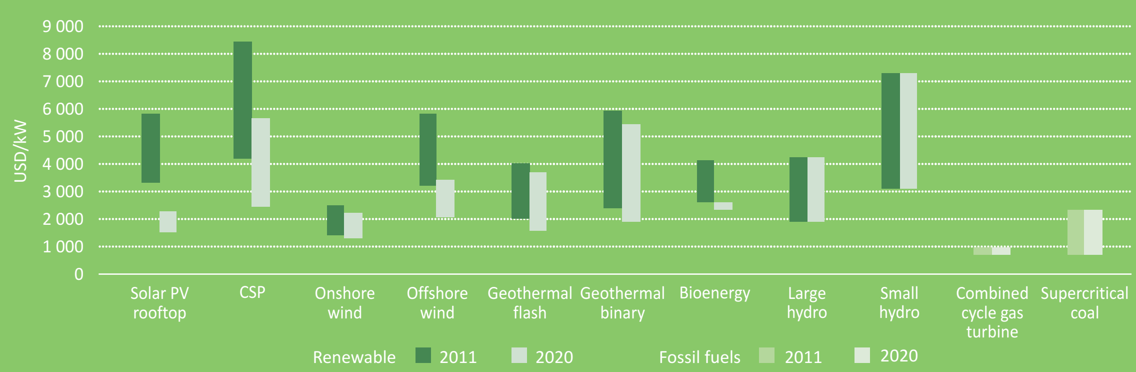
4 Data for non-hydro renewables from BNEF, 2011; hydro investment estimates are derived from IEA analysis.

Renewable power overview

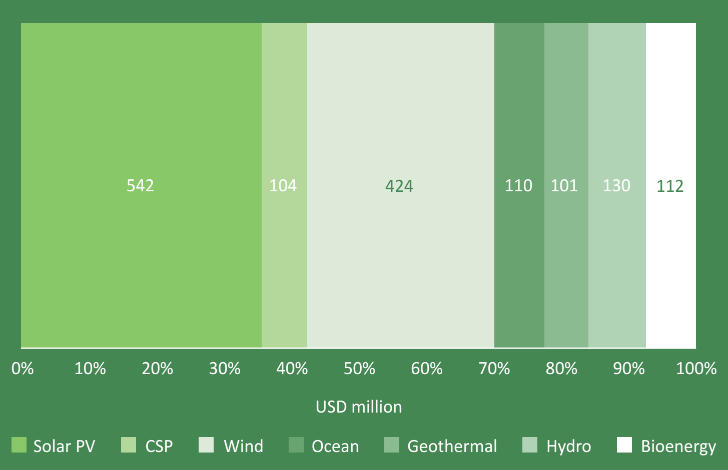
A portfolio of renewable power technologies has seen positive progress over the past decade, and is broadly on track to achieve the 2DS objectives by 2020. Some renewable technologies still need policy support to drive down costs, boost competitiveness and widen their market reach. Enhanced RD&D is also needed to speed up the progress of emerging renewable technologies that are not advancing quickly enough (*e.g.* CSP and offshore wind).

Technology developments

2.14: Technology investment costs, 2011 and 2DS objectives



2.15: Public RD&D spending in 2010



Key technology trends

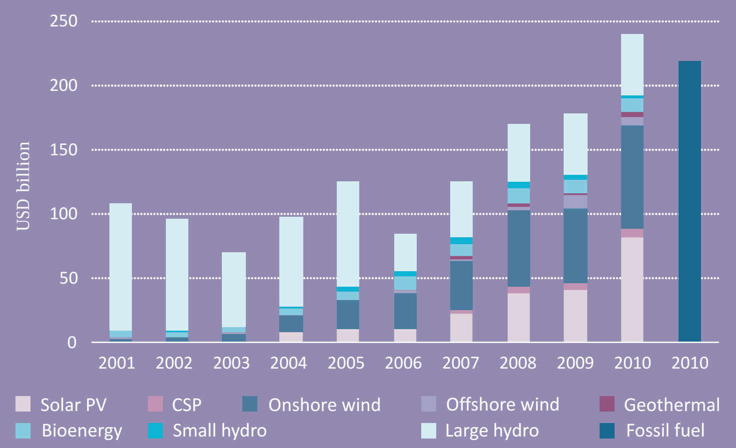
The different renewable technologies are at very different stages of development

A portfolio of renewables is becoming increasingly competitive

Solar PV has seen particularly impressive progress with up to a 75% decrease in system costs in just three years in some countries

Market creation

2.16: Annual capacity investment



Average annual investments required to 2020 USD billion

Onshore wind	60
Offshore wind	10
Solar PV	50
CSP	15
Hydro	80
Bioenergy	10
Geothermal	10

Technology penetration

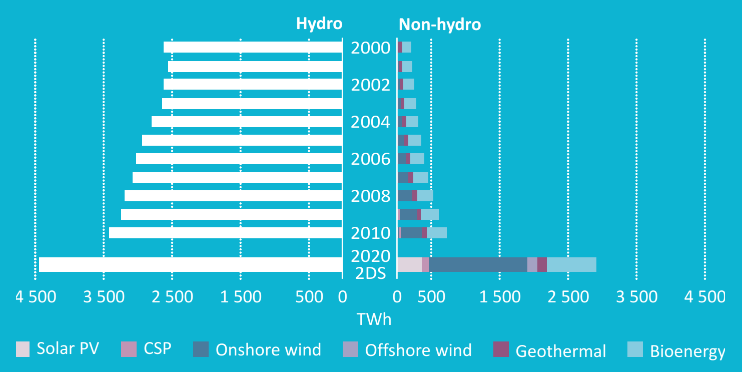
Deployment to new markets

Hydropower, bioenergy, geothermal and onshore wind are already deployed across many countries and continents

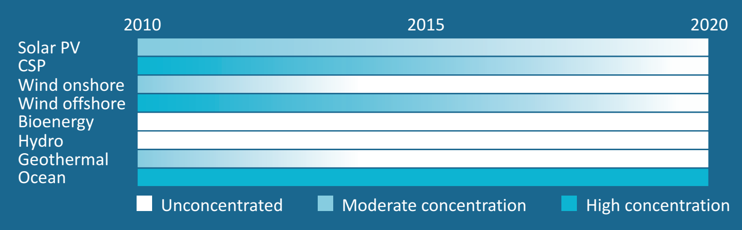
Solar PV must be deployed to more countries with large resource potential to maintain high rates of growth

Offshore wind, CSP, and ocean hold large potential, but the scale-up of projects over the next decade is critical to achieve 2DS targets

2.17: Renewable power generation and 2DS



2.18: Market concentration and required diffusion



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Under favourable market and resource conditions, onshore wind is also nearing competitiveness. In Brazil's 2011 capacity auctions, wind energy was more competitive than natural gas generation, even in the absence of specific government support for wind energy. This is promising for the future of renewables competitiveness.

Solar PV had a record market deployment year in 2011, with 27 GW of new capacity installed worldwide, an increase of almost 60% with respect to the 17 GW of new additions in 2010. Italy became the first market worldwide (9 GW), followed by Germany (7.5 GW), which remains the country with the largest cumulative installed capacity. High rates of PV deployment resulted from attractive and secure rates of return for investors, while government-supported tariffs remained high and system prices decreased rapidly (in some countries PV system prices decreased by 75% in three years). However, the growth of PV has so far remained concentrated in too few countries. This has escalated total costs of policy support, triggering an intense debate about the need to reduce tariffs and/or introduce caps to policy support. These uncertainties may reduce future investor confidence in these markets. In the future, it is likely that European market deployment will slow, while new markets will emerge (*e.g.* China and India) and other OECD markets will increase (*e.g.* the United States and Japan).

Scaling up deployment

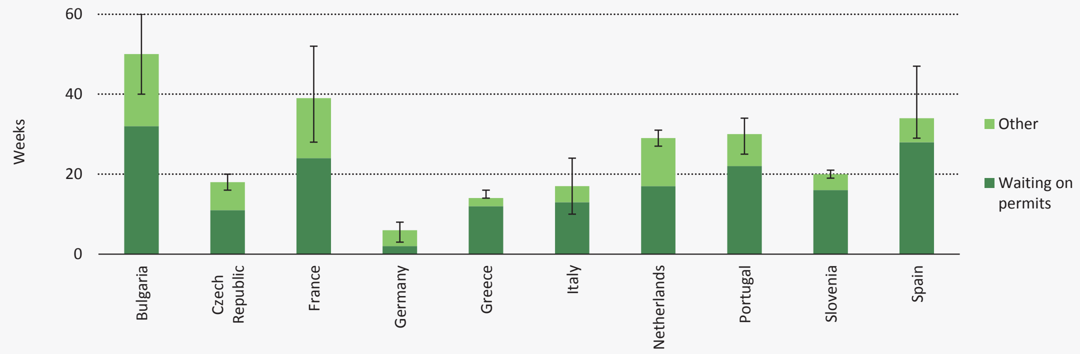
While progress in renewables has largely been on the upswing, the challenge of reaching or maintaining strong deployment of many renewable technologies should not be underestimated, particularly as the cumulative installed capacity grows and issues of grid integration of variable renewables (such as wind and PV) emerge in some countries. Keeping on track for the 2DS goals will require:

- in leading countries, sustained market deployment of renewable technologies that best fit their local market conditions (in terms of costs, resources and technology maturity);
- further expansion of renewables into markets with large resource potential, beyond the efforts in a few market-leading countries; and
- continued RD&D into emerging technologies, such as offshore wind, CSP and enhanced geothermal.

Government action is needed in a number of critical areas, such as **effective and efficient policy design:** an increasing number of governments are adopting renewable energy policies; more than 80 countries had renewable energy policies in place in 2011 (*e.g.* feed-in tariffs, tradable green certificates, tenders, tax incentives, grants). These policies must be designed to effectively keep pace with technology cost reductions, to moderate policy costs to governments and to maintain investors' confidence, all while helping renewables to compete.

Smooth planning and permitting processes: delays in planning, restrictions to plans, lack of co-ordination among different authorities and delays in authorisation can jeopardise projects and significantly increase transaction costs for investors. Currently, the length of time for project approval processes varies significantly across countries. For example, waiting for permits for rooftop solar projects in certain European countries (with the exception of Germany) accounted for over 50% of the total project timeline (Figure 2.19). For emerging technologies, such as CSP and offshore wind, it is important to develop clear, streamlined planning and permitting processes so these technologies can be deployed rapidly.

Figure 2.19 Time needed to develop small-scale rooftop photovoltaic projects in select European Union countries



Note: Average values shown; error bars show minimum and maximum total durations.
Source: PV legal, 2010; from IEA, 2011c.

Key point *Overcoming non-economic barriers, such as planning and permitting process delays, is central to reducing project transaction costs and uncertainties.*

Broader environmental management and public acceptance: lack of public acceptance and sustainability concerns slowed the development of some renewable energy technologies. Hydropower is one example; multilateral development banks halted investment in hydropower projects in the 1990s due to environmental and social challenges.[5] Major efforts continue to address these problems through the development of sustainability assessment protocols.[6] CSP is another example; many favourable sites are in semi-arid regions, where water scarcity can be an issue, given water requirements for CSP production. Managing water resources and associated environmental impacts is essential to ensuring the long-term sustainability and acceptance of this technology. In fact, these same issues need to be more broadly addressed for other clean energy technologies (*e.g.* CCS, bioenergy and biofuels).

Grid integration and priority access: while many countries implemented attractive incentives for developing renewables projects, the power produced needs to be effectively integrated into the grid, along with assurances that energy will be purchased. This can be achieved through policy tools, such as priority dispatch and renewable off-take agreements.[7]

Market diversification: hydropower, bioenergy, geothermal and onshore wind are already deployed across many countries and continents. The growth in PV is moderately concentrated in relatively few countries. To maintain positive growth rates, PV and other renewable technologies need to expand into areas of significant resource potential (Figure 2.18).

5 Multilateral development bank investment in hydropower project developments has since increased, with the World Bank investing over USD 1 billion in hydropower projects in 2008.
6 For example, IEA Hydropower Implementing Agreement, *Recommendations for Hydropower and the Environment;* International Hydropower Association, *Hydropower Assessment Sustainability Protocol.*
7 A renewable off-take agreement requires utilities to purchase produced renewable electricity.

Continued support for innovation and RD&D: several technologies are approaching market competitiveness with conventional power generation for base load (*e.g.* onshore wind, some bioenergy technologies) or for peak load (*e.g.* solar PV), but less mature technologies (such as advanced geothermal, offshore wind and CSP) still require government RD&D support to improve performance and reduce technology costs. Offshore wind technologies require larger wind turbines that can be deployed offshore and platforms suited to deeper water. For CSP, improved heat-transport media and storage systems are critical. Support for RD&D of these renewables needs to be coupled with continued measures that foster early deployment and provide opportunities for learning and cost reduction.

Industry

Industry accounts for about one-third of total final energy consumption and almost 40% of total energy-related CO_2 emissions. Developed economies relied on industrial development to drive economic growth, and many developing economies are now following a similar path. CO_2 emissions in the industry sector are projected to increase by close to 30% by 2020, but to achieve the 2DS objectives, industry must limit its increase of direct CO_2 emissions in 2020 by about 17% compared with the current level. If industry takes advantage of available options – deploying existing BATs, developing new technologies that deliver improved energy efficiency or enable fuel and feedstock switching, promoting recycling and introducing CCS – it can achieve its 2DS targets. Over the next decade, priority should go to applying available BATs to newly built and refurbished manufacturing facilities, retrofitting existing plants, and optimising production processes to maximise energy efficiency.

Progress assessment

From 2000 to 2009, production and energy consumption in all industry sectors increased, although at different rates (Figure 2.20). Since 2000, growth has been primarily driven by developing economies, namely: China, which doubled its industrial energy consumption; and India, where energy demand increased by 50%. OECD member countries experienced a major downturn in production, due in part to the economic recession since 2008: total materials production[8] in the OECD decreased from 1 691 million tonnes (Mt) in 2007 to 1 373 Mt in 2009.

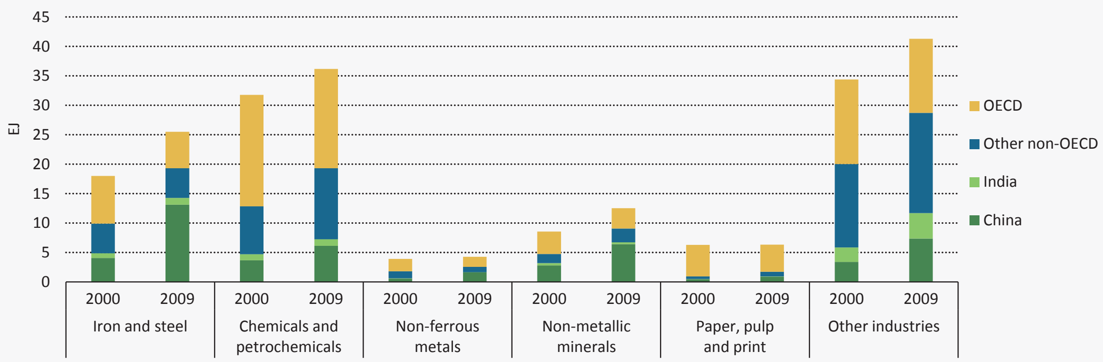
Improvement in industry energy intensity[9] helped slow growth in industry energy consumption. Between 1990 and 2009, manufacturing value-added doubled, while energy intensity decreased by an average of about 2% per year (Figure 2.21). From 2000 to 2009, however, rates of energy intensity improvement declined to an average of 1.6% per year. These data should be treated with caution, as improvements in industry energy intensity do not necessarily mean that the industry is becoming more energy efficient. The changes in energy intensity can also be attributed to changes in the structure of the economy (including shifts from and towards energy-intensive industries) and fluctuations in materials prices.

While this progress is laudable, to achieve the 2DS objectives, the five most energy-intensive industrial sectors[10] need to make marked progress in incorporating energy

8 Includes crude steel, cement, primary aluminium, paper and paperboard, and feedstock use.
9 The amount of energy used per unit of output, measured in terms of energy per tonne of production.
10 These include the iron and steel, cement, chemicals, pulp and paper, and aluminium sectors.

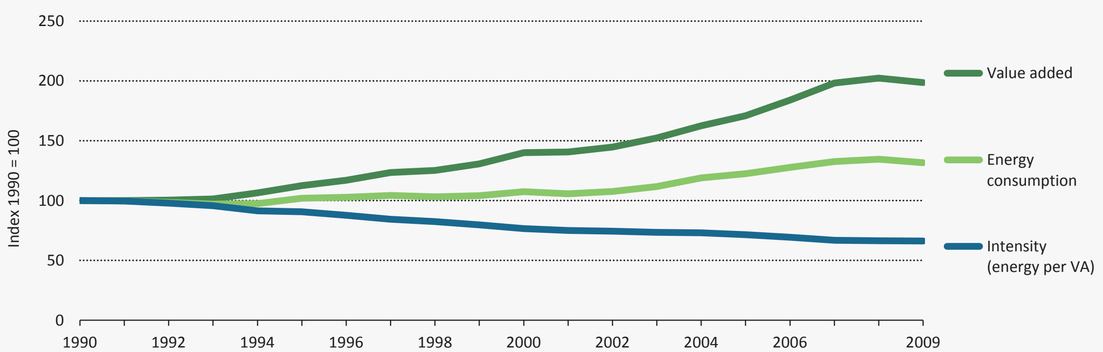
efficient technologies, recycling and energy recovery, CCS, alternative materials use, and fuel and feedstock switching (Table 2.5). In the short term, these sectors must increase efficiency by steadily adopting the most efficient BATs when building or retrofitting facilities, and when optimising production systems and manufacturing practices, to reduce emissions significantly. After 2020, the introduction of CCS and the deployment of new technologies become crucial. These energy-intensive sectors have significant untapped potential for delivering the CO_2 emissions reduction needed to achieve the 2DS objectives.

Figure 2.20 Energy use by industry sector and region in 2000 and 2009



Key point *Energy use has increased across all industry sectors, but is primarily driven by China and emerging countries.*

Figure 2.21 Progress in industrial energy intensity



Note: Sector energy consumption data include-crude steel, cement, primary aluminium, paper and paperboard, and feedstock use.
Sources: IEA Indicator analysis; Added-value data: UN National Account, 2011.

Key point *Between 1990 and 2009, energy intensity decreased on average at 2% per year.*

Table 2.5 Share of technology contribution to industry CO_2 emissions reduction potential by 2020

Industry sector	Average energy efficiency	Recycling and energy recovery	CCS	Fuel and feedstock switching/ alternative materials	Total savings (Mt CO_2)
Iron and steel					354
Cement		na			119
Chemicals					440
Pulp and paper					49
Aluminium			na		7
Total					969

Note: Share of emissions reduction potential by 2020 denoted as follows: ≥50%; 10≤ ≤50% ; ≤10%; Average energy efficiency includes improvements to existing facilities and the use of BATs as new facilities are built.

Key point *Over the next decade, improvements in energy efficiency in the five major sectors play the greatest part in reducing CO_2 emissions from industry.*

Iron and steel

The recent rapid expansion of crude steel production (67% growth between 2000 and 2010) and the resulting additional capacity positively affected the energy efficiency of the iron and steel industry (World Steel, 2011). Additional capacity has reduced the average age of the capital stock, and the new plants tend to be more energy efficient, although not all have introduced BATs. In several countries, existing furnaces have been retrofitted with energy efficient equipment, and energy efficiency policies have led to the early closure of inefficient plants. The iron and steel sector still has the technical potential to further reduce energy consumption by approximately 20%.

Cement

The thermal energy consumption of the cement industry is strongly linked to the type of kiln used and the production process. Vertical shaft kilns consume between 4.8 gigajoules per tonne (GJ/t) and 6.7 GJ/t of clinker.[11] The intensity of wet production process varies between 5.9 GJ/t and 6.7 GJ/t of clinker. The long drying process requires up to around 4.6 GJ/t of clinker; adding pre-heaters and pre-calciners (considered BAT in this sector) further reduces the energy requirement to between 2.9 GJ/t and 3.5 GJ/t of clinker.

Since 1990, the use of dry production process has increased in all geographical regions for which data are available. Despite the recent improvements in energy and emissions intensity, there is still significant room for improvement. If all plants used BATs, the global intensity of cement production could be reduced by 1.1 GJ/t of cement, or about 30% (from an intensity of 3.5 GJ/t of cement today).

Chemicals and petrochemicals

It is difficult to measure the physical production of the chemical and petrochemical industry, given the large number of products. Plastic production represents the largest and fastest-growing segment of the chemical and petrochemical sector, representing approximately 75% of the total physical production (Plastics Europe, 2011; SRI Consulting, 2009). The use of best practice technologies, process intensification, co-generation,[12] recycling and energy recovery together can save over 13 EJ in final energy.

11 Clinker is a core component of cement made by heating ground limestone and clay at a temperature of 1 400°C to 1 500°C.

12 Co-generation refers to the combined production of heat and power.

Aluminium

The International Aluminium Institute (IAI) annually surveys facilities worldwide[13] on energy use in production. The average energy intensity of aluminium refineries, reported in IAI statistics, was 12 GJ/t of aluminium in 2000. The intensity remained relatively stable throughout the decade because most improvements occurred earlier, but in 2010, intensity saw a decrease to 11.2 GJ/t of aluminium. The application of BAT in the aluminium industry can help further reduce energy use in aluminium production by approximately 10%, compared with current levels.

Pulp and paper

The main production facilities for the pulp and paper sector are pulp mills and integrated paper and pulp mills. Most of the sector's efficiency improvements have come from integrated pulp and paper mills that use recovered heat in the production process. Additionally, the production of recovered paper pulp uses 10 GJ to 13 GJ less energy per tonne than the production of virgin pulp. Current levels of recovered paper production vary from 30% in the Russian Federation to over 60% in Japan and Germany. Recycling rates can be increased in most regions, especially in many non-OECD countries, where the recovered paper production rate varies from 10% to 50%. The upper technical limit to waste paper collection is over 80% (CEPI, 2006), but practically it may be closer to 60%. Globally, the sector has improved energy intensity by 1.8% per year since 2005.

Recent developments

The global economic recession has, in many cases, slowed manufacturing production, resulting in a short-term increase in energy intensity because production processes are not optimised:

- World crude steel production fell from 1 351 Mt in 2007 to 1 232 Mt in 2009, mostly in OECD economies, where production sank by 25%. Led by China and India, steel production in Asia continued to climb, although at a slower place (World Steel, 2011).
- The cement industry grew, but the rate of growth dropped to 4% between 2007 and 2009 (compared with an overall average of 7% between 2000 and 2009). The sector's energy intensity improved in 2009 to 3.52 GJ/t cement (up from 3.38 GJ/t in 2007).
- From 2008 to 2009, primary aluminium production slumped by 7%, but preliminary data for 2010 suggest the beginning of recovery.

Scaling up deployment

- Important economic barriers to achieving energy savings potential in industry (*e.g.* required up-front capital investments, low fuel costs and long life spans of infrastructure) can be targeted by government policies and measures: energy management policies; minimum energy performance standards for industrial equipment, electric motors and systems; energy efficiency services for small- and medium-sized enterprises; and complementary economic and financial policy packages that support investment in energy efficiency (Table 2.6). In particular, uptake of ISO 50001[14] energy management systems and standards can help industry sectors continuously improve energy performance.

13 The survey covers around 70% of global metallurgical alumina and primary aluminium production.
14 ISO 50001, *Energy Management Systems: Requirements with Guidance for Use*, is a voluntary international standard developed by ISO (International Organization for Standardization). It provides organisations with requirements for energy management systems.

Many governments have advanced energy efficiency by implementing such policies, but more aggressive measures are required to achieve the industry sector's full energy efficiency potential and the 2DS objectives.

Table 2.6 Policy action to enhance industrial energy efficiency

Recommendations	Policy options
Energy management in industry	Industrial energy management policies, including monitoring and measuring energy consumption, identifying energy-savings potential, setting benchmarks for industry energy performance, publicly reporting progress.
High-efficiency industrial equipment and systems	Mandatory minimum energy performance standards for electric motors and other categories of industrial equipment, such as distribution transformers, compressors, pumps and boilers. Measures to address barriers to energy-efficiency optimisation in design and operation of industrial processes (*e.g.* providing information on equipment energy performance, training initiatives, audits, technical advice and documentation, and system-assessment protocols).
Energy efficiency services for small- and medium-sized enterprises	Support for energy audits, supported by information on proven energy efficiency practices; energy performance benchmarking.
Complementary policies to support industrial energy efficiency	Removal of energy subsidies and internalisation of external costs of energy through policies, such as carbon pricing. Increased investment in energy-efficient industrial equipment and processes through targeted financial incentives, such as tax incentives, risk-sharing or loan guarantees with private financial institutions, and promotion of the market for energy performance contracting.

Source: Adapted from IEA, 2011b.

Buildings

Residential and commercial buildings account for approximately 32% of global energy use and almost 10% of total direct energy-related CO_2 emissions. Including electricity generation emissions (plus district heat), buildings are responsible for just over 30% of total end-use energy-related CO_2 emissions.

Energy demand from the buildings sector will more than double by 2050. Much of this growth is fuelled by the rising number of residential and commercial buildings in response to the expanding global population. Between 2000 and 2010, global population rose by 12.9%. In the residential sector, mounting energy demand was further exacerbated as the number of people per household decreased in many economies (average OECD occupancy in the residential sector dropped from 2.9 in 2006 to 2.6 in 2009) and the size of dwellings increased. For example, in the United States, average household size increased from 166 square metres (m^2) to 202 m^2 between 1990 and 2008, and China's urban houses increased in size from 13.7 m^2 to 27 m^2 per occupant between 1990 and 2005 (National Bureau of Statistics of China, 2007).

To achieve energy-savings potential in the buildings sector, stringent energy-saving requirements for new buildings plus retrofits of existing buildings is necessary. The efficiency of the building shell must be upgraded and buildings need to incorporate more energy-efficient building technologies for heating, ventilation and air conditioning (HVAC) systems; high-efficiency lighting, appliances and equipment; and low-carbon or carbon-free technologies, such as heat pumps and solar energy, for space and water heating and cooling (Table 2.7).

Table 2.7 Opportunities for energy and CO_2 emissions savings in the buildings sector

Major savings areas	Relative importance over next decade
Building shell measures	
New residential buildings in non-OECD countries	Medium to large
Retrofits of residential buildings in OECD countries	Large
New commercial buildings	Large
Retrofits of commercial buildings	Medium to large
Energy efficiency	
Lighting	Medium
Appliances	Large
Water-heating systems	Large
Space-heating systems	Medium to large
Cooling-ventilation systems	Medium to large
Cooking devices	Small to medium
Fuel switching	
Water-heating systems	Medium to large
Space-heating systems	Medium to large
Cooking devices	Small

Note: = Large energy-savings potential; = Medium to large energy-savings potential; = Small to medium energy-savings potential.

Key point *Significant potential for energy savings and CO_2 emission reductions over the next decade can be realised by improving the building shell in new buildings (globally) and by retrofitting existing buildings (in particular, in OECD member countries).*

Progress assessment

Assessing the progress of energy efficiency in buildings is a challenge. Data on the deployment of energy-efficient technologies are limited, and many different technologies and components contribute to the overall energy performance of buildings. Progress is therefore evaluated by reviewing building energy codes, improvements in appliance efficiency, and deployment of solar thermal and heat pump technologies for heating and cooling. This assessment remains largely incomplete until further global data collection enables better analysis of efficiency in the buildings sector. Increased data and analysis will help drive policy prioritisation. In general, this preliminary assessment suggests that buildings require increased application of energy efficiency potential in order to achieve the 2DS objectives.

Building energy codes and minimum energy performance requirements

To effectively reduce building energy consumption, building energy codes must be mandatory and include minimum energy performance requirements for the overall building (including its various end-uses), cover the entire building stock and be stringently enforced. Currently, few countries meet these requirements:

- Building energy codes exist in all OECD countries, and in a number of non-OECD countries (such as China, Russia, India and Tunisia). At present, only European Union countries, China and Tunisia have *mandatory* building energy codes that require minimum energy performance.

- In other countries, energy codes are voluntary at the national level, while some provinces and states have made them mandatory (*e.g.* in the United States, building energy codes are mandatory in 22 of 50 states for residential buildings and are voluntary in all but eight of the remaining states, which do not have energy codes). When codes are voluntary, there is usually no enforcement in place.
- Only France, Denmark and Tunisia include minimum energy performance requirements for the overall energy consumption of buildings, applicable to five end-uses: heating, cooling, water heating, lighting and ventilation.
- Most energy codes target only new buildings or extensions, and therefore do not apply to a large proportion of the existing building stock. This is especially problematic in OECD countries, where most of the efficiency potential requires retrofitting existing buildings. In addition, a large part of the building stock in OECD countries was built before the first building energy codes emerged in the 1970s.

Box 2.3 European Energy Performance in Buildings Directive (EPBD)

The European Commission Directive 2002/91/EC introduced the concept of minimum energy requirements for the overall energy consumption of buildings. It included five end-uses, in line with the current ISO standard (heating, cooling, ventilation, lighting for non-residential only and water heating).

The 2010 update to the EPBD 2010/31/EC also:

- provides methodologies for setting minimum performance requirements and for shifting the focus from up-front investment costs to life-cycle costs;
- requires member states to report the national parameters and calculations used for setting their minimum energy performance every three years to the European Commission; and
- requires all new structures in the European Union to be nearly zero-energy buildings by 2021 and 2020 for the public sector.

Member states are required to implement the EPBD update by the second half of 2012.

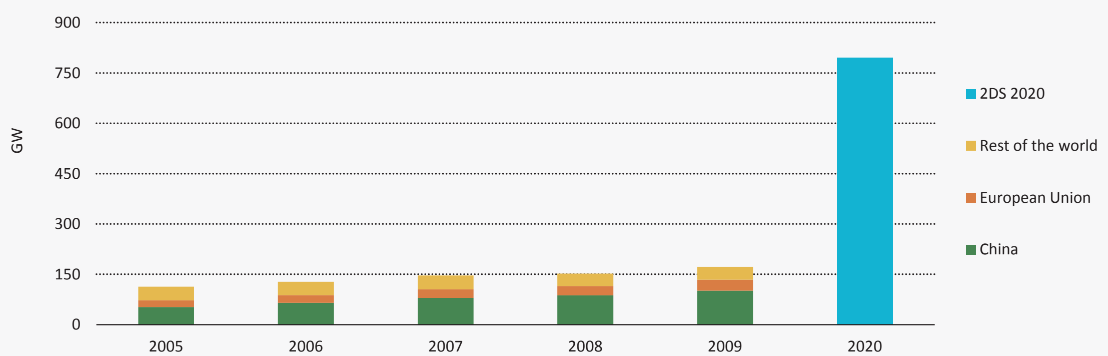
In summary, relatively little has been done to effectively address energy consumption in new and existing buildings globally, leaving significant untapped potential that can be achieved in various ways.

Low- and zero-carbon technologies for heating and cooling systems

Low-carbon or zero-carbon technologies for heating and cooling systems in residential and commercial buildings are critical to achieve the CO_2 emissions reduction in the 2DS. These include active solar thermal, heat pumps for both heating and cooling, and co-generation for buildings and large-scale heating technologies (*e.g.* district heating systems and co-generation for district heating). While these technologies are already commercially available, significant potential exists for enhanced deployment and improvements in system cost and efficiency (IEA, 2011e).

Solar thermal capacity of 172 GW at the end of 2009 (Figure 2.22) corresponded to heating for around 250 million m^2. The majority of capacity is in China, Europe and North America. Early estimates for 2010 put capacity at around 200 GW or 280 million m^2 (IEA SHC, 2011). In 2009, the collector yield (energy output of installations) of all water-based solar thermal systems in operation was over 140 000 GW equivalent to 14 million tonnes of oil equivalent (Mtoe), and 46 Mt of CO_2 emissions savings. The costs of solar thermal systems range from USD 1 100/kW to USD 2 140/kW for new single-family dwellings, and USD 1 300/kW to USD 2 200/kW for retrofits of existing housing. For multi-family dwellings, unit costs are slightly lower, at USD 950 to USD 1 050/kW for new, and USD 1 140/kW to USD 2 050/kW for retrofits. In general, the pace of solar thermal system deployment must pick up dramatically to achieve the *ETP* 2DS objectives by 2020.

Figure 2.22 Active solar thermal system deployment and 2DS 2020 objectives



Source: IEA analysis; IEA SHC, 2011.

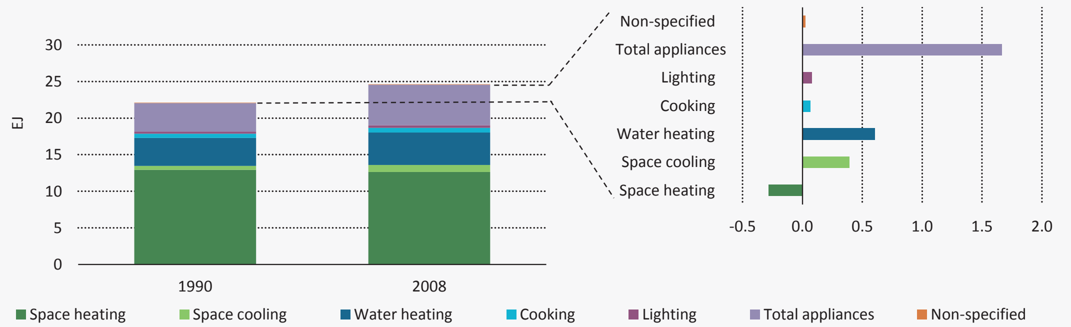
Key point *Accelerated, widespread deployment of solar thermal systems must occur to achieve the 2DS targets.*

While the global market for heat pumps is harder to assess, approximately 1 million ground-source heat pumps were installed in Europe in 2010, or 12.5 GW of installed capacity. Worldwide, an estimated 800 million heat pumps have been installed. Sales in Europe were just over USD 100 000, a drop of 2.9% between 2009 and 2010, following a 6.6% drop from 2008 to 2009 (EurObserv'ER, 2011). This slump is likely due to an uncertain financial outlook for many households, but studies also suggest that public scepticism about the technology persists in a number of countries. As a result of technological innovations, air-source heat pumps have, in recent years, been accepted under criteria outlined in the EU Renewable Energy Directive. Most are employed to cool buildings in summer (moderate climate) at quite low efficiencies. They are estimated to account for 80% of the total heat pump market in Europe, with 350 000 sales in 2010.

Energy efficiency of building appliances

A sample of data from 18 OECD member countries highlights that, while space and water heating remain responsible for the largest share of end-use energy consumption, appliances accounted for more than one-half of the 11% increase in end-use energy consumption from 1990 to 2008 (Figure 2.23). This trend is mainly attributable to the rapidly rising use of small personal appliances and electronics, such as flat-screen televisions, mobile telephones and personal computers.

Figure 2.23 Energy consumption in buildings by end-use and share of increase in energy consumption, 1990-2008

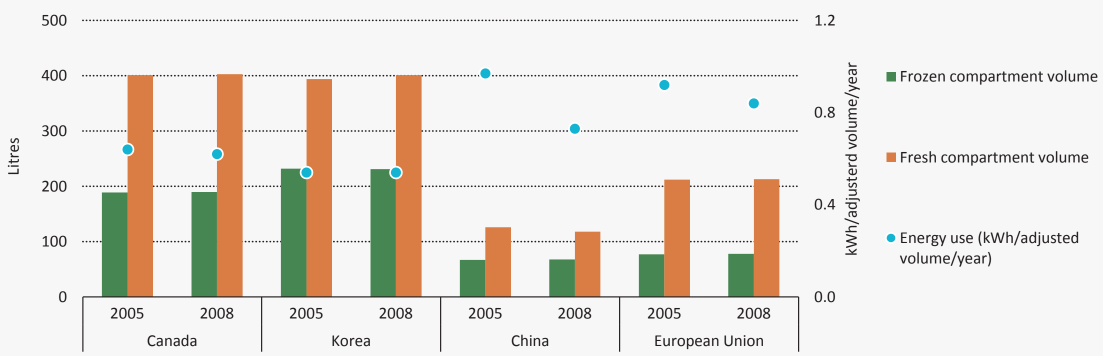


Note: Countries analysed are Australia, Austria, Canada, Denmark, Finland, France, Germany, Ireland, Italy, Japan, the Netherlands, Norway, Slovakia, Spain, Sweden, Switzerland, the United Kingdom and the United States.

Key point *The growing number of small appliances and electronics has increased building energy demand.*

Encouraging progress has been made in the energy efficiency of equipment and appliances, largely driven by minimum energy performance standards and labels. Energy efficiency of refrigerators, for example, has substantially improved in China and the European Union in a short period (Figure 2.24), and similar efficiency upgrades have been made to other appliance categories (*e.g.* washer/dryers, lighting, air conditioners). On the whole, while positive, efficiency improvements have been offset by two important factors: the fast-climbing number and use of large appliances as new markets are created (particularly in emerging economies), and accelerating popularity of small personal electronics.

Figure 2.24 Energy use and volume for combined refrigerator and freezer units



Note: Efficiency of appliances is not directly comparable among countries or regions, given variations in test procedures. This graph mainly aims to highlight efficiency progress within economies over time, plus variations in appliance sizes in different regions.
Source: 4e IA, 2011.

Key point *Energy efficiency of appliances has improved rapidly in some countries, but trends towards larger appliances must be avoided to help reduce overall energy consumption.*

Scaling up deployment

Enhancing the efficiency of buildings and scaling up the deployment of energy-efficient buildings technologies require targeted policies and measures.[15] In the buildings sector specifically, barriers such as split incentives between tenants and landlords, lack of awareness of efficient technologies, absence of qualified "green" technicians, and high initial investment costs threaten market-driven energy savings measures (IEA, 2011b). Governments can address these barriers and promote energy savings in the buildings sector by implementing a package of policies, coupled with financing tools and models to help overcome high up-front investment costs. In particular, governments should work at national and sub-national levels to:

- require all new buildings, as well as buildings undergoing renovation, to meet energy codes and minimum energy performance standards;
- support and encourage construction of buildings with net-zero energy consumption;
- implement policies to improve the energy efficiency of existing buildings with emphasis on significant improvements to building envelopes and systems during renovations;
- develop building energy performance labels or certificates that provide information to owners, buyers and renters; and
- establish policies to improve the energy efficiency performance of critical building components in order to improve the overall energy performance of new and existing buildings.

In the area of appliances and equipment specifically, improvements in energy efficiency are mainly attributed to two policies: minimum energy performance standards and labels. Ideally, these policies should be combined, as is done in China, India and now the European Union. Governments must support these with test standards and measurement protocols, in addition to market transformation policies, to encourage consumers and manufacturers to value higher efficiency. Several governments are making good progress in the development of standards and labels (Table 2.8), but significant savings potential remains. This is in part due to the fact that the development of these two major policies has been a component approach, rather than a comprehensive one. HVAC system product requirements, for example, focus on individual components (such as chillers in the case of the United States), but not on the terminal units, air handling units and other operational equipment. Enhanced international collaboration in this area can support the development of harmonised test procedures and more stringent appliance standards.

Heating and cooling technologies and systems have not entered the mainstream energy policy debate, in part due to the lack of data and information regarding their deployment levels and energy saving potential. Collecting such enhanced data (building characteristics plus technology deployment, cost and efficiency) will significantly help system planning for the buildings sector.

A number of policies to support greater use of low-carbon heating and cooling technologies are beginning to attract attention, particularly renewable heat policies. While renewable heat sources have been covered indirectly under general renewable energy legislative frameworks since the 1990s, in the past five to seven years, more targeted policies have been developed. The European Union Directive to promote the use of energy from renewable sources has been a key driver for this change in EU countries.

15 The IEA developed *25 Energy Efficiency Policy Recommendations* (2011b), which outlines a series of targeted policy measures for buildings, appliances and equipment, lighting, transport, industry, energy utilities and cross-sectoral issues.

Table 2.8 Policies to enhance equipment and appliance efficiency

Appliances	Minimum energy performance standard	Labelling
Clothes washers	Brazil, Canada, China, European Union, India*, Korea, Mexico, Switzerland, United States	Australia, Canada, European Union, Korea, Mexico, New Zealand, Norway, Switzerland, Turkey, United States
Residential refrigerators	Australia, Brazil, Canada, China, European Union, India, Japan, Korea, Mexico, New Zealand, Switzerland, United States	Australia, Canada, European Union, India, Japan, Korea, Mexico, Norway, New Zealand, Switzerland, Turkey, United States
Commercial refrigerators	Australia, Brazil, Canada, European Union, India, Korea, Mexico, New Zealand, Switzerland, United States	European Union, Korea, Mexico, New Zealand, Norway, Switzerland, Turkey
Computers	Australia, India*, Japan	India*, Japan
Distribution transformers	Australia, Canada, China, European Union, India, Japan, Mexico, United States	India, Japan
Fans	Canada, India*, Korea, New Zealand	India, New Zealand
Motors	Australia, Canada, China, European Union, Korea, Mexico, New Zealand, Switzerland*, United States	Korea, Mexico, Switzerland*
Room air conditioners	Australia, Brazil, Canada, China, European Union, India, Japan, Korea, Mexico, New Zealand, South Africa*, Switzerland, United States	Australia, Canada, European Union, Japan, Korea, Mexico, New Zealand, Norway, Switzerland, Turkey, United States
Standby power	Eeropean Union, Mexico, South Africa*, United States	
Television	Australia, Brazil, China, European Union, Japan	Brazil*, Japan, United States
Phase out of conventional incandescent light bulbs	Australia, Brazil, China*, European Union, Japan*, Mexico, New Zealand*, Switzerland, United States	

Note: * Denotes that policy is voluntary in nature.
Source: CLASP database, IEA analysis.

Direct capital cost subsidies, tax incentives and soft loans for the purchase of renewable heating systems are the most widely adopted financial mechanisms in the European Union that support renewable heat (IEA, 2011c). Other policy mechanisms, such as renewable obligations and feed-in tariffs, are also gaining traction: in 2011, the United Kingdom introduced the first feed-in tariff type policy for the heat market under its Renewable Heat Incentive (RHI) and will soon publish the "Heat Strategy", which prioritises further development of heat networks, especially in urban areas. While more countries are implementing dedicated renewable heat policies, finding the appropriate policy design is a challenge, given the distributed nature of heat generation and its fragmented market (IEA, 2011c). Sharpening the focus on developing dedicated renewable heat policies and sharing experiences on the most effective policy designs would accelerate deployment of renewable heat technologies.

Transport

Economic growth in emerging economies has spurred widespread demand for personal vehicles and for moving freight by road. Energy demand in the transport sector has steadily increased in recent years and is projected to more than double by 2050. Currently, the transport sector accounts for 20% of the world's primary energy use and 25% of energy-related CO_2 emissions. Under the 2DS, transport also holds the potential to reduce CO_2 emissions by 30% from current levels by 2050. Achieving this target requires a combination of improved fuel efficiency; new types of vehicles, such as battery electric (BEVs) and plug-in hybrid electric vehicles (PHEVs); and alternative fuels capable of reaching very low CO_2 emissions per kilometre (*e.g.* advanced biofuels).

Road transport, including both light-duty vehicles (LDVs) and heavy-duty trucks, consumes the most energy (approximately three-quarters) in the transport sector and has experienced the most rapid growth in absolute terms (close to a 20% increase from 2000 to 2009). The best opportunity to make the transport sector more energy efficient lies primarily with LDVs.

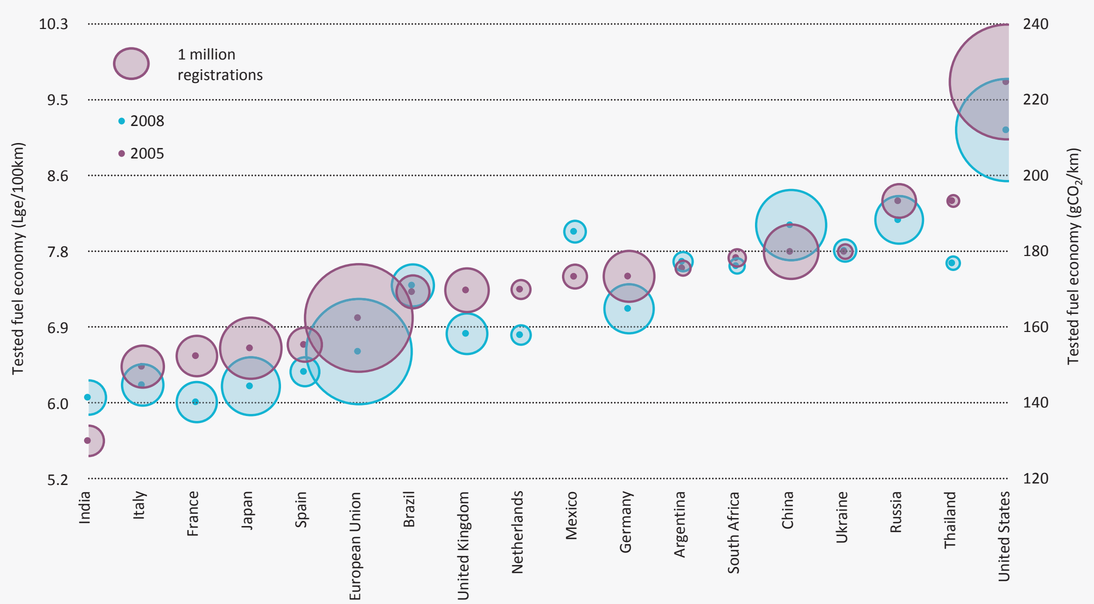
Fuel economy

Enhancing the fuel economy of vehicles and vehicle fleets is the single best opportunity to curb fossil fuel use and reduce CO_2 emissions within the transport sector over the next decade. Evidence to date suggests that many governments' fuel economy ambitions are not currently set high enough to achieve the 2DS objectives.

Progress assessment

Average fuel economy levels vary significantly by country (Figure 2.25), from approximately 6 litres (L) per 100 km for the least fuel-intensive end of the spectrum (India) to over 9 L/100 km at the most fuel-intensive end (the United States). Average new LDV global fuel economy improved at a rate of 1.7% between 2005 and 2008.[16] Trends also suggest that, while some countries are improving their fuel economy considerably (*e.g.* European Union), others are quickly becoming less fuel efficient (*e.g.* China, Brazil, Mexico, India) – in many cases, owing to increased sales of larger vehicles, among other factors.

Figure 2.25 Light-duty vehicle fuel economy and new vehicle registrations, 2005 and 2008



Note: Lge = litre of gasoline equivalent. gCO_2/km = grams of CO_2 emissions per kilometre.
Source: Polk, 2009; IEA analysis and data.

Key point *Fuel economy has improved in most countries, but decreased in some countries owing to the increase in sales of larger vehicles.*

16 Average of 21 countries and sample of cars examined by the Global Fuel Economy Initiative.

While the overall picture of fuel economy is positive, the rate of improvement needs to increase in order to achieve the 2DS by 2020. The 2DS is consistent with the objectives of the Global Fuel Economy Initiative[17] (GFEI) to improve the fuel economy of new LDVs by 50% by 2030; attaining an average annual fuel economy improvement of 2.7% (Table 2.9).

Table 2.9 Progress of new vehicle fuel economy against the 2DS target

		2005	2008	2020	Average annual percentage change	
Fuel economy (Lge/100 km)	Estimated global average	8.1	7.7		2005 to 2008 (actual):	-1.7%
	2DS 2020 objectives	8.1	7.4	5.6	2005 to 2020 (required):	-2.7%

If fuel economy standards in line with the 2DS (5.6 L/100 km by 2020) become compulsory for all new LDVs worldwide, fuel consumption in 2020 will drop by approximately 25%, falling further to 50% in 2050 as the vehicle stock turns over (compared with the 2005 base level of fuel economy). Global CO_2 emissions from these vehicles will fall by roughly 0.2 gigatonnes (Gt) in 2020 and 1.5 Gt in 2050. This excludes savings from sales of new technology vehicles, such as BEVs and fuel-cell vehicles. Improving all other modes (trucks, ships, aircraft, etc.) by estimated achievable amounts (improvement of 30% to 50% efficiency, depending on the mode) yields total CO_2 emissions savings to the transport sector of approximately 0.5 Gt in 2020 and 3 Gt in 2050. Oil demand in transport can be cut by 3 million barrels per day (mb/d) in 2020 and close to 20 mb/d in 2050.

Recent developments

Attributing shifts in overall fuel economy to any one factor is not possible, but recent trends explain at least some of the observed changes. Some countries already have new (or stronger) fuel economy standards and increases in fossil fuel prices have shown evidence of pushing consumers to buy more efficient vehicles; in many countries, however, consumer demand is shifting to larger, heavier vehicles.

New, more robust vehicle efficiency standards have indeed improved average fuel economy of fleets in a number of countries (Figure 2.26). In OECD countries, the market share of large sports utility vehicles (SUVs) decreased, while the number of smaller vehicles increased in some countries: small cars gained approximately 5% market share in 2008 compared with 2005 (IEA, 2011d).

Box 2.4 Impact of heavy-duty vehicles

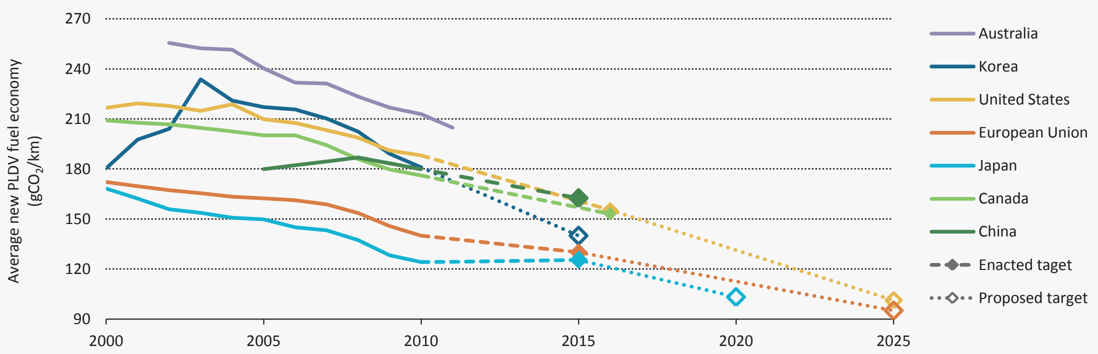
The escalating number of trucks and lack of fuel-economy standards for commercial vehicles will have a major impact on CO_2 emissions and average fuel economy levels, particularly in non-OECD economies. Most member countries are working on commercial vehicle fuel-economy standards, and some have been implemented. Much more must be done in this area.

Conversely, as the purchasing power of economies grows, vehicle sales increase, and as larger vehicles start penetrating the market, downward pressure is put on fuel economy, as seen in China. While a fuel economy standard was introduced in 2005, the share of new large vehicle registrations increased from 2005 to 2008. On average, fuel economy worsened, although the fuel standard helped limit this effect. India, Indonesia and Mexico

17 The Global Fuel Economy Initiative (GEFI) is a partnership of IEA, UN Environmental Programme, International Transport Forum and FIA Foundation. Its core objective is to improve global fuel economy by 50% by 2030.

showed similar trends, although their economies have no fuel economy standards. Avoiding purchase shifts to larger, more energy-intensive vehicles is critical.

Figure 2.26 **Vehicle fuel economy, enacted and proposed standards**

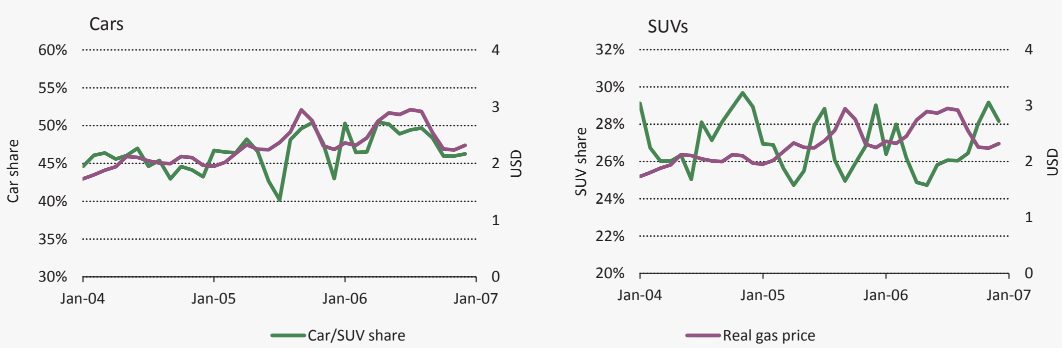


Note: United States and Canada LDVs include light commercial vehicles, SUVs and passenger vehicles.
Source: Enacted and proposed targets: GFEI, 2011; IEA analysis and data.

Key point *Although fuel economy and emissions standards for vehicle fuel economy will markedly improve efficiency, they are not sufficient to achieve the 2DS objectives.*

Studies also show that short-term and sustained high gasoline prices influence vehicle choice, with consumers purchasing more efficient vehicles as fuel prices climb – and are sustained. A study undertaken in the United States found that, as gasoline prices increased, consumers purchased smaller, more efficient vehicles; the inverse was true when gasoline prices decreased, with an increase in the share of SUVs sold (Figure 2.27). This trend points to the impact that fuel prices have on consumer decision making.

Figure 2.27 **United States passenger vehicle market shares and actual price of gasoline, 2004 to 2006**



Note: The right-hand scale shows the average inflation-adjusted price per gallon for all grades and formulations of gasoline; price is 2007 USD per gallon.
Source: CBO, 2008. Data from Congressional Budget Office are based on data from Automotive News and the Department of Energy, Energy Information Administration.

Key point *Higher fuel prices show evidence of driving consumers to purchase more efficient vehicles.*

Scaling up deployment

Improving vehicle fuel economy and average fleet fuel economy is influenced by both technical advances and consumer choices. On the technical front, factors include vehicle size, vehicle weight and power train characteristics (*e.g.* engine displacement, transmission type, fuel type, engine aspiration type and engine power). Consumers, however, when deciding which car to purchase, focus on the overall vehicle price, fuel prices, fuel type, parking space availability, design and style, safety, interior space and design, cargo volume, power and power-to-weight ratio, reliability, and brand image (IEA, 2011d).

To improve fuel economy at the scale and pace required to meet efficiency and emissions objectives of the 2DS, governments need to implement policies that address technical fuel economy requirements and consumer choice determinants. Fuel economy or greenhouse-gas (GHG) emissions standards have proven an important policy tool. While some governments have standards in place (Figure 2.26), many are in force only through 2020 (the United States' standards extend through 2025). Existing fuel economy and emissions standards must be extended and made tougher in order to reach the 2DS goals for fuel economy improvement. Countries without such standards should consider the implementation of this effective policy tool.

In addition, other measures, including vehicle taxes and incentives, fuel taxes, traffic control measures and the provision of consumer information, are required to help guide decision making by consumers (Table 2.10). Government implementation of such policies is relatively limited, despite the fact that consumers will ultimately decide whether to purchase a more, or less, fuel efficient vehicle.

Table 2.10 Technical and consumer policies in place, 2011

	Policy aspects	Governments
Policies targeting technical efficiency		
Fuel economy standards	Limit to litres/100 km across fleets or based or vehicle weight or class. Stringency of standards, test procedures and number of vehicles classes vary by country.	Australia*, Canada, China, Korea*, Japan, United States
GHG emissions standard	Limit on emissions/km	European Union, California (United States)
Policies targeting consumer choice		
Fiscal incentives	Registration taxes increase with vehicle and engine size, and CO_2 emissions; sales incentives for more fuel efficient and lower CO_2 emitting vehicles.	Brazil, China, France, Germany, India, Italy, Japan, Korea, Russia, South Africa, Spain, Turkey, United Kingdom, United States
Consumer information	Labels showing vehicle fuel economy and GHG emissions.	Australia, Brazil, Chile, European Union, China, India, Korea and others
Driving prioritisation and penalty	Driving lane prioritisation for high-efficiency vehicles; banning of SUVs and charges for low-efficiency vehicles.	Several US states; London, Paris

* Policy under development.
Source: IEA analysis; UNCSD, 2011.

Electric vehicles and hybrid electric vehicles

Progress assessment

While fuel economy plays the central role in reducing transport-sector CO_2 emissions by 2020, the 2DS also shows strong penetration of hybrid vehicles, PHEVS and BEVs, which reach substantial yearly sales (over 7 million) and stocks (over 20 million) in this time frame.

While this represents rapid development of a nascent market, if achieved, BEVs and HEVs will still account for only 2% of the world vehicle fleet in 2020.

Many governments have adopted strong targets for electric vehicle deployment in the 2015 to 2020 time frame (Figure 2.30) in line with the 2DS objectives. But to achieve this goal, sales must nearly double each year between 2012 and 2020, cost must continue to decline, infrastructure needs to be developed, and consumer choice and confidence requires a boost.

Recent developments

Fuel price increases not only influence consumers to purchase more efficient vehicles, but also drive up interest in alternative transport modes. This was especially true for hybrids, which showed strong popularity in the United States in 2008. While interest has since dropped off in the United States, hybrids have taken off in Japan. Since 2008, Japan overtook the United States as the largest hybrid market worldwide.

In 2011, BEV sales finished below expectations by analysts and automakers, making 2012 an even more crucial year for the electrification of the vehicle fleet. However, in a year that saw a continued recession and production bottlenecks as a result of the Great East Japan Earthquake (Figure 2.31), it is perhaps encouraging that the 40 000 EVs sold matches the number of HEVs sold in six years (1997 to 2003). While obstacles remain, BEV business models developed further in 2011, as did battery technologies; both are important to bringing down the cost of BEVs.

In terms of business models, Paris launched an ambitious electric car-sharing scheme (Autolib), which aims to put 3 000 electric cars into service, while taking 22 500 conventional gasoline-powered vehicles off the road by 2014. This pilot test should help familiarise consumers with the technology.

Battery costs are often cited as the biggest hurdle to EV competitiveness with standard gasoline cars. Estimating battery costs is difficult and hard to separate from total vehicle prices. In addition to production costs, prices often reflect other overhead costs, such as marketing. Based on available reports, batteries had, roughly, a cost-based price at medium-high volume production of around USD 750/kWh in early 2011. Reported costs through the year declined, and at the beginning of 2012 stand at around USD 500/kWh. If this improvement continues, batteries can reach USD 325/kWh or less by 2020, which is sufficient to bring EVs close to cost-competitiveness with internal combustion engine vehicles, which is years ahead of past projections (Figure 2.28).

Scaling up deployment

As noted, current government targets are in line with achieving the required annual sales of 7 million EVs and HEVs, amounting to 20 million vehicles in stock globally by 2020. Achieving this goal requires additional policy support, including incentives for consumers, policies that give confidence to manufacturers and funding to build recharging infrastructure.

Key elements to encourage widespread consumer acceptance and adoption of EVs include:

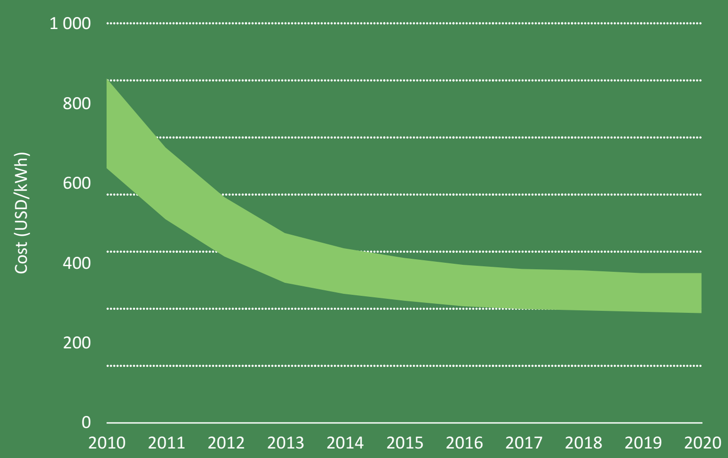
- Levellising the cost of ownership of EVs (*e.g.* monthly vehicle purchase, operation and fuel costs that compare with conventional gasoline-powered vehicles) via incentive programmes. It remains to be seen whether the current incentive levels, USD 5 000 to USD 7 500 per vehicle in most OECD countries, are sufficient to achieve this, but falling battery and vehicle costs will certainly help.
- Reducing concerns about battery life and vehicle resale value, possibly through battery leasing programmes.

Electric vehicles overview

Governments have set targets to achieve 20 million electric vehicles (EVs) on the road by 2020, in line with levels required to achieve the 2DS objectives. Achieving this goal hinges on increasing vehicle production, lowering costs, developing infrastructure and boosting consumer choice and confidence.

Technology developments

2.28: Estimated battery cost reductions to 2020



325

USD/KWH ESTIMATED TARGET PRICE FOR EVS TO BE COST-COMPETITIVE WITH INTERNAL COMBUSTION ENGINE VEHICLES

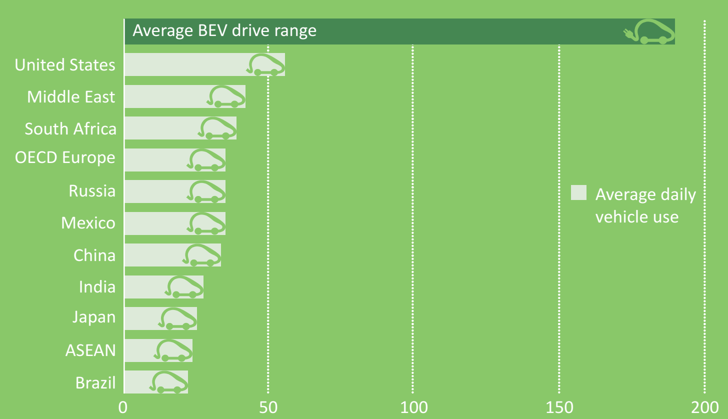
Key technology needs

Battery cost reductions are key to future EV competitiveness

While EV driving range is greater than average daily vehicle use, further improvements are required

Public confidence in the technology must be increased through consumer education and information

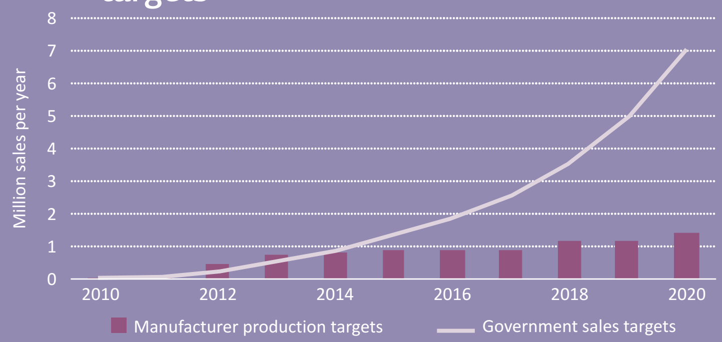
2.29: BEV driving range and average LDV travel per day



Source: CE Delft/ICF/Ecologic

Market creation

2.30: Government and manufacturer EV targets



Key developments

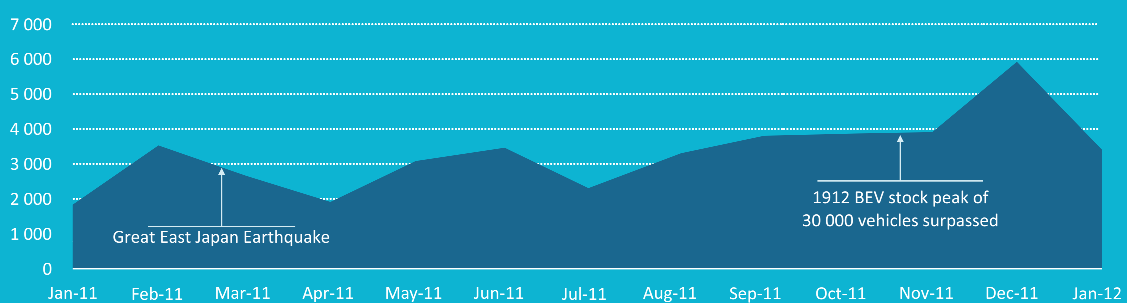
Government targets are set to achieve stock of 20 million vehicles by 2020

Manufacturer production after 2014 remains uncertain

USD 1 billion in infrastructure investment over the past few years, against an average annual investment of over USD 2 billion to be on track with the 2DS by 2020

Technology penetration

2.31: World EV sales



Source: MarkLines

Achieving EV goals

Annual sales of EVs must double every year between now and 2020 to achieve the 2DS objectives

To achieve this goal, policies to help levelise the cost of EV ownership will be necessary through incentive programmes, until battery costs come down

2.32: EV stock

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- Providing adequate recharging infrastructure to enable full local access and mobility, and reduce consumer concerns regarding range limitations. Consumer education will also be an important factor in this regard, as evidence shows that current EV driving range (190 km) is well above average daily vehicle use in many countries (Figure 2.29). Improvements to driving range are still required, as inter-urban range limitations may take longer to address.
- Implementing some temporary advantages, such as priority access to urban parking spaces, access to low-emission zones or access to priority access lanes on highways.

Enhanced deployment of EVs is also highly dependent on manufacturer commitment to develop and market the vehicles. While production announcements seem to be in line with the levels required to achieve government sales targets through 2014, beyond this date the picture is less certain. Current subsidy programmes with one- to two-year time horizons do not instil confidence in manufacturers that markets will develop and demand will grow (Figure 2.30). Longer-term, clearer policy signals from governments would shore up industry confidence and induce investment.

Biofuels

Progress assessment

Biofuels are one of the main alternative fuels that can offer very low net GHG emissions. In contrast to BEVs or vehicles running on hydrogen, biofuels have been produced commercially in both the United States and Brazil for several decades. The sector grew the fastest in the past ten years. Driven by policy support in more than 50 countries (Figure 2.36), production of global biofuels grew from 16 billion Lge in 2000 to more than 100 billion Lge in 2011 (Figure 2.37).[18] Globally, biofuels accounted for around 3% of road transport fuels, with a considerable share in Brazil (21%), and an increasing share in the United States (4%) and the European Union (about 3%).

Not all biofuels in the market today, however, can actually reduce GHGs on the scale needed to meet the targets in the 2DS. Improving the efficiency of conventional fuels, and commercially deploying advanced biofuels, will clearly still be required (Figure 2.34). In the 2DS, the use of biofuels increases to approximately 240 billion Lge in 2020, which, when produced sustainably, leads to a reduction of approximately 0.1 Gt of CO_2 emissions in the transport sector.

Achieving the 2DS objectives largely depends on developing advanced biofuels, with a target of approximately 22 billion Lge by 2020, and important reductions in production costs (Figure 2.33). Installed advanced biofuel capacity (lignocellulosic ethanol, biomass-to-liquids and other types) today is less than 200 million Lge, with most plants operating well below capacity. Another 1.9 billion Lge/year production capacity is currently under construction, and project proposals for an additional 6 billion Lge annual capacity by 2015 have been announced (IEA, 2011f). Given the industry's volatile nature and limited operational history, many of these facilities may experience delays and cancellations, or begin with low production rates. Even without taking these potential shortfalls into consideration, achieving the 2DS by 2020 will still require a fourfold increase in production capacity beyond current announcements, which represents a major challenge. Achieving this will require a significant and sustained push by policy makers.

18 Production volumes in 2011 were actually slightly below those in 2010, mainly due to lower-than-expected ethanol production in Brazil. However, with new sugar cane fields coming into production, the shortage of Brazilian ethanol will likely disappear in the next few years.

Recent developments

Blending mandates for transport fuels and financial incentives have driven the rapid growth in the biofuels sector over the last ten years, but high feedstock prices, overcapacity, changing government policies and public discussion on the sustainability of biofuels have recently slowed this growth. This may limit future expansion of fuels that rely on comparably costly feedstock (such as vegetable oil) and provide only limited GHG benefits. Several developments in 2011 point in this direction:

- In 2011, Brazil's bioethanol production was challenged by a poor sugar cane harvest and high sugar prices. Production dropped 15%, as many mills shifted from ethanol to sugar. This situation will likely reverse itself in the next few years as new sugar cane fields come into production.
- In the United States, the world's largest producer of biofuels, support measures and policies changed considerably as of 2012. The ethanol blenders' tax credit (USD 0.45 per gallon for blenders of corn ethanol) and the tariff on imported ethanol (USD 0.54 per gallon on imported ethanol) expired at the end of 2011. This is not expected to lead to significant changes for the industry in the short term, as the biofuel blending mandate – the Renewable Fuels Standard 2 – is still in place and requires a steadily increasing proportion of biofuels to be blended into gasoline. This standard requires the blending of fuels other than corn-ethanol, such as cellulosic biofuels and other advanced biofuels, and limits the role of corn ethanol over time. Support for advanced biofuels was also bolstered in 2011, when the United States announced intentions to invest USD 510 million over the coming years to promote their production.
- In the European Union, overall biofuel production continues to grow, but the biodiesel sector is struggling with plant utilisation rates of around 50% of production potential. Higher feedstock prices, in combination with economic pressures and increasing GHG-reduction thresholds in EU legislation, will likely limit future growth of the biodiesel sector.

Scaling up deployment

The development of advanced biofuels needs to be accelerated, primarily through dedicated government support for RD&D and, in particular, sound backing for the initial commercial production units. Financial support – direct financing, loan guarantees or guaranteed premiums for advanced biofuels – is crucial to reduce risks associated with large investment in pre-commercial technologies. A premium for advanced biofuels, similar to feed-in tariffs for renewable electricity, also effectively addresses the currently higher production costs compared with conventional biofuels. Support for advanced and other, truly low-GHG biofuels must continue until at least 2020 to ensure the scale up and cost reductions necessary for biofuels to reach maturity and full commercialisation.

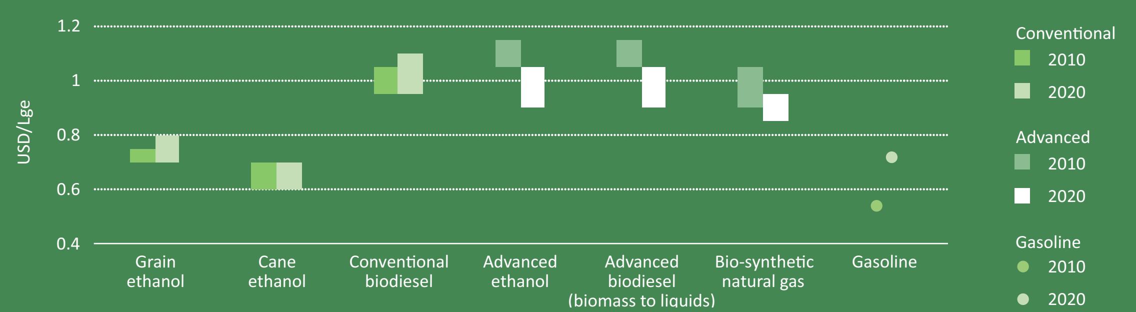
An important requirement for further expansion of biofuel production is that their use leads to considerable net-GHG reductions and other environmental benefits, compared with fossil fuels. Support policies for biofuels should add incentives promoting the most efficient biofuels (in terms of overall GHG performance), backed by a strong policy framework that ensures that food security and biodiversity are not compromised, and that other social impacts are positive. This includes sustainable land-use management and certification schemes, as well as support measures that promote low-impact feedstock (such as wastes and residues) and efficient processing technologies. Sustainability certification should be based on internationally agreed-upon indicators, such as those developed by the Global Bioenergy Partnership, to help avoid market confusion.

Biofuels overview

Biofuel (bio-ethanol and biodiesel) production has grown dramatically over the past decade due to strong policy support, but sustainability challenges may slow their production. Biofuels production needs to double, requiring a four fold increase in advanced biofuels production over currently announced capacity by 2020, to achieve 2DS objectives.

Technology developments

2.33: Biofuel production costs, 2010 and 2DS objectives



Technology needs

Cost reductions through RD&D and construction of commercial-scale advanced biofuel plants are required to achieve the 2DS objectives by 2020

Sustainability concerns must be addressed, through internationally harmonised sustainability certification, as basis for biofuels economic support measures

2.34: Litre of fuel equivalent per hectare

Market creation

2.35: Biofuel production capacity investment

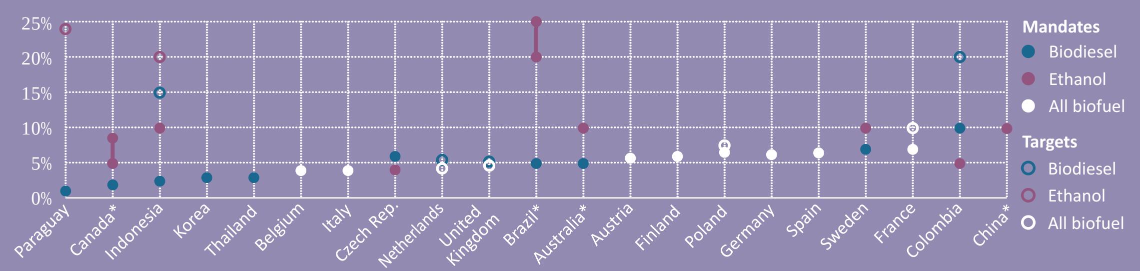
Source: BNEF

Market developments

To achieve the 2020 2DS objectives, an average annual investment of USD 110 billion will be required in biofuels

The United States, the world's largest producer of biofuels, has production targets of 56 billion Lge in 2012, up to 78 billion Lge by 2015, and 136 billion Lge by 2022

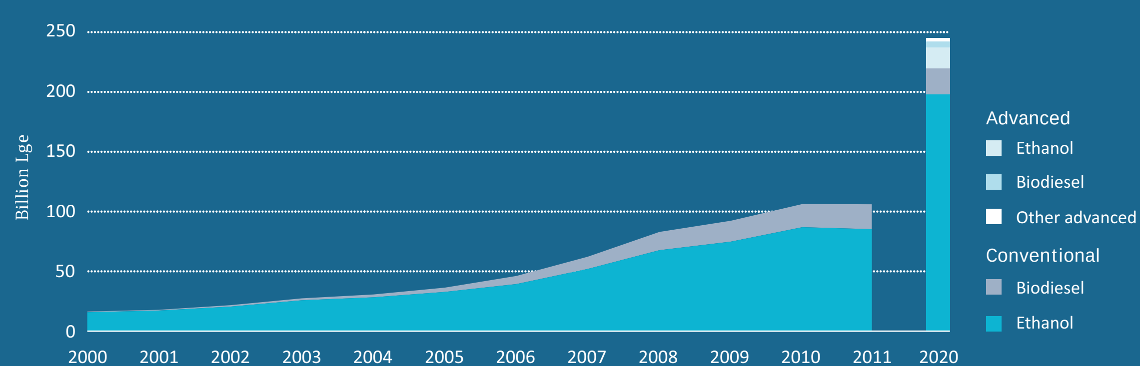
2.36: Biofuel blending mandates and targets in key regions



* Denotes a country where mandates are limited to sub-national territories or vary between sub-national territories (see notes).

Technology penetration

2.37: World biofuel production, 2000-11 and 2DS objectives



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Carbon capture and storage

Progress assessment

With the world's dependence on fossil fuels not expected to abate significantly in the short to medium term, CCS is a critical technology to reduce CO_2 emissions and decarbonise both the industry and power sectors. Development and deployment of CCS is seriously off pace to reach 269 Mt/CO_2 captured across power and industrial applications in 2020 in the 2DS. This is equivalent to about 120 CCS facilities.

Progress in CCS is largely characterised by the extent to which the technology evolves through large-scale demonstration projects. It also depends on sufficient funding and whether governments enact policies that support the demonstration and future deployment of the technology. Projects can be categorised by key development phases, defined as follows:

1. **Identify:** establish preliminary scope and business strategy.
2. **Evaluate:** establish development operations and execution strategy.
3. **Define:** finalise scope and execution plan.
4. **Execute:** detail and construct asset.
5. **Operate:** operate, maintain and improve asset.

Currently, 65 large-scale integrated CCS projects are under construction or in planning phases (GCCSI, 2011). Only four operating projects carry out sufficient monitoring to demonstrate permanent storage of CCS. Clearly, a challenging road lies ahead for deploying CCS in the near term (Figure 2.41).

It can take upwards of ten years to build a new CCS project from the ground up through to operation, although this varies by sector and specific project. Considering the distribution of projects, by the middle of this decade, there should be about 10 operating large-scale integrated CCS projects. What is not clear is whether they will incorporate sufficient monitoring to demonstrate permanent CO_2 storage. At minimum, an additional 110 planned projects must successfully be brought on line by 2020 to get back on track to meet the 2DS objectives. This is an incredibly ambitious target based on current deployment rates.

Recent developments

The current funding and policy environments represent a very serious challenge, since sustained effort by governments around the world is needed to promote CCS. The number of large, integrated operational projects remained constant throughout 2011, as new projects entered the development pipeline, and the same number of projects was cancelled. Given the high capital cost, risks associated with initial projects and the fact that CCS is motivated primarily by climate policy, the technology needs strong government backing by way of CO_2 emissions reduction policies and dedicated demonstration funding.

New funding for CCS demonstration projects peaked in 2008, when several governments supported CCS technology demonstration as part of economic stimulus plans. Since then, additional funding has been limited, and the allocation of announced funds still lags. Currently, approximately USD 21.4 billion is available to support large-scale CCS demonstration projects, but as of 2012, only 60% of available funding had been allocated to specific projects (GCCSI, 2011). Persistent global economic challenges in many countries will further constrain government budgets, meaning that public funding for CCS will likely be cut back. Already, USD 0.4 billion in previously announced CCS funding has been withdrawn (Figure 2.40).

A few recent developments in CO_2 emissions policy may provide some positive impetus in driving CCS development:

- The United Kingdom commenced an electricity market reform process in July 2011, intended to drive decarbonisation of the electricity sector, including through broad CCS deployment. Proposed measures include an emissions performance standard to ensure that no new coal-fired plants are built without CCS; a carbon price floor, intended to strengthen the incentive to invest in low-carbon generation; and feed-in tariffs combined with contracts-for-difference, to guarantee the price paid to generators.
- The Australian government passed new legislation on 8 November 2011 that introduces a carbon price of AUD 23 (USD 24.6) per tonne starting 1 July 2012, which will increase 2.5% per year. The initial price is fixed for three years before shifting to an emissions trading scheme on 1 July 2015. The government expects the carbon price to encourage investment in low-emission technologies, including CCS.

These are examples of early steps towards policy architecture that is more favourable to wide-scale CCS deployment.

Scaling up deployment

To scale up CCS, dedicated government funding and a broad carbon policy must be supported by a long-term strategy for CCS deployment and enabling regulatory frameworks. The IEA has developed guidance on how policy design can support CCS technology uptake from demonstration to wide-scale deployment, as well as criteria for governments to consider when developing CCS laws and regulations, through a model legal and regulatory framework addressing 29 specific issues (IEA, 2010; IEA, 2012). Three countries, Australia, Norway and the United Kingdom, are implementing comprehensive legal and regulatory frameworks, deployment programmes and policies, and have long-term CCS strategies (Table 2.11).

Table 2.11 Country policies and frameworks to support CCS deployment

Comprehensive legal and regulatory frameworks in place*	
Permitting processes allowing exploration for, access to and use of pore space for geologic storage of CO_2	Australia**, Canada**, European Union, France, Italy, Norway, Spain, United Kingdom, United States
Frameworks for managing project-period and long-term liability associated with storage operations and stored CO_2	Australia**, Canada**, European Union, France, Italy, Norway, Spain, United Kingdom
Monitoring, reporting and verification requirements	Australia**, Canada**, European Union, France, Italy, Norway, Spain, United Kingdom, United States
Financial and policy incentives	
R&D programme and support	Australia, Canada, European Union, Finland, France, Germany, Italy, Japan, Korea, Norway, South Africa, Spain, Sweden, United Arab Emirates, United Kingdom, United States
Demonstration programme and support	Australia, Canada, European Union, France, Italy, Korea, Norway, Spain, United Arab Emirates, United Kingdom, United States
Deployment programme and support	Norway, United Kingdom
A price or limits on CO_2 emissions that could lead to use of CCS in the power and industrial sectors	Australia (from July 2012), Canada (from July 2015), EU ETS, UK electricity market reform (from 2014)
Deployment strategy	
Long-term policy frameworks	Australia, Norway, United Kingdom

* Highlights only select criteria from IEA's Carbon Capture and Storage Model Regulatory Framework.
** Indicates activity is also occurring at a sub-national level (*i.e.* state or province).
Note: Japan has allocated approximately JPY 22 billion (USD 276 million) to undertake site characterisation, which will support demonstration.

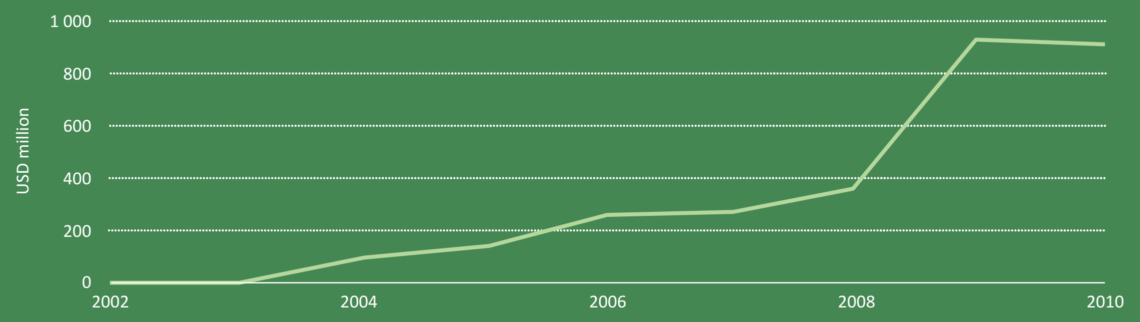
For global progress to be made in CCS deployment, more countries will have to expand their CCS commitments. The private sector is otherwise highly unlikely to take on the risks of investing in CCS demonstration projects.

Carbon capture and storage overview

Carbon capture and storage contributes a major share of potential CO_2 emissions reduction in the 2DS, but progress in building commercial-scale demonstrations has been slow. For CCS to remain an option for curbing CO_2 emissions from power and industry, governments must urgently scale up financial and policy support.

Technology developments

2.38: Government spending on CCS R&D in IEA countries

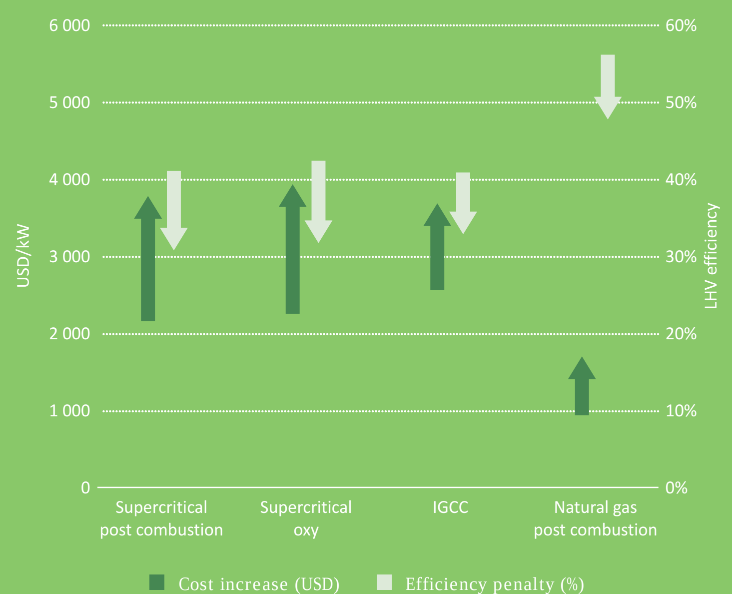


Technology needs

Energy and resource penalties associated with CO_2 capture must be reduced through technology improvements and experience

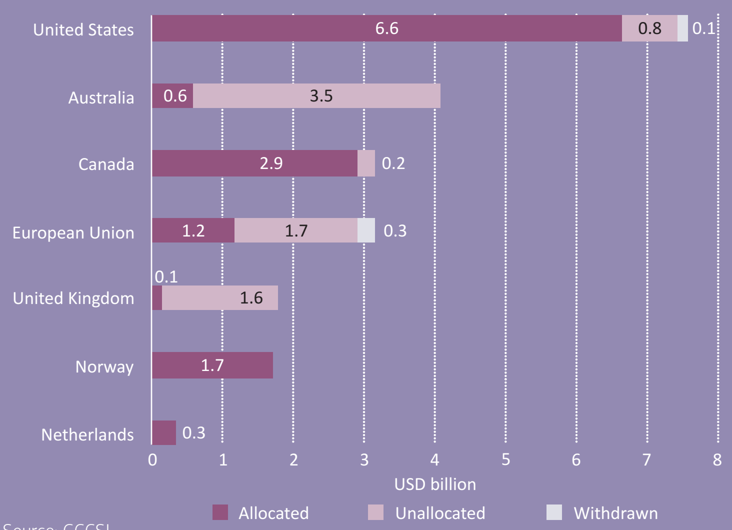
Additional large-scale storage sites are required to validate design, management and monitoring tools

2.39: CCS Cost increase and efficiency penalty



Market creation

2.40: CCS project funding status, end 2011



Source: GCCSI

Key developments

Countries must assess and recognise the role of CCS in their energy future, and develop suitable deployment strategies

Announced funding must be allocated to large-scale CCS demonstration projects with high probabilities of success

Technology penetration

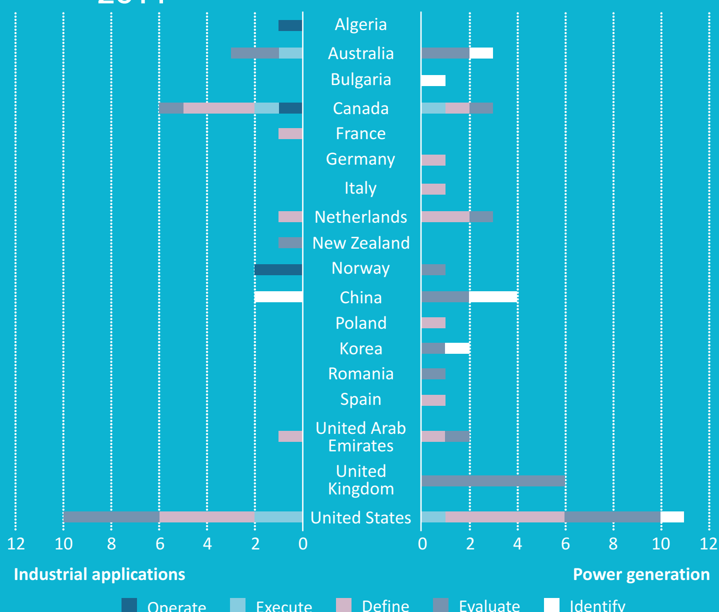
16

GW OF POWER GENERATION FITTED WITH CCS IN 2020

196

MT OF CO_2 CAPTURED IN INDUSTRIAL APPLICATIONS IN 2020

2.41: Large-scale integrated CCS project status, 2011



Source: GCCSI

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Technology overview notes

Unless otherwise sourced, data in the two-page graphical technology overview are from IEA statistics and analysis. Additional notes below provide relevant details related to data and methodologies.

Higher-efficiency, lower-emissions coal overview

Figure 2.3: "OECD 5" is a weighted average of the efficiency of coal-fired power plants installed over the five-year period in Australia, Germany, Poland, the United Kingdom and the United States

Figure 2.4: Costs refer to overnight investment costs. Overnight cost is the present value cost of total project construction, assuming a lump sum upfront payment and excluding the cost of financing.

Figure 2.5: Total investments calculated are based on capacity additions, and cost and construction time estimates from the IEA. Total investment is allocated to the year in which the plant is assumed to have begun construction. This method was chosen to allow for consistency of comparison between different technology areas.

Figure 2.6: Capacity in 2014 is calculated based on plants under construction as of 2010 year-end.

Nuclear power overview

Figure 2.8: France data are 2009. South Africa data are 2008. The South Africa and Brazil RD&D trend from 2000 to 2010 is excluded as no historical data exist for this period.

Figure 2.10: Cost estimates from NEA, 2010. The total investment is allocated to the year in which plant construction began. This method was chosen to allow for consistency of comparison between different technology areas.

Figure 2.11: The post-Fukushima 2025 estimate takes into account changes to government nuclear policies, expected project completions by that date, and existing capacity with an assumption of a 60-year plant lifetime in the United States and a 55-year lifetime in all other countries.

Renewable power overview

Figure 2.14: Costs refer to overnight investment costs. Overnight cost is the present value cost of total project construction, assuming a lump sum upfront payment and excluding the cost of financing.

Figure 2.15: Public RD&D spending includes data from IEA member countries, as well as Brazil (data are from 2010), India, Russia and South Africa (data are from 2008).

Figure 2.16: Annual capacity investment from non-hydro renewables from the BNEF database; large hydropower investment is based on Platts, 2010. Costs are based on IEA estimates.

Figure 2.18: Market concentration is calculated based on the Herfindhal-Hirschman Index (HHI), to assess current renewable market concentration and required concentration under the *ETP 2012* 2DS by 2020. The HHI is a commonly accepted measure of market concentration. It is calculated in this case by squaring the market share of each country competing, or expected to compete in the market (taking the 50 largest countries in terms of market share), and adding the resulting numbers. A total of <0.15 means that the market is unconcentrated; 0.15-0.25 represents moderate concentration; and >0.25 represents high concentration.

Electric vehicles overview

Figure 2.31: January 2012 data are estimates.

Biofuels overview

Figure 2.34: Biofuels yields are indicated as gross land use efficiency, not taking into account the potential for a reduction in land demand through co-products, such as cattle feed, heat and power.

Figure 2.36: The United States is omitted from this figure as its biofuels target is not a blend percentage, as it is in other cases. The target is: 78 billion litres in 2015, of which 11.4 billion litres is cellulosic-ethanol; 136 billion litres in 2022, of which 60 billion litres is cellulosic-ethanol.

Carbon capture and storage overview

Figure 2.38: Public RD&D data includes all IEA countries with the exception of Finland, Greece, Hungary, Ireland, Luxembourg, Poland and Sweden.

Figure 2.41: Project numbers are as of November 2011. The graph includes only operating projects that demonstrate the capture, transport and permanent storage of CO_2 with sufficient measurement, monitoring and verification systems, and processes to demonstrate permanent storage. Given frequent updates to the GCCSI database, project numbers may have been updated since publication.

Chapter 3

Policies to Promote Technology Innovation

Governments that wish to see the *ETP 2012* 2°C Scenario (2DS) goals realised must play a key role in turning low-carbon technologies from aspiration into commercial reality. Support for technology innovation will be decisive in determining whether these goals are reached. Targeted policies, from the creation of national energy strategies to support for research, development, demonstration and deployment, will lead to a more secure, sustainable and affordable energy system; help stabilise the global climate; and underpin sustainable long-term economic growth.

Key findings

- ***Investment in energy research by IEA member governments has been decreasing as a share of total national research and development (R&D) budgets*** *and currently stands at about 4%.*
- ***In some cases, governments' lack of clear, coherent strategies that specify individual technology priorities for clean energy research, development and demonstration (RD&D) could pose a risk to further deployment of technologies required in the 2DS****. When funding is spread too thinly across many areas, countries could end up failing to back their objectives with sufficient financial support.*
- ***Pre-commercial technologies, such as offshore wind, concentrated solar power (CSP), carbon capture and storage (CCS), and integrated gasification combined cycle (IGCC), appear to be stuck at the demonstration phase****. As a result, their enormous potential to cut carbon dioxide (CO_2) emissions is being jeopardised.*
- ***Patents for renewable energy technology saw a fourfold increase from 1999 to 2008, led by solar photovoltaics (PV) and wind****. While these two technologies have successfully taken off, patent development has failed to result in sufficient commercial applications of other technologies, such as CSP, enhanced geothermal and marine energy production.*
- ***The maturity, modularity and scalability of PV and onshore wind have enabled them to achieve more success in the current business and financial climates****. Meanwhile, high capital costs and perceived risks are holding back technologies such as CCS, IGCC, CSP and enhanced geothermal.*

- ***Carbon pricing is one of the cornerstone policies, but adequate low-carbon innovation will not emerge simply through this route. A carbon price should be flanked by policy packages****, such as feed-in tariffs (FIT) or tradable obligations, that drive significant scaled-up deployment of emerging technologies and thus lower costs. Additional targeted measures should focus on unlocking energy efficient potentials where it is cost-effective to do so.*

- ***The design of policies (packaged or not) needs to take careful account of the interactions among policies and incorporate the ability to adjust for change over time****. Some combinations of policy instruments appear more capable than others of achieving the 2DS in 2050, based on the characteristics of comparable technologies that share similar impediments to development, deployment and diffusion.*

Opportunities for policy action

- *Broad policy action from governments to promote innovation in low-carbon technology should include developing a national energy strategy with clear priorities, increasing support for R&D, creating mechanisms to fund capital-intensive demonstration and early deployment, ensuring demand for clean energy technologies, encouraging private sector investment in innovation, and strengthening international collaboration.*

Recent trends in innovation in low-carbon technologies have been mixed. Public policy can play a critically important role in accelerating the rate of innovation and enabling energy system change at the pace and scale required to achieve the 2DS. Identifying the core principles for measures that promote clean energy technologies facing similar barriers to development, deployment and diffusion is an important first step. Any successful innovation[1] evolves through several phases, including fundamental research, applied research, development, demonstration, deployment and diffusion.[2] Energy technology policy meant to accelerate the innovation process should encompass this whole range of activities (often simultaneously, rather than sequentially), be tailored to specific technologies and evolve as technologies evolve.

The relationship between innovation and climate policy is one of mutual interdependence. Innovation is generally recognised as a requirement for transitioning to a low-carbon economy. But climate policy also represents an important driver for innovation. If demand for innovation is augmented, a continuing flow of technological developments will improve the portfolio of available mitigation options; bring down the costs of achieving global climate change goals; and also provide significant economic, environmental and security benefits.

IEA analysis suggests that time is running out for the transition to a low-carbon energy system (IEA, 2011a). But the process of technological change often takes considerable time – in some cases decades, not years. Historical data suggest that there are some limits to the rate at which new energy technologies can be deployed (Kramer and Haigh, 2009), but technology advances in other fields (*e.g.* information technology [IT], communications) demonstrate that deployment can be accelerated under certain conditions and justify government action.

1 Broadly speaking, innovation is the implementation of a new or significantly improved product or process that reduces costs or improves performance.

2 A classical perspective tends to describe the technical change as a linear process (Schumpeter, 1942). Although, in this chapter, the stages of innovation are treated separately for analytical purposes, the process of innovation and technology substitution are typically incremental, cumulative and assimilative (Fri, 2003), and feedback occurs between the different stages of the processes.

The costs of transforming the global energy sector will increase if this transformation is delayed, given the long economic lifetimes of much of the world's energy-related capital stock and the high cost incurred if it becomes necessary to retire infrastructure early or retrofit it to meet climate imperatives (IEA, 2011a). To avoid this, several well-known market failures holding back innovation need to be overcome – negative externalities associated with environmental challenges, difficulties for firms to fully appropriate the returns from their investments, and entry barriers affecting new technologies and competitors (OECD, 2011).

Innovations in clean energy technologies are often much more capital-intensive than innovations in other fields. They require long-term R&D and substantial capital investments for large-scale demonstrations that often entail significant risks. Even after technologies are proven and, in principle, commercially available, they often remain trapped in the cycle of small volume and high cost (Grubb, 2004). Financing the demonstration at full commercial scale and early deployment of capital-intensive energy technologies represents an important challenge for the private sector. This has left many promising energy innovations in a commercialisation "valley of death". Governments wishing to foster early adoption of low-carbon technologies can help by mitigating the risks associated with developing and commercialising advanced energy technologies, addressing bottlenecks that affect existing technologies, and mobilising private-sector funds.

An assessment of the rates of low-carbon technological innovation, based on both input and output metrics, indicates that some technologies are progressing well, but others are not (Table 3.1). The characteristics of those technologies that have been more successful in the current business and financial climates, based on their technology and economic risk profiles – such as the maturity, modularity and scalability of PV and onshore wind – contrast with the high capital costs and perceived risks that are holding back such technologies as CCS, IGCC, CSP and enhanced geothermal.

Public R&D investments in low-carbon technologies offer many benefits, including economic development, productivity growth, accelerated technology learning rates and more rapid development of patents (OECD, 2001). They have led, in the past, to large improvements in the performance of specific energy technologies, energy sectors and even national economies.

While it is difficult to make detailed evaluations of the specific outcomes and returns from energy RD&D, studies show positive results. For example, the European Union estimates an internal rate of return of 15% from the period 2010 to 2030 for its RD&D investments in its Strategic Energy Technology Plan (SET Plan) (Wiesenthal *et al.*, 2010). In the United States, the Department of Energy found that its investment of USD 17.5 billion (present value) between 1978 and 2000 – primarily in RD&D for energy efficiency and fossil energy – provided a yield of USD 41 billion (Gallagher, Holdren and Sagar, 2006).

While government spending on energy RD&D has been increasing in absolute terms over the past decade and received a substantial increase as part of "green stimulus" spending programmes in 2009, it has been largely decreasing as a share of OECD member governments' total R&D budgets over the past 30 years. Governments have preferred other areas of R&D, such as health programmes, space programmes and general university research, to energy; the shares of these other areas have either increased or remained stable over the period, while energy has declined (Figure 3.1). The area of R&D that receives the most government support is defence and, while it has also seen its share of funding decline, it remains dominant with a share of 30%. Energy has varied between 3% and 4% since 2000.

Table 3.1 Indicators used to assess the rates of low-carbon technological innovation

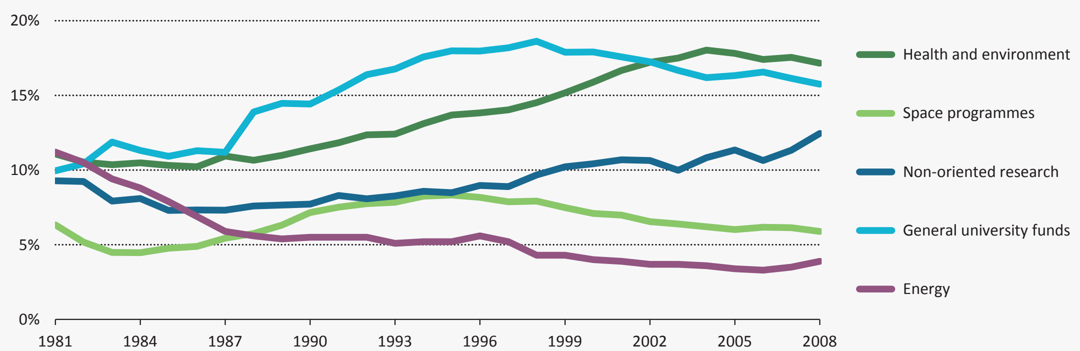
Stage of innovation	Indicators used in evaluation	Comment
Research, development and demonstration	Change in annual government RD&D expenditures	Government spending for clean energy technologies has been increasing, in absolute terms, but decreasing as a share of total RD&D budgets (Figure 3.1). Renewables, hydrogen and fuel cells have seen the biggest increases since 2000, while funding for nuclear RD&D has declined significantly (although it still accounts for the largest share of global spending on low-carbon energy technologies, roughly 30%). CCS has rapidly increased its share of funding in the limited number of countries for which data exist.
Technology development	Number of patents	There was a sharp rise in clean energy patents filed between 2000 and 2008, at an average growth rate of 10%, which is higher than the rate for many technology areas and is driven by renewable energy. Between 1995 and 2005, patents filed in leading industrial economies relating to renewable energy grew around 20%. For this same period, patents in biotechnology grew about 5%, and patents for IT grew about 18% (PATSTAT). Patents are concentrated in a small number of assignees (Box 3.1).
Technology demonstration	Number of demonstration projects in specific technologies	Technologies such as CCS and IGCC need to be built at large scale to demonstrate reliability and performance, and require huge investment. Currently they appear to be stuck at the demonstration phase. From 2005 to 2011, the number of large-scale CCS demonstrations increased from two to four. At least 20 full-scale projects would be required in 2020 to meet 2DS projections.
Technology deployment	Growth of deployment rates	Some renewable energy technologies have experienced significant growth rates in deployment over the past decade, such as onshore wind and PV (42% and 27% annual growth, respectively), while geothermal, marine and CSP have grown more slowly. For example, from 2005 to 2010, installed CSP capacity increased only from 380 megawatts (MW) to 1 300 MW, well below the levels of deployment expected to be required to meet the 2DS objectives. Similarly, IGCC is another crucial technology for making coal-fired power more efficient in the near term and certainly in the 2DS in 2050. However, deployment of higher-efficiency coal technologies has been extremely slow. From 2005 to 2011, the number of IGCC installed demonstrations increased from 1 545 MW to 2 045 MW, and just two 250-MW units were added between 2000 and 2011 (IEA Clean Coal Centre).
Technology diffusion	Number of inventions patented in at least two countries; statistics on world trade of low-carbon capital and intermediate high-tech goods	Data for the 2000 to 2005 period on inventions that are patented in more than one country (PATSTAT) show that the most widely diffused technologies are lighting, in particular light-emitting diodes (LEDs) and compact fluorescent light bulbs (CFLs), wind power, and electric and hybrid vehicles, with more than 30% of inventions transferred. Biomass and hydropower are more localised, with less than 20% of inventions transferred. Technology has been exchanged mostly between OECD countries and to the faster-growing economies of non-OECD countries. Statistics on world trade, from the United Nations Commodity Trade Statistics database (UN COMTRADE), show that between 2005 and 2008, China, India, Brazil and Russia increased both imports and exports of a range of renewable energy products and associated goods*, with China and India switching from being importers to net exporters of these technologies.

Note: * The analysis focuses mainly on products and components used for wind, solar and hydro, but it excludes biofuels and geothermal (IEA, 2010).

Statistics in this field are, however, very imprecise. For instance, mapping scientific activity through the number of patents that influence green technologies shows that the fields of chemistry and material science (usually funded under "General university funds") are at least as important as research on energy and the environment (the latter funded under the category "Health and environment"). Encouraging the development of more generic and general-purpose technologies, such as materials technologies, nanotechnologies, life sciences, green chemistry and information and communication technologies (ICTs), may be just as important as spending on energy RD&D (OECD, 2010).

Funding for energy R&D is perhaps indicative of broader government priorities. Some analysis of larger spending categories for the US government reveals that total spending on energy is roughly 0.2% of the total federal budget, while defence (19%) and medical insurance (12%) have much larger shares. Widening the analysis beyond the United States to include more countries[3] reveals that social protection and health spending account for perhaps 50% of government expenditures on average. Energy and fuel account for a proportion of a broader economic affairs category, according to the UN Functions of Government definition of public spending, and this category generally accounts for somewhere in the region of 10% of total government spending for the countries analysed. Energy is likely to be a fraction of this.

Figure 3.1 OECD countries' spending on energy RD&D as a share of total R&D budgets



Source: OECD.

Key point *Governments have preferred other areas of R&D to energy; the shares of these other areas have either increased or remained stable over the past 30 years, while energy has declined.*

Governments' lack of prioritisation for energy RD&D presents challenges and could pose a risk in the future to further deployment of technologies required in the 2DS, particularly given the increasing constraints of public budgets. The IEA has called for a twofold to fivefold increase in annual public RD&D spending on low-carbon technologies to achieve the 2DS in 2050. The gap in public spending appears to be much larger for some technologies, including advanced vehicles, CCS and smart grids, than for others, such as bioenergy and solar power (IEA, 2010).

3 The analysis focused on the following countries: China, France, Germany, Italy, Japan, Korea, Spain, the United Kingdom and the United States.

Box 3.1 Patent data as a measure of energy technology innovation

Analysing patents filed in a given year offers interesting insights into trends and growth in energy technology innovation.* For example, in 2008, renewable energy sources accounted for 1.5% of all patents filed, a fourfold increase from the number filed in 1999. Innovation in some renewable energy sources has grown faster than others, particularly PV and wind. In 1999, 161 PV inventions were filed, but by 2008, filings had risen to 1 138. This dramatic increase in technology development has contributed in part to massive cost reductions in PV panels and a 50% increase in deployment from 2005 to 2010. Other contributing factors to these cost reductions include a rise in skilled labour, better production methods and economies of scale.

While development of CSP has seen similar growth (based on patent count), demonstration and deployment rates have not kept up, despite its potential to reduce CO_2 emissions in the 2DS. Attracting the financing needed to demonstrate commercial viability and scale is much more costly for CSP than for PV: PV offers modularity, while CSP plants are more capital-intensive because they require a much larger scale than PV applications. This same situation is reflected in enhanced geothermal systems, marine technologies and CCS. The latter is a particularly vital technology to achieve the 2DS objectives, and patent development has accelerated: 52 patents were filed in 2000 and 215 in 2008 – a threefold increase. However, only four large-scale demonstration projects were in operation as of December 2011.

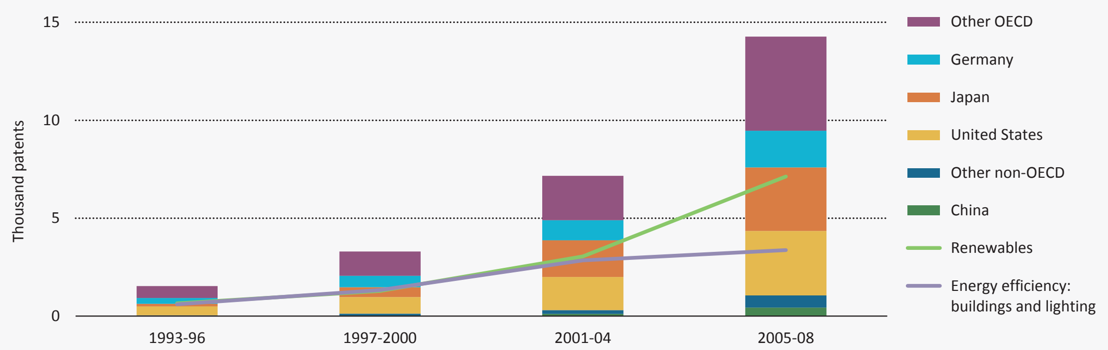
Many countries are focusing more funding for RD&D on technologies to improve the efficiency of energy use in buildings, but at vastly different rates of development. Lighting, particularly LEDs and CFLs, has seen enormous sustained growth in patents filed since the early 1990s, which has accelerated further in the last decade. In contrast, technologies for improving building insulation have changed little. The same holds true for heating and cooling technologies, with little or no growth in innovation observed post-2000.

Innovation appears to be highly concentrated in a small number of actors, with OECD countries holding an overwhelming majority of patents in all categories of clean energy technology (Figure 3.2). The United States, Japan and Germany are the top three inventor countries for most technologies, but China has been catching up in the last few years (for which data are available). China has ambitious plans, outlined in China's National Strategies and Policies for Innovation, to generate an enormous number of patents – 2 million filed by 2015 in total – up from 600 000 in 2009 (Liu, 2007). Energy technologies will certainly benefit from this push by China's government.

* While patents are a useful indicator of product and process innovation, they do not capture the entire landscape of innovation and knowledge protection. One relevant aspect is that patents are only one option within intellectual property protection mechanisms and there are other ways to protect innovations, ***e.g.*** copyrights or trademarks.

It is important not to over-emphasise the role of RD&D alone in reorienting national energy trajectories. Targeted efforts to promote deployment of current and new energy technologies play a major role in translating the results of RD&D activities to changes in the energy system (Sagar and van der Zwaan, 2006). In particular, Breyer *et al.* (2010) point to a significant positive effect on incentives for early deployment on private RD&D investment levels in the case of PV. In addition, a number of prominent innovation researchers argue that the current imperative of redirecting energy system change, the lead times and lock-ins associated with energy infrastructure imply a focus on improving known technologies and components, rather than breakthroughs (Winskel *et al.*, 2011; AEIC, 2011). Chapter 2 on Tracking Clean Energy Progress provides a more detailed assessment of the rate of deployment of low-carbon technologies and complements the analysis provided here.

Figure 3.2 Clean energy patents filed by inventor's country of residence



Source: EPO/OECD Worldwide Patent Statistical database (PATSTAT).

Key point *Patents filed in low-carbon technology areas have increased sharply since 2000, driven by renewable energy.*

Policy framework for low-carbon innovation

Governments can play an important role in steering innovation trends in clean energy over the long term. In general, governments help by creating supportive policy environments and safeguarding the drivers of innovation. Technology policies, targeted at both supply and demand, need to be aimed at accelerating commercialisation of clean energy technologies and stimulating private-sector investment. While the precise combination of policy measures depends on the specific technology and country circumstances, in all cases it is important to establish an appropriate framework in which innovation can thrive, and within which effectiveness and efficiency of individual policies can be assessed.

The IEA has compiled a set of recommendations for good practice in the development of a clear and effective policy framework for energy technology innovation (Figure 3.3):

1. Countries should develop comprehensive national energy technology strategies that include quantifiable objectives consistent with other related policy objectives. Governments should prioritise their efforts in areas where they already have capabilities and potential cost-competitiveness or other particular comparative advantages, since meaningful resources can rarely be provided to all candidate options, and different technologies have different needs.

2. Public investment in RD&D projects should be sufficient to help lower innovation costs, expand opportunities for breakthroughs and test new business models. Linkages with support policies for early commercial deployment of technologies may be required to address under-valuation of low-carbon technologies and overcome barriers when market incentives are insufficient. Support for commercial deployment of technologies should, however, be temporary and accompanied by phase-out schedules.

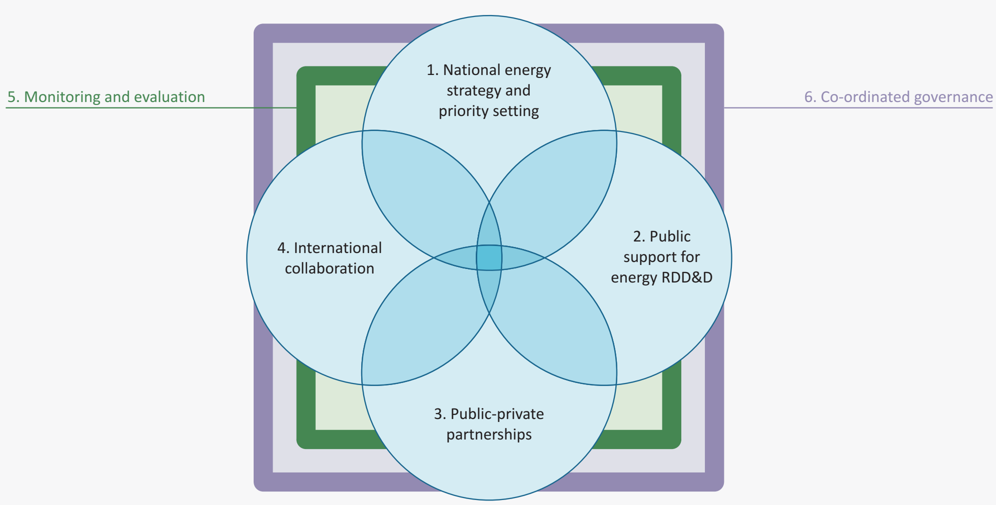
3. Governments should encourage industry engagement at all stages of the innovation process through public-private dialogue and partnerships. The goal is to share risks, experiences and finances, in order to enhance the effectiveness of public investment, increase the marketability of innovations and prevent governments from crowding out private investment.

4. Greater international collaboration can help to share costs for technology development, gain access to relevant research and expertise, and accelerate technology deployment. It can also lead to risk reductions and expanded learning. Knowledge-sharing and its appropriate use can be an efficient way to avoid unnecessary duplication of effort and wasted resources.

5. Monitoring and evaluation of the performance of technology options, international and public-private collaborative efforts, public spending, and support policies are essential. Feedback from the results will help ensure that interventions are effective and efficient in meeting public policy objectives.

6. Strong and effective co-ordination of the various institutions dealing with energy technology development, demonstration, deployment and diffusion will help improve governance of energy technology innovation. Governments should also plan their interventions across topic areas (*e.g.* energy, environment, industrial development), pay attention to the governance of funding, and adopt clearly defined rules for the management and protection of intellectual property.

Figure 3.3 **An energy innovation policy framework based on good practices**



Source: Adapted from Chiavari and Tam, 2011.

Key point *Governments should create an environment in which clean energy innovation can thrive and within which policies are regularly evaluated to ensure that they are effective and efficient.*

Box 3.2 Recommendations for good practice policy frameworks with various country examples

1. A national energy strategy designed to accelerate the development and adoption of low-carbon technologies is the single most important step to address the energy innovation challenge.

Since 2006, the Swedish Energy Agency has used a strategic planning process, FOKUS, to formulate the agency's vision, set priorities, and identify the short- and medium-term goals of the national programme for energy RD&D, innovation and communication. FOKUS is closely tied to and informed by monitoring and evaluation, and relies on two classes of indicators: indicators for building knowledge and competence, and indicators used for commercialisation and other utilisation of results. Thanks to FOKUS, the vision, strategy and priorities for energy innovation are clearer, and goals can be realised more effectively. As a result, commercialisation efforts have also improved.

2. An integrated approach to innovation should include public support for RD&D, combined with targeted incentives for the deployment of energy technologies.

Brazil's Proalcool programme was established as a response to the 1973 oil crisis and was based on the allocation of large governmental subsidies to ethanol producers, consumers and the car manufacture industry. The Proalcool programme outlined a successful long-term policy that cut the cost of producing ethanol, built the necessary infrastructure and encouraged people to buy vehicles that ran on ethanol. But the intervention faced some rough patches when the price of oil plunged in the late 1990s. It holds lessons for other efforts aiming to promote new technologies, showing that subsidies may be needed for decades rather than just a few years. But the net benefits can be huge, as they were for Brazil.

Deregulation in the sugar and ethanol sector took place progressively and in a transparent way, and motivated private actors to respond. For instance, they increased expenditures and participation in RD&D to raise productivity, and technological and managerial efficiency at the mills. The reduction in cane ethanol production costs represents one of the major benefits of the programme, since it has made cane ethanol roughly competitive with oil, especially since 2005.

3. Engaging in and managing effective public-private partnerships reduce the costs of low-carbon innovation.

Announced in 2003, FutureGen is a United States-led public-private partnership established to design, build and operate a first-of-its-kind coal-fuelled, near-zero-emissions power plant. In January 2008, however, the US Department of Energy cancelled the original plans. A revised version of the project was later revived, thanks to federal funding of USD 1 billion from the 2009 American Recovery and Reinvestment Act. The revised project focused on the construction of the world's first full-scale oxy-combustion, coal-fired plant designed for permanent CO_2 capture and storage, which could have an important value towards reducing costs of innovation for CCS.

Public-private partnerships have generally been perceived as being particularly effective in funding projects that require enormous resources in the long term, that relate to high risk in high-tech areas and that face critical technological bottlenecks. Stability in funding is a key factor of success for a public-private partnership, but political realities and budget constraints may cause problems and delays.

4. Strengthening international collaboration can increase the pace of innovation.

The European Union's SET Plan was developed in 2007 to accelerate innovation in cutting-edge low-carbon technologies in member countries. Today it is the main technology pillar of the EU energy and climate policy. The plan provides a framework for stepping up RD&D activities and helping cut costs further for technologies that can contribute to realising the EU vision of an 80% to 95% reduction in greenhouse-gas emissions by 2050. It is designed to provide new strategic planning, more effective implementation, more joint funding of projects through large public-private partnerships (European Industrial Initiatives), and new and reinforced approaches to international co-operation. In addition, the plan also focuses on building new market opportunities for the European energy industry in developing and emerging economies. A quantitative assessment of the impact of the SET Plan finds that the additional investments in research make it possible to reach the European energy and climate targets at lower costs (Wiesenthal *et al.*, 2010).

5. In-depth evaluations help identify the most effective approaches to encourage innovation.

A study was carried out in Japan to help its Ministry of Economy, Trade and Industry and the New Energy and Industrial Technology Development Organisation understand the level of commercial take-up of energy research and the resulting socio-economic impacts. The research used an econometric approach to calculate the cost-benefit of public R&D investment, using Japan's PV power R&D projects as an example and focusing on the added value of the public investment. The study demonstrated that investment in R&D drove down prices and enabled the successful introduction of the installation-incentive grant scheme, which contributed to an increase in the level of installed PV capacity. In addition, a cost-benefit analysis indicated considerable economic benefit from the investments.

6. Co-ordinating the system of institutions within which innovation takes place is an important part of the innovation challenge.

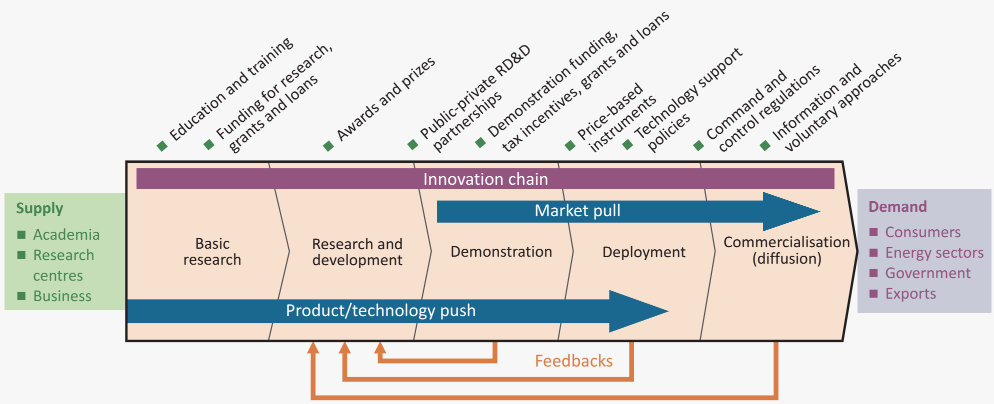
Within the UK innovation system, multiple organisations play key roles in advancing innovation and low-carbon technology development and deployment, including Devolved Administrators; Research Councils; the Technology Strategy Board; the Energy Technologies Institute; the Carbon Trust; the Department of Business, Innovation and Skills; and the Department of Energy and Climate Change. As a result, the innovation system lacks clarity and connectivity, with a number of different institutions appearing to cover similar stages of innovation or technology areas. In working towards a more strategic and focused approach, these entities have set up a Low-Carbon Innovation Coordination Group to identify and exploit opportunities for synergy, avoid duplication of activities and incorporate an awareness of each others' plans into decision making. They are now drawing on its shared Technology Innovation Needs Assessment evidence base to develop technology plans, ensure that prioritisation is consistent, and assess the inherent capabilities and effectiveness of current efforts.

Technological innovation and public policy

Innovation theory describes technological innovation through two approaches: the technology-push model, in which new technologies evolve and push themselves into the marketplace; and the market-pull model, in which a market opportunity leads to investment in R&D and, eventually, to an innovation. Application of this push-pull framework to public policy offers insights for integrated government actions that influence innovation in these two approaches. Governments can encourage investment in energy technologies and innovation on the supply side – technology-push measures – and they can increase demand for low-carbon energy technologies – market-pull measures (Figure 3.4).

Literature on the effectiveness of energy technology policy and on the economics of innovation strongly suggests that both approaches are necessary and should be integrated, although their relative importance may differ from case to case and emphasis will shift from push to pull as technologies mature. Studies acknowledge that the optimal level of public funding and allocation is specific to individual technologies (Sagar and van der Zwaan, 2006; Nemet, 2009).

Figure 3.4 Examples of technology-push and market-pull policy instruments



Source: Adapted from IEA, 2008.

Key point *There is a wide selection of policies that can be implemented to develop and deploy new and improved technologies, and the use of multiple instruments may be justified.*

In addition to the more conventional push-pull models, which still influence much of the policy debate, more recent and realistic dynamic models recognise innovation as a complex interactive model, involving networks of actors, sources and constraints of an emerging technology system (research institutes, testing and regulatory bodies, project developers, etc.),[4] and emphasising the importance of interactions between different levels in the system.[5] These models see push-pull policies as part of a wider innovation system and stress the role for public policy to build capabilities rather than merely implement policies, which enables countries to control the politics around the policy, as well as the policies themselves.

When do technology support policies make sense?

In *ETP 2012*, technologies with a deployment cost of up to USD 160 per tonne of carbon dioxide (tCO_2) are needed to achieve the 2DS in 2050. This does not, however, mean that a single economy-wide carbon price rising to this level will be a sufficient policy response or will give a least-cost transition to low-carbon energy infrastructure. This section explores the case for supplementing a carbon price by providing targeted direct support to emerging low-carbon technologies to bring down their cost and ensure the system is prepared to take them up when the time comes.

The role of a carbon price and supplementary policies

Putting a price on greenhouse-gas (GHG) emissions should be one of the cornerstone policies in climate change mitigation. Without measures that put a price on emissions, it will be significantly more difficult and more expensive to implement the economic transformation required to put the world on track to meet the Copenhagen Accord (2009) goal of limiting temperature rise to 2°C. A key strength of carbon-pricing mechanisms is that they have a wide reach: by pricing pollution appropriately, producers and consumers

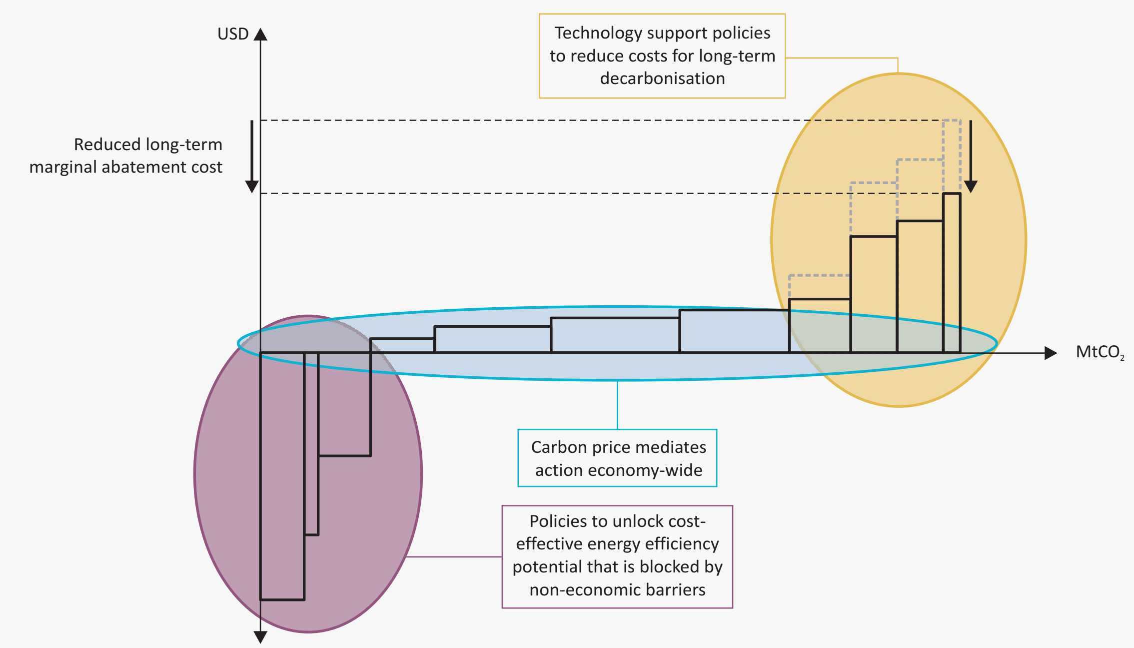
4 Technology Innovation Systems (TIS) approach (Jacobsson and Bergek, 2011).
5 Multi-Level Perspective (or transitions theory) (Geels and Schot, 2010).

throughout the global economy see the correct incentives without second-guessing the technical and business solutions for reducing greenhouse gases.

Pricing mechanisms are inherently cost-effective as they encourage abatement to be made first where it is cheapest. They engage actors in all parts of the value chain, providing incentives for efficient investment decisions, operational decisions and consumption choices, with no one paying more for mitigation at the margin than anyone else. The ability of carbon pricing to cope effectively with climate and economic uncertainties is also very important, allowing innovative responses over regulatory command-and-control approaches that run the risk of freezing technologies.

IEA analysis has consistently found that there are benefits when carbon pricing is accompanied by complementary policies. Although the details of a cost-effective policy package will vary among countries and regions, in general there is a case for supplementing carbon pricing with cost-effective energy efficiency and technology policies (*i.e.* RD&D support and deployment policies) to improve the short- and long-term cost-effectiveness of emissions reductions.[6] These three policy areas – carbon price, energy efficiency policies and technology support – are the backbone of a least-cost package to achieve decarbonisation (Hood, 2011). They are shown schematically in Figure 3.5, which shows abatement potential as a function of carbon price.

Figure 3.5 The core policy mix: carbon price, energy efficiency and technology policies



Notes: CO_2eq = carbon dioxide equivalent; $MtCO_2$ = metric tonne carbon dioxide.
Source: Hood, 2011.

Key point *Combining policies for research, development, demonstration and deployment of new technologies with carbon pricing and energy efficiency policies provides the least-cost policy mix for transition over the long term.*

6 Additional policies aimed at avoiding locking in high-emissions infrastructure and overcoming barriers to financing could also be considered (Hood, 2011).

Technology policies can reduce both direct implementation costs and carbon prices over the long term. Targeted energy efficiency policies can reduce the short-term costs of climate change response by unlocking energy savings that are not responsive to price signals because they are blocked by market failures and non-economic barriers, such as:

- incentives split between those responsible for paying energy bills and those responsible for energy efficiency investments,
- information failures that mean cost-benefits are not apparent at the time of investment, and
- behavioural traits that mean consumers may not always act in their own economic interests (Ryan *et al.*, 2011).

To the extent that these barriers can be overcome and cost-effective savings can be exploited, the direct cost of implementing abatement actions is lower, and a lower carbon price is needed to achieve climate targets.

Policy interactions

Policies can be mutually reinforcing, can work against one another or can be redundant – depending on how they are designed and implemented. Although there is a strong case for combining policies to improve cost-effectiveness, implementation details are critical.

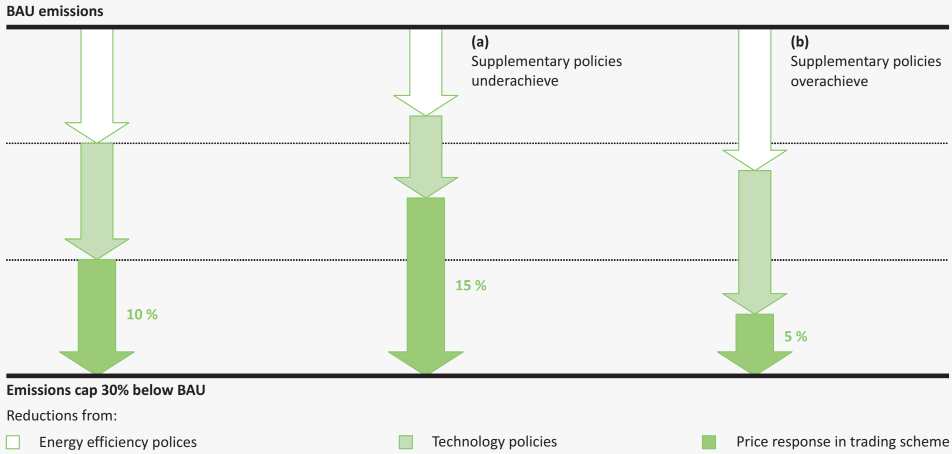
Supplementary policy interactions with emissions trading systems have particular issues.[7] Because supplementary energy-efficiency or technology-support policies deliver some of the required abatement under an emissions trading system's cap, they reduce the abatement needed in response to the price signal, reducing allowance prices. If an emissions trading system cap is set without taking this impact into account, it can undermine the signals for long-term investment in clean technologies that the emissions trading scheme was intended to provide.

Similarly, over- or under-delivery of supplementary policy targets can lead to significant swings in demand for allowances in an emissions trading system and hence, greater uncertainty in carbon prices (Figure 3.6). In this example, a 30% emissions reduction target is set under an emissions trading scheme, but reductions are delivered in part by supplementary energy efficiency and technology policies, with the price response delivering the balance. If supplementary policies over- or under-deliver their expected level of emissions reduction the abatement required from the price mechanism can be significantly higher or lower, leading to added uncertainty in carbon prices that could deter investors.

In a similar effect, if supplementary policies deliver a significant proportion of the abatement required under the cap, modest fluctuations in the economic conditions affecting capped sources can lead to significant changes in the abatement required from the price mechanism; hence, there are greater fluctuations in carbon prices. Excessive price uncertainty has been shown to delay investment decisions, requiring a higher price on emissions to trigger investment (IEA, 2007).

7 These interactions are also important to other quantity-based obligations, such as clean energy quotas or other tradable certificate schemes.

Figure 3.6 Emission trading system combined with supplementary policies



Note: BAU = business as usual.
Source: Hood, 2011.

Key point *When the reductions required under an emissions trading system cap are delivered in part by supplementary policies, such as energy efficiency measures and technology support policies, the remaining abatement required in response to a price signal (and the resulting carbon price) can depend strongly on the reductions achieved by the supplementary policies.*

Managing the interactions between policies is, therefore, a further critical element in least-cost policy response by ensuring appropriate alignment initially, designing policies to maximise certainty of delivery and incorporating ongoing review to realign policies over time (Hood, 2011). Considering more specifically the interactions of policies for renewable energy and climate, Philibert (2011) concludes that if the renewable energy policy is defined first, given its longer-term role and strategic importance in addressing climate change, the carbon policy should then be adjusted to take the renewable energy policy into account. This can be done with either relatively more ambitious targets or with a more flexible design incorporating a carbon price floor.

In addition to managing interactions within good policy mixes, there are negative policy interactions to avoid. One clearly redundant (and therefore costly) policy combination is the introduction of a tax on emissions already covered by a trading scheme with the intention of increasing the carbon price. Here, the additional emissions reduction prompted by the tax simply enables equivalent emissions to be made elsewhere. The permit price drops, so that the total (tax plus permit) price is unchanged (Duval, 2008). While this increases the certainty of the price, it does not increase the overall level. A second generally counterproductive mix is adding a technology standard to activities covered by an emissions cap (Oikonomou, Flamos and Grafakos, 2010). This restricts flexibility in finding the least-cost means of compliance and raises costs.

The case for technology support policies

Introducing targeted support policies to advanced low-carbon technologies may have various drivers other than climate change mitigation, such as energy mix diversification, which reduces dependence on energy-exporting countries and contributes to increased energy security; strengthening the competitive edge of domestic markets and industries; a desire to improve productivity and develop local employment; and a contribution to the reduction of other pollutants besides CO_2 and related environmental risks (Philibert, 2011). Many countries have already embraced innovation as a source of green growth because of the larger social and economic benefits derived from it.

Targeted technology support can also improve the long-term cost-effectiveness and feasibility of climate policy. There are two dimensions to this: the benefits of cost reduction from learning effects in deployment, and constraints of time to scale up new technologies.

The cost reductions associated with deployment of emerging technologies are well known and described by *experience curves*. Here, the short-term costs of targeted support can be weighed against the expected long-term cost savings arising from learning effects. Early support can bring technology costs down, meaning lower total costs of abatement over the long term than would otherwise be the case for a given level of emissions reduction.

The benefits of advanced technologies in substantially reducing the cost of climate goals are well established in the modelling literature. A review of 768 modelling scenarios found that, in addition to bringing down total abatement costs, advanced supply technologies (such as CCS) play a particular role in limiting costs in the worst-case technology scenarios. As such, support could also be considered a hedging strategy against very high costs. In this study, the most powerful predictor of high costs was a lack of CCS, combined with fewer technological advances in the buildings or transport sectors (McJeon *et al.*, 2011).

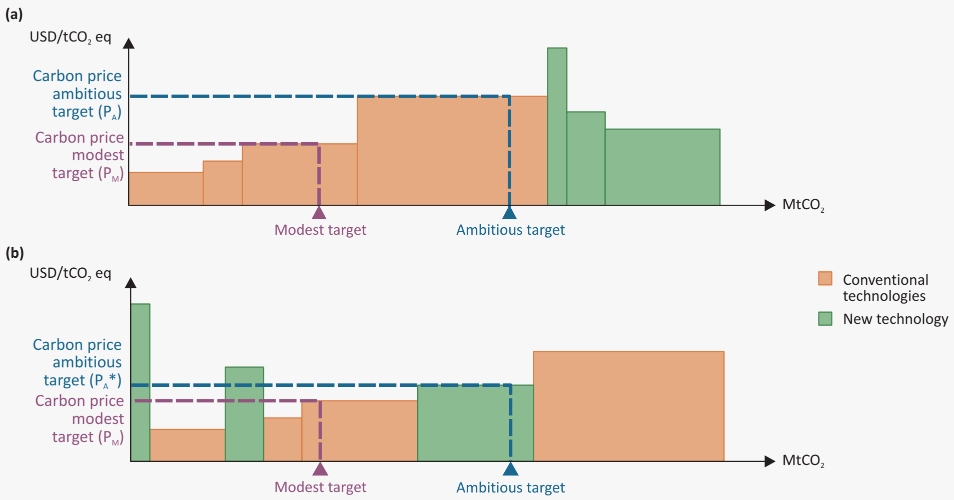
Targeted technology support may also have wider economic benefits. Rising carbon and energy prices can negatively impact macro-economic factors, such as gross domestic product and employment, so there are benefits in ensuring that carbon prices do not rise higher than necessary (Hood, 2011). Significant rises in energy prices may also raise the issues of the distribution of costs and, in particular, impacts on low-income consumers, which can undermine the political feasibility of using high carbon prices to drive technological change. Policies to redistribute revenues are possible, but in some instances it may be more feasible (although second-best from an economic efficiency perspective) to deploy some expensive technology options through direct support rather than carbon pricing.

This is illustrated schematically in Figure 3.7, which considers the potential role for a single new technology in meeting modest and ambitious climate targets. Following the approach of Blyth *et al.* (2009), abatement potential from the new technology is shown in three blocks to indicate cost reductions expected through deployment.

In case (a), both the modest and ambitious climate targets are met with conventional technologies alone. The direct cost of abatement measures is the area of the blocks up to the level of each target. Assuming a carbon price was used to drive deployment, the marginal technology costs P_M and P_A will also be the prevailing carbon prices. Because the cost of the initial block of new technology was higher than that of existing technologies, the new technology was not supported in this case.

By contrast, case (b) shows an approach with early technology support. Here the first two blocks of the new technology are supported early with supplementary policies beyond a carbon price, which allows the third lower-cost block to become available. In this example, the early technology support would not be justified in response to a modest climate target: the early deployment substantially increases the direct cost of abatement measures and, in this example, has no effect on the carbon price. However, with an ambitious target, both the direct costs of abatement (the sum of the blocks up to the target level) and the economy-wide carbon price (P_A*) are lowered.

Figure 3.7 Direct cost reductions and carbon price reductions from early technology support



Notes: Brown blocks represent costs of existing technologies; green blocks represent cost reductions in a new technology due to deployment.
Source: Adapted from Blyth *et al.*, 2009.[8]

Key point *Early support for new technologies can lower their costs. For deep climate targets, this can mean reduced direct costs and lower economy-wide carbon prices.*

This illustrates why technology learning is not a justification for *any* level of early support: the cost-effectiveness of supplementing the carbon price relies on the rate of technology learning, the total abatement potential expected from the technology and the stringency of the climate goal.

As a final note on costs, the marginal abatement cost curves for conventional technologies often neglect to include subsidies that are already in place for fossil fuels. Current state spending on fossil fuel-consumption subsidies alone is USD 409 billion, compared with USD 66 billion for renewable energy (IEA, 2011a).

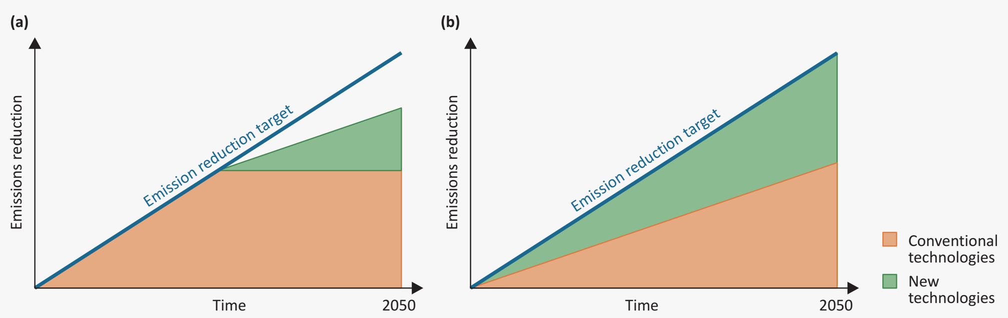
Another justification for early technology deployment relates to constraints on time. New technologies take time to diffuse and scale up, even without considering learning effects. If significant quantities of low-carbon infrastructure and technologies are needed to meet a climate goal in 2050, it can be necessary to start deployment decades ahead to allow time for scaling up. Constraints of this nature are a particular issue, where supporting infrastructure and systems need to be transformed. Examples are the deployment of electric vehicles, or widespread adoption of CCS which requires CO_2 distribution pipelines and storage sites.

The deployment rate of new technologies can also be constrained by locked-in existing infrastructure, for example building stock and urban form. When there are time constraints for the scale up of new technologies, it can even be cost-effective to begin high-cost abatement activities before low-cost opportunities are exhausted (Vogt-Schilb and Hallegatte, 2011).

8 Adapted from *Energy Policy*, Vol. 37, No. 12, William Blyth, Derek Bunn, Janne Kettunen, Tom Wilson, "Policy Interactions, risk and price formation in carbon markets", pp. 5192–5207 (2009), with permission from Elsevier.

Returning to Figure 3.7, consider a very ambitious climate target that requires all conventional and new technology options to be deployed, but where the rate of scale up of the new technology is constrained. If the deployment of the new technology is delayed until abatement from conventional technologies is exhausted (Figure 3.8, case [a]), the new technology may be unable to scale up quickly enough to deliver the required emissions reduction. In this example, the constraint on the scale up means that, in order to deliver the required emissions reduction in 2050, deployment of the new technology would need to begin immediately (case [b]) – even if this may not seem cost-effective in the short term, compared with conventional technology costs.

Figure 3.8 **Effect of the time needed to scale up new technology to meet climate target**



Key point *New technologies take time to scale up, so deployment may need to begin early to achieve deep emission reductions in 2050. Time, as well as cost, is a relevant factor in the justification for early support of emerging technologies.*

For this type of optimal forward-looking investment to be delivered by a carbon price alone, firms need to be completely certain of climate obligations to 2050 and have an investment horizon that takes the full time frame to 2050 into account in their investment decisions. In reality, neither of these conditions holds; studies have concluded that a single carbon price would not give a least-cost economic transformation where there is lack of foresight and inertia in the energy system (Lecocq, Hourcade and Duong, 1998). In particular, it may be optimal to begin action early in sectors where there is significant inertia, such as transport and buildings, and where long-lived capital stock risks being locked in (Jaccard and Rivers, 2007). These studies point to the need to distinguish in the short term between mitigation *actions* (such as technology support, which lowers costs over the long term) and *abatement*. A least-cost strategy needs both.

Energy technology policies

Ultimately, considerable innovation will be required to achieve a potentially wide portfolio of promising competing technologies at every stage of technological development, covering the various sectors of the energy system, and to deliver them on a large scale. Given the need for urgent change, spreading funding too thinly across small, subcritical areas risks not producing any long-term benefits. Different technologies have different needs and face specific barriers to being developed, deployed and eventually commercialised. Active policies supporting innovation represent a technology opportunity with economic benefits. These constitute arguments in favour of adopting a more technology-focused approach beyond RD&D, through the various stages of the innovation chain. Such an approach requires a good understanding of the state of development of technologies and the market structure in which they are being developed, and the ability to monitor their performance and respond rapidly to new information.

Technological change is influenced by government policies and can be sped up by a variety of support measures, including economic instruments (such as carbon pricing and energy taxes), regulatory measures (such as standards and mandates), and direct public-support investment for research, development, demonstration and deployment of new technologies (Figure 3.4).

Low-carbon technology categories

Clean energy technologies can be grouped into four categories (Weiss and Bonvillian, 2009):[9]

- experimental technologies requiring extensive long-term research;
- potentially disruptive technologies that can be launched in niche markets where they face limited initial competition;
- secondary (and component) technologies that will not have the advantage of an initial niche market and that will face market competition immediately;
- incremental technologies that offer relatively small improvements in existing functionality raising efficiency of resources and energy use, without fundamentally changing the underlying core technologies.

Selected low-carbon technologies expected to be required to achieve the 2DS allocated to the above-mentioned categories generally face four types of impediments – technical, market, institutional or political, and social and environmental (OECD, 1998) – that may constrain penetration of new energy technologies and undermine the effectiveness of policies (Table 3.2).

Table 3.3 adapts Grubb's (2004) simplified framework that reduces the innovation chain to three components: early research, marketisation and market penetration. Policy measures meant to accelerate innovation must encompass these different activities, often simultaneously. (Experimental technologies, in Table 3.3, is the exception, where it is too soon to consider any market-pull measures focusing on market penetration: hence, the white cell to indicate irrelevance.) Policy measures can be tailored to the specific categories of technologies identified in Table 3.2, according to the challenges they aim to address: the darker the colour, the greater the challenge for the related policy measures.

9 This categorisation of technologies does not include enabling technologies, such as energy storage, which represents a strategic and necessary component for the efficient utilisation of renewable energy sources and energy conservation, and which plays a fundamental role to achieve the 2DS in 2050.

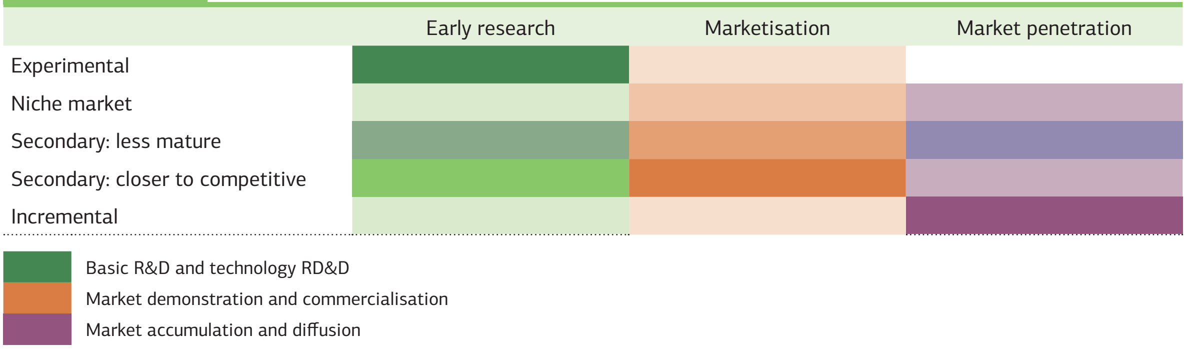
Table 3.2 Categories of low-carbon technologies with the four impediments

Technology	Technical challenges	Market challenges	Institutional and political challenges	Social and environmental challenges
Experimental technologies				
Nuclear fusion	Research on materials and on concept improvements	Very high costs; commercial use not expected until after 2050		
Hydrogen fuel cells	Not yet technically mature, low-carbon hydrogen production still expensive, safety of hydrogen storage	High cost of fuel cells and of hydrogen	Major infrastructure provision, difficulties of regulatory frameworks	Public acceptance and safety perception
Disruptive/niche-market technologies				
LEDs	Enhancement of luminous efficacy, reliability of lighting system, thermal problems	Economically viable in niche markets, but cost reductions for market competitiveness	Lack of consumer awareness	
Off-grid solar	Cost and efficiency of batteries	High initial investment costs, limited access to funds	Non-economic barriers, capacity building for local technicians	Lack of "buy-in" by local communities and target consumer groups due to concerns about technical reliability of solar home systems, for example, which in many cases have been plagued by low-quality problems
EVs and PHEVs	Reduction in battery costs, reduction in amount of materials used, recycling of batteries	Cost of battery and infrastructure requirements, vehicle cost not competitive	Charging infrastructure; lack of understanding of consumer needs and behaviours	
Secondary technologies: closer to competitive secondary				
Nuclear fission	Technological developments to improve safety, performance, lifetime management, radioactive waste handling	Very large capital cost to build nuclear power plants	Supply chain capabilities, human resource availability, lack of regulatory framework	Final disposition of waste, public concern about safety risks
Geothermal	Resource assessment, more competitive drilling technology, research on materials and components	Cost competitive in many cases, financial risks of exploration phase, high cost of drilling	Lack of awareness of resources and applications, lack of appropriate legislation, complex permit procedure, shortage of qualified workers	Health, safety and environmental concerns, public opposition due to visual and odour-related impacts
Biofuels	Develop and demonstrate at commercial scale, advanced biofuels technologies	High cost, volatile oil price	Supply chain development needed	Uncertainty over benefits, public concern about sustainability

Table 3.2 Categories of low-carbon technologies with the four impediments *(continued)*

Technology	Technical challenges	Market challenges	Institutional and political challenges	Social and environmental challenges
On-grid solar (PVs)	Innovations in storage, grid integration, and other emerging technologies; development of new materials	High initial investment cost (higher than other electricity generation technologies), despite fast decrease in solar panel prices	PV bubbles and high policy costs, trade restrictions, planning delays, administrative barriers, access to the grid, lack of skilled professionals	
On-grid onshore wind	More efficient and reliable turbine technology and design, developments in storage technologies	Close to becoming cost-competitive and prices decreasing, but facing high up-front capital cost	Constraints on planning and permitting, new grid infrastructure and grid integration	Local community concerns, perception that wind farms spoil the landscape
Secondary technologies: less mature secondary				
CCS	Research on more efficient and cost competitive CCS technologies, large-scale demonstrations in fully integrated chain	Not commercially viable for use in power generation or other carbon-intensive industries, high cost of capturing CO_2	Lack of regulatory framework, mechanisms for financing CO_2 transportation infrastructure	Public concern about long-term safety of CO_2 storage
CSP	Development and demonstration of innovative component parts, applications and cycles at all scales	Not yet competitive with fossil fuels in wholesale bulk electricity markets, except in isolated locations	Slow pace of procedures for obtaining permits for CSP plants and access lines	Concerns with amount of cooling water used and land use requirements
Offshore wind	Develop turbines better suited to conditions offshore, exploit offshore potential in deep waters	High investment cost of offshore wind	Shortage of trained, experienced staff	
Enhanced geothermal	Map reservoir conditions, still at a demonstration phase, research to improve enhanced geothermal technologies	Enhanced geothermal not commercially viable		Environmental concerns
Incremental technologies				
Building technologies	Improvements in technical efficiency of components and in the design of buildings and systems	Initial cost barriers, perceived high risks, access to capital, lack of information on financial products	Lack of knowledge of actors involved, lack of information on existing building stocks	
Smart grids	Research on most suitable grid architectures to improve flexibility and security, large-scale system-wide demonstrations	Lack of business model to fund demonstrations and deployment and share risks	Need for new electricity system regulations, lack of awareness of benefits	Data privacy

Table 3.3 **Focus of policies applying to different technology categories and their relative importance within the innovation chain**



Note: The darker the colour, the greater the challenge for the related policy measures.

Experimental technologies

Publicly supported, long-term R&D is required for such high-risk, high-payoff technologies. Specific market-pull measures should be delayed until technologies reach a sufficiently mature state of development. Technology performance should be reviewed periodically to guide support decisions.

Recommendations for government policy packages for experimental technologies:

- **Public investment in long-term basic and applied R&D**. Policy makers should focus on public R&D direct subsidies, mostly through grants and contracts, which affect more long-term research. (Tax credits mostly encourage short-term applied research.)

  Nuclear fusion is still in the proof-of-concept phase, and the current focus of research is ITER, formerly known as the International Thermonuclear Experimental Reactor, now under construction in France. Expected to start operation in 2020, ITER aims to demonstrate the feasibility of fusion energy over its 20-year operating life. If all goes well, the next step is demonstration of a practical fusion-based energy-generating system, probably in the 2030s or 2040s. However, commercial use of such technology is not expected until after 2050 and may still be many decades away.

  For hydrogen and fuel cells, field tests are already ongoing, with some manufacturers agreeing on initiating market deployment in 2015; this technology may start making a contribution before 2050. A number of significant technological challenges still need to be addressed before hydrogen fuel-cell technology reaches the market at a competitive cost. The potential of fuel-cell technology for higher efficiency and zero-emission vehicles has already been demonstrated worldwide. Governments' investment in hydrogen infrastructure can help create a market for hydrogen vehicles (see Chapter 7, Hydrogen).

- **Government support for higher education and training**. Availability of suitably trained scientists and engineers is important over the long term. There should be recruitment campaigns to bring researchers into the experimental field to build the human capital necessary to foster innovation.

- **International co-operation**. Participation in mutually advantageous international collaborative efforts should be explored through the development of a national strategy for international R&D collaboration, which includes criteria for setting priorities, both in terms of technology areas and partners for collaboration. The development of energy technology roadmaps can be a valuable first step in enhancing co-operative or collaborative R&D among countries. Collaboration on very large, capital-intensive research topics, which are far from commercialisation and which are too expensive for a single country to undertake on its own, is more likely to include direct involvement in specific projects, rather than the simple exchange of technical information and expertise.

Existing models for international technology collaboration include bilateral agreements; multilateral technology-oriented partnerships, such as the International Partnership for the Hydrogen Economy; and regional multi-technology frameworks, such as the Asia Pacific Partnership, EU Framework Programmes, European Research Area Networks and Nordic Energy Research.

Experience indicates that successful international energy technology R&D collaborations share the following characteristics: objectives closely aligned with national priorities; foundations on common interest and mutual advantage; clearly defined rules of engagement; clear measures of success and criteria for evaluation; broad stakeholder participation; and adoption of flexible arrangements for the allocation of intellectual property.

- **Private sector involvement and funding**. As a technology is recognised as marketable and its functionality is confirmed through testing, public funding for early demonstrations becomes important and should be accompanied by consortia and risk-sharing models for financing that involve industry.

  The private sector should be engaged early on to contribute its knowledge and experience to the development of technology roadmaps and platforms. It can collaborate in joint research with academia and national laboratories, and operate projects that demonstrate the technology.

Disruptive technologies launched in niche markets

Technologies that emerge in protected spaces or niche markets, such as LEDs and off-grid solar, can generate initial revenue and support product improvements without facing significant direct competition from incumbent large-scale technologies. As such, they can evolve over time, start competing with the dominant technologies and eventually overturn them. Early movers in these industries achieve economies of scale and the benefits of clustering research centres, manufacturers and suppliers that form a critical mass in support of continued growth by the sector.

Governments should contribute to niche development, for instance through grant support for applied R&D and through direct equity investment in promising niche companies, and explore opportunities for early deployment of these technologies, as significant benefits (cost savings) exist when deployment can be focused in niche markets. These markets often provide high growth rates and require fewer learning investments as the cost of alternative technologies is also higher. If a carbon price is in place, it can help bring technologies out of the niche into the mainstream. But it should not be applied widely just to help a niche technology scale up production and reduce costs.

Recommendations for government policy packages for technologies launched in niche markets:

- **Grants and direct equity investment in niche companies**. Support for applied R&D, or demonstration of pre-competitive manufacturing technology, can be in the form of grants or equity investment in promising niche companies. Risk-sharing schemes with the private sector are an option, particularly to address research priorities for close-to-market technologies with known and relatively low costs. Business capacity building (*e.g.* through "technology incubators", such as the United Kingdom's Carbon Trust) can be promoted by government-funded organisations specialising in developing companies, employing university-based (usually) ideas. Support in co-ordinating activities of the industry supply chain can also be particularly important for these technologies, linking up technology developers and financiers.

- **Support for small- and medium-sized enterprises (SMEs)**. In general, disruptive technologies tend to be pioneered by smaller firms or new entrants to a market. Measures supporting RD&D in SMEs, such as expert or government consulting support for niche players (*e.g.* spin-outs or spin-offs), and tax credit schemes with special bonuses for start-up companies, are important: SMEs can create new markets and introduce innovations that are subsequently adopted and adapted by larger firms. Opening green public procurement to SMEs may also help strengthen green innovation in such firms.
- **Targeted measures**. Targeted support, such as low-cost financing, regulatory mandates and public procurement programmes, can help develop the technology within the protected niche. For example, several countries prohibit the production and sale of incandescent light bulbs as a way of promoting high-efficiency light sources, such as LEDs and CFLs.
- **International standards**. Establishing common standards, codes and certificates, and promoting integration of components have particular importance for this category of technologies because they create confidence and improve competitiveness by eliminating administrative hurdles and reducing unit costs.

Secondary technologies

Combining technology policies, such as those for RD&D support and deployment, with carbon pricing allows learning that will unlock long-term climate mitigation potential by lowering long-term costs. Technology support measures can help increase penetration of secondary technologies in the market and improve economies of scale. They should be robust enough to withstand early-phase cost increases, during the demonstration and early commercialisation, due to materials and supply chain pressures, early technical and engineering problems, and a risk-adverse financial environment. But mechanisms should be designed carefully to avoid extended support for uneconomic technologies that could distort incentives.

Recommendations for government policy packages for secondary technologies in addition to a carbon price:

- **Capital investment in long-term RD&D**. Accelerating technical improvement of products and components, and industrial processes, and scaling up manufacturing to increase efficiency and cost reductions should primarily be the role of industry. The major role of public funding should be to ensure that longer-term important RD&D does not lose favour.
- **Direct public support to demonstrations**. Government investment at the demonstration stage is especially critical to speed innovation, particularly in the case of some capital-intensive supply-side technologies, such as CCS, second-generation biofuels, enhanced geothermal and offshore wind.
- **Regulatory requirements and public incentives** to expand secondary technologies and accelerate market competitiveness. These include such policies as FIT, tradable obligations or other technology, or fuel mandates that drive significant scale up of technology deployment to lower costs to the level of incumbent technologies. Bloomberg New Energy Finance indicates that FITs have encouraged wind and solar energy deployment, with

64% of global wind capacity and 85% of PV capacity built in markets subject to FITs (BNEF, 2011). Similarly, IEA (2011b) analysis shows that nearly all countries with growing markets for PV have used FITs.

- **Public information campaigns**. Raising awareness about sources of energy supply and communicating both the benefits and risks of specific technologies can help increase acceptance and boost wider deployment of technologies that are hampered by "not in my backyard" (NIMBY) or public acceptance issues.
- **International partnerships**. Broad co-operation accelerates learning, transfers knowledge, promotes adaptation of technologies (and incremental innovation), and helps broaden markets for low-carbon technologies. Inter-project collaborations can be a particularly efficient approach for large-scale technologies.

Some technologies, such as CCS, nuclear power and biofuels, require tailored government efforts in order to expand to the level envisaged in the 2DS in 2050. These technologies, with their high capital costs, are more likely to need preferential financing or guarantees to reduce private investment risks. In addition, well-thought-out communication strategies should be implemented for these technologies, which face some serious public (and often political) opposition.

Incremental technologies

Incremental technologies that introduce greater efficiencies are the dominant form of innovation in the marketplace. Newell (2011) notes the importance of incremental innovation in several areas, including resource extraction and processing, internal combustion energy efficiencies, and industrial process efficiencies. In the presence of a carbon price, several energy efficient technologies are apparently cost-effective. However, the delivery of energy efficiency is limited by a number of non-economic and market failure barriers, some of which cannot be addressed by a carbon price at any level. For instance, when behavioural failure, split incentives and informational failures prevail, targeted policies may be needed to directly influence investment in energy efficiency or energy-efficient behaviour and to unlock the cost-effective energy efficiency potential (Ryan *et al.*, 2011).

Recommendations for government policy packages to supplement carbon pricing for incremental technologies:

- **Demonstration of energy-savings technologies at scale to educate the market**. RD&D should focus mainly on efficiency gains.
- **Emphasis on market-pull measures to address barriers**. The main policy measures targeted at energy efficiency market failures are regulations, such as minimum energy performance standards or "white certificate" obligations, provision of information (*i.e.* energy performance labelling and consumer feedback tools, such as smart meters) and financial instruments (*e.g.* grants, subsidies and financing by public-private partnerships).
- **Voluntary approaches**. These can be a transitional step to accommodate mandatory standards (*e.g.* for buildings) later on. Examples of "technology-forcing" demand-side policies include Japan's Top Runner programme introduced in 1998, where products available in a specific market category are periodically tested, and the most efficient model becomes the new baseline for energy efficiency standards. This typology of policies promotes technology development and market transformation and can frequently deliver net economic savings over project lifetimes.
- **International agreements on technology standards**. These can also be applied from a competitiveness point of view, as well as to help reduce risks of technology obsolescence.

Chapter 4

Financing the Clean Energy Revolution

The transition to a low-carbon energy sector is achievable and holds tremendous business opportunities. Investor confidence, however, remains low due to uncertain policy frameworks. Private-sector financing will only reach the levels needed if governments create and maintain supportive business environments for low-carbon energy technologies.

Key findings

- ***Achieving a low-carbon energy sector requires total investments of USD 140 trillion to 2050.*** *This represents USD 36 trillion more than a scenario where controlling carbon emissions is not a priority, an average of USD 1 trillion additional investments each year to 2050, equivalent to an extra USD 130 per person each year.*
- ***Over the next decade, an estimated USD 2 trillion needs to be invested annually*** *in the power, transport, industry and building sectors. Additional investments for low-carbon technologies are nearly USD 5 trillion, or USD 500 billion annually. More than half of these additional investments are needed in the buildings sector.*
- ***Reductions in fuel costs will more than offset higher investments in low-carbon technologies****. Total fuel savings are estimated at USD 100 trillion between 2010 and 2050, with undiscounted net savings of USD 60 trillion, or an average of USD 1.5 trillion annually. Using a 10% discount rate still shows net savings of USD 5 trillion and highlights the affordability of moving to a low-carbon energy sector.*
- ***The transition to a low-carbon energy sector produces significant benefits****. Not only will it reduce environmental damage, but it will improve energy security globally as dependence on fossil fuels decreases. Spending on fuel will decline sharply with the switch from fossil fuels to renewable energy sources. For countries that import oil and gas, their current account balances will improve, freeing up foreign reserves for other uses.*
- ***Financing for low-carbon energy technologies remains a challenge****, despite significant capital available in financial markets. Funding for early-stage development capital for companies developing new technologies is particularly difficult and faces competition from other sectors.*
- ***Uncertainty in national regulatory policies and support frameworks remains the most common obstacle to accessing greater private financing for clean energy technologies****. Failure to set the right low-carbon policies and market mechanisms could encourage continued investments in assets that are vulnerable to climate change, and risk locking in carbon-intensive assets.*

Opportunities for policy action

- *Governments must create and maintain a supportive business environment to allow clean energy technologies to develop and show solid returns. This will entice companies and investors towards low-carbon technologies and away from traditional fossil-based energy investments.*
- *We could pay a high price for failing to adequately assess climate change risks. Governments and investors should work together to better understand the economic and financial costs of delayed action on climate change.*

Identifying the sources and amount of investment needed to achieve a low-carbon energy sector for energy supply and demand technologies is a complex, sensitive task. The range of technologies is wide, and experts have different views on what should and should not be included. In this analysis, investment needs for energy supply are defined as investments in power generation, transmission and distribution (T&D). Investments in oil, gas and coal exploration and extraction are not included.[1]

Investments in demand-side technologies are essential to the buildings (residential and commercial), industry and transport sectors. For buildings, investment includes heating and cooling, other end-use technologies and energy-efficient building shells (insulation, windows, roofs and sealers); industry requires investment in more efficient production plants and carbon capture and storage (CCS). Transport investments take in the cost of the production of light- and heavy-duty vehicles, bus and rail networks, aircraft and ships, which are expressed as either full vehicle costs or powertrains (engines) only. Investments in transport infrastructure for roads, rail and parking can be found in the analysis of transport investment needs (see Chapter 13, Transport), but are not included in the total investment needs for transport technologies.

Investment costs can be presented as absolute values or as additional values. Absolute values, or total capital investments, may be more relevant when discussing financing needs of the industry and power sectors, where corporations need to raise large amounts of capital. Additional values may be more appropriate for the buildings and transport sectors, where the largest share of investments will be borne by individual consumers and investment requirements can be relatively small. When discussing climate finance needs in developing countries, it may make more sense to focus on additional investment requirements as absolute investments, particularly in the early years when these countries still rely heavily on fossil fuel technologies.

Investment costs of an energy technology revolution

The additional investments outlined in this chapter are based on a comparison of the *ETP 2012* 6°C Scenario (6DS) and the 2°C Scenario (2DS). The 6DS assumes that current energy and climate policies remain unchanged in the future, while the 2DS aims to reduce energy-related carbon dioxide (CO_2) emissions by 50%, compared to 2005 levels. Climate

1 These investment estimates can be found in IEA, 2011.

finance discussions focus on funding additional investment needs, which is generally defined as the difference between the capital investments in the 2DS and the 6DS – it is also referred to as the additional investments required for achieving the 2DS targets.

Understanding the 6DS investment requirements

The costs of energy supply and demand technologies in the 6DS are estimated to be USD 105 trillion between 2010 and 2050, representing average annual investments of USD 2.6 trillion[2] (Table 4.1). About half of these investments will be needed in the transport sector, where light-duty vehicles account for 60% of total transport investments. Investments in the power sector are estimated at USD 28 trillion, while investments in industry – based on the five most energy-intensive sectors (iron and steel, chemicals, cement, pulp and paper, and aluminium) – amount to USD 10 trillion.

As economies across the globe continue to grow, their investment needs will also rise. In OECD member countries, most investment will be needed to replace or retrofit ageing infrastructure, while in non-OECD countries, investments will focus on new infrastructure to meet continually growing demand as these economies mature. Over the next decade, total investments in the 6DS are estimated at USD 19 trillion, rising to USD 23 trillion from 2020 to 2030, and USD 62 trillion after 2030.

Table 4.1 Investment requirements by sector in the 6DS and 2DS

	6DS (in USD trillions)			**2DS** (in USD trillions)		
Sector	**2010 to 2020**	**2020 to 2030**	**2030 to 2050**	**2010 to 2020**	**2020 to 2030**	**2030 to 2050**
Power	5.9	6.5	15.9	6.5	8.7	20.7
Buildings	3.2	3.9	9.1	6.2	6.9	14.7
Industry	2.8	2.3	4.4	3.1	2.7	5.4
Transport	(33.0) 7.0	(44.8) 9.9	(137.3) 32.5	(33.7) 8.1	(47.3) 12.5	(149.9) 44.4
Total investment	**19.0**	**22.7**	**61.9**	**23.9**	**30.9**	**85.2**

Notes: Industry includes iron and steel, chemicals, cement, pulp and paper, and aluminium. Transport includes the cost of the powertrain only; full vehicle costs are shown in parentheses.
Source: Unless otherwise noted, all tables and figures in the chapter derive from IEA data and analysis.

Investments in the 2DS and the additional investment needs

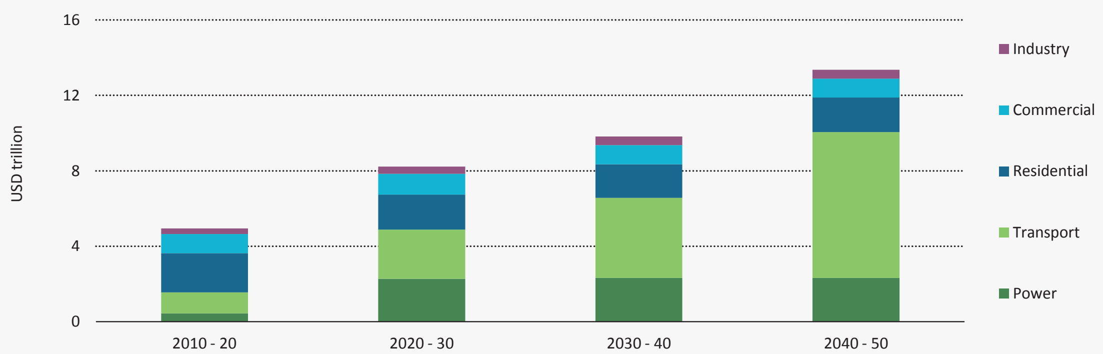
Total investment needs in the 2DS between 2010 and 2050 (Figure 4.1) are estimated to be USD 140 trillion, or USD 36 trillion higher than the investments outlined in the 6DS.[3] These additional investment requirements are equal to approximately 1% of cumulative gross domestic product over this period and do not represent a large burden on the global economy. From 2010 to 2020, the additional investment requirements are relatively modest, with improvements in energy efficiency (leading to reduced capacity additions) helping to offset higher investment costs for low-carbon technologies.

2 Only the cost of the powertrain is included under transport. If the full vehicle costs were included, the total would rise to USD 270 trillion.

3 The additional investment requirements to achieve the 2DS are lower in *ETP 2012* than in *ETP 2010*, due to lower additional costs in transport. This reduction is caused by higher vehicle purchase costs in the 6DS and lower costs for advanced vehicle technologies in the 2DS, compared to *ETP 2010*. The assumed advanced vehicle incremental costs in *ETP 2012* are approximately 20% lower than in *ETP 2010*.

Average annual investments in the 2DS, from 2010 to 2020, are USD 2.4 trillion, 25% higher than in the 6DS. From 2020 to 2030, annual investment requirements under the 2DS rise to USD 3 trillion. This 36% increase over the 6DS is due to higher investments in renewable power, retrofits of residential and commercial buildings and CCS in the power and industry sectors.

Figure 4.1 **Additional investment needs in the 2DS compared to 6DS**



Key point *Growth in additional investments over time are led by the higher costs of decarbonising the transport sector.*

After 2030, the higher investment costs of decarbonising the transport sector and greater investments in low-carbon power significantly increase investment needs, with annual investments in the 2DS reaching USD 4.3 trillion, or over 50% more than 6DS investment requirements. Approximately 65% of total additional investments to convert the energy sector will be required after 2030 as low-carbon energy technologies gain a wider market share. Prior to 2030, total additional investments in OECD countries will represent nearly 50%, while after 2030 their share falls to less than 40%.

Table 4.2 **Total additional investment needs of selected countries to 2050 in the 2DS**

USD trillion	Power	Transport	Buildings	Industry	Total all sectors	Annual per capita (USD)
United States	1.15	1.90	1.50	0.20	4.80	386
European Union	1.20	2.20	2.30	0.20	5.90	294
Other OECD	0.60	1.50	1.70	0.20	4.00	223
China	1.20	4.50	1.55	0.40	7.70	143
India	1.05	1.90	0.75	0.20	3.90	80
Latin America	0.30	0.50	0.60	0.10	1.50	80
Other developing Asia	0.10	0.70	1.30	0.10	2.25	54
Middle East and Africa	1.30	0.80	0.90	0.10	3.15	64
Other non-OECD	0.40	1.55	0.90	0.10	3.00	222
Total all regions	**7.35**	**15.70**	**11.55**	**1.60**	**36.20**	**131**

Note: Totals may not add up due to rounding.

The transition to a low-carbon energy sector requires additional investment of USD 130 per person per year, on average, between now and 2050. Regionally, this varies widely from USD 386 per person per year in the United States to USD 54 per person per year in developing countries in Asia (not including China or India). The different per capita investment reflects the cost of regional options needed and consumption patterns, as well as varying population sizes. The more energy per capita a country consumes, the higher the expected cost (*e.g.* OECD countries). The additional investment requirements of each region are based on the *ETP 2012* scenarios, which assume a least-cost path to achieving the ambitious climate change goals; they do not reflect who bears the burden of these investments.

Low-carbon energy investments to 2020

Over the next decade, an estimated USD 24 trillion needs to be invested in the power, transport, buildings and industry sectors in the 2DS. Investments in the transport sector represent the largest share, accounting for nearly 34% of total investments, which will globally exceed USD 8 trillion over the next decade. Over this same 10 years, a projected 1.7 billion new vehicles will be purchased globally. Buildings sector investments to 2020 will reach over USD 6 trillion; just over half of this is needed in OECD regions for significant investments in retrofitting existing building envelopes and improving the energy efficiency of heating, ventilation and air conditioning (HVAC) systems, appliances and other equipment.

Investments in the power sector are estimated at USD 6.4 trillion under the 2DS, of which China will account for nearly 30% of these investments - equal to the combined investments of the United States and the European Union. China's economic growth is expected to remain strong over the next decade, resulting in increased investment needs across all sectors, but particularly in the power and transport sectors to meet growing demand for electricity and higher vehicle penetration rates. In OECD regions, investments are dominated by the buildings and transport sectors, which combined make up between 65% and 70% of total investments in the next decade.

Table 4.3 Total investment needs in the 2DS 2010 to 2020

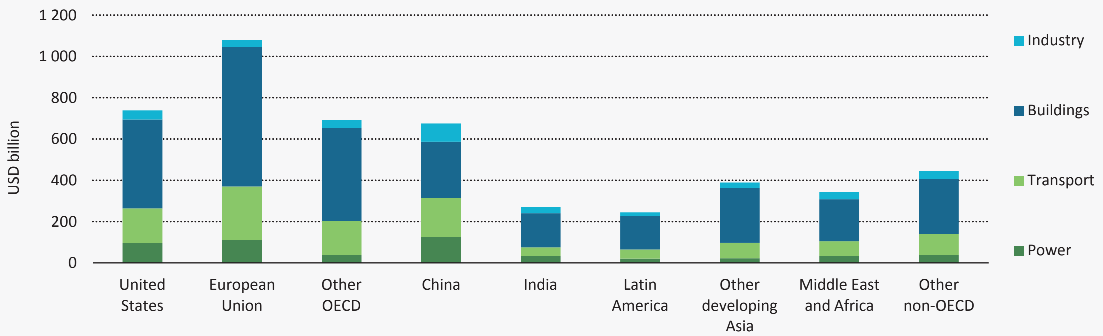
USD billion	Power	Transport	Buildings	Industry	Total all sectors
United States	850	1 300	900	250	3 300
European Union	950	1 800	1 300	250	4 300
Other OECD	650	1 150	900	250	3 000
China	1 800	1 450	900	850	5 000
India	500	300	300	300	1 450
Latin America	300	350	300	200	1 100
Other developing Asia	250	600	450	300	1 600
Middle East and Africa	450	550	400	500	1 900
Other non-OECD	600	650	700	250	2 200
Total all regions	**6 350**	**8 100**	**6 100**	**3 100**	**23 700**

Note: Totals may not add up due to rounding.

Compared to the investment requirements over the next decade under the 6DS of USD 19 trillion, total additional investment needs to achieve the 2DS is projected to be USD 5 trillion or 25% above investments needed in the 6DS. OECD member countries represent over half (USD 2.5 trillion) of these total additional investments, with the European Union accounting for the largest share of any region at 22%, or USD 1.1 trillion (Figure 4.2).

The largest share of additional investment needs in 2DS compared to 6DS over the next decade are required in the buildings sector, representing more than half at USD 2.9 trillion globally. On a regional basis, buildings represent by far the largest share of additional investment needs for all countries, accounting for 70% (other developing Asia) to 40% (China) of the share of total additional investments. Early investments in low-carbon building options are critical to achieving the high share of energy efficiency outlined in the 2DS. Delays in implementing these investments will result in the need for additional investments for new power generation capacity, as well as higher fuel costs in buildings and an increase in the number of people without access to reliable and affordable energy.

Figure 4.2 Cumulative additional investments in the 2DS compared to 6DS, 2010 to 2020



Key point *Additional investments in the buildings sector dominates in all countries, accounting for 40% (China) to 70% (other developing Asia) of additional investments.*

The importance of implementing energy efficiency measures over the next decade cannot be over-emphasised. In many cases these options have short payback periods with low or negative abatement costs. Investments with longer payback periods (such as deeper renovations in buildings) will also be needed to avoid technology lock-in. For new buildings, mandatory building codes with stringent minimum energy performance requirements (standards), aiming at zero-energy buildings, are essential. For existing buildings, governments should implement mandatory annual renovation rates, where retrofits to low-energy standards are based on an analysis of the lifetime energy costs. There is also a need to enforce building codes and energy requirements at the design, construction and operation stage of the building, and stringent penalties in case of non-compliance should be defined and implemented by governments. New financing mechanisms will also need to be explored.

The diverse nature and large number of individual transactions in the buildings sector mean that transaction costs associated with investment in individual energy efficiency projects in buildings can be prohibitive. A mechanism to pool individual transactions into a portfolio of energy efficiency projects could help to overcome this barrier and governments could play an important facilitation role.

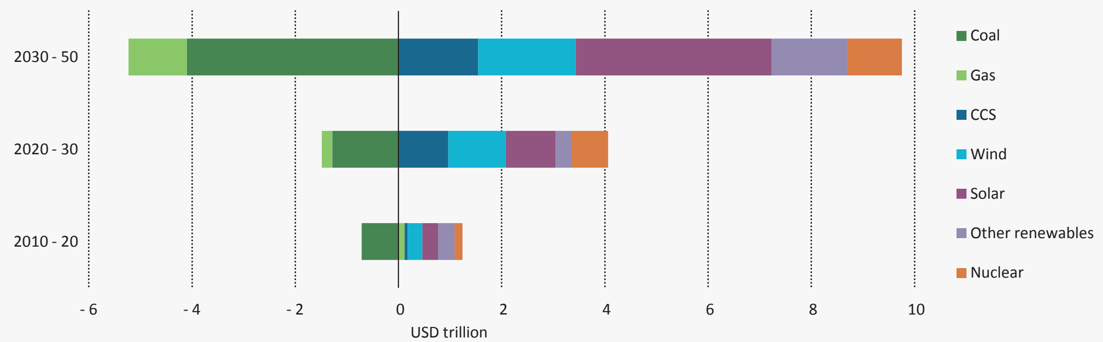
Investment costs of decarbonising the power sector

Decarbonising the power sector requires switching from traditional fossil fuel plants to a mix of renewable energy, nuclear and fossil fuel plants equipped with CCS. In addition investments will also be needed in T&D to connect more variable renewable sources, modernise existing assets and introduce enhanced demand-side management. Total investments in the power sector, from 2010 to 2050 under the 2DS, are USD 36 trillion, of which USD 25.4 trillion is for low-carbon power generation and USD 10.5 trillion for T&D investments.

These investments (USD 7.6 trillion) are 30% higher than in the 6DS, and the majority of these additional investments will take place after 2030 as the benefits of greater energy efficiency help reduce the need for new power capacity. Improvements in energy efficiency in the buildings and industry sectors reduce electricity demand by 19% compared to the 6DS. This lowers the investment amount required to extend distribution networks, which more than offsets any additional investments in transmission to accommodate more variable renewables. As a result, investments in T&D are relatively similar in the 6DS and the 2DS.

In the 2DS, additional investment in low-carbon power generation technologies rises rapidly from USD 500 billion between 2010 and 2020, to USD 4.5 trillion from 2030 to 2050 (Figure 4.3). The high capital cost of many low-carbon technologies, combined with grid integration limits for variable renewables, means that switching from fossil fuel-based power generation technologies will require several decades. Higher investments for wind, solar, nuclear and CCS in the 2DS are partially offset by reduced investments for coal- and gas-fired generation in the 2DS, compared to the 6DS. As the cost of solar technologies falls in the long term and becomes cost competitive with other technologies, a sharp rise in solar investments is expected post-2030.

Figure 4.3 **Additional investment needs in power generation in the 2DS compared to 6DS**

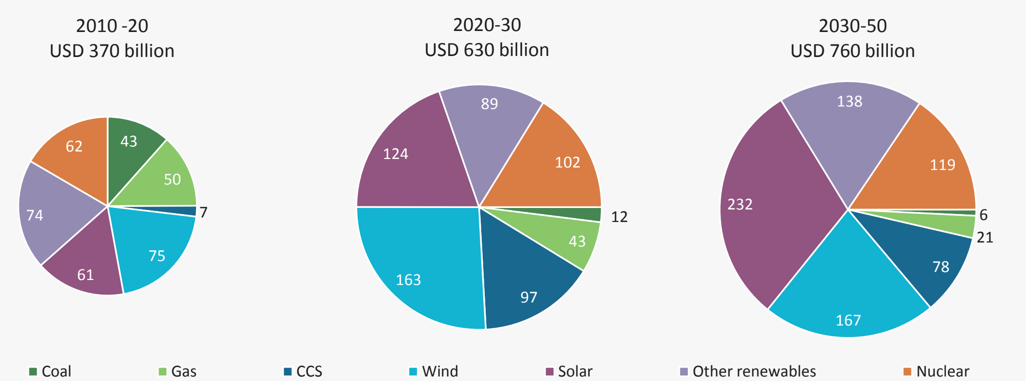


Key point *Renewable energy sources dominate investments in power generation in the 2DS.*

Average annual investments for power generation from 2010 to 2020 under the 2DS are nearly 20% higher than in the 6DS. The shares of wind (20%), solar (16%) and nuclear (17%) account for 53% of total investment versus 25% for coal and gas combined. The current high cost of low-carbon technologies will continue to be a limiting factor in many emerging and major economies for at least another decade.

Deployment of low-carbon power generation technologies rises significantly after 2020, however, as the cost of low-carbon power technologies declines and countries gain experience in integrating larger shares of variable renewable energy into their generation portfolios as well as nuclear. In the following decade, annual investments rise to USD 630 billion (Figure 4.4), with wind (26%) and solar (20%) accounting for the largest shares. Investment in coal and gas plants without CCS falls to nearly zero, while investments in coal and gas plants with CCS reach over 15%. After 2030, solar represents the largest share of total investments (30%), followed by wind (22%) and nuclear (16%); CCS and other renewables make up the remainder. Total average annual investment after 2030 is double that of the 2010 to 2020 period.

Figure 4.4 **Annual investment needs in power generation by technology sector in the 2DS, 2010-50 (USD billion)**



Key point *In the 2DS, investments in coal-fired plants do not decline significantly until after 2020.*

Low-carbon investments in the transport sector

The transport sector requires the largest share of future energy-related investments in the 6DS, with an estimated USD 215 trillion designated for cars, trucks, planes and ships over the next 40 years. If the cost of the powertrain only of road vehicles is counted, and the vehicle body excluded, then only an estimated USD 50 trillion will be needed.[4]

The transport sector can be decarbonised to a large extent through a combination of improved vehicle fuel economy (via improvements to the vehicle body) and use of biofuels and advanced vehicles (such as plug-in electric, pure electric and fuel-cell). This adds USD 15.7 trillion in investments between 2010 and 2050 and yields a significant (approximately USD 60 trillion) reduction in future fuel costs. This is based on the *ETP 2012* 2DS analysis of the transport sector, which combines improvements in low-carbon transport technologies with modal shifts. Investment requirements are examined under an *Avoid/Shift* scenario, where greater modal shifts are assumed to significantly lower investment needs (see Chapter 13, Transport).

4 Planes, ships and rail include full costs.

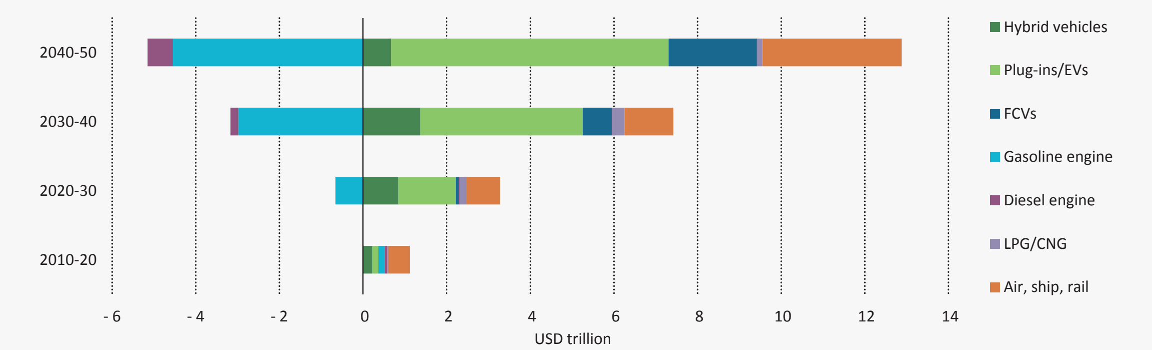
Table 4.4 Total transport investments in the 6DS and the 2DS, 2010 to 2050

Transport types	6DS (in USD trillions)			2DS (in USD trillions)		
	2010 to 2020	2020 to 2030	2030 to 2050	2010 to 2020	2020 to 2030	2030 to 2050
Hybrid vehicles	0.1 (0.5)	0.3 (1.8)	2.7 (14.6)	0.3 (2.0)	1.2 (6.7)	4.7 (26.1)
Plug-in and electric vehicles	0.2 (0.8)	0.2 (1.1)	0.7 (3.0)	0.3 (1.6)	1.6 (7.7)	11.1 (53.6)
Fuel-cell vehicles	–	–	–	–	0.1 (0.4)	2.8 (13.9)
Gasoline engines	2.7 (18.8)	3.9 (25.4)	10.6 (69.7)	2.9 (18.0)	3.3 (17.8)	3.1 (17.6)
Diesel engines	0.8 (9.5)	1.0 (11.6)	2.6 (33.4)	0.9 (8.7)	1.0 (9.2)	1.8 (16.9)
LPG/CNG	0.1 (0.3)	0.1 (0.8)	0.6 (3.9)	0.1 (0.4)	0.3 (1.5)	1.1 (6.9)
Plane, ship and rail	3.2	4.3	15.3	3.7	5.1	19.8
Total	**7.0 (33.0)**	**9.9 (44.8)**	**32.5 (137.3)**	**8.1 (33.7)**	**12.5 (47.3)**	**44.41(149.9)**

LPG = liquefied petroleum gas; CNG = compressed natural gas.
Note: Table includes the cost of the powertrain only; full vehicle costs are in parentheses. Planes, ships and rail show full costs. Totals may not add up due to rounding.

Under the 2DS, investments in conventional gasoline and diesel vehicles will be diverted to low-carbon advanced vehicles (Figure 4.5). Over the next two decades, additional investments in low-carbon transport remain relatively low as significant cost reductions are needed before these vehicles break into the mass market. After 2030, sharp declines in battery costs and fuel-cell vehicles occur in the 2DS, with investments in advanced vehicles surpassing conventional vehicles.

Figure 4.5 Additional investment needs for low-carbon transport in the 2DS

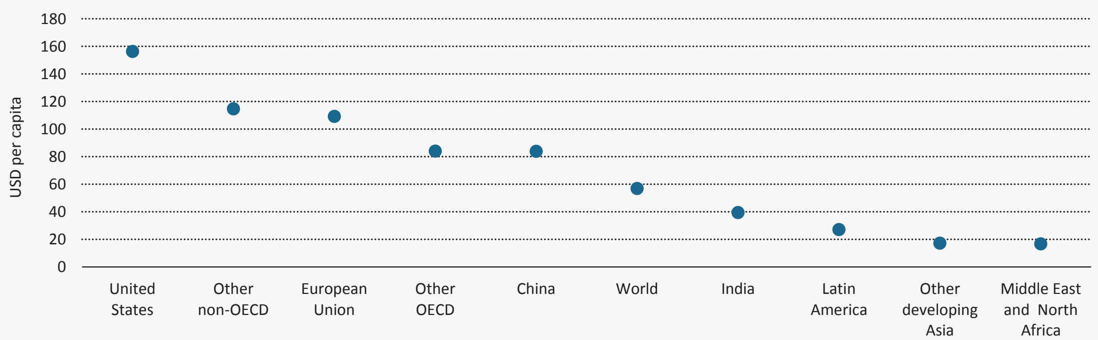


Key point *The cost of decarbonising the transport sector accelerates after 2030 as greater investments are made in advanced vehicles and low-carbon options in air, shipping and rail.*

A comparison of regional investment needs shows that China accounts for the largest share of transport investments (based on full vehicle costs) in both scenarios – USD 60 trillion in the 6DS and USD 65 trillion in the 2DS – roughly 24% of total investments in global transport in each. This level of investment is slightly less than the United States and Europe combined over this same period.

On a per capita basis, the additional cost of decarbonising the transport sector varies significantly by region: the United States has the largest costs of USD 156 per year, and other developing Asian countries and the Middle East and Africa follow at USD 17 per year (Figure 4.6). On a global basis, the average additional per capita costs in transport are USD 57 per year.

Figure 4.6 Additional per capita investment needs in the transport sector in the 2DS, 2010 to 2050



Key point *Regional investment costs for decarbonising transport vary widely and are generally higher in developed countries.*

Investment needs in the buildings sector

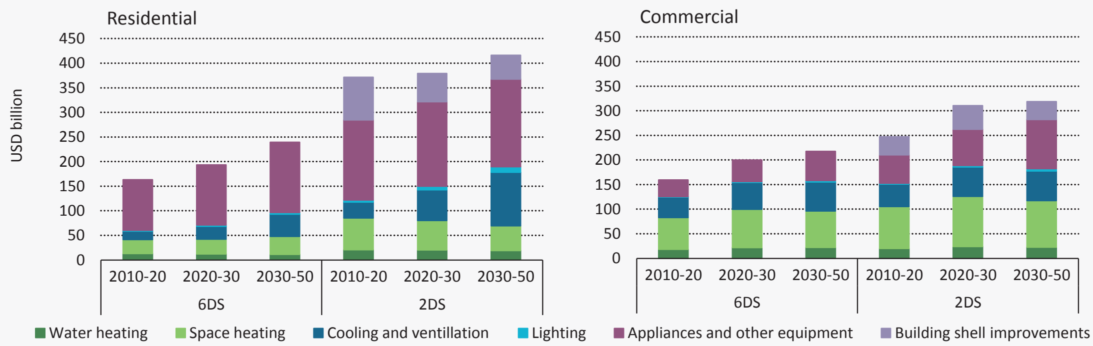
Significant opportunities exist to reduce energy use and CO_2 emissions in the buildings sector through the use of more energy efficient building envelopes, HVAC systems, lighting and appliances. Over the next four decades, an estimated USD 16.3 trillion will be required to purchase these technologies in the 6DS: this breaks down into USD 8.3 trillion for residential buildings and USD 8 trillion for commercial buildings (Figure 4.7). Achieving a low-carbon buildings sector requires an additional USD 11.4 trillion, or 70% more, in spending for both sub-sectors.

In the residential sub-sector, more efficient building envelopes, HVAC systems and appliances require approximately 30% each in additional investment. In the commercial sector, the largest share of additional investments is for more efficient building envelopes (40%), followed by appliances and other equipment (33%).

Comparing the additional investment needs in the 2DS, 2010 to 2030 and 2030 to 2050, shows several interesting trends. In OECD member countries, the level of investment is higher in the earlier time period than in the later, because existing building stock requires significant retrofitting. This is particularly the case in the European Union, where the residential sub-sector requires more than twice the additional investment needs of the commercial sub-sector.

China's rapid economic growth over the next two decades is expected to substantially expand its commercial building sector. In contrast, additional investment needs of other non-OECD countries are in the residential sector, some two to six times higher than in the commercial sector. As these economies are less mature, the relative size of the commercial sector compared to the residential sector is significantly less than in developed economies. This difference declines as the economies mature and the commercial sectors grow.

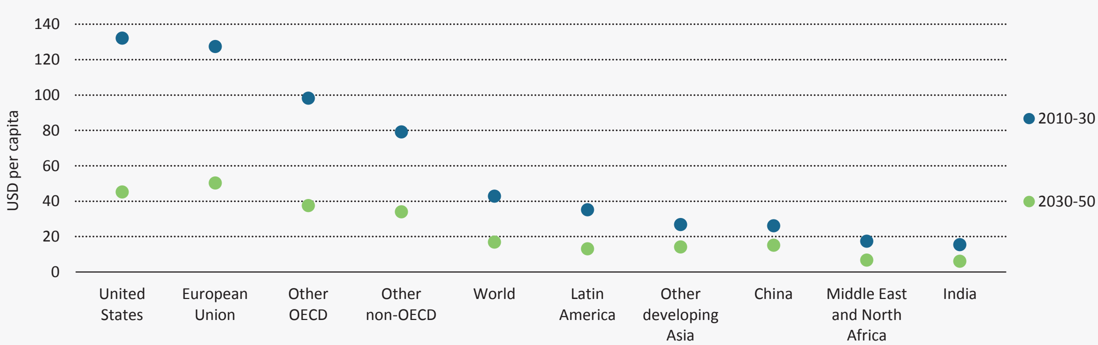
Figure 4.7 Average annual investment by end use in the 6DS and the 2DS



Key point *In the 2DS, higher investments will be needed for more efficient HVAC systems and building shell improvements.*

In all regions, the *ETP 2012* scenarios show lower annual per capita spending for buildings in the latter period, 2030 to 2050 (Figure 4.8). Over the next two decades, however, an additional USD 46 per capita will need to be spent in the buildings sector per year, falling to USD 18 after 2030. This emphasises the necessity for early implementation of stringent policies for energy efficiency by 2020. The additional per capita spending for buildings in the 2DS is the highest among OECD member countries, with significantly lower per capita investment in non-OECD countries.

Figure 4.8 Additional per capita investment needs in the buildings sector in the 2DS compared to 6DS

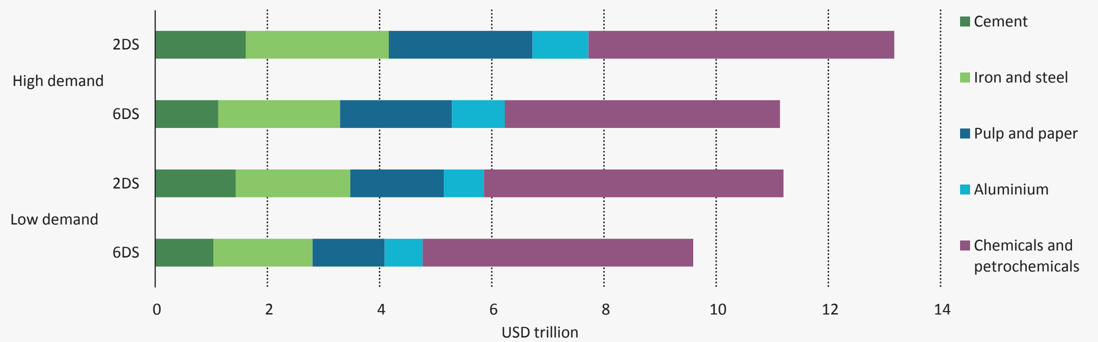


Key point *The cost of reducing energy use and CO_2 emissions in the buildings sector varies widely in different countries, with higher investments needed prior to 2030.*

Investment needs in the industry sector

Investment requirements in industrial production plants for the five most energy-intensive sectors (chemicals and petrochemicals, iron and steel, pulp and paper, cement and aluminium) are estimated between USD 9.6 trillion and USD 11 trillion from 2010 to 2050 in the 6DS and the 2DS (Figure 4.9). A significant reduction in industrial emissions under the 2DS requires investing in more energy efficient equipment, improved energy management, additional recycling, fuel switching and CCS to capture process emissions. Investment needs for the 2DS are about 20% higher than in the 6DS, with additional investments of USD 1.6 trillion to USD 2 trillion from 2010 to 2050.

Figure 4.9 Total investments in industry in the 6DS and the 2DS, 2010 to 2050



Key point *Investments needed in the 2DS are moderately higher than in the 6DS.*

A breakdown of regional investment requirements in industry shows that OECD member countries represent less than one-quarter of future investments, as industrial production declines in OECD regions and rises in emerging and developing countries in Asia, the Middle East and Africa. In the 6DS, investment requirements in industry for China are higher than for all OECD member countries combined; in the 2DS, this investment occurs in the OECD industry sector only after 2030, due to higher costs of reducing emissions intensity, particularly with the implementation of CCS.

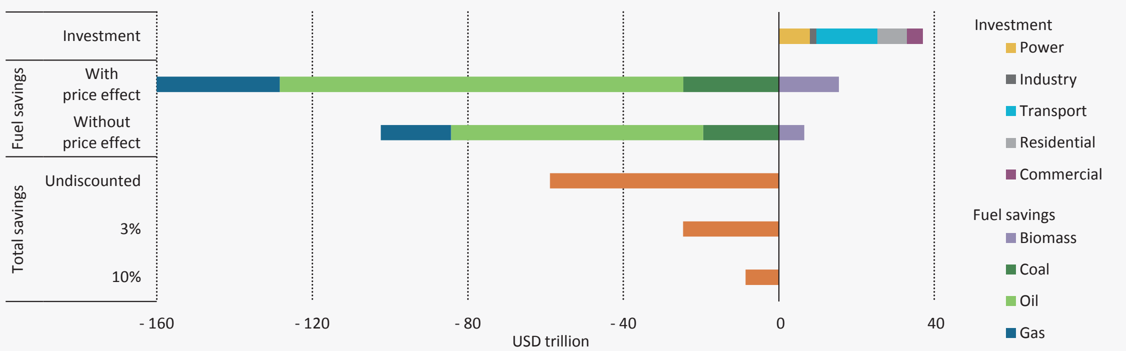
Additional investment requirements to achieve the 2DS are much higher after 2030 than in the earlier decades because CCS technologies, which represent one of the highest additional costs for the industry sector, are not widely deployed until after 2030 when the technology is expected to reach commercial deployment.

Benefits of a low-carbon energy sector

The benefits of additional investment in a low-carbon energy sector include not only reduced environmental damage, but also improved global energy security when dependence on fossil fuels is reduced. Improvements in energy efficiency also reduce the growth rate of energy consumption. The amount spent on fuel drops sharply with the switch from fossil fuels to renewable energy and biofuels. For countries that import oil and gas, this positively affects current account balances and frees up foreign reserves for other uses. In addition, the transition to a low-carbon energy sector provides significant health benefits and additional employment opportunities.

The move away from traditional fossil-based energy technologies significantly reduces the purchase of oil, gas and coal. An estimated USD 103 trillion will be saved in the 2DS from lower fossil fuel use, compared to an additional USD 6 trillion spent on additional biomass, a net saving of USD 97 trillion (Figure 4.10). This calculation includes only the impact of 214 billion tons of oil equivalent (Gtoe) of reduced fossil fuel purchases. If the impact of lower fuel prices is also taken into consideration, the total reduction in fuel purchases is USD 150 trillion. As the demand for oil, gas and coal declines in the 2DS, the prices of these fuels will also fall.

Figure 4.10 Additional investment and fuel savings in the 2DS compared to 6DS, 2010 to 2050



Note: Total is based on fuel savings without price effect.

Key point *Fuel savings more than compensate for the higher investment needs in the move to a low-carbon energy sector.*

Additional investment needs compared with fuel savings in the 2DS shows a net benefit of over USD 61 trillion from 2010 to 2050. Applying a 10% discount rate to both the additional investments and fuel savings still means a net savings of USD 5 trillion: *the move to a low-carbon energy sector is clearly affordable*. The challenge is to change investment patterns to favour higher capital-intensive technologies with lower fuel inputs.

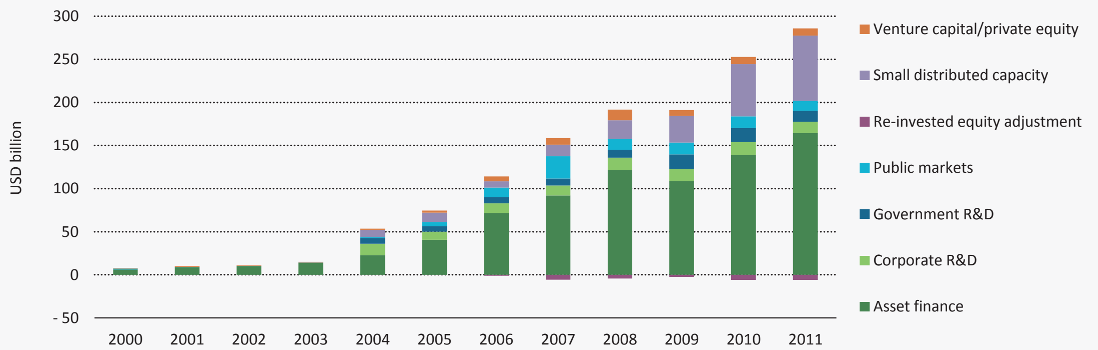
All end-use sectors show significant fuel savings as a result of investments in low-carbon technologies. A comparison of additional investments against fuel savings shows that the greatest benefits are in the industry sector, where fuel savings are estimated at 6 times the additional investment costs, a net savings of more than USD 10 trillion. The transport sector, which requires the largest share of additional investment, shows the largest absolute fuel savings of nearly USD 70 trillion, and net savings of USD 55 trillion. Fuel savings (including lower electricity costs) in the buildings sector amounts to USD 19 trillion and represents a net savings of USD 7 trillion.

Current trends in low-carbon energy investments

Investments in clean energy in 2010 and 2011 show solid progress, with total annual investments reaching USD 247 billion in 2010 and USD 260 billion in 2011 (BNEF, 2012).[5] Total investments in 2010 rose 30% compared to 2009, reflecting government stimulus and support. Early signs indicate that certain low-carbon energy technologies (such as wind) are maturing: investments in low-carbon power generation technologies over the last two years surpassed investment in fossil fuel-based generation. A comparison of financing for clean energy projects in 2010 and 2011 with investment needs for the next decade reveals that current investment levels must at least double by 2020.

Asset finance remains the largest source of financing, accounting for 56% of all investments (Figure 4.11). The share of funding for small distributed capacity also rose significantly in recent years, given strong incentives for rooftop photovoltaic (PV) systems. Fundraising in public markets remains weak, however, due to poor performance and low valuations of clean energy equities and indexes.

Figure 4.11 Global investments in low-carbon energy technologies



Notes: Investment volumes from 2000 to 2003 exclude corporate R&D, government R&D and small distributed capacity, which were not tracked over this period. Adjustments for re-invested equity from 2000 to 2005 are excluded as they also were not tracked over this period. The figures exclude investments in large hydro and nuclear, estimated at USD 370 billion, or an average of USD 37 billion annually from 2000 to 2011.
Source: BNEF, 2012.

Key point *Investments in low-carbon energy technologies have risen more than tenfold over the last decade.*

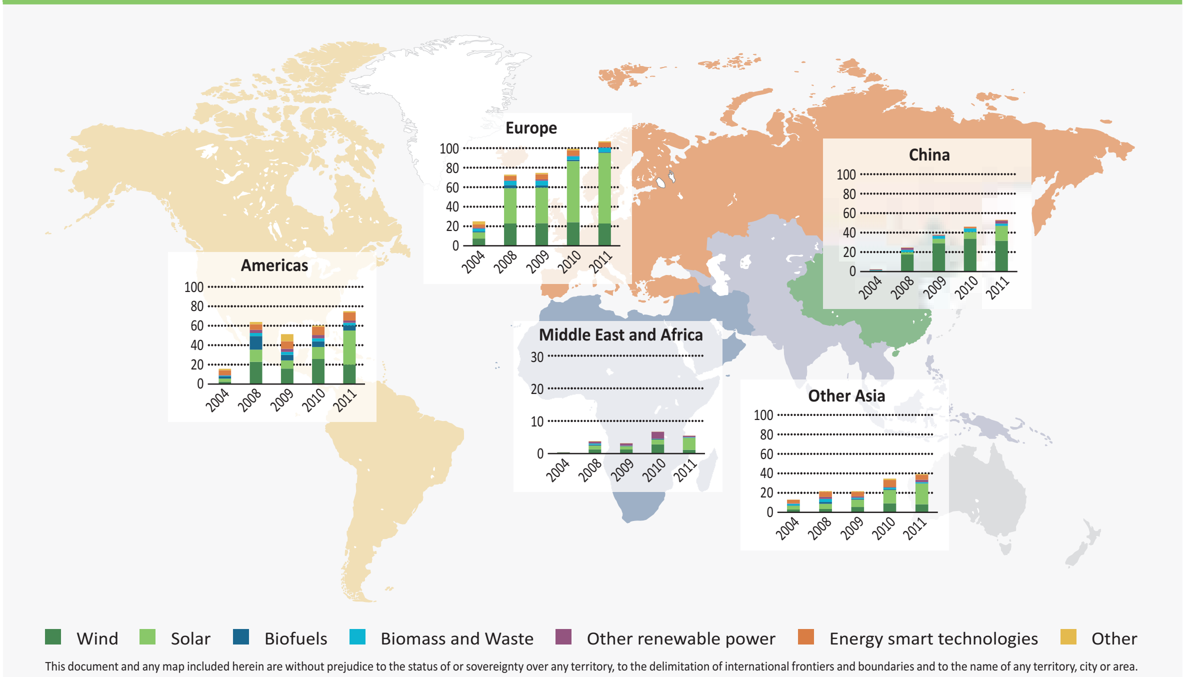
In 2010, generous feed-in tariffs in the European Union helped push investments in solar technologies (USD 97 billion) ahead of wind for the first time (USD 86 billion). The sovereign debt crisis in the European Union in 2011 caused many countries to re-evaluate generous incentive schemes for investments in solar. Strong incentives for PV have increased demand and production of PV modules. Increased competition among manufacturers globally has led to an oversupply of PV modules, which has driven down prices.

The European Union continues to hold the record for investments in clean energy, accounting for 39% of total global investments in 2010 and 2011 (Figure 4.12). China reported the highest rise in clean energy investments with an eightfold increase between 2005 and 2011, reaching USD 47 billion in 2010 and 2011. Investments in the

5 These numbers are based mainly on investments in renewable energy, as data available for other sectors are limited.

United States remain moderate and growth has been disappointing, despite significant opportunities for wind and solar deployment. Incentives schemes in the United States have focused primarily on tax credits, but have not sparked anticipated growth due to the recession, which reduced the number of investors able to take advantage of these tax credits. Investments in India showed the largest increase (52%) between 2010 and 2011, with strong investment growth in solar technologies.

Figure 4.12 Regional investments in low-carbon technologies



Note: Investments in USD Billion.
Source: BNEF, 2012.

Key point *Europe remains the largest overall market for low-carbon technologies, although China has grown significantly in recent years.*

Significant investments have also been made in large hydro,[6] nuclear and high-efficiency coal plants. An estimated USD 100 billion to USD 270 billion has been invested in these projects over the last decade. In order to reach the 2DS target, investments in low-carbon energy technologies will need to at least double, reaching USD 500 billion annually by 2020, and then double again to USD 1 trillion by 2030.

Development banks and export credit agencies

Development banks and export credit agencies have helped fill a funding gap created by the global economic recession and banking crisis. In 2010, development banks provided over USD 13 billion in finance for renewable energy projects, while export credit agencies provided an estimated USD 2 to USD 3 billion in loans, guarantees and insurance. Development banks provide loans at lower rates than commercial banks to stimulate economic growth and provide funding for national development or support development abroad.

6 Large hydro is defined as plants producing more than 50 megawatts.

The European Investment Bank (EIB), Brazilian Development Bank (BNDES), European Bank for Reconstruction and Development (EBRD) and Kreditanstalt für Wiederaufbau (KfW) have provided nearly 80% of total funding from development banks for clean energy projects since 2007 (Table 4.5). For BNDES and KfW, much of their funding supported domestic manufacturers. EIB, which funds projects throughout Europe, has been the largest source of finance for development banks since 2009 and has helped bridge the lack of funding stemming from the sovereign debt crisis in the European Union.

Table 4.5 **Project finance for clean energy projects from development banks (USD million)**

Development bank	Country/region	2007	2008	2009	2010
European Investment Bank (EIB)	European Union	1 128	1 361	2 682	5 409
Brazilian Development Bank (BNDES)	Brazil	1 554	6 206	2 240	3 149
European Bank for Reconstruction and Development (EBRD)	multilateral	934	982	1 317	2 164
Kreditanstalt für Wiederaufbau (KfW)	Germany	697	968	1 207	1 525
Asian Development Bank	multilateral	121	208	612	819
World Bank	multilateral	207	205	474	748
China Development Bank	China	119	417	500	600
Agence Française de Développement (AFD)	France	254	141	245	294
African Development Bank (AfDB)	multilateral	0	0	68	108
Overseas Private Investment Corporation (OPIC)	United States	19	0	121	95
Indian Renewable Energy Development Agency (IREDA)	India	94	68	87	115
Nordic Investment Bank (NIB)	Nordic countries*	163	378	235	113
Inter-American Development Bank (IDB)	multilateral	128	662	264	83
Total		**5 418**	**11 596**	**10 052**	**15 222**

* Denmark, Estonia, Finland, Iceland, Latvia, Lithuania, Norway and Sweden.
Note: Table above excludes investment in large hydro.
Source: BNEF, 2012.

Export credit agencies (ECAs) provide funding in the form of direct loans, loan guarantees or insurance for exports, often as a guarantee for projects that are seen to be risky, primarily due to their location or sometimes due to the use of less mature technologies. ECAs are a good fit for financing riskier deep offshore wind farms in Europe and concentrating solar power (CSP) projects in North Africa. Developers of these very large projects may have difficulty raising sufficient finance without the additional risk cover provided by ECAs, which have offered them the most support.

A comparison of financing for clean energy projects in 2010 and 2011 against investment needs for the next decade reveals that investment levels must at least double by 2020. But, as stimulus funding comes to an end and many countries' concerns about controlling budget deficits grow, the clean energy sector will need to find alternative sources of finance. Achieving the investment rates outlined in the 2DS and the 6DS means attracting more funding from institutional investors.

Onshore wind and PV seem particularly suited to attracting financing, given estimated growth rates and prior funding. Offshore wind, nuclear and hydro, however, may face financing challenges due to their large capital requirements and higher construction risks. Policy support should focus on helping newer technologies, such as offshore wind and CSP, establish a financial and commercial-scale track record and gain investor confidence, which will make raising funds for these technologies easier after 2020. Such policies should aim at improving efficiency and reducing technology costs, while avoiding massive deployment of immature and costly projects. Policies will also need to focus on financing energy efficiency in the buildings sector to realise the energy savings potential there. From 2020 to 2030, CCS and offshore wind will need greater financing, but after 2030 different technologies, low-carbon vehicles and solar, will require a larger share of funding.

Status of climate finance

Under the Copenhagen Accord (COP 15, in Copenhagen) of the United Nations Framework Convention on Climate Change (UNFCCC), developed countries committed to jointly mobilising USD 100 billion per year by 2020 for climate change mitigation and adaptation in developing countries. They agreed that this funding will come from a wide variety of sources, public and private, bilateral and multilateral, including alternative sources of finance, and that a significant portion of such funding should flow through the new "Green Climate Fund". This fund could provide much-needed early finance for investments in low-carbon technologies.

At COP 17, in Durban, delegates formally established the Green Climate Fund and set general parameters for its operation, although many questions remain as to how to finance it, how to manage and allocate its contributions, and which technologies and countries it should target. The fund will take a country-driven approach, with funding mechanisms designed to ensure consistency with national climate strategies and plans. Financing will be in the form of grants and concessional lending, as well as other instruments approved by the Green Climate Fund Board, tailored to cover identifiable additional costs of investments necessary to make the project viable. The fund will seek to mobilise additional public and private finance through its activities and support enhanced action on adaptation, mitigation, technology development and transfer, capacity building and the preparation of national reports by developing countries. The allocation of resources should be balanced between adaptation and mitigation activities, and a results-based approach will be an important criterion for allocation of its resources.

Although the Green Climate Fund has the potential to play a key role in climate finance, it is not a complete solution. As discussed below, to achieve the appropriate type and scale of investments, mobilising domestic financial resources within developing countries will be even more important. Large emerging and developing countries need to establish their own sound domestic frameworks that enable them to raise finance from domestic sources. Among the many objectives that the Green Climate Fund should strive to achieve, two in particular stand out. The first is to allocate funds so that they can leverage domestic sources of finance for investments in low-carbon energy technologies. The second objective is to ensure that the least-developed countries receive an appropriate share of the pledged funds because these countries do not have the financial capability to raise sufficient investment capital.

Sources of current international climate finance flows

Estimated at approximately USD 70 billion to USD 199 billion per year, the current total level of climate-specific financial flows from developed to developing countries appears close to the amount pledged under the Copenhagen Accord (Table 4.6). However, there is no agreement yet on which financial flows should count towards the USD 100 billion commitment. For example, does funding need to be additional to current levels, should non-concessional (commercial) finance be counted, and how can governments demonstrate that they have mobilised the funding? There are also significant data gaps that make it difficult to measure and track these flows, particularly for private funding (CPI, 2011; OECD, 2011b; Clapp *et al.*, forthcoming).

Table 4.6 Estimated volume of annual climate finance for mitigation in developing countries, 2009-10

Source	Total in USD
Bilateral funds	15-23 billion
Multilateral funds	15-20 billion
Export credits	0.7 billion
CDM offsets	2.2-2.3 billion
Philanthropy	0.4 billion
Private finance	37-72 billion
Total	**70-119 billion**

Notes: CDM = Clean Development Mechanism. Figures are indicative estimates of annual flows for the latest year available, 2009/2010.
Source: Clapp *et al.*, forthcoming.

A further important distinction needs to be made between financing incremental costs versus the full capital investments. Incremental costs refer to financial resources provided to cover the difference between a less costly, more polluting option and a costlier but more climate-resilient solution. Capital investments are the full tangible investments in mitigation or adaptation projects (CPI, 2011). For example, the USD 2.2 billion to USD 2.3 billion value of Clean Development Mechanism offsets represents the incremental support required to make these projects viable. The capital investment in these projects (estimated at USD 45 billion), on the other hand, is primarily from the private sector (Clapp *et al.*, 2012). The data presented in Table 4.6 represent some incremental costs and some capital investment, so care needs to be taken when interpreting these numbers.

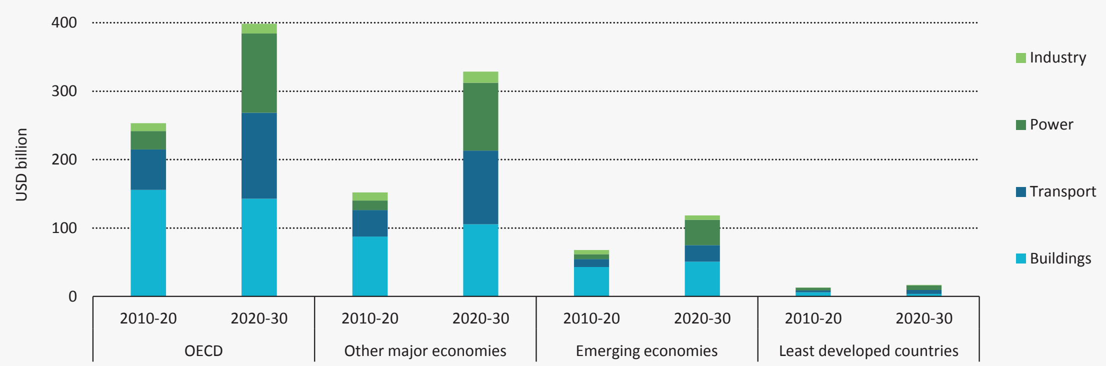
Table 4.6 also shows how much climate finance the private sector already provides to developing countries, estimated at 50% to 60% of current flows. The private sector plays a crucial role in capital investment in climate mitigation and adaptation projects, and will need to take an even greater part in scaling up mitigation and adaptation investment.

How much additional investment is needed?

The additional investment needs in the energy sector for achieving the 2DS are substantial (Figure 4.13). For emerging economies and least developed countries, the gross additional investments required (*i.e.*, not taking into account fuel savings) in the 2DS compared to the 6DS total USD 76 billion per year from 2010 to 2020, and USD 130 billion per year from 2020 to 2030. Adding in other major economies brings the annual additional investment in non-OECD countries to USD 226 billion from 2010 to 2020 and USD 439 billion per year from 2021 to 2030.

The investment needs in non-OECD countries clearly exceed the USD 100 billion of pledged climate finance (a significant share of which will be dedicated to adaptation funding). However, this does not necessarily mean that this funding will be insufficient. As discussed elsewhere in this chapter, the additional investment needs are partially compensated by fuel savings, meaning that the incremental cost is much less (and can even result in net savings over the long term to 2050). If the Green Climate Fund and other vehicles for the USD 100 billion can structure their funding so that they primarily target those incremental costs not compensated by fuel savings while leveraging private finance for the cost-effective component of these investments, then reaching the required scale of finance becomes more achievable.

Figure 4.13 Additional annual investment needs by income category to achieve the 2DS, 2010-20 and 2020-30



Key point *OECD countries will account for the largest share of additional investments.*

A major element in scaling up finance to the required levels is the ability to mobilise private sector finance in developing countries. If the majority of the USD 100 billion is directed to emerging economies and the least developed countries, with a much smaller share allocated to other major economies to leverage domestic sources of finance, the financing challenge can be dramatically curtailed. During the COP 15 negotiations in Copenhagen, China stated that it would not seek funding from the Green Climate Fund. Of the USD 150 billion of annual additional investment needed by 2020 by other major economies, China accounts for approximately USD 70 billion. Financial institutions in China (such as the China Investment Corporation and China Development Bank), as well as Brazil's development bank, are already leaders in climate finance, providing some of the largest sources of funding for low-carbon energy technologies.

To maximise the impact of available funds, priority should be given to energy efficiency actions, particularly those that help the buildings sector and urban infrastructure avoid the lock-in of older high-emissions technologies. Over the next decade, energy efficiency will have the greatest impact on CO_2 mitigation. A second area of priority is low-carbon projects in the power sector. The power sector is expected to be one of the fastest growing sources of CO_2 emissions; given the long operational lives of these assets, early investments in low-carbon power generation will be important to avoid costly lock-in of high carbon-intensity power generation technologies (IEA, 2011).

Where will the money come from?

The total value of the global financial market reached USD 212 trillion at the end of 2010, up from USD 175 trillion in 2008 and USD 114 trillion in 2000 (McKinsey, 2011). In 2010 alone, USD 11 trillion was added to global capital markets. The availability of capital does not seem to be a major issue in funding the energy technology revolution, as there is an abundance of capital in the market. The barriers, however, centre on accessing this capital at the right price and inducing companies and investors away from traditional fossil fuel energy and towards low-carbon energy technologies. Over the next decade, an estimated USD 1 trillion needs to be invested each year in low-carbon technologies on both the supply and demand sides.

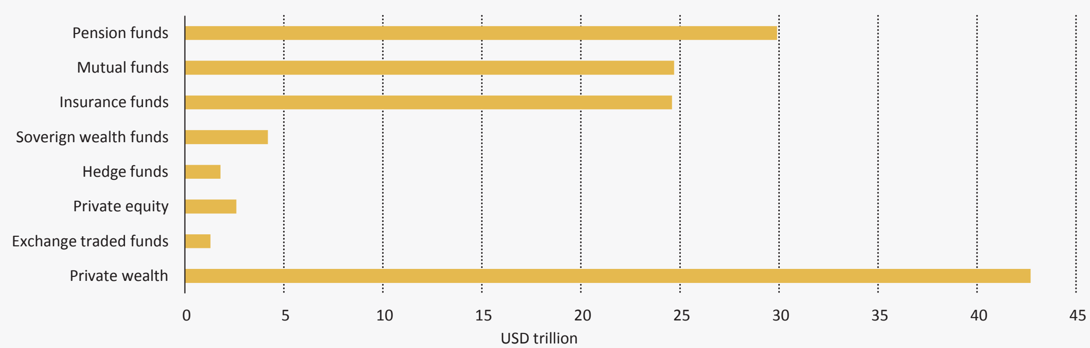
Adequate early-stage development capital for companies developing new technologies remains a hurdle because some of the nascent technologies (such as deep offshore wind and advanced geothermal projects) are too capital-intensive for venture capital and pose too much risk for private equity or bank lending. Holders of the majority of available capital seek investment opportunities that demonstrate stable cash flows and moderate returns, such as onshore wind. Although some investors, such as venture capital and private equity firms, are willing to take on higher risks for larger returns, they represent a much smaller share of the global capital market.

Government support mechanisms will be particularly important to offset early-stage technology risks that investors are currently not willing to take. As the technology matures and success of early projects establishes credibility with investors, government intervention should be gradually phased out.

Unlocking trillions from institutional investors to scale up financing for low-carbon technologies

Of the USD 212 trillion in global capital markets, more than half are global fund management assets. This industry can be split into conventional fund assets, which are typically managed by pension, mutual and insurance funds; and unconventional fund assets, comprised of wealthy individuals, sovereign wealth funds and hedge funds. These investors had combined assets of USD 117 trillion at the end of 2010, with conventional assets rising 10% in 2010 to USD 79.3 trillion and unconventional assets rising 12% to USD 37.7 trillion (Figure 4.14). Since 2000, assets under the management of conventional funds have grown at a compound annual growth rate (CAGR) of over 7%, while unconventional funds (including private wealth) increased at a CAGR of 6%.

Figure 4.14 Global assets under management, 2010



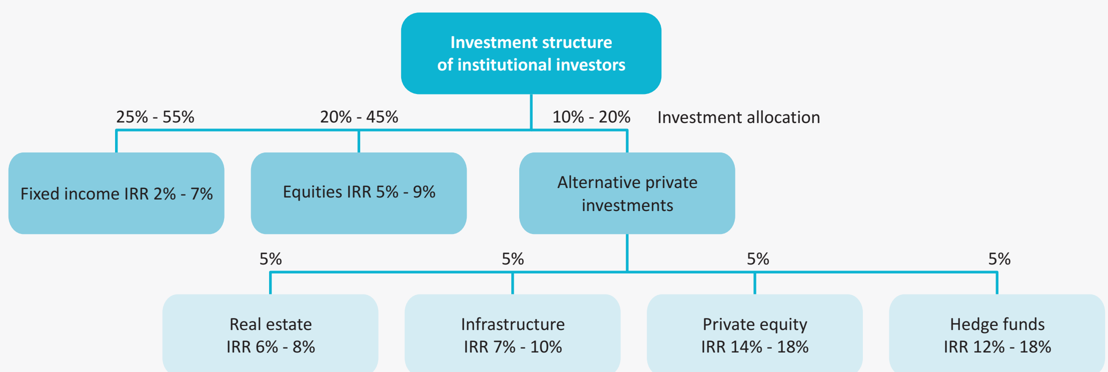
Note: Approximately one-third of private wealth is invested in pension and mutual funds.
Source: OECD Global Pension Statistics and Institutional Investors database.

Key point *Availability of capital does not appear to be a major issue for funding the energy technology revolution.*

Conventional fund managers generally have poor appetites for risk and invest primarily in liquid (*e.g.* exchange-listed and freely tradable) equities and fixed-income and other securities, seeking average annual returns of 4% to 8%. Pension and insurance funds invest pension contributions and insurance premiums to fund future long-term and statistically determinable liabilities. Pension funds and insurance companies have greater flexibility in making long-term, illiquid investments. Mutual funds invest for capital appreciation and the time horizons for these funds range from short to long term. Because mutual funds must be able to redeem shares on a daily basis, they have large cash reserves and are nearly fully weighted to listed equities and bonds. The investors are major shareholders in listed companies and hold significant positions in government and corporate debt. Public pension funds, like private pension funds, need adequate risk-adjusted returns for their investments and stable inflation-adjusted income streams.

Investments in low-carbon power generation technologies, which often offer stable income streams through long-term power purchase agreements, appear to offer a good fit for risk-wary investors . The average returns targeted by these investors vary, depending on the associated risks of the different investment vehicles (Figure 4.15). It is important to note that the expected average return is based on variable performance of different investments, so the actual target investors strive for needs to be higher to achieve the indicated average rate of return. For example, an infrastructure fund, expecting returns of 7% to 10%, will generally invest at 10% to 15% because some returns will be lower than the target rate.

Figure 4.15 **Asset allocation and expected returns from institutional investors**



Notes: Significant ranges exist in different countries for asset allocation; figures shown above represent current allocations in various countries. Internal rate of return (IRR) is used to measure and compare the attractiveness of different investments. In this figure, it illustrates the expected average net returns to investors from different investment vehicles. For alternative private investments, which are made via private unlisted funds, there is a differential of 2% to 5% between the gross returns from the investment and the net returns to an investor, to cover the cost of the fund manager. In the infrastructure "asset class", there is a wide range of assets with varying risk profiles and return expectations. The 7% to 10% returns noted above are generally expected for what is known as "core infrastructure", which refers to mature "brownfield" operating assets with long-term inflation-linked cash flows and concession or monopoly-like status, such as transmission lines. New "greenfield" infrastructure projects, which entail construction risk or where revenues are more variable (e.g. ports or toll roads), have volume risks (e.g. wind production) or pricing risks, and generally require higher returns to attract investors.
Source: Brown J. and M. Jacobs, 2011 and OECD, 2011.

Key point *Investors require significant returns on investments.*

Allocation of pension funds to clean energy technologies is currently very low, less than 1% (Della Croce R *et al*, 2011), although not much data are currently available on allocations by other investors. In contrast, fund holdings in traditional energy companies (most of which are primarily based on fossil fuels) are estimated to be about 5% to 8%. Raising adequate financing for clean energy requires greater investment by pension fund managers and other conventional and unconventional fund investors. This will occur only if investment opportunities in clean energy offer adequate risk-adjusted returns. Pension funds cannot and should not be expected to invest in clean energy simply because society needs it. Government policies can correct market failures with regulations and policies aimed at filling the gap between investment risks and market barriers. Governments can also ensure that adequate domestic frameworks covering energy, climate and investment policies are in place to attract sufficient capital to the clean energy sector.

Understanding investment risks

Prior to investing in any project, investors assess its risks. A number of different risks are evaluated, from regulatory and policy risks to construction and markets risks (Table 4.7). Investors seek conditions and an environment in which these risks can be understood, managed and anticipated (Hamilton, 2009). Policies can help address investment risks and market barriers to create suitable environments for low-carbon energy technologies to attract private sector finance.

Table 4.7 Risk analysis for investments in low-carbon energy technologies

Type of risk	Description
General political risk	Concern about political stability and the security of property rights in country, along with generally higher cost of working with unfamiliar legal systems.
Currency risk	Concern about loss of value of local currencies.
Regulatory and policy risk	Lack of long-term low-carbon development strategies; concern about the stability and certainty of the regulatory and policy environments, including longevity of incentives for low-carbon investment and reliability of power purchase agreements; instability in the price of carbon, such as weak or unstable environmental regulations; existence of fossil fuel subsidies that make such investments more attractive to investors.
Construction and execution risk	Local project developers or firms lacking the capacity and experience to execute the project efficiently; general difficulty of operating in a distant and unfamiliar country; level of risk subject to the maturity of the technology and the track record of the technology provider.
Technology risk	Uncertainty whether a new or relatively untried technology or system will perform.
Unfamiliarity risk	Amount of time and effort needed to understand a type of project that is unfamiliar to the investor.
Public acceptance risk	Opposition from the public to low-carbon technologies, such as wind farms, CCS and nuclear.
Market risk	More competitors entering the market; change in consumer preferences and demand; technological advances.

Source: Adapted from Brown J. and M. Jacobs, 2011.

The ability to evaluate and manage the risks outlined in Table 4.7 differs depending on the stakeholders, and their experience and capability to properly support these risks. For example, in the case of offshore wind projects, one of the largest risks comes with construction. Building offshore wind farms is still at a relatively early stage and faces a number of untried challenges during the construction phase, as well as the operation phase. Companies with significant experience in developing wind farms, in particular offshore wind farms, are particularly well placed to support the construction risk of developing offshore wind farms. Once construction is completed and the wind farm is operating, it can be sold (either in part or entirely) to a different actor that is equally adept at owning these assets and managing the market risks of projects in their operating phase.

Venture capital and private equity funds for early-stage investments

Venture capital funds are raised from a wide range of sources with high risk tolerances and are generally used to finance new technology development. These funds usually focus on early-stage technology development and funds are provided in exchange for equity in a company. More recently, a growing trend among non-specialist venture capital investors is to target later-stage, less-risky investments (Taylor Wessing, 2011). This puts additional pressure on securing funding for early-stage demonstration projects, as the pool of funding is limited to specialist venture capital funds that have the resources and knowledge to analyse these projects.

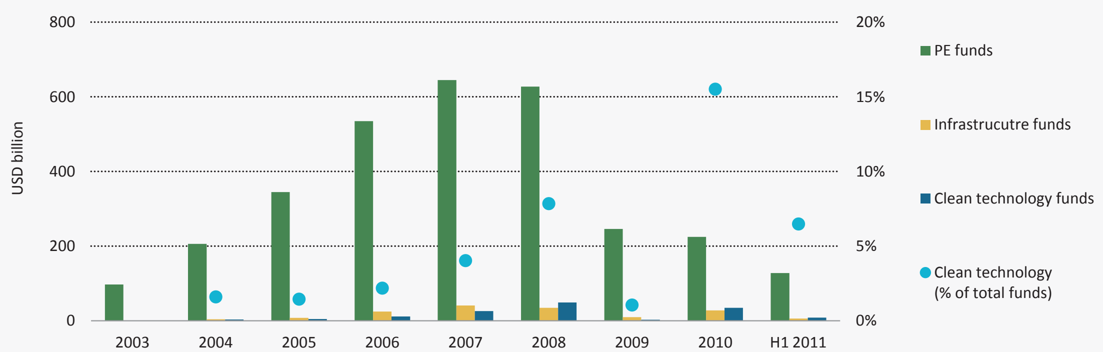
Private equity funds are raised from sources with a medium risk tolerance and generally finance more mature technology. These investors have indicated a clear preference for established, profitable businesses at the expansion stage or mature companies, and have a dislike for technology risks (Taylor Wessing, 2011).

A clear exit strategy is crucial for both venture capital and private equity funds. This can be in the form of a trade sale to a strategic investor, such as an energy company, or an initial public offering. Venture capital funds generally have a five- to seven-year investment horizon and look for returns of four times their initial investment. Private equity funds, on the other hand, tend to invest for three to five years and seek returns of two to three times their inital investment, which in the clean energy area is proving difficult to achieve.

Despite an abundance of capital in the market, significant gaps persist, particularly financing for early-stage development for companies with new, unproven or less mature clean energy technologies, such as CCS for a cement kiln or floating offshore wind turbines. The competition for early development capital from other sectors is also high.

A mismatch exists between the size of fund allocations available from venture capital funds and those needed for certain clean energy technologies (*i.e.* offshore wind technologies require funds on the order of USD 50 million to USD 100 million versus USD 5 million to USD 10 million for an average venture capital investment). Funding sizes are more suited to private equity or bank lending, but the technologies are generally too risky for these investors.

Figure 4.16 Private equity fundraising and share of clean technology



Source: Hg Capital.

Key point *Clean technology funds remain a relatively small share of total private equity funds; total funds available are well below what is needed to support low-carbon technology development.*

In these cases, government intervention is particularly important and may take the form of grants, subsidies, publicly funded venture capital or loan guarantees that sufficiently offset project risk for private equity or bank lending. The funding environment for early-stage projects will improve as the first projects demonstrate their profitability. Government support in this area can play a pivotal role in helping establish an investment track record.

Technology developers are also turning more and more to strategic investors (specialist energy companies and utilities) to help mitigate risk. These investors can help provide credibility for a project, as well as access to the end consumer.

Sovereign wealth funds and green investing

A sovereign wealth fund (SWF) is a state-owned investment fund composed of financial assets, including stocks, bonds, real estate or other financial instruments, funded by foreign exchange assets (Sovereign Wealth Fund Institute, 2012). Assets under SWF management have shown the largest increase among various conventional and non-conventional fund owners, rising from just over USD 1 trillion in 2000 to over USD 4.8 trillion in 2011 (Table 4.8). Although still less than one-quarter of total funds managed by public and private pension funds, the individual size and long-term investment horizon of SWFs make them a very attractive source of finance for low-carbon energy investments.

Of the total SWF assets, 56% (USD 2.7 trillion) is derived from oil and gas exports. This makes clean energy an attractive investment vehicle for funds wanting to hedge against future changes in the energy sector. The SWFs of China and the United Arab Emirates (UAE) have been particularly active in the clean energy sector. The China Investment Corporation has invested in wind farms and the UAE has supported Masdar, a company set up to develop renewable energy and other sustainable technologies.

Table 4.8 Sovereign wealth funds with over USD 100 billion in assets

Sovereign wealth fund	Country	Assets under management (USD billion)	Source of funds
Abu Dhabi Investment Authority	United Arab Emirates	627	Oil
Safe Investment Co.	China	568	Non-commodity
Government Pension Fund	Norway	560	Oil
SAMA Foreign Holdings	Saudi Arabia	473	Oil
China Investment Corp.	China	410	Non-commodity
Kuwait Investment Authority	Kuwait	296	Oil
HK Monetary Authority Investment Portfolio	Hong Kong (China)	293	Non-commodity
Government of Singapore Investment Corp.	Singapore	248	Non-commodity
Temasek Holdings	Singapore	157	Non-commodity
National Security Fund	China	135	Non-commodity
National Welfare Fund	Russia	114	Oil

Note: Figures are based on December 2011 values.
Source: Sovereign Wealth Fund Institute, 2012.

Sovereign wealth funds can act as stabilisation funds, which serve short- to medium-term objectives and usually have a shorter investment horizon; savings funds with long-term objectives, typically aimed at generating higher returns over a longer horizon; pension reserve funds, which base their investment horizon on when future anticipated liabilities are due (which can be decades in the future); or hedges against country-specific risks, in which case the funds will hold assets with a negative correlation to the country's major exports to offset terms of trade shock.

Sovereign wealth funds should consider both private and social returns; these funds are intended to safeguard the interests of citizens in the country where they are held. The funds' longer-term investment horizon also means that longer-term risks (such as the impact of climate change) may be particularly important to these investors. As major shareholders in corporations, SWFs and other large institutional investors can influence the management of firms that they own to make more environmentally responsible business decisions. In addition, they can provide much-needed capital for investments in climate-change mitigation infrastructure, which can help spur growth when the global financial sector is hit by a credit crunch.

Sovereign wealth funds are in a unique position to help new and emerging technologies establish an investment track record. Such efforts may require large capital outlays and longer pay-back periods, and may not be suitable for conventional funds. The long-term focus of SWFs allows them to take on higher-risk investments, but it should be noted that these risks still must be justified by higher returns. The number of high-risk investments that these and other institutional investors are able to manage is not unlimited. SWFs are financial investors and are not excessive risk-takers. They have a fiduciary responsibility to provide financial stability for future generations and, hence, need to ensure adequate returns for the risk associated with any investment.

Domestic policy frameworks for investing in clean energy

Raising sufficient finance for investments in low-carbon energy technologies depends on governments setting the right domestic policy framework to facilitate investments by the private sector. An appropriate policy framework needs to cover not just climate policy, but energy and energy technology policy, as well as investment policy. Although there is some co-ordination in the development and implementation of climate and energy policy, little or no co-ordination occurs with investment policies. In order to attract sufficient financing for investment in clean energy, the policies aimed at accelerating deployment of low-carbon energy technologies must effectively (and reliably) create environments for investment.

The OECD's *Policy Framework for Low-Carbon, Climate Resilient Infrastructure Investment* (OECD, 2012) defines overarching principles and a checklist for policy action. It lists critical areas of public intervention – policies and financial tools and instruments – driving private sector investment in low-carbon, climate-resilient infrastructure.

The framework brings together what have traditionally been treated as separate policy domains, *i.e.* climate change, investment and financial sector policies, and provides a structure for understanding how policies can establish ideal conditions to scale up green investment. However, given the diversity of domestic and sector contexts for infrastructure, and the variety of investment barriers and policy priorities, the exact policy mix and the sequencing of instruments will need to be tailored to the specific needs of different countries.

When considering the framework for low-carbon energy investments in Box 4.1, a few clarifications are needed. Given the long life of energy assets, it is important to highlight the need for long-term target setting and policy predictability. Targets in the energy sector should be set beyond just the short term (less than two years) and the medium term (two to five years), to possible long-term horizons of more than 20 to 30 years. With many energy assets operating for 30 to 40 years or longer, and requiring large up-front capital costs, policy predictability is as important as policy uncertainty to raise investor risk. Domestic frameworks need to minimise this risk, so that investors are confident of policy stability over a longer payback period.

Box 4.1 Policy framework for investment in low-carbon, climate-resilient infrastructure

Strategic goal-setting for a green economy
Clear, long-term vision and targets for infrastructure and climate change; policy alignment and multilevel governance, including stakeholder engagement

Enabling policies for competitive, open markets and greening infrastructure investment

Sound investment policies; market-based and regulatory policies to "put a price on carbon" and correct for environmental externalities; remove barriers and disincentives and incentivise LCCR innovation and investment

Financial policies and instruments to attract private sector participation
Financial reforms to support long-term investment; innovative financial mechanisms for risk-sharing such as green bonds; transitional direct support for LCCR investment.

Mobilising public and private resources for a green economy
R&D, human and institutional capacity-building to support LCCR innovation, monitoring and enforcement capacity.

Promoting green business conduct and consumer engagement in inclusive green growth
Corporate and consumer awareness programmes, corporate reporting, information policies, outreach.

Source: ODI and OECD, 2012.

Efforts to remove barriers and disincentives to investment should also faciliate planning and permitting of low-carbon energy projects, which often lead to delays and higher financing costs. The need for incentives for low-carbon energy investments, where the technology cost is higher than the fossil fuel alternative, is clear, but such incentives need to be designed to reflect changes in technology maturity and the benefits of learning. Incentive schemes need to avoid the boom and bust cycles experienced recently in PV markets.

Adequate legal and regulatory frameworks are particularly important for a number of low-carbon energy technologies, such as nuclear and CCS, where appropriate regulation is critical to technology uptake and public acceptance of these technologies. Stringent building codes and minimum energy performance standards need to be applied and carefully monitored to support many of the lower-cost energy-efficiency options needed to achieve deep emission reductions in the energy sector.

Public acceptance and education is particularly important for the low-carbon energy sector. The role – and impact – of the public in adopting lower-carbon energy technologies cannot be understated. Governments and industry need to allocate more resources to educate the public about the need and benefits of low-carbon energy technologies.

Financial regulation and the impact on clean energy investments

New financial regulation has been introduced by governments to reduce the risk of another global financial crisis created by poor risk management in the finance sector. For example, the increased capital requirement of Basel III may limit balance-sheet lending, and restrictions on equity investments could limit the pool of available capital for private equity investments (Della Croce R. *et al*, 2011). These new rules will effectively triple the capital reserves that the world's banks must hold against losses. Basel III is expected to increase credit and liquidity costs, affecting long-term bank-financed debt for project finance in particular.

Solvency II in Europe, which sets new requirements on capital adequacy and risk management for insurance companies, could deter investment of insurance funds in long-term assets. Holdings in equities will need to be backed by reserves of 30% to 40%, while European sovereign debt is deemed risk-free. These rules may lead European investors away from equities and into bonds. In addition, a number of quantitative and qualitative investment restrictions on pension funds could limit the amount of available capital through restrictions on foreign investments and the asset classes that they can invest in.

Governments and regulators need to re-evaluate the impacts of these new financial regulations to ensure that they do not lead unnecessarily to additional barriers to investing in low-carbon energy technologies. When evaluating energy and climate policies, governments should also consider whether investment policies are adequate to attract sufficient private finance to this sector.

Barriers and options to scaling up private sector finance

A number of existing barriers need to be overcome if institutional investors are to increase allocations to clean energy technologies (Table 4.9). These include the lack of investment track records and policy unpredictability, both of which result in higher risks and, hence, higher required returns for these projects. Institutional investors make investment decisions based on an evaluation of risk and return profiles. The ability to properly evaluate and manage these risks will help to overcome many of the barriers.

Table 4.9 Barriers to greater financing from institutional investors

Barrier	Description
Investment track record	Lack of an investment track record, leading to higher perceived risks and higher required returns.
Liquidity and size	Insufficient liquidity in financing vehicles and lack of projects of adequate size for investment. Some projects are not sufficiently large enough (minimum investment size of USD 10 million to USD 30 million) to justify the cost of due diligence.
Policy unpredictability	Policy unpredictability and regulatory uncertainty.
Lack of expertise	Few funds with the in-house expertise to properly evaluate investment opportunities in this sector.
Short-term focus	Financial governance structure of investors more adaptable to short-term investment strategies. Market structure less favourable for financing assets requiring high up-front capital costs.
Passive funds	High share of passively managed funds and absence of clean energy sector in the largest and most highly tracked bond and equity indexes.
Geographic mandate	Fund possibly required to invest the majority of its funds locally, leaving only a small portion to be invested abroad.

Certain limits can be overcome with government policies, while others, such as a fund's geographic mandate or its passive nature, require changes in the governance structure. In both cases, governments can play a role in making investments in low-carbon technologies more attractive than traditional fossil-based energy investments by correcting market failures that do not adequately price the environmental and social costs of climate change. The costs to energy security and economic development from excess dependence on foreign imports of energy should also be considered.

Financing vehicles for clean energy also needs a certain level of liquidity to be appropriate for institutional investors. Although potentially very large, the current market for clean energy is relatively small and far from liquid. Pension-fund investors and other large institutional investors require investment-grade vehicles with a size of at least USD 10 million to USD 30 million (USD 200 million to USD 300 million for bonds) due to the high transaction costs associated with due diligence. In many cases, investors lack the expertise to adequately evaluate the risk and reward profiles of clean energy projects and require higher returns than with traditional fossil fuel-based investments.

Energy efficiency

Certain features of energy efficiency projects (such as high transaction costs, valuation criteria, risk assessment, lack of awareness and capacity) make it more difficult to find financing through traditional sources, such as banks. Many financial institutions are not familiar with the unique characteristics of energy efficiency projects and have limited internal capacity to properly appraise the risks and benefits. They also do not usually recognise the potentially large business opportunity in energy efficiency lending and, therefore, do not have the management commitment or the organisational structure to finance these projects on a large scale.

When companies are unable to procure loans for implementation of energy efficiency projects, they will either finance these projects with their own equity or postpone the investment. Certain government programmes, such as those promoting energy efficiency through subsidies and incentives, can temporarily drive the market forward, but the effects are rarely sustainable. The evidence suggests that policies, both financial and nonfinancial, exist to overcome the perceived higher risk associated with energy efficiency investments. Three policies in particular – risk guarantees, training and education, and increased public-private sector collaboration – are both effective and complementary.

Mechanisms and financing vehicles to leverage private-sector investment

A range of public finance mechanisms and financing vehicles have been identified that can be used to overcome these barriers (Table 4.10). Public finance should be used to underpin and develop early investment-grade projects to allow the private sector to move into new markets and help build up the technical capacity of a country. Early public-private partnerships should be encouraged, as they can help demonstrate technologies and create new markets.

The current economic crisis has reduced the amount of public finance available to support low-carbon energy technologies. Public finance must be used as efficiently as possible and should be targeted at mechanisms that can leverage high levels of private sector finance. Well-designed public finance mechanisms can leverage between three and fifteen times their amount in private-sector investments (IIGCC, 2010).

Table 4.10 Public finance mechanisms to leverage private-sector investments

Mechanism	Description and context	Estimated leverage ratio	Technology stage
Debt funds	Credit lines for senior, mezzanine or subordinated lending incentives.	n.a.	Demonstration, deployment and commercial roll-out
Loan guarantees	Pledge by a government or government-supported entity to protect the lender from technology, business model or other proof of concept risk (suitable for countries with high political risk, dysfunctional energy markets and lack of policy).	6 to 10 times	Demonstration, deployment and commercial roll-out
Export credit	A lending or guarantee line intended to promote exports of domestic clean energy manufacturers.	n.a.	Diffusion and maturity
Risk insurance	Indemnity coverage for investors, contractors, exporters and financial institutions, which is intended to spur investment in developing countries.	n.a.	Diffusion and maturity
Energy service-company funds	Financing vehicle for energy efficiency.	n.a.	Diffusion and maturity
Policy insurance	Countries with strong regulatory systems, but where specific policies are at risk of destabilising.	10 times and higher	Diffusion and maturity
Equity pledge fund	Projects with strong internal rate of return, but where equity cannot be accessed.	10 times	Diffusion and maturity
Subordinated equity fund	Risk projects, with new or proven technologies; public sector first loss.	2 to 5 times	Demonstration, deployment and commercial roll-out
Publicly-backed green or climate bonds	Typically issued by a government agency or multinational institution; publicly-backed bond programmes with tax incentives or ring-fenced funds suitable for smaller developers or markets with high capital costs.	n.a.	Commercial roll-out

Sources: BNEF, 2011; Caperton, 2010; Justice, 2009; Climate Bond Initiative.

Well-targeted public finance mechanisms can help create an investment track record and offset some of the perceived investment risk that private investors are not currently willing to support. For certain less-mature technologies such as CCS or those not yet cost-effective (some building technologies), where there is a larger public-good aspect, the role of public finance and regulation will be particularly important.

Different financing models will emerge in different countries, depending on the market structure of the energy sector and maturity of the financial market. In many emerging countries, such as China and Brazil, the role of state-owned development banks and state-owned enterprises means that the role of public finance will be much greater than in more liberalised energy markets, such as the United Kingdom and the United States.

Green or climate bonds

Green bonds offer the largest potential to attract funding from institutional investors in the next decade. Bonds represent roughly 50% of holdings by institutional investors, making this asset class particularly attractive. With a value of USD 95 trillion, the global bond market offers plenty of opportunities to raise large amounts of finance for clean energy technologies.

The current market size of self-labelled climate change-related thematic bonds (labelled as green, climate and clean energy) is, at USD 16 billion (Table 4.11), far below what is needed to create a liquid asset class that institutional investors could easily access.

Table 4.11 Green bond market (USD billion)

Multilateral development bank bonds	7.2
US municipal clean energy or energy efficiency bonds	0.8
Renewable energy project bonds	8.5
Total	**16.5**

Note: As of March 2012.
Sources: Climate Bonds Initiative and Bloomberg database.

The largest green bond issuances to date have come from clean energy bond programmes offered by multilateral development banks, such as the World Bank and EIB, totalling USD 7.2 billion. These bonds have the highest credit rating of AAA, and have helped establish early confidence in the green bond market. The US government has allocated USD 2.4 billion for its Clean Renewable Energy Bonds program that allows municipalities to finance public sector renewable energy projects.[7] In addition, a number of large bond issuances ranging from USD 500 million to USD 850 million in the United States have raised capital for wind and solar farm construction, and renewable energy manufacturers are increasingly turning to the bond markets in the absence of restricted bank lending.

An estimated USD 200 billion of bonds have been identified that can be classified as climate-change investment-related bonds, once asset-backed and corporate bonds are included (CBI and HSBC, 2012). Climate bonds are defined as those issued to fund *or refinance* climate change mitigation, adaptation or resilence projects (Climate Bonds Initiative). Included investments range from clean energy and grid development to water adaptation and flood defense.

Bonds can be issued by banks, governments or corporations. They can be asset-backed securities linked to a specific project or they can be treasury-style bonds issued to raise capital to fund a portfolio of projects. For a specific bond to have sufficient liquidity, it needs to be issued with a size of at least USD 300 million to USD 400 million. Below this threshold, climate bonds will have difficulty attracting sufficient interest from mainstream markets.

Institutional investor appetite for bonds is largely in the investment grade area and in large-scale issuance. A liquid market requires issuance of upwards of USD 200 billion to USD 300 billion, made up of bonds rated BBB or higher.

Qualifying as investment grade is an issue for clean energy investments, with rating agencies typically awarding BB or lower credit ratings for wind and solar project bonds. A focus on issuing bonds for refinancing rather than project funding is one way of addressing this, with established projects likely to achieve higher ratings than pre-development project bonds. This would involve banks maintaining current bank debt to bond ratios of 20:1, but securitising loans within two years of development to avoid the liquidity ratio issues involved in long-term holding of lower-grade debt.

Another strategy would be to bring rating agencies, investors and governments together to discuss optimal means of overcoming barriers to investment in clean energy projects. The lack of track records for large-scale climate change-related bonds means that this risk is seen as greater than existing investments; this is compounded when policy is perceived as the main (and volatile) sector risk by investors.

7 Of the USD 2.4 billion allocated under the US government programme, only USD 600 million of bonds have been issued. Many developers who won consent to issue the bonds have not yet done so.

Governments can help bring institutional investors into the market in several ways:

- Provide insurance and other guarantees in relation to policy risk. For example, the German government currently guaratees domestic power purchase agreements and in some other European countries, such as Greece.
- Provide legislative or tax credit support for qualifying bonds. The US government, for example, provides tax credits for clean energy bonds and the UK government reduces the risks of securitised energy efficiency loan portfolios through the legislated repayment collection mechanisms in its Green Deal legislation.
- Issue government climate bonds, as Australia is doing for its Clean Energy Finance Corporation, to lend to intermediary banks to direct to energy developers.

The last option is also a means of addressing problems of lack of scale, with large sovereign or multilaterial bank bonds raising funds for distribution across a portfolio of projects (Climate Bonds Initiative).

Banks can issue asset-backed securities that effectively aggregate portfolios of smaller loans into institutional investor-sized offerings. The market for asset-backed securities is still weak, but investment grade ratings can for the moment be achieved with partial or even full guarantees, all the while educating investors about the underlying projects in anticipation of the recovery of an asset-backed securities market.

Large corporations, such as utilities, can do the same, helping develop an investment track record for underlying assets by linking their bond issuance to low-carbon projects while providing full, and later partial, credit rating through the corporate balance sheet. Over time, this will allow utilities to better focus their balance sheets on the development of new energy infrastructure.

Recommended actions for the near term

Investments in clean energy technologies must at least double by 2020 to transform the energy sector. Investment decisions made over the next decade will lock in energy use and emissions for at least the next two to three decades. Greater investments are needed in energy efficient building technologies, which account for the largest share of additional investment needs in the 2DS across all countries and regions. Delayed action on implementing energy efficiency will result in higher fuel costs as well as additional investments in the power sector.

Urgent support is needed to address financing gaps in early-stage technology development. Public spending on R&D should rise by a factor of two to five times current spending. Private-sector R&D will also need to increase to support and enhance low-carbon technology development.

Governments should ensure that national policy frameworks provide a supportive business environment which allows low-carbon technologies to show solid returns and hence attract greater private capital to the sector. Companies need to make the transition away from traditional fossil fuel-based technologies to low-carbon energy technologies.

Enhanced dialogue between governments and investors is needed to better evaluate the economic and financial costs and benefits of moving to a low-carbon energy sector. Investors need to better understand the energy and climate risks of their portfolios and should consider increasing allocation to low-carbon energy technologies as a hedge against the future downsize risk of climate change.

In the near term, the bond market offers perhaps the most attractive opportunity to scale up private sector financing for low-carbon technologies. Governments could help create a liquid green (or climate) bond market by issuing publicly backed green bonds or by providing insurance or other guarantees to support policy risk.

Part 2

Energy Systems

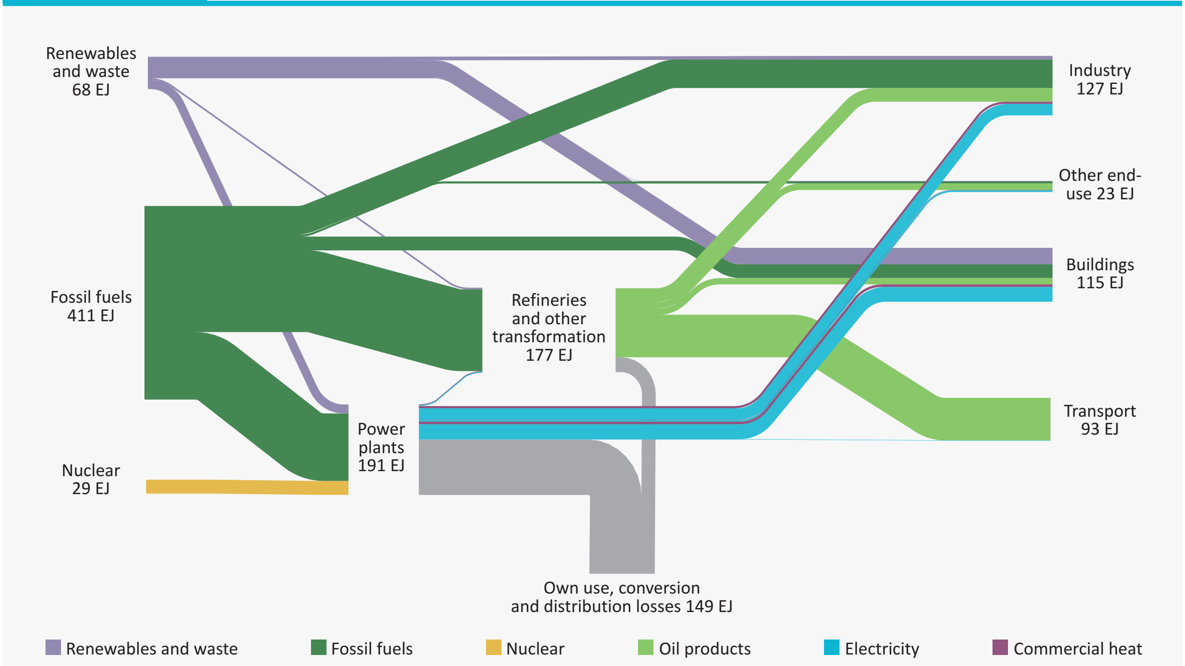
Part 2 analyses, from three different angles, the interdependency of energy technologies, and the value of increased integration for the energy system as it is decarbonised. Chapter 5 focuses on heating and cooling with the link between heat and electricity as a central theme, together with how the integration of different energy services can improve overall efficiency and operation. Electricity system flexibility and investment needs in transmission and distribution are covered in Chapter 6. A forward-looking analysis of the conditions under which hydrogen could play a major role in the future energy system is found in Chapter 7.

Energy Systems Thinking

The current energy system is dominated by large, centralised generation based mainly on fossil fuels (Figure ES.1). The low-carbon energy system of the future will be characterised by greater diversity of technologies and fuels, more renewable energy, and increased complexity across the entire infrastructure (Figure ES.2). Managing energy effectively – which implies reducing costs and increasing efficiency while, also ensuring reliability and security – will require a highly inter-related system in which every piece fits together.

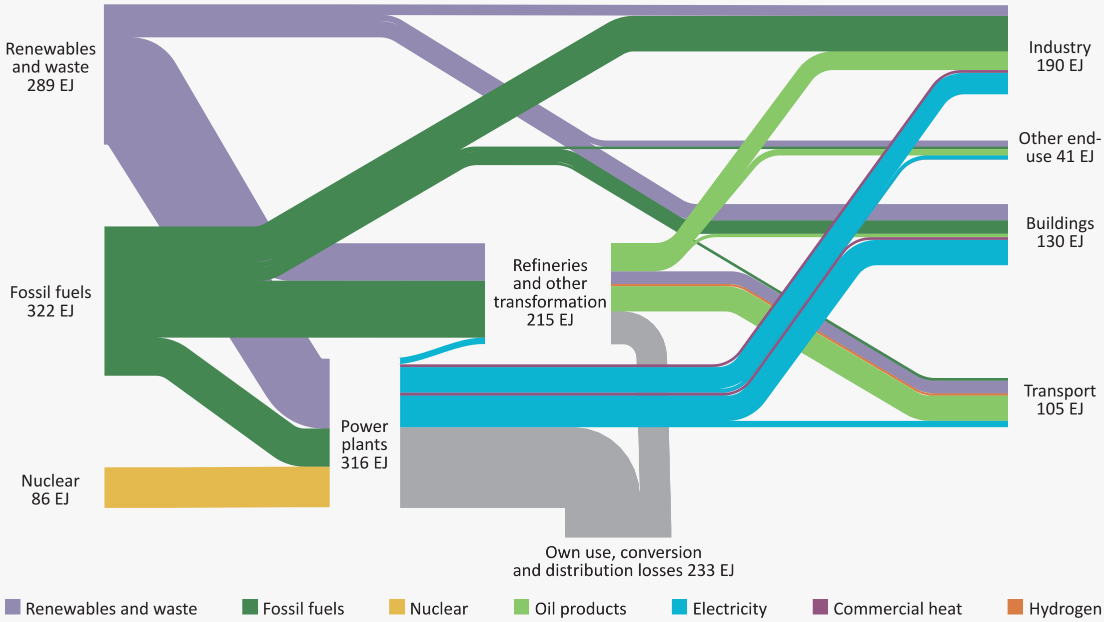
A systems approach to energy must carefully examine the existing divisions between energy sources and end uses, with the aim of identifying potential synergies that allow for more effective use of each element. The following three chapters highlight innovative ideas about unlocking the benefits within targeted areas, and moving towards a more unified energy system overall in the context of the *ETP 2012* 2°C Scenario (2DS) and *ETP 2012* 4°C Scenario (4DS).

Figure ES.1 Global energy flows in 2009



Key point *Fossil fuels dominate the current energy system across all sectors.*

Figure ES.2 Global energy flows in the 2DS in 2050



Key point *To meet global climate goals, the current energy system will evolve and use greater amounts of renewable energy and a wider range of energy carriers.*

In broad terms, an energy system is made up of three components:[1]

- ***Energy sources*** which include fossil fuels, renewable energy and nuclear.
- ***Energy conversion and distribution***, which includes technologies that convert primary energy into useable energy (*e.g.* generation of heat and electricity, refineries) and those that transfer energy from the point of production to the point of use (*e.g.* pipelines and shipping, electricity transmission and distribution networks).
- ***Energy services***, such as transport, heating and cooling, lighting, and industrial processes.

Much of the production and transfer of energy are undertaken within four broad sectors in mind: power, industry, transport and buildings. Fossil fuels currently dominate all sectors because of their high energy density, availability, low cost, and relative ease of conversion and transport.

The decarbonisation of the energy system, as an example of large-scale systems thinking, and the deployment of a range of fuels, enabling technologies and improvements in end-use efficiency are considered, while ensuring an economical and secure energy future. These figures demonstrate the evolution in energy flows required to meet global climate goals by comparing the current global energy system with the 2DS scenario in 2050. The

1 Source: adapted from George, A., K.P. Donaghy, R. Howe, T. Jordan and J.W. Tester, "A Systems Research Approach to Regional Energy Transitions: The Case of Marcellus Shale Gas Development." Cornell University White Paper, 22 September 2010, Ithaca,
NY, http://cce.cornell.edu/EnergyClimateChange/NaturalGasDev/Documents/PDFs/White%20Paper_9-22-10.pdf.

2DS shows modest growth in overall energy demand, but a significant shift to renewable energy and increase in the use of electricity in 2050. Each sector shows a difference in the types of fuel and energy carriers used. The transportation sector is most compelling as it is currently dominated by refined oil products, but is powered by five different fuel sources in 2050 – natural gas, biofuels, hydrogen and electricity, in addition to refined oil products.

"Systems thinking" within the energy context challenges all stakeholders to re-examine the energy equation from the aim of averting greenhouse-gas (GHG) emissions, while ensuring an economical and secure supply of energy. It is an approach that can optimise the use of low-carbon energy sources and constrain fossil fuel consumption to the relatively small number of applications that truly require such high levels of energy density. It recognises that converting and delivering low-carbon energy can leverage the existing energy system infrastructure, with additional investment and changes to design, planning and operation (both from technical and market perspectives). Systems thinking sees the potential for devices that use energy to become active participants in the energy system.

Systems thinking also challenges the traditional distinctions between end-use sectors on two levels. First, it sharpens the focus on the useful energy needs of specific sub-groups within a sector (the efficiency of the actual service provided, *e.g.* thermal comfort, instead of the energy delivered); second, it looks for complementary resources and needs across different sectors. Three areas which illustrate the importance of systems thinking, highlighting the links between each sector by looking at complementary resources and needs, are:

- heating and cooling;
- flexible electricity;
- hydrogen.

Examples of inter-relations among different sectors considered include: electric vehicles that link the transport sector to the power sector; increased use of electricity or co-generation in heating; use of thermal storage to balance variable renewable generation; more sophisticated demand-response; and the possibility of using hydrogen for energy storage and as an energy carrier in connection to heating, power generation and transportation, to name just a few applications.

Challenges and opportunities

Without diminishing the importance of understanding and applying new technologies, stakeholders will need to improve their understanding of evolving energy systems. Systems approaches to energy deployment must also look to use existing infrastructure while simultaneously optimising new investments in all sectors. Through this evolution, new stakeholders not traditionally involved in either a specific part of the energy sector or the energy sector in general will be needed.

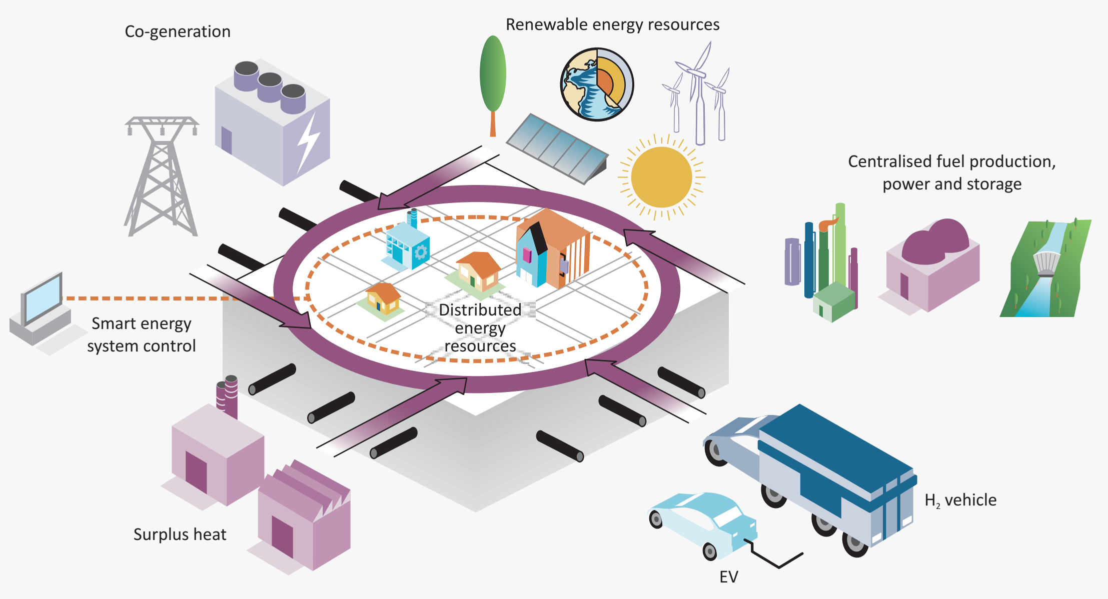
One example is the improvement of the flexibility of the electricity system to accommodate an increasing share of variable renewable investments. The typical approach so far has been to use reservoir hydro or to install fossil fuel peak power stations, but more innovative approaches are possible. Efforts to increase the flexibility of existing base-load capacity, as well as to improve regional interconnections and leverage excess flexibility from reservoir hydro generation, reduce the need for peak plant investment and increase the utilisation of existing generation facilities. Additionally, a large untapped resource on the demand side exists, which needs to be unlocked through increased deployment of smart grids, and this will require new technology, stakeholder involvement and business models. Such changes will be challenging for both energy providers and customers, but by considering opportunities throughout the system, cities, regions and countries can choose the best solutions to match their specific circumstances and resource endowment, optimising investments.

Energy sector interfaces

The energy system of the future will be significantly more complicated and will require greater integration (Figure ES.3).

In order to optimise the overall energy system, it will be essential that the interactions – for example, between heat systems and electricity – provide additional benefits, such as improved efficiency and system support services. An example can be found in regions where thermal comfort in buildings is provided by appliances that use electricity, either directly or through heat pump technology and co-generation as a source of heat and power. Currently, these sources and loads are rarely optimised beyond efforts to increase efficiency of individual devices. For example, many co-generation plants operate based on heat demand, and electricity is therefore produced whether there is adequate demand or not, increasing the variability in electricity systems. In this case, technology applied with the intention of increasing efficiency of the co-generation plant increases the need for electricity system flexibility. On the demand side, during very cold days or very hot days, electrically supplied heating or cooling loads stress the capacity of the system.

Figure ES.3 The integrated and intelligent energy network of the future



Key point *The energy system of the future will integrate the sources of and requirements for energy from all parts of the energy system. This will increase complexity, but also offer improved efficiency and better use of energy resources*

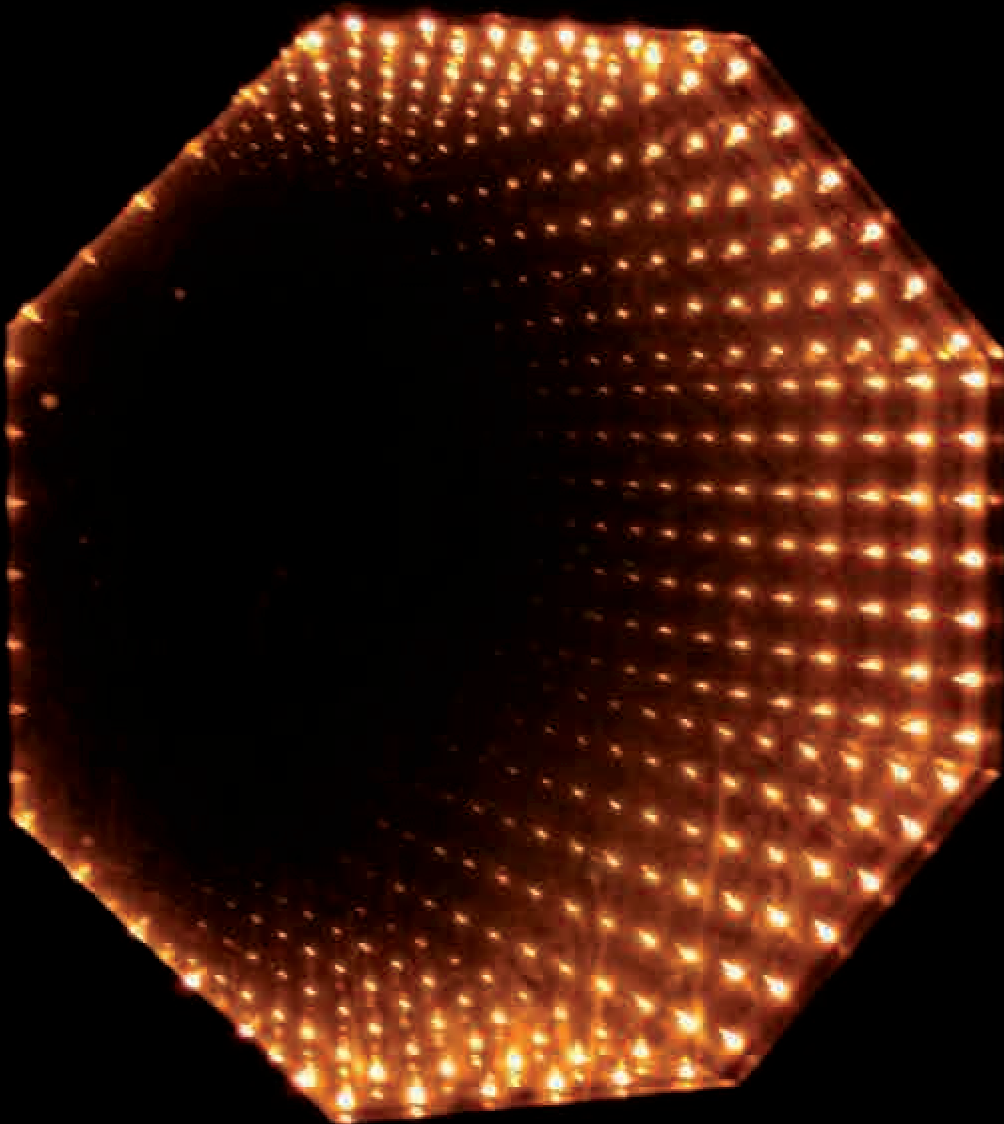
Alternatively, if the local area has a balanced mix of electrically based heating along with a district heating system, heating demand during periods of cold weather would require both heat and electricity at the same time. In this scenario, a co-generation plant could meet the heat and electricity demands in a balanced manner. Instead of adding to the flexibility need of the electricity system, the co-generation plant would become a flexible resource. Thermal storage could be added at both production and end-user sites to provide a more robust system with even wider operating parameters (efficiency and overall financial operation of such a system would have to be considered on a case-by-case basis, including regulatory and market context in larger applications).

Hydrogen is an energy carrier that could be utilised more in the future. Its capability to fuel all end-use sectors, in combination with its ability to provide dense and long-term energy storage, could make hydrogen a pivotal element to a highly-integrated energy system. Although the concerns of the overall efficiency of converting electricity into hydrogen and back again must be addressed, hydrogen production during periods of excess electricity generation would minimise the impacts of low efficiencies. Hydrogen storage may be an important component in achieving a very high penetration of variable renewable power. Hydrogen from renewable excess electricity can also be mixed up to 20% with natural gas, thereby utilising the already existent and extensive transport, distribution and storage network for natural gas. For use in the transport sector, local production of hydrogen through decentralised small-scale generation could be combined with existing infrastructure in the chemical and refining industry. This may serve as a transition strategy in the move to a large-scale hydrogen infrastructure that will not be needed in the short to medium term.

These examples demonstrate that it is necessary to consider all possible energy carriers in conjunction with a good working knowledge of the actual energy service demands to be met in the energy system. Infrastructure plays a key role here: while more integrated electricity grids are desirable, even greater benefits can be accrued by designing more integrated networks, where a variety of energy carriers are managed intelligently (Figure ES.1).

The following chapters will further examine and illustrate detailed considerations into building and operating an energy system, as demonstrated in Figure ES.2. These considerations will establish the need for change in the way they are designed and operated in order to address increased complexity while providing a clean, reliable and secure energy system.

Chapter 5



Heating and Cooling

Heating and cooling remain neglected areas of energy policy and technology, but their decarbonisation is a fundamental element of a low-carbon economy. The wide variety of interacting demands, energy carriers, technologies and stakeholders involved imply that a systems approach will be required to find least-cost solutions.

Key findings

- ***A systems approach will be needed to achieve higher energy service efficiencies and a low-carbon heat supply.*** *Integration efforts could enable further decarbonisation in other sectors. Supply of heat is very heterogeneous: it spans many sectors, fuels and energy networks, and demands fluctuate daily and seasonally.*

- ***Circumstances such as geographic location and degree of industrialisation can heavily influence the choice and effectiveness of various technologies.*** *Decarbonising heating and cooling requires planning that considers whole-system costs and all options in view of local energy resources and demands. Failing to account for these factors can increase the costs of decarbonisation and preclude further CO_2 reductions for many years to come.*

- ***District heating and cooling networks are being installed at a rapid pace and are fundamental for decarbonisation.*** *In combination with daily and seasonal storage, networks open up opportunities beyond co-generation[1] for other low-carbon technologies (such as heat pumps or solar heating and cooling), to participate in energy networks that interact with the electricity and transport sectors.*

- ***Smart heat pumps installed and operated adequately could help accommodate a higher share of variable renewable electricity in addition to delivering high energy and CO_2 savings.*** *Heat pumps are a critical technology for achieving low-carbon thermal comfort in building interiors, and are receiving more attention in industrial applications and in district heating networks. They do not perform well in all instances, however, and can have significant impacts on electricity networks.*

- ***Large quantities of heat are currently wasted in power stations and high-temperature industries, problems that will only increase as emerging economies continue to industrialise.*** *This waste heat can be reused in other industrial processes, adjacent industries or nearby urban areas to provide both heating and cooling.*

- ***Income growth, urbanisation and decreasing household size in emerging economies could vastly increase the need for electricity generation capacity and make decarbonisation more costly.*** *The environmental and financial costs of cooling are frequently overlooked as the current demand is low and relatively few abatement technologies are available.*

1 Co-generation refers to the combined production of heat and power.

- ***Due to the low deployment level of low-carbon heating and cooling technologies, special consideration should be given to promote flexibility and diversity.*** *Technologies that currently have low visibility in the heating and cooling market, including solar cooling, multi-generation and geothermal heat, could play a much more important role in the future.*

Opportunities for policy action

- *Promote policies that encourage the adoption of renewable heating and cooling technologies in appropriate applications, that take into account actual service needs; the technologies they are substituting for; the potential for energy efficiency improvements before adoption of the new technology; or access to district energy networks, sources of waste heat or alternative options.*
- *Encourage the construction and expansion of district energy networks in urban areas. These can serve as a backbone to facilitate the diffusion of low-carbon technologies, and provide co-benefits to the rest of the energy system.*
- *Increase the training and skills of practitioners in the low-carbon building and architects to installers, to ensure technologies are adequately appraised, installed and operated in the right applications, and that the sector transitions occur with minimum cost and impact to the energy system.*
- *Increase interministerial collaboration among stakeholders and disseminate knowledge of energy systems to ensure that decarbonising heating and cooling is compatible with, and facilitates, decarbonisation efforts in other sectors. Independent bodies of experts such as systems authorities should be set up to evaluate policies and progress towards decarbonisation across the whole energy system.*

Heating (and cooling) account for as much as 46% of global final energy demand, yet little progress towards decarbonisation has been made. While energy is an overarching theme of the climate change debate, in practice most of the attention focuses on electricity and transport. Few low-carbon policies explicitly address the provision of heating (or cooling); as a result, the conditions under which low- carbon heating and cooling systems can successfully develop are not well understood.

Electricity is one single product: an energy carrier that is generally distributed through a grid from generators to final users. By contrast, the structure of the demand and supply of heating and cooling[2] is highly heterogeneous. Understanding the nature and magnitude of these services is critical to identifying technologies and solutions that can decarbonise this neglected area of the energy economy.

The main uses of thermal (heating and cooling) energy span all sectors: buildings, where indoor spaces are warmed or cooled to comfort levels and water is heated for various uses; industry, where heat is used to drive industrial processes or machinery; and power, where thermal plants (fossil fuel, nuclear) transform heat into electricity.

Demand for thermal comfort serves as a useful introduction to the complexities in this area. Energy is consumed to warm (or cool) the indoor environment in homes, commercial premises or public buildings to comfortable levels, generally around 20°C (68°F). This demand can be met in several ways.

2 The demand for heating and cooling can be referred to as "thermal" demand.

Fuels can be burned on-site: locally sourced (in the case of traditional forms of biomass), transported (gas, heating oils or biomass pellets) or distributed in a grid (natural gas). Electricity can be used by highly efficient heat pumps to transfer heat for the building from the outside air or the ground, or power electric air conditioners to extract it. District heating and cooling systems send water (hot or cold) through networks of pipes into heat exchangers in buildings. The networks can be supplied in a variety of ways, most commonly with heat from thermal electricity generation or from waste treatment, but also from residual heat from industry or even other buildings, and from a variety of renewable sources. In newly built homes with airtight, highly efficient shells, demand for thermal comfort can be negligible – although an element of external energy (often electricity) is required to ventilate the interior. Finally, heat can be stored at a much lower cost than electricity, in hot water tanks or even in the materials of a building.

This chapter considers the current state of the technologies that supply heating and cooling across all sectors. It assesses the characteristics and likely evolution of the global demand for heating and cooling and what options or technologies exist for decarbonising the supply. Systems aspects form a central part of the analysis, highlighting the need for integrated planning and policy making.

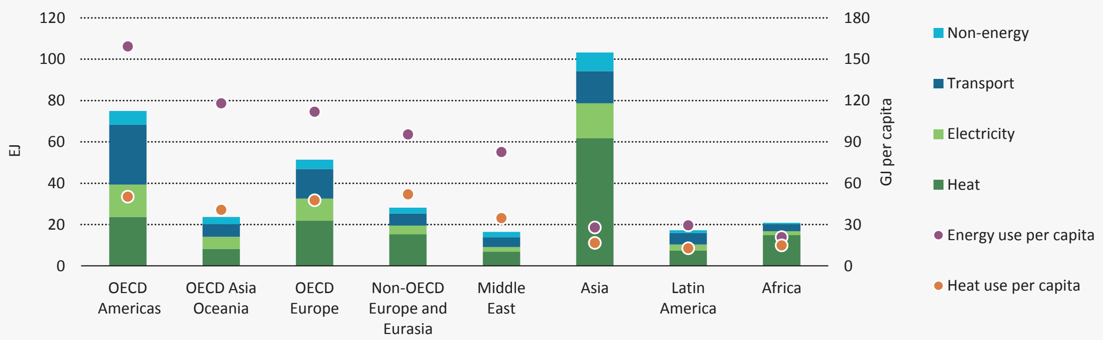
An overview of global heating and cooling use

Energy consumption to generate heat varies with the level of economic development. The highest percentages of total final energy in the form of heat are seen in Africa (71%) and Asia (60%), largely due to widespread, inefficient use of biomass for cooking and heating (Figure 5.1). Developing countries have a high percentage of heat as an energy source: easily accessible, low-cost energy sources are combusted inefficiently, providing minimum comfort in relatively small spaces. In developed countries, higher living standards have brought heating distribution systems to larger living areas, which allows efficient use of more valuable energy sources (*e.g.* gas, electricity). Development is also accompanied by mass motorisation, the electrification of other energy services and a demand for higher temperatures in industry, which requires higher-quality, more efficient fuels – all of which change the relative share of heat in the energy mix. Finally, a strong component of the demand for heat – the demand for thermal comfort – is heavily influenced by climate and geographic location. This does not include only average annual temperatures, but also seasonal and daily variability and other factors such as humidity or hours of sunlight.

Worldwide, 66% of heat is generated by fossil fuels. This share rises in OECD countries to 85% and falls to 57% in non-OECD countries (Figure 5.2). The large proportion of heat generation from fossil fuels in OECD countries is in many cases used to provide low-grade heat services (*i.e.* heat below 100°C), which can be supplied by a wide range of low-carbon alternatives. In Europe, for example, natural gas – which can heat steam up to several hundred degrees – is largely imported and burnt in households to provide space heating, where demand is met at approximately 21°C. It makes little economic sense for low-grade heat services to be provided by expensive fossil fuels when low-grade energy sources are available. Restricting the use of fossil fuels to applications where higher energy quality is required would conserve a precious resource and reduce unnecessary emissions.

The high percentage of combustible renewables in developing countries reflects the use of traditional forms of biomass (*e.g.* wood, waste, cattle dung). While these might seem beneficial when viewed solely in light of their global warming potential, their use decreases indoor air quality and has associated health impacts. Deforestation is also a major environmental concern in many regions of the world.

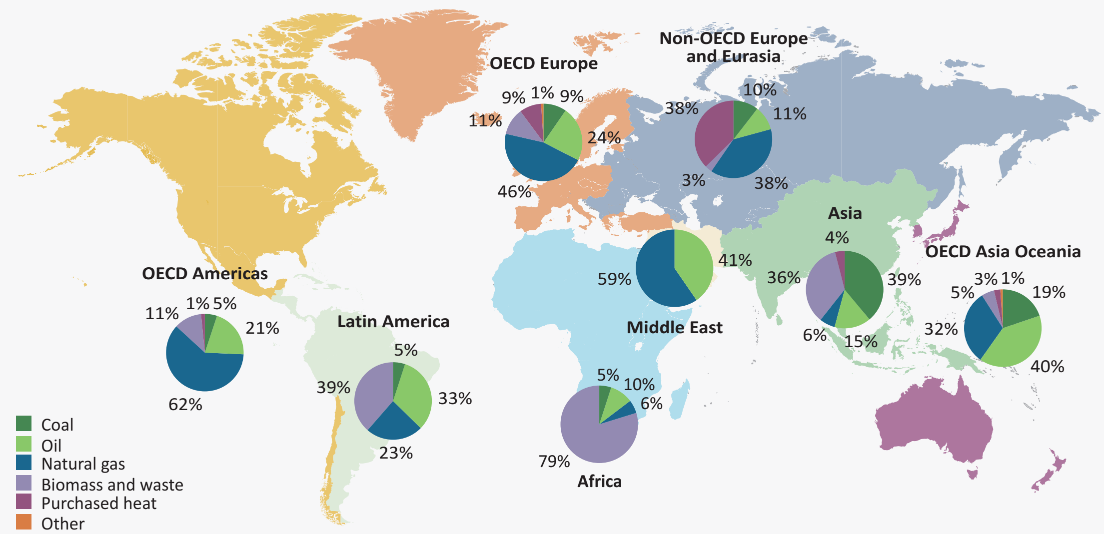
Figure 5.1 Total final energy consumption by region as electricity, heat, transport and non-energy uses, 2009



Note: EJ = exajoule.
Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *The share of energy used for heating purposes in the emerging economies of Asia, Latin America and Africa is relatively high.*

Figure 5.2 Heat generation by region for different fuel types, 2009



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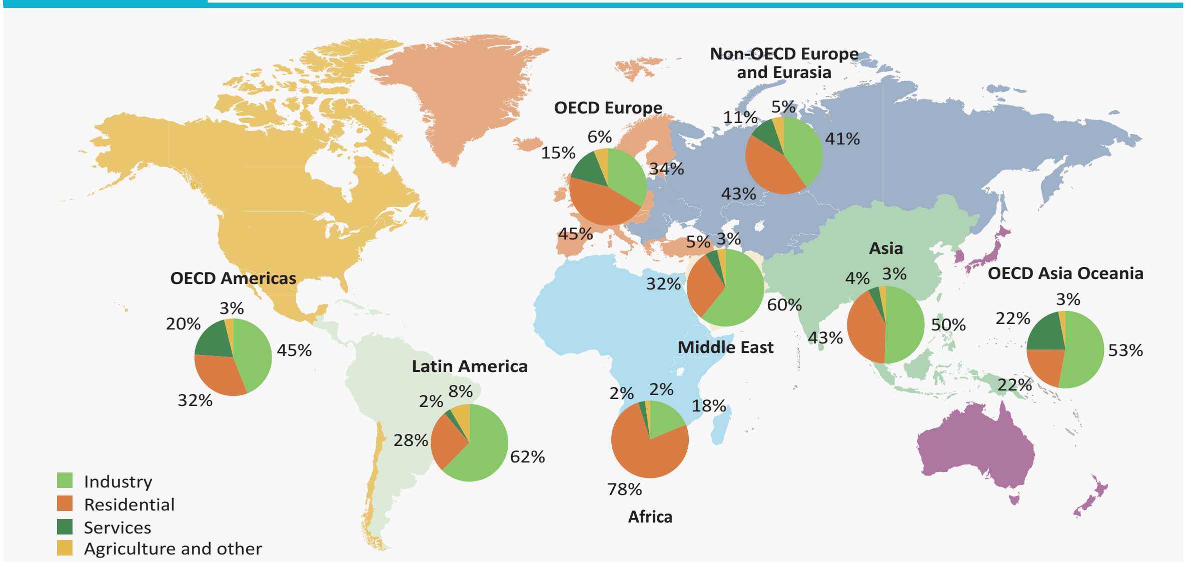
Key point *Fossil fuels dominate the energy mix for providing heating services.*

Traditional biomass sources are often dispersed, and much time and effort is spent, almost entirely by women, to collect firewood or adequate wastes. All of this constitutes a significant barrier to further development due to the loss in productive capability. On the whole, the continued use of traditional biomass is unsustainable in the long term.

In OECD countries, 42% of heat is used in the industrial sector, while the residential sector accounts for 36%. This compares to 46% in each sector in non-OECD countries (Figure 5.3). The outsized proportion of heat used in industry worldwide, 45%, is a result of the huge expenditure of energy required to achieve the high temperatures demanded by many industrial processes, most of which is currently met with energy-dense fossil fuels.

Two main factors determine heat use and demand for cooling in the residential sector: climatic conditions and ancillary uses, such as cooking. The latter is the largest share among all sectors in developing countries, due to the low conversion efficiencies of traditional biomass.

Figure 5.3 Global heat consumption by region in various sectors, 2009



This document and any map included herein are 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 *High-temperature energy demand in industry generally dominates over low-temperature demand in households, commercial premises and public buildings.*

Heat loss in current energy systems

Globally, the large quantities of wasted heat are remarkable, and raise the question of how much of this potential can be successfully tapped to meet heating services that would otherwise be provided in a less sustainable manner.

Current fossil fuel-based energy systems produce high-temperature steam in stationary power plants to drive turbines that, in turn, generate electricity. Different industrial sectors use heat of varying temperatures. Cement kilns require peak temperatures on the order of 1 400°C while the reduction of iron oxide to iron during the smelting process occurs at around 1 250°C. At the other end of the spectrum, processes such as sterilisation in the food industry or drying in the textile industry are achieved under much lower temperatures. In some cases, heat-driven engines generate electricity on-site to drive industrial motors.

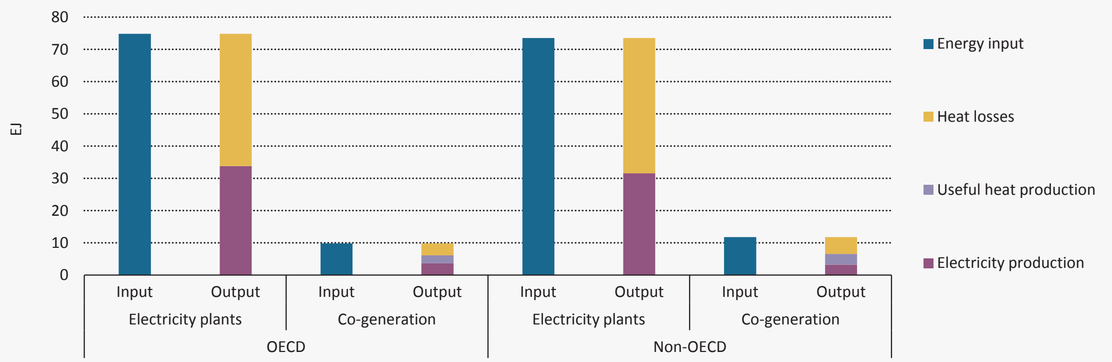
A large percentage of the heat used in these processes is currently wasted – rejected into the atmosphere, water (*e.g.* rivers, lakes, oceans) or the ground. This waste heat can, in many cases, be captured economically and reused to increase process or plant efficiency. Beyond these high-temperature uses, substantial quantities of low-grade heat remain that are suitable for heating building spaces or residential hot water supply, or to provide air conditioning from heat-driven chillers. Capturing and reutilising these large quantities of waste heat efficiently requires district energy infrastructure.

In the power sector alone, 60% of the energy input of thermal power plants in non-OECD countries is wasted in cooling towers and rivers (Figure 5.4). Despite higher efficiencies and greater penetration of heat-recycling technologies, OECD countries have similar absolute levels of heat losses.

These heat losses from electricity generation can be reduced or made useful for other purposes through co-generation (Box 5.4), yet current deployment remains slow. For example, only 10% of power generation in OECD countries is via co-generation; in non-OECD countries, the level is 9%, in this case largely due to the predominance of dated equipment installed during the era of centrally planned economies.

The industrial sector, in both OECD and non-OECD countries, is also characterised by large heat losses. However, the integration of heat at different temperatures and electricity is more widespread in industrial processes than in the generation of electricity. Much of this waste heat is collected and reused, as there are direct economic benefits for industrial users: the net losses are proportionally smaller.

Figure 5.4 **Heat loss in power generation by region, 2009**



Key point *Thermal power plants in both OECD and non-OECD countries emit large amounts of energy in the form of heat to the environment. This heat has the potential to be captured and reused economically with greater use of co-generation, or fed to energy networks to provide heat to buildings or industrial processes.*

Future demand for heating and cooling

Four main trends determine future demand for heating and cooling, and the technologies that can deliver these services: the future need for thermal comfort in residential and commercial buildings; the rate and pattern of urbanisation in emerging economies; the future demand for space cooling in developing regions; and heat demand from industry. The following section will elaborate on each.

Heating and cooling in residential and commercial buildings

The design and insulation of buildings greatly determines the amount of energy intensity (energy per square metre) needed for heating and cooling. The influence of building technology on the amount of energy needed to provide thermal comfort is huge: the *ETP 2012* 2°C Scenario (2DS) incorporates efficiency improvements that halve the heating demand in OECD countries by 2050.

Even where new buildings are typically built with an efficient thermal envelope, their design reflects aesthetic or cultural preferences that are not always well adapted to the actual climate (*e.g.* large, detached houses with inadequate shading and ventilation in hot climates or buildings with expansive glass in cold climates). While renovating or retrofitting buildings to new construction or insulation standards still faces significant barriers in many cases, opting for piecemeal refurbishment in the short term can exacerbate the problem by locking in a sub-optimal building stock for many years to come.

New building construction in many OECD countries is being directed towards zero-energy consumption. Many countries are implementing stringent standards in the near term: for instance, the European Union as a whole has mandated that all new government buildings from 2018 meet nearly zero-energy standards. These standards aim to reduce energy for space-heating demand through more effective building envelope measures (*e.g.* higher R-values, phase-change materials or adaptive windows), passive solar energy and balanced ventilation systems with heat recovery.

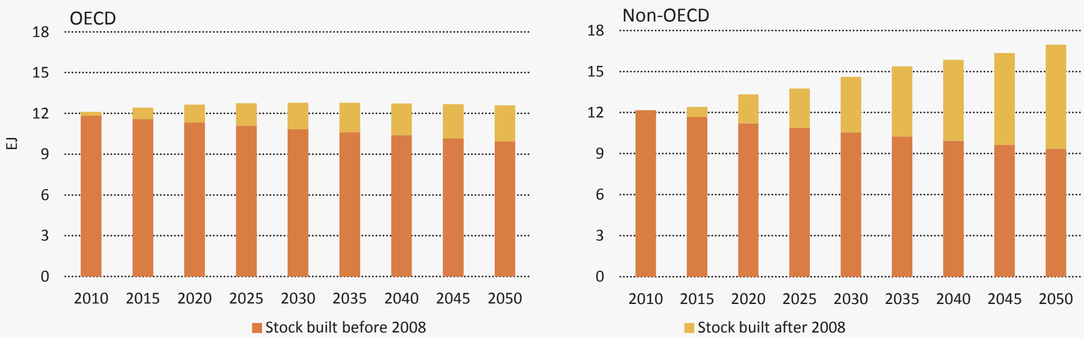
Buildings with such high energy efficiency standards have a much-reduced energy demand to meet thermal comfort, which can be fully met with solar photovoltaic (PV) and some form of storage, or with a low-capacity heat pump. These buildings also reduce the variability and peaking of demand for thermal comfort, thereby reducing the need for investment in standby capacity to heat or cool during periods of extreme weather conditions. The thermal mass of low-energy buildings can itself serve as a buffer to balance excess electricity production and accommodate a higher share of renewables.

In most OECD countries, more than two-thirds of existing older buildings will still be standing in 2050. Energy demand for space heating in OECD countries is expected to remain flat and begin a declining trend after 2020, as a result of new energy efficient buildings in combination with an ambitious annual retrofit of 2.5% for existing buildings (Figure 5.5). An in-depth discussion of these measures can be found in Chapter 14, Buildings. Of critical importance for achieving the 2DS goals, these retrofits need to be carried out in a holistic manner. Piecemeal refurbishments can introduce technologies that provide increased energy efficiency in the short term but may prove incompatible with deeper retrofits, thus delaying and increasing the cost of deeper renovations.

Governments in non-OECD countries face a different set of challenges. As income levels rise, the demand for thermal comfort (heating and cooling) increases, combined with the risk of locking in older technologies in building stocks. However, an estimated 52% to 64% of the building stock that will exist in non-OECD countries by 2050 has not yet been built. The opportunity to build to more efficient standards in these regions is great.

Occupant behaviour is a subject that is often neglected due to its complexity and lack of research base. Analysts increasingly recognise that people's behaviour can have a strong influence on future thermal comfort demand – particularly in lower-carbon systems. Household occupancy declines in all scenarios to 2050, and at faster rates in non-OECD countries, while household floor area increases. When coupled with work patterns typical of OECD countries, the need for constant heating and cooling of spaces throughout the day will fall. Current heating and cooling technologies use fossil fuels or electricity that are able to heat (or cool) building materials quickly, but many low-carbon technologies perform better in buildings with a high thermal mass.

Figure 5.5 OECD and non-OECD energy demand by building stock vintage



Key point *Non-OECD countries face different challenges than OECD countries in reducing the demand for space heating and cooling.*

A second important behavioural aspect in this area of technology policy is the actual perception of thermal comfort. Many current technologies and the policies underpinning their deployment take temperature as the central parameter affecting energy demand (*e.g.* when calculating heating and cooling demand in terms of heating or cooling degree days). Radiant heat from a high temperature source (*e.g.* low surface area, wall-mounted radiators generally associated with fossil fuel boilers) can provide a higher perception of warmth than a heat emitter with a high surface area but a lower operating temperature. The latter is typical of many low-carbon systems, which can lead to their being oversized or over-utilised.

Moisture content can also greatly affect the demand for heating and cooling, as occupants respond differently to different combinations of temperature and humidity. As building envelopes are tightened to reduce heating and cooling loads, moisture build-up will require attention. Not only can it affect the perception of thermal comfort and cause heating and cooling systems to be operated by their users in a manner different than designed, but it could also lead to condensation and decay of building materials.

All of these factors will require more advanced controls than those currently installed in new buildings and retrofits, and a more direct engagement with users of low-carbon heating and cooling technologies. This is an area in which the impacts of a transition to low-carbon energy systems have not yet been fully quantified, and further research is required.

Urbanisation patterns and heating and cooling use

A projected 6.3 billion people will live in cities around the world in 2050, up from 3.5 billion today. In China alone, the number of urban dwellers will double to 1.1 billion (UN, 2011).

In building- or population-dense environments, district heating and cooling systems become feasible because distribution networks are shorter and heat-generating infrastructure is more compact. These infrastructures, which allow large economies of scale and efficiency gains through co-generation and other local heating sources, require a certain density of demand to warrant their capital-intensive investment. Energy sources that are unconventional today, such as waste incineration and waste heat from other heat users, are also more feasible at higher demand densities.

Compact urban development with closely nestled, multi-use buildings and apartments can, however, compromise decentralised low-energy design practices, such as natural lighting, ventilation and decentralised use of solar energy. Higher densities limit the potential of ground-source heat pumps because there are limits to the rate at which heat can be extracted. At very high urban densities, infrastructure costs are sufficiently reduced to warrant investment in deep boreholes that gain direct access to geothermal energy to feed a district heating or cooling network. This also opens up opportunities for underground seasonal storage.

A similar issue occurs with cooling and air conditioning units. In large apartment blocks, they create heating corridors – heat pumped from an indoor environment is ventilated into another adjacent environment and the efficiency of other nearby equipment is consequently reduced.

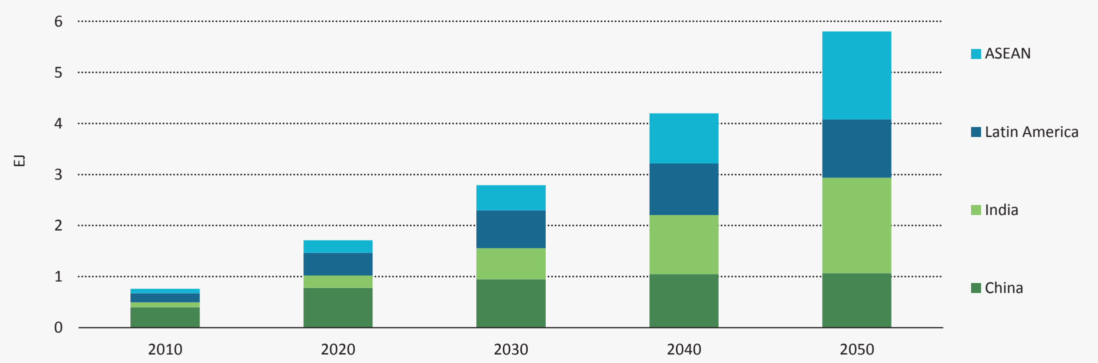
Finally, urbanisation leads to a heat-island effect, in which heat losses from high concentrations of electrical equipment and lighting, from heavy traffic, and from the thermal mass in built-up areas increase ambient temperatures in a city.

The future demand for cooling

Cooling services provide individual comfort and refrigeration in the buildings sector and process cooling in the industrial sector. Energy-use data for cooling, however, is not collected systematically at an international level; it is generally assigned to overall electricity use in the buildings and industry sectors. Unlike space heating, space cooling demand is highly correlated to income. Penetration rates of air conditioning in urban households in China, for example, grew from 2.3% in 1993 to 61% in 2003 (McNeil and Letschert, 2007).

ETP 2012 scenarios estimate the potential and impact of cooling technologies worldwide. Both the penetration of cooling technology in buildings and the energy consumption of each unit are driven by climate, income and urbanisation. At lower per capita incomes, ownership and size of cooling equipment rise quickly in regions with higher cooling degree days where it may be considered a basic need. Even in more developed areas with cooler climates and regions with very few cooling degree days, cooling demand is still heavily driven by income beyond the USD 10 000 per household mark.

Figure 5.6 Estimates of cooling energy demand in selected regions



Key point *Cooling energy demand is projected to increase rapidly in regions where urbanisation is expanding and incomes are rising*

Box 5.1 **Cooling technologies: strategies for curbing cooling demand**

While definite projections on cooling demand are difficult to obtain due to the lack of data and a poor research base, strategic planning and adequate technology in both emerging and developed economies could provide enough flexibility to hedge against these uncertainties.

A first step is action on stringent building codes. In cold and overcast countries (*i.e.* most of OECD Europe), the most common strategy is to use high levels of insulation, make building envelopes tighter and install double-glazed windows. A rising need for cooling suggests that building envelopes should be able to adapt to changing conditions. This is an effective strategy in warmer climates, where buildings could filter air selectively from inside or outside, or use adaptive windows capable of adjusting to solar radiation. Passive cooling strategies, such as evaporative or radiative cooling or natural ventilation, are particularly effective in reducing cooling loads in climates with high daily temperature variations. These decisions, however, need to be made early in the development process.

The 2DS shows that significant savings can be achieved by 2050 simply by upgrading air conditioner, chiller and other cooling systems in residential and commercial buildings to current best available technology (BAT) standards.

This scenario saves 24% of all energy used for cooling in the *ETP 2012* 4°C Scenario (4DS), and 38% in relation to the *ETP 2012* 6°C Scenario (6DS). Other technologies that play an important role in the 2DS include absorption cooling and solar cooling.

Absorption cooling, like other cooling systems, expands and compresses a fluid in a thermodynamic cycle. This technology uses heat (rather than electricity) to drive the compression stage, which allows such systems to be coupled to co-generation units, district heating networks or sources of waste heat. It is well suited to meet cooling demands from the commercial sector in the 2DS at high efficiencies.

Solar cooling – discussed in the section "Decarbonising the heat sector" – shows great potential in the 2DS, achieving a 6% share of final energy demand for cooling in 2050 up from a low base of around a thousand installations as of 2011. The dominant technology uses an absorption cycle as described above, driven by heat captured from solar thermal collectors. Because peak cooling loads generally coincide with periods of high solar irradiation, solar cooling could greatly reduce the impact of future cooling loads on the energy system.

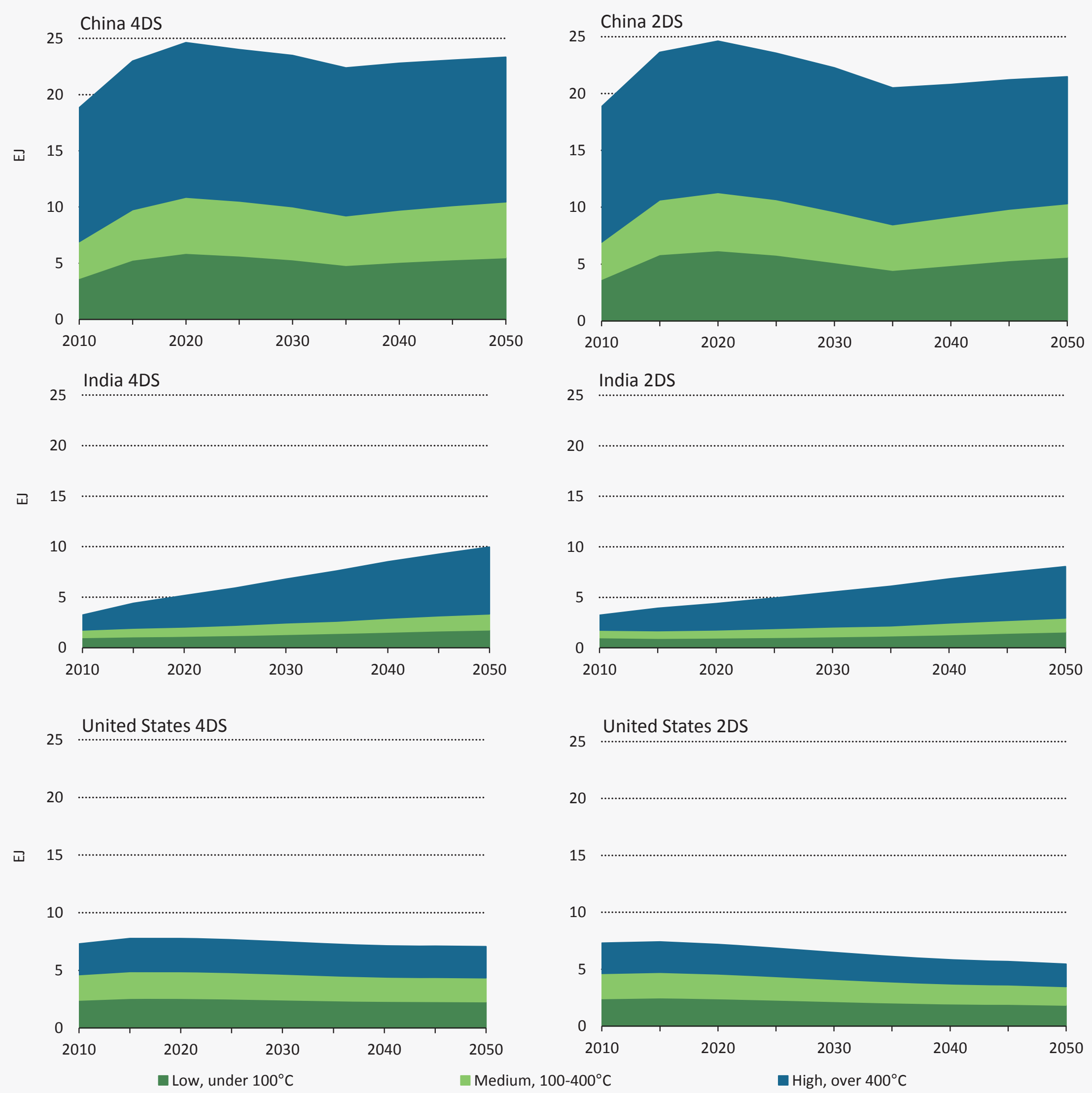
Likely trends for energy demand for cooling in selected regions show that the largest increases will occur in regions with rapid urbanisation and income growth (Figure 5.6), particularly in the ASEAN (Association of Southeast Asian Nations) and India.

Climate change will also increase demand for cooling. Countries with considerable heat demand could experience fewer heating degree days and more cooling degree days. While the net energy delivered might decrease (*e.g.* ADAM, 2009), because there are few alternatives to electricity for providing cooling, the share of electricity in overall energy demand is expected to increase. There remain large uncertainties in current models over the regional impacts of climate change. Nevertheless, some early studies have attempted to quantify these (*e.g.* Isaac and Van Vuuren, 2008), and a similar methodology has been employed in *ETP 2012* models. Over the next few decades, the impact of increasing cooling degree days will be strongest in developing Asia, where a combination of rapid urbanisation and rising incomes sets the scene for a strong and rapid increase in cooling demand.

Heat demand in industry to 2050

The central role of temperature in industrial energy demand and in the future potential for low-carbon technologies cannot be overstated. The laws of thermodynamics show that the value of a heat source and the cost to supply a heat load are closely associated with the temperature level. Two sources of heat can carry the same energy content, but more useful work can be obtained from the higher temperature source. By the same law, elevating a flow of heat to a higher temperature requires great energy expenditures, with concomitant thermodynamic losses. The 2DS and 4DS show the demand for, and availability of, heat by temperature level up to 2050 for three regions: China, India and the United States (Figure 5.7).

Figure 5.7 **Industrial energy demand by temperature level in selected regions**



Key point *The demand for temperature varies with the industrial structure of each region.*

The United States is a mature economy where heat demand has been declining due mainly to energy efficiency improvements and changes in industrial structure. China shows a much greater magnitude of heat demand, with the greatest share of heat generation going to the high-temperature requirements in the cement, and iron and steel sectors. Due to a future decrease in construction activity plus further improvements in energy efficiency, the *ETP 2012* scenarios project a decline in heat demand beyond 2020, particularly from higher-temperature industries.

The industrial sector in India shows expected large growth in high-temperature industries; similar trends are expected in other fast-growing developing countries in Asia. These regions show the largest potential from waste heat integration, heat cascading and co-siting options (see below, "Industrial co-generation and waste heat").

Decarbonising heating and cooling

The successful decarbonisation of the heat sector lies in developing a locally based merit order of energy sources that addresses the particular characteristics of local energy demands. Thermal comfort varies seasonally and daily; thus, from a technology and policy perspective, it should be separated from other, process heating demands that have a flatter load profile (*e.g.* industrial heat or hot water demand in buildings) and interact in a different manner with the rest of the energy system.

These demands must be matched to locally available energy resources. First in the merit order are energy efficiency measures to reduce the absolute level and manage peaks in demand for thermal comfort. Efficiency measures can be viewed as a resource with a local potential and local costs, depending on the age and construction types of residential, commercial and industrial building stock. Technologies that can exploit the energy efficiency resource are discussed in depth in Chapter 14, Buildings.

Second are locally available sources of heat, which include industrial waste heat, heat from thermal power generation or heat from buildings themselves (particularly retail complexes or data centres). Heat networks are required to connect these resources with consumers of heating and cooling services; such networks function best in high-density areas where demands are concentrated and diverse. These networks also offer larger potential for other, low-grade heat resources including renewable heating and cooling technologies and large-scale heat pumps, all of which show higher efficiencies in these larger applications. In areas with lower densities or where heat networks are impractical, distributed technologies including micro co-generation or heat pumps can play a central role.

This idealised vision outlines the main parameters of a sound energy policy that aims to increase efficiency and decarbonise the heat sector. Unfortunately, it belies much of the real complexities in applying low-carbon technologies for heating and cooling, which are discussed for each solution in depth in the following section.

District heating and co-generation of heat and power

Locally available sources of heat can be tapped to feed into building heating networks. While co-generation has historically been an effective match (Box 5.4), technology improvements now allow a variety of increasingly lower temperature sources to be linked to consumers via heating networks. These include waste heat from industrial sites or nearby power stations, geothermal heat, solar thermal heat, biomass combustion and heat pumps – all of which can be fed into networks of insulated pipes and substations to distribute heat to customers. Networks can vary greatly in size and load, from small networks servicing industrial parks to entire cities, as in the case of Copenhagen, Stockholm and Malmö. The adequacy of district heating as a low-carbon option depends on the size and characteristics of the heat load served, the energy demand density of the area, the availability and quality of heat sources, the combustion of specialised fuels, and the temperature of the heating service being met.

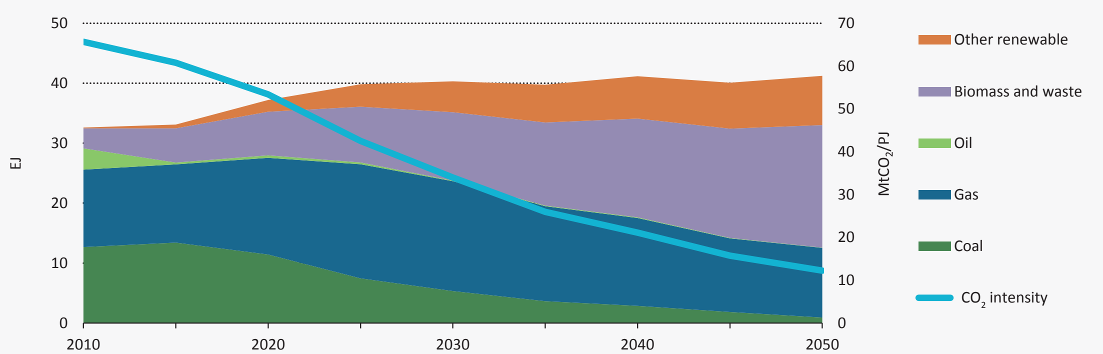
Because the transmission and distribution (T&D) infrastructure accounts for a large proportion of the costs of district heating systems (Mancarella, 2011), a higher density of demand generally favours district heating. Advances in technology now make it possible to implement or extend district heating networks with low distribution temperatures to heat loads in sparser areas (IEA DHC, 2010; Persson and Werner, 2011). Different heat sources can be tailored to variable heating (and cooling) loads, producing a highly efficient and flexible utilisation of resources to provide the required service.

This flexibility of services provided by district heating and cooling should be an important consideration in developing energy policies for a future with many uncertainties and challenges regarding technology development, fuel availability and prices, environmental impacts, and power plant siting.

As with the electricity network, there is great scope for decarbonising heating and cooling via thermal grids. District energy infrastructure has already enabled relatively swift transitions in primary energy consumption. For instance, starting in 1980, Sweden has accomplished a shift in its energy mix, largely facilitated by district heating, with the result that oil dependency plummeted from 89% in 1980 to just 7% in 1990. By 2000, 61% of the energy input to district heating systems came from renewable sources; as of 2008 it had increased to 77%.

The 2DS shows that such aggressive action is possible at a global scale and at a comparable pace. In the 2DS, the carbon dioxide (CO_2) intensity of district heating and cooling networks in 2050 is one-sixth that of existing systems (Figure 5.8). Biomass and a mix of other renewable energy sources make up almost three-quarters of primary energy consumption in 2050. While the primary energy input to district heating networks does not show a sustained increase in the 2DS, due to improvements in the efficiency of the building stock to reduce space heating and cooling loads, the share of district energy networks in useful energy demand in buildings is in fact doubled in the period from 2010 to 2050.

Figure 5.8 Fuel mix and CO_2 intensity of district energy networks in the 2DS



Key point *The use of renewable heating and cooling in district energy networks drastically reduces carbon intensity by 2050.*

Even where district heating makes environmental and economic sense, its wider use has barriers that must be addressed to achieve the technology penetration in the 2DS. For example, necessary road works and retrofitting buildings to connect to the network creates planning issues. Where regulation has opened up district heating networks to third parties, their presence arguably improves the potential for competition in heating and cooling: each producer can then sell thermal energy to the network. In practice, profitability often depends on a large share of customers in the area joining the scheme, which might lock out other alternative solutions that might otherwise have been more beneficial from a systems perspective.

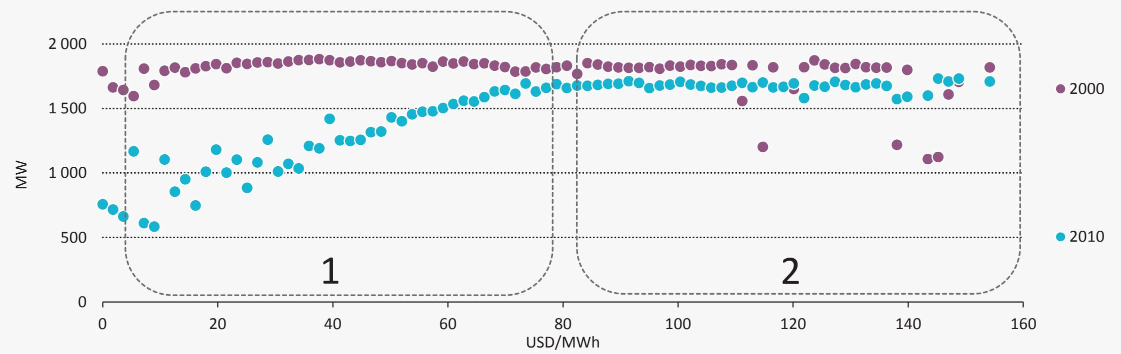
Box 5.2 Integrating heat and electricity: wind and co-generation in Denmark

Nordic countries are pioneering many forms of energy networks, including heating and cooling networks that use surplus heat. Denmark is a leader in this effort: district heating accounts for 62% of final electricity and heat demand. At the same time, variable renewables have reached a high penetration, with wind power meeting 31% of final electricity and heat demand.

Recent regulatory changes in Denmark made it possible for co-generation plants to sell produced electricity in the power market, leading to positive synergies between heat and electricity. During periods of high electricity prices arising from low wind power availability, co-generation plants feed electricity into the grid and store heat in large accumulators or in the heat networks themselves (Figure 5.9, Period 2). Conversely, during periods of surplus wind generation (resulting in depressed electricity prices), output from co-generation plants is lowered and heat demand is serviced from the stored capacity (Figure 5.9, Period 1). High-capacity direct electric boilers provide additional capacity to make use of the low-carbon, low-price electricity.

This serves as an early example of the co-benefits of integrating a variety of energy demands and vectors. It also shows how such efforts will require a new regulatory environment and a hierarchy of control levels responsive to a variety of signals from suppliers and consumers.

Figure 5.9 Integration of co-generation and district heating in electricity markets in Denmark



Key point *Integrating several sources of generation and various demand vectors can create system-wide benefits.*

Heat pumps

As the supply of electricity undergoes rapid decarbonisation in the 2DS, the use of electricity to meet future demand for thermal comfort and water heating offers significant potential to reduce emissions. Electric heat pumps are the preferred technology when considering the electrification of low-temperature heating demands (space, water heating and some industrial heating demands).

Direct electric heating, powered by electricity generated on-site or drawn from power grids, is widespread, generally found in regions and periods with low electricity prices at the time of construction (Norway, Canada, France) or chosen due to low heating loads (central China). Direct electric heating can only deliver as much heating as electricity consumed, and because transforming other sources of energy into electricity is a costly and often inefficient process, these options do not generally offer sustainable solutions and already face restrictions in many countries. In the 2DS, electric boilers have some role in district heating networks as backup capacity (Box 5.2).

Heat pumps, however, show strong potential in the 2DS in the right applications. Meeting the levels of deployment envisaged in that scenario, however, poses significant challenges to the way heat pumps are designed, installed and operated within the overall energy system.

Heat pumps are essentially air conditioning units working in reverse: they extract thermal energy from outside the conditioned space, upgrade it to a useful temperature and deliver it to the conditioned space. To do this, they employ some form of energy to power a thermodynamic cycle (Box 5.3) – usually electricity, but also heat in absorption heat pumps, *e.g.* from gas combustion. Heat pumps can be classified by the heat source they draw upon: the surrounding air, the ground or a nearby body of water. In a ground-source heat pump, plastic tubes are looped either horizontally over several hundred square metres, or vertically in a borehole 100 to 200 metres deep.

Transforming other sources of energy into electricity is a costly process that can be inefficient when compared to other sources of heating such as direct fossil fuel combustion. When heat is delivered by a heat pump, the system is able to compensate for this, since when functioning adequately, heat pumps deliver more energy in the form of heat than they require in the form of electricity. (The total system efficiency of providing heat with heat pumps compared to other heating technologies is discussed later in this chapter [Box 5.4]).

Heat pumps are generally designed and manufactured using an instantaneous measure of efficiency at a given temperature under test conditions (the coefficient of performance). The coefficient of performance often also determines the level of policy support for heat pumps. In practice, their performance is better captured by the seasonal performance factor (SPF): the proportion of useful thermal energy delivered relative to the electricity consumed by the heat pump over the whole year. This is because the performance of a heat pump is proportional to the temperature difference between the evaporator and the condenser element, which varies continuously over the course of the season. On colder days of the year this difference is greater, which results in lower system efficiency.

Ground-source heat pumps generally exhibit higher SPFs because the ground temperature stays relatively constant throughout the year (Figure 5.11). Air-source heat pumps, the fastest-growing family of heat pump technologies, are more susceptible to these effects as air temperature varies more from season to season, leading to generally lower efficiencies.

Box 5.3 Heat pump technology

In residential heating, heat pumps are generally used to tap freely available low-temperature heat sources and transform them into higher-temperature useful heat for heating systems (*e.g.* under-floor heating, wall-mounted radiators or ducted air systems). In specific applications, heat pumps can provide domestic hot water (65°C), usually in combination with a relatively high-temperature heat source, such as exhaust air.

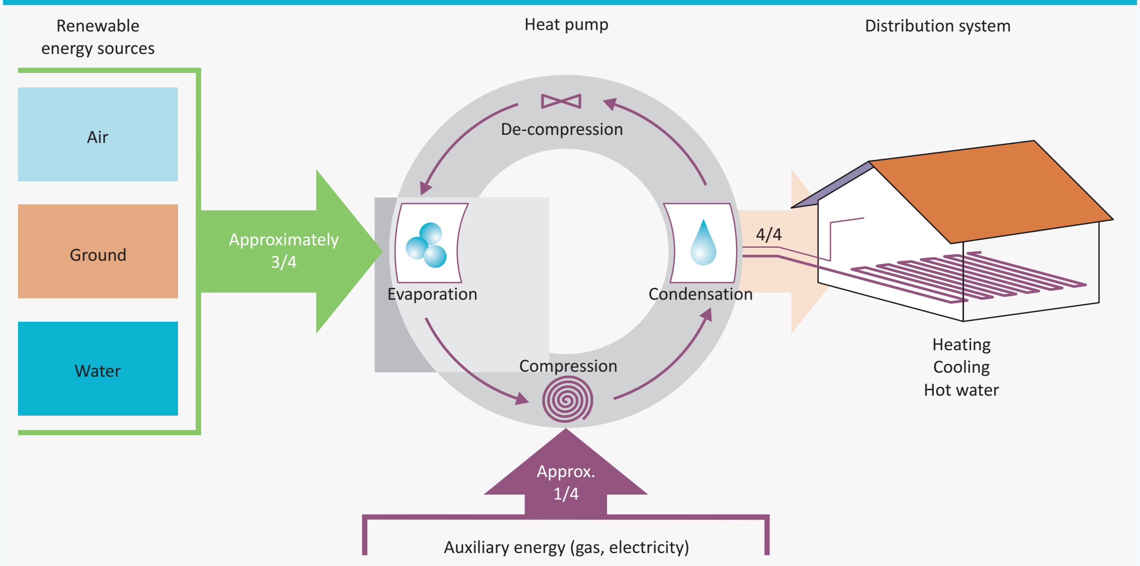
The general operating principle in the more common compression heat pumps is that when a gas is compressed, its temperature rises. The heat pump process is essentially a four-step cycle:

1. A closed circuit containing a working fluid with a very low evaporation temperature is confronted with the external heat source (*e.g.* ground water of 10°C), which causes the working fluid to evaporate.
2. The evaporated working fluid is then compressed by a source of power, usually electricity.
3. The compression is carried out to the extent that the rise in temperature is sufficient to heat water within the central heating system (by means of a heat exchanger). The hot vapour enters the condenser, where it condenses and gives useful heat.
4. Pressure is lowered in the expansion valve and the vaporised working fluid returns to its original state.

The working fluid then re-enters the evaporator and the cycle starts over again (Step 1).

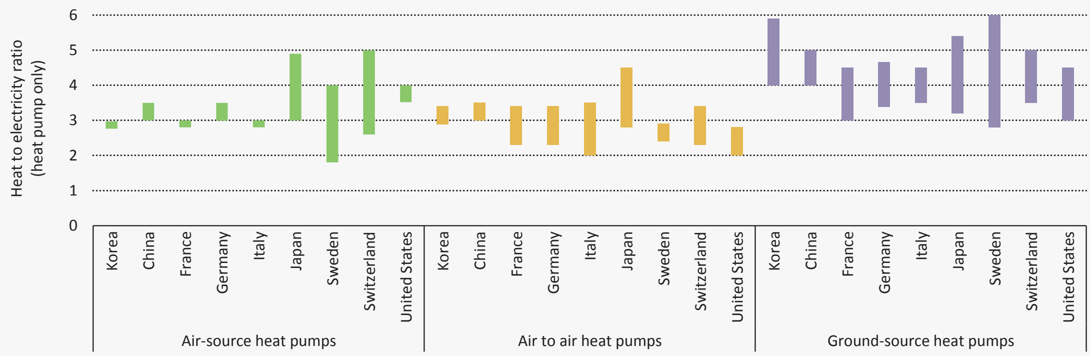
Figure 5.10 demonstrates how heat pumps work as well as the sources (air, earth, water) from which they can extract heat. It also shows the relative shares of energy extracted from the heat source and the additional energy needed to make this heat useful. In this case, the relative share is three units of energy of the heat source and one unit of additional power (usually conventional electricity). The type of heat source and its temperature range influence the amount of additional energy needed to produce useful heat. The ideal heat source has a high and stable temperature during the heating season.

Figure 5.10 Heat pump technology



Key point *Heat pumps use a relatively small amount of electricity to extract heat from the air, water or ground.*

Figure 5.11 Representative efficiencies of air- and ground-source heat pump installations in selected countries



Key point *The efficiency of heat pump technologies varies greatly by region and specific installation, and is generally higher for ground-source heat pumps than for air-source heat pumps.*

Alternative design options exist for heat pump systems used for space heating and cooling and for water heating. The heat pump can be sized to meet the full demand, including peak loads. Heat pumps, however, are not well suited to meeting instantaneous changes in heating or cooling loads: such response requires large water tanks and careful sizing and optimisation (an example of system integration). An alternative approach is to include an additional method of heating (typically a resistance heater) to meet building needs when the external temperature is low, and to meet short-term peaks and other supplementary needs. Supplying some portion of the load with an electrical resistance heater will reduce the overall SPF of the domestic system.

Because their cost scales quickly with greater capacity, current heat pumps are not sized for peak demand during the cold season. Instead, they rely on backup capacity, often in the form of direct electric heating. When a heat pump cannot modulate its output fast enough or when it is unable to raise the temperature to the required level, ancillary backup capacity covers the shortfall, which reduces the overall efficiency of the system. Technology developments can overcome some of these deficiencies; much progress has been made in recent years in inverter-connected systems capable of continuous modulation.

Due to the widespread use of fossil fuels for heating buildings, many have "wet" heating systems (*e.g.* radiators) that put out heat from a small surface area. Such systems must operate at higher temperatures to maintain the thermal comfort required. Heat pumps perform better when heat can be distributed at lower temperatures. In new houses, under-floor or forced-air distribution systems can easily be incorporated during the design phase. Retrofitting existing buildings by replacing radiators with such lower-temperature distribution systems adds significant additional cost and considerable inconvenience for the occupants.

Box 5.4 Heat pumps versus co-generation

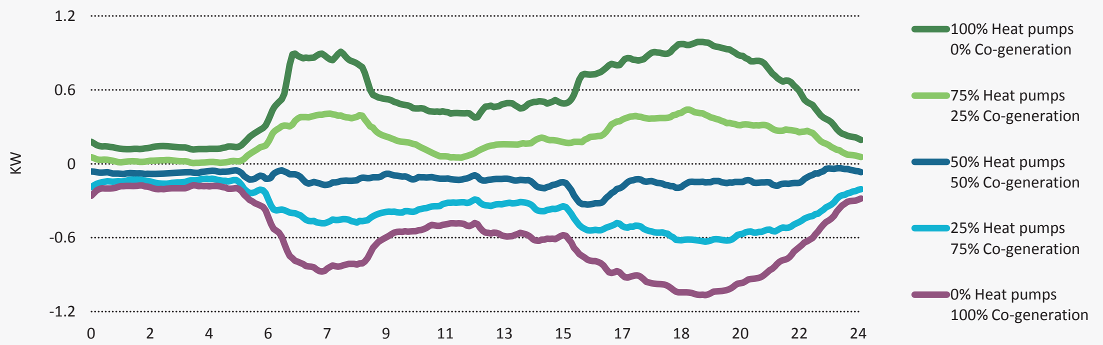
Heat pumps and co-generation are often seen as conflicting technologies. In a co-generation unit, waste heat from the thermal generation of electricity can be reused to maximise the production of electricity, or some can be extracted and fed to a district heating network – at a cost in relation to the efficiency of electricity generation. The ratio of the extracted, usable waste heat to the reduction in electricity generation efficiency is called the Z-factor or Z-ratio, and is equivalent to the coefficient of performance of a heat pump. The higher the Z-ratio, the higher the proportion of heat generated for every unit of electricity lost or used.

This ratio allows, in principle, a direct comparison between the two technologies. In the district heating network in Malmö, Sweden (typical of Northern Europe), a 450 megawatt-electrical (MW_e) combined cycle gas turbine (CCGT) co-generation plant produces 90°C supply temperatures for the network. A Z-ratio of seven can be calculated from data measured on-site (Kemp *et al.*, 2011). Building-scale heat pumps powered by electricity from an equivalent CCGT electricity-only plant would need a coefficient of performance of seven or better to deliver heat with comparable efficiency.

This specific case illustrates the need for strategic local planning that takes into account a broad variety of parameters to achieve a low-carbon heat supply. District heating networks can be fed by a variety of sources beyond co-generation, including low-grade waste heat. This reduces the need for a co-generation plant, which remains a relatively large and inflexible investment with high up-front costs. Larger heat pumps (like larger co-generation plants) have higher efficiencies and can be used to upgrade the temperature of many waste heat sources, making them suitable for use in district heating networks.

Co-generation – whether or not it feeds district heating networks – and heat pumps or other electric heating have important synergies in a future smart electricity grid. A balanced mix of co-generation units and heat pumps, both connected to the local electricity grid, can work together to reduce peak electricity loads and minimise investment needs (Figure 5.12). With smart control, heat pumps and other electric heating would draw electricity to produce heat at the same time as the co-generation units generate electricity. In summer, absorption chillers coupled to the co-generation units and heat pumps operating in reverse to provide cooling would offer the equivalent effect.

Figure 5.12 Electricity load profile of a set of houses employing a mix of heat pumps and co-generation to meet space-heating needs



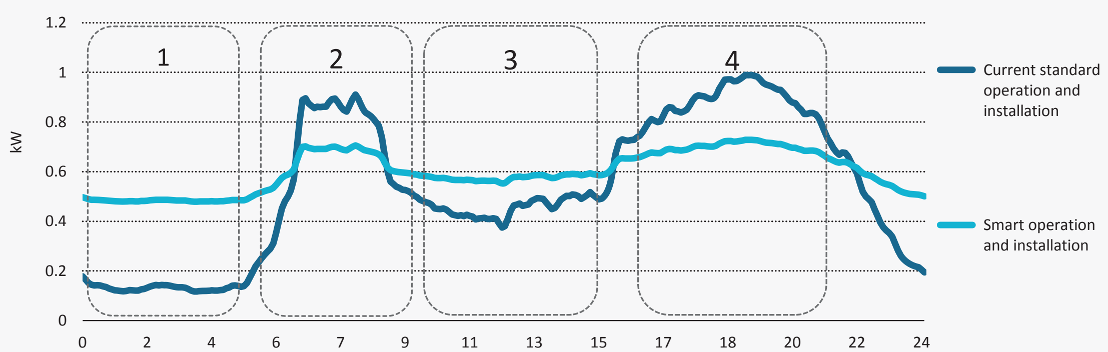
Key point *Compared to deployment of only one technology, the simultaneous use of co-generation and heat pumps flattens the load profile and reduces the upstream impact of both distributed energy technologies on the electricity system.*

Heat pumps in future electricity systems

Electrifying a significant portion of heating and cooling services could have an important impact on electricity systems that are required to meet demand during peak periods. The peak power demand of a domestic heat pump is typically 3 kilowatts (kW) to 8 kW for an individual household. The impact on peak grid demand would be less than the direct sum of all these heat pump capacities in the system, since not all of them would operate simultaneously at a given peak.

ETP 2012 has developed case studies for the 2DS that evaluate the increase in peak demand from a high penetration of heat pumps in OECD countries with high heat demands. The base case assumes aggressive deployment of heat pumps to 2050, and requires sustaining the current 28% annual growth rate of heat pumps in the European Union. By 2050, heat pumps would deliver 38% of useful energy demand for space heating in the OECD region.

Figure 5.13 **Electricity load curve in the high-penetration base and smart case studies**



Key point *A high penetration of heat pumps could place significant additional load on electricity networks. Good design in adequate applications, smart operation and storage can mitigate these impacts.*

Peaks in demand from heat pumps are likely to occur more often in winter, which coincides with peak demands for electricity for other uses. If heat pumps are operated on a time-of-day cycle, similar to many central-heating timers, the additional demand would coincide with traditional morning and evening demand increments (Periods 2 and 4 in Figure 5.13), adding to the burden on peak electricity capacity. In fact, because they operate at relatively low temperatures and have a lower rate of heat delivery, such operation profiles are a worst-case scenario for heat pumps and could lead to an average additional peak electricity demand of 22% in the OECD region.

Meeting the increased peak electricity demand in such a scenario would require additional investment in electricity generation assets, mainly involving peaking plants with low annual operational hours. The resulting changing demand profiles would also require reinforcements to electricity T&D networks. Smarter operation of heat pumps, combined with efforts to reduce overall heating needs, can counter this risk of increased demand

– and transform heat pumps into active players in the energy system. More efficient building envelopes, together with advanced measures (such as phase-change materials in insulation), provide the thermal mass necessary to maintain a flatter operational profile for heat pumps. In conjunction with advanced controls and ancillary storage, and supplemental technologies, heat pumps can be operated to offer demand-response (DR) services (see Chapter 6).

In such a scenario, heat pumps operate during periods of lower demand or with excess low-carbon electricity (Periods 1 and 3 in Figure 5.13), and make use of thermal storage or the building envelope to maintain a flatter operational profile.

It should be noted that the benefits of "smart" heat pumps deliver diminishing returns as the penetration increases because there are limits on how flexibly they can operate while maintaining comfort levels.

Nevertheless, any scenario with a significant share of heat pumps requires network reinforcement, which has the potential to disrupt road transport and other services. Installing smart meters and building-scale energy systems can provide the necessary control for smart operation but adds to the cost and hassle factors of this transition. Because of the sensitivity of their performance to installation and operation, heat pump installation needs to be assessed holistically with other measures in order to minimise their impact on electricity networks.

Indeed, to achieve the penetration levels and efficiencies of heat pumps in the 2DS, they would have to become the dominant heating technology in new housing without access to energy network infrastructure. In addition, around one-quarter of the existing housing stock would have to be refurbished to high building envelope standards by 2030 to allow heat pump installations to reach a high coefficient of performance.

Crucially, to ensure appropriate sizing, installation and optimisation, the skills of the current installer base must be greatly enhanced. Particular focus must be placed on energy systems training, and holistic design and operation. Installers must ensure that heat pump installations are fit for the purpose, and end users must learn to manage thermal comfort and system issues.

Industrial co-generation and waste heat

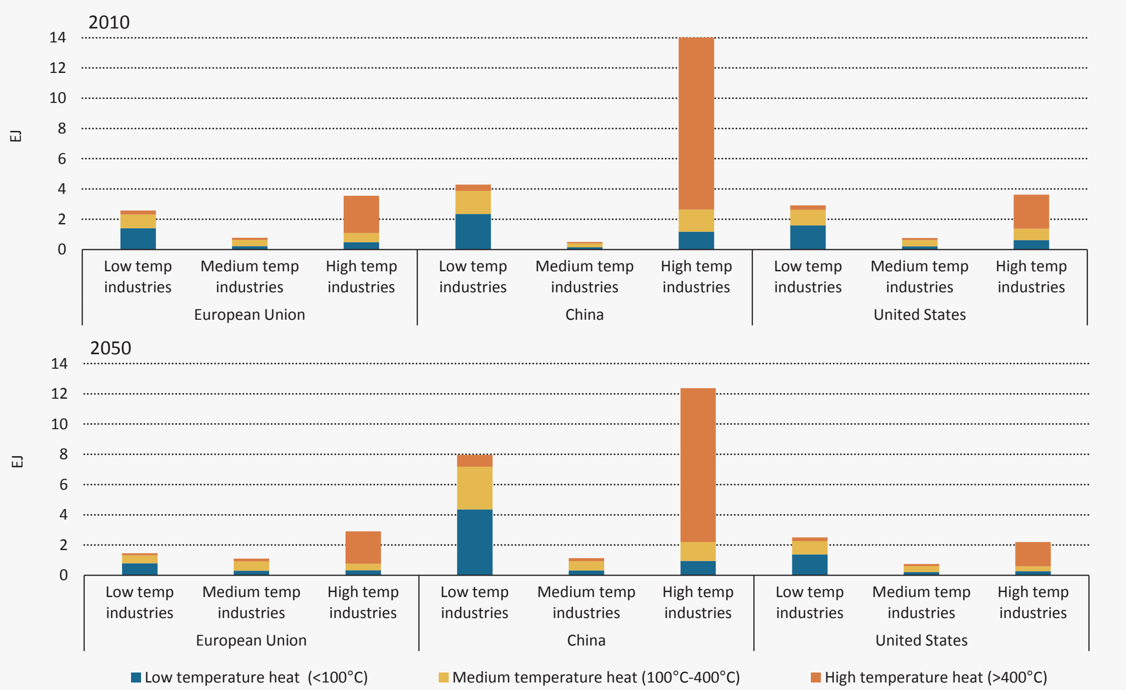
While progress in the integration of energy demands in industry has been considerable, the expected large growth in industry in many non-OECD regions warrants a deeper look at the potential for low-carbon heat generation in industry. Co-generation deployment in emerging economies, and the potential for integrating heat inflow and outflow from different industries (also called heat cascading) emerge as important options.

Industries require heat at different temperatures, which can be broadly classified as low (<100°C, *e.g.* the peak temperature demand for food and tobacco manufacture), medium (100°C to 400°C, *e.g.* pulp and paper) and high (>400°C, *e.g.* iron and steel).

An analysis of two OECD countries – Canada and Japan – reveals the large quantities of energy that industries requiring high temperatures expend to achieve sufficient heat, with concurrent high energy losses (Figure 5.14). Particularly as non-OECD countries undergo greater industrialisation, substantial energy and economic benefits could be realised by creating integrated industrial parks where high-temperature industries are sited near low- and medium-temperature industries. This would allow the waste heat from high-temperature industries to provide inflow to the processes of low-temperature industries. While there are some real-world examples of such initiatives in Northern Europe and elsewhere, the level of strategic planning and stakeholder integration required, as well as regulatory obstacles, have prevented a higher level of deployment.

Within the low- and medium-temperature industries, there is more potential for heat cascading within the industries themselves as most have a wide variety of process heat demands.

Figure 5.14 **Heat demand in industries using variable heat temperatures in selected regions**



Key point *The variety of temperatures in different industrial sub-sectors holds great opportunity for heat cascading.*

Trends of increased co-generation and use of waste heat are expected to continue to 2050 in both OECD and non-OECD countries. It should also be noted, however, that industries often use high-temperature steam to meet demands that could be serviced at lower temperatures. In the long run, restructuring many of these industrial processes may be cost-effective and beneficial to the overall energy system, but high up-front costs present a significant obstacle.

Geothermal heat

Geothermal energy is thermal, renewable energy stored in the earth in rock or trapped as vapour or liquids (water or brines). It can be used to generate electricity and provide heating and cooling with very low levels of GHG emissions. Direct-use geothermal applications include mature technologies to provide heat for industrial processes, space conditioning, district networks, swimming pools, greenhouses and aquaculture ponds. In Iceland, where there are favourable geologic conditions and efficient hot-water distribution networks, 88% of all households use geothermal heat (produced mostly in co-generation plants). Other OECD countries using geothermal for district heating include Austria, Belgium, Denmark, Germany, Hungary and Slovakia.

Recent rapid increases in the numbers of geothermal heat-only plants and in geothermal co-generation binary plants in northern Europe confirm that interest is growing. Several Eastern European countries that now face the need to renovate ageing district heating systems realise that they are located above or close to deep geothermal aquifers. Even tropical countries, such as the Philippines and Indonesia, are becoming aware of the potential benefits of geothermal heat for agricultural applications (such as crop drying) or food cooking. The projection for geothermal heat use in the 2DS is related to the development of advanced hot rock technologies, which will benefit from co-generation increasing their economic viability.

Solar heating and cooling

Solar thermal collectors produce heat from solar radiation by heating a fluid that circulates through the collector. Solar thermal panels producing low-temperature heat (less than 80°C) are widely available commercially. By the end of 2008, global installed solar thermal (low- and medium-temperature) capacity totalled 152 gigawatt thermal (GW_{th}). Almost 90% of this capacity is in China (88 GW_{th}), Europe (29 GW_{th}) and OECD North America (16 GW_{th}), the three regions that show the largest growth in solar thermal capacity in the 2DS.

In certain countries (*e.g.* Israel and China), solar water heaters are already a mainstream technology, with markets showing self-sustained growth without any financial support or price-affecting mechanism. In warm-climate countries, electric water heating can account for large shares of electricity demand. In South Africa, hot water production is responsible for one-third of the power consumption of the average household, contributing to peak power demands and occasionally leading to power blackouts (IEA, 2009). In these countries, solar water heaters are a simple and affordable solution to reduce power capacity requirements. In Israel, replacing electric boilers with solar water heaters saved an estimated 4% to 8% of total annual electricity demand.

Solar thermal energy is not limited to water heating. At present, Austria, Germany and Spain have sophisticated markets for different solar thermal applications. These include systems for space heating of single- and multi-family houses and commercial properties, as well as a growing number of systems for air conditioning, other cooling and industrial applications.

Low- and high-concentrating technologies can deliver medium- and high-temperature solar heat for industrial processes. Rooftop solar thermal panels producing medium-temperature heat (up to 150°C), such as the compound parabolic concentrator collector, are still in the early stages of development, although some are available on the market. This collector is a low-concentrating technology that can bridge the gap between the lower temperature (<80°C) solar application field of flat-plate collectors and the much higher temperature (>200°C) applications of high-concentrating technologies. High-concentrating solar thermal technologies can generate high enough temperatures to produce electricity, but can also be used in (process) heat applications.

As with other low-carbon heating and cooling options, solar thermal technologies can realise a greater potential in energy networks, and are a central component in decarbonising district heating networks in the 2DS. Already by the end of 2009, 115 solar-supported district heating networks and 11 solar-supported cooling systems with an installed capacity of 350 kilowatt thermal capacity (kW_{th}) were installed in Europe. The 2DS assumes that new low-temperature district heating networks are supported by similar shares of solar thermal.

Bioenergy for heat generation

Modern biomass combustion to produce heat is a mature technology and, in many cases, is competitive with fossil fuels (IEA, 2007). Modern on-site biomass technologies include efficient wood-burning stoves, municipal solid waste incineration, pellet boilers and biogas. Biomass is also used in co-generation, which is more efficient than electricity or heat alone. Where the heat can be usefully employed, overall conversion efficiencies of 70% to 90% are possible.

Common feedstocks in biomass-fired co-generation plants are forestry and agricultural wastes and the biogenic component of municipal residues and wastes. Sweden is the largest consumer of wood and wood waste for district heating, followed by Finland and the United States. Denmark, Germany and Sweden are the largest users of municipal solid waste incineration for district heating.

An alternative to providing heat directly through combustion of biomass resources is to produce a biomass-derived gas. The anaerobic digestion of biomass to biogas (consisting of methane, CO_2, water and other chemical compounds) occurs when biomass decays in the absence of oxygen. This process is applied to organic waste in landfills, for example, and has also been commercialised in the form of dedicated biogas digesters fed with manure, organic waste and energy crops. Biogas digesters can have a capacity of a few kilowatts (household size) to several megawatts in commercial agricultural biogas plants. Alternatively, it should also be possible to produce gas by the thermal gasification of biomass, although such processes are less developed than anaerobic digestion. Biogas can be burned for heat-only purposes or in co-generation plants; after refinement, it can also be fed into gas networks and substituted for natural gas.

Integrated energy networks

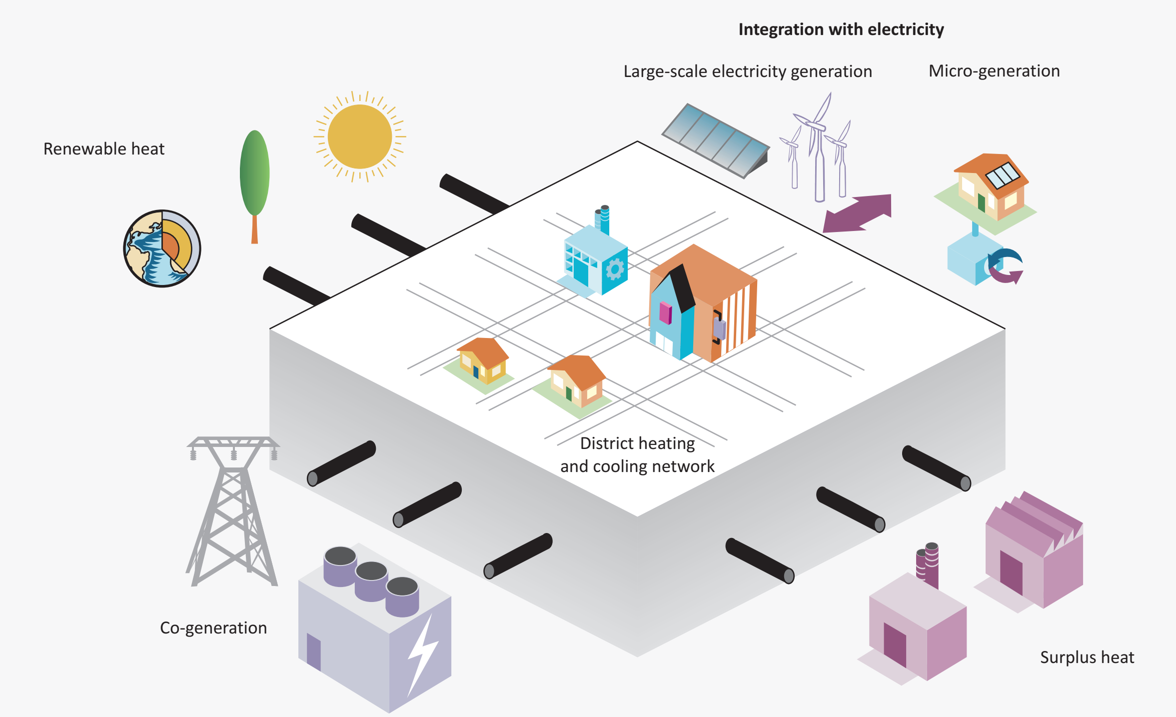
Current energy systems have developed in a largely unconnected manner, in parallel with an infrastructure that supplies fuels capable of delivering high-temperature heat to provide services of different temperatures in homes, power stations, industries and vehicles. Future low-carbon systems should be customised to use a variety of energy sources with different – and generally lower – temperature capacities and different regional, daily and seasonal availabilities (Orecchini and Santiangeli, 2011).

All possible energy carriers should be considered in conjunction with in-depth understanding of the actual energy service demands to be met at various points within the energy system. Infrastructure plays a crucial role here: while more integrated electricity grids are desirable, even greater benefits can be accrued by designing more integrated energy networks, in which a variety of energy carriers are intelligently managed (Figure 5.15).

District energy networks are an important component of smart energy networks, and allow many of the technologies above to expand their potential. Yet decentralised technologies, including micro-generation and small-scale storage, also have a critical role. This is illustrated by many of the examples shown in previous sections: co-generation units exploiting synergies with heat pumps and electric heaters, or electric boilers operating in response to changes in variable electricity generation (Denmark).

In industrialised countries, there is little interaction or connection among coal, petroleum products, biomass, and grid-bound energy carriers (electricity, natural gas, and district heating and cooling). Each energy service is delivered through different infrastructures, which were developed and operate independently. Synergies among various forms of energy represent a great opportunity for system improvements (Hemmes *et al.*, 2007). Electricity can be transported over large distances and heat offers cost-effective energy storage capacity. As intermittent primary energy sources (*e.g.* wind and solar) reach scale, storage becomes important to balance variable (renewable) electricity production. In an intelligent energy network, the advanced control of heat – as demand, supply and storage for energy – has an important role.

Figure 5.15 The energy system as an intelligent energy network



Key point *Energy networks connect a wide variety of energy sources of different availabilities with variable demands, exploiting synergies among different sectors.*

Recommended actions for the near term

Achieving a highly efficient and low-carbon system for heating and cooling will require integrated planning across three levels: the **overall system, local communities** (*e.g.* cities or neighbourhoods) and **individual buildings**.

At the **overall system level**, procedures should be put in place that allow decisions to be informed by developments and operation at the regional and individual building scales. Local heating networks and individual micro-generation systems will require real-time information on the carbon intensity of the electricity grid, the load on the local network and the electricity prices. These activities require more sophisticated levels of monitoring and control, beyond the reach of current roll-out programmes for smart meters and building-scale energy management system. Thorough understanding of systems integration is essential and the skills of practitioners at all decision levels need to be improved. Some researchers (*e.g.* Kemp *et al.*, 2011) have advocated for a system authority: a government advisory body tasked with ensuring that energy systems perform and deliver as expected. Such an agency could provide advice and feedback across departments, but also guide local regions as low-carbon master plans develop at the city or regional level.

At the **community level**, sources of locally available heat should be assessed and matched against demand. Planning procedures and policies should be put in place that give adequate incentives to integrate the system cost-effectively, for example by using excess heat from industry or power plants, geothermal heat and heat from waste, as well as other renewables exploiting solar and biomass resources. New permitting procedures, building codes and market mechanisms that provide direct economic incentives for more efficient energy use are all needed to realise the vision of an integrated system. At present, the complexity of the regulations and incentives in the heating and cooling markets is a barrier for the diffusion of low-carbon technologies and system integration. Policies and incentives need to be simplified and focused towards end objectives rather than particular technologies.

At the **individual building level**, policies should ensure that practitioners adequately consider the relative practicality and economic effectiveness of all available low-carbon options in a holistic manner, in view of local conditions: the standards of the building envelope; the existing heating system; access to existing infrastructure including district heating or gas networks; the occupational profile of the building; whether there is available space for storage or an individual heating system; and the capacity of the local electricity network. The skills required to integrate and deploy low-carbon heating and cooling technologies successfully are beyond the current levels generally available from fragmented markets of electricians, plumbers and other installers. Furthermore, incentives should align with longer-term planning and objectives. For example, technology that might deliver partial savings today (*e.g.* sub-standard insulation or a co-generation unit fuelled by gas) might be inadequate in a future system with more ambitious targets.

Chapter 6

Flexible Electricity Systems

A flexible electricity system supports secure supply in the face of varying generation and demand. As electricity becomes the core fuel of a low-carbon economy, a system that intelligently manages all sources and end uses is critical.

Key findings

- ***Analysis of smart-grids' deployment to 2050 shows that the benefits outweigh investment cost.*** *In the five regions modelled by the IEA, smart grids enabled cost reductions in generation, in transmission and distribution, in retail operations, and in the overall system – but not necessarily in the same sectors in which investments were made. Regulations and business cases are needed to help resolve this conflict, which at present is a significant barrier to broad-scale use of smart-grid technology.*
- ***Policies that encourage greater sharing of risk, costs and benefits can stimulate the development of innovative and optimal flexible electricity systems.*** *Achieving a low-carbon economy requires a transition from the existing electricity system, in which generation follows demand, to one that optimises the use of all operational resources available. To date, too much focus has been placed on using generation capacity to provide needed flexibility, while investment in other flexibility approaches is lacking. Although the maturity of technologies may vary, targeted investment is needed to determine the most cost-effective options for both the short and long terms.*
- ***The need for flexibility in the electricity system is increasing rapidly, as variable renewable generation comes on line.*** *Variable renewable generation sources (*e.g. *wind, solar photovoltaics [PV], wave, and tidal) are becoming a dominant input to the electricity system, reaching 20% to 55% of regional generation capacities by 2050 in the* ETP 2012 *2°C Scenario (2DS). Integrating variable generation into the grid means balancing the electricity flow from generation with demand, while adjusting to meet peaks and lows of both.*
- ***The demand-response resource is underutilised: substantial potential exists to deploy technology to utilise predictable but intermittent electricity demand to manage less-predictable electricity supply.*** *Enabled by smart-grid technologies, demand response can technically provide between 50% and greater than 300% (depending on the region) of the regulation and load-following flexibility needed to 2050. Demand response is less suitable to the scheduling time frame, yet can still contribute.*
- ***Current technology to store electricity provides few unique benefits and is more expensive than other flexibility methods.*** *Although existing storage facilities provide a prime resource for balancing variable renewables, it is unclear whether new storage proposals – especially small- and medium-scale distributed storage – will play a significant role in the future due to high costs and less-expensive competing solutions.*

Opportunities for policy action

- *Remove barriers to investment in new technology by reforming electricity system regulation and implementing policies that promote the sharing of risks, costs and benefits by all stakeholders (including all electricity system sectors, customers and society at large).*
- *Create mechanisms and specific regulations by which new actors (e.g. aggregators and telecom and internet providers) that are vital to supporting smart grids can access electricity markets.*
- *Pilot and demonstrate demand-side flexible electricity projects to address customer concerns about service impact, privacy and cyber security, as well as availability and dependability.*
- *Enable the use of system-based approaches for flexibility that will help reduce operating costs by fully exploiting existing and new infrastructure, while maximising deployment of variable renewable generation.*

Electricity systems are physical infrastructure that is planned and operated under market and regulatory structures. The physics of the system do not directly interact with the economic and administrative structures put in place to ensure its reliability, affordability and, in recent years, environmental sustainability, which are all managed for the greatest benefit to society. *ETP 2012* examines the evolving electricity system in its entirety from generation to demand, including transmission and distribution (T&D) networks, challenging its current operating approaches and introducing technology options to take flexible electricity into the future. As a starting point, the operation of the electricity system must confront three primary elements: energy, capacity and flexibility.

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. Usage is tallied over a given time frame to provide a value for the total amount of energy used, but this total does not indicate *when* it was used. A system must incorporate enough source inputs (fossil fuel, renewables, nuclear or other) to produce the amount of electricity needed over a chosen time frame, but this is not the whole story.

Capacity, measured in megawatts (MW), is the instantaneous amount of power produced, transmitted, distributed or used at a given instant. This system indicator dictates that there must be enough generation and T&D infrastructure at every point in the system to meet the highest instantaneous demand over the course of a year – the peak demand. As demand for electrical energy grows, its impact on peak demand must be evaluated in order to ensure new capacity is deployed where needed.

Flexibility, which is measured in positive or negative MW per time, is an indication of the ability of the electricity system to respond to – and balance – supply and demand in real time. Flexibility already exists and is reliably used, but the increasing presence of variable renewables (such as wind and solar PVs) is inducing greater need and different management of electricity flows.

This chapter examines how the evolution of electricity systems creates the need for new approaches to deliver energy, capacity and flexibility. Flexibility resources, for example, include generation technologies, interconnection, demand response and storage – as well as their potential synergies. Future deployments of T&D systems – with a cost-benefit analysis of smart-grid technologies – are included to gauge the amount of investment needed in this area.

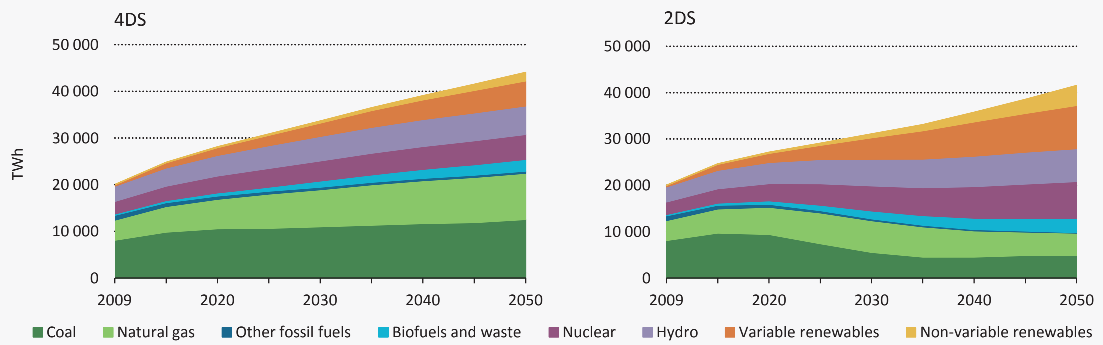
The chapter considers pertinent regulatory issues only generally because they are so complex, and vary widely across national and international jurisdictions. It suggests solutions only for prominent barriers. Various generation technologies and market operations are covered only as they specifically relate to flexibility.

Electricity system indicators

Electrical energy

Under the *ETP 2012* analysis to 2050, the share of electricity as a fraction of total energy demand rises from 17% in 2009 to 23% in the 4°C Scenario (4DS) and 26% in the 2DS. Despite the overall increase in the fraction of electricity use, more efficient use means that the 2DS shows a smaller increase in generation of 105% by 2050, compared to 120% in the 4DS (Figure 6.1). Although total electrical energy changes very little, the portfolio of generating technologies varies significantly, depending on the *ETP 2012* scenario.

Figure 6.1 Annual electricity generation



Notes: TWh = terawatt hours; coal and natural gas includes generation equipped with CCS.
Source: Unless otherwise noted, all tables and figures in this chapter are derived from IEA data and analysis.

Key point *The 2DS has lower electricity generation in 2050 compared to the 4DS, even though electricity is a larger share of overall energy demand.*

Under the 4DS, fossil fuel technologies continue to generate over 50% (28% coal and 22% natural gas) of global electricity in 2050, decreasing from 67% in 2009. Coal technology is down from 39% in 2009, with very little carbon capture and storage (CCS) deployed, and the share of natural gas changes by less than 1% compared to 2009 levels. Renewable energy grows from just over 1% in 2009 to 16% in 2050, reflecting growth in both variable renewable generation (wind, PV, tidal and wave) and non-variable renewable generation (geothermal and concentrating solar power, but excluding bio-energy and hydro[1]). Electricity from both nuclear and hydro increases, but as a percentage of the overall generation portfolio they decrease slightly by 1% and 2% of the total, respectively. Given these parameters, the 4DS shows 17% higher emissions, compared to current levels.

1 Bio-energy and hydro are captured in separate categories.

The 2DS portrays an electricity system that is largely decarbonised by 2050, with over 55% of electricity coming from all renewable technologies (variable sources – 22%, non-variable sources – 10%, Bio/Waste – 7%, Hydro – 17%) and 19% from nuclear. Coal without CCS declines to less than 2% of overall generation, while coal with CCS increases from 0% to 10%. Natural gas without CCS accounts for only 8% and natural gas with CCS accounts for 4%.

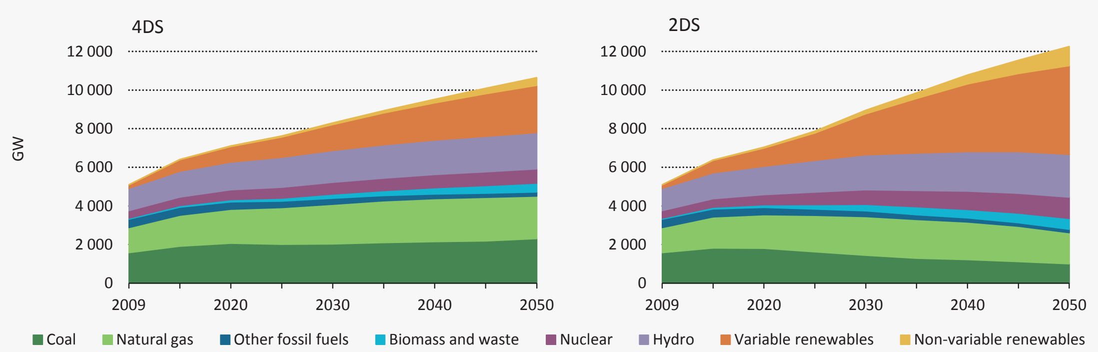
Capacity

Megawatts of electrical power indicate the instantaneous amount of electricity flowing from the generation, transmission or distribution sectors. This metric also shows the capacity of system infrastructure generally, in the context of meeting annual, seasonal or daily peak demand (plus associated contingency factors). This value is used to compare existing system installations and plan future capacity to determine if the peak demand can be met reliably and adequately.

Even though electrical energy demand in 2050 is lower in the 2DS than in the 4DS, the need for generation capacity is higher (Figure 6.2): overall capacity increases 109% in the 4DS and 140% in the 2DS from 2009 to 2050. This larger increase in overall capacity in the 2DS is due to greater use of variable renewable energy resources which have an inherently lower average capacity factor. In total, variable renewables represents just under 40% of total capacity in the 2DS, compared to 23% in the 4DS.

Fossil fuel generation capacity decreases under both scenarios, compared to the 2009 levels of over 30% capacity for coal and 25% for natural gas. In 2050, coal generation capacity (without CCS) in the 4DS falls to 20% and to 3% in the 2DS. Natural gas (including CCS) decreases to 21% in the 4DS, and falls further to 13% in the 2DS. On a net basis, coal generation with and without CCS increases 46% by 2050 under the 4DS, but decreases by almost 40% under the 2DS. Natural gas with and without CCS increases 70% under the 4DS and 24% in the 2DS.

Figure 6.2 **Generation capacity by technology**



Notes: GW = gigawatt; coal and natural gas includes generation equipped with CCS.

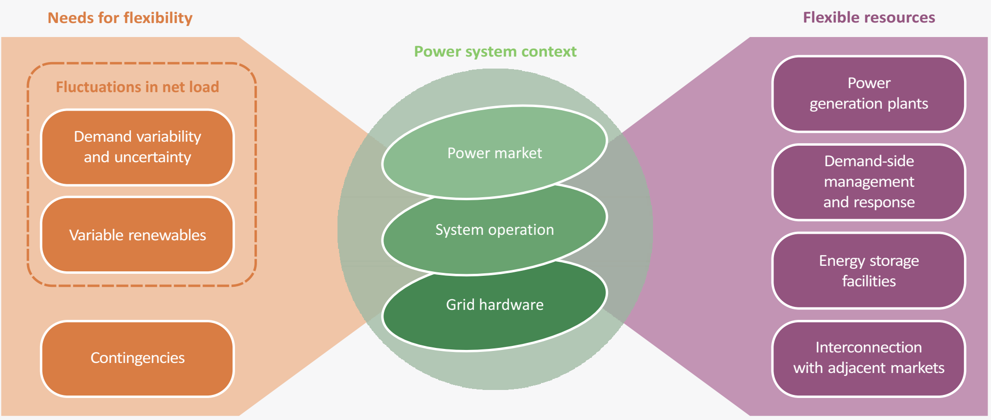
Key point *Generation capacity by 2050 is higher in the 2DS compared to the 4DS, despite lower electricity demand due to greater deployment of variable renewables with lower capacity factors.*

Transmission and distribution capacity cannot be summed up the same way as generation, but must be considered at every point in the system so that adequate capacity is available to transport generation resources to all demands in the system. Lack of capacity at a given point in the system does not necessarily impact the entire system, but it does affect the generation and customers on either side of the congested point, distorting the price of electricity.[2]

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). For example, a given combined cycle gas turbine (CCGT) plant may be able to ramp output up or down at 10 MW per minute" (IEA, 2011a, p. 35). Electricity systems need flexibility and employ a range of resources to meet it within their technical, regulatory and market frameworks (Figure 6.3).

Figure 6.3 **Overview of flexibility needs and resources**



Key point *The need for flexibility, resulting from variable renewables, demand and contingencies, can be met by four flexible resources: generation, demand response, storage and interconnections.*

The deployment of variable renewable generation adds to the flexibility requirement in many regions globally. Demand fluctuations under normal operating conditions are relatively regular and predictable over daily and seasonal time periods, based on large amounts of data collected over many years. The flexibility need created by variable renewables is less predictable and more difficult to forecast, especially over longer time frames. For example, on a day-ahead scale, system level wind forecast errors of under 6% (root mean square error) of production have been demonstrated over the course of a year in Germany[3] (Lange and Focken, 2011). For comparison, day-ahead load forecast errors are typically below 1% mean average error of production. As a result, operators must conservatively operate the system, assuming that the actual variable renewable generation can be lower or higher than predicted (Kassakian and Schmalensee, 2011).

2 Flexibility and other ancillary services, if constrained by market-based or technical congestion, can have an impact on the overall system operation.

3 Accuracy in forecasting wind is dependent on seasonality, terrain and spatial smoothing effects. The accuracy of forecasting is improving rapidly. Forecasts also increasingly include information on their accuracy, such as for weather situations that are easy to predict versus ones that are hard to predict.

In addition to meeting flexibility needs with all available technical resources, the regulatory and market environments must also be considered. This includes the structure of the power market, operating approaches and the existing grid hardware. In this context, there is a range of tradeoffs, considering the resources that best fit the current and future needs. Such tradeoffs include cost, technical availability and the ability to adjust the regulatory and market structure to take advantage of such resources throughout the system.

Flexibility time frames

Flexibility is largely managed by the ancillary services in electricity systems, namely non-energy services that support the production and delivery of electrical energy (*e.g.* reactive power for voltage control and spinning reserve). Traditionally, these services were part of the "package" provided by vertically integrated utilities that utilised a range of technologies within their portfolio. But as the electricity industry in many countries has been deregulated or unbundled to introduce competitive markets for power generation, ancillary services may now fall outside of the regulated business area of utilities, and must be provided independently. This new structure requires specific regulatory and market mechanisms in order to ensure these services are available.

Box 6.1 What are ancillary services?

Non-energy services that are necessary to support the generation and delivery of electricity. These include, but are not limited to: regulation, spinning or operating reserves, voltage support, and black-start capability. Ancillary services are typically provided as a by-product of electricity generation but can be supplied by a range of technologies and approaches such as generation, storage, demand response and interconnection with other regions or electricity systems.

Notes: Black-start capability refers to the ability of a generator to start without external electricity supply. This is important during a system outage where grid power may not be available to support restoration of generation capability.

Flexibility can be divided into three categories – stability, balancing and adequacy[4] – which reflect different aspects of system operation and different time frames. The analysis in this publication will focus on the balancing time frame. Within balancing, the analysis is divided into several time frames to reflect specific needs of a given system (Figure 6.4). Balancing categories and terminology differ from market to market, but the principle and range of varying time frames can be applied across all systems (DeCesaro, Porter and Hein, 2009).[5]

The balancing time frames of regulation, load-following and scheduling differ in response time and duration[6] (Table 6.1). Regulation is typically provided by peak power plants (such as gas turbines or reservoir hydro plants, pump storages, etc.) that can rapidly adjust output levels. Load-following is provided by generators already synchronised to the grid or are capable of being started up relatively quickly. Scheduling mostly covers the duration of several hours; today, it is normally provided by generators that require at least several

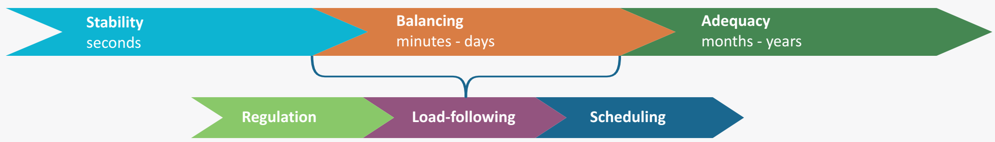
4 Stability refers to the maintaining of voltage and frequency of a given power system within acceptable levels. Adequacy refers to the ability of a power system to meet the demand for electricity under all conditions over the course of a year – typically in reference to peak demand. System-specific regulations determine how the system must be planned, built and operated to meet these needs.

5 The following sources were also considered in the evaluation of a framework for the balancing analysis: Rebours and Kirschen, 2005; and Kirby, 2004.

6 Duration refers to the length of time over which the type of balancing service is required.

hours to start up and reach the appropriate operating level. These generators may also need several hours or days to stop operation and require long cooling times before being re-started and re-synchronised to the grid. However, demand-side measures, storage and interconnection can be used to meet each of these balancing needs as demonstrated in Figure 6.3.

Figure 6.4 Flexibility and balancing time frames



Notes: As in the previous IEA analysis, focus will be on the balancing time frame, and using the terminology commonly associated with ancillary services.

Key point *Flexibility for balancing is divided into regulation, load-following and scheduling to allow quantification of need and evaluation of appropriate technology.*

Table 6.1 Comparison of time frames for balancing

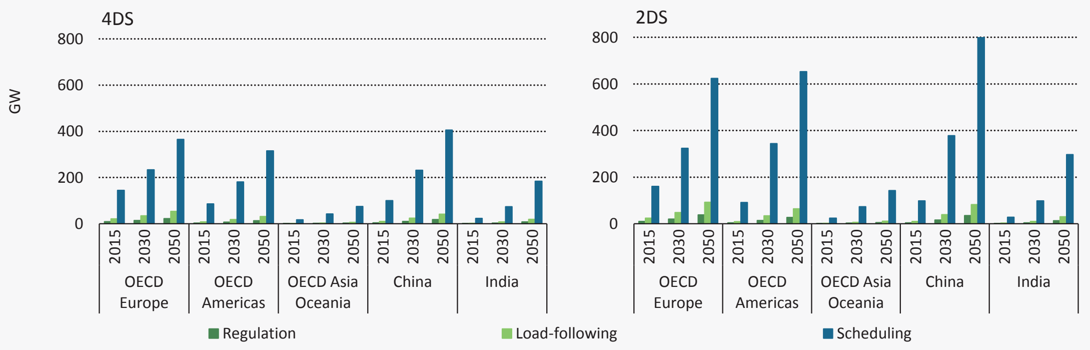
	Response time	Duration
Regulation	~ 1 minute	10 minutes
Load-following	~10 to 30 minute	1 hr
Scheduling	~ 1 day	6 hrs

Quantifying flexibility requirements for variable renewable energy sources

The assessment of flexibility needs is highly influenced by the particular variable renewable(s) deployed, as well as by variability of demand and contingency requirements. Adapting the Flexibility Assessment Tool (FAST)[7] methodology, an initial estimate of flexibility needs has been developed for variable renewable deployments from now to 2050 for power systems in five regions: OECD Europe, OECD Americas, OECD Asia Oceania, China and India.[8] Regional values from the FAST methodology were input along with the modelled values of future regional variable renewable deployments to 2050. The analysis of balancing requirements for regulation, load-following and scheduling emphasises the pressing need for flexibility in all time frames (Figure 6.5).

7 Details of the FAST methodology and results can be found at: www.iea.org/w/bookshop/add.aspx?id=405
8 Factors that serve as inputs to this analysis vary widely across the regions examined; thus, this analysis is intended to demonstrate indicative values and trends rather than precise projections.

Figure 6.5 Balancing requirements in key regions



Key point *Balancing requirements are increasingly important, especially in the 2DS, which has far more deployment of variable renewables.*

The 2DS analysis reveals much more need for flexibility compared to the 4DS, given greater deployment of variable renewables. The five regions show different needs within the scheduling, load-following and regulation time frames, and each region will make quite different choices about how best to match available resources with flexibility requirements. Although the scheduling requirement is much higher than for regulation or load-following, the response time is longer and can thus be met by a broader range of resources, such as large-scale base-load generation and industrial load reductions.

Developing flexible resources in the power system

In most regions, dispatchable generation technologies that are able to adjust output on demand serve as the primary flexible resource. But, as the need for flexibility increases, it will be necessary and economical to incorporate interconnection, storage and demand response.[9]

To integrate flexibility resources into the electricity system, it is critical to look at the system in its entirety: generation, transmission, distribution and end use. Not all flexibility resources are at the same stage of maturity: interconnection is a technically mature approach, but only used in some regions. By contrast, residential demand response for flexibility is still in the pilot or demonstration phase. Technical and cost issues need to be considered, but it is also essential to anticipate public reaction to the news that a new transmission line will pass through their community, for example.

Generally, a suite of solutions (based on regionally available types of flexibility) emerges, where current costs are evaluated against expected future costs, and current needs compete with long-term needs. Individual technologies must be examined as to how they best fit flexibility needs and evaluated against existing regulatory and market barriers that may prevent certain options from being considered in favour of conventional approaches.

9 Currently, demand response is used primarily for peak demand reduction rather than system flexibility, but the Electric Reliability Council of Texas (United States) employs demand response on a large scale for system reliability during events needing very rapid ramp rates (primarily due to variable renewables).

Generation technologies and flexibility

Power generation technologies play a significant role in providing flexibility. Centralised fossil fuel technologies, especially open-cycle gas turbines (OCGTs), are generally considered first, but all generation technologies have the technical ability to provide some flexibility over at least one of the balancing time frames. The electricity industry has acknowledged that flexibility needs will increase in the future, and many newer deployments upgrade these abilities.

Centralised generation technologies

Representative values for different power plant flexibilities show that their range varies considerably (Table 6.2). Hydro generation can respond more quickly than all others listed, but even technologies that typically provide base-load generation offer some flexibility, especially over longer time periods. Both new coal and nuclear plants are being designed with increased flexibility capabilities and older plants are being retrofitted to increase their flexibility potential.

Table 6.2 Comparison of generation plant flexibility

	CCGT	OCGT	Coal (conventional)	Hydro	Nuclear
Start-up time (hot start)	40-60 minutes	<20 minutes	1-6 hours	1-10 minutes	13-24 hours
Ramp rate	5-10% per minute	20-30% per minute	1-5% per minute	20-100% per minute	1-5% per minute
Time from zero to full load	1-2 hours	<1 hour	2-6 hours	<10 minutes	15-24 hours
Minimum stable load factor	25%	25%	30-40%	15-40%	30-50%

Note: Biomass and biogas are increasingly being used in CCGT, OCGT and coal plants.
Sources: IEA, 2012; Siemens, 2011; VGB, 2011; and expert opinion.

Operating a plant flexibly, instead of as traditional base-load supply, requires a different business model: capacity factors decrease, for example, while maintenance costs increase. If a plant has not been designed to operate flexibly, ramping it up and down may significantly shorten its expected operational life (depending on the technology). Moreover, if investments in existing generation technology assume that the plant will operate for a given number of years at a given capacity, a change to flexible operation can decrease the net electrical output of the plant. If revenues are reduced, the altered operating pattern can threaten the plant's financial viability. At present, it appears that such risk and uncertainty are having a negative impact on future investment in plants needed to provide flexibility: regulatory and market structures must step in to address the situation (the impact of flexible operation of gas powered generation is also discussed in Chapter 9).

Distributed generation technologies

Power generation is becoming increasingly distributed[10] as a wide range of technologies are deployed to tap into diverse resources. Back-up generation, self-generation (more common in industry), co-generation[11] and micro-generation can use fossil fuels, biofuels, and variable renewables using solar and wind energy, among others. While there are many advantages to distributed generation, the lack of centralised (or co-ordinated) monitoring and control of medium- and low-voltage networks makes it difficult to manage the generation across the power system.

10 Full agreement is lacking on the exact definition of distributed generation. It is generally accepted to include low-power-capacity generation units that are connected to medium- or low-voltage networks. Based on this, there is some overlap in what some consider centralised generation versus distributed generation.

11 Co-generation refers the combined production of heat and power.

Moreover, regulation or network approaches in certain jurisdictions prevent some technologies from feeding electricity into the grid (such as back-up generators or self-generation) or, conversely, allow generators to inject power into the grid as it is available with no consideration of actual power needs at a given time. The net result is that distributed generation technologies are either prevented from supporting the grid or actually increase the need for flexibility in the grid. Yet numerous ancillary services could be provided by distributed generation sources (Table 6.3).[12] With current technology, wind power plants can be designed to industry specifications, such as riding through voltage dips, supplying reactive power, controlling terminal voltage, and adding output and ramp rate control (Holttinen *et al.,* 2009).

Table 6.3 Ancillary services provided by distributed generation technologies

	CCGT	Co-generation		Diesel and CCGT standby	Bio-energy	Wind	PVs	Hydro
		Large	Micro					
	> 100 MW	1 – 100 MW	1-5 kW	<50 MW	1- 100 MW		<100kW	>1 MW
Frequency	Yes	Limited	No					Yes
Reserve	Yes	Possible	Possible at high penetration	Yes	Possible	Possible	Possible	Possible
Reactive	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes
Network support	Yes	Yes	Possible at high penetration	Yes	Yes	Yes	Limited	Yes

Note: The ability for wind to provide ancillary services will be affected by the specific generator technology deployed.
Source: Adapted from Degner, Schmid and Strauss, 2006.

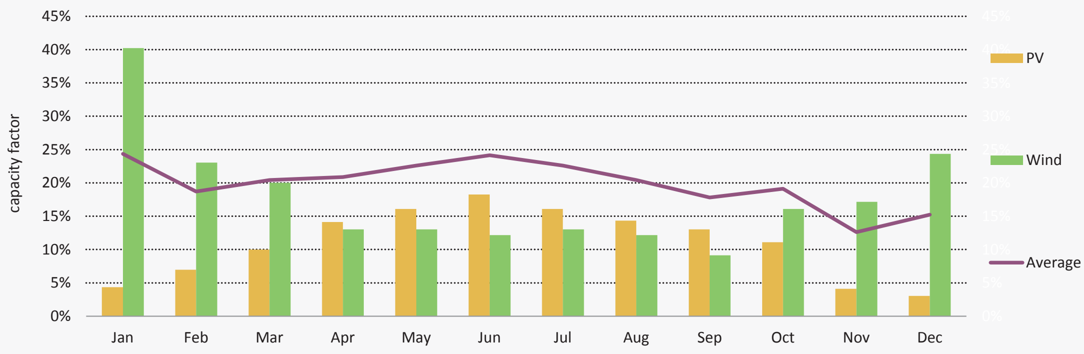
Although not prevalent today, operation of an electricity system that includes the monitoring and control of distributed generation technologies is becoming more feasible as information and communications technology (ICT) or smart grids are incorporated, especially in distribution networks. An opportunity exists to unlock these generation sources for network support, although it will significantly increase the complexity of system operation.

The design of incentive mechanisms and associated regulations to support deployment of variable renewables dictates whether system operators can use variable renewable sources for flexibility. Where feed-in tariffs provide revenue based on MWh supplied to the system but do not restrict the injection of power, generator owners have no motivation to support overall system operation or help to ensure system reliability and economic dispatching. Spain applies a more effective approach: wind farms over 10 MW must be integrated into the central system control centre, which means generation can be curtailed when required on a system basis, applied fairly across generators.[13] In the future, if these wind farms could provide balancing services, curtailment can be reduced, thus maintaining the revenues of generator owners.

Similarly, the output of different variable technologies can be aggregated system-wide for more efficient operation. For example, an inverse correlation of seasonal capacity factors (actual power output divided by maximum potential output) of wind and PV was evident for 2005 in Germany: high wind in winter and more sun in the summer. This means that the net production of the combined wind and PV technology deployments is less variable than that of individual technologies (Figure 6.6). To realise such a smoothing effect, the outputs of the technologies in question must have the same order of magnitude for capacity and timescale. In the United Kingdom, wave and wind power time series have similar smoothing on a daily basis (IEA, 2008).

12 This table is not exhaustive and continued technology development is expanding the ability of various generation technologies to provide additional and increased levels of ancillary services.
13 Curtailment controlled centrally can spread the impact over all generators and reduce the impact on individual generators.

Figure 6.6 **Monthly capacity factors for wind and photovoltaic in Germany, 2005**



Source: ISET, 2007.

Key point *Electricity production from a combination of wind and photovoltaic can be less variable than that of each individual technology.*

Transmission and distribution networks in flexible electricity systems

Ageing infrastructure, greater penetration of distributed and variable renewable energy sources, and increased electricity demand underscore the need to invest in T&D systems. Despite better understanding of the roles of networks in recent years, evolution of the electricity system and new developments in technology now challenge conventional operating and investment approaches. It is increasingly clear that T&D networks can provide critical support in efforts to optimise future power systems.

Role of transmission

The main role of a transmission system is to 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. This role can be carried out by a single electricity system or managed and co-ordinated by several systems operating in concert. Transmission can also play an important role where trade occurs among several countries or systems (*i.e.* the Nordic region of east Denmark, Finland, Norway and Sweden).

As the variability of both power sources and demand increases, along with rising overall electricity demand, transmission systems can serve a dual role: where practical, they can supply power (as a good) *and* provide flexibility (as a service). The choice of the service provided via a given transmission line is affected by historical uses, market structure, technical capability and system operation.

The value of interconnection to adjacent power systems is not determined solely by access to additional capacity in MW; it depends on the availability of adjacent systems to provide flexibility as needed within the required balancing time frames. Equally important is the extent to which the needs of interconnected areas coincide, and whether the connected areas need flexibility and power at different times (IEA, 2011a).

Reducing variability. Transmission systems can reduce the system variability of individual generation plants – particularly of variable generation technologies – by increasing the geographic spread of all generation deployment. System-wide aggregation, or the interconnection of systems, effectively "groups" multiple generation plants (having either similar or different technologies) to smooth out the peaks and valleys associated with individual plants. If outputs of many variable renewable power plants – based on different resources and, importantly, located over a wide area – are managed jointly, their net variability in the power system as a whole is smoother than with individual plants.

In the case of variable renewables, particularly wind, weather patterns play an important role. Although weather fronts can be continent-wide, in statistical terms, the greater the distance between two generators, the less their outputs will correlate. This effect is particularly important with load-following (IEA, 2008). In this context, centralised wind forecasting becomes an essential tool for co-ordinating regional transmission systems. The greatest emphasis is on the next hour and ramp forecast, corresponding to regulation and load-following time frames (Jones, 2011).

Existing and new infrastructure considerations. Optimal utilisation of existing transmission infrastructure capacity requires a range of advanced conductor, power electronics and control technology. These technologies support additional electricity services and higher flow of bulk electricity via existing infrastructure. In cases where bi-directional flow of power is required, older technology, especially at connection nodes, will likely need to be upgraded.

Greater flexibility in transmission will require the building of new power lines and optimisation of existing ones, activities that face the obstacles of increased costs and mounting public opposition (NIMBY or BANANA[14] mindsets), notably in areas with higher population density. Transmission built specifically for variable renewable generation has lower capacity factors than transmission for base-load technologies, which may mean a lower return on investment. To minimise costs, peak generation technology is often built as near as possible to load centres. But many renewable resources (*e.g.* off-shore wind farms, wave power) are located at greater distances from demand centres, requiring longer transmission networks at a higher cost. Transmission lines should be designed to accommodate multiple system needs, such as electricity trade, flexibility and integration of different renewables, in order to capture a range of benefits and reduce costs attributed to individual applications.

Role of distribution systems

The traditional role of distribution systems is to transport electricity from the transmission system to end users. While the overall distance electricity is transported during the distribution stage may be quite short, the system typically requires many nodes and terminations to convert electricity from high voltages to levels that can be used in industrial, service and residential applications. Distribution systems are typically more complex than transmission systems and together with historic use of centralised generation sources has resulted in passive systems with one-way flow of electricity from generation to demand – often described as "fit and forget".[15]

Enabling distributed energy resources[16] for flexibility. In general, relatively little effort has been made to monitor, control or manage distribution systems, in part because the cost of adding these abilities is high due to the many connections to substations, transformers and customers.

But the role of distribution is evolving rapidly: operators now see the potential to create active distribution systems in which two-way flow enables distributed generation (including

14 NIMBY = not in my back yard; BANANA = build absolutely nothing, anywhere, near anyone.

15 A passive network is designed and deployed using a set of static worst-case scenario metrics, with no or very little measurement, monitoring or control within the system itself. "Fit and forget" basically means, once installed, the system is left to operate as is, without intervention by the system operator.

16 Distributed generation, demand response and storage technologies are together referred to as distributed energy resources.

variable renewables, self-generation and back-up power) and storage technology (including electric vehicles) to feed into the electricity system. A range of new capabilities is being added as the costs for these added functions decrease and benefits are demonstrated.

A substantial challenge is that distributed generation and storage devices that can be connected to distribution systems are typically much smaller than those connected at the transmission level. This means the number of individual devices connected to the system will increase substantially, creating even greater complexity for monitoring, control and management.

The ability of distributed energy resources to add flexibility to the system remains largely untapped because of existing technical limitations and market barriers. To take full advantage of the energy, capacity and flexibility from distributed energy resources (whether for individual homes or service and industrial applications), it is imperative to install information and communication technology (ICT) in parallel with the power infrastructure, and to further develop operation and control methodologies.

As electricity distribution evolves from a passive to an active functionality, and as flexibility resources become more widely utilised within the distribution system, the relationship between the operators of distribution and transmission systems will need to be redefined. Distribution system operators will have the ability to manage the supply of flexibility and other ancillary resources in the distribution system in order to support overall electricity system operation, offering new alternatives to approaches typically carried out at the transmission system level.

Network investments for a flexible electricity system

Electricity networks in the coming decades will require significant investment, driven by rising demand, accelerated deployment of renewables and replacement of ageing infrastructure. System extension is inevitable to connect remote, renewable energy-rich regions with demand centres; additional capacity will be needed to address bottlenecks in meeting demand. Investments in T&D networks have been analysed in three categories:[17]

- **Grid extension investments** that expand and strengthen networks to accommodate growing electricity demand.
- **Grid renewal investments** include the refurbishment or replacement of network assets that reach the end of their operational lifetimes (averaging 40 years, although some older lines still operate today).
- **Renewable integration investment** represents additional grid extension needed to connect renewable-energy generators to the network. It may include added distance to connect remote renewable generation sources to demand centres (including submarine power cables to connect offshore wind), and may result in higher energy-specific costs due to the variability of the resource and resulting lower load factors.

The three investment categories cover the main sources, but do not reflect, for instance, investments to improve system reliability for existing consumers.

Using these three investment categories for T&D under both the 2DS and the 4DS provides a way to compare needs between and within both parts of the network. The difference in cumulative cost between the 2DS and 4DS ranges from 2% to 12% in the countries analysed (Figure 6.7). Europe has the highest difference, where the 2DS requires greater investment than the 4DS, as does India. OCED Americas, OECD Asia Oceania and China exhibit a trend where the 2DS investment is lower than in the 4DS.

17 The methodology was developed for *World Energy Outlook 2011* and is described in detail at: www.iea.org/weo/docs/weo2011/other/WEO_methodology/Methodology_TransmissionDistribution.pdf

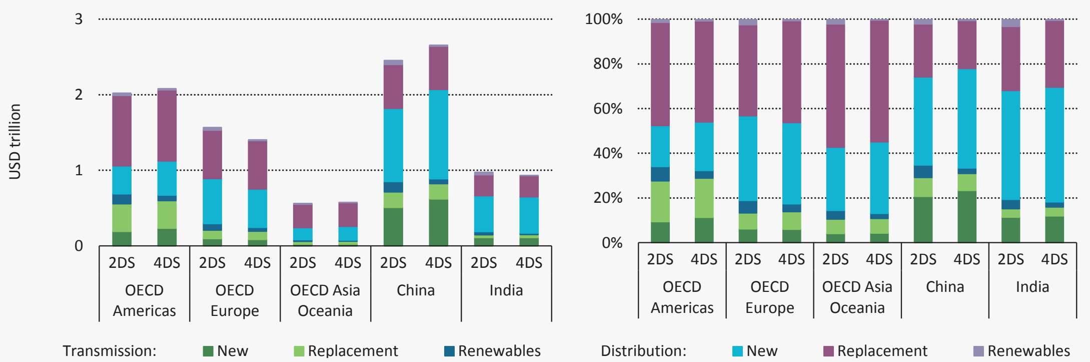
Investment costs are heavily weighted toward the distribution system in all regions. One significant factor is the length of the distribution system, which represents 92% of the total actual global T&D network length in 2009 (ABS, 2011).

In the OECD regions, investments to replace ageing distribution infrastructure account for 50% to 70% of total distribution investment, surpassing investments in new networks. To meet markedly increasing demand, investment in new distribution to 2050 is over 60% of total distribution investment in China and India. This trend showing the difference between OECD regions and China and India is similar for transmission investments.

The total additional investments to accommodate renewable generation vary between the 2DS and 4DS, but do not make up more than 10% of total investments in T&D. Although this investment is small compared to overall investments, it is an important component for flexibility, especially in the transmission system.

Public resistance to the placement of such infrastructure in many regions means that considerable non-financial effort is needed to deliver these resources. Clear communication of the criticality of network infrastructure while presenting a range of solutions to be considered will help to gain the support of all stakeholders.

Figure 6.7 Cumulative investments in transmission and distribution to 2050 by cost and percentage



Note: Data for modelling source from IEA, 2011, and ABS, 2011.

Key point *The difference between overall 2DS and 4DS network investment costs is minor, but sectoral allocation changes and must be evaluated based on actual system needs to optimise overall regional investments.*

Smart grids in the transmission and distribution network

Transmission and distribution systems will continue to use and deploy conventional technology (such as cabling, transformers and switch gear), but the installation of smart-grids throughout the electricity system makes it possible to optimise investments. Smart-grids[18] are essential to the more sophisticated measurement, monitoring and control needed to utilise the flexibility resources available within the electricity system (Table 6.4).

18 For accepted definitions of smart grids, see: IEA, 2011c; Brunner, Mäki and Strunge, 2011; and Kärkkäinen, 2009.

Table 6.4 Smart-grid technologies

Technology area	Hardware	Systems and software	Network deployment
Wide area monitoring and control	Phasor measurement units (PMU) and other sensor equipment.	Supervisory control and data acquisition (SCADA), wide-area monitoring systems (WAMS), wide-area adaptive protection, control and automation (WAAPCA) and wide-area situational awareness (WASA).	Transmission
Information and communication technology integration	Communication equipment (power line carrier, WiMAX, LTE, RF mesh network, cellular), routers, relays, switches gateway, computers (servers).	Enterprise resource planning software, customer information system.	Transmission and distribution
Renewable and distributed generation integration	Power conditioning equipment for bulk power and grid support, communication and control hardware for generation and enabling storage technology.	Energy management system (EMS) Distribution management system (DMS), SCADA, geographic Information system (GIS).	Transmission and distribution
Transmission enhancement	Superconductors, FACTS, HVDC.	Network stability analysis, automatic recovery systems.	Transmission
Distribution grid management	Automated re-closers, switches and capacitors, remote-controlled distributed generation and storage, transformer sensors, wire and cable sensors.	GIS, DMS, outage management system (OMS), workforce management system (WMS).	Distribution
Advanced metering infrastructure	Smart meter, in-home displays, servers, relays.	Meter data management system (MDMS).	Distribution and (transmission)
Electric transportation charging	Charging infrastructure, batteries, inverters.	Energy billing, smart charging grid-to-vehicle (G2V) and discharging vehicle-to-grid (V2G) methodologies.	Distribution
Customer-side systems	Smart appliances, routers, in-home display, building automation systems, thermal accumulators, smart thermostat.	Energy dashboards, energy management systems, energy applications for smart phones and tablets.	Distribution and (transmission)

Notes: Where transmission is noted in parentheses, it indicates that the given technology plays a minor role in transmission systems. Information and communication technologies are increasingly found in T&D networks and tend to cross all technology areas; FACTS = Flexible alternating current transmission system; HVDC = high voltage direct current.

Smart-grids' installation in T&D networks will incorporate a wide range of hardware and software technologies. Some technology will be installed beyond the networks (in homes or at generation plants) to provide more real-time data and link various parts of the electricity system. This will enable better planning and operation of the system, better deployment and use of infrastructure to meet actual needs, and less reliance on worst-case scenarios and estimations. In this context, the use of smart grids requires consideration from the beginning of next stages of upgrading, or planning the deployment and operation of networks. Deployment of smart-grid technology will add up-front cost to the overall investments in the system, but initial studies show that these investments have a positive net value.

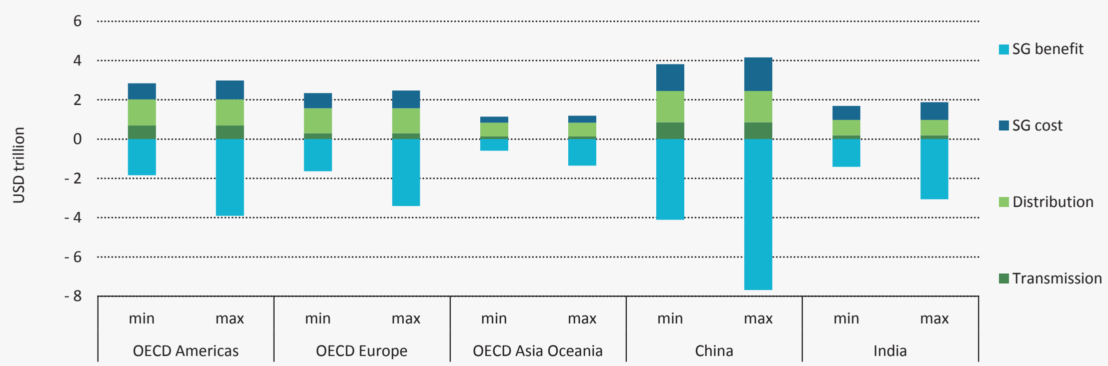
Financial benefits of smart-grid investment

ETP 2012 analysis provides an estimate of the incremental costs and benefits of smart-grid deployment over the long term, compared to simply expanding and upgrading a conventional T&D grid. The methodology relies on a bottom-up approach to estimate technology costs at five-year intervals between 2010 and 2050. Technology costs are calculated by multiplying unit costs by the number of units required and overall market penetration, while considering component replacement at the end of their technical lifetimes. The component renewal calculation is crucial, as many digital devices have considerably shorter lifetimes (10 to 20 years) than mechanical components (40 to 50 years).[19] A learning factor was assumed for all technologies according to their maturity level. The analysis assumed that all five base regions have identical unit costs, but different technology penetrations; the estimates were based on government plans and policy support in place as of 2011.

Deployment of smart grids in the 2DS permeates the entire electricity system; the resulting increase in system capacity helps to reduce congestion. As a result, investment decreases for some network components and possibilities open up to implement a range of operating paradigms previously not feasible. Included are full participation of residential customers in generation and demand-side flexibility services, and technology options that increase existing power-line capacities to alleviate congestion and enable maximum utilisation of existing and new systems.

The minimum and maximum cases of the 2DS demonstrate the level of uncertainty in the future costs and benefits (Figure 6.8). The costs are relatively easy to quantify because relevant data are readily available; in actual fact, the cost difference between the two cases is quite small. Putting a monetary value on the benefits of smart-grid deployment is much more difficult, in part because there is still some debate as to the precise level of benefit they can deliver. As a result, the range between the minimum and maximum benefits is larger.

Figure 6.8 **Cumulative costs and benefits of smart grids versus conventional T&D systems in the 2DS to 2050**



Notes: Transmission and distribution shown in Figure 6.8 are the same as those in Figure 6.7. Reduction and/or deferral of network investments are shown as benefits. SG = smart grid; min = minimum; max = maximum.

Key point *Smart-grids' costs are substantial, but estimated benefits do exceed investment.*

The additional costs of smart grids versus costs of investments in conventional T&D to 2050 for the 2DS include technologies (such as smart metering infrastructure and PMUs) that are atypical in T&D investment modelling.[20] Since this analysis covers a 40-year period,

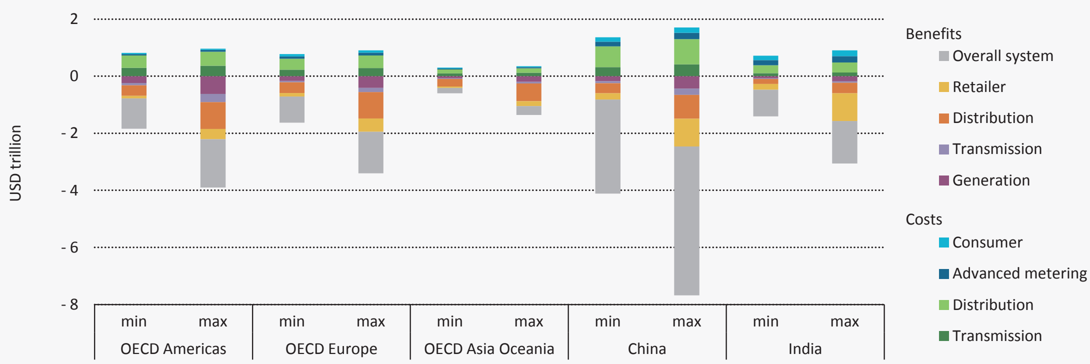
19 The data were compiled by expert interviews and technical reports (EPRI, 2008; EPRI, 2010a; EPRI, 2011; Institute for Energy Efficiency, 2011; Commission for Energy Regulation, 2011).

20 Additional details for the modelling can be found on the *ETP 2012* website.

costs also include replacement of some technologies (*e.g.* smart meters). The benefits, shown as negative costs in Figure 6.8, include both operational and capital savings. Operational cost savings include reduced fuel use due to efficiency savings, direct carbon dioxide (CO_2) emissions reductions, and lower operation and maintenance costs. Examples of capital investment savings include reduction and/or deferral of conventional T&D investments and of generation infrastructure investments.

Removing the conventional T&D investment costs allows an examination of sector-specific technology costs for smart grids, which can be divided among the broad categories of consumer, distribution, transmission and advanced metering infrastructure (Figure 6.9). The benefits can be attributed to retailer, distribution, transmission, generation and overall system benefits (which demonstrate direct benefits to the electricity system).

Figure 6.9 **Sector- and technology-specific smart-grids' costs and benefits in the 2DS to 2050**



Notes: min = minimum; max = maximum.

Key point *Total benefits of smart-grid investments outweigh the costs, but direct benefits of investment in one sector may be found in other sectors, complicating the business case and potentially acting as a barrier to deployment.*

The financial benefits arising from smart-grid investments are greater than the total cost of investment, making a strong case for smart-grid technologies. But in some cases, the benefits are spread throughout the electricity system to sectors other than the one that needs to make the investment. This complicates the business case for investments, since all benefits may need to be monetised and accounted for in order to create a positive business case. Advanced metering infrastructure to manage peak demand is a case in point: reducing peak demand benefits the T&D system and lowers the cost of generation. Investment costs, however, will be borne entirely by the distribution system stakeholders, who will likely need to adjust their pricing for goods and services to realise a sufficient return on their investment. Technical solutions and regulatory changes are needed to address this barrier.

Smart grids facilitate use of other technologies, such as distributed generation, electric vehicles (EVs), large-scale variable renewables and storage. Capturing and monetising the benefits related to these technologies can considerably increase the overall value of smart grids (shown in Figure 6.9). Potential external benefits include increased adoption of distribution generation technologies, lower electricity bills for consumers and EV support in system balancing. Such benefits are not included in *ETP 2012* analysis, as more work is needed to assess their actual value and determine feasibility.[21]

Smart grids also offer opportunities for individual consumers to participate in the market by providing energy services (through self-generation and changes in demand). They can also take advantage of clearer signals of actual consumption to reduce electricity use. As above, such benefits are not quantified in this analysis, even though they are a very important feature of smart grids. These savings have been partly quantified in the other sectors, but the analysis also assumes that cost reductions will be reflected in the consumers' rates.

On a regional basis, the benefits reaped from smart-grid investments depend greatly on how well the smart grid is deployed, what type of regulatory support is enacted and whether consumers actually adopt their role in overall system co-ordination. This regional aspect calls for the development of targeted roadmaps to ensure that smart grids meet the specific needs of individual systems and begin delivering benefits in the earliest possible time frame. Smart grids may yield a more secure, economical and carbon-neutral electricity system, but they can only unleash their potential when fully deployed and fully co-ordinated, which requires investments along the entire value chain.

Unlocking demand-side resources for flexibility

Demand response is a mechanism by which the demand side of the electricity system can provide flexibility; it refers to the shifting of loads over given time periods, but does not always imply reducing overall electrical energy consumption. Demand response to reduce peak load has been in use for decades and is well understood, but applying its technologies and principles to provide flexibility to the electricity system is a relatively new approach and current understanding is low. In the flexibility equation, demand response requires the ability to both reduce and increase demand, primarily to balance the system in relation to inputs (or fall-offs) of variable generation.

Demand response is currently the least used of the four flexibility resources, but pilot and field tests with smart-grid technology in the distribution system are expected to show significant potential. Several technologies and approaches exist, but three main obstacles deter their broader deployment: the metering, control and communication technologies required are still expensive to install and maintain; optimisation algorithms for aggregated portfolios are not yet publicly available; and market rules differ between countries (Kärkkäinen, 2009). As technology development continues, along with expected cost reductions, use of the demand side for flexibility is expected to increase rapidly; however, public acceptance is also a major issue that must be addressed in most jurisdictions.

Box 6.2 Relationship between peak demand and flexibility in future system planning

The reduction of peak demand, in the short term, will increase the amount of system capacity that can be used for flexibility and the transport of power. In the long term, however, this may reduce system investment and the amount of transmission and distribution capacity, resulting in congestion that traps the demand-side flexibility resource. System design must move beyond using peak demand as the primary driver for capacity investments; an optimised design also must address the need for flexibility.

21 The costs attributed to the customer for advance metering infrastructure are quite small, compared to overall smart-grid deployment costs. The largest amount of investment is required in the distribution network.

Technical resources for flexibility

To determine how much the demand side can contribute to the flexibility need, *ETP 2012* carried out an analysis of the technical potential. Several factors (such as consumer acceptance) will constrain actual use to only a fraction of this potential, but the analysis at least provides useful estimates of the size and importance of this demand-side resource.

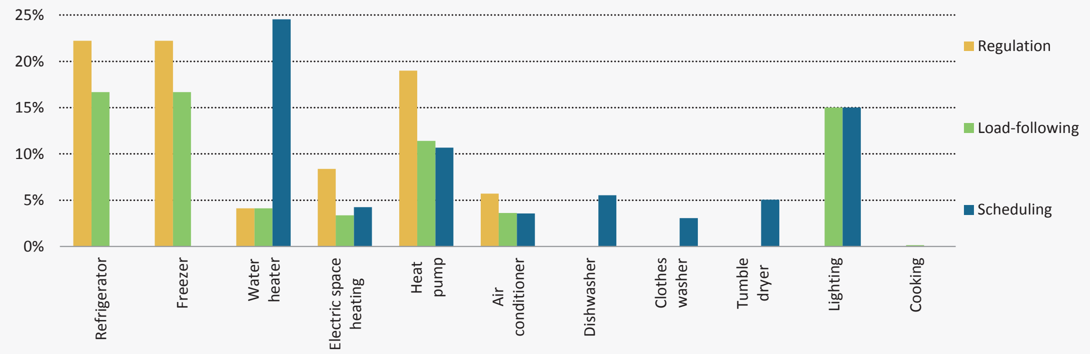
To assess the level of flexibility resources available in the residential and service sectors,[22] load types were evaluated to determine suitability for demand-response flexibility. Appliances were then mapped against the flexibility time frames of regulation, load-following and scheduling (Table 6.5).[23]

Table 6.5 Load types suitable for balancing services

	Residential	Service
Regulation	Refrigerator, freezer, water heater, space heater, air conditioner	Refrigeration, air conditioning, water heating, space heating
Load-following	Water heater, space heater, air conditioner	Water heating, space heating, air conditioning, others
Scheduling	Washing machine, tumble dryer, dishwasher, air conditioner	Lighting, others

The analysis uses a constraint to ensure that the approach does not affect the service delivery of the appliance. To gain consumer acceptance, providing flexibility must be transparent and avoid any inconvenience to the customer. Thus, it is estimated that only a fraction of the individual appliance loads can be expected to provide flexibility to the electricity system at a given time (Figure 6.10).

Figure 6.10 Fraction of appliance load that can be used for flexibility in the residential sector



Key point *Different appliances have different operation characteristics, which affect their ability to contribute to the three flexibility time frames.*

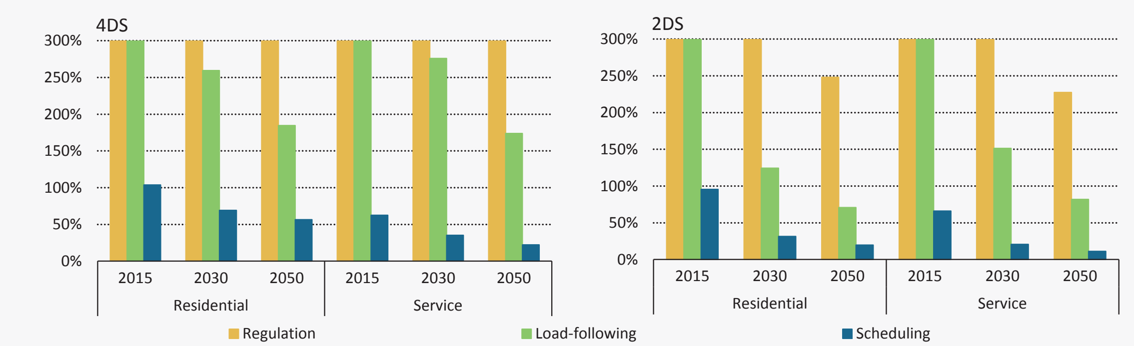
22 Demand response in the industrial sector has not been calculated on a regional level in this analysis because it is location- and industry-specific in its application. Further analysis should be carried out in this area.

23 The data were compiled by expert interviews and technical reports (Bloor *et al.*, 2009; Stamminger, 2008; Timpre, 2009; Xu, Østergaard and Togeby, 2010).

Electric vehicles also can contribute as a demand-response resource for the electricity system; their potential has not been considered in this analysis since stock levels are currently very low and therefore cannot contribute significantly at this time. As deployments of EVs increase from current levels, it will first be important to mitigate peak demand issues for vehicle charging. But as the EV stock grows, so does its potential contribution to electricity system balancing. Customer acceptance issues related to the business model, particularly with respect to driving range and battery life, will need to be addressed (among other challenges).

Technical potential of residential and service sectors. To calculate the potential technical fraction of demand-response flexibility, the amounts of flexibility available from diverse individual loads (Figure 6.10) were aggregated over five regions and compared to the flexibility requirement. This is examined for the residential and service sectors in the 4DS and 2DS (Figure 6.11); the figure features OECD Americas, but other regions show similar trends.

Figure 6.11 Sectoral flexibility potential in OECD Americas by percentage of requirement and GW



[GW]	4DS						2DS					
	Residential			Service			Residential			Service		
	2015	2030	2050	2015	2030	2050	2015	2030	2050	2015	2030	2050
Regulation	57.9	73.0	90.3	50.8	69.3	88.7	54.6	60.9	67.4	31.6	48.4	61.8
Load-following	32.9	42.9	54.9	17.3	24.6	30.2	31.1	36.4	42.1	9.5	14.9	18.3
Scheduling	95.8	140.4	198.5	57.7	71.2	77.9	87.4	108.3	129.2	60.6	71.8	73.5

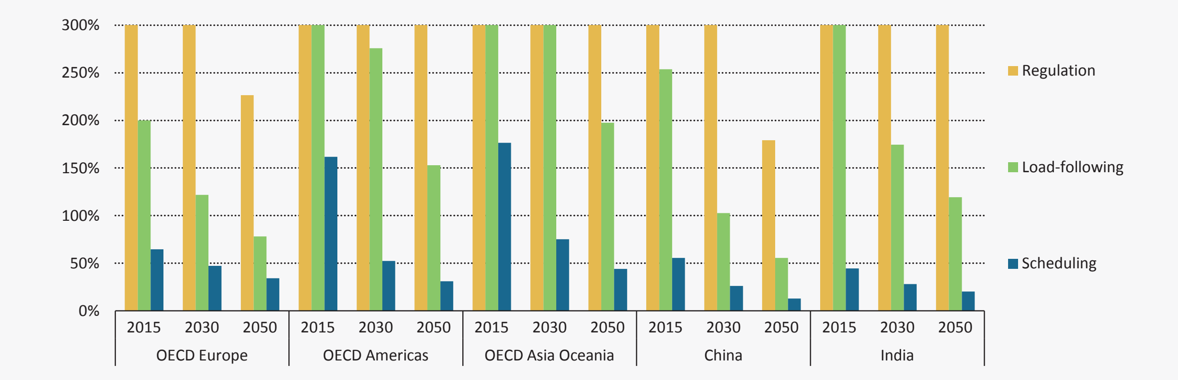
Note: The respective regulation, load-following and scheduling balancing values of the residential, and service sectors can be added to indicate the total flexibility for each balancing type.

Key point *Significant untapped flexibility resources exist in both residential and service sectors. In the 2DS, the lower demand resulting from increased energy efficiency reduces the amount of flexibility these sectors can contribute.*

When compared to the flexibility requirement shown in Figure 6.5, each respective demand sector provides over 100% of the regulation and load-following needs in the 4DS to 2050. In the 2DS, the service sector still provides over 100% of regulation and over 80% of load-following, while the residential sector provides over 100% for regulation and over 50% for load-following. The scheduling time frame has much lower, albeit significant, values for both sectors in both scenarios; this reflects the greater flexibility requirements for scheduling and the poorer ability of the demand side to provide flexibility over those time periods.[24]

On a net basis, the increased energy efficiency (demand side) in the 2DS lowers the overall electricity demand compared to the 4DS, despite the higher use of electricity for heating and other applications; the result is less demand to provide flexibility services. On a percentage basis, this is compounded by the fact that more variable renewable generation in the 2DS means higher flexibility requirements than in the 4DS. This trend should be monitored as the electricity system evolves, but since both scenarios have sufficient flexibility resources, it is a secondary consideration. Combining the residential and service sectors, all five regions analysed show large technical demand-side flexibility resource even in the 2DS (Figure 6.12).

Figure 6.12 Regional demand-side flexibility resource in the 2DS



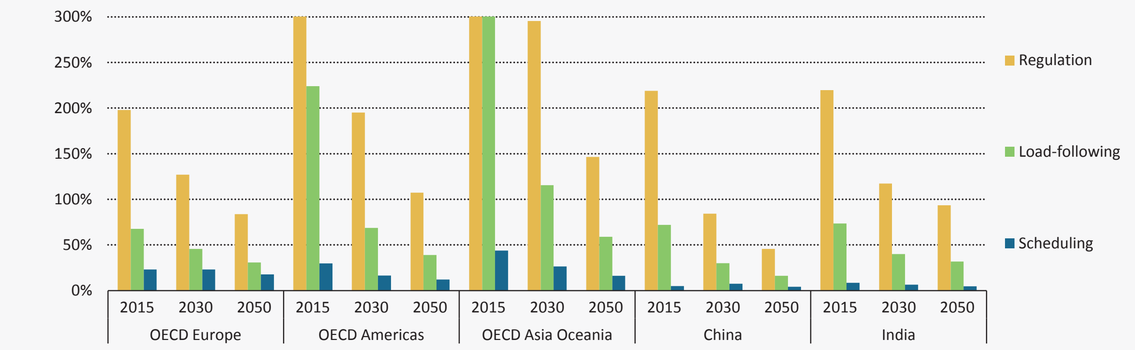
Key point *A large amount of demand-side resource can be found in all regions analysed.*

Non-seasonal loads for flexibility. The overall potential of demand response for flexibility, at levels over 100% of the total flexibility requirement in many cases, is impressive. But the question remains whether the resource will be available when needed, given the different variable renewable technologies deployed, daily and seasonal variations, and challenges with forecasting. An initial approach can be to employ appliances that operate consistently throughout the year (such as electric water heating, refrigeration and freezers) instead of considering all appliances including heating loads that do not exist during warm months or cooling demands that do not occur in cold months. Even these few applications demonstrate the significant potential available, well over 50% of the total requirement in many cases (Figure 6.13).

Releasing the potential of demand-based flexibility. Unlike peak demand, which is quite regular on a seasonal and daily basis, the supply of variable renewables exhibits an inherent uncertainty that makes the need for flexibility significantly more irregular. The inability to predict, on a long-term basis, when fluctuations will occur means that the seasonal price schedules often used to reduce peak demand are of little value. Other price signals are an option, but must be provided in real-time (or near real-time) and in ways that allow consumers to change how they use electricity. With larger service and industrial customers, a price signal provides a higher net value while the premise of contractual arrangements offers certainty to system operators. For smaller customers, who individually gain less net value, it is particularly difficult to gauge what action to take.

24 As methodologies and approaches evolve for providing demand-side flexibility, it is expected that time frames can be increased through broader aggregation approaches.

Figure 6.13 Demand-side flexibility resource excluding seasonal loads in the 2DS



Key point *Non-seasonal loads offer large flexibility resources and reduce concerns regarding unavailability of demand-side resources.*

Direct load control, where a device is controlled remotely on an agreed-upon basis by a third party or utility, long a conventional method to deliver peak demand, could be a key technology in the delivery of flexibility services. Building and home energy-management systems can play a significant role, particularly when aggregated across many customers. The rapid response needed for regulation and load-following will, however, require a high-performing communication and control infrastructure. While a dedicated system may be appropriate for industrial or larger service customers, considering the high number of customers and devices in the residential sector, the approach may not be cost-effective.

An alternative approach might be to leverage existing communication infrastructure in other industries (such as cellular and internet). Bundling of such services with energy services brings significant benefit, but also creates specific issues. Owners of communication infrastructure interested in energy service may not be welcome by incumbents in the electricity system and markets. New regulation needs to be enacted to give new entrants (and partnerships) access to the market, to thereby, for example, leverage the experience of incumbents in the electricity market with more customer-oriented ICT companies. Such mechanisms could help optimise cost and effectiveness – such as reliability and safety – in direct load control (BNEF, 2011).

Customer acceptance of demand response, especially at the residential level, requires attention to public education and ongoing provision of transparent information. Smart meters and other end-user technologies collect more detailed data on customer energy consumption at frequent intervals and allow richer information exchange between utilities, retailers and consumers. Customers benefit by being able to adjust (manually or automatically) usage patterns (including by appliance) based on detailed electricity consumption and cost information. Utilities also benefit from access to this information by gaining an improved understanding of consumption patterns and trends, allowing them to make more targeted investments.

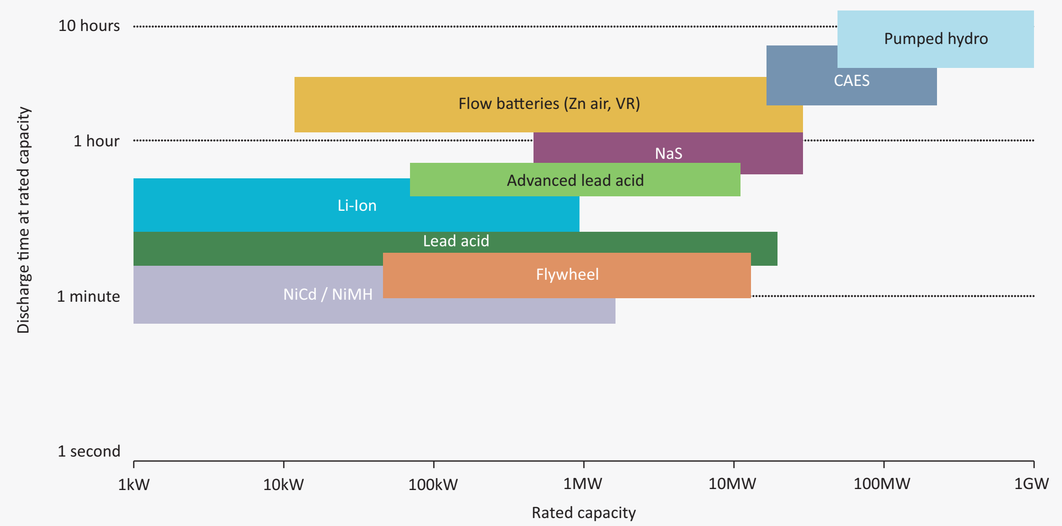
Data privacy and cyber security, however, are major challenges. Increased collection of energy consumption data offers significant insight into household behaviours and patterns (*e.g.* when residents arrive or leave home, what sort of appliances are used and when). The ability to glean such information from electricity usage data has obvious consumer privacy implications, particularly considering the potential interest of third-party service providers in using the data for purposes beyond electricity supply (*e.g.* targeted marketing, production of data products or insurance risk assessment).

Mechanisms are needed to manage the risks of misuse or mismanagement of private data, consistent with the control of data access and use in other sectors, such as telecommunications. Different countries and applicable jurisdictions must consider how current information privacy regimes address the complex privacy issues raised by grid modernisation and what additional measures (*i.e.* legislation, broad regulatory measures, new standards, voluntary codes of conduct, best practice guidelines) are needed to protect consumers. Appointing or creating appropriate entities to have regulatory or oversight responsibilities to ensure compliance and determine the extent to which utilities can or should be relied on to protect customer privacy will likely be necessary.

Electricity storage

While it is not possible to effectively store large amounts of electrical energy, electrical energy can be converted to other forms,[25] stored and then reconverted back into electrical energy with some (predictable) energy loss in the process. Storage technologies distinguish between energy and capacity. Energy (in kWh) is the fundamental quantity delivered, while the rated capacity (in kW) of a facility determines the maximum rate at which stored energy can be delivered to an electricity system. Thus, storage technologies have two fundamental characteristics that determine their suitability for a particular application: the capacity at which they can discharge stored energy (in kW); and the time it takes to fully deplete the energy store at this capacity level (the discharge time). Storage technologies can be categorised by the range of rated capacities of installations and their associated discharge times (Figure 6.14).

Figure 6.14 **Storage technologies by rated capacity and discharge time**



Source: EPRI, 2010b.

Key point *The technical applicability of storage technology depends on both rated capacity and discharge time at rated capacity.*

25 In compressed air energy storage, electrical energy is converted and stored as a compressed gas. Battery technologies convert electrical energy and store it as chemical energy, using compounds such as sodium sulphur (NaS), lithium ion (Li-Ion), nickel-cadmium (NiCd), nickel-metal hydride (NiMh), and lead acid and flow batteries, such as vanadium redox (VR) and zinc air (Zn Air). Flywheels store kinetic energy (EPRI, 2010b).

Storage applications and technologies

Storage resources can consume or produce energy, and are usually able to switch from generation to consumption relatively quickly. Thus, storage is a valuable source of flexibility for the power system. During times of excess generation or shortfalls, for example, variable renewable energy can be stored and released as needed. Producing energy during high demand periods contributes to system security margins and defers the need for additional generation capacity.

Storage technologies also provide significant flexibility through the range of ancillary services (regulation, reserves, voltage support and black-start capability) that have typically been provided as a by-product of electricity generation. It should be noted that storage, while a versatile resource in any electrical system, has no unique contribution that cannot be provided by other technologies, in particular transmission and interconnection. Therefore, when assessing applications, storage must be compared to other competing measures: conventional generation technologies, transmission, interconnection, network devices (*e.g.* capacitors and static compensation devices), operational practices (*e.g.* forecasting, generation re-dispatch, protection measures and use of dynamic line rating information) and demand response.

Pumped hydro. Pumped hydro plants convert electrical energy into potential energy by pumping water from a lower reservoir to an upper reservoir, then generating electricity as the water is released from the higher reservoir back to the lower. The process has a relatively high efficiency of 65% to 80%. Large power and storage capacities are possible with pumped hydro: power capacity is determined by the number and size of turbines/pumps, while storage capacity reflects the size and elevation of the upper water storage body. Pumped hydro is particularly valuable for energy arbitrage[26] (in addition to ancillary services) and has capacity similar to a conventional hydro plant.

With approximately 130 GW installed worldwide, pumped hydro accounts for over 99% of the world's storage (EPRI, 2010b; IEA statistics). Most was developed from 1970 to 1995, taking advantage of the high daily electricity price spread (*e.g.* from high-priced oil peak-load plant to lower-priced nuclear base-load plant). During that period, the arbitrage opportunity justified the development of pumped hydro.

In the 1990s, the use of gas generation increased dramatically for both base load and mid-merit, using CCGTs and OCGTs, for peak plants. As a result, the daily price spread narrowed, undermining the incentives to build more pumped hydro. At present, energy arbitrage, the traditional driver for investment in pumped hydro, does not stand up in market conditions (Pieper and Rubel, 2011). Current viable scenarios centre on the provision of ancillary services, such as black start, or very specific conditions, such as small-island power systems (Carailis and Zervos, 2007), both of which have seen investment increasing of late.

Compressed air energy storage. Compressed air energy storage (CAES) is the second-largest storage capacity connected to the electricity system; with 400 MW installed worldwide, it accounts for 0.3% of total storage. Following compression, electrical energy is stored either under or aboveground. The compressed air is then combined with gas to generate electricity and CAES efficiency is therefore difficult to calculate as a hybrid device, but it has similar efficiencies to pumped hydro. Only two CAES plants exist in the world: in Huntorf, Germany (290 MW), and in McIntosh, AL, United States (110 MW). Interestingly, both were commissioned in the same period as most of the pumped hydro.

26 Arbitrage refers to the use of inexpensive electricity to fill a storage device (typically at night) for later release at times when electricity is more expensive (typically during the day).

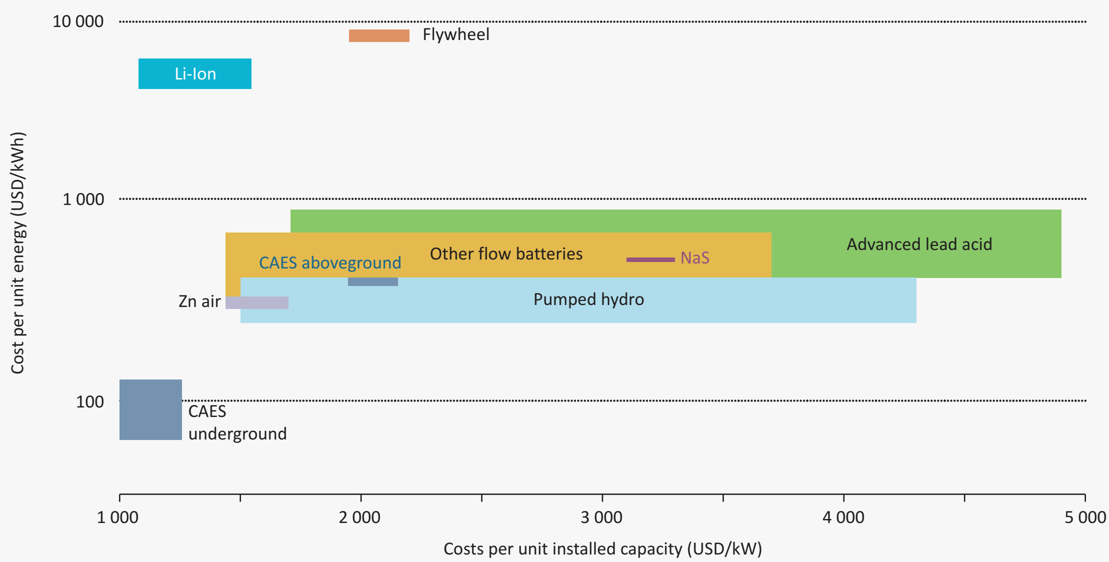
Both CAES plants use caverns in which salt is dissolved to store the compressed air, although other geological structures may be suitable, including abandoned mines, aquifers and depleted gas fields. Aboveground CAES would require a purpose-built vessel. Similar to pumped hydro, the main CAES application is in energy arbitrage and ancillary services.

Other storage technologies: At 316 MW worldwide, sodium sulphur (NaS) batteries are the next-largest (0.25%) electricity system connected to storage technology. All other storage technologies combined – including battery technologies, flywheels and super capacitors – account for just 85 MW or approximately 0.07% of global capacity (EPRI, 2010b). These technologies are generally employed in highly specialised applications such as ancillary services and localised power quality applications.

Barriers to energy storage

All storage technologies are characterised by relatively high capital costs compared to conventional generation technologies. Combined with the conversion energy losses, this creates a significant barrier to wide-scale deployment.

Figure 6.15 Lifecycle costs of storage technologies per unit installed capacity and energy



Notes: Values include both battery and balance of system costs for applications, including system support, frequency regulation and renewable integration applications. For above ground CAES technology, data for utility transmission and distribution grid support applications are plotted. Commercially-deployed cost data is used where possible. Where data was not available from reliable sources, technologies are omitted from the graph.
Source: Data from EPRI, 2010b.

Key point *The cost of storage technologies varies widely; determining appropriate applications is vital to financially sustainable deployment.*

Cost reductions are therefore critical if storage is to play a large part in future electricity systems. To date, much of the analysis values only energy arbitrage, although valuation of other storage applications is ongoing – particularly its flexibility (Ma *et al.*, 2011; Lannoye, Flynn and O'Malley, 2012). Because the characteristics of storage are so different from conventional generation, some institutional barriers exist (as is true of demand response) which are being addressed by the modification of market rules. Cost targets for research programmes can be used as a proxy for future cost trends. The US Department of Energy, Advanced Research Projects Agency, set a price target of USD 100/kWh, which is lower than all the highlighted technologies (Figure 6.15); however, cost and cost projections vary widely and are difficult to verify.

The two main forms of storage deployed commercially today, pumped hydro and CAES, both largely depend on the availability of suitable geological structures, which may have already been exploited or may not be available in some regions. Historically, the environmental impact of such developments had a lower level of public opposition. Some battery technologies depend on the availability of specialised materials. In the case of lithium-based battery technologies, the sufficiency of the economically recoverable resource has been called into question (Sims *et al.,* 2011). Other battery technologies, notably NaS and advanced lead acid, have a limited number of charge and discharge cycles before performance is materially impaired, restricting their suitability for some applications.

Future potential of storage

Several proposals for storage are circulating, such as 7.4 GW pumped hydro in Europe (Deane, Ó Gallachóir and McKeogh, 2010), but few have actually been constructed. Some projects have been undertaken to retrofit existing hydro facilities with reversible pumps to create a pumped hydro facility (Estanqueiro, Mateus and Pestana, 2010; REN, 2008) or to install variable speed pumps to increase the ability to provide flexibility. These projects recognise that rather than pumping at a fixed load, pumped hydro stations can operate over a wider range of load levels to better accommodate renewable energy resources (Deane, Ó Gallachóir and McKeogh, 2010). In the area of battery storage, research and development into new materials and technologies focuses on reducing costs and addressing cycle limitations.

Increased deployment of variable renewables, in particular wind and PV, is forcing greater focus on electrical energy storage technologies to meet the flexibility challenges of integrating renewable energy across multiple time horizons (Lannoye, Flynn and O'Malley, 2012; NERC, 2010). As more and more variable renewable energy sources are connected to electricity systems, it will become increasingly difficult to accept this energy at all times. Such sources may need to be curtailed because of insufficient transmission capacity, or because the system load or flexibility are too low to accommodate the additional input (IEA, 2011a). The current consensus is that, for penetration levels up to 30% to 40%, storage for energy arbitrage is not yet economically justified, compared to competing technologies (GE Energy, 2010; Denholm, Ela and Kirby, 2010).

At higher penetrations of variable renewables, storage for energy arbitrage does start to make economic sense (Tuohy and O'Malley, 2011). But against other options, in particular building more transmission, the case for storage is less clear (EASAC, 2009). The increasing difficulty in building transmission for wind and solar deployment may obviate this situation (Denholm and Sioshansi, 2009). Greater interconnection via transmission may use the large existing hydro storage resources more optimally. Other more specialised applications for energy storage, such as the provision of very fast-acting reserve and virtual inertial response, particularly on isolated or weakly connected power systems, may also prove cost-effective (Wu *et al.*, 2008; Delille, Francois and Malarange, 2010). The ability of storage to increase flexibility across multiple time horizons underpins its potential value to a system with increasing flexibility needs.

The potential CO_2 benefits of storage may be unclear in some situations. Several studies show that storage increases CO_2 emissions,[27] but these results are system specific and

27 Storage technology can increase the use of inexpensive coal generation, and therefore add to CO_2 production.

depend on assumptions around fuel mixes and carbon prices (Ummels, Pelgrum and Kling, 2008). As variable renewable energy penetrations increase to high levels, storage eventually has a CO_2 benefit because it reduces the curtailment of generation from variable renewables (Tuohy and O'Malley, 2011).

While storage may be a valuable source of flexibility for a power system, its deployment is restricted primarily by high capital costs and low conversion inefficiencies. In specific cases where the competing technologies are expensive, the value of storage can outweigh the higher costs. Increased production from variable renewable generation and the increasing need for flexibility in the future may create new opportunities for storage. Much research and development work is under way internationally to explore new ways to achieve the benefits of storage at lower cost, to reduce the costs of new and emerging storage technologies, and to address other barriers to increased deployment.

Technology choices in electricity system flexibility

Both demand and generation, as modelled in the 4DS and 2DS, will be subject to a broad range of change in the future electricity system where a large share of electricity will be generated from variable renewables, and which will include new electricity demands, such as electric vehicles and increased use in space conditioning.

Increased electrification will affect the economics of power systems and the value proposition of generation, T&D, demand response and storage resources. New links will be found between electricity infrastructure and other uses of energy, such as making the link between thermal energy storage and power system operation to provide lower-cost energy storage to benefit the heat and electricity sectors (Kiviluoma and Meibom, 2010). Adding thermal storage to co-generation plants will not only reduce the variability to the electricity system, but can actually become a flexibility resource. Electric vehicles are still in the early stages of development and deployment, but offer an interesting and potentially useful form of storage, linking the electricity sector to the transport sector. Some studies explore vehicle-to-grid application, through which energy is stored in vehicle batteries and returned to the grid, but it is not clear how significant this will be (IEA, 2011b; Kempton and Tomic, 2005). Converting electricity into hydrogen (or other fuel forms) is technically possible and has future potential, but with high capital investment in infrastructure and in further development of capacity or options to store electricity for later reuse (Sims *et al.,* 2011). The scale of investment required is an impediment to realising these technologies in the near to medium term.

Although not exhaustive, Figure 6.16 summarises the operational status of many technologies described in this chapter, and also highlights the many aspects of the electricity system that must be addressed on a daily basis. Multiple technologies can meet many of these system requirements, with due consideration of the particular aspects of a given electricity system and available resources. Alongside many existing and conventional approaches, new ones are becoming viable and could offer secure economic solutions to system operation. It is only by thinking in terms of complete systems that optimum solutions can be found.

As technologies are developed and become mature – in some cases very rapidly – Figure 6.16 will change. Moreover, as operating measures evolve, new choices for planning, operation and maintenance will be available for electricity system stakeholders. Continued monitoring of technological development and the sharing of best practices can help to ensure that barriers to these opportunities are addressed and optimal approaches are chosen.

Figure 6.16 Technology options for non-energy electricity system applications

	Application by response timeframe										Discharge time/ duration
	Hours					Minutes			Seconds		
	Energy arbitrage	Generation capacity deferral	(T &D) investment deferral	Congestion management	Voltage support	Black start	Spinning reserve/load following	Renewable ramp reduction	Regulation	Power quality	
Generation											
Conventional generation		M	M		M	M	M	M	M		> Hours
Generation re-dispatch			M	M							> Hours
Hydro generation			M	M	M	M	M	M	M		> Hours
Distributed generation					D	D	D	D	D	D	Minutes/hours
Demand response											
Industrial	M	M		D	D		M				Hours
Commercial/residential				D	D	D	D	D	D	D	Minutes/hours
Network/interconnection											
Interconnection	M	M	M	M		M	M	M			Hours
Transmission	M	M	M	M	M	M			M	M	> Hours
Static compensation devices			M		M						> Hours
Power electronics										M	Seconds
Storage technologies											
Pumped hydro	M	M	M	M	M	M	M	M	M		Hours
CAES	C	C	C	C	C	C	C	C			Hours
Flywheel						D	D	D	D	D	Minutes
Super capacitor										D	Seconds
Battery technology						D/C	D/C	D/C	D/C	D/C	Hours/Minutes
Operational measures											
Protection measures			M	M							Seconds
Dynamic line rating			C	C							Hours
Forecasting	M										Hours

Technology maturity key: M Mature C Commercial D Demonstration

Note: Battery technologies consist of a range of chemical conversion approaches that differ in application and maturity. Of these technologies, flow batteries can be considered at the R&D stage at this time.

Key point *Conventional and new technology options along the electricity system value chain need to be considered to discover secure and economic operational solutions.*

The role of regulation in electricity system evolution

More adaptable electricity system policy and regulation will help deliver a more flexible electricity system – and thus a value proposition – from smart-grid deployments to all electricity system stakeholders. The range of potential flexibility resources and the need to deploy resources throughout the electricity system (*e.g.* from generation to demand) require that regulation be particularly adaptable, as does the fact that system flexibility will be developed incrementally rather than all at once. Current regulatory and market systems can hinder (and already have hindered) demonstration and broader deployment projects. Regulatory and market models that address system investment, prices and customer interaction must evolve as technologies offer new options.

Strong government[28] leadership – local, national and international – in regulation is needed to support and facilitate the delivery of investment where it's needed (both conventional and new technology investments at the demonstration and deployment phase) and determine where benefits are likely to accrue. Clear statements of investment objectives and priorities at the political level can provide a framework for collaboration among diverse market players while also helping to allocate roles and responsibilities.[29]

Provision of flexibility from dispatchable generation technology is sometimes hindered by the absence of any market or regulatory structure to compensate such services. Since the revenue structure of flexibility services is different from that of bulk electricity production, clear, stable and long-term regulatory policies are needed to encourage investment. If not, investment will be stifled and the resulting lack of flexibility could harm system reliability. This situation will only worsen as the need for flexibility increases.

To enable demand response to provide flexibility services, regulatory mechanisms must be put in place to open the market to new actors (such as aggregators and telecom and internet providers) that are not currently involved in the electricity industry. At the same time, regulation will need to address data privacy and security. Without attention to these issues, consumer backlash may prevent optimum deployment of smart grids (or important elements of them) and, ultimately, the economical and efficient provision of flexibility.

As grid modernisation efforts move forward, adapting existing policy, regulatory and market environments to support new technology investment will be a major challenge for electricity sector stakeholders. International collaboration on policy and regulatory environments that support new technology investment is an essential undertaking for all actors. The different approaches to enhance system flexibility that regions may choose, based on what resources are available to them, will also add to regulatory complexity. This may make it more difficult to share "lessons learnt" across jurisdictions. Other potential problems include regulatory challenges (including telecom investments), broader implications of managing effects of technology deployment on customers, clarification of the roles of individual market participants and enhanced collaboration.

Recommended actions for the near term

The electricity system of the future will be substantially different from the one currently in place. To meet future electricity system needs, it is vital to focus not only on the end point, but also on plans to manage the transition. This chapter highlighted several pertinent aspects of the future electricity system: growth in demand and capacity, and the increased need for flexibility to 2050; investments needed in networks and smart grids; and the technical potential of demand response and storage to provide flexibility.

28 This includes governments at the national, sub-national or even local level depending on jurisdictional structure.

29 A series of preliminary case studies in the United States on legal, policy and regulatory barriers to the implementation of smart-grid technology supports the idea that clear state policies assist in fast-tracking deployment and reduce confusion around market goals and implementation. See "Smart Grid Collaboration Needed to Repower U.S., VT Law School Study Suggests", www.vermontlaw.edu/Academics/Environmental_Law_Center/Institutes_and_Initiatives/Institute_for_Energy_and_the_Environment/Ongoing_Research_Projects/Smart_Grid_Project.htm

The need for flexibility is increasing as quickly as variable renewable generation comes on line, but deployment of this resource can be carried out incrementally. It is vital to focus on better links among planning, regulation, technology and customers, taking a long-term perspective on investments that may increase electricity rates today but help manage rates in the future. Further refinements in quantifying flexibility needs and resources will yield more accurate assessments, which can then lead to more optimum technology deployments.

Approaches currently used to plan the electricity system are typically based on peak demand and worst-case scenarios. Smart-grid deployment, along with better understanding of the need for flexibility and other ancillary services, will change the way systems are designed and deployed. More real-time data will support better planning, maintenance and operation of systems, thereby improving overall system management. But continued modelling and evaluation of costs and benefits will be needed to ensure that rational investment decisions are made.

Multiple resources can be used to provide flexibility, but applicability will often be regionally dependant. Thus, it is essential to consider local attributes – from technical, regulatory, market and behavioural perspectives – to find practical and economically sound solutions. Engaging with the global community to determine best practices can be helpful in the evaluation of such solutions, but ultimately decisions must be taken in the context of local situations.

The links between the electricity and heat and/or transportation systems are starting to attract widespread consideration. Such linkages will require operational changes and add further complexity, but this can be managed through smart-grid deployments. Further effort and study are needed to demonstrate how variability can be reduced at the same time that flexibility resources are added. Continued investigation into finding additional linkages among various energy systems, coupled with the development of regulatory and business models, can yield more opportunities to increase efficiency and make better use of existing infrastructure.

As demonstrated, the largest portion of investments in the electricity system will be needed in the distribution network. Substantial scope exists to investigate energy system interaction in urban centres (often referred to in the context of Smart Cities), an area that could help to address the near-term issues of EV impact on the electricity system and identify where greater demand resources exist for flexibility and peak demand reduction. A scoping exercise to determine gaps in analysis would be a first step in this area.

The use of smart grids in developing countries and emerging economies needs further study and analysis. The challenges experienced, such as high technical and commercial losses, as well as very high growth rates, could significantly benefit from cost-effective smart-grid deployments. The need for deployment of electricity system infrastructure due to growth in demand could be met from the beginning with smart and flexible electricity systems, including micro- and mini-grid applications used for rural electrification.

Chapter 7

Hydrogen

Hydrogen could play an important role in a low-carbon energy system, but this depends on many factors, such as the level of system integration. An increasing role for hydrogen could help avoid over-reliance on other low-carbon energy sources, particularly bio-energy.

Key findings

- ***Hydrogen is a flexible energy carrier with potential applications across all end-use sectors.*** *It is one of only a few near-zero-emission energy carriers (along with electricity and biofuels) and should be carefully considered as part of a global decarbonisation strategy.*

- ***Hydrogen could play an important role in a low-carbon road transport system,*** *but faces significant barriers. Hydrogen, used in fuel-cell electric vehicles (FCEV), is a logical low-carbon solution for a range of vehicle types, such as longer-range cars and trucks. Hydrogen technology, however, suffers from a nearly complete lack of infrastructure, and fuel cells (FC) are still expensive. On-board hydrogen storage is still a concern. A major co-ordinated societal effort will be needed to overcome these challenges.*

- ***Hydrogen could be deployed in buildings and increasingly used in industry.*** *Low-carbon hydrogen from renewable sources of energy or fossil fuels in combination with carbon capture and storage (CCS) can be mixed with natural gas for use in conventional heating and power applications. In the long run, industrial processes such as the production of steel could be decarbonised through hydrogen-based steel making. In buildings, micro co-generation units with hydrogen fuel cells could be an important application.*

- ***Hydrogen may become especially important in the very long term.*** *Sectoral emissions reductions to meet the 2°C target appear achievable through 2050 without using hydrogen, for example by relying on intensified use of electricity and biofuels in transport, or on carbon capture and storage in industrial applications. But in the very long term, completely eliminating fossil fuels in transport and industry without resorting to hydrogen may be hard to achieve.*

- ***Large-scale hydrogen energy storage could help enable high levels of variable renewable energy deployment in the future.*** *As costs decrease and technology matures, the potential of hydrogen to provide temporal decoupling of electricity supply and demand on minute-by-minute to weekly time scales could provide the flexibility needed to maximise the integration of variable renewable sources of energy.*

- ***The construction of an entire hydrogen transmission and delivery infrastructure will require major investments,*** *yet small compared to expected total transport spending. On a global scale, hydrogen generation, transmission/distribution, and refuelling infrastructure could be developed for around USD 2 trillion, to meet an ETP target of serving* *a global fleet of 500 million hydrogen vehicles by 2050. This represents about 1% of total projected road transport vehicle and fuel costs between 2010 and 2050.*

- ***Establishing a hydrogen infrastructure will require concerted action among all potential stakeholders.*** *This includes the refining/chemical industry, natural gas grid operators, power providers, car manufacturers, station owners and municipalities, and will need strong government support. The level of co-ordination and investments needed represent major challenges.*

Opportunities for policy action

- *Ongoing hydrogen research and development is crucial. Fuel-cell vehicles are improving rapidly, but achieving further cost reductions and addressing on-board energy storage issues could speed deployment. The interaction between large-scale variable energy integration, energy storage and the use of hydrogen as both a fuel and feedstock needs to be investigated in more detail and on regional levels.*
- *More hydrogen early deployment projects are needed. Over the next five to ten years, planning for the possibility of a major hydrogen system roll-out will require gaining more real-world experience with hydrogen, including developing early full-featured systems that service significant numbers of fuel-cell vehicles and perhaps other fuel cell applications in buildings and industry. Such projects will help to resolve remaining technical and legal issues, along with more fully developing optimal roll-out strategies.*
- *Research, development, demonstration and early deployment (RDD&D) expenditures on hydrogen and fuel-cell vehicles should be sharply increased. For a system that would cost USD 2 trillion to build (and with USD 3 trillion per year global vehicle industry), research, development and deployment (RD&D) expenditures on fuel-cell electric vehicles and hydrogen should account for at least USD 3 billion. This represents a fivefold increase compared to current spending of about USD 600 million per year, but is still a tiny amount compared to what the roll-out for a full hydrogen/FCEV system will cost; if that cost could be cut by a few percent through stronger RD&D programmes, they would pay for themselves many times over.*

Hydrogen (H_2) is a flexible energy carrier that can be produced from various conventional and renewable energy sources, including natural gas, coal, biomass, and non-renewable and renewable electricity. It can be used in all sectors, either as an energy carrier or as feedstock. Today it is almost entirely used as a feedstock in the refining and chemical industry (about 6 exajoules [EJ]). But can hydrogen really play a growing future role as an energy carrier in the transport, industry and buildings sectors?

A decade ago, the answer seemed to be yes and "hydrogen economy" was the buzzword. In particular, shifting transport fuels away from petroleum products to hydrogen promised several advantages: zero greenhouse or pollutant emissions at point of use, efficient end-use applications (*e.g.* fuel cells), and the possibility for decentralised generation and storage.

Today the picture is, if anything, cloudier. In transport, hydrogen's potential has been challenged by electricity, in the form of electric vehicles. Future applications in buildings may be less important than previously thought, if heating demands decline or are met in other ways (*e.g.* district heating, heat pumps). New, major applications in industry may take many decades to develop.

But hydrogen remains one of a very few energy carriers capable of achieving near-zero carbon dioxide (CO_2) performance. Hydrogen's potential added value will depend on many factors, across several demand sectors, and must be evaluated from a systems perspective.

Its ability to serve as a low-carbon fuel and feedstock for a number of applications, as well as providing a potentially important energy storage option, may be valuable in the future.

Looking at hydrogen across sectors, with a view to timely development of demand and infrastructure, reveals some synergies, but also a number of challenges that call for careful consideration. Hydrogen's dominant form of production is as yet unknown. The methods for transporting hydrogen to the end user will evolve over time, from low to higher volumes as markets develop. Net system costs and benefits have not been fully worked out, nor have the economically and technologically efficient transformation pathways.

Perhaps the most important question is whether hydrogen is truly needed to achieve a sustainable low-carbon energy system. It is certainly possible to envisage a future energy system built mostly around electricity, although electricity does not appear to be suitable for some services, such as long-haul trucking, shipping and aviation. More energy-dense, low-carbon fuels will be needed and, while biofuels are eventually expected to provide a near-zero greenhouse gas (GHG) option, advanced biofuels also have important hurdles to overcome to reach a commercial position. Further, the long-term biomass supply outlook is unclear, particularly considering various sustainability aspects and potential emissions related to direct and indirect land use change. Finally, energy storage (particularly for more than a few hours) is still a challenge, one where hydrogen might play a useful role.

Given that deploying hydrogen will require major capital investments and has a range of market barriers to overcome, it is important to consider where it is really needed and where it simply provides a potentially superior and/or low-cost service compared to other solutions. This chapter addresses how hydrogen could be deployed, how much might be needed, by when, and at what cost; and ultimately, whether it should be deployed at all. Although the answer to this last question cannot be definitive and should therefore be revisited at a later date, this chapter examines whether hydrogen use may be critical to meeting emissions reduction targets for 2050, given what we know at this moment.

Hydrogen today

Today's annual hydrogen production of around 6 EJ is split 50-50 between the refining and chemical industries. In refineries, hydrogen is mainly used for hydro-treating and hydro-cracking, with much of it generated on-site during catalytic reformation. Some refineries rely solely on catalytic-reformer hydrogen, while more complex refineries produce it on-site, using refinery off-gas[1] and/or supplementary natural gas. In the chemical industry, most hydrogen goes into the production of ammonia- and nitrogen-based fertilisers. Globally, 48% of bulk hydrogen is produced with natural gas steam reforming, 30% is oil-based, 18% is derived from coal gasification and about 4% is generated using electrolysis (Saur, 2008).

Beyond industrial applications, hydrogen is still in its infancy. Fuel-cell electric vehicles are now in the demonstration phase but some car manufacturers claim they will start commercialisation in 2015 (*e.g.* H_2-Mobility project). Today about 650 FCEVs are on the road worldwide (Table 7.1). They are served with hydrogen by about 200 pilot refuelling stations, the majority of which are in the United States. Although mostly non-public, different refilling technology layouts are currently being tested with the help of pilot and demonstration projects. A business case for hydrogen-fuelled vehicles already exists with materials handling equipment: about 800 FC forklifts are operated in the United States for indoor facilities. In multi-shift operations they might provide a more economic service than battery-electric forklifts, which face challenges due to frequent battery change-outs and longer recharging time.

1 Refinery off-gases are carbon and hydrogen rich exhaust gases which occur during refining.

In recent years, considerable funding was allocated to hydrogen RD&D in the United States, Germany, Japan and Korea among others, with a clear focus on transportation. Under the German National Innovation Program Hydrogen about EUR 1.4 billion will be spent on hydrogen RD&D between 2007 and 2016, with half of the money coming from industry. In the United States, annual expenditures averaged around USD 160 million over the past five years, and funding for hydrogen-related RD&D via the Japanese New Energy and Industrial Technology Development Organization was about USD 100 million in 2011. According to Japanese prospects, the FCEV demonstration phase will be finished by 2015, followed by early commercialisation. Hydrogen RD&D was funded with some USD 600 million over the past ten years in South Korea, and finally the European Commission allocated about USD 600 million to research and demonstration projects for 2008 to 2013.

Table 7.1 **Spotlight on hydrogen vehicles and infrastructure numbers in today's leading countries**

	United States	Japan	Germany	South Korea	World
FCEV stock (number of vehicles)	~300	~50	~65	~130	~650
Of which, buses	~60	~15	~8	~4	~200
Number of hydrogen stations	~80	~16	~8	~13	~200
Hydrogen pipeline network length (km)	~1 000	na	~290	na	~2 500

Note: na = not available.
Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Hydrogen in the energy system context

According to *ETP 2012* modelling results, the increased integration of (partly) variable renewable energy resources (varRE) into electricity systems constitutes one of the most-effective CO_2 mitigation options together with efficiency improvements. But this may require the ability to store energy to balance electricity supply and demand in the long term.

The added value of hydrogen lies in its potential for flexibility: it can be produced from different sources, either renewable sources or in combination with CCS, in small- and large-scale applications; it has the possibility of being stored either in gas or liquefied form over long periods of time; it can be transported over long distances; and it can be used as a carbon-free fuel in a number of applications across all sectors.

Potential end-use applications include:

- **Transport.** As a transport fuel for FCEVs, including passenger cars, trucks and buses, and possibly even ships. In the near term, car and bus fleets are likely to be the main focus of demonstration projects and could be important early adopters of commercially available hydrogen.
- **Industry and transformation sector.** Increasing demand as a feedstock in the refining and chemical industries, due to lower crude-oil quality and the need for cleaner petroleum-based fuels,[2] as well as increasing demand for fertilisers. Hydrogen may also eventually be used as reductant in the steel industry.

2 Heavy, extra heavy or tar-sand crude oils need special treatment to reduce sulfur content and increase the ratio of hydrogen to carbon, both demanding additional hydrogen.

- **Buildings.** Decentralised co-generation, using stationary fuel cells. Excess electricity could be used for grid stabilisation. In the near term, natural gas can be blended with hydrogen and used with the current infrastructure.

As an intermediate energy carrier, hydrogen could also play a significant role for:

- **Energy storage.** As countries ramp up renewable, variable energy sources (*e.g.* wind turbines and solar photovoltaic), excess electricity might need to be stored for a few hours or in some cases for days, weeks or months. Since electricity can be used to create hydrogen via electrolysis and the hydrogen can later be converted back to electricity, hydrogen storage provides an option for large-scale and long-term energy storage.

Box 7.1 Spotlight on large-scale hydrogen storage

Because large quantities of hydrogen can be stored in underground caverns providing high energy density, it might be one of the few storage options with sufficient capacity on a weekly or monthly time scale. Instead of re-electrifying hydrogen, it can be used for other purposes, such as transport fuel. The overall benefits on the demand side, together with large-scale variable renewable energy integration on the supply side, might then justify the high infrastructure investments.

To calculate the benefits of hydrogen storage, estimates need to be based on:

- **Evaluation of electricity storage needs.** The projected integration of variable renewable energy and the resulting impact on the electricity supply and demand balance, on different time scales, need to be examined on a regional basis. Based on this, the need for dispatchable electricity has to be estimated, taking into account all other options to control the supply side, such as back-up capacities and grid extensions, as well as demand side management and the use of smart grids.
- **Evaluation of storage potentials and technologies.** Usefulness of different storage applications needs to be determined, as well as time scales and respective costs. Mining the storage potential of smart grids and a sizeable fleet of battery-electric vehicles (BEVs) is needed. It needs to be clarified whether conventional back-up capacities, such as natural gas turbines, can play a role under an aggressive mitigation scenario, and whether they are still competitive at few full-load hours.

During the last decade, considerable research has been undertaken identifying optimal pathways for hydrogen integration within end-use sectors, especially transportation. Several studies have demonstrated how an uptake of hydrogen can contribute to different climate targets, using energy-system optimisation models. The crucial role of hydrogen infrastructure deployment has been investigated in detail, but the existing modelling analysis did not look into the effect of hydrogen storage on the integration of variable renewable energies in the power sector in much detail (Gül *et al.*, 2009). Other spatially and temporally detailed energy system models – for example REMix (DLR, 2010) – take into account the impact of different energy-storage options on costs, emissions and renewable energy integration, but they often focus on the power sector only and do not represent synergies with other end-use sectors.

- **Synthetic fuels.** Production of synthetic natural gas or other synthetic hydrocarbons. Adding hydrogen to syngas from biomass gasification (instead of the classic shift reaction) could substantially increase the biomass potential.

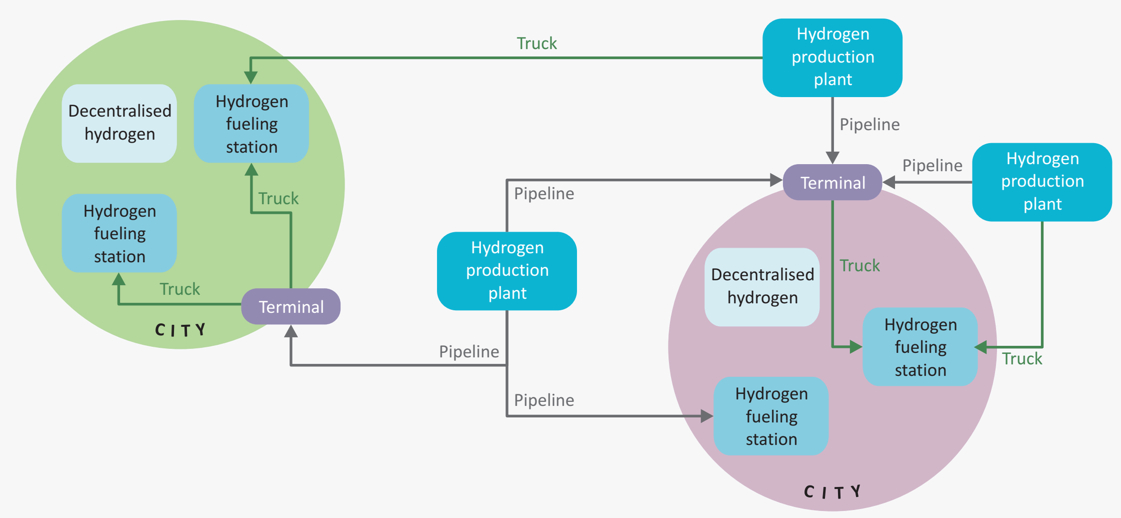
Energy sources used to generate hydrogen will affect its availability, the required infrastructure and its carbon intensity. Using natural gas is an option (via methane reforming to obtain hydrogen) because it is widely available and distribution infrastructures already exist in many countries. This could help make hydrogen fuel available for vehicles in the near term, but will not provide a particularly low GHG pathway. To achieve long-run sustainability, the focus must eventually shift to carbon-free hydrogen production, via natural gas or coal with CCS, biomass gasification, or from electricity, generated with renewable energy resources.

Hydrogen technologies and conversion pathways

In examining how a hydrogen system would look and how much it would cost, a number of aspects must be considered. The general design and geographic layout of a hydrogen production, transport and distribution system (Figure 7.1) has a significant impact on the optimal hydrogen generation technologies and infrastructure requirements:

- **Centralised production.** Hydrogen is produced and stored in large-scale facilities and then transported and distributed via trucks (in gas or liquefied form) or pipelines.
- **Decentralised production.** Electricity, natural gas or biomass is transported and hydrogen is produced in small-scale applications at the demand site.

Figure 7.1 **Different hydrogen generation and transportation layouts**



Source: Gül, 2008.

Key point *Different transmission and distribution infrastructure layouts mainly depend on hydrogen demand, transport distance and resource availability.*

The differences between centralised and decentralised production are substantial. Initially, a hydrogen system might take a small, decentralised approach. Finally shifting to larger-scale centralisation might result in low-cost hydrogen supply in the long run. This transition, together with finding the optimal combination of centralised and decentralised hydrogen production, is one of the major challenges in achieving the widespread use of hydrogen.

A number of hydrogen-generation technologies are suitable for either small- or large-scale application, although investment costs per unit are higher on a smaller scale. Further, it makes a big difference whether hydrogen itself – or the electricity, natural gas or any other liquid or solid feedstock necessary to produce it – has to be transported. The question of whether hydrogen production is centralised or decentralised depends on several factors, with demand versus transport distance and the availability of primary energy resources being the most important ones.

During the roll-out phase of end-use technologies (apart from yet existent hydrogen use in refineries and chemical industry), the hydrogen flow needed is small and does not justify investment in large-scale generation facilities. Hydrogen used in the initial phase can come from two sources:

- excess hydrogen from existing hydrogen production plants for the chemical and refining industries;
- on-site hydrogen production at refuelling stations, using small-scale natural gas steam reformation or electrolysers.

Increasing today's annual hydrogen generation of 6 EJ by 10% would be enough to satisfy demand from 30 million FCEVs,[3] or 4% of current passenger light-duty vehicles (passenger LDVs). Currently hydrogen is produced from fossil resources (such as natural gas) without CCS, but still the use of hydrogen and FCEVs would reduce emissions as the well-to-wheel efficiency is higher than using natural gas directly with an internal combustion engine (ICE). Using existing hydrogen production infrastructure could help ease the technology deployment phase.

Initial end-use hydrogen demand is likely to come from the transport sector and, in particular, from fleet vehicles, such as city buses, commercial fleets or taxis, because these can be centrally fuelled and hence generate sufficient demand to justify investing in a supply system. Fleet vehicles can serve as the foundation for an initial refuelling network, which can then be enlarged to city clusters and main intercity highways.

Using hydrogen on a larger (*e.g.* city-wide) scale requires long-term planning, and building the necessary infrastructure will not happen quickly. Planning can simplify the transition from initial on-site hydrogen generation to central production (*e.g.* using an existing hydrogen facility) with adequate transport, which may suffice until the system becomes fairly large. At that point, it finally makes sense to consider investment in a dedicated hydrogen pipeline transmission and distribution system.

It is possible to start planning such a system early. New natural gas distribution networks can be designed with an eye towards future transport and distribution of hydrogen. There is already some experience with pipelines that were originally intended to transport petroleum being used for hydrogen at moderate pressures up to 50 bar (AirLiquide, 2005). It is also important to take into account current hydrogen pipeline infrastructure. Today, around 2 500 kilometres (km) of hydrogen pipelines exist, with 1 500 km in Europe and the remainder mainly in the United States (Gillette and Kolpa, 2007). Large-scale demonstration projects partially need to build on existing generation and transmission and distribution (T&D) infrastructure to provide high impact at lower costs.

Fuel-cell electric vehicles will only be attractive for a broader clientele if a sufficient network of refuelling stations is in place. Thus, roll-out of the infrastructure and end-user technologies has to take place at the same time or even before, causing a classic "first-mover" disadvantage (or "chicken-or-egg" problem), due to underutilised infrastructure and

3 Assuming fuel consumption to be 1.1 kg of hydrogen per 100 km at 15 000 km per year.

poor payback rates on investments until FCEVs are widespread. The required refuelling infrastructure will clearly need strong government support during such a transition period, which could last many years if FCEVs are slow to gain market share.

Hydrogen generation

Gaining an overview of different generation technologies requires a comparison of levellised production costs (Table 7.2). Hydrogen generation costs (as well as net carbon emissions) depend on the respective energy source. Generation costs need to come down significantly for low-carbon hydrogen to become competitive with other fuels. The United States Department of Energy (US DOE) estimates that delivered costs of hydrogen need to drop to below USD 4 per kilogramme (kg) (equals around USD 1 per litre of gasoline equivalent [Lge]) for FCEVs to become competitive against other efficient vehicles – in particular to hybrid electric vehicles.

Hydrogen transport and distribution in a mature market could add up to around USD 2/kg, depending on demand flow and distance but also on the needed storage pressure, which should make future generation costs less than USD 2/kg. The envisaged production costs of hydrogen in an established market indicate that efforts are still needed to bring down costs of low-carbon hydrogen. So far, only natural-gas steam reformation with CCS, coal gasification in combination with CCS, biomass gasification and thermo-chemical separation with nuclear heat seem able to reach the production cost target in the future if hydrogen needs to be transported to the end consumer over longer distances.

Table 7.2 Levellised costs of hydrogen-generation technologies, ranges depend on scale

Generation technology	CCS	Deployment phase (USD/kg)	Established market (USD/kg)
Natural gas steam reforming (small and large scale)	No	1.9 to 3.6	1.7 to 2.8
Natural gas steam reforming (large scale only)	Yes	~1.8	~1.8
Coal gasification	No	~1.1	~0.7
Coal gasification	Yes	~1.4	~1.1
Electrolysis (average mix, small and large scale)	-	4.9-5.5	5.0-5.5
Electrolysis from wind (on-shore)	-	~7.0	~3.9
Electrolysis from solar	-	~10	~4.9
Biomass gasification (small and large scale)	No	1.9-3.5	1.6-2.8
Biomass gasification (large scale only)	Yes	~2.1	~2.1
Thermochemical separation, nuclear	-	~3.5	~1.5
Thermochemical separation, solar	-	~7.0	~3.5

Note: Cost calculations are based on a discount rate of 8%. Fuel prices are based on the 2DS. Oil prices are USD 78/bbl in 2010 and USD 87/bbl in 2050. Coal prices are USD 3.4/GJ in 2010 and USD 2.1/GJ in 2050. Gas prices are USD 4.2/GJ in 2010 and USD 6.6/GJ in 2050. For biomass-based options a biomass price of USD 6/GJ has been assumed. The price of CO_2 is not reflected in this table.

Several hydrogen production technologies to date are restricted to certain application sizes. Natural gas steam reforming is already used on large scale in the chemical and refining industry. Scaling down the process to some 100 kg of hydrogen per day is challenging. Three different technologies currently exist: steam reforming, partial oxidation and auto-thermal reforming. Maintaining optimal chemical conversion in the presence of a catalyst at high temperatures and medium pressures makes small-scale on-site steam reforming costly and difficult to adapt to transient operations due to limited and irregular hydrogen demand.

Coal gasification and subsequent hydrogen production are options for regions with abundant coal resources, but CCS must be applied to mitigate CO_2 emissions. The technology is capital intense and only suitable for large-scale applications. Lessons learned from integrated gasification combined cycle (IGCC) projects will be helpful in further exploring this technology. The combined production of hydrogen and synthetic fuels is also an option, but it significantly increases carbon emissions (compared to producing only hydrogen), as the produced synthetic fuel still contains carbon. A drawback of coal gasification is the need for pure oxygen, which has a costly and thermodynamically inefficient generation process.

Biomass gasification is another variant of the gasification process, but its scale can be restricted by available biomass supply and feedstock costs. Using agricultural waste can make this option more competitive. Other processes that produce hydrogen and synthetic fuels, or even use hydrogen as a feedstock to hydrogenate (*i.e.* add hydrogen molecules to) the produced syngas from biomass gasification instead of using the water-gas shift reaction, can significantly increase the resource potential of biofuels.

Transformation of excess electricity into hydrogen at large wind or solar power plants requires large-scale electrolysers, which do not yet exist. Two basic types of low-temperature electrolysers, alkaline and proton exchange membrane (PEM), are commercially available in sizes up to 1 500 kg/day (alkaline only), with efficiencies around 67% (NREL, 2009a). If higher capacity is needed, several electrolysers have to be applied in parallel, which also offers the opportunity of modular expansion. High-temperature solid-oxide electrolysers are still in the research phase, but could significantly increase efficiency.

Another possibility for generating hydrogen is through thermo chemical separation of water. At high temperatures of more than 900 degrees Celsius (°C), plus help from chemicals such as sulphur and iodine, water is split into its elements. The main issues are capturing the split hydrogen, corrosion and the low process efficiency (around 43%), as well as the sustainable generation of the required heat (IEA, 2005). One possibility for sustainable heat generation could be the use of concentrated solar power in regions with high solar potential. The use of renewable heat could also help to overcome the efficiency issue.

Last but not least, a range of more uncertain generation technologies exist that are still in the research phase. These include photo-electrochemical and photo-biological generation of hydrogen and the fermentation of biomass. These technologies could draw on a huge resource base, but still need to be improved to become cost competitive.

Hydrogen transport and distribution

Transporting and distributing hydrogen may well be the biggest challenge to integrating hydrogen fully into the overall energy system. The physical properties of hydrogen at ambient conditions are quite unfavourable. Its low volumetric energy density (around 30% of methane at 15°C and 1 bar), together with the ability to embrittle metal-based materials, put constraints on its transport and storage.

If hydrogen is centrally produced, three options for transport are available in the near term:

- Transport of hydrogen gas with truck-trailer combinations at pressures of 200 bar currently, with up to 900 bar in the future. The loading capacity is around 300 kg (at 200 bar) up to 900 kg (at 520 bar), with investment costs of USD 300 000 to USD 600 000 per truck-trailer.

- Transport of liquefied hydrogen using truck-trailer combinations with capacities up to 4 000 kg and investment costs of around USD 800 000.
- Transport of hydrogen gas via pipelines. The diameter of the pipeline is determined by the expected hydrogen flow, the inlet pressure and the pressure drop over distance.

It is worth noting that the transport and delivery infrastructure cannot be examined in isolation because all three delivery options require different equipment at a given station.

While transport of hydrogen gas by trailer is relatively cheap in terms of investment, it is restricted by its low load capacity, which is decreased further because the truck cannot be fully emptied. A driving pressure difference between the trailer and the storage unit at the station is required. Given the fact that an average refuelling of a hydrogen-powered car is around 5 kg, one truck could only supply a station with enough hydrogen to fill about 50 to 150 cars per day (if the station gets one delivery per day). Depending on the delivery distance, this would require significant time, energy and trucks for transport. Currently, hydrogen is stored on board FCEVs in gaseous form under 350 bar or 700 bar. Compression equipment at the station therefore needs to be added to the list of costly investments. Especially in the United States, where most conventional stations (and potentially also hydrogen stations) are owned by small businesses, this barrier needs to be addressed when the hydrogen distribution network is planned.

Liquefied hydrogen significantly increases trailer capacity, but at an expense of around 25% to 30% of the transported energy needed for the liquefaction process. Because it takes less energy to pressurise a liquid than a gas, the high pressure needed for on-board storage of hydrogen gas is relatively easy to achieve. The equipment at the station – including cryogenic vessel, pump, vaporiser and dispenser – are less capital-intensive than low-pressure storage and on-site compression of gas. Shifting investment from relatively small-scale but numerous refilling stations towards a centralised liquefaction plant at the place of hydrogen generation or at the city terminal could help realise benefits from economies of scale.

Pipeline transport of hydrogen gas is the cheapest option concerning variable costs. At moderate pressures below 100 bar, pipelines require about 3% of the transported energy per 100 km. The pipeline infrastructure is not in place yet, so building the necessary point-to-point transmission and inner-city distribution networks would require considerable investment.

Currently, a 20-inch steel transmission pipeline operated at a pressure of 100 bar would cost about USD 1 250 000 /km. Embrittlement is no longer a major issue due to proper material selection such as flexible-fibre-reinforced polymer pipelines. Pipeline transmission comes with the disadvantage of shifting investment for compression equipment to the station.

Levellised costs of the transport and distribution options depend heavily on distance and hydrogen demand. Low demand at shorter distances can be satisfied by trucking hydrogen gas, while high demand with long distances might be better served by trucked in liquefied hydrogen. High flows and medium distances favour pipelines. With lower numbers of FCEVs (less than 10% of total vehicles), investing in a pipeline T&D system is not economical.

With low hydrogen demand, on-site electrolysis may be a good option to provide hydrogen initially if no existing hydrogen plant is nearby. Electrolysers are also available at small capacities of 50 kg/day and less. Current hydrogen costs, including on-site electrolysis, compression and storage for a station dispensing 1 500 kg/day, would be in the range of USD 4.90/kg to USD 5.70/kg (NREL, 2009a). A station of this size could supply about 300 cars per day.

Annual hydrogen demand for a single FCEV might be in the range of 170 kg,[4] roughly 33 refuels per year. Hence, a 100% utilisation rate of the above-mentioned station would require 3 000 FCEVs. This in turn means that, for example, 1% of the vehicles in a big city (500 000 inhabitants) must be FCEVs,[5] which may not happen before 2025 to 2030. Due to smaller scale and lower utilisation rates of refilling stations, hydrogen costs for on-site generation may be significantly higher in the near term.

Smaller-scale hydrogen stations are needed in the near term: around ten stations per city[6] may be sufficient if stations are clustered (HYRREG/SUDOE, 2010; Ogden *et al*, 2011) and can survive with initial capacities as small as 50 kg/day. In a second step, corridors connecting urban centres could be equipped with hydrogen refuelling stations before building denser area coverage.

In a more mature market, a successful strategy would shift investment away from individual hydrogen stations thus following a centralised approach. If hydrogen was delivered as gas under high pressure or in a liquefied state, investment for compression equipment at the station would be significantly reduced. Furthermore, the centralised production facility could profit from economies of scale. If hydrogen is used as a large-scale energy storage option, there might be little alternative to the centralised system layout.

Safety issues are a concern with hydrogen handling. In general, hydrogen is prone to leakage due to its much lower viscosity and smaller molecules compared to natural gas. As the lightest molecule, it disperses very quickly in case of leakage and can form potentially flammable but quickly dissipating clouds. It burns very quickly and is more combustible (at lower temperatures) than gasoline or natural gas, unless its concentration is low. However, hydrogen flames have low radiant heat.

Leak detection is potentially more difficult than it is for natural gas. Natural gas and propane are also odourless, but the industry adds a sulphur-containing odorant. Currently, there are no known odorants light enough to travel with hydrogen, and at the same dispersion rate. Odorisation of hydrogen also introduces the potential for impurities in the fuel, which could hinder the performance and durability of equipment such as fuel cells.

Hydrogen storage

Hydrogen offers a valuable medium for energy storage because it can be converted from and back to electricity (although at low net efficiency). Different storage systems are needed for different applications;

- long-term storage of energy: large underground cavities suitable to store hydrogen at pressures of 80 bar and more are required;
- medium-sized storage systems for refilling stations: given that hydrogen is already used in many commercial applications in the chemical and refining industries, mature gaseous or liquid storage systems are already available;
- small-scale on-board storage for transport applications: in the near term, on-board storage in vehicles will be in the gaseous form, at around 700 bar; other chemical storage options such as liquid hydrocarbons might also be viable while the use of metal hydrides or surfaces of nanoporous materials is still in the research phase.

4 Assuming vehicles are driven 15 000 km/year with fuel consumption of 1.1 kg of hydrogen per 100 km.
5 Assuming 600 passenger LDVs per 1 000 people.
6 Assuming 500 000 inhabitants and a density of around 2 800 inhabitants per km², if the time per trip to the station was not to exceed 10 minutes at an average speed of 20 km per hour (km/h) and a tortuosity factor (deviation from straight line) of 0.7, ten stations per city would be the lower limit.

Large-scale energy storage

Underground storage of hydrogen in depleted gas reservoirs, aquifers and mined salt caverns may be an option if large capacities of variable renewable energy sources for electricity generation are integrated, although from the perspective of purity but also reactivity of hydrogen it is still unclear whether depleted gas reservoirs and aquifers can offer a viable solution. There is already a precedent of storing natural gas underground, and existing know-how will be helpful for hydrogen storage. Total round-trip efficiency of a hydrogen storage system – including electrolysers, compressors, storage and fuel cells – is in the range of 28% for current systems with a PEM fuel cell, up to 55% for a future system with a solid-oxide fuel cell (NREL, 2009b).

Not many alternatives exist for large-scale energy storage to balance electricity supply and demand on more than a daily basis. Electricity may be stored in different types of batteries: two major characteristics are different peak power and capacity, but all existing batteries have comparably low energy densities. Consequently, storage capacity is restricted by size and investment cost.

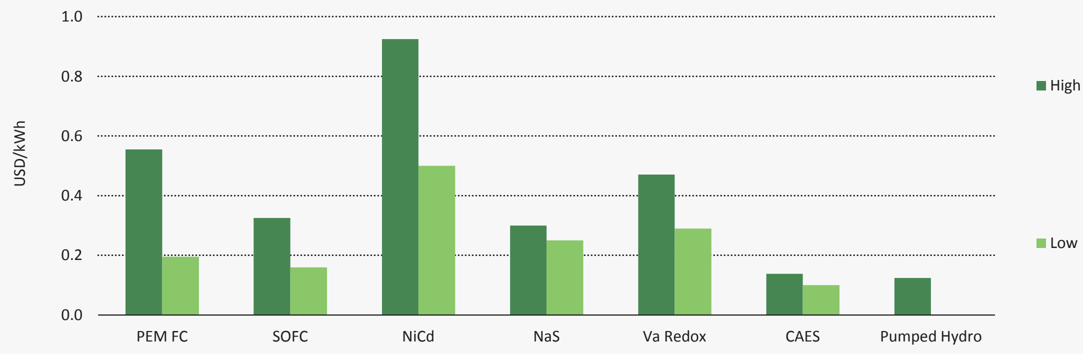
Pumped-storage hydropower and regulated hydropower plants offer large capacities with high total efficiencies (70% to 80%), but are obviously restricted by geographic conditions. Huge projects, with a size of several thousand megawatt-hours (MWh) of storage capacity, come at the expense of massive environmental interventions due to very low energy density.

Compared to hydrogen, compressed air energy storage (CAES) offers higher cycle efficiency (around 70%) at the expense of 100 times less energy density (compared to hydrogen at 120 bar). In addition, heat from the compression process will have to be stored if no supplementary gas is to be used to reheat the compressed air during the expansion process.

A near-term option to store and use excess electricity from variable renewable energy is to generate hydrogen via electrolysis and mix it with natural gas. The natural gas blend can contain up to 20% hydrogen and still be distributed via the current infrastructure to end-use applications with little modification. Metering may require a standardised hydrogen-natural gas mix, making additional hydrogen storage a necessity. Blending natural gas also provides the opportunity to connect electricity and natural gas grids (power-to-gas). This would help decouple electricity supply and demand by taking advantage of the already existing, extensive natural gas transport, distribution and storage networks. It raises the possibility of re-electrifying the hydrogen-natural gas blend using already existant natural gas combined-cycle power plants.

Levellised costs for electricity storage depend on the price for electricity and the maturity of the technology over time (Figure 7.2). Furthermore optimal charging cycles need to be achieved to maximise load hours and reduce costs. For both hydrogen pathways (PEM and solid oxide fuel cell [SOFC]), high costs in the near term are based on above-ground storage tanks, while the low costs in the long term are based on geological underground storage. Compared to stand-alone storage in different types of batteries, hydrogen could be more economical in the future. Compared to CAES or pumped hydro storage, stored hydrogen offers the flexibility to either be re-electrified, be used as transport fuel or to provide chemical feedstock. While more research is needed in this area, it appears that creating the flexibility to sell electricity at peak times or hydrogen as transport fuel when less electricity is demanded may improve the attractiveness of hydrogen storage.

Figure 7.2 Levellised costs of electricity storage



Source: NREL, 2009 b.

Note: PEM FC = Proton exchange membrane fuel cell; SOFC = Solid oxide fuel cell; NiCd = Nickel-cadmium battery; NaS = Sodium-sulphur battery; Va Redox = Vanadium redox flow battery; CAES = Compressed air energy storage. For the high case the assumed price for electricity is USD 0.06 per kilowatt-hour (kWh), for the low case USD 0.04 /kWh.

Key point *Hydrogen storage may be cost competitive in the future if envisaged cost reductions of the technology can be achieved.*

On-board energy storage

Hydrogen can be stored on board vehicles by physically increasing its density via compression or liquefaction, or in a chemically bound form such as a hydrocarbon liquid (such as methanol), via metal hydrides or in nanoporous surfaces.

Today, compressed hydrogen gas is usually stored at 350 bar or 700 bar, requiring sufficiently strong tanks made of composite materials. Liquefied hydrogen (cryogenic hydrogen) needs to be stored at extremely low temperatures, around -250°C (ambient pressure), and if the stored hydrogen warms up, it needs to be flared. Using a combination of compressed and cryogenic storage, the tank is filled with liquid hydrogen, but hydrogen may change phase if it warms up, and pressure may increase to 350 bars, before being flared.

Adsorbing hydrogen on large surfaces offers higher energy density but thermal energy is needed to release the hydrogen again.

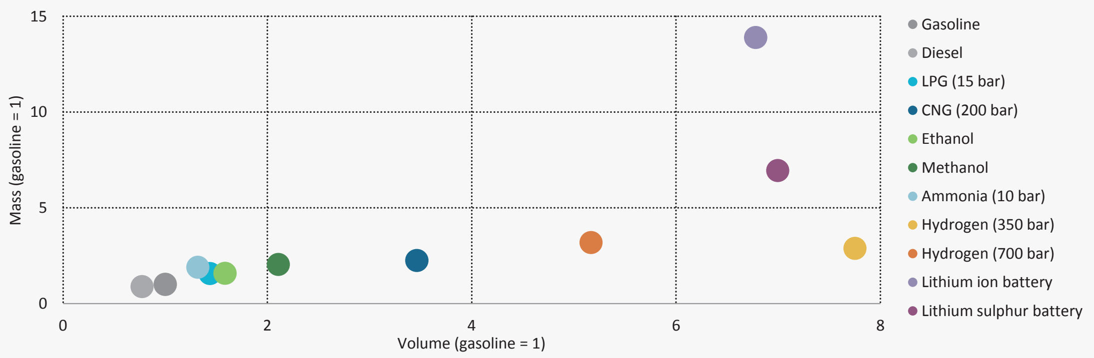
Storing hydrogen in liquids like methanol or ammonia makes it easier to transport under ambient conditions, but additional reforming equipment is required for FCEVs to generate hydrogen on-board again, resulting in an around 10% net cost increase (for methanol). In the case of methanol or ammonia, setting up the infrastructure also requires significant investment.[7] Finally, there are issues associated with handling and storage of relatively toxic and corrosive liquids (at least for methanol and even more serious for ammonia). Still, it is worth considering liquid options which may be particularly useful for niche applications like auxiliary power generation (*e.g.* on board of heavy duty vehicles to provide electricity when the engine is turned off).

Different vehicle on-board energy storage systems are benchmarked regarding mass and volume against gasoline in Figure 7.3. Vehicle effciency, as well as the weight of the tank, are taken into account. Hydrogen finds itself in the middle field with a far lower weight than batteries, and comparable (350 bar) or less (700 bar) space requirements. At 700 bar,

7 Ogden (1999) showed that additional investment at the vehicle level for on-board reformation of methanol, plus new additional methanol production capacity, might outweigh the liquid fuel's transport advantages.

hydrogen is still well below the energy density that gasoline or other liquid hydro-carbon fuels (*e.g.* biofuels) provide. As a result, such storage takes up considerable space on vehicles, typically reducing storage space for luggage and other items.

Figure 7.3 **Comparison of volumetric and mass storage requirements by fuel**



Note: Vehicle efficiency as well as weight of the tank is taken into account and benchmarked against gasoline.

Key point *Compared to batteries, on-board hydrogen storage weighs much less and uses less space (at 700 bar). Compared to liquid fuels hydrogen requires much more space.*

Today's FCEVs reach fuel economies of around 1.1 kg of hydrogen per 100 km; values around 1 kg/100km to 0.9 kg/100 km seem to be likely by 2020. Reaching a 500 km range is possible with 5 kg storage capacity. However, at 700 bar, the tank would be as large as 190 litres. Argonne National Laboratory (2010) projected that a 5.6 kg hydrogen on-board tank at 700 bar would cost around USD 3 500 even at high production volumes, which substantially increases the cost of FCEVs. Other estimates find somewhat lower potential future costs; NRC (2008) estimates a range of USD 10/kWh to USD 18/kWh in mass production, which equals about USD 1800 to USD 3400 per 5.6 kg tank. Substantial reductions of costs of carbon fibre composite material as well as production costs are needed.

Hydrogen end-use technologies

If pure hydrogen is used as an energy carrier, transformation of hydrogen into end-use energy will almost always rely on electricity generation using different types of fuel cells. If hydrogen is mixed with natural gas, burning it in gas turbines or using it in current residential and industrial burners is possible as well.

During the last 20 years, key attributes such as the power density, durability and cold start performance of fuel cells have been significantly improved. Today several types of fuel cells in different power ranges exist for stationary and transport applications. The four main types of fuel cells can be categorised by the type of electrolyte they use, as well as their operating temperatures:

- phosphoric acid fuel cells (PAFC);
- solid oxide fuel cells (SOFC);

- molten carbonate fuel cells (MCFC); and
- polymer electrolyte membrane fuel cells (PEMFC).

Phosphoric acid fuel cells use phosphoric acid as an electrolyte and porous carbon electrodes containing a platinum catalyst. They were the first fuel cells ever used commercially, primarily in stationary power applications. PAFCs can tolerate hydrogen impurities and can achieve overall efficiencies of around 85% when used for co-generation of heat and electricity, and around 37% to 42% for electricity production alone. However, they are larger and heavier than other fuel cells with the equivalent power output.

Solid oxide fuel cells use a non-porous ceramic electrolyte and appear to be a promising technology for electricity generation. Their electrical efficiency is expected to be in the range of 45% to 60%, with overall efficiencies of 70% or more. Their preferred electrolyte material is solid, dense, stabilised zirconia, instead of a liquid electrolyte, allowing operating temperatures to reach from 800°C to 1 000°C. Such high temperatures make precious-metal catalysts and external reformers unnecessary, helping to reduce the cost of SOFCs. However, this potential benefit is offset by heat-related cell design problems and slow start-up capability.

Molten carbonate fuel cells are being developed to be fuelled by natural gas (other fuels as well as pure hydrogen may be possible). MCFCs use a molten-carbonate-salt electrolyte suspended in a porous, inert ceramic matrix. Like SOFCs, they do not need an external reformer because they operate at high temperatures (greater than 650°C). In addition, they do not use precious-metal catalysts, further reducing their cost. MCFCs can achieve electrical efficiencies of around 50% (60% when combined with a turbine) and overall efficiencies of up to 90% if used for co-generation. MCFCs are much less prone to carbon monoxide (CO) or CO_2 poisoning than other fuel cells. Efforts are also under way to extend their economic life, which is limited by their high operating temperature and electrolyte-induced corrosion.

Polymer electrolyte membrane fuel cells use a solid polymer electrolyte and operate at relatively low temperatures (about 80°C), have a high power density (generate more power per volume) and can vary their output quickly in order to meet demand. They are the fuel cell of choice for the automotive market given their size and operating temperatures (around 80°C). They are available in a range of sizes suitable for both cars (60 kW to 80 kW) and large trucks (up to 250 kW), with efficiencies of around 50%.

A PEM is a thin plastic sheet that allows hydrogen ions to pass through. It is coated on both sides with highly dispersed metal alloy particles, most of which are platinum and extremely sensitive to CO poisoning. New platinum/ruthenium catalysts seem to be more resistant to carbon monoxide. Research is also focusing on new high-temperature membrane materials that will be less prone to poisoning. In addition, high-temperature PEMs avoid the need for large cooling systems.

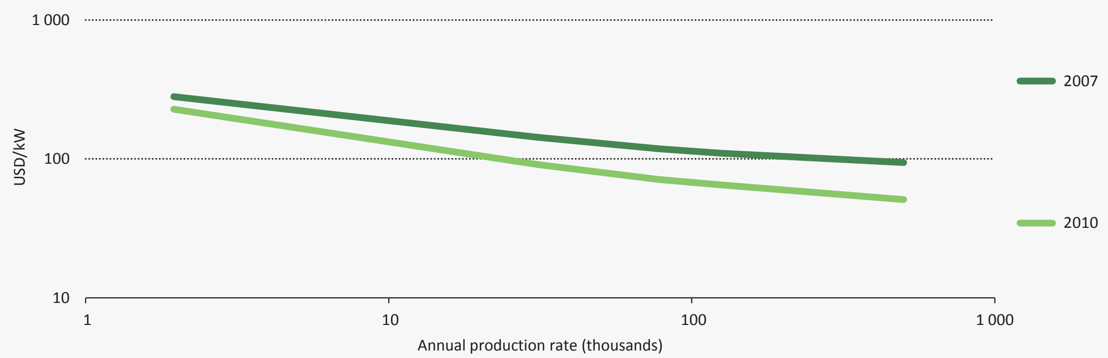
Although the quantity of platinum required for a PEMFC is declining with research and development efforts, it is still a significant cost hurdle. As an order of magnitude, current fuel-cell technology requires 0.5 grams (g) to 0.8 g of platinum per kW electric output. In transport, to power an 80 kW engine today, around 50 g of platinum are needed for the fuel cell, ten times the amount used in a catalytic converter for ordinary exhaust treatment. According to McKinsey (2010) and the US DOE it is likely that the requirement for platinum could decrease to around 6 g to 11 g per car. Furthermore, it is claimed that 85% to 90% of platinum in a fuel cell could be recovered.

As of 2010, global PEMFC capacity of around 400 MW has been installed (Schoots, Kramer and van der Zwaan, 2010; DOE, 2011). Costs per kW were somewhere around USD 1 000 for PEMFCs in transport applications. According to Schoots, Kramer and van der Zwaan, increasing today's capacity by 600 MW to reach 1 000 MW (*e.g.* adding the equivalent of 7 500 FCEVs with 80 kW or 2 400 buses with 250 kW) could probably reduce costs to around USD 450/kW.

Several major car makers now claim to be able to introduce FCEVs on a commercial scale (perhaps 50 000-100 000 units per year), at around USD 50 000 by 2015. This suggests fuel-cell system costs of about USD 25 000, or around USD 300/kW. This cost is expected to decline to under USD 100/kW in the future – but when this will happen is unclear and will depend on both RD&D and production rates.

Projected fuel-cell costs are a function of annual production rate (Figure 7.4). The DOE revised its 2007 cost assessment in 2010, almost halving projected production costs,[8] at a large-scale production rate of 500 000 fuel-cell systems per year, from about USD 100/kW to USD 50/kW. If production costs dropped to this extent, an 80 kW fuel-cell system would cost around USD 4 000, almost competitve with a gasoline engine of the same size. However some other estimates are higher. For example, Schoots, Kramer and van der Zwaan (2010) estimated minimum fuel cell system material costs of USD 150/kW without assembly. Further, an annual production rate of 500 000 fuel cells would be difficult to achieve before 2020 to 2025.

Figure 7.4 Fuel-cell cost reduction as a function of annual production rate



Source: US DOE, 2011.

Key point *The costs of fuel cells are projected to drop significantly with large-scale production.*

Hydrogen-powered vehicles

Today's passenger LDV sales by market segment hint at possible future market shares for FCEVs, if their total costs become competitive or if policies help make up cost differences (Figure 7.5). Since FCEVs are most likely to be adopted in medium to larger cars (given the cost sensitivity of small car buyers), the sales share of larger car segments is important. IEA data on global passenger LDV sales by segment for the year 2008 show that around 58% of vehicles are relatively larger cars, sport utility vehicles (SUV) and passenger light-trucks (class D or higher).[9] If no significant downsizing of vehicles occurs, up to 75% of the entire passenger LDV market could be suitable for FCEVs (including class C).

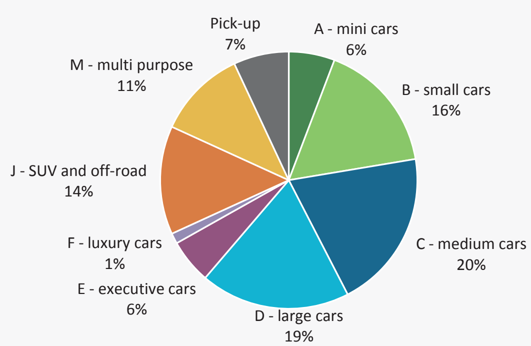
8 Including reductions from less precious metal (e.g. platinum in the fuel-cell stack) used and economies of scale.
9 According to the official European Commission classification system.

In a FCEV or any electric vehicle, the electric motor transforms electricity into mechanical energy. The hybridisation of FCEVs enables regenerative braking and the use of a smaller fuel cell because electricity stored in a battery helps satisfy peak demand during acceleration. The size of the battery in a FCEV is comparable to gasoline hybrid cars (around one kWh). Roughly one-third of total production costs for FCEVs, BEVs and plug-in hybrid electric vehicles (PHEV) are dedicated to the electric powertrain and have similar parts (McKinsey, 2010). Hence, FCEVs, BEVs and PHEVs will likely benefit from each other's mass deployment.

For heavy-duty vehicles (trucks), fuel cells may be one of only a few options available to cut CO_2 emissions. For medium- and long-distance trucking, dominated by highway travel, batteries are cost- and weight-prohibitive and cannot provide the needed range or durability – unless a major breakthrough in battery technology occurs. Long-range fuel-cell systems with compressed or liquid hydrogen might be better solutions, though cost and durability are significant barriers. The most apparent course at this point is a continuation of conventional (diesel engine) technology with increasing use of low net-carbon emission (high-energy-density) biofuels. Fuel cells will need considerable refinement and cost reduction to compete in this sector.

City buses may well be the first commercial application for fuel-cell vehicles. In many cities, hydrogen buses with zero tailpipe emissions can contribute to better air quality. Fuel cells have the range needed for the intensive daily travel of urban buses. Given the higher overall capital costs of buses – which are commonly subsidised globally – the additional costs for the fuel-cell powertrain may be proportionately less important and more acceptable than with passenger LDVs. City buses are centrally refuelled already, so station size can be optimised for demand.

Figure 7.5 Global passenger LDV sales by class segment, 2008



Source: IEA data

Key point *From the size perspective, up to 75% of the passenger LDV market could be suitable for FCEVs (class C and higher).*

Fuel cell versus battery and plug-in hybrid electric vehicles: competitive or complementary?

FCEVs and BEVs are often perceived as competitors but actually might occupy different market niches. Because BEVs are limited in range and have a long recharging time, they are most suitable for small- to medium-sized vehicles for urban use. In comparison, FCEVs have a considerably higher driving range than BEVs and their refuelling time is comparable to a conventional petroleum-fuelled vehicle. From the service perspective it is more likely that FCEVs and PHEVs target the same niche: medium- to large-size cars with a driving range of 500 km and more.

PHEVs are a potentially important option because they can run partly on electricity without any long-distance driving penalty. However, they will not be a very low CO_2 emission option unless advanced, low-GHG biofuels[10] become widely available or they can run on a very low share of liquid fuel. While these vehicles could compete with FCEVs, they could alternatively provide a pathway to FCEVs, since eventually the ICE could be replaced by a fuel cell, a final step to reach non-petroleum, very low CO_2-emissions driving.

A comparison of technical and economic parameters of FCEVs, BEVs and PHEVs, for both the deployment phase and in the longer term to 2040, shows that projected incremental vehicle costs for FCEVs over a conventional ICE vehicle remain somewhat higher, even in the long term (Table 7.3). Such projections are highly uncertain, however.

Table 7.3 **Comparison of key technical and economical parameters of fuel-cell, battery and plug-in hybrid electric vehicles (Class C/D market segment)**

	FCEV			BEV (150 km)			PHEV		
	2015	2020	2040	2015	2020	2040	2015	2020	2040
Battery cost (USD 1 000)		-		8.8	7.2	6.0	2.7	2.2	1.7
Cost per kWh (USD)		-		352	302	261	352	302	261
Capacity (kWh)		-		25	24	23	8	7	7
Drive train including motor, fuel cell stack and H_2 tank (USD 1 000)	24-45	16.4	8.2	1.4	1.4	1.4	4.2	4.2	4.1
Incremental costs relative to gasoline ICE (USD 1 000)	24-40	12.5	3.4	5.9	3.4	2.6	3.5	2.8	2.3
Refuelling time (3 kW/50 kW)	5 min	3 min	3 min	8.1 h/ 30 min	8 h/ 29 min	7.6 h/ 27 min	2.6 h/ 9 min gas: 3 min	2.4 h/ 9 min gas: 3 min	2.2 h/ 8 min gas: 3 min
Fuel consumption (per 100 km, tested fuel economy)	1.1 kg	1.0 kg	0.8 kg	17 kWh	16 kWh	15 kWh	3.2 Lge	3.0 Lge	2.8 Lge
Range (km)	500	500	500	150	150	150	700	700	700

Note: This table represents vehicle cost assumptions for the high hydrogen case.

Battery-electric vehicles and PHEVs are currently more mature than FCEVs in terms of commercialisation, and there is increasing confidence that cost-reduction targets for 2020 can be achieved possibly even sooner. In 2011, around 40 000 BEVs and PHEVs were sold, and battery costs appeared to reach about USD 500/kWh, down from USD 750/kWh just a couple of years earlier. By 2020, costs are projected to drop to USD 350/kWh or less, which will cut the incremental costs of BEVs to below USD 5 000, which should be close to cost-competitive on a "life-cycle" basis, including fuel cost savings, discounted over the vehicle's life span.

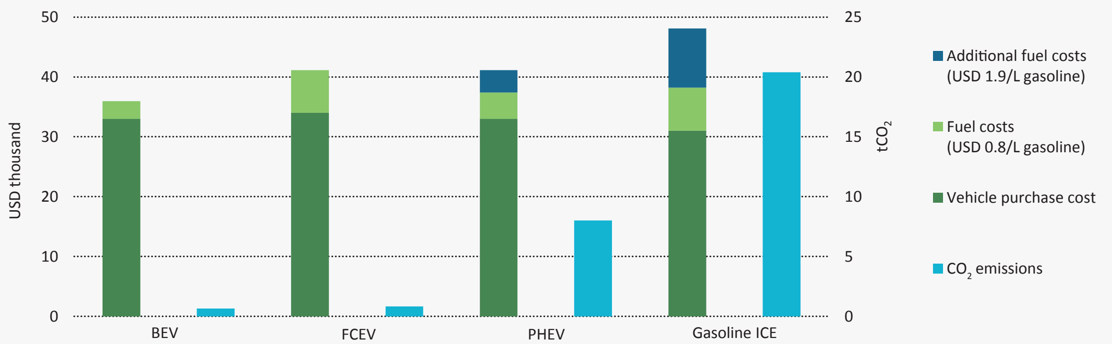
10 Advanced biofuels comprise low life-cycle greenhouse gas fuels based on non-food biomass crops.

If improvements in battery energy density can be achieved, driving range could also be increased over time – although with greater range comes longer recharging time and higher battery cost (at least compared to using smaller batteries at a constant range). A similar trade-off will present itself for FCEVs: higher range will require increased on-board hydrogen storage, though the cost of storage is much lower than for BEVs.

Vehicle purchase and fuel costs versus lifetime fuel emissions for FCEVs, BEVs, PHEVs and gasoline ICE vehicles, under long-term assumptions, are shown in Figure 7.6. Vehicle costs for FCEVs, BEVs and PHEVs are higher than for gasoline ICE vehicles, though for BEVs (with 150 km driving range)[11] and PHEVs this is fully offset by lower fuel costs over vehicle life. The dark blue bar denotes additional fuel cost that could result from a higher oil price or fuel taxes, which would be sufficient to result in life-cycle cost parity for FCEVs with PHEVs. In fact, USD 1.9/ L retail is already the norm in many parts of Europe and in Japan.

Clearly, BEVs and FCEVs have very low overall fuel-related emissions if low-carbon electricity as well as hydrogen is assumed. The decarbonisation of the power sector and hydrogen generation are therefore necessary prerequisites to achieve high emission reductions. Compared to the conventional gasoline ICE vehicle, the PHEV with a 60% share of electric driving and a 25% biofuel blend more than halves emissions.

Figure 7.6 **Long-term vehicle and fuel costs vs. vehicle lifetime CO_2 emissions**



Key point *Compared to PHEV and gasoline ICE vehicles, by 2040 cost parity of FCEVs can be reached at gasoline prices of USD 1.9 per litre and higher.*[12]

Vehicle driving range varies considerably among the three technologies, with BEVs having the most restricted range per recharge, and PHEVs the highest driving range. The United States provides an interesting example of how much this might matter. The United States has some of the highest-mileage drivers in the world. Yet in 2009, 95% of all driving trips were below 50 km (Moawad *et al*, 2009), suggesting that there might be a potentially large niche for limited-range vehicles such as BEVs. However, it is also clear that many people buy cars with a view to the full range of travel services, including longer trips. This would tend to give an advantage to FCEVs and perhaps especially to PHEVs, since they can provide very long-range

11 BEVs with higher driving range would need a larger battery, which would increase costs and recharging time. With the underlying assumption on battery costs BEVs with a 300km range would reach cost parity with gasoline ICE vehicles.

12 Assumptions: 15 000 km/year, USD 0.1/kWh electricity, USD 5/kg hydrogen (H_2), 60% electric driving for PHEV, vehicle details see Table 7.3 for 2040 with purchase costs of USD 30 700 for the gasoline ICE vehicle with a consumption of 5.0 L/100km. Emission factors: Electricity – 0.21 kg/Lge; hydrogen – 0.16 kg/Lge; gasoline-biofuel blend 2.26 kg/Lge; all emission factors on a well-to-wheel basis.

service. The future purchasing behaviour of motorists, and their perceived need for range, could have a large impact on the success of these different technologies.

Hydrogen in buildings and industry

Hydrogen is interesting in part due to its ability to store and carry energy in an efficient manner. For transport, hydrogen could be superior to electricity for on-board energy storage and resulting vehicle range. This attribute is less important for stationary end-use applications: buildings and industry would likely only use hydrogen if it could substitute for other carbon-intense energy carriers, or if it could store energy more effectively than other options elsewhere in the overall energy system. Storage of excess renewable power generation could be an example of this.

For stationary applications, fuel cells will need to have an operating life of some 40 000 to 80 000 hours, which is significantly longer than the 20 000 hours that current systems have achieved. Increasing the average life of fuel cells will be imperative to reducing the cost of the electricity they generate. Improved fuel-cell designs, new high-temperature materials, catalysts, membranes, bipolar plates and gas diffusion layers all need further development. Fuel cells need to achieve overall efficiency levels similar to those of conventional technologies and benefit from their relatively high electricity-generating efficiencies.

Cost and durability need to be addressed through R&D and demonstration; economies of scale will help reduce costs from current levels but are insufficient in themselves, and significant R&D efforts are required to reduce the cost of fuel-cell stacks and the balance of the plant's (*e.g.* power conditioning systems, fuel pre-treatment and controls). At present, component degradation and failure is not particularly well understood, and more R&D is required to better understand these issues and improve system design.

In buildings the use of high-temperature fuel-cell micro co-generation[13] applications could be beneficial if large-scale application in combination with a smart grid is used to balance heat and power supply. A micro co-generation system could be power-led, in which case electricity demand is covered by the fuel cell. The fuel cell then also provides heat at the given ratio of total versus electric efficiency. In the case of higher heat demand, additional heat would need to be generated by a peak burner. Alternatively, the system could be heat-led, and supplementary electricity could thus be fed back to the electricity grid. Solid oxide fuel cell co-generation systems might be a near-term solution because they can be fuelled with natural gas but could still take advantage of the higher efficiency of a fuel-cell system compared to conventional ICE micro co-generation.

The high operating temperature of SOFCs makes them potential candidates for pairing with gas turbines or micro-turbines in a hybrid configuration. In this configuration, the hot exhaust gases of the fuel cell would be passed through a micro-turbine, replacing its fuel combustor. When combined with a gas turbine, SOFCs are expected to achieve an electrical efficiency of between 58% and 70%, and up to 80% to 85% efficiency in co-generation mode. One RD&D goal for SOFCs is to enhance their sulphur tolerance so that they can be fuelled by gas derived from coal. The development of low-cost high-durability materials also presents a critical technical challenge for this technology.

In industry, hydrogen may eventually find its way to steel production. As iron is obtained through the reduction of iron ore, the classic process of smelting iron ore involves using coke, both as a fuel to reach the needed temperatures and as a reducing agent. In a direct reduction process, iron ore is reduced in a solid state and at lower temperatures by a hydrogen-rich reducing gas. However, molecular hydrogen cannot reduce liquid iron oxide:

13 For more on co-generation, see Chapter 5 on heat.

atomic or ionised hydrogen is needed to do so. But these states can only be achieved at very high temperatures, such as in the vicinity of an electric or plasma arc. Hydrogen plasma-smelting reduction would require 14.3 GJ (gigajoules) H_2/tonne (t) iron and 2.2 GJ electricity/t iron (Hiebler and Plaul, 2004). If low-cost CO_2-free hydrogen and electricity were available, this could be an alternative for smelting reduction processes with CCS. This option is being investigated in the United States by the American Iron and Steel Institute (AISI), the US DOE and various steel companies sponsoring a project in the framework of the Ultra-low CO_2 Steelmaking (ULCOS) programme at the University of Utah to examine the reduction of fine ore concentrate using hydrogen.

In Japan, the use of waste heat from coke ovens for gas reforming for hydrogen production and iron-making is being researched. As the amount of waste heat from coke ovens is limited, this is a niche option that will generate less than 0.5 GJ additional hydrogen per tonne of steel. Coke oven gas is rich in hydrogen and can be used for iron-making, but the quantities are limited, typically 2 GJ/t iron produced in a conventional blast furnace.

Hydrogen versus direct use of electricity

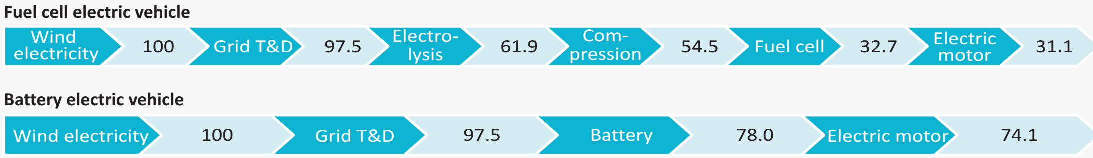
Future use of hydrogen, whether in different non-stationary and stationary applications, mostly ends up with hydrogen being transformed into electricity for end-use energy. To illustrate the round-trip efficiency, two examples from the transport and buildings sector are chosen to compare the transformation pathway from the energy source to the energy sink, on the one side incorporating hydrogen, on the other side using electricity directly or via battery storage. For both examples, renewable wind electricity is chosen as the energy source. When comparing different technological options, efficiency is just one criterion among others: for a FCEV, lower overall efficiency might be acceptable if having a higher driving range than for a BEV is the result. Finally, the cost-effectiveness of each single application will decide its success.

The transport example compares a hydrogen-fuelled FCEV to an electric vehicle with battery storage (Figure 7.7). With a BEV, the use of electricity involves transport by the grid, storage in a battery and final transformation to mechanical energy (for vehicle movement) by an electric motor. Starting with 100 kWh, it loses only 26 kWh in its transformation, leaving 74 kWh available for propulsion. For the hydrogen used in a FCEV, renewable electricity generates hydrogen via electrolysis. Then the hydrogen is compressed and loaded onto the vehicle. On board the FCEV, hydrogen is re-electrified using a PEM fuel cell. Out of the original 100 kWh of electricity, only 31 kWh will be used for vehicle propulsion at the end. Finally, if renewable electricity is used the BEV pathway is more than twice as efficient as the hydrogen FCEV pathway.

In the buildings sector, a comparison of different transformation pathways is more complex, as both power and heat play a role. Conventional co-generation is complicated by the fact that heat and power demands are not always complementary. On the supply side, each unit of electricity generated comes with a certain amount of heat. Co-generation is only beneficial if both heat and power can be used. Optimising the system, in a way that both heat and power supply are balanced, adds some complexity.

The hydrogen pathway including central electrolysis, pipeline transport and a stationary co-generation fuel cell, has an overall efficiency of 53%. The FC co-generation unit has a total efficiency of 85% and an electric efficiency of 60% (Figure 7.8). Thus each kWh of electricity generated comes with 0.42 kWh of heat. Given that today's residential heat demand is about three times the electricity demand, additional energy for pure heat generation is needed because the fuel cell cannot deliver it under a power-led control regime.

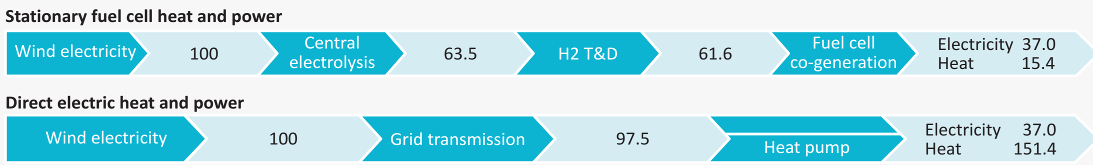
Figure 7.7 **Energy losses for hydrogen versus direct electricity in the transport sector**



Key point *Comparing FCEVs and BEVs, the direct use of electricity is more than twice as efficient as hydrogen.*

With better insulation to reduce heat demand, this picture could change drastically, but still overall hydrogen transformation would remain quite inefficient, with only a little more than half of the energy recovered.

Figure 7.8 **Energy losses for hydrogen versus electrified heat and power in the buildings sector**



Key point *In buildings, the direct use of electricity for heat and power applications is more efficient than hydrogen.*

The fully electrified residential heat and power system provides another picture: if from the original 100 kWh of electricity only 37 kWh are used for power applications (as in the hydrogen example), another 151 kWh of low temperature heat can be generated using the remaining electricity with a ground source heat pump (assuming a coefficient of performance of 2.5).[14] Of course, the application of ground source heat pumps in densely populated urban areas is restricted by factors such as access to the ground and available heat potential, which might impose serious constraints on this option.

Levellised cost comparison

While conversion efficiency is important, using hydrogen for energy storage can be a critical added value, particularly if large amounts of variable renewable energies are integrated into the power sector. Separating energy demand and supply, in terms of timing, could be quite valuable.

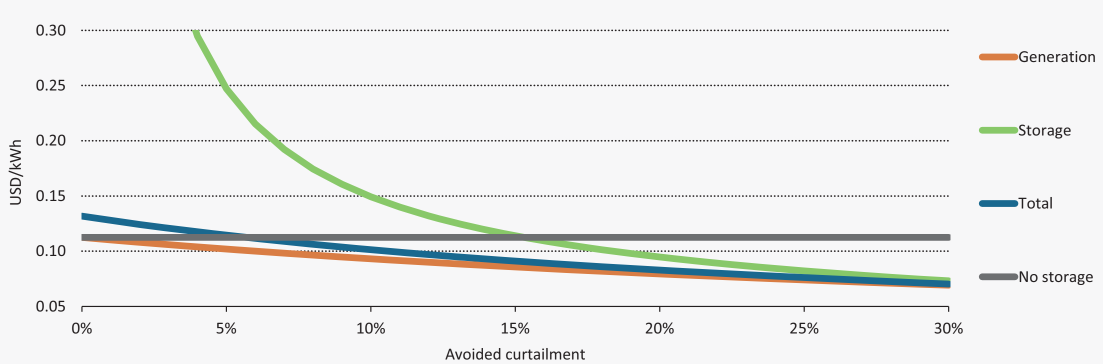
14 Heat pumps have coefficients of performance (COP) greater than one as the heat energy, which is lifted to a higher temperature level, comes from the environment; see also Chapter 5 on heat.

With large amounts of variable power, excess electricity generation above the demand level can occur at certain times of the day and year. Storing excess power rather than just switching off the supply system may make more economical sense. In that case, the cost of setting up hydrogen generation, storage, and transport and distribution infrastructure must be evaluated against the benefits of carbon-free electricity and the opportunity costs of alternative load levelling and energy storage systems.

Grünewald *et al.* (2011) showed that energy storage provides economic benefits in a low-carbon energy system. Full-load hours of conventional back-up generation capacity may decline with increasing penetration of variable renewable power, especially if incentives are taken into account. In the *ETP 2012* 2°C Scenario (2DS), which projects a high level of renewable energy by 2050, about 1% of total global power generation goes through energy storage, at a variable renewable energy penetration of little more than 20%.

The result of a comparison of levellised costs for wind electricity with and without hydrogen storage is shown in Figure 7.9. Without storage (the black line), the wind park has an assumed capacity factor of 20% and electricity is generated at around USD 0.11/kWh. It is further assumed that the wind park could generate significantly more electricity but the capacity factor is reduced to 20% due to external factors such as constrained grid capacity. The coloured lines show levellised costs for the wind park with hydrogen storage. They are a function of avoided curtailment, namely switching off the wind park due to grid restrictions. With adding storage (green line), more wind can be used and curtailment is reduced, causing total generation costs to fall (blue line) due to the higher capacity factor of the wind turbines alone (orange line).

Figure 7.9 **Levellised costs of wind energy and hydrogen storage assuming long-term investment costs for hydrogen storage equipment**



Key point *Adding a hydrogen storage system to a wind park could reduce levellised costs of electricity generation at reduced curtailment greater than 5%.*

This simple example shows that adding storage can lower total levellised costs (although round-trip efficiency is low), if 5% or more of annual curtailment is avoided. If 10% of curtailment is avoided, generation costs are already reduced by 10%. The capacity factor of the wind turbines is then increased to 30%, which could be achieved at good wind sites. Nonetheless, the hydrogen storage option has to be proven against alternatives such as grid extension, demand-side management and other storage alternatives.

In the case of the wind park with hydrogen storage, instead of re-electrifying the hydrogen, it could be sold as transport fuel. Generation costs of hydrogen at 10% reduced curtailment would be around USD 3.6 /kg, already including compression to 120 bar. Ideally, in a highly integrated energy system the operator could compare actual margins and then decide whether to re-electrify the hydrogen or sell it as transport fuel.

Box 7.2 Energy storage requirement: Germany

Assuming very high levels of renewable energy penetration in the German power grid (85%), long-term energy storage demand might be in the range of 20 terawatt-hour electric (TWh_{el}) to 40 TWh_{el}. At such high levels of renewable energy penetration, flexibility measures such as demand-side management in combination with smart grids as well as an integrated European grid network might still not be enough to account for seasonal fluctuations (Sterner, 2010). The current storage potential of pumped hydro in Germany accounts for 0.04 TWh_{el} . In that case hydrogen storage might be an attractive option.

The existing natural gas grid provides storage capacity of around 220 TWh thermal (th) (Sterner, 2010). The same storage potential would only account for one-third of the energy if it was used for hydrogen. Assuming a 50% electric efficiency of fuel cells and disregarding the fact that not all of the natural gas storage could be used for hydrogen without significant modification, around 37 TWh of electric energy could still be stored. If hydrogen was used to generate synthetic methane, the conversion efficiency would again be lowered by 10 percentage points, but the current infrastructure could be used to the whole extent.

However, if all of Germany's cars were BEVs (45 million cars) with 30-kWh batteries, and half of overall capacity could be used for grid stabilisation simultaneously, then the BEV storage potential would be sufficient to satisfy German power demand for around 10 hours. This seems to be a lot, but the actual useful storage potential would be lower. Due to daily car use and long charging times, BEVs and the smart grid can provide energy storage on an hourly basis only.

Hydrogen trajectory to 2050 and beyond

The following shows the potential role of hydrogen in end-use sectors to 2050 in the main 2DS and two hydrogen-specific variants. The two variants aim at exploring the effects on energy use, emissions and costs if hydrogen is used in much higher quantities (2DS high-hydrogen) or not used at all (2DS no-hydrogen) in the industry, buildings and transport sectors until 2050 (Table 7.4).

In the industry sector, new hydrogen-based technologies to decarbonise the steel-making and chemicals and petrochemicals industries are investigated with respect to energy use and emissions in the 2DS high-hydrogen variant.

In the buildings sector, mainly the effect of introducing fuel-cell micro co-generation is examined in the 2DS high-hydrogen variant.

In the transport sector, the additional scenarios vary the degree of hydrogen fuel-cell vehicle market penetrations and thus hydrogen use; in the 2DS variants there is no overall change in total vehicle stock, sales or travel activity. Hydrogen is only considered for road passenger and freight transport; it is not assumed to be used in the air, rail or shipping sectors.

Table 7.4 Overview of scenario assumptions

	2DS	2DS high-hydrogen	2DS no-hydrogen
Transport	The deployment of FCEVs in the passenger LDV sector begins in earnest in 2025 and reaches a significant market share by 2040. By 2050, FCEVs are 17% of new passenger LDV sales and 13% of the total passenger LDV fleet. In the road-freight sector, FCEVs are incorporated as light commercial vehicles, medium-freight trucks and to a lesser extent, heavy-duty trucks. By 2050, FCEVs have a share of around 11% of truck sales and 7% of total truck stock.	In the high-hydrogen scenario, FCEVs are commercially introduced by 2020 and reach significant market share by 2030. By 2050, FCEVs make up twice the number of vehicles as in the 2DS, accounting for 27% of all passenger LDV fleet. The increase of FCEVs is at the expense of PHEVs, although the share of electric vehicles stays the same, following the 2DS. Market penetration of commercial FCEVs for trucking starts by 2030 and grows to 14% of the truck fleet by 2050. Here, FCEVs take market share from conventional diesel commercial vehicles.	This scenario has no FCEVs at all: FCEV passenger LDVs are replaced by PHEVs. With no commercial FCEVs, there are a greater number of conventional diesel trucks, using an increasingly biofuel-blended diesel fuel. The assumptions about electric vehicle penetration stay the same.
Industry	For hydrogen iron smelting and the production of hydrogen in the chemicals and petrochemicals sector, demonstration is assumed to start in the next 15 to 20 years. Initial market penetration is expected by 2050.	In the high-hydrogen scenario, hydrogen-based steel-making starts penetrating the market by 2030-35. By 2050, about 8% to 11% of all crude steel production will use hydrogen. In the chemical and petrochemical sector, CO_2-free hydrogen starts playing a role as early as 2030. By 2050, more than 15% of the sector energy and feedstock needs are met with CO_2-free hydrogen.	n.a.
Buildings	No use of hydrogen currently included in the buildings sector.	Fuel-cell co-generation units are commercially available in the residential and commercial sectors starting in 2030. By 2050, fuel-cell co-generation units will provide 5% of the energy needs in the residential sector and 1.5% in the service sector.	n.a.

Note: n.a. = not applicable.

Scenario results: energy use and greenhouse-gas emissions

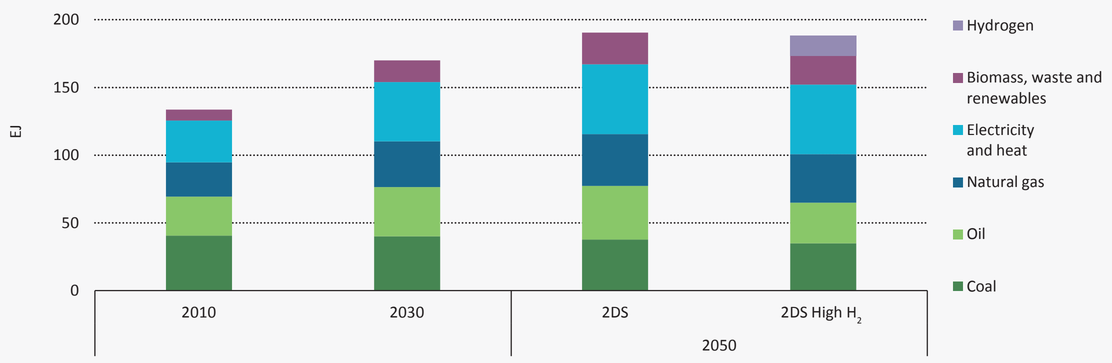
Industry sector

Research is currently ongoing for the development of new technology options for industry that would dramatically reduce the carbon footprint of the sector. Production of hydrogen from CO_2-free sources for the chemicals and petrochemicals industry and the production of hydrogen-based steel are being researched in many countries and hold promising CO_2 reduction potential for these large energy consumers and emitters.

In the 2DS high-hydrogen variant, the deployment of breakthrough technologies that would allow the production and use of CO_2-free hydrogen is expected to start by 2030-35. Such deployment would have an impact on the energy mix used by industry (Figure 7.10). In the 2DS high-hydrogen variant, the use of fossil fuels in the chemicals and petrochemicals and the iron and steel sectors would be 17% lower than under the 2DS. Overall, for the entire industry sector, hydrogen would account for around 7% of the total industrial energy needs in 2050.

This step change in the production process of industry would also have an impact on the CO_2 emissions of the sector. In the iron and steel sector, without the breakthrough technologies expected in the 2DS high-hydrogen variant, the sector will be highly dependent on CCS to achieve deep CO_2 emissions reductions. In the 2DS, CO_2 emissions from the iron and steel sector would be 1 $GtCO_2$ lower than under the 4DS in 2050; 45% of the reductions will be achieved through the large-scale deployment of CCS. In the chemicals and petrochemicals industry, a large share of the 42% reductions between the 4DS and 2DS will be from energy efficiency improvements.

Figure 7.10 Industrial energy consumption



Note: Does not take into account the additional energy required to produce the hydrogen.

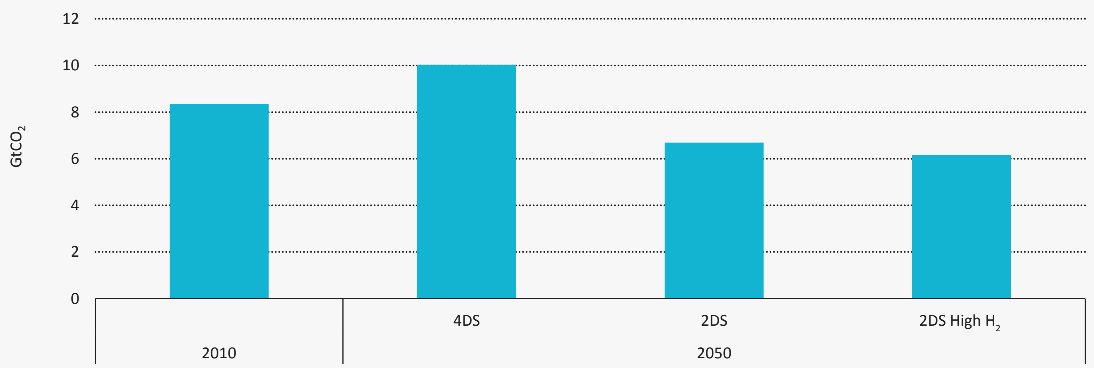
Key point *The use of hydrogen would displace the oil used in chemicals and petrochemicals, and coal used in iron and steel.*

In the 2DS high-hydrogen variant, CO_2 emissions from iron and steel will reach 1.7 $GtCO_2$ by 2050. The contribution of CCS in the CO_2 reduction will be lower, and would account for about 40% of the reductions between the 4DS and 2DS high-hydrogen variant.

For the chemicals and petrochemicals sector, the use of hydrogen will contribute to the reduction of 0.5 $GtCO_2$ in the 2DS high-hydrogen variant compared to the 2DS.

Overall, for the industry sector, the 2DS high-hydrogen CO_2 emissions will reach 6.2 $GtCO_2$ by 2050 (Figure 7.11).

Figure 7.11 Industrial CO_2 emissions



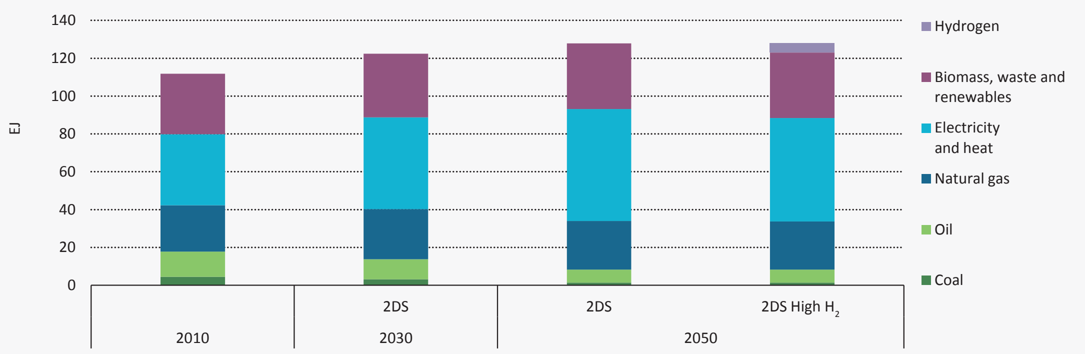
Key point *CO_2 emissions in the 2DS high-hydrogen variant would be 8% lower in 2050 than in the 2DS.*

Buildings sectors

While the technologies currently exist to achieve a near-decarbonisation of the buildings sector (assuming a decarbonisation of the power sector), there are options that still require further R&D and will help lower the impact of decarbonisation on the power sector. Micro-co-generation fuel cells are one of these technologies.

If fuel cells decline in cost in line with expectations, they could become a very attractive technology; and if hydrogen production costs come down and hydrogen distribution infrastructure is available, fuel cells will also have a significant role in decarbonising the heat supply as well as in improving overall efficiency.

Figure 7.12 Buildings energy consumption



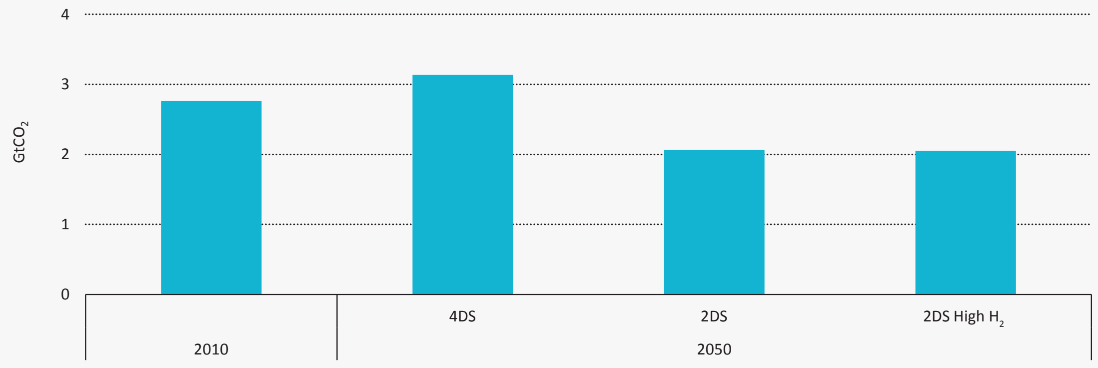
Key point *About 5% of total buildings' energy consumption would come from hydrogen in the 2DS high-hydrogen variant.*

Heating equipment in the building sector has a relatively long life cycle. As a result, even if fuel-cell co-generation starts penetrating the market as early as 2030, the impact on the overall sector will mostly be seen after 2050. Nevertheless, some changes will already be evident in 2050.

Under the 2DS high-hydrogen variant, the fuel mix in the buildings sector will be different than under the 2DS (Figure 7.12). Hydrogen will account for about 5% of total buildings' energy needs in 2050. The higher use of hydrogen will not only displace fossil fuels, but will also displace electricity and help ease the pressure on the power sector.

Given the high share of near-carbon-neutral electricity implicit in the 2DS and the relatively low market penetration of fuel-cell co-generation, limited impact on CO_2 will be observed in terms of CO_2 emissions. Under the 2DS high-hydrogen variant, direct CO_2 emissions from the buildings sector will be 1% lower than under the 2DS in 2050 (Figure 7.13).

Figure 7.13 Buildings CO_2 emissions



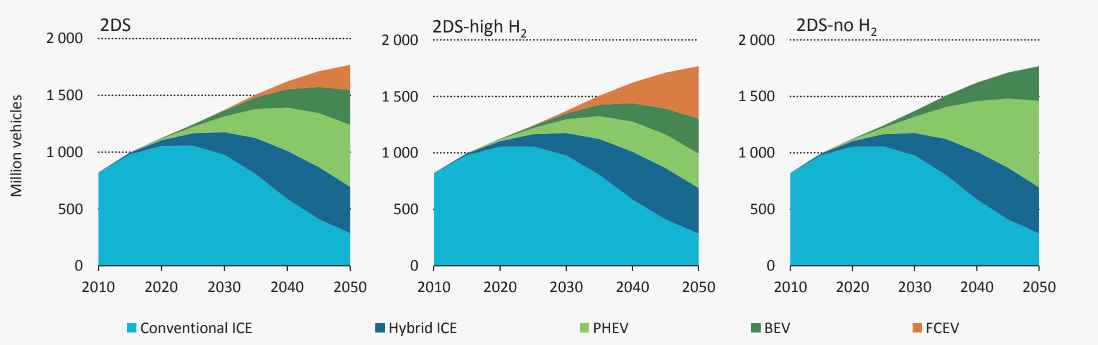
Key point *Given the slow turnover of equipment and the high share of electricity in the buildings sector, marginal impact will be observed in 2050.*

Transport sector

The evolution of global passenger LDV stock over time for the three mitigation scenarios is shown in Figure 7.14. In all three scenarios, a high share of vehicles has been either hybridised or electrified by 2050. While in the 2DS electric vehicles are dominated by PHEVs, FCEVs reach the highest share of electric vehicles in the 2DS high-hydrogen variant. FCEVs are completely replaced by PHEVs in the 2DS no-hydrogen variant. In all scenarios, it takes a significant amount of time to get from first introduction to significant shares of vehicles on the road. In the high-FCEV case, with rapid sales' ramp-up starting in 2020, there are about three million FCEVs on the road by 2025 and 23 million by 2030, only 2% of total vehicle stocks in that year. By 2050, FCEVs at 470 million represent about a quarter of passenger LDVs.

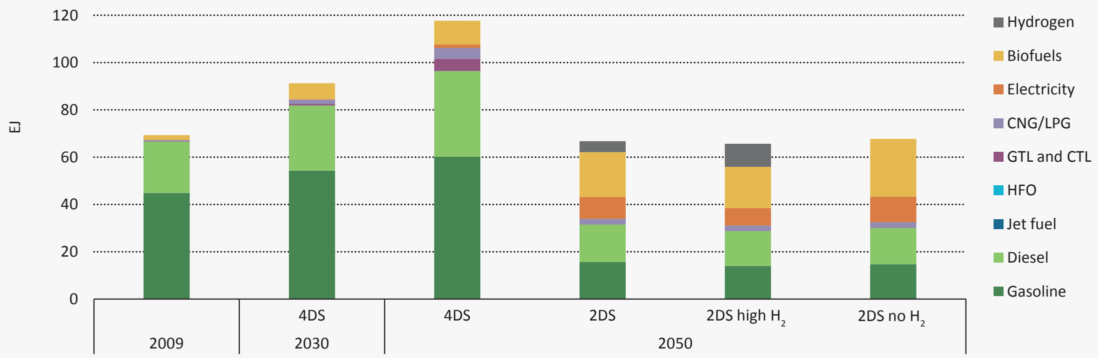
Total fuel demand from road transport varies significantly between the 4DS and all 2DS variants (Figure 7.15). The 4DS shows considerable growth of energy demand, by more than 60% between 2009 and 2050.

Figure 7.14 Passenger LDV stock by technology



Key point *It will take time for FCEVs to gain significant market share.*

Figure 7.15 Fuel demand by fuel type



Key point *Compared to the 4DS, total road vehicle fuel demand in all 2DS variants is almost halved and much more diversified by 2050.*

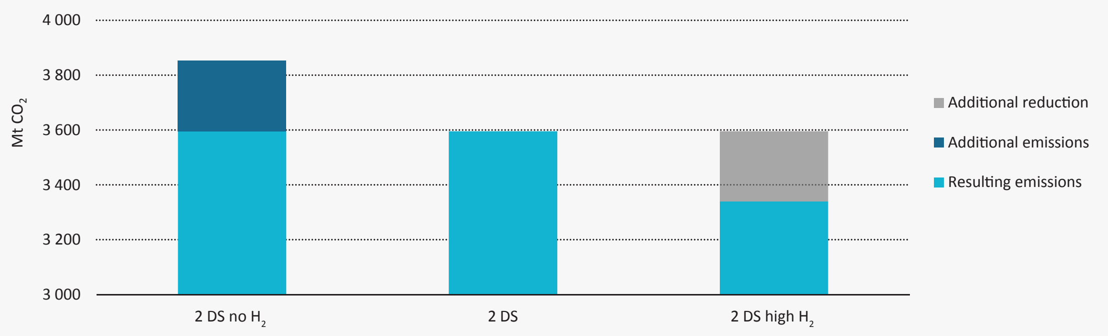
In the 2DS, energy use and fuel mix need to change dramatically to meet the targeted CO_2 emissions cuts. By 2050, global energy demand from road transport returns to 2009 levels, and is more diversified due to higher shares of low-carbon fuels: half of road transport fuel demand is supplied by low-carbon electricity, biofuels and low-carbon hydrogen, with biofuels alone accounting for about a third of road transport energy use. Due to earlier and higher penetration of FCEVs in the 2DS high-hydrogen case, hydrogen accounts for 15% of total road transport energy demand by 2050. With no hydrogen, total fuel demand is slightly higher due to less-efficient vehicles, and the share of biofuels and diesel rises to fill the gap.

Annual CO_2 emissions from road transport for the 2DS and its high- and no-hydrogen variations are shown in Figure 7.16. Compared to the sector's emissions target, the 2DS high-hydrogen variant saves an additional 250 megatonnes of CO_2 ($MtCO_2$). With no hydrogen, about the same amount of additional emissions occur, due to increased use of PHEVs and heavy-duty vehicles (HDVs) running on a gasoline-biofuel or diesel-biofuel blend. Thus the difference between no hydrogen and high hydrogen in transport is about 500 $MtCO_2$.

With no hydrogen, to meet the 2DS emissions target, the additional emissions are offset by increasing the share of advanced biofuels in the gasoline and diesel blend. In total, the demand for biofuels increases by more than 20% from 27 EJ to 33 EJ per year, requiring 12 additional EJ (70 EJ total) of raw biomass for biofuel production. According to *ETP 2012* analysis, another 80 EJ of raw biomass is needed for heat and power generation.

The total of 150 EJ of raw biomass per year is believed to be a feasible, but nonetheless an ambitious, global supply target. This is also in line with the scenario review conducted in IPCC (2011), which, for the year 2050, finds a 120 EJ/yr to 155 EJ/yr raw biomass demand (only for energy use) in the median case, increasing up to 300 EJ/yr in the highest bio-energy case. Beyond 2050 (as discussed in Chapter 16), a lack of hydrogen in transport puts ever-increasing pressure on biofuels to help deliver a near-zero emission system by 2075. Hydrogen could be increasingly important in moving transport toward a very low emissions system beyond 2050.

Figure 7.16 Road transport CO_2 emissions by 2050

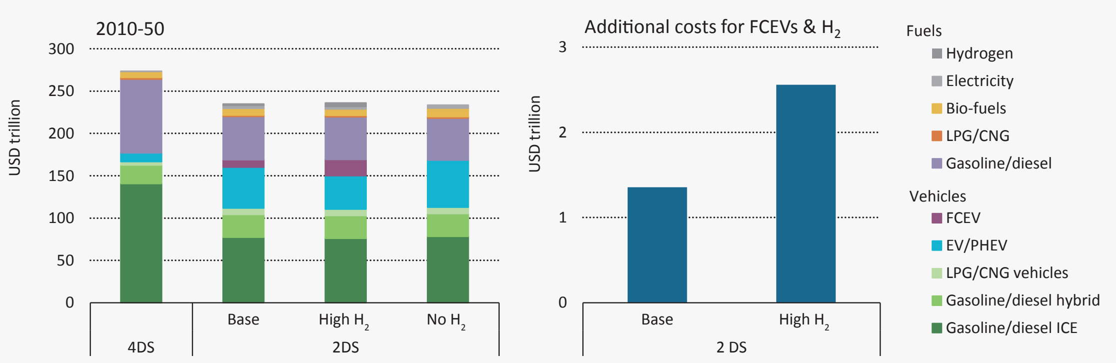


Key point *Key point: By 2050 FCEVs could save another 250 $MtCO_2$.*

The total cost of fuels and vehicles through 2050 shows the general picture already revealed in *ETP 2010*: although the 2DS requires higher investment in vehicle technology than the 4DS, these additional costs are more than completely offset by fuel savings (Figure 7.17). This holds true with a zero discount rate (shown in Figure 7.17) or even with discount rates of up to 10% (see Chapter 4 on finance).

In the 2DS, overall costs in road transport to 2050 are 13% less than in the 4DS. FCEVs and hydrogen add a net USD 1.2 trillion to total costs, thus somewhat lowering the total savings relative to the 4DS. This rises to USD 2.5 trillion in the high-hydrogen case. Compared to the 2DS no-hydrogen case, total additional expenditure for hydrogen vehicles and fuels is around 1% of total costs, but might open the way towards more sustainable transport.

Figure 7.17 Cumulative global costs for road vehicles and fuels



Note: The blue bars show additional costs for FCEVs and hydrogen compared to the 2DS no-hydrogen variant.

Key point *Total costs of vehicles and fuels are reduced in the 2DS and its variations compared to the 4DS.*

In total, between USD 0.8 trillion and USD 2.1 trillion needs to be spent over the next 40 years for hydrogen generation, transport, distribution and retail infrastructure (Figure 7.18). Although USD 2.1 trillion represents a huge investment, it is small compared to the around USD 250 trillion that will be spent globally on road vehicles and fuels up to 2050. On a per kilometre basis, total infrastructure investment in the 2DS high-hydrogen variant would add USD 0.02/km[15] for all FCEVs used up to 2050.

By comparison, investment in the recharging infrastructure for BEVs and PHEVs from 2010 to 2050 is about USD 1 trillion, to serve a global stock of nearly 1.2 billion vehicles (*Kaneko, Cazzola and Fulton*, 2011). With projected cumulative sales of 1.8 billion vehicles through 2050 (out of nearly 5 billion total vehicle sales), this translates into an additional charge of about USD 0.004/km for BEVs and PHEVs. Recharging infrastructure for PHEVs and BEVs includes slow home and public charging as well as a small share of fast public charging. It does not include upgrading the electricity grid. Given the fact that by 2050 all plug-in EVs account for 5% of the total electricity demand of all sectors and might add significant value for short-term energy storage, the additional costs for grid upgrade might be moderate.

For FCEV infrastructure the bulk of investment happens after 2030 and, in the beginning, predominantly finances networks of retail stations, which in this scenario mostly produce hydrogen on-site using electrolysers (Figure 7.18). With increasing demand, investment in generation and transmission equipment is higher.

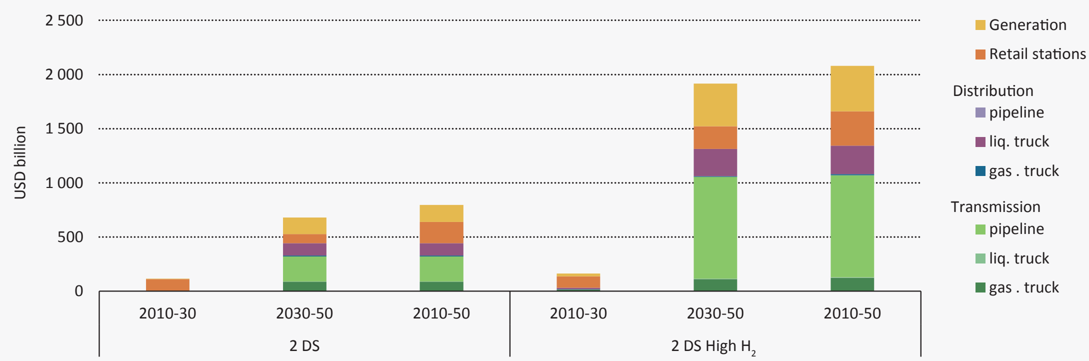
When sufficient demand justifies the development of a pipeline transmission network, even larger investments are needed. In the current model this happens between 2035 and 2040 for most regions. This may be a challenging barrier, but with an assumed point-to-point transmission distance of 150 km, levellised transmission costs of USD 0.5 to USD 1/kg (given higher flows) will not be achieved without pipelines.[16] To achieve targeted total costs of hydrogen generation and delivery of around USD 4/kg, low transmission costs are essential.

Because it will probably take 20 to 30 years for demand to rise to a level that justifies investment in a sufficient pipeline network, a large stock of truck-trailer combinations for liquid and gas hydrogen transport might be operational at the time of infrastructure change. Switching to pipeline transmission could therefore cause lock-in effects. In the European Union, for example, there might be as many as 25 000 hydrogen delivery truck-trailer combinations on the road before the introduction of pipeline transmission becomes justifiable. That this rolling stock could become partly obsolete when pipeline transmission is introduced could be a potential barrier to choosing the most efficient method of hydrogen transmission.

By 2050, inner-city distribution of hydrogen still relies on truck delivery of liquefied hydrogen. Although liquefaction requires high initial investment and drives up variable operation costs due to high energy demand, the per-kilogram costs of hydrogen distribution and retail are still lower than with inner-city pipelines. Construction of an inner-city pipeline distribution network is capital- and time-intensive, plus pipeline distribution increases investment costs at the station for compression equipment (required to increase pressure to the vehicle's on-board storage level). Yang and Ogden (2007) assume a rather moderate 350 bar for on-board storage, but pressure is already at 700 bar today, making city pipelines even less attractive.

15 Assuming a total life cycle travel of 150 000 km per FCEV.
16 According to Yang and Ogden (2007), liquefied transport could bring transmission costs down to USD 1.8/kg for the 150 km distance.

Figure 7.18 Global cumulative investment in hydrogen generation, transport and distribution infrastructure



Key point *The bulk of investment in hydrogen infrastructure begins after 2030.*

High utilisation rates of refilling stations and related infrastructure are crucial to recover investment costs. During the roll-out phase, the hydrogen infrastructure is likely to be under-utilised. Especially for small stations either with gaseous or liquid hydrogen delivery, fixed costs constitute more than 80% of the total costs (Yang and Ogden, 2007). In the 2DS, assuming sufficient density of refilling stations to attract people to purchase FCEVs, in OECD member countries an average utilisation rate of only 15% of capacity is achieved by 2030, growing to around 70% in 2050. Due to earlier and more aggressive development of the FCEV market in the 2DS high-hydrogen variant, the utilisation rate of refilling stations does much better, reaching 45% by 2030 and around 80% by 2050. Further increasing utilization rate by clustering hydrogen infrastructure and the use of small scale retail stations is necessary to minimize risk on investment.

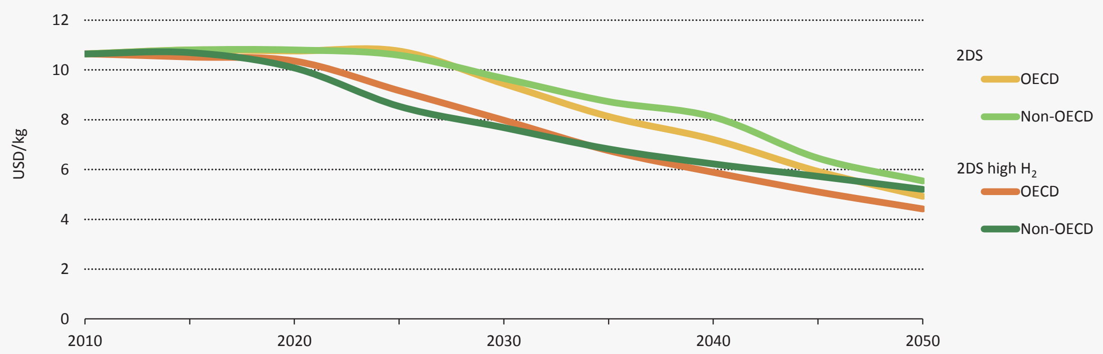
The cost of hydrogen (retail price equivalent at the station) declines over time, with different rates for the 2DS and its high-hydrogen variation, in OECD and non-OECD regions (Figure 7.19). As system size increases, utilisation rates improve and production costs for hydrogen decrease over time. Thus, the retail cost for hydrogen decreases fairly dramatically: from USD 11/kg in 2020 to around USD 4 to 5/kg by 2050. In the 2DS high-hydrogen case, hydrogen costs fall much faster, due to the earlier switch from expensive on-site electrolysis to centralised production of hydrogen, as well as better utilisation of the infrastructure.

The following conclusions can be drawn from the scenario results:

- The use of lower-cost PHEVs for individual passenger travel and diesel/biofuel trucks for long-haul applications can compensate for hydrogen vehicles, if biofuels account for one-third of road transport fuel demand. Until 2050, emissions targets might still be met without hydrogen, but this emissions trajectory will not be sufficient to reach the 2°C target after 2050 (see also Chapter 16). Biomass supply is likely to become constrained and might not meet demand due to competition for this resource from transport, buildings, industry and power sectors. Furthermore emissions related to indirect land use change are still poorly quantified.
- Necessary investments to install the generation, transport, distribution and refuelling infrastructure for high numbers of FCEVs is around USD 2.1 trillion globally, representing

around 1% of all costs of vehicles and fuels until 2050. The faster the FCEV technology roll-out takes place, the faster the cost of hydrogen can be reduced by centralising hydrogen production and more effectively utilising the infrastructure. Both refuelling and recharging infrastructures (for FCEVs and BEVs) may be necessary, since the two vehicle types serve different niches.

Figure 7.19 Cost of hydrogen at the station



Key point *Hydrogen costs decline more rapidly in the high-hydrogen scenario, thanks to faster learning and optimisation.*

- Introducing hydrogen vehicles will require strong policy support because the total cost of vehicle ownership will be higher than alternative vehicle technologies, even in the long term. Especially during the technology roll-out phase, which could well take 15 years to reach a 5% to 10% share of the passenger LDV fleet, government support to provide a sufficiently dense refilling network might be necessary to compensate for underutilised infrastructure. Vehicle and infrastructure roll-out have to be strongly co-ordinated to make the best use of government support.
- The evolution of the T&D infrastructure might create lock-in effects when transmission equipment becomes obsolete and transport and delivery structures cannot be arbitrarily combined with refuelling station equipment and on-board storage devices.

Recommended actions for the near term

More RD&D for fuel cells and on-board hydrogen storage systems is needed. Making FCEVs cost competitive with other EVs, hybrid and ICE vehicles, strongly depends on the cost of fuel cells and the on-board storage system. For fuel cells, the use of platinum needs to be minimised; for the on-board storage system, carbon fibre composite material costs and production costs need to be reduced by at least 75%. For stationery high temperature fuel cells, increasing durability needs to be addressed and the efficiency of electrode fabrication (including reduction of precious metals) must be improved to reduce stack costs.

Enhanced, larger-scale demonstration hydrogen/FCEV projects in the transport sector are needed. If hydrogen is to play a major role in the future, more and larger-scale demonstration projects (such as "early adopter cities") are needed over the next five to ten years. These will provide critical learning and refinement experiences that could later guide mass deployment. Identifying cities with already-existing hydrogen infrastructure for the chemical/refining industry and extending these systems to include transport demonstration projects might be relatively cost-effective.

More work is needed to identify optimal hydrogen transmission and distribution pathways. Developing strategies for hydrogen T&D infrastructure roll-out and optimal station size, configuration and density is a necessary prerequisite to FCEV commercialisation. Modelling results should be increasingly complemented in coming years by empirical findings from demonstration and early adopter experiences.

The progress of FCEVs, along with BEVs and PHEVs, should be closely tracked. Estimated FCEV costs have dropped rapidly in recent years and this may continue. Tracking the progress of battery electric vehicles and plug-in hybrids is also important, since these technologies are already being rolled out and are entering a mass-production phase. The extent of their market penetration and the market segments where they do or do not succeed (*e.g.* small versus large passenger LDVs, trucks), will help define a potential complementary role for FCEVs.

Economic incentives to promote clean vehicles should be introduced. Transport policies over the next decade must move towards giving strong incentives for low-carbon vehicles. Fiscal regimes (such as vehicle taxation systems) should evolve toward a fuel-economy and CO_2 emissions basis. Fuel taxes should reflect various external costs such as CO_2 and air pollutant emissions, guided by the "polluter pays" principle. Stronger international and national climate policies with clearer CO_2 emissions reduction targets, carbon-price systems and sectoral emission caps will promote public acceptance and purchase of FCEVs.

Hydrogen introduction into gas grids needs to be explored. Synergies between natural gas networks and hydrogen need to be actively exploited. A regulatory framework to blend natural gas with hydrogen, including quality and metering standards, should be established.

Comprehensive international standards for hydrogen handling need to be developed. For on-board hydrogen storage and refuelling devices as well as for hydrogen transport, the ongoing work on internationally accepted safety codes and standards has to be continued. Developing international design codes for refilling stations could ease the infrastructure roll-out for the transport sector.

More research is needed on hydrogen for large-scale energy storage. The knowledge base on the interaction between large-scale variable energy integration, energy storage and the use of hydrogen as a fuel in various sectors needs to be improved. Uncertainty about energy-storage needs on different time scales and under different market situations has to be reduced to help explore the potential of hydrogen.

Part 3

Fossil Fuels and CCS

Part 3 focuses on technologies for coal, natural gas and carbon capture and storage, and how the roles of these technologies will change over time. The use of fossil fuels needs to be reduced dramatically by 2050. Nevertheless, they will continue to play an important role in the global-energy system for decades.

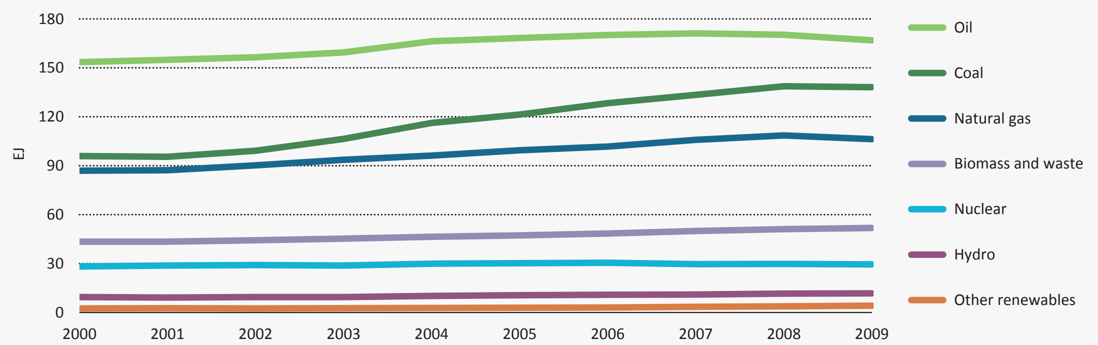
Reversing the trend of increasing coal use is the single most important factor in achieving the ETP 2012 2°C Scenario; Chapter 8 sets out the critical first steps in this transition and establishes the pathway to achieve the 2050 objectives. In Chapter 9, the changing role of natural gas is explored, while Chapter 10 brings more clarity on the status and prospects for carbon capture and storage technologies.

The Future of Fossil Fuels

Fossil fuels are the primary source of anthropogenic greenhouse-gas (GHG) emissions. With more than 80% of total primary energy demand satisfied by fossil fuels in 2009, oil, gas and coal[1] are used extensively across the power, industry, buildings and transport sectors.

Over the past decade, fossil fuels have also satisfied the major share of the incremental growth in primary energy demand (Figure F.1). Between 2000 and 2009, demand for nuclear power grew by 1.2 exajoules (EJ), biomass and waste by 8.4 EJ, hydro by 2.3 EJ, and renewable energy technologies by 1.7 EJ. Coal grew by 42 EJ, far exceeding the increase in demand from all non-fossil energy sources combined. The mix of fossil fuels used in a country or region is driven mainly by resource availability and domestic fuel prices.

Figure F.1 Growth in total primary energy demand



Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *Demand for coal over the last 10 years has been growing faster than for any other energy source.*

Meeting increasing energy demand with a predominance of fossil fuels is clearly not consistent with low-carbon goals, unless GHG mitigation technologies are available and widely deployed. Pledges made under the United Nations Framework Convention on Climate Change (UNFCCC) and the Copenhagen Accords, and subsequently confirmed at the 16th session of the Conference of the Parties to the UNFCC (COP 16) in Cancun, are estimated to be consistent with a long-term temperature rise of at least 3.5°C. To meet these goals, not to mention those of the *ETP 2012* 2°C Scenario (2DS), will require rigorously enforced policies, combined with a robust commitment to technology development, innovation and deployment.

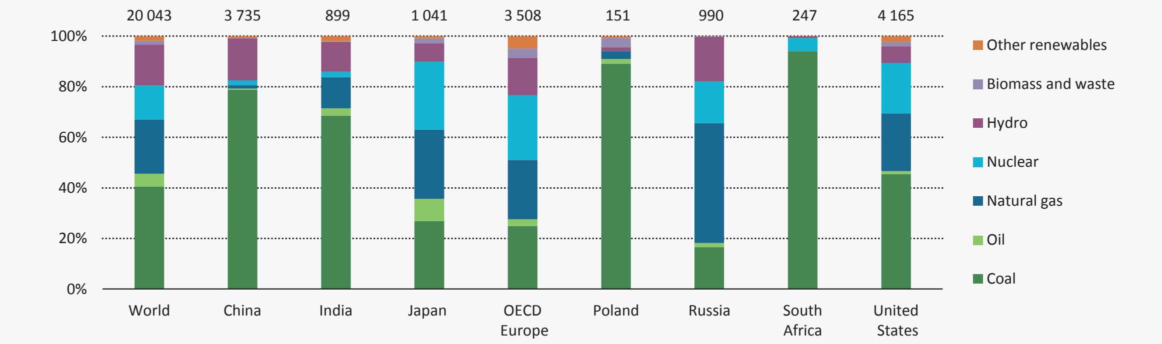
1 For primary energy demand, values quoted for coal also include peat, *i.e.* actually coal plus peat.

To lower GHG emissions from fossil fuels, three options are available:

- improve the efficiency of technologies used to convert fossils fuels into energy, especially in power generation;
- reduce the consumption of fossil fuels by switching to lower-carbon alternatives;
- sharply reduce carbon dioxide (CO_2) emissions entering the atmosphere using carbon capture and storage (CCS) technologies.

In 2009, around two-thirds of the world's electricity was generated from fossil fuels, with 40% from coal, 21% from natural gas and 5% from oil (Figure F.2).

Figure F.2 Electricity generation by resource in selected countries and regions in 2009



Note: The numbers above the country/region names indicate the terawatt-hour (TWh) electricity production in 2009.

Key point *Many countries and regions rely heavily on fossil fuels for electricity generation.*

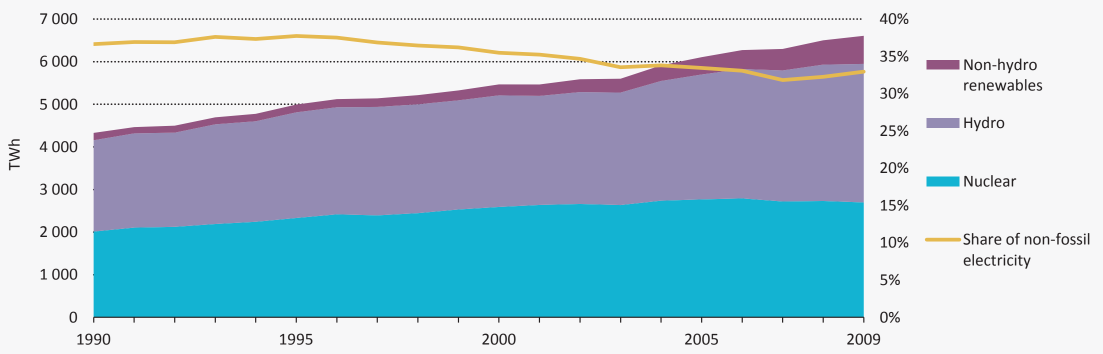
While the trend of generating electricity from oil has steadily declined in recent decades, the use of coal and gas has risen (except during the economic crisis in 2009, when total power output fell in many countries).

Much of the increasing demand for electricity has come from rapidly emerging economies, particularly China and India, which have both benefitted enormously over the past decade from their access to large domestic reserves of coal. Factors such as the quality of coal reserves, distance to point of use, availability of gas, competition between coal and gas, and environmental pressures, however, are likely to test their ability to continue this path in the future.

In a system where the contribution from variable renewable energy technologies is increasing, generation from coal and gas needs to become more flexible. Some capacity is required to compensate for periods when the wind does not blow or the sun does not shine; in other words, some coal- or gas-fired capacity will need to be on standby to generate at variable load when needed.

Although non-fossil energy generation – from nuclear, large-scale hydro and renewable energy technologies, for example – has risen impressively over the past two decades, its share of total generation has generally declined (Figure F.3). Consequently, CO_2 emissions continue to grow. In 2009, power generation alone contributed 41% of total CO_2 emissions to the atmosphere.

Figure F.3 Non-fossil electricity generation



Key point *Despite an increasing contribution across two decades, the share of non-fossil generation has failed to keep pace with the growth in generation from fossil fuels.*

Total CO_2 emissions from natural gas-fired plants are about 20% those of coal, despite being used to generate almost half the amount of electricity. This is due to a combination of the higher average efficiency of gas-fired plants, combined with the fact that gas has a lower ratio of carbon-to-heat content.

If the 2DS is to be achieved, the increasing share of fossil-based power generation must be reversed or its environmental impacts markedly reduced. Support for the growth of low-carbon options, including lower-emission fossil-fuel technologies, is crucial to a sustainable energy system. The bulk of coal and gas technologies remaining in service will almost certainly need to be retrofitted with CCS, and cost-effective policies that provide incentives to investors and companies must be put into action.

In the following chapters, covering coal, natural gas, and carbon capture and storage, the role of fossil fuels in ETP scenarios is explored in greater depth. Technology options and pathways to a low-carbon energy system, and the role that fossil fuels can play in them, are analysed.

Chapter 8

Coal Technologies

The growing reliance on coal to meet rising energy demands presents a major threat to a low-carbon future. To meet CO_2 emissions reductions goals, strong policies to encourage technology improvement, the timely deployment of carbon capture and storage technologies, and switching to lower carbon alternatives are essential.

Key findings

- ***Coal demand would need to fall by around 46% between now and 2050 in order to meet the goals of the 2DS; and generation of electricity from coal would need to fall by 43%.*** *Even with substantive use of CCS, older, inefficient plants would need to be retired and consumption of coal reduced by switching to lower-carbon sources of generation.*
- ***Substantial numbers of old, inefficient coal power plants remain in operation.*** *More than half of present capacity is over 25 years old and comprises units of 300 megawatts or less. Three-quarters of coal-fired plants in operation use subcritical technology.*
- ***The increasing use of widely available, low-cost, poor-quality coal is a cause for concern.*** *Improving the environmental and economic performance of plants using this fuel is critical, given the large number of coal-fired plants being built around the world.*
- ***Supercritical technology, at a minimum, should be deployed on all combustion installations.*** *IGCC plants should deploy gas turbines that allow high turbine-inlet temperatures for maximum efficiency.*
- ***Research, development and demonstration of advanced technologies should be actively promoted.*** *For example, operation with steam temperatures approaching or exceeding 700°C and IGCC with 1 500°C-class gas turbines will be capable of reducing CO_2 emissions from power generation plants to around 670 g/kWh. Less than 670g/kWh may be expected for IGCC with more advanced gas turbines.*
- ***To achieve deeper cuts, CCS offers the potential to reduce CO_2 emissions to less than 100 g/kWh.*** *There are drawbacks with the present generation of CCS technology, however: capital and operating costs are high; a high energy penalty is imposed on plant efficiency (7 to 10 percentage points); and it is immature (at least in terms of integrating capture, transport and storage on full-scale power plants).*
- ***It is important to reduce local pollution by lowering emissions of non-GHG pollutants, i.e. nitrogen oxides, sulphur dioxide and particulate matter.*** *Efficient flue-gas treatment is cost-effective and widely available, and deployment could be made mandatory.*

Opportunities for policy action

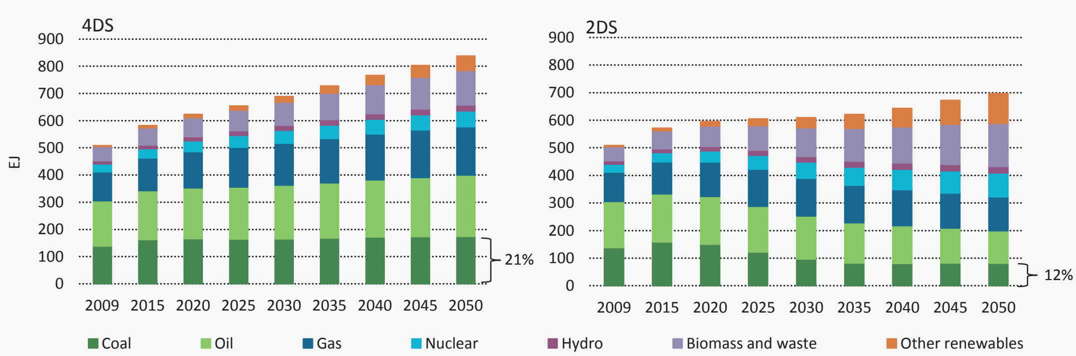
- *Increasing the average efficiency of global coal-fired power generation plants will be essential over the next 10 to 15 years. Generation from older, inefficient plants will need to be reduced, the performance of existing plants improved and new, highly efficient, state-of-the-art plants installed.*
- *Conducting programmes aimed at developing the next generation of technologies will be critical to raising average plant efficiency.*
- *First-generation, large-scale CCS plants need to be demonstrated and deployed. These facilities will contribute markedly to reducing the cost and energy penalty of the CO_2 capture process, to reducing risks associated with CO_2 transport and to proving the credibility of long-term storage.*

Role of coal in the energy mix

Coal is by far the most abundant fossil-fuel resource worldwide. Recoverable reserves can be found in 70 countries or more. At 1 trillion tonnes (BGR, 2010), there are sufficient reserves for 150 years of generation at current consumption rates.

Most of the rise in global CO_2 emissions since 2000 is the direct result of the increase in coal-fired power generation. In 2009, coal-fired power plants accounted for 73% of total CO_2 emissions from the sector, up from 66% in 1990. Emissions by 2050 are projected to increase by one-third and average atmospheric temperatures to rise by 4°C if only those emission-reduction policy commitments and pledges announced to date are implemented; projections in the *ETP 2012* 4°C Scenario (4DS) are consistent with this case. To meet the *ETP 2012* 2°C Scenario (2DS), CO_2 emissions need to halve from current levels by 2050. Cutting emissions from coal will be a major factor in the transition from the 4DS to the 2DS (Figure 8.1).

Figure 8.1 Two very different futures for coal demand



Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *Global primary coal demand increases by 14% in the 4DS, but falls by around 60% in the 2DS.*

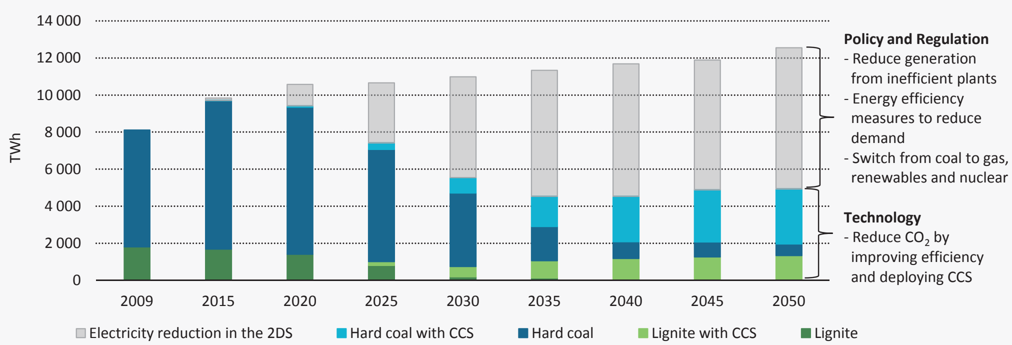
Role of coal in electricity generation

In 2050, coal is projected to generate 12 500 terawatt-hours (TWh) of electricity in the 4DS and 4 900 TWh in the 2DS. To achieve this reduction, coal-fired generation in the 4DS must be replaced by generation from lower-carbon alternatives, such as natural gas, renewable energy technologies or nuclear, and by reducing generation from older, less efficient coal-fired plants (Figure 8.2). In regions where the demand for electricity is rising, the decision to reduce generation from coal-fired plants will depend on the availability and cost of alternative fuels or other lower-carbon sources of power. It will also depend on the particular energy policies adopted.

Improvements in technology can also reduce the CO_2 intensity factor; high-efficiency technologies, such as ultra-supercritical technology, and carbon capture and storage (CCS) will play an important role in achieving this goal. Improvements to technology have the potential to reduce CO_2 emissions from coal-fired generation without CCS to 670 g/kWh, compared to higher than 1 100 g/kWh for some subcritical coal plants. To achieve greater CO_2 abatement, CCS technologies are the only means of realising major emissions reductions of 80% to 90%, bringing them down to less than 100 g/kWh.

However, the energy penalty[1] is high for currently available CCS technologies, reducing efficiencies by around 7 to 10 percentage points. Technology development to reduce the energy penalty, particularly by testing and gaining operational experience on large-scale demonstration plants, is crucial for the future of CCS.

Figure 8.2 The 4DS and 2DS visions for electricity generation from coal



Note: TWh = terawatt-hour.

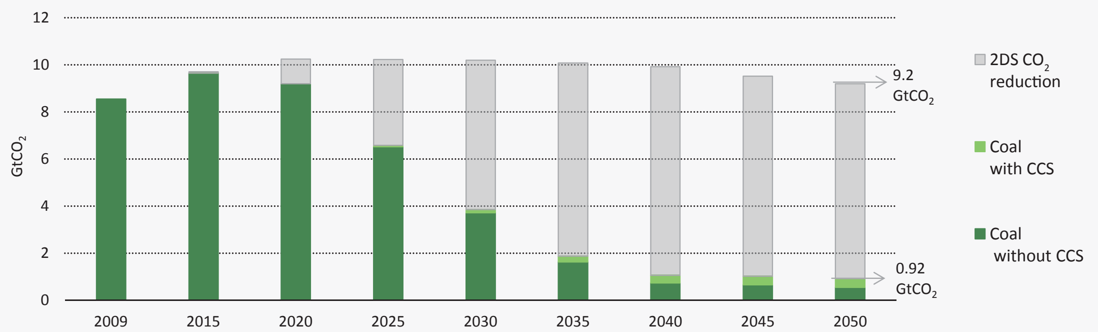
Key point *Reducing generation from older, less efficient plants; using coal more efficiently; deploying CCS; and switching from coal to lower-carbon fuels are essential to meet the 2DS emissions goals.*

Coal's dominant role in CO_2 emissions

In the 2DS, total carbon dioxide (CO_2) emissions in 2050 are reduced to 14 gigatonnes (Gt), or less than half the level emitted in 2009. This means emissions must be 25 Gt lower in 2050 than the 39 Gt projected in the 4DS. For coal, the difference in CO_2 emissions between the 4DS and the 2DS in 2050 is a little over 8 Gt (Figure 8.3).

1 Energy penalty refers to the net loss of energy (or electricity) when a power plant uses CCS.

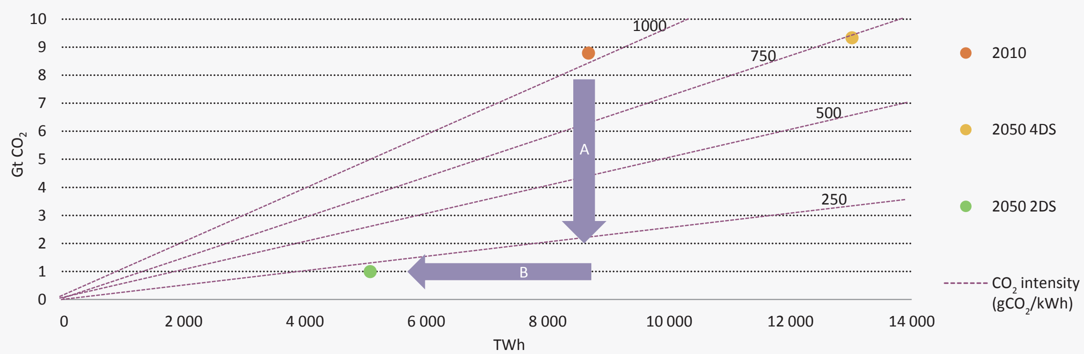
Figure 8.3 CO_2 emissions for the 4DS and the 2DS in coal-fired power generation



Key point *The CO_2 emitted from coal-fired power generation in the 4DS must be reduced by almost 90% if the 2DS is to be achieved.*

Global CO_2 emissions from coal-fired electricity generation are plotted against electricity generated in Figure 8.4. In the 4DS, although the CO_2 intensity factor decreases, the resultant CO_2 emissions are found to increase due to the increased generation from coal. To achieve the 2DS, not only must the CO_2 intensity factor be decreased through improved technology, but overall power demand and generation must also be decreased through improvements in energy efficiency (from the introduction of policy and regulation).

Figure 8.4 CO_2 emissions intensity from coal-fired power generation



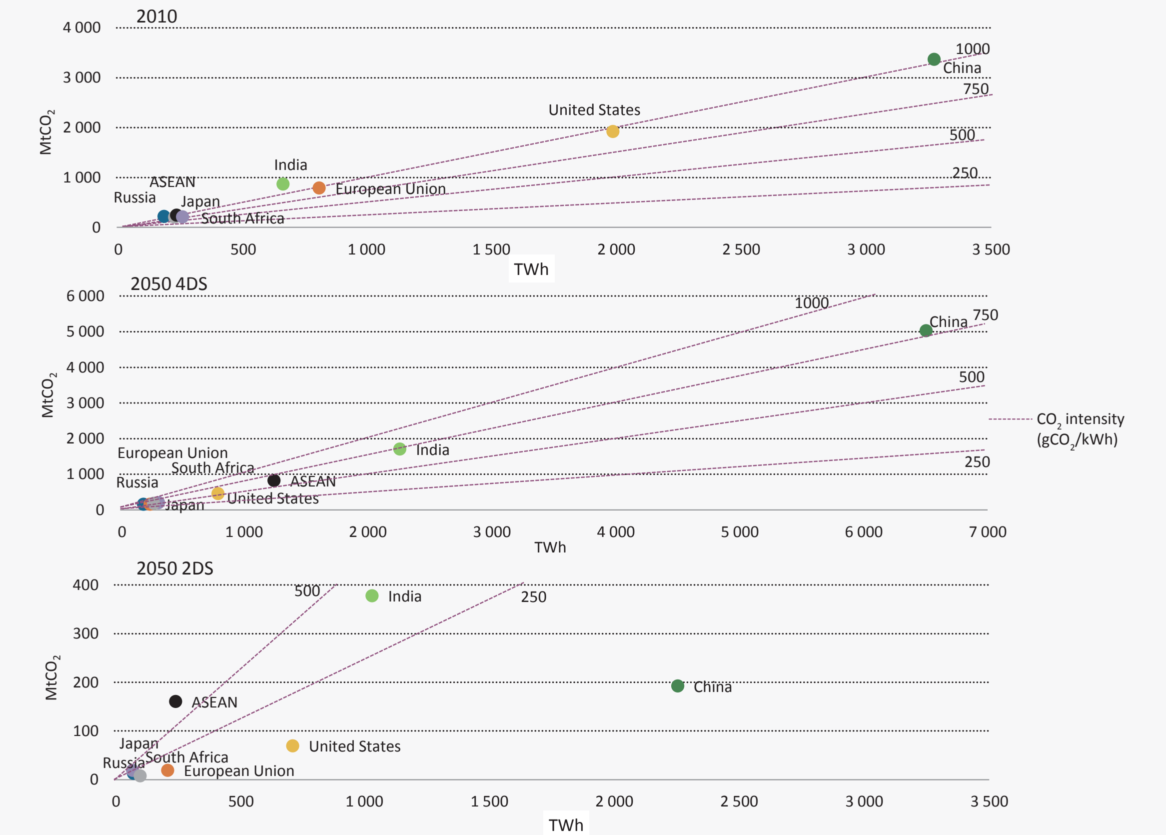
Notes: A= Technology developments contribute to lowering the CO_2 intensity factor. B= Policies and regulation help realise a lower electricity demand.

Key point *Technology improvement coupled with targeted policy and regulation are essential to realise the 2DS target in 2050.*

Regional CO_2 emissions for each scenario are compared in Figure 8.5. In the 4DS, China, India and countries of the Association of Southeast Asian Nations (ASEAN), along with the United States, will be the major CO_2 emitters in 2050. More than 80% of global electricity from coal will be consumed by China, India, the ASEAN and the United States in that year.

Reducing energy dependence on coal will require strong policy action coupled with intensive technology development.

Figure 8.5 Regional CO_2 emissions intensity from coal-fired power generation



Key point *China, the United States and India will need to reduce substantially both the CO_2 intensity and the amount of electricity generated from coal over the next four decades.*

Coal-fired power generation

Today a wide chasm exists between the average performing coal-fired plant and state-of-the-art. Closing this gap would be hugely beneficial to the environment.

Efficiency of generation from coal

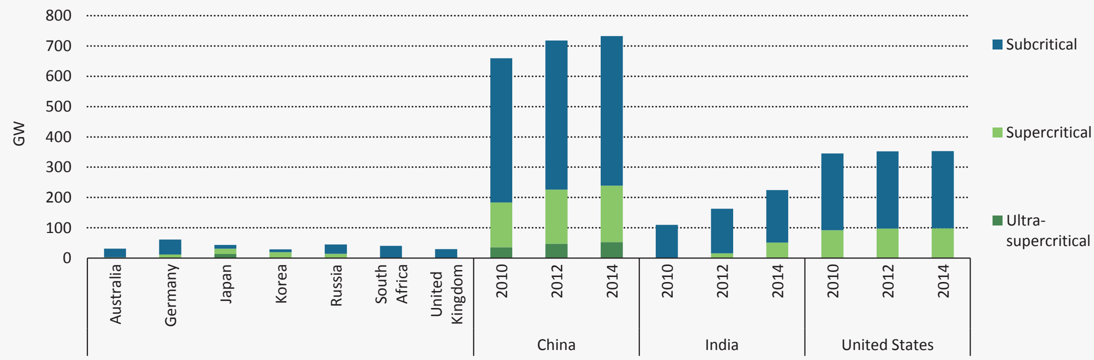
The average efficiency[2] of coal-fired power generation units in the major coal-using countries of Australia, China, Germany, India, Japan and the United States varies enormously (MEF, 2009), with values ranging from 30% to 40% (LHV, net) in 2005. The efficiency differences arise from diverse factors such as the age of operating plants, local climatic conditions, coal quality, operating and maintenance skills, and receptiveness to the uptake of advanced technologies (Figure 8.6). A large number of low-efficiency plants remain in operation, with more than half of all operating plant capacity older than 25 years and with unit sizes of 300 megawatts-electrical (MW_e) or less. Almost three-quarters of operating plants use

2 Unless otherwise noted, efficiency notations in this chapter are based on the lower heating value of the fuel and net output (LHV, net). Lower heating values, unlike higher heating values (HHV), do not account for the latent heat of water in the products of combustion. European and IEA statistics are most often reported on an LHV basis. For coal-fired power generation, efficiencies based on HHV are generally around 2% to 3% lower than those based on LHV. Net output refers to the total electrical output from the plant (gross) less the plant's internal power consumption (typically 5%-7% of gross power).

subcritical technology (Figure 8.8), while current state-of-the-art technology operates under ultra-supercritical (USC) steam conditions capable of efficiencies up to 45% (LHV, net).

The adoption of supercritical (SC) technology as the technology of choice for new plants in both OECD and non-OECD countries can lead to a significant rise in the global average efficiency of coal-fired power generation. In addition, further research and development (R&D) efforts by industry, with the support of enabling policy, is absolutely essential to ensure more advanced and efficient technologies enter the marketplace in the future.

Figure 8.6 Capacity of coal-fired power plants in major coal-using countries



Note: Refers to capacity in 2010 unless specified otherwise. Definitions of sub-critical, supercritical and ultra-supercritical technology are given in Box 8.1.
Source: Platts, 2011.

Key point *More opportunities should be taken to adopt supercritical technology or better in both OECD and non-OECD countries.*

Potential for CO_2 capture in coal-fired power generation

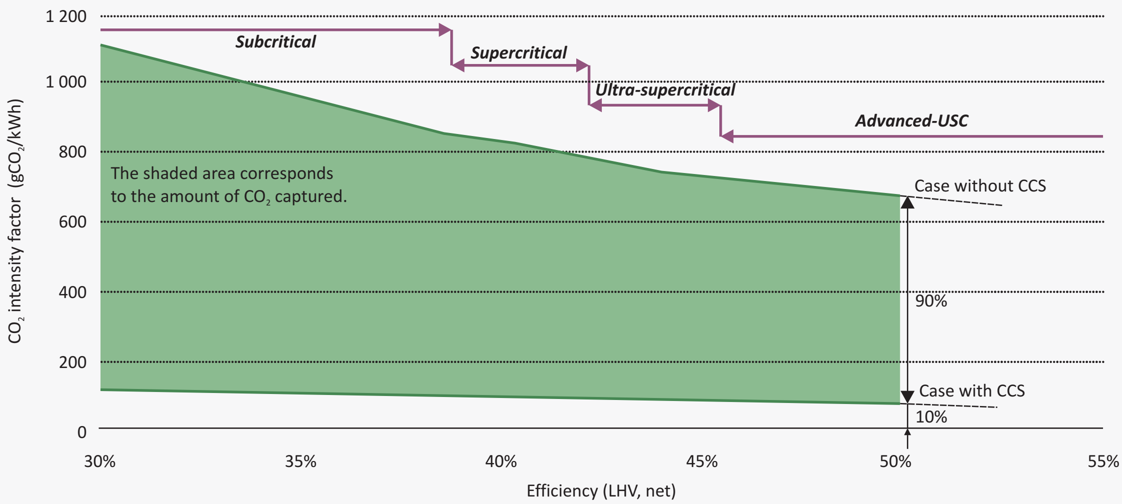
Given the recent increase in construction of new coal-fired power plants, plus a strong likelihood that such construction will continue until at least 2020, CCS will need to be added to a significant proportion of operating coal power plants in order to meet sustainable, low-carbon climate targets, in particular the 2DS. Retrofitting or adding CCS after a power plant has already been commissioned is a complex task and requires consideration of many site-specific issues. Moreover, there are drawbacks: the capital and operating costs of CCS are high, and the energy penalty on plant efficiency is 7 to 10 percentage points, with current technology. Further development of CCS is required, particularly on large-scale integrated demonstration plants, before the technology can be described as technically mature. The economic and technical barriers to deployment of CCS for both coal and gas are clear.

Intensity factors for pulverised coal combustion (PC) plants with increasing efficiency are shown for cases with and without CCS in Figure 8.7. A CO_2 capture efficiency of 90% is assumed, independent of the efficiency of the PC plant. The amount of CO_2 captured decreases markedly as the efficiency of the PC plant increases. For ultra-supercritical (USC) plants with an efficiency of 45%, around 25% less CO_2 is captured than by subcritical plants of 35% efficiency. Consequently, higher-efficiency plants require CCS units with lower capacity – and lower operating costs.

A recent IEA report (IEA, 2012) proposed that retrofitting CCS technologies becomes unattractive for coal-fired power generation plants with efficiencies less than 35% (LHV).

In fact, deployment of CCS in coal-fired power generation is more favourable for plants operating under supercritical steam conditions or better. The development of CCS with a low energy penalty and low cost would be the ideal, accompanied by strong policies and regulations to accelerate the demonstration of large-scale, integrated CCS. This transition could provide the know-how to lead to more effective plant construction and operation.

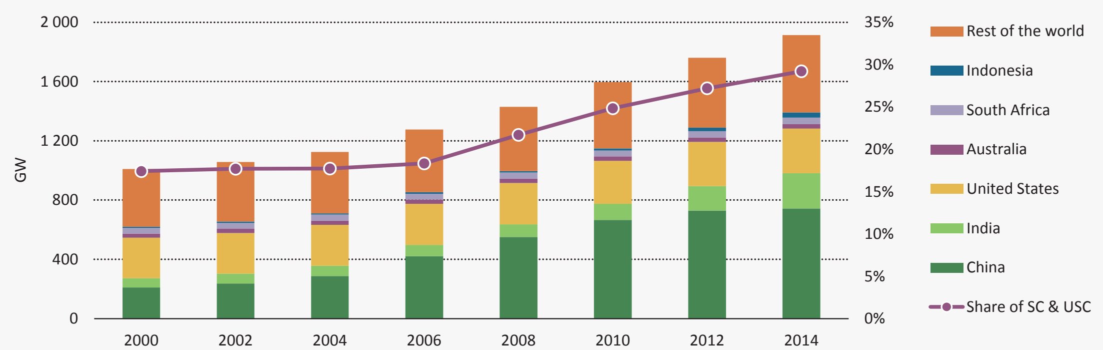
Figure 8.7 CO_2 emissions from coal-fired power generation



Note: The case with CCS assumes 90% of CO_2 in the flue gas is captured.
Source: Adapted from VGB, 2011.

Key point *Increasing plant efficiency plays an important role in reducing the cost of CO_2 abatement, e.g. increasing efficiency from 40% to 42% results in a 5% decrease in CO_2 emissions.*

Figure 8.8 Trend of installed capacity in coal-fired power generation



Source: Analysis based on data from Platts, 2011.

Key point *The number of plants planned or under construction indicates that growth of coal-fired power generation in Asia will continue.*

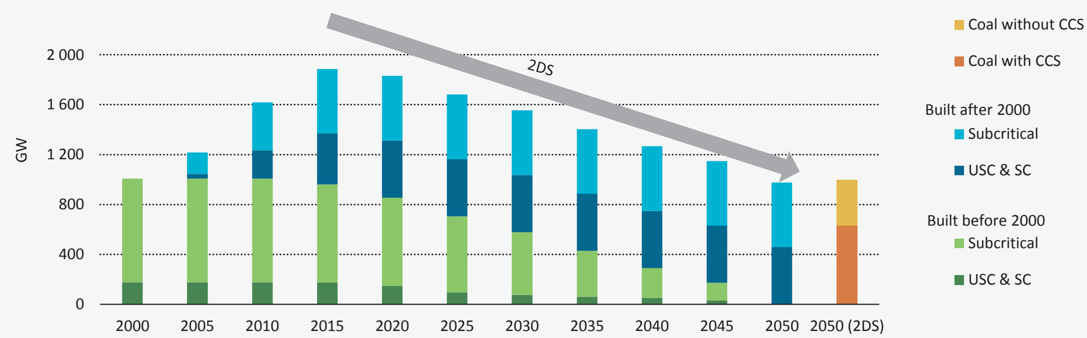
Locking in carbon technology

A considerable amount of new capacity will be added over the next decade to meet the growth in electricity demand in the emerging economies of China, India and Southeast Asia.

Investment decisions for this new capacity will lock in technology. Whether it is the best available technology will depend on the investment decision; either way, it will have a major bearing on emissions levels for decades to come. Most power plants, particularly coal-fired ones, have long economic lives (Figure 8.8).

Most new power plants projected for construction between 2010 and 2015 will be located in the emerging economies of Asia, and the technology decisions have already been made. Assuming a coal-fired plant has an average lifespan of 50 years, the capacity projected in the 2DS to be operating in 2050 has, in practice, already been met (Figure 8.9). With no policies to encourage their early retirement, newly constructed power stations can operate and emit CO_2 up to 2050, presenting a major barrier to meeting the 2DS target. Furthermore, almost half of total capacity in 2050 is still projected to be subcritical, the majority of which would present an unattractive proposition for CCS retrofit (IEA, 2012). In the 2DS, it is projected that 63% of coal-fired capacity would be fitted with CCS in 2050. For consistency with this scenario, most subcritical plants would be decommissioned through stringently enforced policies before the end of their natural lifetimes, causing significant economic losses.

Figure 8.9 Projected capacity of coal-fired power generation plants



Note: Plant lifetime is assumed to be 50 years.
Source: Analysis based on data from Platts, 2011.

Key point *Capacity additions over the next decade will lock in technology with lower efficiency and high CO_2 emissions.*

To achieve the 2DS, technology development together with the introduction of strong policies to promote lower-carbon power generation will be essential (Table 8.1).

Table 8.1 Technologies and policies to achieve the 2DS

Subjects	Actions for CO_2 reduction in coal-fired power plants
Technology development	1. Develop plants with efficiencies in excess of 45% (LHV, net), with capacity factors[3] of 85% or higher. 2. Accelerate demonstration of large-scale, integrated CCS and develop CCS with a lower energy penalty.
Policy	3. Reduce generation from less efficient subcritical plants and/or significantly increase their efficiency. 4. Switch from coal-fired generation to generation from gas, renewable energy and nuclear. 5. Promote deployment of ultra-supercritical technology for new installation and repowering. 6. Promote broad deployment of large-scale CCS plants.

3 The capacity factor of a power plant is the ratio of its actual output over a period of time to its potential output, if it had operated at full capacity over that same period. In this chapter, it is used synonymously with plant availability.

Potential for reducing emissions and improving air quality

Globally, the capacity of most coal-fired power generation plants is based on pulverised coal combustion (PC) technology, some on circulating fluidised bed combustion (CFBC) technology and a handful on integrated gasification combined cycle (IGCC) technology. With more than 1 600 gigawatts (GW) of generation capacity, the global coal-fired power plant fleet accounts for more than 8 Gt of CO_2 emissions annually – roughly a quarter of total anthropogenic global CO_2 emissions.

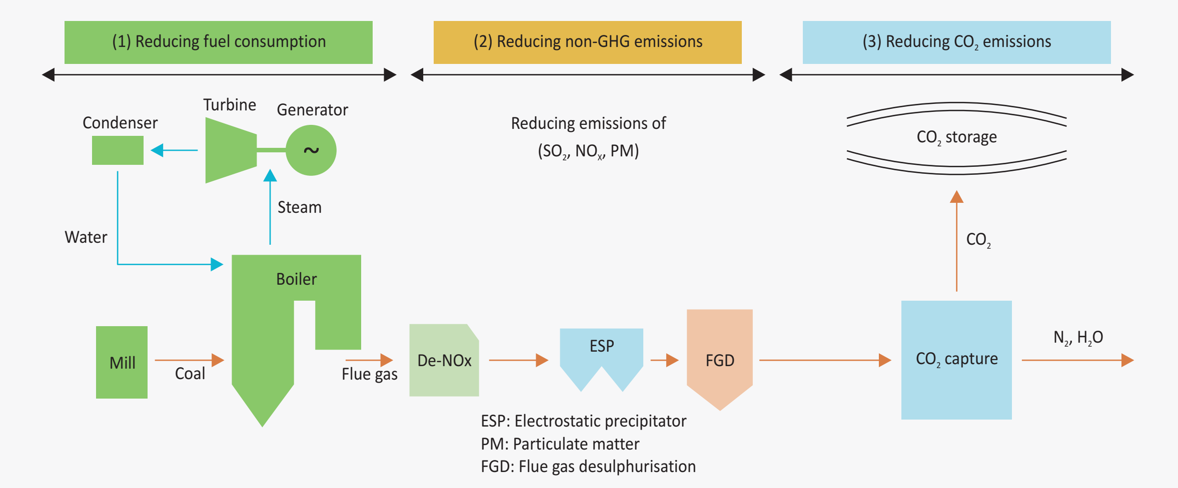
Despite climate-change concerns, power generation from coal is expanding faster than ever; record growth over the last five years added more than 350 GW of capacity. With no action, the resultant increase in CO_2 emissions presents a serious threat to the global climate.

The efficiency of PC and CFBC plants is strongly dependent on steam conditions and there has been an ongoing effort to increase steam temperatures over the past three decades. Although PC and CFBC are technically mature, efficiency can be increased and CO_2 emissions decreased by developing so-called advanced ultra-supercritical (A-USC) technologies. Advanced integrated combined cycle combustion (IGCC), achieved largely through the application of advanced gas turbines, also decreases CO_2 emissions.

In addition to reducing CO_2 emissions, reducing emissions of nitrogen oxides (NO_X), sulphur dioxide (SO_2) and particulate matter (PM) is also important, particularly at the local or regional level. These pollutants give rise to local environmental problems that for many may be more pressing than the global issue of climate change. There are three primary technology pathways (Figure 8.10) to reduce emissions and improve air quality:

- efficiency improvement, which reduces fuel consumption and generally reduces emissions of all pollutants;
- air quality control, which reduces non-GHG emissions by treating flue gas for NO_X, SO_2 and PM; and
- CCS, which reduces CO_2 emissions via the capture, transport and subsequent long-term storage of CO_2.

Figure 8.10 **Technology pathways for cleaner coal-fired power generation**



Key point *Reducing emissions is the critical technology challenge for coal-fired plants.*

Box 8.1

Coal-fired power generation technologies

Coal-fired power generation technologies in operation today, or under development, have markedly different technical features, performance characteristics and costs.

Subcritical technology: For conventional boiler technology – the type most commonly used in existing coal-fired plants – water is heated to produce steam at a pressure below the critical pressure of water (22.1 megapascal [MPa]). Subcritical units are designed to achieve thermal efficiencies of typically 38% to 39% (LHV, net).

Supercritical (SC) technology: Steam is generated at a pressure above the critical point of water, so no water-steam separation is required (except during start-up and shut-down). Supercritical plants are more efficient than subcritical plants, typically reaching 42% to 43%. The higher capital costs may be partially or wholly offset by the fuel savings (depending on the price of fuel).

Ultra-supercritical (USC) technology: Similar to supercritical generation, but operating at even higher temperatures and pressures, thermal efficiencies may typically reach 45%. Although there is no agreed-upon definition, some manufacturers refer to those plants operating at a steam temperature in excess of 600°C as being ultra-supercritical (although this varies according to manufacturer and region). Current state-of-the-art USC plants operate at steam temperatures up to 620°C, with steam pressures from 25 MPa to 29 MPa.

Advanced ultra-supercritical (A-USC) technology: Substantial effort in several countries is aimed at achieving efficiencies up to and then in excess of 50%. For this, materials that are capable of withstanding steam conditions of 700°C to 760°C and pressures of 30 MPa to 35 MPa must be developed. The materials under development are non-ferrous alloys based on nickel, termed superalloys.

Integrated gasification combined-cycle (IGCC): Coal is partially oxidised in air or oxygen to produce a fuel gas at high pressure. Electricity is then produced via a combined cycle. The fuel gas is burnt in a combustion chamber before expanding the hot pressurised gases through a gas turbine. The hot exhaust gases are used to raise steam in a heat recovery steam generator before expanding it through a steam turbine. Thermal efficiencies may approach 50% with the latest 1 500°C gas turbines.

CO_2 intensity factors and fuel consumption for coal-fired power generation technologies

	CO_2 intensity factor (LHV, net)	Fuel consumption[a]
A-USC (700°C*) IGCC (1500°C)**	669 g CO_2/kWh (50%)	288 g coal/kWh
Ultra-supercritical	743 g CO_2/kWh (up to 45%)	320 g coal/kWh
Supercritical	798 g CO_2/kWh (up to 42%)	343 g coal/kWh
Subcritical	881 g CO_2/kWh (up to 38%)	379 g coal/kWh

[a] For coal with heating value 25 MJ/kg
* Steam temperature. ** Turbine inlet temperature.
Source: VBG, 2011.

Technologies for improving efficiency and reducing emissions

There is potential to improve the performance of PC, CFBC and IGCC technologies significantly from those achievable at present.

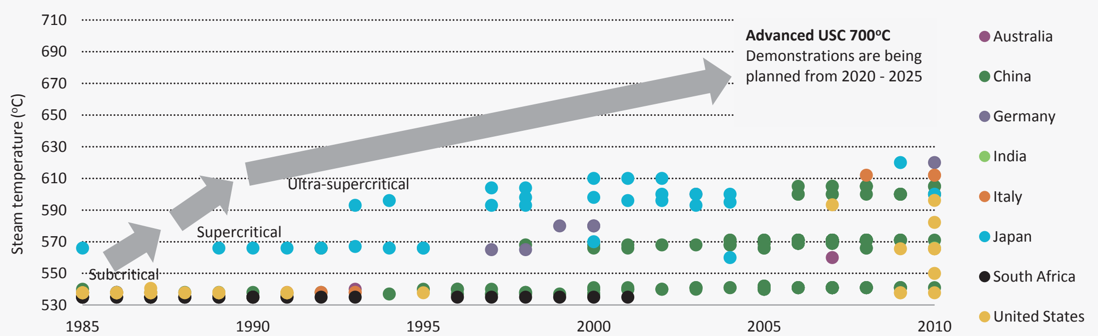
Pulverised coal combustion

With PC technology, powdered coal is injected into the combustor and burned to raise steam for subsequent expansion in a steam-turbine generator. Many factors determine the efficiency: for example, the degree of coal burnout, the extent of heat transfer in the boiler, the configuration of the water-to-steam cycle, the turbine design and the plant's internal power consumption. Some units use additional heat recovery from the flue gas in special corrosion-resistant heat exchangers.

The temperature of the cooling water (or air) has a major influence on final efficiency. Lower water temperature makes plant performance more efficient, but access to low-temperature water is subject to the plant's location. The most effective means of achieving high efficiency is to use steam temperatures and pressures above the supercritical point of water, *i.e.* at pressures above 22.1 megapascal (MPa). Units using state-of-the-art conditions (ultra-supercritical) operate at steam parameters between 25 MPa and 29 MPa, with temperatures up to 620°C (Figure 8.11).

With bituminous coal, plants incorporating ultra-supercritical technology can achieve efficiencies up to 45% (LHV, net) in temperate locations. Lignite plants can achieve efficiencies close to 44% (Vattenfall, 2011a). Both fuel consumption per kilowatt hour (kWh) and specific CO_2 emissions decrease as steam conditions are raised. For advanced-USC, which is still under development (demonstration projects are planned after 2020), a 15% cut in CO_2 emissions is expected, compared with conventional supercritical technology. Although ultra-supercritical plants were first introduced in OECD countries, as of 2011 China has 116 GW of 600 MW_e ultra-supercritical units and 39 GW of 1 000 MW_e ultra-supercritical units in operation, out of a total coal-fired fleet of 734 GW (Zhan, 2012).

Figure 8.11 State-of-the-art steam conditions and future perspectives in PC plants



Note: Plants over 600 megawatt-electrical (MW_e) output are listed.
Source: Analysis based on data from Platts, 2011.

Key point *Ultra-supercritical plants are already in commercial operation in Japan, Korea, various countries in Europe and, more recently, China.*

Circulating fluidised bed combustion

CFBC is particularly suited to fuels with low heat content. The fuel is crushed, rather than pulverised, and combustion takes place at lower temperatures than in PC systems. A highly mobile bed of ash and fuel is supported on an upward current of combustion air. Most of the solids are continuously blown out of the bed before being recirculated back into the combustor. Heat is extracted for steam production from various parts of the system.

Limestone is fed to the combustion system to control SO_2 emissions, typically achieving 95% abatement. Emissions of NO_x are intrinsically low, due to the relatively low combustion temperature. The capacity factor of CFBC power plants is comparable with PC plants. The technology is mature and supercritical CFBC plants are now in operation in China, Poland and Russia (Jantti and Rasanan, 2011; Jantti *et al.*, 2009; Li *et al.*, 2009; Minchener, 2010).

Integrated gasification combined cycle

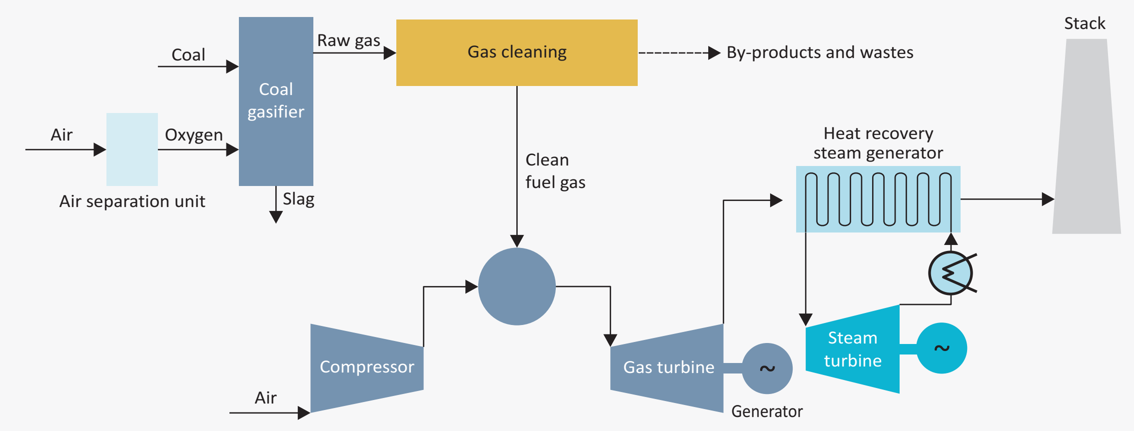
IGCC uses gasification, with sub-stoichiometric levels of oxygen or air, to convert coal into a gaseous fuel that is cleaned before it is fired in a combined cycle gas turbine (Figure 8.12). The fuel gas is cleaned by removing PM and then cold gas scrubbing to take out NO_x precursors and sulphur compounds. There are commercial demonstration plants operating in the United States, Europe and Japan, and more plants are under construction in the United States and China.

IGCC has inherently low emissions, partly because the fuel needs to be very clean to protect the gas turbine. However, as IGCC plants are generally accepted as having higher capital and operating costs than PC plants, and their unit size is constrained by the size of gas turbine, their market deployment has been slow. Important RD&D objectives for IGCC are to reduce costs and improve plant availability, as well as to raise efficiency and demonstrate the means to incorporate CO_2 capture.

Various factors determine the efficiency of IGCC. With the latest 1 500°C-class gas turbines, efficiencies comparable with those of advanced ultra-supercritical PC systems, (*i.e.* 50% LHV, net) are considered possible with bituminous coals. By 2050, the application of 1 700°C-class gas turbines might bring CO_2 emissions from IGCC below 670g/kWh.

Lower-grade coals tend to penalise efficiency and costs. Research and development is under way to mitigate this penalty, namely through drying systems for lignite and solid feed pumps. Conventional large-scale oxygen production uses a considerable amount of energy. Air requires a larger gasifier and produces a fuel gas with lower heat content; around 4 megajoules per normal cubic metre (MJ/Nm^3) compared with 12 to 16 MJ/Nm^3 for an oxygen-blown gasifier.

Figure 8.12 Integrated gasification combined cycle power generation



Source: Adapted from Henderson and Mills, 2009.

Key point *With the latest 1 500°C-class gas turbines, efficiencies of 50% (LHV, net) may be achievable with bituminous coals.*

IGCC is more expensive than combustion systems for power generation and, because of the lack of operational reference plants, higher redundancies are applied to mitigate risks. Until the system reaches maturity, its capacity factor is unlikely to reach that of PC plants, due to the relative lack of operating experience, the large number of sub-systems and the aggressive conditions within a gasifier. Cost-competitiveness will depend on sufficient numbers of plants being deployed. It is anticipated that IGCC may become more cost-competitive with PC when CCS is applied to both. The development of hydrogen-burning gas turbines brings a new challenge for IGCC with CCS.

Co-deployment with renewables

Biomass co-firing. Co-firing biomass in coal-fired power plants offers a means of reducing CO_2 emissions. Assuming biomass to be a carbon-neutral fuel, its use in co-firing has attracted government support in a number of countries, such as the United Kingdom. Prior to co-firing, a blend with a particular biomass-to-coal ratio (normally 10% to 15%[4] of biomass) must be prepared and suitable technologies for handling and stable firing must be developed. Additionally, as coal-fired plants generally operate with much higher steam parameters than biomass-fired power plants, the co-fired biomass is converted at a higher efficiency. It should be noted, however, that co-firing 10% to 15% of the energy content in a large-scale thermal power plant (1 000 MW_e) would correspond to a biomass supply chain of around 250 MW_{th} to 350 MWth, which may become a challenge logistically and economically.

Dispatchable power plants. Since variable renewable energy technologies (*e.g.* wind and solar) are being connected to conventional grids, more flexible resources are needed to generate electricity supply. Dispatchable operation, particularly the ability to change load on demand, presents challenges to coal-fired plant operation. In some countries, new coal-fired units will be expected to load-follow to satisfy the fluctuating demand for electricity. This will have a major impact on the cost of power, with higher maintenance and extra fuel costs, additional capital costs and, possibly, capacity costs to kick in when no generation from the unit is required (Mills, 2011). Coal-fired plants are less flexible than gas-fired CCGTs, as there is a need to manage the thermal transients resulting from high steam temperatures and wall thickness on pressure components. Further R&D and technology demonstration is required to address the need for flexibility to accommodate the increase in renewable capacity.

Present status of non-GHG pollutant emissions reduction

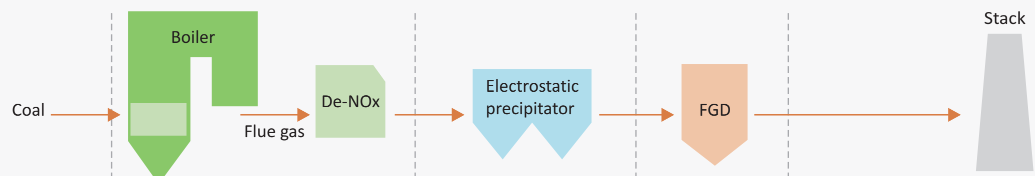
By using currently available flue gas treatment systems, it is possible to reduce emissions of NO_x, SO_2 and PM to below the most stringent levels demanded anywhere in the world (Figure 8.13). To minimise NO_x concentrations, a combination of combustion technologies, including staged air and fuel mixing for low-NO_x combustion, and post-combustion technologies, usually selective catalytic reduction, are used. Particulate matter is removed by electrostatic precipitators or fabric filters, and SO_2 by using flue gas desulphurisation, usually scrubbed with limestone slurry.

Other technologies are available for NO_x and SO_2 control, and each one has further potential for improving performance. For plants fitted with technology to capture CO_2, particularly those employing amine scrubbing, lower emissions of SO_2 and, to a lesser extent, NO_x would be favoured. Acid gases irreversibly degrade the solvent, preventing its regeneration and significantly increasing the costs of the overall process. Moreover, particulate matter can build up in the solvent and, if not filtered out, will require the solvent be changed more frequently.

4 By energy content.

Dry SO_2 control systems that offer extremely high performance are deployed at some plants. Further reducing environmental emissions beyond those achievable at present is likely, with targets of less than 10 mg/Nm³ for NO_x and SO_2, and less than 1 mg/Nm³ for PM being suggested (Henderson and Mills, 2009). Although mercury emissions from coal-fired power plants vary widely, much of the mercury released in a plant may be deposited on the fly ash, in the selective catalytic reduction system and/or in the flue gas desulphuriser. The highest levels of control are achieved with fabric filters fitted for particulate removal. In plants equipped with the full range of flue gas treatment systems, with no additional equipment for mercury removal, it is possible to reduce mercury emissions to less than 3 μg/Nm³. Injecting activated carbon offers a means to capture mercury, and multi-pollutant removal systems can also be effective.

Figure 8.13 **Current capability of flue gas treatment system for coal-fired power plants**



	Boiler / De-NOx	Electrostatic precipitator	FGD
NOx (mg/Nm³)	< 500 - 1 000 → < 50 - 100		< 50 - 100
SO_2 (mg/Nm³)	< 1 000 - 5 000		< 20 - 100
$PM_{2.5}$ (mg/Nm³)	< 20 000	< 50	< 10

Current performance at stack[5]
< 50 - 100
(<0.16 - 0.42 g/kWh)
< 20-100
(< 0.06 - 0.42 g/kWh)
< 10
(< 0.032 - 0.042 g/kWh)

Note: FGD = Flue gas desulphurisation.

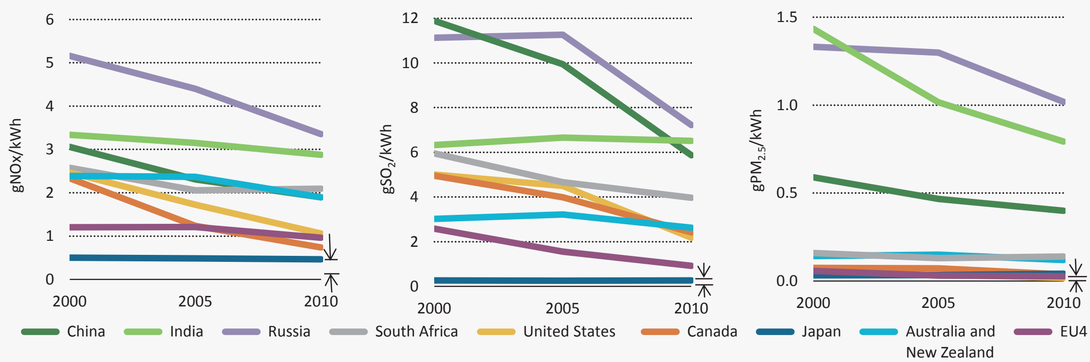
Key point *Flue gas treatment systems currently available can reduce SO_2, NO_x and PM significantly.*

Reducing non-GHG pollutant emissions has presented a major technical challenge over the past few decades: in some countries, such as Japan, OECD Europe and North America, emissions of air pollutants to the atmosphere have been dramatically reduced (Figure 8.14). To reduce emissions of NO_x, SO_2 and PM to current state-of-the-art levels, focused policy measures need to be put in place in both OECD and non-OECD countries, with appropriately strict penalties for non-compliance. Market-based systems to achieve least-cost compliance have been successful in several countries.

For CFBC, limestone is fed into the combustion system to control SO_2 emissions, typically achieving 95% abatement. Emissions of NO_x are intrinsically low due to the comparatively low combustion temperature. Additional SO_2 or NO_x capture systems can be added where very low emissions are required.

5 To convert mg/Nm³ into g/kWh, it is necessary to assume values for the plant efficiency and the flue-gas volume per unit of energy. In Figure 8.13, plant efficiency is assumed to range from 30% to 40% (LHV, net) based on regional average efficiencies. The flue gas volume is assumed to be 353 m³/GJ (LHV), which may vary with coal composition, but the band of fluctuation is roughly less than 5%.

Figure 8.14 NO_x, SO_2 and PM emissions from coal-fired power plants



Note: EU 4 includes France, Germany, Italy and United Kingdom. Ranges sandwiched between the arrows indicate currently achievable performances from flue gas treatment systems.
Source: Includes data from Cofala *et al.*, 2010.

Key point *Strong policies could accelerate the uptake of more effective flue gas treatment systems.*

In IGCC, stringent particulate control (via medium temperature filtration) and desulphurisation (through liquid scrubbing) occur before the fuel gas is sent to the gas turbine. Scrubbing ammonia from the gas also reduces NO_x emissions. Most NO_x control is achieved by mixing the fuel gas with nitrogen or steam prior to combustion. Advanced ultra-low NO_x burners are being developed by gas turbine manufacturers to achieve extremely low emissions in the future. An interim means of achieving ultra-low NO_x is to add selective catalytic reduction. Sulphur gases captured from fuel gas, at around 250°C, using metal oxides in a transport reactor, should increase efficiency and reduce costs (Gupta, Turk and Lesemann, 2009).

Advantages and disadvantages of other power generation technologies

While PC and CFBC technologies are technically mature, ongoing development is targeted at raising efficiency and thereby reducing CO_2 emissions to less than 700 gCO_2/kWh. Reducing emissions of non-GHG pollutants and incorporating CO_2 capture are two more targets. It is considered possible that IGCC efficiency could be raised to the level of advanced-USC through the use of 1 500°C-class gas turbines. Furthermore, advanced fuel cells in integrated coal-gasification fuel cell (IGFC) cycles may in the future achieve even higher thermal efficiencies, possibly reducing CO_2 emissions to around 500 gCO_2/kWh to 550 gCO_2/kWh.

Maximum unit size is another important factor when installing new power generation capacity. A single PC unit is now capable of producing up to 1 050 MW_e (Matsuoka, 2008).

Generation from natural gas inherently emits less CO_2 than coal. Replacing coal plants with natural gas plants could reduce CO_2 emissions substantially (Table 8.2).

Table 8.2 Performance of coal- and natural gas-fired technologies

Fuel type	Plant type	CO_2 emissions (g/kWh)	NO_x emissions (mg/Nm^3)	SO_2 emissions (mg/Nm^3)	PM emissions (mg/Nm^3)	Max. unit capacity (MW_e)	Capacity factor (%)	CCS energy penalty (%-points)
Coal	PC (USC)	740	<50 to 100 (by SCR)	<20 to 100 (by FGD)	<10	1 050[c]	80	
	CFBC	880 to 900	<200	<50 to 100 (in situ)	<50	460[d]	80	7 to 10 (post-combustion and oxy-fuel)
	PC (A-USC)[a]	669 (700°C)	<50 to 100 (by SCR)	<20 to 100 (by FGD)	<10	<1 000 (possible)	-	
	IGCC[a, b]	669 to 740	<30	<20	<1	335	70	7
	IGFC[a]	500 to 550	<30	<20	<1	<500	-	
Gas	NGCC	400	<20	Almost none	0	410[d]	80	8
	NGFC[a]	300 to 330	<20	Almost none	0	<600	-	

[a] Under development.
[b] Only six IGCC plants currently in operation.
[c] In operation (sliding pressure-type).
[d] In operation.
Note: For the successful realisation of integrated gasification fuel cycle (IGFC) and natural gas fuel cycle (NGFC), the development of reliable fuel-cell technology is essential.
Source: Includes data from IEA, 2011a; Henderson and Mills, 2009; and VGB, 2011.

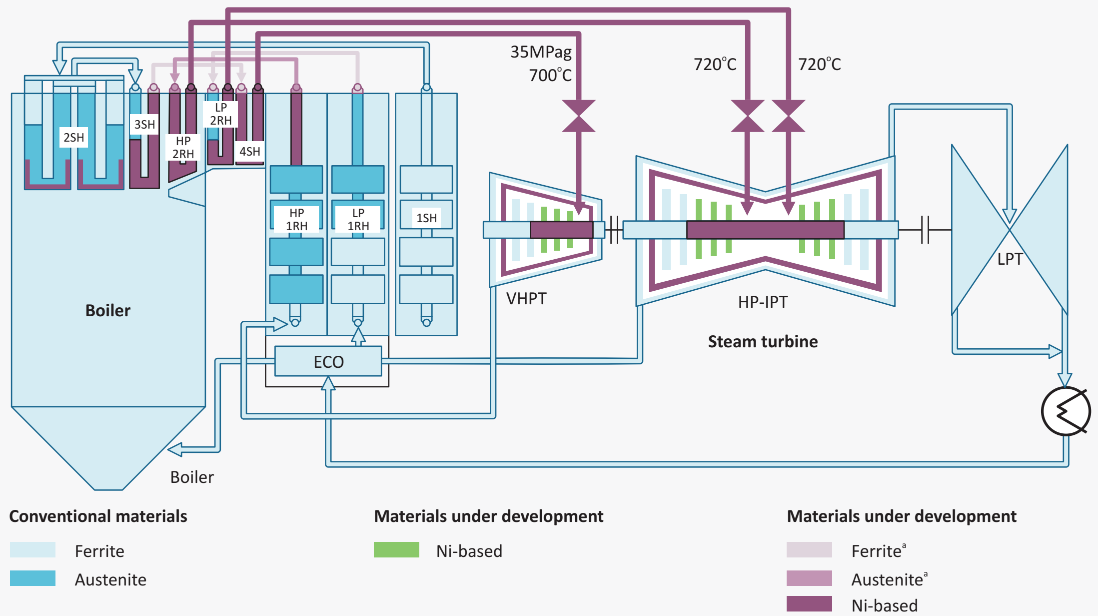
Emerging technologies

Successful development and future deployment of emerging technologies could significantly improve the performance of coal-fired power generation plants.

Advanced ultra-supercritical pulverised coal combustion

Manufacturers and utilities are working to achieve efficiencies approaching 50% (LHV) and higher by using advanced ultra-supercritical steam conditions of 700°C to 760°C at pressures of 30 to 35 MPa. Superalloys (non-ferrous materials based on nickel) used in these systems are markedly more expensive than steel, but only those parts exposed to the highest temperatures will be fabricated from them (Figure 8.15). Superalloys are already used in gas turbine systems, but component sizes in a coal plant are larger, the chemical environment is different, and pressure differentials are far higher. Consequently, new formulations and production methods are necessary. In China, Europe, India, Japan and the United States, efforts are underway to develop advanced ultra-supercritical technologies, which should become operational in the early 2020s. Commercial deployment of the technology is unlikely to begin until the mid-2020s.

Figure 8.15 **High-temperature materials for a double-reheat[6] advanced ultra-supercritical design**



Note: [a]Composition of ferrite and austenite are adjusted for particular applications.
Source: Fukuda, 2010.

Key point *To raise efficiency, some components within the boiler will be exposed to very high steam temperatures; manufacturing those components from nickel-based super-alloys will enable them to withstand the high temperatures.*

IGCC and related advanced technologies

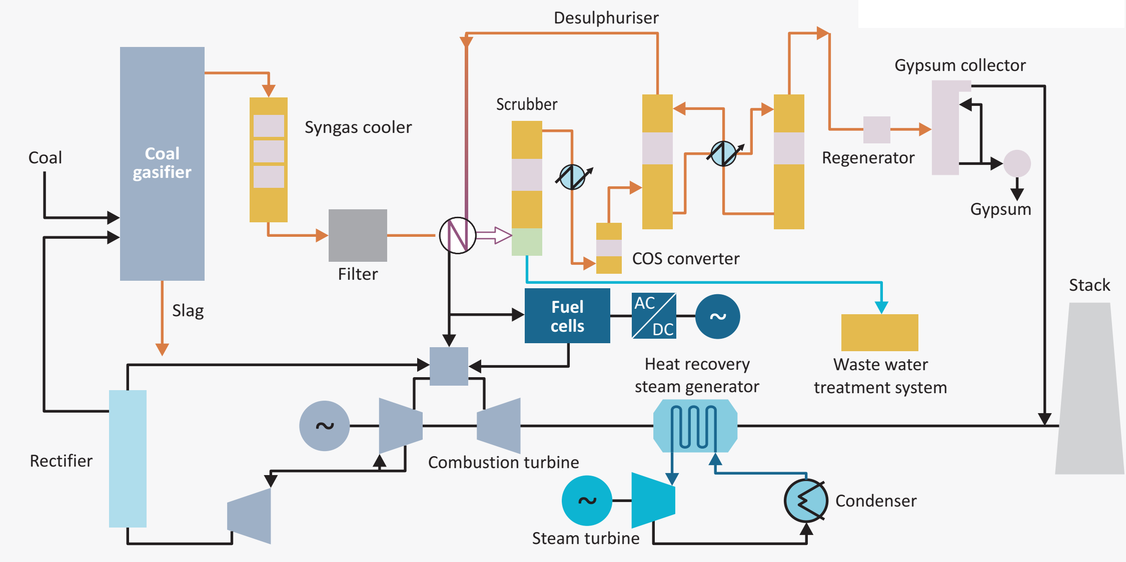
The fuel gas from coal gasification consists mostly of hydrogen and carbon monoxide that, apart from power, can be used to produce hydrogen, transport fuels, synthetic natural gas (SNG) and chemicals. Consequently, IGCC in some locations may provide the basis of polygeneration[7] plants with the flexibility to switch product output according to market demand. This flexibility could potentially offset the higher capital requirements of such systems. In theory, CCS could integrate well with polygeneration (Carpenter, 2008).

In the longer term, the use of advanced fuel cells in IGFC cycles might permit even higher thermal efficiencies (Figure 8.16). In an IGFC, part of the hydrogen exiting the gasifier is diverted into a fuel cell. By optimising the cycle, it is possible to raise the efficiency significantly above that of using just an IGCC.

6 The thermodynamic efficiency of a steam cycle increases with the increasing temperature and pressure of the super-heated steam that enters the turbine. It is possible to further increase the mean temperature of heat addition by taking back partially expanded and reduced-temperature steam from the turbine to the boiler, reheating it, and re-introducing it to the turbine. This can be done either once or twice, known as single and double reheat. The improvement in thermal efficiency can be one percentage point with the addition of the second reheat stage.

7 The property of gasification plants to offer products in addition to power is known as polygeneration.

Figure 8.16 Integrated gasification fuel cell (IGFC) cycle



Source: NEDO, 2006.

Key point *An IGFC cycle has the potential to reach a high thermal efficiency.*

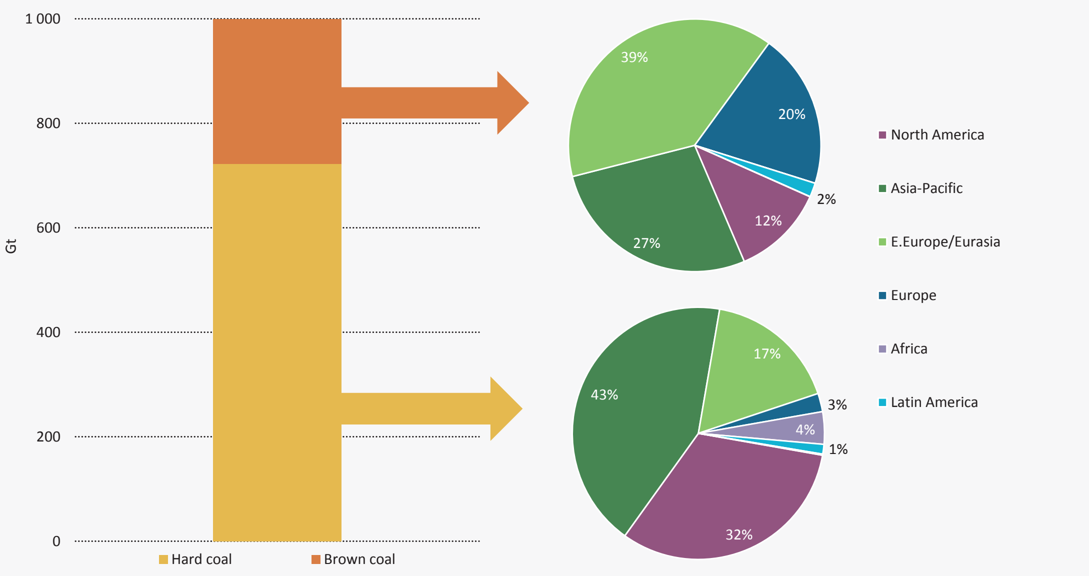
High-efficiency technologies for low-grade coals

Lignites[8] often have high moisture content, but they inevitably lose efficiency when deployed in conventional firing systems for power generation. Removing the moisture before combustion is an important technology to improve efficiency in a lignite-fired power plant (Figure 8.17).

Lignite drying increases efficiency and substantially reduces CO_2 emissions if the technology employs low-grade heat and recovers as much energy from the drying as possible. This can be applied to combustion (Figure 8.18) or gasification-based plants (Hashimoto, 2011). Drying systems are being developed in Australia, Japan, OECD Europe and the United States (Harris, 2012; Bowers, 2012; Kinoshita, 2010). Energy for drying comes from in-bed tubing in which low-pressure steam is condensed, with waste heat recovered from the condensate. The altered heat balances in the boiler necessitate changes to the furnace size, heat-transfer surface area and flue gas recirculation. Boiler cost savings will be largely offset by the cost of the dryer.

8 Lignite, also referred to as brown coal, is the lowest rank of coal and is used almost exclusively as fuel for electric power generation.

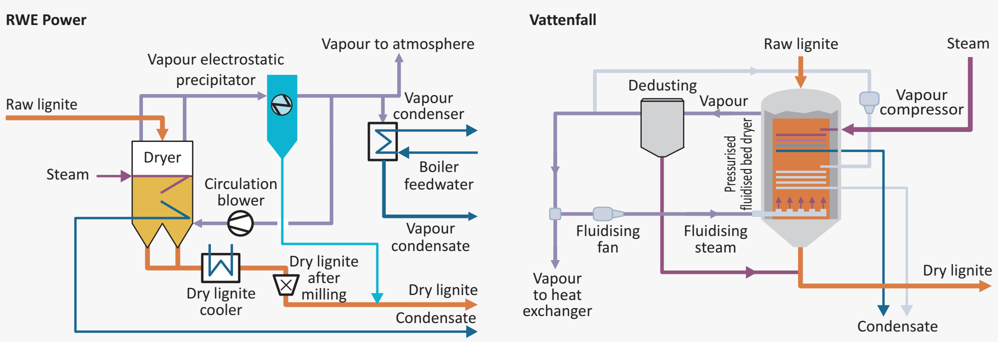
Figure 8.17 Proven recoverable coal reserves



Note: Hard coal includes anthracite and bituminous coal. Brown coal includes sub-bituminous coal and lignite.
Source: IEA, 2011b.

Key point *There are sufficient reserves of coal for a projected 190 years of generation at current consumption rates.*

Figure 8.18 Advanced lignite pre-drying in pulverised coal combustion



Source: RWE, 2010[9] and Vattenfall, 2011b.

Key point *In both processes, the steam cycle is optimised for maximum efficiency.*

9 RWE Power's WTA process shows one of several process variants being developed and tested.

A technology currently in its infancy is the MRC-DICE (Wibberley, 2012). Micronised refined coal (MRC) is mixed with water prior to firing it in a direct injection coal engine (DICE). MRC is produced by milling coal to a fine powder, which is then cleaned to reduce its ash content to very low levels. The coal-water slurry is destined for combustion in diesel engines with expected efficiencies similar to those obtained from diesel fuel. The technology promises to be highly flexible and highly responsive, with the potential for application at scales from 10 MW_e to 100 MW_e. It also promises to be highly suitable for application with low grade coals.

Water consumption

A typical 600 MW coal-fired power plant with open-loop cooling draws more than 48 million litres of water per hour to run its cooling system at full operating capacity (US DOE, 2006). Only a small percentage, around 1 million litres per hour, of this water is consumed, but some is lost to evaporation before being returned to the source. An open-loop system can negatively impact ecosystems when heated water is returned to a cooler natural source (*e.g.* sea water). This impact can be mitigated by using closed-loop systems, but net water consumption typically increases in such systems due to higher evaporation rates during the cooling process.

The use of air-cooling systems can substantially reduce water consumption in coal-fired power generation and they are employed in some areas, such as north-western China, where water use is limited. However, this approach raises capital and operating costs. An air-cooling system results in a substantial reduction of plant efficiency and leads to an increase in air emissions, including those of CO_2. Even though many parts of the world have water shortages, air cooling on coal-fired power plants has not yet been widely adopted.

Coal mining sometimes requires large quantities of water for dust suppression, land reclamation and coal washing, depending on site-specific mining conditions, methods and local regulations. Water consumption can range from 40 to 400 litres per tonne of coal mined (US DOE, 2006).

Recommended actions for the near term

Coal is the most abundant and widely distributed fossil fuel, with reserves of at least 190 years at current consumption rates, and is the most widely used source of power generation. It is the fastest growing energy source, accounting for nearly half of global incremental energy supply over the last decade, and has brought affordable, secure electricity to hundreds of millions of people, generally outside the OECD. Moreover, continuing expansions of coal-fired plants mean that this trend is unlikely to change markedly before 2020, if even then.

Addressing the environmental impacts of coal use is a pressing energy policy priority. By 2020, CO_2 emissions from global coal-fired power generation must already have peaked if they are to be consistent with the 2DS. Conventional pollutants, including SO_2, NO_X, particulate matter and mercury, will cause very serious local pollution issues if measures to reduce them are not successful. Technologies that address the environmental impacts of sharply increased coal use must be developed and deployed rapidly on new coal-fired plants and, almost certainly, be retrofitted to the most suitable existing plants.

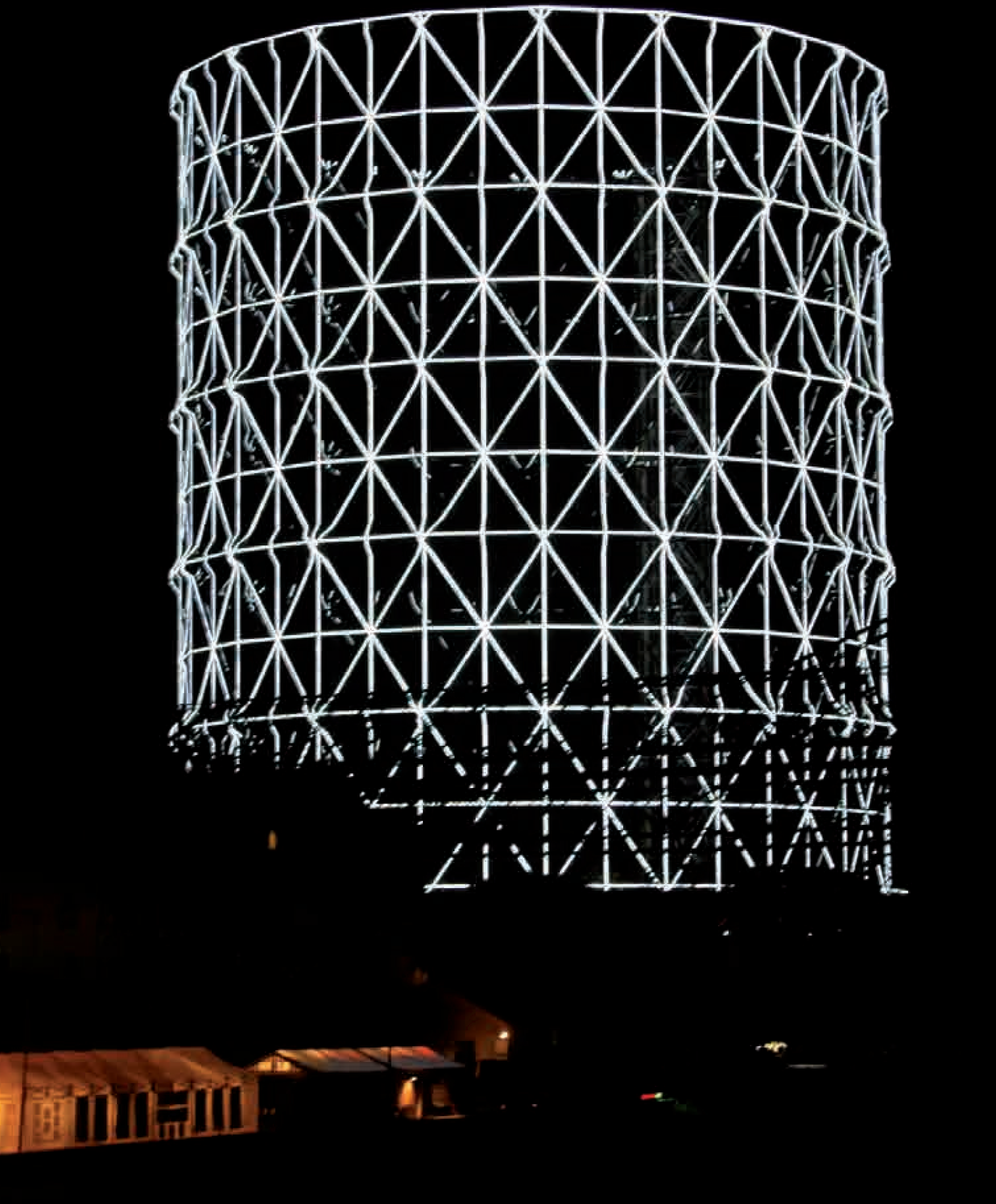
Greater efficiencies must be achieved in the power generation sector. Deploying supercritical and ultra-supercritical technologies, both available now, will make this possible. Even higher efficiencies can be achieved when newer technologies, such as advanced ultra-supercritical plants, become available. Poorer quality or low-grade coals, such as lignite, are candidates for more efficient technologies, notably pre-combustion drying. Expanded use of IGCC offers the potential for higher efficiency and lower pollution as well.

CCS must be developed and demonstrated rapidly if it is to be deployed after 2020 at a scale sufficient to achieve the 2DS. Given that ongoing investments in new coal-fired power plants are of such magnitude, retrofitting high-efficiency CCS will almost certainly be required on better-performing plants as well as new ones. CCS plants in the future will need to have much higher overall efficiency and lower capital costs than the current technology seems likely to deliver.

There must be a shift away from reliance on coal. In a truly low-carbon future, coal will not be the dominant energy source. Generation from older, less efficient coal plants must be minimised and the uptake of new low-carbon power generation technologies maximised. But at present, it is almost impossible to see a future where coal is not utilised to meet growing power demand, especially outside the OECD, but also in many OECD countries.

In the interim, a range of new technical solutions will be required. They will need to be developed, and their deployment actively encouraged, using a mixture of policy, regulatory and market-based incentives, supported by large-scale, targeted R&D and demonstration programmes.

Chapter 9



Natural Gas Technologies

Even in the 2DS, natural gas will remain important in the power, buildings and industry sectors to 2050, where it will continue to be used directly as fuel or indirectly as gas-fired electricity.

Key findings

- ***Unconventional gas production comprised 13% of global gas supply in 2009.*** *In the 2DS, although total gas production decreases after peaking in 2030, the share of unconventional gas continues rising to 24% in 2035 and 34% in 2050. In the 4DS, the share of unconventional gas is projected to increase to 27% in 2050.*
- ***Continuous technology improvement at each stage of unconventional gas exploration and production is essential.*** *It goes hand in hand with reducing the environmental impact of those processes.*
- ***In the 2DS, the share of natural gas in total primary energy demand declines more slowly – and later (after 2030) – than other fossil fuels.*** *Although total primary natural gas production declines between 2030 and 2050, global gas use in 2050 is projected to be 12% higher than in 2009.*
- ***By 2050, total primary gas demand projected in the 4DS must be 30% (or 55 EJ) lower to achieve the 2DS.*** *The largest reduction takes place in the power generation sector.*
- ***In the 2DS, use of gas in the power sector leads to a reduction in CO_2 emissions of 20 Gt between 2009 and 2050, relative to the 4DS.*** *This is achieved through efficiency improvements in gas-fired power generation technologies, fuel switching from coal to gas, the deployment of carbon capture and storage (CCS), and an increasing use of biogas. CCS accounts for 40% of this reduction.*
- ***In the 2DS, natural gas acts as a transitional fuel towards a low-carbon energy system, whereas in the 4DS, gas demand increases markedly across the world in all sectors.*** *The carbon intensity of the global power mix becomes lower than the specific carbon emissions from combined cycle gas turbine (CCGT) plants by 2025 at the latest.*
- ***As the scale of emissions reductions intensifies towards the second half of the projection period, the role of gas in the power sector changes.*** *In the 4DS, gas is increasingly used for base-load power plants, displacing those with higher carbon intensity (coal) and those with lower carbon intensity and higher investment costs (nuclear). In the 2DS, the flexibility of gas-powered generation principally complements variable renewables and increasingly serves as peak-load power to balance fluctuations in generation.*

Opportunities for policy action

- *The introduction of a targeted regulatory regime would mitigate the potential for environmental risks associated with production of unconventional gas. Examples of areas that such a regime might cover include the application of green completion techniques during well development or the focus on a life-cycle approach to water management. The establishment of national platforms or an international, multi-stakeholder platform could facilitate collaboration and encourage the exchange of knowledge, experience and best practice.*
- *The introduction of appropriate policy incentives and regulatory frameworks would encourage industry to further improve efficiency and to reduce the footprint of natural gas production, conversion and end use.*
- *In some countries where unconventional gas production is still in its infancy, formulating a policy and pricing framework that allows them to tap into international experience will provide access to best available technologies and accelerate growth in production.*
- *The importance of gas-fired technologies to provide flexibility for power generation over the next ten years cannot be overstated. Other means to provide flexibility are either limited in size (interconnectors) or are in the early stage of deployment (storage and demand-side management), and will not be sufficiently mature to operate at the scale required in the short term.*
- *Over the next ten years, gas will also displace significant coal-fired power generation (though, it should be noted, natural gas-fired generation will itself need to be displaced in the longer term to decarbonise the power sector still further). This strategic increase in gas infrastructure will require careful planning if the construction of too many gas-fired power plants is to be avoided and the potential for stranding assets in the longer term minimised.*
- *The impact of greater penetration of renewables on the viability of new and existing gas-fired power plants will need to be addressed. While gas-fired plants will operate at or near base load initially, they will increasingly be required to complement variable renewable generation. Consequently, they will increasingly be required to cycle at lower loads or even stand idle. It is likely that appropriate policies and packaged measures, both market-based and regulatory, will be required to compensate.*
- *Funding for research, development and demonstration should be directed at technology options that lead to further decarbonisation of the natural gas infrastructure, e.g. power generation and CCS.*
- *First-generation, large-scale gas plants with CCS need to be demonstrated and deployed. These facilities will contribute markedly to reducing the cost and energy penalty of the CO_2 capture process, to reducing risks associated with CO_2 transport and to proving the credibility of long-term storage.*

Role of gas in energy

Today, natural gas is a versatile and abundant energy source for the power, industry, buildings and, to a lesser extent, transport sectors. Its chemical composition offers technical advantages in a broad range of end-use applications. Natural gas is a clean-burning fuel, producing mainly carbon dioxide (CO_2) and water, which does not require post-combustion waste treatment. Its low carbon-to-hydrogen ratio means that it emits substantially less CO_2 than other fossil fuels, particularly when used in high-efficiency CCGT plants in the power sector. Furthermore, its use is flexible in scale and responsive to demand fluctuations.

Natural gas has become the fuel of choice for power generation in OECD member countries, the Middle East, North Africa and Russia. The efficiency and reliability of gas-fired power generation has improved over the past decade. Compared with coal-fired power plants, it offers lower emissions, shorter construction times and lower capital costs. Technical and economic characteristics currently make the gas-fired power plant the preferred complement to variable renewable power generation.

Natural gas represents a large share of the total primary energy supply in OECD countries (24%), Russia (54%), the former Soviet Union (52%), the Middle East (48%) and North Africa (44%).[1] China is the fastest-growing market, at 20% per year from 2009 to 2011, making it the fourth-largest gas user. (In 2009, however, gas made up less than 4% of China's total primary energy supply.)

Natural gas demand is diverse in different regions (Table 9.1). The highest gas demand comes from OECD countries and Russia, with the Middle East and North Africa rapidly increasing their gas use. Just under half of global gas demand is in OECD countries, mainly in the power and buildings sectors. In the rest of the world, except for China and Brazil, the power sector tends to be the largest consumer. The industry sector includes non-energy use of natural gas, such as for chemicals and fertiliser production. The role of non-energy use in industry is more important in non-OECD countries, particulary in Asia. Gas consumption for commercial heat is high in non-OECD Europe and Eurasia, where demand benefits from an extensive existing production and distribution infrastructure, particularly from district heating networks.

Table 9.1 Primary natural gas demand, 2009

Region	Total (PJ)	Power (including co-generation)*	Commercial heat*	Extraction, pipeline transport and other transformation**	Buildings	Industry	Transport	Other end use***
World	106 354	36%	3%	13%	23%	23%	1%	1%
OECD Americas	27 784	31%	0%	14%	32%	23%	0%	0%
OECD Asia Oceania	6 176	52%	0%	4%	27%	16%	1%	0%
OECD Europe	18 307	33%	2%	5%	37%	20%	0%	3%
Russian Federation	14 666	42%	17%	13%	13%	16%	0%	0%
Other Non-OECD Europe and Eurasia	7 044	26%	11%	14%	28%	17%	0%	5%
Africa	3 482	50%	0%	18%	7%	25%	0%	0%
China	3 247	17%	3%	16%	33%	31%	0%	0%
India	2 048	47%	0%	9%	0%	39%	4%	0%
Other Asia	6 963	50%	0%	15%	5%	26%	3%	1%
Brazil	712	15%	0%	29%	2%	44%	10%	0%
Other Latin America	4 028	28%	0%	20%	12%	36%	3%	0%
Middle East	11 897	40%	0%	16%	14%	29%	1%	0%

Note: PJ = petajoules.
*For power, including co-generation,[2] and for commercial heat, the natural gas contribution represents the gas input to the plants.
** Other transformation includes gas works, oil refineries, liquefaction plants and other non-specific transformation processes.
*** Other end use includes agriculture, fishing and other non-specific energy use.
Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

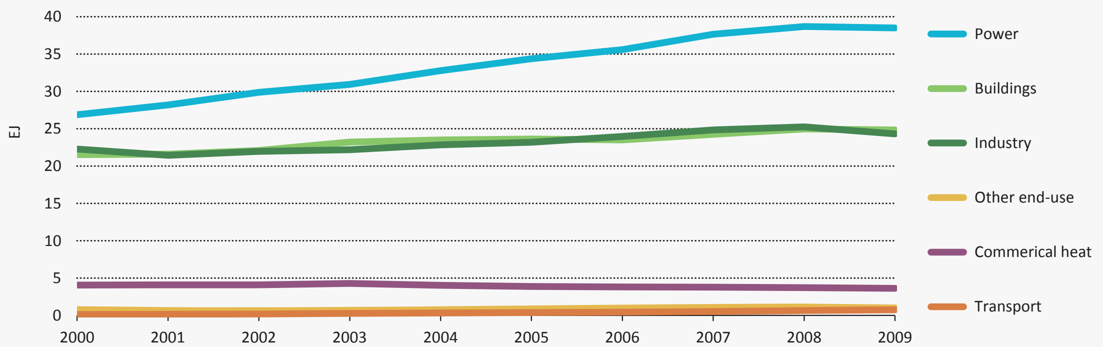
Key point *The power sector is the largest consumer of gas globally and in most regions.*

1 Based on IEA 2009 data.
2 Co-generation refers to the combined production of heat and power, sometimes referred to as combined heat and power (CHP).

On a per capita basis, primary energy demand in OECD Americas represents around 60 gigajoules (GJ) per capita, compared with roughly 29 GJ per capita in OECD Asia Oceania and 33 GJ per capita in OECD Europe. Outside the OECD regions, non-OECD Europe and Eurasia and the Middle East are the only areas with gas consumption higher than 20 GJ per capita. In 2009, Russia consumed 103 GJ per capita; other non-OECD Europe and Eurasia, 36 GJ per capita; and the Middle East, 61 GJ per capita.

The power sector has been the fastest-growing user of natural gas in the last decade (Figure 9.1). This trend is more pronounced in OECD countries, where direct consumption in the end-use sectors has been stable.

Figure 9.1 **Global final natural gas consumption in different sectors**



Notes: For power, including co-generation plants, and for commercial heat, gas contribution represents the gas input to the plants. Other end use includes agriculture, forestry, fishing and non-specified energy use.

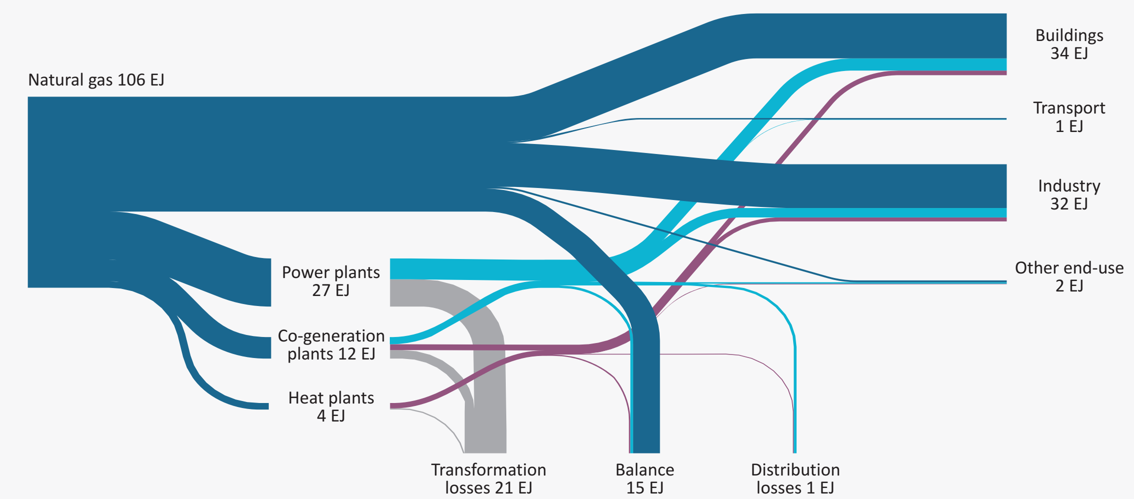
Key point *Between 2000 and 2009, the power sector was the strongest consumer of natural gas, increasing 43% since 2000.*

Natural gas is consumed by end users either directly as feedstock or indirectly as electricity and commercial heat (Figure 9.2). Converting natural gas into electricity, however, leads to significant losses, largely due to inefficiencies of gas-fired power plants,[3] which have a global average efficiency of 43% (LHV).[4] Conversion processes – whether in power plants, heat plants or co-generation plants – use 40% of the primary natural gas supply, whereas electricity and heat represent only 21% of final natural gas consumption across all sectors.

Figure 9.3 shows the share of natural gas compared with other energy sources in three major end-use sectors. Natural gas is used directly in the industry and buildings sectors, largely to generate heat. In addition, natural gas fuels power generation plants and is also used indirectly as electricity. The total direct and indirect share of natural gas accounts for 30% in the buildings sector and 22% in the industrial sector. Natural gas use in transport has a minor share except in some non-OECD countries.

3 Newer gas-fired combined cycle plants are much more efficient.
4 Unless otherwise noted, efficiency notations in this chapter are based on the lower heating value (LHV) of the fuel.

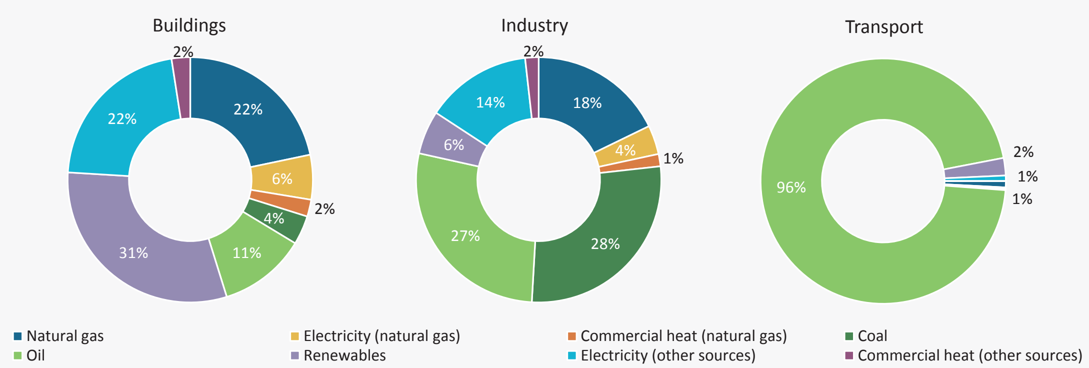
Figure 9.2 Energy flows in the global natural gas system, 2009



Note: Balance = Extraction, pipeline transport and other transformation processes, which include gas works, oil refineries, liquefaction plants, other non-specific transformation processes and other non-specific losses.

Key point *Electricity and heat plants represent 40% of primary natural gas supply but only 21% of final natural gas consumption, due to conversion losses.*

Figure 9.3 Direct and indirect use of natural gas across end-use sectors, 2009



Key point *Natural gas delivers roughly one-quarter of final energy use in the buildings and industry sectors, either directly as heat or indirectly as electricity.*

Main drivers of the changing gas demand

Natural gas demand is influenced by policy, geopolitics, economics, technology and environmental concerns. The main drivers for gas demand will evolve over time, depending on the context:

- ***Access to supply and infrastructure.*** Access to supply shapes current and future use of natural gas. Supply is influenced by availability of gas resources (both conventional and unconventional gas), fuel production from other sources (*e.g.* hydrogen and organic waste), and upstream and downstream infrastructure and distribution networks. Major gas projects are currently planned in all countries consuming the largest shares of gas; for example, the Nabucco and South Stream pipelines in the European Union.

- ***Economic development.*** Economic development has historically translated into increased gas demand. With economic development, the demand for heat and electricity – and thus, natural gas – rises in the buildings (residential and service) and industry sectors as personal incomes and activity climb. The growth of natural gas has been greatest in the power sector and its future role there is particularly important.

- ***Competitiveness of natural gas prices versus other sources.*** The versatility of natural gas allows it to compete in different ways that affect demand. Lower prices often encourage demand, but can also reduce capital expenditure. The price of natural gas will determine its competitiveness with other fuels, such as coal, nuclear, biogas and hydrogen. Low gas prices increase competition with base-load power generation plants, such as coal and nuclear. A carbon price favours natural gas, compared with sources that have higher emissions (*i.e.* coal and oil), but not low-carbon fuels, such as hydrogen[5] and biogas. On the demand side, gas is also competing with electricity and renewable energy technologies as a heat source (*e.g.* solar heating systems and heat pumps).

- ***Environmental impact using other forms of energy.*** CO_2 and other emissions (unburnt hydrocarbons, nitrogen oxides [NO_X], particulate matter) from natural gas processes are evaluated against other options and, depending on environmental policies, influence prices or translate into penalties. Natural gas combustion does not require solid waste management processing, as does nuclear (handling spent nuclear fuel) or coal (disposing of coal ash).

- ***Changes in technology.*** Increased efficiency in power generation or combustion processes may reduce primary energy demand for natural gas. Better flexibility in the power sector to balance the use of variable renewable energy sources requires additional back-up capacity, which can come from natural gas-fired power plants. Natural gas-fired power plants also compete with other flexible options, such as interconnectors, demand-side management and storage. Similarly, they aslo compete in terms of scalability, capability for system integration and lead times for construction. In the transport sector, the introduction of natural gas-powered passenger cars or heavy-duty vehicles could increase demand for natural gas.

- ***Government policies.*** Government support for low-carbon technologies and regulations to reduce CO_2 will have an impact on natural gas demand. National or international carbon goals will define whether gas technology can be classified as low-carbon. An uncertain policy framework can discourage investment in innovation and alternate energy sources, and favour continued deployment of low-risk conventional fossil fuel-fired (including gas) power plants.

Unconventional gas

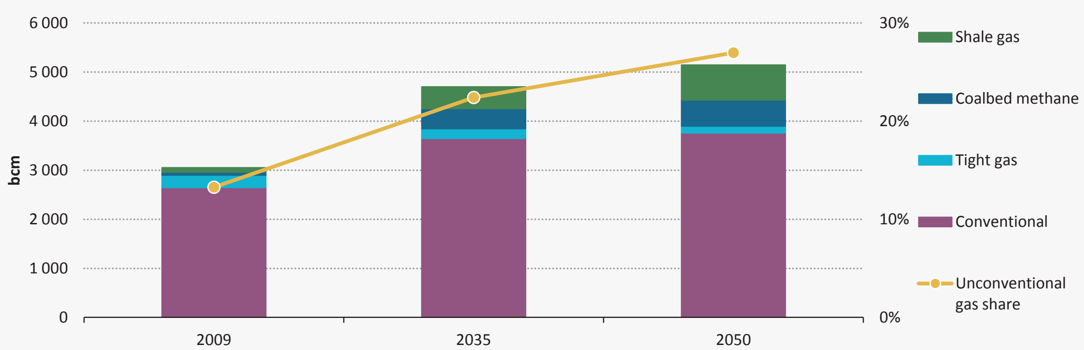
The supply of natural gas has evolved dramatically in the past few years. The emergence of unconventional gas production, which includes tight gas, shale gas, coalbed methane (CBM)

5 Produced from a clean energy source.

and methane hydrates,[6] has opened the door to a combination of technology applications with the capacity to transform the energy landscape.

In the *ETP 2012* 4°C Scenario (4DS), global gas production increases from 3 051 billion cubic metres (bcm) in 2009 to an estimated 5 150 bcm by 2050, a growth of more than 60% in four decades. This expansion is due largely to a substantial step-up in production of unconventional gas, even though conventional gas continues to provide the majority of the gas supply. Unconventional gas production comprised 13% of global gas supply in 2009 and is projected to increase to 22% (1 050 bcm) by 2035 and to 27% (1 390 bcm) by 2050. This rise assumes a high rate of adoption and spread of technologies to develop unconventional gas resources in most gas-consuming countries, as well as greater amounts of investment to sustain and expand production (Figure 9.4).

Figure 9.4 **Unconventional gas supply in the 4DS**



Key point *In the 4DS, unconventional gas production is projected to rise from 13% of global gas supply in 2009 to 27% in 2050.*

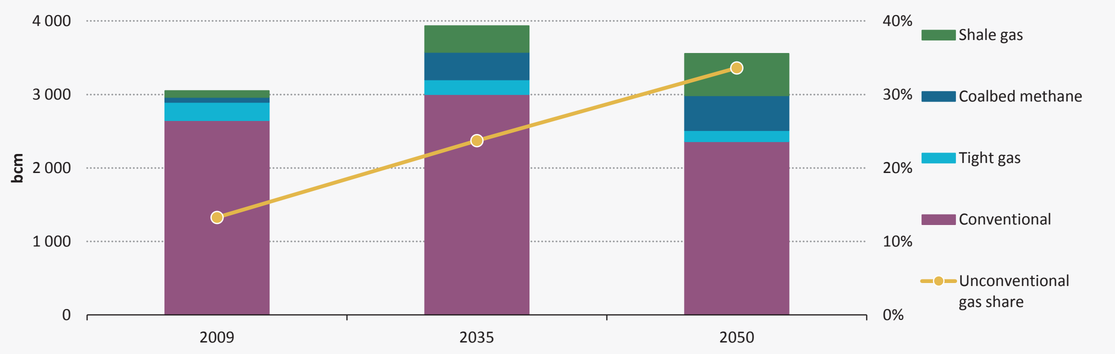
In the *ETP 2012* 2°C Scenario (2DS), however, global natural gas production peaks at around 3 880 bcm in 2030 and then declines to 3 560 bcm in 2050. For this low-carbon scenario, the high-carbon intensity of gas (relative to renewables and other non-fossil fuels) leads to lower demand, and hence lower investment, on top of the increasing operational costs to develop more challenging gas fields. Conventional gas accounts for much of the decline. The share of unconventional gas production continues to increase, reaching 24% (930 bcm) of total demand in 2035 and 34% (1 200 bcm) in 2050 (Figure 9.5).

Notably, shale gas production increases from 88 bcm (3%) in 2009 to 570 bcm (16%) in 2050, and coalbed methane production from 67 bcm (2%) to 470 bcm (13%) over the same period. In line with assumptions made in *World Energy Outlook 2011*, production costs of unconventional gas decline, ranging from USD 3 to USD 9 per million British thermal units (MBtu), depending on the region. The projection reflects the cost competitiveness of unconventional gas, notably shale gas and coalbed methane, in the long run. The advantage of indigenous production becomes more important when conventional gas from major gas-producing countries declines and countries wishing to avoid excessive import dependence look to develop domestic resources.

6 *Tight gas* is natural gas trapped in extremely low-permeable and low-porous rock, sandstone or limestone formations; such gas may contain condensates. *Shale gas* is natural gas contained in organic-rich strata dominated by shale; because of the types of reservoirs where it is found, it is sometimes considered a sub-category of tight gas. *Coalbed methane* is methane adsorbed on to the surface of coal within coal seams. *Methane hydrates* are made up of methane molecules trapped in a solid lattice of water molecules under specific conditions of temperature and pressure.

Unconventional gas resources are geographically more dispersed than conventional gas resources, which are mainly concentrated in countries of the former Soviet Union and the Middle East. Russia, Iran and Qatar account for more than half of global conventional gas reserves. Asia Pacific and North America, which are expected to become the largest gas markets within the next two decades, each hold around 20% of recoverable unconventional gas reserves.

Figure 9.5 Unconventional gas supply in the 2DS



Key point *In the 2DS, although total gas production decreases after peaking in 2030, the share of unconventional gas continues to increase, reaching 24% by 2035 and 34% by 2050.*

The deployment of technologies – horizontal drilling in conjunction with multi-stage hydraulic fracturing – to explore and unlock the shale gas resources (so far, almost exclusively practised in the United States) has led to significant new supplies of gas, which put downward pressure on gas prices in OECD North America. Unconventional gas production in the United States has tripled over the past decade, reaching over 350 bcm in 2010, and provides 58% of the United States' natural gas supply.

Lower gas prices, coupled with the lower cost and higher efficiency of CCGTs, have resulted in some displacement of base-load coal-fired generation in the United States. Between 2005 and 2010, total gas demand increased by 9%, with three-quarters consumed by the power sector. Over the same period, total power generation increased by 2%, while generation from gas-fired plants rose by 29%; and generation from coal and oil dropped by 7% and 66%, respectively. The joint attractions of the low cost of gas and high flexibility of CCGTs may also displace investment in new coal and nuclear plants in the United States.

Total global recoverable natural gas resources (Table 9.2) can sustain more than 200 years of use at current rates of production. At an estimated 331 trillion cubic metres (tcm), total unconventional gas resources are abundant; they comprise 209 tcm of shale gas, 47 tcm of coalbed methane and 76 tcm of tight gas.[7]

7 As countries evaluate their domestic resource potential more precisely, these estimates are subject to revision.

Table 9.2 Recoverable resources of natural gas by type and region (tcm)

	Total gas		Unconventional by type		
	Conventional	Unconventional	Tight gas	Shale gas	CBM
E Europe & Eurasia	131.1	42.7	10.0	12.3	20.3
Middle East	124.8	11.8	8.0	3.8	0.0
Asia Pacific	35.2	92.6	19.9	57.0	15.7
OECD Americas	44.9	77.3	12.8	55.8	8.8
Latin America	23.1	48.1	14.7	33.4	0.0
Africa	37.1	37.3	7.4	29.8	0.1
OECD Europe	23.9	21.5	3.4	16.4	1.7
World	420.3	331.3	76.2	208.5	46.6

Source: IEA, 2012a.

Box 9.1 Unconventional gas in China

The most recent geological survey conducted by China's Ministry of Land and Resources (MLR) estimated China's technically recoverable shale gas reserves at 25 tcm, compared with a much lower 14 tcm in the United States (MLR, 2012). This amount can potentially provide more than 200 years of gas supply in China at current rates of consumption.[8]

The first-ever shale gas exploration tender, open to Chinese bidders only, was issued by MLR in 2011. Four blocks were announced, covering an area of 11 000 square kilometres (km^2). The second tender was issued in 2012 with more blocks open for exploration and production.

China's major oil and gas companies are acquiring expertise by buying into overseas assets. In December 2011, PetroChina started producing a reported 10 000 cubic metres (m^3) per well per day from about 20 wells drilled in southern Sichuan province.

In 2011, shale gas was officially approved by China's State Council as a new independent mineral resource, paving the way for large-scale investment and development in the near future. A Shale Gas Production Plan was issued by China's National Energy Administration for China's 12th Five-Year Plan (2011 to 2015), which sets ambitious production targets of 6.5 bcm by 2015 and 60 to 100 bcm by the end of 2020. If China achieves these targets, gas will play a much bigger role in the country's energy mix.

Tight gas production already accounts for some 20% of China's gas production, and the trend is set to continue. Among major partnerships announced, Royal Dutch Shell and China's National Petroleum Corporation (CNPC) signed a 30-year deal in 2010 to develop a tight gas block in Sichuan province. Shell already operates 17 drilling wells for both tight and shale gas in China and plans to spend USD 1 billion a year over the period 2011-15 on shale gas exploration. Total (France) and CNPC signed an agreement in early 2011 to jointly develop tight gas in the South Sulige field, with projected production of 3 bcm.

With its extensive coal deposits, China also possesses huge potential for developing coalbed methane.[9] In 2010, China produced an estimated 3 billion tonnes of coal, almost a fivefold increase over the amount in 1980. Methane emissions from coal mines, previously released to the atmosphere, are now being captured and utilised. By 2009, 3 500 wells had been drilled and coalbed methane production capacity went from virtually zero in 2006 to 6.4 bcm. In parallel to the growing production, China has also constructed pipelines with a capacity to carry 4 bcm annually. In 2011, the National Energy Administration set a production target of 20 to 30 bcm by 2015, more than double the 9 bcm produced in 2010.

8 Total gas demand in 2010 stood at 107 bcm in China (IEA, 2011c), but is planned to increase rapidly towards 250 bcm by 2015.
9 Official data put coalbed methane-in-place at 37 tcm (<2 000 metres in depth) and technically recoverable resources at 11 tcm.

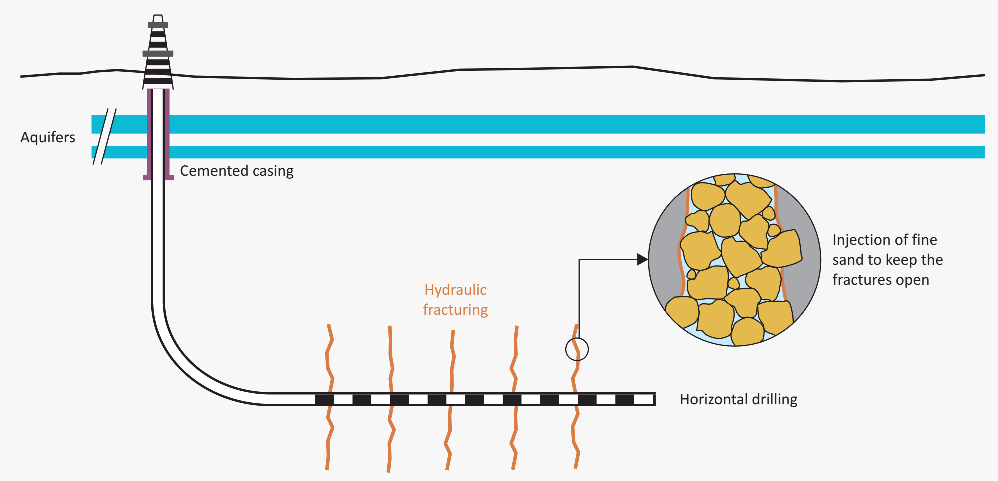
Technology status

Tight gas, shale gas and coalbed methane are commonly found in geological formations with low permeability and low porosity. As a result, drilling vertical wells to release the gas produces only low flow rates: unconventional gas yields recoverable resources of 0.04 bcm to 0.6 bcm per square kilometre (bcm/km^2), compared with an average of 2 bcm/km^2 from conventional gas fields. Consequently, unconventional gas requires drilling more wells, making extensive use of horizontal drilling and, for some types of unconventional gas, using extended artificial stimulation (hydraulic fracturing, or simply "fracking") to improve the flow of gas from the reservoir to the wellbore, which increases investment costs and brings additional economic and environmental risks.

Horizontal drilling and hydraulic fracturing are the principal technologies that have enabled large-scale, unconventional gas production (Figure 9.6). Together with advanced seismic techniques to detect sweet spots[10] in tight formations and to indicate the best drilling locations, they have enhanced yields of unconventional gas to commercially attractive levels.

Horizontal drilling maximises reservoir contact. Hydraulic fracturing is then used to create fractures in the rock in order to release gas and allow it to flow into the wellbores. Fracturing is achieved by pumping large quantities of water-based fluids under high pressure, mixed with specific chemical additives and proppants. Proppants are small, solid particles, usually fine sand or ceramic beads, injected to prevent the cracks from closing while gas flows to the wellbores. In the case of shale gas production, once the fracturing process is complete, 20% to 40% of the fluid injected flows out of the well, depending on the characteristics of the reservoirs. The return water[11] is treated for disposal or reuse.

Figure 9.6 **Horizontal drilling and hydraulic fracturing**



Key point *Horizontal drilling and hydraulic fracturing are essential technologies for large-scale unconventional gas production.*

10 Sweet spots are zones of open natural fractures, where the porosity and permeability of a particular area of reservoir rock are higher than average.

11 Return water refers to flowback plus produced water. Flowback water consists mainly of water and chemical additives used in hydraulic fracturing. After fracturing, some of the fluid returns to the surface with the gas. Produced water is naturally contained in the geological formations and flows to the surface throughout the lifespan of a gas well. In coalbed methane production, "dewatering" is a major issue as reservoirs tend to contain a large amount of water, which generally must be removed prior to production, posing significant water-management issues.

Box 9.2 Methane hydrates

Although many consider the resource potential of methane hydrates substantial, few believe they will contribute significantly in the short or medium term to hydrocarbon supplies. Methane hydrates are found in locations where the ambient temperatures and pressures are conducive to formation of their particular crystalline structures, such as the Arctic and sub-seafloor formations. Producing gas from methane hydrates will require considerable investment in infrastructure and pose demanding technological challenges. Global resources of methane hydrates are estimated to store as much organic carbon as all the world's oil, natural gas and coal deposits combined (US DOE, 2006). One cubic metre of methane hydrate contains about 164 m^3 of methane gas at standard conditions (273.15 K, 100 kilopascal). Rough estimates place methane hydrate accumulations in the range of 1 000 tcm to 5 000 tcm (IEA, 2009a). With its sizeable long-term potential, there is considerable interest in assessing the possibility of exploiting these resources in the future.

One distinctive feature of methane hydrates is that, unlike other types of unconventional gas, the structure that holds the gas in place is likely to dissociate during the production phase and destabilise the surrounding geological formations (PTAC, 2006). Methane hydrates are predominantly methane molecules caged by water molecules (*i.e.* a clathrate structure) at elevated pressures and low temperatures. When either the pressure is decreased or the temperature increased, they dissociate into water and gas. As the trapping structure is destroyed, the gas released needs to be captured or it will be released to the atmosphere. Technologies used to stimulate methane hydrate production usually alter the pressure and temperature equilibrium, which results in gas dissociation. Current research focuses on pressure, thermal and chemical stimulation techniques, as well as on the potential to displace methane with CO_2 hydrate. However, improving basic knowledge and gaining a better geological understanding of hydrate formation under different conditions, the deposition process, and on marine accumulations are essential first steps to future exploitation.

Environmental impacts of unconventional gas

Unconventional gas can and will significantly augment the global supply of gas. Equally significant, however, are the environmental challenges that come with the exploration and production of unconventional gas, which need to be thoroughly assessed and addressed. Some of the greatest public concerns touch on the high volumes of water used; on pollution of water, ground and air; and on concerns regarding land use before, during and after the gas production phase. France and Bulgaria have already banned fracturing techniques in their territories. The Shale Gas Subcommittee of the United States Secretary of Energy Advisory Board has published two reports and offered a series of recommendations for immediate steps to reduce the environmental impacts of shale gas production. Poland, in its early exploratory stage for shale gas, ranks attention to environmental risk assessment, monitoring, management and mitigation as high priority tasks.

The prospect of environmental degradation, such as groundwater contamination, raises serious public concern, with calls for government and industry to put off or delay development of these resources. Water management, as well as management of other environmental impacts, must be factored in when planning and evaluating programmes for exploration and production.

The surge of unconventional gas production, particularly of shale gas, has been recent. Regulators are just now catching up with the regulatory oversight needed for the special stimulation technologies and processes for unconventional gas production, in order to prevent potential adverse impacts on human health and the environment. Lessons learnt in one country can provide valuable insights to other countries set to embark on a similar production path.

Impact on water

Substantial amounts of water are used in unconventional gas production, especially with hydraulic fracturing. Shale gas production, for example, uses an average of 10 000 to 15 000 m^3 of water per well for drilling and fracturing. The volume of water needed is specific to the gas reservoir, depending on a number of factors, such as the depth and geology of the reservoir and the extent of fracturing. In general, unconventional gas production from horizontal wells with multi-stage hydraulic fracturing requires 10 times more water per well than do conventional wells of a similar depth. This means that if the production of unconventional gas accelerates in the future, water availability (specifically, competition for it in areas with scarce water) will become an increasingly important issue and the treatment of return water will need to be dealt with as an integral part of the production planning.[12]

Water is used in all parts of the process, namely, in horizontal well drilling and completion, as well as in hydraulic fracturing. Supplies of water come from different sources, such as surface water bodies (*e.g.* river, lake or sea), groundwater (either shallow aquifers, which can be used for other purposes, or deep saline aquifers), wastewater or recycled water from previous operations. During hydraulic fracturing, water-based fluid is pumped in at high pressure to crack the subsurface rock of low porosity and permeability and, consequently, improve gas flow to the wellbores. As noted earlier, when the fracturing phase is complete, part of the water pumped in flows back as the pumping pressure is released. Due to the high volume of water required, field operators need to have a comprehensive water management plan, including:

- water sourcing;
- treatment, recycling, reuse and disposal of flowback and produced water; and
- prevention of groundwater contamination.

Water, together with proppants (to prevent the closure of cracks formed), typically makes up 99.5% of the volume of the fracturing fluids used in hydraulic fracturing. The remaining 0.5% comprises chemical additives to improve the fluid's performance; the additives can include acid, friction reducer, surfactant, gelling agent and scale inhibitor (API, 2010). The composition of the fracturing fluid is tailored to differing geologies and reservoir characteristics in order to address particular challenges, including scale build-up, bacteria growth and proppant transport.

An important challenge for the industry is the treatment, recycling, reuse and ultimate disposal of the flowback and produced water, which often contain residual fracturing fluid and may also contain substances found in the reservoir formations, such as gases (*e.g.* methane, ethane), trace elements of heavy metals and naturally occurring radioactive elements (SEAB, 2011).

For coalbed methane production, large amounts of water already present in the reservoir need to be removed (dewatering) prior to gas production, which creates treatment, reuse, reinjection and other challenges. These may differ from shale gas, particularly since the degree of fracturing needed may vary.

Since the boom of shale gas production in the United States, several incidents of contamination of local drinking water have been recorded, which have brought the issue

12 In the future, fracturing the rock using propane gel (+ proppant) may replace hydraulic fracturing. The technology, presently being investigated by industry, uses a gel produced mainly from propane to replace the water. Deploying this technology would reduce substantially the volume of water used by the industry and alleviate many of its water management problems. However, development of the technology is yet at an early stage, with much testing to be completed before it meets the operational and environmental stadards required for broader industry application.

of possible water table and groundwater contamination to the forefront. In particular, collected return water, if not properly treated before disposal, risks surface spills that can pollute nearby aquifers and the ground.

Poor well completion and poor management of production pressure are possible causes of flowback water leakages and migration. The composition of chemicals used is another public concern; greater transparency of chemical use seems essential if this concern is to be alleviated. Regulatory oversight of water-cycle management, including the treatment and disposal of water, and the disclosure of chemical composition are being advanced in several unconventional gas-producing countries, such as the United States, Canada and Australia.

Impact on landscape

The low-permeability, low-concentration and low-recovery factors of unconventional gas resources require that many more wells be drilled for gas to be produced at commercial volumes. Industry practice to drill numerous wells in a single location ("pad") minimises the surface disturbance. The number of wells drilled from one pad can range from 3 to 20.

In the Barnett Shale, for example, almost 15 000 wells had been drilled by the end of 2010 over an extended area of 13 000 km^2. This resulted in an average well density of 1.15 wells per km^2 – almost three times the typical spacing for conventional fields in the United States. In some of the more intensely developed areas, as many as 6 wells per km^2 have been drilled (Lechtenböhmer *et al.*, 2011).

Production wells require roads to connect drilling pads; pipelines or trucks to transport gas, petroleum liquids or wastewater; storage sites; and water treatment facilities. With 500 to 1 000 truck trips per well site cited, accidents due to the intensive truck traffic must also be a consideration and, indeed, can be a major source of surface spills of chemicals. Pipeline use can minimise surface disturbance and reduce these risks. Infrastructure needs add to the surface impact of gas production and must also be evaluated from a large-scale, regionally cumulative perspective prior to development.

Impact on air

Higher volumes of greenhouse gases (GHGs), *e.g.* methane and CO_2, are emitted during the extraction of unconventional gas compared with conventional gas. Total emissions from shale gas production (well to burner, or end use) are estimated to be 3.5% higher, in the best case, where gas is flared; and 12% higher, in the worst case, where the gas is vented (IEA, 2011a). Best practice, such as green completions,[13] mandates avoiding or reducing both venting and flaring.

Greenhouse-gas emissions arise primarily from drilling, fracturing and well completions. Trucks and transportable diesel engines that power the drilling rigs are another source of CO_2 emissions. Once the wellbore is formed, pumps drive hydraulic fluids at high pressure to crack open the rock, potentially resulting in GHG and other pollutant emissions, although gas or electric pumps can mitigate these. Methane leakage occurs if casing and cementing in the well completion processes are in any way defective, which makes best-practice well completions essential. A gas production system comprises a large number of individual components, such as valves, pipe connectors, gauges and compressors. Wear and tear, rust and corrosion, and improper installation and maintenance can all result in fugitive emissions if the highest standards are not maintained.

Fugitive emissions recorded in gas processing and transmission can also be significant, but are more difficult to measure. Gas is usually transported in pipelines to processing plants

13 Green completions are techniques or methods to reduce the amount of natural gas released to the atmosphere during well completions. For instance, operators can employ sand traps, surge vessels, separators and tanks as soon as practicable to maximise resource recovery and minimise release to the environment (COGCC, 2008).

or storage sites before eventual delivery to customers. Leaks occur, for instance, from joints and microscopic holes (from corrosion) in pipelines, or in gas processing plants from the numerous valves, pneumatic devices, flanges and other fittings. New technologies for leak detection in gas pipelines are being developed and deployed to monitor and minimise fugitive emissions.

In many cases, it is likely that unconventional gas will primarily be produced and consumed domestically or, at least, not be transported or piped over long distances as is often the case for conventional gas. Consequently, emissions resulting from transport of unconventional gas may be comparatively low.

Technology development and dispersion

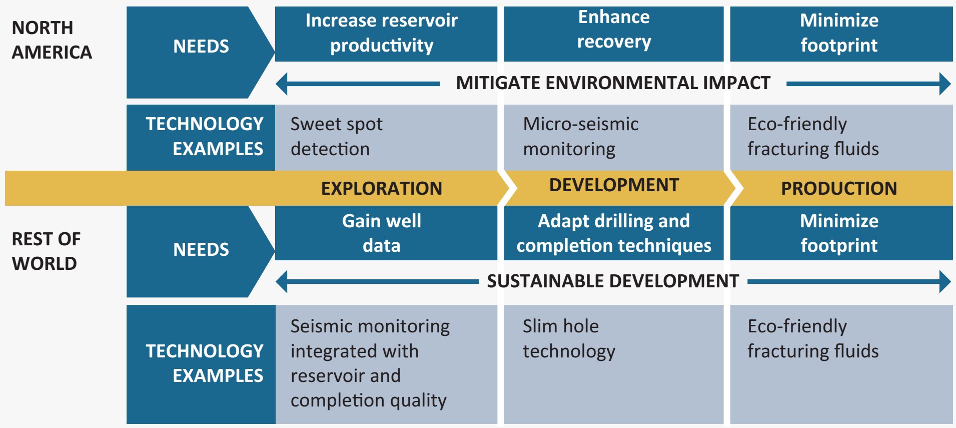
As technologies mature and learning takes hold, gas production from tight formations should accelerate and industry practice improve. The gas recovery factor (*i.e.* the percentage of the gas initially in place that is ultimately recovered), currently averaging around 20%, can be improved. Directional drilling with real-time sweet spot detection can help locate the most productive drilling areas and reduce surface and subsurface impact. Further development of more environmentally friendly fracturing fluids and proppants is needed to find more suitable physical and chemical properties for different reservoir structures; such developments should also lead to a general reduction in their use and to reduced risks to human health and the environment. Continuous technology improvement and advances at each stage of the exploration and production of unconventional gas production processes goes hand in hand with reducing the environmental impact of those processes.

As countries engage in early exploratory activities and large-scale extraction and production of unconventional gas, some will pioneer technology advances. Their first priority will be a comprehensive assessment of the scale of their potential gas resources and then decisions about the appropriate technologies for local conditions, coupled with a thorough evaluation of the environmental impacts of exploration and production activities. Global collaboration is essential at this stage to capture and share information and best practices, including appropriate and effective regulation, as technologies are being tried or developed in other parts of the world.

Technology dispersion can happen in different ways. The fact that multinational oil and gas companies and service providers operate in different countries facilitates technology dispersion through staff mobility and the sharing of expertise. In emerging economies, joint ventures or partnerships with local firms are common, particularly in oil and gas exploration.

In countries where exploration has just started and where there is limited subsurface data, uncertainties in the cost estimates and environmental risks associated with production can be high. In such cases, baseline data on, for example, water aquifers and sources are needed on a cumulative region-wide basis. Technology dispersion is complicated by the fact that unconventional gas is produced from geological formations that are highly heterogeneous. Porosity, water saturation, permeability and organic content – characteristics vital in determining whether a reservoir shows potential for economic production – can vary abruptly from one reservoir to the next or even vertically and laterally in a given reservoir (Boyer *et al.*, 2006). Because of this heterogeneity, the drilling, stimulation and completion programmes have to be adapted to regional situations. For instance, the “statistical” model deployed for shale gas production improved the economics of the process in North America. It requires a large number of wells to be drilled over an extended area in addition to optimising production from each well. This approach may have to be adapted for countries with limited land, higher production costs and population density. In one of the shale gas basins in the United States, almost 80% of the production came from less than one-third of the wells (Wilczynski, Ashraf and Saadat, 2011). Within and outside North America, there is a different set of technology needs and solutions with regard to unconventional gas production (Figure 9.7).

Figure 9.7 Technology needs and solutions



Source: Adapted from Wilczynski, Ashraf and Saadat., 2011.

Key point *Technology needs and solutions for unconventional gas production should be adapted according to experience and geographical location.*

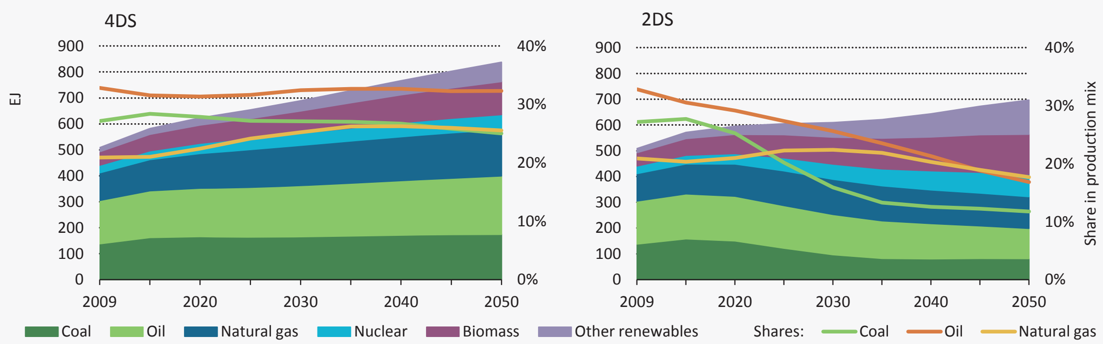
Role of gas in future scenarios

There are compelling reasons that the short-to-medium term (*i.e.* to 2035) should be declared the "golden age of gas" (IEA, 2011a). During this period, the perception holds that natural gas is plentiful and improves energy security while meeting environmental goals. Since natural gas reserves and resources are expected to remain abundant to 2050, does this golden age continue beyond 2035 or does natural gas enter a transition phase? Do perceptions shift such that, instead of being part of the solution, natural gas becomes part of the problem?

In the 4DS, global primary production of natural gas grows continuously to 2050 and is 67% higher than in 2009. Over the same period, the share of natural gas in overall primary energy production increases from 21% to 26%. In the 2DS, the growth of natural gas is slower, and demand peaks in 2030 and decreases between 2030 and 2050. Globally, primary natural gas production is higher by 28% in 2030 than in 2009, and higher by 16% in 2050.

Natural gas plays a prominent role in total primary energy production in the 2DS: it is the second-largest primary energy source in 2050, behind biomass and waste and ahead of oil (Figure 9.8). Although the share of fossil fuels in total primary energy production declines by 2050, the share of natural gas declines least. After 2030, primary natural gas production falls off in absolute and relative terms. These reductions indicate the change in perception after 2030, when natural gas begins to be viewed as a high-carbon fuel and, although it is the cleanest of fossil fuels, it becomes a major source of CO_2 emissions.

Figure 9.8 Role of natural gas in total primary energy production

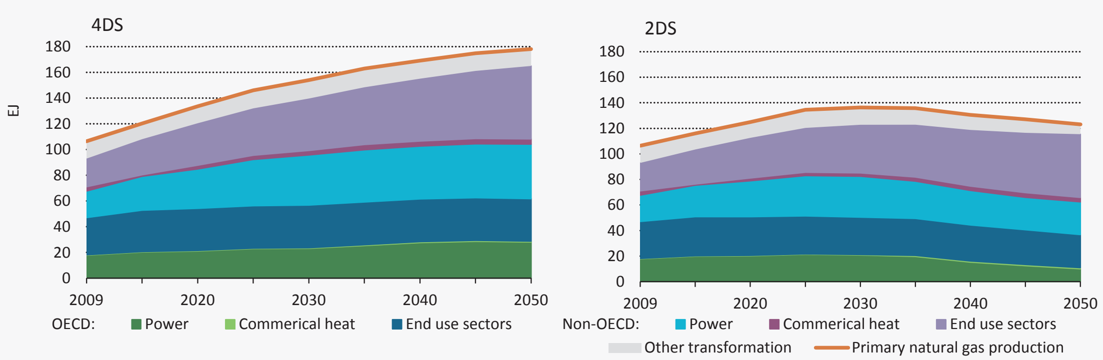


Key point *In both the 4DS and the 2DS, natural gas is the second-largest contributor to primary energy supply in 2050.*

In both the 2DS and the 4DS, the contribution of natural gas to the primary energy supply mix to 2050 is significant (Figure 9.8). Demand from the power sector and the end-use sectors account for virtually all natural gas demand (Figure 9.9). In the 4DS in non-OECD countries, natural gas demand from the end-use sectors increases by 159% and from the power sector by 106%. The increases in OECD countries of 14% (end-use) and 57% (power sector) appear rather modest in comparison.

In the 2DS, growth in natural gas demand in non-OECD countries is 126% in the end-use sectors and 24% in the power sector. In contrast, natural gas demand in OECD countries in the end-use and power sectors decreases by 11% and 44%, respectively. On a global basis, demand for natural gas from the end-use sectors increases by 48% to 2050. In OECD countries, the increase in gas consumption comes mainly from fuel switching, whereas in non-OECD regions, strong economic growth drives higher demand. The generation of electricity from gas in the 2DS markedly changes after 2030 and decreases by 52% in OECD and 20% in non-OECD countries.

Figure 9.9 Role of natural gas in power and end-use sectors



Notes: For power, including co-generation plants, and for commercial heat, gas contribution represents the gas input to the plants. Other transformation includes gas works, oil refineries, liquefaction plants and other non-specific transformation processes.

Key point *In the 2DS, natural gas demand in the power sector decreases by 34% between 2030 and 2050, while natural gas demand in the end use sectors increases by 13%.*

Natural gas continues to play a major role in the 2DS and the 4DS to 2050. The growth in demand for natural gas in the end-use sectors illustrates the importance of this energy source.

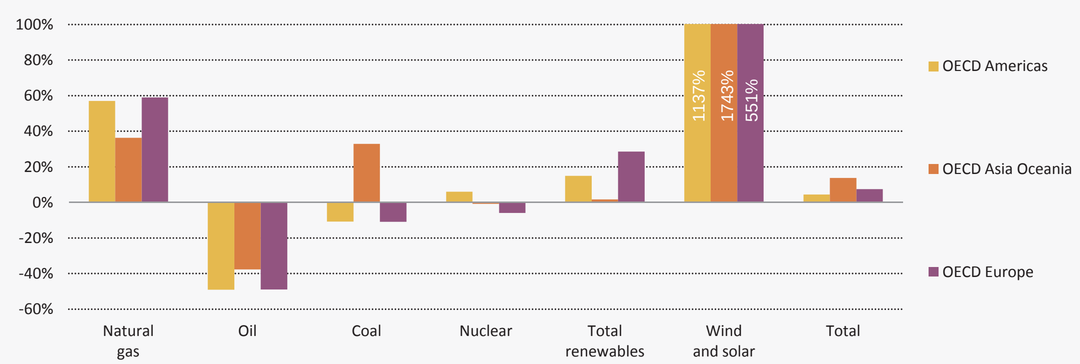
In the 2DS, natural gas demand in both end-use and power sectors is lower than in the 4DS. Reduction in the end-use sectors is particularly challenging as natural gas use is more dispersed across them. As natural gas use in the power sector is more concentrated than in the end-use sectors, policies can be better focused and implementation more effective.

Gas for power generation

Electricity supply and demand need to be constantly balanced in real time. Demand fluctuates over the course of each day and, depending on the demand, requires power plants to provide base, intermediate and peak loads. Natural gas-fired power plants can operate across the spectrum of load demand.

Globally, electricity generation from natural gas has grown by around 150% since 1990, reaching 4 300 terawatt hours (TWh) in 2009; over the same period, its share of total generation rose from 15% to 21%. Gas is the main fuel for power generation in the Middle East and Russia, which have large gas reserves. Across the OECD, gas-fired power generation rose between 2000 and 2009 (Figure 9.10). While gas-fired power generation increased by 57% in OECD Americas, 36% in OECD Asia Oceania and 59% in OECD Europe, total power generation in these regions increased by only 4%, 14% and 7%, respectively. Apart from the huge expansion of solar and wind (from a low base), natural gas has been the strongest-growing power generation source in OECD countries, ahead of coal, nuclear and oil.

Figure 9.10 **Incremental growth in OECD electricity generation, 2000 to 2009**



Key point *Natural gas-fired power generation increased by an average of 5% annually in OECD countries between 2000 and 2009, while electricity demand increased just 1% annually over the same period.*

In a constrained investment environment, the lower perceived risks associated with gas-fired power generation sparked a dash for gas in the past decade. This was the case particularly in OECD countries, which were characterised by a greater use of variable renewable energy, a slower increase in electricity demand, a declining support for nuclear and more occasions when peak-load electricity was required.

Power generation from natural gas is expected to increase to 2030 in both the 2DS and the 4DS, though more strikingly in the latter (Figure 9.11). Between 2030 and 2050, however, the role of gas in power generation differs dramatically in the two scenarios.

In the 4DS, natural gas-fired generation increases strongly, mainly driven by non-OECD countries. Gas-fired power generation will supply base-load plants, displace generation from coal and meet rapid new growth in demand.

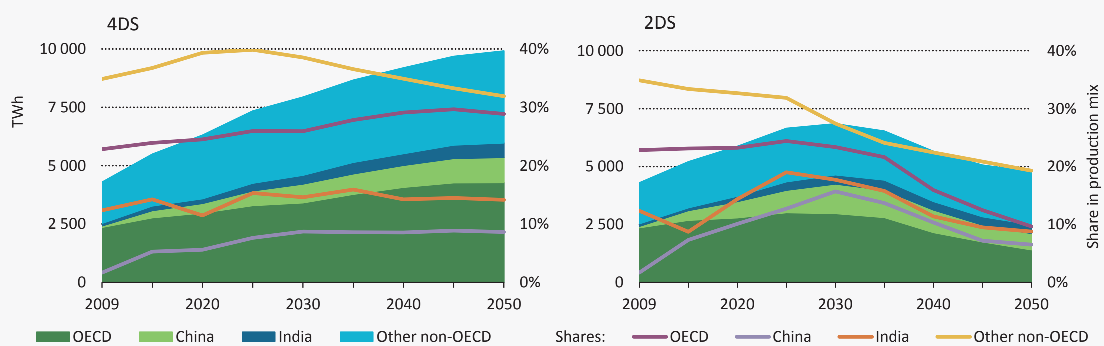
However, the CO_2 emissions linked to gas-fired power generation are not sufficiently low to meet the levels required in the 2DS. In the short-to-medium term, gas effectively reduces carbon emissions by displacing more carbon-intensive energy sources but, to meet the emissions levels required by the 2DS, between 2030 and 2050 global natural gas-fired generation must decrease from 6 847 TWh to 4 777 TWh – in other words, by 30%.

The majority of the power generation capacity needed to meet electricity demand in the 2DS will be very low carbon, including renewable energy technologies (biomass, wind, hydro, solar and others), coal plants equipped with CCS, and nuclear power plants. Nonetheless, natural gas power plants will still be best placed to provide peak-load and back-up capacity to balance the variability in electricity demand and production from renewable energy sources.

China and India will rapidly build up the share of gas in their generation mix (currently relatively low) by 2030 to 2035, before they gradually decrease it to 2050. In contrast, the share of gas in electricity generation drops steadily in the OECD and in other non-OECD countries. With gas turbines and combined cycle power plants typically designed for a service life of more than 25 years, this transition to 2050 will require long-term vision and political will, with quickly evolving policy. Rigorous planning and construction processes are also essential to minimise (ideally, to avoid) stranded assets.

In both the 2DS and the 4DS, gas continues to generate electricity, but the role of gas power generation changes considerably. The results indicate that gas in 2050 provides base-load capacity in the 4DS and peak-load capacity in the 2DS.

Figure 9.11 **Future natural gas-fired power generation in different regions**



Notes: Natural gas-fired power generation includes generation in power plants equipped with CCS units. Biogas is not included; this is covered in Figure 9.22.

Key point *Global gas-fired generation in the 2DS drops by 30% from 2030 to 2050.*

Status of gas turbine technology

There are two main types of gas-fired power plants, open-cycle gas turbine (OCGT) plants and CCGT plants. OCGT plants consist of a single-compressor gas turbine, connected to an electricity generator via a shaft. OCGTs are characterised by operational flexibility, low specific investment cost and high operational cost. They provide peak demand for daily, as well as for unexpected variations in demand due to special events, weather changes and seasonal fluctuations.

Combined cycle gas turbine plants have the same basic components as OCGTs, but the heat from the gas turbine exhaust is used to produce steam in a heat-recovery steam generator (HRSG) that drives a steam turbine and generates additional electric power. CCGTs are much more efficient (up to 60%), have lower operational costs, and are mostly operated at intermediate or base loads. In the future, balancing variations in power demand with power supplied from variable renewable energy sources will require more flexible technology, particularly in CCGTs. While the gas turbine can be controlled rapidly by adjusting the injection of gas into the combustion chamber, the responsiveness of the steam cycle is slower due to thermal inertia. Flexible operation reduces efficiency and increases material stress.

The main advantages of an OCGT are its simplicity and its low capital cost per unit output, mainly resulting from its compact (relative to its output) and lightweight design. Additionally, its technical flexibility translates into faster start-up and shut-down times; these help smooth out fluctuations in the grid response to peak demand and improves its reaction time in emergency situations. A typical OCGT may produce 10 megawatts (MW) to 300 MW of power, with efficiencies typically ranging from 35% to 42% at full load (IEA, 2010b).

The flexibility of gas turbines, their operational characteristics and their response rates are compared with other power generation technologies in Table 9.3. OCGTs can ramp from zero to full load in less than an hour, while CCGTs can take up to two hours. Start-up times for state-of-the-art OCGTs are less than 20 minutes and for CCGTs less than 60 minutes. Both have shut-down times of less than an hour. They also offer advantages on ramp rates: 20% to 30% per minute for OCGTs and 5% to 10% per minute for CCGTs.

Table 9.3 Comparison of the flexibility of gas plants with other energy plants

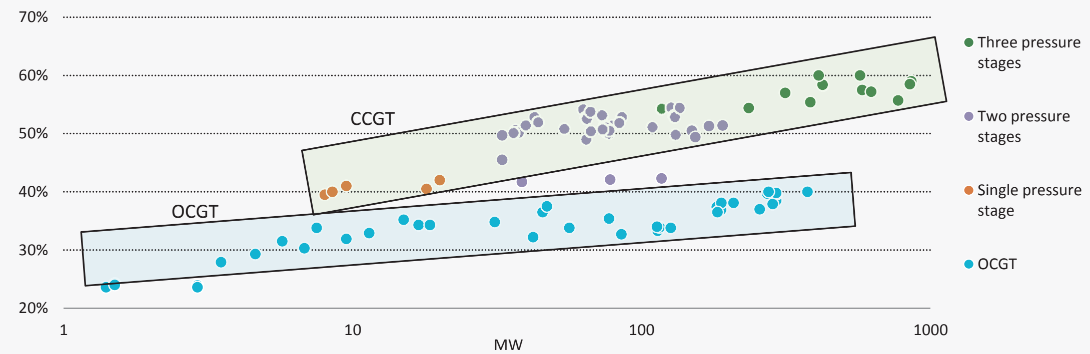
	CCGT	OCGT	Coal (conventional)	Hydro	Nuclear
Start-up time (hot start)	40 to 60 minutes	<20 minutes	1 to 6 hours	1 to 10 minutes	13 to 24 hours
Ramp rate	5% to 10% per minute	20% to 30% per minute	1% to 5% per minute	20% to 100% per minute	1% to 5% per minute
Time from zero to full load	1 to 2 hours	<1 hour	2 to 6 hours	<10 minutes	15 to 24 hours
Minimum stable load factor	25%	25%	30% to 40%	15% to 40%	30% to 50%

Source: IEA, 2012; Siemens, 2011; and VGB, 2011; and expert opinion.

Figure 9.12 illustrates the range of efficiencies that can be achieved in practice by OCGTs and CCGTs.[14] A trend of higher efficiency with increasing unit power output is clearly evident.

14 In general, CCGTs operate with one, two or three steam-pressure stages.

Figure 9.12 Efficiency ranges for OCGTs and CCGTs



Source: GTW, 2010; Gotoh *et al.*, 2011

Key point *Higher efficiencies are generally achieved by larger capacity units.*

As a result of the higher heat content of natural gas and the greater efficiencies of the conversion technologies, gas-fired power plants emit fewer GHG emissions than coal-fired plants. The best coal-fired power plants produce around 740 gCO_2/kWh, whereas comparable state-of-the-art commercial CCGT power plants emit less than 400 gCO_2/kWh – almost 50% less.

Gas-fired technologies also emit fewer non-GHG pollutants. Emissions of sulphur dioxide (SO_2) from CCGTs and OCGTs depend on the quality of gas. No SO_2 is emitted when using liquid natural gas because the sulphur content, usually present as hydrogen sulphide, is removed prior to the liquefaction process. On the other hand, emissions may rise when using natural gas with a high sulphur content (sour gas); in general, however, emissions of SO_2 are much lower than for coal-fired power plants.

The advantages of gas-fired CCGTs over coal-fired technology may be summed up as:

- capital costs per kilowatt hour for CCGT plants are lower and construction times shorter;
- CCGT plants offer higher efficiency, contribute less to local air pollution and, in general, offer greater operational flexibility and lower carbon intensity;
- for the same output, CCGT plants have a smaller footprint; this reduces their land requirement, which increases public acceptance.

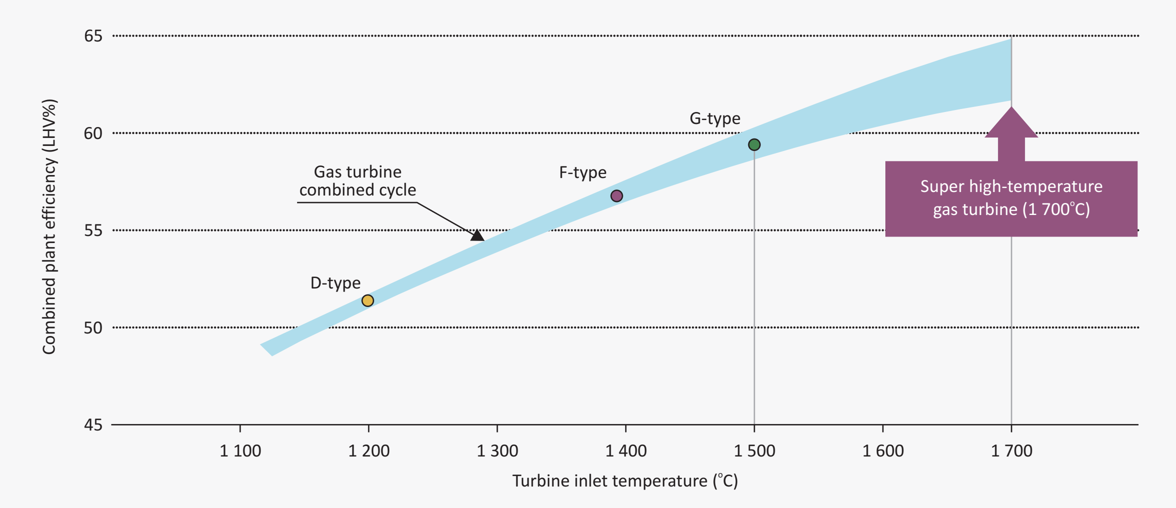
Research and development

Continued advances in technology are expected to improve efficiency and reduce both the capital and operational costs of gas-fired power plants. To achieve the 2DS, CO_2 emissions will need to be lowered, which will be achieved in part by:

- replacing less efficient power plants with best practice technology;
- improving the performance of plants required to operate at part load or cyclically.

The efficiency of a gas turbine may be improved by increasing its inlet temperature (figure 9.13). Using a 1700°C-class gas turbine on a CCGT could raise its efficiency to around 63%; this potential is being promoted, for example, by the Japanese government, with pilot plants expected to be in operation from 2016. On the other hand, a higher turbine inlet temperature leads to increased emissions of NO_x 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 under development. Materials that are resistant to high temperatures and corrosion, cooling techniques, and ceramic thermal barrier coatings are also being developed to protect blades and other internal turbine components.

Figure 9.13 Efficiency projections for combined cycle gas turbines



Key point *By increasing the turbine inlet temperature, CCGTs have the potential to achieve an efficiency of around 63% (LHV).*

Integration of variable renewable generation

Power generation from renewable energy technologies offers the potential to reduce CO_2 emissions and improve energy security in many countries. However, new, flexible energy systems and technologies are required to integrate the growing contribution from renewable energy technologies into the grid. The future of gas to manage grid demand is tightly bound to the future of variable renewable energy technology.

OCGTs and CCGTs can provide the flexibility to match fluctuations in the power system in terms of technology, as can other gas-fired power generation systems. Reciprocating engines (internal combustion engines) are technologically mature and, for distributed generation technology, low-cost. They have an advantage in start-up time, varying from 30 seconds to 15 minutes. Although their efficiency starts at around 25%, the most advanced natural gas-fired engines now have electrical efficiencies approaching 45%, higher than OCGT plants. The capacity of reciprocating engines, from 5 kilowatts (kW) to as high as 7 MW, is relatively low compared with large-scale CCGTs and OCGTs. However, they can play an effective role in smaller electricity grids or in decentralised power distribution systems.

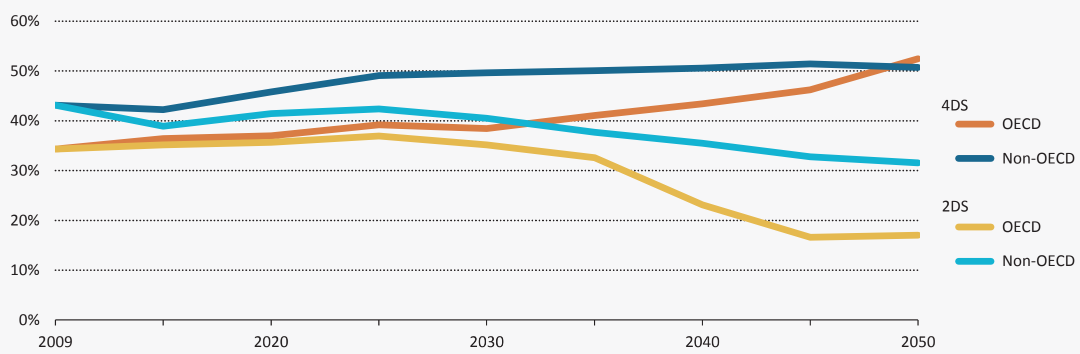
Pumped hydro is an established storage option and presents another possible solution to balance variable renewable energy. However, there are energy losses and the fluctuating output can lead to the breakdown of components. Apart from pumped hydro, options at present are limited (see Chapter 6, Flexible Electricity Systems). The number and capacity of interconnectors are limited; demand-side management and non-hydro storage are only now in the early stages of development.

The role of gas-fired power generation differs between the 2DS and the 4DS. In the 2DS, where gas power plants are increasingly used for peak power, the average capacity factor[15] of the gas-fired power fleet, comprising OCGTs and CCGTs, decreases. Capacity factors of CCGTs are normally around 40% to 80%, while peak-power requirements are typically 10% to 15%, but can be less. The evolution over time of the average capacity factor of gas-fired generation gives an indication of the role of the power plants.

In OECD and non-OECD countries, capacity factors in the 2DS and the 4DS diverge continuously to 2050; they differ by more than 5% after 2025 in the OECD and after 2035 in non-OECD countries (Figure 9.14). A high capacity factor signals that the plant is operated for many load hours and thus at base load. Low capacity factors translate to a few hours of operation and correspond to peak-load operation. The spread between the 4DS and the 2DS is more pronounced in OECD countries, where average capacity factors converge towards the base-load factors more suited to CCGTs in the 4DS and to peak-load operation more suited to OCGTs in the 2DS. In the 2DS, in OECD countries, a large amount of additional variable renewable energy requires gas installations to be operated increasingly as peak-load plants; the consequent lowering of capacity factors has a negative impact on the ongoing viability of existing plants and on the potential to attract investment for new plants.

In non-OECD countries, capacity factors are higher in both the 2DS and 4DS. In China and India, gas-fired power plants are increasingly operated at base load until 2030 to 2035. Generation from gas is a low-carbon, base-load alternative to coal-fired power, with the motivation comparable to the “dash for gas” in OECD countries during the last decade. Nevertheless, compared with the present, capacity factors continue to decrease to 2050 in the 2DS.

Figure 9.14 **Capacity factors of gas-fired power plant fleets in OECD and non-OECD countries**



Note: Generation from natural gas-fired plants equipped with CCS is not included.

Key point *The role of gas in the 2DS and the 4DS is different: gas increasingly provides base load in the 4DS and peak load in the 2DS.*

15 The capacity factor is the ratio between the actual and the theoretical maximum amount of electricity produced over a year.

Balancing the fluctuations in output, from variable renewable energy sources in the 2DS, calls for increased use of CCGTs for load cycling. Technically, variable renewable energy technologies, backed by flexible gas turbines, can generate base-load power and compete with other base-load technologies, including nuclear and coal plants. However, carbon emissions and operational costs must be assessed on a system level, rather than on a single technology level. For load cycling, however, neither CCGTs nor OCGTs operate at maximum efficiency, and from the viewpoint of reducing CO_2 emissions, particularly with OCGTs, the benefit of the renewable source of generation may well be significantly eroded. To maintain the highest average generating efficiency possible in the 2DS, the development of more advanced technologies, with the potential to achieve even higher conversion efficiencies, is essential.

Indeed, cyclic operation has a number of downsides. Apart from reducing overall efficiency, it leads to the fatigue of gas turbine components. Due to variable gas demand, it also has an impact on gas supply; the whole gas supply chain, including storage facilities, will need to adapt to the requirements for flexibility. In particular, gas storage, now largely dedicated to meeting seasonal demand swings, will need to be expanded, located closer to power plants, and have faster and more frequent draw-down capabilities.

Importantly, this increased use of gas power plants to cover variability in electricity demand will affect the economics of gas generation. Periods with strong renewable energy production (steady winds or lengthy solar radiation) can reduce the need for gas power-plant output and reduce return on investment and profitability for the gas power-plant operator.

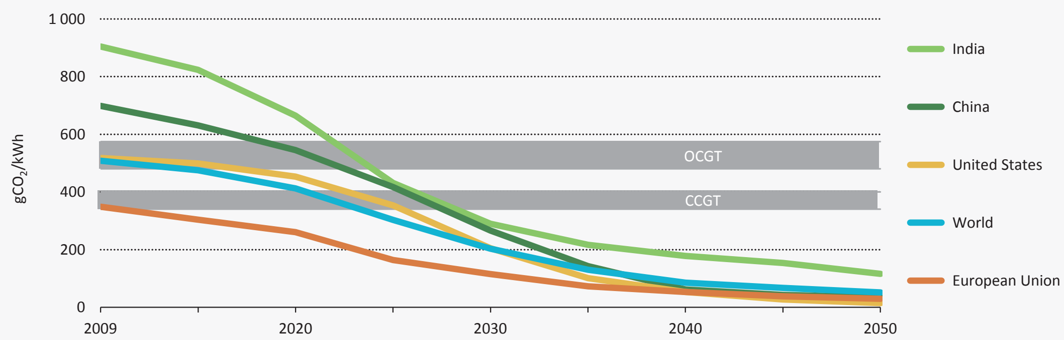
In the long run, a shrinking capacity factor will increase marginal costs to generate electricity for gas power producers. In a merit order system, gas peak-power plants are some of the last plants to be dispatched and thus set the price. Increased costs and reduced profitability can curtail investment in a technology that is essential to keep the lights on. Paradoxically, increasing marginal costs of peak-power plants benefit generators with lower marginal costs, including variable renewable energy. The integration of variable renewable energy plants at a large scale are the main technical drivers for an increased use of peak-power plants.

The challenge of operating a system that encourages high shares of variable renewable energy sources, while also ensuring an uninterrupted power supply, is common to many countries. A regulatory framework must, therefore, promote all sources that can provide flexibility (flexible power plants, interconnectors, demand response and storage). In the short-to-medium term, peak-load plants based on gas are the most mature source of flexibility, and appropriate regulatory measures must ensure adequate incentives for investment. Some regulators set *ex ante* capacity payments for plants that provide peak capacity. Others use a more market-oriented approach that takes consumption into account and also compensates for the reduction of peak loads. Such regulatory approaches are already in place, for example, in Spain, Ireland and some parts of the United States (*e.g.* in New England).

Achieving the 2DS

Achieving the 2DS requires a transition from high-carbon to low-carbon generation. Globally, the average carbon intensity from power generation declines rapidly and falls below the carbon intensity of CCGTs in 2025 and OCGTs in 2015 (Figure 9.15) in the 2DS: consequently, at those times, natural gas fired in those technologies becomes a high-carbon option. As a result, technological improvements must fill in and provide the reductions in carbon emissions after 2025; such improvements include the continued development of more efficient technologies to produce electricity from natural gas and the application of CCS. Lower-carbon fuels, such as biogas and hydrogen, will also be important. Imposing a carbon price will penalise the use of high-carbon fuels, now including natural gas, and make the development and deployment of advanced low-carbon technologies more cost competitive. In the 4DS, the global average carbon intensity does not fall below the carbon intensity of CCGTs until 2040.

Figure 9.15 Average CO_2 emissions from the power sector in different countries in the 2DS



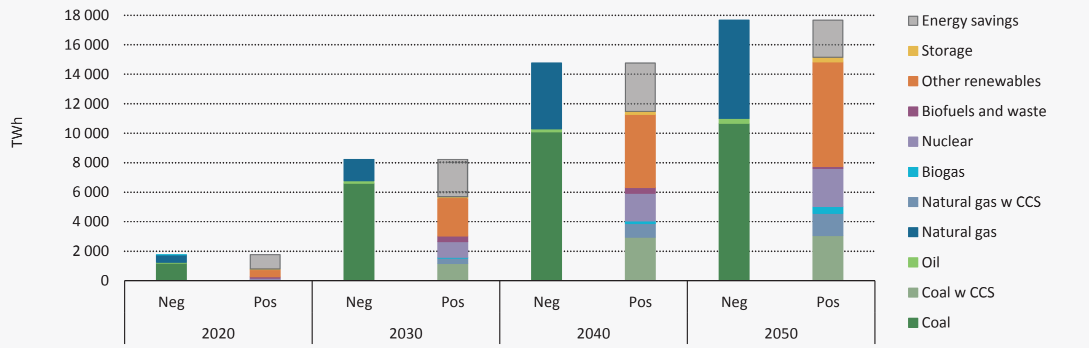
Key point *Globally, CCGTs are the most efficient natural gas-fired power generation plants but, in the 2DS, become high-carbon plants after 2025.*

Essentially, moving from the 4DS to the 2DS requires a balance between switching away from fossil fuels and substantially reducing CO_2 emissions from gas-fired power plants. The development of technologies to reduce the carbon intensity of power generation from natural gas is unlikely to happen without focused policies, regulation and market-based schemes to encourage them.

The power generation sources that need to be displaced in the 4DS (negative bars) and be replaced by additional low-carbon generation sources (positive bars) to achieve the 2DS are illustrated in Figure 9.16. The difference between the negative and positive bars is the net difference between the 4DS and the 2DS, and it is no surprise that fossil fuels are the net sources displaced. Projected generation from gas falls during the transition occurring from 2020 to 2050, but especially after 2030. The largest reductions from the 4DS are from coal-fired generation. The majority of additions come from renewable energies (both variable and non-variable). The reduction in electricity consumption resulting from energy efficiency measures and the development and application of more efficient technologies provides another critical contribution.

The path towards the 2DS depends, therefore, on increased end-use energy efficiency (reducing demand), improved conversion technologies, greater deployment of CCS, and an overall shift from fossil fuels to renewable energy technologies and nuclear. Projected CO_2 emissions reductions in the 2DS, relative to the 4DS, are shown in Figure 9.17, in which several trends become clear. Until 2030, the switch from coal to gas has a major impact on reducing emissions, although the combustion of natural gas blended with biogas or hydrogen contributes to this reduction. After 2030, however, natural gas becomes high-carbon relative to the carbon intensity required to meet the 2DS; as a consequence, the application of CCS to gas-fired power steps up appreciably.

Figure 9.16 Change in sources of power generation from the 4DS to the 2DS



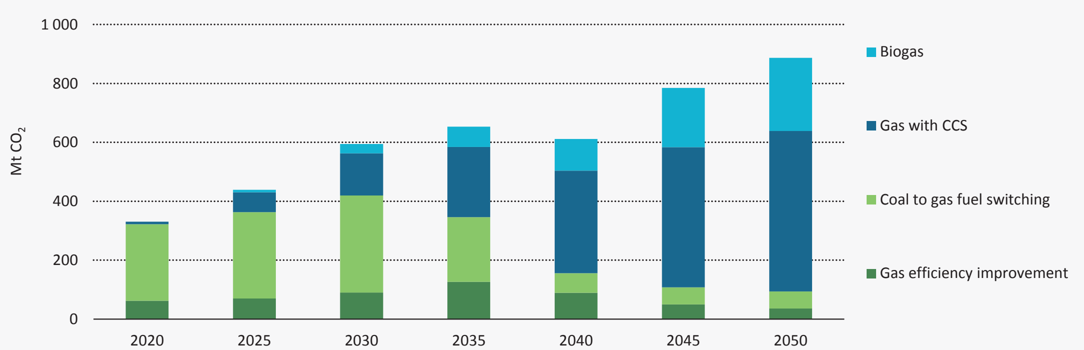
Notes: Neg = negative, the power generation sources that need to be displaced in the 4DS. Pos = positive, the low-carbon power generation sources added to achieve the 2DS.

Key point *A reduction in consumption of natural gas, greater deployment of CCS and increased use of biogas are essential to achieve the 2DS.*

Throughout the period from 2009 to 2050, continuous improvements to existing gas-fired technologies contribute to reducing emissions. As time goes on, however, the development of emerging technologies becomes more significant. These technologies, with higher conversion efficiencies, offset to an extent the losses in efficiency that come with the cyclic operation of gas-fired technologies required to complement generation from variable renewable sources.

From 2009 to 2050, relative to the 4DS, gas-related CO_2 emissions in the power sector are reduced by 20 gigatonnes of CO_2 ($GtCO_2$) in the 2DS. The reduction comprises 2 700 megatonnes of CO_2 ($MtCO_2$) from efficiency improvement in gas-fired power generation, 6 900 $MtCO_2$ from fuel switching from coal to gas, 7 800 $MtCO_2$ from employing CCS and 2 700 $MtCO_2$ from use of biogas.

Figure 9.17 CO_2 emissions reductions in the power sector by gas technologies in the 2DS, relative to the 4DS



Key point *Fuel switching, efficiency improvement, CCS in gas-fired power generation and use of biogas are essential to achieve the 2DS.*

Emerging technologies for gas-fired generation

Gas-fired technologies have improved steadily over the last few decades. There is a wide range of mature, commercially available technologies, but some new and emerging technologies are expanding the range of potential applications, not only in the power sector but also in the industry and buildings sectors.

Combined cycle gas turbine equipped with fuel cells

The high operating temperatures of solid oxide fuel cells (SOFCs) make them potential candidates for pairing with gas turbines in a hybrid configuration (Figure 9.18). This "fuel-cell hybrid CCGT" could potentially reach an efficiency of 70%, 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. The process control of combining an existing technology (CCGT) with an emerging technology (SOFC), presents a major challenge. In heavy-duty use, the ability of the SOFC to operate at high pressure needs to be confirmed. The cost is estimated at around USD 2 000/kW by the 2020s for heavy-duty use.

Integrated solar combined cycle gas turbine

An integrated solar combined cycle (ISCC) plant comprises a combined cycle plant and a solar field to produce steam to drive the steam turbine or to raise the inlet all temperature (Figure 9.19). Depending on the size of the solar field, an ISCC is 10% more efficient than a combined cycle plant. Moreover, the additional costs are relatively low because the steam turbine and generator are already part of the ISCC plant. The turbine is driven by steam from the HRSG and the solar field; therefore, the capacity can be almost doubled, compared with a stand-alone combined cycle plant. However, when solar energy is not available, the steam turbine operates at part load with reduced thermal and economic efficiency.

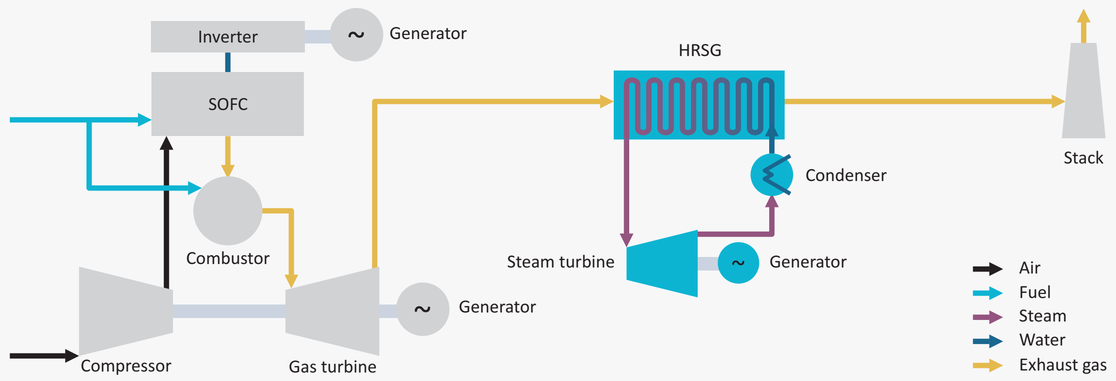
Integrated solar combined cycle plants are under construction or are in the planning stage in Algeria, Egypt, India, Mexico, Morocco, Iran, Italy, Tunisia and the United States, regions with many days with full sun. Plant capacities range from a few MW to more than 500 MW, with efficiencies estimated to lie between 61% and 70% (IEA, 2009b; US DOE, 2011a).

Humid-air turbine

The humid-air turbine system is a regenerative-gas turbine cycle using humidified air. The same output power and efficiency as a CCGT system can be achieved by the gas turbine alone, *i.e.* with no steam turbine. Particular features of the system are its simple plant configuration, which potentially translates into lower capital costs, and its ease of operation and control, combined with lower NO_x emissions from the combustor. Furthermore, with no steam turbine, its start-up time is shorter and its ramp rate is higher than for a CCGT. The stable minimum load of a humid-air turbine is lower than that of a CCGT and it can achieve an efficiency of over 50%.

A major technical challenge is to develop the mechanism to inject moisture into the compressor. By employing an advanced water-atomising cooling system, the moisture injection system has been simplified; it is planned for Higuchi's development to enter practical application as the advanced humid-air turbine (Figure 9.20), with testing currently under way in Japan at the pilot scale (Higuchi *et al.*, 2008).

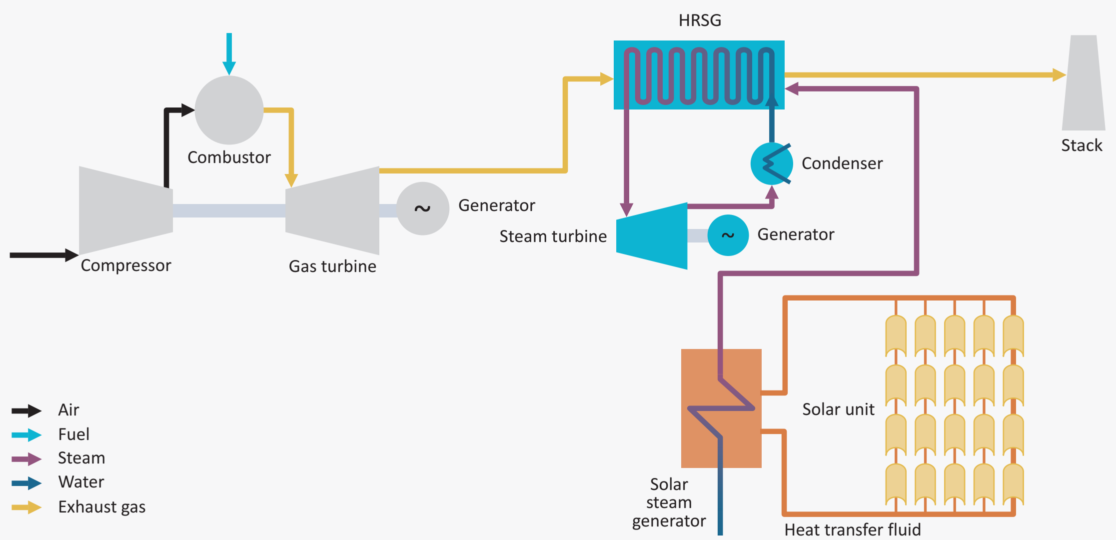
Figure 9.18 System flow of CCGT with solid oxide fuel cell



Source: Adapted from Kobayashi *et al.*, 2011.

Key point *CCGTs with fuel cells have the potential to deliver very high thermodynamic efficiencies, up to 70%.*

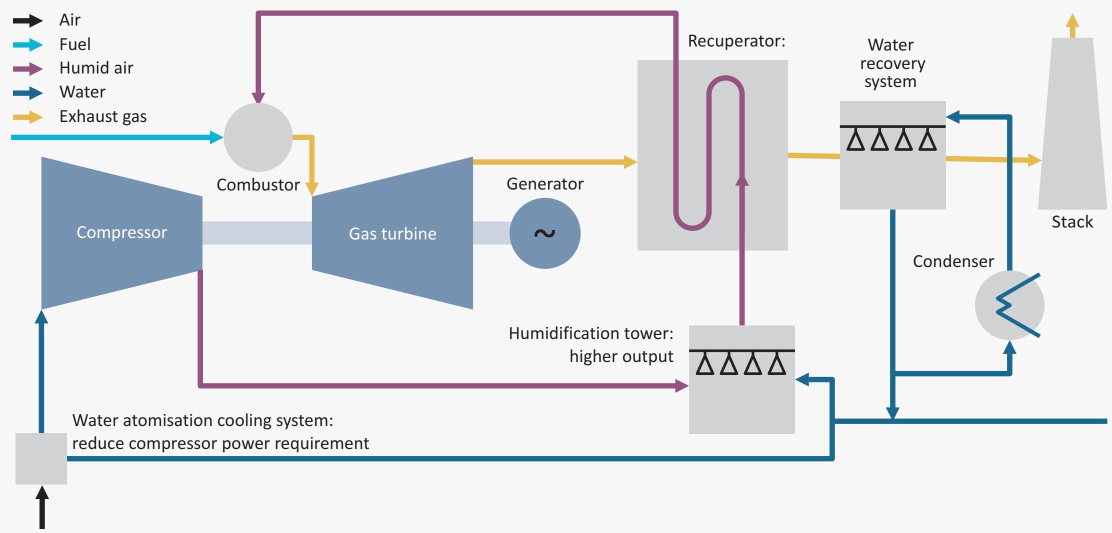
Figure 9.19 Integrated solar combined cycle system flow



Source: Adapted from Green Rhino Energy, 2010.

Key point *ISCCs have the potential to achieve higher efficiencies by combining CCGTs and solar energy.*

Figure 9.20 Advanced humid-air turbine system flow



Source: Adapted from Higuchi *et al.*, 2008.

Key point *An advanced humid-air turbine system offers the potential for high efficiency coupled with low capital costs and flexible operation.*

Carbon capture and storage

Gas-fired power generation technologies with CCS have the potential to substantially curb CO_2 emissions. CCS comprises three separate technologies: CO_2 capture, CO_2 transport and CO_2 storage. Capture of CO_2 is preferably from any large point source, such as a natural gas power plant. Typically, around 90% of the CO_2 produced during combustion is captured. Following compression to a supercritical fluid, CO_2 is transported, usually via pipeline, to a storage site. There, it is injected into geological formations that can permanently trap CO_2 in the subsurface. There are three types of capture technology that may be applied to a natural gas-fired power plant: post-combustion, pre-combustion and oxy-combustion.

The addition of CCS significantly and negatively affects plant efficiency and raises capital and operational costs much higher, especially in the capture process. While the transport and storage of CO_2 may present other challenges, on average they represent only around 20% to 30% of the total costs.

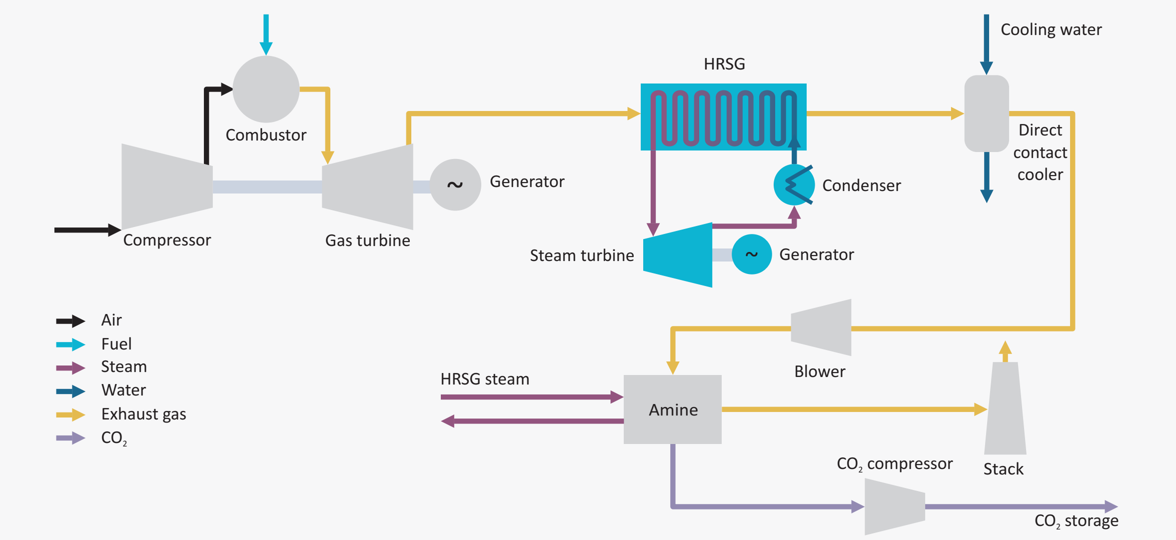
The post-combustion process applied to a CCGT plant selectively separates CO_2 from the other flue gases, compresses it and transports it to permanent storage (Figure 9.21). In this process, the volumetric concentration of CO_2 in the flue gas is less concentrated (3% to 5%) than for coal (10% to 15%) and, as a result, the energy consumed by the capture process will be higher than for coal. Consequently, the cost of CO_2-avoided[16] for gas plants is expected to be higher than for coal-fired plants (GCCSI, 2012a; US DOE, 2008).

Pre-combustion capture of CO_2 occurs after converting natural gas, by steam reforming, into CO_2 and hydrogen. In this case, the CO_2 in the gas mixture is present at higher concentrations and separation is more easily and less expensively achieved with acid gas

16 Adding CCS to a CO_2 emitting plant results in decreased CO_2 addition to the environment. This difference in the amount of CO_2 emitted is referred to as CO_2 avoided.

removal, a commercially available process. Available hydrogen can also be fired in a gas turbine, especially designed for the purpose. Though the energy penalty associated with pre-combustion capture is lower than for post-combustion, it remains significant (GCCSI, 2012b).

Figure 9.21 Schematic diagram of post-combustion capture



Source: Adapted from US DOE, 2008.

Key point *CCS can reduce CO_2 emissions from a CCGT by 90%.*

Oxy-combustion takes place in an oxygen-enriched atmosphere. The resulting combustion products comprise around 90% CO_2 (on a dry basis). Once dried, it can be transported and stored without further purification. Although the cost of the capture process is lower than for both post-combustion and pre-combustion capture, the savings are offset by the requirement for an air separation unit to provide the oxygen.

Some CCS projects fuelled by natural gas are being developed, but they are relatively few in number compared with coal. Given the costs of CCS and the associated energy penalty and operational costs, large-scale deployment of the technology is likely only with strong political commitment to long-term emissions reduction goals, accompanied by near-term incentive mechanisms. At Lacq in southwest France, Total is currently testing a 30 megawatts thermal (MW_{th}) pilot oxy-combustion plant, which injects the captured CO_2 into a depleted natural gas reservoir (GCCSI, 2012c).

Decarbonising natural gas infrastructure and adding flexibility to the fuel supply

The high investment costs necessary to develop gas infrastructure require a commitment to use gas for a long period, as decisions taken can have a strong influence on future technoloy choices (technology lock-in). With uncertainty surrounding future utilisation, new infrastructure has to enable a certain flexibility in fuel supply to accommodate a low-carbon energy system. Biogas and hydrogen can partially displace natural gas, as both are able to use existing natural gas pipeline networks and gas-fired power plants.

Box 9.3 Production of biogas in Germany and China

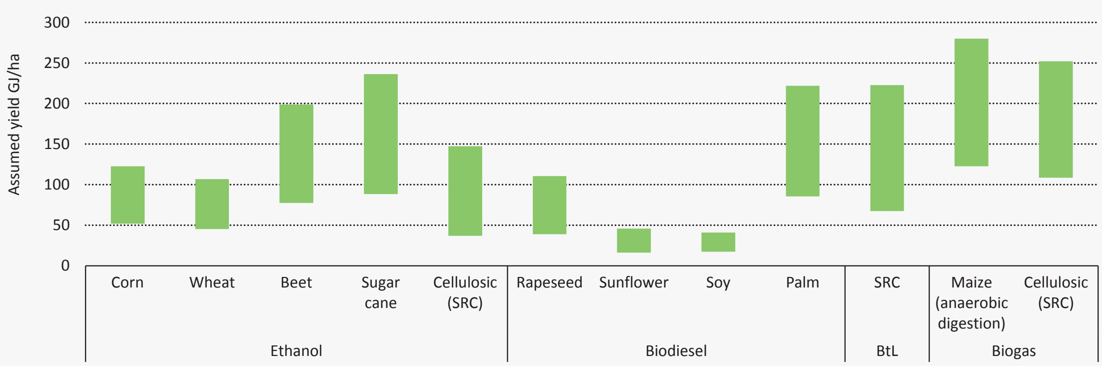
Germany is the leading biogas producer in Europe. By the end of 2011, Germany had installed around 7 000 biogas plants, with a total capacity of 2 728 megawatt electric (MW_e) (FNR, 2012). The average capacity factor of its biogas plant fleet in 2010 was 63%. Currently, with 77 plants, Germany is upgrading its biogas so it can be fed directly into the natural gas grid. Germany's national goal is to deploy more than 1 000 upgraded plants by 2020 and substitute 6% of actual natural gas consumption by biogas (DENA, 2012).

China deploys biogas digesters in rural areas to convert organic waste into biogas. Today, over 40 million households have small-scale biogas digesters (Tienan, 2011) producing biogas, primarily for cooking, significantly displacing wood and coal use.

Biogas is primarily composed of methane. It can be used directly or blended with natural gas and is a potential long-term solution for decarbonising the natural gas sector. Biogas, like biomass, is designated carbon neutral and, if coupled with CCS, will effectively reduce atmospheric CO_2 concentrations. Biogas produced from the breakdown of readily available residues and wastes (such as manure, food-processing residues, the organic fraction of household waste and sewage sludge), has virtually no impact on land use.

The production of biogas from anaerobic digestion has a lower impact on land use than other biofuels, and has a considerably higher fuel yield per hectare of land (Figure 9.22). Biogas can be used as a fuel for transport, heat or electricity, and can also be integrated into the current gas grid if the biogas is upgraded to natural gas quality. Other feedstocks, such as wood, are well suited to thermochemical conversion into biosynthetic natural gas (bio-SNG) or liquid biofuels, as well as into heat and power.

Figure 9.22 Biogas energy potential from one hectare of land



Notes: BtL = biomass-to-liquids. In addition to land-use efficiency, a complete assessment of yield must also consider the value and impact of co-products. See IEA (2011b) for a comparison of impacts on land use. Woody crops from short-rotation coppice (SRC) yield on average an estimated 15 tonnes per hectare.

Key point *Biogas produces higher yields of potential energy per hectare of land and thus has lower land-use requirements than other biofuels.*

The production of biogas can increase energy security, bring additional income to rural communities and the agricultural sector, and reduce GHG emissions considerably compared with natural gas or other fossil energy sources.

Hydrogen and natural gas are both energy carriers and can be transformed from one to the other through steam methane reforming (natural gas to hydrogen) or captive hydrogen methane production (hydrogen to natural gas). Steam reforming natural gas results in positive net CO_2 emissions, whereas the production of synthetic methane captures CO_2. This chemical link between hydrogen and natural gas can potentially enable the power grid to be coupled with the gas grid. One near-term option is to blend natural gas with up to 10% hydrogen[17] produced from excess renewable power (see Chapter 7).

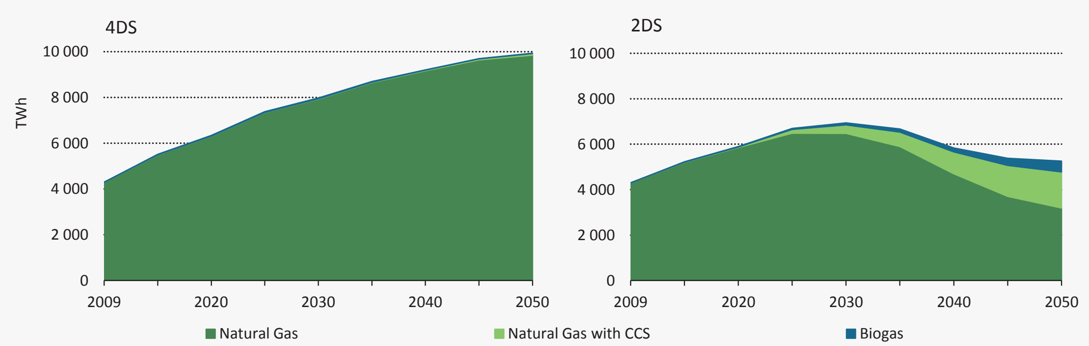
Excess renewable electricity can be transformed, via electrolysis, into hydrogen to generate synthetic methane. Methane is easily stored, transported and distributed via the extensive existing natural gas grids and used to generate electricity for peak demand in conventional CCGT power plants. The low overall efficiency of this complex process[18] may be outweighed, in the future, by the benefits of energy storage and especially the use of existing infrastructure. In Werlte, Germany, one such pilot plant is planned for completion by May 2013, where 1.4 million m^3 of synthetic natural gas will be produced each year (Solar Fuel, 2011).

On the other hand, reforming natural gas to produce hydrogen on a large scale may make hydrogen transmission and distribution infrastructure more attractive. Without CCS, however, it will not contribute to reducing CO_2 emissions in the long term.

Over the next 20 years, the relatively low price of natural gas will ensure it plays a leading role, but niche applications for hydrogen in the gas system should still be pursued to capture synergies for the long term. Natural gas development can leverage the future use of hydrogen. In the longer term, biogas and hydrogen can be integrated in the natural gas infrastructure, further reducing CO_2 emissions, while lowering investment in new infrastructure.

The projected roles of biogas and CCS in decarbonising the natural gas sector are shown in Figure 9.23. In the 2DS, natural gas-fired power plants equipped with CCS generate 1 588 TWh and biogas-fuelled power plants, 481 TWh.

Figure 9.23 **Electricity generation from gas**



Key point *In the 2DS, natural gas with CCS and biogas both contribute to decarbonising energy production from natural gas and, in 2050, provide an additional 65% of electricity on top of that generated from conventional natural gas.*

17 Providing consistent gas quality may require additional hydrogen storage, as metering needs a constant ratio of natural gas to hydrogen.

18 The major technical challenge in the process is to split an oxygen atom from the very stable CO_2 molecule, which is very energy-intensive. Research is focusing on reducing the energy requirements in the presence of catalysts.

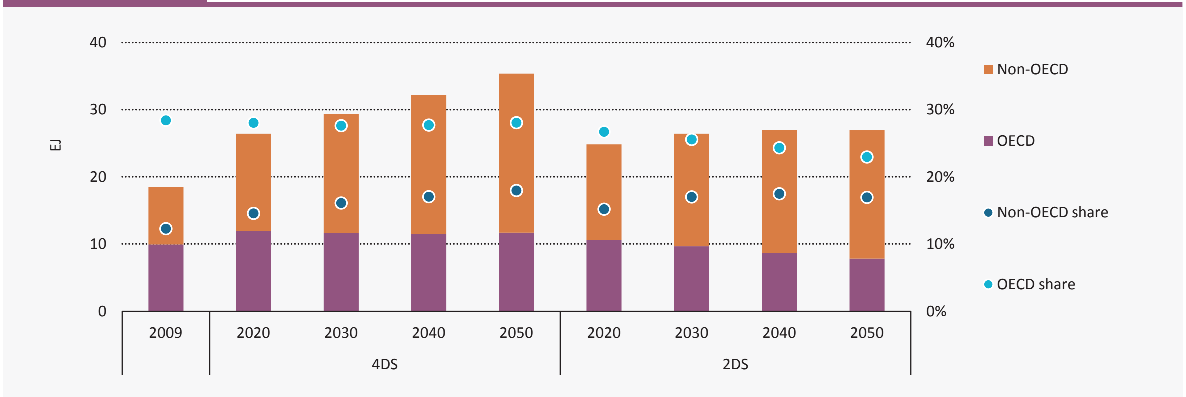
Gas use in the industry and buildings sectors

The industry and buildings sectors are by far the largest gas-consuming end-use sectors, with natural gas consumption playing a crucial role in each (Figure 9.3). As electrification progresses, both sectors become more dependent on electricity, which increasingly comes from natural gas in the 4DS.

Industry sector

In 2009, direct natural gas consumption in the industry sector, including energy and non-energy uses, represented 18% of final energy consumption. If natural gas-powered electricity is added, total consumption becomes 22%. The future share of natural gas in final industrial energy consumption in the 4DS is projected to stabilise at around 23% in OECD countries and increase in non-OECD countries from 15% in 2009 to 20% in 2050 (Figure 9.24).

Figure 9.24 Final natural gas consumption in the industry sector



Key point *In the 2DS, final natural gas consumption in the industry sector increases by 30% to 2030 and then stabilises.*

In absolute terms, consumption of natural gas in industry increases by 165% throughout the 2009 to 2050 period in non-OECD countries in the 4DS for several reasons:

- Iron and steel manufacturing switches away from coal-based direct reduced iron (DRI), mostly in India and South Africa, while Russia, the Middle East, Latin America and Africa increase their use of gas-based DRI.
- Aluminium production incorporates greater use of recycled material. The re-melting technology uses natural gas, whereas smelters use electricity.
- Chemicals production shifts away from oil and coal as feedstocks, largely replaced by gas.

These three trends highlight that a move to natural gas or switching from higher carbon-emitting fuels to natural gas provides some benefit in the short-to-medium term, but is not sufficient to satisfy the 2DS. In the longer term, global consumption of natural gas needs to be reduced. In the 2DS, natural gas consumption is projected to grow more slowly to 2050 and is approximately 20% lower in 2050, compared with the 4DS. In non-OECD countries, the industry sector must make significant efforts to contain gas consumption; this sector is especially sensitive to the costs of producing raw materials. In the 2DS, the share of natural gas in final industrial energy consumption decreases in OECD countries after 2020, but only stabilises in non-OECD countries after 2030. Natural gas technologies and processes that increase energy efficiency, such as regenerative and oxy-fuel burners and co-generation, are critical to the sector.

Natural gas as feedstock

Apart from its use as a fuel, natural gas also serves an important role as feedstock to produce ammonia, methanol and other hydrocarbon-based products. In fact, the demand for natural gas is also linked to the demand for these products.

For some natural gas components, such as ethane, propane and butane, a process of thermal cracking transforms them into olefins (*e.g.* ethylene and propylene), which are the backbone of many more complex products, including plastic film, detergents and synthetic lubricants.

Anhydrous ammonia is the basis of nearly all synthetic nitrogen fertilisers. Ammonia is produced by combining nitrogen with hydrogen. When nitrogen is obtained from the atmosphere, the hydrogen comes from natural gas and, to a lesser extent, from naphtha, coke-oven gas, refinery gases and heavy oil. In fact, about 77% of global ammonia production is based on hydrogen from steam reforming of natural gas. In the future, the commercialisation of other hydrogen production processes, notably electrolysis from excess renewable energy production, may reduce dependence on natural gas and at the same time reduce carbon emissions.

Methanol is used as antifreeze, solvent and fuel. About 75% of methanol production comes from natural gas; the remainder is coal-based, essentially in China (IEA, 2009c). The carbon from the natural gas feedstock is “locked into” final products, such as plastics, solvents, urea and methanol. The locked-in energy may be recovered through incineration at the waste treatment stage, when the carbon content is liberated, contributing directly to industrial emissions.

Natural gas as energy carrier

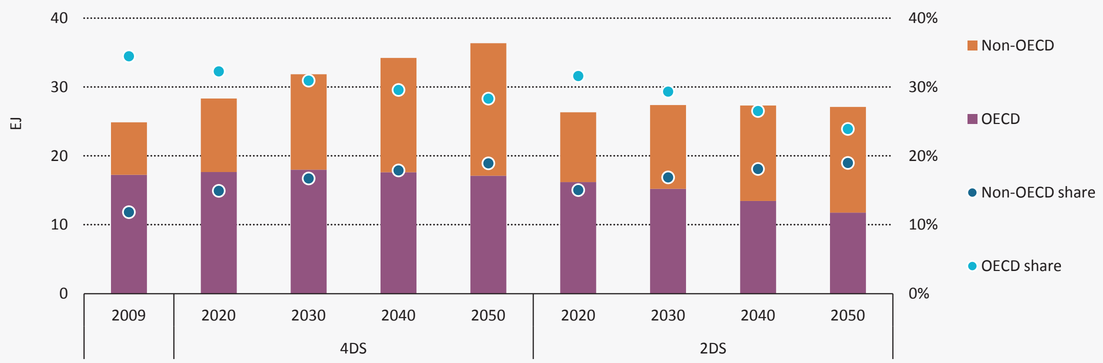
In the manufacturing industries, including iron and steel, pulp and paper, and non-metallic materials (cement), natural gas serves mainly to generate heat in a combustion process. In the medium term, switching from coal and fuel oil to natural gas will considerably reduce CO_2 emissions. In the longer term, however, to offset its emissions, gas itself needs to be replaced by hydrogen, biomass, waste or, potentially, by very low-carbon electricity. Fuel switching is an important option in achieving reductions in CO_2 emissions. For example, switching from blast furnaces to gas DRI can significantly reduce the carbon intensity of iron production.

Buildings sector

In the buildings sector (both residential and commercial buildings), natural gas is consumed mainly for space heating, water heating and cooking. Compared with the 4DS, compliance with the 2DS targets requires that natural gas consumption in the buildings sector contracts.

From 2009 to 2050, final natural gas consumption in the 4DS is projected to increase by 152% in non-OECD countries and remain at 2009 levels in OECD countries. In the 2DS, however, natural gas consumption in non-OECD countries only increases by a factor of two (101%) to 2050. In OECD countries, there is a marked decrease of 32% in consumption to 2050, which reduces the share of gas in total final consumption from 34% in 2009 to 24% in 2050 (Figure 9.25). Natural gas is displaced by lower-carbon alternatives in all applications, including solar water heating and cooling, biomass and waste boilers, low-carbon electricity, and renewable heat from co-generation systems and district heating networks.

Figure 9.25 Final natural gas consumption in the buildings sector



Key point *In the 2DS, final natural gas consumption in the buildings sector increases by 9% to 2030 and then stabilises.*

Technologically, natural gas systems in the buildings sector are advanced, with overall thermal efficiencies as high as 95%. This is not to say that further energy and gas savings in existing buildings cannot be made. By and large, the buildings sector, especially residential buildings, is slowly renewing outdated, inefficient equipment that is still in operation. Upgrading gas systems with best practice technology will considerably increase efficiency and lower gas demand.

In the future, heat pumps, solar thermal, and biomass and electricity-fuelled boilers displace natural gas-fired boilers for space and water heating. However, increasing electrification will save resources and reduce emissions only if the power sector is decarbonised. When deciding which electricity technologies to deploy, energy efficiency and emissions must be assessed along the whole electricity value chain. In the 2DS, the power sector decarbonises rapidly and the replacement of gas boilers by heat pumps contributes to overall CO_2 reductions. Strategies to reduce carbon emissions or improve energy efficiency must take a holistic, cross-sectoral view of the energy system to be effective.

Installing smart gas meters in buildings will help increase efficiency in the retail market. Increased sensors and control capabilities allow remote diagnoses of heat and energy losses and timely intervention. More co-benefits can be expected from data mining and analysis. A co-ordinated approach and engagement with the electricity and other sectors (*e.g.* water and telecommunications) means deployment costs can be shared and operational synergies realised.

Technologies for the industry and buildings sectors

Gas technologies for industry and buildings are different processes that transform the chemical energy of natural gas into useful energy, such as mechanical, heat and electrical energy. Research and development have led to impressive technological progress over recent decades, exploring physical limits in increasing efficiencies and minimising local pollutants. Today, policy makers must prioritise and accelerate fleet modernisation by deploying state-of-the-art technologies in the industry and buildings sectors.

Distributed power generation and co-generation

Distributed generation uses small-scale technologies to generate end-use power, mainly in the industry and buildings sectors. The advantages of these technologies are expanding energy supply options, offering standby and emergency generation, providing generation in remote off-grid areas, and satisfying high-quality power requirements. Furthermore, distributed power generation avoids losses associated with electricity transmission and distribution.

Combined heat and power or co-generation units use the heat rejected or lost during electricity generation processes (thermal efficiency of 30% to 40%) for heating applications. Co-generation can raise thermal efficiency to 75% to 80% (*i.e.* the efficiency of converting fuel energy into useful energy) and, in the most efficient cases, even to 90% or higher. Recovery of heat is especially beneficial in distributed applications, where end users demanding heat are located close to the thermal conversion unit (heat supply). The heat recovered can provide space heating, water heating or process heating for the industry and buildings sectors, which effectively increases energy efficiency by utilising heat losses from the electricity generation process.

The additional investment costs for co-generation systems vary according to the heat delivery system, but savings in operating costs often outweigh the higher upfront costs. Co-generation plants are energy-efficient and cost-efficient. In addition, they have the flexibility to optimise heat and electricity production and consumption within a decentralised economy. Fuels for co-generation vary from country to country: they include oil and biomass, but globally are dominated by natural gas and coal.

The capacity of a co-generation unit ranges from 1 kW for residential use to 500 MW for industrial use. Globally, co-generation produced 1 901 TWh of electricity in 2009 and accounted for around 9% of total global electricity production. More than 20% of the power generated in Denmark, Finland, Latvia, the Netherlands and Russia comes from co-generation plants fuelled mainly by natural gas, which benefit from district heating distribution systems that connects generators and end users.

Gas engines: Available in a wide range of sizes, from a few kilowatts to over 10MW, gas, engines are reciprocal combustion engines fuelled by natural gas. Due to their compact design (high energy output per engine volume) and relatively low capital costs, gas engines[19] are frequently used for distributed power generation in the industry and buildings sectors. Electric efficiencies range from 30% for smaller stoichiometric rich-burn engines to over 40% for large lean-burn engines. Generally, natural gas engines have higher efficiencies than gas turbines of comparable size. The state-of-the-art power generation efficiency of gas engines has increased significantly over the last 20 years, from around 33% in 1990, to about 40% in 2000, to nearly 48.5% today. These improvements are due largely to the development of lean-burn processes (also lowering NO_X emissions), introduction of turbochargers, improved ignition timing and enhanced fluid dynamics (US DOE, 2011b; NPU, 2011).

Incremental improvements in efficiency and performance are still achievable, including some reduction in the delivered cost of energy. The US Department of Energy's (US DOE's) Advanced Reciprocating Engine Systems (ARES) programme aims to deploy an advanced natural gas-fired reciprocating engine by 2013 with the following characteristics:

- improved fuel-to-electricity efficiency of 50%;
- engine improvements in efficiency, combustion and dispatch strategy that substantially reduce overall emissions to the environment, including a NO_X target of just 0.1 g per horsepower hour; and

19 Large gas-fired power plants composed of several gas engines, with a capacity of a few hundred megawatts, are also used for centralised power generation.

- reduced power cost, with a target for operating and maintenance costs of 10% less than current state-of-the-art engine systems.

Turbines and micro-turbines: Gas turbines are available in a wide range of sizes, from micro-turbines (under 300 kW) to very large gas turbines in CCGTs (200 MW to 300 MW). The efficiency of a 10 MW mid-sized gas turbine lies between 30% and 35%, lower than a gas engine. With their potential for high-temperature heat recovery, gas turbines are popular for distributed generation and co-generation applications, particularly in industries that require high-temperature process heat, such as the food processing and paper industries.

Micro-turbines are small gas turbines, typically with capacities under 300 kW. Simple cycle micro-turbines have very low efficiencies (12% to 15%), but recuperated units that use a heat exchanger to transfer some of the exhaust heat to the incoming air stream can achieve electrical efficiencies of about 23% to 27%. If used for co-generation, overall efficiencies are typically between 64% and 74%. Due to their light weight and compact size, micro-turbines can be used in areas with space and weight constraints. They are available as packaged, self-contained units.

The potential to improve micro-turbines is similar to gas turbines, although some advances may take time to filter down to micro-turbines due to their small scale. In general, improvements occur in new materials, such as ceramics and thermal barrier coatings that allow significant increases in engine operating temperatures and pressures, thereby improving efficiency. The US DOE's Advanced Microturbine Systems programme has a goal of 40% electrical efficiency, very low NO_x emissions (less than 7 parts per million), and improved durability (11 000 hours of reliable operation between overhauls and a service life of at least 45 000 hours).

Fuel cells

Fuel cells create electricity and heat as co-products of an electrochemical process in which hydrogen and oxygen are converted into water. A natural gas steam reformer can be coupled to a fuel cell to produce hydrogen from natural gas. The process emits CO_2, however, and is not a long-term solution to mitigate CO_2 emissions. Overall electrical efficiencies (and CO_2 emissions) of a reformer and fuel cell system are comparable to gas engine generators. Natural gas can probably only be considered as a transitional fuel to create markets for fuel cells and clean hydrogen (see Chapter 7).

The four main types of fuel cells are categorised by the type of electrolyte they use – phosphoric acid fuel cells (PAFC), solid oxide fuel cells (SOFC), molten carbonate fuel cells (MCFC) and polymer electrolyte membrane fuel cells (PEMFC) – as well as their operating temperatures. The only commercial and industrial (10 kW or larger) fuel cell technology that has been commercially deployed with sufficient durability is the PAFC. MCFC has been deployed, but still faces issues relating to durability. On the other hand, SOFC using natural gas is expected to play a leading role, and has an electrical efficiency of around 60%, although commercial and industrial SOFC is still at the research and development phase. Over recent years, as the reliability and durability of PEMFC and SOFC improved, they have been increasingly adopted for residential use.

Reducing costs is one of the biggest challenges facing the future deployment of fuel cells. Their high costs are partly a function of the small number produced. The US DOE's Hydrogen, Fuel Cells and Infrastructure Technologies Program is targeting an equipment cost of USD 1 000 per kW for a 2 kW-class fuel cell by 2020 (US DOE, 2011).

Burners

Upgrading burners in large gas-fired combustion units can improve efficiency and lower emissions of local pollutants. Heat-recirculating, regenerative burners increase combustion efficiency by preheating the air inflow. Regenerative burners are installed in pairs and are operated alternately: while one is firing, the other uses the exhaust gases to pre-heat and warm the inflowing air. The process increases flame temperatures and increases efficiency. However, the higher temperature favours formation of NO_X, which requires further exhaust gas treatment.

Gas use in the transport sector

Its high calorific value and low CO_2 content make natural gas attractive as a fuel for the transport sector, but its low energy density requires compression or liquefaction. While the number of natural gas vehicles (and fuel stations) has grown in the past decade, especially in public transit, they remain a niche market for now, with less than 1% of both world road-transport fuel consumption and total world gas demand. In some countries, natural gas plays a more important role, with the market share of natural gas vehicles (NGVs) exceeding 10%: Bangladesh, 61%; Armenia, 30%; Pakistan, 30%; Bolivia, 26%; Argentina, 24%; Colombia, 24%; Iran, 14%; and Malaysia, 11% (IEA, 2010a).

Natural gas vehicles have lower GHG emissions than today's gasoline engines. The comparison with diesel vehicles, however, depends on the type of vehicle (*e.g.* passenger car or heavy-duty vehicle). Local emissions from NGVs, namely unburnt hydrocarbons, NO_X and particulate matter, are generally lower than from either diesel or gasoline engines.

Natural gas vehicles and fuel technology are almost cost competitive with conventional powertrains, with distinct advantages over electric powertrains. In the longer term, however, this technology must be further decarbonised. Biogas, biosynthetic gas, and gas-to-liquid conversion are feasible options for the heavily oil-dependent transport sector. The advantage of leapfrogging the use of natural gas in the passenger car sector directly to fuel-cell or battery-powered cars is that no transitional infrastructure for gas is needed.

Natural gas use in the transport sector grows in both the 2DS and the 4DS in OECD and non-OECD countries. Its use increases over the outlook period by 50% in the 4DS and 87% in the 2DS due to an increase in natural gas-powered passenger cars, buses and trucks that is more pronounced in the 2DS. Natural gas use in transport represents 5% of primary natural gas demand globally in the 2DS and remains at 1% in the 4DS in 2050.

Role of gas in a low-carbon economy

Natural gas is an abundant and flexible fuel for the 2010 to 2050 time frame, playing an important role in the transition to a low-carbon energy system. Future policies need to focus on preventing technology lock-in while developing natural gas infrastructure. The flexibility of the fuel is invaluable in switching to a less carbon-intensive energy system. Both hydrogen and biogas can potentially supplement or replace natural gas, while exploiting existing pipelines for transport and technologies for power generation. CCS is essential to make the necessary deep cuts in CO_2 emissions. Policies addressing the post-2035 climate targets will be major factors influencing the future of natural gas.

In the 4DS, the golden age of gas is prolonged. Natural gas demand is projected to increase in all sectors. Only growth in the OECD power sector is constrained after 2035. OECD countries in all other sectors and non-OECD countries in all sectors continue to increase their use of natural gas. In the power sector, natural gas is increasingly used for base-load power generation.

In the 2DS, transition to a lower-carbon energy system is necessary. In OECD countries, natural gas consumption is reduced in all sectors except transport. In non-OECD countries, demand growth is constrained in all end uses and flattens in the power sector. In the power sector, natural gas will be increasingly used for load following to balance variable renewable power generation.

The future role of natural gas will be driven by carbon emission targets, and the 2DS brings a number of co-benefits. Reducing dependence on a non-renewable energy source, such as natural gas, can calm geopolitical tensions resulting from unevenly distributed global resources and decreases environment pollution during exploration, production and consumption.

Recommended actions for the near term

Natural gas will play an important role in the global energy mix over the next decades. It is the only fossil fuel whose consumption in the 2DS is projected to be higher in 2050 than in 2009. Moreover, increasing production of unconventional gas leads to an improvement in energy security in many regions. To 2025, natural gas is important in meeting short-to-medium-term environmental goals. In fact, it will be instrumental in reducing the carbon intensity of energy use over the next 10 to 15 years.

Over the next 10 years, it is crucial that the environmental challenges of exploration and production of unconventional gas be addressed in a responsible manner. The increasing supply of unconventional gas will continue to offer a competitive edge over other fossil fuels and trigger the displacement of high carbon-intensive energy sources in the power sector. In parallel with heightened interest in indigenous production, governments will have an important role in setting the policy and regulatory framework to minimise and mitigate the associated environmental risks. Industry must be encouraged to adopt state-of-the-art technologies for exploration and production. National platforms or an international, multi-stakeholder platform would facilitate collaboration and promote the exchange of knowledge, experience and best practice.

Synthetic natural gas, biogas and hydrogen can all be blended with natural gas, transported in existing natural gas infrastructure, and burnt to generate gas-fired electricity and heat. The current demonstration efforts under way to explore the potential for synthetic natural gas, biogas and hydrogen to offset or supplement the use of natural gas need to go further. Switching to or co-firing lower-carbon energy sources is clearly in the interest of all stakeholders.

In a low-carbon economy, variable and non-variable renewable generation will replace a significant part of today's base-load capacity and coal in particular in the next 10 to 20 years. Though the importance of gas-fired technologies to provide the flexibility to complement variable renewable generation over this period has been acknowledged, many more countries will need to put theory into practice over this period. Other means to provide flexibility – interconnectors, electricity storage and demand-side management – will need sufficient and timely resources before they will be ready to contribute at the scale required.

It must be recognised that, where there is significant variable generating capacity, the operation of back-up or stand-by capacity to balance grid demands will run at a loss in a market-based economy. The reduced profitability of natural gas-fired generation can threaten investment in essential gas-fired back-up capacity. Policies to address the viability of such capacity, both existing and new, need to be devised and implemented, *e.g.* provision of capacity payments or compensation. Dialogue between government and industry is needed, with solutions likely to become embedded in new regulatory frameworks.

During the period of rapid growth in gas-fired power generation, quickly evolving policy and rigorous planning and construction processes are essential to avoid over-construction and stranded assets. Gas-fired assets can have an operating lifetime of 25 to 30 years and steps will need to be taken if unregulated construction of infrastructure is to be avoided.

In addition, the next 10 to 20 years are particularly important to decarbonise the natural gas infrastructure with more technology options. With government (setting the market conditions) and industry (responding with innovative developments) working in partnership on these matters, a more efficient technology and greater efficiency of natural gas production, conversion and end use will result.

Policy drivers and market-based incentives will need to be in place if CCS is to be demonstrated successfully and available for deployment at the scale required to meet the 2DS.

Chapter 10

Carbon Capture and Storage Technologies

Carbon capture and storage technology is an important part of the emissions reduction puzzle. Deploying CCS at the levels shown in the *ETP 2012* 2°C Scenario is technically feasible; however, it will require significant effort by both government and industry.

Key findings

- *Carbon capture and storage (CCS) is an important emissions reduction technology,* ***contributing one-fifth of the total emissions reductions globally through 2050.*** *This is a global average, meaning that the contribution of CCS to meeting emissions reduction goals is even higher in some regions.*
- *Carbon capture and storage is the* ***only currently available technology that can allow industrial sectors, such as iron and steel, cement, natural gas processing, etc., to meet deep emissions reduction goals.*** *In some regions, such as OECD Asia Oceania CCS plays a larger role in reducing emissions from industry than from electricity generation.*
- ***Delaying or abandoning CCS as a mitigation option in electricity generation will increase the investment required in electricity generation by*** *40% or more in the ETP 2012 2°C Scenario (2DS) and may place untenable demands on other emissions reduction options.*
- ***Nearly 123 gigatonnes of carbon dioxide (GtCO$_2$) need to be safely stored in geologic formations through 2050.*** *A vast majority of this storage volume is likely to be in saline aquifers. Carbon dioxide storage through enhanced oil recovery may provide opportunities for learning, offsetting costs of capture and infrastructure development.*
- ***Many CO$_2$ capture technologies are commercially available today and can be applied across different sectors.*** *While most are capital-intensive and costly, they can be competitive with many other low-carbon options. Challenges lie in integrating these technologies in large-scale projects.*
- *Room to manoeuvre and still reach the 2DS emissions target is shrinking fast.* ***This leads to increasing pressure to consider retrofitting existing power plants and industrial facilities with CCS.*** *Requirements that make new facilities CCS-ready today will help minimise additional costs of retrofitting in the future.*
- *Great strides have been made in the last few years in regulating CO$_2$ storage, but* ***the absence or incomplete implementation of laws and regulations still present barriers*** *to development of storage projects.*

Opportunities for policy action

- *Governments must assess the role of CCS in their energy futures, explicitly recognising the role that CCS will play, and develop suitable deployment strategies including appropriate incentives for CCS and a clear timeline to develop enabling regulations.*
- *To date, no large power plants (i.e., hundreds of megawatts [MW] and up) with CCS exist, so redoubling government and industry efforts to demonstrate CCS at a commercial scale in different locations and technical configurations is critical. This must include large-scale injection and storage projects to demonstrate safe and effective CO_2 storage.*
- *Devise and implement appropriate and transparent incentives, policies and mechanisms to drive CCS deployment. Long-term climate change mitigation commitments and resulting policy action are required to create investor certainty.*
- *Develop enabling legal and regulatory frameworks for both demonstration and deployment of CCS, so that lack of regulation does not unnecessarily impede or slow deployment. While developing a regulatory framework for CCS technology can seem daunting, the foundations are already in place in many jurisdictions. Furthermore, regulations can be tailored to the stage of technology deployment.*
- *Develop clear, accurate information on the geographic distribution of storage capacity and associated costs for storing CO_2.*
- *Increase emphasis on CO_2 transport and storage infrastructure development. Developing storage sites and transport infrastructure is time-consuming, requiring co-operation between different private entities and government. Without transport and storage, large integrated CCS projects cannot be successful.*
- *Engage the public at both policy and project levels and ensure transparency, flexibility and a two-way flow of information from early stages. Governments can prepare the way for CCS deployment by highlighting the role of CCS within a country's climate mitigation and energy plans. Not attending to public concerns over CO_2 storage can easily be fatal for CCS.*

The need for carbon capture and storage technology and potential applications

Carbon capture and storage holds substantial potential to reduce emissions of CO_2 that cause climate change: in the 2DS, CCS accounts for slightly more than one-fifth of needed emissions reductions between 2015 and 2050. CCS is a set of technologies that can be used in combination to reduce CO_2 emissions from large point sources, such as coal- and gas-fired power stations and natural gas processing facilities. Power stations and other industrial sources, such as gas plants, refineries, steel mills and cement manufacturing, where CCS can be applied account for 17 $GtCO_2$, or 57%, of global, annual energy-related CO_2 emissions (IEA, 2009; IEA, 2011a). Alternative low-carbon technologies exist for electricity generation, but in other industries, CCS is often the only alternative to achieve deep emissions reductions. It is thus critically important to understand the role that CCS can play in these applications to meet emissions reduction goals of the 2DS.

In CCS, 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. The injection site must be monitored to demonstrate retention of the CO_2. All necessary technologies exist today, but have been integrated in large industrial-scale projects in only a small number of cases.

Separation, compression and – to a lesser degree – transport of CO_2 is expensive in the amount of energy needed and, in most cases, each step requires significant capital investments. In power generation, however, the cost of electricity from power plants with CCS is estimated to be competitive with many other low-carbon technologies, such as wind or solar power (IEA, 2010; ZEP, 2011). In addition, power plants with CCS can be reliably dispatched and generate base-load power, which is not always the case with alternative low-carbon technologies.

The sectors and processes to which CCS can be applied

From a technical perspective, CCS technologies can be applied to any process that produces CO_2. However, the economies of scale associated with CCS mean that it only makes sense to apply CCS to stationary, large point sources of CO_2 (*i.e.* those producing hundreds of thousands of tonnes of CO_2 per year) at reasonably high concentrations (*i.e.* above a few percent of CO_2 by volume). There are numerous processes that meet these criteria in both electric generation and certain industrial applications, such as gas plants, refineries, steel mills and cement manufacturing.

In the electricity sector and some industrial sectors (*e.g.* cement manufacture), separation of CO_2 is generally an extra step that must be added to traditional processes; in some other industrial sectors (*e.g.* petrochemicals), CO_2 separation is already part of the process. Regardless of the sector, processes where CO_2 separation is inherent (*e.g.* natural gas sweetening) are referred to as high-purity sources. Where CO_2 separation must be added, it can be accomplished by pre-combustion, post-combustion and oxy-combustion processes, or possibly a combination of these.

Carbon dioxide capture processes are currently at different stages of readiness (Table 10.1). In applications where CO_2 separation is an inherent part of production, capture processes are commercially available and in common use. In other applications, such as coal-fired electricity generation, CO_2 separation processes are less advanced, requiring demonstration at large scale before they can be considered commercially available. However, note especially in this table that, with the prominent exception of electricity generation from biomass, CO_2 capture processes are at the pilot stage for all industrial sectors and processes, and that capture is commercially practised and available for high-purity sources.

Table 10.1 Routes to CO_2 capture in electric power generation (by fuel) and industrial applications (by sector)

		Pre-Combustion	Post-combustion	Oxy-combustion	Inherent	Other
Electric power	Gas	Concept.	Pilot	Pilot		Concept. (CLC)
	Coal	Pilot	Pilot	Pilot		Concept. (CLC)
	Biomass	Concept.	Concept.	Concept.		
Industrial applications	Fuel processing	Pilot		Pilot		
	Iron and steel		Pilot	Pilot		Pilot (HIsarna, Ulcored) Demo (FINEX) Commercial (DRI, COREX)
	Biomass conversion	Pilot	Demo		Commercial	
	Cement manufacture		Pilot	Pilot		Concept. (carbonate looping)
	High-purity sources		Pilot		Commercial	

Notes: Concept. = conceptual design stage; CLC = chemical looping combustion.
Sources: Rubin *et al.*, 2010; IEA and UNIDO, 2011; GCCSI, 2011; Carpenter, 2012.

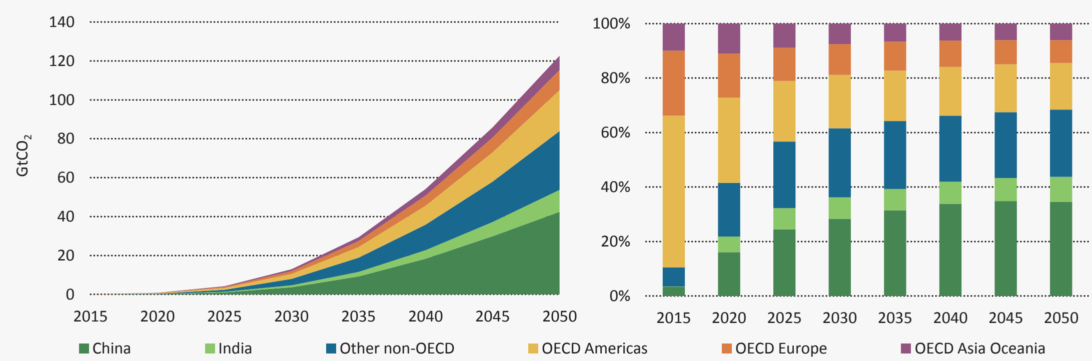
Key point *Numerous CO_2 capture routes are in pilot-testing or demonstration stages for CCS in electric power and industrial applications.*

Deployment of CCS in the *ETP 2012* Scenarios

In the 2DS, a portfolio of technologies is expected to help cut energy-related CO_2 emissions by over 23 $GtCO_2$ per year relative to the *ETP 2012* 4°C Scenario (4DS) in 2050. CCS contributes one-quarter of this total in 2050, and one-fifth of the cumulative emissions reductions between 2015 and 2050 (see Figure 1.10). In the 4DS, the cumulative amount of CO_2 captured between 2015 and 2050 is only 17% of that captured in the 2DS; thus, stringent emissions reduction policies are necessary for the widespread deployment of CCS.

In the 2DS, CCS is deployed in power generation and industrial applications, with a total cumulative mass of 123 $GtCO_2$ captured between 2015 and 2050. The emissions reductions resulting from application of CCS are split about equally between power and industrial applications. The largest deployment of CCS occurs in non-OECD countries, with China capturing just over one-third of the cumulative mass of CO_2 over the 2015-to-2050 time period. In 2020, approximately 260 million tonnes of CO_2 ($MtCO_2$) is captured and stored, about half in OECD countries. After this, deployment is more rapid in the non-OECD world, which captures and stores over 1.60 $GtCO_2$ in 2030, versus 860 $MtCO_2$ in OECD countries. By 2050, non-OECD countries will have captured just over 70% of the cumulative mass of CO_2 (Figure 10.1). This finding reinforces earlier IEA analysis that non-OECD countries will play a critically important role in the deployment of CCS technologies.

Figure 10.1 **Cumulative mass of CO_2 captured globally in the 2DS (left) and the corresponding fraction of CO_2 captured by region (right)**

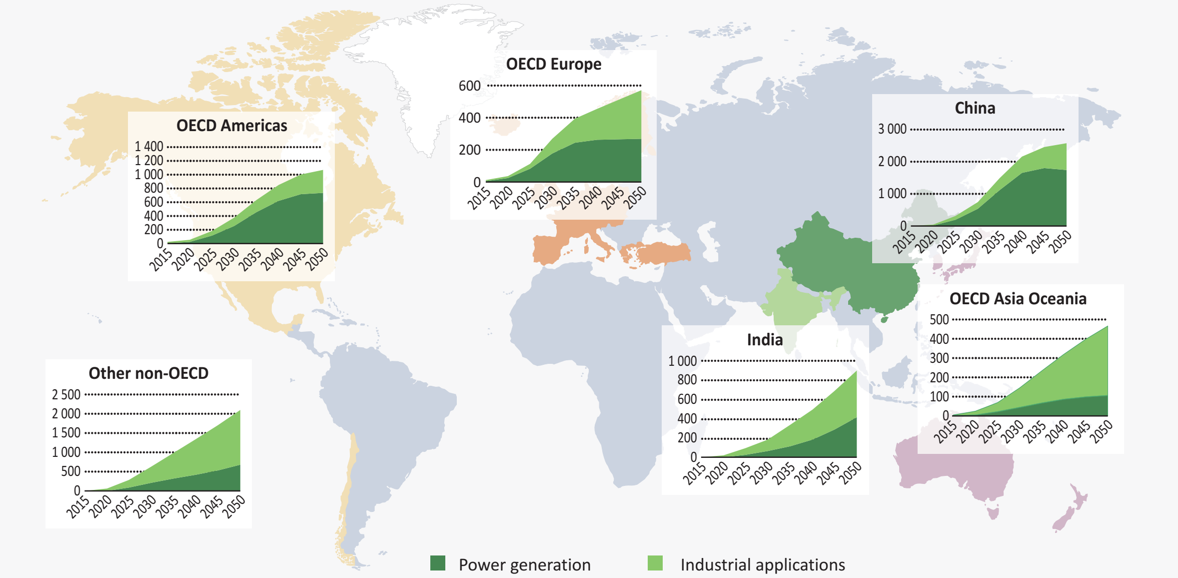


Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *Between 2015 and 2050, almost 123 $GtCO_2$ is captured and stored in the 2DS; in the near term, the largest amount of CO_2 is captured in OECD countries, but by 2050, non-OECD countries will have captured more CO_2 than OECD countries.*

Globally, the growth rate in CCS deployment, measured by the increase in the annual CO_2 capture relative to the installed base, is largest between 2020 and 2025 and moderates considerably post-2030. At the regional level, the peak rates of growth occur in roughly the same period, but the maximum growth rate varies (Figure 10.2). Deployment in the power sector is slightly higher than in industrial applications, with 55% of the total CO_2 captured between 2015 and 2050. However, the fraction of CO_2 captured from the power sector varies significantly by region (Figure 10.2). In OECD Asia and Oceania only 29% of captured CO_2 comes from power; in the OECD Americas and China, this figure is over 70%.

Figure 10.2 Capture rates from power generation and industrial applications of CCS by regions in the 2DS



Key point *The majority of CO_2 is captured from power generation in OECD North America, Europe and China under the 2DS; however, in the OECD Pacific countries, India and other non-OECD countries, CO_2 from industrial applications dominates.*

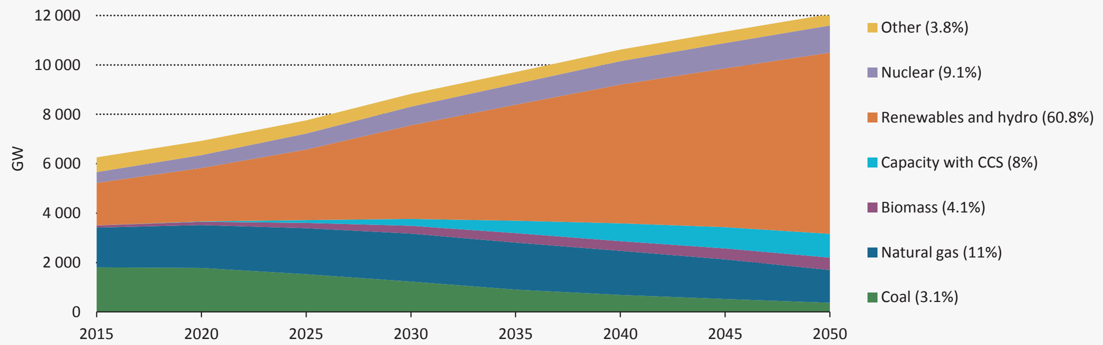
Carbon capture and storage applied to electricity generation

Carbon capture and storage has traditionally been recognised as critically important to decarbonisation of electricity generation in countries that depend heavily on coal as a fuel, such as the United States and China. Indeed, the majority of support for CCS demonstrations has been focused on power applications (GCCSI, 2011). In the 2DS, the majority of CO_2 captured comes from the power applications, but the resulting emissions reductions are about equally split between power and industrial applications.

The capacity of power stations equipped with CCS increases from just under 280 gigawatts (GW) in 2030 to 960 GW in 2050 in the 2DS (Figure 10.3). By 2050, 63% of coal-fired electricity generation (630 GW) is equipped with CCS, 18% of gas (280 GW) and 9% of biomass (50 GW). While CCS is most often associated with coal-fired generation, in 2030 in the 2DS, about one-fifth of all CCS-equipped generation (60 GW) is natural gas-fired. Globally, the annual growth rate of CCS-equipped generating capacity (expressed as a fraction of existing capacity) peaks between 2020 and 2030 and falls rapidly thereafter. Between 2030 and 2050, the growth rate in natural gas-fired electricity generating capacity equipped with CCS is equal to or greater than that for coal-fired generation.

Deployment under the 2DS also relies heavily on non-OECD countries, especially China (Figure 10.4). By 2050, over one-third of all electric power generation capacity equipped with CCS is in China, with the next largest fraction located in OECD North America. Despite the large amount of CCS-equipped electricity generation in China, this only represents about 61% of all coal-fired generation in the country in 2050 under the 2DS. Conversely, in OECD North America, almost all coal-fired and 36% of natural gas-fired generating capacity is equipped with CCS. The amount of biomass-fired electricity generating capacity equipped with CCS grows slowly but consistently between 2020 and 2050; however, the final amount of CCS-equipped biomass-fired generating capacity is relatively small due to the rapid growth in other fuels (Figure 10.3).

Figure 10.3 **Global power generation capacity by fuel type in the 2DS and the corresponding 2050 fraction of total capacity**



Key point *By 2050, 960 GW of electric generation capacity (8% of global capacity) is equipped with CCS in the 2DS.*

Removing CCS from the list of options to reduce emissions in electricity generation increases the required capital investments necessary to meet the same emissions constraint by between 40% and 57% in the electricity sector relative to the incremental capital investment required to reach the 2DS target.[1] Moreover, relative to the 2DS, there is a 5% decrease in coal-fired electricity generation capacity and nearly 30% increases in gas-fired and nuclear capacity globally in 2050 without CCS (Table 11.2). The installed capacity for all types of renewable generation also increases by 13% in 2050 under a "no CCS" scenario.

Capture technology status and outlook in power generation

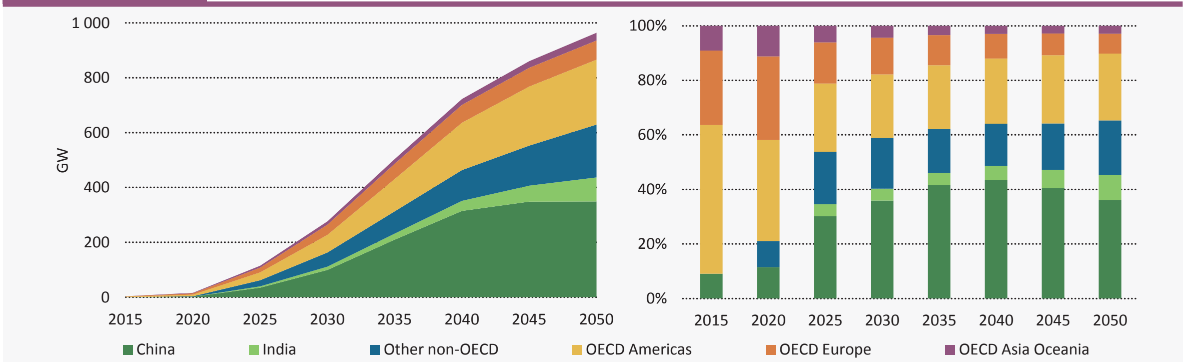
Technologies for CO_2 capture in power generation can be grouped into pre-combustion, post-combustion and oxy-combustion processes (Figure 10.5). Regardless of the capture process used, the objective is the same: to separate CO_2 from the fuel or combustion products while generating electricity. At the present time, no one type of process is clearly superior to another; each has particular characteristics that make it suitable in different cases of power generation fuelled by coal, oil, natural gas and biomass.

In post-combustion capture processes, fossil fuels or biomass are burnt in the traditional way (*i.e.* with air in a boiler or gas turbine), producing flue gas consisting primarily of nitrogen, water and CO_2. Typically the CO_2 concentration in these flue gases ranges from 4% (natural gas-fired turbine) to 15% (pulverised coal boiler). Because most of the flue gas is nitrogen, CO_2 must be separated to make downstream handling cost-effective and use the subsurface storage resource efficiently. While there are numerous possible processes to separate CO_2 from flue gas, such as membranes, cryogenic distillation or adsorption,

1 The 40% difference refers to the additional costs of the 2DS relative to the 6DS, the 57% to the additional costs relative to the 4DS.

the most technologically mature and cost-effective ones are currently based on absorption. In these processes, gaseous CO_2 is absorbed into an aqueous solvent in an absorber vessel, the solvent is circulated into a stripper, and heat is then applied, thus liberating the absorbed CO_2. The released CO_2 is then dehydrated and compressed to pressures sufficient for transport (*i.e.* usually greater than 8 megapascals [MPa] or 80 bar).

Figure 10.4 **Electric power generation capacity equipped with CO_2 capture (left) and the corresponding fraction of capacity by region (right)**



Key point *In the near term, most power generation equipped with CCS will be built in OECD countries; by 2050, the majority is located in non-OECD countries.*

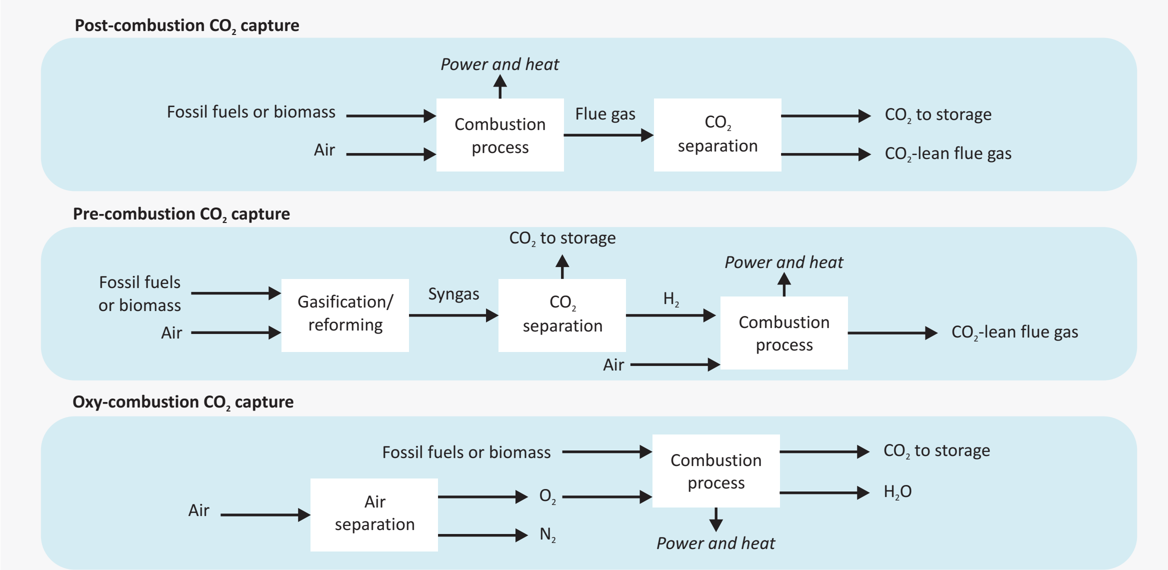
Pre-combustion capture processes are similar to post-combustion capture processes, insofar as the CO_2 is removed from a gas stream using an absorption process. In pre-combustion capture, however, the CO_2 is contained in a high-pressure fuel gas (syngas), typically produced through gasification of coal or other fossil fuel or biomass. The syngas consists primarily of hydrogen, carbon monoxide, nitrogen (the amount of which depends on the gasification or reforming technology), and water. The syngas is then modified in a shift process, producing hydrogen and CO_2, after which the CO_2 can be removed using commercially available solvent processes. After removal of CO_2, the fuel gas is burnt in a combined cycle gas turbine, modified for the hydrogen-rich fuel, to produce electricity. As in post-combustion capture, the captured CO_2 is dehydrated and compressed for transport to a storage site.

In oxy-combustion processes, the fuel is burnt in oxygen rather than traditional air. The resulting flue gas is primarily CO_2 and water. Some of the flue gas is recycled in the combustion process to maintain similar combustion temperatures as in a conventional (air-fired) power plant, and the remainder is dehydrated and compressed for transport and eventual storage. Very large volumes of oxygen are needed for combustion in this process, which requires a large, costly air separation unit.

All three capture processes require significant amounts of energy to separate CO_2 from the flue gas, fuel or oxygen from air. For example, capturing 90% of CO_2 from flue gas in a post-combustion capture process on a coal-fired power plant using existing capture processes requires the energy equivalent of approximately 20% of plant output. However, current capture processes are highly inefficient. The theoretical minimum work to capture CO_2 from this type of power plant is around 4% of the net electrical power output of a typical plant, or approximately 160 megajoules per tonne (MJ/t) of CO_2 (McGlashan and Marquis, 2007; Bhown and Freeman, 2011). This indicates that there is strong potential for technological innovation to reduce the efficiency penalty associated with CO_2 capture.

The energy penalty resulting from relatively inefficient separation means that to produce the same amount of electrical energy from a power plant with CO_2 capture, the amount of fuel, other resources and, to some extent, water consumed by the power plant must be increased. For a typical coal-fired plant with post-combustion capture, the increase in consumption of resources is around 30%; for an integrated gasification combined-cycle (IGCC) plant with pre-combustion capture, the increase is 25%; and for a natural gas combined-cycle (NGCC) plant with post-combustion capture, the increase is around 17% (IEA, 2011b).

Figure 10.5 The three principal CO_2 capture routes in electric power generation



Key point *Multiple routes exist to capture CO_2 from combustion of fossil fuels and biomass.*

The energy penalty can be reduced, not only by increasing the efficiency of CO_2 separation, but also by increasing the performance of the underlying power generation technologies, integrating capture systems with power generation more efficiently, and – for oxy-combustion and pre-combustion capture – increasing the efficiency of air separation. In addition, the impact on water resources can be reduced by adoption of different approaches, such as dry cooling (Zhai and Rubin, 2010). In some regions, water availability may limit growth in thermoelectric power generation, including that equipped with CCS.

The net impact of the addition of capture equipment, an increase – relative to a plant without capture – in power plant capacity to account for the energy penalty, the additional fuel consumption, and use of other resources is a rise in the levelised cost of electricity (LCOE). The increase in LCOE ranges from 33% for NGCC with post-combustion capture to 64% for pulverised coal (PC) plants with post-combustion or oxy-combustion plants (Table 10.2). Nonetheless, under the 2DS, the most relevant comparison is not the cost of conventional technologies without CCS, but the cost of alternative low-carbon generation options, such as nuclear, large-scale hydroelectricity, wind and concentrating solar power, with energy storage. The LCOE of fossil fuels with CO_2 capture (including estimated transport and storage costs) is reckoned to be competitive with these other options (see Figure 11.10).

The LCOE from plants equipped with CO_2 can be decreased by reducing the energy penalty, the overall capital cost of the plant and contingency costs associated with the plant – the latter typically are higher for new technologies. As with many other technologies, learning effects tend to decrease these costs as capacity increases (McDonald and Schrattenholzer, 2001). Analysis of the learning rates for analogues to the components in a coal-fired power plant with CO_2 capture suggests that costs will decrease between 3% and 5% with each doubling of installed capacity (Rubin *et al*., 2007). In the 2DS, reductions in the investment cost for coal-fired power plants with CCS begin once a capacity threshold is crossed and are consistent with these rates.

Table 10.2 The average cost and performance impact of adding CO_2 capture in OECD countries

	Coal			Natural gas
Capture route	Post-combustion	Pre-combustion	Oxy-combustion	Post-combustion
Reference plant without capture	PC	IGCC (PC)	PC	NGCC
Net efficiency with capture (LHV, %)	30.9	33.1	31.9	48.4
Net efficiency penalty (LHV, percentage points)	10.5	7.5	9.6	8.3
Relative net efficiency penalty	**25%**	**20%**	**23%**	**15%**
Overnight cost with capture (USD/kW)	3 808	3 714	3 959	1 715
Overnight cost increase (USD/kW)	1 647	1 128 (0)	1 696	754
Relative overnight cost increase	**75%**	**44% (0%)**	**74%**	**82%**
LCOE with capture (USD/MWh)	107	104	102	102
LCOE increase (USD/MWh)	41	29 (0)	40	25
Relative LCOE increase	**63%**	**39% (0%)**	**64%**	**33%**
Cost of CO_2 avoided (USD/tCO_2)	**58**	**43 (55)**	**52**	**80**

Notes: Average figures for OECD countries do not include cost of CO_2 transportation and storage.
PC = pulverised coal; LHV = low heating value; kW = kilowatt; MWh = megawatt hour.
The accuracy of capital cost estimates from feasibility studies is on average ± 30%; hence, for coal the variation in average overnight costs, LCOE and cost of CO_2 avoided between capture routes is within the uncertainty of the study.
Underlying oxy-combustion data include some cases with CO_2 purities < 97%. Overnight costs include owners', engineering procurement construction (EPC) and contingency costs, but not interest during construction (IDC).
A 15% contingency based on EPC cost is added for unforeseen technical or regulatory difficulties for CCS cases, compared with a 5% contingency applied for non-CCS cases. IDC is included in LCOE calculations.
Source: IEA, 2011b. Based on IEA analysis of conceptual design studies; not directly applicable to real investment cases.

Key point *Applying CCS to a power plant is expected to increase the LCOE by between one-third and two-thirds depending on the type of plant; however, the LCOE and cost of CO_2 avoided is competitive with alternative low-carbon electricity generation options.*

In addition to improvements in current technologies, innovative technologies are on the horizon that may allow more efficient separation of hydrogen, CO_2, or oxygen and process intensification (*i.e.* integration of multiple processes in smaller equipment) for capture from traditional power generation cycles. Alternatives to traditional power generation cycles that result in production of relatively high-concentrated CO_2 streams also exist. Examples of innovative and alternative technologies follow:

- New solvents, such as advanced amines and ammonia, and associated processes are under development for post-combustion capture and are expected to decrease the energy penalty of capture (Rubin *et al*., 2010).

- Membrane-based separation systems are under development that may allow the production of hydrogen and the separation of hydrogen from CO_2 to occur in a single process step, decreasing the energy penalty for pre-combustion capture (Rubin *et al.*, 2010; Scholes *et al.*, 2010).

- Integrated gasification fuel cell-based processes show promise as fuel and oxidant (air) are naturally separated in fuel cells, reducing or eliminating the need for CO_2 capture, and operate at high temperatures allowing usable heat to be recovered through traditional steam cycles (NETL, 2009; Li *et al.*, 2010).

Power system impacts of carbon capture and storage

IEA scenarios suggest that CCS should contribute quantities of CO_2 emissions reductions similar to renewable energy over the coming decades. Given the expected large share of variable renewables in power generation, the flexibility offered by dispatchable low-carbon generation options – fossil fuels with CCS is one example – and energy storage is commanding more attention. In addition to posing a technological challenge, rapidly increasing renewable penetration can also raise economic issues, as fossil fuel-based plants with CCS initially designed for base-load operation may operate fewer full-load hours.

Flexibility in power generation with CCS can be achieved by part-load operation of CO_2 capture and compression systems. Temporary bypassing and halting of the CO_2 capture unit offers extra power output, in the order of 25%, within very short response times. Similar effects can be achieved by shifting energy-intensive process steps to temporary storage of required process fluids, such as CO_2-rich solvents or oxygen, leading to a significant increase in power output.

The greatest flexibility, on both shorter and longer time scales, however, can be achieved by fully decoupling the CCS and power generation process. In this case, CO_2 is permanently captured and stored during hydrogen generation from coal or natural gas. The hydrogen is either used directly, for power generation, or stored in underground caverns – an already-proven option with large potential, given the high energy density of compressed hydrogen. While the capture process is not exposed to intermittent operation, the stored hydrogen is available for flexible power generation in gas turbines, gas engines or fuel cells. The plant also has the ability to switch to co-production of chemical by-products when its electricity is not required by the grid (Davison, 2011).

Potential for retrofitting existing power plants with carbon capture and storage

With more than 1 600 GW of installed generation capacity in 2010, global coal power-plant installations account for almost 9 Gt of CO_2 emissions each year. This represents roughly one-fourth of total anthropogenic global CO_2 emissions. Despite climate change concerns, power generation from coal is expanding faster than ever: capacity additions reached record growth of more than 350 GW over the last five years. Under the 4DS, an additional 430 GW is added through 2035. The cumulative emissions potential from infrastructure already in place and under construction will amount to more than 590 Gt until 2035. This represents 80% of all allowed emissions from energy until 2035, if the world is to reach a 2DS trajectory (IEA, 2011a). Without immediate and future action, this development represents a significant threat to the global climate.

To avoid retiring existing, but not fully depreciated, power plants early, while staying within a 2DS carbon trajectory, they can be retrofitted with CCS. In some circumstances, retrofitting plants is a lower-cost option to reduce CO_2 emissions than replacing the plant with an alternative form of low-carbon electricity generation.

Retrofitting CCS to existing plants is a complex process, encompassing many site-specific aspects, and largely depends on market- and technology-specific operational conditions. Carbon abatement policies will play a key role in determining the economic attractiveness and feasibility of retrofitting CCS in comparison with other technologies. More attention is currently placed on analysing the technical conditions to retrofit existing plants. A combination of factors, such as plant size, efficiency and age, will determine the technical attractiveness, along with general availability of space for capture and compression at plant sites and access to transport and storage (IEAGHG, 2011; NETL, 2011; MITei, 2009).

In the most general terms, larger, more efficient plants (and hence, younger) are suitable for retrofit. Currently, some 470 GW of coal-fired power stations are larger than 300 MW and younger than 10 years. This represents 29% of the total installed coal-fired power station fleet in the world. Of course, not all these plants are suitable for economic retrofitting, due to land use constraints, plant layout, geographical location, and lack of access to transport and storage.

Using these high-level proxies, it is possible to assess which countries, of the ten largest emitters of CO_2 from coal-fired power generation, have the most retrofit potential after 2020. Coal-fired power plants in China, Japan and Korea are young compared with the rest of the world, and many of these units have large capacities and modern steam parameters. For example, 390 GW, or 83% of large plants (*i.e.* greater than 300 MW), that are less than a decade old are located in China. Chinese power plants are, overall, the most modern worldwide: 58% of Chinese units are younger than 10 years and larger than 300 MW. With significant capacity additions expected in the coming years, total capacity in China is likely to exceed 1 100 GW by 2035 under the 4DS. Managing CO_2 emissions from its coal-fired plants will be of utmost importance for meeting sustainable climate targets. Therefore, maximising the potential to retrofit Chinese power plants is crucial.

Under the 4DS, India doubles its coal-fired power capacity by 2035, which makes it the second-largest producer of coal power worldwide. In comparison, coal-fired power stations in the United States, Russia and Poland are older and smaller. They present challenges to retrofitting with CCS, high investment notwithstanding, unless it is combined with general plant upgrades and lifespan extensions.

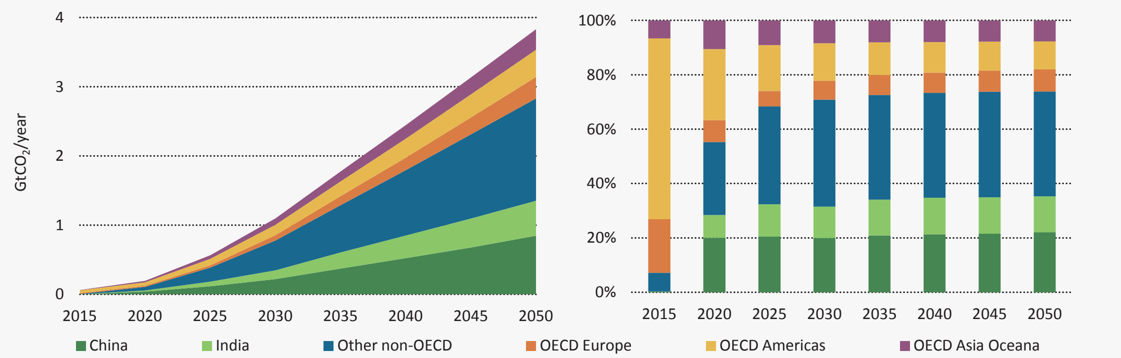
Given the magnitude of expected global coal-fired power capacity, it is critical that construction of new installations allows economical retrofit at a later stage. This helps avoid locking in older technologies that will emit unsustainable amounts of CO_2 over the long operating lifespan of coal power plants. With new power investment projects, industries should therefore consider potential technical options for retrofitting, consider including the necessary space for capture equipment at the plant site, and investigate potential transport and storage options (IEAGHG, 2007). Governments and industry in the relevant countries should analyse the potential of CCS retrofitting, investigate and enact frameworks to ensure that retrofitting is possible when necessary drivers are in place, and also engage in dialogue on how to best encourage retrofitting in the future.

Carbon capture and storage in industrial applications

Carbon capture and storage can be applied to many different industrial processes (Table 10.1), such as iron and steel production, cement kilns, biofuel production, gas processing and refining. Today, the only operating CCS projects capture CO_2 from industrial sources, namely gas processing and production of synthetic natural gas and fertiliser. In the 2DS, industrial applications of CCS are equally as important as application of CCS to power generation at the global level. However, in some regions, such as the OECD Pacific, and in some non-OECD countries (*e.g.* India), industrial applications of CCS are far more important than applications in power generation (Figure 10.2).

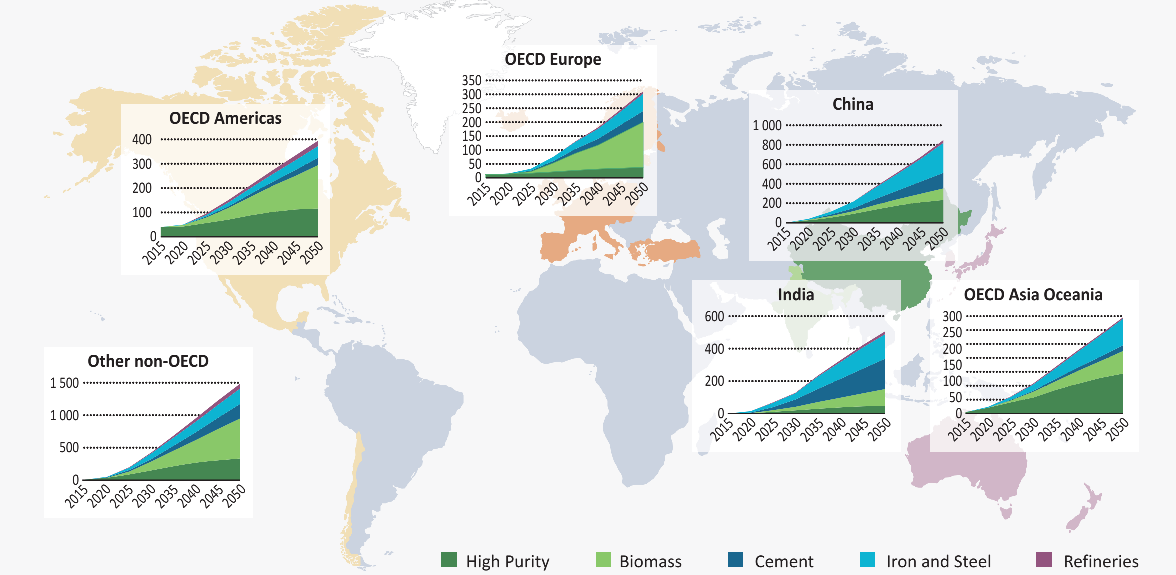
In 2030, 1.10 $GtCO_2$ per year are captured from industrial facilities in the 2DS; this sum increases to 3.83 $GtCO_2$ per year in 2050 (Figure 10.6). By as early as 2020 in the 2DS, the majority of these projects are located in non-OECD countries, primarily China and India. As a result, non-OECD countries account for 72% of the cumulative amount of CO_2 captured from industrial applications of CCS between 2015 and 2050 in the 2DS – China alone accounts for 21% of the global total.

Figure 10.6 Annual capture rate from industrial applications of CCS (left) and the corresponding fraction of CO_2 captured annually by region (right)



Key point *By 2050, 3.8 $GtCO_2$ per year are captured from industrial applications, the majority in China, India and other non-OECD countries.*

Figure 10.7 Capture rates by region modelled for different industrial applications



This document and any map included herein are 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.

Note: Capture rate in $MtCO_2$/year.

Key point *The predominant industrial application of CCS will vary by region and over time.*

Of the cumulative mass of CO_2 captured from industrial applications between 2015 and 2050, 30% comes from application of CCS to industrial processes that produce high-purity CO_2, such as gas processing and fertiliser manufacture. While capture from high-purity sources of CO_2 initially predominates in such regions as OECD North America and Europe, capture from other, higher-cost sources of CO_2 becomes more widely practiced globally post-2025 in all regions. Capture from biomass conversion (*e.g.* biomass to hydrogen, synthetic natural gas and liquid fuels) also grows rapidly, contributing 29% of CO_2 captured from industrial applications – or 13% of all CO_2 captured – between 2015 and 2050 (Box 10.1).

Capture technology status and outlook in industrial applications

Suitability of CCS in industrial applications depends on the costs and readiness of capture technologies. Several industrial processes produce highly concentrated CO_2 vent streams as a natural result of the process (*e.g.* gas processing, ammonia and ethanol production). Capture from these "high-purity" sources is straightforward, but the CO_2 does require additional purification or dehydration before compression, transport and storage. These processes offer early opportunities to demonstrate CCS, if business models, transport and storage infrastructure, and regulatory frameworks align. Three of the four operating large-scale CCS projects, as of 2012, capture CO_2 from gas processing; the remaining project captures CO_2 by converting coal to synthetic natural gas and other products (*e.g.* fertilisers).

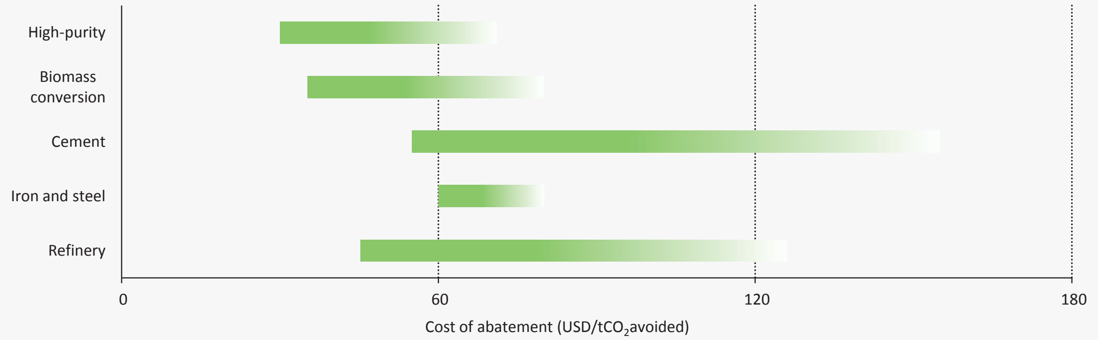
Other industrial applications of CCS – for example, blast furnaces and cement kilns – require additional CO_2 separation technologies to concentrate dilute streams of CO_2 for transportation and storage. In the case of cement kilns, this capture step requires far-reaching process modifications. By and large, the same CO_2 separation technologies applied in power generation work for industrial sources, including chemical or physical absorption, adsorption, cryogenic distillation, and membrane separation. Processes can be modified to capture CO_2 in three general ways:

- for processes producing dilute streams of CO_2, separation can be applied using processes similar to those employed in post-combustion capture;
- for processes where combustion in oxygen can be substituted for combustion in air (*e.g.* utility boilers), oxy-combustion capture can be used;
- for processes where CO_2 can be removed from a fuel or feedstock, pre-combustion capture fits.

For most industrial processes that produce dilute streams of CO_2, capture technologies are already available, but are only at demonstration or earlier stages (Table 10.1). However, given similarities between CO_2 separation processes in power and industry, learning and innovations from capture in one sector could spill over into the other. In addition, this ongoing learning with new industrial technologies may offer more efficient and less costly capture of CO_2. In iron and steel, for example, processes at pilot and demonstration scales may offer less expensive options for capture than top-gas recycling blast furnaces (Carpenter, 2012).

Given the broad range of industrial processes suitable for CO_2 capture and the often unique nature of industrial facilities, there is much more variation in cost estimates for CCS in industry. According to current estimates, the costs of abatement in various industrial applications range from USD 30/t to above USD 150/t (Figure 10.8).

Figure 10.8 **Typical ranges of costs of emissions reductions from industrial applications of CCS**



Notes: The range of costs shown here reflect the regional average cost of applying CCS in each sector, and, therefore, the overall cost of abatement in a sector will be affected by the assumed level of CCS uptake in each sector (IEA, 2009 and IEA and UNIDO, 2011). These costs include the cost of capture, transport, and storage, but do not assume that storage generates revenues – *i.e.* CO_2 storage through enhanced oil recovery (EOR) is not considered as a storage option.

Key point *A wide range of abatement costs through CCS exists in industrial applications.*

Box 10.1 **Combining CCS with biomass energy sources**

Bio-energy with carbon capture and storage (BECCS) is an emissions reduction technology offering permanent net removal of CO_2 from the atmosphere. This has been termed “negative carbon emissions”; it offers a significant advantage over other mitigation alternatives that do not actually decrease the amount of CO_2 in the atmosphere, only emissions going into the atmosphere. BECCS works by using biomass that has removed atmospheric carbon while it was growing, and then storing the CO_2 emissions resulting from combustion permanently underground. While BECCS has significant potential, it is important to ensure that the used biomass is sustainable, as this will significantly impact the level of emissions reductions that can be achieved and, hence, define “how negative” the resulting emissions can be (IEAGHG, 2011a).

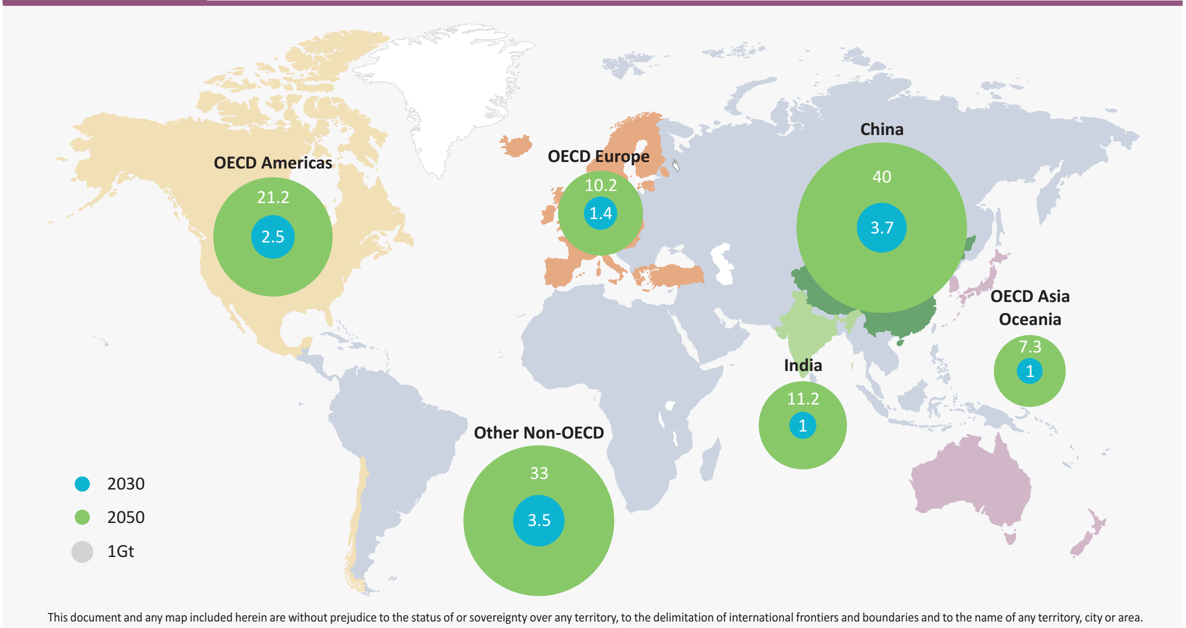
BECCS can be applied to a wide range of biomass conversion processes and may also be attractive from a relative cost perspective. Applications range from capturing CO_2 from biomass co-firing and biomass -fired power plants to biofuel production processes. To date, however, BECCS has not been fully recognised or realised. Incentive policies to support it need to be based on an assessment of the net impact on emissions that the technology can achieve. In reviewing how negative emissions are dealt with under international greenhouse gas (GHG) accounting frameworks, an IEA working paper (IEA, 2011c) finds that, while current frameworks provide limited guidance, proposed and revised guidelines under the United Nations Framework Convention for Climate Control (UNFCCC) can offer an environmentally sound reporting framework for BECCS. As they currently stand, however, the new UNFCCC guidelines do not tackle a critical issue that has implications for all biomass energy systems, namely the overall carbon footprint of biomass production and use. The IEA (2011c) recommends that, to the best extent possible, all carbon impacts of BECCS be fully reflected in carbon reporting and accounting systems under the UNFCCC and Kyoto Protocol. A solid understanding of the life-cycle emissions savings that BECCS could achieve may be a crucial pre-condition for well-calibrated BECCS support.

At the point of fuel transformation, both fossil fuels and biomass normally release GHG. Although it may use different technologies, capture equipment fulfils the same function for each fuel: preventing emissions from reaching the atmosphere. This could be reflected in one set of incentives for capture and storage technology – independent of the fuel on which the equipment ultimately operates – and an additional set of incentives specific to BECCS, to reflect the negative life-cycle emissions that BECCS can achieve.

Transport and storage of CO_2

While capture of CO_2 is the most costly component of the CCS chain – contributing 80% or more of the current cost of avoidance in power generation – transportation of CO_2 to a storage site with sufficient capacity to hold desired volumes of injected CO_2 at acceptable injection rates safely over time is a necessity. Under the 2DS, between 2015 and 2030, 13 $GtCO_2$ are captured and stored globally; through 2050, this total grows to 123 $GtCO_2$ (Figure 10.9). The total global storage rate is 2.41 $GtCO_2$ per year in 2030, growing to 7.83 $GtCO_2$ per year in 2050.

Figure 10.9 **The cumulative amount of CO_2 captured from 2015 to 2030 and to 2050 by region in the 2DS**



Note: Mass stored in Gt CO_2

Key point *Between 2015 and 2050, 123 $GtCO_2$ are captured globally under the 2DS and will need to be transported to suitable sites and stored.*

From a technical standpoint, transport of CO_2 is perhaps the most straightforward and well-known step in the CCS chain. At commercial scale, the amount of CO_2 likely to be captured from industrial facilities or power plants is on the order of hundreds of thousands to millions of tonnes of CO_2 per year. For example, a 500 MW supercritical pulverised coal power plant with CCS would likely capture 3 to 4 $MtCO_2$ per year. For these amounts of CO_2, the only practical and cost-effective transport options are ships (including barges) and pipelines (Skovholt, 1993; Svensson *et al.*, 2004).

Globally, there is considerable experience in transporting CO_2 and similar fluids via pipeline. In 2010, over 60 $MtCO_2$/year were shipped through a 6 600-kilometre (km) pipeline network in the United States, the majority of which was used for enhanced oil recovery. Historically, the frequency of incidents associated with these pipelines is comparable to transportation of other fluids – for example, natural gas – although further research is needed to assess the risk of onshore pipelines in densely populated areas (Gale and Davidson, 2004; Koornneef *et al.*, 2009). There is also limited experience with transport of CO_2 using offshore pipelines in the Snøhvit project in Norway. Further areas of technical research include, for example, the impact on transport systems of long-term exposure to co-contaminants and impurities. Regardless of technical experience, however, countries need appropriate regulations to ensure that pipelines can be appropriately sited, operated in a safe manner and, should the need arise, accessed by third parties wishing to transport CO_2.

The cost of pipeline transport varies with the capacity of the pipeline (*e.g.* tonnes of CO_2 transported per year), the length of the pipeline, the terrain through which the pipeline crosses and, for onshore cases, land use along the route. In general, the cost of transport decreases sharply as capacity grows and increases linearly with distance. Relative to capture, the cost of transport of CO_2 by pipeline is low, typically on the order of dollars per tonne for onshore pipelines that move millions of tonnes per year over hundreds of kilometres (Doctor *et al.*, 2005; McCollum and Ogden, 2006; McCoy and Rubin, 2008). For example, a recent study estimated the cost to be around USD 2/t to transport 10 $MtCO_2$ per year over 250 kilometres (onshore) in the United States and that costs could be lower for integrated, high-capacity pipeline networks (Chandel, Pratson and Williams, 2010). Offshore pipeline costs for CO_2 transport are higher, but the most cost-effective transport option depends on the specifics of the situation (Doctor *et al.*, 2005; ZEP, 2011).

Experience in transporting large volumes of CO_2 by ship exists, but is limited thus far. Most experience comes from transporting CO_2 in small ships or barges. Several studies have examined the design of ship transport systems and estimated their cost (Doctor *et al.*, 2005; Aspelund, Mølnvik and De Koeijer, 2006; Decarre *et al.*, 2010; Chyioda, 2011). Ship transport of CO_2 is similar in many respects to transport of liquefied petroleum gas (LPG); however, unlike LPG, liquefied CO_2 must be transported under pressure in addition to being refrigerated. Thus, a ship transportation system requires CO_2 liquefaction, temporary storage and loading facilities at the port; specifically designed ships; and unloading and (possibly) temporary storage facilities at the geologic storage site. The most recent studies of transporting CO_2 by ship from port locations to offshore platforms in the North Sea for storage have estimated the cost to be USD 20/t to USD 30/t of CO_2 transported, depending on the capacity of the system and transport distances (Aspelund, Mølnvik and De Koeijer, 2006).

It is difficult to make general statements about the cost, performance and, to some extent, risk associated with geologic storage, due to geologic variability and site-specific characteristics. However, the fundamental physical processes and engineering aspects of geologic storage are well understood, based on decades of laboratory research and modelling; operation of analogous processes (*e.g.* acid gas injection, natural gas storage, enhanced oil recovery); studies of natural CO_2 accumulations; pilot and demonstration projects; and currently operating large-scale storage projects.[2] Further research and experience is nonetheless needed, since the volume of fluid injection associated with CCS

2 Numerous comprehensive studies of analogues have been made: for example, see Benson *et al.* (2002; 2005) and Bachu (2008).

is, in general, larger and new demands are being made on existing technologies to predict and monitor the behaviour of CO_2 in the subsurface.

A suitable geologic formation for CO_2 storage must have sufficient capacity and injectivity to allow the desired quantity of CO_2 to be injected at acceptable rates through a reasonable number of wells, and it must be able to prevent this CO_2 (and any brine originally present in the formation) from reaching the atmosphere, sources of potable groundwater and other sensitive regions in the subsurface (Bachu, 2008). Geologic formations that possess these characteristics are saline aquifers, oil and gas reservoirs, and to a lesser extent, coal seams.

There have been many efforts at global, basin, regional and national scales to characterise the amount of CO_2 that can be stored. Most of these efforts have focused on estimating the mass of CO_2 that can be stored in the pore space, given various high-level technical cut-offs, leading to the estimation of a theoretical or technically accessible storage resource (Bachu *et al.,* 2007; Bradshaw *et al.,* 2007; IEAGHG, 2011). For example, the US Department of Energy's National Energy Technology Laboratory has estimated that the US onshore, technically accessible storage resource is between 1 420 $GtCO_2$ and 15 000 $GtCO_2$ (NETL, 2010; Goodman *et al.,* 2011). The Norwegian Petroleum Directorate estimates storage capacity of 72 $GtCO_2$ in the Norwegian sector of the North Sea. In addition to these, other recent studies have been completed for Japan (Ogawa *et al.,* 2011), South Africa (Council for Geoscience, 2010), Europe (Vangkilde-Pedersen *et al.,* 2009) and Australia (Carbon Storage Taskforce, 2009).

The results of storage assessments, while inconsistent in some cases, nonetheless suggest that the available global pore space resource is more than sufficient to store the 123 $GtCO_2$ captured in the 2DS.[3] Better understanding is needed of how this storage resource is distributed globally and how much can be converted to capacity – analogous to the difference between hydrocarbon reserves and resources (Friedmann *et al.*, 2006). However, this also requires better knowledge of the distribution of storage costs and economic cut-offs for storage.

Among areas where geology is suitable for CO_2 storage, the cost of storage is highly variable. Early estimates of storage cost tended to rely on relatively simple correlations to estimate the performance and cost of storage – although the representative costs in these studies are well within the range of cost estimates today. More complex models have shown that the cost of storage could vary significantly depending on numerous geological factors, such as the distribution of permeability, porosity and connected reservoir volume.[4]

Recent estimates of the onshore cost of storage in saline aquifers in the United States range from less than USD 1/t of CO_2 stored to just over USD 20/t of CO_2 stored (Eccles *et al.*, 2009); however, these costs do not include monitoring, measurement and verification (Benson, 2006); the expected cost of long-term liability; the cost of exploration for the sites; and US-specific costs associated with acquiring the necessary property rights to store CO_2. European estimates for the costs of onshore storage in saline aquifers (including costs of monitoring, measurement and verification, or MMV) range from USD 1.3/t to USD 16/t of CO_2;[5] offshore, these costs are almost twice as high (ZEP, 2011).

The cost of storage through CO_2-enhanced oil recovery is more complex because, in addition to geological factors, it depends on oil price. Furthermore, while the economics of

3 Other studies have estimated that the global pore space resource is sufficient for CCS to play a significant role in reducing emissions over the next century (Dooley, 2011; Szulczewski *et al.*, 2012).

4 Examples of studies that use more complex models that incorporate site-specific data include those by McCoy and Rubin (2009) and Heath *et al.* (2012).

5 Initial study quotes costs in EUR. Converted into USD using average 2010 exchange rate.

CO_2-EOR are generally attractive, there are a host of factors that make development of CO_2-EOR projects for storage outside established areas more difficult than the economics otherwise imply (Box 10.2).

Finally, the geologic and economic suitability of a formation for CO_2 storage is only one precondition for investment in CCS projects. Other equally important issues are the proximity of the given sites to sources of CO_2, and the economics of building and operating the linking transport infrastructure.[6]

Box 10.2 **Carbon dioxide storage and enhanced oil recovery**

Injection of CO_2 to improve recovery of oil has been practiced commercially since the early 1970s in the United States. In 2010, there were nearly 140 projects under development or in operation globally. The majority of the projects operate in the United States, where they produce nearly 280 000 barrels of oil per day (Moritis, 2010). However, most of these projects use CO_2 from natural geologic accumulations, and those using anthropogenic CO_2 do not monitor, measure or verify sufficiently to qualify as CCS. The notable exception is the Weyburn CO_2-EOR project in Canada, which stores around 2 $MtCO_2$ per year generated by a coal gasification project in the United States. In many regions, including the United States, there appears to be considerable potential to increase oil production and the amount of CO_2 stored via CO_2-EOR (*e.g.* see NETL, 2011).

Historically, CO_2 is the largest expense associated with EOR projects, so most projects in operation today are designed to minimise the amount of CO_2 used to recover a barrel of oil and, hence, the amount stored. While it is clear that CO_2 storage projects can afford to purchase anthropogenic CO_2, particularly high-purity sources (IEA and UNIDO, 2011), there are numerous issues surrounding storage in CO_2-EOR projects – particularly outside the United States (Dooley, Dahowski and Davidson, 2010; MITei, 2010). For example, as noted above, conventional CO_2-EOR projects do not undertake MMV activities sufficient to assess whether storage is likely to be permanent; they also do not select and operate sites with the intent of permanent CO_2 storage. Furthermore, conventional CO_2-EOR projects generate net emissions of CO_2 when combustion of fossil fuel products is included (Jaramillo, Griffin and McCoy, 2009), so, relative to storage in saline aquifers, they deliver a lesser emissions reduction benefit.

Climate and energy policies may be able to mitigate these issues; however, today, the extent to which CO_2-EOR can usefully contribute to emissions reduction goals is unclear. While many uncertainties exist, CO_2-EOR can nevertheless offer a route to partly offsetting the costs of demonstrating CO_2 capture, drive development of CO_2 transportation infrastructure, and present opportunities for learning about certain aspects of CO_2 storage in some regions. The IEA is currently analysing these issues.

Recommended actions for the near term

To deploy CCS on the scale and timeline outlined in the 2DS, policy makers will need to take immediate actions to enable and, further, to actively encourage private investment in CCS.

Governments that have not yet done so must assess the role of CCS in their energy future, explicitly recognise the role that CCS is to play and send clear, consistent policy signals. Without an understanding of the role CCS could play in their energy futures, countries (or other jurisdictions) cannot develop clear policies to enable and encourage deployment of CCS technology. The principal benefit of CCS is emissions reductions and, thus, CCS

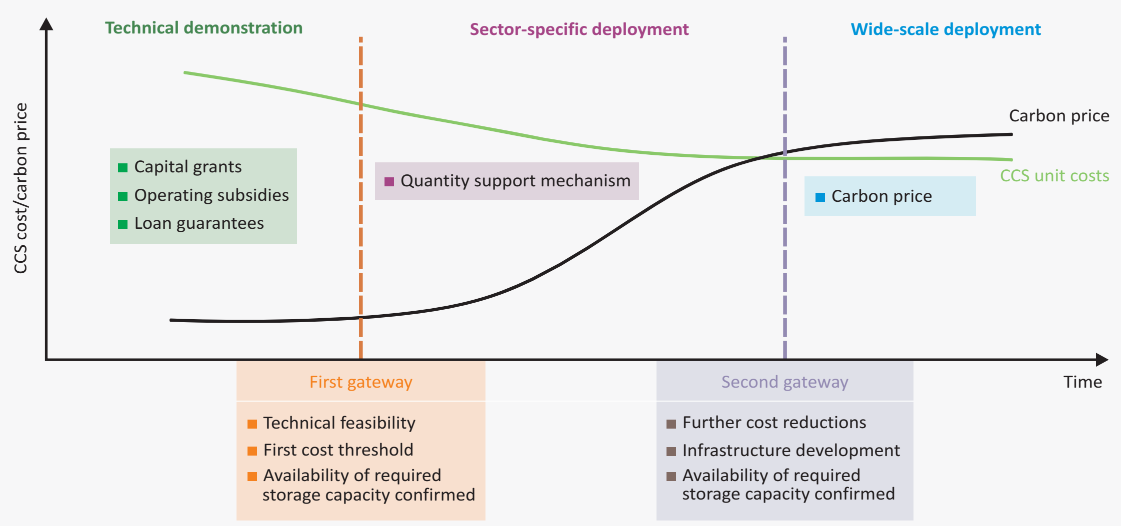
6 For example, Gresham *et al.* (2010) present an example from the US showing that the combined cost of transport and storage may be less when CO_2 is transported over long distances and stored in more favourable formations, rather than using nearby, less suitable formations.

deployment policies must be supported by strong and credible long-term commitments to reducing emissions from power generation and industry. In the absence of such clear policy signals, private entities will not invest in CCS technology.

While most of the technologies to separate, capture, transport and store CO_2 are well-known and have been practised for decades, experience in their integration into large-scale installations covering the whole chain is limited (Table 10.1). The limited experience with CCS comes from industrial applications, but in 2012, no large-scale (*i.e.*, hundreds of MW and up) power plants installed with CCS yet exist. It is, therefore, critically important that governments and industry redouble their efforts in commercial-scale demonstration, in various locations and technical configurations. This must include commercial-scale storage projects that demonstrate safe and effective CO_2 storage and mechanisms to encourage knowledge exchange between projects to maximise learning between storage projects.

CCS deployment requires strong policy action – it is not something that markets will currently deliver. Governments must enact incentive policies that support not only first-mover demonstration projects, but also wider deployment. An optimum portfolio of incentive policies will evolve as the technology transitions from being relatively untested at a large scale to being well-established (Figure 10.10). Policies range from technology-specific support, which explicitly targets technology learning, to technology-neutral mechanisms, such as CO_2 pricing, which allow deployment of CCS when it is most cost-effective among other abatement options (IEA, 2012).

Figure 10.10 **Incentive mechanisms for CCS must be tailored to the stage of technology development**



Source: IEA, 2012.

Key point *The most appropriate policy mechanisms to incentivise CCS deployment will change with time.*

In jurisdictions that plan to undertake CCS, governments must ensure that legal and regulatory frameworks, or a lack thereof, do not unnecessarily impede demonstration and deployment of CCS. Appropriate regulatory frameworks are critical to ensure effective and safe storage of CO_2 underground. In 2009, the IEA recommended that OECD countries develop frameworks for CCS demonstration by 2011, early-mover non-OECD countries by 2013, and other non-OECD countries with CCS potential by 2015 (IEA, 2009). Jurisdictions in the European Union, the United States, Canada and Australia have established legal and regulatory frameworks for CCS over the past few years (IEA, 2011d). While developing a legal and regulatory framework for a novel technology is a daunting challenge, a regulatory framework for CCS can be developed in phases, where regulations are tailored to the stage of technology deployment, as has been done in some jurisdictions. Regardless of the approach, development must begin as soon as possible to ensure that lack of appropriate regulation does not slow deployment (IEA, 2010).

Over 13 Gt of CO_2 storage capacity is required by 2030 in the 2DS, and 123 Gt by 2050. While some countries and regions have undertaken high-level assessments of their storage resources, and the estimated storage resources are more than sufficient to meet these targets, the geographic distribution of usable CO_2 storage capacity (*i.e.* storage resources that can be developed at a certain price) in many parts of the world is unknown. Also, the technical potential for CO_2 storage (at country and, to an extent, basin scales) has not been linked to cost to form a coherent picture of usable capacity. Thus, governments must enhance their efforts to develop clear and accurate information about the geographic distribution of storage capacity and associated costs. As part of this process, governments should consider the impacts of competing uses of subsurface resources (*e.g.* development of shale gas).

Governments and industry should assess the future need for transport and storage infrastructure and, where appropriate, plan for and incentivise development of this infrastructure. Developing storage sites and transport infrastructure is time-consuming and requires co-operation between different private entities and government. Without transport and storage, large integrated CCS projects cannot be successful. The complexity of linking capture, transport and storage at this early stage of CCS technology deployment presents a significant barrier to deployment. In addition, aspects of injectivity and capacity of particular storage sites and CO_2 production from sources will have an impact on the overall design of CCS systems.

Inadequate public engagement over CCS projects has shown itself to be a critical issue. Recent examples in Germany and the Netherlands illustrate that under-appreciation of public concerns over CO_2 storage can easily be fatal for CCS. The Netherlands has since elected to allow only offshore storage of CO_2, while in Germany CO_2 storage legislation has been sidetracked. Engagement should occur at strategic, policy level, with government highlighting the role of CCS within a country's energy and climate mitigation mix;[7] and at the project level, by ensuring transparency, flexibility and a two-way flow of information from early stages.[8] The bottom line is that the public should be engaged early and often, at both policy and project levels.

7 See work by Fleishman, Bruine de Bruin and Morgan (2010) for detailed discussion.
8 See, for example, work by WRI (2010) and CSIRO (2010).

Part 4

Scenarios and Technology Roadmaps

Chapter 11 through 14 provide an extended analysis of *ETP 2012* scenarios by sector (energy supply, industry, transport and buildings) with the aim of identifying the technology and policy pathways required for the *ETP 2012* 2°C Scenario. Chapter 15 presents updated summaries of IEA technology roadmaps, giving additional details on how central technologies need to develop in order to reach the 2°C Scenario.

For the first time, *ETP 2012* contains a quantitative analysis of the energy system beyond 2050. These results are outlined in Chapter 16, which investigates how energy-related CO_2 emissions could be eliminated completely by 2075.

Finally, Chapter 17 presents the *ETP 2012* scenarios in the context of nine world regions, offering assessments of current technological and policy challenges, and identifying opportunities for each.

Chapter 11

Electricity Generation and Fuel Transformation

Decarbonising the world's energy conversion sector is crucial for achieving deep emissions cuts in the entire energy system. Low-carbon electricity is a prerequisite to reducing fossil fuel use and to mitigating emissions in the end-use sectors. In addition to decarbonised electricity, alternative fuels, such as biofuels and hydrogen, are needed to reduce the dependency on oil use, especially in the transport sector.

Key findings

- ***In the ETP 2012 2°C Scenario (2DS), global CO_2 emissions from the power sector in 2050 have to be cut by almost 80% from today's level of 12 $GtCO_2$.*** *More than 90% of the global electricity demand in 2050 is supplied by low-carbon technologies: renewable technologies reach a share of 57% in the world's electricity mix, nuclear power provides around 20%, and power plants equipped with carbon capture and storage (CCS) contribute 14%.*

- ***Massive deployment of these zero- or low-carbon technologies is needed over the next four decades to reach the 2DS.*** *Cumulative investments of around USD 7.7 trillion in power generation are required in the 2DS, in addition to the USD 18 trillion investment in the ETP 2012 6°C Scenario (6DS), between today and 2050.*

- ***Around 1 000 GW of existing coal capacity (or capacity under construction) may still be operating in 2050, producing annual CO_2 emissions of 4 Gt.*** *This exceeds by far the global CO_2 emissions of 2.5 Gt in the power sector in the 2DS. Co-firing with biomass and retrofitting with CO_2 capture can reduce the carbon intensity of this locked-in capacity. Early retirement of around 850 GW of coal-fired energy capacity is, however, unavoidable to reach the 2DS.*

- ***Petroleum use in the end-use sectors is 20% lower than today in the 2DS in 2050.*** *Alternative fuels, particularly biofuels and hydrogen, gain significant market shares. In the 2DS, biofuels provide one-fifth of global liquid fuel demand in 2050. Hydrogen, mainly used in the transport sector, reaches a production of 5 exajoules (EJ) by 2050 and replaces around 10 EJ of oil, an amount corresponding to today's oil demand in the transport sector in China and India combined.*

- ***Combining biofuel production with CCS can result in an annual net removal of 1.3 $GtCO_2$ from the atmosphere in 2050 in the 2DS.*** *Realising this potential requires a detailed assessment of infrastructure, on both national and local levels, to match biomass feedstock supply with possible plant sites and suitable storage locations. It also has to take into account competing CO_2 storage needs from power generation and industry.*

- ***Hydrogen may become an attractive storage option for surplus electricity from variable renewables.*** *In the 2DS, 14% of global electricity production from variable renewables is used to produce hydrogen. Improvements in electrolysis technology, in terms of costs and efficiency, as well as the development of the necessary transport and storage infrastructure, are prerequisites for using hydrogen as an energy storage as well as a fuel or feedstock in other sectors.*

Opportunities for policy action

- *By using best available technology (BAT) when building new plants in the next ten years, countries can avoid locked-in coal-fired power generation. Assessing existing coal plants for equipment upgrades or replacement will improve efficiency and performance. Co-firing with biomass can be a cost-effective measure to reduce carbon emissions from coal plants in the near term, depending on the available biomass supply. Converting conventional power plants into co-generation*[1] *plants to supply heat to nearby industry or residential areas holds significant potential, but needs further analysis.*
- *Renewables dominate electricity supply in the 2DS in 2050. Transparent, predictable policy frameworks for renewable technologies need to be tailored to the maturity of specific technologies and linked to clear targets. For example, renewable technologies that are close to cost-competitiveness, such as solar photovoltaics (PV) and onshore wind, may still require incentives for deployment to bring costs down further. Less mature renewable technologies, such as concentrating solar power (CSP), offshore wind or enhanced geothermal, may need additional research, development and demonstration (RD&D).*
- *The majority of the liquid biofuel production by 2050 will be based on advanced biofuel conversion technologies, such as cellulosic ethanol or Fischer-Tropsch (FT) biodiesel production. These technologies, which are currently in or at the demonstration stage, still require improvements in their technical and economic performance. To avoid adverse impacts from increased biofuel production on land use and food production, mandatory sustainability requirements are needed, based on internationally agreed certification schemes.*

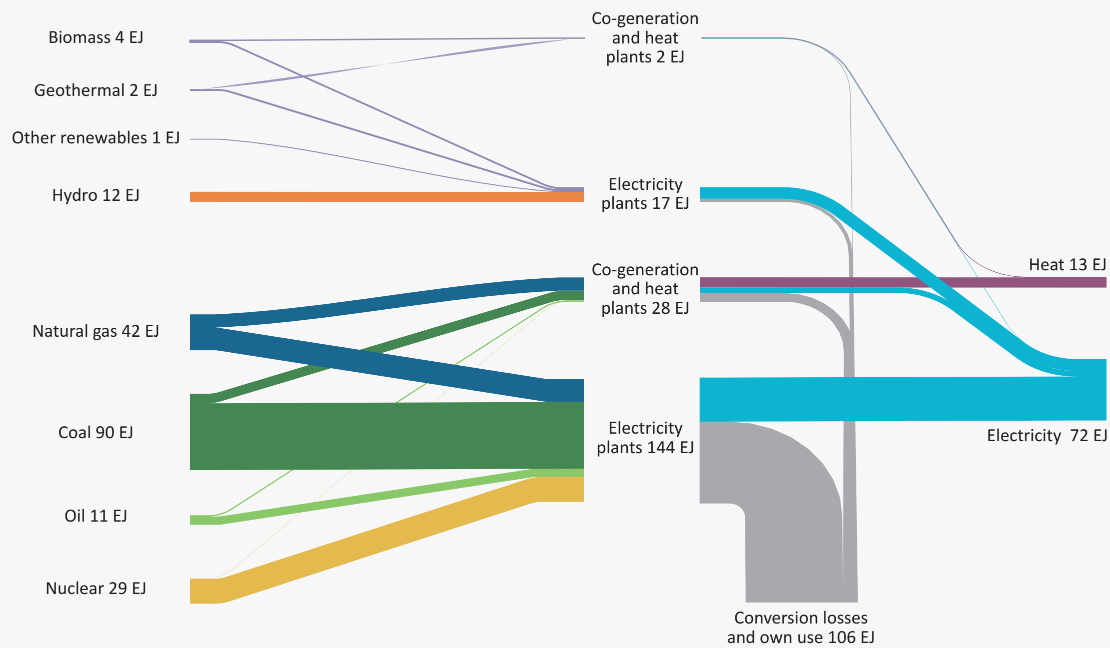
The energy conversion sector transforms primary energy into secondary energy sources. One can distinguish the power sector within the conversion sector, providing electricity and centralised heat; and the fuel transformation sector, comprising all other conversion processes of primary energy into secondary final energy use, such as refining.[2]

Around one-third of global fossil primary energy use, mainly coal and gas, is consumed by the power sector today. Generation of electricity and heat loses energy in the process, which accounted for 56% of the total energy input into power, co-generation and heat plants in 2009 (Figure 11.1). These losses led to around 12 gigatonnes of carbon dioxide ($GtCO_2$) emissions – almost 40% of global energy-related CO_2 emissions. Therefore power generation is the main producer of energy-related CO_2 emissions.

1 Co-generation refers to the combined production of heat and power.

2 Deviating from usual IEA energy balance conventions, coke ovens and blast furnaces are accounted for in the industry sector in the *ETP 2012* analysis.

Figure 11.1 **Sankey diagram of energy flows in the power sector, 2009**



Notes: Other renewables consists of wind, solar and ocean energy. Following IEA energy balance conventions, for autoproducer co-generation plants, only heat generation and fuel input for heat sold is considered, whereas the fuel input for heat used within the autoproducer's establishment is not included, but accounted for in the final energy demand in the appropriate consuming sector.
Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *Losses represent more than half of the energy going into electricity, co-generation and heat plants.*

Converting all coal and gas plants today to the best available technology holds significant reduction potential, in terms of energy inefficiency and CO_2 emissions. If all coal power plants in the world had an efficiency of 40%, instead of the global average of 34% today, they would save 20 EJ of coal, approximately one-sixth of global coal production, and corresponding emissions of 2 $GtCO_2$. For gas power plants, a similar increase in average efficiency, from the current value of 40% to 50%, would yield savings of 200 billion cubic metres, or 7% of global gas production, and CO_2 reductions of 0.4 Gt.

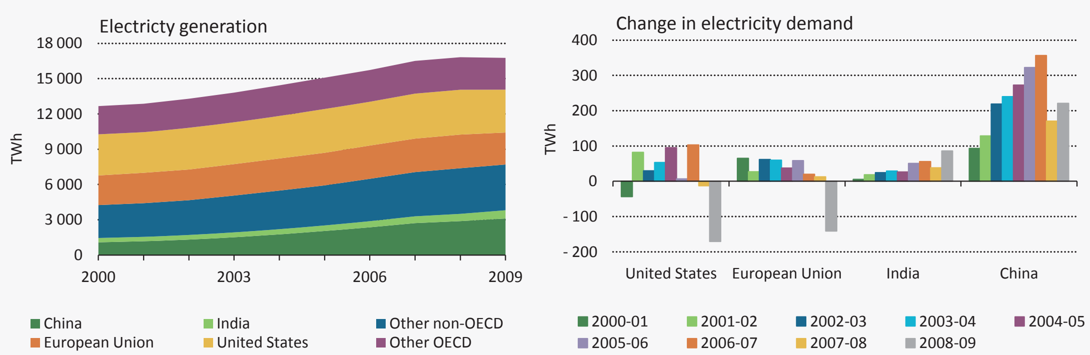
The energy input into the fuel transformation sector corresponds to around 45% of global fossil primary energy, mainly crude oil being transformed into petroleum in oil refineries. On a global average, around 7% of energy is lost in oil refining. The efficiency of a refinery depends on various factors: the type of crude oil, its processing through the complex refinery configuration and the desired product mix. As a result, assessing the potential for efficiency improvement is more difficult. In 2009 the refining sector was responsible for around 680 million tonnes of CO_2 ($MtCO_2$), or 2% of global energy-related CO_2 emissions.

Overall losses in power and fuel transformation are responsible for around one-quarter of global primary energy use and more than two-fifths of global energy-related CO_2 emissions. Therefore, in order to reach the ambitious CO_2 reduction levels in the 2DS, deep emissions cuts in these sectors, especially power generation, are a prerequisite.

Recent trends in electricity generation and fuel transformation

Global electricity demand grew by more than 4 000 terawatt hours (TWh), or almost one-third, between 2000 and 2009 (Figure 11.2). China alone was responsible for almost half of this increase, largely driven by electricity use in industry. The economic recession led to an absolute decline in electricity demand between 2008 and 2009 in OECD member countries, whereas in emerging economies, such as China and India, electricity demand continued to increase. In China, however, it rose at a slower rate compared with previous years.

Figure 11.2 Global electricity generation by region



Key point *Electricity demand increased by almost one-third worldwide in the past decade, largely driven by economic growth outside the OECD, particularly in India and China.*

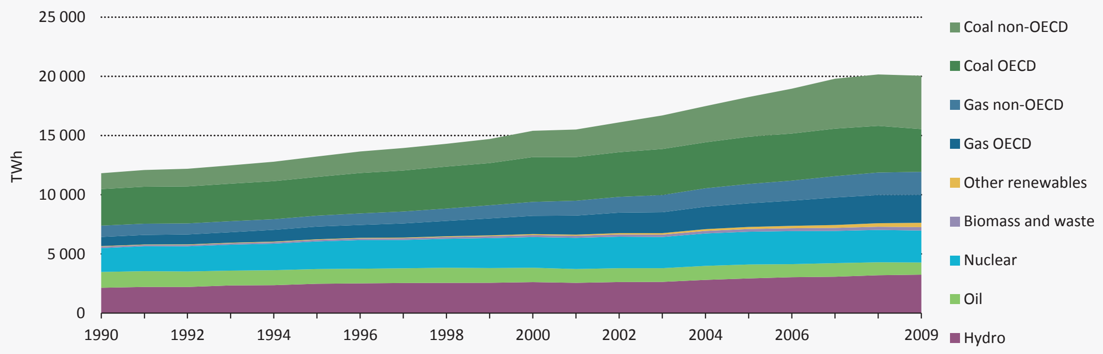
The majority of the increase in electricity demand was supplied by coal and natural gas. The growth in electricity generation in non-OECD economies over recent years made coal the fastest-growing primary energy source. The regional trends in coal-fired electricity generation, however, have been quite diverse: generation has more than doubled since 2000 in non-OECD countries, but has slightly declined (by 5%) in OECD countries (Figure 11.3).

For gas, the developments have to some extent been contrary. In OECD countries, gas generation has grown by more than 50% since 2000. An abundant supply of natural gas, due to production increases in all parts of the world (especially the former Soviet Union and the Middle East) and the growth in unconventional gas production (in the United States), in combination with lower capital costs and shorter construction times for gas plants, are some of the factors explaining this trend.

Other reasons are the opportunities to hedge against volatile electricity prices due to the correlation of gas and electricity prices on many electricity markets; lower environmental impacts compared with coal plants; and more positive public acceptance compared with nuclear, coal or wind sources. Furthermore, gas plants provide a high operational flexibility with short start-up times and high load gradients, which allow them to react quickly to demand changes or compensate for short-term variations in the electricity production from wind or solar PV.

Non-hydro renewable energy technologies showed the strongest growth over the last decade in power generation, expanding by a factor of more than 2.5, although from a low starting point. Also, hydropower generation has increased by around 25% since 2000. In 2010 alone, renewables accounted for approximately half of the 194 gigawatts (GW) capacity added globally, especially from wind, hydro and PV (REN21, 2011). The global share of renewables in power generation, however, stagnated due to the strong growth in coal-fired generation in non-OECD countries at a value slightly below 20% in the last decade.

Figure 11.3 Global electricity generation by fuel



Key point *Coal remains a major fuel source in global power generation and had the largest increase in absolute terms over the last decade.*

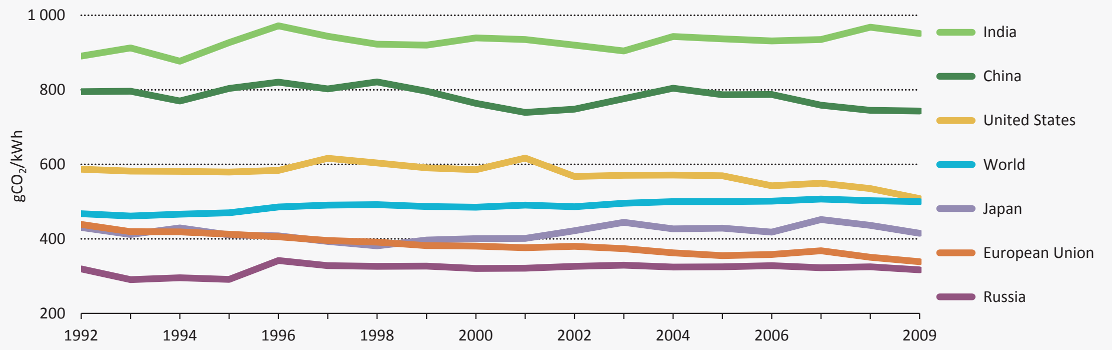
Trends in the generation mix are also reflected in the average CO_2 intensity of electricity generation. No real progress in significantly reducing the CO_2 intensity was achieved in the last decade, although intensities in Europe and the United States fell by around 10% during this period (Figure 11.4). Switching from coal to gas and increasing electricity production from renewables have been the main factors in Europe's drop in CO_2 intensity, while efficiency improvements in gas-fired generation, particularly through new combined-cycle plants, was the main factor in the United States. Despite this progress, absolute CO_2 emissions from the power sector, including co-generation and district heating plants, increased globally by 2.7 Gt since 2000, driven by the growth in coal-fired generation.

This development is aggravated by the fact that the average global efficiency of coal plants has not much improved, staying around 35% over the last decade. Almost 500 GW, or 55%, of coal capacity built between 2000 and 2009 were subcritical plants, not the more efficient supercritical or even ultra-supercritical plants. Currently, China and India are closing or modernising old, inefficient coal plants and introducing policies to promote adoption of more efficient technologies.

China implemented a programme in 2006 to decommission small, inefficient coal power plants, which resulted by mid-2010 in the closure of a total capacity of 71 GW, compared with its total installed subcritical capacity of 475 GW in 2010. India has introduced rehabilitation and modernisation programmes to improve the operational efficiency and to provide additional power output from existing coal plants. Supercritical technology is mandatory for India's so-called ultra-mega power projects, a series of projects with at least 4 000 megawatts (MW) each to reduce power shortages. Its 12th Five-Year Plan (2012 to 2017) aims to base at least half of all new coal plants on supercritical technology; in the 13th Five-Year Plan, all new coal plants will be at least supercritical (Mathur, 2010).

While growing economies, such as China and India, are installing massive additions of capacity to meet growing demand, developed countries are confronted with the task of modernising their ageing power infrastructure (Figure 11.5). In the European Union, around 40% of the power plants are more than 30 years old; the situation is similar in the United States. The major challenge in these regions is mobilising the necessary investments to modernise the power plants, but it also presents an excellent opportunity to drastically improve the efficiency and environmental impacts of power generation.

Figure 11.4 CO_2 intensity of electricity generation in selected countries



Note: gCO_2/kWh = grammes of carbon dioxide per kilowatt hour.

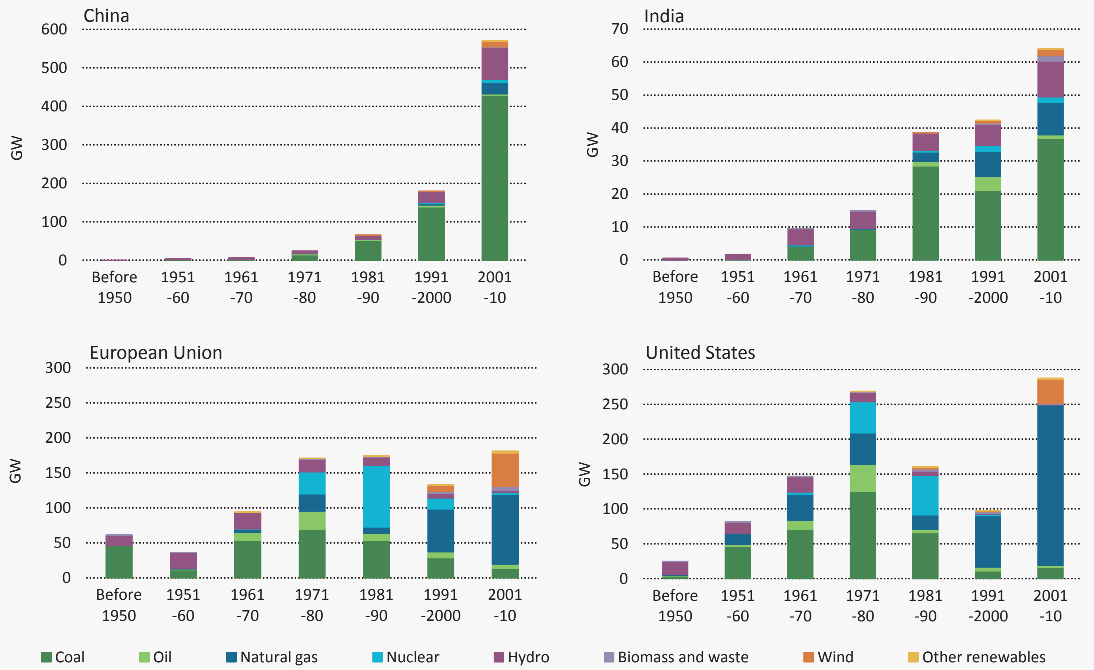
Key point *CO_2 intensity has moderately declined in some OECD regions, but average global CO_2 intensity is still increasing.*

The European Union took action in this direction, with the 2020 targets in its integrated climate and energy package, to reduce greenhouse-gas (GHG) emissions by 20%, compared with 1990; to increase the share of renewables in gross final consumption to 20%; and to reduce primary energy use by 20%. The renewables target can increase the European Union's share of renewables in power generation from 19% in 2009 to above 30% by 2020 (Beurskens and Hekkenberg, 2011). In addition, the EU Industrial Emissions Directive (EU, 2011), which sets stricter limits on air pollutants from industrial installations, may further speed up the closure of old coal-fired power plants. These installations must be shut down by 2023 at the latest, if they cannot meet these new requirements.

The United States has excellent ressource conditions for some renewable sources, particularly solar and wind. A majority of US states have introduced renewable portfolio standards, requiring utilities to provide a certain share of their electricity from renewable sources. On a federal level, in 2011 the United States launched the SunShot Initiative to cut the total costs of electricity from PV by 75% by 2020, which will make it cost-competitive with other forms of electricity (US DOE, 2011).

From 2000 to 2009, the global fuel transformation sector was characterised by a 14% growth in liquid fuel demand, almost exclusively from petroleum products. The economic recession led to a 2% decline in petroleum demand between 2007 and 2009, caused by reduced demand for diesel and heavy fuel in freight transport, and by less demand for oil in the industry sector. A major share of the decrease in petroleum demand occurred in OECD countries, whereas consumption in non-OECD countries continued to grow, although at a slower rate (Figure 11.6).

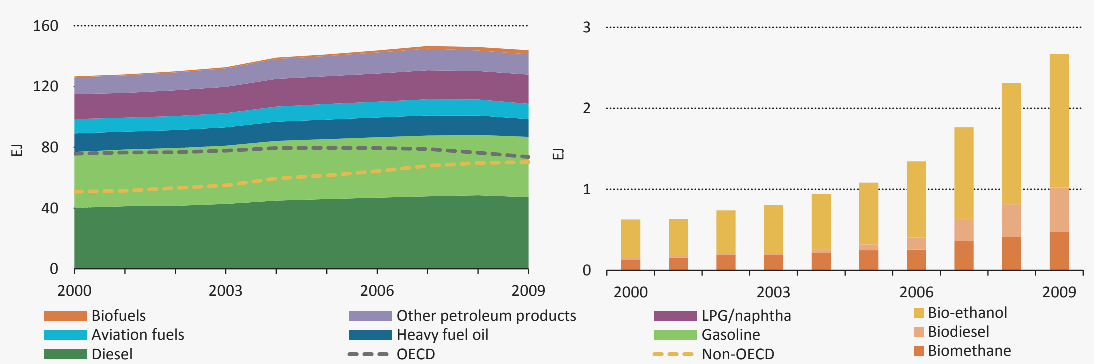
Figure 11.5 Age of existing power generation capacity today in the United States, the European Union, India and China



Source: Platts, 2010; IEA analysis.

Key point *Ageing infrastructure is the challenge in many OECD countries, whereas emerging economies have to cope with a growing demand for electricity.*

Figure 11.6 Final liquid fuel supply (left) and biofuel production (right)



Key point *Biofuel production has grown rapidly over the last decade, albeit from a low starting point, but oil continued to dominate global liquid fuel supply.*

On the product side, the increase in petroleum consumption between 2000 and 2009 was driven by demand for lighter products, with diesel alone being responsible for 46% of the petroleum demand increase between 2000 and 2009, whereas demand for heavy fuel oil was slightly declining over the period, despite an increased consumption for shipping, due to a shift from heavy fuel oil in industry and power generation to other fuels, such as coal and natural gas.

The refining capacity is generally, in the long term, closely related to the petroleum demand. Between 2000 and 2010 the world's crude distillation capacity grew by 9% from 81.2 million barrels per day (mb/d) to 88.2 mb/d. More than half of this new capacity was added in China and India, reflecting their growing petroleum demand. The trend for lighter petroleum products, such as diesel, gasoline and jet fuels, and for cleaner fuel emissions specifications in many countries, in combination with a generally heavier crude oil supply, led to more complex refinery configurations. Global hydrocracking capacity, which is a refinery conversion process to produce middle distillates, such as diesel and kerosene, grew by more than one-quarter over the last decade, with 80% of the new capacity being added in the OECD (OGJ, 2000 and 2010). Similar growth could be observed in hydrotreating capacity, a process to remove impurities such as sulphur from petroleum products. Again, more than three-quarters of this capacity have been added in OECD countries over the last decade due to more stringent vehicle emissions standards, but similar investments are likely to occur also in other parts of the world with the introduction of tighter emissions standards. Worldwide CO_2 emissions from refining increased between 2000 and 2009 only by 2% from 666 Mt to 678 $MtCO_2$, corresponding to a decline in CO_2 intensity from 0.164 tonnes of CO_2 (tCO_2) to 0.152 tCO_2 per tonne of crude oil processed.

Production of biomass-based fuels (including biomethane) has more than quadrupled since 2000, but from a very low starting point, so that biofuels made up only 0.5% of global final liquid fuel demand in 2009. Despite the economic crisis, biofuel production capacities for biodiesel and bio-ethanol continued to grow, both at a rate of 10% over the last two years. The United States (58% share) and Brazil (30% share) dominate global bio-ethanol production. The market for biodiesel is much smaller and less concentrated, compared with bio-ethanol. Germany, France, Argentina and Brazil were the largest producers in 2010. The European countries combined provided more than half of the global biodiesel production (Figure 11.7).

The fact that bio-alcohols and biodiesel can be blended with conventional petroleum products facilitates their successive introduction in the transport sector. Compared with other alternative transport fuels, such as hydrogen or electricity, liquid biofuels do not require the development of a new distribution infrastructure, but in principle can use the existing system developed for petroleum. Also, on the vehicle side, the existing engine technology can be used with some adjustments needed, depending on the amount of biofuels blended with conventional petroleum. Blends of bio-ethanol with gasoline and biodiesel with conventional diesel have been introduced in several countries. In the case of bio-ethanol, however, some restrictions apply: its miscibility with water does not allow the transport of ethanol-gasoline in pipelines due to possible corrosion, so that ethanol has to be transported by truck to the filling station. Biobutanol, an alcohol with similar production pathways as ethanol, can be a promising alternative to bio-ethanol, since it can be, due to its hydrophobic nature, transported in pipelines. A further advantage of biobutanol is that it can be blended in any concentration with gasoline without modifications in existing engines, whereas ethanol requires modifications on the engine side for blends above 10%, due to its higher octane level than gasoline (Swana *et al.*, 2011).

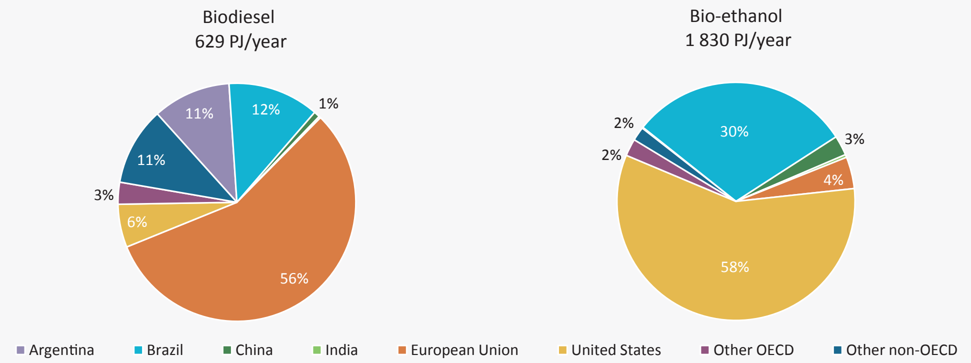
Bio-ethanol today is produced either from sugar crops through fermentation or from starch crops by first converting the starch into glucose and then fermenting it into ethanol. Bio-ethanol production today in the United States is largely based on maize, while ethanol in Brazil is derived from sugar cane. Commercially available biodiesel technologies use vegetable oil based on oil seeds, as well as animal fats and used cooking oil, all of which are converted with the help of ethanol or methanol into biodiesel. Today, main feedstocks for biodiesel production are rapeseed and sunflower oils in Europe, whereas in South America and the United States soybean oil is the main feedstock. In Asia, biodiesel production is based largely on palm oil.

In addition to these conventional biofuel conversion technologies, several advanced technologies are currently under development. An example is the production of bio-ethanol by converting lignocellulosic feedstocks through biochemical processes into sugar, which can then be fermented into ethanol.

Advanced biodiesel conversion technologies produce products comparable to conventional diesel or kerosene. Hydrotreating vegetable oil into biodiesel is one technology currently under development. Gasification of biomass and conversion of the resulting syngas through Fischer-Tropsch synthesis into a hydrocarbon liquid represents another advanced biodiesel conversion process, also referred to as biomass-to-liquid (BTL) process. Gasification of biomass can also produce synthetic natural gas from biomass (bio-SNG) as a substitute for conventional natural gas. Some advanced biofuel conversion technologies are just now starting to enter the demonstration stage, but have a combined production capacity of only around 6 petajoules (PJ) per year – a very small fraction of global liquid fuel demand (IEA, 2011a).

Advanced biofuel conversion technologies using lignocellulosic feedstocks are especially attractive, as they can use agricultural or forestry residues and thus do not necessarily compete for land with food or feed production. Using algae for biofuel production is another promising route to reduce competition with other land uses due to their high productivity per hectare and the possibility of being grown on non-arable land. In addition, algae can use a variety of possible water sources, *e.g.* fresh, brackish, saline or wastewater, as well as recycle CO_2 and other nutrient waste streams. Compared with other advanced biofuel conversion technologies, however, more basic research and development (R&D) is required to optimise the algae strains, to address concerns regarding the effects from possible contaminations and to scale up production levels.

Figure 11.7 Regional biofuel production capacities, 2010



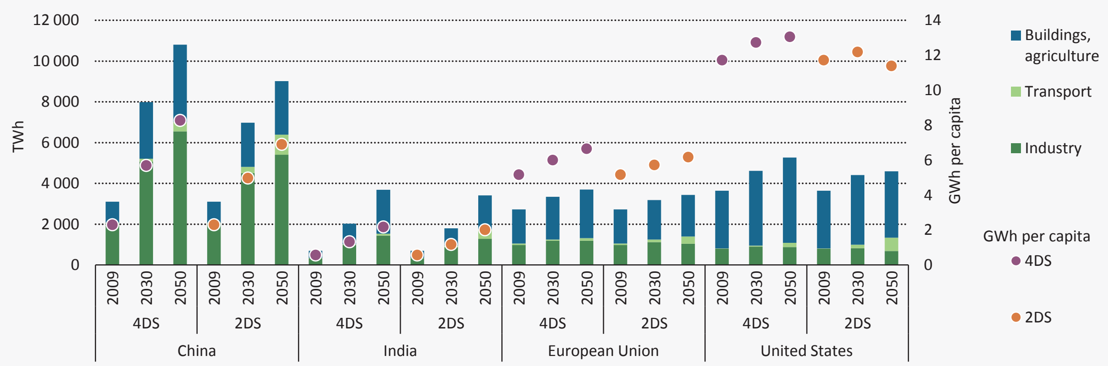
Key point *The major share of global biodiesel capacity is installed in Europe, while the United States and Brazil lead in bio-ethanol production.*

Scenario results for electricity generation

In the *ETP 2012* 4°C Scenario (4DS), global final electricity demand grows from 16 700 TWh in 2009 to 37 800 TWh in 2050, driven by increased demand in the buildings and industry sectors. On a regional level, most of the demand growth occurs in non-OECD countries, whereas demand in OECD countries rises only moderately. By 2050, China reaches a per capita consumption similar to the European Union (Figure 11.8). Their demand structures differ, however: China has a much higher share of industrial consumption, so its residential per capita consumption will be 1 600 kilowatt hours (kWh) per capita in 2050, still 33% lower than in the European Union.

In the 2DS, more efficient use of electricity in the industry and buildings sectors leads to a reduced electricity demand of 33 900 TWh in 2050. These efficiency improvements in electricity use are partially offset by increased electricity demand from electric vehicles in the transport sector, as well as the rising use of heat pumps for heating and cooling purposes in the buildings sector. As a result of these two counteracting developments, the share of electricity in final energy use increases from 17% today to 26% in the 2DS in 2050.

Figure 11.8 Final electricity demand by sector



Key point *Electricity demand grows strongly in absolute terms in China and India, but electricity use per capita is still significantly lower than in the United States.*

Fossil fuels continue to dominate power generation in the 4DS (Figure 11.9, left), although their share falls from 67% in 2009 to 52% in 2050. Around 100 GW of coal or gas capacity are added each year in this scenario by 2050. This rate is exceeded by the deployment rate of 130 GW per year for all renewable power technologies combined: wind has the highest construction rate with 55 GW per year, followed by PV with 30 GW. The renewables share in electricity generation almost doubles from 19% in 2009 to 36% in 2050.

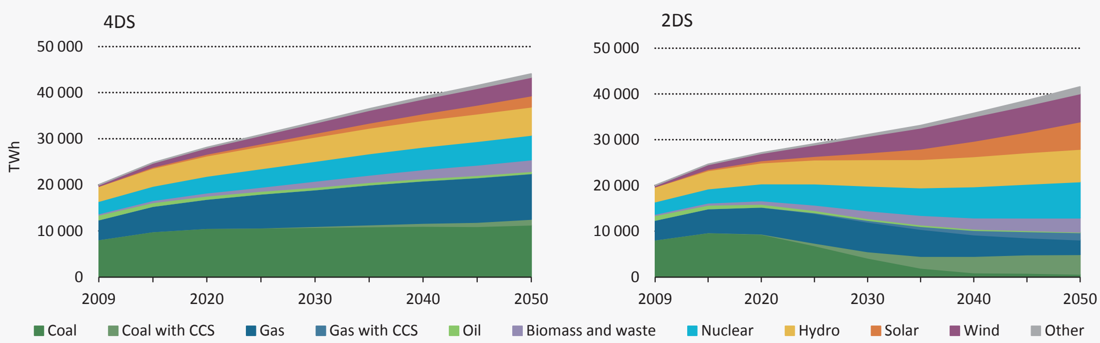
Together with the efficiency improvements in fossil power generation by the continuous deployment of ultra-supercritical and supercritical plants in coal-based generation and natural gas combined-cycle plants, the average CO_2 intensity of electricity generation drops from today's 500 grammes (g) of CO_2 per kWh to around 280 gCO_2/kWh by 2050. Despite these improvements, absolute CO_2 emissions from power generation continue to grow in the 4DS, although at a slow pace. Starting from 11.8 $GtCO_2$ in 2009, they peak around 15 $GtCO_2$ in 2035 and slightly decline thereafter to 14 $GtCO_2$ in 2050.

A markedly different power generation mix emerges in the 2DS. Renewables provide 57% of the electricity generation. Hydropower, the largest renewable source in power generation, keeps approximately the same 17% share in the 2DS generation mix as in 2009. Generation from wind and solar grows rapidly, each providing around 6 000 TWh of the total electricity generation of 41 600 TWh in 2050 (Figure 11.9, right). Nuclear power reaches a 19% share in the electricity mix, and fossil fuel plants with CCS contribute around 14%. The remainder is largely from gas-fired power plants, which together with flexible hydropower plants provide flexibility to balance renewable generation from variable sources, such as solar, wind and ocean energy. In addition, the flexibility of the electricity system must increase, requiring a mix of further measures, including the development of smart grids, stronger grid interconnections, electricity storage and demand-side response measures (see Chapter 6).

Co-generation plants for electricity and heat can provide high overall conversion efficiency of 80% to 90%, where the heat, which otherwise is lost in the cooling condenser of conventional steam-cycle power plants, is used for space heating or for steam and process heat in industrial production processes. In the 2DS, electricity produced by co-generation plants doubles globally from 1 900 TWh in 2009 to almost 4 000 TWh in 2050, with the majority of co-generation plants providing heat for industry. Energy-saving measures in the industry and buildings sectors, as well as the increased electrification of heat, however, limit the deployment of co-generation in the 2DS, so that global co-generation of electricity is 27% lower than in the 4DS.

As a result of the massive deployment of low- or zero-power technologies, the emissions intensity in the 2DS falls globally below 60 gCO_2/kWh in 2050. Absolute CO_2 emissions in the power sector peak at 13 $GtCO_2$ in 2015 and fall to 2.4 $GtCO_2$ by 2050, a reduction of 80% compared with 2009 emissions levels.

Figure 11.9 **Power generation mix in the 4DS and the 2DS**



Note: "Other" includes geothermal and ocean energy.

Key point *In the 2DS, global electricity supply becomes decarbonised by 2050.*

The overall CO_2 reduction target of the global energy system becomes the main force driving long-term deployment of low-carbon power technologies in the 2DS. The CO_2 price, increasing in the 2DS from USD 40/tCO_2 in 2020 to USD 150/tCO_2 in 2050, influences the electricity generation costs of CO_2-emitting technologies and thereby the relative cost-competitiveness of low-carbon power technologies. The most important technical and economic factors influencing the electricity generation costs – and hence, the technology choice in the power sector in the long run – are fuel input prices, conversion efficiency, specific investment and operating costs of a technology, plant load factors, plant construction time and technical lifetime, as well as the discount rate.

Many of these factors are dynamic, changing over time, such as fuel prices. Technical parameters also improve as technologies progress and evolve. Not all factors are purely exogenous input assumptions in the analysis. For instance, specific investment costs for renewable technologies are described using so-called learning curves, which link, based on empirical observations, the specific investments of technology with cumulative installed capacity.

In early stages of development, emerging new power technologies may be proved in pilot and demonstration projects, but may not yet be cost-competitive, compared with the incumbent fossil generation options. Nevertheless, policy support for the deployment of the new technology can be justified to bring down its specific investment costs due to learning effects, if they show promise in becoming cost-competitive in the future. Thus, the earlier additional learning investments required to support the technology deployment can be offset by future savings, if the future costs of the new technology fall below the costs of today's incumbent technologies.

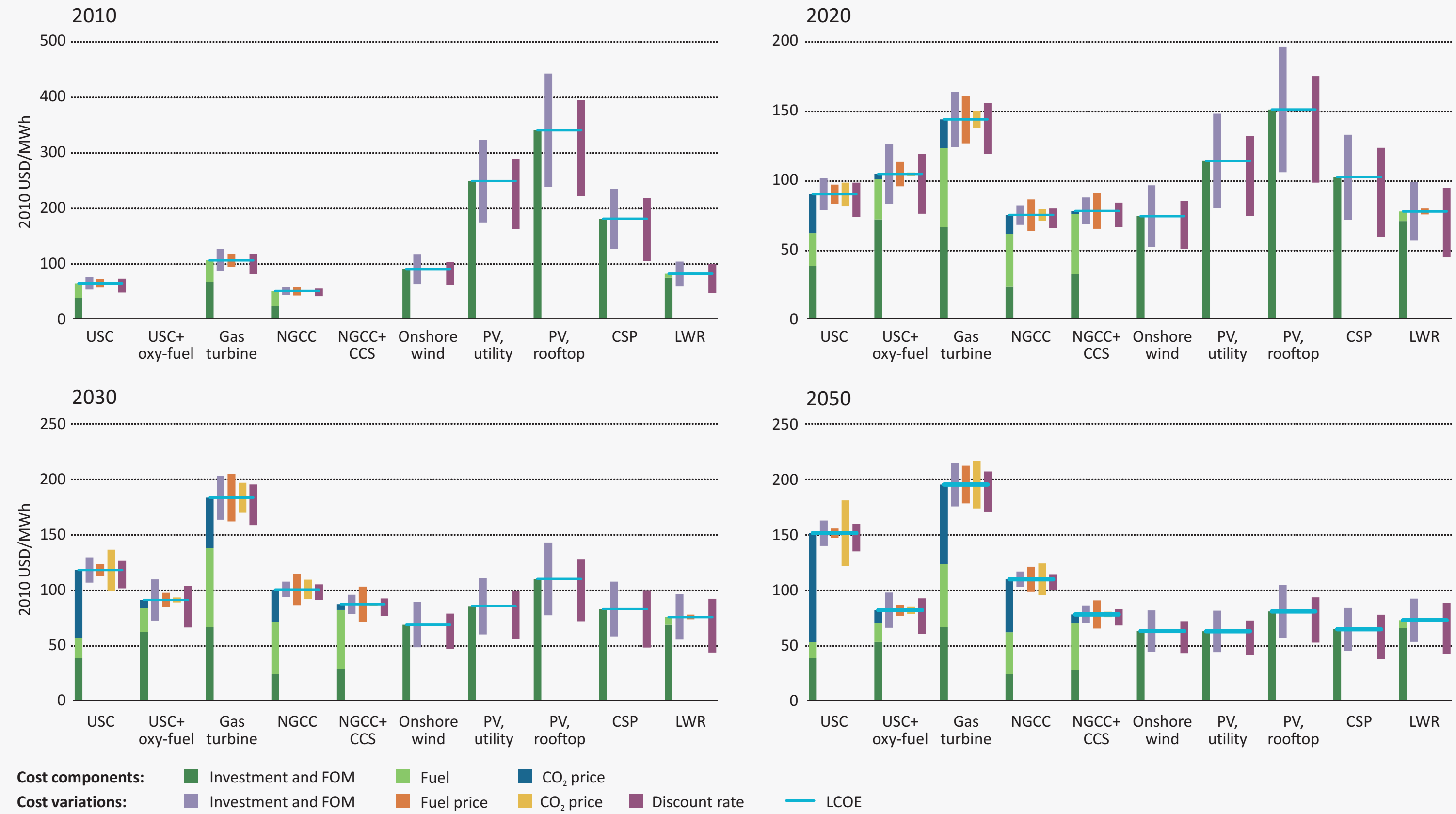
To illustrate how the competitiveness of power technologies changes over time in the 2DS, Figure 11.10 presents the levellised electricity generation costs for selected technologies in the United States, broken down into investment costs, operating and maintenance costs, fuel costs, and CO_2 price penalty. A summary of the underlying technology assumptions for the United States follows in Table 11.1. For other regions, the technology assumptions differ in the scenario analysis by taking into account local factors, such as labour costs (which influence the investment costs) or technical conditions (*e.g.* cooling options that affect the realisable efficiency for steam-cycle power plants). The effects of variations in investment costs, fuel and CO_2 prices as well as the discount rate on the generation costs are also included in Figure 11.10.

The concept of levellised costs has shortcomings, however (Joskow, 2010). It does not take into account the daily variability of electricity demand. Technologies that are able to follow the load can provide electricity during peak times, which in deregulated electricity markets also means times of higher electricity prices. This additional flexibility represents a value that justifies higher generation costs compared with less flexible generation technologies.

For variable renewable technologies, such as solar or wind, the value of the electricity supplied depends on when it is produced: production during peak times allows higher generation costs, whereas during off-peak times, lower electricity prices mean less revenue from the produced electricity. Therefore, the value of electricity produced from a variable renewable technology depends on how close its production profile matches the demand profile. Large discrepancies require additional measures, such as using a pumped storage plant or shifting consumption by demand-side management, which increases the overall costs of integrating variable renewables into the electricity system. Due to these limitations of the levellised cost approach, the generation cost levels shown in Figure 11.10 should be regarded only as an approximate indication of when certain technologies may become competitive in the future.

In 2010, natural gas combined-cycle (NGCC) technology without CO_2 capture shows the lowest average generation costs. Increasing CO_2 prices, changes in fossil fuel prices over time in combination with reduced costs for renewable technologies, and fossil fuel plants with CO_2 capture alter the ranking over time.

Figure 11.10 Levellised electricity generation costs for selected technologies in the 2DS in the United States



Notes: Levellised cost calculations are based on a discount rate of 8%. Fuel and CO_2 prices are based on the 2DS. Coal prices are USD 3.4/GJ in 2010, USD 3.2/GJ in 2020, USD 2.5/GJ in 2030 and USD 2.1/GJ in 2050. Gas prices are USD 4.2/GJ in 2010, USD 6.2/GJ in 2020, USD 8.0/GJ in 2030 and USD 6.6/GJ in 2050. Nuclear fuel costs are set to USD 0.7/GJ. CO_2 prices are USD 0/tCO_2 in 2010, USD 40/t in 2020, USD 90/t in 2030 and USD 150/t in 2050. Variations are based on 30% increase and 30% decrease of the investment and fixed operating cost parameters in Table 11.1, and the mentioned fuel and CO_2 prices. Lower and upper bounds of the discount rate variation correspond to a discount rate of 3% and 10%, respectively. FOM = Fixed operating and maintenance costs; USC = ultra-supercritical coal plant; USC + oxy-fuel = ultra-supercritical coal plant with oxy-fuelling and CO_2 capture; NGCC + postcomb. = natural gas combined cycle with post-combustion CO_2 capture; LWR = nuclear light water reactor; Onshore = onshore wind turbine.

Key point *Many low-carbon power technologies in the 2DS become cost-competitive over time with fossil-fuel power plants, due to cost reductions from technology learning and the increasing CO_2 price penalty for fossil-fuel generation without CCS.*

Table 11.1 Technical and economic assumptions for selected power technologies in the United States

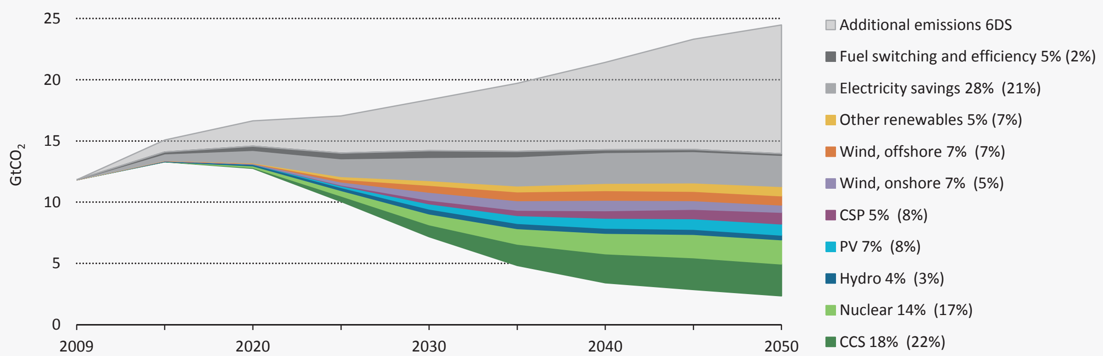
	Overnight investment costs (2010 USD/kW)				Fixed operating and maintenance costs (2010 USD per kW/yr)				Net conversion efficiency (lower heating value) (%)				Technical lifetime (years)	Construction time (years)	Capacity factor (%)				Learning rate (%)
	2010	2020	2030	2050	2010	2020	2030	2050	2010	2020	2030	2050			2010	2020	2030	2050	
USC	2 300	2 300	2 300	2 300	46	46	46	46	47	48.5	50	52	35	4	85	85	85	85	
USC + oxy-fuel	n.a.	4 000	3 450	2 950	n.a.	120	104	89	n.a.	39	42	44	35	4	n.a.	85	85	85	
Gas turbine	500	500	500	500	10	10	10	10	38	39	40	42	30	1	15	15	15	15	
NGCC	1 000	1 000	1 000	1 000	20	20	20	20	57	59	61	63	30	3	60	60	60	60	
NGCC + CCS	n.a.	1 800	1 600	1 500	n.a.	54	48	45	n.a.	51.5	54	56	30	3	n.a.	85	85	85	
Wind, onshore	1 800	1 600	1 550	1 500	36	32	31	30	100	100	100	100	25	1	26	28	29	31	7
Wind, offshore	3 800	2 900	2 430	2 150	114	87	73	65	100	100	100	100	25	2	36	39	40	42	9
PV, utility scale	4 000	1 880	1 440	1 050	40	19	14	11	100	100	100	100	25	1	19	20	20	21	18
PV, rooftop	4 900	2 300	1 750	1 300	49	23	18	13	100	100	100	100	25	0	17	18	19	20	18
CSP	6 500	3 700	3 000	2 300	65	37	30	23	40	40	40	40	30	2	45	45	45	45	10
Nuclear, LWR	4 600	4 350	4 250	4 000	115	109	106	101	36	36	37	37	50	5	85	85	85	85	

Notes: kW = kilowatt; n.a. = not available.

By 2020, onshore wind becomes cost-competitive compared with an NGCC plant without CO_2 capture. In addition, rooftop PV installations also reach competitiveness by then. Their generation costs are much higher, but they compete at retail price levels where prices are higher, not in the wholesale electricity markets like the other technologies.[3] By 2030, CSP as well as coal and gas plants with CO_2 capture achieve generation cost levels comparable to NGCC plants, which suffer from increasing CO_2 prices over time in the 2DS. The further increase of the CO_2 price in the 2DS by 2050, to USD 150/tCO_2, further penalises those gas and coal plants without CO_2 capture. The wind and solar technologies reach generation costs of USD 60-80 per megawatt hour (MWh), which is similar to a gas-fired plant with CO_2 capture.

Compared with the 4DS, cumulative CO_2 emissions from the power sector in the 2DS between 2009 and 2050 fall by 258 Gt. Around one-quarter of this reduction is not achieved directly in the power sector itself, but from electricity savings in the end uses through more efficient use of electricity or a switch to renewable energy sources, *e.g.* solar water heating (Figure 11.11). The cumulative abatement actually realised in the power sector is around 187 Gt. Renewables provide more than one third of the reduction from the 4DS to the 2DS, with solar (PV and CSP) responsible for 12% and wind for 14%. The deployment of coal and natural gas plants equipped with CO_2 capture leads to cumulative reductions of 18%. Nuclear power is responsible for 14% of the emissions savings.

Figure 11.11 **Key technologies to reduce CO_2 emissions in the power sector in the 2DS, relative to the 4DS**



Note: In the legend, the first percentage number for a technology refers to its share in cumulative CO_2 reductions between 2009 and 2050, while the percentage in parentheses refers to a technology's contribution in the annual reduction, in 2050, from 14 Gt in the 4DS to 2.5 Gt in the 2DS. "Other renewables" includes cumulative reductions of 3% from biomass, 1.5% from geothermal energy and 0.5% from ocean energy as well as annual reductions in 2050 of 3.3% from biomass, 2.0% from geothermal energy and 1.2% from ocean energy.

Key point *Electricity demand savings and renewables are each responsible for one-third of the cumulative CO_2 reductions in the power sector in the 2DS.*

Already in the 4DS, electricity generation from renewables increases markedly by 2050 compared with today, meaning renewables provide significant CO_2 reductions over time in this scenario. Compared with the 6DS, which assumes no other policy measures than what exist now, the 4DS results in cumulative CO_2 reductions of 187 Gt in the global power

3 In 2010, average wholesale electricity prices in the United States were in a range of 38-56 per megawatt hour (MWh), whereas retail electricity prices for residential and commercial consumers were in a range of USD 100-115/MWh (EIA, 2012; EIA, 2011).

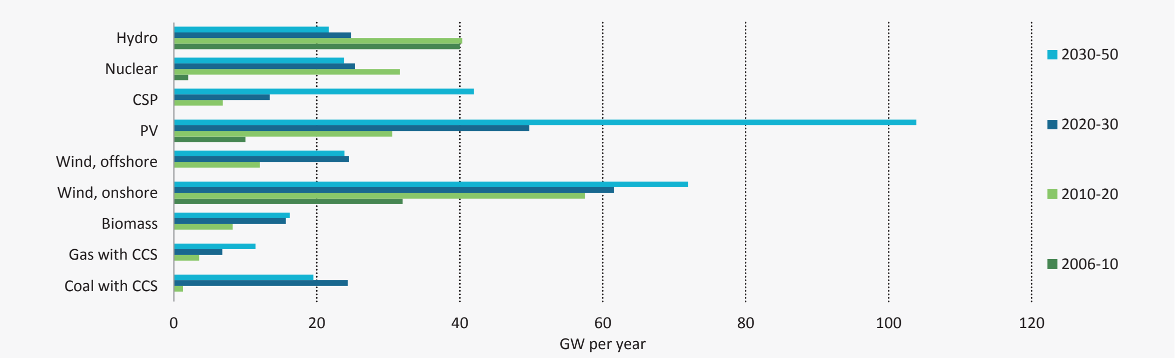
sector (see dotted area in Figure 11.11). Major contributors to the CO_2 reductions between the 6DS and the 4DS are electricity savings in the end uses, which alone is responsible for around half of the cumulative reductions, and renewables, which account for around one-third of the CO_2 savings. Particularly, wind and solar each provide around 10% of the emissions reduction between the 6DS and 4DS in the power sector.

Achieving a decarbonised power sector in the 2DS requires massive investments in low-carbon power generation technologies. Global installed wind capacity increases to 2 350 GW from 194 GW in 2010. A similar large-scale expansion of solar power technologies is needed, with PV reaching an installed capacity of 2 000 GW and CSP more than 850 GW in 2050 in the 2DS. Nuclear power capacity will almost triple between today and 2050 to a level of 1 100 GW. Overall, additional investments of USD 7.7 trillion in power generation are needed in the 2DS relative to the 6DS between 2011 and 2050 (Table 11.2). These investments are, however, more than offset by fuel cost savings in the order of USD 33.7 trillion. These savings are mainly caused by the drastic reductions in coal and gas use for power generation in the 2DS compared with the 6DS, and to a lesser extent by the reduced electricity demand in the 2DS.

Continuing use of fossil fuels for power generation in the 2DS requires that plants be equipped with CCS, which accounts for almost 60% of the remaining fossil-fuel generation in 2050. Global installed CCS capacity increases to 960 GW by 2050, of which 630 GW are coal-fired, 280 GW are gas plants and the remainder use biomass, either in dedicated biomass power plants or through co-firing in coal plants with CCS. For CCS, demonstrating the technology on a commercial scale and developing the CO_2 transport and storage infrastructure will be crucial.

The corresponding average construction rates for additional capacity over the next four decades needed to reach these deployment levels are shown in Figure 11.12. Except for hydro, where recent capacity additions in China and India led the growth between 2006 and 2010, deployment of all low-carbon technologies must be drastically accelerated over the next decades in the 2DS. The required deployment rates appear huge, if compared with present capacity rates for PV or offshore wind, for example.

Figure 11.12 Average annual capacity additions in the 2DS



Key point *Massive acceleration of deployment of low-carbon power technologies is needed over the next four decades.*

It should not be forgotten, however, that fossil fuels achieved growth rates of similar magnitude in the recent past. The average construction rate for coal power plants was

75 GW per year between 2006 and 2009, and for gas plants around 50 GW per year. Construction rates of nuclear power must also rise dramatically compared with the new-build rates observed over recent years. The required rate of adding around 27 GW of nuclear power each year over the next four decades is ambitious, but is technically feasible as similar construction rates occurred in the 1980s, when a smaller number of countries pursued nuclear programmes.

In addition to deploying low-carbon power technologies, many coal-fired power plants that have been built recently or are currently under construction will have to be decommissioned in the 2DS before the end of their technical lifetimes. This lock-in of generation assets is especially an issue in fast-growing economies, where large amounts of fossil generation capacity with less efficient technology have been added over recent years to cope with growing demand for electricity. *World Energy Outlook 2011* showed that existing fossil-fuel power plants (or those under construction) can produce annual emissions of around 8.8 $GtCO_2$ in 2035 (IEA, 2011b). By 2050, the locked-in fossil capacity will still correspond to annual emissions of around 4 Gt in 2050, an amount *higher* than the emissions of the entire power sector in the 2DS. Early retirements and retrofits of fossil-fuel plants with CO_2 capture or with co-firing of biomass (in coal plants) are therefore unavoidable in order to substantially decarbonise the power sector in the 2DS.

Early retirements in the 2DS comprise almost 850 GW of coal capacity by 2050, of which around 700 GW are based on subcritical technology. Retrofitting with CO_2 capture equipment is economically unattractive for these plants, since it results in an extreme low conversion efficiency. Overall, the premature retirement of coal power plants means lost revenues for electricity, which are estimated (on an undiscounted basis) at around USD 3.6 trillion between 2012 and 2050. This number appears huge, but must be compared with the cumulative CO_2 price penalties of USD 7.2 trillion, which would have to be paid if the plants continued to operate until the end of their technical lifetime.[4]

Nevertheless, alternatives for the early closure of plants have to be considered, if they are at all technically feasible and economically viable. For supercritical or ultra-supercritical coal plants, retrofitting them with CCS represents an option of continuing operation with reduced emissions. In the 2DS, only around 100 GW of coal capacity are retrofitted with CCS because plants producing 150 GW have been retired early: their remaining lifetimes are too short to justify the additional investment for the retrofit.

Co-firing with solid biomass in existing coal power plants is another cost-effective measure to reduce carbon emissions from coal plants. Additional investment costs for co-firing range from USD 300 to USD 700 per kilowatt electrical capacity (based on the power output from the biomass), resulting in CO_2 avoidance costs of USD 10 to USD 60/tCO_2, depending on the biomass costs. Co-firing with biomass and waste is already commercially applied today to plants in several parts of the world, including the United States, Europe and Australia (IEA Bioenergy Task 32, 2009).

The share of biomass or waste being co-fired is, however, limited: on the one hand by the biomass supply available, and on the other hand by the costs of the necessary adaptation measures to the plant, which are mainly linked to fuel preparation processes for the biomass. Typical co-firing shares of biomass are in the range of 10% to 30% of the totalthermal output of a pulverised coal plant (Spliethoff, 2010). In the 2DS, the share of

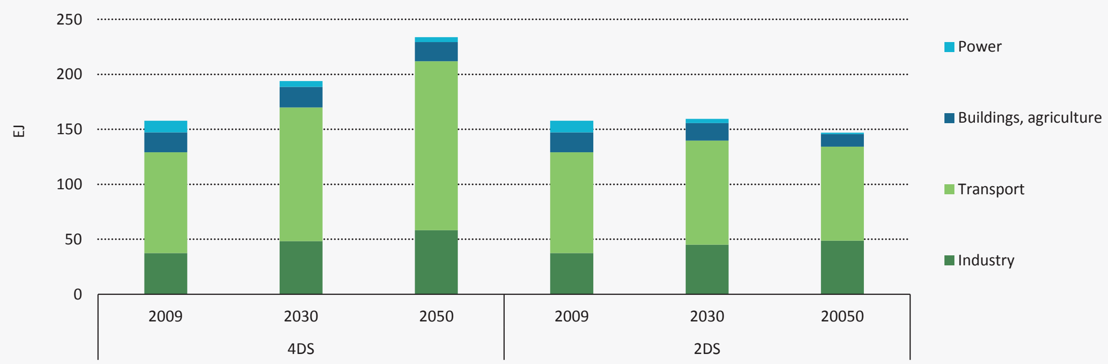
4 The estimation of net revenue losses is based on assumed average full-load of 5 000 hours and base-load electricity prices in the 2DS increasing from USD 40/MWh in 2015 to USD 60/MWh in 2050. The CO_2 price penalty is calculated evaluating the CO_2 emissions from the continued operation of the plants with the CO_2 prices in the 2DS.

electricity from co-fired coal plants in the total output of all coal plants peaks at 6% in 2030 and declines thereafter to 5% in 2050. While in early years, biomass is co-fired in existing coal plants without CCS, by 2050 co-firing is applied to plants with CCS to further offset the remaining carbon emissions of the capture plant through the captured CO_2 from the biomass.

Scenario results for fuel transformation

Global liquid fuel demand (including biofuels and hydrogen) increases in the 4DS by around 50% by 2050 compared with today. Petroleum use in the transport sector, especially from the growth in travel demand in non-OECD regions, is primarily responsible for this growth (Figure 11.13). In the 2DS, the impact of growth in transport activities on liquid fuel demand is gradually offset, initially by more efficient conventional vehicles and later through the deployment of electric vehicles, so that global liquid fuel demand stabilises at around today's levels in 2050.

Figure 11.13 Liquid fuel demand by end-use sector



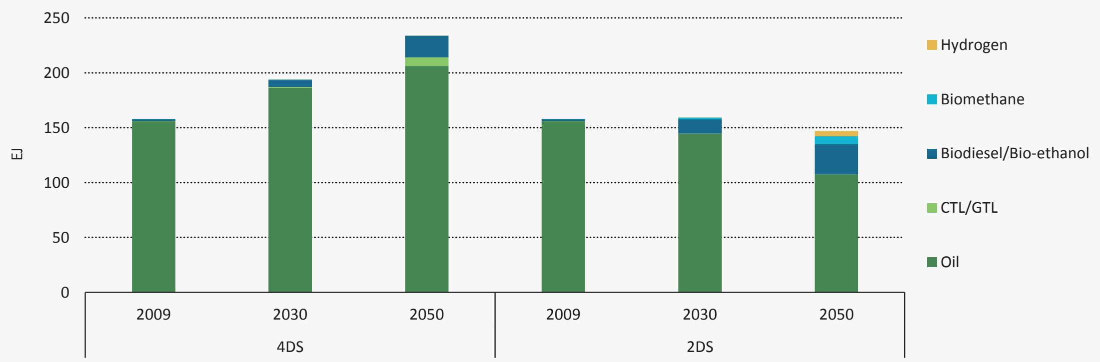
Note: Liquid fuel demand includes liquid biofuels, hydrogen and biomethane.

Key point *Fuel savings and fuel substitutions, primarily in the transport sector, stabilise liquid fuel demand near today's level in 2050 in the 2DS.*

The increase in liquid fuel demand in the 4DS is not met by conventional crude oil production alone (Figure 11.14). With oil prices increasing over time in this scenario, reaching around USD 120 per barrel (bbl) in 2050, alternatives to petroleum, such as gas-to-liquids (GTL), coal-to-liquids (CTL) and biofuels, become more competitive. Fossil CTL and GTL synfuels as well as biofuels start to be deployed on a larger scale after 2025 in the 4DS, providing 3% and 9%, respectively, of global liquid fuel demand by 2050. Emissions from refining and fossil synfuel production increase to 1.2 $GtCO_2$ by 2050 in this scenario.

Oil demand in the 2DS in 2050 is more than one-quarter lower than in 2009 (Figure 11.14). Liquid biofuels provide 27 EJ (or 18% of global liquid fuel demand), with around 70% from BTL plants and 30% from advanced ethanol plants using lignocellulosic feedstocks. In addition, around 7 EJ of bio-SNG and 5 EJ of hydrogen are produced in 2050. The bio-SNG, representing around 6% of the global gas demand in 2050, is blended with natural gas. Most of the 5 EJ of hydrogen production is used in the transport sector, with around 1 EJ being produced from biomass. Overall, around 75 EJ of biomass are used globally in 2050 in the 2DS to produce biofuels, including hydrogen and bio-SNG. A precondition for such an increased use of biofuels is, however, that the biomass feedstock is produced in a sustainable way to avoid adverse effects on food production and negative impacts on GHG emissions from land-use changes (*e.g.* replacing food crops and forests with energy crop plantations). In contrast to the 4DS, GTL or CTL production capacity is not developed under the stringent CO_2 reduction conditions of the 2DS, corresponding to a CO_2 price of USD 150/tCO_2 in 2050.

Figure 11.14 Liquid fuel supply



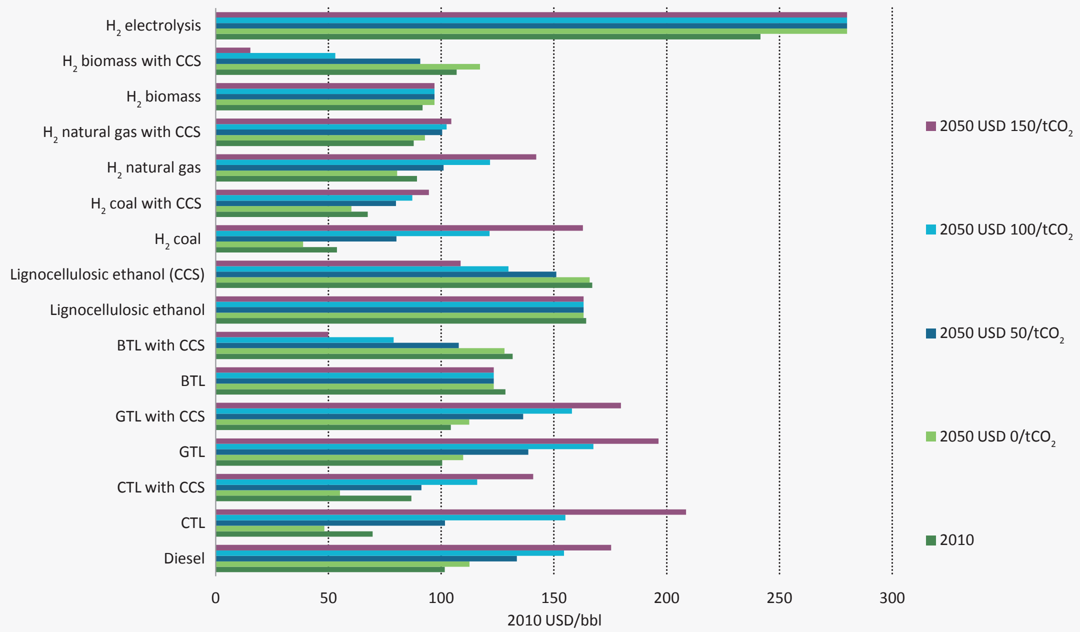
Note: Liquid fuel supply includes liquid biofuels, hydrogen and biomethane.

Key point *Fuel alternatives to petroleum gain market shares, but most liquid fuel supply still relies on oil in 2050.*

The effect of the CO_2 price on the production costs for various alternative fuel technologies is shown in Figure 11.15. Without any CO_2 price, CTL and GTL (in regions with low gas prices) without CCS is cost-competitive in the near term with conventional petroleum at an oil price range of USD 60-100/bbl. Hydrogen from coal has even lower production costs, but requires additional investments in the distribution system and vehicle technology compared with liquid fuels. Additional costs for capturing CO_2 from a CTL or GTL plant are rather modest, so that in the 4DS in 2050, despite a CO_2 price of around USD 60/tCO_2, the prevailing oil price of USD 120/bbl makes CTL still economical with conventional petroleum. The cost advantage changes in favour of biomass-fired technologies as CO_2 prices increase further.[5] For biofuels produced in combination with CCS, the production costs even decline as CO_2 prices increase, since the captured carbon from the biomass input represents a net removal of CO_2. This translates into a carbon credit and reduces the biofuel production costs of a plant with CCS accordingly.

5 A CTL plant without CO_2 capture emits around 115 tCO_2 per gigajoule (GJ) of fuel produced. These emissions are 1.5 times higher than the emissions caused when actually burning the produced fuel. Due to the lower carbon content of natural gas, the emissions of GTL plants are much lower, with around 28 tCO_2 per GJ of fuel produced.

Figure 11.15 Production costs of selected alternative fuels for different CO_2 price levels



Notes: H_2 = hydrogen.
Cost calculations are based on a discount rate of 8%. Fuel prices are based on the 2DS. Oil prices are USD 78/bbl in 2010 and USD 87/bbl in 2050. Coal prices are USD 3.4/GJ in 2010 and USD 2.1/GJ in 2050. Gas prices are USD 4.2/GJ in 2010 and USD 6.6/GJ in 2050. Global average electricity prices are USD 18/GJ in 2010 and USD 34/GJ in 2050. For biomass-based options in this illustration, biomass prices are assumed to be USD 6/GJ in 2010 and USD 8/GJ in 2050. In the scenario analysis, the biomass costs vary depending on the resource type and the region. For fossil-based fuel options (coal, gas, diesel), costs include the CO_2 price penalty when burning the produced fuel, whereas for biomass-based options with CCS the CO_2 price credit for the captured CO_2 results in a reduction of the production costs.

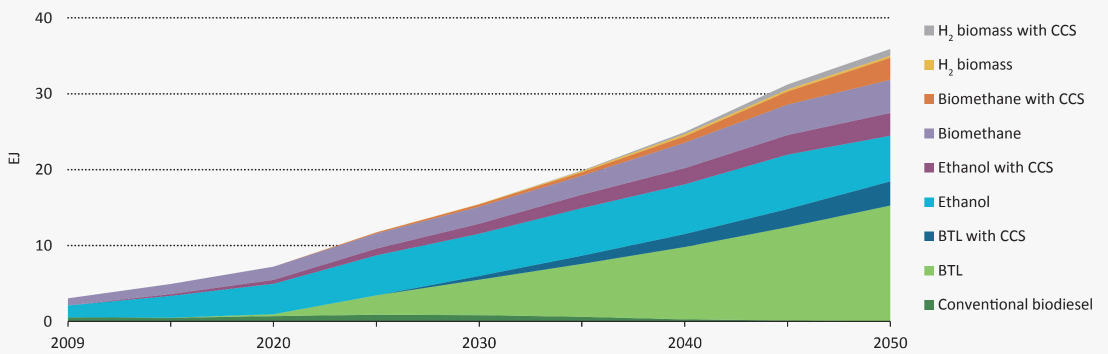
Key point *The CO_2 price is an important factor influencing the cost-effectiveness of alternative fuel production options.*

Capturing CO_2 from biofuel production plants and storing it underground becomes an attractive CO_2 mitigation option in the 2DS: during its growth the crop sequesters CO_2 from the atmosphere, which is captured in the biofuel plant and then stored underground. This cycle results in a removal of CO_2 from the atmosphere and leads to "negative" emissions for the use of bioenergy in combination with CCS (BECCS). In the 2DS, 28% of the biofuel production comes from plants with CCS (Figure 11.16).

Additional capture costs for gasification-based technologies (BTL, bio-SNG and hydrogen from biomass) are comparably low because CO_2 is removed from synthesis gas in the process to increase product yield. Also, ethanol plants provide a relatively pure CO_2 as flue gas, so that additional capture costs are mainly connected to the treatment of CO_2 (dehydrating and compressing) for subsequent transport to the storage site.

Since such capture plants, for economic reasons, have to be large-scale installations, they must secure sufficient, sustainably produced biomass input, while simultaneously providing the necessary CO_2 transport and storage infrastructure: all are critical factors that limit the use of biomass with CCS. In the 2DS, around 1.3 $GtCO_2$ is captured from biofuel plants in

Figure 11.16 **Fuel production (including hydrogen and biomethane) from biomass by technology in the 2DS**

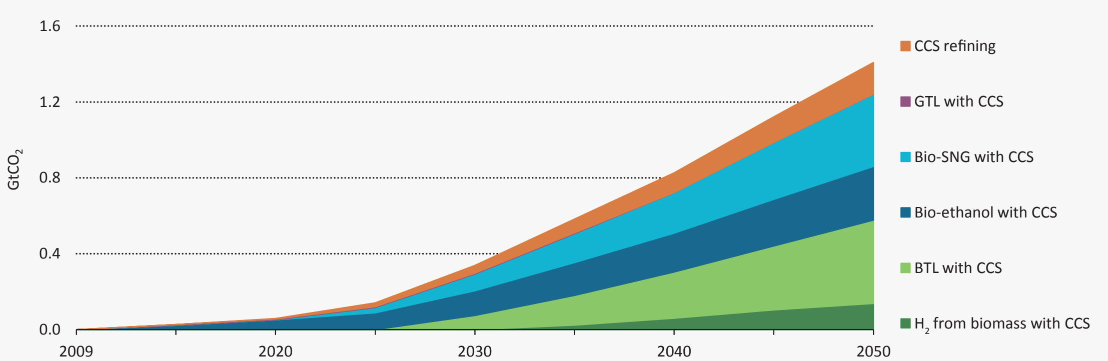


Key point *Almost 30% of biofuel production is based on plants equipped with CCS.*

2050, which corresponds to around 4% of the total annual CO_2 reductions from the 4DS to the 2DS (Figure 11.17). In addition, 167 $MtCO_2$ are captured in the refining industry, mainly at central refinery co-generation plants or steam boilers.

Reduced petroleum demand is, however, the primary reason for declining CO_2 emissions in the refining sector, down from 680 $MtCO_2$ today to 350 $MtCO_2$ in 2050 in the 2DS. Taking into account the fact that the CO_2 that is captured from biomass-conversion processes results in "negative" emissions, the overall annual net emissions of the fuel transformation sector become negative by 2050, with an annual amount of around 900 $MtCO_2$ removed from the atmosphere.

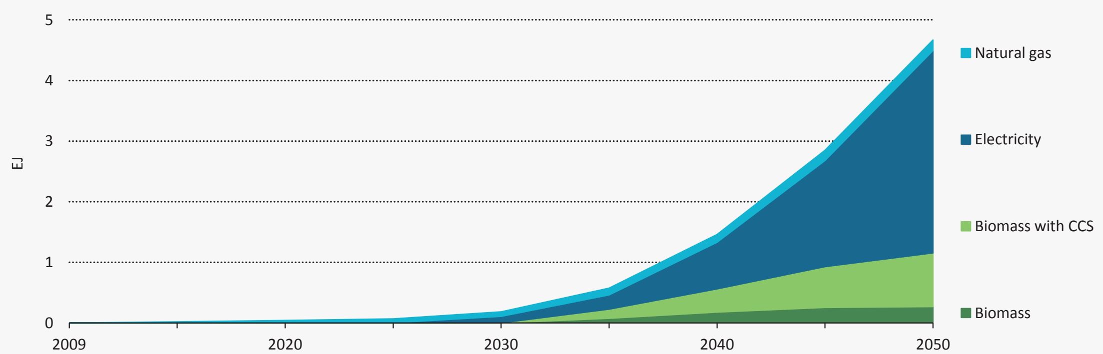
Figure 11.17 **CO_2 captured in the fuel transformation sector in the 2DS**



Key point *Biofuel production with CCS can be an attractive option resulting in "negative" emissions.*

Around 70% of hydrogen is produced from electricity (Figure 11.18). With increasing variable renewable generation in the power sector by 2050 in the 2DS, the transformation of electricity into hydrogen becomes an attractive means for storing part of the surplus electricity during times of low electricity demand and using it as fuel, mainly in the transport sector and to some extent also feedstock in the industry sector. Taking into account the better fuel economy of a fuel cell vehicle compared to a conventional gasoline car, hydrogen use in transport replaces around 10 EJ of oil in the 2DS in 2050.

Figure 11.18 Hydrogen production by fuel in the 2DS



Key point *Hydrogen may become an attractive storage option for surplus electricity from variable renewables by 2050.*

In the 2DS, around 1 300 TWh of electricity in 2050 are used globally to produce hydrogen, which represents around 14% of the electricity produced from variable renewable energy sources (solar, wind, ocean energy). Converting electricity to hydrogen and using it as fuel or feedstock can be an option for long-term storage of electricity. The necessary electrolysing technology, however, has yet to be demonstrated on a scale large enough to absorb the electricity from large solar and wind plants. The development of the necessary infrastructure to transport and store hydrogen poses a further challenge. Blending hydrogen with natural gas may be an alternative in regions with existing gas infrastructure. As discussed in more detail in Chapter 7, hydrogen may become cost-effective in the future compared with competing storage technologies, provided that envisaged cost reductions in large-scale hydrogen production and storage technologies are achieved. The possibility of using hydrogen as transport fuel or as industry feedstock can further increase its attractiveness, since they avoid losses from converting the hydrogen in stationary fuel cells back into electricity.

Variants of the 2DS for the power sector

To address the inherent uncertainties in the future progress of low-carbon technologies in the power sector, variants of the 2DS were analysed exploring different electricity mixes. The variants compared with the base 2DS were the 2DS without CCS (-no CCS), the 2DS with a higher renewable share (-hiRen) and the 2DS with a higher generation from nuclear power (-hiNuc). All the variants' results, for the global power sector between 2009 and 2050, show the same cumulative CO_2 emissions budget – 320 Gt – as in the base 2DS.

The 2DS-no CCS variant assumes that CCS is not available as a mitigation option in the power sector. This variant should *not* be regarded as a prediction that CCS will not be available in the future, but rather that removing CCS illustrates its contribution to cost-effective emissions reductions in the power sector. In 2050 in the 2DS, CCS provides 14% of global electricity generation. In the 2DS-no CCS variant, generation from CCS is mainly replaced by increased production from renewables and also by nuclear power (Table 11.2). Without CCS, cumulative investment needs in the power sector increase by USD 3.1 trillion compared with the 2DS. This represents a 40% increase in the additional capital costs needed to reach the same climate target as in the 2DS, and underscores the important role CCS may play in decarbonising the power sector. Taking into account the cumulative fuel cost savings of the 2DS-no CCS variant relative to the base 2DS of USD 1.2 trillion, the overall costs of this variant are USD 1.9 trillion higher than in the base 2DS.

The second variant, 2DS-hiRen, explores a higher renewable share in the generation mix driven by a lower deployment of nuclear and, at the same time, a delay in the development of CCS. Progress in demonstration projects for CCS has been much slower than anticipated a few years ago due to a lack of concrete long-term commitments to emissions reductions among governments, inadequate and delayed funding programmes, and in a few cases, inadequate public engagement at both policy development and project development stages. The uncertainty regarding the future role of nuclear has increased since the Fukushima Daiichi nuclear accident arising from the Great East Japan Earthquake. Planned projects are likely to be delayed, costs may increase due to tighter security standards and countries may decide to alter their course regarding nuclear.

In the 2DS-hiRen variant, it is assumed that only 50% of the nuclear capacity additions seen in the base 2DS are realised. Plants already under construction today are assumed to be completed. This means that instead of adding nuclear capacity on the order of 1 050 GW, only 500 GW are added by 2050. Total installed nuclear capacity in this variant comprises 570 GW in 2050, compared with 1 100 GW in the base 2DS. The deployment of commercial-scale CCS plants in the 2DS-hiRen is assumed to be delayed by 10 years, from 2020 to 2030.

As a consequence of the later deployment, global installed capacity with CCS in 2050 falls from 960 GW to 460 GW. The smaller contribution from both nuclear and CCS in the 2DS-hiRen variant towards the reduction target requires a faster and greater ramp-up of generation from renewable sources. The renewables share in 2050 increases from 57% in the base 2DS to 71% in the 2DS-hiRen, largely due to an increase in generation from solar and wind energy. Generation from natural gas also increases, partly due to the need to provide flexible generation to integrate the larger generation from variable renewable sources in the system. Cumulative additional investment in this scenario is around USD 2.5 trillion, which represents an almost 32% increase in the additional capital costs needed to reach the emissions trajectory of the 2DS. The lower consumption of coal in this variant results in fuel cost savings of USD 0.4 trillion compared with the 2DS and offsets part of the additional investments, so that the overall costs of the 2DS-hiRen variant are USD 2.1 trillion higher than in the base 2DS.

In the 2DS-hiNuc variant, the maximum allowed nuclear generation capacity is increased to 2 000 GW in 2050. Almost all of this nuclear potential is used and the share of nuclear in the generation mix increases to 34% in 2050. Compared with the base 2DS, nuclear replaces power plants with CCS and renewables, whose share in 2050 falls: in the case of CCS from 15% to 7%, and in the case of renewables from 57% to 49%. The scenario reflects a world with larger public acceptance of nuclear power. On the technical side, the average construction rate for nuclear power plants in the period 2011 to 2050 rises from 27 GW/yr in the base 2DS to 50 GW/yr in this variant. In addition, this variant requires a larger nuclear fuel supply, which would require – depending on the future success in uranium exploration – also the recycling of spent fuel through advanced nuclear reactors or the use of unconventional uranium resources. The cumulative investment costs of this variant are only USD 0.2 trillion higher than in the base 2DS and are more than offset by costs savings for fossil fuels in the order of USD 2 trillion.

Table 11.2 Global electricity production by energy source and by scenario

	2009	6DS, 2050	4DS, 2050	2DS (base), 2050	2DS-no CCS, 2050	2DS-hiRen, 2050	2DS-hiNuc, 2050
Production (TWh)							
Coal	8 118	22 419	11 308	629	778	471	667
Coal with CCS			1 245	4 303		2 069	1 809
Natural gas	4 299	10 418	9 851	3 190	4 276	4 373	3 405
Natural gas with CCS			70	1 588		680	1 155
Oil	1 027	528	453	120	118	123	124
Biomass and waste	288	1 833	2 407	2 750	2 850	2 889	2 801
Biomass with CCS			107	338		196	91
Nuclear	2 697	4 236	5 337	7 918	10 170	4 291	14 006
Hydro	3 252	5 738	6 121	7 094	7 274	7 159	6 420
PV	20	556	1 153	2 655	3 237	4 822	2 639
CSP	1	439	1 264	3 333	3 687	4 215	2 688
Wind, onshore	270	2 163	3 398	4 197	4 409	4 760	3 765
Wind, offshore	3	395	625	1 948	2 345	2 500	1 234
Geothermal	67	390	567	981	1244	1 366	729
Ocean	1	117	182	521	837	810	243
Total	**20 043**	**49 232**	**44 087**	**41 565**	**41 226**	**40 723**	**41 776**
Share (%)							
Coal	41%	46%	26%	2%	2%	1%	2%
Coal with CCS	0%	0%	3%	10%	0%	5%	4%
Natural gas	21%	21%	22%	8%	10%	11%	8%
Natural gas with CCS	0%	0%	0%	4%	0%	2%	3%
Oil	5%	1%	1%	0%	0%	0%	0%
Biomass and waste	1%	4%	5%	7%	7%	7%	7%
Biomass w CCS	0%	0%	0%	1%	0%	0%	0%
Nuclear	13%	9%	12%	19%	25%	11%	34%
Hydro	16%	12%	14%	17%	18%	18%	16%
PV	0%	1%	3%	6%	8%	12%	6%
CSP	0%	1%	3%	8%	9%	10%	6%
Wind, onshore	1%	4%	8%	10%	11%	12%	9%
Wind, offshore	0%	1%	1%	5%	6%	6%	3%
Geothermal	0%	1%	1%	2%	3%	3%	2%
Ocean	0%	0%	0%	1%	2%	2%	1%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Renewable share	**19%**	**24%**	**36%**	**57%**	**63%**	**71%**	**49%**
Cumulative emissions (Gt CO_2), 2009-50		765	578	320	320	320	320
Additional cumulative costs relative to 6DS (2010 USD trillion)							
Investment costs			2.5	7.7	10.8	10.2	7.9
Fuel costs			–12.0	–33.7	–34.9	–34.1	–35.8
Total			**–9.5**	**–26.0**	**–24.1**	**–23.9**	**–27.9**

Recommended actions for the near term

Given the long technical lifetime of most of the technologies used in the electricity and fuel transformation sector, decisions over the next ten years will affect the structure of these sectors in 2050 and thereby the possibility and the costs of reaching a development path compatible with the 2DS.

The lock-in into carbon-intensive power technologies has to be avoided as far as possible. Special attention should be paid to improving the efficiency of fossil-fired power plants. More efficient use of coal does not only provide CO_2 reductions but also other environmental benefits, such as better air quality. New plants should be based on the best technology available. Their planning should take into account the later retrofit with CCS. For existing fossil-fuel plants, the possibilities for upgrading equipment, retrofitting with CO_2 capture or replacing with a new plant should be assessed.

Co-firing of biomass can be, depending on the available biomass supply, a proven and low-cost measure to reduce carbon emissions from coal-fired generation. The overall efficiency of existing fossil-fired plants can also be improved by using the waste heat, otherwise lost to the environment, for heating or cooling purposes in nearby industrial plants or buildings. The conditions for conversion into co-generation plants, however, are site specific. Governments and utilities should evaluate its potential and, where appropriate, promote its development.

Policy support for renewables in power generation has to be continued, taking into account the development status of individual technologies. Renewable energy sources will play a crucial role in a decarbonised power system, providing almost 60% of electricity in 2050. By 2020, 27% of electricity is based on renewable sources in the 2DS, compared with around 20% today. Several renewable technologies, such as hydropower, biomass and conventional geothermal energy, are already cost-competitive, depending on the local conditions. Others, such as onshore wind or PV, become competitive in several countries or require, as do CSP, offshore wind and enhanced geothermal, additional efforts to foster technological progress.

Many countries have introduced policy frameworks to support renewable technologies. Governments should ensure that policies are designed in a transparent and predictable way and backed by long-term targets. At the same time, policies should be flexible enough to be adjusted to the achieved maturity and market competitiveness levels of the individual technologies.

Countries pursuing nuclear power have to review safety protocols in order to convince a more sceptical public. In order to reach national nuclear deployment goals, governments have to address public concerns regarding nuclear power. Safety protocols and licensing standards for nuclear should be reviewed and updated. Experience from the Fukushima accident arising from the Great East Japan Earthquake should be shared internationally, and recommendations from the post-Fukushima stress tests should be implemented with appropriate speed. Independent regulatory institutions overseeing the nuclear industry should be strengthened.

Efforts for research and demonstration of biofuel conversion technologies have to be intensified. Biofuels are an alternative to oil in the transport sector, resulting in CO_2 reductions but also reducing the dependency on fossil fuels. Compared with other alternative transport fuels, such as hydrogen, liquid biofuels require no investment in a new distribution infrastructure and can be used with existing engine technologies. Liquid biofuels are especially needed for transport modes, where other alternatives for emissions reductions are more challenging, such as aviation or shipping.

Realising the scale-up in biofuel production, as envisaged in the 2DS, will require more research to improve the efficiency of existing conventional biofuel technologies in order to minimise feedstock input and land-use impacts. In addition, governments should provide support (*e.g.* grants or loan guarantees) for demonstration projects of large-scale advanced biofuel plants to address the high investment risks associated with such projects. In parallel, further research and development is needed to improve the performance and reliability of these advanced conversion technologies. To avoid negative impacts from increased biofuel production on food security or on GHG emissions (due to land use changes), mandatory certification schemes for biofuel production, based on internationally agreed-upon criteria, should be introduced.

Chapter 12

Industry

Industry must reduce its direct carbon dioxide emissions by 20% if it is to contribute to the global target of halving energy-related emissions by 2050. Bringing about the needed technology transition will require both a step change in policy implementation by governments, and unprecedented investment in best practice and breakthrough technologies by industry.

Key findings

- ***The implementation of best available technologies (BATs) could reduce energy consumption by 20% from today's level*** *and offer some of the least-cost options to reduce energy consumption and emissions in industry. Action is needed to ensure the new facilities and retrofit equipment are reaching BAT level, otherwise this capacity will be sub-optimal and very costly to upgrade.*

- ***Efficiency alone will not be sufficient to offset strong growth in demand****, and new technologies, such as smelting reduction, separation membranes, advanced catalysis, black liquor gasification, and carbon capture and storage (CCS), are needed to achieve significant energy emissions reduction.*

- ***Decarbonisation of the power sector will nearly eliminate indirect carbon dioxide (CO_2) emissions in industry by 2050****, which today represent 20% of total industry CO_2 emissions. Greater electrification of industrial processes offers new opportunities to further reduce CO_2 intensity, but additional research and development (R&D) is needed particularly in the iron and steel and chemical and petrochemical sectors.*

- ***CCS represents the most important new technology option for reducing direct emissions in industry****, with the potential to save 2.0 gigatonnes of CO_2 ($GtCO_2$) to 2.5 $GtCO_2$ in 2050. Without CCS, emissions in 2050 would not be reduced.*

- ***A move away from fossil fuels for combustion and feedstock and toward increased use of biomass and waste represents a critical option to reduce CO_2 emissions****, accounting for more than 20% of the reduction between the ETP 2012 4°C Scenario (4DS) and 2°C Scenario (2DS). However, significant competition for limited biomass resources from other sectors may lead to increased costs and possibly make industrial applications less attractive.*

- ***Reaching the goal of the 2DS requires industry in developed and developing countries to spend an estimated USD 10.7 trillion to USD 12.5 trillion*** *between 2010 and 2050. This represents between USD 1.5 trillion and USD 2.0 trillion above the investments required by the 4DS and the ETP 2012 6°C Scenario (6DS).*

Opportunities for policy action

- *Support for demonstration of carbon capture technologies is needed in the high-purity, cement, iron and steel and pulp and paper sectors. Governments also need to accelerate development of CO_2 transport and storage options, and to put in place required regulatory frameworks to facilitate CCS in industrial applications.*
- *Government and industry should increase R&D for novel processes, including electrification and hydrogen options, which allow for carbon-free production of materials in the longer term.*
- *Clear, stable, long-term policies that put a price on CO_2 emissions are necessary if industry is to implement the technology transition needed to achieve deep emissions reductions. Government intervention is also needed in the form of standards, incentives and regulatory reforms.*

Over recent decades, global industrial energy efficiency has improved and CO_2 intensity has declined substantially in many sectors. This progress has been more than offset by growing industrial production worldwide, most noticeably in developing countries. As a result, total industrial energy consumption and CO_2 emissions have continued to rise.

Production of industrial materials in most sectors is expected to double or triple to satisfy growing demand over the next 40 years. As a result, projections of future energy use and emissions, based on current technologies, show that without decisive action by all stakeholders, the upward energy trends in the recent past will continue. This is clearly not sustainable.

Making substantial cuts in industrial CO_2 emissions requires the widespread adoption of BATs and the development and deployment of a range of new technologies. This technology transition is urgent. Analysis of the sector shows that industrial emissions must peak in the coming decade to avoid the worst impacts of climate change.

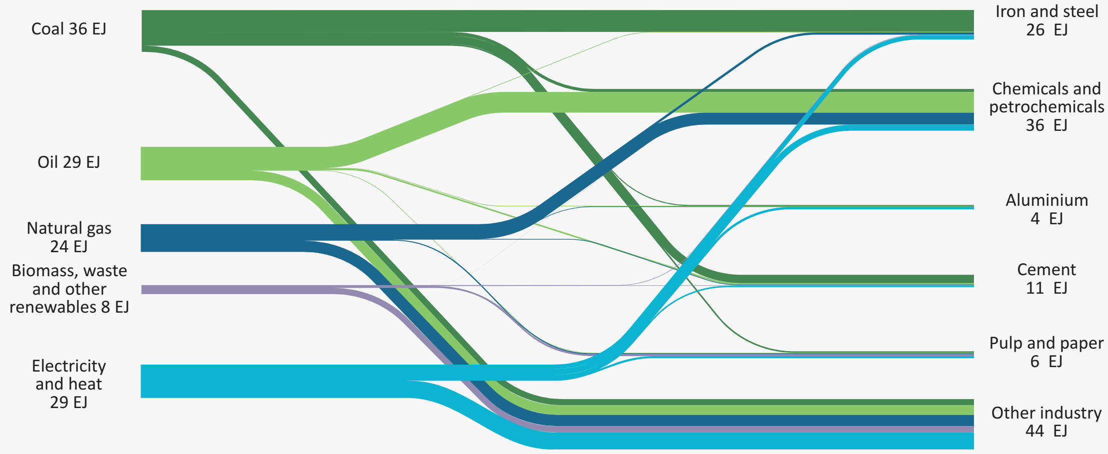
Industry and governments need to work together to research, develop, demonstrate and deploy (RDD&D) the promising new technologies already identified, as well as find and advance novel processes that allow carbon-free production of common industrial materials in the longer term. They should also investigate the development of new materials that would allow emissions reduction down the value chain.

Industrial energy use and CO_2 emissions

Total final energy use by industry, including energy use in coke ovens and blast furnaces and as a feedstock, reached 126 exajoules (EJ) in 2009. The five most energy-intensive industry sectors – iron and steel, cement, chemicals and petrochemicals, pulp and paper, and aluminium – accounted for over 65% of total industrial energy consumption (Figure 12.1). These sectors consume about three-quarters of all fossil fuels used in industry and are responsible for an even higher share of total industrial CO_2 emissions, some 78%.

While gross domestic product (GDP) has increased almost fourfold since 1971, industrial energy consumption has increased by about 75%. Most of the growth occurred in the last decade with the increased demand for, and production of, industrial materials in developing countries. This increase is reflected in the substantial change in regional industrial energy consumption (Figure 12.2). While OECD member countries were using 63% of industrial energy in 1971, the share decreased to 36% in 2009. Asian countries are now the main energy users, accounting for 41% of total industrial energy consumption.

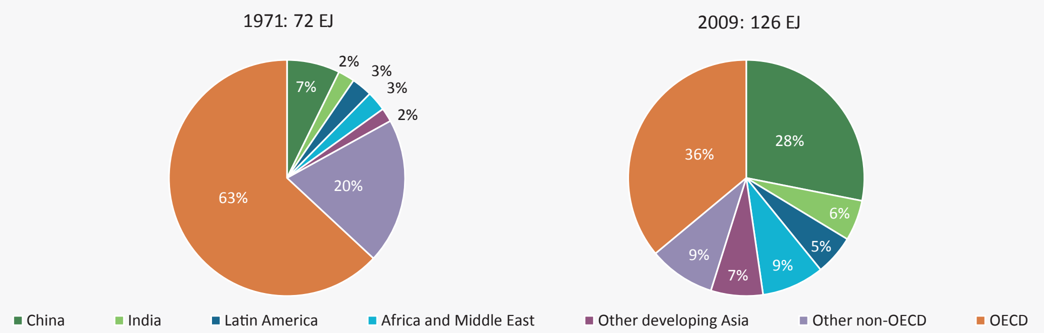
Figure 12.1 Energy consumption flow in the industry sector, 2009



Note: Includes energy use as feedstock and in coke ovens and blast furnaces.
Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *Iron and steel and chemicals and petrochemicals accounted for about 50% of industrial energy consumption in 2009.*

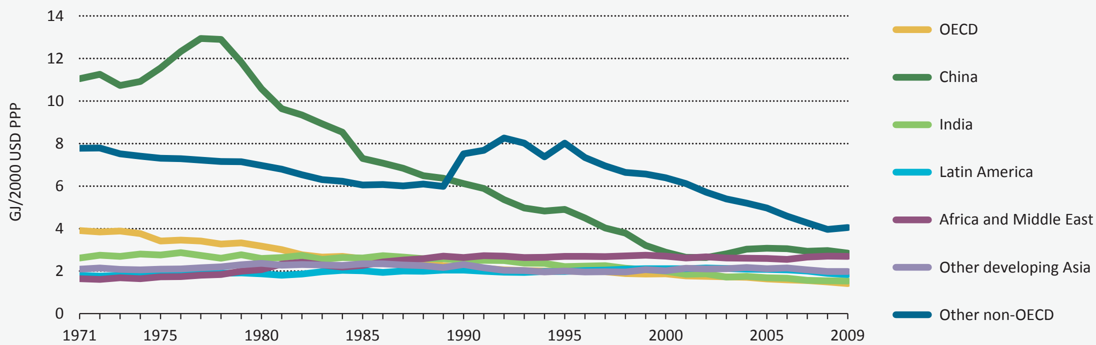
Figure 12.2 Global industrial energy consumption by region



Key point *Industries in Asia accounted for 41% of industrial energy consumption in 2009, up from 11% in 1971.*

At the same time, a substantial shift has been observed in the share of industrial energy consumption by sector. The five most energy-intensive sectors now account for more than 65% of the total industrial energy consumption, up from 51% in 1971. The structural changes within the industry sector had an upward impact on overall energy intensity. However, the improvements in energy efficiency offset this impact in many regions of the world. As a result, there has been a convergence of the energy intensity in industry – the energy use by unit of industrial value-added (Figure 12.3). Developing countries generally improved the most, partly due to a significant change in the mix of industry in these countries (relatively lower energy-intensive industry accounting for a higher share of the economy), the closure of small, inefficient units and the high production growth rate allowing the addition of new and efficient production capacity.

Figure 12.3 Evolution of aggregate industrial energy intensity by region



Notes: GJ = gigajoules, PPP = purchasing power parity.

Key point *The average energy intensity of regions is converging over time.*

Since 2000, major changes have occurred in the industrial sector worldwide. Developing countries, led by China, saw their production share increase from 52% to 73% for the five main industrial sectors analysed in this chapter. OECD countries experienced a major downturn due to the global economic recession, which started in 2008 and deepened in 2009. While there were positive signs of a slow recovery in OECD countries starting in 2010, overall production in most sectors is not yet back to 2000 levels.

Industry scenarios

Worldwide implementation of BAT is just the first step if industry is to make deep cuts in CO_2 emissions. To analyse the longer-term potential contribution of new technologies for emissions reduction, a detailed modelling framework is used to examine three different scenarios and two variants in the industrial sector to the year 2050.[1]

The *ETP 2012* 6DS reflects developments that are expected on a business-as-usual basis. Only the energy and climate policies and measures that have already been implemented are taken into account in this scenario. Following such a path leads to an eventual 6°C rise in global temperature. For industry, this scenario results in CO_2 emissions that are 45% to 65% higher in 2050 than they were in 2010. While autonomous energy efficiency is observed, no major shifts in technology or energy consumption mix are expected in this scenario.

The *ETP 2012* 4DS is consistent with a carbon portfolio for the global economy that limits the rise in temperature to 4°C by 2050. Such a scenario requires that all policies and measures currently planned be duly implemented. Industry increases the adoption of BATs in new facilities. Use of biomass and other alternative energy sources also increases. Industrial CO_2 emissions under this scenario would increase 20% to 30% between 2010 and 2050.

1 For more detail on the different scenarios developed for *ETP 2012* see Annex A: Analytical approach.

However, to limit the impact of climate change, further reductions beyond those foreseen in the 4DS are required. The *ETP 2012* 2DS examines the implications of a policy objective to achieve the required emissions reduction that limits the growth in global average temperature to 2°C. In this scenario, global energy-related CO_2 emissions in 2050 are half the current level. Achieving this goal also requires deep cuts in other greenhouse-gas emissions.

The 2DS explores the technical options that need to be exploited to halve global CO_2 emissions by 2050. This does not mean that industry necessarily needs to reduce its emissions by 50%. Reaching the global CO_2 emissions objectives in the most cost-effective way does require each economic sector to make a contribution, based on its costs of abatement. Under this scenario, industrial CO_2 emissions would be between 6.7 $GtCO_2$ and 6.8 $GtCO_2$ in 2050, about 20% less than current levels.

Given the recent global economic crisis and uncertainties about projecting long-term growth in consumption, two variants have been developed for each industry and for each scenario: a low-materials demand case (low-demand) and a high-materials demand case (high-demand). The difference in global materials production between the low- and high-demand cases to 2050 varies between 15% and 35%. As both the 2DS low- and high-demand cases are driven by the same level of CO_2 emissions reduction in 2050, the high-demand case requires greater reductions in emissions levels than the low-demand one. As a result, costs are also higher in the high-demand case.

The scenarios take an optimistic view of technology development and assume that technologies are adopted as they become cost-competitive and that non-technical barriers, such as social acceptance, proper regulatory framework and information deficits, are overcome. The analysis here does not assess the likelihood of these assumptions being fulfilled, but it is clear that deep CO_2 reductions can be achieved only if the whole world plays its part.

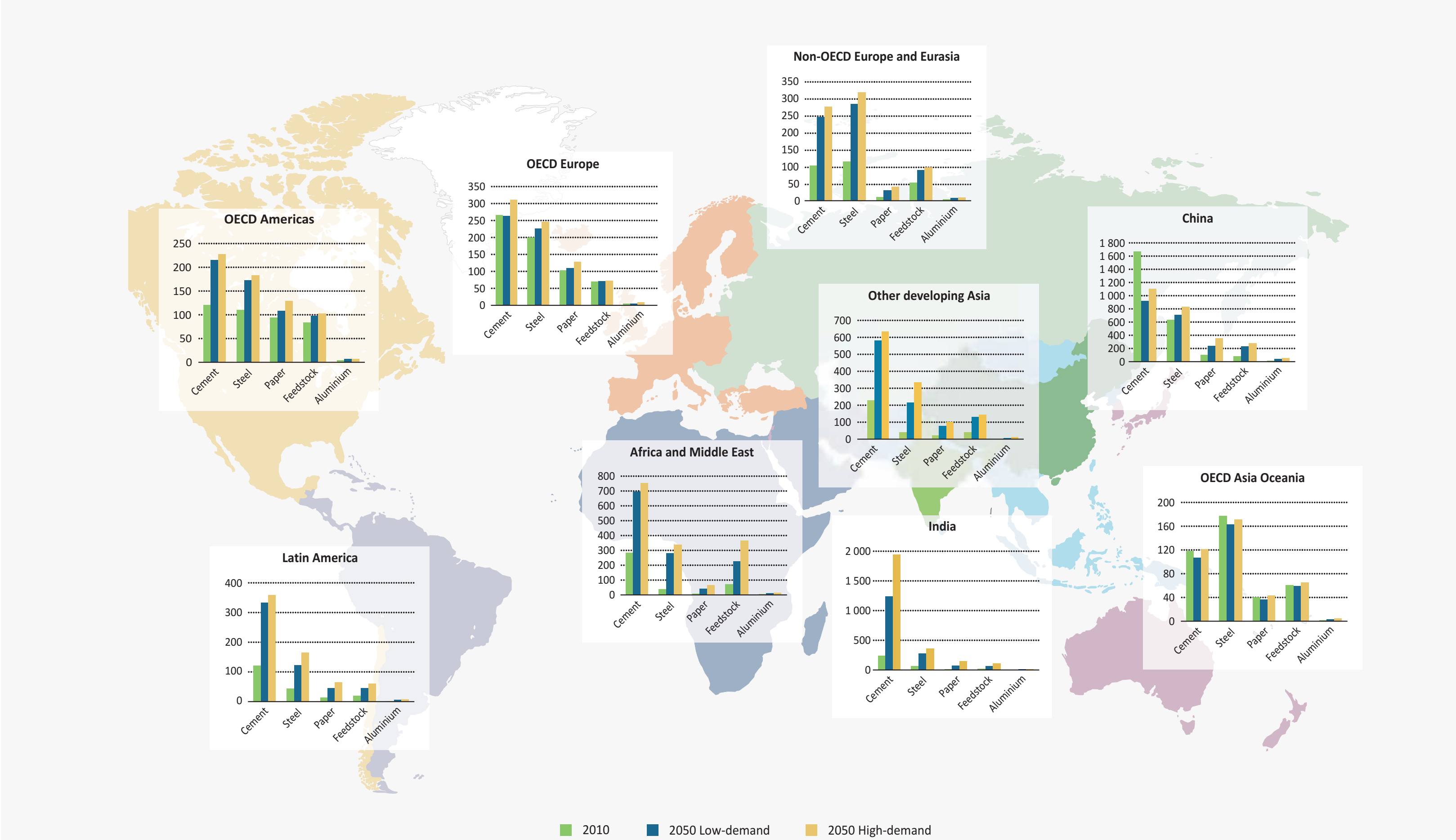
These scenarios are not predictions. They are internally consistent analyses of the pathways that may be available to meet energy policy objectives, given a certain set of optimistic technology assumptions.

Scenario results

China, India and other developing countries in Asia have dominated growth in industrial production since 1990. Based on observed historical trends and projected growth in population and GDP in developing countries, the IEA scenarios assume that in the next 20 to 40 years, as industrial development matures, there will be another significant change in industrial production (Figure 12.4). Growth in China's materials will flatten or, in the case of cement, decline. But in most non-OECD regions, industry development accelerates. Materials production in Asia (excluding China), and Africa and the Middle East more than triples over the 2010 to 2050 period. Most of the growth in North America occurs within the next decade, as industry will be recovering from the heavy impact of the recent economic recession. Other OECD countries are expected to show relatively flat production or only modest increases as consumption levels for materials in these countries are already mature and population growth is expected to be relatively flat or declining.

Materials consumption and production are assumed to be the same under all three scenarios analysed. The differences lie in the different primary resources and the processes used in materials production. For example, the 2DS assumes use of a higher share of recycled materials (*e.g.* steel, aluminium, paper, plastics), which are usually processed with relatively more efficient technologies.

Figure 12.4 Materials production in 2010 and 2050



This document and any map included herein are 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.

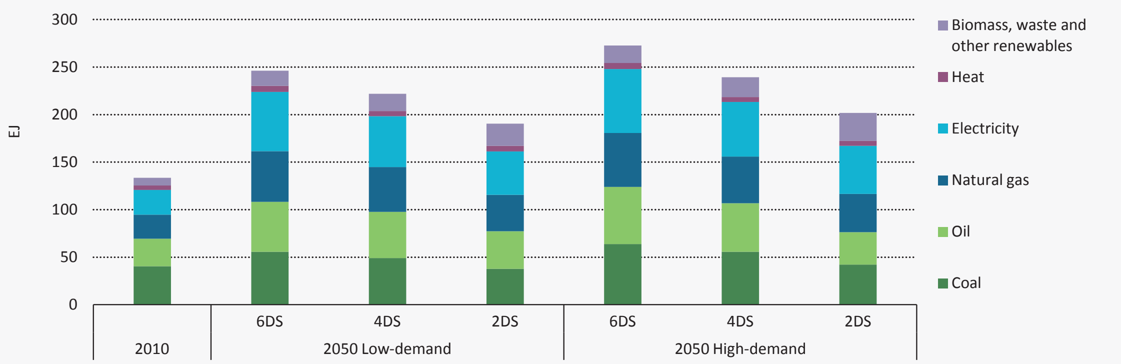
Notes: Feedstock = chemicals and petrochemicals feedstock. All values in million tonnes.

Key point *Growth in industrial production will be the strongest in non-OECD countries in the 2010 to 2050 period.*

Industrial energy consumption is, to a large extent, driven by production of materials. Other parameters can influence how energy consumption evolves over time. While more growth generally results in greater energy consumption, it also opens up opportunities to improve the overall efficiency of the industry by adopting BATs in the new facilities or production units being built.

This improved efficiency contributes to the further decoupling of materials production and energy consumption. Changes in the raw materials or processes used can also, in some cases, allow a shift from fossil-fuel consumption to other less carbon-intensive energy sources. Energy consumption levels and patterns in the 2DS, compared with the 6DS and the 4DS, illustrate the decoupling of energy consumption and materials production that can be achieved (Figure 12.5).

Figure 12.5 **Final energy consumption in industry**



Key point *Energy consumption in 2050 will be 15% lower in the 2DS than in the 4DS.*

A significant reduction in CO_2 emissions in industry, to between 6.7 $GtCO_2$ and 6.8 $GtCO_2$, is only possible if all sub-sectors contribute (Figure 12.6). The reductions envisaged under the 2DS in industry can be achieved by deploying existing BATs, by improving production techniques, and by developing and installing new technologies that deliver improved energy efficiency, enable fuel and feedstock switching, promote more recycling, and increase capture and storage of CO_2. Many new technologies that can support these outcomes – such as iron and steel smelting reduction process, new separation membranes, and advanced co-generation and regenerative burners – are currently being developed, demonstrated and adopted by industry.

Additional research, development and demonstration (RD&D) is needed to develop breakthrough process technologies for the CO_2-free production of materials and to advance understanding of system approaches, such as the optimisation of life cycles through recycling and developing new materials that contribute to emissions reductions in other sectors. These longer-term options will be needed in the second half of this century to ensure sustainability of industrial processes to the end of the century and beyond.

Box 12.1 Investment needs and fuel savings

In the 2DS, investment needs by 2050 in the five most intensive sectors are estimated to be between USD 10.7 trillion and USD 12.5 trillion between 2010 and 2050; this represents USD 1.5 trillion to USD 2.0 trillion above the investments required by the 6DS and 4DS. Most of the additional investment is needed in the cement, iron and steel, and chemical and petrochemical sectors. These sectors account for the largest share of emissions in industry.

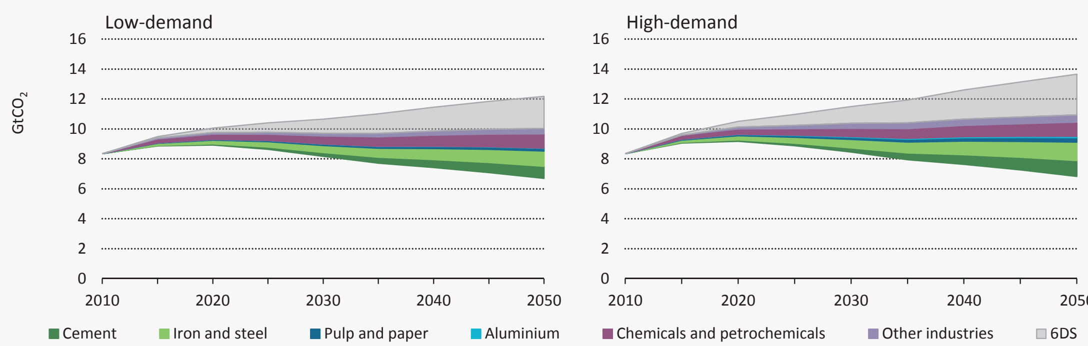
The additional investments in best available and new technologies, made at the time of plant or unit refurbishments, will yield significant savings in fossil-fuel consumption. The total fuel savings in the 2DS compared with the 6DS are estimated to be around USD 7.8 trillion for the 2010-50 period (undiscounted). Overall, the net cumulative savings are estimated at USD 5 trillion to USD 6 trillion.

Iron and steel

The iron and steel sector is the second-largest industrial user of energy, consuming 26 EJ in 2009, and is the largest industrial source of CO_2 emissions with 2.3 $GtCO_2$.

While global crude steel production stayed nearly constant between 1975 and 2000, it grew 67% between 2000 and 2010, an average annual growth rate of 5.3% per year. The rapid expansion of production capacity has generally had a positive effect on the industry's energy efficiency. Additional capacity has reduced the average age of the capital stock. New plants tend to be more energy-efficient than old plants, although not all new plants apply BATs. In addition, existing furnaces have been retrofitted with energy-efficient equipment, and ambitious efficiency policies have led to shuttering inefficient plants early in several countries.

Figure 12.6 Direct CO_2 emissions reduction by industry between the 4DS and 2DS



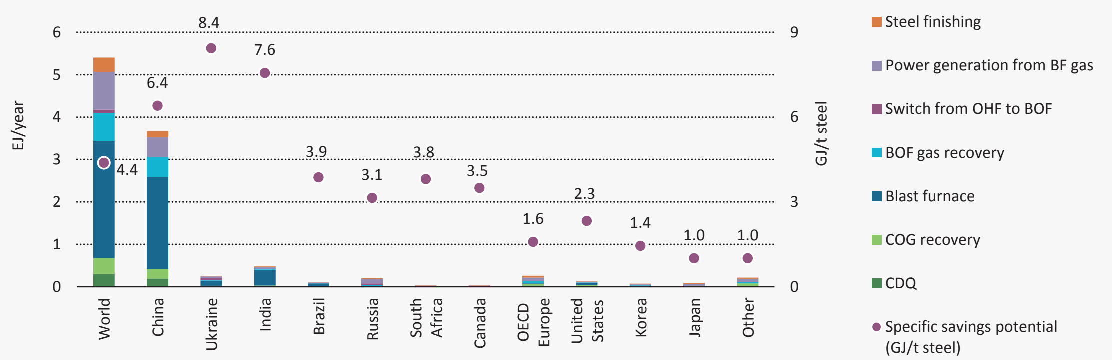
Key point *CO_2 emissions need to peak by 2020 to achieve the 2DS emissions target.*

But at the same time, recycling as a proportion of total steel production has declined from 47% in 2000 to around 31% in 2010. This relative decline in the share of scrap use is in part attributable to China's use of blast furnace (BF) and basic oxygen furnace (BOF) technologies in 2010 – as the availability of scrap is not sufficient to meet the rapidly growing production – rather than scrap-intensive electric arc furnaces (EAF), plus the increasing amount of steel embedded in products that are still in use and have not reached the end of their lifespan. With relatively stable levels of scrap available for reuse, more crude steel has had to be produced from ore to meet the rapid rise in demand for steel.

The iron and steel industry has been greatly affected by the global economic downturn. World crude steel production decreased from 1 351 megatonnes (Mt) in 2007 to 1 232 Mt in 2009 (Worldsteel, 2011). Most of this decrease occurred in OECD countries, where production decreased by over 25%. The industry shows some signs of recovery: in 2010, crude steel production reached 1 417 Mt, an increase of 15% over the previous year. The five most important producers (China, Japan, the United States, Russia and India) accounted for over 65% of total global crude steel production in 2010.

While disaggregated energy data at the process level are not currently available to construct detailed indicators, bottom-up estimates can be made for energy and CO_2 emissions reductions that can be achieved by applying BAT. It is possible to break down the estimated technical potential based on current production volumes and current energy consumption. While there has been substantial improvement in iron and steel energy intensity in the recent past, industry has the technical potential to reduce its energy consumption by 5.4 EJ (Figure 12.7), about 20% of the sector's current total energy consumption, by applying BAT. More than 65% of this technical potential is in China. If achieved, over 400 $MtCO_2$ would be avoided, about 18% of total direct CO_2 emissions from the iron and steel industry. While the technical potential is considerable, the economic potential for achieving these savings is significantly less as it requires major rebuilding or refurbishing of plants. This potential may also be particularly difficult to achieve in countries with small-scale production plants and low-quality indigenous coal, iron and ore, and where the plants are relatively new.

Figure 12.7 **Current energy savings potential for iron and steel, based on best available technologies**



Notes: The rate of implementing best available technologies in practice depends on a number of factors, including capital stock turnover, relative energy costs, raw material availability, rates of return on investment and regulations.
BF = blast furnace; OHF = open-hearth furnace; BOF = basic oxygen furnace; COG = coke-oven gas; CDQ = coke dry quenching (also includes advanced dry quenching); GJ/t = gigajoules per tonne: EJ/year = exajoules per year.

Key point *The iron and steel sector can achieve energy savings of 5.4 EJ in the medium to long term by applying currently available BATs.*

Globally, per capita consumption of crude steel amounted to 201 kilograms (kg) in 2010. Driven by strong economic growth in developing countries, which raised the income per capita, the consumption rate is expected to increase to between 270 kg/capita and 319 kg/capita by 2050. To meet this strong demand, crude steel production is estimated to increase from 1 417 Mt in 2010 to between 2 438 Mt and 2 943 Mt in 2050.

About 31% of crude steel production in 2010 came from recycled steel. This is estimated to increase to about 45% in 2050 in the 6DS and 4DS. Under these two scenarios, coal-based direct reduced iron (DRI), which is mostly produced in India and South Africa, is increasing as a share of iron production.

The picture that emerges from the 2DS is totally different from the 6DS and 4DS (Table 12.1). The production of coal-based DRI will be phased out. Production from gas-DRI, and blast furnaces equipped with CCS, will increase substantially. New processes and technologies, such as smelting reduction, also increase notably under the 2DS.

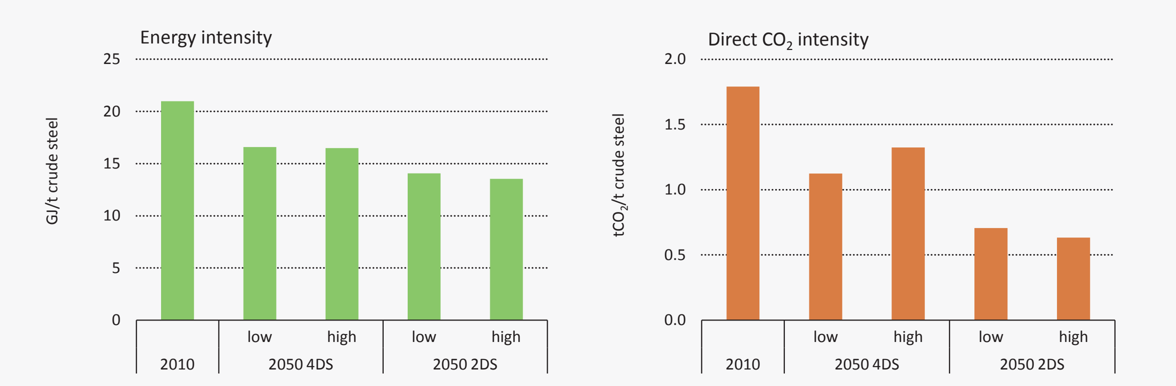
Table 12.1 Iron and steel production by scenarios

Production (Mt)		Low-demand case 2050			High-demand case 2050		
	2010	6DS	4DS	2DS	6DS	4DS	2DS
Crude steel	1 232	2 438	2 438	2 438	2 943	2 943	2 943
EF steel	351	1 224	1 259	1 233	1 484	1 523	1 500
BF/BOF	881	1 213	1 179	1 205	1 459	1 420	1 442
Pig iron	913	1 211	1 177	1 087	1 457	1 418	1 216
Smelting reduction	0	12	12	128	12	12	237
Gas-based DRI	47	187	187	254	224	224	310
Coal-based DRI	17	127	127	0	152	152	0
Scrap use	354	1 116	1 153	1 193	1 359	1 400	1 444

Notes: EF = electric furnace; BF = blast furnace; BOF = basic oxygen furnace; DRI = direct reduced iron.

The differences in production and process routes used in the different scenarios will have a strong impact on the energy and CO_2 intensity of the iron and steel sector. Under the 2DS, energy intensity in 2050 is about 35% lower and CO_2 intensity is 61% to 65% lower than the current levels (Figure 12.8). The improvements in overall energy intensity of crude steel production can be mostly attributed to increased recycling and use of scrap, the relative increase in the share of new efficient plants, and the penetration of new technologies. But the additional energy required for CCS partly offsets the improvements in energy intensity.

Figure 12.8 Iron and steel energy intensity and direct CO_2 emission intensity

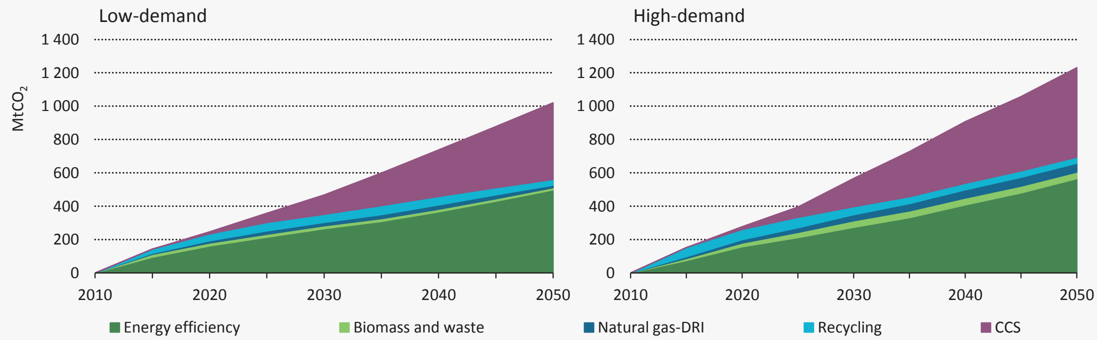


Key point *The application of CCS on blast furnaces and gas-DRI explains the greater improvement in CO_2 intensity.*

Despite the increase of 72% to 108% in crude steel production between 2010 and 2050, total direct CO_2 emissions decrease by 37% in the 2DS low-demand case and by 40% in the 2DS high-demand case compared with the 4DS. The pursuit of four main technology options – energy efficiency, fuel switching, CCS and better materials flow management – are required to maximise energy savings and CO_2 emissions reductions (Figure 12.9).

Maximising energy efficiency is the most important option for the iron and steel sector. There is significant energy-efficiency potential through replacing small-scale facilities in developing countries and outdated OHF in Ukraine and Russia. From 2020 onward, CCS starts to have a more measurable impact and, by 2050, accounts for 45% of CO_2 emissions reductions from the 4DS.

Figure 12.9 **Technologies for reducing iron and steel direct CO_2 emissions between the 4DS and 2DS**



Key point *Half of the CO_2 reductions between the 2DS and 4DS are from improved energy efficiency.*

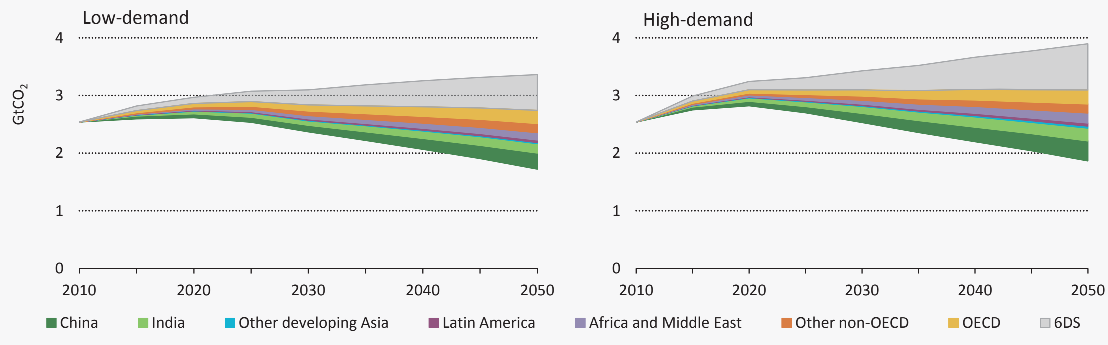
In the 6DS, emissions are expected to continue to rise year to year from 2.5 $GtCO_2$ in 2010 to 3.4 $GtCO_2$ (low-demand case) or 3.9 $GtCO_2$ (high-demand case) in 2050. In the 4DS, emissions are expected to peak between 2025 and 2030 to reach between 2.7 $GtCO_2$ (low-demand case) and 3.1 $GtCO_2$ (high-demand case) in 2050.

In the 2DS low-demand case, global emissions peak between 2015 and 2020, and then begin to decline as more efficient and cleaner technologies are introduced (Figure 12.10). With lower growth rates in production than developing countries, the contribution to reducing emissions by OECD countries in 2050 is consequently much smaller.

Although it is important that OECD countries take the lead in new technology deployment and diffusion, implementation alone of policies and measures to achieve reductions in CO_2 emissions in OECD countries is not sufficient to reduce global emissions from industry. Non-OECD countries, which will account for over 90% of the crude steel production increase between 2010 and 2050, must contribute.

In order to reach the targets set out in the 2DS, multiple technology options need to be developed and deployed in the iron and steel sector. No one single option can yield sufficient reductions in direct CO_2 emissions.

Figure 12.10 Emissions reduction in the iron and steel sector by region



Key point *China accounts for about one-quarter of the reductions between the 4DS and the 2DS.*

Energy efficiency research should focus on new technologies that allow the use of low-quality coal and low-quality ore. Smelting reduction technologies in combination with pre-reduction facilities seem to offer the best prospects.

Natural gas-based DRI production, which is a well-established technology, can replace coal-based DRI. The development and exploration of unconventional gas reserves may play a role in further increasing the share of gas-based DRI in some countries. Gas can also be injected into blast furnaces, but volumes are limited by process conditions. Biomass, plastic waste and carbon-free electricity and hydrogen are other future options.

The increased use of charcoal for iron-making will require the development of an integrated agriculture, food, environment and water management policy to enable a large-scale transition to charcoal from sustainable plantations.

Hydrogen can be substituted for coal and coke in ore reduction, but the technology is far from the demonstration phase and the impact of CO_2 emissions will depend on the energy source used and the energy required to produce hydrogen. Production of iron by molten oxide electrolysis offers great potential to reduce global CO_2 emissions if the power sector is decarbonised.

The deployment milestones indicate some of the main technology assumptions in the 2DS (Table 12.2). Pursuit of different options will require that all stakeholders collaborate to ensure proper funding and support is available for demonstration programmes and address the non-technical barriers such as public acceptance, notably in the case of CCS.

The total investments implied in the 6DS and 4DS are estimated to be between USD 1.6 trillion and USD 2.3 trillion between 2010 and 2050 (Table 12.3). The investments required are not uniform over time or between regions. The estimates depend on the capacity growth and the type of technologies available at the time of construction or refurbishments of plants. The total incremental costs for the iron and steel sector to reach the 2DS are USD 180 billion to USD 290 billion higher than the investments under the 4DS.

Table 12.2 Main technology options for the iron and steel sector for the 2DS

Technology	Research and development needs	Demonstration needs	Deployment milestones
Smelting reduction	Improve heat exchange in FINEX. New configuration of HIsmelt to lower coal consumption. Integrate HIsmelt and Isarna processes (Hisarna). Pair straight hearth furnaces.	Demonstration plants are already operational for FINEX and HIsmelt. Demonstration plant for producing reduced iron oxide pellets is operational by 2015. Demonstration plant with smelter is operational by 2020.	Share of crude steel production from smelting reduction rises to between 128 Mt and 237 Mt in 2050.
Top-gas recycling blast furnace	Trial of existing experimental furnace was successful.	Commercial-scale demonstration of a small blast furnace is operational by 2014. Full-scale demonstration plant is operational by 2016.	Deploys in 2020. Contributes to a 20% decrease in coke needs by 2050.
Use of highly reactive materials	Development of innovative agglomerate to lower reducing agent in blast furnaces.	Demonstration plants already operational for ferro-coke.	Deployment after 2020.
Use of charcoal and waste plastic	Proven technologies are available. Focus research on improving the mechanical stability of charcoal.		Between 1.8 EJ and 3.3 EJ of charcoal and waste plastic is used globally in 2050.
Production of iron by molten oxide electrolysis	Assess technical feasibility and optimum operating parameters.	If the laboratory-scale project is successful, demonstration starts in the next 10 to 15 years.	Deploys after 2030. Reaches marginal market share by 2050.
Hydrogen smelting	Assess technical feasibility and optimum operating parameters.	If the laboratory-scale project is successful, demonstration starts in the next 15 to 20 years.	Deploys after 2040. Reaches marginal market share by 2050.
CCS for blast furnaces	Focus research on reducing the energy used in capture.	Demonstration plant already operational.	Equip 75% to 90% of all new plants built between 2030 and 2050 with CCS. Equip 50% to 80% of refurbished plants between 2030 and 2050 with CCS.
CCS for DRI		2015-20	Equip 75% to 90% of all new plants built between 2030 and 2050 with CCS. Equip 50% to 80% of refurbished plants between 2030 and 2050 with CCS.
CCS for smelting reduction		2020-30	Equip 75% to 90% of all new plants built between 2030 and 2050 with CCS. Equip 50% to 80% of refurbished plants between 2030 and 2050 with CCS.

Notes: FINEX is a smelting reduction process developed by Pohang Iron and Steel Company (POSCO) that consists of a melting furnace with a liquid iron bath, in which coal is injected and iron fines are pre-reduced in a series of fluidised bed reactors.
HIsmelt (high-intensity smelting) is an iron bath reactor process.
Isarna is a smelting-reduction technology under development by the Ultra-Low CO_2 Steelmaking (ULCOS) consortium. It is a highly energy efficient iron-making process based on direct smelting of iron-ore fines, using a smelting cyclone in combination with a coal-based smelter. All process steps are directly hot-coupled, avoiding energy losses from intermediate treatment of materials and process gases.

Table 12.3 Investment needs in the iron and steel sector to 2050 (in USD trillion)

	6DS low-demand	6DS high-demand	4DS low-demand	4DS high-demand	2DS low-demand	2DS high-demand
Total	1.6 to 1.8	1.9 to 2.2	1.6 to 1.8	2.0 to 2.3	1.8 to 2.0	2.3 to 2.5
OECD	0.2 to 0.2	0.2 to 0.3	0.2 to 0.2	0.2 to 0.3	0.3 to 0.3	0.3 to 0.3
Non-OECD	1.4 to 1.6	1.7 to 1.9	1.4 to 1.6	1.8 to 2.0	1.5 to 1.7	2.0 to 2.2

Cement

Although energy intensity per tonne of cement produced is less than that of other energy-intensive materials, the volume of production is much higher, with an estimated 3 048 Mt produced in 2009. The direct CO_2 emissions from thermal energy consumption and production processes were estimated to be 2.3 $GtCO_2$ in 2009. The energy, CO_2 intensity and volume of cement produced make this sector responsible for more than one-quarter of the direct emissions by the manufacturing industry.

Cement production increased from 980 Mt in 1980 to 1 650 Mt in 2000, an average annual growth rate of 2.6% per year. Driven by the rapid economic growth in developing countries in recent years, the rate of increase accelerated to 7% between 2000 and 2009. Due to the recent economic crisis – which more heavily affected the cement industry in OECD countries – annual growth in cement production dropped to 4% between 2007 and 2009. China is by far the largest producer of cement: while it accounted for 36% of global production in 2000, it now produces more than 50% of the world's cement.

Thermal energy consumption by the cement industry is strongly linked to the type of kiln used. Vertical shaft kilns consume between 4.8 gigajoules per tonne (GJ/t) and 6.7 GJ/t clinker. The long drying process requires around 4.6 GJ/t clinker, whereas adding pre-heaters and pre-calciners further reduces the energy requirement to between 2.9 GJ/t and 3.5 GJ/t clinker.

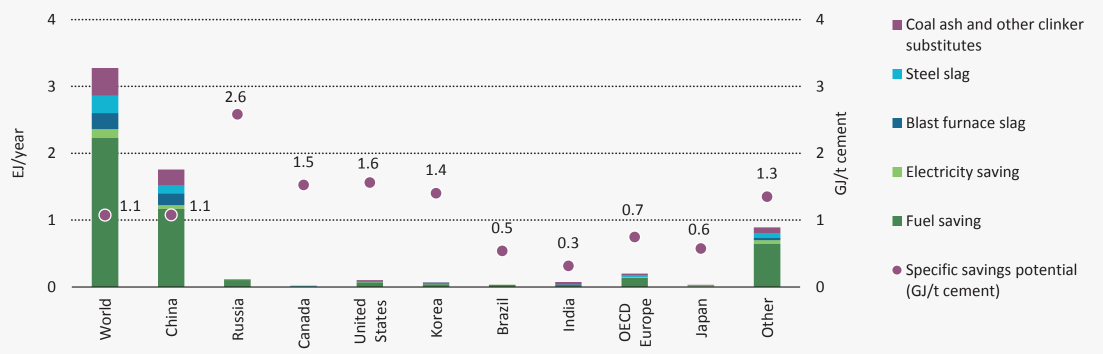
The rising number of dry-process kilns with pre-heaters and pre-calciners has had a positive impact on energy consumption in clinker production. Higher energy prices – coupled with buoyant economic growth, most noticeably in non-OECD countries – have resulted in lower energy intensities. Developing countries have added new large-scale, dry-process capacity to meet demand, thereby reducing the share of smaller, less-efficient kilns. Higher energy prices have also encouraged cement producers in developed countries to invest in new, more efficient plants or retrofits to improve energy efficiency.

Despite the recent improvements observed in the energy and emission intensity of cement plants, there is still potential for further improvement through the application of BATs and other options, such as increasing the use of clinker substitutes. Current BAT for the cement industry is a dry-process kiln with a pre-heater and a pre-calciner. Up to six stages of pre-heating can be used if the raw material feed has a low moisture content of less than 6% (VDZ, 2008), although a five-stage pre-heater is the norm in Europe for new plants.

In general, developing countries have lower technical potential than developed countries for reducing their energy consumption by applying BAT in cement since a large share of the production capacity is relatively new and efficient. Globally, if all plants used BATs, the global intensity of cement production could be reduced by 1.1 GJ/t cement produced, with significantly higher savings possible in many countries and regions (Figure 12.11).[2]

2 The calculation of potential savings is based on the assumption that the energy efficiency of cement kilns is improved first, so that subsequent savings are evaluated relative to BAT, and energy savings from clinker substitutes are based on BAT-level of energy consumption. An alternative approach would be to assess the savings from clinker substitutes at current energy efficiencies and then assess BAT savings from the lower level of clinker demand. This approach would yield a slightly lower share of savings from energy efficiency and slightly more from clinker substitutes.

Figure 12.11 Current energy savings potential for cement, based on best available technologies



Key point *The application of BAT and energy efficiency options could reduce energy consumption by 30% from today's level.*

There are major differences in per capita cement consumption between countries. In 2009, the global average per capita consumption was about 450 kg. By 2050, the demand is slightly higher and averages between 470 kg/capita and 590 kg/capita. This relatively small increase is attributable to trends in different countries and regions. China's and Korea's per capita demand (1 218 kg/capita and 1 028 kg/capita, respectively) is currently substantially higher than the average world demand. Demand from these two countries is expected to decrease and, by 2050, will be close to the world average. On the other hand, consumption in non-OECD countries (excluding China) is expected to rise from an average of 218 kg/capita in 2009 to between 480 kg/capita and 570 kg/capita in 2050.

Two main differences can be observed between the different scenarios (Table 12.4). The clinker-to-cement ratio in the 6DS and 4DS is 8% to 12% lower in 2050 than in 2009. In the 2DS, the ratio declines even further, to about 0.66 in 2050. The second difference relates to the mix of energy sources used to produce cement. In the 6DS and 4DS, the energy mix remains fairly unchanged between 2009 and 2050. In the 2DS, the share of coal decreases substantially from 67% in 2009 to about 35% in 2050. The use of biomass, waste and alternative fuels will increase to reach almost 30% of total energy consumption by 2050.

The clinker-to-cement ratio and the energy mix greatly influence the total energy consumption and direct CO_2 emissions of the cement sector. Energy intensity under the 4DS and 2DS is 23% to 29% lower than in 2009. The similar energy intensity between the two scenarios is attributable to several factors, including the increased use of alternative fuels and the application of CCS.

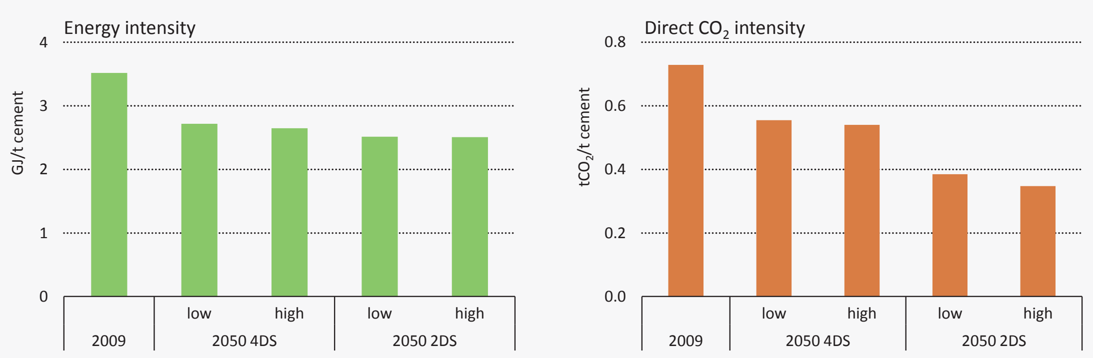
Fuel switching and the use of alternative fuels can offer important CO_2 reductions and in some cases result in lower operating costs. Cement kilns require only modest additional investment to utilise alternative fuels, and these can be attractive from an economic and CO_2-reduction perspective. Regulatory or institutional barriers can inhibit the use of alternative fuels: coherent policy frameworks on waste and the life cycle of waste are needed at the national level to help ensure that increasing quantities of waste are available and that they are treated so as to be useable in cement kilns. However, the increased use of alternative fuels tends to increase electricity consumption for pre-treatment and handling. The higher volume of alternative fuels used in the 2DS and the energy penalty resulting from the application of CCS offset part of the improvement from the lower clinker-to-cement ratio.

Table 12.4 Cement industry main indicators and energy sources by scenario

		Low-demand case 2050			High-demand case 2050		
	2009	6DS	4DS	2DS	6DS	4DS	2DS
Cement consumption (kg/cap)	451	472	472	472	593	593	593
Production (Mt)	3 048	4 400	4 400	4 400	5 521	5 521	5 521
Clinker-to-cement ratio	0.80	0.73	0.71	0.67	0.72	0.70	0.66
Total energy consumption (EJ)	10.7	13.4	12.9	12.0	15.0	14.6	13.8
Coal	7.2	8.0	7.0	4.4	9.1	8.2	4.9
Oil	1.3	2.2	2.1	1.1	2.4	2.3	1.2
Natural gas	0.6	1.0	1.2	1.4	1.1	1.2	1.9
Electricity	1.2	1.6	1.6	1.7	1.9	1.9	2.0
Biomass, waste and other renewables	0.4	0.6	1.0	3.4	0.6	1.1	3.9

In contrast, the increased use of alternative fuels and the use of CCS substantially help to decrease the direct CO_2 intensity in the 2DS. CO_2 intensity in the 2DS is 47% to 52% lower than in 2009, and between 31% and 36% lower than under the 4DS (Figure 12.12).

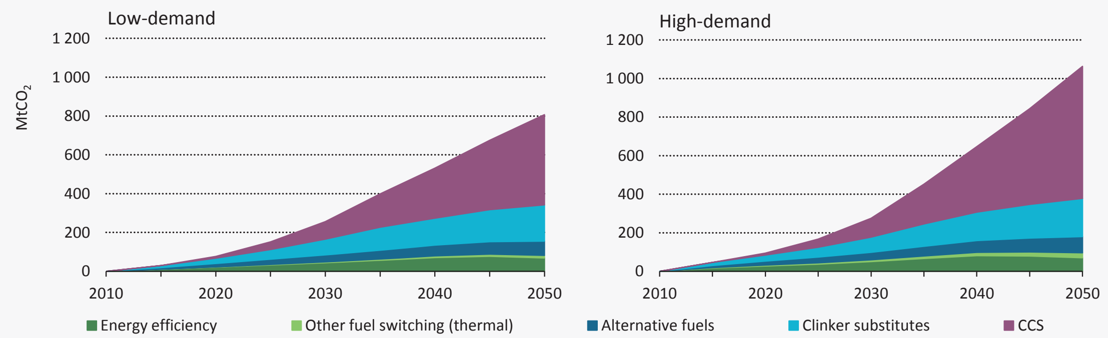
Figure 12.12 Cement energy intensity and direct CO_2 emission intensity



Key point *CO_2 emissions intensity in the 2DS is reduced by half compared with 2009.*

Efficiency improvements in the 2DS over and above the 4DS account for approximately 20% of total emissions reduction (Figure 12.13). Given the large share of process emissions, CCS is essential to reducing CO_2 emissions in the cement sector. By 2050, CCS is the most important option, accounting for more than 50% of the reduction. Without the implementation of CCS in this sector, CO_2 emissions in 2050 will be higher than their 2009 level, even if all other technology options are implemented.

Figure 12.13 **Technologies for reducing cement direct CO_2 emissions between the 4DS and 2DS**



Key point *CCS is required to reduce direct CO_2 emissions in the cement sector.*

Between 2009 and 2050, most of the growth in cement production comes from non-OECD countries. Production in OECD countries only slightly increases, reflecting the fact that the population increases by only 4% between 2030 and 2050. Cement production more than triples between 2009 and 2050 in India, Africa and other developing countries in Asia (excluding China), with the result that about 45% of all production in 2050 will be in these countries.

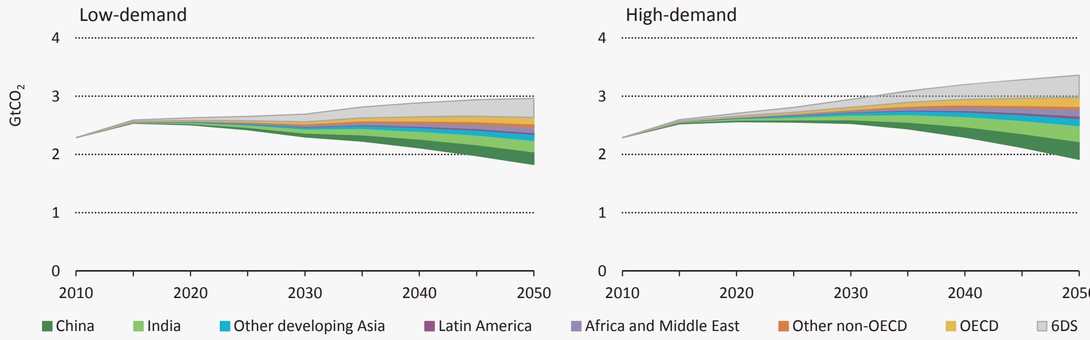
Direct CO_2 emissions continue to rise in both the 6DS and 4DS. In the 2DS, emissions also increase in the short run, but at a slower pace (Figure 12.14).

Regional trends in CO_2 emissions vary considerably. In the 4DS, emissions decrease in some OECD countries, while India's emissions increase about fourfold between 2009 and 2050. These emission trends are consistent with the production trends. Overall direct CO_2 emissions in 2050 would be 19% and 34% higher, respectively, in the 4DS low- and high-demand cases, than in 2009.

In the 2DS low-demand case, emissions peak between 2015 and 2020, and then begin to decline as more efficient and cleaner technologies are introduced. Emissions from OECD countries are expected to be between 29% and 32% lower in the low- and high-demand cases in 2050 than in 2009. For non-OECD countries, emissions are 16% and 10% lower, respectively, than in 2009. However, given the expected growth rate in the cement production from non-OECD countries and their importance on the global market, they will contribute the most to reducing direct CO_2 emissions.

Four primary technology options need to be exploited to reduce emissions in the cement sector (Table 12.5): improving energy efficiency, switching to less carbon-intensive fossil fuels and expanding the use of alternative fuels, implementing CCS, and expanding the use of clinker substitutes.

Figure 12.14 Emissions reduction in the cement sector by region



Key point *India and China account for more than 50% of the reductions between the 4DS and 2DS.*

The expanded use of clinker substitutes can substantially reduce energy needs and CO_2 emissions from the cement sector. However, it is hampered in some cases by regulatory or institutional barriers.

Further reductions in clinker-to-cement ratios require additional research and development to assess substitution materials and to evaluate regional availability. Developing and implementing international standards for blended cements can also support greater use of clinker substitutes.

Table 12.5 Main technology options for the cement sector for the 2DS

Technology	Research and development needs	Demonstration needs	Deployment milestones
Energy efficiency and shift to BATs	Ongoing further improvements of BAT. Fluidised bed technology.		Phase-out of inefficient wet kilns in small cement plants. International standard for new kilns.
Alternative fuels	Ongoing identification and classification of suitable alternative fuels.		Global shares increase from 4% in 2010 to about 30% in 2050.
Clinker substitutes	Analyse substitution material properties and evaluate regional availability. Develop and implement international standards for blended cements.		Global average clinker-to-cement ratio to reach between 0.66 and 0.67 by 2050.
CCS post-combustion	Pilot plant needed by 2013. Gas cleaning.	2015-20	About 50% to 70% of all new large plants and 30% to 45% of retrofitted plants equipped with CCS by 2050.
CCS oxy-fuelling		2020-30	

Widespread application of CCS is essential for the cement sector to reduce CO_2 emissions below current levels. Reaching the level of CCS implied in the 2DS means demonstrating CCS at cement plants by 2015 in order to ensure that different technology platforms are tested as early as possible. This is an essential precursor to starting commercial deployment between 2020 and 2025.

The deployment of CCS on any significant scale will require a clear long-term policy framework that stimulates the reduction of CO_2 emissions. In addition, the legal and regulatory framework for CCS must be decided upon and implemented in order to facilitate the development of the essential CO_2 pipelines and storage facilities.

Under the 2DS, total investment needs for the cement sector amount to between USD 1.4 trillion and USD 1.6 trillion (Table 12.6). Additional investment needs in the 2DS compared with the 4DS and 6DS are dominated by the additional up-front costs of installing CCS at cement plants; developing countries will need to make most of the investments. It is critical to overcome the barriers in developing countries posed by limited capital and multiple demands for its use. In Europe, CCS can double the capital cost of a cement plant (ECRA, 2008), as well as increase energy use and operating costs.

The total investment needs and marginal abatement costs for the cement industry are critically sensitive to future costs of CCS. If it is not commercially available until 2030, achieving the 2DS will require retrofitting more large- and medium-scale plants with CCS after 2030 to ensure that a sufficient share of cement kilns operate with CCS by 2050. This will significantly increase the marginal cost in the 2DS.

Table 12.6 Investment needs in the cement sector to 2050 (in USD billion)

	6DS low-demand	6DS high-demand	4DS low-demand	4DS high-demand	2DS low-demand	2DS high-demand
Total	910 to 1 043	988 to 1 125	931 to 1 070	1 016 to 1 159	1 399 to 1 437	1 605 to 1 616
OECD	58 to 67	68 to 77	59 to 69	69 to 80	104 to 110	121 to 126
Non-OECD	852 to 976	920 to 1 048	872 to 1 001	947 to 1 079	1 295 to 1 327	1 484 to 1 490

Chemicals and petrochemicals

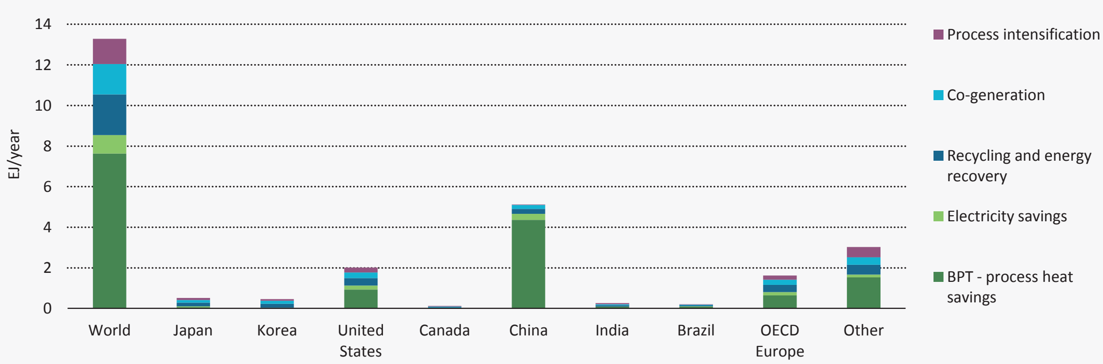
The use of energy and feedstock in the chemical and petrochemical sector accounted for approximately 10% of worldwide final energy demand in 2009, equivalent to 36 EJ. This sector of industry consumes the most energy, 29% of the total industrial final energy demand.

It is difficult to measure the physical production of the chemical and petrochemical sector given that end products are raw materials for other chemicals, that the material flows in the sector are interlinked to each other, and the large number of intermediate products that are traded at all levels of production. Some information, however, is available for some products. Plastic production represents both the largest and the fastest-growing segment of the chemical and petrochemical sector. Production increased more than 5% per year between 2002 and 2008 (PlasticsEurope, 2009), the latest year for which data are available. While growth has levelled off in some industrialised counties, production in China and other emerging economies continues to increase rapidly.

The potential for energy savings and CO_2 emissions reduction for the other sectors are established by comparing the current performance of a sector to the performance it could achieve if all the industrial plants in that sector were to have adopted BAT for the sector. These are technologies that, although they are usually in operation in some modern plants, are often not yet widely proven at industrial scale either technologically or economically. In the chemical and petrochemical sector, given the scale of most chemical and petrochemical plants, it is more appropriate to analyse potential improvements in energy efficiency by referring to the most advanced technologies that are in use at industrial scale; in other words, best practice technology (BPT) that is economically viable.

The analysis of energy savings that can be achieved by implementing BPT (Figure 12.15) is performed only in core chemical processes in this sector, although further opportunities for energy savings are possible in the short to medium term. As discussed in more detail in *Chemical and Petrochemical Sector – Potential of Best Practice Technology and Other Measures for Improving Efficiency* (IEA, 2009), process integration, co-generation,[3] and recycling and energy recovery all offer opportunities for reducing the industry's energy use and CO_2 emissions. The worldwide potential savings from these measures and from applying BPTs is more than 13 EJ in terms of final energy. The potential varies significantly between regions.

Figure 12.15 **Current energy savings potential for chemicals and petrochemicals, based on best practice technologies**



Key point *The chemical and petrochemical sector holds the potential for more than 13 EJ in energy savings.*

The world average consumption of high-value chemicals (HVCs)[4] is expected to increase from 44 kg/capita in 2010 to between 87 kg/capita and 105 kg/capita in 2050 in the low-demand and high-demand cases, respectively. The variations in production in the different scenarios are explained by increased recycling of post-consumer plastic wastes, which reduces the need for production of high-value chemicals (Table 12.7).

In the 2DS low- and high-demand cases, HVC and methanol production increases by 170% between 2009 and 2050. The largest growth in HVC production is expected to occur in Africa and the Middle East. Ammonia production grows between 67% and 94%.

3 Co-generation refers to the combined production of heat and power.
4 High-value chemicals include ethylene, propylene and BTX (benzene, toluene and mixed xylene).

Table 12.7 High-value chemical, ammonia and methanol production by scenario

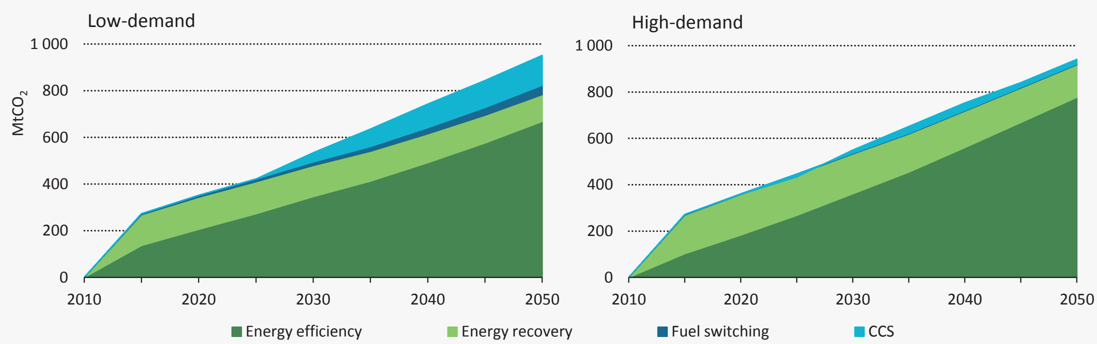
Production (Mt)		Low-demand case 2050			High-demand case 2050	
	2010	6DS	4DS	2DS	6DS	4DS	2DS
Ethylene	123	320	298	277	376	331	290
Propylene	77	208	192	178	243	196	158
BTX	105	283	268	254	331	279	234
Total HVC	*304*	*810*	*758*	*710*	*950*	*806*	*683*
Ammonia	159	259	259	259	300	300	300
Methanol	49	171	171	171	191	191	191

Note: BTX = benzene, toluene and mixed xylene.

Energy use in the 4DS low-demand case will increase from 42 EJ in 2010 to 82 EJ in 2050, and to 83 EJ in the high-demand case. In the 2DS, energy consumption will increase only 65 EJ to 64 EJ in 2050, thanks to greater energy efficiency and increased recycling that reduces energy intensity. The 2DS also assumes the use of biomass and waste, which accounts for 4% in the low-demand case, and 5% in the high-demand case, of total chemicals and petrochemicals energy use by 2050.

The largest reductions in direct emissions in the global chemical and petrochemical sector are from the thermal energy efficiency improvements (Figure 12.16). CCS also offers an increasingly important contribution to reducing emissions in the sector, and early deployment should focus on implementation in ammonia plants. CCS, in combination with large-scale co-generation units and in HVC production, will also need to be developed for the sector to realise the full potential of this option.

Figure 12.16 Technologies for reducing chemicals and petrochemicals direct CO_2 emissions between the 4DS and 2DS

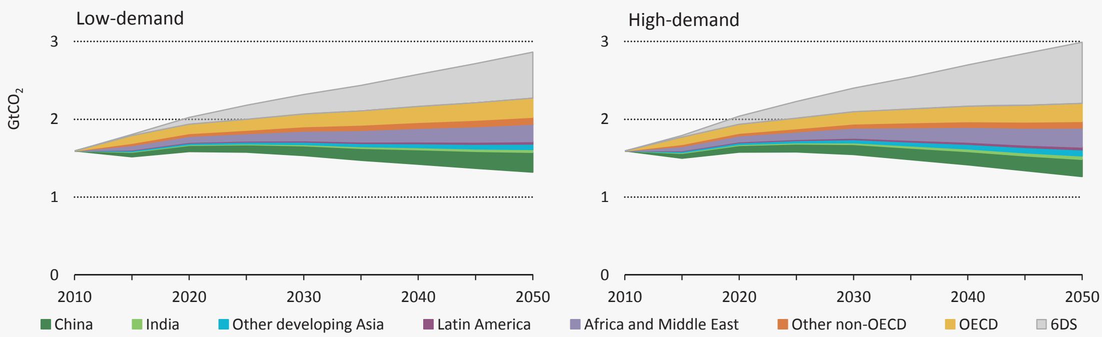


Key point *Energy efficiency accounts for more than 70% of the reduction potential in the chemical and petrochemical sector.*

Regional CO_2 emissions grow the fastest in Asia, and Africa and the Middle East, with emissions in these regions increasing threefold from the current rate in the 4DS

(Figure 12.17). These increases are in line with the expected production increase in chemical and petrochemical products. In OECD countries, emissions decline in this scenario as the efficiency improvements offset the upward impact of the small growth in chemicals production. Given the strong growth expected in Africa and the Middle East, these regions will contribute substantially to reducing CO_2 emissions. The move away from coal, and to a lesser extent oil, for the production of chemicals partly explains China's large contribution to the overall emissions reduction.

Figure 12.17 Emissions reduction in the chemical and petrochemical sector by region



Key point *China and Africa and the Middle East account for more than 50% of the reductions in the chemical and petrochemical sector.*

If the expected substantial growth in the chemical and petrochemical sector in the coming decades is to be sustainable and consistent with achieving broader goals for CO_2 emissions reduction, steps will need to be taken to bring to fruition many of the technological developments envisaged in the 2DS.

Implementing BPT in the short term and applying new technologies in the long term can enable the sector to significantly reduce its energy needs and its CO_2 intensity as well as reach the emissions levels implicit in the 2DS. Ambitious R&D – spanning basic and applied research, followed by effective new technological developments in such areas as catalysts, membranes and other separation processes; process intensification; and bio-based chemicals – can lead to substantial energy and/or CO_2 emission savings. All countries should strive to achieve current BPT levels by 2030 and additional improvements are needed which will further reduce energy intensity.

New technologies need to be on-line from 2020 onwards, and specific technological goals met, for the chemical and petrochemical sector to realise its full potential in reducing CO_2 emissions (Table 12.8). As companies invest in new technologies, they will make fundamental and, in many cases, irreversible choices about feedstock, as what they choose to support is likely to remain in use for decades.

Large-scale plants for the production of bio-based chemicals and plastics are currently being built. How well these plants and their products function over the next 10 to 20 years will determine, to a large extent, the success or failure of bio-based chemicals and plastics. Policy support needs to extend over relatively long periods in order to be successful. Designing suitable and affordable policies for bio-based chemicals and plastics is a challenge, given the complexity of the sector and its products, international trade agreements and the need to avoid displacing food production.

Box 12.2 Use of hydrogen in the chemical sector

Hydrogen could be used to replace fossil fuel based feedstocks and energy use in the chemical sector for the production of ammonia, methanol, ethylene and propylene. Currently, hydrogen production is predominantly based on fossil feedstocks via steam or autothermal reforming and partial oxidation with substantial CO_2 emissions. Hydrogen generation by these processes is coupled with the production of carbon oxide (CO) and CO_2, which are often used in subsequent transformations (*e.g.* urea from ammonia or methanol production). A smaller amount of hydrogen is produced by water electrolysis, a highly energy-intensive process whose resulting CO_2 emissions depend on the underlying energy mix of the electricity generation.

Existing processes could be adapted to reduce or eliminate CO_2 emissions linked to hydrogen production. Fossil fuel feedstocks could be used in combination with CCS. Replacement of fossil fuels by bio-based feedstocks could then even lead to negative emissions. Water electrolysis to produce hydrogen still has potential for significant improvements and energy savings but would require major R&D commitment. CO_2 emission-free production of hydrogen via electrolysis requires a decarbonised electricity supply. Hydrogen production through photocatalytic routes is currently a subject of fundamental research.

Active government policies will be essential to enable and promote the transition to more efficient and low-carbon technologies. Given the nature of the chemical industry, these policies need to extend from fundamental R&D schemes to demonstration plants and support schemes for early implementation.

Table 12.8 Main technology options for the chemical and petrochemical sector for the 2DS

Technology	Research and development needs	Demonstration needs	Deployment milestones
New olefin production technologies	Improve methanol-to-olefin (MTO) processes and oxidative coupling of methane (OCM).		Currently under way with full commercialisation starting after 2020.
Other catalytic processes	Improve performance and further reduce gap to thermodynamically optimal catalytic process by 65% to 80%.	Under way.	Starting in 2020-25.
Membranes	Develop other novel separation technologies.		Expand use of membrane separation technologies.
Bio-based chemicals and plastics	Develop bio-based polymers.	Bio-based monomers.	Wider use of bio-based feedstock from 2025. Global share of bio-based feedstock to increase and reach between 4% and 5% of total feedstock used in 2050.
Hydrogen			Deployment after 2040. Marginal market share by 2050.
CCS for ammonia		Two plants by 2013.	31 plants by 2020 and 122 plants by 2030.

For the chemical and petrochemical sector, cumulative investment up to 2050 is estimated to range between USD 5.3 trillion and USD 6.1 trillion in the 2DS (Table 12.9), about USD 250 billion over the investments required in the 4DS.

Table 12.9 Investment needs in the chemical and petrochemical sector to 2050 (in USD trillion)

	6DS low-demand	6DS high-demand	4DS low-demand	4DS high-demand	2DS low-demand	2DS high-demand
Total	4.8 to 5.4	4.9 to 5.5	5.1 to 5.7	5.2 to 5.9	5.3 to 6.0	5.5 to 6.1
OECD	0.5 to 0.6	0.5 to 0.6	0.6 to 0.7	0.5 to 0.6	0.7 to 0.8	0.6 to 0.7
Non-OECD	4.3 to 4.8	4.4 to 4.9	4.5 to 5.0	4.7 to 5.3	4.6 to 5.2	4.9 to 5.4

Pulp and paper

The pulp and paper sector is the fourth-largest industrial sector in terms of energy use, consuming 6 EJ of energy in 2010. Because the primary input for pulp and paper production is wood, the industry has ready access to biomass resources, which it uses to generate approximately half its own energy needs. Most G8 countries,[5] except Russia and Germany, have experienced declining production in this sector since 2000, ranging from 0.2% to almost 5% down per year. The recent economic recession deepened it. Globally, the production of paper and paperboard has increased by 22% since 2000. China was the largest producer of paper and paperboard in 2010.

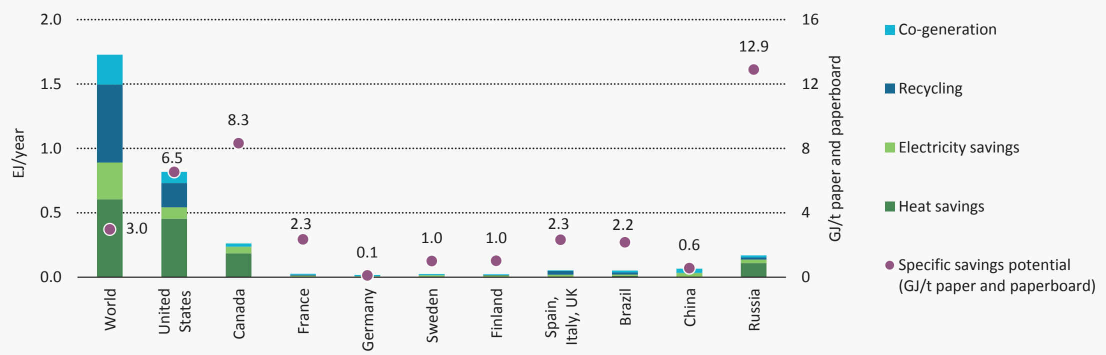
Because use of recovered paper has risen, pulp production since 2000 has grown more slowly – while remaining relatively stable – than paper and paperboard production. Pulp production was 187 Mt in 2010, only 0.7% higher than in 2000. Over this same decade, recovered paper use increased by 32%. The heavy use of biomass as fuel makes this sector one of the least CO_2-intensive, although CO_2 intensity varies widely in different countries, depending on biomass availability, the use of recycled fibre and the industry structure.[6]

The IEA has developed an index for the potential improvement of energy efficiency that assesses current performance against BAT. Using IEA energy statistics for final energy use,[7] a separate BAT value is derived for mechanical pulp, chemical pulp,[8] waste paper pulp and de-inked waste paper pulp plus seven paper grades. Multiplying production volumes by this BAT value gives a figure representing the practical minimum energy use. By dividing this figure by actual energy use, an energy efficiency index (EEI) is derived from which the potential for improvement can be calculated.

The EEI can be used to assess the possible energy savings in the pulp and paper sector by applying BAT or by increasing the use of co-generation or recovered paper. However, given data quality issues and potential differences in system boundaries and measurement methods, the indicators should be used very cautiously. Globally, the analysis suggests that using BATs can yield total energy savings of 0.9 EJ for heat and electricity use (Figure 12.18). If global recycling increases to the current European level of 69% (CEPI, 2012), another 0.6 EJ of energy can be saved. More widespread use of co-generation can achieve an additional 0.2 EJ.

5 The G8 countries include Canada, France, Germany, Italy, Japan, the United Kingdom, the United States and Russia.
6 The combustion of biomass is considered carbon neutral.
7 As IEA statistics also include printing, an adjustment is made to remove energy use for printing on the basis of available energy data from national sources or to estimate it by comparing countries with a similar industry structure.
8 A reduction of 2.5 GJ is applied to integrated chemical pulp to reflect the lower heat requirement for drying pulp.

Figure 12.18 Current energy savings potential for pulp and paper, based on best available technologies



Key point *The largest specific savings potential are in Canada, Russia and the United States, where existing plants are relatively older.*

The per capita consumption of paper and paperboard is expected to double between 2010 and 2050. This growth will be driven by higher demand for paper in developing countries and will be different for each type of paper. The demand for household and sanitary paper, as well as wrapping and packaging paper, is expected to more than double, while the demand for newsprint and printing paper will increase at a much slower pace between 2010 and 2050 (Table 12.10).

Table 12.10 Pulp, paper and paperboard production by scenario

Production (Mt)		Low-demand case 2050			High-demand case 2050		
	2010	6DS	4DS	2DS	6DS	4DS	2DS
Recovered paper	182	373	387	402	485	502	520
Chemical wood pulp	135	262	262	240	408	408	402
Mechanical wood pulp	33	33	33	33	45	45	24
Other fibre pulp	19	17	18	19	19	18	19
All pulp	*187*	*312*	*313*	*292*	*473*	*472*	*445*
Household and sanitary paper	29	56	56	56	69	69	69
Newsprint	33	33	34	33	46	46	46
Paper and paperboard (not elsewhere specified)	17	38	38	38	39	39	39
Printing and writing paper	110	161	161	161	302	302	302
Wrapping, packaging paper and board	206	466	466	466	618	618	618
All paper and paperboard	*395*	*755*	*755*	*755*	*1 074*	*1 074*	*1 074*

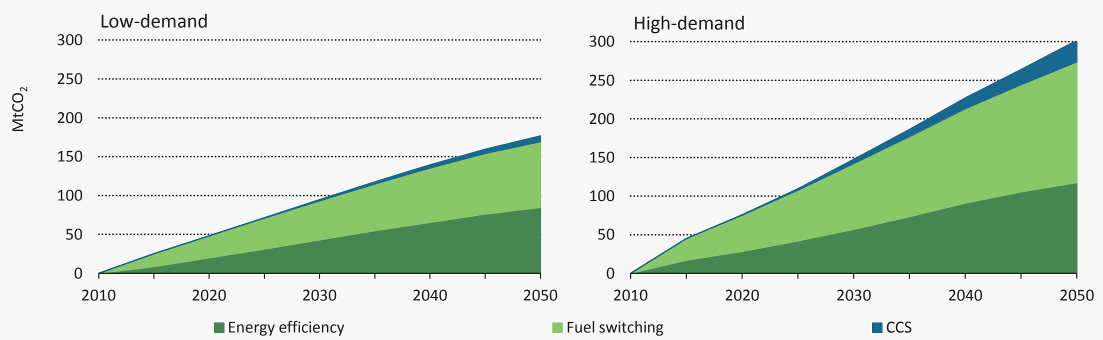
Sources: FAOSTAT 2011, and IEA analysis.

While paper and paperboard production is assumed to be the same in the three different scenarios, the use of recovered paper is about 8% higher in the 2DS than in the 6DS in

2050. Growth in use of recovered paper reduces the need for pulp production from virgin fibres, a change that improves energy intensity. However, production of recovered paper pulp, which uses fossil fuels, is generally more CO_2-intensive than production of chemical pulp because the latter uses biomass for energy, which is considered CO_2 neutral. As a result, using higher levels of recovered paper can significantly reduce energy intensity in the sector but at the cost of higher CO_2 emissions.

Total direct CO_2 emissions are 54% lower in the 2DS low-demand case, and 64% lower in the high-demand case, than in the 4DS. Energy efficiency and fuel switching represent the largest contribution to reducing direct emissions, at 48% each in the 2DS low-demand case. In the 2DS high-demand case, fuel switching plays the most important role in reducing emissions. By 2050, total direct emissions reduction below the 4DS levels is 175 $MtCO_2$ in the low-demand case and 300 $MtCO_2$ in the high-demand case (Figure 12.19). Carbon capture and storage appears later in the sector and begins to have an impact by 2030, accounting for 4% of the reductions in 2050 in the 2DS low-demand case, and 9% in the 2DS high-demand case.

Figure 12.19 **Technologies for reducing pulp and paper direct CO_2 emissions between the 4DS and 2DS**

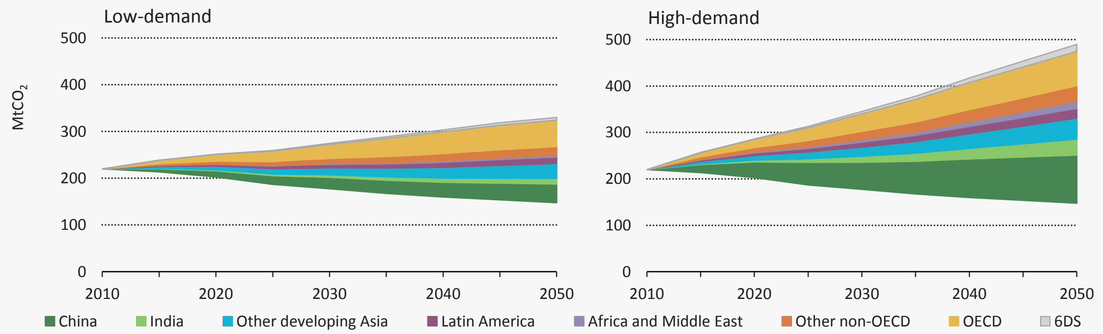


Key point *Energy efficiency and fuel switching are critical options for reducing direct emissions in the pulp and paper sector.*

Paper and paperboard consumption is assumed to continue to grow most strongly in non-OECD countries, especially in Asia, where demand from China is expected to increase almost threefold from current levels by 2050 in the low-demand cases in all scenarios. As a consequence, the global share of paper and paperboard consumption shifts significantly from OECD to non-OECD countries, with the share from the former falling from its current rate of 55% to between 31% and 24% by 2050.

Almost 40% of the growth in paper and paperboard production between 2010 and 2050 will come from China. As a result, 23% and 32% of the reduction in the low- and high-demand cases, respectively, will also come from this country (Figure 12.20). In the case of OECD Americas, production is expected to remain at the same level throughout the projected period. However, given the significant potential for improving energy efficiency and the application of CCS – resulting in the sector becoming a CO_2 sink (*i.e.* capturing more CO_2 emissions than it actually emits) – the region is expected to significantly contribute to the global emissions reduction.

Figure 12.20 Emissions reduction in the pulp and paper sector by region



Key point *Direct CO_2 emissions will continue to rise year by year in the 4DS.*

Deploying a wide range of BATs and newly emerging technologies will enable the sector to reduce significantly both its energy needs and its CO_2 intensity and achieve the emissions reduction implicit in the 2DS (Table 12.11). All countries should implement BATs, or attempt to, by 2025 and then improve them 15% to 20% by 2035; use black liquor and biomass gasification more widely; increase waste heat recovery; and implement new technologies in pulping and paper making. Greater use of co-generation would also provide a relatively low-cost opportunity for the sector to increase energy efficiency, although higher levels of co-generation will be possible only if there is a suitable regulatory framework that facilitates the sale of surplus electricity to the grid. Gasification technology and wood-based biorefineries have the potential to turn the pulp and paper sector into a major energy supplier in the future.

Table 12.11 Main technology options for the pulp and paper sector for the 2DS

Technology	Research and development needs	Demonstration needs	Deployment milestones
Black liquor gasification	Improved reliability and gas clean-up.	Under way.	Beginning 2015-25.
Biomass conversion to fuels and chemicals	Efficient and low-cost removal of tar. Production of high-value chemicals and liquid fuels.	Under way.	Beginning 2015-25.
Advanced water-removal technologies	Enhance water-removal techniques.		Beginning 2015-25.
CCS		Two plants by 2020-25.	40% to 50% of all new plants equipped with CCS by 2050.

Improved reliability and gas clean-up for black liquor gasification are needed in the short term. Early commercial biomass-integrated gasification with combined cycle plants need to be deployed within the next five to ten years, and wider deployment should occur from 2015 to 2025. In addition to black liquor gasification, lignin production from black liquor and biomass gasifications with synfuel production also offers opportunities to increase biomass use in the sector and to raise the profitability of pulp and paper mills. However, the increased use of biomass in the energy sector is expected to compete with the biomass requirement of the paper industry.

Government policies are needed to facilitate a transition to more efficient and/or lower-carbon technologies. Such a transition will be possible only when the policy framework supports the necessary technology development and its adoption. Cheap and available capital will be needed to stimulate investment in new technologies. Achieving the results outlined in the 2DS will be very challenging for the sector and will require significant co-ordination and collaboration between industry and government, as well as action from all major pulp and paper-producing countries.

Total investment required for the pulp and paper sector in the 2DS is USD 1.4 trillion to USD 2.4 trillion (Table 12.12). About 55% of the additional investments between the 4DS and the 2DS will be required in OECD countries, where plants are relatively older and will need replacement or refurbishments in the short to medium term.

Table 12.12 Investment needs in the pulp and paper sector to 2050 (in USD trillion)

	6DS low-demand	6DS high-demand	4DS low-demand	4DS high-demand	2DS low-demand	2DS high-demand
Total	1.1 to 1.2	1.7 to 1.8	1.1 to 1.2	1.7 to 1.8	1.4 to 1.5	2.1 to 2.4
OECD	0.3 to 0.4	0.4 to 0.5	0.3 to 0.4	0.4 to 0.5	0.5 to 0.6	0.7 to 0.8
Non-OECD	0.8 to 0.8	1.3 to 1.3	0.8 to 0.8	1.3 to 1.3	0.9 to 0.9	1.4 to 1.6

Aluminium

Globally, around 40 Mt of aluminium was produced from bauxite in 2010, more than twice the amount produced 20 years ago. Production in China, India and particularly the Middle East is growing rapidly, while it has been declining in the United States and Europe in recent years.

The recent economic downturn had an impact on overall aluminium production, most noticeably in OECD countries. Primary aluminium production decreased 7% from 2008 to 2009 although 2010 production surpassed that of previous years, up 3% on 2008, with 2011 up a further 7.5% on 2010.

The International Aluminium Institute (IAI) annually surveys facilities worldwide[9] on energy use in production. The average global energy intensity of alumina refineries remained relatively stable throughout the last decade at around 15.5 GJ/t alumina. The intensity ranges from under 10 GJ/t alumina in South America to over 18.5 GJ/t alumina in China and is as much a function of ore quality as it is of technology efficiency, although there are potential efficiency gains to be made through technology improvements and operational adjustments such as bauxite sweetening.

Specific power consumption for primary aluminium production has declined in most regions, achieved by building new, more energy-efficient facilities and by retrofitting old plants with new cells. Since 1980, average electricity consumption of primary aluminium production has declined by about 0.4% per year.

Globally, and by region, the performance of aluminium smelters has consistently improved since the mid-20th century due to growth in aluminium demand and the concurrent addition

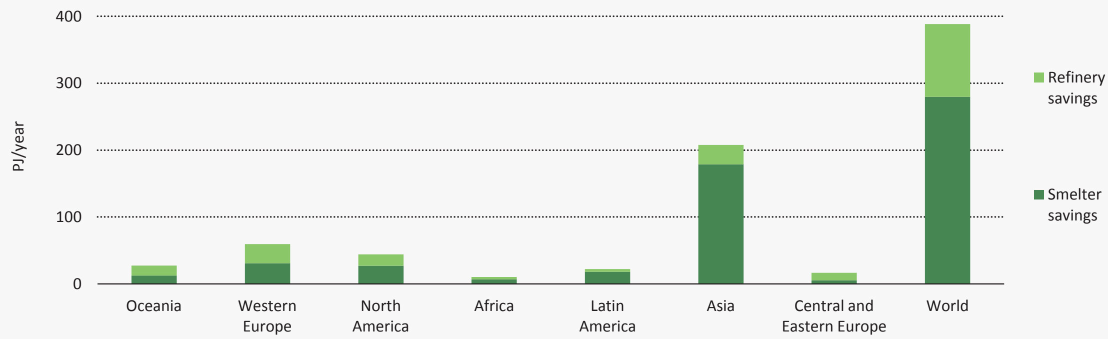
9 The survey covers around 70% of global metallurgical alumina and primary aluminium production.

of new, more efficient capacity. This has accelerated in recent years, due to the acceleration in demand from developing markets. But considerable scope remains for further energy savings (Figure 12.21). The main opportunities involve the additional improvements and operational adjustments and replacing old smelter technologies with modern pre-bake cells, developing process controls that optimise cell-operation conditions, improving insulation to reduce heat losses, and reducing consumption of electricity by auxiliary technologies (such as compressors and fans).

Energy savings are also possible in thermal processes, such as anode manufacture and casting, while increased recycling, requiring up to 95% less energy than primary production, also impacts the energy intensity of aluminium products. The application of BAT in the aluminium industry can help reduce energy use in aluminium production by about 10% compared with current levels.

Energy efficiency improvements in both refining and smelting have an important role to play. Realising these savings in refineries will require improved controls and processes to increase yields of alumina, combined with reduced heat loss, better heat transfer and improved waste-heat recovery, including the introduction of more co-generation. In smelting, the main savings will come from improved process controls, reduced heat losses, and electricity savings in auxiliary uses.

Figure 12.21 **Current energy savings potential for aluminium, based on best available technologies**



Note: For refinery savings, Oceania and Asia potentials are based on the average specific consumption of East Asia and Oceania, and Africa's potential is calculated based on the average specific consumption of Africa and South Asia.

Key point *More than 50% of the global potential to reduce energy consumption in aluminium is in Asia.*

The per capita consumption of finished aluminium will almost double between 2010 and 2050 under a low-demand case and will increase 2.8 times in the high-demand case. This substantial increase is explained by higher aluminium consumption in a wide range of sectors, especially transport, construction and engineering. To meet the increased demand, the primary production of aluminium will increase from 41 Mt in 2010 to 89 Mt in the 2DS low-demand case and 122 Mt in the high-demand case. The lower production in 2DS, compared with the 4DS and 6DS, is explained by the increased use of recycled aluminium (Table 12.13).

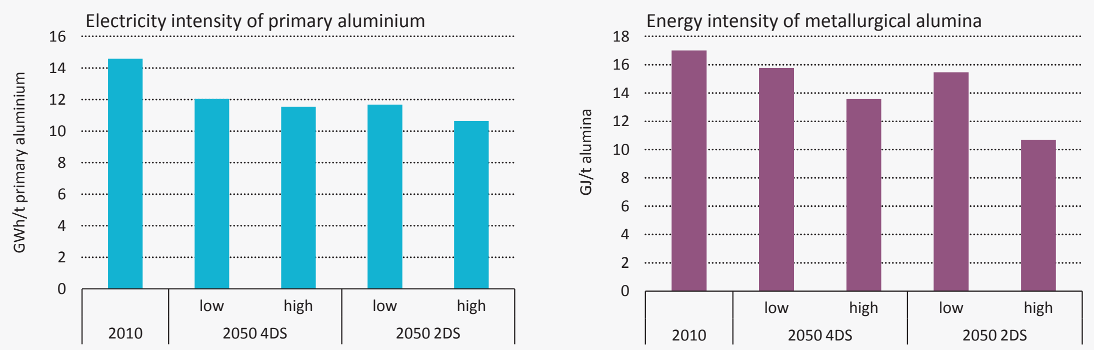
Table 12.13 Alumina and aluminium production by scenario

Production (Mt)		Low-demand case 2050			High-demand case 2050		
	2010	6DS	4DS	2DS	6DS	4DS	2DS
Alumina	85	188	178	169	252	239	226
Primary aluminium	41	99	94	89	135	129	122
Recycled aluminium	37	101	106	111	141	148	155

Notes: Recycled aluminium includes recovered and recycled aluminium within the industry. Recycled aluminium, excluding industry internal recovery and recycling, was 21 Mt in 2010.

In the 2DS, production from recycled and recovered aluminium (within and outside the industry boundary) increases from 47% in 2010 to about 55% of total aluminium production. Given that production from recycled aluminium requires 3% to 8% of the energy to produce primary aluminium and, taking into account the decreasing demand for alumina production, this small shift has large benefits for the energy consumption of the sector (Figure 12.22).

Figure 12.22 Intensities of primary aluminium and metallurgical alumina production



Key point *Higher shares of new alumina and aluminium plants in both the 2DS and 4DS high-demand scenarios further reduce energy intensity.*

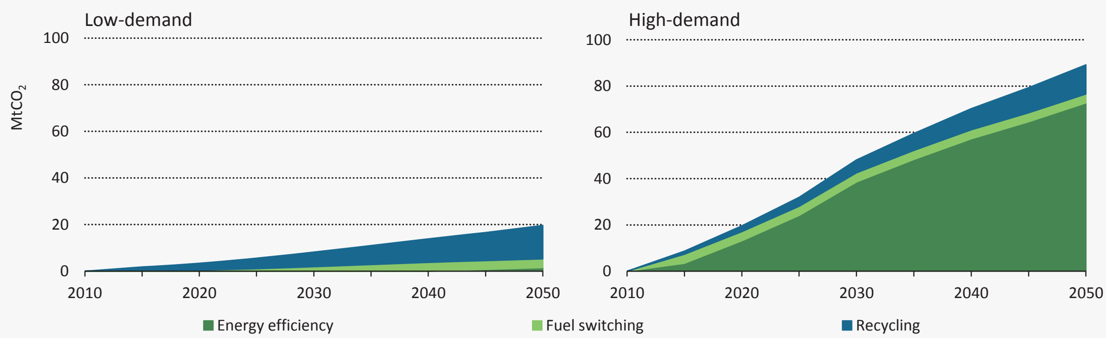
In the 2DS, total direct and indirect CO_2 emissions[10] fall by 55% and 64% in the low- and high-demand cases, respectively, in 2050, compared with the equivalent 4DS. Most of the reduction in total CO_2 emissions comes from using low-carbon electricity.

Decarbonising the power sector will not be sufficient to achieve the emissions reduction goal of the 2DS. Additional CO_2 savings will have to come from a reduction in direct CO_2 emissions. In the low-demand case, about three-quarters of emissions reduction comes from an increased use of aluminium scrap. In the high-demand case, recycling makes

10 Because indirect CO_2 emissions account for 75% of total emissions in the aluminium industry, it is important to look at total direct and indirect emissions for this sector.

a much smaller contribution (due to the increasing amount of aluminium embedded in products still in use and that have not yet reached the end of the product use/lifespan – with more primary aluminium required to meet the rapid rise in demand), with the largest share of reduction due to improved energy efficiency (Figure 12.23).

Figure 12.23 **Technologies for reducing aluminium direct CO_2 emissions between the 4DS and 2DS**



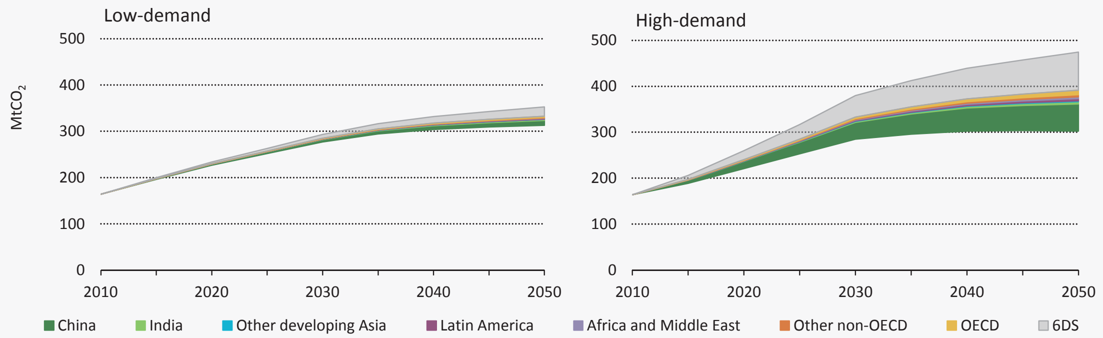
Key point *Improvement in energy efficiency, through the use of new technologies, is critical to reducing direct CO_2 emissions in the aluminium sector.*

Most of the reduction potential in the aluminium industry is in China. Many bauxite deposits in China have a high silica content and are low grade, requiring a more complex refining process. About 15% of China's alumina output is currently produced by the standard Bayer process; the remainder uses a combination of sintering and parts of the Bayer process. Such combined processes can be two to four times more energy intensive than the ordinary Bayer process. This explains China's potential to reduce direct emissions significantly (Figure 12.24). For China to achieve this potential, alternative higher-quality bauxite sources need to be secured.

Reducing CO_2 emissions from the generation of the electricity used in smelters is the single largest opportunity for long-term emissions reduction in the aluminium sector. Globally, around 50% of the total electricity used by the aluminium industry comes from near-zero-carbon hydroelectric sources, often in remote locations where there are few competing uses for electricity. Measures to create a global carbon price would encourage new aluminium plants to be sited where they have access to available and competitively priced, low-carbon electricity. In the longer term, the average CO_2 intensity of grid electricity is likely to decrease substantially in many countries, so that by 2050, low-carbon grid electricity may become the norm.

Future technological developments could also provide an opportunity to reduce the direct emissions of CO_2 from aluminium smelting (Table 12.14) although they may require increased energy intensity. Although the two most promising technological developments – inert anodes and carbothermic reduction – have both been the subject of research for many years, neither has reached commercial scale. The development of cell technologies with CCS capacity is still only at the research stage.

Figure 12.24 Emissions reduction in the aluminium sector by region



Key point *Between 54% and 66% of the emissions reduction potential in the aluminium sector is in China.*

Table 12.14 Main technology options for the aluminium sector for the 2DS

Technology	Research and development needs	Demonstration needs	Deployment milestones
Wetted drained cathodes		Ready for demonstration.	Deployment to start by 2015 with full commercialisation by 2030.
Inert anodes	Extensive testing at laboratory and batch scale.	Ready to be demonstrated at plant level.	Deployment to start between 2015 and 2020 with full commercialisation by 2030.
Carbothermic reduction	Extensive research under way.	2020-25.	Deployment to start between 2030 and 2040 with full commercialisation by 2050.
Kaoline reduction	Research under way.	2025-30.	Deployment to start between 2035 and 2045.

Total investment costs from 2010 to 2050 in the 6DS and 4DS are between USD 0.7 trillion and USD 1.1 trillion. The reductions envisaged in the 2DS require additional investments of about USD 20 billion above the 4DS (Table 12.15). This takes into account the additional investment costs of more efficient refinery and smelter technologies, plus investment savings from anode production as carbon anodes are replaced by inert anodes. However, the calculation excludes the additional costs of low- or zero-carbon electricity generating capacity.

Table 12.15 Investment needs in the aluminium sector to 2050 (in USD billion)

	6DS low-demand	6DS high-demand	4DS low-demand	4DS high-demand	2DS low-demand	2DS high-demand
Total	678 to 775	937 to 1072	864 to 987	994 to 1137	715 to 817	995 to 1138
OECD	91 to 100	116 to 128	123 to 135	127 to 140	103 to 113	131 to 144
Non-OECD	587 to 675	821 to 944	741 to 852	867 to 997	612 to 704	864 to 994

Recommended actions for the near term

Achieving significant CO_2 reductions in industry will require steep changes in policy implementation by governments and unprecedented investment in best practice and new technologies by industry.

What happens over the next ten years will be crucial to ensure that the most promising emerging technologies will be available post-2030 to help industry achieve the goal set out in the 2DS. Not all technologies now being investigated will reach commercial deployment, making it all the more critical that a portfolio of promising technologies is developed by industry and supported by government.

Energy efficiency and the implementation of BAT need to be given priority right now to avoid locking in sub-optimal technologies. Plants that will be built or refurbished over the next ten years will account for 30% of the overall industrial production in 2020, and 10% in 2050. Action is needed to ensure the new facilities and retrofit equipment are reaching BAT level, otherwise this capacity will be sub-optimal and very costly to upgrade. Government intervention will be needed in the form of standards, incentives and regulatory reforms, including removal of price subsidies, if the potential offered by current technologies is to be realised.

The development and deployment of promising new technologies will also be needed; this will require substantial investment. Industry will continue to take the leading role but governments will need to go far beyond what they have done in the past to create economic and financial incentives to stimulate change. There is an urgent need for major acceleration in RD&D, with government support for demonstration projects being particularly important. This will require greater international collaboration and will need to include mechanisms to facilitate the transfer and deployment of low-carbon technologies in developing countries.

Crediting mechanisms need to be developed to encourage investments in emissions reduction where they are least expensive, for example in developing countries. Such an approach will only be acceptable politically as long as it does not lead to the subsidisation of developing countries' industries at the same time that developed countries apply cost increases of their companies.

The iron and steel, and cement sectors have embarked on co-operative sectoral R&D programmes into low-CO_2 technologies, sometimes with public support. Governments should explore the possibility of public funding in this area. In the end, however, climate policy frameworks should allow industry – and other sectors – to cut emissions at least cost. Some flexibility is essential in the face of major uncertainty about the long-term contribution of all emitting sectors to global mitigation.

Research is needed to advance understanding of system approaches such as optimisation of life cycles through recycling and using more efficient materials, and develop new materials that contribute to emissions reduction in other sectors. New lightweight steel, high-strength aluminium, novel chemical materials and other new industrial material may eventually play a key role and help the transport, buildings and power sectors achieve further emissions reductions.

Chapter 13

Transport

By lowering vehicle, fuel and infrastructure costs, the *ETP 2012* 2°C Scenario (2DS) saves USD 65 trillion in global transport costs through 2050, while cutting carbon emissions by more than 50% compared with the *ETP 2012* 4°C Scenario (4DS).

Key findings

- ***The transport sector remains dependent on oil because it has high energy density 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, price volatility, and environmental issues related to the extraction and combustion of oil.*
- ***The past decade's economical, political and oil-market turbulence was mirrored in the transport sector, which saw erratic trends in vehicle sales in many countries.*** *Car sales slumped in OECD member countries, but grew at unprecedented rates in non-OECD countries. Travel in OECD countries appears close to the saturation level but in the developing world, it will likely increase several-fold between 2010 and 2050.*
- ***To reach 2DS targets, an Avoid/Shift/ Improve philosophy is needed.*** *The adoption of new technologies and fuels* (Improve) *plays a critical role.* Avoid *(slowing travel growth via city planning and demand management) and* Shift *(enabling people to shift some travel to transit, walking and cycling, and to shift goods from trucks to rail) also help cut energy use and carbon dioxide (CO_2) significantly.*
- ***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 decade, while also developing the market for zero-tailpipe emissions vehicles (e.g. electric vehicles, fuel-cell vehicles).*
- ***Deployment of electric vehicles has already started,*** *with major producers selling about 40 000 during 2011.* ***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.*
- ***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 today and 2050 would represent only a small share of total worldwide expenditures on transport – likely to amount to several hundred trillion dollars over this time frame.*

Opportunities for policy action

- *Eliminate fuel subsidies and set taxation systems to reflect the full range of external costs of fuels and vehicles, including CO_2, pollutant emissions, traffic congestion and other impacts.*

A global carbon price would help, but integrating transport's external costs can also be achieved via alternative national policies.

- *Implement and tighten fuel economy standards for all types of road vehicles, including cars and trucks, with a five- to ten-year vision. The global average 2030 new passenger light duty vehicle (LDV) should consume no more than 4 litres gasoline equivalent (Lge) per 100 kilometres (km). In some countries such a target can be achieved even sooner.*
- *Support urban and regional development of infrastructure for electric vehicle recharging, with a coherent policy framework including price incentives to promote electric and plug-in electric hybrid vehicles (PHEV). A stable framework is needed through at least 2020, to build industry and consumer confidence.*
- *Implement high-quality mass transport systems in urban areas. For example, implementing improved bus systems featuring bus rapid transit (BRT) in the world's 1 000 largest cities would provide tremendous mobility benefits, along with significant fuel savings and CO_2 reductions.*
- *Create international frameworks and incentive systems to spur rapid efficiency improvements and CO_2 reductions in shipping and aviation.*

In 2009, the transport sector accounted for approximately one-fifth of global primary energy use and one-quarter of energy-related carbon dioxide (CO_2) emissions. These shares have slightly decreased since the last *Energy Technology Perspectives* (IEA, 2010a) and are projected to stabilise at these levels in the coming decades. The transport sector relies on oil for more than 93% of the energy used. Oil will remain the primary transport fuel for the foreseeable future (IEA, 2011a), necessitating strategies to reduce this dependency and increase energy security.

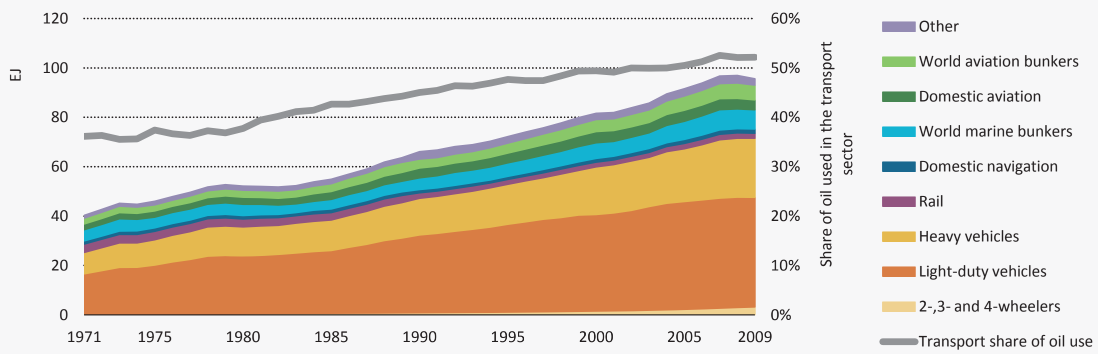
Several new vehicle technologies have become available in the past 10 years, but the sector is decarbonising too slowly to reach the ambitious target of the 2DS. This analysis reveals two significant considerations: the importance of avoiding focusing solely on one technology and instead pursuing a multi-pronged portfolio approach, and the utility of a temporal perspective, which involves pursuing strategies simultaneously for both the near term (*e.g.* fuel economy improvement, modal shift) and the longer term (*e.g.* electric vehicles, advanced biofuels, fuel-cell vehicles).

Energy use

Energy use in the transport sector has been increasing at approximately the same pace as all other sectors and represents the largest share of oil use since the early 2000s. This trend is projected to continue and account for almost all of the increased demand for oil (IEA, 2011a). The picture that emerges is clear: the largest share of energy use within the transport sector comes from road vehicles. Aviation has also sharply increased in the last decade, and together, the most oil-intensive transport modes have increased faster than the others (Figure 13.1).

On a regional level, transport energy use is rising faster in non-OECD regions than in the OECD regions, yet North America and Europe still use the most energy compared with all other regions in the world. On a per-capita basis, the story remains the same, with North America and Australia having the highest transport oil use per capita, around 1 200 to 1 500 tonnes of oil equivalent (toe) per 1 000 capita. India and China, however, are in the range of 50 toe to 150 toe per 1 000 capita.

Figure 13.1 World transport energy use by mode



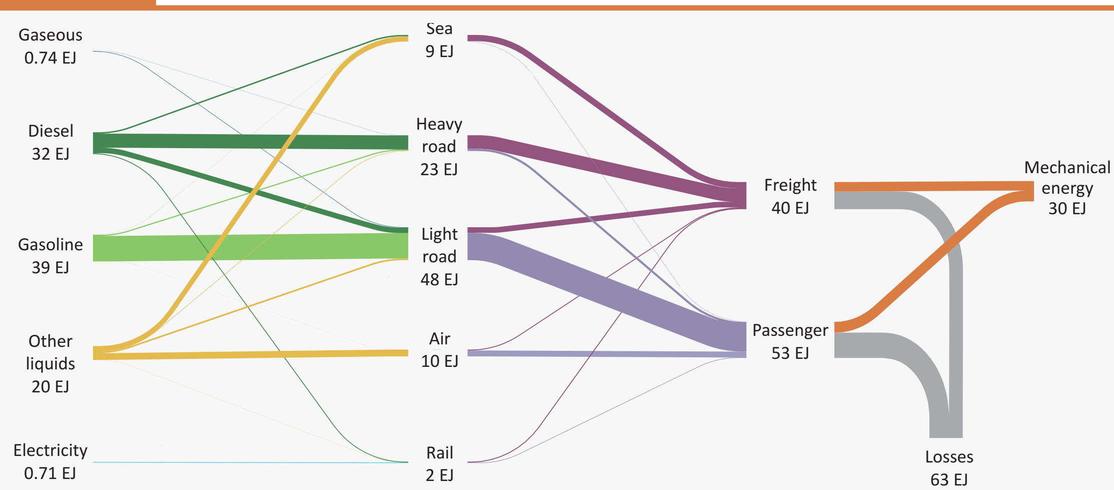
Notes: Light-duty vehicles are cars and light trucks (up to 3.5 tonnes); heavy vehicles are trucks and buses.
Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

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

Gasoline remains the predominant type of transport fuel and accounts for almost half of energy use in North America, but just one-quarter in Europe, where diesel fuel represents half of energy use. Heavy fuel oil occupies the third place in non-OECD regions, but in the OECD region, jet fuel ranks just below gasoline and diesel use, due to increasing passenger travel by air.

As currently developed, transport systems are very inefficient in transforming primary energy into moving people and goods: the low efficiency of the typical internal combustion engine, with an average conversion efficiency of 25%, is the primary factor (Figure 13.2).

Figure 13.2 Final energy distribution in the transport sector, 2009



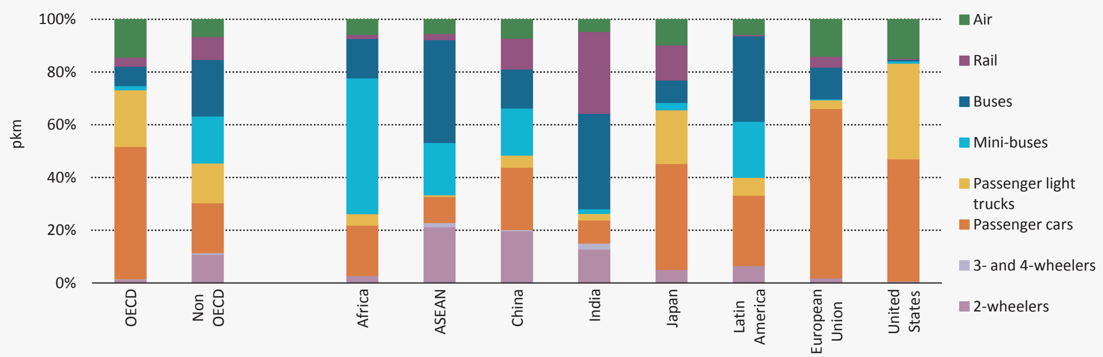
Key point *Heat loss represents the biggest share of energy use in the transport sector.*

Passenger travel and mobility

Within the OECD, average car travel represents 60% to 80% of motorised passenger travel (based on passenger-kilometres per year), except in South Korea, where other modes have larger shares. North America has a large share of light trucks, which includes sport utility vehicles, whereas Europe has few light trucks and more small passenger vehicles (Figure 13.3).

Non-OECD regions have a much larger variety of motorised passenger travel modes. Rail travel plays a large role in Russia, other former Soviet countries and India; elsewhere in non-OECD regions, rail is a minor travel mode, as is air travel. Road mass transportation represents a highly significant travel mode in India, Latin America and Africa, but is less popular in OECD countries and the Middle East, where car ownership is high. Non-motorised modes (not represented in Figure 13.3) represent a big proportion of trip share but a modest modal share due to the short average trip distance.

Figure 13.3 Motorised passenger travel mode share, 2009



Notes: Shares are based on estimated total passenger-kilometres, nationally and regionally, for each mode. ASEAN is Association of Southeast Asian Nations.

Key point *Passenger car and light truck travel dominates in the OECD and has reached a third of travel in non-OECD regions.*

The United Nations estimates that more than half the world now lives in cities, and projects that approximately 75% of the world's population will live in urban areas by 2050 (UN, 2011). This has widespread implications for transport and especially public transit. Many cities worldwide are already experiencing severe and increasing congestion, along with deteriorating local air and noise pollution. To combat these trends, more and more cities are heavily investing in public transportation, car sharing and other innovative travel modes. Bus rapid transit is one such travel mode, covered later in the chapter.

Freight transport

Freight transport activity is linked to economic growth and goods demand. In a globalised world, international freight transport will increase over time, especially as non-OECD regions grow more prominent in international trade. The past decade has seen continuous increases in road and rail freight, as measured in tonne kilometres (tkm). On a weight basis, rail is still the dominant mode for freight (53% of tkm over land), but there are big regional differences (IEA, 2009). With a projected decarbonised power sector (see Chapter 11), it is likely that CO_2 emissions from rail transport will dramatically decrease as the rail infrastructure gets electrified– a trend that is already taking place as countries seek to lower their energy imports and become more energy independent.

For road freight, strong efficiency improvements are possible and necessary, given that electricity and hydrogen will have only limited applications. Natural gas may be an increasingly important fuel in some countries. Introducing advanced biofuels can also help diversify energy sources, particularly for long-haul trucking.

In the near term, improved fuel economy offers the greatest CO_2 reduction potential. Efficiency technology options include hybridisation, improved aerodynamics, light-weighting and logistical measures using intelligent transport systems (IEA, 2012a). One reason for the large potential is that fuel economy standards for medium and heavy trucks have received limited consideration in most countries. At present, only Japan and the United States have implemented fuel economy standards for heavy vehicles. European legislation covering heavy-duty trucks is expected in the coming years. Standards are needed for commercial trucks around the world as most businesses exhibit a high discount rate and require a very short payback period for fuel economy improvements, and progress has been slow (Duleep, 2011).

The turbulent decade: 2000 to 2010

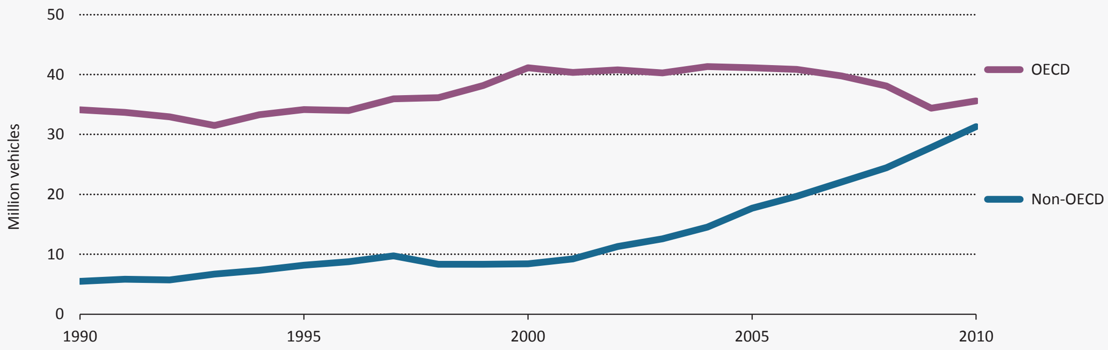
The future of transport will largely be written in cities, and in the past decade, the majority of the world came to live in urban areas. Severe congestion, altered travel patterns and the introduction of several transport innovations characterise these areas. If the past decade is any indication of what lies ahead, detailed analyses can better prepare cities to budget, set environmental and health goals, and plan for more densely populated cities.

The past decade was characterised by many tumultuous events, including wars, several natural catastrophes, significant oil price fluctuations and a major recession. All of them had implications for all levels of governance (from cities to country regions) and the transport sector, but none more so than the economic recession. The financial crisis which began in 2008 constrained transport budgets, decreased access to mobility options in certain areas, and greatly depressed and altered automobile sales.

Economic crisis and vehicle sales

The last decade showed the emergence of developing countries and the saturation of OECD member countries with respect to passenger LDV sales. Non-OECD regions are gaining market share and will soon overtake OECD sales figures (Figure 13.4). The automotive market has changed dramatically over the past decade, especially in the last few years. For example, sales of passenger LDVs in the United States halved between 2008 and 2009; the following year, in 2010, sales recovered, almost reaching 2008 levels, but by then China had become the top passenger LDV seller worldwide. The starkest change between 2000 and 2010 took place in China. Car sales skyrocketed from a little more than 500 000 in 2000, to 4 million in 2005, to over 12 million in 2010, about a 20-fold increase.

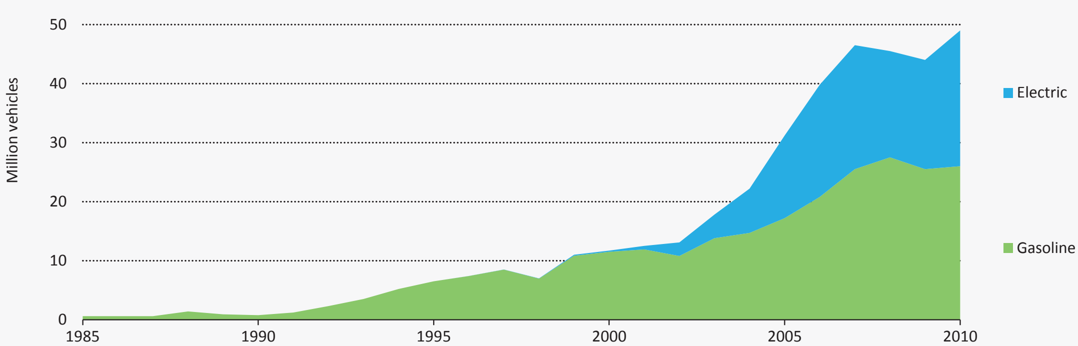
Figure 13.4 Passenger LDV sales worldwide



Key point *Non-OECD countries are poised to overtake OECD countries in sales, probably before 2015.*

Two-wheelers remain the most popular mode of transportation in Asia, with an emergence of electric scooters and e-bikes; the total stock of electric 2-wheelers has reached more than 120 million in China alone (including pure electric mopeds and power-assisted bicycles). The penetration of electric 2-wheelers in China is a rare case where a new type of powertrain has succeeded in becoming dominant in such a short time frame (Figure 13.5). China's government drove this change by restricting the sales and use of ICE 2-wheelers in many urban areas; e-bikes have also been helped by an ownership cost (purchase price and fuel cost) that is competitive with traditional motorised 2-wheelers (Cherry, 2010). This has not been the case everywhere: in Europe, electric scooters have not reached cost parity with their gasoline counterparts.

Figure 13.5 China 2-wheeler sales

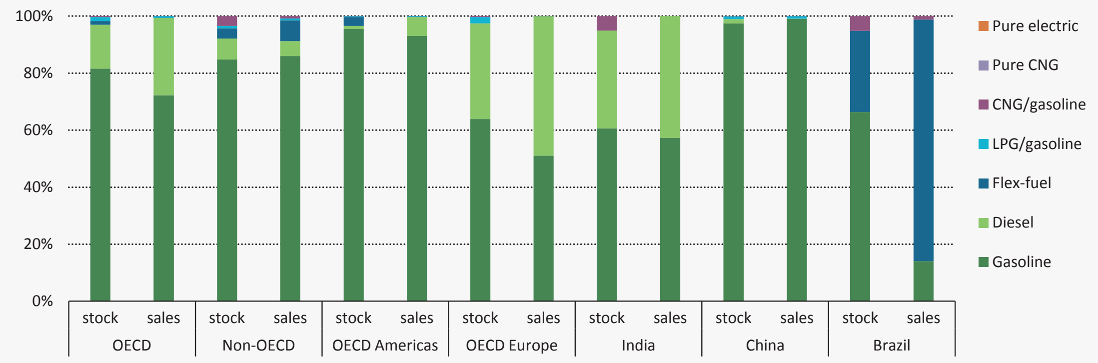


Key point *Electric 2-wheeler sales in China now match gasoline-powered 2-wheelers, after just a decade on the market.*

Alternative technologies shares

Gasoline engines still dominate the world passenger LDV market, with diesel in OECD Europe and India, flex-fuel[1] in Brazil, and liquefied petroleum gas (LPG) vehicles in South Korea being notable exceptions. Almost 90% of the worldwide stock of passenger LDVs in 2000 was fuelled by gasoline and, even though that share decreased to about 80% by 2010, it still shows the preponderance of gasoline-powered vehicles (Figure 13.6). In some regions, diesel engines have gained significant market shares, thanks to higher efficiency and advantageous fiscal and exhaust emissions policies.

Figure 13.6 Passenger LDV sales and stock shares by technology, 2010



Key point *Gasoline and diesel vehicles dominate sales and stock of passenger LDVs in most major markets.*

Dieselisation rates

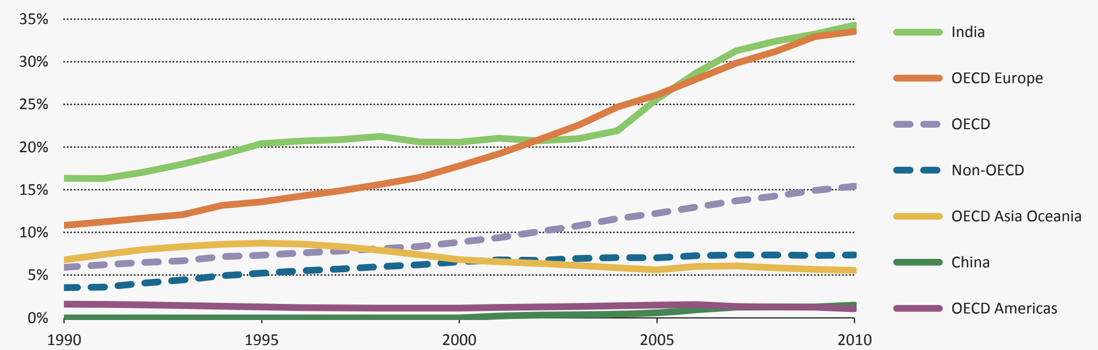
Diesel is the second most important fuel in the transport sector worldwide, and achieves the highest volume use by trucking in nearly all countries. It is also of rising importance for passenger LDVs in many countries and regions (Figure 13.7). Dieselisation has been promoted in some regions, thanks to less-stringent local pollution standards, improved fuel quality and favourable fuel taxes. In 2000, France already had one of the highest market shares of diesel passenger LDVs in the world, which peaked at 77% of new vehicle sales in 2008 and settled at 70% in 2009 and 2010 (ADEME, 2011).

Such penetration rates of diesel engines cannot be explained by economic optimisation only; indeed, to be cost-effective, a diesel vehicle has to be driven more than 15 000 km per year to amortise the initial cost premium. Travel surveys in France show that the average mileage for diesel drivers is well below this mark (TNS, 2012). Other factors that may influence this trend are expected rising fuel prices, a perception that diesel cars are more reliable, and perhaps an element of local custom and social status.

India has the highest passenger LDV diesel market share among non-OECD countries and regions; its sales share in 2000 was 23% and jumped to 43% in 2005, stabilising at this level in 2010 (Figure 13.6). Globally, diesel sales have risen from 5% in 1990 and 8% in 2000, standing at 13% in 2010.

1 Flex-fuel vehicles are capable of running with an ethanol mix of up to 85% in the gasoline fuel tank.

Figure 13.7 Stock share of diesel passenger LDVs

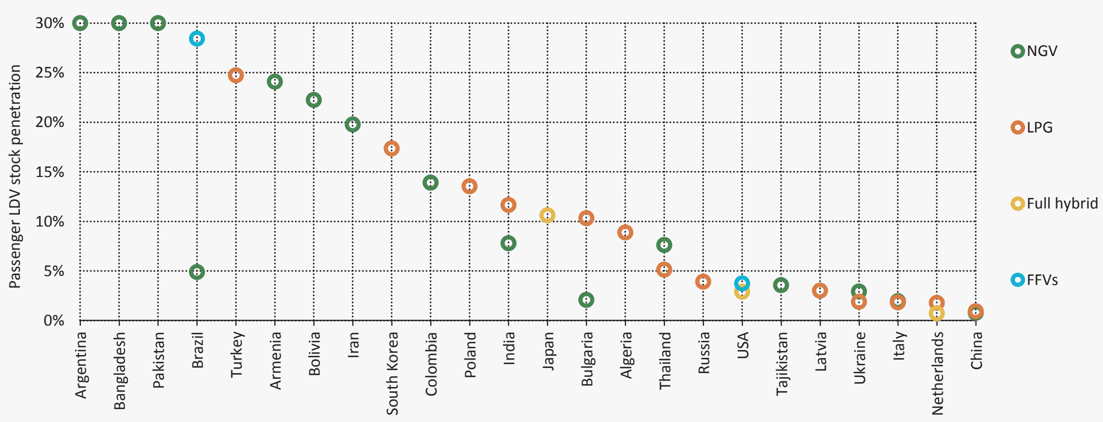


Key point *Diesel penetration has grown steadily in Europe over the past two decades and in India since 2004.*

Penetration of niche technologies

Until the past decade, alternative vehicles (non-gasoline or diesel vehicles) had only a marginal impact on the global passenger LDV market. But several technologies and fuels are making inroads in certain markets (Figure 13.8). While increasing sales are changing the once-homogenous passenger LDV mix in certain markets, these are not yet enough

Figure 13.8 Stock share of non-gasoline and non-diesel technology for passenger LDVs, 2010



Notes: NGV = natural gas vehicle, LPG = liquefied petroleum gas vehicle; and FFV = flex-fuel vehicle. 30% means 30% or above.

Key point *Few countries have more than a 30% share of alternative fuel vehicles, and only a handful have a significant share of more than one alternative vehicle technology in the total stock.*

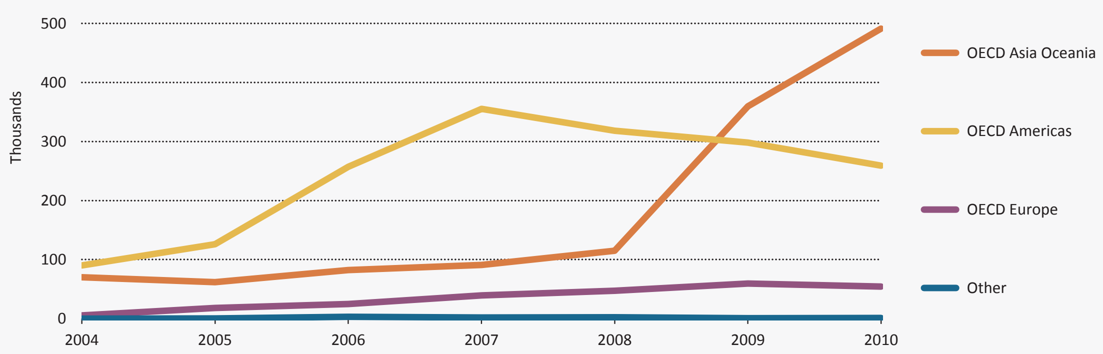
to change the global balance, with unabated dominance of gasoline- and diesel-powered vehicles. Specific policies to promote the diffusion of such technologies have been adopted in countries where alternative technologies have high penetration rates. Without strong policies (at the national or regional level), alternative technologies are not likely to penetrate the mass market. These policies are mainly driven by the abundant local energy resources available in a given country. IEA's mid- and long-term projections of alternative power for vehicles show that most are likely to remain niche technologies unless specific policies are put in place to drive change. Tightening fuel economy standards is likely to trigger wider adoption of hybrid-electric vehicles (HEVs) in the near future.

Scaling up niche technologies to reach the mass market: How will electric vehicles fare?

Several markets show high penetration for various new powertrain options such as HEVs, NGVs, and LPG vehicles, but these are all still marginal on a global scale. Can local success stories be transported globally to help a niche technology gain significant market share? One instructive lesson is the HEV, which became available in global markets as early as 1997. Although it boasted of improved efficiency and good customer perception, it took until 2010 to reach 1% of the world's sales share. But HEVs have fared far better in OECD Asia Oceania (especially Japan) than elsewhere (Figure 13.9), as specific policies were launched to incentivise HEV purchase.

If 13 years is any indication of how long it takes for a new technology (*i.e.* HEVs) to go from market introduction to significant market share, then introducing battery-electric vehicles (BEVs) will be very challenging. Yet many countries and car manufacturers have shown significant interest in a fast introduction of BEVs (IEA, 2011b), with many countries setting targets for sales or stocks in the 2015 to 2020 time frame, suggesting a general sense that this breakthrough technology can go from market newcomer to market mainstay in a shorter period of time than the HEV.

Figure 13.9 Hybrid passenger LDV sales by region



Key point *OECD Asia Oceania, led by Japan, has seen a rapid rise in HEV sales since 2007, while sales have fallen in North America.*

BEVs (or other new vehicle technologies) may scale the market "valley of death" faster than HEVs in the past decade for several reasons:

- HEVs created an impetus for manufacturers to expand their production lines beyond traditional engine and fuel options, with expanded consumer choices, reducing the hurdles for newer technology's fast deployment.
- The ability to produce hybrid vehicles was not widespread in 1998, and it took many years for a significant number of models to become available. That number is still fairly low and has already been surpassed by the number of BEV models available.
- Recently enacted sustainability goals and fuel economy standards will put additional pressure on manufacturers and consumers to lower the CO_2 emissions per kilometre (km) for a given vehicle.
- Rising oil prices may encourage consumers to shift away from fossil-fuel-based vehicles toward other energy sources with potentially more stable fuel prices and better efficiency allowing smaller exposure to price fluctuations.
- Governments have put in place ambitious programmes involving significant funding to manufacture vehicles, deploy infrastructure and reduce costs to the consumer.

Still, several factors may impede or slow the introduction of BEVs, where in fact HEVs have a much stronger position:

- BEVs need a dedicated recharging infrastructure that will take many years to fully build.
- For the foreseeable future, BEV recharging time will be much longer than the vehicle owner is accustomed to; the refuelling model needs to evolve toward a "recharge while parked" approach.
- BEV driving range is greatly restricted compared with gasoline- and diesel-fuelled vehicles. Many transport surveys emphasise that BEVs have more than enough range for daily commutes, but it is still questionable whether many car buyers will be willing to pay for a vehicle capable of travelling a maximum of 150 km before recharging.
- A BEV and its battery are still expensive. Even though economies of scale and technology improvements are anticipated, early buyers should not expect cost savings with a BEV. It will require strong government support programmes to offset this cost disadvantage; while most governments in OECD countries now have support programmes, it is not clear whether these will be effective.

These shortcomings are serious and raise questions about whether BEVs can penetrate the market any faster or to a greater extent than HEVs have. On balance, it appears likely to require a very strong set of policies over the course of a decade to bring BEVs into the market and establish them commercially with a substantial market share (*e.g.* 10% or more of global passenger LDV sales). Other technologies, such as PHEVs and fuel-cell electric vehicles (FCEVs), might help bridge the gap, being complementary to BEVs (Figure 13.14).

Fuel economy

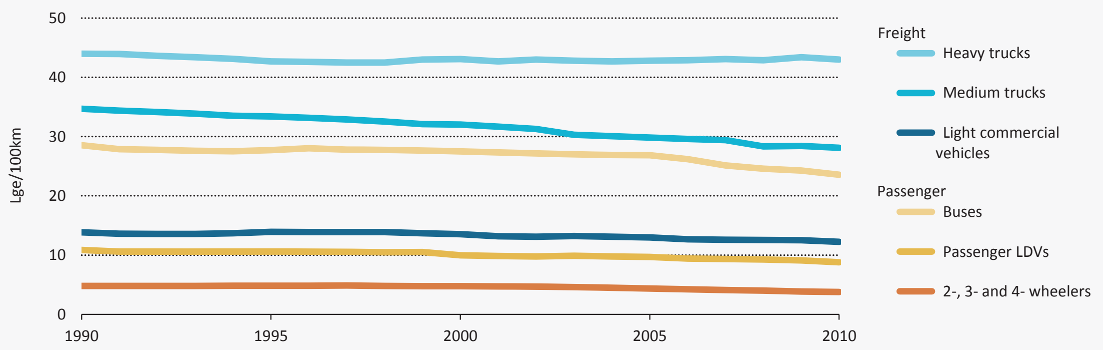
While new vehicle technologies may significantly lower oil use and diversify energy sources for the road-transport sector in the long term, dramatically improving fuel economy holds the greatest potential for the next decade. An analysis by the IEA and the Global Fuel Economy Initiative (GFEI, 2011) shows that the current pace of progress in improving fuel economy is not fast enough to meet necessary CO_2 emissions reduction goals to reach the 2DS.[2]

2 See www.globalfueleconomy.org for more details about GFEI, of which the IEA is a partnering agency.

The global average fuel economy for new passenger LDVs in 2005 was approximately 8 litres of gasoline equivalent (Lge) per 100 kilometres. This improved to about 7.7 Lge/100 km in 2008, but the rate of change (-1.7%) was much less than will be needed to meet GFEI targets (-2.7%) of 4 Lge/100 km by 2030 (GFEI, 2011). Although several legislations to improve fuel economy in the OECD are moving forward, the >50% variation in average fuel consumption for new passenger LDVs in the region suggests that significant, untapped potential exists to reduce CO_2 emissions with improved passenger LDV fuel economy. Differences in income, retail fuel prices, cultural habits and land-use patterns all help explain the wide range in national average fuel economy.

In addition, actual in-use fuel economy is significantly different from what fuel tests show (Figure 13.10). The gap between tested fuel economy and on-road fuel economy is about 20%. Improvements in the average fuel economy of in-use stock tend to lag behind those in tested new-car fuel economy, as new cars slowly replace old ones. More details about on-road fuel economy and how to improve it are highlighted in IEA (2012a).

Figure 13.10 Road vehicle stock average fuel economy

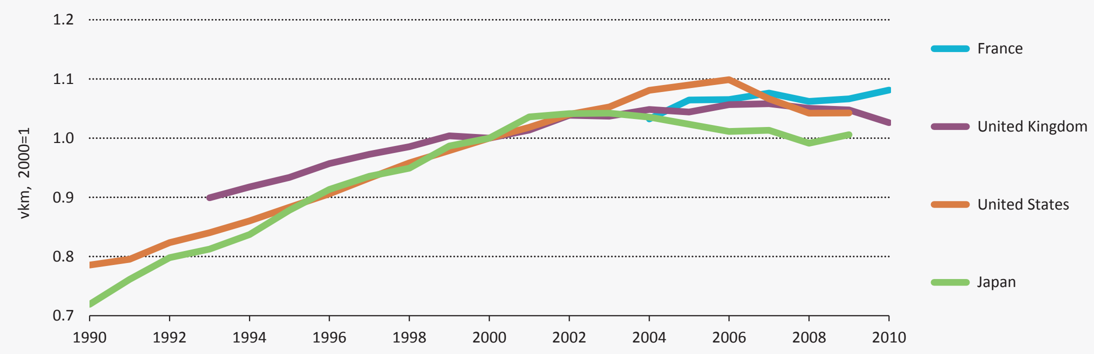


Key point *Improvements in stock on-road fuel economy have occurred slowly, with medium-duty trucks showing the biggest overall improvement since 1990.*

Passenger and road-freight vehicle travel

Passenger vehicle travel has grown rapidly around the world for the past few decades, and continues to grow rapidly in non-OECD countries, though a saturation point may be occurring in the OECD (Figure 13.11). After many decades of steady growth, there are increasing numbers of countries where vehicle travel has stabilised or is even declining, such as Japan. Whether this continues in the future will depend on many factors such as population and income growth, but there may be limits on vehicle travel per person that are being reached. If so, these limits are quite different in different countries; for example, average vehicle travel per person and per vehicle in Japan (about 9 000 km per vehicle per year) is far lower than in Europe (about 14 000), which in turn is well below levels in the United States (19 000 per year).

Figure 13.11 Passenger LDV travel for selected OECD countries, indexed to 2000

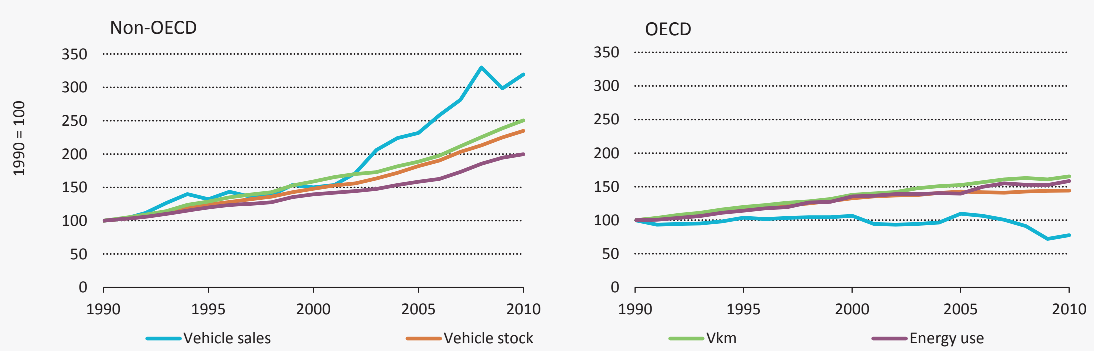


Key point *Key point: Vehicle travel began to flatten or even decline after 2000, suggesting "peak" travel may be occurring in the OECD.*

Road-freight traffic activity and energy use each have almost doubled worldwide over the last two decades, though with different rates in OECD and non-OECD countries (Figure 13.12). Even though commercial vehicle sales seem closely linked to the strong economic fluctuations over the past few years, stock, travel (in vehicle kilometres [vkm]) and energy use have shown steady increase.

Since 2000, OECD country activity growth has slowed, however, and vehicle sales since 2005 have declined. In non-OECD countries, activity growth rates have been increasing since 2000, led by a rapid rise in vehicle sales. In absolute terms, non-OECD trucking activity is still well below that of the OECD (*e.g.* in terms of the number of vehicles and amount of energy use in the road-freight sector), suggesting that it could be many years before non-OECD growth rates slow in the manner now occurring in the OECD.

Figure 13.12 Historical road-freight trends



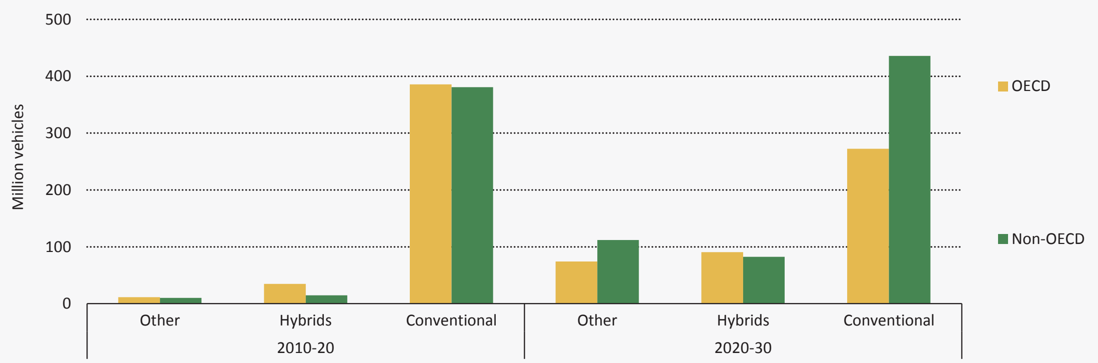
Key point *Energy use in the road-freight sector has dramatically increased since 1990 in both OECD and non-OECD countries. Since 2000, growth has slowed in the OECD, while the non-OECD has experienced higher growth rates.*

Looking ahead at transport technologies

In order to substantially and permanently reduce oil dependence and GHG emissions in the transport sector, new vehicle technologies and fuels are needed. During the next 10 years, improving the efficiency of today's propulsion systems and fuels – namely, vehicles with internal combustion engines using petroleum fuels – holds the greatest potential for change. But the move to new technologies and fuels must begin now, so that after 2020 the world is positioned to make a much larger transition to these alternatives.

The importance of improving the efficiency of conventional vehicles becomes clear when one considers the numbers of these vehicles that will be sold in the next 10 to 20 years, even in a scenario such as the 2DS with very rapid uptake of new technologies (Figure 13.13). This figure separates conventional internal combustion engines, electric-hybrid engines, and all others (mainly PHEV, BEVs and fuel-cell vehicles). In the next 10 years, vehicles with internal combustion engines (including HEVs) represent more than 95% of all vehicles sold; in the 2020 to 2030 time frame, this figure drops to about 85%. After 2030 (not shown), sales of conventional ICE vehicles drop rapidly and by 2050 are below 30%.

Figure 13.13 **Cumulative sales of passenger LDVs by technology type for the next two decades, in the 2DS**



Key point *Energy savings in the next decade must come mainly from vehicles with conventional powertrains, while hybrids and other new-technology vehicles must prepare for a bigger role after 2020.*

New technologies for light-duty vehicles and fuels

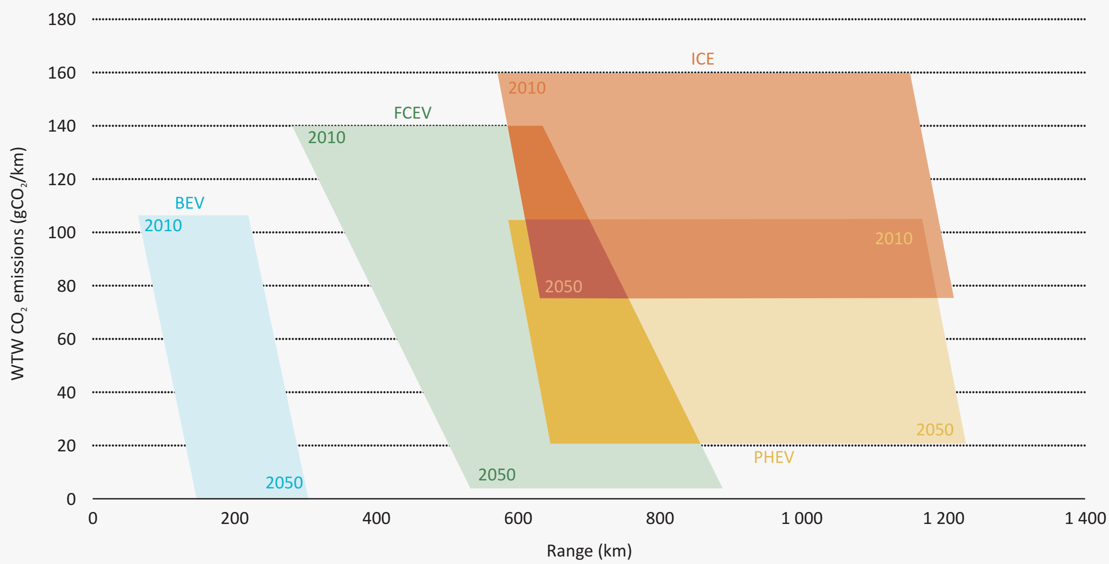
Even as gasoline- and diesel-powered LDVs improve their efficiency over the coming decade, sales of new-technology vehicles need to gear up to penetrate markets after 2030, as manufacturers will struggle to further improve conventional vehicles with internal combustion engines. New technologies and new fuels often have great difficulty in achieving significant rates of market penetration. Cost is certainly one of the main factors affecting how a technology gains popularity among car buyers, but so too are the ease of refuelling and vehicle driving range, among others.

Electricity and hydrogen are two of the most important potentially zero-oil or zero-carbon fuels (energy carriers). However, it is necessary to differentiate two separate vehicle categories according to the intended use:

- Those mostly used in urban areas; such vehicles shall switch to lower energy-density fuels, as the needed travel range is limited.
- Longer-distance vehicles that require fuels with greater energy density and fast refuelling, such as passenger LDVs for long trips or long-haul trucks. Ships and aircraft will also require very energy-dense fuels.

For a typical mid-size passenger LDV, several possible paths can emerge in terms of well-to-wheel GHG emissions versus vehicle range (Figure 13.14). The best compromise depends on the user's driving pattern, and no technology has emerged as a clear winner yet.

Figure 13.14 CO_2 efficiency versus vehicle range for a typical mid-size passenger LDV in the 2DS, 2010 to 2050



Notes: BEV = battery-electric vehicle; FCEV = fuel cell electric vehicle; ICE = internal combustion engine; PHEV = plug-in hybrid electric vehicle. WTW GHG emissions = well-to-wheel, including emissions from fuel production, distribution and use in the vehicle. The use of advanced biofuels (not shown in the figure) can substantially lower the WTW GHG emissions of ICEs, possibly to zero.

Key point *The ICE has excellent range but a limited GHG abatement potential using petroleum fuels. PHEVs can provide lower GHGs while maintaining range; FCEVs and BEVs can provide near-zero GHG but with range compromises.*

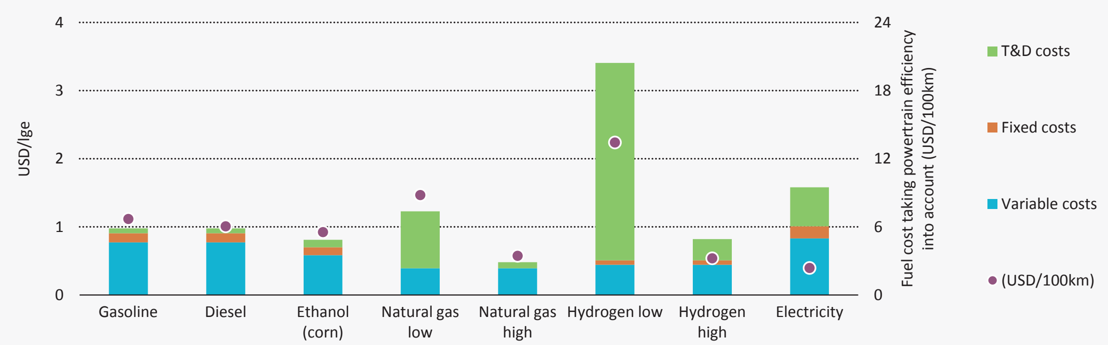
The IEA (2009) presented detailed fuel and vehicle costs and their evolution over time. With new data available in recent years, fuel-cost numbers have been updated, in particular for the costs of batteries and recharging infrastructure, as well as the costs of fuel cells and hydrogen infrastructure, as discussed in Chapter 7.

The cost of gaseous fuel (natural gas and hydrogen) depends on how much transmission and distribution (T&D) infrastructure is constructed (scale) and how intensively it is utilised (Figure 13.15). In many countries, natural gas vehicles (NGVs) have some available gas infrastructure, but virtually none exists for hydrogen for fuel-cell vehicles (FCEVs), unless hydrogen is mixed with natural gas. Battery-electric vehicles have a major advantage in this regard, since electricity T&D infrastructure is already widespread.

Electricity cost for BEVs will be affected by charger costs and could be somewhat higher than electricity for other uses, but for home recharging the charger cost appears likely to be fairly low on a per-kWh basis. Fast chargers are still very expensive (up to 50 times the cost of a home charger) but if the optimum ratio of BEVs per quick charger can be reached, such that public fast chargers are used frequently (this might take several hundred or even thousands of BEVs per charger, depending on use patterns), this would keep public charging costs low on a per-vehicle basis.

Although the operating cost of hydrogen FCEVs (which heavily depends on T&D utilisation) is still uncertain, it has the potential to be competitive with PHEVs and NGVs, thanks to its higher vehicle efficiency. The larger expected range of FCEVs may also play a role in assuaging the concerns about range that are often mentioned by BEV users. As highlighted in Chapter 7, fuel cells could replace the ICE in the PHEVs, providing a pathway where FCEVs eventually complement (and benefit from) vehicle electrification. However, there would need to be a hydrogen supply infrastructure in addition to an electricity recharging infrastructure for vehicles.

Figure 13.15 **Fuel costs in 2050 for selected fuel pathways, per unit of energy and distance travelled**



Notes: Estimates reflect oil price of USD 120 per barrel; "high" cases reflect high utilisation of refuelling stations and short-distance fuel shipment; "low" cases reflect low utilisation of refuelling stations and long-distance fuel shipment; circles show cost per kilometre (right axis), reflecting vehicle efficiency impacts.

Key point *At low vehicle-to-infrastructure ratios, gaseous fuels for transport may be very expensive, but their cost becomes competitive with high utilisation rates.*

Given recent updates for estimated future vehicle technologies and their costs, relative vehicle costs in the 4DS and 2DS have evolved downward, as highlighted by the marginal abatement curves in Chapter 1. The IEA uses a learning function that relates the cost of new technologies to their cumulative production. For electric vehicles, for example, starting with 10 000 sales in 2010, there are about 10 doublings of cumulative production to get to 20 million EVs on the road in 2020 (in the 2DS).

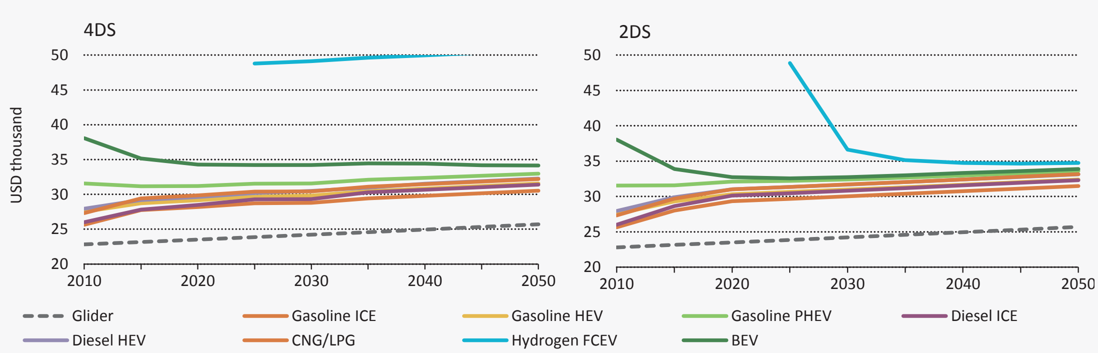
Applying this to the key BEV technology, batteries, with an assumed learning rate of 0.85 (15% cost reduction per doubling of production), total battery costs drop from a current level of about USD 500 per kilowatt hour (kWh) to under USD 350 per kWh in 2020, making BEVs much more cost-competitive with gasoline vehicles (IEA, 2011b). If batteries follow the cost path of many other technologies, electric vehicles may reach cost-competitiveness if enough are manufactured in the coming decade.

At the same time, efficiency improvements in gasoline- and diesel-powered vehicles are expected to drive up the cost of conventional vehicles. All vehicle types will cost more, due to advanced material adoption and added safety systems, along with other various upgrades over time (Figure 13.16); most of those measures are reflected in the glider (the vehicle without the powertrain) cost.

Fuel-cell electric vehicles are still at the research, development and demonstration (RD&D) phase. Mass-market production of FCEVs in the 2DS starts in earnest from 2025, with significant numbers manufactured by 2030. Proton-exchange membrane fuel cell technology has been continuously improving in recent years, especially regarding durability, cold-start capabilities, size and cost of the fuel-cell system. The cost of hydrogen storage in a 70-megapascal tank has also been significantly reduced during the last decade. FCEV costs may be reduced further with innovations from ongoing RD&D programmes over the next two decades, followed by mass production and learning (Table 7.3, Chapter 7).

Costs of selected powertrain alternatives, with respect to the glider, show that purchase prices are likely to increase, regardless of the powertrain option, due to the increasing complexity of vehicles, such as the hybridisation of internal combustion powertrains (Figure 13.16). After 2015 for BEVs and 2025 for FCEVs, average vehicle costs drop dramatically, due to mass production and resulting learning and technical progress. When lifetime fuel costs are taken into account, the fuel savings from these technologies increasingly compensate for the initial vehicle-cost premium, as the oil price rises over time (particularly as it goes beyond USD 120 per barrel) and as battery and BEV costs drop (IEA, 2009).

Figure 13.16 Passenger LDV cost evolution by technology type



Note: Costs are shown for a typical US vehicle.

Key point *The cost of BEVs and FCEVs approaches conventional vehicles in 2DS.*

Fuel economy improvement

The IEA, in co-operation with the GFEI, has identified targets for new passenger LDV fuel economy and has begun to track progress toward these targets. Most important is the goal that the average new PLDV worldwide will cut fuel use per kilometre by 50% between 2005 and 2030 (GFEI, 2009). The first progress report (GFEI, 2011) provides data and estimates of the global average fuel economy of new cars. Some fuel economy improvements were achieved between 2005 and 2008, but they are not sufficient to be on track with the GFEI target to halve the fuel consumption of new cars between 2005 and 2030 (Table 13.1).

Table 13.1 **Fuel economy status worldwide and comparison against long-term GFEI objectives (Lge/100km)**

	2005	2008	2030	Annual change 2005-08	Required annual change 2005-30 (to reach GFEI target)
OECD average	8.21	7.66		-2.1%	
Non-OECD average	7.49	7.68		0.3%	
Global average	8.07	7.67		-1.7%	
GFEI objective	8.07		4.03		-2.7%

Data show that fuel economy has further improved since 2008, because new policies and standards have been implemented in many countries that have had a positive effect on car purchase behaviours. The size of the average car decreased between 2005 and 2008 in OECD countries, unlike in non-OECD countries, where midsized vehicles have gained market share. Together with the changes in fuel type and engine technology, this explains most of the evolution between 2005 and 2008 (GFEI, 2011).

If new LDVs can reach 4 Lge/100 km by 2030, along with substantial improvements for heavy-duty trucks, ships and aircraft, global transport fuel demand can be cut by about 30% compared with the 4DS, and 40% compared with the 6DS in the 2040-50 time frame, given stock turnover rates (IEA, 2012a).

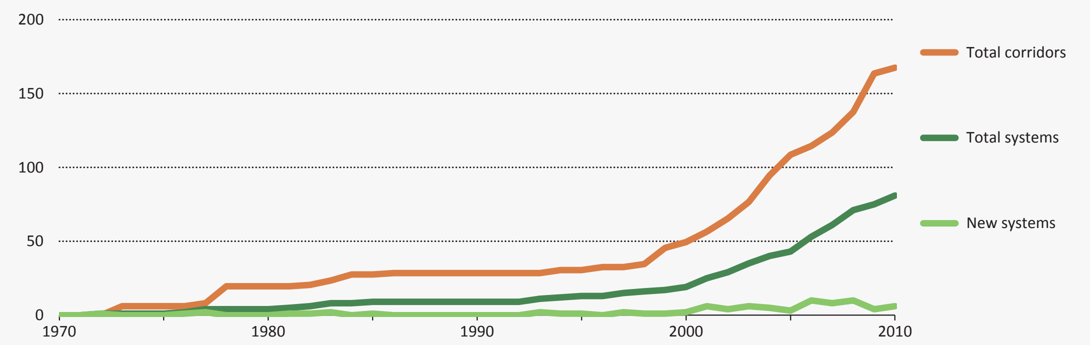
Technologies and systems to promote modal shift

Several options are available to improve the transport system as a whole, use less energy, and make it easier for people and goods to get from point A to point B. Some of these options require some degree of technological innovation, but above all they require better planning and combining the right set of existing technologies and organisational tools.

Bus rapid transit is one such option available to cities attempting to combat increasing congestion and worsening local pollution, as the number of cars in metropolitan areas rapidly swells. BRT systems involve operating high-capacity buses in corridors that use private lanes isolated from the rest of the traffic. These typically use a similar boarding system as metros, with pre-payment at turnstiles (IEA, 2002). BRT systems are a potent solution for reducing traffic congestion and increasing mobility for a broad cross-section of the population, especially those who do not own a car (more than 80% of people worldwide). In fact, a well-designed BRT system is much like a surface metro, for a small fraction of the implementation cost. New BRT systems built around the world in recent years have proven cost-effective and highly effective at moving people, with boarding rates far above conventional bus systems, and approaching those of underground metro systems.

The length of BRT corridors has grown swiftly in correlation with the increasing number of BRT corridors around the world (Figure 13.17). The IEA is a member of the global BRT data group that has compiled recent data from over 100 systems on every continent (EMBARQ, ALC-BRT and IEA, 2012). BRT systems have gained popularity since the mid-1990s, after Colombia's very successful system in Bogota.

Figure 13.17 **Historical timeline of bus rapid transit corridors and systems**



Key point *The period 2000 to 2010 saw a dramatic increase in the number of BRT systems and corridors around the world.*

The IEA (2012b) forecasts substantial energy savings from a modal shift to BRT, with the possibility of greater savings as BRT systems continue to expand and new ones are built. If implemented widely enough, BRT can contribute substantially to global CO_2 savings, potentially up to 0.5 $GtCO_2$ cumulative in the 2010 to 2050 time frame.

Besides BRT, there are many interventions to shift people from personal car trips to public transportation. System innovations, in addition to telecommuting and more integrated land-use planning, should not be overlooked:

- Public transport encompasses many mobility options in addition to BRT that vary across regions, such as light rail, more bike lanes, increased pedestrian access and improved mini-buses. Compared with traditional buses, BRT has the advantages of higher load factors and better average speeds, which translate into better fuel consumption. An average city bus operates at around 16 kilometres per hour (km/hr) versus a BRT bus at 21 km/hr (IEA, 2012b).
- Advanced technologies and fuels affect consideration of different types of public transportation. BRT's potential modal share by 2050 is significant, but this system innovation is more a model of how a city can establish new mass transit service by leveraging investments already made in roads. Equally important to the expansion of public mobility services is a city's long-term vision, along with integration of land-use and transportation planning.
- Real-time information using the latest mobile technologies can greatly help the commuter have a seamless multi-modal trip. New ticketing options could also make the mass-transport journey more appealing.

BRT systems are significantly cheaper than other urban mass transportation systems (Table 13.2). They nonetheless have a more limited GHG mitigation potential, unless the vehicles become electrified using trolley buses or adopt a low-carbon energy source such as biofuels.

Table 13.2 Comparison of three options for passenger mass transport in cities

	Light rail	BRT	Metro
CO_2 intensity (gCO_2/pkm)	4 to 22	14 to 22	3 to 21
Capital cost (USD millions/km)	13 to 40	5 to 27	27 to 330
Network length that can be built for USD 1 billion (km)	25 to 77	37 to 200	3 to 37
World network length in 2011 (km)	15 000	2 139	10 000
Capacity (thousand passengers per hour per direction)	2 to 12	10 to 35	12 to 45

Source: IEA, based on Kenworthy, 2003; Flyvberg, 2008; Dung and Ross, 2008; UITP, 2012.

Aviation and shipping: Innovations and outlook

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 the transport sector's energy use, and must be part of a global effort to cut energy use and GHG emissions in order to reach the 2DS.

Aviation

Despite the economic crisis that had some impact on air travel, the future of the air industry is looking bright as traffic is still increasing, and is expected to triple by 2050. Emerging economies are now involved in more than half of all air travel (based on their airports' being the origin and/or destination of flights). Worldwide, the aircraft fleet is getting older in certain regions, with North America and Africa having among the oldest planes in service (Table 13.3).

Given that new aircraft designs, such as the Boeing 787 and Airbus A380, have 20% to 30% lower energy use per passenger seat-kilometre than the planes they replace in the market (and as little as half the energy intensity of old planes that come out of service), it is critical that rates of new aircraft introduction remain high to ensure ongoing efficiency improvements. While these aircraft use new technologies, such as lighter materials and advanced aerodynamic designs, it may take many years for the technologies to appear in all classes of new aircraft, which also slows the rate of efficiency improvements across the commercial stock.

Table 13.3 Aircraft fleet share by aircraft type, by region in 2010

Type of aircraft	World	Latin America	North America	Africa	Europe	Middle East	Asia
Modern	70%	67%	59%	56%	75%	72%	79%
Out of Production	30%	33%	41%	44%	25%	28%	21%

Source: Airbus, 2011.

Several initiatives are emerging that will form the basis for a policy framework to lower GHG emissions from the sector. These include the EU Emissions Trading System (EU ETS), which started to include international aviation in January 2012; all flights to, from and within Europe are subjected to emissions trading. This has proven to be contentious with many foreign airlines and its future is uncertain. The Aviation Global Deal Group has established a voluntary coalition of several airlines and NGOs that is pushing to incorporate international aviation into global climate change talks.

The aircraft industry is still working on reducing GHG emissions from aircraft operation with some new steps in terms of flight operations, and further demonstration of biofuel use in commercial flights. The IEA (2009) and the World Bank (2012) summarise most of the mitigation options for the airline industry.

Shipping

In 2010, international shipping accounted for almost 80 trillion tonne-kilometres of traded goods that were transported on about 85 000 ships. The sector relies mainly on heavy fuel oil and emitted about 1 $GtCO_2$, a figure that could more than double by 2050. A range of technologies exists for both new and existing ships (as retrofits) that could cut average ship energy intensity by up to 50% for most large ship types (IEA, 2009). The challenge will be encouraging shipbuilders, owners and operators to invest in these technologies, but as oil prices rise, there will be increasing incentive to do so.

To reduce emissions from international shipping, two new agreements are expected to enter into force internationally on 1 January 2013 (IMO, 2011):

- EEDI: Energy Efficiency Design Index for new ships;
- SEEMP: Ship Energy Efficiency Management Plan for all ships.

The EEDI requires a minimum efficiency level per tonne-kilometre for new ships of different types and sizes. Technological measures included within EEDI comprise the bodywork (*e.g.* optimised hull dimensions, lightweight construction, hull coating and hull air lubrication) and the powertrain (*e.g.* waste heat recovery, hybrid electric propulsion, wind power and contra-rotating propellers), as well as the reduction of auxiliary demands (*e.g.* hotel loads and variable speed for pumps and fans).

The SEEMP aims to enhance the energy efficiency of general ship performance. The Energy Efficiency Operational Indicator (EEOI) is a measure to monitor ship and fleet efficiency that will be introduced; it helps ship operators optimise their business strategy while saving energy. The SEEMP includes engine monitoring and better maintenance (*e.g.* on hulls and propellers), but also operational measures such as speed reduction and weather routing.

Both initiatives aim to reduce CO_2 emissions from international shipping by 40% by 2050. However, these improvements are already accounted for in the 4DS. In the 2DS, further reductions to stabilise 2050 shipping emissions at the 2010 level require phasing out heavy fuel oils and eventually diesel fuel, to be replaced by lower-carbon fuels.

The most obvious option is biofuel, which could be classified as near-zero carbon if produced using advanced approaches; for now, it will likely be a "drop-in" diesel replacement. The cost could be relatively high in the near term, and the current supply of biofuels is in question. Under the 2DS, stabilising shipping emissions at 1 $GtCO_2$ after all efficiency measures are implemented, will require an estimated 20% of the world's shipping fuel to be low-carbon biofuels by 2050. This amount will need to eventually rise to near 100% if shipping is to be fully decarbonised.

Scenarios: long-term vision for short-term action

The transport sector will significantly evolve by 2050, especially in non-OECD regions, where the latest trends reflect rapid growth that will likely continue. Using the IEA's mobility model (Fulton, Cazzola and Cuenot, 2009), several scenarios have been simulated to analyse the impact of different mobility demand patterns and technology adoption rates on energy use and CO_2 emissions.

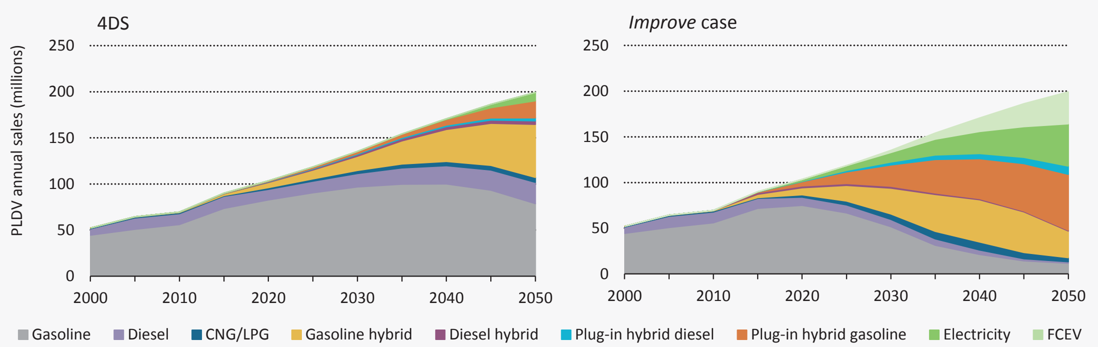
The 6DS simulates what will happen if the various policies currently under consideration are not implemented, including post-2015/2016 fuel economy standards in the European Union and the United States, and extensions of current national funding commitments for BEV and PHEV programmes. (Many of these funding commitments are scheduled to end within one to two years if not renewed or updated.) As a result, electric mobility fails to significantly penetrate the mass market. Biofuels, especially second-generation biofuels, do not grow significantly in the future apart from a few existing niches.

The 4DS for transport represents the trajectory that unfolds with existing and upcoming policies. OECD countries continue to tighten fuel economy standards up to 2025 for both passenger LDVs and road-freight vehicles. PHEV and BEV market penetration is slow, similar to what happened with HEVs initially. The recent establishment of an EEDI 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 (for transport) comprises two cases, here called *Avoid/Shift* and *Improve*. When put together into a single scenario as *Avoid/Shift/Improve*, they achieve the transport contribution to the 2°C target:

- The *Improve* case focuses on technology improvements that lower GHG emissions; it implies tightening fuel economy standards through 2030 on new cars, matching the GFEI target (Table 13.1). Electric vehicles start displacing the ICE from the mid-2020s, joined by FCEVs in the 2040s (Figure 13.18). The EU ETS for aviation is expanded globally to the whole airline industry, and the shipping industry completes its shift to low-sulphur fuels, allowing for significant efficiency improvements.

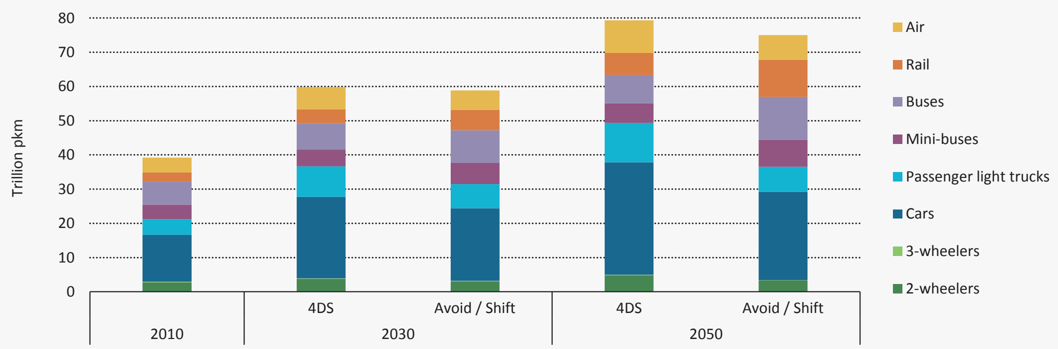
Figure 13.18 Global portfolio of technologies for passenger LDVs



Key point *In the Improve case, electric, PHEV and FCEVs together account for nearly three-quarters of new vehicle sales in 2050.*

- The *Avoid/Shift* case analyses the effect of modal-shifting policies and investments on GHG emissions. The policies adopted in this case help improve the share of the most efficient modes, including virtual mobility and other demand-management policies that mitigate mobility needs. Policies that promote carpooling, car sharing, BRT systems and high-speed trains are implemented to reduce reliance on energy-intensive mobility (Figure 13.19).

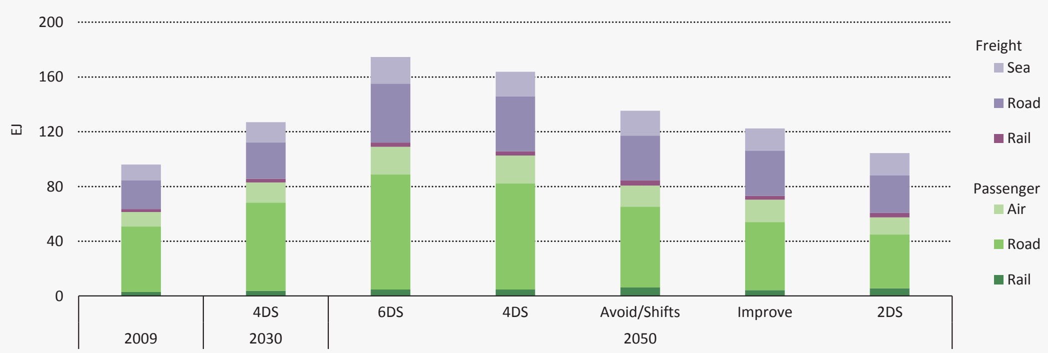
Figure 13.19 Passenger activity evolution by scenario



Key point *Policies should direct a shift to bus and rail to capitalise on their better energy and GHG efficiency.*

The 2DS combines the *Avoid/Shift* and *Improve* cases to reach significant GHG abatement by 2050, and to reach near-zero GHG emissions by 2075 (see Chapter 16). Energy use, however, could increase by up to 70% if no further policies are adopted in the coming decades, as in the 6DS (Figure 13.20).

Figure 13.20 Energy demand in the transport sector by mode



Key point *The 2DS reflects both travel* Avoid/Shift *changes and vehicle* Improve *changes, which combine for maximum fuel savings.*

Strong curbs in transport oil use and cuts in GHG emissions are necessary in order to meet the 2DS. Applying more efficient technology and fuels is critical but may not be enough to reach the target and, apart from fuel economy, will not 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.

Travel demand management and modal-shift policies can complement aggressive adoption of new technologies in the transport sector. This is especially true for urban passenger travel, where various options abound to cut dependence on individual passenger vehicles. In fact, if urban areas (where 70% of humans will live by 2050) can grow "smartly", the demand for travel could be 10% to 20% lower than if the urban areas grow in a haphazard manner (*e.g.* due to shorter trips). If more travel is served by the most efficient modes (mass transit, walking and cycling), an additional significant cut to energy use and CO_2 can be realised.

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.

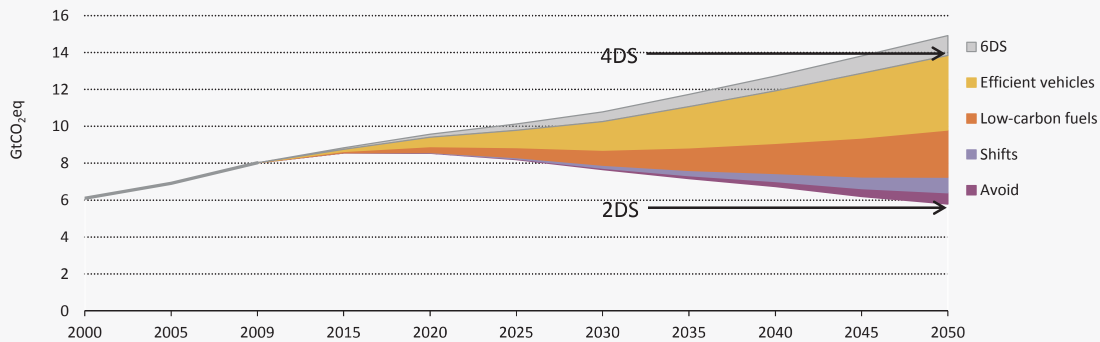
Even with these *Avoid* and *Shift* strategies, average travel per capita is expected to more than double over the next four decades; consequently, the technology portfolio for the transport sector will need to significantly evolve in order to achieve the very low CO_2 targets set in the 2DS for passenger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

Electric vehicles will achieve very low emissions anywhere with a strongly decarbonised electric system, itself a key target in the 2DS (Chapter 11). Hydrogen and fuel cells may yet play a significant role in the future of mobility, particularly for large, longer-range vehicles (Chapter 7). For trucks, ships and aircraft, deep decarbonisation must either come from hydrogen or biofuels, and given the possible constraints on biofuel supplies, the potential role of hydrogen should be carefully considered.

The GHG mitigation potential from the transport sector in the 2DS remains high, even though petroleum fuels will remain important for decades to come. The remaining GHG emissions from the transport sector in 2050 can be returned to 2005 (Figure 13.21). These emissions are well-to-wheel, and so include GHG emissions from other sectors, such as power generation and oil refining.

In the next decade, strong changes in travel and vehicle trends must be achieved, with rapid uptake of new technologies, in order to be on track to achieve the long-term targets under 2DS (Table 13.4). Though the 2020 market shares may not appear high, the annual sales growth rates that are needed to get there (particularly for BEVs and PHEVs) are very high and unprecedented. Achieving these 2020 targets will require strong government support measures such as favourable tax policies and heavy investments in infrastructure. Key policy steps over the next 10 years are discussed at the end of the chapter.

Figure 13.21 Well-to-wheel greenhouse gas emissions mitigation potential from the transport sector



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

Table 13.4 Transport sector's 2020 objectives to be reached in the 2DS

		Market share for year 2010	2050 share in 2DS	Needed share in 2020	Annual growth 2010-20	Note
Share of sales	BEVs	0%	22%	2%	56%	
	PHEVs	0%	34%	4%	107%	
	FCEVs	0%	17%	0%	N/A	Mass deployment after 2020
Share of fuel use	Biofuel	2%	25%	5%	9%	
Share of passenger kilometre	Public transport	22%	35%	25%	3%	
	Rail	7%	17%	8%	4%	

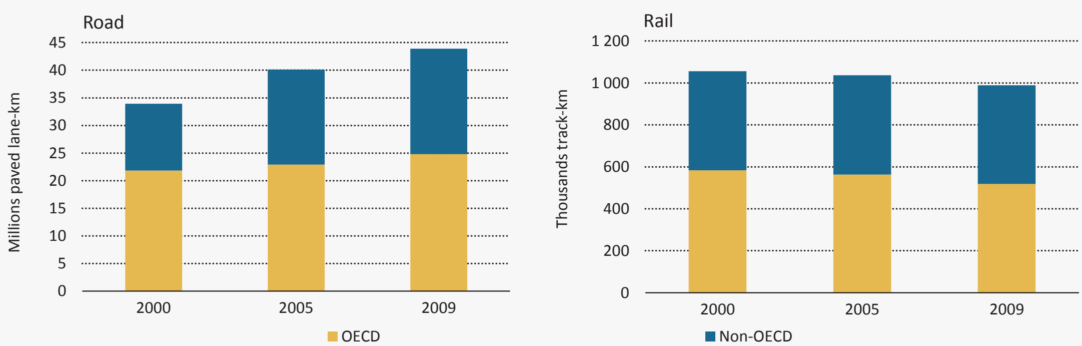
Focus on transport infrastructure

All the scenarios – the 2DS, 4DS and 6DS – show massive increases in the numbers of vehicles, the extent of passenger travel and the amount of goods transported around the world (especially in non-OECD countries). This travel growth implies the need for a commensurate increase in transport infrastructure. But how much infrastructure will be needed? What will this cost? Is this even feasible in some places? For example, can road capacities be increased to keep up with projected growth in vehicles and vehicle kilometres of travel in countries such as India, with nearly a tenfold increase expected in car travel?

Countries are already addressing this issue. In the past decade, global transport infrastructure grew significantly, especially in emerging economies. Between 2000 and 2009, global roadway infrastructure increased 30% (nearly 10 million additional lane-kilometres since 2000). China, in particular, nearly doubled its total paved roadway network. Non-OECD countries accounted for roughly 80% of total new roads built since 2000 (Figure 13.22).

Railways had a different trajectory over the past decade: globally, track kilometres decreased by roughly 5%, nearly 67 000 km, between 2000 and 2009. Nearly all of these lost track kilometres were in Canada and the United States, where unused rail track was mostly dropped out of service rather than physically removed. In contrast, rapidly emerging economies, including China, India and the Association of Southeast Asian Nations (ASEAN), added roughly 15 000 track kilometres during the same period, about an 8% increase over 2000 levels (Figure 13.22).

Figure 13.22 **Historical road and track kilometres extent**



Source: IEA analysis based on IRF, 2012; UIC, 2012.

Key point *Road networks have increased, mainly in non-OECD countries, while rail track length has decreased slightly over the last decade.*

As global travel continues to increase, supporting infrastructure must grow simultaneously. This is especially true in non-OECD countries: between 2000 and 2010, non-OECD passenger and freight travel surpassed OECD travel levels. That said, non-OECD infrastructure still is less extensive than in OECD countries. By 2010, non-OECD countries averaged about 40% more travel (in total travel kilometres) than OECD countries on roughly 20% fewer infrastructure kilometres. Although non-OECD countries have added significant infrastructure since 2000, they still need to add much more to keep up with projected increases in travel demand.

Since the IEA data are national and multinational in scope, rather than urban, it is difficult to say how these figures translate into traffic congestion in urban areas around the world, but with more travel on fewer roads, it seems likely that urban traffic congestion in non-OECD countries is on average as bad as, or worse than, in OECD countries.

Infrastructure cost has also been considered. Cost estimates for new infrastructure, as well as historic national infrastructure investments and expenditures, were collected in partnership with the OECD International Transport Forum, the International Road Federation, the International Union of Railways and the Asian Development Bank.

Road and rail infrastructure costs reflect many uncertainties regarding the nature and scope of individual projects. To account for these uncertainties, average region-wide estimates were applied (Table 13.5), as a range of costs for OECD and non-OECD regions per infrastructure-kilometre and per passenger- and tonne-kilometre. Costs were divided into capital (or construction) costs, reconstruction or upgrade costs, and operation and maintenance (O&M) costs.

While specific costs of infrastructure development and maintenance depend on the nature of the project and the intensity of infrastructural use, average infrastructure costs per kilometre of road and rail appear relatively constant across global regions. In contrast, there is a considerable breadth in the range of costs per passenger- and tonne-kilometre. The range in costs can be explained by the average frequency of travel per road and rail kilometre over the expected lifespan of the infrastructure. For example, countries with high occupancy for their infrastructure (*i.e.* high average travel levels relative to infrastructure length) have low average costs for passenger and freight travel. As travel relative to infrastructure network length converges across global regions, it is expected that average costs follow this trend.

Table 13.5 Cost range to build new road and rail infrastructure, 2010 (USD millions)

		Road		Rail	
		Capital	Annual O&M	Capital	Annual O&M
Cost per kilometre	OECD	1-1.5	0.02-0.04	2.2-6	0.11-0.3
	Non OECD	1-1.3	0.036-0.039	2-4.5	0.1-0.24
Cost per passenger- and tonne-kilometre	OECD	0.03-0.11	0.0004-0.002	0.002-0.06	0.0001-0.003
	Non OECD	0.02-0.08	0.0003-0.002	0.001-0.02	0.0001-0.009

Source: IEA estimates based on ADB, 2012; ITF, 2011; IRF, 2012; UIC, 2012.

Overall, rail is much more expensive than roads to maintain and develop, when considered as a unitised infrastructure cost (Table 13.5). In contrast, the cost of developing and maintaining rail per passenger- and tonne-kilometre generally is significantly lower than roads. This difference in cost per passenger- and tonne-kilometre reflects the overall capacity of rail to carry considerably higher passenger and freight loads (per vehicle- and per infrastructure-kilometre).

Transport infrastructure scenarios

In the 4DS, global road traffic activity is expected to more than double to nearly 43 trillion annual vehicle kilometres by 2050. To accommodate this growth, global road infrastructure is expected to increase by roughly 60% above 2010 levels by 2050 (an increase of roughly 14 million paved lane-kilometres by 2030 and an additional 12 million paved lane-kilometres by 2050). China and India account for nearly 35% of expected roadway additions.

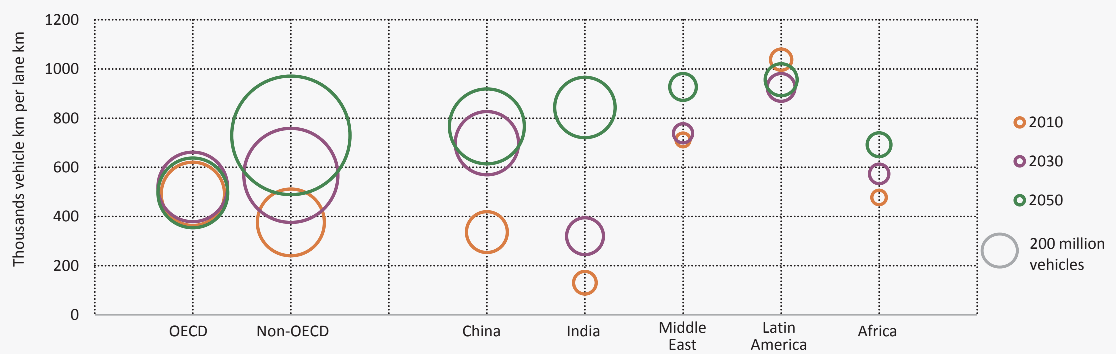
These assumed rates of roadway expansion are critical to determining the ratio of travel to roadway (and thus a broad measure of traffic congestion for countries and regions in the future). If countries can add roadway even faster than assumed here, there will be less pressure on traffic; if they are slower (which is quite possible), things could be worse. There is also the risk of a powerful feedback effect: adding more roadway encourages a faster uptake of cars and spurs more travel, possibly at the expense of travel via more efficient modes. However, such feedback effects have not been explicitly taken into account in the car-travel projections in these scenarios; car travel continues to be a function of car ownership and fuel price, and ownership primarily a function of income growth.

Under these roadway projections to 2050, average national infrastructure occupancy levels are not expected to increase significantly in OECD countries. These countries are expected to continue to add roadway infrastructure at a pace commensurate with vehicle travel increases. In contrast, average national road-occupancy levels in non-OECD regions are expected to significantly increase by 2050. In most non-OECD countries, road travel will outgrow infrastructure additions due to limitations in construction capacity and overall roadway density. In particular, China, India, the Middle East and Africa will experience significant growth in average road-occupancy levels, despite continued roadway construction.

Average road-occupancy levels for OECD and several non-OECD regions in 2010, 2030 and 2050 evolve in markedly different directions. Despite heavy infrastructure growth, average road-occupancy levels are still predicted to increase significantly (Figure 13.23).

China, which is expected to surpass US road infrastructure density by 2050, will have nearly four times the number of vehicles and twice the number of annual vehicle kilometres as the United States by 2050.[3] In terms of vehicle travel per infrastructural kilometre, this means that China's average national road vehicle occupancy will increase by 2.5 times by 2050, or 1.4 times the average US road-occupancy levels. This jump in average road-occupancy levels in China will have significant implications for road traffic activity, especially in urban centres in China.

Figure 13.23 **Average national road-occupancy levels relative to total vehicle stock**



Note: The size of the bubble indicates vehicle stock in millions.

Key point *Road-occupancy levels will increase considerably in most non-OECD countries by 2050.*

India's average road occupancy is expected to increase 6.5 times from 2010 levels or, like China, roughly 1.5 times average present US levels. In contrast, India is projected to have roughly half the vehicle ownership rate of China by 2050. Indian road-occupancy levels will continue to rise beyond 2050 as vehicle ownership approaches expected Chinese and OECD ownership levels. Latin America, which currently has one of the highest average regional road-occupancy levels in the world, is expected to slightly reduce it with continued infrastructure additions.

3 China and the United States have roughly the same physical land area in square kilometres.

Global rail travel is projected to double by 2050 in the 4DS. To support this growth, global rail track kilometres need to increase by roughly 20% above 2010 levels by 2050 (or approximately 175 000 additional track kilometres by 2050). China and India account for roughly one-quarter of expected additions of rail track kilometres. North America, Europe, Russia (together with other former Soviet countries) and Latin America account for roughly 75% of remaining expected new track kilometres.

Global railway travel per track kilometre is not expected to increase as significantly as road- occupancy levels. Again, rail-occupancy levels in OECD member countries are expected to remain relatively constant as track is added at a level commensurate with rail traffic growth. In non-OECD countries, rail travel per track kilometre will increase between 20% and 110%, depending on the country, although none of these projected increases are as remarkable as road-occupancy growth.

The less outstanding increases in rail-occupancy levels across the globe can be explained in part by overall capacities of rail cars to carry more passengers and more tonnes of freight. While significant roadway vehicle additions will be necessary to accommodate growth in passenger and freight road-travel demand, considerably fewer railway cars will be necessary to accommodate rail traffic growth.

The global railway infrastructure projections include high-speed rail (HSR) track. By the end of 2011, there were approximately 16 500 km of HSR, or roughly 1.5% of total global rail track kilometres. An additional 7 500 km of HSR is expected to be constructed by 2025, where nearly all of those expected additions are in countries that already have HSR (UIC, 2012). Several additional countries have expressed interest in developing HSR corridors, although none of these planned developments is certain.

Infrastructure additions in the 4DS will have significant costs. Capital construction, reconstruction, and O&M costs to 2050 for road and rail infrastructure are expected to be in the range of USD 75 trillion, or roughly USD 2 trillion per annum over the 40-year period (Table 13.6). This equates to slightly more than 1% of global gross domestic product (GDP), which is broadly consistent with existing transport infrastructure expenditures today.

Table 13.6 Road and rail infrastructural kilometres and costs to 2050

	2010-50 infrastructure additions (thousands of km)		2050 infrastructure network (thousands of km)		Cost to 2050: capital + O&M (USD trillions)
	Road	Rail	Road	Rail	
OECD	5 400	46	28 800	565	31
Non-OECD	20 300	130	39 300	600	45

These global road and rail cost projections do not reflect expected exceptional infrastructure expenditures in certain countries or regions. Countries and regions with high projected infrastructure development levels (*e.g.* China, India) or large infrastructure networks to operate and maintain (*e.g.* Canada, the United States and Russia) have expected transport expenditures that are above the global average of roughly 1% of GDP (possibly as high as 2% in some cases). These higher projected costs largely are the result of road capital, reconstruction, and O&M costs. To this extent, budget constraints could have the potential to limit roadway development and upkeep significantly. By the same token, high road expenditures in those regions may limit overall economic performance and investments in other sectors.

Box 13.1 Parking infrastructure

Global passenger LDV stock is projected to increase 2.5 times by 2050. Conservatively speaking, this equates to roughly 3 billion additional parking spaces, or approximately 45 000 km^2 of new parking, not including areas around, or access to, parking spaces. If all regions increased their parking infrastructure to average OECD levels (roughly three spaces per vehicle), PLDV parking could account for as much as 125 000 km^2 of space by 2050 (roughly the size of Greece). The cumulative cost of constructing, operating and maintaining these parking spaces between 2010 and 2050 is expected to be in the range of USD 22 trillion to USD 30 trillion.

Cutting infrastructure requirements via Avoid and Shift

Infrastructure projections were adjusted to reflect road and rail travel changes in the *Avoid/Shift* case and in the 2DS, which includes *Avoid/Shift* along with *Improve* cases. While vehicle technology and fuel improvements decrease overall energy consumption in the transport sector, the *Improve* case does not produce any changes in overall vehicle infrastructure demand (not including fuel recharging infrastructure which is considered part of the fuel infrastructure). The *Avoid/Shift* case, however, produces considerable changes in the overall demand for road and rail infrastructure to 2050.

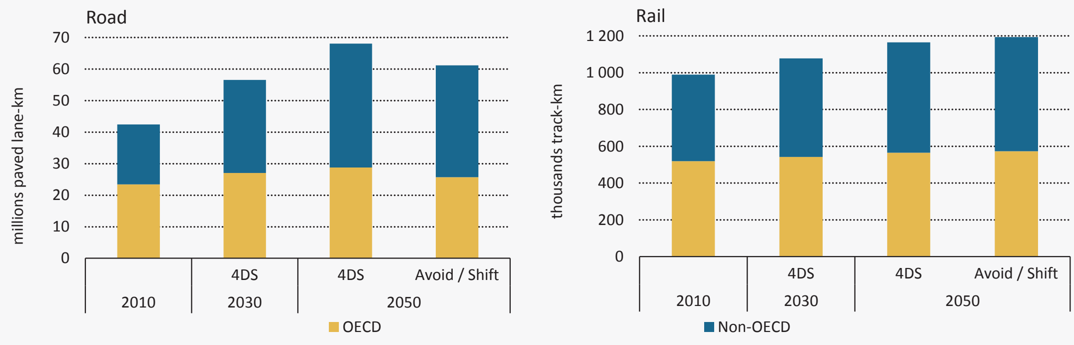
In comparison with the 4DS, road vehicular travel decreases by nearly 25% by 2050 in the *Avoid/Shift* case (or roughly 9 trillion annual vehicle kilometres). As a result, road infrastructure in the *Avoid/Shift* case is expected to be approximately 7 million lane kilometres (26%) lower than the 4DS in 2050. This decrease in additional road infrastructure significantly reduces projected roadway expenditures: the cumulative cost of roadway construction, reconstruction, and O&M beyond 2010 in the *Avoid/Shift* case is estimated to be roughly USD 60 trillion, a 15% savings compared with the 4DS level.

Railway travel, by contrast, is expected in increase under the *Avoid/Shift* case due to shifts in passenger and long-distance freight travel to rail. In this scenario, annual rail travel is expected to increase by roughly 6.1 trillion passenger- and freight-tonne kilometres, or 28% over 4DS rail travel. Global rail infrastructure therefore is expected to increase to 1.2 million track kilometres, or a 17% increase over 4DS rail additions.

Included in this estimate is HSR, where the IEA projects that the global HSR network could reach nearly 118 000 km by 2050. This HSR estimate is consistent with the potential global HSR network if HSR corridors that are already proposed and planned are constructed by 2050. The consequent cumulative cost of railway construction, operations and maintenance (including HSR) is estimated to be in the range of USD 10 trillion, or a 60% increase over the 4DS.

Overall, the *Avoid/Shift* case represents a savings of roughly 7 million additional infrastructure kilometres to 2050 (Figure 13.24). It also represents a savings of nearly 17 000 km^2 of passenger vehicle parking (not shown here). This equates to a net cumulative savings of approximately USD 14 trillion on transport expenditures for road, rail and parking to 2050, or roughly 15% of projected expenditures to 2050 under the 4DS (Table 13.7). Most of this savings is due to shifts from road to rail and subsequent reductions in vehicle parking development. Transport infrastructure expenditure reductions in the 2DS equate to a savings of roughly 0.2% of global cumulative GDP to 2050.

Figure 13.24 Infrastructure kilometre projections



Key point *The pace of road building in non-OECD countries can be significantly slowed down in the Avoid/Shift case.*

Table 13.7 Cumulative transport land infrastructural cost to 2050 (USD trillions)

		4DS		Avoid/Shift	
		2010-30	2010-50	2010-30	2010-50
OECD	Road	13.9	27.4	11.2	22
	Rail	1.3	3.1	1.6	4.5
	Parking	6.1	11	4.4	7.9
	Total	21.3	41.5	17.2	34.4
Non-OECD	Road	19	42.3	17.3	37.3
	Rail	1.5	3.2	2.3	5.5
	Parking	4.6	11.2	3.3	7.2
	Total	25.1	56.7	22.9	50.1
World	Road	32.9	69.8	28.5	59.3
	Rail	2.8	6.3	3.9	10
	Parking	10.7	22.2	7.7	15.1
	Total	46.4	98.3	40.1	84.4

Transport cost assessment: adding up vehicles, fuels and infrastructure

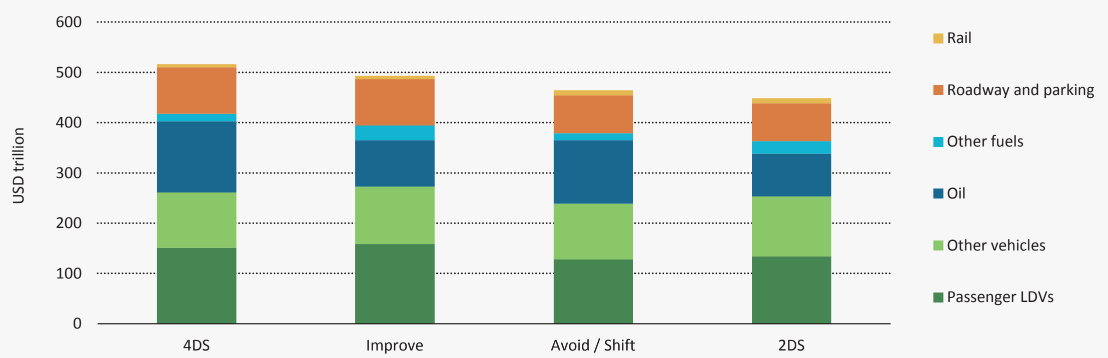
To evaluate the costs associated with each scenario, the model adds together the total costs (public and private) that society will spend on transport and mobility during the coming decades. This cost assessment includes:

- **Vehicles:** The cost of buying, maintaining and operating the vehicles during their lifetime.
- **Fuels:** Extracting, producing, transporting and storing the fuels that power the vehicles, including fuel transport and recharging infrastructure.
- **Vehicle infrastructure for land transport:** Infrastructure needs assessed according to the traffic activity evolution of both road and rail (as discussed in the previous section).

This simple accounting of projected costs neither captures all costs (*e.g.* travel time, pollution costs) nor considers all benefits (some types of transport may be more highly valued than others). Therefore, it should be considered a partial analysis and the results must be interpreted in that context. The costs of the transport system presented here are not discounted and do not include taxes.

The totals for those costs measured amount to USD 500 trillion over 40 years (Figure 13.25), close to two orders of magnitude higher than the estimated cost to deploy new technologies and promote alternative modes. The results also show that the savings, from fewer vehicles and less infrastructure, along with much lower fuel spending, more than compensate for the early investment in new technologies. The 2DS (*Avoid/Shift/Improve*) is estimated to be the least expensive scenario by about USD 10 trillion compared with the others.

Figure 13.25 Cumulative transport costs, 2010 to 2050



Key point *The* Improve *case greatly reduces the expenditures on fuels, whereas the* Avoid/Shift *case cuts down infrastructure and vehicle costs.*

In the *Improve* case, vehicle cost increases significantly (on the order of USD 20 trillion) over the 2010-50 period, due to the premium price paid for fuel-efficient and new-technology vehicles. However, this is more than compensated by the fuel savings over the lifetime of the vehicles (the exact impacts are dependent on the price of fuels; see Chapter 1 for primary energy cost assumptions).

Infrastructure costs are similar in both the 4DS and *Improve* case (with the refuelling infrastructure already included in fuel costs, and road and rail costs included under infrastructure). Thus, in both scenarios, the total transport expenditures through 2050 are about USD 500 trillion, suggesting that a new-technology, low-carbon scenario is not significantly more expensive than a baseline scenario; and any net additional costs on the order of a few USD trillion over the next 40 years (if they occur) will be negligible compared with the total expected costs of transport.

In contrast to the cost similarity between the 4DS and the *Improve* case, the *Avoid/Shift* case can provide about 10% cost savings over the next four decades, due to three significant changes: fewer passenger LDVs, lower fuel demand, and reduced need for infrastructure to accommodate the vehicles.

This analysis suggests that large cost savings are associated with shifting some travel away from cars and toward mass transit modes. However, this is still a partial result: more work is needed to estimate the impacts that shifts to HSR will have on airport costs and to look at impacts of shifting to freight. Further, work is needed on precisely what benefits are associated with these scenarios: people buy cars partly because they need them for mobility and partly for other reasons.

Improving transport options to allow greater mobility without cars should mean that lower demand for cars is a cost reduction without a benefit reduction. However, policies to encourage alternatives to driving (mostly likely also needed in the *Avoid/Shift* case) could mean lost benefits as people are given incentives to shift to non-car modes that they might not prefer. But provision of more transit and non-motorised modes, and more intelligent land-use planning ("smart growth") should be able to provide substantial net mobility benefits with net reductions on the cost side – and therefore substantial net benefits to society.

Recommended actions for the near term

A wide range of actions is needed to change travel patterns, improve efficiency and adopt new fuels in the transport sector, in order to be on track to reach the 2DS in 2050. To drive all the changes described in this chapter, countries and the international policy community should create specific policy targets and measures to move things in the right direction, at the necessary pace.

Many actions should start now, and some initial results can be expected by 2020, but some changes will take much longer. Primary action should focus on implementing and tightening fuel economy standards for road vehicles in all major markets, to be on a path to reach 4.0 Lge/100 km by 2030 (or before) for new passenger LDVs on average. By 2020, at least 90% of global commercial vehicle production should be covered by a strong fuel economy standard (IEA, 2012a).

To reach a 2020 target of over 20 million BEVs and PHEVs on the road (IEA, 2011b), these vehicles must be supported with price incentives in a cost-sustainable fashion (such as via CO_2-based vehicle taxation, bonus-malus systems, etc). In parallel, co-ordination of recharging infrastructure growth must be led by national, regional and municipal governments, with targets commensurate with the growth of the BEV/PHEV stock.

Bus and rail systems must also receive strong public support in terms of service quality and the size and number of systems. The total network length of BRT systems worldwide should be doubled by 2020. For high-speed rail, at least a 50% increase of the global network should be achieved.

New regulatory and economic tools to incentivise low-carbon mobility (and to help pay for sustainable transport systems) should be developed. Petroleum fuel subsidies should be eliminated in all countries, and fuel taxes set to internalise environmentally related external costs to reflect the real cost of transport modes. Vehicle tax systems should be shifted toward a fuel economy/CO_2 basis. A fuel economy or CO_2-based registration tax for vehicles that provides incentives to purchase clean, low carbon vehicles while also raising net overall revenues to help pay for public transport systems, may provide a sustainable financial solution.

A global aviation emission trading system, if implemented by 2020, could play a key role in helping aviation reach the 2DS targets. Further consolidation of the efficiency (EEDI) index for maritime transport, with linked incentives, could do likewise.

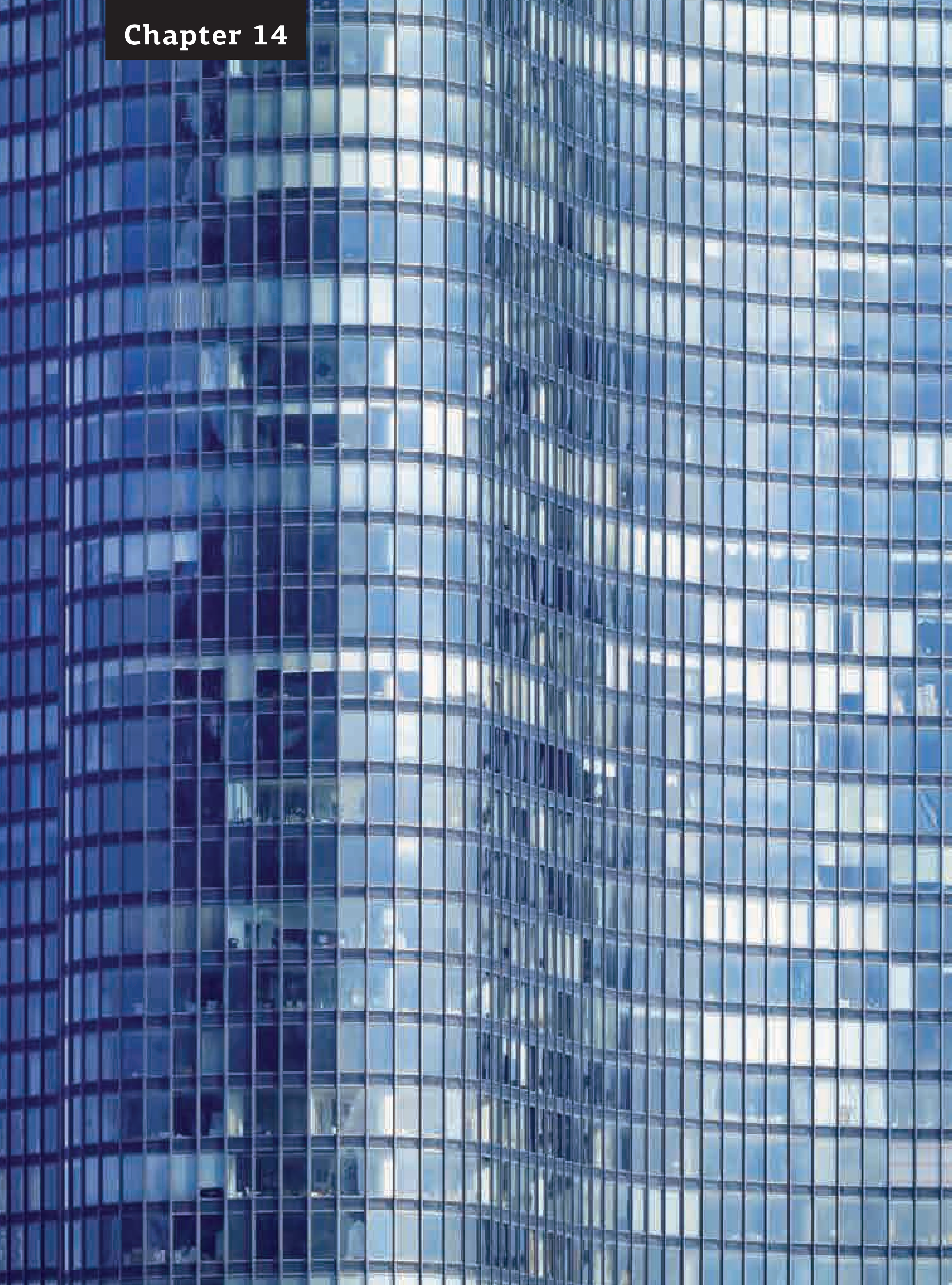
On the fuel side, a stable, long-term policy framework for low-carbon, advanced biofuels will need to be created in order to increase investor confidence and allow for the expansion of sustainable biofuel production (IEA, 2011c). Commercial-scale production of advanced biofuels by 2015, along with a clear plan for a globally sustainable feedstock supply system, will be needed in order to achieve rapidly rising market share after 2020.

For hydrogen and fuel cell vehicles, more extensive demonstration programmes that could evolve into full deployment efforts in key cities and countries could help speed their development and increase the probability that they can play an important role in the future. This is especially important given ongoing uncertainties with both electric vehicles and biofuels, the only other potentially zero-carbon energy carriers.

Finally, given the costs of transport systems, vehicles and fuels (rising to a cumulative total of USD several hundred trillion over the next four decades, or more than USD 10 trillion per year on average), current RD&D expenditures appear very low. A strong intensification of RD&D in areas like batteries, advanced charging systems, hydrogen storage, lightweight materials, and new fuel systems for shipping and aircraft are warranted.

Each of the individual targets represents an important step to achieving lower-energy, low-carbon mobility by 2020. Individual countries may have different appropriate targets – one size does not fit all. Because these measures and targets involve many different stakeholders and specialities, a cross-cutting effort will be needed, involving local, national and international co-ordination.

Chapter 14



Buildings

Technologies that can help achieve deep carbon dioxide emissions reduction in the buildings sector are already available. Ensuring that all available options will be tapped will require unprecedented effort and co-ordination by policy makers, builders, investors, technology developers, manufacturers, equipment installers, energy management companies and consumers.

Key findings

- ***The buildings sector must reduce its total carbon dioxide (CO_2) emissions by over 60% by 2050.*** *Such a reduction in CO_2 emissions is required to limit global temperature rise to 2 degrees Celsius (°C).*

- ***The buildings sector's CO_2 emissions account for about one-third of all end-use CO_2 emissions,*** *if upstream emissions from electricity generation are attributed to electricity consumption in the sector.*

- ***Emissions reduction in the buildings sector are vital to any long-term strategy to curb carbon intensity.*** *With more than half the current global building stock expected to still be standing in 2050, and considering that buildings can last for over 100 years, actions cannot be limited to tighter controls on new construction.*

- ***Strong, prompt and careful policies can promote high-efficiency standards in both new and existing construction,*** *helping to avoid locking in low-efficient buildings and offset costly intervention outside of scheduled refurbishment or initial construction.*

- ***Energy-consuming products within buildings are replaced much more frequently than buildings.*** *Choosing the best available technology (BAT) at the time of renovation or purchase is important in reducing energy demand in buildings.*

- ***Numerous technologies can significantly reduce CO_2 emissions in new and existing buildings.*** *These include high-efficiency envelopes; light bulbs; heating, ventilation and air-conditioning (HVAC) systems; co-generation and heat pumps for space and water heating. Most are already available and economical over their life cycles. Some of these technologies have long payback times and high upfront costs, however, which calls for a shift of focus from economics to finance.*

- ***The buildings sector needs to make additional investments in efficient building shells and equipment to transform its energy consumption and emissions profile.*** *This would be, over and above the ETP 2012 6°C Scenario (6DS), estimated at USD 7.5 trillion in the residential sub-sector and USD 4.0 trillion in the services sub-sector. These investments would make it possible to achieve energy savings significant enough to offset the additional costs of deep emissions reduction.*

- ***Policy challenges in OECD member countries and non-OECD Europe and Eurasia countries are different from those***

of developing countries. *In the first category, a significant level of* CO_2 *emissions results from space heating, and the current building stock will become less efficient as it ages unless retrofitted. In the second category, rapid new building construction offers opportunities to improve efficiency standards for new construction relatively easily.*

Opportunities for policy action

- *A necessary first step in improving energy efficiency in the buildings sector is to develop and enforce stringent buildings codes that include minimum energy performance for new and refurbished buildings. Improved building-shell efficiency has the additional benefit of allowing the equipment required for space heating and cooling to be downsized.*
- *Policies are required to promote the research, development, demonstration and deployment (RDD&D) of new technologies for buildings and the energy-using equipment inside them in order to integrate them into the smart energy networks of the future and ensure proper technical assistance and public awareness.*
- *Government policies need to target non-technical barriers, such as public acceptance, shortages of skilled workers, and market risks of new technologies that significantly weaken penetration of new, more efficient technologies.*

The buildings sector uses a wide array of technologies and materials in the building shell, in space heating and cooling systems, in water-heating systems, in lighting, in appliances and electric consumer products, and in business equipment. From an energy perspective, buildings are complex systems, in which the interaction of technologies almost always influences energy demand. Occupancy profiles, the design of buildings and their interaction with the environment, the behaviour of occupants, and the local climate all affect overall energy demand in a building.

Most buildings last for decades, some for centuries. More than 50% of the current global building stock will still be standing in 2050; in OECD countries, that figure is closer to 75%. Buildings are more frequently refurbished than replaced, and the fact that refurbishments rarely include energy efficiency components has significant implications for policy makers. The low replacement or refurbishment rate of existing residential building stock in OECD countries is a significant constraint, particularly on reducing heating and cooling demand under ambitious CO_2 reduction scenarios. Services sub-sector buildings are generally less constrained in this respect because they are replaced or refurbished earlier than residential buildings.

Energy-consuming technologies and appliances are replaced much more frequently than buildings. Heating, ventilation and air-conditioning systems are generally upgraded or replaced every 15 to 20 years. Roofs, facades and windows need periodic replacement or restoration. Office equipment is rotated out after three to five years. New household appliances are purchased every 5 to 15 years. Consumables, such as light bulbs, have much shorter life spans. Choosing the BAT at the time of renovation or purchase significantly contributes to reducing energy demand in buildings and affects the costs and benefits associated with energy savings.

Building emissions are rising swiftly as the constructed environment expands and the ownership of energy-consuming equipment increases. In the services sub-sector, architectural trends, such as the popularity of large glass walls and windows, may add to the energy intensity of new buildings. Policies to improve energy efficiency in new and existing buildings need to ensure that new structures incorporate the highest standards of efficiency into design.

Significant reductions in CO_2 emissions are achievable in new and existing buildings with currently available technologies. Many are already cost-effective over total life-cycle costs. But non-technical barriers, such as public awareness and acceptance, shortages of skilled workers, and market risks of new technologies, can significantly decelerate their scale-up and use.

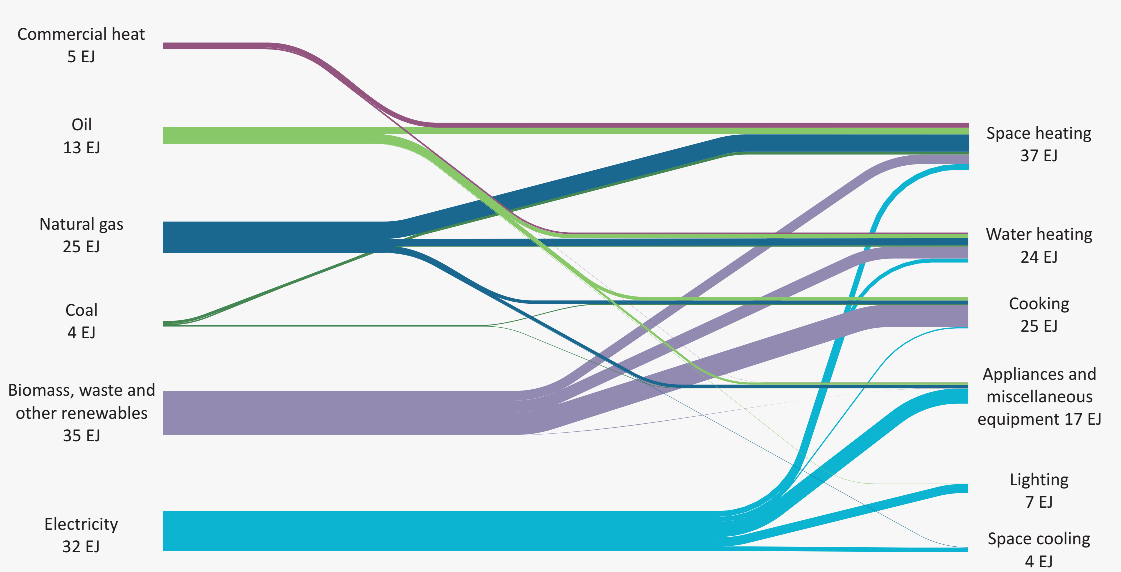
Government policies need to target these barriers, encourage more research and development (R&D) in new technologies and optimise their deployment and performance in different operating and climate conditions. Ensuring that the whole buildings sector embraces these technologies and efficiency standards requires strong policy action and integrated strategies by the construction industry, developers, building owners, policy makers and building occupants (WBCSD, 2009).

Energy use and CO_2 emissions

The buildings sector, including both the residential and services sub-sectors, consumes approximately 32% of global final energy use, making it responsible for almost 15% of total direct energy-related CO_2 emissions from final energy consumers. If indirect upstream emissions attributable to electricity and heat consumption are taken into account, the buildings sector contributes 26% of all CO_2 emissions.

Total energy consumption in the buildings sector amounted to 115 exajoules (EJ) in 2009. Electricity and renewables are the main energy sources used by the sector, accounting for about 60% of total buildings' energy consumption (Figure 14.1). Renewables, most notably biomass, are mostly used in developing countries as cooking fuel. Electricity is consumed by all end-use categories, but especially by appliances.

Figure 14.1 Energy consumption flow in the buildings sector, 2009



Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

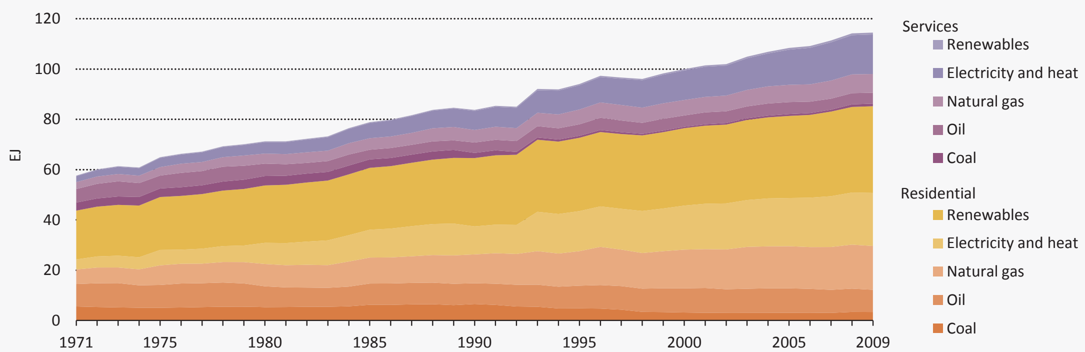
Key point *Almost 50% of energy consumption in buildings is used for space heating and appliances and miscellaneous equipment.*

Between 1971 and 2009, total energy consumption in the buildings sector grew 1.8% a year from 58 EJ to 115 EJ (Figure 14.2). The residential sub-sector requires the largest share of energy, around 75% of total energy consumption in buildings, although the services sub-sector has increased its share since 1990.

Over the 1971 to 2009 period, direct CO_2 emissions rose at a slower pace than energy consumption, 0.4% per year. This difference is mostly due to the change in the mix of energy uses in the buildings sector: 45% of total energy consumption came from electricity, commercial heat and renewable energy in 1971, and 63% in 2009.

Taking into account emissions from the generation of electricity and heat within the buildings sector, direct and indirect CO_2 emissions of buildings grew 1.9% a year between 1971 and 2009. Overall, direct CO_2 emissions from fossil fuels accounted for 36% of the buildings sector's emissions in 2009, 2.9 gigatonnes of CO_2 ($GtCO_2$), with indirect emissions accounting for the remaining 64%.

Figure 14.2 World buildings energy consumption by energy source



Key point *The residential sub-sector consumes about three-quarters of the total energy used in the buildings sector.*

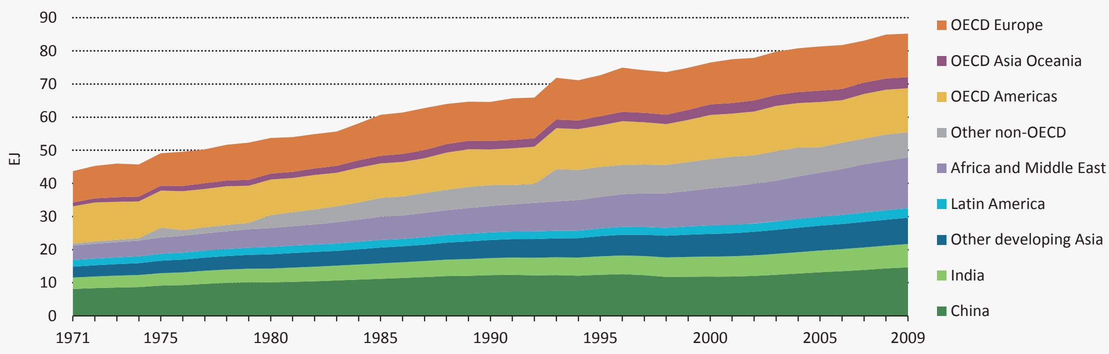
The residential sub-sector

The world's population was 6.7 billion in 2009 (UN, 2011), an increase of 10% since 2000. Most of the population growth was in non-OECD countries, where the population increased by 12%.

The evolution of energy consumption in the residential sub-sector is closely related to the increase in population and number of households, income growth, increase in appliance ownership, and energy efficiency improvements.

In 2009, OECD households consumed 35% of total global energy in the residential sub-sector, down from 39% in 2000 (Figure 14.3). Since 2000, energy consumption in OECD regions has grown 0.2% per year, with the fastest increase in the OECD Asia Oceania region (0.5%). OECD Americas is the only OECD region to have experienced faster growth since 1990 than since 1971. The energy consumption of households in Africa and the Middle East grew 3.5% annually between 1990 and 2009, significantly faster than in developing countries in Asia (excluding China and India), where energy consumption grew 2.0% per year.

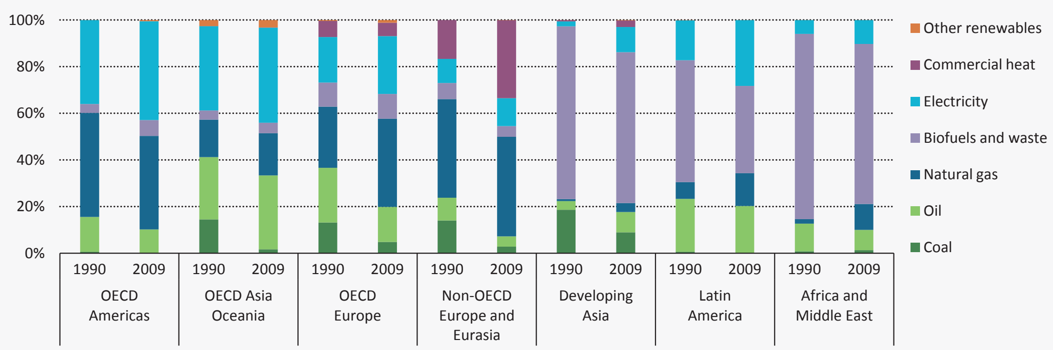
Figure 14.3 Total residential sub-sector energy consumption by region



Key point *While energy consumption remained relatively stable in OECD countries from 1971 to 2009, it increased by almost 3% per year in non-OECD countries.*

Electricity and natural gas are the main fuels used in OECD countries (Figure 14.4). Natural gas, mostly used for space heating purposes, accounted for 37% of household energy requirements in OECD countries in 2009. Although starting from a very low level, other renewables, including solar and geothermal, were the fastest-growing energy source in the residential sub-sector, increasing by 150% between 1990 and 2009. Electricity increased by 48% over the same period; this increase was largely due to higher numbers of people in OECD countries buying and using more small electric appliances and electronic devices.

Figure 14.4 Residential energy consumption by energy source



Key point *A large share of energy needs in non-OECD countries is met by biofuels and waste.*

In non-OECD countries, biofuels and waste (particularly traditional biomass such as wood, charcoal and dung) remain the largest source of energy in the residential sub-sector, with consumption at 32 EJ in 2009 (or 57% of residential final energy).[1] As in OECD countries,

1 The efficiency of traditional biomass use is typically very low (around 8% to 15% for traditional cook stoves is common). Its use has a wide range of negative impacts, such as degraded indoor air quality and deforestation. Switching to modern biomass or commercial fuels would consume a fraction of current energy, as these energy sources are much more efficient and have significant co-benefits.

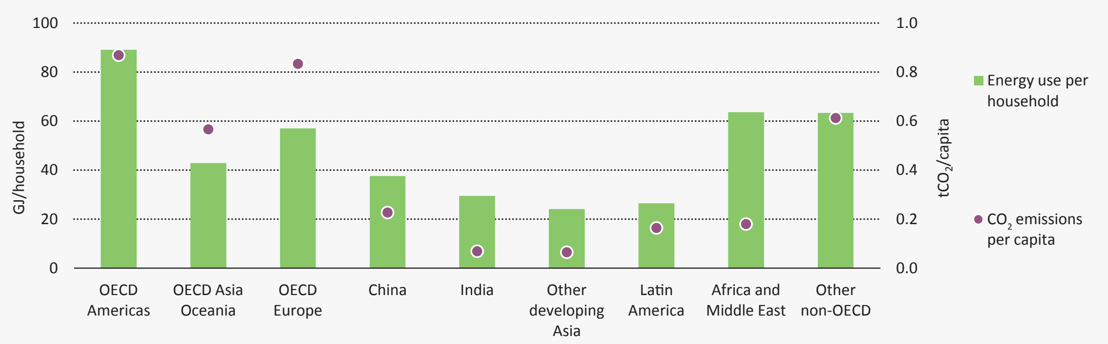
however, electricity is the fastest-growing energy commodity after other renewables; its use has increased 220% since 1990 to reach 12% of total final energy consumption in 2009. This increase was driven by the increased ownership of appliances and a greater electrification of households. The declining share of inefficient traditional biomass use in favour of electricity and commercial fuels is one of the main factors restraining the growth in energy use in non-OECD countries. In non-OECD Europe and Eurasia, district heating remains important in the residential sub-sector with consumption of commercial heat reaching 2.6 EJ in 2009, or 33% of total household energy consumption.[2]

Energy consumption per household varies significantly and depends on factors such as geographic and climatic region, income, energy sources and prices, appliance ownership, and house size. OECD Americas has the highest energy consumption per household (Figure 14.5) in the residential sub-sector, driven by Canada and the United States where high incomes, large houses, high appliance ownership rates, low energy prices and significant space heating or cooling needs predominate.

The relatively high energy intensity in the category other non-OECD countries, including non-OECD Europe and Eurasia, is mostly driven by high space-heating requirements and the low efficiency of existing building stock.

Developing countries generally have lower energy consumption, due in part to the relatively low penetration of appliances, and lower emission intensity, due in part to the high share of traditional biomass[3] used to meet the energy needs.

Figure 14.5 Energy and direct CO_2 emissions intensity in the residential sub-sector in 2009



Key point *Energy consumption per household is higher in OECD countries than most non-OECD countries.*

The services sub-sector

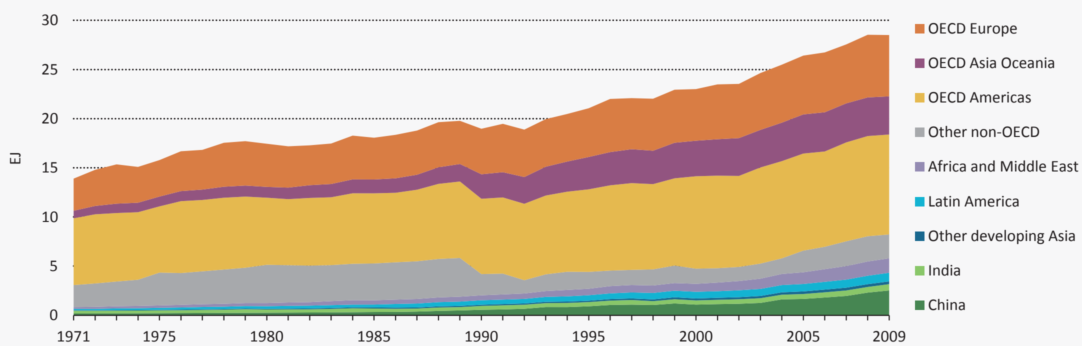
Energy use in the services sub-sector relates to the level of economic activity and the related growth in floor area. Between 2000 and 2009, the rate of growth in value added in the services sub-sector grew rapidly in most countries. China experienced an impressive 10% per year growth over this period and now has the second-largest services sub-sector by value in the world.

2 In IEA statistics for the residential and services sub-sectors, "heat" refers only to purchase heat. It is not the total energy consumed for heating purposes.
3 Biomass is considered CO_2 neutral in this analysis.

Final energy consumption in the services sub-sector doubled between 1971 and 2009 to reach 29 EJ (Figure 14.6), 25% higher than in 2000. Energy consumption grew 11% in OECD countries (despite a small 1.0% decline between 2008 and 2009 due to the economic downturn) and 73% in non-OECD countries. Despite the slower increase in services sub-sector energy in OECD countries, and the more marked impact of the recession on them, these countries still accounted for about 70% of global energy consumption in this sub-sector.

Non-OECD regions have largely grown more quickly, but they are starting with a generally low level of energy consumption (with the exception of non-OECD Europe and Eurasia). Energy consumption by China's services sub-sector increased 10% per year between 2000 and 2009; other developing countries in Asia saw rates of 5% per year, and Africa and the Middle East grew 7% per year. China now accounts for 9% of global services sub-sector energy consumption, up from 5% in 2000. In 2000, non-OECD countries consumed about 20% of global energy in the services sub-sector; by 2009 this had grown to about 30%.

Figure 14.6 **Total services sub-sector energy consumption by region**



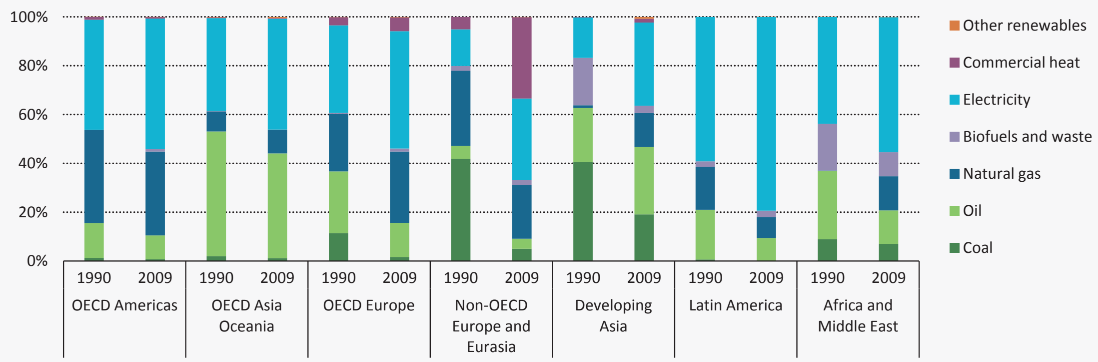
Key point *OECD countries account for over 70% of the energy consumed in the services sub-sector.*

Substantial differences in the services sub-sector energy mix between countries and regions (Figure 14.7) reflect differences in level of economic development, income, geographic region, climatic conditions and energy resources. Electricity and natural gas are the dominant final energy sources in many OECD countries, although oil is also an important fuel in the OECD Asia Oceania region and China.[4] Direct coal use retains a significant share in developing Asia and South Africa. In non-OECD Europe and Eurasia, almost 35% of the services sub-sector's energy demand is met by district heating, although the electricity demand exploded to more than double between 1990 and 2009.

The services sub-sector is electricity-intensive. Its electricity needs account for almost 50% of the global energy consumption by the total buildings sector. This reflects the impact of electrical devices, such as lighting and office equipment, in services sub-sector buildings in OECD countries. Developing countries will also shift toward this pattern of energy consumption. Increased global access to electricity plus rising incomes in some developing countries have already contributed to the growth in electricity consumption.

4 Oil appeared to account for 32% of final energy use in China in 2009, but this share may be inflated by a statistical convention that includes some commercial transportation in the services sub-sector.

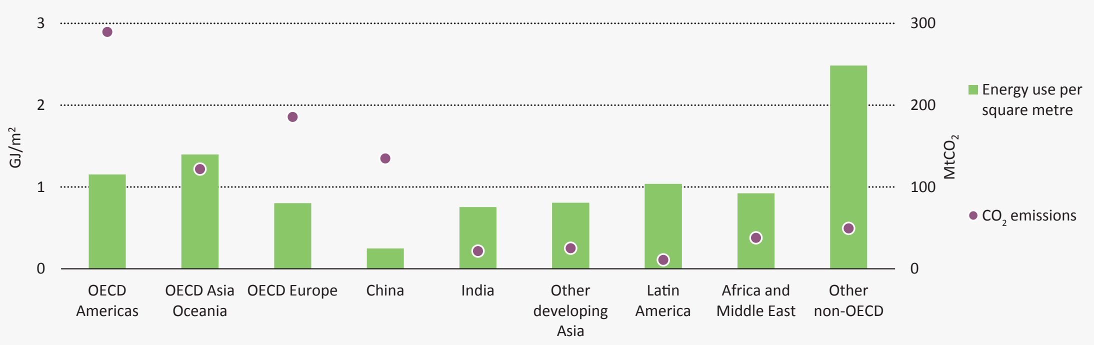
Figure 14.7 Services energy consumption by energy source



Key point *Electricity is the most important energy source in most regions.*

In the services sub-sector, energy consumption per unit of floor area also varies significantly depending on the region. These variations can be attributed, in part, to climate differences. For example, other non-OECD countries have the highest energy intensity in terms of energy consumption by unit of floor area (Figure 14.8) because of their relatively cold climate and high number of heating degree days.[5]

Figure 14.8 Energy intensity and direct CO_2 emissions in the services sub-sector in 2009



Key point *OECD countries are, in general, more energy intensive than developing countries.*

But drawing conclusions about the efficiency of the services sub-sector based solely on overall energy intensity of the sector can be misleading. Energy intensity is highly dependent on the structure of the services sub-sector. Different building types have

5 Heating degree days are calculated from the difference between the average daily outdoor temperatures and a reference temperature (*e.g.* 18°C).

different energy needs (*e.g.* health-care facilities require more energy than warehouses), and the relative importance of the building types within the services sub-sector will have a direct impact on the sector's energy intensity and CO_2 emissions.

Scenario results for the buildings sector

Analysis in this chapter is based on three *ETP 2012* modelling scenarios that assess the means by which it may be possible to limit global temperature rise to 2°C, 4°C or 6°C by 2050. The *ETP 2012* 4°C Scenario (4DS) illustrates what is likely to happen if only *actions that are currently planned* are taken to address climate change and energy security concerns. This is used as a reference scenario, or marker, against which the potential impact of actions to improve energy efficiency and further reduce CO_2 emissions can be assessed. In the 6DS, only *policies and actions that are currently in place* are taken into account.

The *ETP 2012* 2°C Scenario (2DS) for the buildings sector explores what needs to be done to meet ambitious emissions-reduction goals of halving global CO_2 emissions by 2050. The 2DS can help policy makers identify technology portfolios and policy strategies that may help deliver the outcomes they are seeking, while fitting the buildings sector within the larger context of the energy system. The 2DS analysis sets out a vision for a more sustainable buildings sector based on energy efficiency and low- or zero-carbon technologies.

Energy demand in the buildings sector is driven by population, geographic region, climatic conditions, incomes, energy prices, services sub-sector value added, services sub-sector floor area and cultural factors. These elements have an impact on the number and size of households, the heating or cooling load, the number and types of appliances owned, and their patterns of use. A number of parameters are key to the buildings-sector scenario:

- ***Population***. The world's population will increase 35% to 9.3 billion in 2050 (UN, 2011), with Africa outgrowing all other continents, followed by Asia (114% and 23% respectively). The population increase translates into a higher number of households and houses, and the corresponding increased demand for services.

- ***Urbanisation***. Today, slightly more than half the world's 6.9 billion inhabitants live in urban areas. By 2050, 6.4 billion people, or 70% of the world population, will live in urban areas while 86% of the world's population will live in less developed countries (UN, 2009). Increased urbanisation will bring greater access to commercial energy sources.

- ***Number of households***. The global number of households is projected to grow 88% between 2009 and 2050, a rate that exceeds that of population growth because of the continuing trend of fewer people per household over the same time period. It is accompanied by a recent trend towards larger floor area per household, which will likely continue, although less markedly in many mature economies because most of the stock is already built and, in some regions, houses are already relatively large.

- ***Gross domestic product (GDP) and value added growth***. Overall, GDP (at purchasing power parity) will be four times higher in 2050 than in 2009. Services' value added is assumed to grow at 3.6% per year between 2009 and 2035, but will slow to 2.8% per year between 2035 and 2050. The growth in the sector's value added reflects the increased demand for services, which will require more buildings.

- ***Services floor area***. This will increase to 1.7 times the 2009 estimated levels in 2050, as the services sub-sector value added continues to grow more rapidly than GDP, particularly in developing countries whose economies are still maturing.

- ***Energy prices***. Crude oil import prices are expected to grow from an average of USD 78.1 per barrel (bbl) in 2010, to USD 118.5/bbl in 2050 in the 4DS, and to USD 86.6/bbl in 2050 in the 2DS. Higher prices will influence the choice of technology and, where possible, the energy source selected.

Technology options and policy requirements for buildings

Buildings are complicated systems, with multi-faceted and intertwined uses of energy. In OECD countries, non-OECD Europe and Eurasia, the biggest opportunities to improve energy efficiency and reduce CO_2 emissions come with space and water heating, air-conditioning, ventilation, lighting, and appliances. In developing countries, lighting and cooking are relatively more important, and cooling will grow in importance as middle-class incomes rise. Other than in China, space heating is less significant for developing countries.

Existing, available technologies offer opportunities to significantly reduce energy use and emissions at low cost. Cutting electricity consumption may be a higher priority than reducing the direct use of fossil fuels in countries with CO_2-intensive electricity generation mixes. The 2DS is based on the large-scale deployment, in the buildings sector, of technologies with the greatest opportunities for cost-effective CO_2 reductions. A necessary first step is to implement policies to ensure the maximum uptake of existing technologies for improving the energy performance of building shells.

- ***Tighter building standards and codes to reach BAT level for new residential and services buildings***. In the 2DS, regulatory standards for new residential buildings in cold climates are tightened progressively to between 15 kilowatt-hours (kWh) and 30 kWh per square metre (m^2) per year[6] for heating purposes, with little or no increase in cooling load. In hot climates, cooling loads are reduced by around one-third. Services buildings' standards are improved, which halves consumption for heating and cooling compared to 2009 and allows heating and cooling equipment to be downsized.

- ***Large-scale refurbishment of residential buildings in OECD countries***. Around 60% of today's residential dwellings in the OECD will still be standing in 2050 and must be refurbished to low-energy standards (output energy needs of approximately 50 kWh/m^2 per year for heating and cooling), providing the opportunity to downsize heating and cooling equipment as an additional benefit. Around 210 million residential dwellings in the OECD must be refurbished between 2010 and 2050.

- ***Highly efficient heating, ventilation and air-conditioning systems***. Heating systems need to be both efficient and cost-effective. In the 2DS, the coefficient of performance[7] of installed cooling systems doubles from today's level.

- ***Improved lighting efficiency***. Notwithstanding recent improvements, many driven by policy changes, considerable potential remains to reduce energy demand from lighting worldwide through the use of the most efficient options such as solid-state lighting (SSL), including light-emitting diodes (LEDs), which may in the future offer even larger reductions.

6 This is the useful energy demand. The actual energy consumption is a function of the fuel mix and the efficiency of the technology used.

7 The coefficient of performance is the ratio of useful energy output (heat or cold) to energy input (typically electricity).

- ***Improved appliance efficiency***. Appliance standards are expected to shift rapidly to least life-cycle cost levels, and to the current BAT levels by 2030.

- ***Widespread deployment of CO_2-low or CO_2-free technologies***. *Heat pumps* for space heating and cooling and water heating. This is expected to occur predominantly in OECD countries, and depends on the relative economics of different abatement options.

  Solar energy for space heating, water heating and space cooling. Often cost-effective today, further cost reductions for systems and the likely availability of low-cost, compact thermal energy storage systems in the near future will help increase deployment, especially in OECD countries.

  Micro-, mini- and fuel cell-co-generation[8] for space and water heating. Co-generation can be an effective abatement option where power generation is CO_2-intensive.

- ***Cross-cutting technologies***. Thermal energy storage coupled with heating and cooling equipment will help improve efficiency, increase the penetration of renewables and offer increased system flexibility. Many complementary technologies will be required to help facilitate these savings, notably smart grids and smart metering.

The transformation described in the 2DS will require significant policy action over a range of technologies (Table 14.1). The degree of urgency for each technology differs, mainly due to the rate of capital stock turnover, and geographic and climatic region. Some changes are more urgent than others and some will achieve greater savings, over different time scales, than others.

Developing countries face quite different policy challenges than OECD countries, non-OECD Europe and Eurasia. The latter have a large stock of residential buildings, most built before 1970, which will be retired slowly and retrofitted with measures to reduce CO_2 emissions. At the same time, the buildings sector in the OECD and non-OECD Europe and Eurasia has significant heating and cooling loads, which policy makers must focus on and significantly reduce.

Currently, the rate of residential building refurbishment to improve energy efficiency is low. Because energy efficiency renovations are potentially expensive, urgent policy action is needed to induce building owners (residential and services sub-sectors) to schedule refurbishments or maintenance activities earlier than the average 20- to 30-year time frame when they traditionally make economic sense. The policy actions must include stringent compliance and enforcement measures.

In contrast, buildings in developing countries tend to have shorter life spans, on the order of 25 to 35 years, and new construction is on a sharp upward trajectory, which is not likely to fall off. Consequently, policies and standards should dictate the minimum energy performance of new buildings, especially for their cooling loads, lighting and appliances. Building codes that reduce the cooling load through better design and more efficient and insulated shells need to be implemented rapidly to block construction of energy-hungry buildings that will last for decades to come.

Appliances and lighting with short economic lives can be replaced relatively quickly with each generation of more energy efficient versions at lower cost overall. For most appliances, initial or early shifts to BAT can be an expensive abatement option until market-scale deployment (and competition) reduces costs. Additionally, there are some appliances, notably washing machines and clothes dryers, whose energy savings potential is modest compared to the likely rate of growth in ownership.

8 Co-generation refers to the combined production of heat and power.

Table 14.1 Priority actions needed to deliver the outcomes of the 2DS

Areas for policy action	Overall savings potential	Policy urgency	Bulk of savings available
Energy efficiency of building shell measures			
New residential buildings	Medium to large	Urgent	Immediately and medium- to long-term
Retrofitted residential buildings	Large	Urgent	Immediately and medium- to long-term
New services buildings	Large	Urgent	Immediately and medium- to long-term
Retrofitted services buildings	Medium to large	Urgent	Immediately and medium- to long-term
Energy efficiency of lighting, appliances and equipment			
Lighting	Medium	Average	Immediately
Appliances	Large	Average	Short- to medium-term
Water heating systems	Large	Urgent	Short- to medium-term
Space heating systems	Medium to large	Urgent	Short- to medium-term
Cooling/ventilation systems	Medium to large	Urgent	Short- to medium-term
Cooking	Small to medium	Average/urgent	Immediately
Fuel switching			
Water heating systems	Medium to large	Urgent/average	Short- to long-term
Space heating systems	Medium to large	Urgent/average	Short- to long-term
Cooking	Small	Average/urgent	Short- to medium-term

Notes: Overall savings potential is relative to contribution to total savings in the building sector. Where two policy urgency ratings are given, it is for OECD/non-OECD.

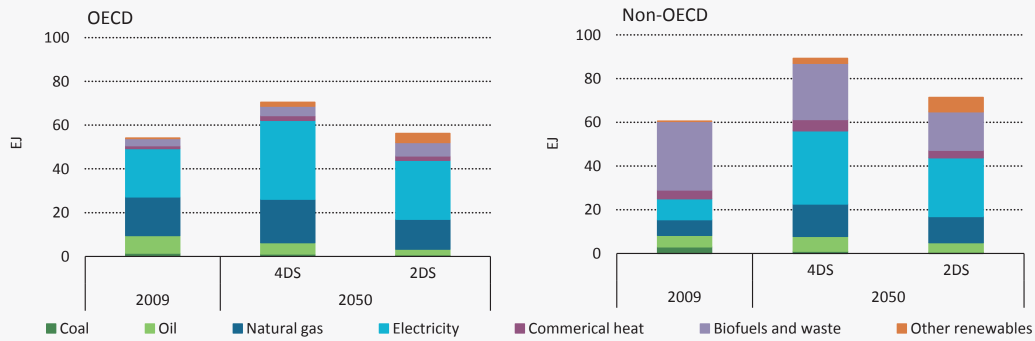
Scenario results

Total energy demand in the buildings sector will increase from 115 EJ in 2009 to 160 EJ in 2050 in the 4DS (Figure 14.9), mainly driven by the services sub-sector, which represents 64% of this growth. The services sub-sector grows more rapidly, at 0.9% a year between 2009 and 2050, although the residential sub-sector is not far behind, growing by 0.6% per year. Energy from non-biomass renewables, predominantly solar, increases as a whole by 6% a year between 2009 and 2050, although it only supplies 3% of the buildings sector's energy consumption in 2050.

In the 2DS, energy consumption in the buildings sector by 2050 is 20% lower than in the 4DS. Energy consumption in 2050 (2DS) is only 11% higher than in 2009, despite a 65% increase in the number of households and greater services sub-sector floor area (72%) over the same time period. Electricity demand grows 1.3% per year and becomes the largest single source of energy. Consumption of oil and coal declines significantly, as does the use of traditional biomass.

The energy sources and growth-demand patterns in OECD and non-OECD countries are dramatically different (Figure 14.9). While electricity and natural gas are the main energy sources for OECD countries, non-OECD countries continue to rely on biomass, mostly for household applications such as cooking, in each scenario. However, non-OECD countries will switch to high-efficiency cook stoves using modern types of biomass or other fuels such as liquified petroleum gas (LPG), natural gas and electricity.

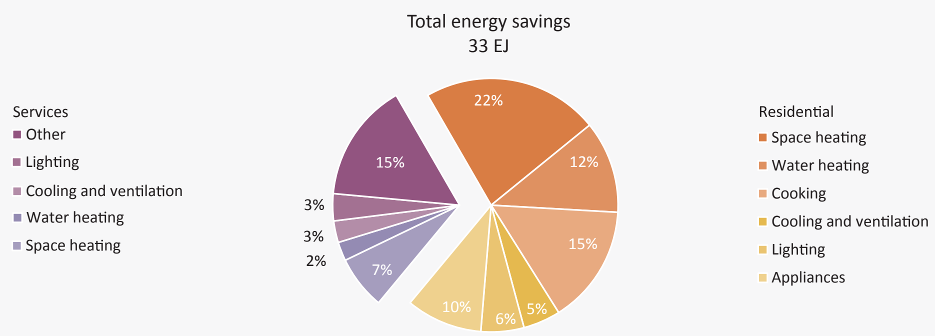
Figure 14.9 Buildings-sector energy consumption



Key point *Biofuels and waste remains a key energy source for non-OECD countries.*

Total energy savings in the buildings sector in the 2DS, compared to the 4DS, amounts to 33 EJ in 2050 (Figure 14.10). Energy savings in residential space heating amount to 22% of the total savings. While the savings in end uses dominated by the use of electricity will not have a direct impact on the energy-related CO_2 emissions in the buildings sector, their overall contribution to a low-carbon future will nevertheless be important. Reduction in electricity demand will have the co-benefit of reducing the number of additional power plants that will need to be built to meet the buildings' energy demand, and will facilitate the decarbonisation of the power sector.

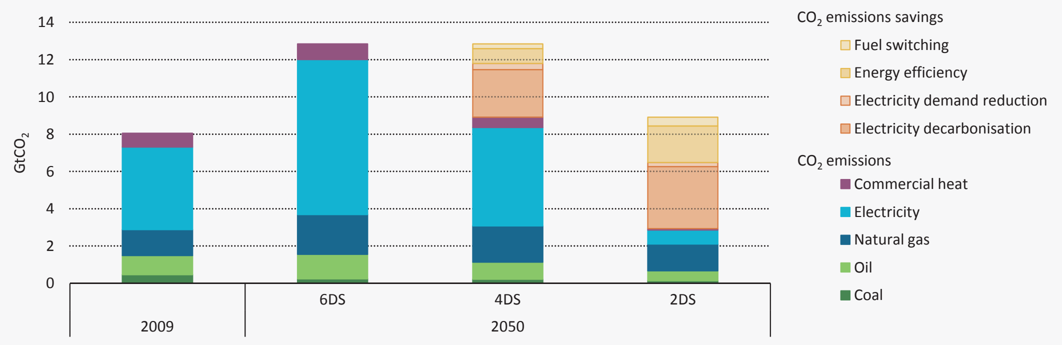
Figure 14.10 Buildings-sector energy savings between the 4DS and 2DS



Key point *About 70% of buildings' potential savings between the 4DS and 2DS are in the residential sub-sector.*

In the 4DS, the 9 $GtCO_2$ in 2050 includes upstream emissions attributable to the consumption of electricity and heat in the buildings sector (Figure 14.11). This is an 11% increase over 2009 levels. The 2DS reduces CO_2 emissions from the buildings sector by 6 $GtCO_2$ from the 4DS level in 2050: 2.4 $GtCO_2$ is directly attributable to energy efficiency and fuel switching in the buildings sector, and 3.6 $GtCO_2$ is the result of decarbonisation of the electricity and heat sectors. As a result, buildings-sector CO_2 emissions in the 2DS are 67% lower than the 4DS level in 2050. This reduces the direct and indirect CO_2 emissions attributable to the buildings sector to 2.9 $GtCO_2$ in 2050, 64% lower than the 2009 level.

Figure 14.11 Buildings-sector CO_2 emissions and reductions

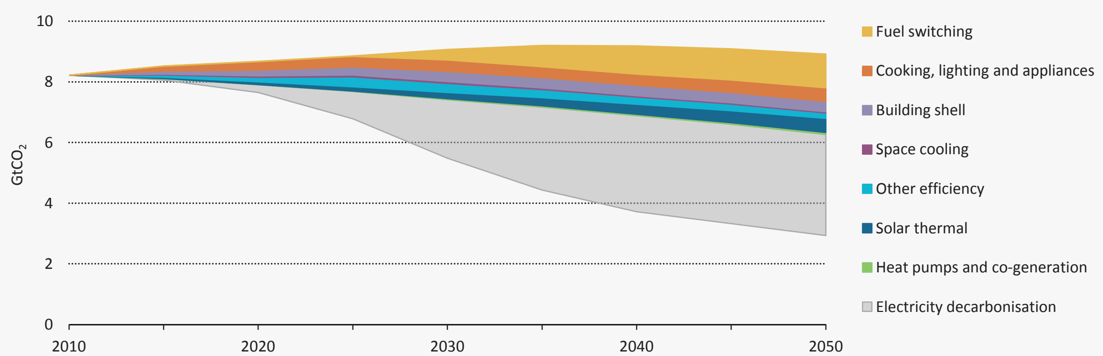


Note: Shaded area represents the savings between the 6DS and the 4DS (in the 4DS column) and between the 4DS and the 2DS (in the 2DS column).

Key point *In the 2DS, total CO_2 emissions are 77% lower than in the 6DS, and 67% lower than in the 4DS.*

The CO_2 emissions savings from the buildings sector in the 2DS can only be achieved if the entire buildings system contributes. Early improvements in the thermal envelope of buildings and other building shell enhancements account for 13% of the total savings from the buildings sector in 2050 (excluding the savings from electricity decarbonisation and associated savings from downsizing of heating and cooling equipment) (Figure 14.12). This necessary first step in improving building efficiency will not only reduce energy needs (heating and cooling loads), it will also allow downsizing of heating and cooling equipment.

Figure 14.12 Contribution of CO_2 emissions reduction options between the 4DS and 2DS



Key point *Improvements in the building shell and energy savings in electrical end uses dominate total CO_2 reductions.*

Increased deployment of more efficient heat pumps and co-generation and solar thermal for space and water heating, as well as cooling, accounts for 21% of the savings. Parts of these savings are possible due to the improvement in building shells. Co-generation plays a notable role in reducing CO_2 emissions, as well as helping balance the renewables-dominated electricity system in the 2DS.

More efficient lighting, appliances and miscellaneous equipment account for 17% of the total reduction. This proves the importance of electrical end-use growth and energy efficiency improvements in non-OECD countries.

Residential sub-sector results

The number of households is projected to grow 67% by 2050, almost twice the rate of increase for the population. OECD countries had an estimated 467 million households in 2009. For non-OECD countries, household numbers were estimated by income level as a basis for projecting future energy consumption at 1 391 million households in 2009.

China and India dominate total household numbers today and are the location for the significant growth in households by 2050 (Table 14.2). These countries are projected to add about 25% to the global growth in households between now and 2050. OECD countries, with low population growth rates and generally fewer people per household already, will contribute only 9% of the total new households formed by 2050.

Table 14.2 Key indicators in the residential sub-sector

Region	Population (million)		Number of households (million)		Per capita income (USD GDP/capita)	
	2009	2050	2009	2050	2009	2050
OECD Americas	466	611	157	216	37 104	72 817
OECD Asia Oceania	203	193	79	79	32 079	63 174
OECD Europe	549	588	230	281	28 956	57 281
China	1 338	1 306	385	460	7 060	48 782
India	1 155	1 692	249	500	3 184	22 294
Brazil	194	223	50	93	10 431	35 986
Other non-OECD	2 856	4 694	702	1 469	5 587	14 328

In the residential sub-sector, total energy consumption grows 0.6% a year between 2009 and 2050, from 85 EJ to 108 EJ in the 4DS (Figure 14.13). Electricity demand in the residential sub-sector continues to climb sharply by 2.3% per year on average, increasing its share of consumption from 20% to 33% between 2009 and 2050. Non-biomass renewables, predominantly solar, grow rapidly by 5.8% a year on average. But this is from a low base and accounts for only 1.5% of total energy consumption in the residential sub-sector by 2050. Gas consumption grows by 1.4% per year and oil consumption by 0.2% per year to 2050. Coal consumption declines by 0.3% per year between 2009 and 2050.

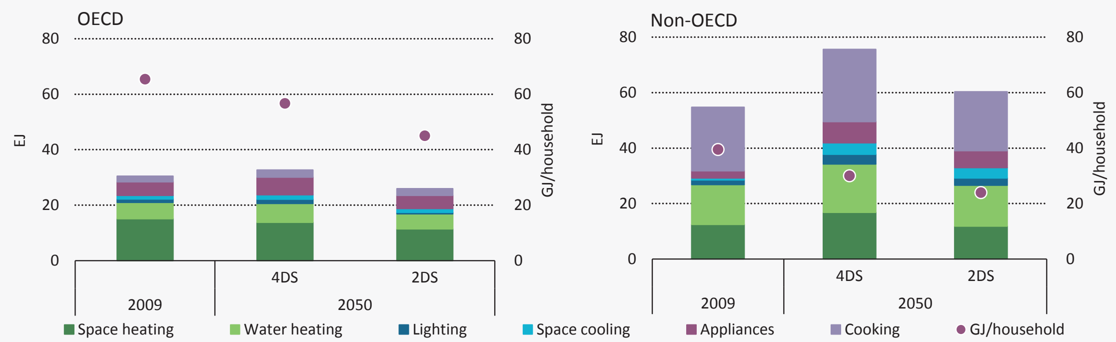
In non-OECD countries, the growth in electricity demand is being driven by the increasing ownership of small and large appliances, as incomes rise and the citizens of these countries aspire to the living standards common in developed countries. In OECD countries, the situation is very different: the energy consumption of large appliances (refrigerators, freezers, washing machines, and clothes dryers) is declining as a share of total electricity consumption, due to the implementation of energy efficiency policies in many countries. But the explosion in miscellaneous electrical appliances, particularly those in the leisure, telecommunications and information technology categories, offset the improvement made in large appliances.

In per capita terms, significant differences in energy consumption still remain between countries and regions, due to different income levels, climates and cultural preferences. In OECD countries, the changes are driven by efficiency improvements. The relatively modest changes in end-use shares for OECD countries by 2050 highlight the fundamental difficulty of rapidly reducing the energy consumption of residential buildings.

Without the large-scale retrofitting of a significant proportion of the existing building stock in OECD countries, it will be difficult to significantly reduce space heating demand. With the exception of heat-pump water heaters, it will be difficult to reduce the energy consumed for sanitary hot water provision.

In non-OECD countries, the continued shift away from traditional biomass for cooking and heating means there is a significant efficiency effect in these households that helps offset the increased energy consumption from the increasing numbers of home appliances and air conditioners.

Figure 14.13 Residential sub-sector energy consumption and intensity



Key point *Despite important decreases in energy intensity in OECD countries, their intensity is still much higher than in non-OECD countries.*

In the residential sub-sector 2DS, total energy demand is reduced by 22 EJ, or 20% compared to the 4DS. Globally, energy consumption for space heating is reduced by 7 EJ below the 4DS in 2050, with a significant increase in the share of solar thermal and micro- and small-scale co-generation (Table 14.3). Deep reductions can also be achieved in cooking. Most of the savings are from the replacement of low-efficiency cooking devices that used traditional biomass.

In OECD countries, most of the building stock was constructed before the 1970s and has very high space-heating requirements. Refurbishment or renovation of these buildings will offer the largest abatement potential, given current low rates of retirement of the existing stock and modest additions of new buildings. But although many measures are cost-effective, comprehensive energy refurbishment to similar standards in new buildings will require significant up-front costs, and their economic viability will depend heavily on energy prices. The 2DS, or any scenario that wants to achieve deep reductions in CO_2 emissions, will require a significant proportion of today's building stock to be renovated to some extent. In the 2DS, 60% of the existing building stock is renovated to a low-energy standard.

This investment will only be economically viable when major scheduled refurbishments are undertaken, typically every 20 to 30 years. Unlike new houses, where the potential for cost reductions from new, tighter building standards are imposed, the costs for renovating existing residences to a high energy efficiency standard are unlikely to decline dramatically over time, as labour makes up a significant proportion of the total cost. Cost reductions in materials and improved processes for refurbishments will never make up for increases in unit labour costs, which means that retrofitting is likely to remain expensive for many dwellings for the CO_2 emissions reduction obtained.

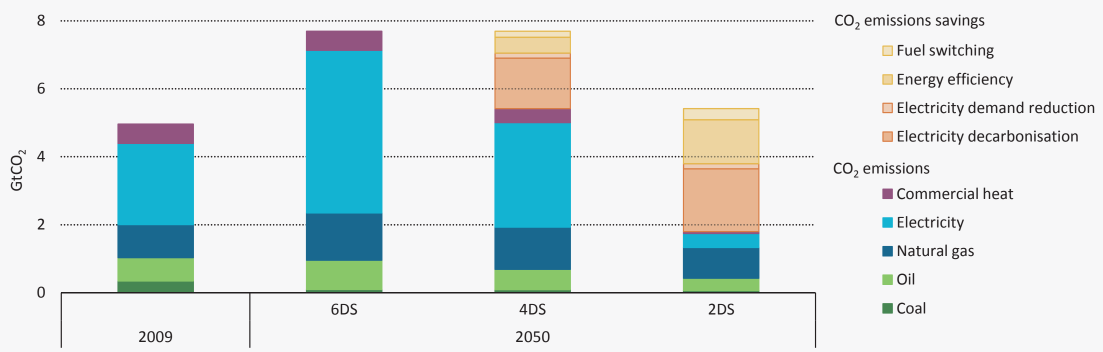
Table 14.3 Changes in residential energy demand in the 2DS compared to the 4DS

Petajoules	Space heating	Water heating	Cooking	Cooling and ventilation	lighting	Appliances
Coal	(-246)	217	(-89)			
Oil	(-1 122)	(-744)	(-1 011)		(-61)	
Natural gas	(-4 303)	(-1 073)	(-707)			
Electricity	(-1 665)	(-3 766)	1 205	(-1 575)	(-1 817)	(-3 222)
Commercial heat	(-1 157)	(-61)	2	34		
Biofuels and waste	(-367)	(-2 364)	(-4 385)			
Other renewables	1 462	3 973	114	918		
Total	**(-7 398)**	**(-3 895)**	**(-5 024)**	**(-622)**	**(-1 877)**	**(-3 222)**

Given the increased penetration of electrical appliances and end uses such as space cooling, decarbonisation of the power sector will play a key role in reducing CO_2 emissions from the residential sub-sector.

In the 2DS, energy efficiency improvements become all the more important in reducing emissions from the sector (Figure 14.14). It will take improvements of the building envelope, the penetration of highly efficient appliances (notably high-efficiency cook stoves in developing countries) and the adoption of efficiency technologies such as heat pumps.

Figure 14.14 Residential sub-sector CO_2 emissions and reductions



Note: Shaded area represents the savings between the 6DS and the 4DS (in the 4DS column) and between the 4DS and the 2DS (in the 2DS column).

Key point *Improvement in energy efficiency will account for more than 35% of the reduction between the 4DS and the 2DS.*

Services sub-sector results

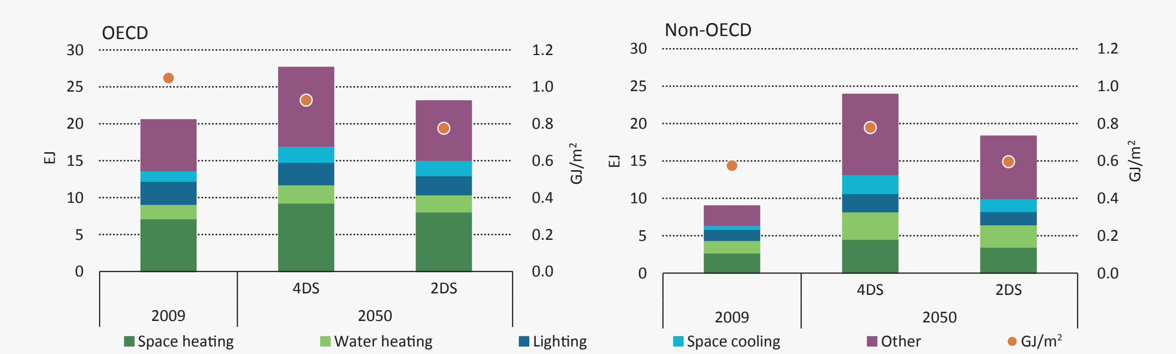
Floor area in services sub-sector buildings is expected to almost double between 2009 and 2050. In developing Asia, floor area will grow swiftly, mirroring the increasing share of the services sub-sector in the overall economy, the rapid growth in urbanisation and rising incomes. In OECD countries, floor area will continue the steady trend since 1990 of continued growth to 2050 (Table 14.4).

Table 14.4 Key indicators in the services sub-sector

Region	Services' floor area (million m²)			
	2009	2015	2030	2050
OECD Americas	8 928	9 878	12 675	14 499
OECD Asia Oceania	2 875	3 127	3 816	4 451
OECD Europe	7 804	8 351	9 927	10 826
China	9 997	11 397	15 750	16 365
India	858	1 155	1 994	3 525
Brazil	371	412	475	581
Other non-OECD	4 390	5 055	7 105	10 256

Global energy demand in the services sub-sector is projected to grow by 75% in the 4DS and 40% in the 2DS, between 2009 and 2050 (Figure 14.15). In non-OECD countries, services sub-sector energy intensity in the 2DS is 4% lower than current levels, and 19% lower than it would be in the 4DS. In OECD countries, energy intensity in the 2DS is 15% lower than current values. While energy efficiency improves in all end uses, space heating and miscellaneous equipment contribute the most improvement in the overall services sub-sector.

Figure 14.15 Services sub-sector energy consumption and intensity



Key point *The strong increase in floor area in non-OECD countries will drive the 88% increase in energy consumption in the 2DS.*

The services sub-sector is significantly more energy-intensive in terms of electricity use than the residential sub-sector. In 2009, electricity accounted for almost 50% of the total energy consumed by the services sub-sector globally. By 2050 in the 2DS, electricity consumption represents 58% of total energy consumption in the services sub-sector.

Space heating accounts for 33%, and water heating 12%, of energy consumption in the services sub-sector in 2009: both totals are considerably lower than in the residential sub-sector. This trend reflects the much greater consumption of electrical end uses, notably space cooling, lighting, office equipment and other electrical equipment (everything from refrigerated display cabinets to electric motors to animate window displays to x-ray machines).

This pattern of savings is also different from that of the residential sub-sector due to the higher share of electricity-intensive end uses. By 2050 in the 2DS, space cooling, lighting and other miscellaneous end uses account for 60% of energy consumption in the services sub-sector. The more rapid growth in services buildings in developing countries accentuates the trend toward greater electricity use in this sub-sector. Energy savings in lighting and miscellaneous equipment will account for 60% of the energy-consumption reduction in 2050 (Table 14.5).

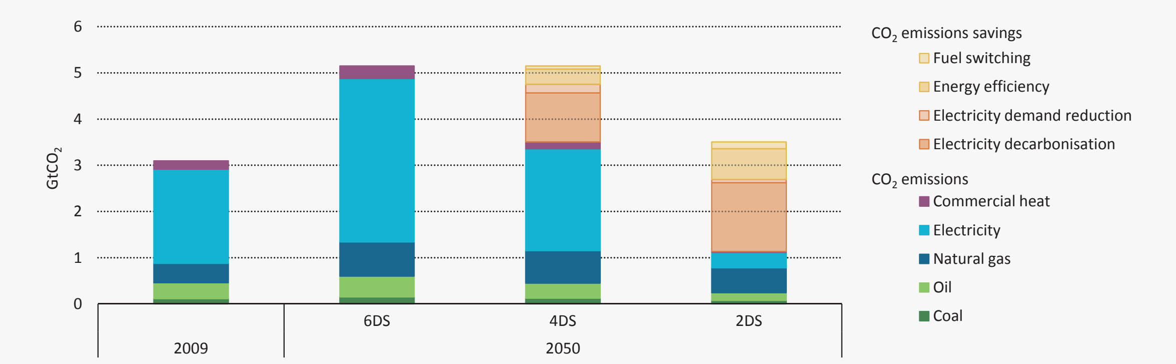
Table 14.5 Changes in services energy demand in the 2DS compared to the 4DS

Petajoules	Space heating	Water heating	Cooling and ventilation	Lighting and miscellaneous
Coal	(-61)	(-79)		(-270)
Oil	(-361)	(-230)		(-1 511)
Natural gas	(-1 205)	(-58)	(-117)	(-1 641)
Electricity	(-981)	(-423)	(-867)	(-2 700)
Commercial heat	(-361)	(-208)	(-40)	(-34)
Biofuels and waste	767	(-2)		(-15)
Other renewables	(-47)	205	77	(-9)
Total	**(-2 260)**	**(-796)**	**(-911)**	**(-6 179)**

The decarbonisation of the power sector is important to reduce CO_2 emissions in the services sub-sector and reach the goals elaborated in the 2DS (Figure 14.16). Replacing less-efficient air conditioners with newer technology in developing countries is one opportunity. In OECD countries, performance standards for air conditioners have generally tightened over time but the average efficiency of the stock is still significantly below today's best units on the market. If further progress can be made in improving the best available technology, the CO_2 savings from cooling systems could be even greater by 2050.

The CO_2 emissions reduction due to improvement in lighting efficiency are greater than average for the buildings sector, despite a large increase in the global level of lighting services between 2009 and 2050. This scenario may become even more efficient as projected performance improvements and cost-reduction scenarios for SSL become commonplace.

Figure 14.16 Services sub-sector CO_2 emissions and reductions



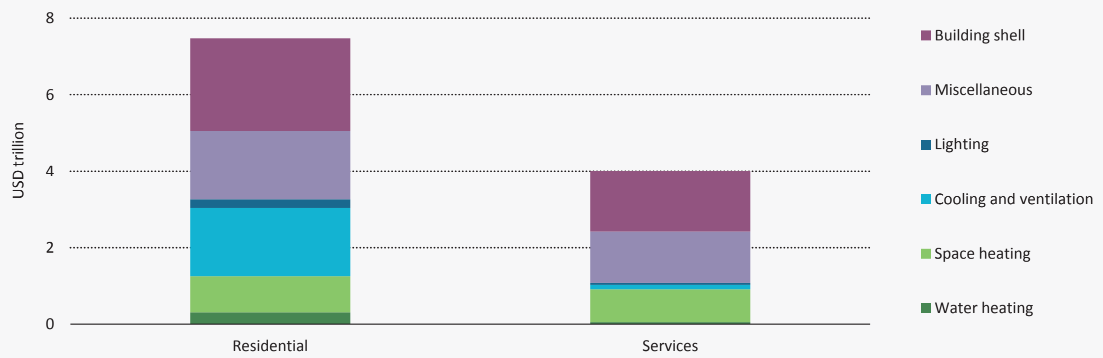
Note: Shaded area represents the savings between the 6DS and the 4DS (in the 4DS column) and between the 4DS and the 2DS (in the 2DS column).

Key point *Electricity decarbonisation is, by far, the largest contributor to CO_2 emissions reduction within the services sub-sector.*

Additional investments required in the buildings sector

Additional investment needed to realise the 2DS is estimated to be USD 11.5 trillion: USD 7.5 trillion in the residential sub-sector and USD 4.0 trillion[9] in the services sub-sector (Figure 14.17). This investment is required to ensure that new buildings meet more stringent building codes, to refurbish around 60% of the OECD building stock still standing in 2050 to low-energy standards, and for additional investments in heat pumps, solar thermal systems, co-generation systems, lighting systems and appliances.

Figure 14.17 Incremental investment needs in the buildings sector in the 2DS, 2010-50



Notes: Building shell includes refurbishment of building shells, new building shell measures, and demolition and early retirement of buildings. Miscellaneous includes appliances, information technologies and office equipment, heat pumps, and other small plug loads in the residential and services sub-sectors.

Key point *Additional investments in building shells account for a third of the total additional investments.*

Funding required for improving building shells, particularly for refurbishing the existing building stock in OECD countries, dominates the total additional investment needs in the 2DS. In the residential sub-sector, improvements in building shells account for almost half of the incremental investment needs; in the services sub-sector, around 40% of all investment is required for this purpose. Also in the services sub-sector, the electrical end uses of lighting, cooling and ventilation, and miscellaneous plug loads dominate the incremental investment needs.

Recommended actions for the near term

The buildings sector is a vital component of any long-term strategy to shift the energy sector to a more sustainable footing. Most buildings last for decades; some last for centuries. More than half of the current global building stock will still be standing in 2050, closer to three-quarters in the OECD. Buildings are much more frequently refurbished than replaced, and the refurbishments rarely include energy efficiency considerations. Delaying actions in the buildings sector will have implications for decades to come.

But the buildings sector is far from homogeneous. Countries are using different construction materials, have access to different energy sources, have different climates and

9 Total incremental investment over and above the 6DS.

different preferences, and are at different stages of economic development. Policy makers should take into consideration all the specificities of a country before developing targeted efficiency policies for the buildings sector.

The policy challenges in the OECD, non-OECD Europe and Eurasia are different from those of developing countries. In the OECD, the existing, less-efficient building stock will age in place for many decades unless retrofitted. In developing countries, rapid new building construction offers opportunities to improve efficiency standards for new construction relatively easily.

Despite this heterogeneity, some policy considerations hold true in any circumstances.

Energy efficiency policies should be based on an ambitious long-term strategy for reducing energy consumption. They should take a holistic approach that addresses indoor comfort, energy security, fuel poverty and climate change challenges.

Careful consideration must be given to policy development if costly interventions outside of initial construction or scheduled refurbishment are to be avoided. Given the slow turnover rates in the sector, strong and prompt actions are required to avoid a lock-in of low-efficiency buildings. A necessary first step is to improve the efficiency of building shells. Governments should develop detailed action plans that would include provisions for rapid implementation of zero-energy buildings when technically feasible and economically viable, and mandatory renovation rates with stringent energy requirements. Mandatory requirements for energy efficiency in building shells should be implemented.

Minimum performance standards and regulations for appliances and equipment, based on best available technologies, should also be developed. Policies and measures targeting public awareness should be implemented to ensure a maximum uptake of state-of-the-art technologies.

Governments need to define and enforce compliance procedures to ensure effective implementation of building-shell, appliance and equipment standards and regulations.

Governments should also support the development of technical training to ensure that all stakeholders involved in building construction and renovation, as well as enforcement officers, have the required skills to implement these policy measures and enforce required energy performance.

Chapter 15

Technology Roadmaps

Technology roadmaps identify priority actions for governments, industry, financial partners and civil society that will advance technology development and uptake based on the *ETP 2012* 2°C scenario. Each roadmap contains milestones for technology development, legal/regulatory needs, investment requirements, public engagement/outreach and international collaboration.

Key findings

- ***Transforming the energy sector requires a diverse portfolio of low-carbon energy technologies*** *to improve energy security and help combat climate change.*
- **The ETP 2012 *Scenarios identify more than 20 priority technology areas and sectors*** *that are essential to shifting the global energy sector away from its current unsustainable dependence on fossil fuels.*
- ***Roadmaps are an effective policy tool for finding a common vision that different stakeholders can implement.*** *To accelerate development of the most urgently needed low-carbon technologies, the IEA designed a series of energy technology roadmaps.*
- ***The IEA has completed 14 technology roadmaps to date,*** *covering low-carbon technologies in the power, buildings, industry and transport sectors. An additional five technology roadmaps are in progress.*
- ***A clear, long-term vision is needed that can underpin investor confidence.*** *Without clear signals or binding policies from governments, the market on its own cannot stimulate industry to act with the speed or depth of commitment needed for current and long-term investment in low-carbon technologies.*

Opportunities for policy action

- *Greater public and private sector research, development and demonstration are needed for a range of low-carbon energy technologies. Public research and development (R&D) spending should increase by a factor of two to five times.*
- *The international community must improve coordination and knowledge-sharing to speed up the transition from demonstration to commercialisation of many low-carbon technologies.*
- *Countries should develop national roadmaps that identify the actions and milestones for developing the critical low-carbon energy technologies that they need.*

A portfolio of low-carbon energy technologies

Tackling today's energy security and climate change challenges requires a revolution in energy technology, in concert with the development, deployment and wide-scale commercialisation of a portfolio of low-carbon energy technologies. Governments and industry together need to pursue energy efficiency, renewable energy, nuclear power, carbon capture and storage (CCS), low-carbon solutions in transport and industry, smart grids, and energy storage (Table 15.1). Additional R&D will also be needed to develop new breakthrough technologies now for zero emissions in end-use sectors in the longer term.

Table 15.1 Emissions reductions and investment needs in the 2DS, by technology

Sector	CO_2 savings (Gt) 2050	Cumulative CO_2 savings (Gt) 2010 to 2050	Investment needs (USD trillion) 2010 to 2050
Power generation			
Bioenergy for heat and power	1.7	20.4	0.5
CCS in power generation	3.3	57.0	2.6
Concentrating solar power	1.7	22.5	2.6
Geothermal for heat and power	0.5	7.1	1.3
High efficiency, low emissions coal	n.a.	n.a.	1.9
Hydropower	0.9	19.4	3.0
Nuclear	3.2	59.6	4.0
Smart grids	1.7	36.4	5.0 to 6.0
Solar photovoltaic (PV)	1.7	27.7	3.9
Wind	3.0	61.0	5.9
Buildings			
Energy efficient heating and cooling equipment	1.1	27.9	0.4
Energy efficient building envelopes	0.3	10.7	n.a.
Solar heating and cooling	0.3	14.5	n.a.
Industry			
CCS in industrial applications	3.8	57.9	1.0
Cement	1.1	18.9	1.4 to 1.6
Chemicals	1.6	32.9	5.4 to 5.5
Iron and steel	1.6	32.0	2.0 to 2.5
Transport			
Electric and plug-in vehicles	1.7	33.3	13.1
Hydrogen fuel cell vehicles	0.7	5.3	3.0
Biofuels	1.6	34	16.0
Vehicle fuel economy	4.7	69.0	n.a.

Notes: Emissions reductions listed in the 2DS are in comparison with the 6DS. Numbers should not be summed to derive a total, as this may double count. Smart grids include direct and enabled emissions reductions. Geothermal and biomass emissions reductions and their investment needs are only for electricity. Cumulative emissions reductions for biomass use in buildings are 3.1 Gt and in industry 4.9 Gt. Solar heating and cooling also includes applications in industry (5.2 Gt cumulative). For biofuels, investment cost shown is for total fuel purchases.
Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Governments have a major role to play in supporting innovative research and development, in developing policies to support market creation, and in cooperating with industry and the financial sector to develop appropriate market conditions to allow technologies to overcome barriers. Careful planning is required to ensure that limited resources are devoted to the highest-priority, highest-impact actions in the near term, while laying the groundwork for longer-term improvements.

The *ETP 2012* Scenarios have so far identified just over 20 priority technology areas that need to be developed. Their contribution to emissions reduction in 2050 and the estimated investments needed to achieve the *ETP 2012* 2°C Scenario (2DS) goals are summarised below. This list should not be construed as being all-encompassing or as including all technologies that need to be developed.

Box 15.1 What is a low-carbon energy technology roadmap?

Roadmaps are an important strategic planning tool for governments and industry to address future challenges, including energy security and climate change. A number of governments, industry organisations and other groups have developed energy technology roadmaps. The IEA low-carbon energy technology roadmaps build from and add value to these roadmaps by creating an international consensus about priority actions and milestones that must be reached to achieve a technology's full potential.

There are a number of common elements to a low-carbon energy technology roadmap:

- **Rationale.** Why is the technology important for climate change mitigation and energy and economic growth?
- **Baseline.** Where is the technology today in terms of performance (*i.e.* USD/kWh; energy conversion efficiency) and installed capacity and energy savings? Which countries are leaders in research, development, demonstration and deployment (RDD&D)?
- **Vision for deployment and CO_2 abatement potential.** What is the pathway from 2010 to 2050 for the technology to achieve its climate change mitigation potential? How much investment does it require? How many projects will it require? Which countries and regions hold the greatest potential?
- **Technology development milestones and actions.** What performance and cost reduction milestones must the technology achieve to meet this vision? Which stakeholders are responsible for addressing these milestones?
- **Policy framework milestones and actions.** What types of policies and regulations are needed to advance the technology? Are there regulatory frameworks that must be developed?
- **Financing milestones and actions.** Are there near-term funding requirements for demonstration? For more competitive technologies, what is the role between greenhouse gases, markets and other incentives?
- **Public outreach and engagement.** What role does the technology play in climate change mitigation? What are other air, water or land use impacts related to the technology? What role can governments play to educate the public? Does the public need to be educated and engaged to understand and support large infrastructure projects?
- **International collaboration.** What are the opportunities to share the technology across borders? Are there existing collaboration mechanisms or do new efforts need to be created?

The role of roadmaps

Roadmaps identify priority actions for governments, industry, financial partners and civil society that advance technology development and uptake to achieve international climate change goals. The vision for each of the roadmaps is based on the 2DS, and each roadmap represents international consensus on milestones for technology development, legal and regulatory needs, investment requirements, public engagement and outreach, and international collaboration.

Given the expected growth in energy use and related emissions outside of IEA member countries, the roadmaps also focus on technology development and diffusion in emerging economies. International collaboration is critical to achieve the *ETP 2012* Scenario goals. The roadmaps are designed to facilitate greater collaboration among governments, business and civil society in both industrialised and developing countries.

In addition, the IEA is developing additional roadmaps that will be published later in 2012 and 2013. These roadmaps include:

- chemical sector;
- energy efficient building envelopes;
- high efficiency, low emissions coal;
- hydropower;
- solar heating and cooling.

These technologies were selected for their CO_2 emissions reduction potential, market readiness, and coverage of demand-side and supply-side emissions. The IEA will revisit this list and update the roadmaps on an ongoing basis. The IEA is also working closely with major partner countries to support the development of national roadmaps.

The first national roadmap, *Wind Development in China*, was recently released. It was developed by the Energy Research Institute of the National Development and Reform Commission (NDRC) together with the IEA, using IEA roadmap tools and methodologies. A roadmap for cement in India is now under way and will be released later in 2012.

Roadmap summaries

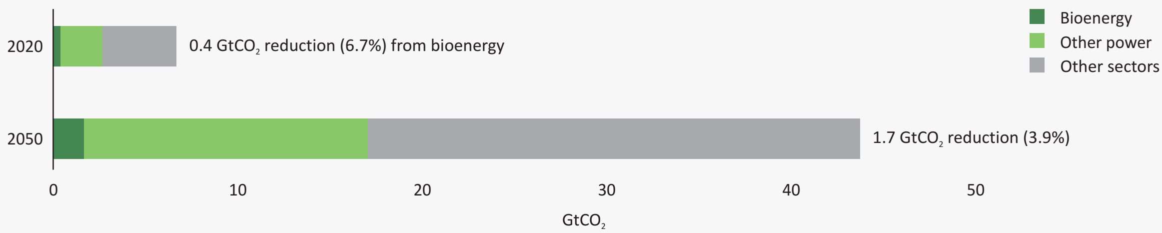
Each roadmap summary provides the reader with a summary assessment of the featured technology and the steps needed to accelerate the technology's adoption under the 2DS. Each roadmap summary includes:

- contribution to CO_2 reductions in 2020 and 2050;
- investment needs;
- priority actions to 2020;

- global deployment to 2050 based on the *ETP 2012* Scenarios;
- technology milestones; and
- policy recommendations.

Bioenergy for heat and power

Contribution to CO_2 reductions



Note: CO_2 savings above include reductions from bioenergy heat in buildings and industry of 0.18 $GtCO_2$ in 2020 and 0.65 $GtCO_2$ in 2050.
Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Investment needs

USD billion	2010-20	2020-30	2030-50
OECD Europe	22	9	19
OECD Americas	15	10	20
OECD Asia Oceania	5	5	6
Africa and Middle East	7	3	7
China	47	120	92
India	14	8	10
Latin America	18	6	12
Other developing Asia	11	15	50
Other non-OECD	4	6	30
World	**143**	**183**	**245**

Note: Investments for heat are not included above.

Future bioenergy electricity generation costs

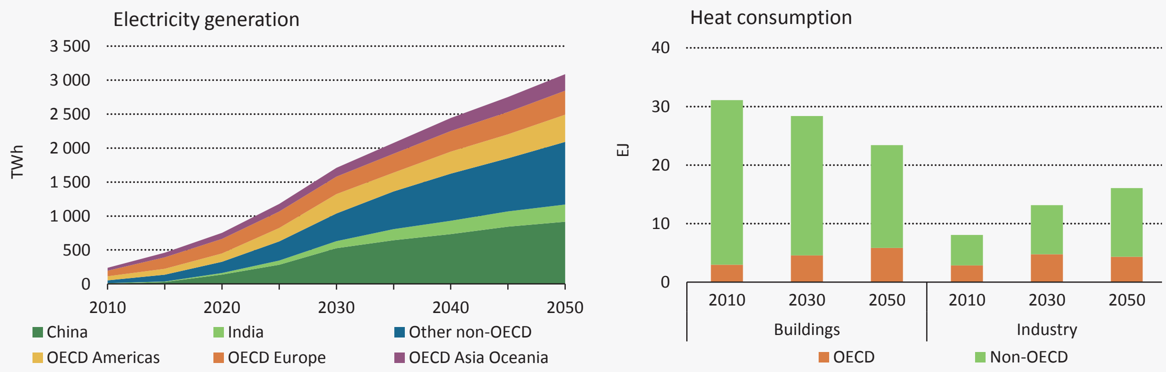
Size	Feedstock	Cost: US cents/kWh
<10 MW	Residues	10.2 to 17.9
	Collected fuels	17.4 to 35.9
10 to 50 MW	Residues	6.4 to 16.5
	Collected fuels	10.2 to 22.8
>50 MW	Traded fuels	7.9 to 16.1
Co-firing	Traded fuels	5.7 to 9.9

Priority actions to 2020

- Link financial support schemes to the sustainable performance of bioenergy and the use of wastes and residues as feedstock.
- Increase research efforts on feedstocks and land availability mapping to identify the most promising feedstock types and locations for future scale-up.
- Establish sustainability targets and certification schemes for biomass used for energy, based on internationally agreed criteria.
- Ensure sustained funding and support mechanisms for emerging technologies such as BIGCC, torrefaction and pyrolysis to reach commercial production within the next 10 years.

Global deployment

Bioenergy electricity generation and heat production



Note: 1EJ = 277.78 TWh.

Technology milestones

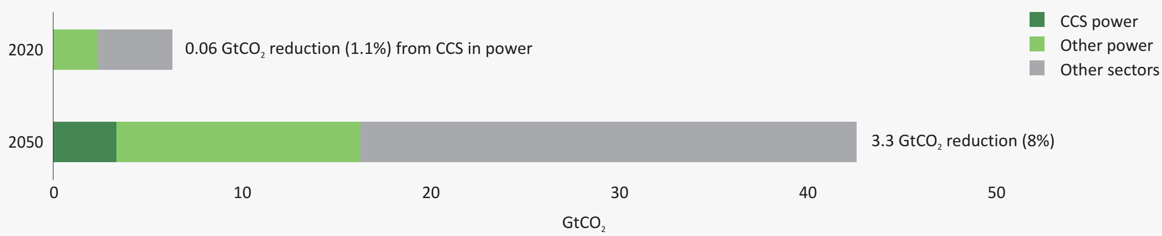
Timing	Technology
2015	Develop low-cost, efficient biomass stoves, suited to customer needs.
2015	First commercial-scale torrefaction and pyrolysis plant.
2015	First commercial-scale bio-synthetic natural gas (bio-SNG) and biomass integrated gasification combined cycle (BIGCC) plant.
2020	Develop "off the shelf" plant design to reduce capital costs.
2020	Replace 100 million traditional biomass stoves with efficient stoves.
2030	Increase average electricity generation efficiency in new plants by 5%.

Policy recommendations

- Create a stable, long-term bioenergy policy framework to increase investor confidence and allow for private sector investments in the sustainable expansion of bioenergy production.
- Increase research efforts on development of bioenergy feedstocks and land suitability mapping to identify the most promising feedstock types and locations for future scaling up.
- Replace traditional biomass use through more efficient stoves and clean fuels (*e.g.* biogas) by the creation of viable supply chains for advanced biomass cookstoves and household biogas systems.
- Implement internationally agreed sustainability criteria, indicators and assessment methods for bioenergy. These should provide a basis for the development of integrated land-use management schemes that aim for a more resource efficient and sustainable production of food, fedd, bioenergy and other services.
- Introduce internationally aligned technical standards for biomass and biomass intermediates, in order to reduce and eventually abolish trade barriers, enhance sustainable biomass trade, and tap new feedstock sources.

CCS in power generation

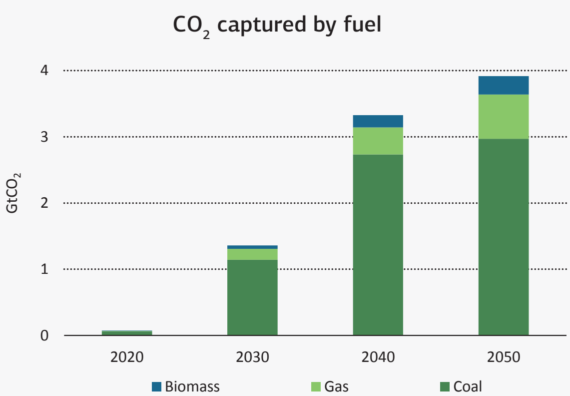
Contribution to CO_2 reductions



Note: CO_2 reductions above are CO_2 saved and not CO_2 captured, which is higher and shown in the figure below.

Investment needs

USD billion	2010-20	2020-30	2030-50
OECD Europe	27	128	57
OECD Americas	25	227	365
OECD Asia Oceania	11	34	50
Africa and Middle East	2	47	127
China	8	362	595
India	0	28	150
Other developing Asia	0	41	127
Other non-OECD	0	82	110
World	**73**	**950**	**1 580**



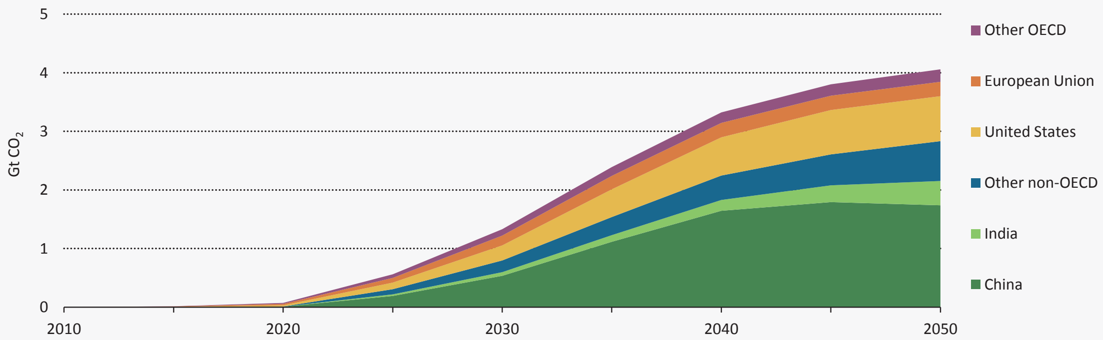
Priority actions to 2020

- Establish enabling policy frameworks to support carbon capture and storage (CCS) development.
- Continue to fund R&D and pilot activities.
- Allocate USD 40 billion for large-scale demonstration and first deployment of the technology by 2020.
- Continue to establish enabling legal frameworks for CCS.
- Countries to assess the role of CCS in their energy futures, explicitly recognising the role that CCS will play.

Electricity capacity (GW)	2015	2020
By fuel		
Coal with CCS	2.5	11.0
Natural gas with CCS	0.9	4.4
Biomass with CCS	0.1	0.6
By region		
Europe	1.0	4.9
United States	1.3	4.1
Other OECD	1.0	3.6
Other non-OECD	0.0	1.5
China	0.3	1.8
World	**3.5**	**16.0**

Global deployment

CO_2 captured by region



Technology milestones

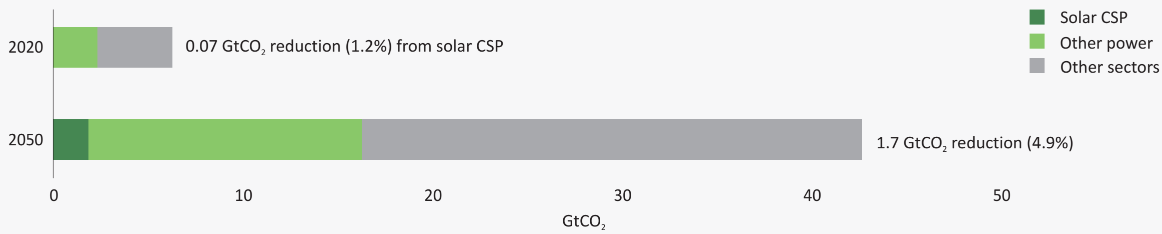
Capture technology	Transport	Storage
Develop post-combustion capture efficiency in such a way that the energy penalty is driven to <8% by 2020-25.	Conduct analysis on source-sink distribution and matching in OECD countries by 2012 and in non-OECD countries by 2015.	Agree on common global methodology to assess CO_2 storage capacity.
Demonstrate IGCC plant in large-scale operation, equipped with CO_2 separation and high-efficiency turbines for hydrogen (H_2).	Perform country- or region-wide analysis of optimal pipeline networks.	Review the key gaps in global storage data coverage.
Reduce energy required for large-scale air separation for oxygen production.	Conduct studies on the design and cost of CO_2 transport via tankers.	Perform a comprehensive assessment of worldwide CO_2 storage capacity.
Continue R&D into novel capture technologies.	Improve understanding of CO_2 transport leakage scenarios and the effects of impurities.	Develop best-practice guidelines for storage site selection, operation, risk assessment and monitoring.

Policy recommendations

- Governments and industry must continue their investment in R&D and pilot scale facilities to test various CCS technologies.
- Governments and industry should collaborate in designing suitable incentive mechanisms for CCS demonstration and deployment; such measures should be implemented by 2015.
- Governments should design financing mechanisms to demonstrate, and later deploy, CCS in developing countries. Possible options through global carbon finance mechanisms should be evaluated and implemented.
- Governments must continue to establish enabling legal and regulatory frameworks for CCS, as well deal with remaining international legal constraints to trans-boundary transfer of CO_2 for storage purposes.

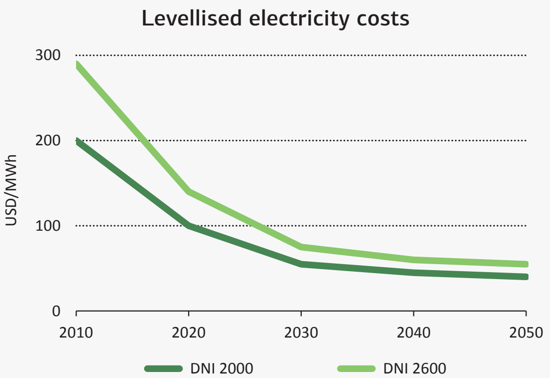
Concentrating solar power

Contribution to CO_2 reductions



Investment needs

USD billion	2010-20	2020-30	2030-50
OECD Europe	29	62	51
OECD Americas	51	142	369
OECD Asia Oceania	5	11	45
Africa and Middle East	37	102	710
China	20	90	269
India	6	47	316
Latin America	6	9	144
Other developing Asia	1	1	51
Other non-OECD	2	3	66
World	**155**	**467**	**2 021**



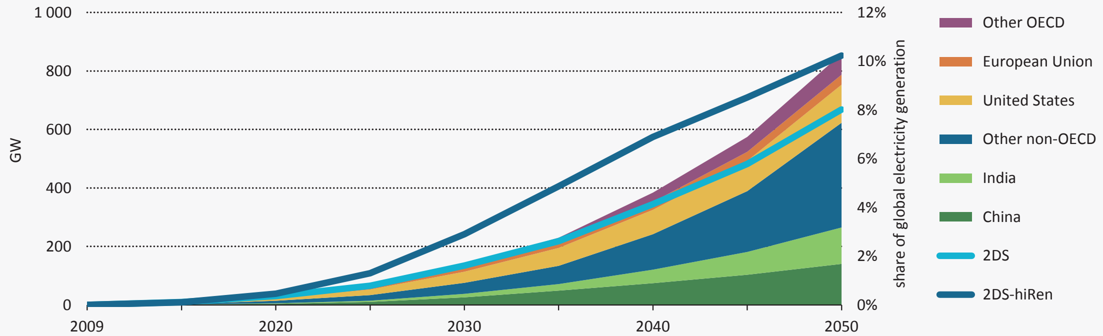
Note: DNI = direct normal irradiance.

Priority actions to 2020

- Facilitate the development of ground and satellite measurement/modelling of global solar resources.
- Support concentrating solar power (CSP) deployment through solar-specific incentives: feed-in tariffs or premiums, binding solar targets, capacity payments or fiscal incentives.
- Avoid arbitrary limitations on plant size and hybridisation ratios.
- Pursue cost reduction potential of heliostat fields with immediate control loop from receivers and power blocks.

Indicator	Milestone
Capacity factor	32% by 2020
Demonstration	Solar tower with supercritical steam cycle. Solar tower with air receiver and gas turbine.
Costs	Achieve competitiveness for peak and intermediate loads by 2020. Cost declines 30% to 40%.
Electricity generation	40 TWh in 2015 and 100 TWh in 2020 globally.

Global deployment



Technology milestones

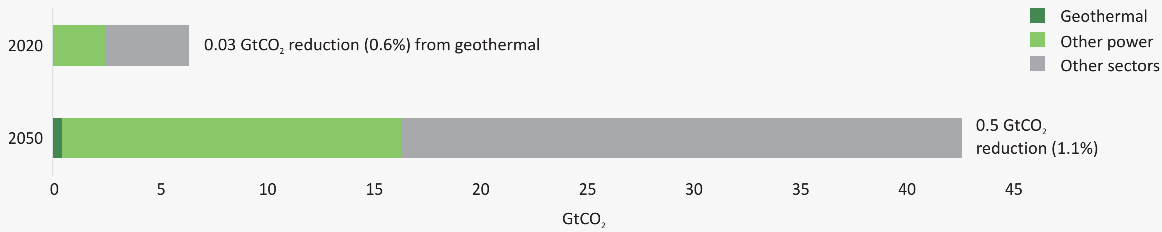
2020	2030	2040	2050
All new plants dry-cooled; working temperature 540°C; larger storage capacities.	Biogas and solar fuels substitute natural gas as back-up fuel in power plants.		
	Hydrogen from solar towers/large dishes introduced in natural gas grids.		
First tower plants with air receivers and gas turbines.		Production of solar-only hydrogen to manufacture liquid fuels.	
First supercritical CSP plants.		Solar production of other energy carriers (*e.g.* metals) for transportation sector.	

Policy recommendations

- Support CSP development through solar-specific incentives. These could include any combination of feed-in tariffs or premiums, binding renewable energy portfolio standards with solar targets, capacity payments and fiscal incentives. Incentives should be on par with ground-mounted photovoltaic (PV).
- Streamline permit procedures and access to grid.
- Develop incentive schemes for solar process heat and solar process fuels.
- Reward CSP plants that have firm capacities.
- Ensure long-term funding for additional research, development, demonstration and deployment (RDD&D) in all main CSP technologies.
- Avoid establishing arbitrary limitations on plant size and hybridisation ratios, develop procedures to reward only the electricity derived from solar.

Geothermal for heat and power

Contribution to CO_2 reductions

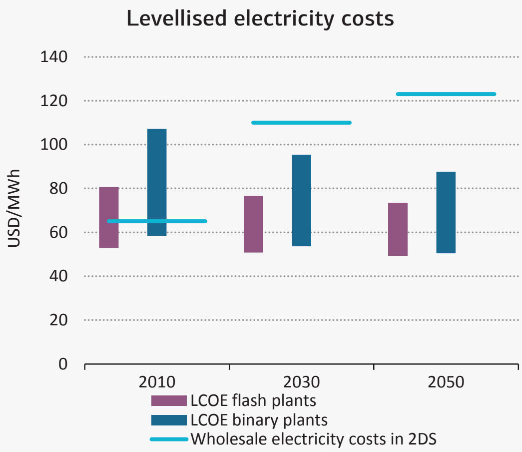


Note: CO_2 savings from heat are not included in figure above.

Investment needs

USD billion	2010-20	2020-30	2030-50
OECD Europe	17	20	246
OECD Americas	30	55	347
OECD Asia Oceania	11	20	126
Africa and Middle East	2	4	9
China	2	8	90
India	1	2	10
Latin America	7	4	14
Other developing Asia	25	31	90
Other non-OECD	9	12	72
World	**104**	**155**	**1 004**

Note: Investments for heat are not included in figure above.



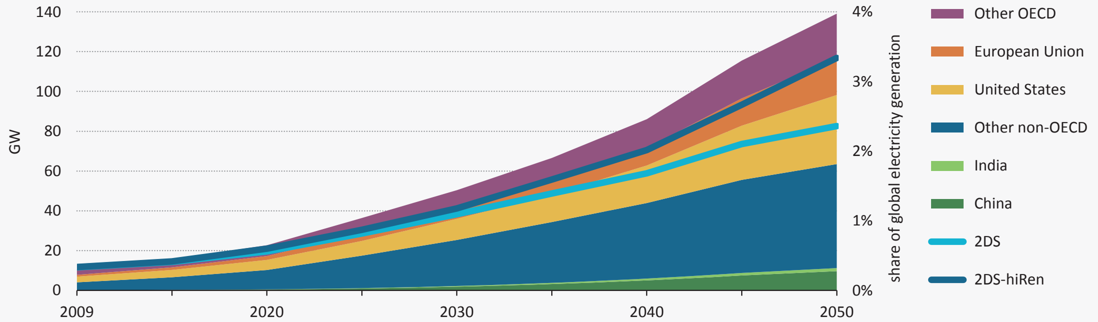
Priority actions to 2020

- Establish targets for geothermal technology and introduce differentiated economic incentive schemes for both geothermal heat and geothermal power.
- Develop publicly available databases, protocols and tools for resource assessment.
- Introduce streamlined and time-effective procedures for issuing permits.
- Expand the knowledge of EGS technology and provide sustained and substantially higher RD&D resources to plan and develop at least 50 more EGS pilot plants during the next 10 years.
- In developing countries, expand the efforts to rapidly develop the most attractive available hydrothermal resources.

Milestones	2015	2020
Drilling	Reduce drilling costs by 10%	
EGS (enhanced geothermal systems) development	Develop 50 EGS plants with an average capacity of 10 MW	
Advanced geothermal technology	Develop exploitation of co-produced geothermal water from oil and gas wells	Develop knowledge for exploitation of super-critical fluids

Global deployment

Geothermal electricity generation and heat consumption



Note: Geothermal head generation also provides significant potential.

Technology milestones

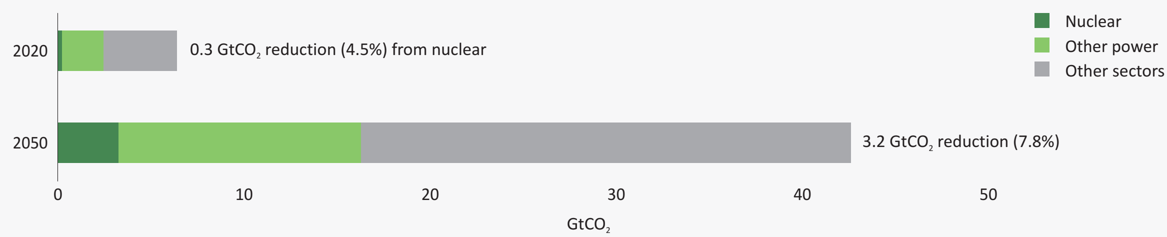
2015	2020	2030	2040	2050
Improve geothermal resource assessment to accelerate geothermal development by developing publicly available databases, by ensuring an integrated approach for EGS identification and by developing geothermal tools for identifying hot-rock and hydrothermal resources.				
Improve accessing and engineering the resource by developing cheaper drilling technologies, by improving hard rock and high-temperature/high-pressure drilling and by improving down-hole instrumentation and well monitoring.				
		Reduce drilling costs by 10%	*Introduce new drilling concepts*	
Develop EGS pilot plants in different geologic environments, develop stimulation techniques and decision tools for reservoir modelling, improve management of health, safety and environmental (HSE) issues, ensure long-term production and scale up EGS to realise 50 to 200+ MW plants.				
		20 MW EGS plants	*50 MW EGS plants*	*(towards 200 MW 2050)*
Explore feasibility of alternative hydrothermal and hot-rock resources.				
		Off-shore geothermal, magma		

Policy recommendations

- Design a holistic policy framework to address technical barriers relating to resource assessment, accessing and engineering the resource, geothermal heat use and advanced geothermal technologies. This holistic framework must also address economic, regulation, market facilitation and RD&D support barriers.
- Make policy makers, local authorities and utilities more aware of the full range of geothermal resources available and their possible applications. This applies particularly to geothermal heat, which can be used at varying temperatures for a wide variety of tasks.
- Address R&D priorities for geothermal energy by accelerating resource assessment; developing more competitive drilling technology; improving EGS technology; and managing HSE concerns.

Nuclear power

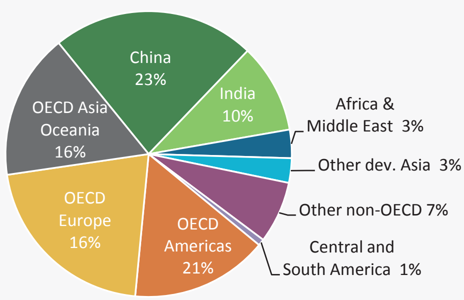
Contribution to CO_2 reductions



Investment needs

USD billion	2010-20	2020-30	2030-50
OECD Europe	52	148	420
OECD Americas	106	180	559
OECD Asia Oceania	133	226	299
Africa and Middle East	32	44	52
China	202	182	533
India	15	101	287
Latin America	9	5	16
Other developing Asia	28	45	38
Other non-OECD	72	79	128
World	**649**	**1 010**	**2 333**

Regional investment needs



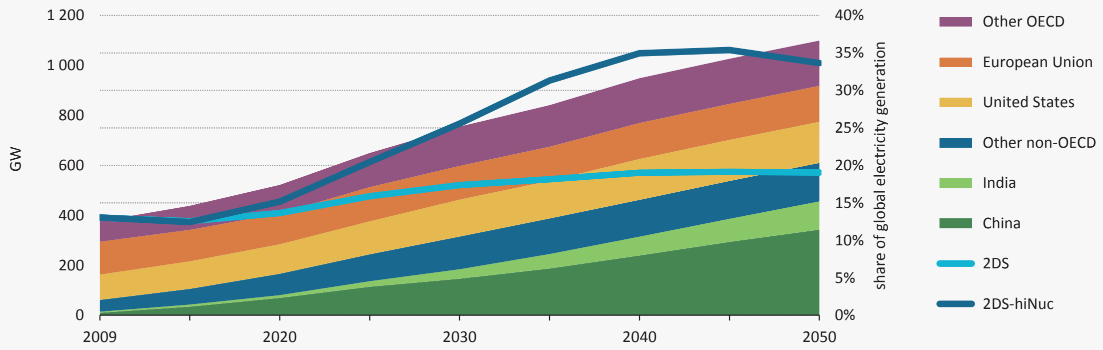
Priority actions to 2020

- Demonstrate ability to build latest nuclear plant designs on time and within budget.
- Apply lessons learned from Fukushima Daiichi accident at both operational and regulatory levels.
- Develop industrial capacities and skilled human resources to support nuclear growth.
- Establish required legal frameworks and institutions in countries where these do not yet exist.
- Continue developing financing models to address the challenge of large upfront capital costs.
- Continue implementing plans for permanent disposal of high-level radioactive waste, with the construction of the first geological disposal sites.

Indicator	Milestones
Capacity added	110 GW 2010 to 2020
Long-term operation	In the United States, 90% of reactors licensed for 60 years. In Europe, most reactors licensed for over 40 years.
Nuclear front end	New uranium mines open. Phase out gas diffusion enrichment.
Nuclear back end	Operation of first geological disposal site for high-level waste by 2020. Continue development of advanced fuel cycles.
Technology development and deployment	More than 10 Gen III+ reactors are in operation and another 10 under construction by 2020. Advanced small modular reactor under construction. Start of construction of first Generation IV (Gen-IV) prototype.

Global deployment

Nuclear capacity and electricity generation



Technology milestones

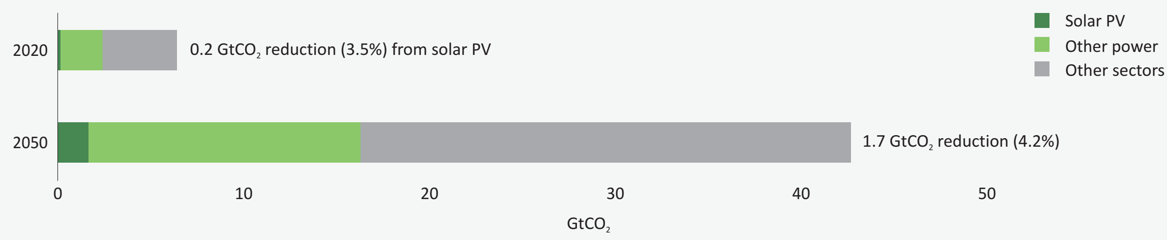
Nuclear fuel cycle	Disposal of spent fuel and high-level waste	Small modular reactors	GEN-IV
Expand uranium production and the capacity of nuclear fuel cycle facilities in line with growth of nuclear generating capacity.	Develop plans for long-term management and disposal of all types of radioactive waste.	Continue the development of advanced small modular reactors.	Complete demonstration projects for the most promising Gen-IV designs by 2030-40.
Strengthen RD&D in advanced fuel cycles, including recycling of spent fuel to reduce uranium consumption and minimise volume of ultimate high-level waste.	Wider deployment of geological repositories for high-level waste. Continue the development of interim storage as a near-term solution.	Support the deployment of nuclear energy for small electricity grids. Also develop non-electric applications of nuclear power to displace fossil fuel usages.	Build and operate first commercial-scale Gen-IV plants 2040 to 2050.

Policy recommendations

- Provide clear and sustained political support for nuclear programmes as part of a national strategy to meet energy and environmental policy objectives.
- Ensure that the lessons learned from the Fukushima accident are shared internationally, and that safety upgrade recommendations from post-Fukushima “stress tests” are implemented in a timely manner wherever necessary.
- Countries introducing nuclear technologies should observe international best practice in developing the necessary nuclear energy legislation and regulatory institutions to ensure that they are both effective and efficient.
- Facilitate the construction of standardised designs for nuclear power plants worldwide and harmonise regulatory requirements to the greatest extent possible.
- Ensure that electricity markets support the large, long-term investments required in nuclear power plants, providing sufficient confidence of an adequate return on investment.
- Encourage risk-sharing during construction and long-term stability in market conditions to attract private sector investment in new nuclear plants.
- Continue efforts to rebuild public confidence in nuclear energy through enhanced public dialogue and stakeholder involvement in decision making.

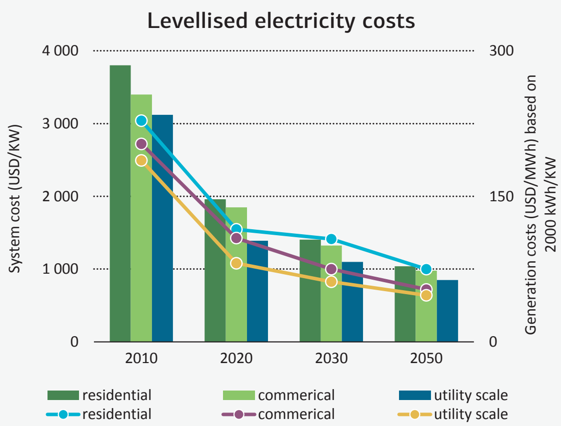
Solar PV

Contribution to CO_2 reductions



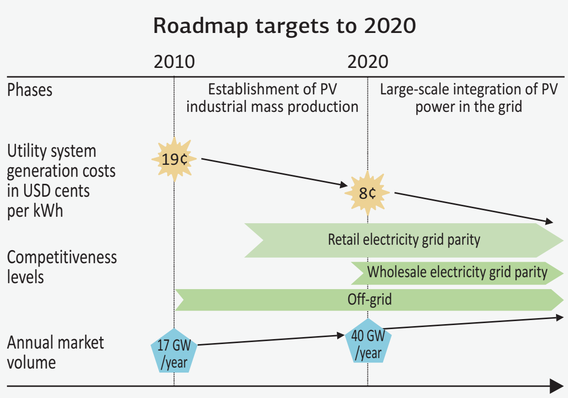
Investment needs

USD billion	2010-20	2020-30	2030-50
OECD Europe	170	86	387
OECD Americas	109	114	388
OECD Asia Oceania	59	49	149
Africa and Middle East	31	65	229
China	89	198	638
India	60	129	397
Latin America	16	27	115
Other developing Asia	26	77	203
Other non-OECD	7	17	87
World	**567**	**761**	**2 594**

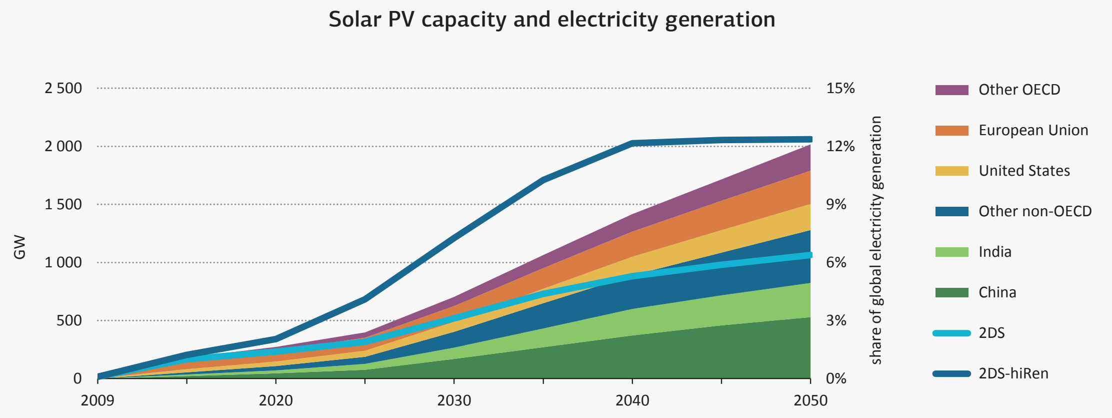


Priority actions to 2020

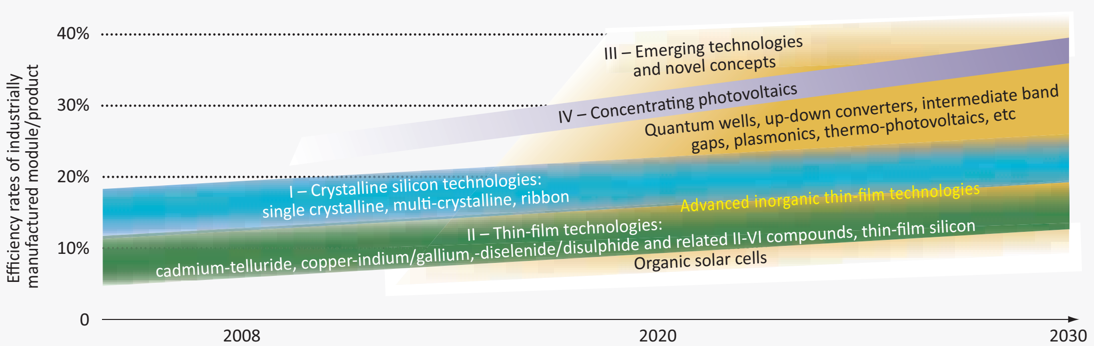
- Implement effective and cost-efficient PV incentive schemes that are transitional and decrease over time to foster innovation and technological improvement.
- Develop and implement appropriate financing schemes,
  in particular for rural electrification and other applications
  in developing countries.
- Increase R&D efforts to reduce costs and ensure PV readiness for rapid deployment, while also supporting longer-term innovations.



Global deployment



Technology milestones

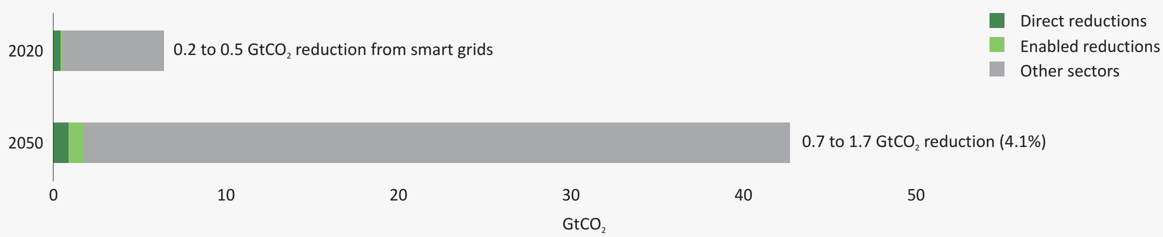


Policy recommendations

- Set long-term targets, supported by a transparent and predictable regulatory framework to build investor confidence, including financial incentives to bridge the transition phase until PV has reached competitiveness.
- Design and implement a regulatory framework to facilitate large-scale PV grid integration.
- Establish internationally accepted standards and codes for PV products and components.
- Enhance training, education and awareness for a skilled workforce along the PV value chain.
- Increase public RD&D funding and ensure sustained funding in the long term.
- Develop and implement smart grids, grid management tools and enhanced storage technologies.
- Develop new mechanisms to support exchange of technology and deployment of best practices.

Smart grid

Contribution to CO_2 reductions



Note: **Direct reductions:** energy savings from peak load management, continuous commissioning of service sector loads, accelerated deployment of energy efficiency programmes, reduced line losses and direct feedback on energy usage.
Enabled reductions: greater integration of renewables and facilitation of electric vehicle (EV) and plug-in hybrid electric vehicle (PHEV) deployment.

Investment costs and benefits in the 2DS

USD billion		2010-20		2020-30		2030-50	
		Cost	Benefit	Cost	Benefit	Cost	Benefit
OECD Europe	min/max	124 - 143	430 - 730	169 -197	320 -856	468 -565	882 - 1820
OECD Americas	min/max	126 - 148	461 - 820	183 -215	360 -948	507 -600	1019 - 2138
OECD Asia Oceania	min/max	54 -61	305 - 452	73 - 85	59 - 340	176 - 205	232 - 564
China	min/max	177 -239	483 - 786	278 - 351	736 -1632	908 -1121	2893 - 5261
India	min/max	113 - 147	264 -391	134 - 173	112-516	475 - 586	1035 -2150

Priority actions to 2020

Technical

- Build up commercial-scale demonstrations that operate across system boundaries of generation, transmission, distribution and end-use and that incorporate appropriate business models addressing cost, security and sustainability.
- Evaluate priorities and develop standards for equipment, data transport, interoperability and cyber security.

Utility business models and regulation

- Develop and demonstrate new regulations and business models to address system-wide and cross-sector barriers to enable practical sharing of smart grids' costs and benefits.
- Address cyber security issues proactively through both regulation and application of best practice in generation, transmission, distribution and end-user sectors.

Stakeholder engagement

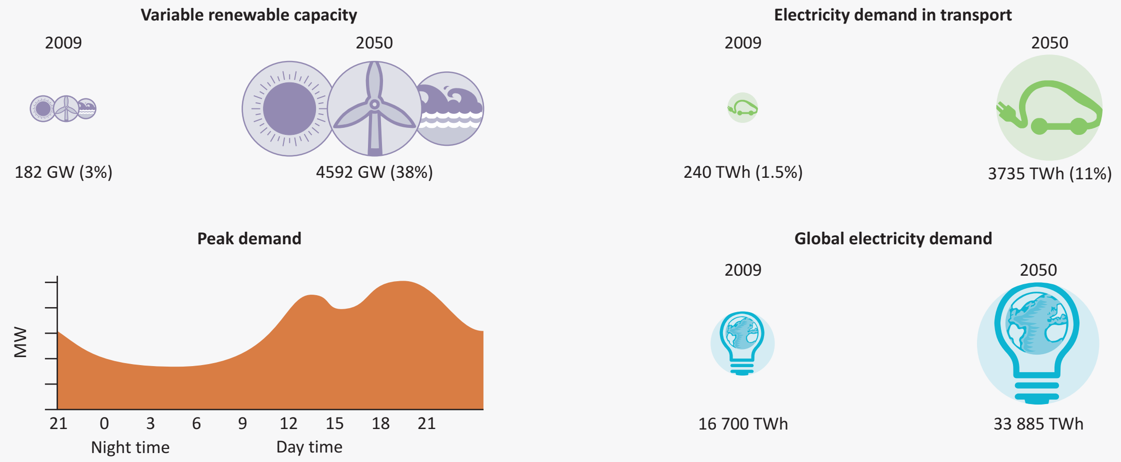
- Accelerate education and improve understanding of electricity system stakeholders – especially customers – to increase acceptance for smart grids' deployment.
- Catalogue and share best-practice advice on automated demand response and energy efficiency, use findings to improve pilot projects.

Analysis

- Quantify smart grids' costs and benefits globally and at a system level and create tools to evaluate smart grid technology options.
- Develop methodologies to asses need for flexibility and determine optimum resources for deployment.
- Evaluate the role of electricity storage in electricity system operation.

Global deployment

Drivers for smart grids deployment



Notes: All 2050 values derived from the 2DS; percentage values represent fraction of total capacity or demand in respective year.

Technology milestones

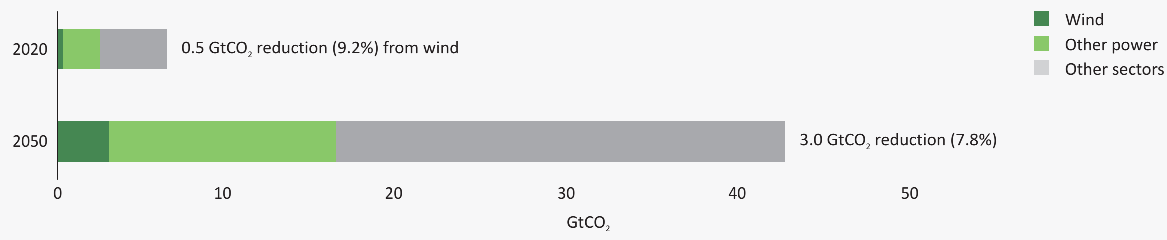
Technology	Demonstration smart grids with increasing levels of demand response for flexibility and consumer-based products, addressing key issues of cost, security, standards and sustainability to 2025.
Electricity system regulation	Determine approaches to address cyber security and system-wide and cross-sector barriers to enable practical sharing of smart grids' costs and benefits by 2020 and through to 2050. Develop regulatory mechanisms that encourage business models and markets to enable a wider range of flexibility mechanisms in the electricity system, which will support increased variable generation penetration from 2011 to 2030.
Consumer policy	Collect and codify best-practice from smart grid and smart metering pilot projects including data privacy and security, and increase study of consumer behaviour from 2011 to 2020. Develop social safety nets for vulnerable customers who are less able to benefit from smart grid pricing structures from 2011 to 2015.
International collaboration	Increase effort in setting standards and sharing demonstration findings in technology, policy, regulation and business models 2011 to 2015, and extend these efforts to 2050.

Policy recommendations

- Address regulatory and market barriers that hinder regional smart grids' demonstration and deployment, and allow sharing of smart grid costs and benefits between generation, transmission and distribution sectors.
- Use an evolutionary approach in the development of regulations that encourage business models and market mechanisms to support increased system flexibility and consumer participation.
- Tackle cyber security issues proactively through standards, regulation and best practice.
- Address special consumer classes that may not be able to easily benefit from smart grids.
- Address privacy, ownership and security of customer usage information by developing policies and protection mechanisms.
- Develop electricity usage tools and business models that encourage consumers to respond to changes in electricity markets and regulation.
- Determine regulatory mechanisms and capacity building needs for developing countries, potentially enabling them to leap-frog conventional electricity system approaches.

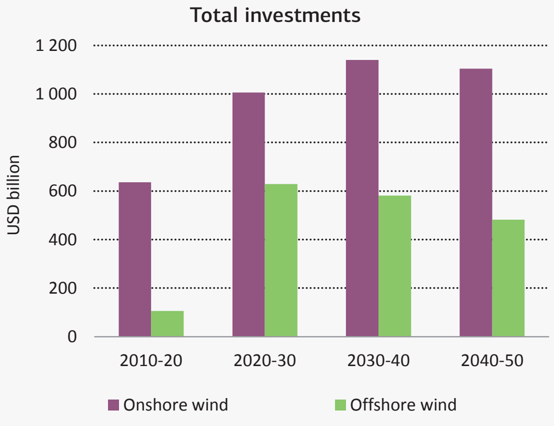
Wind

Contribution to CO_2 reductions



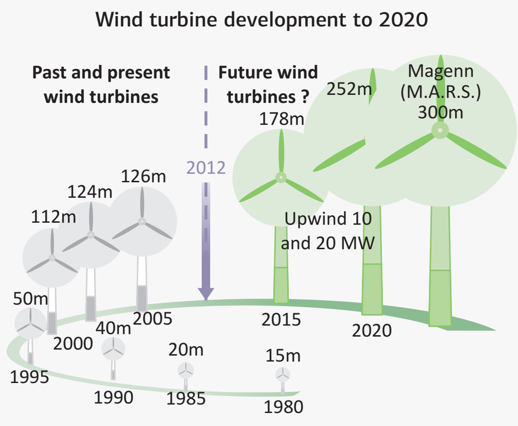
Investment needs

USD billion	2010-20	2020-30	2030-50
OECD Europe	256	337	831
OECD Americas	209	455	628
OECD Asia Oceania	32	69	120
Africa and Middle East	42	173	194
China	305	385	839
India	36	38	158
Latin America	25	12	74
Other developing Asia	53	105	279
Other non-OECD	22	61	185
World	**980**	**1 634**	**3 307**



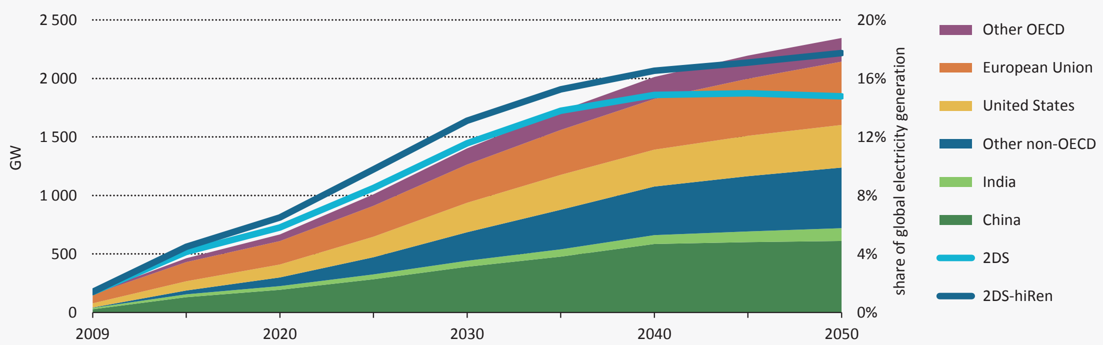
Priority actions to 2020

- Accelerate, harmonise and streamline permitting practices ("one-stop shop") while ensuring integrated system planning.
- Accelerate electricity system integration and transformation, *e.g.* enhanced market design and deployment of "smart grid" technology. Assess and exploit all available system flexibility.
- Bring the offshore supply chain to full maturity and reduce costs for offshore wind.
- Raise public awareness of the benefit of wind power and the accompanying need for additional transmission infrastructure.
- Develop more accurate, longer-horizon forecast models for use in power system operation.



Global deployment

Wind capacity and electricity generation



Technology milestones

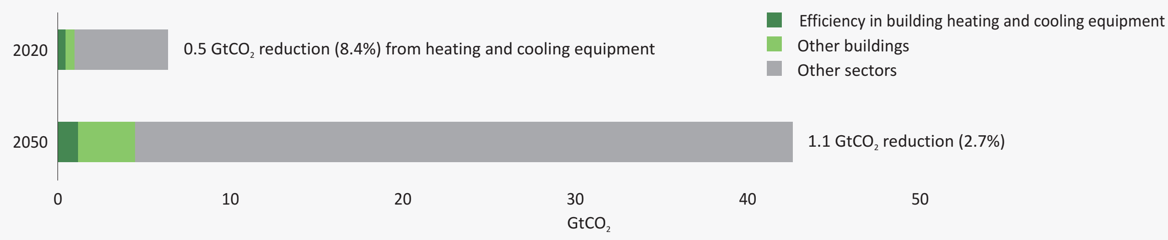
Policy and regulation	Transitional support mechanisms; integrated deployment plans and "one-stop-shop" permitting in all markets (2015).
System integration	Timely development of flexibility resources: assess system flexibility resources and needs, optimise market design to facilitate the provision of flexibility (2015); pilot, demonstrate and deploy demand response for flexibility with increasing scale to 2020; improve interconnectors between power systems (2020); implement "smart grids", including continental scale and marine super-grids (2030). Improved forecasting models taken up in system operation (2015).
Manufacturing and technology	Develop advanced rotors, lighter and stronger materials (2020); improve economics of offshore foundations <40m, supply chains and installation strategies (2020); develop next generation offshore turbines and floating foundations (2020 and beyond).
Finance	Public loan guarantees and risk mitigation instruments for innovative technologies; targeted development financing and CO_2-based mechanisms.
Public support	Improved assessment and mitigation methods for socio-environmental impacts until 2020; better understanding of the environmental impacts of offshore wind deployment until 2015. Raised public awareness of value of wind energy and of the need for stronger transmission systems up to 2030.

Policy recommendations

- Where not already in place, establish long-term targets based on short-term milestones for wind energy deployment, as part of an integrated energy policy.
- Implement transitional support mechanisms that provide sufficient incentive to investors and stimulate cost reductions.
- Accelerate, harmonise and streamline permitting practices ("one-stop shop").
- Provide incentives for accelerated construction of transmission capacity to link wind resources to demand centres (using latest proven technology); establish mechanisms for cost recovery and allocation.
- Conduct public outreach programs recognising the value of wind energy as part of a portfolio of greenhouse-gas (GHG) emissions- and pollution-abatement technologies; promote the role of new transmission in achieving these goals.
- Develop methods to assess the need for additional power system flexibility for variable renewables' deployment; carry out grid studies to examine opportunities, costs and benefits of high shares of wind integration.

Energy efficient buildings: heating and cooling equipment

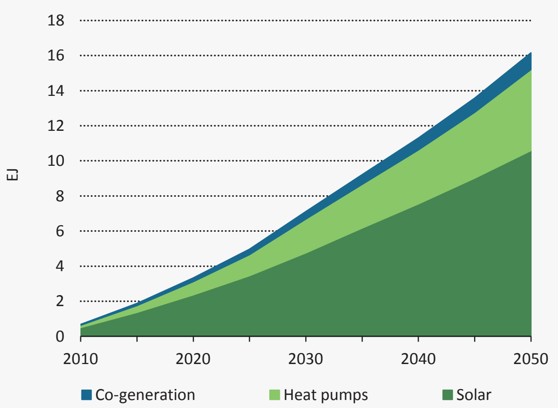
Contribution to CO_2 reductions



Investment needs

USD billion	2010-20	2020-30	2010-50
OECD Europe	312	322	581
OECD Americas	494	527	922
OECD Asia Oceania	124	125	221
Africa and Middle East	149	220	815
China	507	1 103	1 641
India	43	52	345
Latin America	58	64	161
Other developing Asia	205	269	722
Other non-OECD	24	33	256
World	**1 916**	**2 715**	**5 662**

Deployment of efficient heating and cooling



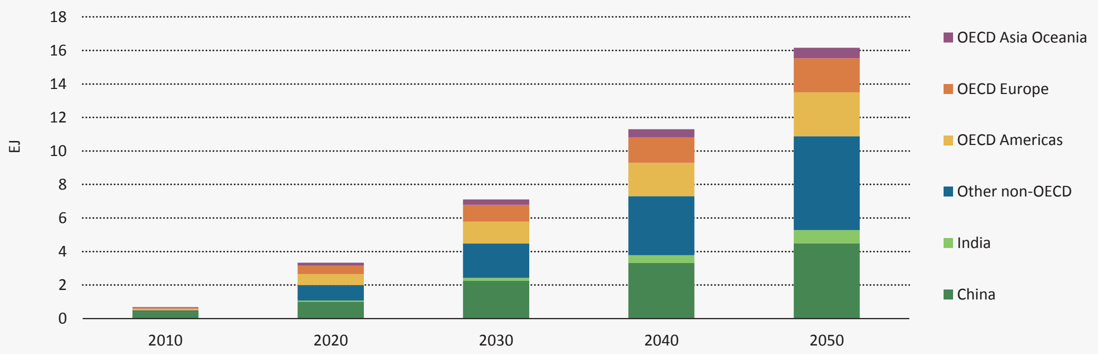
Priority actions to 2020

- Implementation of policies such as minimum energy performance standards, labelling, utility programmes and financial incentives to address market barriers and failures.
- Improvement of standard education of key professionals such as architects, designers, engineers, builders and building owners and operators/users.
- Harmonisation of performance and test procedures for heating and cooling systems.
- Expansion and/or implementation of mandatory quality assurance and certification schemes for equipment and installers by governments, and harmonisation of these across the heating and cooling industry.

Technology	Costs and performance goal to 2020
Active solar thermal	Installed capacity -30% to -50%; delivered energy cost -30% to -45%.
Thermal storage	Installed capacity -35% to -50%.
Heat pumps: space and water heating	Installed capacity -10% to -20%; coefficient of performance 10% to 20% higher.
Heat pumps: cooling	Installed capacity -5% to -15%; coefficient of performance 10% to 30% higher.
Co-generation: fuel cells	Installed capacity 20% to 40%; total efficiency 90%; delivered energy costs -15% to -35%.
Co-generation: microturbines	Installed capacity 5% to 10%; total efficiency 70% to 80%; delivered energy costs -15% to -35%.

Global deployment

Deployment of efficient heating and cooling technologies



Technology milestones

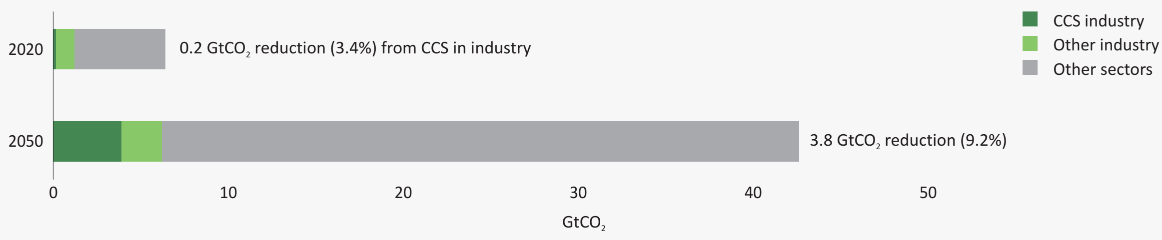
Active solar thermal	Co-generation	Heat pumps	Thermal energy storage
Integration of solar thermal collectors into building shells. Deployment of new collectors from 2015.	Polymer electrolyte membrane fuel cells (PEMFC) and solid oxide fuel cells (SOFCs) with higher efficiency and durability at lower costs.	More efficient components and systems for heat pumps. 20% improvement in coefficient of performance by 2020; 50% by 2030.	R&D collaboration with end-use technologies including active solar thermal, heat pumps and co-generation in buildings.
R&D for desiccant and sorption systems, and high-temperature solar collectors for solar cooling.	Improve micro turbine performance and efficiency. Increase flexibility of systems.	Begin deployment in 2015 of more efficient integrated heat pump systems.	Develop materials for compact thermal energy storage.
Development of systems suitable for large-scale mass production by 2020.	Develop standardised co-generation packages and operational strategies for different sectors.	Develop hybrid heat pump systems. Widespread deployment from 2020-25.	By 2015-25, develop and demonstrate systems with integrated, advanced compact thermal energy storage.

Policy recommendations

- Increase technology R&D, significant demonstration programmes and development beyond best available technologies.
- Improve information for consumers and metrics for analysing the energy and CO_2 savings of heating and cooling technologies, as well as the financial benefits gained over their life cycle.
- Enhance international collaboration in R&D, best-practice policy packages and deployment programmes to maximise the benefits of policy intervention, as well as transfer of knowledge between countries and regions.
- Convene a policy co-ordination working group to develop regulatory and policy framework for heating and cooling systems in buildings.
- Introduce a stable, long-term regulatory framework aligned with high-level goals for energy and CO_2 savings in buildings.
- Introduce a portfolio of deployment incentives to help reduce first-cost barriers and other market-based barriers. A portfolio mixing regulatory (minimum energy performance standards, utility obligations, etc.) with fiscal or financial incentives (tax rebates, cash incentives, etc.) is required.

CCS in industrial applications

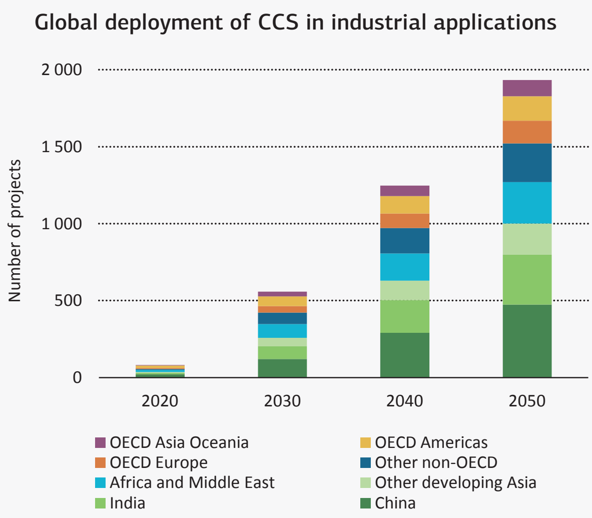
Contribution to CO_2 reductions



Investment needs

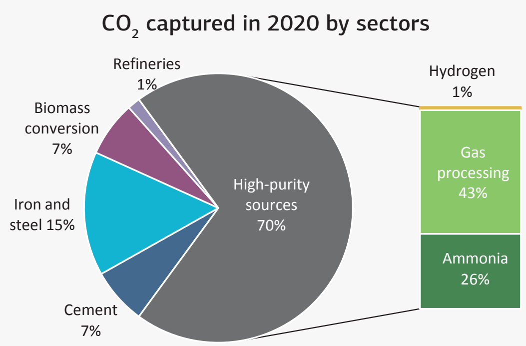
Additional investments (USD billion)	2010-20	2020-30	2030-50
OECD Europe	3	19	56
OECD Americas	5	21	46
OECD Asia Oceania	2	16	43
Africa and Middle East	3	34	99
China	6	39	163
India	4	34	125
Latin America	1	16	51
Other developing Asia	2	23	80
Other non-OECD	1	19	51
World	**26**	**221**	**714**

Note: Excludes investment needs in transport and storage.

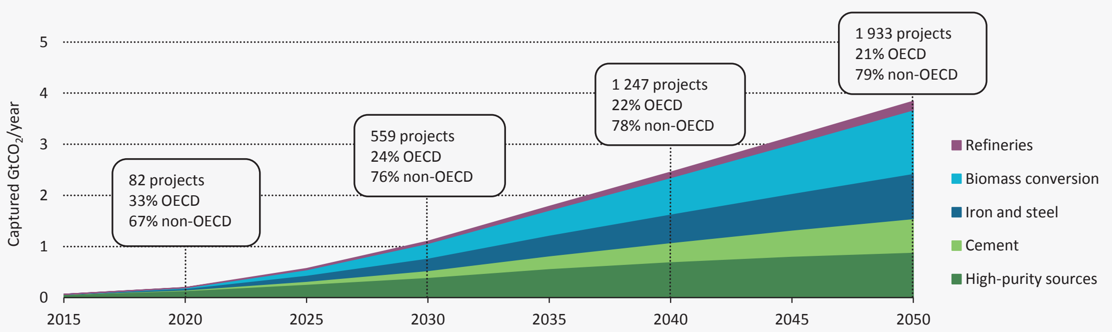


Priority actions to 2020

- USD 26 billion to fund 82 projects by 2020.
- Funding and collaboration mechanisms to support demonstration and deployment of CCS in developing countries, where some of the largest opportunities exist for industrial CO_2 capture.
- Improved data on current emissions and technologies, as well as cost data and projections.
- More global assessments of CO_2 sources and potential reservoirs, including storage opportunities in enhanced oil recovery operations.



Global deployment



Technology milestones

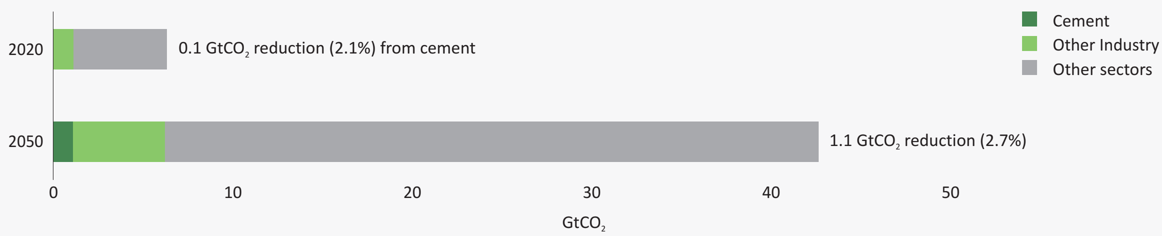
Biomass	High-purity	Cement	Iron and steel	Refineries
R&D for removal of tars from gasification.	Compile inventory of hydrogen, ammonia and ethylene oxide technologies to verify suitability for CCS.	Post combustion: improve chemical absorption solvents to reduce energy needs.	R&D in cost- effective and energy-efficient capture techniques in top gas recycling blast furnaces (TGR-BF).	Access waste heat use in solvent regeneration and capture processes.
R&D to combine shift and CO_2 capture in a single reactor, improve CO_2 capture ratio.	Establish CO_2 transport and storage demos involving hydrogen, ammonia and ethylene.	Oxyfuel: improve energy efficiency of air separation technologies.	Smelting to achieve 2 Mt per year per furnace by 2020 and have a share of 3% to 5% of total crude steel production by 2035.	R&D to combine shift and CO_2 capture in a single reactor, improve CO_2 capture ratio.
Four conversion plants with CO_2 compression, transport and storage by 2020 (one with gasification + CO_2 capture).	Realise 55 gas processing, coal- or gas-to-liquids, ethylene oxide or ammonia production plants with CCS by 2020 and 171 plants by 2030.	Post-combustion pilot before 2015, demo by 2015-20. Oxyfuel pilot by 2020, demo by 2025-30.	Full-scale TGR-BF demo by 2016, 80% of new BF and direct reduced iron (DRI) in OECD with CCS by 2030 and 60% in non-OECD.	Industrial-scale oxyfuelled fluid catalytic converter demo by 2020.

Policy recommendations

- Review opportunities for industrial CCS, or encourage industry to undertake such a review, and ensure that CCS in industrial applications is given the required attention in government scenarios and policy.
- Set up programmes to raise public awareness and understanding of the need for CCS, so that it can become part of a low-carbon industrial development strategy.
- Implement demonstration programmes that include industrial CCS.
- Design policy frameworks and provide incentives that accelerate commercial-scale CCS deployment in industry beyond the demonstration phase. Incentive policies should be analysed and then adapted to meet the specific needs of different industry sectors.
- Explore sector-based approaches, including technology transfer and mandates, for CCS policies in appropriate specific sectors, *e.g.* steel and some high-purity sources.
- Start developing a mechanism that rewards industry for achieving negative emissions through the use of biomass and CCS.

Cement sector

Contribution to CO_2 reductions

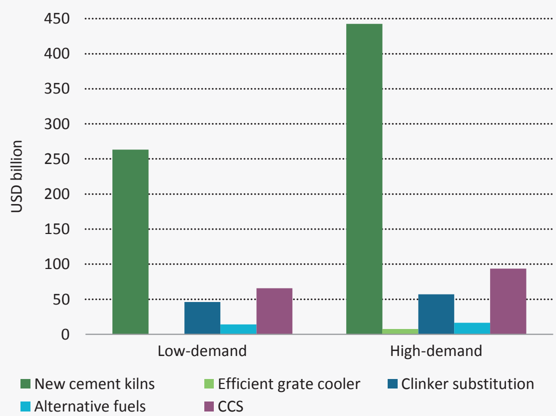


Investment needs

(USD billion)	2010-20	2020-30	2030-50
OECD Europe	18	15	39
OECD Americas	21	12	26
OECD Asia Oceania	8	6	17
Africa and Middle East	35	36	100
China	101	66	183
India	76	113	250
Latin America	17	17	35
Other developing Asia	36	36	86
Other non-OECD	14	11	24
World	**327**	**312**	**760**

Note: low demand.

Additional investment 2010 to 2050



Priority actions to 2020

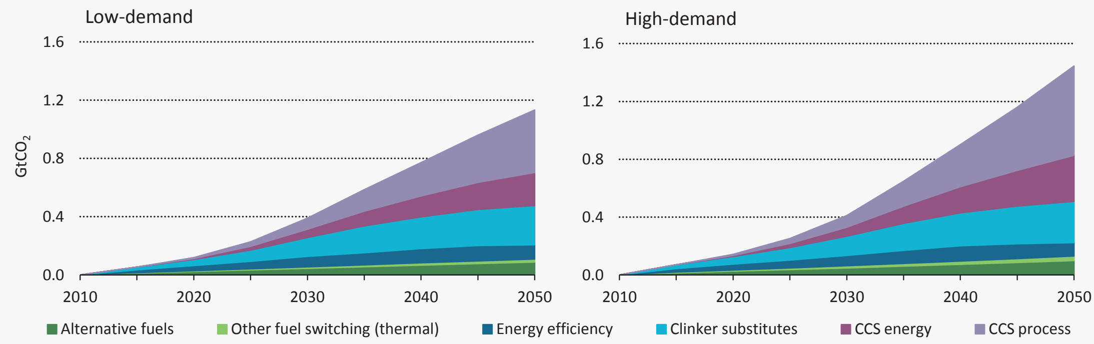
- Share best practice policies for the promotion of energy efficiency and CO_2 emission reduction measures.
- Phase out all wet and vertical shaft kilns.
- Ensure national waste disposal policies enable the full potential of co-processing in the cement industry.
- Develop new or revise existing cement standards and codes to allow more widespread use of blended cement and facilitate the use of a new generation of emerging cements.
- Governments should provide financial incentives for the demonstration of CO_2 capture technologies for cement kilns.

Roadmap targets to 2020

Low-demand case	2010	2015	2020
Thermal energy per tonne of clinker (GJ/tonne)	3.9	3.8	3.7
Share of alternative fuel and biomass use	4%	10%	12%
Clinker to cement ratio	0.80	0.78	0.77
Number of CCS pilot plants	0	0	11
$MtCO_2$ captured	0	0	13
tCO_2/t cement	0.73	0.71	0.68

Global deployment

CO_2 emissions reductions in the cement sector



Technology milestones

Energy efficiency	Alternative fuel use	Clinker substitutes	CCS
Reduce average thermal energy intensity of clinker production to 3.5 GJ/t by 2030 and 3.0 GJ/t by 2050.	Identify and classify new materials that can be used as alternative fuels.	R&D into processing techniques for potential clinker substitutes that cannot currently be used.	Complete large-scale demonstration of oxyfuel plants by 2020-25. Begin deployment on all large new kilns by 2025.
Reduce average electric energy intensity of cement production to 97 kWh/t by 2030 and 85 kWh/t by 2050 with new grinding technologies.	Alternative fuel use to reach 25% to 30% by 2030 in OECD countries and 10% to 15% in non-OECD by 2030 and 25% to 30% by 2050.	Access substitution material properties and evaluate regional availability.	Deploy 120 to 140 kilns with CCS by 2030, 300 to 400 by 2040 and 500 to 700 by 2050. Capture costs of USD 100 € (2030) and USD 75 € (2050) for PC and USD 50 € (2030) and USD 40 € (2050) for oxyfuel.
R&D to improve existing BAT by 20% by 2050.		Cement to clinker ratio reaching 74% in 2030 and 67% in 2050.	CO_2 capture to reach 0.13 Gt to 0.14 Gt in 2030, 0.37 Gt to 0.47 Gt in 2040 and 0.66 Gt to 0.94 Gt in 2050.

Policy recommendations

- Promote adoption of best available technologies for new and retrofit kilns. Phase out inefficient long-dry kilns and wet production processes. Develop and implement international standards for energy efficiency and CO_2 emissions in the cement industry.
- Encourage and facilitate increased alternative fuel use. Review and update legislation to ensure the use of alternative fuels and biomass is incentivised by policy, not limited.
- Encourage and facilitate increased clinker substitution by developing new or revising existing cement standards and codes to allow more widespread use of blended cements.
- Support the development of CCS through enhanced R&D and funding for large-scale demonstration projects.
- Encourage international collaboration and public-private partnerships on technology implementation and sharing of best practice policies to support enhanced energy efficiency and CO_2 emissions reductions.

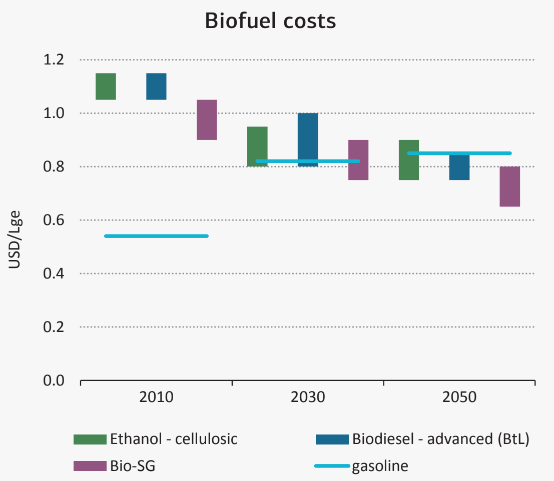
Biofuels

Contribution to CO_2 reductions

Investment needs

(USD billion)	2010-20	2020-30	2030-50
OECD Europe	182	354	1 831
OECD Americas	470	898	3 230
OECD Asia Oceania	77	241	1 347
Africa and Middle East	16	121	1 013
China	109	376	1 560
India	22	84	793
Latin America	215	352	1 281
Other developing Asia	21	131	909
Other non-OECD	16	42	274
World	**1 128**	**2 599**	**12 239**

Note: Investment needs represent total fuel purchases.

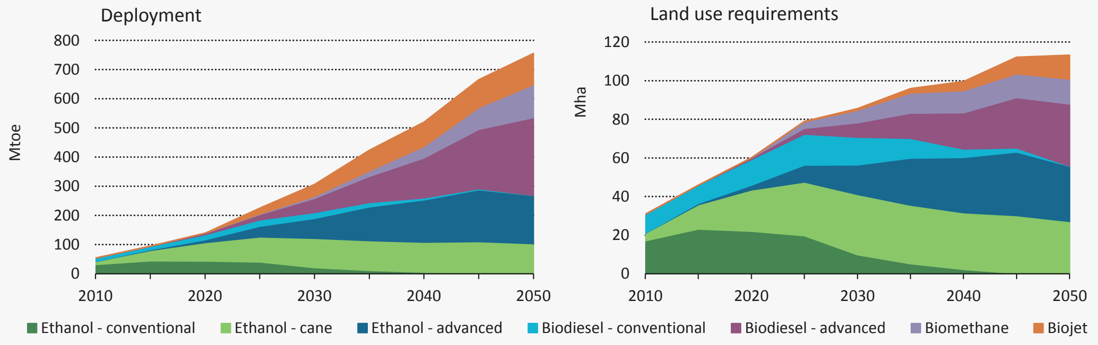


Priority actions to 2020

- Introduce sound support mechanisms for commercialisation of advanced biofuels.
- First of their kind commercial-scale biomass-to-liquids (BtL), cellulosic-ethanol, and bio-synthetic gas (bio-SG) plants.
- Ensure sustained funding and support mechanisms for promising advanced biofuel technologies to reach commercial production within the next 10 years.
- Initiate large-scale feedstock trials in different world regions to exploit the potentials of different feedstocks.
- Establish sustainability targets and certification schemes for biofuels, based on internationally agreed criteria.
- Increase research efforts on feedstock and land-availability mapping to identify the most promising feedstock types and locations for future scale-up.

Global deployment

Biofuels deployment and land use requirements



Note: This is gross land demand excluding land use reduction potential of biofuel co-products.

Roadmap milestones

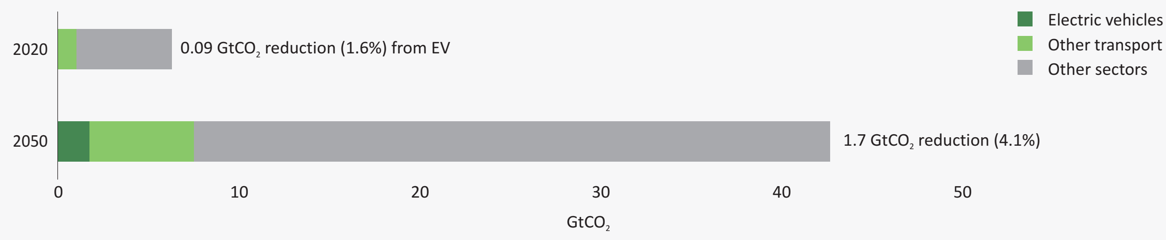
Conventional biofuels	Advanced biofuels	Feedstocks	Sustainability
Further improved process efficiency, including reduced energy use.	Enhance feedstock flexibility and improve enzyme/catalyst efficiency.	Large-scale field trials and breeding efforts for promising feedstocks in different world regions.	Introduce sound, internationally aligned sustainability criteria.
Advanced process integration to create more added value from co-products.	Reduce costs through more efficient processes, better energy efficiency, and more profitable co-product integration.	Further refine analysis of existing land and feedstock potentials on the ground.	Link economic incentives for biofuel production to their sustainability performance.
Improved life-cycle GHG savings.	Introduce commercial-scale production units for promising technologies.	Reduce trade barriers to support international feedstock trade.	Introduce land-use policies for biofuels and bioenergy, and integrate with agricultural and forestry policies.

Policy recommendations

- Create a stable, long-term policy framework for biofuels to increase investor confidence and allow for the sustainable expansion of biofuel production.
- Introduce mandatory sustainability requirements based on internationally aligned certification schemes.
- Link financial support schemes to the sustainability performance of biofuels to ensure >50% lifecycle GHG emission savings for all biofuels. Incentivise use of residues and wastes.
- Reduce and eventually abolish tariffs and other trade barriers to enhance sustainable biofuel trade.
- Support international collaboration on capacity building and technology transfer to promote the adoption of sustainable biofuel production globally.

EV/PHEV

Contribution to CO_2 reductions



Investment needs

(USD billion)	2010-20	2020-30	2030-50
OECD Europe	43	275	1 380
OECD Americas	36	248	1 473
OECD Asia Oceania	28	154	853
Africa and Middle East	3	73	768
China	150	674	4 150
India	7	67	1 536
Latin America	3	33	333
Other developing Asia	10	49	417
Other non-OECD	3	36	274
World	**283**	**1 609**	**11 183**

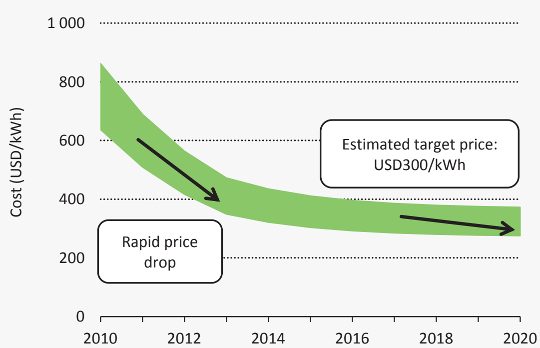
Note: Powertrain (engine) investments only.

- Current status of investment is at nearly USD 10 billion in fiscal, infrastructure and RD&D investment over 2009-11 time frame. In 2010-20, bringing battery costs down will be the high priority; in 2020-30 building up recharging infrastructure; and in 2030-50 shortening charging times.
- Public investment needs are estimated to be USD 23 to USD 45 billion per year in order to reach the 2DS outcomes by 2050. This includes vehicle subsidies, recharging infrastructure and RD&D.
- The number of models of PHEVs and EVs being released into the market is rapidly increasing and is projected to be 50% each of PHEV and EV models by 2020, *i.e.* 40 PHEV models and 20 EV models by 2020.

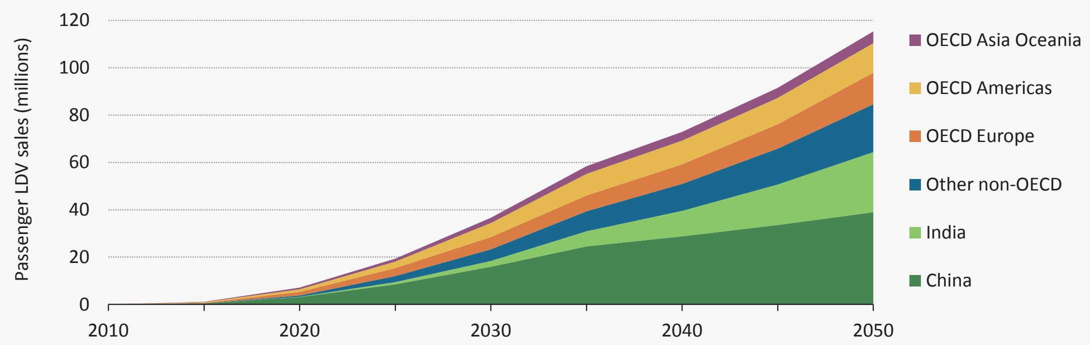
Priority actions to 2020

- Adequate incentives for PHEV/EV purchase and production in line with targets; co-ordination of recharging infrastructure development in urban areas.
- Low- and medium-volume production, with design optimisations to 2015, then rapidly increasing numbers of models offered and average production volumes; battery and other costs decline to target levels.
- Plugs and charging systems compatible across major regions, including basic "smart metering" systems for home and public recharging stations; protocols for fast recharging.

Battery costs through 2020



Global deployment



Technology milestones

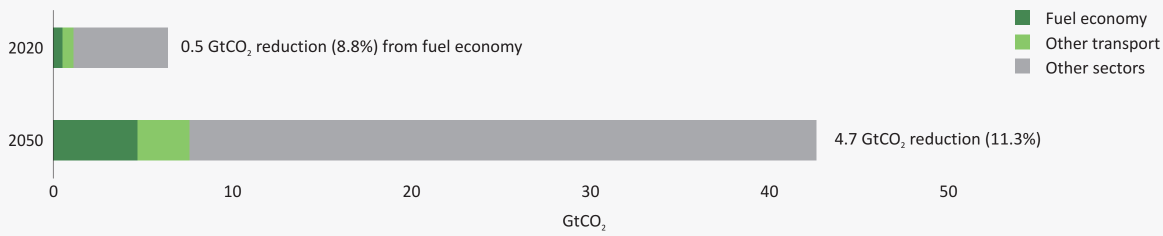
2050: Plug-in hybrid and electric vehicle sales 100 million (Global market share 60%)	
Policy framework	Availability of higher-power/energy-dense batteries should position policy makers to encourage remaining segments of light-duty vehicle market to "go electric," including greater use in larger, longer-distance vehicles.
Vehicles/batteries	EVs achieve superiority to internal combustion engines in most respects, and close the gap in driving range.
Codes/standards	Codes and standards refined as needed; modified to accommodate innovations in batteries, smart grid systems, etc., but to minimise the need for reinvestment in existing systems.
Recharging/electricity infrastructure	Ongoing recharging infrastructure and generation system expansion and refinement as needed, with ongoing increase in systems and capacity to handle fast charging.
RD&D	Focus on improving battery performance to maximise vehicle driving range.

Policy recommendations

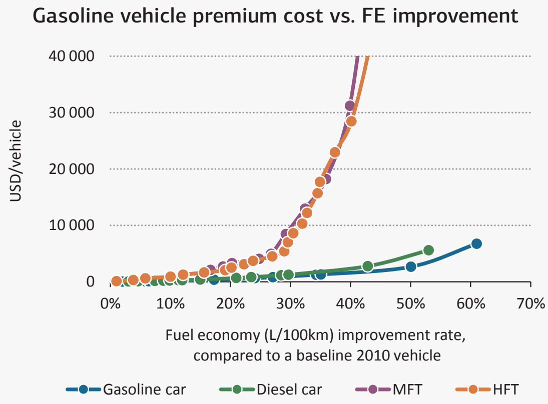
- Make policy support a priority, especially in two areas: ensure vehicles become cost-competitive through market-supportive feebates and other financial instruments; and provide adequate recharging infrastructure to support both home charging and construction of public fast-charging facilities.
- Put the consumer first by improving understanding of consumer needs and desires, as well as consumer willingness to change vehicle purchase and travel behaviour. Implement information campaigns to assuage range and fuel economy anxiety.
- Measure performance using the IEA roadmap's set of proposed metrics and targets for key attributes like driving range (enough to cover at least 95% of all trip lengths) and battery requirements (battery costs below USD 300/kWh), to ensure that PHEVs/EVs achieve their potential.
- Continue research, development and demonstration in order to reduce battery costs and ensure adequate materials supply. Conduct research on smart grids and the vehicle-grid interface as well. In total, public investment in EV technology innovation needs to increase five to tenfold over the next 5 to 10 years.

Fuel economy

Contribution to CO_2 reductions



Investment needs



- The cost of fuel economy improvements ranges from very low for some technologies to several thousand USD per vehicle for others (such as full vehicle hybridisation).
- Automakers are expected to finance all technology additions and pass costs through to consumers.
- Total additional investment costs per vehicle to consumers reach USD 1 000 in 2020 and USD 4 000 by 2050.
- Truck technologies appear to be more expensive than cars after a 30% improvement. Relative to the vehicle purchase price, the difference between cars and trucks is significantly smaller.

Priority actions to 2020

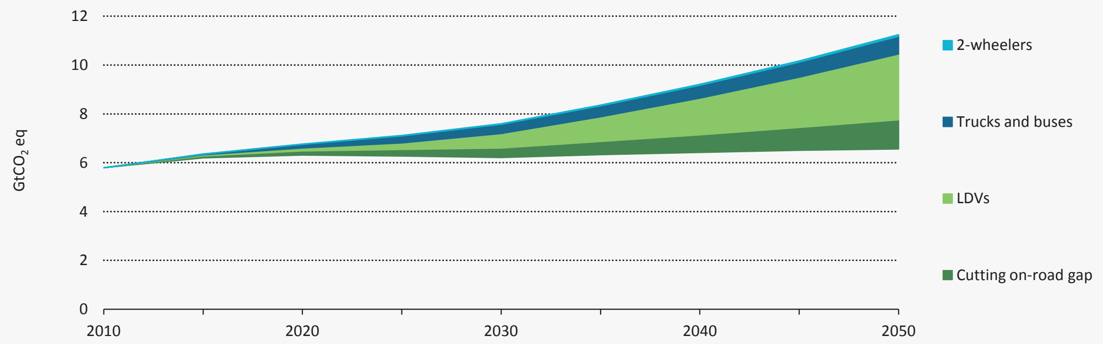
- Achieve comprehensive fuel economy policies (including labelling and standards) in all major economies by 2015. Tighten standards in all countries that have them by 2020.
- In other countries, implement labelling and standards or at least fiscal incentive programs that tax “gas guzzlers” higher than efficient vehicles. Such sliding-scale taxes could also promote new technologies like EVs, or be technology-neutral.
- Create in-use fuel economy campaigns and better track the in-use fuel economy of vehicle fleets around the world.

Roadmap targets to 2020

Low-demand case	2005	2008	2020	Annual change 2005-08	Required annual change 2005-20
OECD average	8.21	7.66		-2.10 %	
Non-OECD average	7.49	7.68		0.30 %	
Global average	8.07	7.67		-1.70 %	
Roadmap target	8.07		5.7		-2.3 %

Global deployment

CO_2 reductions from fuel economy in the 2DS



Note: Cutting on-road gap includes savings from cutting on-roadmap gap with off-cycle methods (*e.g.* eco-driving, traffic flow improvements).

Technology milestones

Policy framework	Full policy package in place in OECD countries and in all major emerging economies by 2015; other economies adopt at least fiscal policies.
Fuel economy improvements	2020: vehicles show substantial improvements compared to 2010; new light-duty vehicles (LDVs) should be below 6 L/100 km on average around the world; by 2030, Global Fuel Economy Initiative (GFEI) target of 4 L/100 km should be attained. New trucks should reach 30% to 40% reduction in fuel intensity compared to 2005 levels by 2030.
Testing/labelling	By 2015, all countries should have a rating system for vehicles and publish this via labelling and other information programmes. By 2020, countries should have evolved their own testing systems as needed to reflect their own in-use conditions.
Fiscal regimes	By 2015, countries should remove fuel subsidies and implement sliding scale vehicle taxation systems to encourage consumers to buy efficient vehicles.
RD&D	Ongoing funding support is needed to develop new technologies and reduce technology costs (*e.g.* hybrids).

Policy recommendations

- All countries should implement vehicle fuel economy labelling systems as soon as possible.
- Large market countries should adopt standards for cars and trucks, and tighten these over time.
- All countries should implement fiscal policies to encourage sales of more fuel-efficient vehicles, with higher taxes on “gas guzzlers”. This could be based on fuel economy or CO_2 emissions per kilometre, since the two are highly correlated. This can be applied to imported cars as well.
- Countries within the same region (*e.g.* South America, Southeast Asia) should consider adopting common or at least similar policies, to encourage manufacturers to change vehicle designs for the common market, and help cut the cost of compliance.

2075: Can We Reach Zero Emissions?

If the energy and technology trajectories in the 2DS through 2050 are extended to 2075, a zero carbon-emissions energy system appears within range, but is not quite achieved. Development of additional "breakthrough" technologies in key areas will help increase the likelihood of meeting this very long-term target.

Key findings

- ***Based on Intergovernmental Panel on Climate Change (IPCC) scenarios, net energy-related carbon dioxide (CO_2) emissions may need to reach zero by 2075 under the ETP 2012 2°C Scenario (2DS).*** *This appears possible, but will be very challenging, even if 2050 targets are met in the 2DS. It depends on many factors that, given the distant time frame, are highly uncertain. Trends projected in the 2DS through 2050 for energy service demand and technology penetration will get close if they continue through 2075, but a gap remains that may need to be closed with additional (i.e. breakthrough) technologies.*

- ***In the extended 2DS, renewables in 2075 provide more than 50% of energy, of which the majority is wind, geothermal, solar and bioenergy.*** *Total energy use rises to 800 EJ, compared with about 700 EJ in 2050, largely due to increased electricity demand as more activities are electrified. The use of coal and oil, in contrast, falls from about 200 EJ to just over 100 EJ by 2075. All coal power plants and the majority of gas-fired plants are equipped with carbon capture and storage (CCS). Energy efficiency continues to improve, but at a declining rate.*

- ***Bioenergy plays an important role in determining the CO_2 reduction potential to 2075.*** *If biomass use is frozen at 2050 levels (for example, due to land use constraints), CO_2 emissions in 2075 are significantly higher than if it can continue to grow, at least with the technology portfolio considered in ETP 2012.*

- ***Electricity demand grows by 40% between 2050 and 2075, due to ongoing electrification of energy services.*** *Already by 2050, electricity is essentially decarbonised with an average global CO_2 intensity of 60 grammes per kilowatt-hour (g/kWh) and total emissions of 2.4 gigatonnes of CO_2 ($GtCO_2$). By 2075, emissions are cut further to 0.2 Gt through ongoing deployment of renewable technologies, which provide about 70% of electricity generation. Most of these technologies are already used today.*

- ***Integrating variable renewable sources in the electricity system will be key,*** *and will require a mix of grid expansion, flexible generation plants, demand-side management and storage technologies. Nuclear power continues to play an important role, but will depend on successful exploration of uranium* *resources and the introduction of fast-breeder reactors to reduce uranium consumption.*

- ***Achieving a zero-carbon energy future in industry will be a challenge.*** *Steady growth in the production of key materials after 2050 will continue to drive up energy consumption. Full implementation of best available technologies (BAT) in the 2DS could contain CO_2 emissions between 2050 and 2075, but achieving a deep reduction in CO_2 emissions over this time period could require additional breakthrough technologies that currently are in the research and development (R&D) phase.*
- ***Transport does not reach zero without substantial additional biofuels or new breakthroughs.*** *Transport activity growth rates slow for both passenger and freight travel after 2050, and with ongoing efficiency improvements, total energy use in the 2DS flattens to 2075. Electricity and hydrogen application in transport continues to expand, but without new technologies, limits are reached. Most of the remaining CO_2 in 2075 is in shipping and aviation, which could be virtually eliminated with sufficient quantities of advanced biofuels.*
- ***Buildings, already down to 2 $GtCO_2$ in 2050, cut this in half by 2075.*** *In the 2DS, most of the existing building stock in OECD countries is refurbished by 2050 and new houses are built using best available technologies and designs. Further improvements can only be gained in end-use equipment and switching from fossil fuel to carbon-neutral energy sources. Reaching zero emissions in 2075 would require an earlier and stronger move away from the use of fossil fuels, which appears problematic in some regions.*

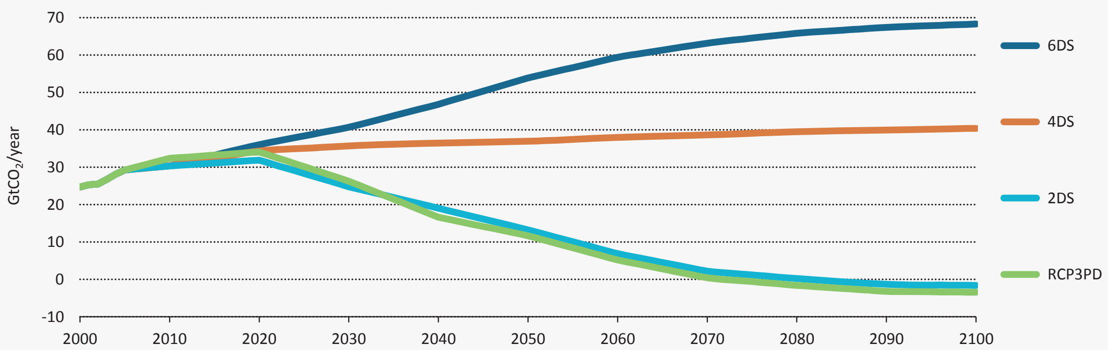
Opportunities for policy action

- *The ETP 2012 analysis to 2075 reinforces the need to maintain a strong research focus on potential breakthrough technologies. The technologies under consideration in ETP 2012, which together can provide deep CO_2 reductions to 2050, may not be sufficient to reach zero emissions in 2075, and countries must continue to develop other (particularly breakthrough) technologies, a range of which are described here.*
- *Hydrogen may play an important long-term role. As one of the three main potentially zero-carbon energy carriers, hydrogen may play an increasingly important role after 2050, in part to help limit reliance on bioenergy. To do so, it must be introduced in a range of applications and sectors well before 2050, since it can take several decades to ramp up systems to scales that can make a significant difference. More research is needed in this area.*
- *Ongoing research on bioenergy potentials is needed to better establish upper bounds for sustainable production, likely geographic sources, etc. In order to avoid drifting towards over-reliance on bioenergy and biofuels, more reliable and detailed estimates of sustainably available biomass are needed. Research should also address likely future changes in land use and trends in biomass demands for other purposes. One key question is whether there will be more biomass available for energy use in the very long term (2075) compared with the long term (2030-50), or less.*

ETP 2012 focuses on the technological and policy pathways to 2050 for an energy system that is consistent with limiting temperature rise to 2°C. Long-term climate impacts of scenarios also depend, however, on how emissions develop beyond the main outlook period.

To explore this longer time frame, this chapter highlights findings obtained when extending the 2DS beyond 2050 (it does not consider 4DS or 6DS extensions). To assess what further reductions in energy-related CO_2 emissions are necessary, the extended 2DS was compared with the representative concentration pathways (RCPs), which were developed to be assessed by all Working Groups for the IPCC 5th Assessment Report.[1] The extended 2DS emissions pathway is slightly more aggressive in reductions than the RCP3PD, a scenario that the climate science literature indicates would result in an 80% chance of keeping long-term temperature rise below 2°C (Figure 16.1).

Figure 16.1 **Long-term energy-related CO_2 emissions derived from ETP scenarios and compared with RCPs.**



Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *Energy-related CO_2 emissions need to be completely eliminated by 2075 in order to limit global temperature rise to 2°C.*

Energy-related CO_2 emissions need to be virtually eliminated by 2075 if temperature rise is to stay below 2°C (Figure 16.1). This chapter extends the 2DS and explores what options exist to bring energy-related CO_2 emissions down to zero by 2075. It looks at this issue by asking several interrelated questions:

- If continued, are the trends established in the 2DS by 2050 sufficient to reach zero emissions in 2075? If not, what emissions level do they achieve (*i.e.* how much above zero)?
- If a gap exists, could it be closed through accelerated deployment or more complete market penetration of the technology portfolio in *ETP 2012* through 2050?
- What contribution could other technologies make in the 2050 to 2075 time frame? What technology breakthroughs would help achieve the goal?
- What implications do post-2050 requirements have on policy priorities in earlier periods?

A particular emphasis is placed on the role of bioenergy in affecting zero emissions, since ongoing expansion of bioenergy use, particularly if combined with carbon capture and storage (BECCS), can help achieve zero emissions across the energy system. There is, however, a high degree of uncertainty regarding the sustainability of higher use of bioenergy. Its use is considered using a comparison of 2DS variants with and without the

1 The RCPs (Van Vuuren *et al.*, 2011; Moss *et al.*, 2010) have been developed as part of the work for the IPCC Fifth Assessment Report (AR5) and are scenarios with emissions pathways that the scientific literature on climate change indicates are consistent with different levels of radiative forcing and resulting temperature rise. There are four RCPs, and the extensions of the 2DS were based the RC3PD. Assumptions on associated emissions from other sectors as well as emissions of non-CO_2 greenhouse gases (GHGs) and aerosol precursors were included, and the emissions pathways were then assessed using the MAGICC6 climate model (Meinshausen *et al.*, 2011).

expansion of bioenergy beyond 2050 levels, particularly for electricity generation along with biofuels for transport. The potential role of other technologies is also affected by the long-term use of bioenergy.

Box 16.1 Long-term emissions pathways

Eventually (beyond 2100), emissions will need to come down to near-zero levels in all scenarios that seek to stabilise temperature not just in the 2DS. This is often overlooked in public debate, but can be simply explained through the dynamics of the carbon cycle.

In a natural (stable) situation, the processes removing CO_2 from the atmosphere (*i.e.* drawing it into the oceans and biosphere) are in equilibrium with those that add CO_2 to the atmosphere. Historical and current anthropogenic emissions data imply that such equilibrium does not currently exist; the additional CO_2 emissions from combustion of fossil fuels, industrial processes and land-use change together add more CO_2 to the atmosphere than is removed by the natural flows. As a consequence, the CO_2 concentration in the atmosphere is increasing rapidly.

In principle, this situation temporarily enhances the natural CO_2 removal rates from the atmosphere to the biosphere and ocean. But the enhanced removal is uncertain: the global warming and ocean acidification impacts associated with increased CO_2 concentration may also destabilise the natural processes that remove CO_2 from the atmosphere. In order to stabilise CO_2 concentrations, the anthropogenic and natural emissions combined need to return to a level equal to the current (enhanced) natural removal rate.

By the end of the 21st century, the extra emissions could still be in the order of a few gigatonnes of CO_2 ($GtCO_2$) per year. In the long run, however, the storage of CO_2 in oceans and biosphere will return to equilibrium with the atmosphere, thereby reducing the net natural removal over the natural emissions back to zero. Overshoot scenarios that aim to profit somewhat from increased short-term emissions levels should have emissions below the net natural removal rate. These scenarios critically depend on low (often negative) emissions in the second half of the 21st century in order to return to low concentration levels quickly enough.

Underlying assumptions in the 2DS for 2075

As this chapter examines only the 2DS, it is not dependent on comparisons to a baseline projection of energy use. It still depends, however, on an underlying projection of economic activity and energy service demand through 2075 as a basis for the *likely* energy use associated with a certain set of technologies, fuel types and energy efficiency levels in the 2DS. Given the distant time frame and inherent uncertainties, a simple approach has been taken in which trends in the 2040 to 2050 time frame are extended, with a number of dampening assumptions (Table 16.1). The projection shows slowly declining growth rates for gross domestic product (GDP), a continuation of the slow decline, in percentage terms, of growth rates throughout the 2009 to 2050 time frame. Some additional decoupling is assumed between activity and GDP, such as in the growth of building stocks and increases in travel, reflecting maturing markets, slowing population growth and some saturations.

The underlying forecast of population growth reflects UN projections, which show the world's population of 6.7 billion in 2009 growing at an average annual rate of 0.78% to reach 9.3 billion in 2050 (UN DESA, 2011). A subsequent slowdown leads to a projected population of 9.9 billion in 2075. This growth will be almost entirely in non-OECD countries, with only a marginal increase in OECD countries' population. Population growth remains a driver in global energy use, but becomes less significant over time.

Global GDP (in USD 2010 at purchasing power parity [PPP]) is expected to grow by 3.3% per year between 2009 and 2050 (Table 16.1); it is expected to slow to 1.8% per year between 2050 and 2075.

Table 16.1 GDP projections (CAAGR)

	2009-20	2020-30	2030-50	2009-50	2050-75
World	4.2%	3.1%	2.9%	3.3%	1.8%
Brazil	4.3%	3.3%	3.0%	3.4%	2.8%
Russia	4.1%	3.3%	2.4%	3.1%	1.8%
India	7.7%	5.9%	4.8%	5.8%	3.9%
China	8.1%	4.4%	3.2%	4.8%	2.4%
South Africa	3.6%	2.6%	2.9%	3.0%	3.1%
Mexico	3.7%	3.1%	2.8%	3.1%	2.4%
United States	2.6%	2.2%	2.1%	2.3%	2.1%
European Union	2.0%	1.8%	1.7%	1.8%	1.6%
ASEAN	5.3%	3.5%	3.8%	4.1%	3.9%

Notes: CAAGR = compounded average annual growth rate; ASEAN = Association of Southeast Asian Nations.
Sources: IMF, 2011 (for 2011-16); IEA analysis.

In terms of behaviour change, the 2075 extension assumes only gradual shifts in societal activities, and includes no major discontinuities such as a sudden shift to a much lower emphasis on material goals or video substitution for travel. However, the relatively robust use of public transit modes that is part of the 2DS through 2050 is continued.

There is considerable uncertainty in these projections: if actual demand for materials and services in 2075 is much higher than what is assumed in *ETP 2012*, fuel demand will also be higher at a given level of energy efficiency. But regardless of demand and efficiency level, the only way to reach a zero-emissions energy system is to use solely zero-emission fuels: primary fuels must either be renewable, nuclear or fossil with CCS, and the carriers delivering final energy must be electricity, hydrogen or biofuels (or possibly another non-carbon option such as ammonia or compressed air). Better efficiency will have the very important impact of requiring less energy – *i.e.* less of these zero-carbon fuels and energy carriers – but it won't change the fundamental picture, that such fuels are absolutely needed and all net-carbon-emitting fuels must be eliminated (or employ CCS).

From a modelling perspective, the exercise is not especially difficult: the first step is to extend the 2050 projections, including the penetration rates of key technologies, to 2075. In the 2DS, these technologies, such as wind, solar, CCS, new technology (and alternative fuel) vehicles, efficient industrial processes and appliances, are mostly well on their way to mass market penetration by 2050, so this process continues. In some cases, they may reach 100% market share before 2075, or they may be prevented from reaching 100% for various reasons, and effectively arrive at a saturation point. The assumptions and projections for a range of key technologies are provided in the sectoral discussions below.

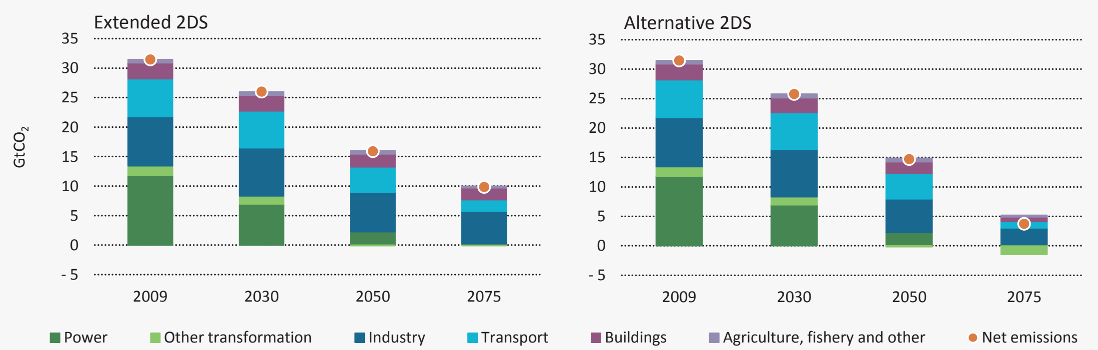
If this extension of the 2050 2DS, succeeds in reaching zero CO_2 emissions by 2075, and if it is apparent that emissions won't rise thereafter, then the goal is achieved. This would suggest that the technologies considered in *ETP 2012* can achieve the goals of the 2DS over the very long term. However, if not, it is worth considering how the gap could be closed, either through faster or deeper penetrations of the given set of technologies, or through additional technologies. This is considered in an alternative 2DS variant.

CO_2 emissions results for 2075

The overall results of the exercise, in terms of CO_2 emissions, indicate that if bioenergy use is kept at its 2050 level of about 160 exajoules (EJ), the extended 2DS reaches approximately 10 $GtCO_2$, well above the zero-emissions target. Allowing biomass and bioenergy use to rise significantly to 2075 in the alternative 2DS case approaches the target (about 4 $GtCO_2$), but raises sustainability concerns (Figure 16.2).

In the extended 2DS with bioenergy held at 2050 levels, power generation approaches zero net CO_2 emissions in 2075, but significant emissions remain from buildings, transport and particularly industry. As discussed for each demand sector below, constraints exist that prevent the complete elimination of fossil fuels from these sectors. In the alternative 2DS case for 2075, with further expansion of 2050 bioenergy use, the gap is cut by more than half. Increased use of bioenergy could provide two key benefits: additional near-zero-emission biofuels use in transport, compatible with long-haul trucks, ships and aircraft (which may have few other options to reach zero emissions), and the introduction of negative emissions related to bioenergy production and use in industry.

Figure 16.2 CO_2 emissions in the extended and alternative 2DS cases



Key point *CO_2 emissions get closer to zero in 2075 in the alternative 2DS case, but remain at 4 $GtCO_2$.*

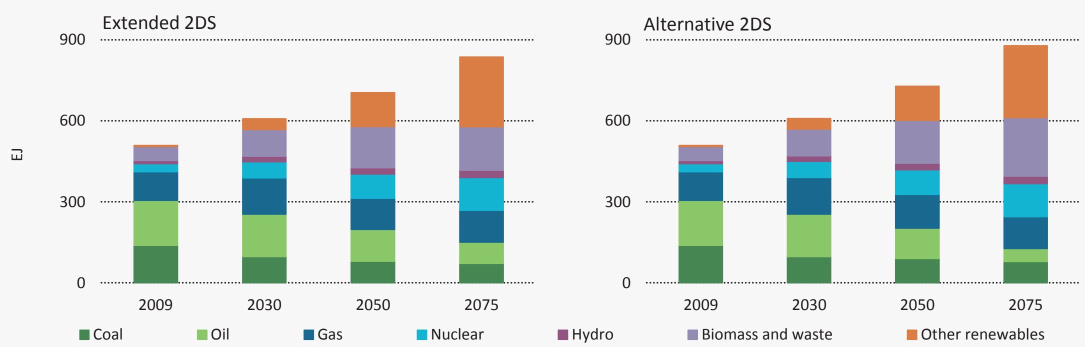
The negative emissions result primarily from BECCS, whereby crops sequest carbon from the atmosphere. This carbon is captured again as biomass and used at the generation plant, allowing it to be stored in the ground. In 2075, a total of around 4.2 $GtCO_2$ are captured from BECCS plants using bioenergy in biofuel production, power generation or the industry sector, compared with an annual amount of around 1.6 $GtCO_2$ captured from BECCS plants in 2050. The role of BECCS is clearly central to these results, and represents an important technology innovation.

Energy use to 2075

The results for CO_2 emissions are rooted in the energy-use projections through 2075. Overall, primary energy use from 2050 to 2075 follows a logical extension of the patterns and trends in the 2040 to 2050 time frame: coal, oil and gas are in decline, while nuclear, wind and solar energy (and other renewables) keep growing to handle the overall growth in energy use (Figure 16.3). In the extended 2DS case, renewables rise from 300 EJ in 2050 to about 450 EJ in 2075. Primary coal demand, mainly in CCS plants in the industry and power sectors, remains flat at a level of 70 EJ, whereas oil demand falls from 110 EJ in 2050 to 75 EJ in 2075 in the extended 2DS and to 50 EJ in the alternative 2DS.

The majority of growth in energy use is for electricity production, and in the alternative 2DS case, considerably more bioenergy is used for electricity generation, industrial use and transport. Total bioenergy use rises from 160 EJ in 2050 to 220 EJ in 2075. The transport sector is responsible for the largest part of the increase, with biomass feedstock used for producing transport fuels (including liquid fuels as well as bio-hydrogen and bio-SNG) increasing from 70 EJ to 105 EJ. Bioenergy use in industry grows by 15 EJ between 2050 and 2075, followed by an additional consumption of 10 EJ in the power sector and of 5 EJ in the buildings sector.

Figure 16.3 **Total primary energy use in the extended and alternative 2DS cases**



Key point *Renewables double between 2050 and 2075, and almost no oil use remains in 2075 in the alternative 2DS case.*

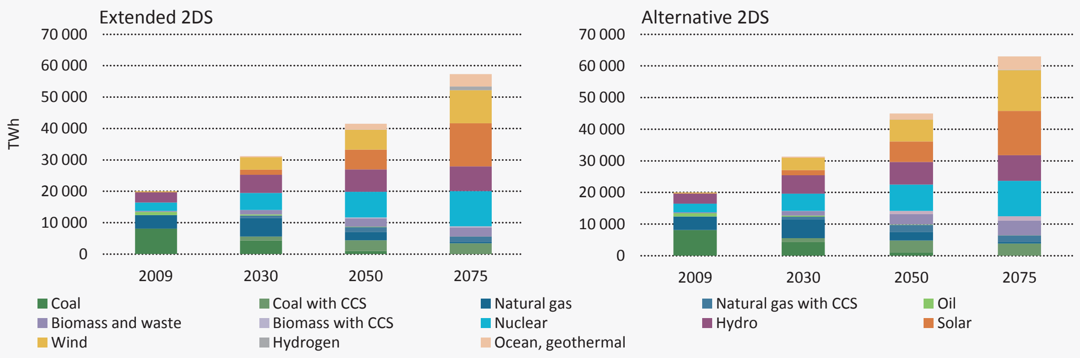
Electricity generation

Electricity generation grows strongly after 2050 in the extended 2DS, increasing approximately 40% to around 60 000 TWh by 2075 (Figure 16.4). Demand growth is driven by a strong increase in electricity use in buildings, industry and transport, and also in the fuel transformation sector, where electricity is used to produce hydrogen via large-scale electrolysis for the transport and industry sectors.

By 2075 in both 2DS variants, 99% of electricity is produced from low- or zero-carbon technologies. The majority of growth in demand between 2050 and 2075 is responded to by renewable sources, whose share in the electricity generation mix increases from 60% in 2050 to more than 70% in 2075. To reach this level of renewables in 2075, the deployment of renewable technologies must be accelerated even before 2050, with electricity generation from renewables in 2050 12% higher in the alternative 2DS case than the extended 2DS. Nuclear maintains its 2050 share of around 20% of generation. The remainder is based on coal- and gas-fired plants in combination with CCS.

Power generation has remaining emissions of 0.2 $GtCO_2$ in 2075, thus is essentially carbon-free (CO_2 intensity is lower than 1 gCO_2/kWh in 2075). To allow the continued use of coal plants with CCS, co-firing of biomass is needed. Without co-firing, the CO_2 intensity of a coal plant with CO_2 capture would be around 120 g/kWh. By blending 10% biomass with the coal, the carbon intensity falls to 30 g/kWh, since the captured carbon from the biomass input leads to negative emissions, which offset a large part of the non-captured emissions from coal. In addition to coal with CCS, 80% of all gas-fired plants are equipped with CCS in 2075, corresponding to a capacity of 600 GW. Overall, the annual amount of CO_2 captured in the power sector increases in the alternative 2DS variant from around 3.5 Gt in 2050 to almost 5 Gt in 2075, with around 80% of the captured CO_2 coming from fossil fuel power plants.

Figure 16.4 **Global electricity generation in the extended and alternative 2DS cases**



Key point *Power generation utilises 99% low- or zero-carbon technologies in 2075 in the 2DS.*

The status of a range of electricity technologies that are important in 2050 and 2075 in the 2DS is shown in Table 16.2. Nuclear power continues to play an important role, but must continue to evolve. The cumulative nuclear generation between 2009 and 2075 would correspond to a requirement of around 9.6 megatonnes of uranium (Mt U), if based on a once-through fuel cycle with light-water reactors. This amount exceeds the 6.3 Mt of identified conventional uranium resources available at costs below USD 260/kg U (NEA/IAEA, 2010). Although increased uranium demand is likely to lead in the future to increased exploration efforts and to the discovery of additional conventional uranium resources, the commercial deployment of advanced nuclear reactors (fast reactors) and fuel cycles has to begin after 2040 in the 2DS, or efforts in the exploration of unconventional uranium resources must be intensified. The unconventional uranium contained in phosphate rocks could result in 22 Mt of additional uranium resources, but more exploration is needed to confirm these estimates (NEA, 2008). Also, thorium, which is more abundant than uranium in the earth's crust, could be used as a fuel in nuclear generation, but the development of dedicated thorium fuel cycles is required. They have been demonstrated in several countries, though not yet developed to a commercial scale. Assuming that only the mentioned 6.3 Mt U of conventional resources are available, fast breeder reactors will provide around 60% of nuclear generation by 2075. Without fast breeder reactors and relying solely on once-through fuel cycles, nuclear generation would have to fall to around 1 400 TWh in 2075. The attainment of 11 000 TWh of nuclear generation with fast breeder technology would then require a much larger deployment of renewables and CCS in the power sector.

Table 16.2 Electricity technologies in 2075 in the 2DS

Technology	2050 status	2075 status	Comments
Concentrating solar power	8% in global electricity generation	13% in global electricity generation	
Solar PV	7% in global electricity generation	9% in global electricity generation	
Wind power	15% in global electricity generation	20% in global electricity generation	
Nuclear power	18% in global electricity generation	19% in global electricity generation	60% of generation based on fast breeder reactors in 2075.
Geothermal power	3% in global electricity	5% in global electricity generation	75% of geothermal generation based on enhanced geothermal systems in 2075.
Biomass power	10% in global electricity generation (alternative 2DS variant)	10% in global electricity generation (alternative 2DS variant)	In extended case, absolute power generation remains constant and relative share in power generation drops to 6%.
Hydro power	1 780 GW installed capacity	2 000 GW installed capacity	

Generation from renewable sources continues to grow after 2050 in the 2DS. Solar and wind each cover around one-fifth of the global electricity demand in 2075. Geothermal generation doubles from about 1 500 TWh in 2050 to 3 000 TWh in 2075. This increase in geothermal generation is largely based on enhanced geothermal systems (EGS), which exploit heat stored in low-permeable rocks. To reach the level envisaged in 2075 for EGS, its deployment has to be accelerated before 2050, compared with the 2DS ending in 2050.

Ocean energy, comprising several technologies such as wave energy, tidal stream energy, tidal range energy, ocean thermal energy conversion (OTEC) and salinity gradient power, could also play a larger role after 2050. Its installed capacity doubles by 2075 to around 500 GW. Pilot plants of various types of ocean energy technologies are already being tested today, but large-scale demonstration is needed to gain more experience in operating these technologies under often harsh offshore conditions.

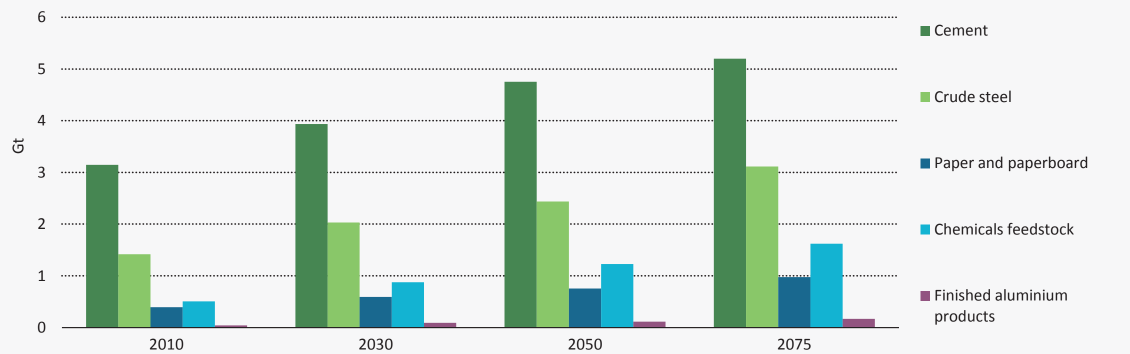
Though new generation technologies will help, the majority of the technologies needed to decarbonise the power sector have been demonstrated already. The major challenge lies not so much in the development of new generation technologies, but in achieving a more flexible operation of the electricity system, especially with an increasing share of electricity coming from variable renewable sources. The variable renewable sources solar photovoltaic (PV), wind and ocean energy reach a combined share of 31% in electricity generation by 2075. Integrating these variable resources in the electricity system requires a mixture of more flexible generation, enhanced regional interconnections and more demand-side responsiveness, along with more electricity storage, the ratio depending on the regional conditions of the electricity system.

Building on achievements to 2050, flexible generation in 2075 in the 2DS is provided by a mix of low-carbon technologies: gas turbine or combined cycle plants fired with biogas, pumped storage or compressed-air storage, as well as stationary fuel cells using hydrogen. Together these flexible plants comprise 1 600 GW or approximately 8% of the total installed capacity in 2075. Stronger transmission grids are another option to smooth out the variation in supply and demand over a larger balancing area. In 2075, supergrids based on high-voltage direct current technology could link renewable generation from remote areas in deserts or offshore locations to urban areas, where the majority of the population is expected to be living at that time. Ongoing efforts to better match demand and supply via the development of smart grids is a further area that can help to facilitate the integration of variable renewables. Given the large-scale deployment of over 1 billion electric vehicles (EVs) by 2075 in the 2DS, smart management of charging times and durations can help to reduce the spread between base and peak demands. In addition, depending on the progress made in battery technology, EVs could serve as large-scale storage for surplus electricity from variable renewable sources in low-demand times, feeding the electricity back into the grid. Large-scale electricity storage will become a necessity 2075; pumped storage and compressed-air storage plants are already established technologies today. Using hydrogen as an electrical-power storage medium could become an attractive option, keeping in mind the growing demand for hydrogen in the transport sector.

Industry

Demand for materials after 2050 is expected to continue rising to 2075, particularly in India, Southeast Asia and Africa as these regions mature (Figure 16.5). The low-demand growth variant is considered up to 2075.[2] In more mature economies such as in OECD member countries, as well as China and Russia, demand for certain materials, such as cement and aluminium, plateaus or declines after 2050. Across the different sectors materials demand will rise 10% to 55% between 2050 and 2075. The strongest demand growth occurs in the aluminium sector, where finished aluminium products are expected to increase by approximately 50%, from 116 Mt in 2050 to 170 Mt in 2075.

Figure 16.5 Global materials production to 2075



Key point *Strong material growth is expected to continue after 2050.*

2 For more information on the different variants analysed in industry, see Chapter 12.

As materials demand rises, industrial energy consumption will also continue its upward trend to 2075. Under the extended 2DS, where only those technologies commercially available to industry in 2050 are available up to 2075, industrial energy consumption would increase from 190 EJ in 2050 in the low-demand case to 211 EJ in 2075 (Figure 16.6). The industrial CO_2 emissions in the extended 2DS would decrease by 17% between 2050 and 2075 to 5.5 $GtCO_2$.

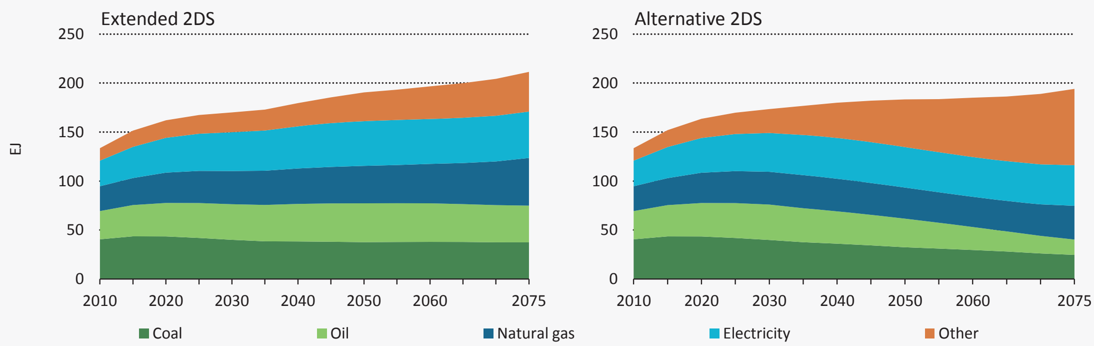
Continued research, development, demonstration and deployment (RDD&D) are required for industry to make its contribution toward a zero-carbon future. Because of the apparent shortfall in reaching 2075 CO_2 targets in the extended 2DS, an alternative 2DS for the industry sector was developed that includes further improvements in energy efficiency (*e.g.* cement kilns to perform at 2.5 gigajoules [GJ] per tonne [t] clinker) and a role for technologies that are not yet mature in 2050 (*e.g.* electrification of the iron and steel sector). The status and application of these technologies in the alternative 2DS is shown in Table 16.3.

Table 16.3 Technology status for the industrial sector in the alternative 2DS

Technology	2050 status	2075 status	Comments
Cement	New kilns built in 2050 perform at 3.0 GJ/t clinker and 95 kWh/t cement. Alternative fuels reach 28% and cement to clinker ratio declines to 0.67 by 2050. CCS is installed in 28% to 34% of plants by 2050.	New kilns built in 2075 perform at 2.5 GJ/t clinker and 55 kWh/t cement. Better understanding of clinker and cement chemistry reduces clinker-to-cement ratio to 0.55 in 2075. CCS in all new plants and 80% of retrofits resulting in an overall implementation of 55% to 68%. Alternative fuels reach 50% to 55% of total energy consumption.	CO_2 intensity of cement production falls to just 0.17 tCO_2/t cement to 0.16 tCO_2/t cement by 2075, about 55% lower than in 2050.
Iron and steel	Smelting reduction to account for 5% to 8% of production by 2050. CCS is equipped in 40% to 45% of plants by 2050. Electrolysis and hydrogen reach only marginal levels by 2050.	Crude steel production from electrolysis and hydrogen reaches a combined share of 7% to 11% of total production. CCS in all fossil fuel plants by 2075.	CO_2 intensity of iron and steel production is about 70% lower in 2075 compared with 2050.
Chemicals and petrochemcials	Catalysis and process intensification reduces energy intensity by 20% and facilitates 5% use of bio-based feedstocks. Bio-based feedstocks reach 3% to 4%. CCS deployed in 44% to 50% of ammonia and 39% to 47% of ethylene plants.	Hydrogen becomes the primary feedstock for ammonia, methanol, ethylene and propylene, replacing 45% of fossil fuel use in the sector. All new ammonia and ethylene plants are equipped with CCS.	Catalysis impact in 2075 similar to that in 2050. CO_2 emissions decrease by 12% between 2050 and 2075.
Pulp and paper	Improvement of BAT by 10% from current levels. CCS deployed in 43% to 50% of chemical pulp plants.	Improvement of BAT by 30% from current levels. Switch away from fossil fuels to renewables and heat pumps for paper drying. CCS installed in 74% to 78% of all pulp plants.	Pulp and paper reaches near-zero CO_2 emissions level by 2075 (65 $MtCO_2$).
Aluminium	Electricity intensity declines 15% in 2075 compared to 2050.	All new plants to perform at 8 500 kWh/t primary aluminium with deployment of carbothermic and kaoline reduction. CCS equipped in 33% to 35% of all plants.	Average energy intensity declines 8% to 11% and CO_2 intensity falls 17% to 22% in 2075 compared to 2050.

Under the alternative 2DS, the continuous energy efficiency improvements in the industrial sector will still not be sufficient to reduce energy consumption between 2050 and 2075 (Figure 16.6). The expected strong material growth, the energy penalty resulting from the implementation of CCS, and the increased use of biomass and waste will offset the reductions in energy achieved through energy efficiency improvements. Fossil fuels will still be in use, mostly in the chemicals and petrochemicals sector where carbon-based raw materials are used to produce carbon-containing products. However, the increase in energy consumption is limited to 6% between 2050 and 2075.

Figure 16.6 **Industrial energy consumption in the extended and alternative 2DS cases**

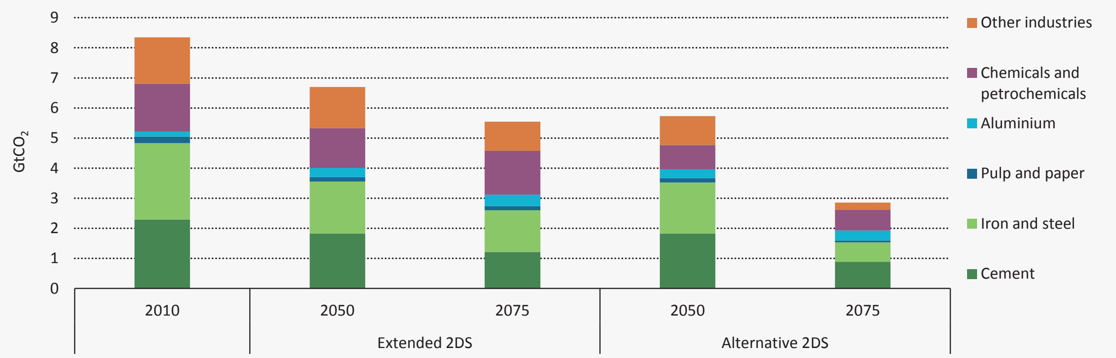


Key point *Bioenergy and alternative sources of energy will account for 40% of energy use in the alternative 2DS in 2075.*

New technologies, additional energy efficiency options and the shift away from fossil fuel use through electrification, as well as the greater use of bioenergy expected in the alternative 2DS, will help limit the rise in industrial CO_2 emissions (Figure 16.7). However, a full decarbonisation of the industry sector will not be realised by 2075. In the alternative 2DS in 2075, CO_2 emissions are about 50% lower than in the extended 2DS. Other industry, including manufacturing industries not specifically shown in the figure, shows the largest CO_2 reductions between 2050 and 2075, as there is a great opportunity to increase the use of bioenergy and alternative fuels. In the pulp and paper sector, CCS is applied on biomass-fired pulp mills, resulting, in some countries, in a net removal of CO_2 from the atmosphere. Large reductions are also observed in the cement and iron and steel sectors between 2050 and 2075. In the cement sector, demand saturates and slows in many countries, and higher rates of CCS allow for greater levels of CO_2 to be captured. Unlike other sectors, which show reductions in CO_2 emissions to 2075, direct emissions from the aluminium sectors rise by 10% due to strong demand growth and lower levels of CO_2 intensity improvements to 2075.

A deeper reduction in CO_2 emissions to 2075 would require that promising new technologies be ready for commercialisation earlier than anticipated, as well as additional breakthrough technologies that are currently far from commercial scale. Achieving near-zero levels of CO_2 in 2075 would require these technologies to penetrate the market before 2050, while existing plants are refurbished or upgraded (where possible) before the end of their lifespan. Identifying potential breakthrough technologies is very difficult, but would include improved industrial processes that would allow energy intensities to fall an additional 10% to 20% between 2050 and 2075. Increased use of hydrogen in the chemical and iron and steel sectors, new CO_2-free clinker alternatives, CCS in aluminium, and electrolysis in the iron and steel sector, are possible candidates. Such new technologies need to reach full-scale demonstration by 2040 so that they may reach commercial scale post-2050. Experience shows that lead times from early-stage R&D to full-scale demonstration may be several decades, which implies that governments and industry need to step up efforts to develop radically more efficient technologies and processes. In addition to these breakthroughs, a much higher share of bioenergy and other renewables (geothermal and solar heat) and advanced heat pumps able to generate heat over 200°C would need to be deployed in other industries to offset the use of fossil fuels.

Figure 16.7 CO_2 emissions in industry in the extended and alternative 2DS cases



Key point *Breakthrough technologies are needed if industry is to reach near-zero levels of CO_2 emissions by 2075.*

Other new technologies could include:

Electricity-based steelmaking. Research on the production of iron by molten oxide electrolysis (MOE) is currently under way. This technique would generate no CO_2. However, substantial basic engineering problems stand in the way of MOE: no suitable anode material exists. The process is also expected to use 2 000 kWh/t iron of electricity. The outlook may be better for plasma injection into existing processes, but the use of hydrogen is another option. If low-cost CO_2-free hydrogen and electricity were available, this could be an alternative for smelting reduction processes with CCS.

New low-carbon cements. A number of new low-carbon or carbon-negative cements are currently under research. They include: Novacem – based on magnesium oxide and special mineral additives; Calera – a mixture of calcium and magnesium carbonates and calcium and magnesium hydroxides; Calix – produced by the rapid calcination of dolomite in superheated steam at about 420°C in a reactor followed by rapid quenching; and Zeobond geopolymer – utilising waste materials of fly ash and bottom ash from power stations, blast-furnace slag from iron-making plants and concrete waste to make alkali-activated cements. The mechanical properties of these novel cements may be similar to those of regular Portland cement. The geopolymer cements have the potential to reduce CO_2 emissions because they do not rely on the calcination of calcium carbonate, and production does not require high-temperature kilns.

Hydrogen in the chemical sector. Hydrogen could be used to replace both fossil fuel-based feedstocks and energy in the chemical sector, for the production of ammonia, methanol, ethylene and propylene. Hydrogen production could be based on electrolysis, which will use zero carbon electricity in the extended 2DS. While some R&D is under way, substantial breakthroughs are still needed. A switch to hydrogen could reduce CO_2 emissions in the chemicals sector by an estimated 1.0 to 1.5 Gt in 2075.

Transport

Transport trends, for both passenger mobility and goods movement, continue to grow after 2050, though at a somewhat slower rate. As urbanisation rates reach very high levels in the post-2050 time frame, urban mobility is expected to saturate; the majority of growth comes from intercity travel in non-OECD regions where per capita intercity travel in 2050 is still much lower than in OECD regions (IEA, 2009). Car ownership in currently emerging markets, such as China and India, also approaches saturation and grows only slowly after 2050, while in regions such as the Middle East and Africa, growth is still robust. Air travel continues to grow in most regions, though at an annual rate of 0.5% between 2050 and 2075, well below the 2030 to 2050 rate of 1% per year. Freight movement also continues to grow at a decreasing rate.

Although efficiency improvements in conventional internal combustion engine (ICE) vehicles will reach certain limits, ongoing improvements in areas such as friction reduction and lightweight materials will continue. Energy losses related to aerodynamics, tyres and accessories will also continue to decline, albeit slowly. Perhaps the greatest potential is in vehicle weight reduction – the "hypercars" of the future could weigh less than half of today's vehicles (RMI, 2012).

In the extended 2DS case, new propulsion-system adoption trends prevalent in 2050 continue to 2075 (Table 16.4); for example, the penetration of electric vehicles in the PLDV sector continues to provide an overall reduction in energy demand as it displaces the remaining ICE vehicles. Fuel cells also help, as they replace the small ICEs on plug-in hybrids, preserving the fairly long range of plug-in hybrid electric vehicles (PHEVs), but with zero tailpipe emissions. For trucks, ongoing penetration of fuel cell hybrid systems provides important efficiency improvements. Ships and aircraft are assumed to achieve a slow but steady additional efficiency improvement after 2050 through incremental measures (most notably via lighter materials, smoother surfaces and fully optimised engine systems). No major changes to propulsion systems are envisioned; the same applies to basic design (*e.g.* no "flying wing" airplane concepts are assumed, though if adopted could increase aircraft efficiency appreciably beyond 2050 levels).

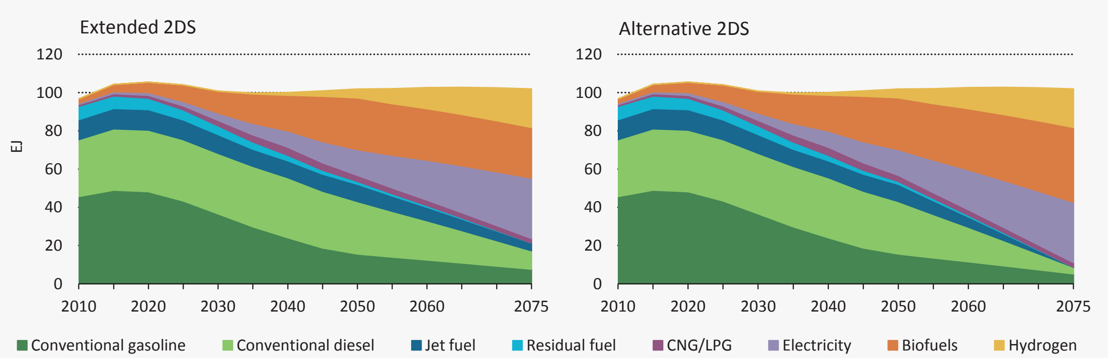
Table 16.4 Transport key technology status in 2050 and 2075

Technology	2050 status	2075 status	Comments
Electric vehicles and PHEVs	Achieves 50% of PLDV sales, 33% of stocks.	Achieves 66% of PLDV sales, 50% of stocks.	EVs completely capture light vehicle, urban vehicle niches; significant penetration in goods delivery vehicles; poor penetration in longer distance trucks.
Fuel cell vehicles	Achieves 25% of PLDV sales, 10% of stocks; 15% of truck stocks.	Achieves 35% of PLDV sales, 30% of stocks; 30% of truck stocks.	Fuel cells for PLDVs mainly replace ICE in plug-in hybrids; also used with plug systems for trucks; some long-haul fuel cells also enter service.
Biofuels	Achieves 27% of transport fuel.	Remains at 27% of transport fuel in extended 2DS; reaches 39% in alternative 2DS case.	

All of these extensions of the 2DS to 2075 are preserved in the alternative 2DS case; the main difference in the alternative 2DS for transport is greater use of biofuels.

The results of these technology improvements from an energy-use point of view are not dramatic, but are sufficient to keep global transport energy use roughly at the 2050 level (about 105 EJ) through 2075 (Figure 16.8). But since there is no significant reduction in energy use, ongoing transport CO_2 reductions must come entirely from fuel substitution. This occurs in a massive fashion, with a combination of biofuels, hydrogen and electricity. In the extended 2DS case, a considerable share of fossil fuels stays in the transport energy mix, mostly in non-OECD countries. In the alternative 2DS variant, fossil fuels are nearly completely displaced by 2075. This reflects a continuation of the market penetration rates seen in the 2040 to 2050 time frame, as well as continued penetration of vehicles that use these fuels, such as electric cars, fuel cell cars and trucks, and all ICE vehicles which substitute biofuels for petroleum fuels.

Figure 16.8 World transport energy use in the extended and alternative 2DS cases



Key point *Hydrogen, biofuels and electricity account for three-fourths of energy use in 2075 in the extended 2DS, and almost 90% in the alternative 2DS.*

The fairly even mix of electricity, hydrogen and biofuels reflects different niches and advantages across the transport spectrum. By 2075, all new cars are either electric or fuel cell; trucks are dominated by fuel cell systems; ships and aircraft still use ICEs and therefore are heavily dependent on biofuels. For all modes of transport, travel range per refuelling will remain a key factor; among cars, electric vehicles will remain limited to those applications where no more than 200 to 250 kilometres of range are needed. Plug-in hybrids that use either hydrogen or biofuels as a complement to electricity may therefore play an important role since they will provide longer ranges. Plug-in hybrids may also be important for trucks, though electricity is assumed to give way to hydrogen for long-haul trucking. The density and range of liquid fuels remains critical for ships and aircraft.

Advanced biofuels will play an important role, if these can achieve truly zero net GHG emissions during all phases of production and use; but available quantities of such biofuels in the 2075 time frame, or at any point in the future, are highly uncertain. In fact, advanced biofuels, at a cost commensurate with or lower than petroleum fuels, may prove to be the most cost-effective and widely applicable of the three zero-emissions energy carriers (biofuels, electricity, hydrogen); if supplies were unlimited it is easy to imagine that advanced biofuels would eventually dominate transport fuels. But supplies could be limited. In the extended 2DS case after 2050, biofuels are increasingly shifted to ships and aircraft, especially in OECD regions, with cars and trucks relying more on electricity and hydrogen.

Overall, transport CO_2 emissions in the extended 2DS case drop from about 6 Gt in 2050 to 3 Gt in 2075. The remaining CO_2 emissions are predominantly in shipping and air, where biofuels represent a significant fuel source, but far from 100%, with the remainder being petroleum fuels. Therefore, to achieve zero GHG emissions in transport, more biofuels are needed in shipping and air, or they must be powered by electricity or hydrogen. These possibilities are discussed below. In order to get very close to zero CO_2 via increased use of biofuels, the amount used in 2075 would have to be close to 50 EJ instead of 31 EJ. Further, all hydrogen, electricity and biofuels would have to have net zero emissions (at least on average), which is assumed in the 2DS after 2050.

Beyond continuing to ramp up biofuels' use, what can be done to approach zero emissions? There is a wide range of additional technologies that could help, though most still require significant development, including major cost reduction. These include:

Application of hydrogen to ships and aircraft. There is considerable research under way on the potential application of hydrogen as a fuel for ships and aircraft. Though today's hydrogen storage options can achieve better energy density than electricity stored in batteries, hydrogen storage has not yet reached the required energy densities needed for long-range travel (several thousand kilometres) with these types of vessels. An important option is liquefaction: liquid hydrogen could increase density by several times over compressed hydrogen. Particularly for ships, liquid hydrogen used with fuel cell systems may become a viable alternative. The main issue is likely to be cost. However, for hydrogen use in aircraft, completely new designs would be needed, and would result in airplane configurations generally believed to be inferior to today's designs. Aircraft may go in a very different direction, with "flying wing" concepts that eliminate or reduce the size of the fuselage to improve lift/drag ratios. This could make it even harder to deploy hydrogen as a fuel.

Better batteries. A breakthrough on battery technologies, such as metal-air designs that could achieve volumetric energy densities that are several times higher, could provide vehicles with commensurate increases in range. A tripling of density (both in terms of volume and weight) without a significant increase in cost, and along with fast-charging capability, would put electric vehicles very close to equal overall performance with ICE vehicles. Ironically, while this could free up more biofuels for ships and aircraft, a side effect might be to eliminate the main advantage of hydrogen as a road fuel. Charging stations will also need to be more powerful in order to recharge a bigger capacity in the same amount of time while the vehicle is parked.

Charge as you drive. If batteries could be recharged without plugging in, and thus recharged during movement, this could be a "game changer" for road vehicles (especially for commercial vehicles that are not often parked). Inductive charging provides just this: charging using electric induction or possibly magnetic resonance approaches that do not require physical contact. Technologically simpler, trolley recharging provides physical contact (such as with urban tram systems today), allowing electricity to be supplied during movement. If roads were outfitted with these systems and cars and trucks made compatible, then vehicles could recharge on highways, extending their range between cities (and/or reducing the battery capacity needed on board). However, these technologies are currently expensive when considered in highway applications, and they have relatively low efficiencies, undermining one of the advantages of plug-in electric vehicles – very high plug-to-wheel efficiencies. Like better batteries, remote charging systems could reduce the need for hydrogen in order to extend the range of road vehicles. They are unlikely to be of much help for ships and aircraft, however.

A range of other potential technologies could also play important roles. These include new types of biofuels (*e.g.* terrestrial and marine algae), flying wing aircraft, very low-energy ships (*e.g.* with greater wind power assistance, air flow systems to cut aerodynamic drag), and many others. Many involve further use of lightweight materials, since these help improve efficiency and cut energy demand. By cutting energy demand, it is more likely that the supply of biofuels and other zero-emissions fuels will be adequate to reach zero net CO_2 emissions in transport.

Buildings

Buildings – as well as population and household size – are a key contributor to ongoing increases in energy service demand in the residential sector. As mentioned, population growth will only slowly increase between 2050 and 2075, with virtually all growth in non-OECD countries. This increase in population, coupled with the continued trend towards fewer occupants per house, will translate into an increase of 0.8% per year in the number of households and 1.0% per year in residential floor area (Table 16.5).

The growth in the service sub-sector is primarily a function of the level of economic activity. In addition, as economies are developing and getting mature, the share of services value added in the total economy is usually increasing. As mentioned, the global GDP (in 2010 USD at PPP) is expected to grow by 3.3% per year between 2009 and 2050, then slows to 2.7% per year between 2050 and 2075. As a result, service sector floor area is expected to continue to grow from 2009 to 2075. Floor area is projected to expand most rapidly in non-OECD countries, driven by the higher rates of growth in their economies and service sectors value added.

Table 16.5 Key activities in the buildings sector

	2009	2050	2075	CAAGR (2009-50)	CAAGR (2050-75)
Population (million)	6 761	9 306	9 905	0.8%	0.2%
Number of households (million)	1 852	3 097	3 494	1.3%	0.5%
Residential floor area (billion m^2)	108	196	254	1.4%	1.0%
GDP (billion 2010 USD at PPP)	70 781	267 034	523 377	3.3%	2.7%
Services floor area (million m^2)	35 223	60 502	73 250	1.3%	0.9%

Improvement in energy efficiency in the buildings sector is expected to continue beyond 2050. However, the rate of improvement will be lower than it was between 2009 and 2050. In the 2DS to 2050, the existing building stock in OECD countries is refurbished to achieve higher levels of efficiency; and globally, new houses are built using BATs and adopting efficiency designs. As a result, the potential efficiency gains from improvements in the building shell beyond 2050 will be more limited.

By 2050, the ownership rate of appliances and electric and electronic equipment will have increased substantially, while the growth in ownership is expected to slow between 2050 and 2075. Given that improvements in energy efficiency will offset part of the increased energy consumption due to higher penetration of equipment, overall energy consumption for these end uses will increase at a much slower pace between 2050 to 2075 than in the period 2009 to 2050. The demand for cooling and ventilation is not expected to reach saturation by 2050, adding additional pressure on energy consumption from this end use between 2050 and 2075.

Given the limited potential that will remain from building shells, the majority of improvements will come from ongoing advances in end-use equipment (Table 16.6). The improvements in energy efficiency will be enough to limit the growth in energy consumption to 0.4% per year between 2050 and 2075, despite a strong increase in the number of households and services floor area.

Table 16.6 Technology status for the buildings sector

End use	2050 status	2075 status	Comments
Space and water heating and space cooling	Heat pumps provide 5% of total space heating energy needs. Solar energy provides 11% of space heating, cooling and water heating energy needs.	Heat pumps provide 10% of total space heating energy needs. Micro co-generation units provide 13% of space heating, cooling and water heating energy needs. Solar energy provides 15% of space heating, cooling and water heating energy needs.	Absorption heat pumps, driven by heat, can use any zero-emission heat source. Small Organic Rankine Cycle systems make use of waste heat to meet other demands in a building. As buildings become more integrated with other local demands and supplies, new system solutions will emerge.
Cooking	20% of residential cooking uses electricity and 46% modern biomass.	31% of residential cooking uses electricity and 33% modern biomass.	Cooking energy intensity decreases from 1.1 MJ/household to 0.9 MJ/household; CO_2 emissions associated with cooking increase by 6% due to the increased use of natural gas between 2050 and 2075.
Lighting and appliances	60% of lighting provided by CFL. 20% of lighting provided by LED.	50% of lighting provided by CFL. 40% of lighting provided by LED.	Lighting energy intensity improves by 20%, from 0.029 MJ/m^2 to 0.024 MJ/m^2, between 2050 and 2075.
Appliances and miscellaneous equipment (services sector)	Fossil fuels account for 40% of energy demand.	Fossil fuels account for 24% of energy demand.	CO_2 emissions associated with miscellaneous equipment decrease from 419 $MtCO_2$ to 368 $MtCO_2$ between 2050 and 2075.
Building envelope technologies	Useful energy consumption for heating and cooling in residential buildings amounts to 260 MJ/m^2. Useful energy consumption for heating and cooling in service buildings amounts to 272 MJ/m^2.	Useful energy consumption for heating and cooling in residential buildings amounts to 202 MJ/m^2. Useful energy consumption for heating and cooling in service buildings amounts to 229 MJ/m^2.	Improvements in building envelopes from advanced technologies (new generation cool roofs and walls, phase change materials, adaptive windows and coatings) reduce the heating and cooling load and allow a downsizing of heating and cooling equipment.

Notes: MJ = megajoule, CFL = compact fluorescent lamps, LED = light emitting diodes.
Miscellaneous equipment includes information technologies (IT) and office equipment, pumps, generators, cooking and other small plug loads.

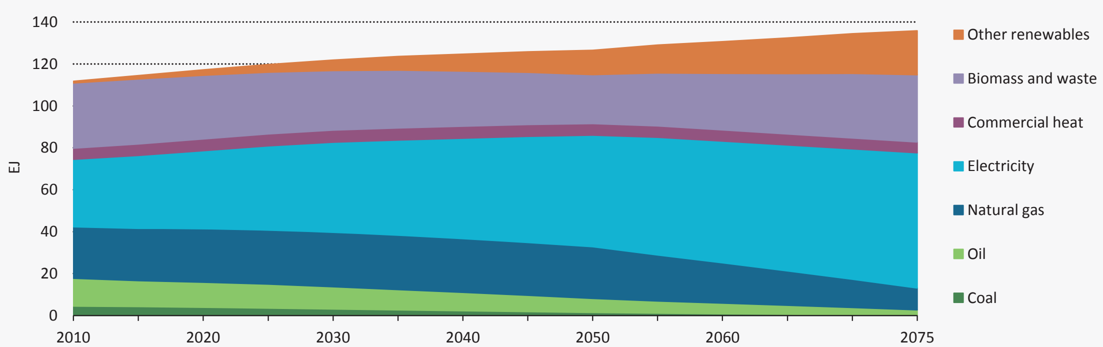
Continuous improvements in building shell technologies and design are the first necessary steps towards a zero-CO_2 emissions future. Not only will they it reduce energy needs for heating and cooling, but will also allow for the downsizing of equipment to meet the same indoor comfort. In warm and humid climates, (*e.g.* India, ASEAN countries, Southern China), the adoption of a suite of passive envelope technologies must accelerate beyond 2050 to mitigate the growth in space cooling demand, including advanced cool roofs and walls, window films, or radiant barriers. In addition, as buildings move towards tighter envelopes, moisture, ventilation and durability of materials will become an increasing concern, and require new building control systems or materials such as dynamic insulation.

Heat pump technologies are proven and mature, but can still play an important role beyond 2050. However, maximising the uptake of this technology will require a number of current market and non-economic barriers to be overcome as well as additional R&D. The RD&D priorities for heat pumps include: improving the components and systems of existing technologies and designing systems that maximise the coefficient of performance across a wide range of applications; adjusting to climate and operator behaviour; and widening the potential market.

Solar thermal technologies provide heat that can be used for low-temperature heat applications, including space heating and cooling, and water heating and cooling. They are an important part of the transition to a sustainable energy profile for the buildings sector. While solar cooling is in its infancy, and improved performance and cost reductions are likely to occur, solar thermal technology for space and water heating are mature and commercially available. Further development is needed to provide new products and applications, reduce the cost of systems, and increase market deployment.

Despite improvements in energy efficiency in all end-use sectors, energy consumption will increase from 127 EJ in 2050 to 136 EJ in 2075 (Figure 16.9). Most of this growth will come from the increased use of space cooling, as well as appliances and other electric and electronic equipment.

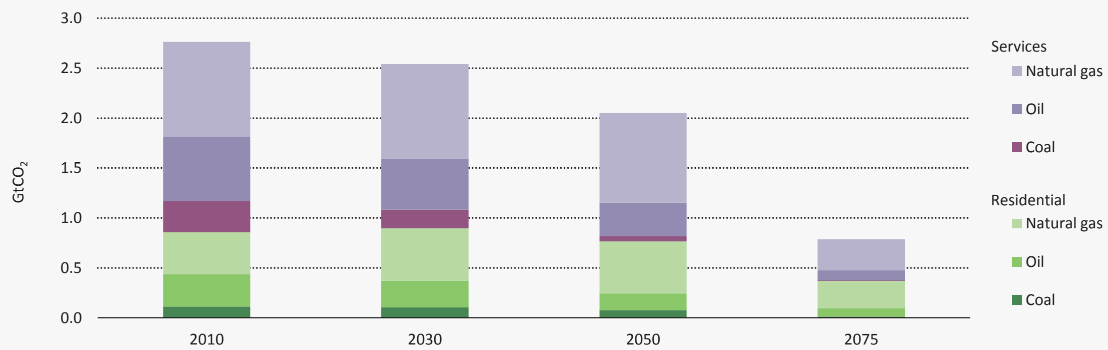
Figure 16.9 Buildings energy consumption by energy source in extended 2DS



Key point *Buildings move strongly away from fossil fuels but retain about 10 EJ of natural gas in 2075.*

The picture that emerges from the trends in direct CO_2 emissions is quite different from the one observed in energy consumption. In 2050, fossil fuels account for only 26% of total energy consumption in the buildings sector, down from 38% in 2009. This trend towards the use of more carbon-lean energy sources, most noticeably bioenergy, is expected to continue at a faster pace to 2075. As a result, direct CO_2 emissions from the buildings sector would decrease from 2.0 $GtCO_2$ in 2050 to 0.8 $GtCO_2$ in 2075 (Figure 16.10).

Figure 16.10 **Buildings direct CO_2 emissions by sub-sector and energy source in extended 2DS**



Key point *Very little coal- or oil-related CO_2 is emitted in 2075 in services or residential buildings.*

Given that it is, in theory, possible to completely phase out the use of fossil fuels in the buildings sector, it is similarly possible to reach zero CO_2 emissions by 2075 (assuming a life expectancy of 25 years maximum for all energy-using devices, so a complete turnover is possible between 2050 and 2075). However, such a dramatic change can result in significantly higher costs for consumers and would have major implications for supply-side sectors. As a result, careful attention should be given to the way decarbonisation is implemented in the buildings sector.

In order to achieve a low-carbon future in the buildings sector, while managing the additional pressure that can be created on the power supply side, some breakthrough technologies are worth considering:

Dynamic building envelope. Research is ongoing to improve building envelopes (roofs, walls, glazed area) and reduce heat/cold gains and losses. These new "smart" envelopes would be able to adjust to variations in temperature or solar radiation. If successful, these breakthrough technologies could play a significant role beyond 2050. Such technologies include advanced phase change materials that maintain even temperatures by storing latent heat in walls and roofs; low-cost bio-based versions that are in development; and electrochromic windows, which change reflectivity to adapt to outside light, thus drastically reducing thermal loads, particularly from cooling.

Co-generation. A number of technological developments are being explored that offer the possibility of expanding the range of potential applications for co-generation in buildings. These include the use of reciprocating engines, including stirling engines, gas turbines, fuel cell microturbines and fuel-cell/turbine hybrids. Fuel cells are a later option for co-generation technology. Fuel cells use an electrochemical process that releases stored energy in hydrogen to create electricity, with heat as a by-product. Fuel cells that include a fuel reformer can utilise the hydrogen from any hydrocarbon fuel, though this results in some CO_2 emissions. Local pollutant emissions from this type of system would be much lower than emissions from the cleanest fuel combustion process. If fuel cell costs decline in line with expectations, they could become a very attractive technology, as their high power-to-heat ratios make them ideal for low base-heat loads. If hydrogen production costs come down and hydrogen distribution infrastructure is available (see Chapter 7), fuel cells will also have a significant role in decarbonising heat supply.

Recommended actions for the near term

The great uncertainty of projections over 60 years into the future raises concerns about whether extending the technology package and trends in place in 2050 in the 2DS can lead to a zero CO_2 emissions energy system in 2075. For the near term, it is clear that aggressive RD&D programmes are needed on a range of energy technologies beyond those that play a major role to 2050 in *ETP 2012*.

Since the technology set needed must help expand the use of zero-carbon fuels, such as electricity, hydrogen and biofuels, technologies that enable greater use of these fuels in more applications may be particularly important. Many such technologies are mentioned in the preceding discussion, such as long-haul trucks which operate on electricity, and ships which run on hydrogen.

Ongoing improvements in efficiency after 2050 will remain critical, since the more energy demand that exists in 2075, the more zero-carbon fuels will be needed – creating particular concerns around bioenergy and biomass availability. But many of today's most promising efficiency technologies will be already extensively used by 2050 in the 2DS. Therefore, other efficiency technologies with long-term prospects (*e.g.* flying wing aircraft) should not be neglected.

This chapter represents just an initial look at achieving a zero-CO_2 energy system. Further research is needed to identify possibilities and obstacles, and help design a viable pathway to reach this important target.

Chapter 17

Regional Spotlights

Realising the *ETP 2012* 2°C Scenario (2DS) will require a truly global commitment. All regions need to take action to realise the 2DS, but each region faces different challenges and opportunities. Domestic energy resources, industry structure and current energy infrastructure will determine which strategies and technologies bring the most benefits to each region.

Key findings

- ***In the 2DS, energy demand in emerging economies would continue to grow, but demand in the European Union and the United States would stagnate or fall.*** *India would see the strongest growth, with 140% higher energy demand in 2050 versus 2009, followed by ASEAN (70%), China (55%) and Brazil (55%).*
- ***The United States would have the highest reduction (75%) in CO_2 emissions by 2050 compared to 2009,*** *followed by Russia (65%) and the European Union (60%). China would cut its emissions by 50%, while CO_2 emissions in India would grow by 35% in the 2DS.*
- ***Decarbonising electricity is critical for all regions,*** *but local conditions will determine the relative importance of technologies needed to achieve this. Hydro power will continue to play a major role in Brazil, while wind would become an important technology option in the European Union and the United States. Solar technologies would be central to decarbonising electricity in India and South Africa, and nuclear power, as well as carbon capture and storage (CCS), would be important in China.*
- ***Emission reduction targets in industry can only be met if all available options are implemented.*** *In North America and Russia, where industrial plants are relatively old, improvements in energy efficiency are vital to meet reduction targets. In countries where cement, and iron and steel dominate the industry sector, such as in India and China, significant deployment of CCS technologies will be required in order to reduce emissions.*
- ***Vehicle fuel economy would need to improve by 30% to 50% by 2050 in all regions,*** *compared to current levels. Emerging economies face a strong trend toward larger vehicles, which makes improvements in fuel economy ever more challenging.*
- ***Travel demand will grow rapidly in non-OECD countries.*** *Preserving higher modal shares for mass transit modes and maintaining lower car shares, for instance, are measures that could mitigate the increase in emissions caused by higher travel demand.*
- ***Decarbonisation in transport could be influenced by fuel shares.*** *Europe is currently dominated by diesel car sales, while North America has very few diesel cars. Other countries have singularities: passenger transport in Brazil is dominated by flex-fuel (alcohol-gasoline) vehicles, while in Pakistan CNG vehicles dominate.*
- ***In OECD countries, close to 70% of the current building stock will still be standing in 2050 and will require retrofits to improve energy efficiency.*** *In developing countries, new building construction offers opportunities to improve efficiency standards more easily and quickly.*

1. Association of Southeast Asian Nations

The Association of Southeast Asian Nations (ASEAN) is made up of the ten member states of Brunei, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, the Philippines, Singapore, Thailand and Vietnam. It is one of the fastest-growing regions in the world and its rapidly rising energy demand is driven by its economic and demographic growth. In 2010, the region's real gross domestic product (GDP) grew at 7.4%, while the population of ASEAN reached close to 600 million.

As a whole, the ASEAN countries have rich fossil fuel resources and large potential in renewable energy, particularly wind, hydro and geothermal. However, fossil fuel resources are unevenly distributed and renewables are seriously underdeveloped due to a lack of technology and investment.

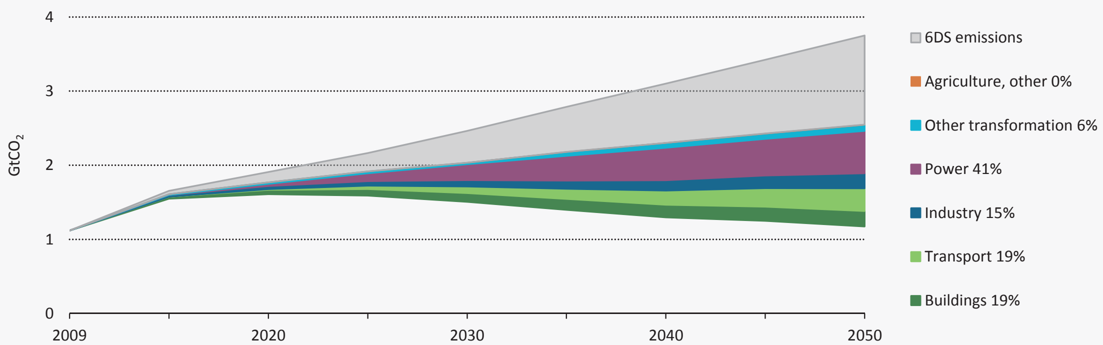
ASEAN energy demand increased at a rate of 3.6% per year from 1995 to 2007. Rapid growth of the region's industrial sector and coal-fired power plants meant that coal demand grew at 13% per year to reach 14.8% of the energy mix in 2007. With the commissioning of gas power plants, gas demand grew at a slower but rapid rate of 6.5% per year to 21.4% of the mix. Oil demand grew at only 2.2% per year, but it remains the major energy source at 36%, driven by ASEAN's rapidly expanding transport demand. Renewables in 2007 were predominately hydro (1.2% of the mix), geothermal (2.9%) and biomass (which declined from 30% in 1995 to 23% in 2007).

According to the *Third ASEAN Energy Outlook (*IEEJ, 2011), demand under business-as-usual (BAU) conditions is expected to grow at a rate of 4.5% per year from 2007 to 2030. Transport-sector demand will grow quickly, driven by increasing per capita income and household vehicle acquisition. Electricity demand will grow rapidly, having major implications for the ASEAN energy system: it will lead to fast development in coal-fired generation, gas-fired generation and hydropower, particularly for the Greater Mekong countries as they develop their vast hydropower potential for cross-border electricity trade. Nuclear energy will be introduced in the region before 2020 and geothermal energy will be further developed in the Philippines and Indonesia.

ASEAN has been a net oil importer since 1995, and is facing a plateauing of its oil and gas production. While new energy-efficient technologies will result in a decreasing ASEAN energy intensity, per capita energy consumption is forecast to double by 2030 (IEEJ, 2011), Carbon dioxide (CO_2) emissions will increase as the consumption of fossil fuels grows faster than that of carbon-free sources such as renewable and nuclear energy.

Under the *ETP 2012* 4°C Scenario (4DS), ASEAN is on a trajectory to double CO_2 emissions by 2050 (Figure 17.1.1).

Figure 17.1.1 Sectoral contributions to achieve the 2DS compared to the 4DS



Notes: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis. Percentages reflect cumulative reductions 2009-50.

Key point *CO_2 emissions in the 2DS are brought back to today's level.*

Decarbonising energy in ASEAN

In moving towards the *ETP 2012* 2°C Scenario (2DS), ASEAN faces strong challenges across all sectors due to the domination by fossil fuels (particularly coal-firing in the power sector).

While some ASEAN member states are setting national CO_2 emissions reduction targets, ASEAN as a whole does not set binding targets. A secure supply of clean energy is the overriding concern for ASEAN. The ASEAN Plan of Action for Energy Co-operation (APAEC) 2010-15 therefore seeks to secure a clean, sustainable energy supply through setting goals for energy efficiency and alternative fuels, and cooperation on broadening the fuel mix via interconnectivity of the ASEAN Power Grid (APG) and the TransASEAN Gas Pipeline (TAGP).

ASEAN has agreed to the aspirational goal of reducing regional energy intensity by at least 8% by 2015 (based on 2005 levels), and the collective target of 15% of total installed power capacity from renewable energy sources by 2015. ASEAN ministers further agreed to consider a higher level of commitment to energy intensity reduction and installation of renewable energy beyond 2015 (ASEAN, 2011).

Energy efficiency

ASEAN has set a regional target to improve energy intensity by 8% by 2015, from the base year of 2005. Energy efficiency is recognised by ASEAN member states as the most effective way to achieve energy security and a clean environment, and countries have set national goals.

ASEAN faces many challenges in the energy efficiency field, with some common barriers across member states for energy efficiency technology development and deployment. Under the APAEC 2010-15, the main aims are to:

- remove subsidies to fossil fuels;
- build public confidence in energy efficiency technologies;
- promote good energy management; and
- facilitate investment through soft loans, co-investment funds, targeted subsidies and tax incentives.

Table 17.1.1 ASEAN energy efficiency goals

Member state	Energy efficiency goal
Brunei Darussalam	To reduce energy intensity by 25% by 2030 with 2005 as the base year.
Cambodia	No action plan but set the target to reduce final energy consumption by 10% in all sectors.
Indonesia	The National Energy Conservation Master Plan (2005): to decrease energy intensity by around 1% per year on average until 2025.
Lao PDR	No Action Plan but set the target to reduce final energy consumption by 10% in all sectors.
Malaysia	National Energy Efficiency & Conservation Master Plan (under development): to reduce final energy consumption by 10% in all sectors from 2011-30.
Myanmar	No Action Plan but set the target to reduce primary energy consumption by 5% (2020) and 8% (2030) compared with BAU.
Philippines	The National Energy Efficiency & Conservation Program: to achieve energy savings equivalent to 10% of the annual final energy demand outlook from 2009-30.
Singapore	To reduce energy intensity by 20% in 2020 and 30% in 2030 from 2005 level.
Thailand	20-Year Roadmap on Energy Efficiency: to reduce energy intensity by 25% from 2010 to 2030.
Vietnam	National Energy Efficiency Program: to reduce energy consumption by 5% to 8% (2010-15).

Source: Suryadi, 2011.

Renewable energy, biofuels and nuclear power

As a means of decarbonising the energy system, ASEAN has agreed to a collective target of 15% of total installed power capacity from renewable energy sources by 2015. Countries have set national goals and some are also planning for nuclear power in the longer term.

Table 17.1.2 ASEAN renewable energy, biofuels and nuclear goals

Member state	Renewable energy and biofuels goal	Nuclear power goal
Brunei Darussalam	10 MV PV by 2030. No biofuels target.	No target.
Cambodia	1.5 MV PV, 87 kW biomass, and 500 kW micro-hydro. No biofuels target.	No target.
Indonesia	Energy mix by 2025: 5% biofuels, 5% geothermal, 2.6% hydro, 0.03% wind, 0.74% biomass.	1.4% nuclear capacity by 2025.
Lao PDR	Hydro projects for domestic use and export. No biofuels target.	No target.
Malaysia	By 2030: 1 340 MW biomass, 410 MW biogas, 490 MW mini-hydro, 854 MW solar, 390 MW municipal solid waste. Biofuels to displace 5% of diesel in road transport.	2 000 MW by 2023.
Myanmar	15%-20% renewable energy in power generation mix.	No target.
Philippines	New capacity by 2030: 1 500 MW geothermal, 2 100 MW hydro, 950 MW wind, 71 MW solar PV, 102 MW biomass. Biofuels to displace 15% of diesel and 20% of gasoline in road transport.	2 000 MW by 2025.
Singapore	5% PV in the power generation mix. No biofuels target.	No target.
Thailand	6 329 MW of various RE power generation. Biofuels to displace 12.2% of fuels in road transport.	Develop 5 000 MW over 2020-28.
Vietnam	By 2030: 2 100 MW wind, 2 400 MW small hydro, 400 MW biomass. No biofuels target.	1 000 MW by 2020, to increase to 10 700 MW by 2030.

Source: IEEJ and ACE, 2011.

The rapid growth of ASEAN electricity demand will be a driving force in increasing use of fossil fuels, especially coal. ASEAN recognises that a cleaner sustainable way to meet this demand is to improve the investment climate for renewables in the power mix and alternative fuels from biomass. To date, higher feed-in tariffs have generally been required and consumers will have to be willing to pay the full cost of energy, including environmental costs, for these technologies to become competitively widespread.

The ASEAN Power Grid

The ASEAN Power Grid (APG) is a key energy infrastructure project in the ASEAN region. The APG, mandated in 1997, aims to enhance cross-border electricity trade to help ASEAN member states more efficiently meet their growing demands for electricity while saving on deferred investments in the power sector. Led by the Heads of ASEAN Power Utilities and Authorities (HAPUA), the APG is proposed as a regional transmission network that links ASEAN power systems, first on crossborder bilateral terms, then gradually to sub-regions, and finally to an integrated ASEAN power system.

The interconnections provide less costly electricity supply and ensure greater efficiency and sustainability of ASEAN energy resources. An interconnected system will facilitate the integration of more variable renewable power capacity, and the future interconnection of the hydropower potential of the Greater Mekong countries will assist in decarbonising some portion of ASEAN electricity consumption.

Currently, the APG has four interconnections and 12 more projects planned for interconnection through 2015. The investment required is estimated at USD 5.9 billion, with a potential savings of about USD 662 million in deferred investment and operating costs resulting from the proposed interconnections. By 2025, there will be up to 19 500 megawatts (MW) of crossborder power purchase, and 3 000 MW of economic exchange through the crossborder interconnections.

Many challenges remain for the APG. A significant number of the projects will require undersea cable interconnections and inland connections, and the financial viability of these is yet to be established and accepted by participating countries. Other matters, including the optimum generation fuel mix for the APG, the establishment of a regional regulatory and technical framework, and a mechanism for raising capital, need to be addressed if there is to be market confidence for the funding and investment of the APG.

The Trans-ASEAN Gas Pipeline

The Trans-ASEAN Gas Pipeline (TAGP) is the second key energy infrastructure project of the ASEAN region. Co-ordinated by the ASEAN Council on Petroleum (ASCOPE), the TAGP aims to develop a regional gas grid by 2020 by linking existing and planned national pipeline networks of the ASEAN member states. The TAGP involves the construction of 4 500 kilometres (km) of pipelines, mainly undersea, worth USD 7 billion.

Cross-border pipelines have expanded from 815 km in 2000 to 3 020 km in 2009. The current eight bilateral interconnections comprise more than half of the total planned length for development. ASEAN is also incorporating liquefied natural gas (LNG) into the TAGP concept, as countries such as Indonesia, Malaysia, Singapore and Thailand undertake construction of LNG regasification terminals.

As with the APG, the TAGP serves to ensure greater availability and sustainability of ASEAN energy resources. The TAGP was not originally conceived as an encouragement to low-carbon development pathways in ASEAN. However, with much of the region's power industry investing in or looking to diversify into coal-fired generation capacity, the increased availability of a secure gas supply throughout ASEAN will serve as an option to decarbonise future power capacity.

With no significant new gas discoveries in ASEAN in recent years, Indonesia's East Natuna field remains the single largest gas resource. However, it is yet to be developed due to its high CO_2 content and pending commercial issues. Its commercialisation will become more crucial for ASEAN as gas production reaches a plateau and ASEAN's quickly growing demand leads to a supply gap as early as 2015, rising to more than 12 billion standard cubic feet per day by 2025.

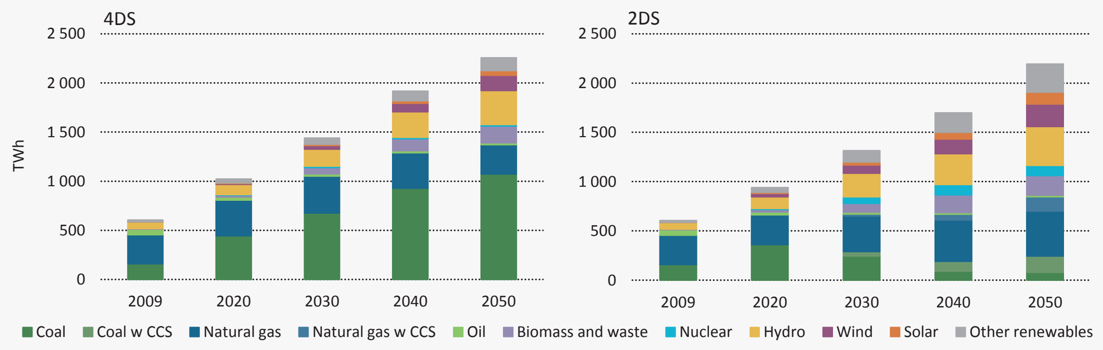
The current cross-border interconnections are bilateral, and to realise the TAGP as an integrated ASEAN gas supply system will require overcoming substantial financial and legal complexities, including increasing investment costs. National technical and security regulation requirements, and differences in the processes of supply, distribution and management for natural gas across the countries, must also be synchronised. As with the APG, the regulatory and technical framework, government support, and business models need to be made ready if there is to be market confidence for the funding and investment of the TAGP. Continuous strong commitment from ASEAN member states to co-operate and collectively pursue initiatives towards realising the ASEAN Economic Community 2015 is key.

Model results for ASEAN by sector

Power

In the 4DS, power generation increases by five, with a quadrupling of fossil-fired generation. Coal covers almost half of the electricity demand in the region by 2050 in this scenario (Figure 17.1.2). This is below what is envisioned in the *ETP 2012* 6°C Scenario (6DS) but still represents an unsustainable pathway.

Figure 17.1.2 ASEAN electricity generation in the 4DS and 2DS

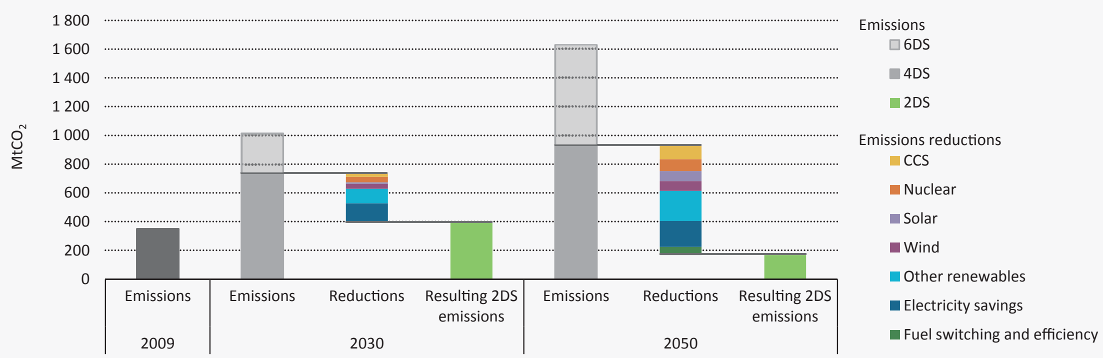


Notes: TWh = terawatt-hour. Other renewables include geothermal and ocean energy.

Key point *While the electricity mix in the 4DS is dominated by coal, renewables provide more than half of the electricity in the 2DS in 2050, with hydro and geothermal power being important options.*

In the 2DS, annual CO_2 emissions in the power sector fall by more than 50% relative to the 4DS in 2050. Renewables provide half of these reductions, with geothermal power alone providing 15% of the mitigation in the power sector (Figure 17.1.3). Efficiency improvements in power generation as well as electricity savings through the more efficient use of energy in the end-use sectors are responsible for one-quarter of the CO_2 reductions in 2050. Fossil-fired plants with carbon capture and storage (CCS) with an installed capacity of 45 gigawatts (GW) provide around 12% of the reductions, whereas nuclear contributes with a share of 11%.

Figure 17.1.3 Annual CO_2 emissions reduction in the ASEAN power sector to reach the 2DS (relative to the 4DS)



Note: Other renewables include biomass, geothermal and ocean energy.

Key point *Renewables provide almost half of the CO_2 reductions in the power sector in the 2DS.*

Industry

Industry used 5.5 exajoules (EJ) of energy in 2009, accounting for 29% of total final energy used in ASEAN. About 41% of the energy used by industry is consumed by the five most intensive industrial sectors. From a global perspective, ASEAN accounts for 4.3% of global industry energy use. The final energy mix of industry is dominated by oil, with a share of 31%.

Production of key material is expected to substantially increase between 2009 and 2050. Production of cement, paper and chemicals will more than double, while production of crude steel and primary aluminium will increase at least eightfold (Table 17.1.3).

Driven by the strong growth in materials production, energy consumption will increase between 2009 and 2050 in all the scenarios analysed (Figure 17.1.4). However, there will be a noticeable shift away from coal, and increased use of biomass and waste in the 2DS. This shift in energy consumption will help limit the increase in industrial CO_2 emissions. In the 2DS, emissions in 2050 are about 50% higher than they were in 2010 (Figure 17.1.5). The least intensive industries of the industrial sector contribute about 35%

of the decrease in CO_2 emissions between the 4DS and 2DS in 2050. The improvements in this sector will come in large part from fuel switching and improvements in energy efficiency.

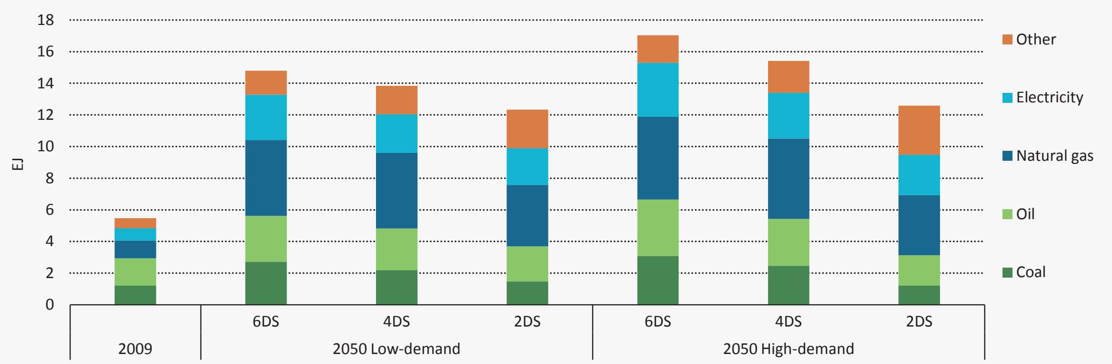
Overall, for the ASEAN industrial sector, fuel switching and energy efficiency will account for 60% of the CO_2 emission reductions in 2050.

Table 17.1.3 Key results for main industrial sectors in ASEAN

		4DS		2DS	
		Low-demand	High-demand	Low-demand	High-demand
	2009	2050	2050	2050	2050
Cement production (Mt)	155	336	384	336	384
Crude steel production (Mt)	17	148	212	148	212
Steel scrap used (Mt)	14	157	223	159	225
Paper and paperboard production (Mt)	20	70	92	70	92
Recovered paper	8	38	46	40	48
Primary aluminium production (Mt)	0.3	7	11	6	10
Electricity intensity of primary aluminium (kWh/t aluminium)	14 882	11 374	11 091	10 963	10 270
HVC production (Mt)	14	37	42	34	36
Ammonia production (Mt)	7	20	22	20	22

Notes: Mt = Million tonnes, kWh = kilowatt-hour.

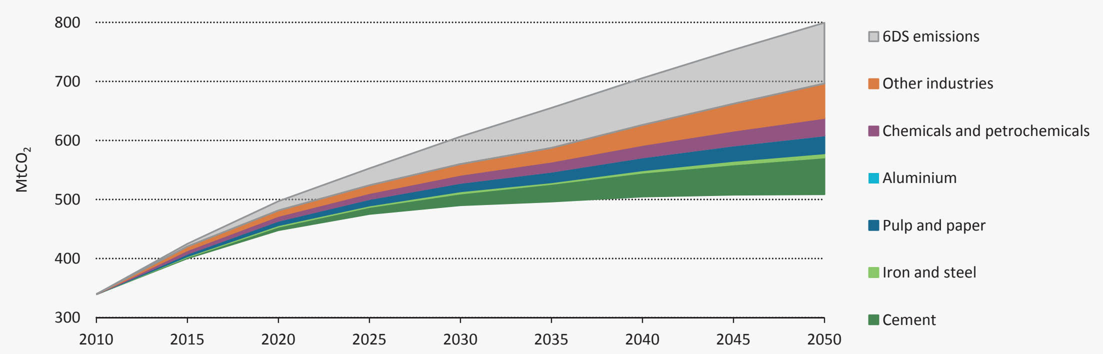
Figure 17.1.4 Industrial energy consumption by energy source in ASEAN



Note: Other includes heat, combustible biomass, waste and renewables.

Key point *The use of fossil fuels decreases from a share of 74% in 2009 to 61% in 2050 in the 2DS.*

Figure 17.1.5 Industrial CO_2 emissions reduction in ASEAN in the low-demand case

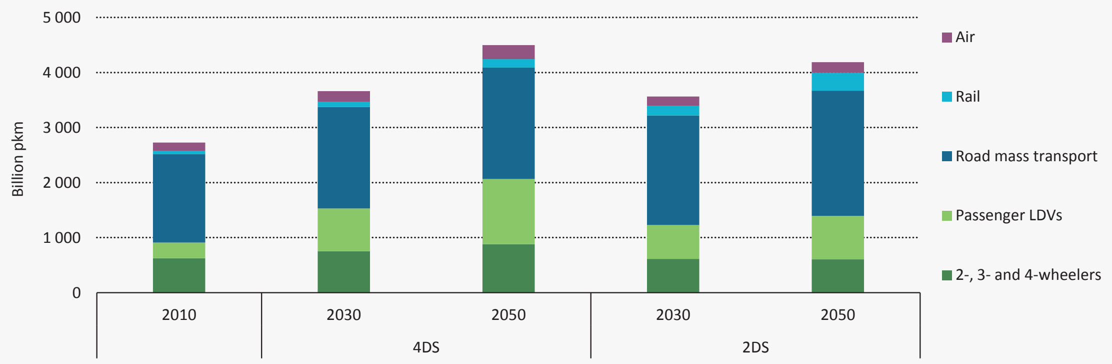


Key point *Efficiency improvements in other industries and the application of CCS in cement will play a key role in restraining the growth in CO_2 emissions.*

Transport

ASEAN's passenger mode shares remain relatively constant across scenarios (Figure 17.1.6), but the increase in the overall sales and stock is rapid (Figure 17.1.8). Personal vehicles (2-, 3- or 4-wheelers) and road mass transport account for the bulk of mode share, with 2-wheelers particularly important in this region, but across all scenarios passenger light-duty vehicles (Passenger LDVs) are projected to account for an increasing share of passenger travel. However, growth in car ownership is significantly slower in the 2DS, in part due to strong investments in mass transit for the benefit of urban dwellers around the region.

Figure 17.1.6 Passenger mode share in the ASEAN region

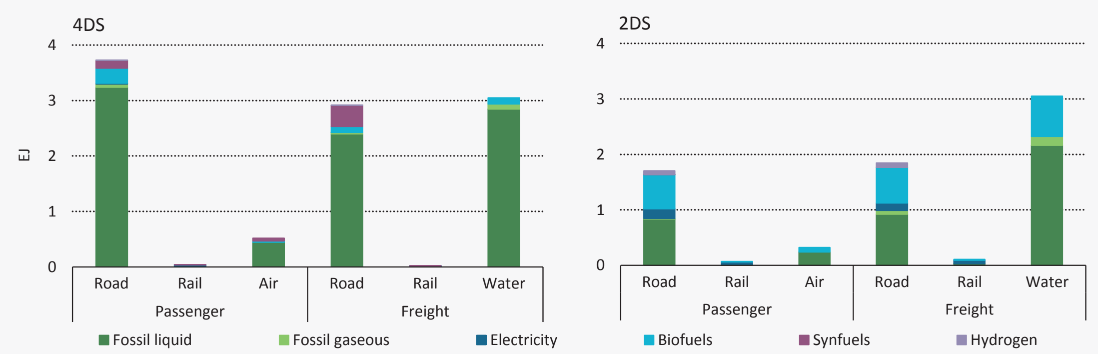


Note: pkm = Passenger kilometre.

Key point *Most of the passenger activity growth is expected to come from passenger LDVs.*

By 2050, transport energy use will become more diverse in the 2DS with biofuel use becoming more popular in the shipping sector, as well as road transport – both passenger and freight (Figure 17.1.7). Road fuel use is cut by nearly half and oil use in road vehicles is cut by much more than half, displaced mainly by biofuels but also by electricity and hydrogen.

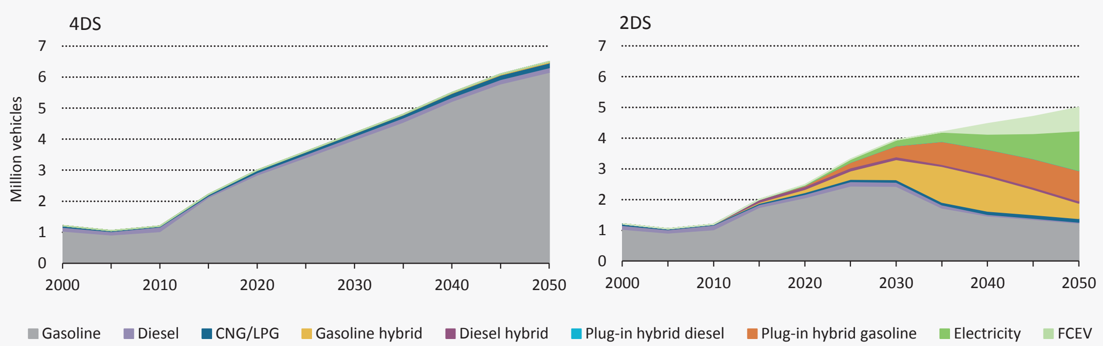
Figure 17.1.7 Transport energy use in 2050 by mode, energy type and scenario



Key point *Shipping energy use is substantial, and efficiency improvements are expected to be limited.*

Plug-in hybrid electric vehicles (Plug-in HEVs), battery-electric vehicles (BEVs), and fuel-cell electric vehicle (FCEVs) together account for almost half of all vehicle sales by 2050, along with relatively sizeable shares of gasoline hybrids and conventional gasoline vehicles (Figure 17.1.8).

Figure 17.1.8 Passenger light-duty vehicle sales by technology type and scenario



Notes: CNG = Compressed Natural Gas, LPG = Liquefied Petroleum Gas, FCEV = Fuel Cell Electric Vehicle.

Key point *Passenger LDVs are expected to grow significantly and continuously in the coming decades.*

Buildings

The ASEAN region already houses a greater population than that of the European Union. However, its countries use four times less energy per capita in the residential sector, and consume six times less electricity. In the residential sector, energy use is dominated by inefficient, traditional biomass: as of 2009, wood, crop bio-matter or cattle waste account for 69% of all the energy used in ASEAN households. The combination of a fast-growing population, which is expected to rise by 30% between 2009 and 2050 (Table 17.1.4), and rapid urbanisation implies that ASEAN cities will add 141 million households by 2050 – the current total number of urban and rural households in the region. This will change the energy mix dramatically, and end-use technology in buildings will play a key role in limiting the impact of increased population on energy and CO_2 emissions.

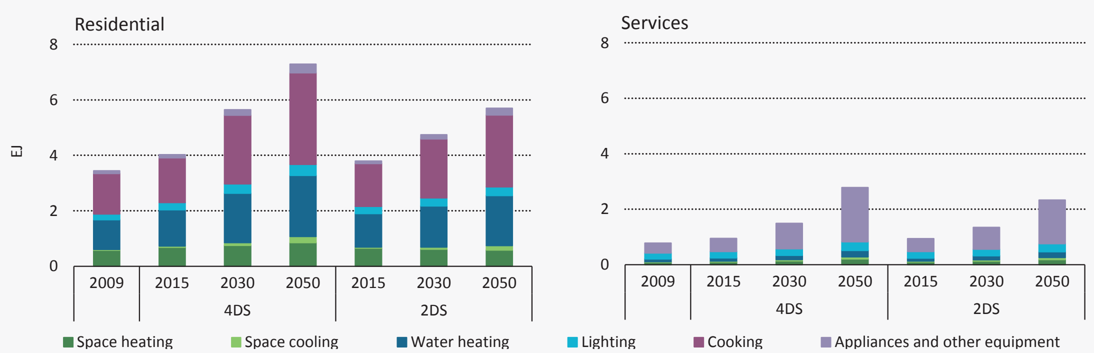
Table 17.1.4 Key activity in the ASEAN buildings sector

	2009	2015	2030	2050	AAGR (2009-50)
Population (million)	575	625	704	756	0.7%
Number of households (million)	141	183	248	309	1.9%
Residential floor area (million m^2)	7 961	9 349	11 941	16 775	1.8%
Services floor area (million m^2)	1 019	1 264	1 885	3 200	2.8%

Notes: AAGR = average annual growth rate, m^2 = square metre.

Despite efficiency gains from switching to more efficient energy sources, notably for cooking in the residential sector, increased activity in the buildings sector results in higher energy consumption in 2050 than in 2009 in any scenario analysed (Figure 17.1.9). In the 4DS, buildings energy consumption is 139% higher than current levels; in the 2DS, it will increase by 90%.

Figure 17.1.9 Buildings energy consumption by end-use in ASEAN



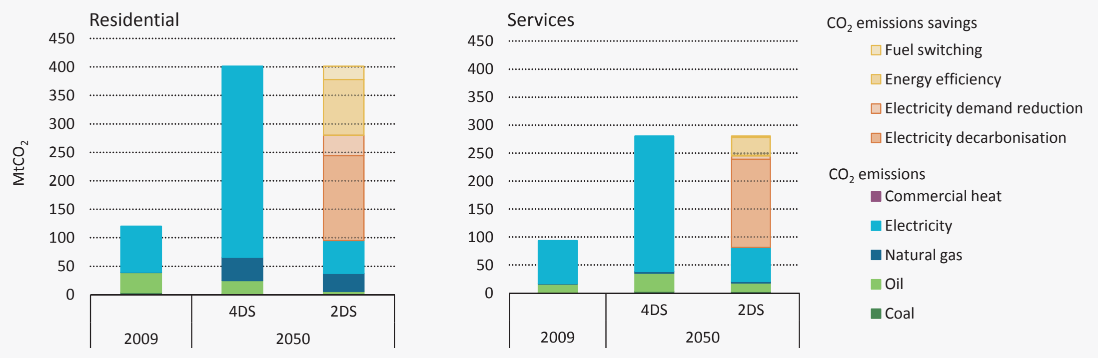
Note: For the service sector, cooking is included in the category appliances and other equipment.

Key point *Strong population growth in ASEAN countries will drive energy demand upwards in all the scenarios analysed.*

Although space cooling accounts for a small share of buildings energy consumption, it deserves special attention. Despite the high number of cooling-degree days in ASEAN countries, air conditioners in buildings remain relatively rare. Space cooling, however, is a latent demand that is highly correlated to affluence. In the 4DS, a fivefold increase in income per capita in 2050 unlocks it, and energy consumption for cooling increases eightfold in the residential sector. The high solar insulation that ASEAN countries receive, which is highest during periods of peak cooling demand, signifies a large technical potential for solar cooling. In the 2DS, as much as 6% of buildings energy demand for cooling is met with solar energy, which in combination with best available technologies (BATs) for heating, cooling and ventilation (HVAC) equipment reduce electricity usage for space cooling by as much as 75% between the 4DS and 2DS. Other technology options in the 2DS include enhanced building shells in new buildings and passive cooling systems, which help reduce the cooling needs.

With widespread electrification and the increased penetration of appliance, electric and electronic equipment, and air conditioners, the decarbonisation of the power sector plays a key role in restraining the growth in the total direct and indirect emissions from buildings; it accounts for about 60% of the reductions achieved in the buildings sector between the 4DS and 2DS (Figure 17.1.10). While energy consumption increases between 2009 and 2050, direct and indirect CO_2 emissions in the 2DS decrease by 17% between 2009 and 2050.

Figure 17.1.10 Buildings CO_2 emissions reductions in ASEAN



Key point *Buildings direct and indirect CO_2 emissions in the 2DS are about 75% lower than in the 4DS.*

2. Brazil

Brazil is the world's fifth-largest country, both by geographical area and by population. With the world's seventh-largest gross domestic product (GDP) in nominal terms, it is the largest economy in Latin America, and an emerging key political and economic leader on both the regional and international scenes. For decades it has been a key participant in developing many international initiatives to reduce greenhouse-gas (GHG) emissions. At the COP15 climate talks in Copenhagen in 2009, Brazil announced one of the most ambitious emissions-reduction targets for an emerging economy, aiming to reduce its GHG emissions by 36% to 39% by 2020 from projected emissions, measured from 1990. This would amount to an absolute reduction of about 20% from 2005 levels.

Although Brazil's primary focus is to reduce emissions in areas such as changes in land use, like agriculture and deforestation, there are several opportunities for abatement in the energy sector, and gains to be made by investing in low-carbon energy projects. The main examples of such opportunities are related to investments aimed at increasing energy efficiency, improving public transportation, deploying renewable energy sources and developing sustainable biofuels. Brazil is already the second-largest producer of biofuels and the third-largest producer of hydropower, and it can take a leadership position in the deployment of low-carbon technologies. However, as Brazil's GDP is assumed to increase by an average of 3.4% per year in the period 2009-50, based on *ETP 2012* projections, annual demand for electricity is expected to grow, and the country faces the challenge of fostering economic development and addressing social inequalities while reducing GHG emissions.

Recent trends in energy

Brazil is the world's ninth-largest energy consumer and, by far, the largest energy consumer in Latin America. In the *ETP 2012* 4°C Scenario (4DS), it is expected to remain in that position, as energy demand is projected to almost double between 2009 and 2050. Brazil's energy mix is currently dominated by oil (40%) and biomass (32%), and their respective shares are expected to decrease to 35% and 15% in 2050 in the 4DS.

Brazil has accumulated exceptional experience in renewable energy, being a country with a very large share of renewables in total primary energy supply (TPES); 45% compared with the 8% average of OECD countries. The power and transport sectors already rely substantially on low-carbon sources. Hydropower represents four-fifths of installed electricity capacity, while ethanol accounts for almost one-fifth of energy demand from transport. Further expansion of renewables is envisaged in the 2020 Brazilian Energy Plan, which expects renewables to reach 47.7% of TPES in 2020. Under the 4DS, renewables reach 48% of TPES in 2050, while the *ETP 2012* 2°C Scenario (2DS) is characterised by a higher share of renewables, accounting for about 53% of TPES. However, the maintenance of a clean energy matrix and further reductions of carbon dioxide (CO_2) emissions in the energy and transport sectors will require substantial efforts and large investments.

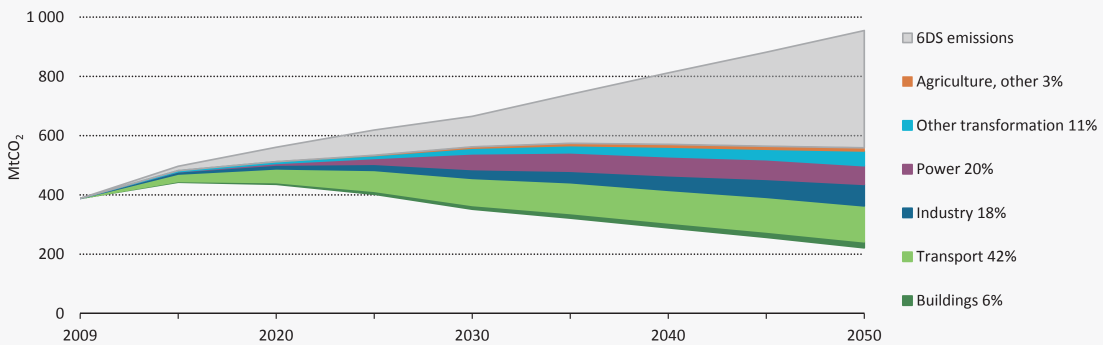
Thanks to deep-water offshore discoveries in recent years, including the Tupi and Jupiter pre-salt fields, in the 4DS Brazil becomes a significant oil exporting country by 2030, when oil production is estimated to reach 11 exajoules (EJ). The deposits are also gas-rich, so the country's natural gas production will increase substantially. But pre-salt oil is hard to access, located up to 6 000 meters below sea level, and preliminary analysis reports high

CO_2 content. Brazil will need to exploit these offshore resources in an environmentally responsible and technologically advanced way, applying CO_2 enhanced oil recovery (EOR) techniques and post-storage in the reservoir to limit CO_2 emissions.

Overview of scenarios and CO_2 abatement options

In 2DS, energy-related CO_2 emissions will be 60% lower compared with 4DS levels (Figure 17.2.1). The transport sector will account for 40% of the overall reductions by 2050. A large increase in biofuel supply, coupled with a reduction of car ownership growth, plays an important role in restraining the increase in CO_2 emissions in the country's energy sector.

Figure 17.2.1 Sectoral contributions to achieve the 2DS compared to the 4DS



Note: Percentages reflect cumulative reductions 2009-2050.

Key point *Brazil's CO_2 emissions will be almost halved by 2050 in the 2DS compared with 2009, with the largest reduction coming from the transport sector.*

Major potentials and challenges

Maintaining a clean electricity matrix while adding capacity

Brazil is going through a period of transition in which its future energy provision structure and consequent technological pathways are being defined. Although accounting for one of the cleanest energy matrices in the world, with electricity consumption per capita still being well below OECD levels, its projected domestic economic growth is expected to put pressure on electricity demand. Government estimates show an annual increase of 4.8% in electricity demand.

In the 4DS, electricity generation is projected to increase by 46% in the next 10 years, with installed new capacity additions being provided mainly from hydro and natural gas, and to a lesser extent also by biomass and wind. As a result, CO_2 emissions from electricity generation increase from 30 to 65 million tonnes of CO_2 (Mt CO_2) between 2009 and 2020 in this scenario.

By 2020 in the 2DS, options with low carbon intensity, such as wind, solar, biomass and nuclear, start adding capacity to the electricity mix, although hydro still dominates the picture. However, significant implementation challenges are involved.

Sustainable development of hydropower

The 2DS assumes continued growth in hydropower capacity from 86 to 101 gigawatts (GW) between 2009 and 2020. This exceeds the trends observed in Brazil's recent past, but is in line with national priorities. In December 2011, the Ministry of Mines and Energy (MME) published its Ten-Year Energy Expansion Plan 2011-2020, which foresees the addition of 69 GW of installed generation capacity (+58%) in the next 10 years. Brazil intends to develop some of its huge unexploited hydro potential, estimated at 180 GW, yet a significant part of it is located in national parks and/or areas inhabited by indigenous communities. In June 2011, the government authorised the construction of what will be the world's third-largest hydroelectric plant after the Three Gorges Dam in China and the Itaipu Dam on the Brazil-Paraguay border. When completed, the total installed capacity of Belo Monte Amazon Dam will be equivalent to 10% of Brazil's current total installed capacity.

Increased electricity supply from large hydroelectric plants involves various problems that, if not dealt with properly, could intensify the use of thermoelectric power and incur higher CO_2 emissions. In particular, difficulties in the environmental licensing process have limited the participation of hydropower in past energy auctions. Controversy around large hydro projects in the Amazon River basin, involving legal challenges and opposition from environmental groups, has caused repeated delays. A number of measures are already being implemented by the government to streamline the environmental licensing procedure for hydropower plants, while ensuring that social and environmental aspects of new projects are taken into account, along with economic, financial and technical factors. Brazil could consider additional opportunities for strengthening strategic planning in the hydropower sector, involving broader multi-sectoral and social participation, which could help accelerate the licensing process.

Brazil has also taken part in a number of collaborations with national and international stakeholders that seek to share expertise, best practices and methodologies related to the sustainability and financing of hydropower. For example, Brazil is bringing its experience and knowledge to the development of a road map on sustainable hydropower, in co-operation with the IEA, to help address untapped hydropower potential in other countries and regions of the world. This could be a fundamental step towards alleviating energy poverty.

Growth of wind generation

Wind energy is a technological area that reflects the Brazilian government's strategic goals for the energy sector. The 2020 Brazilian Energy Plan estimates strong growth in wind energy for the next ten years, rising ninefold from 0.7% to 6.1% of total final consumption in the power sector, and reaching 11.5 GW. In the 2DS, there is an increase in installed capacity in the next decade, reaching 6 GW in 2020.

The development of wind energy in Brazil started in 2002 through the Programme of Incentives for Alternative Electricity Sources (PROINFA), which aimed at diversifying the electricity mix by increasing the use of new alternative energy sources. This model was replaced in 2009 by a new approach of regulated procurement by means of tenders, a type of system that promotes a competitive market and cost-effective projects without the need for subsidies, and that has spurred large investments in wind power. In 2011, the power auctions were hailed as a major success. The average contracted prices for wind were lower than auction prices for thermal electricity, and secured the construction of 2.9 GW of wind farms.

There are some risks associated with these lower prices, however. Competition to reduce costs may increase project vulnerability, particularly among newer, less experienced developers. Also, many of these wind projects have thin equity margins, which means that room for error/delays in projects is much smaller from a financial standpoint. Another important challenge that could delay the implementation of some wind projects regards grid infrastructure, which requires additional investments that cannot be met exclusively by wind-farm developments. The government is working towards the development of a policy and regulatory environment that supports smart grid investments and enables the integration of wind energy.

Also, although funding from the Brazilian Development Bank (BNDES) has played an important role in providing low-cost financing to a number of wind power projects, further development of the sector, beyond the capacity planned under the PROINFA target and the auctions' results, would require securing greater financial resources to ensure the continued cost competitiveness of wind power generation with other power sources. This could include the use of carbon-credit market incentives.

Developing sustainable biofuels for transportation

Brazil is a world leader in ethanol from sugar cane production and use. It is the world's second-largest producer of ethanol and the world's second-largest exporter, after the United States. In terms of volume, ethanol already accounts for almost half of Brazil's light-duty transportation fuels. Still, the transport sector accounts for more than half of Brazil's total CO_2 emissions.

In the 2DS it is projected that biofuels will represent half of the country's transport sector energy needs, most being used for road transport, some in the marine transport sector, and a limited amount as fuel for aviation.

Brazil has a long history of replacing gasoline with ethanol. Starting in 1975 with Brazil's National Alcohol Programme (Proalcool), which established mandatory blends for ethanol in gasoline (progressively increased to 25%), by 1985 more than 85% of Brazil's new cars were alcohol powered, and 2 million of the total 10 million cars were fuelled completely by ethanol. In the 1990s, higher sugar prices combined with lower oil prices resulted in a supply crisis and return to gasoline-run cars, culminating in the deregulation of the sector in the late 1990s. However, in 2003, with the launch of flex-fuel vehicles (FFV) – a technology that allows the vehicles to run on gasoline, ethanol or a mix in any proportion in the same tank – consumption of ethanol in the domestic market started to increase again significantly. This represented a new phase of sustained growth for ethanol, and in early 2010 the FFV fleet reached 10 million vehicles or approximately 42% of the light vehicle fleet in the country.

Brazil has been successful in integrating biofuels on a large scale into its economy. However, the expansion of the Brazilian sugar-energy industry faces some important barriers. Key challenges include artificially low prices for gasoline and oil price volatility (which affect the attractiveness of ethanol), the fluctuation of ethanol prices (caused, for instance, by weather conditions and rises in sugar prices), and the need for a sustained expansion of the sugar-energy industry to meet the strong growth of the FFV fleet.

To address these barriers, Brazil should consider tying the price of gasoline to the international market. Additional measures to promote the attractiveness of ethanol price over gasoline could include reducing taxes on ethanol (which are higher than for diesel), improving the infrastructure and supply system, reducing agricultural and industrial costs, and making flex-fuel engines more efficient. In response to strong demand and the need for increased production, Brazil approved a plan in 2010 to invest over USD 400 billon in the industry in order to meet the increase in domestic demand, while also targeting a future tripling of ethanol exports.

Although in the next ten years Brazil's focus should be on expanding its first-generation biofuel industry, further investments in second-generation biofuels should be a strategic priority, especially because Brazil currently seems to be the only country with considerable potential to produce second-generation biofuel feedstocks sustainably, mainly on underutilised pastureland (IEA, 2010).

In addition, the country could have a very important role in the next decade in providing its technological capacity and expertise for the development of biofuels in many countries in Latin America and Africa. This would bring down the demand for oil and help to create greater energy security.

Conclusion

Attention to opportunities for clean energy developments will be important in the next decade, particularly at a time when Brazil's focus is on the major infrastructure investment obligations required to prepare for the 2014 World Cup and 2016 Summer Olympics. It is therefore important that renewable sources are successful in surpassing carbon-based thermal plants in cost and reliability, in order to add capacity to the electricity mix and contribute to the projected growth in generation demand.

Power generation from hydropower and wind offer considerable potential, and Brazil plans strong growth in these technologies. In order to exploit these opportunities effectively, the government has already started developing co-operative planning strategies to address the difficulties in the environmental licensing procedure for hydropower plants. Additional focus could be placed on setting up a policy and regulatory environment that supports smart grid investments, and ensuring the continued cost competitiveness of wind power with other power sources.

In addition, Brazil should take advantage of its long experience and knowledge to expand production and use of sustainable biofuels in the transport sector, avoiding the GHG emissions associated with the use of the ethanol substitute. The lack of market-determined gasoline prices is an important factor affecting ethanol competitiveness. Policy instruments promoting the sustained attractiveness of ethanol compared to gasoline should be considered by the government in order to speed industry expansion to meet growing demand.

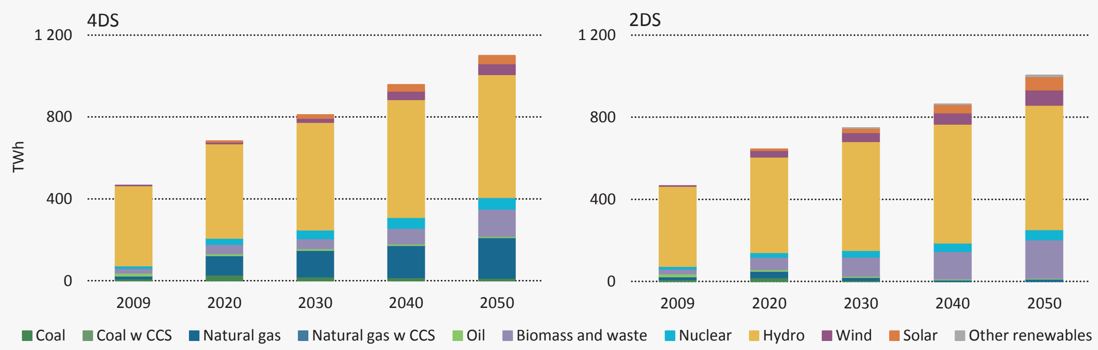
Model results for Brazil by sector

Power

Due to hydropower, electricity in the Brazilian power system has a CO_2 intensity of 60 grammes per kilowatt-hour (g/kWh), the same as the level achieved globally by 2050 in the 2DS. In the 4DS, strong growth in biomass-based generation and hydropower limits, coupled with the uptake of natural gas, lead to an intensity increase to around 80 g/kWh (Figure 17.2.2).

In the 2DS, further cost-effective reductions in intensity are realised by a mix of wind, solar and biomass. Renewables provide around 80% of these reductions relative to the 4DS scenario, with the largest part coming from biomass. Electricity savings in the end-use quarters are responsible for around one-fifth of the abatement. As a result, CO_2 emissions in the power sector drop to 12 million tonnes (Mt) in 2050, a more than 50% reduction relative to 2009 (Figure 17.2.3).

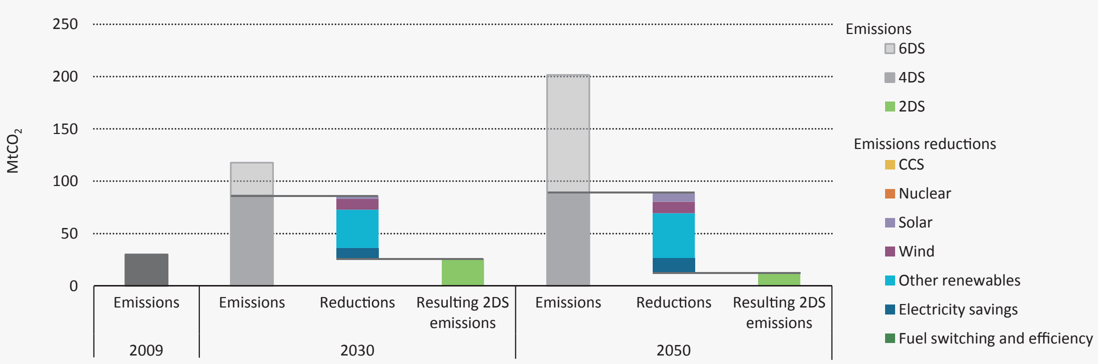
Figure 17.2.2 Electricity generation in the 4DS and 2DS



Notes: Other renewables include geothermal and ocean energy, TWh = terawatt-hours.

Key point *Renewables, notably hydro, biomass, wind and solar, cover the increase in electricity generation in the 2DS.*

Figure 17.2.3 Annual CO_2 reductions in the power sector to reach the 2DS (relative to the 4DS)



Note: Other renewables include biomass, geothermal and ocean energy.

Key point *Today's already low CO_2 emissions in the Brazilian power sector are more than halved in the 2DS.*

Industry

Industry used 3.5 EJ of energy in 2009, accounting for 40% of the final energy used in Brazil. Of the five most intensive industrial sectors, the iron and steel sector is, by far, the largest user of energy; in 2009, it used 25% of the energy consumed by the industry as a whole. The second-largest user, chemicals and petrochemicals (including the energy used as feedstock), accounted for 18%. From a global perspective, Brazil accounts for 2.7% of global industry energy use. Biomass and waste are a key energy source in Brazil. In 2009, biomass and waste provided 38% of industrial energy needs. About 17% of the global industrial use of biomass and waste is from Brazil.

Production of key material is expected to increase at a sustained pace between 2009 and 2050. Production of crude steel will remain important, increasing more than threefold between 2009 and 2050 (Table 17.2.1). All the scenarios, 6DS, 4DS and 2DS, are driven by the same level of materials production. The differences between the scenarios lie in the different primary resources and processes used in material production (*e.g.* higher share of recycling in the 2DS).

Driven by the strong growth in materials production, energy consumption will increase between 2009 and 2050 in all the scenarios analysed. Biomass and waste will continue to play an important role; its share will remain relatively stable in the 6DS and 4DS between 2009 and 2050 (Figure 17.2.4). Brazil already uses high shares of biomass, and is one of the only users of charcoal in the iron and steel industry.

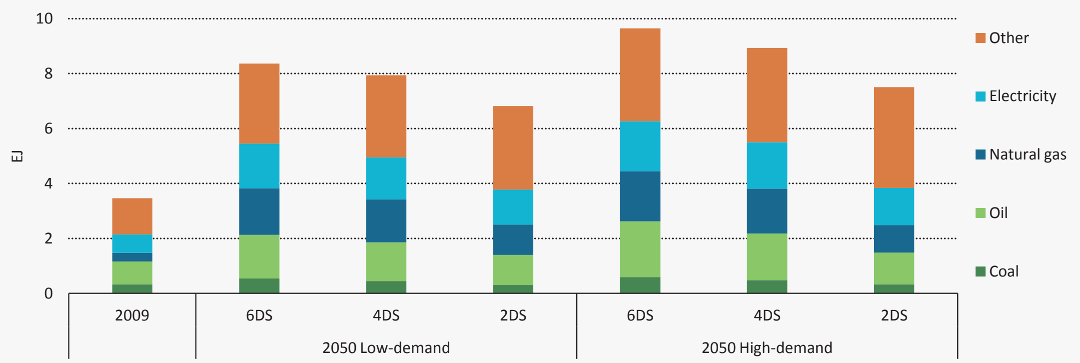
While energy consumption will double between 2009 and 2050 in the 2DS, industry CO_2 emissions will only be 16% higher in 2050 in the 2DS than they currently are, and 32% lower than they would have been in 2050 in a 4DS. About 50% of the reductions from the 4DS can be attributed to the steel and chemicals industry (Figure 17.2.5). Deep reduction in these sectors can be achieved through the application of carbon capture and storage (CCS) and improvements in energy efficiency. Overall, energy efficiency accounts for 46% of the reductions in the industrial sector. The other, less-intensive industries will also play a key role in reducing CO_2 emissions. These reductions would mostly come from a switch away from oil to natural gas and renewable energy sources and greater efficiency.

Table 17.2.1 Key results for main industrial sectors in Brazil

		4DS		2DS	
		Low-demand	High-demand	Low-demand	High-demand
	2009	2050	2050	2050	2050
Cement production (Mt)	52	100	122	100	122
Crude steel production (Mt)	27	73	83	73	83
Steel scrap used (Mt)	10	37	43	38	44
Paper and paperboard production (Mt)	9	27	40	27	40
Recovered paper (Mt)	4	14	20	14	21
Primary aluminium production (Mt)	2	2	3	2	3
Electricity intensity of primary aluminium (kWh/t aluminium)	15 629	13 361	12 657	12 986	11 580
HVC production (Mt)	7	16	21	15	17
Ammonia production (Mt)	1	4	4	4	4

Note: HVC = high-valued chemicals.

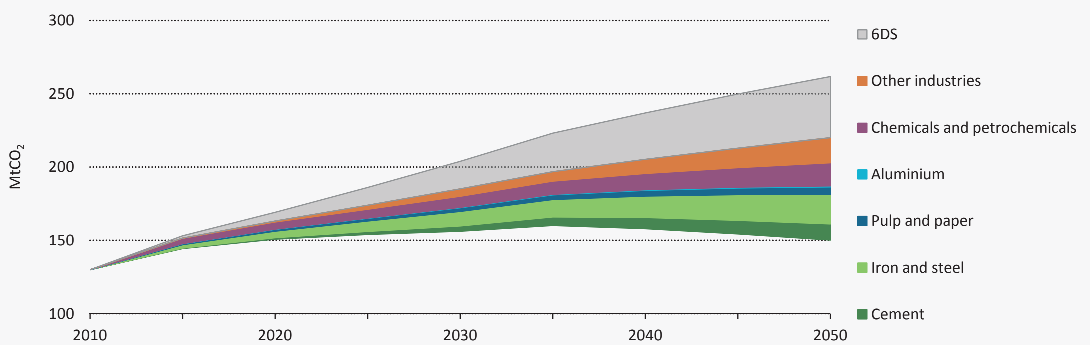
Figure 17.2.4 Industrial energy consumption by energy source in Brazil



Note: Other includes heat, combustible biomass, waste and renewables.

Key point *The use of biomass, waste and other renewables will account for 40% to 50% of industrial energy consumption under the 2DS.*

Figure 17.2.5 Industrial CO_2 emissions reductions in Brazil in the low-demand case



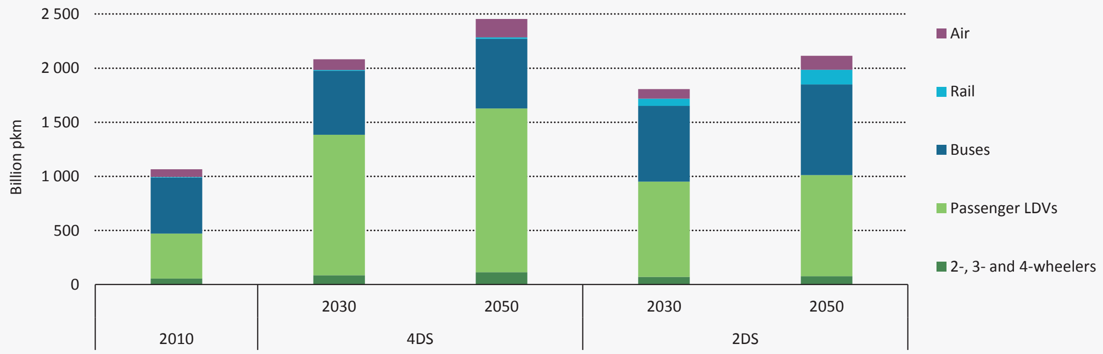
Key point *While CO_2 emissions continue to grow to 2050, implementation of the 2DS will limit this increase to 16% from today's level.*

Transport

The rise of megacities and the trend towards a highly urbanised population slows the growth of car ownership in Brazil, despite GDP per capita rising steadily to 2050. Nonetheless, annual car sales do triple over this period in the 4DS and are just slightly lower in the 2DS. With strong investments in urban and intercity mass transport (rail and bus), the passenger travel share of these modes remains quite high in the 2DS (Figure 17.2.6). Ongoing, massive investments will be required to ensure high-quality transit systems around Brazil, such as are currently on display in Curitiba (bus rapid transit [BRT]) and to some degree in Rio de Janeiro (BRT and metro lines).

The large agricultural area in Brazil will help to increase the use of biofuels to decarbonise transport; a very high share of cane and cellulosic bioethanol, along with biomass-to-biodiesel fuels, are included in the 2DS. Brazil is likely to remain one of the top producers and users of biofuels in the decades to come, with biofuels representing half of the country's transport sector energy needs (Figure 17.2.7). Flex-fuel vehicles, which are similar to gasoline vehicles, will remain market leaders in the 4DS. High biofuels compliance will also be needed in alternative technologies adopted in the 2DS, such as hybrids and diesel engines for heavy vehicles, to combine the efficiency of advanced vehicles with the low carbon content of biofuels (Figure 17.2.8).

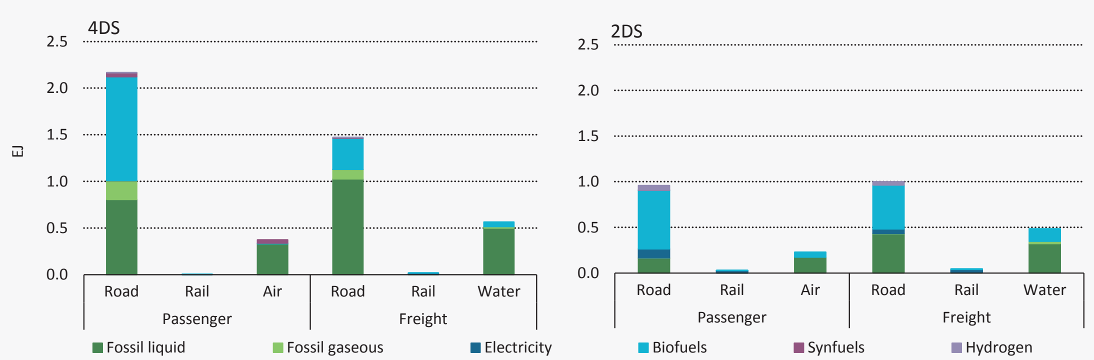
Figure 17.2.6 Passenger mode share in Brazil



Notes: LDV = light-duty vehicles, pKm = passenger kilometres.

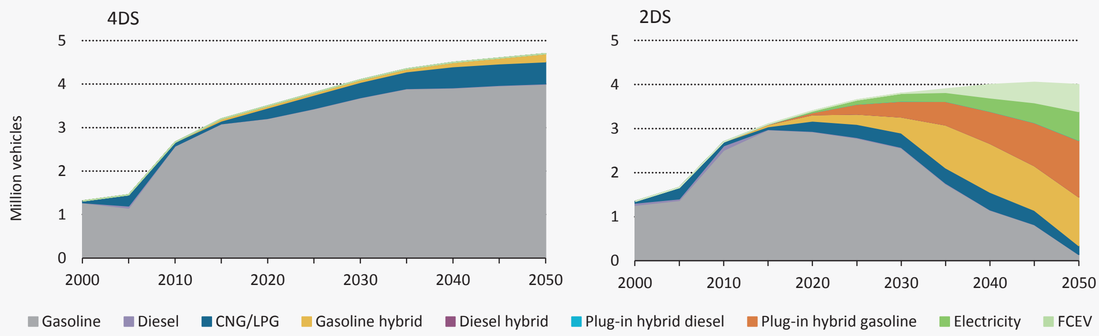
Key point *Individual modes will represent most of the energy use in the coming years.*

Figure 17.2.7 Transport energy use in 2050 by mode, energy type and scenario



Key point *Biofuels will play a key role in the Brazilian transport sector.*

Figure 17.2.8 Passenger light-duty vehicle sales by technology type and scenario



Notes: CNG = compressed natural gas, LPG = liquified petroleum gas, FCEV = fuel cell electric vehicle.

Key point *Most of the gasoline vehicles today are capable of running with a mix of up to 85% of ethanol.*

Buildings

The buildings sector, including the residential, commercial and public service sectors, currently accounts for about 16% of total final energy consumption in Brazil.

The key drivers for the buildings sector – number of households and floor area – are expected to increase substantially to 2050 (Table 17.2.2). The population in Brazil is expected to increase only by 0.3% per year to around 223 million in 2050. However, the trend towards fewer people per household will accelerate and, as a result, the total number of households will increase by 1.7% per year. The floor area of the service sector is expected to grow rapidly as economic growth continues for the entire 2009 to 2050 period.

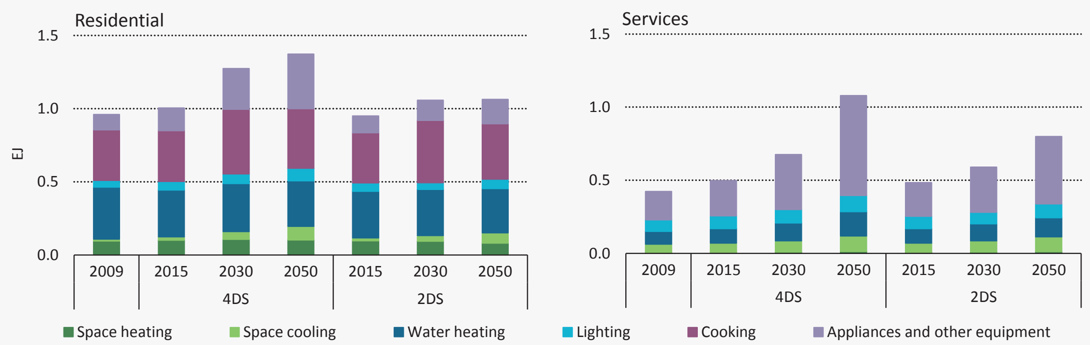
Table 17.2.2 Key activities in the buildings sector

	2009	2015	2030	2050	AAGR (2009-50)
Population (million)	194	203	220	223	0.3%
Number of households (million)	47	64	85	93	1.7%
Residential floor area (million m^2)	3 202	3 773	4 879	6 443	1.7%
Services floor area (million m^2)	371	412	475	581	1.1%

Notes: AAGR = average annual growth rate, m^2 = square metre.

As a result of increased activity in the buildings sector, energy consumption will be higher in 2050 than it was in 2009 in any scenario analysed (Figure 17.2.9). In the 4DS, energy consumption in 2050 is almost two times higher than at present; in the 2DS, it will increase by only 36%. The lower rate of increase in the 2DS is attributable, in part, to the improvement in building shells, which helps reduce cooling needs; the adoption of best technologies for cooling and water-heating equipment; and greater use of electricity in the residential sector.

Figure 17.2.9 Buildings energy consumption by end-use in Brazil

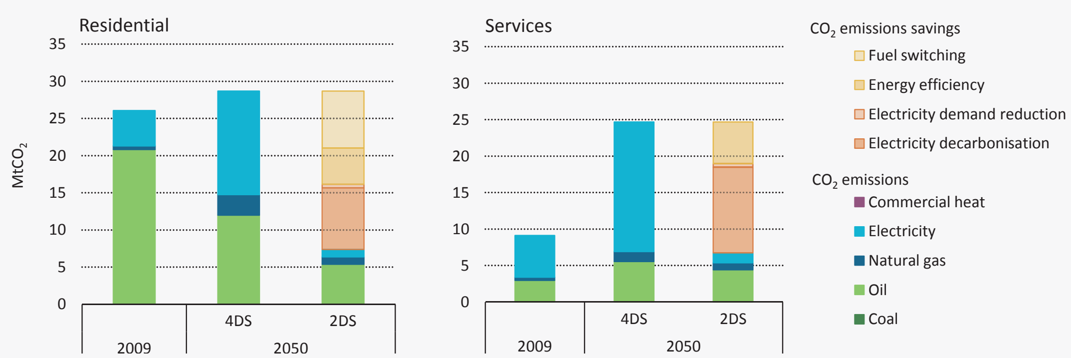


Note: In the service sector, cooking is included in appliances and other equipment.

Key point *While the number of households will double between 2009 and 2050, residential energy consumption will increase by only 13% in the 2DS.*

Electricity will account for 65% of buildings energy consumption in the 2DS in 2050, up from 49% today. This increase is driven by the increase in appliance ownership and the proliferation of electric and electronic equipment. As a result, the decarbonisation of the power sector will play a key role in reducing direct and indirect CO_2 emissions from the buildings sector and will account for 51% of emissions reductions between the 4DS and 2DS (Figure 17.2.10). Improvements in energy efficiency and fuel switching will together account for 47% of the reductions.

Figure 17.2.10 Buildings direct and indirect CO_2 emissions and reduction in Brazil



Key point *Improvements in energy efficiency will have an important role to play in reducing CO_2 emissions from fossil fuels.*

3. China

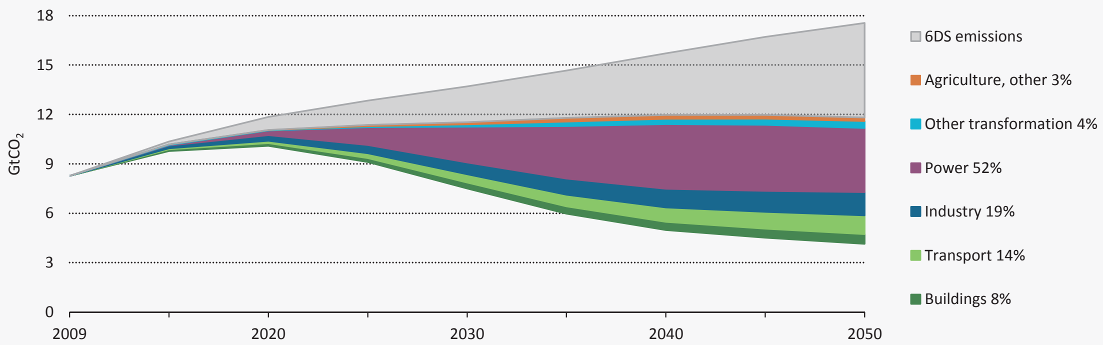
China confronts all the key challenges faced worldwide in making the transition to a more sustainable, yet affordable and secure, energy system. In China, these challenges are compounded by the enormity of scale and continuing economic expansion. What happens in China could profoundly affect the world as a whole, as the solutions China finds to its problems may then be implemented elsewhere. The application of the strong, sustained actions needed to produce the *ETP 2012* 2°C Scenario (2DS) could cut China's projected CO_2 emissions in 2050 by well over half compared with 2009 levels (Figure 17.3.1). If China succeeds in this it will provide a powerful example for the world.

Sustainability has long been a theme in Chinese energy policy. Already in the 1980s, the national commitment to improving energy efficiency led to a long-term decline in energy intensity (energy use per unit of gross domestic product [GDP]) seen nowhere else. China has the potential to become much more efficient, and the mandatory targets of the country's Five-Year Plans (FYPs) provide inspiration for increasingly sophisticated measures. More recently, a growing commitment to non-fossil energy for power generation has prompted fast-growing fleets of nuclear, wind and solar power stations.

At the same time, coal will remain the mainstay of China's energy system for many years. To a certain extent, natural gas may displace coal. However, an increasing reliance on imports is likely, even with possible future domestic supplies of unconventional gas. Even though coal use peaks at some point in all the *ETP 2012* scenarios, in 2050 it will still be a major contributor to the total primary energy mix, mainly for power generation, but also as an industrial fuel. Growth in renewable energy sources will be the most important contributor for decarbonisation of the Chinese energy system, particularly in electricity generation. While carbon capture and storage (CCS) is an important technology to reduce emissions, there is still great uncertainty in China – as elsewhere – regarding the technological, cost and policy factors that will determine whether, when and at what scale CCS can be deployed.

Fortunately, China is not limiting itself to any single fuel, technology or approach in pursuing more sustainable, lower-carbon energy. In the policy arena, for instance, administrative measures were instituted in the 11th Five-Year Plan (FYP [2006-10]) to meet national, local and facility-level targets for energy intensity improvements alongside market-based and fiscal measures. The same is being done for the CO_2-intensity targets in the 12th FYP (2011-15), which, among many other measures, provides for regional pilot programmes for carbon emissions trading. The country's leadership has long emphasised the role of improved technology in attaining a variety of national socioeconomic development goals, and energy is one of the areas receiving the most attention. Legislation, rules and regulations, standards, directives, and other instruments continue to be issued across the entire range of technologies, sectors and energy sources covered in this report. This is matched by efforts to improve implementation, and to utilise international co-operation among government, business and academic organisations. A November 2011 white paper (Information Office of the State Council) summarises China's many efforts in response to climate change. The approaches described therein are essential to the 2DS path described below.

Figure 17.3.1 Sectoral contributions to achieve the 2DS compared with the 4DS



Notes: Percentages reflect cumulative reductions 2009-50.

Key point *China's emissions are halved by 2050 in the 2DS, with the power sector providing half of the cumulative emissions reductions compared with the 4DS.*

Energy efficiency and decarbonisation of the power sector

Energy efficiency

Greater efficiency remains the single most important approach for improving energy sustainability in China, particularly in the earlier part of the scenario period. Reducing energy demand is essential to decarbonisation, since most increments in energy use are more cheaply supplied by coal than by lower-carbon sources. This is reflected in the constantly renewed attention accorded to efficiency. The 12th FYP sets a target of reducing energy use per unit of GDP by 16% in 2015 compared with 2010. (This follows strong performance in the 11th FYP, when the country came very close to reaching the goal of lowering energy intensity by 20% in 2010 compared with 2005.)

A variety of programmes and regulations are supporting these goals. In 2011, for instance, new demand-side management implementation measures went into effect, mandating that utilities meet a certain percentage of electricity demand each year through end-use efficiency measures by customers. The success of the "Top-1 000 Energy-Consuming Enterprises" programme in fostering energy savings by the country's largest industrial users, by setting targets and detailing investment and operational plans to achieve them, is now being expanded to cover 10 times as many enterprises, thereby covering the great majority of industrial energy use nationwide. Appliance, equipment, motor vehicle and building standards have long been in effect, and China continues to gradually tighten those standards and improve enforcement mechanisms.

The State Council released a Comprehensive Programme for the Reduction of Emissions and Energy Savings during the 12th FYP period (August 2011) that features, among other elements, a section on technology. In addition to calling for increasing resources, expanding education and technology research organisations, and mounting national research projects, the plan also singles out particular technologies, such as rare earth permanent magnet motors, semiconductor lighting, utilisation of low-temperature waste heat, and geothermal technologies. In many sectors, detailed plans have a technology focus. The Ministry of Transport, for instance, has developed a 12th FYP for energy savings and emissions reductions that has a strong emphasis on technological improvements in fuel economy for vehicles of all sorts, development and deployment of electric and other vehicles – requiring parallel development with the utility sector of smart grids – and system technologies such as advanced information systems and traffic controls.

The agencies and organisations tasked with technology development, from groups such as the Ministry of Science and Technology, the Chinese Academy of Sciences and the Chinese Academy of Engineering, to sectorally focused research organisations and the research and development (R&D) arms of state-owned and non-state firms, are all augmenting R&D spending on energy efficiency technologies, in renewable energy and in other clean energy arenas. A series of tax breaks and subsidies with limited lifetimes, both for manufacturers and purchasers of new equipment, have been put in place to foster basic research and to bring newly developed equipment to market.

Because of the continuing electrification of the country, and since the prime mover for most electric power is the most carbon-intensive fuel, coal, the greatest potential for emissions reduction through efficiency is in electricity end use. As the industrial sector still accounts for the largest share of electricity use, industrial uses (such as motor systems) hold the greatest potential, and are therefore the focus of policy and technological development.

Through efforts like this, China could achieve the goals of the 2DS. If successful, the means by which it does so will provide a singularly powerful example to the many other emerging economies that face similar challenges.

Decarbonisation of the power sector

Even with full attainment of its efficiency goals, China will need to do more to reduce the carbon intensity of its power sector. The 12th FYP goals recognise this, and the carbon intensity target is, in fact, a 17% reduction in 2015 compared with 2010, one percentage point more stringent than the energy intensity target. To take account of continued strong growth in overall energy demand, as well as more-rapid-than-expected expansion of renewables, the government has recently increased the initial targets for additions to renewable power generating capacity in the 12th FYP. China stands at 260 GW of hydropower in 2015, 100 GW of wind (including 5 GW of offshore wind), 13 GW of biomass power, 10 GW of solar (including 1 GW of concentrating solar photovoltaic [CSP]), 100 MW of geothermal, and 50 MW of tidal. The 2015 target for additions to the nuclear fleet is 40 GW, although safety checks in the wake of the Great East Japan Earthquake have slowed the pace of construction somewhat.

China's investments in renewables have been impressive, and the scale of activity in China – both in manufacturing and installation – means that it is a leader in bringing down the cost of making and operating renewable power facilities. Other developments are important as well, including the rolling out of better high-capacity long-distance transmission, electricity storage and smart grids to integrate larger shares of geographically dispersed renewables into more responsive regional and national grids. This is not just a hardware problem. Utility regulations and pricing regimes that provide appropriate incentives to generators and grids to work together, and to integrate demand-side resources, will need to improve significantly if the recent momentum in expansion of renewables is to be maintained.

China's plans call for tremendous expansion of the nuclear fleet, and the 2DS also envisions a substantial contribution. This is an area in which new technologies are called for, and one where China has strong technical resources, both domestic and through international collaborations, to draw on. With the largest current programme in the world for building nuclear power plants, and national and local administrations favourable to such development, both for energy security reasons and for local environmental improvements, the country seems ripe for deployment not only of next-generation conventional reactors, but demonstrations of innovative reactor types developed at home. While cost, and perhaps increasingly safety and security concerns, will prevent too-rapid expansion, China has the potential (perhaps more than in other countries) to see development consistent with *ETP 2012*'s more ambitious scenarios.

Because of heavy reliance on coal, improving its current and future use is critical to reducing the carbon intensity of China's power sector, even in the 2DS. There, most coal-fired power plants are phased out – a very distant possibility in the minds of many, requiring the early retirement of large numbers of relatively efficient plants using relatively inexpensive, mainly domestic fuel. This would entail strong measures such as a high carbon tax (one at a low level has been discussed seriously in China), carbon trading, and perhaps a permanent programme of retiring the oldest, least-performing plants based on the recent and quite successful programme of plant phase-outs (about 70 GW in the 11th FYP). As a result of these closures, and the construction of large numbers of supercritical and ultra-supercritical coal plants (which now account for over 200 GW of China's 670 GW of coal-fired power capacity), average efficiency and environmental performance has been improving dramatically. Simply based on their size and age, a significant portion of China's coal-fired power stations could be suitable for retrofitting of post-combustion carbon capture, if plant economics are favourable and access to transport and storage are available. Despite widespread scepticism about its technical, economic and regulatory feasibility (as elsewhere), Chinese generators and research teams have been very active in research, development and demonstration (RD&D), and also in initiating ideas for integrated coal refineries that would produce power, heat, chemicals and fuel from coal, and be suitable for capturing carbon as well.

Conclusion

The commitment of China's government to a lower-carbon path is clear, both in its domestic initiatives and in its continuing engagement internationally, where it displays active technological co-operation and growing leadership in climate negotiations. Climate policy has clearly been mainstreamed in the energy sector, with energy companies actively involved in informing policy and R&D. Climate change, and energy sustainability more broadly, however, are far from the only priorities that the country must work on. In the environmental arena, water quality and availability issues are of even greater urgency than atmospheric pollution, and despite the country's success in lifting most people out of poverty, there is great pressure to continue improving well-being and equality.

Nevertheless, climate change and technological improvements are constant, major themes, not only for the national government, but for the local administrations that wield considerable power to direct investment activities and that are essential to enacting directives that support national strategic aims. Moreover, China's powerful energy companies are seeing promise not just in meeting domestic demand for lower-carbon energy services, but, as with the international solar photovoltaics (PV) market, in seeking opportunities for meeting demand elsewhere. China is not an island, and must play an integral part in the lower-carbon energy future of the world.

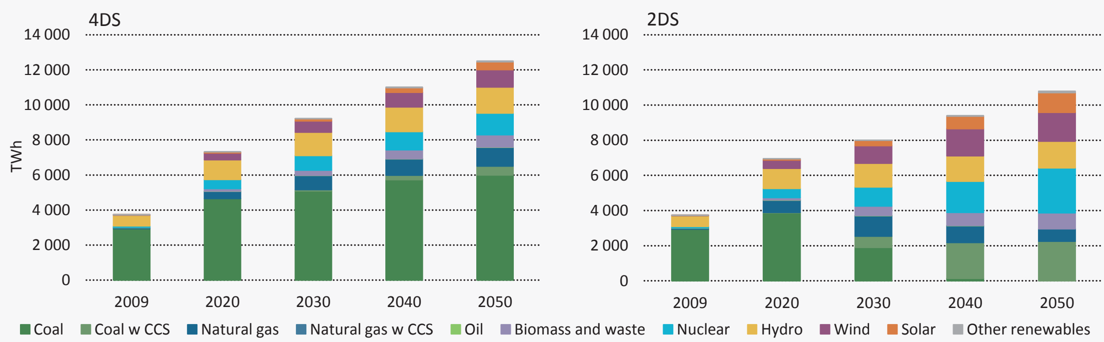
Model results for China by sector

Power sector

In the *ETP 2012* 4°C Scenario (4DS) coal will continue to play in important role in China's electricity mix in 2050, though its share decreases from almost 80% in 2009 to around 50% in 2050 due to growth in natural gas, nuclear and renewables, notably wind and hydro (Figure 17.3.2).

In the 2DS, CO_2 emissions in the power sector are reduced by more than 80% in 2050 compared with 2009. Nuclear alone provides 26% of the CO_2 reductions in the power sector in 2050. All renewables combined provide a similar reduction, with wind and solar power being the most important contributors (Figure 17.3.3). The share of renewables in power generation increases from 17% in 2009 to almost 50% in 2050. The use of coal depends on the success of CCS. Around 1.7 Gt of CO_2 from coal is captured in the power sector in 2050, corresponding to 23% of the annual CO_2 savings relative to the 4DS.

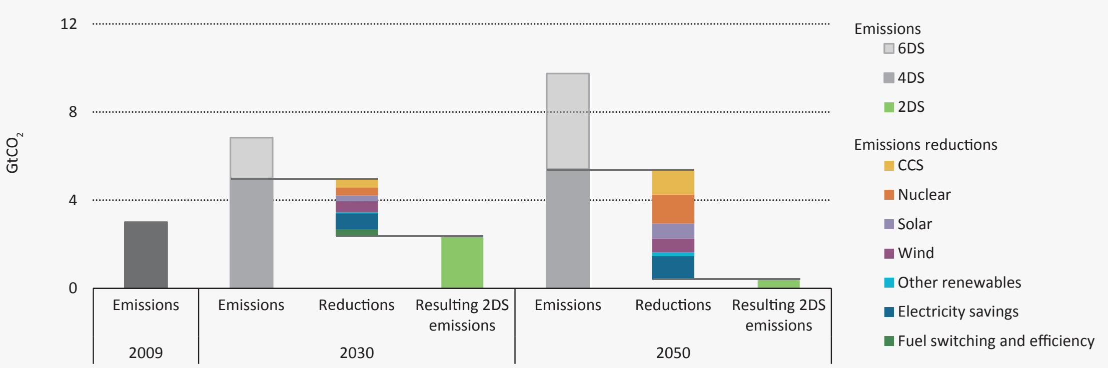
Figure 17.3.2 Electricity generation in China in the 4DS and 2DS



Notes: Other renewables include geothermal and ocean energy. TWh = terawatt-hours.

Key point *The renewable share in the power mix in 2050 increases from around 30% in the 4DS to almost 50% in the 2DS.*

Figure 17.3.3 Annual CO_2 reductions in the power sector to reach the 2DS (relative to 4DS)



Note: Other renewables include biomass, geothermal and ocean energy.

Key point *Nuclear power and CCS each provide around one-quarter of the annual CO_2 reductions in 2050 to reach the 2DS.*

Industry

Industrial energy consumption in China reached 35 exajoules (EJ) in 2009, accounting for 53% of the total final energy consumption of the country. China is the world's largest industry energy user, accounting for 28% of global industrial energy consumption. The final energy mix of industry is largely dominated by coal, which accounts for more than 60% of the energy consumed (Figure 17.3.4). Electricity, the second most important energy source in the end-use mix, accounts for 21%. The share of coal use is expected to substantially decrease in the future and, by 2050, will account for a third of total industry energy consumption.

China dominates global industrial production and is the largest producer of cement, crude steel, aluminium, and, since 2008, paper and paperboard. These four intensive industrial sectors account for 60% of China's total industry energy consumption and over 80% of total direct CO_2 emissions. Production of materials is expected to continue growing over the next 40 years, although at a slower pace (Table 17.3.1). The noticeable exception is production of cement, which is expected to peak by 2020 and slowly decline afterward. Nevertheless, per capita consumption of cement will continue to be strong and, by 2050, will still be at least 35% higher than the global average.

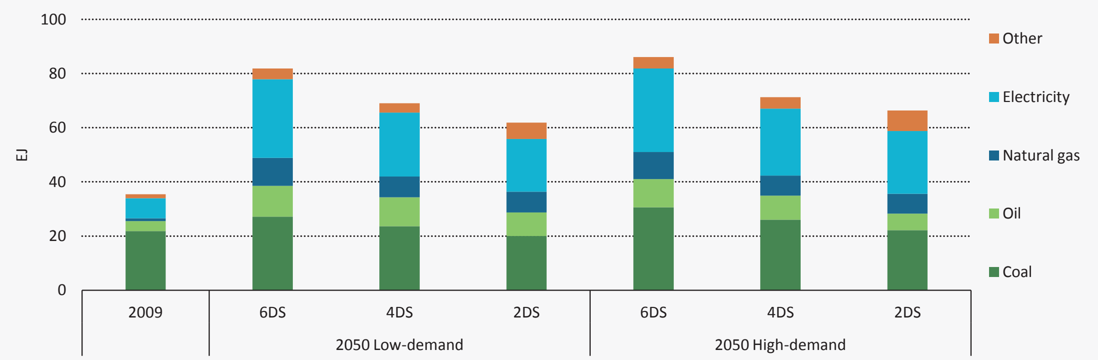
Given the importance of the Chinese industry at the global level, it will account for almost 30% of the global CO_2 reductions between the 2DS and the 4DS in 2050. All industries will have a key role to play in reducing China's industrial CO_2 emissions (Figure 17.3.5). About 60% of the reductions that can be achieved in the iron and steel sector are from the application of CCS. China is already taking action to shut down small, inefficient cement kilns. Furthermore, because most cement plants will already be built between 2020 and 2025 when CCS can start playing a role, this option can only be applied to refurbished units. As a result, the most important option to reduce CO_2 emissions in cement is to increase the share of alternative fuels and clinker substitutes. Overall, the adoption of best available technology (BAT) in the different industries and implementation of energy efficiency measures would account for about 40% of the CO_2 reductions in 2050 in the 2DS compared with the 4DS.

Table 17.3.1 Key results for main industrial sectors in China

		4DS		2DS	
		Low-demand	High-demand	Low-demand	High-demand
	2009	2050	2050	2050	2050
Cement production (Mt)	1 630	914	1 097	914	1 097
Crude steel production (Mt)	574	699	829	699	829
Steel scrap used (Mt)	70	208	245	219	255
Paper and paperboard production (Mt)	90	236	353	237	353
Recovered paper	40	129	185	132	189
Primary aluminium production (Mt)	13	37	51	35	48
Electricity intensity of primary aluminium (kWh/t aluminium)	14 144	11 700	11 204	11 374	10 325
HVC production (Mt)	35	201	156	190	134
Ammonia production (Mt)	51	56	64	56	64

Note: HVC = high-valued chemicals.

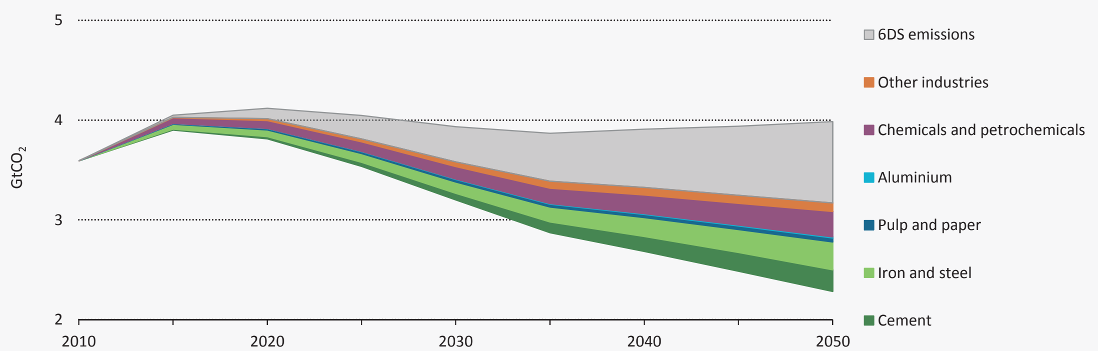
Figure 17.3.4 Industrial energy consumption by energy source in China



Note: Other includes heat, combustible biomass, waste and renewables.

Key point *Greater electrification of the industry sector will help limit the use of coal in China.*

Figure 17.3.5 Industrial CO_2 emissions reductions in China in the low-demand case



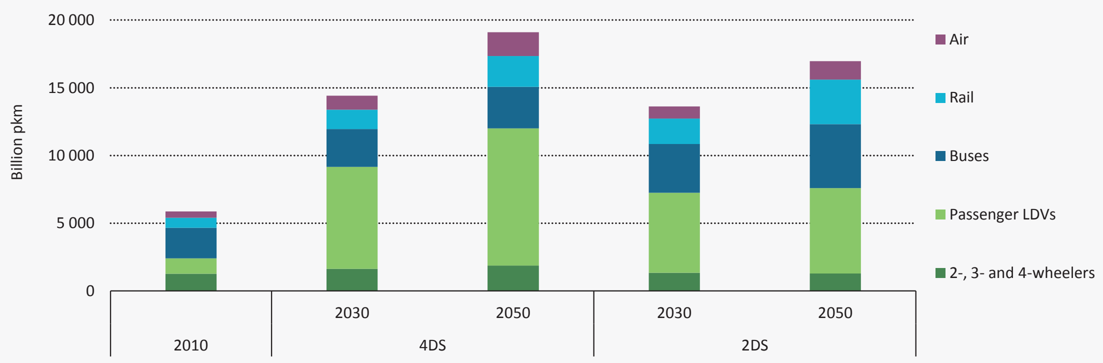
Key point *China has the potential to reduce its CO_2 emissions by over 40% in the next 40 years.*

Transport

China's car share of passenger mobility is expected to approach saturation by 2050 with sales reaching more than 60 million per year in the 4DS, about the same as today's world total and a tenfold increase of 2009 sales. In the 2DS, with ambitious policies to slow car growth and to shift towards more efficient modes of transportation, the peak car share is reached in 2030 and then declines (though total car use still increases, but at a slower rate than other modes). In this scenario, mass transportation within and between cities gains significant market share (Figure 17.3.6), and car sales are somewhat lower in 2050 than in the 4DS, though still several times greater than today.

By 2050 in the 2DS, the energy feeding the transport sector comes from a wide range of energy sources, thanks to a portfolio of vehicle technologies (Figures 17.3.7 and 17.3.8). China is expected to play a leadership role in deploying plug-in vehicles; battery electric vehicles (BEVs) and plug-in hybrid-electric vehicles (HEVs); and eventually fuel-cell electric vehicles (FCEVs). China's target of 5 million plug-in vehicles by 2020, if achieved, would likely give it the most such vehicles of any country. As with OECD countries, plug-in vehicles would cover more than half the vehicle fleet in 2050, resulting in strong shifts towards low-carbon fuels and decarbonisation of the sector. This is due as well to the strong decarbonisation that occurs in electric power generation in this scenario.

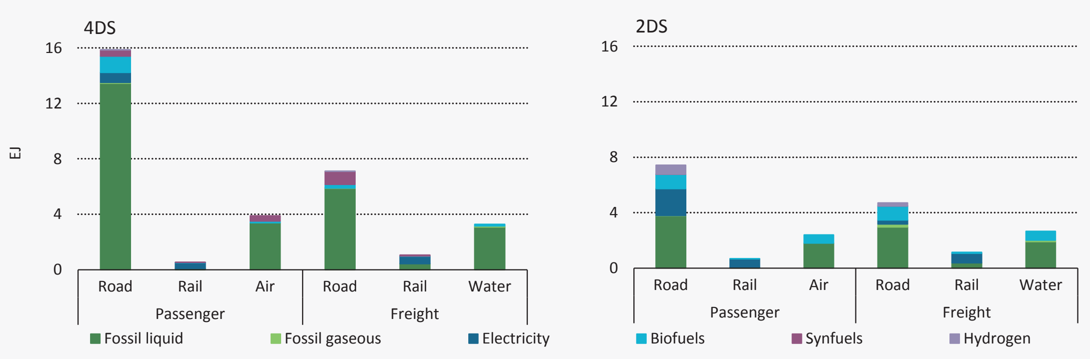
Figure 17.3.6 Passenger mode share in China



Note: pkm = passenger kilometre.

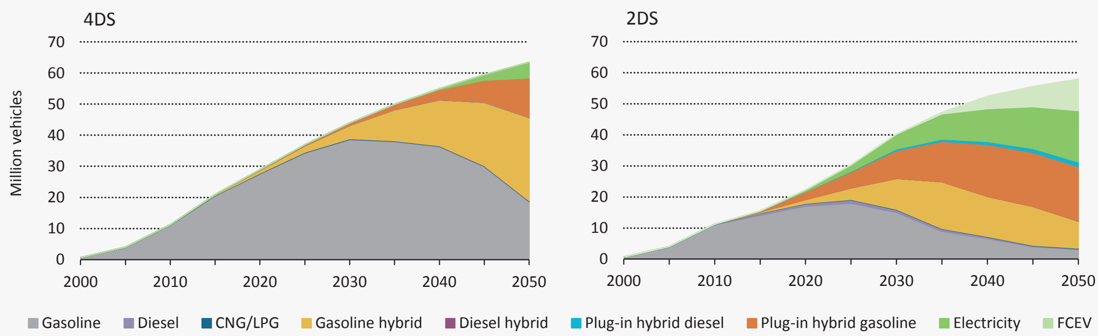
Key point *High sales of passenger light-duty vehicles (PLDVs) are likely to continue in the decades to come.*

Figure 17.3.7 Transport energy use in 2050 by mode, energy type and scenario



Key point *With a fast-growing fleet, upcoming policies on vehicles' fuel economy can have a substantial impact on future fuel demand.*

Figure 17.3.8 Passenger light-duty vehicle sales by technology type and scenario



Notes: CNG =compressed natural gas, LPG = liquefied petroleum gas.

Key point *The Chinese technology portfolio is expected to evolve quickly, with rapid penetration of advanced technologies.*

Buildings

Direct CO_2 emissions from the Chinese buildings sector accounted for 5% of total China CO_2 emissions in 2009. This relatively low share compared with the OECD average of over 10% is partly due to the size of the industrial sector in China, but also due to the widespread use of biomass in rural and less developed areas, the relatively low penetration of appliances and cooling equipment, and sub-standard heating facilities in many northern areas. Residential and services' floor areas are expected to increase by 27% and 47% respectively in the period from 2009 to 2050 (Table 17.3.2). The average lifetime of buildings in China is not well known, but could be as low as 25 to 30 years. All these factors signify that urban development and regeneration activity could remain high for many years to come. Early and decisive action is important if China is to avoid the risk of locking into a high-energy and high-carbon building stock. Direct CO_2 emissions in the 2DS in 2050 are 320 $MtCO_2$, which is around 35% lower than in the 4DS in the sector as a whole.

Table 17.3.2 Key activity in China's buildings sector

	2009	2015	2030	2050	AAGR (2009-50)
Population (million)	1 338	1 378	1 402	1 306	-0.1%
Number of households (million)	385	403	443	460	0.4%
Residential floor area (million m^2)	42 867	46 727	50 886	54 352	0.6%
Services floor area (million m^2)	9 997	11 397	15 750	16 365	0.9%

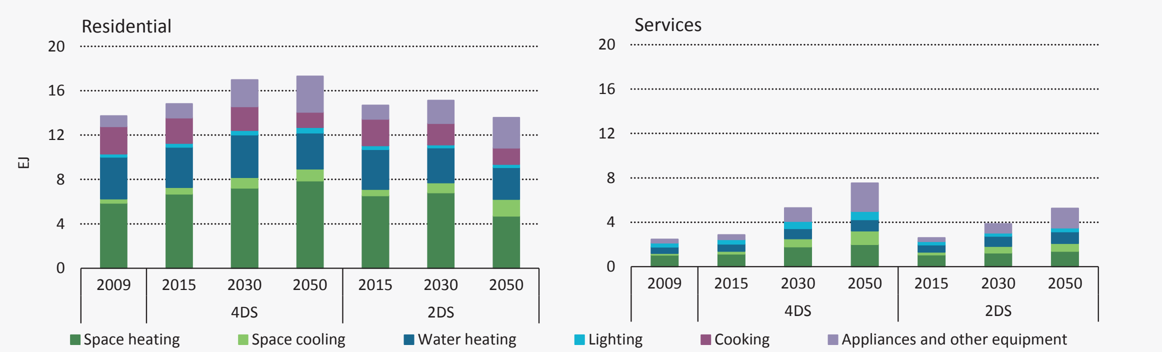
Notes: AAGR = average annual growth rate, m^2 = square metre.

Reflecting greater access to commercial fuels in the residential sector, both electricity and gas increase dramatically in the 4DS and the 2DS by 2050 (between four- and fivefold). Electricity dominates across all the end uses in the buildings sector in the 4DS, rising from about 15% of China buildings energy consumption today to more than 45% in 2050. As a result, a virtually decarbonised power sector will help deliver over 55% of all direct and indirect CO_2 savings between the 4DS and 2DS (Figure 17.3.10). Among the technology options that would help limit the use of electricity, energy efficient appliances in Chinese households save 133 TWh of electricity, equivalent to the annual output of almost two power plants the size of the Three Gorges Dam.

Despite the increase in the number of households, energy consumption for residential cooking will decrease by about 40% between 2009 and 2050 in the 2DS scenario. Most of this decrease will be achieved by moving away from inefficient traditional biomass and by a greater penetration of modern commercial fuels.

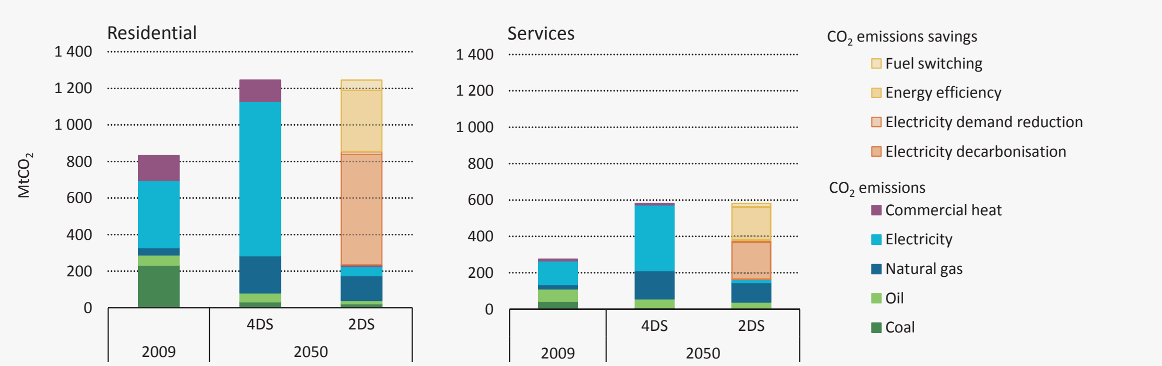
Vast differences in China's climatic zones have a strong influence on technology options available for energy efficiency and CO_2 abatement. In fact, space conditioning (heating and cooling) holds by far the largest potential for energy reduction across all end uses (Figure 17.3.9). In northern areas the potential lies in improving the energy efficiency of the heating supply, which at present is largely centralised and antiquated. In later years, higher incomes and the drive for private ownership of individual heating plants see high-temperature carbon-free solutions penetrate the market. These include biomass boilers and – aided by cost reductions in the intervening years – micro co-generation units. In the central climatic transition areas, the same drivers fuel a high penetration of bi-modal heat pumps. In the southern region where cooling dominates, a variety of technologies, including highly efficient rooftop units (RTUs) in commercial areas and high-efficiency heat pumps in residential areas, will play a key role in reducing cooling demand.

Figure 17.3.9 Buildings energy consumption by end use in China



Key point *Reduced energy demand in space heating and residential cooking will be central in restraining the growth in buildings energy consumption.*

Figure 17.3.10 Buildings CO_2 emissions reductions in China



Key point *Of the reductions in 2050 between the 4DS and 2DS, 57% will be from the decarbonisation of the power sector.*

4. European Union

The main principles of European Union (EU) energy policy are well established: having put its energy system on a decarbonisation pathway, especially emphasising the growing contribution of renewable energy, Europe has been and is likely to remain in the forefront of climate policy. Restructuring of the European gas and electricity system, based on unbundled networks that provide third-party access, is well under way, as is the process of integrating the competitive segments into a single European market. The recent decline of internal oil and gas production has led to a rapid increase in import dependency. A more systematic approach for managing these fuels is needed, and will require major infrastructure investments as well as enhanced energy relations with key producing countries. Clearly, a range of important challenges should shape energy policy in the coming decade.

The economic environment has significant influence on European energy policy: even if it is successfully resolved, the Eurozone crisis will have major implications. Energy demand will be lower than previously projected, which will likely ease, at least to some degree, the burdens of decarbonisation and import dependency. Yet the prevailing macroeconomic situation affects the financial capability of the private and public sectors. Both are emphasising caution regarding investments and budgetary commitments, and the need for cost-effective energy policy.

Efficient competition is, without doubt, the most powerful mechanism to enforce economic efficiency. In electricity, policies to integrate power markets and expand interconnections should continue. Greater competition for wholesale markets has been a remarkably successful policy for conventional power generation. But the large majority of new supply coming to the European system is renewable electricity. At present, feed-in tariffs at the national level are the dominant driver of investment, and competition is limited. Because they provide adequate investment security, feed-in tariffs are an effective policy to jump-start development of a new technology. As renewable investment is reaching a macroeconomically important scale, energy policy needs to consider a transition to a more market-based approach, parallel to the completion of the single market from both an infrastructure and regulatory point of view. The policy vision should be to develop a single, integrated competitive market in low-carbon electricity. For very important technologies, such as onshore wind and solar photovoltaics (PV), "learning-by-doing" improvements have exceeded expectations. Other innovations may encounter greater challenges, so energy policy needs to retain a strategic flexibility over technologies.

Current European energy policy envisages a large-scale deployment of variable renewable energy sources (varREs), particularly wind and solar power. Some of this generation, such as offshore wind on the North Sea, will be located far from the consumption centres. Measurable acceleration of efforts to develop the transmission system is needed, with a focus on linking clusters of renewable production with load centres and enabling the use of flexibility resources on a European scale. A genuinely integrated system will be better able to cope with the growing variability of supply. Dispatchable power plants and energy storage facilities (such as pumped storage hydro) will continue to play an instrumental role in providing flexibility. But increased physical volatility is likely to translate into financial volatility; thus, the risk of under-investment in flexibility is real and might necessitate market design reforms. A strong interest in harmonising market design and investment incentives on a European level reflects understanding that segmented initiatives in an interconnected system are likely to lead to distortions. A more elastic demand response is an important complement to production flexibility in energy policy. Demand response should be linked to production through efficient market signals delivered by a smart grid. The information technology (IT) to support demand response already exists; the policy and regulatory framework needs to be developed further.

The future of nuclear power in Europe is uncertain: some countries recently implemented phase-outs; others are keen to keep or acquire nuclear. But even in supportive political frameworks, both investment financing and project management capability seem to fall short of the replacement investment needed as current capacities are retired beyond 2020. Nuclear is still the largest low-carbon electricity source in Europe by far; a continental-scale phase-out would put additional burden on renewable deployment to achieve climate objectives. Those countries that aim to retain nuclear will need to design and implement policies to tackle the associated financial challenges.

Deployment of carbon capture and storage (CCS) is lagging. In the next decade, Europe needs to take action on its policy commitments to facilitate initial deployment.

The European Union Emissions Trading Scheme (EU ETS) is the largest single carbon-pricing mechanism in the world. Unfortunately, its success threatens to be undermined by a combination of initial oversupply of emissions allowances in the market, weaker than expected electricity demand and strong growth of renewable energy, which are driven by policies outside the trading system. Given the inherent efficiencies of market-based policies, the EU ETS should remain the cornerstone of European climate policy. Nevertheless, policy considerations aimed at enhancing coherence between renewable policies and the ETS would be justified.

The potential to enhance energy efficiency in Europe is large. Reducing the market and institutional barriers that hinder improved energy efficiency should be a key energy policy priority. As the building and vehicle stocks represent a considerable proportion of the energy efficiency potential, the actual savings are most likely to be in gas and oil. Ongoing electrification of the energy system is likely to drive up electricity demand in Europe despite stringent application of energy efficiency policies.

Even with strong efforts on renewable deployment and energy efficiency, Europe will almost certainly face an increasing import dependency of oil and gas as indigenous resources are depleted. As a result, policies aimed at enhancing energy security will become more important. Enhancing competition in the natural gas market appears to be the area in which European energy policy can make the most measurable difference, across both internal and external dimensions.

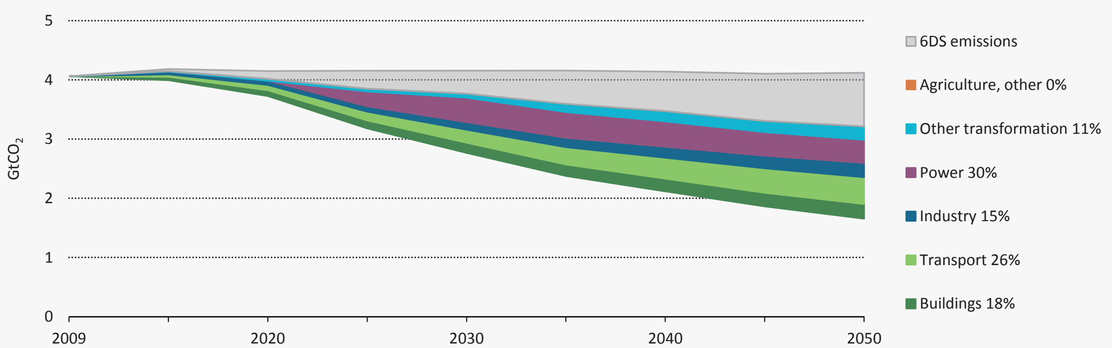
The internal dimension is the completion of the single gas market in terms of market integration and physical infrastructure. Development of gas trading hubs and gas-to-gas competitive trading is especially important, as Europe needs efficient price signals provided by transparent, liquid and trusted markets that are able to replace oil price indexation (a pricing regime that probably has lost its economic foundation due to the decreasing physical substitutability of oil and gas). The changing role of gas, with a stronger focus on backing renewable energy, calls for more efficient, more liquid markets as well as more flexible infrastructure. Policies aimed at encouraging sustainable use of Europe's unconventional gas production are also important, as this new supply would create additional competition.

The external dimension is aimed at developing new gas supply sources and the infrastructure needed to transport them to the European market. Most of the actual project development will be undertaken by private corporations, and any such project must be commercially viable. Nevertheless, major new gas infrastructure projects face a host of financial, regulatory and often geopolitical obstacles; maintaining a supportive policy framework remains essential.

Model results for the European Union by sector

In the *ETP 2012* 4°C Scenario (4DS), the European Union experiences a slow but steady decline in CO_2 emissions after 2020 (through to 2050) thanks to a range of measures and CO_2 pricing policies consistent with that scenario. In the *ETP 2012* 2°C Scenario (2DS), reductions begin by 2015 and after 2020 are achieved on a faster and steeper basis (Figure 17.4.1). By 2050, CO_2 emissions fall to 1.7 gigatonnes (Gt), less than half the level seen in the 4DS, reflecting faster uptake of a range of key technologies. About one-third of the additional CO_2 reductions in 2050 come from the transport sector and one-quarter from electric power. Buildings and industry provide smaller additional reductions.

Figure 17.4.1 Sectoral contributions to achieve the 2DS compared with the 4DS



Note: Percentage numbers reflect cumulative reductions 2009-50.

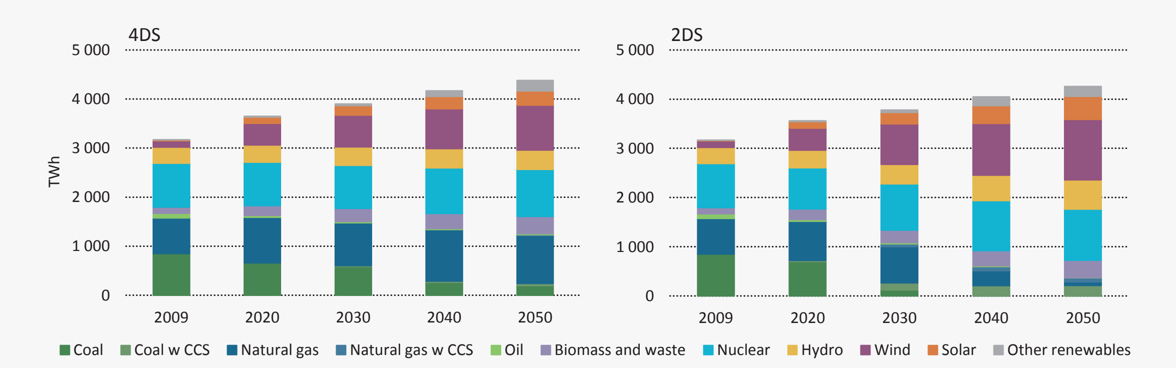
Key point *The power and transport sector provide more than half of the cumulative reductions needed to achieve the 2DS relative to the 4DS.*

Power sector

In the 4DS, CO_2 emissions in the power sector are reduced by more than 60% by 2050 compared with 2009, mainly driven by the deployment of wind power. Gas maintains its share in electricity generation over the period, whereas coal generation falls by more than 75% compared with 2009 (Figure 17.4.2).

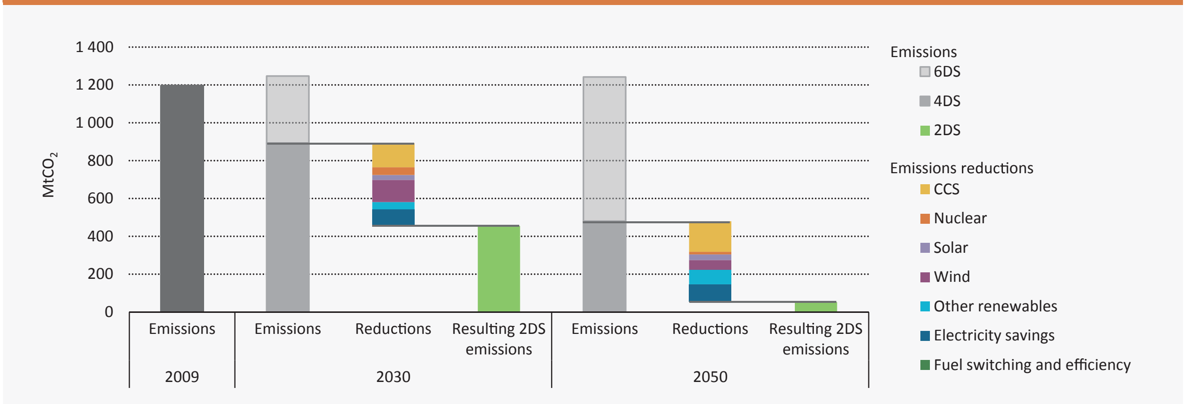
In the 2DS, renewables in the power system exceed 60% of electricity generation by 2050 and are responsible for 37% of the additional CO_2 reductions compared with 4DS (Figure 17.4.3). As renewables show a strong growth in the 4DS, reaching a share of 50% in the generation mix in 2050, they don't provide that much additional reduction in the 2DS. The capacity of coal- and gas-fired power plants with CCS reaches 62 GW in 2050 in the 2DS and provides a similar annual CO_2 reduction to renewables in 2050, with a share of 38%.

Figure 17.4.2 Electricity generation in the 4DS and 2DS



Key point *Renewables cover two-thirds of the electricity mix in 2050 in the 2DS, with wind power alone reaching a share of 30% in the mix.*

Figure 17.4.3 Annual CO_2 reductions in the power sector to reach the 2DS (relative to the 4DS)



Note: Other renewables include biomass, geothermal and ocean energy.

Key point *Renewable and CCS each provide almost 40% of the CO_2 reductions in 2050 in the power sector.*

Industry

In European Union countries, industry used 14.7 exajoules (EJ) of energy in 2009, accounting for 28% of total EU energy consumption and 12% of global industrial energy use. Oil, natural gas and electricity dominate the final energy mix of industry, each accounting for about 25% of total energy consumption.

In the short term, production of materials will increase at a relatively fast pace as the economy recovers from the global economic crisis. Afterwards, production of key industrial materials will remain relatively stable (Table 17.4.1). The low-demand variant of the scenarios assumes a modest decline in OECD countries; the high-demand variants highlight moderate demand growth. For non-OECD countries in the European Union, both variants assume moderate growth in production.

Significant energy and CO_2 savings in European industry are possible through the implementation of today's best available technologies (BATs). It is estimated that the application of BATs could save about 1.5 EJ, the equivalent of 10% of current energy consumption in industry. Some of this potential will be realised as old, inefficient capacity is refurbished or scrapped and replaced.

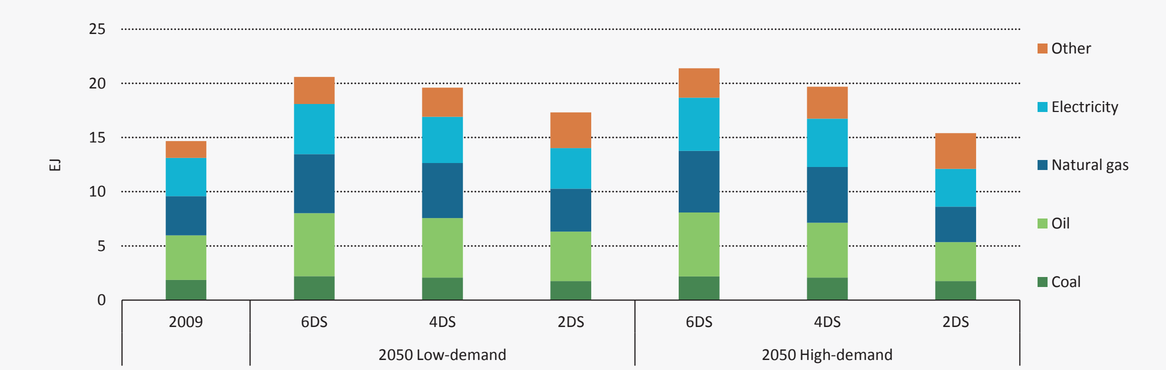
Improved energy efficiency and fuel switching are important options for the European Union, together accounting for 21% of the total reductions in 2050 in the 2DS compared with 4DS; the share of alternative fuels will increase from 15% in 2050 in the 4DS to 20% in the 2DS (Figure 17.4.4). CCS offers the largest single option to reduce industrial CO_2 emissions. Without CCS, industrial CO_2 emissions in 2050 would only be 15% lower than today's level; application of CCS brings the reductions to almost 40%. The chemicals and iron and steel sectors in the European Union account for more than half of all industrial energy use and CO_2 emissions, and represent two-thirds of the potential savings in 2050 in the 2DS.

Table 17.4.1 Key results for main industrial sectors in the European Union

		4DS		2DS	
	2009	Low-demand 2050	High-demand 2050	Low-demand 2050	High-demand 2050
Cement production (Mt)	219	230	239	230	239
Crude steel production (Mt)	139	266	266	266	266
Steel scrap used (Mt)	76	181	180	185	183
Paper and paperboard production (Mt)	87	91	101	91	101
Recovered paper (Mt)	45	57	64	59	66
Primary aluminium production (Mt)	4	6	9	5	8
Electricity intensity of primary aluminium (kWh/t aluminium)	15 828	13 489	12 352	13 103	11 221
HVC production (Mt)	48	94	85	88	71
Ammonia production (Mt)	14	29	31	29	31

Note: HVC = high-valued chemicals.

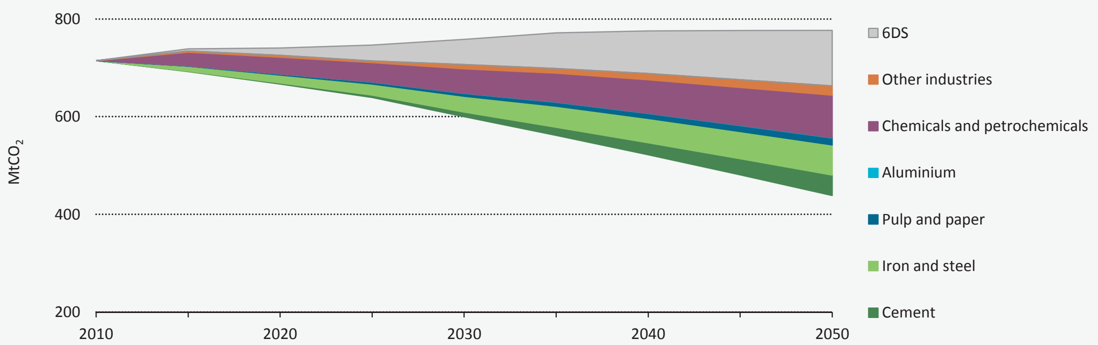
Figure 17.4.4 Industrial energy consumption by energy source in the European Union



Note: Other includes heat, combustible biomass, waste and renewables.

Key point *Under the 2DS, energy consumption will remain relatively stable between 2009 and 2050.*

Figure 17.4.5 Industrial CO_2 emissions reductions in the European Union in the low-demand case

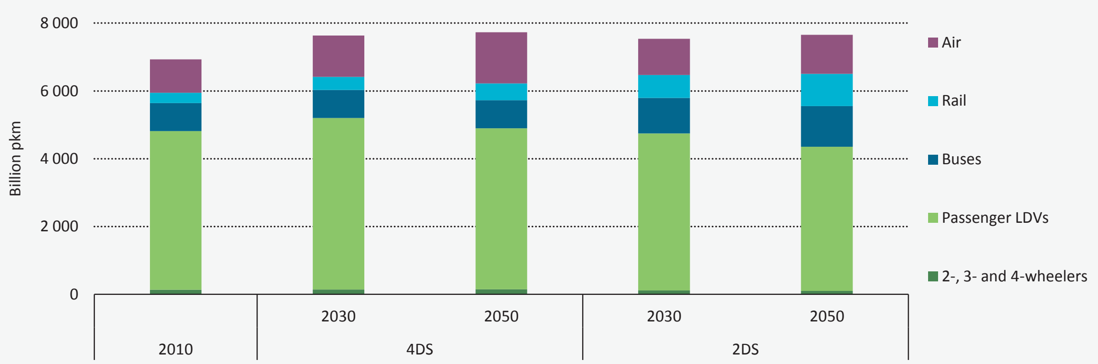


Key point *Chemicals and petrochemicals will account for the largest share of emissions reductions in the 2DS.*

Transport

In the 4DS, car ownership in Europe sees about a 20% increase between 2009 and 2050, even though in many Western European countries the market is already close to saturation. The increase occurs primarily in the newer EU member states. Air travel is projected to rise from today's 15% share of passenger travel to around 20% by 2050 (Figure 17.4.6). The 2DS includes some shifting from car and air travel to bus and rail transport systems; the share of public transport for both road and rail transport more than doubles by 2050. This reflects both an opportunity to rationalise travel systems using cost-effective planning and transit investments, and the need to use modal shift toward high-efficiency modes as part of an overall sustainable transport strategy. Such a strategy will provide a range of important benefits, such as cutting traffic congestion and improving road safety.

Figure 17.4.6 Passenger mode share in the European Union

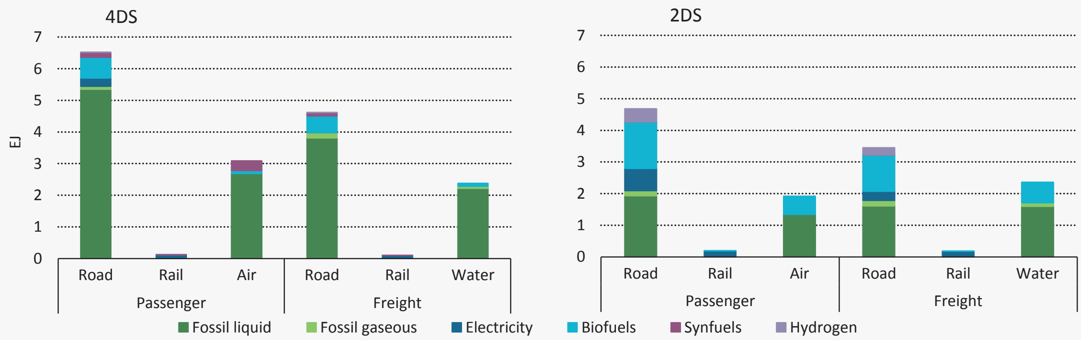


Note: pkm = passenger kilometre.

Key point *Most of the growth in passenger activity is expected to come from air in the 4DS, rail and buses in the 2DS.*

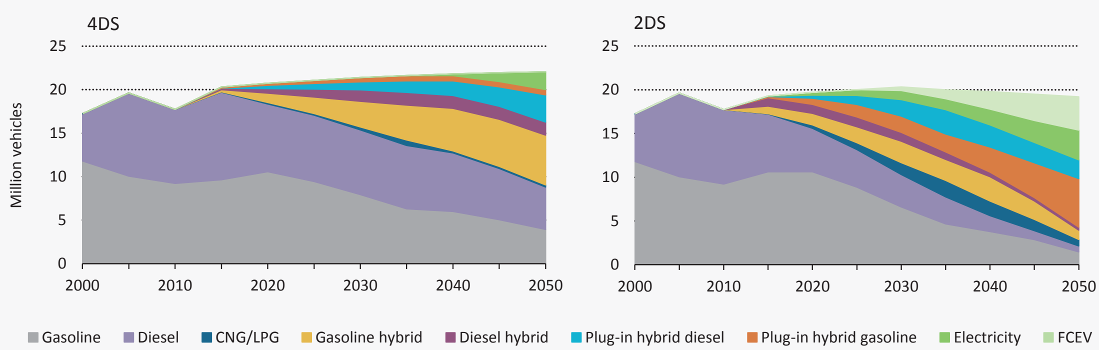
Major CO_2 reductions in the 2DS come from shifting road transport fuel to very low-carbon fuels (electricity, hydrogen, biofuels). Biofuels play a particularly significant role within the future fuel mix for trucks and aircraft in Europe, especially in the 2DS, in which a third of energy use comes from biofuels (Figure 17.4.7). The technology mix for passenger light-duty vehicles (PLDVs) is quite diversified, including both diesel and gasoline hybrid vehicles as well as plug-in hybrid versions (Figure 17.4.8). Natural gas vehicles play a bigger role in the 2DS than in the 4DS, but can provide deep CO_2 reductions through 2050 only if they evolve to using biogas (biomethane), which requires the development of a supply and distribution system. Although biogas could be quite a cost-effective fuel option, it appears likely to lose out to liquid biofuels, which have higher energy density and are better suited to trucks and other long-range vehicles.

Figure 17.4.7 Transport energy use in 2050 by mode, energy type and scenario



Key point *Energy use for road and air travel is significantly cut by 2050 in the 2DS, and all modes shift towards more biofuels, electricity and hydrogen.*

Figure 17.4.8 Passenger light-duty vehicle sales by technology type and scenario



Notes: CNG=Compressed Natural Gas, LPG=Liquefied Petroleum Gas.

Key point *The European light-duty vehicle market is close to saturation; technology innovation and strong policies can revolutionise the types of vehicles on the road by 2050.*

Battery electric vehicles (BEVs) and fuel-cell electric vehicles (FCEVs) also gain market share, especially after 2030. Europe already has significant electric vehicle (EV) deployment and may lead the way, along with the United States, Japan and China, in global EV deployment over the coming decade. Cities are taking the lead role, but strong national policies are also being put into place. The key in Europe will be whether the national governments stand behind their support policies long enough to develop a large and truly competitive market for EVs, which appears unlikely before 2020.

Buildings

The population in the European Union will remain relatively stable between 2009 and 2050 (Table 17.4.2). However, the growth in services value added and residential income will have an upward impact on the total buildings floor area.

Climatic conditions, building type and living preferences vary greatly within the European Union. In accession countries, residential floor space per capita is around 25 square metres (m^2), whereas in Northern and Southern Europe this figure is close to 50 m^2. Two-thirds of the services sector floor space is situated in countries in Northern Europe, with long heating seasons and a low cooling demand.

Table 17.4.2 Key activity for the buildings sector in the European Union

	2009	2015	2030	2050	AAGR (2009-50)
Population (million)	500	506	516	512	0.1%
Number of households (million)	206	217	238	252	0.5%
Residential floor area (million m^2)	19 500	20 514	22 554	24 666	0.6%
Services floor area (million m^2)	7 250	7 767	9 250	10 112	0.8%

Notes: AAGR = average annual growth rate, m^2 = square metre.

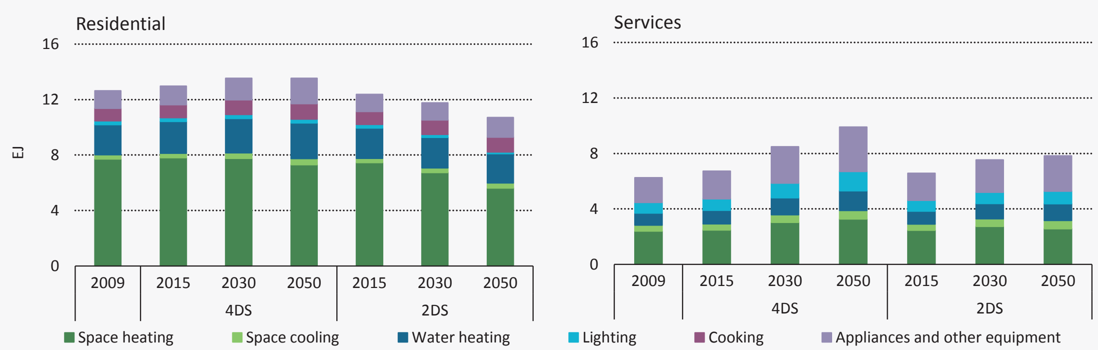
Residential building type (multi- or single-family), which has a strong influence on technology options, also differs by country, but the correlation is far from homogeneous: in the United Kingdom, almost 90% of households live in single-family homes; in Spain, 65% live in apartments. Regardless, age is a common feature of the European building stock: one-third of all residential buildings were built before 1960, and almost 84% are at least 20 years old. As energy use is strongly linked to age, there is enormous energy and CO_2 savings potential in upgrading building envelopes to modern standards.

In the 2DS, refurbishing older building stock to reach performance levels comparable to that of current newly built homes and offices, in combination with energy efficiency improvements in end-use heating and cooling equipment, help save as much as 2.5 EJ of energy required for space conditioning (space heating and cooling) in 2050 compared with the 4DS, or 51% of all energy savings (Figure 17.4.9). Building envelopes can also have a strong influence on demand for cooling. In the 4DS, rising demands for cooling comfort – even in European Union countries with a relatively low number of cooling degree-days – increases the electricity demand from air conditioners by 45% from today's level. A variety of technologies help save as much as 10% of electricity from cooling in 2050 in the 2DS compared with the 4DS: passive cooling in new buildings, and building retrofits in existing stock; accelerated diffusion of BAT-grade cooling equipment; increased penetration of solar cooling in Southern Europe; and, albeit to a lesser extent, district cooling networks in

Northern Europe. Overall, energy consumption in the 2DS is 2% lower than in 2009, thanks to lower energy requirements for space heating that offsets the growth in energy use in the other end uses.

A switch to cleaner fuels, mainly towards biomass-fuelled boilers in Northern Europe, saves almost 110 megatonnes (Mt) of direct and indirect CO_2 emissions in the 2DS – 20% of all savings in this scenario (Figure 17.4.10). A large penetration of high-efficiency, bi-modal heat pumps powered by low-carbon electricity greatly reduce the carbon intensity of water heating and save 0.8 EJ in 2050 relative to the 4DS. Overall, direct and indirect emissions will be 53% lower in the 2DS compared with the 4DS. Improvements in energy efficiency in all buildings' end uses will play a major role, contributing to 42% of this decrease.

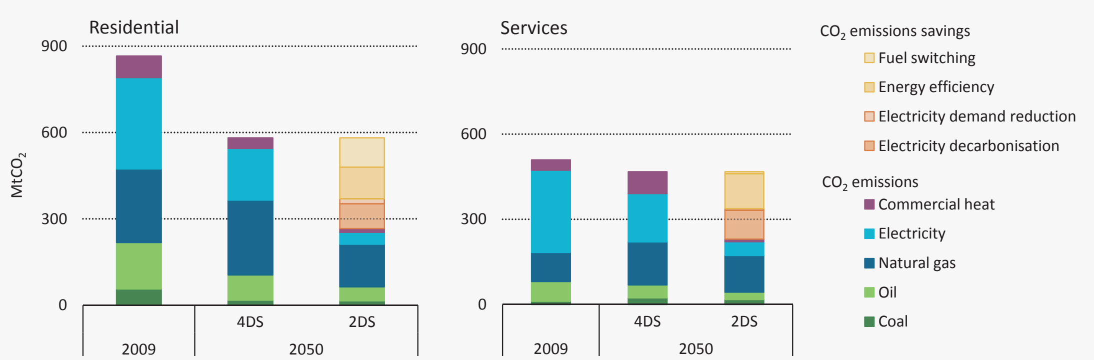
Figure 17.4.9 **Buildings energy consumption by end use in the European Union**



Note: For services, cooking is included in appliances and other equipment.

Key point *Total energy consumption will stay almost constant between 2009 and 2050 in the 2DS.*

Figure 17.4.10 **Buildings CO_2 emissions reduction in the European Union**



Key point *Energy efficiency will play a key role in reducing direct and indirect CO_2 emissions, accounting for over 40% of the reductions between the 4DS and 2DS.*

5. India

India was the world's third-largest energy consumer in 2009 according to the *World Energy Outlook 2011*, and its energy demand is set to grow more than fourfold over the coming decades in all three scenarios considered for the *ETP 2012* analysis. The country's strong economic growth, combined with its large share of population that does not yet have access to electricity and modern fuels for cooking and heating, imply that India will need to exploit all energy sources and technologies to advance its economic and social development goals. The 70% of Indian households that have access to electricity consume only one-fifth of the global average. India is conscious that in pursuing rapid economic growth, overcoming energy poverty and increasing energy consumption, it must keep in mind environmental and social considerations.

India is pursuing a comprehensive set of policies to move the country to a low-carbon growth path. In 2009 India announced that it would reduce the emissions intensity of its gross domestic product (GDP) by 20% to 25% over the 2005 levels by the year 2020. In fact, India's energy efficiency improved already by 16% between 1990 and 2009.

Specific measures to attain these goals are also being developed through the national missions identified in the National Action Plan on Climate Change of 2009. Two of those nine national missions are directly linked to energy: the National Mission on Enhanced Energy Efficiency (NMEEE) and the Jawaharlal Nehru National Solar Mission (JNNSM). The NMEEE is aiming at 23 million tonnes of oil equivalent (Mtoe) of fuel savings over a period of five years through various policy initiatives and instruments. This would be equal to an avoided capacity addition of 19 000 megawatts (MW) and the reduction of about 100 megatonnes of carbon dioxide ($MtCO_2$) emissions per year. The JNNSM foresees the installation of the equivalent of 20 gigawatts (GW) of solar power by 2020.

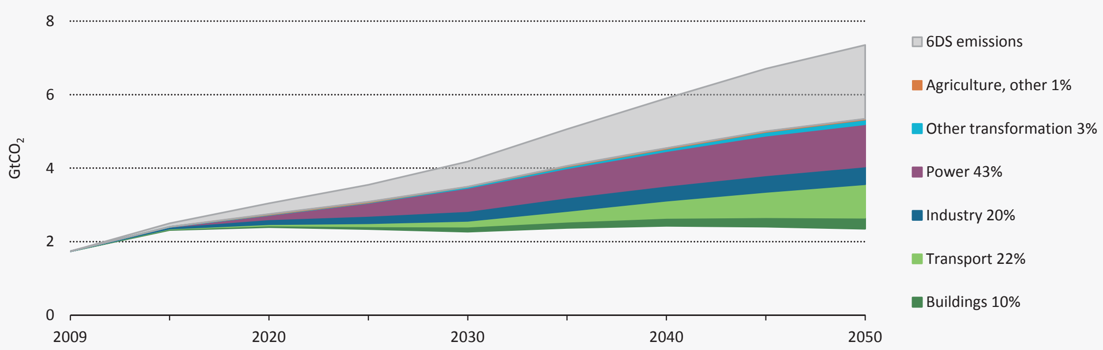
Currently nuclear power accounts for about 4 GW or 2% of installed capacity and about 3% of generated electricity. In light of the 2008 civil nuclear agreement with the United States and the subsequent agreement with the Nuclear Suppliers Group (NSG), India is now in a position to import nuclear fuel and technology. Bearing this in mind, the Indian government is expecting that by 2020 it will have almost 18 GW of installed nuclear capacity. India also is actively pursuing membership in the NSG, though it is not clear if membership will be possible without India also adhering to the Non-Proliferation Treaty. Membership in the NSG could further boost the role of nuclear energy in India's energy mix.

The IEA *ETP 2012* analysis underlines the importance of decarbonising the power sector if India is to attain its objectives of moving the economy onto a sustainable low-carbon growth path. The difference between the *ETP 2012* 4°C Scenario (4DS) and the 2°C Scenario (2DS) shows that the single largest cumulative contributor to reaching the 2DS is the power sector (Figure 17.5.1).

In the 4DS, coal will remain the single largest power-generating source with a share of over 50% of total generation by 2050. The share of coal is cut by more than half by 2050 in the 2DS, but not before having peaked in 2020, accounting for 58% of total generation. Coal with carbon capture and storage (CCS) is expected to play a key role in the 2DS, building up rapidly after 2030. Conscious of the continued importance of coal to its energy economy, India is implementing various measures to enhance the efficiency of its coal-power stations: upgrading existing power plants, moving towards supercritical technology and using better coal preparations. However, CCS is not currently a technology that India is officially promoting to decarbonise its power sector.

In 2011 India issued an interim report, "Low-Carbon Strategies for Inclusive Growth". The report suggested that with aggressive efforts India could bring down the emissions intensity of its GDP by as much as 35% over 2005 levels by 2020. The findings and recommendations of this report are likely to be reflected in the upcoming 12th Five-Year Plan that India began implementing as of 1 April 2012. The final 12th Five-Year Plan is currently under preparation and is expected to focus on reducing the energy intensity of its economy through enhanced benchmarking of its energy efficiency policy against international standards, and by increasing the domestic energy supply through enhancing all forms of renewable and nuclear energy.

Figure 17.5.1 Sectoral contributions to achieve the 2DS from the 4DS



Note: Percentages reflect cumulative reductions.

Key point *India's CO_2 emissions triple in the 4DS compared with 2009, whereas in the 2DS the increase is limited to a third, with the power sector, transport and industry providing the largest reductions.*

Major potentials and challenges: energy efficiency and decarbonisation of the power sector

Energy efficiency

A major step towards exploiting the energy efficiency potential in its economy was the enactment of the Indian Energy Conservation Act in 2001, under which a dedicated Bureau of Energy Efficiency (BEE) has been created. The BEE has since launched a number of policies including development and introduction of minimum energy performance standards (MEPS) and labelling for equipment and appliances (including industrial motors); launching the Energy Efficiency Building Code (2006); promoting energy efficiency in household lighting through a clean development mechanism (CDM) project to introduce compact fluorescent lights (CFLs); and a dedicated project to enhance technical capacities and access to finance for small and medium enterprises, the backbone of India's economy.

Special emphasis is being given to improving energy efficiency in the industrial sector, which has the third-largest emissions reduction potential in the 2DS. The liberalisation of the Indian economy led to enhanced competition among domestic and global products; this forced the manufacturing sector to improve its energy efficiency as a means of managing costs. Consequently, more and more energy efficiency technologies were introduced. Some of the world's most energy efficient units in the cement, fertiliser and refining sectors have been set up in India. However, they now co-exist with older, smaller units that employ much less efficient technologies. Currently, in light of overall strong demand growth, each company has to confront the question of whether to invest in capacity expansion or invest in energy efficiency improvements. Indian policy makers are trying to encourage the least efficient producers to adopt more efficient production processes through several policy instruments.

Under the NMEEE, the BEE launched the market-based Perform, Achieve, Trade (PAT) scheme in 2011. Under the PAT, energy efficiency improvement targets will be assigned to the country's eight most energy-intensive industrial sectors, including fertiliser, cement, power stations and steel. Those units that exceed their benchmarks will be issued energy-saving certificates that can then be sold to those units that fail to meet the set targets. These eight sectors will cover 65% of India's total industrial energy consumption. Expected savings are 19 GW of energy and emissions reductions of 98 million tonnes a year once the scheme is implemented. It is estimated that the expected investment will be around USD 15 billion.

In addition to the PAT scheme, the NMEEE has also launched two policy initiatives aimed at facilitating risk-sharing and reducing barriers for financing of energy efficiency investments through creation of a partial-risk guarantee fund and the venture capital fund. In addition, under the NMEEE the BEE has created Energy Efficiency Services Limited, a company that is tasked with developing a viable energy service company (ESCO) market to offer access for energy efficiency technology and financing to various sectors and to offer training and capacity building.

The vast majority of BEE's initiatives are currently primarily addressing the saving of electricity. Improving end-use efficiency has the largest potential to contribute to a reduction of CO_2 emissions. Under the 4DS and the 2DS, electricity savings account for one-quarter of all CO_2 reductions relative to the *ETP 2012* 6°C Scenario (6DS) in 2050. However, the BEE is also looking towards the potential for fuel savings in oil and gas. Following extensive stakeholder consultations, the BEE is now close to announcing nationwide vehicle fuel efficiency standards and targets for all vehicles plying Indian roads.

The BEE's energy efficiency initiatives are firmly focused on developing innovative approaches to deliver market-based instruments and financing of energy efficiency projects. If India continues to pursue its proactive and inventive approach and remains successful in offering solutions for the small- and medium-size enterprise sector, it is putting itself on the route to transforming its economy to the low-carbon path outlined in the 2DS. Moreover, Indian energy efficiency activities are already offering many best-practice experiences not only for other emerging economies, but also for the OECD countries aiming to improve their energy efficiency achievements.

Decarbonisation of the power sector

India was the first country in the world to establish a dedicated ministry for new and renewable energy in the early 1990s. Thanks to strong political will and the creation of a conducive policy framework, India has established the world's fifth-largest wind capacity

(14 GW in 2011) after China, the United States, Germany and Spain. Wind energy contributed over 6% of installed capacity and almost 2% to total generated electricity. Leading in technology and being a major exporter of equipment, India's wind-energy sector is now established globally. Under both the 4DS and the 2DS, India will also install offshore wind capacity, resulting in a strong increase of total installed wind-energy capacity to 6% of total generated electricity by 2050 in the 2DS.

India now hopes to replicate this achievement in the solar sector. In January 2010, India launched the JNNSM, which aims to install 22 GW of solar power (including photovoltaic [PV] and concentrating solar power [CSP]) and 20 million solar lanterns by 2022, and to have established 100 GW of solar-based generating capacity by 2030. The Indian policy target for 2030 is close to the 2DS, under which installed solar capacity reaches 109 GW in 2030. Achieving grid parity by 2020 and parity with coal-based thermal power by 2030 are key milestones in India's JNNSM. The second major objective of the JNNSM is to transform India into a global solar energy manufacturing hub.

However, these ambitious solar targets start from a low base. In 2009, solar power derived solely from solar PV contributed only a miniscule share to overall gross electricity generation. Under the 2DS, combined solar capacity is set to increase rapidly from 26 GW in 2020 and 184 GW in 2035, to over 419 GW in 2050. Solar power is seen as the strongest-growing power sector technology in India, both in terms of installed capacity and gross electricity generation, reaching 21% of total generated electricity in 2050. Even in the 4DS, solar power will account for 8% of total generated electricity by 2050.

Solar power is also the largest contributor of CO_2 emissions reductions at 23% of all generating sources and electricity savings in the 2DS relative to the 4DS.

Policy instruments of the JNNSM combine solar purchase obligations and generation-based incentives. India launched a feed-in tariff system in 2009 to support various renewable energy technologies, but special emphasis was given to solar projects. The JNNSM foresees various financial and technological incentives for power producers, as well as subsidies for domestic consumers to install rooftop solar panels that would eventually form a feed-in system to the regional grids. In July 2011, India launched the first renewable energy-based mini-grid system to help optimise the country's transmission and distribution capacity and provide a fully fledged opportunity to integrate renewable-based electricity into the power system.

In 2010 the Indian government announced the introduction of renewable energy certificates for all renewable energy sources; in March 2011 India successfully started the trading of Renewable Energy Certificates and included a special sub-category for solar energy certificates. These concerted efforts over an extended period of time combining technical and financial assistance are required to achieve the goal of shifting the Indian power sector towards solar energy.

In actively pursuing solar energy, India is trying to leverage its strong natural resource base with its strength in the tertiary sector. Moreover, the exploitation of solar energy is also a means of addressing the country's energy-access challenge, especially in rural areas.

Another technology India is very actively pursuing in its efforts to decarbonise the power sector is nuclear energy. The official aim of India's nuclear power programme is to become independent of imported fuel beyond 2050 through the use of thorium following a three-phase approach. The existing capacity consists mainly of domestic pressurised heavy water reactors that require natural uranium as fuel. In addition India is constructing light water reactors using imported enriched uranium. In phase two India will construct fast breeder reactors and in phase three, thorium-based reactors.

By 2051, India aims to have 208 GW of thorium-based nuclear capacity. These ambitious targets exceed the role of nuclear of the 2DS, which shows 113 GW of nuclear capacity in 2050. India's aim to develop its own nuclear fuel and its ambitious capacity targets are, however, being challenged by the local population in the aftermath of the Great East Japan Earthquake. To respond to these concerns the Indian government is revisiting the safety of existing and planned future reactors. Moreover, competing demands over land and water could also act as limiting factors to the ambitious goals of India's nuclear power plans.

Conclusion

India faces formidable energy challenges over the next decades. The country has no choice but to consider all available technologies in a positive light, even those it is currently reluctant about, if it is to ensure that its energy needs are being met while local and global environmental problems are being addressed.

In the coal sector India has to overcome many challenges to introduce the latest and most efficient clean-coal technologies on a broad scale. In the solar sector, India faces increased competition from international manufacturers, especially from China and the United States. This should have a positive impact on moving costs for solar energy faster towards grid-parity while stimulating the creativity of India's own manufacturing base. The creation of the BEE has been a significant step towards the realisation of the energy efficiency potential in the Indian economy. Indian policy makers are aware that the potential for savings in the end-use sectors is critical not only to move the country to a low-carbon growth path but also to overcome the continuous power shortages the country is still facing. Nuclear power can also play a significant role in CO_2 reductions; the challenge will be to increase public acceptance of new nuclear sites.

India has a golden opportunity to leap towards a new age of energy technology in the next decades. With a solid engineering base and a strong and innovative private sector that has consistently surprised the world with pioneering and affordable technological solutions, India is well suited to apply these advantages to its energy sector. India will also need to urgently address the issue of subsidies in the energy sector, which is preventing rational allocation and use of energy.

Recent initiatives to establish dedicated university and training courses for new energy technologies, including solar, and to provide training for energy managers and energy technicians will go a long way not only to transform the energy system but also to prepare human resources for the challenges lying ahead. Enhancing its support of research and development (R&D) and technology co-operation within India and with international partners can also offer many benefits.

India, being a major contributor to the global energy economy, is aware of the need for action to address the key challenges of energy policy, improving global energy security, enhancing economic growth and development, and producing and using energy as efficiently as possible.

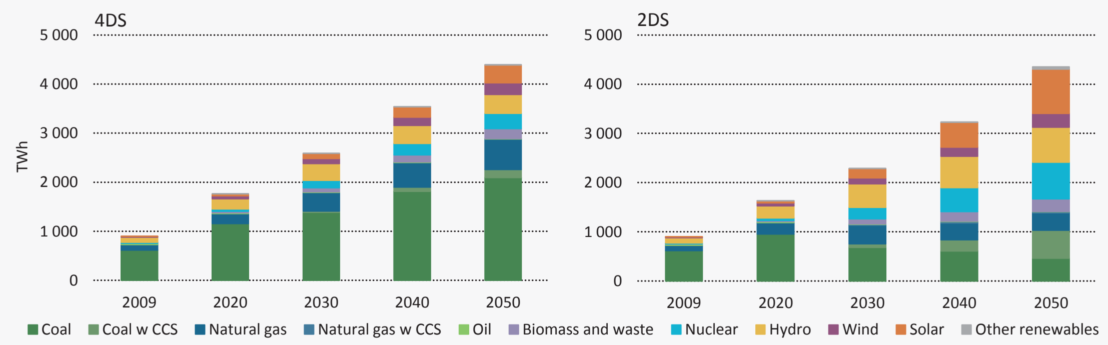
Model results for India by sector

Power

In the 4DS, fossil fuels will continue to dominate power generation with a share of 65% (Figure 17.5.2). Efficiency improvements, especially in coal-fired plants, limit the growth in annual CO_2 emissions to approximately a doubling by 2050 compared with 2009.

In the 2DS, CO_2 emissions in the Indian power sector are reduced by around 55% relative to 2009 (Figure 17.5.3). Due to excellent resource conditions, solar provides almost one-quarter of the annual reductions relative to the 4DS in 2050. Hydro and nuclear power, as well as CCS, are further technologies needed to substantially decarbonise the power supply by 2050.

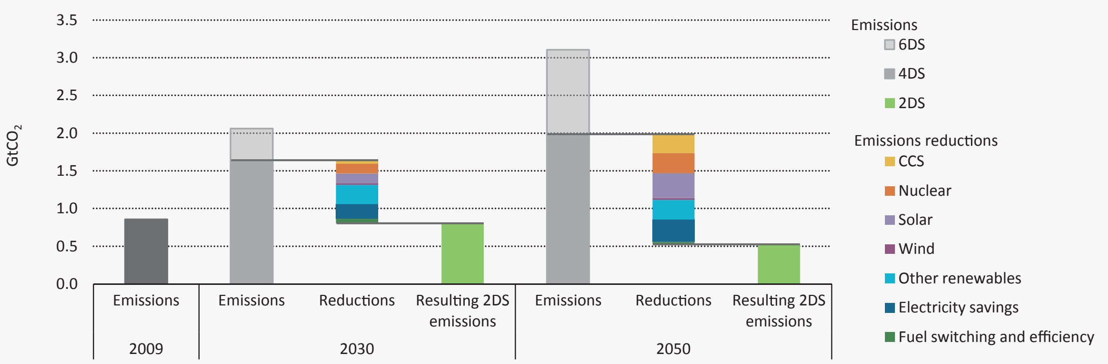
Figure 17.5.2 Electricity generation in the 4DS and 2DS



Notes: TWh = terawatt-hour. Other renewables include geothermal and ocean energy.

Key point *Due to excellent resource conditions, solar power provides one-fifth of the electricity needs in 2050 in the 2DS.*

Figure 17.5.3 Annual CO_2 reductions in the power sector to reach the 2DS (relative to the 4DS)



Notes: Other renewables include biomass, geothermal and ocean energy.

Key point *Renewables are responsible for 40% of the CO_2 reductions in 2050 in the 2DS; CCS, nuclear power and electricity savings in the end-use sectors each provide around one-fifth of the reduction.*

Industry

Indian industry used 7.0 exajoules (EJ) of energy in 2009, accounting for 3.6% of the final energy consumed in India. From a global perspective, India is the fourth-largest industrial energy consumer with a 5.6% share of global industrial energy use, surpassed only by China, the United States and Russia. The final energy mix of industry is dominated by coal and oil, which account for 55% of industry energy consumption.

The *ETP 2012* scenarios assume that industrial development and materials production will accelerate as the Indian economy matures (Table 17.5.1). This growth will be particularly noticeable for the cement industry, where India is expected to follow the unprecedented growth rate observed in China in the last decade.

Table 17.5.1 Key results for main industrial sectors in India

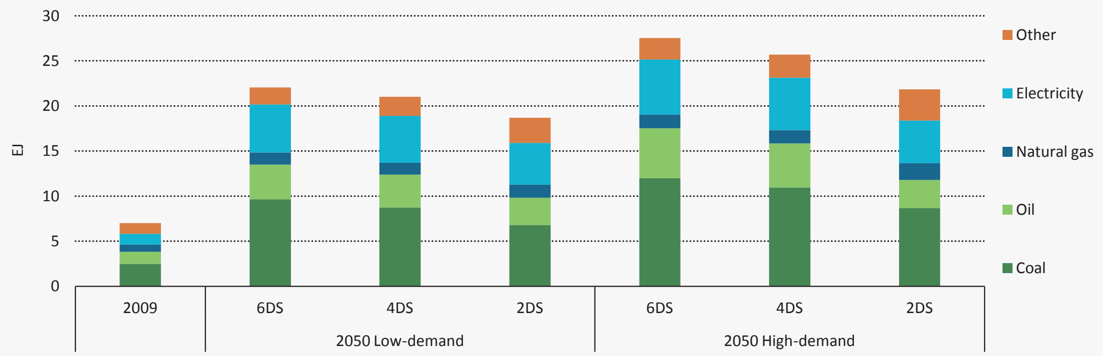
		4DS		2DS	
		Low-demand	High-demand	Low-demand	High-demand
	2009	2050	2050	2050	2050
Cement production (Mt)	217	1 236	1 947	1 236	1 947
Crude steel production (Mt)	64	278	357	278	357
Steel scrap used (Mt)	6	42	56	48	66
Paper and paperboard production (Mt)	8	70	144	69	144
Recovered paper (Mt)	1	15	31	17	35
Primary aluminium production (Mt)	1	9	12	8	11
Electricity intensity of primary aluminium (kWh/t aluminium)	14 882	11 793	11 378	11 406	10 557
HVC production (Mt)	10	46	73	43	63
Ammonia production (Mt)	14	31	33	31	33

Notes: HVC = high-valued chemicals, kWh = kilowatt-hour.

As a result of this increase in industrial production, energy use and CO_2 emissions will rise in any scenario analysed. Industrial energy consumption will reach between 21 EJ and 26 EJ in the 4DS. In the 2DS, this increase can be limited to between 19 EJ to 22 EJ (Figure 17.5.4). The growth in CO_2 emissions could be limited to an increase of about 130% between 2010 and 2050 in the 2DS. While reductions in all industry sectors are required to achieve the ambitions of the 2DS, action is particularly crucial in the five most energy-intensive sectors analysed. A range of measures will be needed, including the application of best available technologies (BATs) for all new and refurbished plants, energy efficiency measures, fuel and feedstock switching (most notably in the chemicals and petrochemicals and cement sector), and the application of CCS in the iron and steel, cement, pulp and paper, and chemicals sectors.

Cement production will increase six- to ninefold between 2009 and 2050. As a result, this sector will account for almost 50% of the reductions between the 4DS and 2DS. Indian cement plants are among the most efficient in the world and have one of the lowest potentials for reducing energy consumption by applying BAT. However, large CO_2 emissions savings potential is available to India through a greater use of clinker substitutes and alternative fuels and the application of CCS for new and, where possible, refurbished plants.

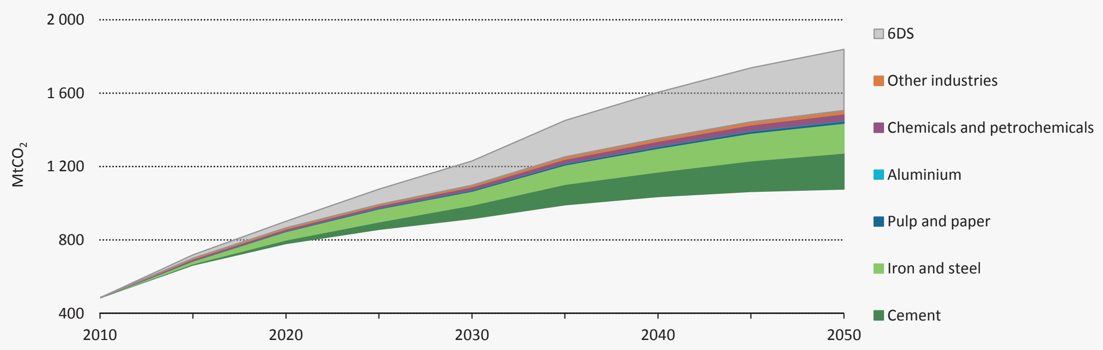
Figure 17.5.4 Industrial energy consumption by energy source in India



Note: Other includes heat, combustible biomass, waste and renewables.

Key point *Coal will remain an important energy source in India.*

Figure 17.5.5 Industrial CO_2 emissions reductions in India in the low-demand case



Key point *Emissions will grow even in the 2DS, but far less than in the 4DS or 6DS.*

Transport

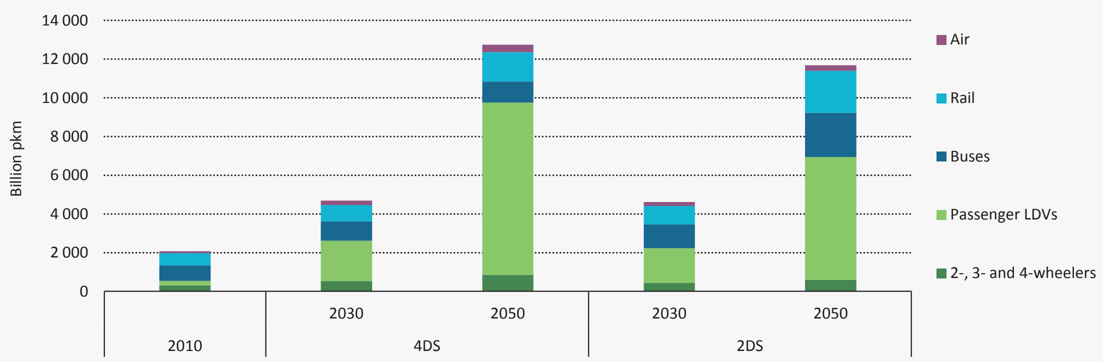
Over the next 40 years, India is expected to have one of the largest increases in car ownership and travel of any country in the world, both in absolute and percentage terms (with over a twentyfold increase from about 2 million in 2009 to over 40 million in 2050). As car ownership increases, the car share of trips is expected to increase fairly dramatically in the 4DS and only to a slightly lesser extent in the 2DS (Figure 17.5.6). Thus, even with extensive investments in urban and inter-urban mass transport systems, it appears unlikely that a massive shift to car-based travel can be prevented.

Nonetheless, a comprehensive and ambitious set of sustainable transport policies and plans can make a big difference in both energy use and other transport-related impacts. Combined with advanced urban planning concepts, the widespread implementation of improved bus systems (including but not limited to bus rapid transit [BRT]) and, where applicable, metro systems, upgraded passenger rail systems including high-speed rail, and even luxury bus coaches for some intercity travel can all help slow car growth and cut traffic congestion significantly. Extensive infrastructure for walking and cycling can also help to ensure that most short trips in cities and towns can be made without cars. Motorcycles and scooters grow rapidly in all scenarios, but are not expected to contribute significant CO_2 reductions in the 2DS relative to the 4DS.

India is rapidly moving towards a world-class auto industry with the capability of producing highly efficient vehicles and introducing new technologies such as electric and plug-in hybrid vehicles. Passenger light-duty vehicles (PLDVs) in India currently consume relatively little fuel on average, due mainly to their small average size, but strong fuel economy standards will be needed to ensure that as vehicles become larger they do not become gas guzzlers. Since standards appear likely to be promulgated during 2012, it is a key moment to ensure that they set ambitious targets for the 2020 time frame.

In the coming few years, India should continue to develop plans for the introduction of electric vehicles (EVs) and conduct pilot projects in "early adopter" cities, but must also co-ordinate this roll-out with a general modernisation and decarbonisation of electric power generation to avoid a situation where EVs emit more CO_2 per kilometre (life cycle) than the internal combustion engine (ICE) vehicles they replace. The overall PLDV technology portfolio is expected to show bigger shares of compressed natural gas (CNG)/ liquefied petroleum gas (LPG) vehicles, as has occurred with buses and 3-wheelers, with India already having one of the bigger CNG fleets worldwide (IEA, 2010). Overall, a co-ordinated introduction of alternative fuel vehicles can help cut transport fossil fuel use and CO_2 by half by 2050 in the 2DS compared with the 4DS (Figure 17.5.7). The rapid sales of new technology vehicles after 2030 will play a key role in this regard (Figure 17.5.8).

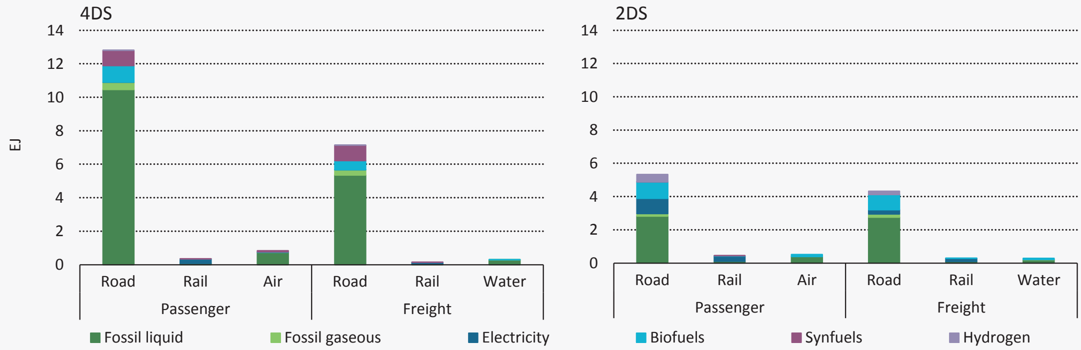
Figure 17.5.6 **Passenger mode share in India**



Note: pkm = passenger kilometre.

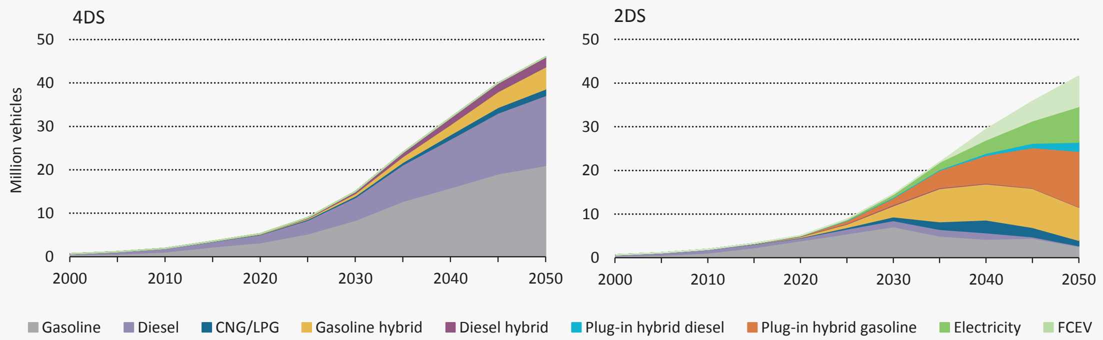
Key point *As income rises, sales of passenger light-duty vehicles will grow dramatically in the coming years, but far less in the 2DS than in the 4DS.*

Figure 17.5.7 Transport energy use in 2050 by mode, energy type and scenario



Key point *Indian oil demand is cut by over 50% in 2050 in the 2DS compared with the 4DS.*

Figure 17.5.8 Passenger light-duty vehicle sales by technology type and scenario



Note: FCEV = fuel-cell electric vehicle.

Key point *Advanced technology vehicles play a key role in India by 2050, but this will require ambitious policies to drive rapid adoption rates after 2020.*

Buildings sector

During the past decades, population growth, the increase in economic development and activity, greater access to diversified energy sources, and migration from rural to urban areas has resulted in the buildings sector experiencing many changes in energy consumption. These changes are expected to continue in the next decades. Population will grow by 0.9% per year between 2009 and 2050 and will reach over 1 690 million in 2050. The continued reductions in the number of people per house will result in the number of households increasing at a much faster rate than the population, at 1.7% per year. Floor area in the service sector will grow by 3.5% per year, but growth will slow over time in line with population and GDP growth (Table 17.5.2).

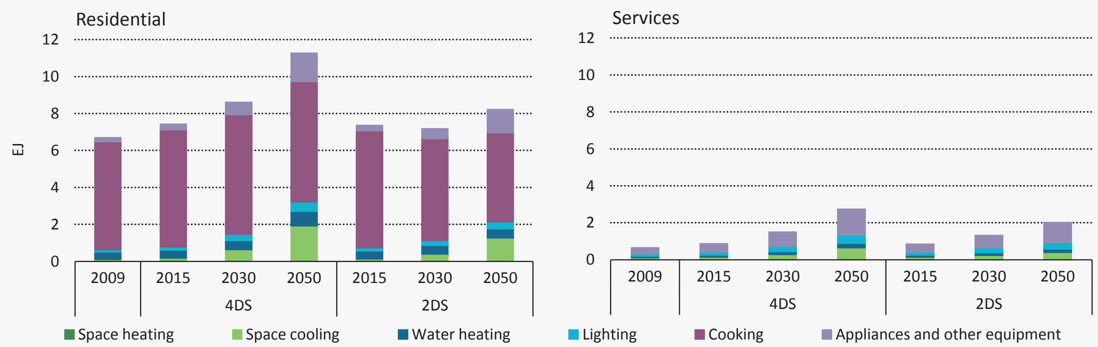
Table 17.5.2 Key activity in the buildings sector

	2009	2015	2030	2050	AAGR (2009-50)
Population (million)	1 155	1 308	1 523	1 692	0.9%
Number of households (million)	249	296	384	500	1.7%
Residential floor area (million m^2)	20 664	25 613	37 058	51 970	2.3%
Services floor area (million m^2)	858	1 155	1 994	3 525	3.5%

Notes: AAGR = average annual growth rate, m^2 = square metre.

Buildings account for about 40% of the total energy consumption in India. This share is among the highest in the world. It reflects the high use of traditional biomass in the residential sector, which accounts for 77% of final residential energy consumption. Urbanisation and higher income and electrification rates will drive rapid growth in electricity demand from both residential and services buildings eightfold between 2009 and 2050 in the 4DS. India crossed the USD 3 000 (at purchasing power parity) income per capita threshold in 2008, beyond which ownership of air conditioners rises dramatically: in the 4DS, the energy demand for cooling increases 20 times in the period from 2009 to 2050 in the residential sector and six times in the services sector. Higher living standards also increase ownership of residential appliances[1] and, as a result, appliances consume four times as much electricity in 2050 in the 4DS as they do today (Figure 17.5.9).

Figure 17.5.9 Energy consumption by energy source



Note: For services, cooking is included in appliances and other equipment.

Key point *All end uses have a role to play in limiting the increase of energy consumption to 37% between 2009 and 2050 in the 2DS.*

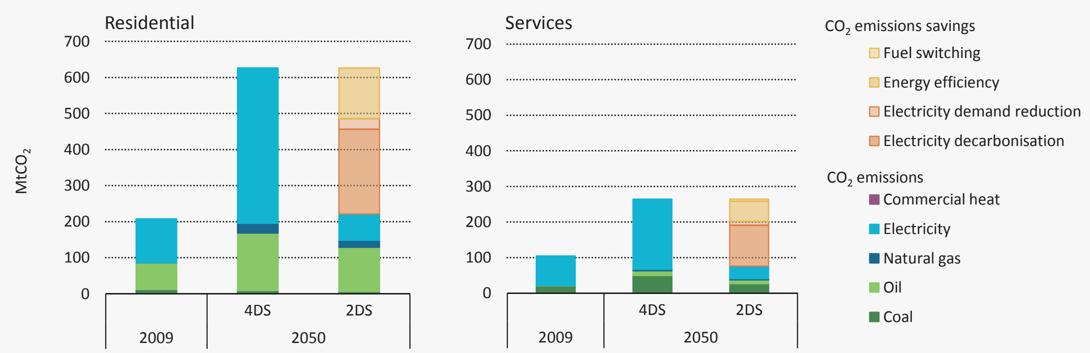
The Standard and Labelling Programme developed by the BEE covers the most widely used appliances and equipment, such as colour TVs, ceiling fans, refrigerators and air conditioners. Since January 2009, energy labelling for air conditioners and refrigerators is mandatory. Driving appliances and cooling equipment meeting minimum energy performance standards (MEPS) into the market in the next decade, and ensuring the

1 Appliances exclude air conditioners, which are analysed separately in the model.

penetration of current BATs from 2020, saves India 244 TWh of electricity in 2050 in the 2DS compared with the 4DS. The supply of lighting also holds great abatement opportunity: as kerosene and other oils are phased out and replaced by electricity, accelerating the penetration of compact fluorescent lamps (CFLs) and light-emitting diodes (LEDs) – once cost reductions have taken place in the initial years to 2050 – could save as much as 215 petajoules (PJ) in the buildings sector as a whole.

These technologies combine in the 2DS to reduce by two-thirds the direct and indirect CO_2 emissions of the 4DS in the buildings sector (Figure 17.5.10). In the services sector, CO_2 emissions are reduced by a third relative to 2009. Given the increased penetration of electricity consuming goods, the decarbonisation of the power sector will account for about 65% of the decrease in emissions.

Figure 17.5.10 CO_2 emissions and reduction by scenarios



Key point *Direct and indirect CO_2 emissions will be 5% lower in 2050 in the 2DS than they were in 2009.*

6. Mexico

As the world's seventh-largest oil producer, Mexico faces particular challenges in the transition to a low-carbon energy system. Most importantly, the country has to overcome the path dependencies that come with the abundant domestic availability of oil and oil-related revenues. The country's energy mix is largely dominated by fossil fuels: oil accounts for 45% of total primary energy supply; natural gas contributes another 42% (SENER, 2011). In addition, oil proceeds contribute up to 39% of total state revenues. Since 2004, however, the productivity of the country's largest oil field has been on a downward trend, without being fully compensated by new finds. At the end of 2010, the reserves-to-production ratio stood at 10.6 years. While sinking oil production represents a challenge for the energy system as a whole, it also provides an opportunity for Mexican policy makers to set the country on track to a low-carbon future.

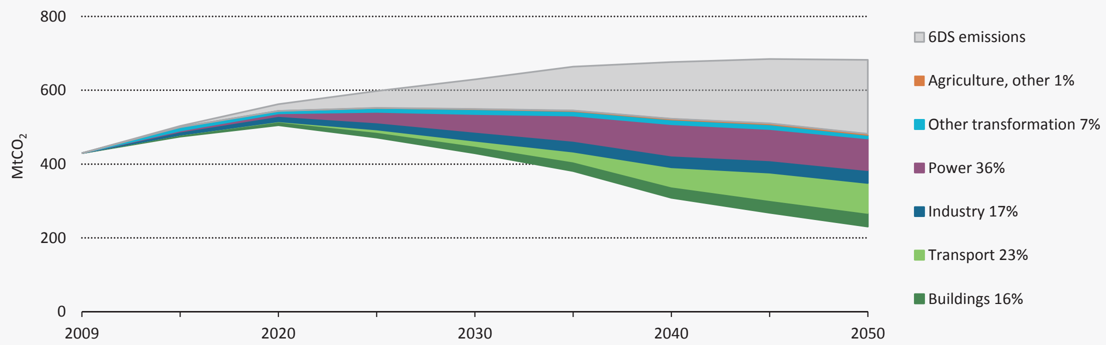
In view of falling domestic oil production and the effects of climate change, low-carbon development has been made a priority under the administration of President Filipe Calderón (2006-12). The National Development Plan, which defines the policy framework for every six-year presidential term, forms the foundation for current efforts towards a low-carbon economy (Presidencia de la Nación, 2007). Based on the current plan's premise of Sustainable Human Development, Mexico has become an active participant in the international climate change policy and the green growth debate. As stated in Mexico's Special Climate Change Programme (Programa Especial de Cambio Climático, PECC), by 2012 the country aims to achieve a reduction of 51 megatonnes of CO_2-equivalent ($MtCO_2$-eq) emissions per year below the baseline (7% of total emissions in 2006). For 2020 a target of 30% below baseline has been set, depending on the availability of financial and technological support. A reduction of 50% compared with the baseline scenario is aimed for by 2050 (Poder Ejecutivo Federal, 2009).

Achieving these ambitious targets will require determined government action, given that under the *ETP 2012* 6°C Scenario (6DS) Mexico is on track for a two-thirds increase in CO_2 emissions by 2050. This chapter gives an overview of the potential alternative energy pathways for Mexico as foreseen by the *ETP 2012* 4°C Scenario (4DS) and the *ETP 2012* 2°C Scenario (2DS) and takes a closer look at opportunities and challenges for emissions reductions in the power sector, which represents the largest share of emissions reductions by 2050 with 37% (Figure 17.6.1).

Major potentials and challenges: energy efficiency and decarbonisation of the power sector

Mexico's particular potentials and challenges in moving towards a low-carbon trajectory involve especially the areas of energy efficiency and solar and wind energy, which account for more than 90% of the 2DS emissions reductions in this sector by 2025 (Figure 17.6.1).

Figure 17.6.1 Sectoral contributions to achieve the 2DS from the 4DS



Note: Percentages reflect cumulative reductions 2009-50.

Key point *CO_2 emissions in Mexico are almost halved by 2050 in the 2DS, with the power sector providing almost 40% of the cumulative CO_2 reductions compared with the 4DS.*

Energy efficiency

The Mexican National Energy Strategy (2012 to 2026) establishes the objectives of reducing total energy consumption by 15% below baseline, which equals cumulative savings of 4 017 terawatt-hours (TWh) over the 2012 to 2026 period (SENER, 2012). In accordance with this long-term objective, Mexico has defined the promotion of efficient production and use of energy as one of the nine main goals of its energy policy (Sectoral Energy Programme, 2007-12). By far, the greatest potential for energy savings is identified in the area of standards and regulations: in 2008, the application of the 18 official energy norms led to an emissions reduction of 12.8 $MtCO_2e$ (SEMARNAT, 2010). The transport sector alone is expected to account for nearly 40% of cumulative savings in the 2012 to 2026 period.

Table 17.6.1 Potential benefits of energy efficiency interventions in Mexico

	Maximum annual emissions reduction		Net benefit of mitigation
	$MtCO_2$-eq/ year	In % of total emissions (2006)	USD/t CO_2-eq
Electricity end-use efficiency			
Industrial motors	6	0.8%	19.5
Residential lighting	5.7	0.8%	22.6
Non-residential lighting	4.7	0.7%	19.8
Residential refrigeration	3.3	0.5%	6.7
Residential air conditioning	2.6	0.4%	3.7
Non-residential air conditioning	1.7	0.2%	9.6
Street lighting	0.9	0.1%	24.2
Co-generation			
Co-generation in PEMEX	26.7	3.7%	28.6
Co-generation in industry	6.5	0.9%	15.0
Renewable heat supply			
Improved cookstoves	19.4	2.7%	2.3
Solar water heating	18.9	2.6%	13.8

Source: Johnson *et al.* 2009: 41, 54; own calculations based on total emissions data from Poder Ejecutivo Federal (2009).

The current energy savings plan (PRONASE), developed by the National Commission for the Efficient Use of Energy (CONUEE, 2009), targets seven priority areas: road transport, lighting, household appliances, co-generation, industrial motors, buildings and water pumpage. These priorities reflect the areas of highest potential emissions reductions beyond the transport sector (see Table 17.6.1). The PRONASE establishes goals and actions in terms of normalisation and standard-setting (*e.g.,* a certification system for estimating the electrical consumption of new buildings) as well as subsidy programmes to replace inefficient equipment. Large potential is also seen in the area of co-generation in PEMEX's refineries and processing plants.

Co-generation

The co-generation potential in PEMEX facilities amounts to 3 153 MW (SENER, 2012), more than triple the national oil company's own electricity consumption. Two large-scale pilot projects have been initiated so far: in 2009 construction of a co-generation facility began at the Nuevo PEMEX gas processing complex in the state of Tabasco. The project has a capacity of 300 megawatts (MW) and 800 tonnes per hours team generation and is due to begin service in September 2012. It will supply 55% of the gas processing plant's steam demand and all of its power demand. On the second project, PEMEX is working jointly with the national power utility CFE on the combined cycle power plant "Salamanca co-generation phase I" (430 MW). The plant is located adjacent to the PEMEX refinery in Salamanca and will be PEMEX's first co-generation facility to be connected to the public grid by the end of 2012.

PEMEX stresses that for all further projects feeding into the National Electricity System, a joint effort with CFE and the private sector will be required. The need for private involvement is partly due to the tight investment restrictions that PEMEX faces because of its dependence on the federal budget. More generally, there are two further barriers to tapping PEMEX's co-generation potential. First, the rates of return offered by this kind of investment are low compared with PEMEX's core business, thus, they have low priority. Second, the conditions for feeding surplus co-generation power into the public grid are considered unattractive (Johnson *et al.*, 2009). Co-generation projects beyond PEMEX also encounter significant barriers. For example, installing a co-generation project larger than 0.5 MW requires 31 permits at all three federal levels, which results in a delay of at least 180 days for the start of any project (ECLAC, OLADE and GTZ, 2009). Streamlining permission procedures could, therefore, go a long way in promoting co-generation in Mexico, not only in PEMEX but indeed in the entire industrial sector. The National Energy Strategy 2012 to 2026 acknowledges these challenges, pointing out the need for strengthening the regulatory framework for co-generation as well as the need for attractive financing schemes (SENER, 2012).

Residential sector

The residential sector also holds significant potential for energy efficiency improvements; efficient lighting, refrigeration and air conditioning could achieve an emissions reduction of 11.6 $MtCO_2$-eq per year (see Table 17.6.1). According to planning documents of the Mexican Secretariat of Energy (SENER), about 30% of energy savings are to be achieved in the residential sector; to this end, the federal government has launched several end-use energy efficiency programmes, for example the distribution of 46 million compact fluorescent lamps (CFLs) to 11 million households, and the replacement of 1.9 million inefficient appliances (mostly refrigerators). The CFL distribution programme is estimated to lead to energy savings on the order of 3 126 gigawatt-hours (GWh) per year; as of March 2012, 21 million CFLs had been distributed. The effect of the appliance substitution programme in the first ten years will add another estimated 11 527 GWh of total savings. If fully implemented, these two programmes would achieve more than one-third of the efficiency savings needed under the 2DS by 2020.

Outlook

In the short term, Mexico seems to be on track for achieving the targets of the 2DS. However, in order to reach the necessary energy efficiency related savings of 55 $MtCO_2$-eq per year by 2050, much more decisive action will be needed. Challenges to energy efficiency include a lack of technical personnel, lack of financing for equipment and project development, relatively little involvement of energy companies, and underdevelopment of the energy services market (ECLAC, OLADE and GTZ, 2009).

Decarbonisation of the power sector

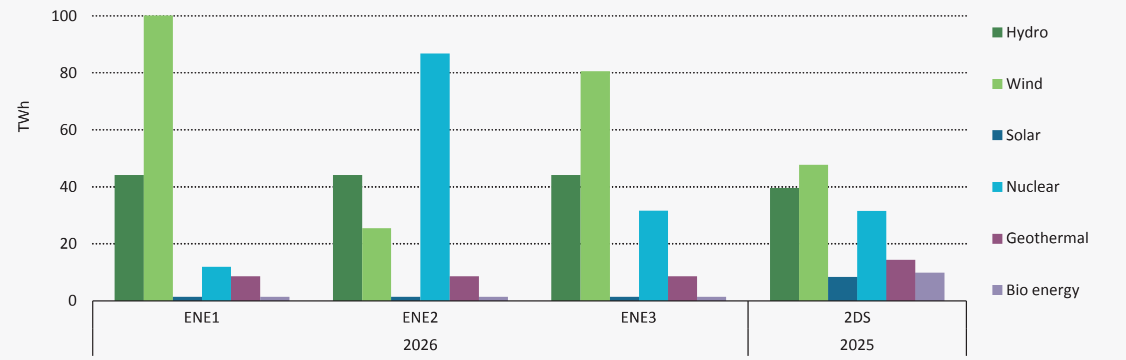
Over the past years, the two fundamental drivers of change in the Mexican energy mix have been the decreasing productivity of Mexico's most important oil field (Cantarell), and the surge in gas production in the United States, which led to a significant drop in the regional gas price. In consequence, Mexico's US gas imports increased fivefold, mainly for use in gas-fired power plants. The share of fuel oil in the Mexican power mix fell sharply from 61% to 21% between 2000 and 2010, whereas the share of natural gas has risen from 20% to 55% (SENER, 2011). The government has recently further amplified this structural change by announcing a major expansion of natural gas infrastructure, adding more than 4 300 kilometres (km) to the transportation pipelines between 2010 and 2020 with associated investments of more than USD 8 300 million (SENER, 2012). The natural gas distribution infrastructure is expected to increase twofold in the same period. In addition, discussions about how to use the country's abundant domestic shale gas resources are under way. While the shift from oil to gas in electricity generation by itself contributes to savings in CO_2 emissions, the transition to a low-carbon power sector in Mexico requires extensive deployment of clean energy technologies.

Clean energy: Mexican energy policy targets through 2026

In 2010, a quarter of installed capacity in Mexico corresponded to clean energy: 18.7% large hydro (>30 MW), 3.8% renewables and 2.3% nuclear. This reflected the preferences of CFE, which has long been reluctant to include variable renewables. Beyond large hydro, therefore, the only renewable energy source that received significant attention in the past was geothermal energy, because of its well-established capacity and steady availability (CCAP, 2009).

The main official long-term target, set out in accordance with the Law for the Use of Renewable Energy and Finance of the Energy Transition (Congreso de la Unión, 2008), is to raise energy generation from non-fossil fuels to 35% by 2026. In the National Energy Strategy 2012 to 2026, three different scenarios for non-fossil electricity generation are contemplated (referred to as ENE1, 2 and 3), all of which would comply with the 35% goal (Figure 17.6.2).

Figure 17.6.2 Targets for non-fossil electricity generation by SENER (2026) and the *ETP* 2DS (2025) in TWh



Key point *Wind, nuclear, and hydro power feature prominently in SENER and ETP scenarios.*

The three ENE scenarios open up a spectrum of possibilities that considers wind and nuclear energy as the two preferred options. ENE1 reflects the possibility of building on recent growth of wind energy in Mexico, with 284 additional wind farms with 100 MW capacity each, boosting the share of wind energy to 20.9%. ENE2 considers building seven to eight new nuclear power plants with 1 400 MW capacity each, jointly providing 18.1% of gross electricity generation. ENE3 tries to find a middle way, consisting of two new nuclear power plants and 209 wind farms, which translates into a share in the electricity generation mix of 16.8% for wind and 6.6% for nuclear (SENER, 2012).

A major barrier for renewables to date has been the legal requirement for CFE to choose the lowest-cost generation option, based on a methodology that does not take into account externalities (in 2010, the cost for developing one kilowatt (kW) of electricity generation in Mexico was USD 973 for a combined cycle plant, USD 2 169 for geothermal and USD 2 360 for wind [*Renewable Energy Report*, 2010]). In the past, the lowest-cost requirement has led to a situation where the deployment of renewable energy projects has greatly depended on Clean Development Mechanism (CDM) financing.

The energy reform of 2008

The first steps towards energy sector reform have been taken; the Law for the Use of Renewable Energy and Finance of the Energy Transition (Congreso de la Unión, 2008) called for a revision of CFE's cost-based planning process to include externalities associated with both conventional and renewable energy sources. The new methodology is currently being developed by SENER in co-operation with the Finance, Environment and Health Ministries. As another result of the law, SENER has launched a *Special Programme for the Use of Renewable Energy*. Among other things, this programme seeks to promote renewables by disseminating information and building a national renewable energy inventory. Furthermore, the programme acknowledges the need to further reform regulatory and financing mechanisms to better tap the nation's renewable energy sources, adapting infrastructure to the inclusion of renewables and fostering research and development in the area. To support this programme, two funds were created, the Energy Transition Fund (*Fondo para la Transición Energética y el Aprovechamiento Sustentable de la Energía*) and the Energy Sustainability Fund (*Fondo de Sustentabilidad Energética*). Finally, based on strengthened regulatory authority, the Energy Regulation Commission (CRE) has created new contract models that facilitate renewable energy projects being connected to the electricity grid.

While these reforms have already resulted in a growing number of renewable energy projects in the country, large-scale deployment of renewables is still mainly restricted to demonstration, off-grid or export projects. The following examples will focus on wind and solar energy, which are expected to contribute the second- and third-largest shares of CO_2 reductions (following energy efficiency) by 2025.

Export and pilot projects as drivers: wind and CSP

Wind energy is expected to reach 19 GW installed capacity in 2025 in the 2DS and contribute 27% of total CO_2 emissions savings. The total potential for wind in Mexico is estimated at 50 GW (capacity factor greater than 20%), with the greatest potential located in the Isthmus of Tehuantepec, the Yucatán and Baja California peninsulas, and the northern part of the Gulf of Mexico. If only those sites are considered, wind energy is expected to become competitive with other generation technologies in the next eight to ten years. SENER estimates total potential at about 20 MW. So far, the only wind projects for public service are the demonstration project La Venta I (1994, 1.6 MW) and the CDM project La Venta II (2006, 83 MW), both operated by CFE. In recent years, wind energy has grown quickly. Installed capacity increased from 85 MW in 2008 to 875 MW in March 2012 and capacity is expected to surpass the 1 gigawatt (GW) milestone in 2012. However, additional projects are mainly made to serve individual customers (*e.g.* the 250 MW Eurus project for the Mexican cement firm CEMEX) or for export to the United States. The Mexican Wind Energy Association (AMDEE) registers 911 MW of additional capacity under construction. Whether AMDEE's goal of 12 GW will indeed be reached by 2024 will depend to a large extent on the evolution of the cost of the technology and of transmission infrastructure development.

Solar energy is expected to contribute another 16% of CO_2 emissions savings by 2025 in the 2DS. This is no surprise, given that Mexico is one of the countries with the highest average solar insolation rates in the world (5.5 kilowatt-hours [kWh] per metre squared per day). The solar insolation in some areas of northern Mexico equals the best areas in northern African deserts. So far, the solar energy in Mexico has been concentrated on small-scale photovoltaic (PV) as one of the most cost-effective solutions to rural electrification. However, a pilot concentrating solar power (CSP) plant, co-funded by the Global Environmental Facility (GEF), is under construction in the state of Sonora ("Agua Prieta II"). As the first CSP plant in Latin America, the project intends to demonstrate the benefits of integrating a parabolic-trough solar field with a conventional thermal facility and consists of a hybrid combined cycle power plant (477 megawatt electrical [MW_e]) and a thermosolar facility (parabolic troughs, 14 MW_e). Construction started in 2009 and the plant is expected to commence operations in 2013.

Conclusion

Mexico's National Development Plan, the energy efficiency and renewable energy programmes derived from it, as well as the scenarios contained in the National Energy Strategy 2012 to 2026 are clear testimony to the country's political will to embark on a low-carbon trajectory. First successes have been achieved, but even more ambitious actions will be necessary to meet the needs of the 2DS. In terms of the three most significant areas of emissions reduction in the power sector (energy efficiency, co-generation and renewable energy), further improvement of the regulatory framework will be crucial to tapping the potential. The new methodology for the planning process of the CFE may be a milestone enabling the sector to tap renewable energies much more extensively in the future.

In the meantime, an encouraging sign of renewable energy taking root in Mexico is the willingness of both domestic and foreign investors to establish production of renewable energy plant components in the country, for example concentrating solar photovoltaic cells and dual-axis tracking systems (Baja Sun Energy), wind turbine blades (Mitsubishi) and wind towers (Trinity, CS Wind). Such pioneering investments also help to make the case for renewable energy in the country from a green-growth and job creation perspective. Even though the industry is still at the embryonic stage, the country possesses vast renewable energy resources and the location and cost advantage to serve the growing renewable energy market in the United States. This makes it the ideal base for a "green" development strategy and ambitious climate goals.

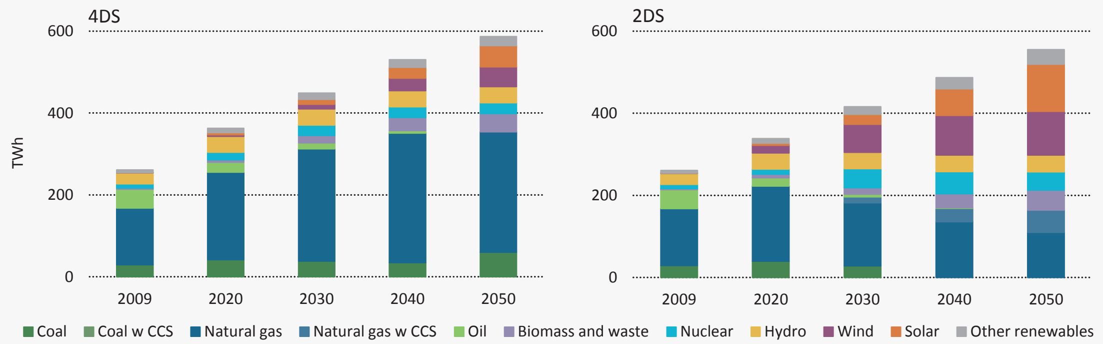
Model results for Mexico by sector

Power

In the 4DS, Mexican power generation continues to be dominated by natural gas (Figure 17.6.3). Electricity generation more than doubles between 2009 and 2050, but more efficient use of gas in power generation, in combination with the increased use of renewables, limits the growth in CO_2 emissions to 56%.

In the 2DS, annual CO_2 emissions in the power sector are more than halved relative to 2009. Increased generation from solar and wind power is the main driver for these reductions, but CO_2 capture from natural gas plants is also an effective option (Figure 17.6.4). The increased use of co-generation plants in industry, fired by gas or biomass, contributes to the emissions reductions as well. Installed co-generation capacity grows to 15 GW by 2050.

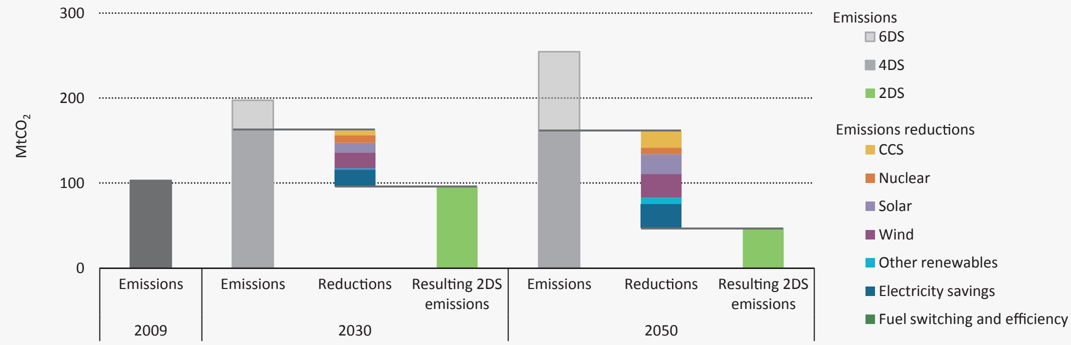
Figure 17.6.3 Electricity generation in the 4DS and the 2DS



Note: Other renewables include geothermal and ocean energy.

Key point *Solar and wind power provide around half of the electricity demand in the 2DS in 2050.*

Figure 17.6.4 Annual CO_2 reductions in the power sector to reach the 2DS (relative to the 4DS)



Note: Other renewables include biomass, geothermal and ocean energy.

Key point *Electricity savings in the end-use sectors as well as solar and wind power are the key mitigation options in 2050 to reach the 2DS.*

Industry

Industry used 1.3 exajoules (EJ) of energy in 2009, accounting for 28% of the final energy used in Mexico. About 54% of the energy is consumed by the five most energy-intensive industrial sectors. The final energy mix of industry is dominated by oil, natural gas and electricity.

The current structure of the Mexican industrial sector is not expected to change dramatically by 2050. The production of the five most intensive industries are projected increase at a pace consistent with the economic growth of the country (Table 17.6.2), as will the other less intensive industries.

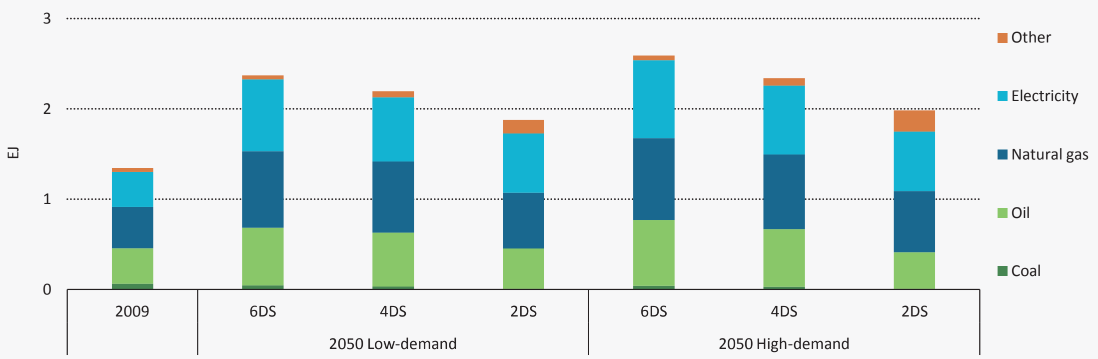
Table 17.6.2 Key results for main industrial sectors in Mexico

		4DS		2DS	
	2009	Low-demand 2050	High-demand 2050	Low-demand 2050	High-demand 2050
Cement production (Mt)	35	65	70	65	70
Crude steel production (Mt)	14	43	50	43	50
Steel scrap used (Mt)	7	27	31	28	32
Paper and paperboard production (Mt)	5	7	14	7	14
Recovered paper (Mt)	3	5	7	5	7
Primary aluminium production (Mt)	0	0	0	0	0
Electricity intensity of primary aluminium (kWh/t aluminium)	15 400	13 900	13 900	13 900	13 900
HVC production (Mt)	2	7	8	7	7
Ammonia production (Mt)	1	2	3	2	3

Note: HVC = high-valued chemicals.

Driven by the slow but constant increase in materials production, energy consumption will increase between 2009 and 2050 in all the scenarios analysed. However, there will be a noticeable shift away from oil and increased use of electricity and renewables and waste in the 2DS (Figure 17.6.4). This shift in energy consumption will help limit the increase in industrial CO_2 emissions. In the 2DS, emissions in 2050 are about 15% lower than they were in 2009. The chemicals and petrochemicals industry will account for 36% of the reductions between the 4DS and 2DS in 2050. The least intensive industries of the sector contribute about 20% of the decrease in CO_2 emissions between the 4DS and 2DS in 2050 (Figure 17.6.5). The improvements in the industrial sector will come largely from energy efficiency improvements and, to a lesser extent, the application of carbon capture and storage (CCS) in the cement and steel sectors.

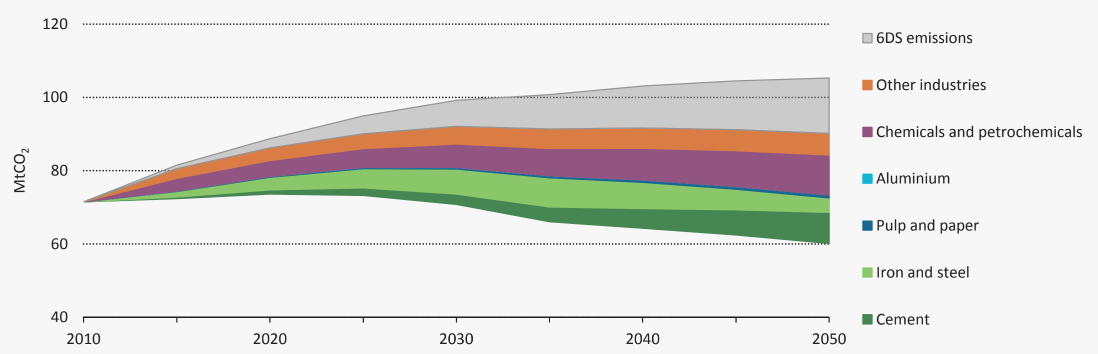
Figure 17.6.5 Industrial energy consumption by energy source in Mexico



Note: Other includes heat, combustible biomass, waste and renewables.

Key point *In the 2DS, fossil fuels will account for about 50% of energy consumption, down from 70% in 2009.*

Figure 17.6.6 Industrial CO_2 emissions reductions in Mexico in the low-demand case



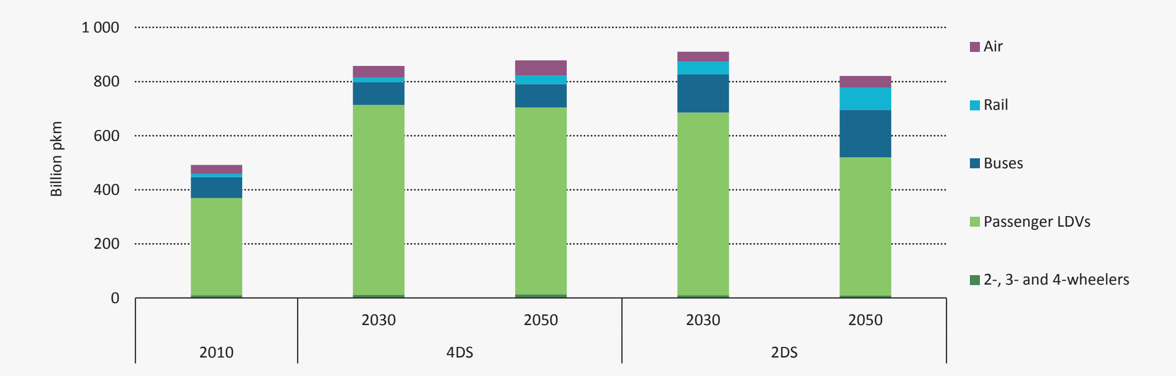
Key point *CO_2 emissions will have to peak between 2020 and 2025 for Mexico to reach the goal of the 2DS.*

Transport

The cross-border flow of used vehicles from the United States makes car purchases accessible for most Mexican households. This leads to a very high share of car travel, which is projected to increase in the absence of policies and investment promoting other modes of transportation (Figure 17.6.7).

The implementation of Mexican fuel economy standards for passenger light-duty vehicles (PLDVs), along with new bus rapid transit (BRT) systems planned for Mexico City and elsewhere, are helping the move towards a more efficient transport system, potentially halving the energy needed in 2050 in the 2DS compared with the 4DS (Figure 17.6.8).

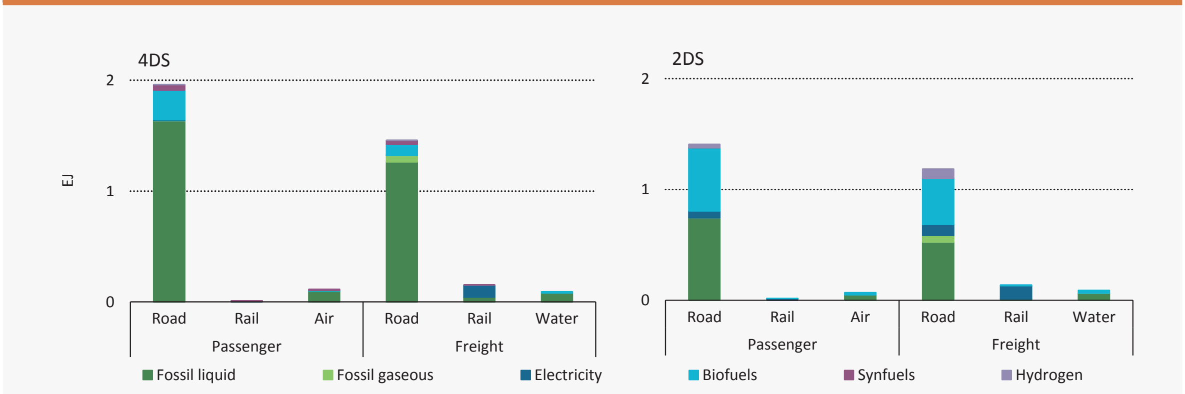
Figure 17.6.7 Passenger mode share in Mexico



Note: pkm = passenger kilometre.

Key point *The easy access to car ownership will need strong policies to be constrained.*

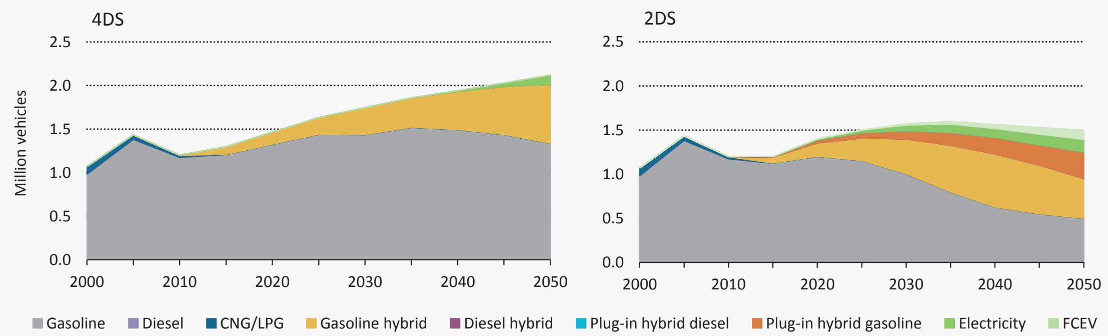
Figure 17.6.8 Transport energy use in 2050 by mode, energy type and scenario



Key point *The switch to biofuels represents the best possibility of reducing the reliance on oil in the Mexican transport sector.*

In the 2DS, alternative fuel powertrains penetrate the Mexican market, with a certain lag compared with the United States and European countries. This delay could, however, be counteracted with aggressive policies that tighten standards to match those set in the United States, and that strongly support rapid uptake of new-technology vehicles, such as electric. Market penetration could be accelerated via sliding-scale vehicle taxation systems based on fuel economy or CO_2 emissions, for example. This scenario also slows the growth of car ownership through much greater investments in mass transport and non-motorised transport systems, along with urban planning measures that reduce the need for cars.

Figure 17.6.9 PLDV sales by technology type and scenario



Note: CNG=compressed natural gas; LPG=liquid petroleum gas; FCEV = fuel-cell electric vehicle.

Key point *Hybrids and advanced biofuels will help significantly reduce the carbon intensity of PLDVs in Mexico.*

Buildings

Mexico's buildings sector is responsible for about 5% of total direct CO_2 emissions in the country (with 80% from the residential sector), and 20% of total final energy consumption. Today, energy consumption in the Mexican buildings sector is dominated by electricity in the service sector and various oil products in households – mainly liquefied petroleum gases (LPG) for space and water heating and cooking. Many households still rely on traditional biomass. Only 23% of final energy demand in households is met by electricity, and 4% by natural gas. However, as a middle-income economy with a fast-growing population, Mexico's buildings sector is set to experience dramatic growth and change.

A 2.7-fold increase in income per capita will drive the number of people per household down, more than doubling the number of households between now and 2050 (Table 17.6.3); around 80% of the additional houses are yet to be built. Growth in the service sector is even more rapid, at an annual rate of 2.1%, increasing commercial floor space by 140% between 2009 and 2050.

Lax building codes in the 4DS and sub-standard end-use technologies increase energy consumption by two, doubling the demand for fossil fuels.[2] Prompt action is thus necessary to reach the 2DS. With stringent building codes and enforcement, the specific demand for

2 Some regulations on insulating materials used in construction already exist. However, these are mainly applicable to regions with extreme weather conditions, leaving most of the buildings unregulated.

space cooling and heating of the average Mexican household could decrease by as much as 35% when compared with the 4DS in 2050. In the service sector, efficiency improvement in water heating would contribute to 15% of the energy reductions (Figure 17.6.10).

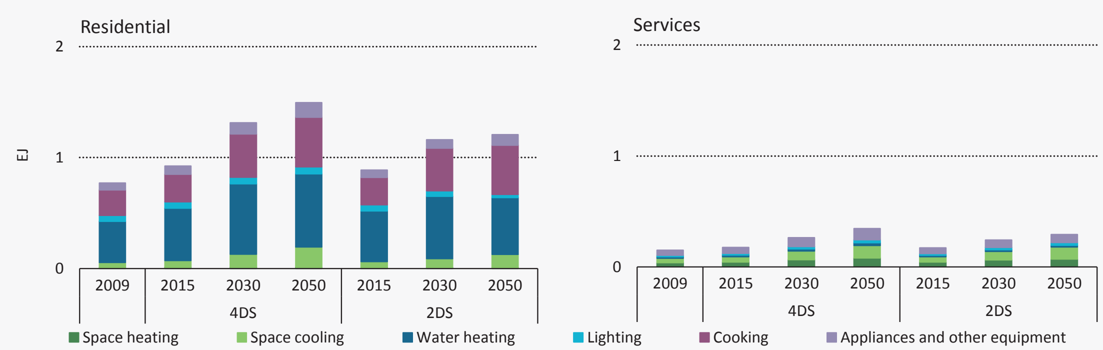
Reducing electricity demand by replacing incandescent bulbs with CFLs and light-emitting diodes (LEDs) after 2020, and ensuring that all new appliances and electronic and electric devices reach the current best available technology (BAT) levels, could save as much as 3 $MtCO_2$ against the 4DS (or 5% of all savings). The Mexican Norm NOM-028-ENER-2010 aims for incandescent bulbs to be phased out by 2013. Other efficiency measures on space heating and cooling and water heating would account for 28% of the reductions. Despite these efforts, the great increase in electrification across all scenarios implies the majority of CO_2 emissions savings in the 2DS will not come from end-use technologies but from the decarbonisation of the power sector: this accounts for 58% of all savings when abating from the 4DS (Figure 17.6.11).

Table 17.6.3 Key activity in the buildings sector

	2009	2015	2030	2050	AAGR (2009-50)
Population (million)	107	120	135	144	0.7%
Number of households (million)	26	37	53	60	2.0%
Residential floor area (million m^2)	3 525	4 181	5 509	7 301	1.8%
Services floor area (million m^2)	903	1 068	1 625	2 152	2.1%

Notes: AAGR = average annual growth rate, m^2 = square metre.

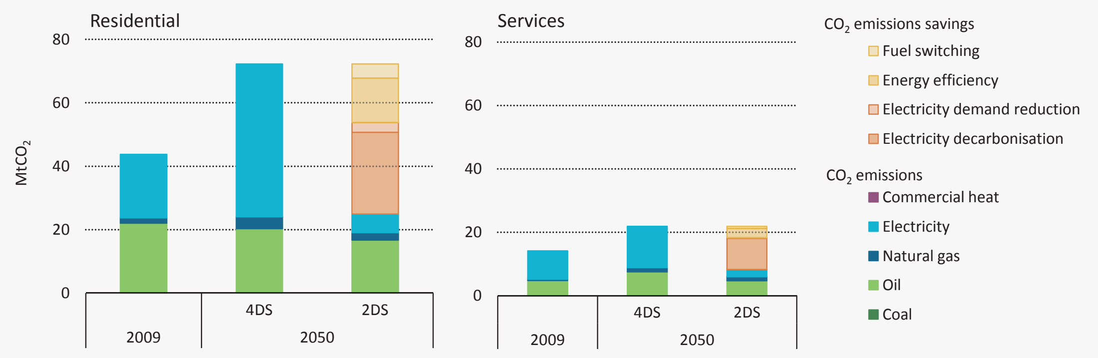
Figure 17.6.10 Buildings energy consumption in Mexico by end use



Note: For services, cooking is included in appliances and other equipment.

Key point *Energy consumption will be higher than in 2009 in any scenario analysed, but the 2DS limits this increase to 60%.*

Figure 17.6.11 Buildings CO_2 emissions and reductions in Mexico by scenarios



Key point *More than half of the reductions from the 4DS will come from the decarbonisation of the power sector.*

7. Russia

In 2010 Russia was the world's largest oil producer, the largest producer and exporter of natural gas, and the fourth-largest energy consumer (behind China, the United States and India). The country's energy mix is dominated by fossil fuels, with natural gas accounting for 54% of the primary energy mix, an increase from 43% in 1991 largely due to a drop in the share of oil and coal. Growth in gas demand in the 1990s was encouraged by domestic pricing policies that kept gas prices low, while those for coal and oil were liberalised. The transition years of the 1990s resulted in little investment in new infrastructure or maintenance across all sectors: industrial, transport, residential and transformation.

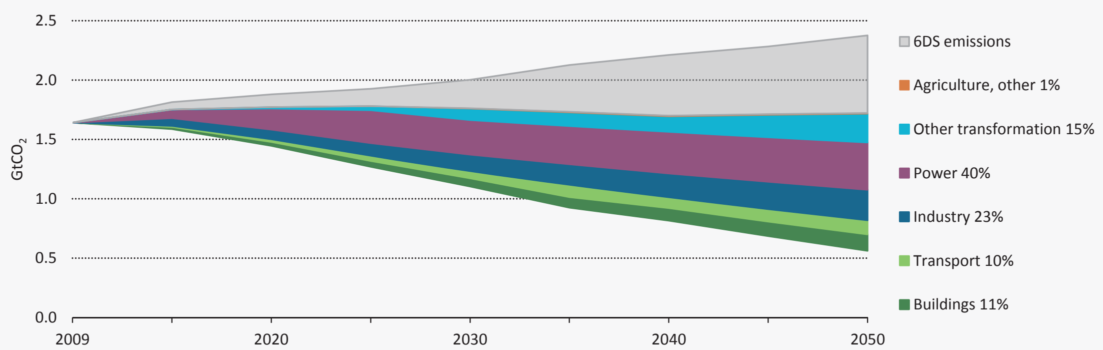
The *ETP 2012* 2°C Scenario (2DS) shows a very different way forward for Russia. As Figure 17.7.1 reflects, Russia's power sector accounts for 40% of potential carbon dioxide (CO_2) reduction to 2050 in the 2DS, while other transformation accounts for another 15%. The high average age of Russian infrastructure means low average efficiency, but also that Russia's "room to manoeuvre" is much greater than that of many other leading industrial economies. The sheer size of the country and its natural resource endowments mean that energy policies and modernisation goals made by the Russian government in the near term will help to shape not only the prospects for national economic development in Russia, but also global energy security and environmental sustainability.

There is greater scope to improve energy efficiency in Russia than in almost any other country. According to the *World Energy Outlook 2011,* if Russia had used energy as efficiently as comparable OECD countries in each sector of the economy in 2008, it could have saved more than 200 million tonnes of oil equivalent (Mtoe), equal to 30% of its consumption that year. These savings would bring Russia's energy intensity very close to that of Canada, which is the OECD country most similar to Russia in terms of average annual temperatures and of the share in gross domestic product (GDP) of energy and heavy industry. Reducing the energy intensity of Russian GDP is a key priority in Russia alongside the goal to modernise ageing infrastructure and the economy as a whole. The aim to reduce Russia's energy intensity by 40% by 2020, compared with that of 2007, was announced by President Dmitry Medvedev in 2008 and its achievement would have substantial implications for energy use and CO_2 emissions reduction in Russia.

Russia adopted the Climate Doctrine Action Plan in April 2011. This plan sets out a range of measures for different sectors of the Russian economy, including economic instruments for limiting greenhouse-gas (GHG) emissions in industry and power generation. The plan consists of 31 items focused mainly on improvement of resource and energy efficiency. The plan suggests that between 2011 and 2020, the Russian Ministry of Economic Development is to introduce changes into Russia's long-term macroeconomic forecasts, taking into account climate risks, mitigation of anthropogenic impacts on the climate and adaptation to climate change. Measures to be taken span all sectors of the economy. In the transport sector, the plan calls for increasing production of hybrid cars and a set of measures to support the use of alternative gas- and hydrogen-based fuels as well as various energy efficiency measures. The construction industry is called on to prepare pilot projects for "passive houses" in 2012 and to develop and introduce economic mechanisms to curb GHG emissions in the industry. The Ministry of Transport has been charged with developing measures to cut down CO_2 emissions from civil aviation by 2015 and from commercial sea and river transport by 2020.

However, the Action Plan is not supported by funding and, in most cases, is more an agenda for policy research and possible future implementation, rather than a specific declaration of policy goals. Another sustainable energy-related target adopted by the Russian authorities in 2007, but still with no backing by legislation or economic incentives, is to increase the share of renewable energy resources (excluding large hydro power) in the electricity mix to 4.5% by 2020. In the 2DS, this target is missed in 2020 with a share of 2%, but met five years later with a 6% share. A more certain target to be reached is Russia's pledge to the Copenhagen Accord – a 15% to 25% reduction in emissions by 2020, relative to a 1990 baseline. The target within this range depends on the extent to which the role of Russia's forests as a carbon sink will be taken into account and whether all major emitters adopt legally binding obligations. The aim to reduce Russia's energy intensity by 40% by 2020 compared with that of 2007 translates into a much higher level of CO_2 emissions reductions.

Figure 17.7.1 Sectoral contributions to achieve the 2DS from the 4DS



Notes: $MtCO_2$ = megatonnes of CO_2; percentages reflect cumulative reductions.

Key point *Russia's CO_2 emissions are cut by almost two-thirds in the 2DS compared with 2009, with the power and industry sectors being responsible for half of the reductions relative to the 2DS.*

Major potentials and challenges: energy efficiency and decarbonisation of the power sector

Russia's fossil-fuel-dominated power sector confronts particular challenges, but also strong potential in its move towards a low-carbon trajectory, especially in the areas of energy efficiency, wind, hydro and biomass energy. These areas account for almost 55% of the 2DS emissions reductions in this sector by 2030 (Figure 17.7.4).

Energy efficiency

Russia is sometimes referred to as the "Saudi Arabia of energy efficiency"; its vast potential to reduce inefficient or wasteful energy consumption can be considered a significant energy reserve. Recognising the benefits of more efficient use of energy, Russia is taking measures to exploit this potential; its president has set the goal of reducing energy intensity by 40% between 2007 and 2020. Furthermore, since 2008, Russia has taken important steps towards creating a legal and institutional framework to enhance efficient energy use and supply. Although there are still gaps in policy as well as in the institutional capacity to implement policies effectively, there are now measures in place or under development covering compulsory energy metering by industry and households, energy efficiency standards for appliances, energy efficiency building codes and standards, compulsory energy audits for large energy consumers, and mandatory reductions in specific energy consumption in public buildings. There is committed federal government support for the development and implementation of regional energy efficiency programmes and a system of federal guarantees for energy efficiency programmes put in place by large enterprises.

Perhaps a far more important driver for energy efficiency improvements in Russia is the priority being given to innovation and modernisation at the highest political level. Given the high average age of Russian infrastructure, modernisation and innovation can bring major gains: for instance, the average thermal efficiency of gas-fired power generation in Russia (excluding co-generation) is 38%, compared with an average of 49% in OECD countries and up to 60% for a new combined cycle gas turbine (CCGT) plant, which is the best available technology (BAT).

Russia is one of the countries with the largest energy savings potential for the five most energy-intensive industries: iron and steel, cement, chemicals and petrochemicals, aluminium, and pulp and paper. However, companies in most sectors lack the incentive to save energy because product prices are growing faster than energy tariffs. The continuation of reforms in the electricity and gas sector is therefore critical to achieving this sector's energy efficiency potential. The continued increase in domestic gas and electricity prices is key to this reform. Domestic natural gas prices, which averaged USD 2.8/million British thermal units (MBtu) in 2010, have yet to reach a level sufficient to generate widespread efficiency improvements, meaning that although the technical potential for savings exists, energy efficiency investments face long payback periods and uncertain rates of return. A related issue is the poor availability of data and insufficient communication, leaving households and companies either unaware of the potential gains from investing in efficiency or underestimating their value. When suitable energy efficiency investments are identified, Russian capital markets are often non-responsive. There is also a relative scarcity of energy efficiency expertise, both within energy-using institutions and to support growth in the fledgling energy services sector.

Despite efforts to develop Russia's institutional capacity and expertise on energy efficiency, notably in the Russian Energy Agency under the Ministry of Energy, this process is still at a relatively early stage and will require a sustained commitment of human and financial resources. Early evidence suggests that some important aspects of the strategy, for example the regional energy efficiency programmes and the industrial energy audits, are making progress but are running behind schedule. Monitoring and evaluation of policies, a crucial element of any successful energy efficiency strategy, is hindered by gaps in the energy data.

Decarbonising the power sector

The total installed electricity generation capacity in Russia in 2011 is around 225 gigawatts (GW), making it the fourth-largest in the world after the United States, China and Japan; together with the extensive heat supply network, it constitutes the backbone of the Russian economy. Over two-thirds of plants are thermal power, a further 21% are hydropower and

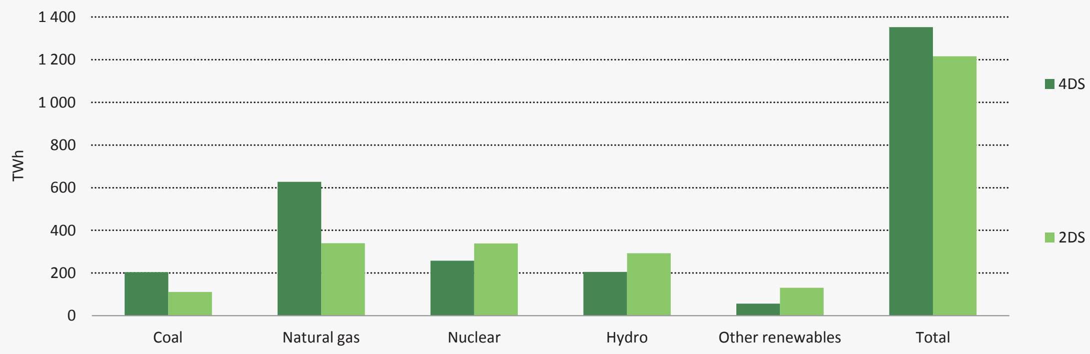
11% are nuclear. Slightly more than half of the thermal plants are co-generation. Gas-fired power plants (electricity-only and co-generation together) make up 44% of total capacity. The electricity and heat systems are linked through the widespread installation of co-generation plants. A major challenge in Russia's heat and power sector is its ageing infrastructure and low record of maintenance over the transition years of the 1990s, when non-payment of bills wreaked havoc with the economics of the sector.

Electricity demand has returned almost to the levels of 1991, and the structure and operation of the industry have been transformed by a major, albeit incomplete, market-driven liberalisation. Production of district heating, by contrast, is around 40% below 1991 levels, growth prospects are uncertain and, although most co-generation plants are now in private hands, the most inefficient boiler-only plants remain the property of municipal authorities. Given the different interests involved, there has been relatively little progress in designing or implementing reforms of the heating sector. The reform of the Russian electricity market, launched in 2003 and one of the most ambitious electricity sector reforms undertaken anywhere, is expected to have a substantial impact on Russia's energy sector and longer-term economic performance. Generating capacity of 100 GW was sold to new owners, including major Russian companies (Gazprom, SUEK, Lukoil) and foreign ones (Enel, E.ON, Fortum). Although liberalisation put a large share of thermal generation capacity into private hands, the state still owns or controls more than 60% of total capacity and this figure has crept up in recent years. Nuclear and most hydropower assets are state-owned, and an additional share of thermal power plants is being brought under the control of majority state-owned companies, notably Inter RAO UES and Gazprom. The main goal of the liberalisation process was to attract badly needed investments to the sector to support its modernisation and refurbishment. At this point, it is not clear if the reform process will bring more central planning features back, or if a truly liberalised sector will emerge, bringing with it market-based signals for timely and innovative investments. This will play a key role in determining how quickly Russia can meet its energy efficiency and decarbonisation goals through innovation and modernisation.

The Energy Strategy to 2030 (Government of Russia, 2009) provides a detailed framework of long-term policy priorities for the entire energy sector. The strategy is supplemented and, in some cases, modified by development programmes for the oil, gas and coal sectors; a similar document for the power sector, called the General Scheme for the Power Sector, was adopted in 2008 and amended in 2010. Investment, efficiency, security and reliability are recurrent themes in the Energy Strategy, which foresees three main changes to the Russian energy balance in the period to 2030: a reduction in the share of natural gas in the primary energy mix to under 50%; an increase in the share of non-fossil fuels in primary energy consumption to 13% to 14% (from 10% today); and a reduction in the energy intensity of GDP.

The Energy Strategy and General Scheme for the Power Sector have quite different outlooks for fuel mix and overall electricity demand compared with the *ETP 2012* 4°C Scenario (4DS), and 2DS. Russian policy makers see electricity consumption in 2030 increasing to 1 545 terawatt-hours (TWh) from 2009 levels of 978 TWh. This compares with 2030 levels of 1 353 TWh in the 4DS and 1 216 TWh in the 2DS, reflecting greater efficiency improvements in these scenarios. The breakdown in terms of input fuel is also very different. In order to meet the 2DS goals, *ETP 2012* projects a needed drop in natural gas of more than a quarter, whereas in the Russian Energy Strategy natural gas remains the main input fuel for power generation; 2DS also sees a dramatic decline in coal-fired power generation. Whereas the Russian strategy and General Scheme see a moderate increase in other renewables (excluding large-scale hydro power), the *ETP 2012* Scenarios call for a major increase in on- and offshore wind and biomass electricity generation.

Figure 17.7.2 Electricity generation in 2030 in the 4DS and 2DS



Key point *In 2030, fossil electricity generation in the 2DS is almost 50% lower than in the 4DS, whereas non-fossil generation increases by 60%.*

Conclusion

Russia's current energy policy path contrasts sharply with the 2DS in its maintenance of a high share of natural gas in the input mix and only modest increase in the share of renewables. In 2011, Russia created energy technology platforms covering nuclear, bioenergy, smart grids, thermal power and distributed energy. Although these platforms are only in their initial phases, they provide the structure and momentum needed for more rapid deployment of wind, biomass and other renewables. The Russian Energy Agency under the Ministry of Energy is increasingly active in the area of bioenergy technology, and RusHydro is actively promoting more large hydro and, to a lesser extent, wind. However, the regulatory framework must be put in place and effectively implemented if any major increase in the share of renewables is to be made, especially in the order of the 2DS where renewables contribute to 35% of the CO_2 emissions reductions in 2030. The overall investment environment in Russia also raises challenges for generating the needed investments across the board, especially for small and uncharted energy efficiency and renewable projects.

Model results for Russia by sector

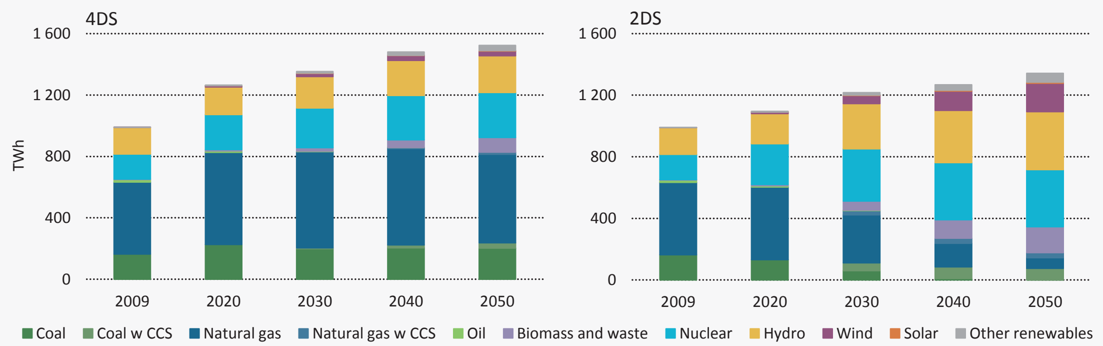
Power

Despite an increased generation from coal, CO_2 emissions in the Russian power sector decline in the 4DS due to efficiency improvements in fossil power generation and an increased generation from nuclear power as well as from renewables, though to a lower extent. As a consequence, the share of fossil fuels in the electricity mix falls from 64% in 2009 to 54% in 2050 (Figure 17.7.3).

In the 2DS, low-carbon technologies cover more than 85% of the electricity demand. Annual CO_2 emissions in 2050 are reduced by more than 85% compared with 2009 levels.

Renewables provide around 40% of the annual reductions in 2050 relative to the 4DS (Figure 17.7.4). Wind alone is responsible for one-fifth of the reduction. Further important options are carbon capture and storage (CCS) at coal and gas power plants, providing 16% of the reductions, as well as nuclear power, which is responsible for around 11% of the CO_2 savings in 2050.

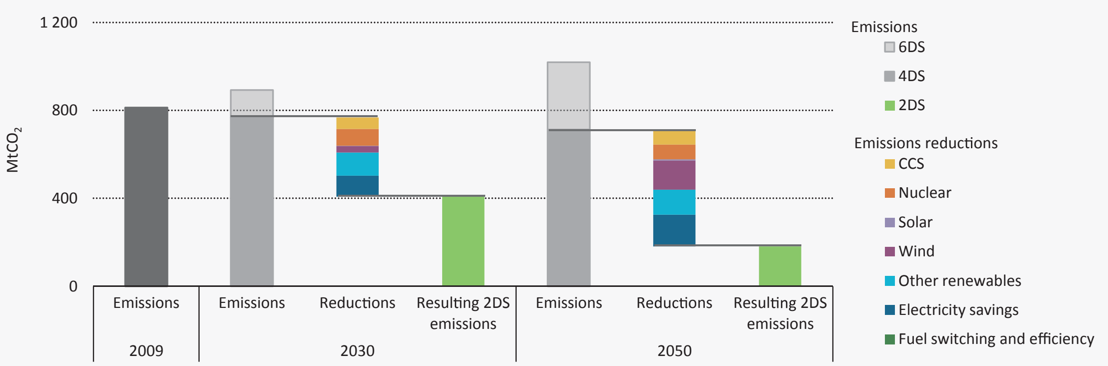
Figure 17.7.3 Electricity generation in the 4DS and 2DS



Note: Other renewables include geothermal and ocean energy.

Key point *Increased electricity generation from nuclear, wind, biomass and hydro are the key options for a decarbonised electricity supply in the 2DS.*

Figure 17.7.4 Annual CO_2 reductions in the power sector to reach the 2DS (relative to the 4DS)



Note: Other renewables include biomass, geothermal and ocean energy.

Key point *Electricity savings in the end-use sectors are responsible for one-third of the CO_2 reductions in 2050 in the 2DS.*

Industry

From a global perspective, Russia is the third-largest industrial energy consumer. Industry accounted for the use of 7.8 exajoules (EJ) in 2009, 45% of total Russian final energy consumption and 6.2% of global industrial energy use. The final energy mix of industry is dominated by natural gas, which accounts for 30% of industry energy consumption.

Russia is among the world's top five producers of crude steel, cement and aluminium. The recent trend in Russian materials production was greatly impacted by the recent economic crisis, with the production of cement decreasing by 26% and the production of crude steel by 17% between 2007 and 2009. However, available data for 2010 show positive signs of recovery. In the scenario analysed, the production level of key industrial materials is expected grow substantially as the economy recovers from the recession, and eventually level off (Table 17.7.1).

As a result of increased production, industrial energy consumption is expected to rise 54% to 66% between 2009 and 2050 in the *ETP 2012* 6°C Scenario (6DS), and 38% to 45% in the 4DS. In the 2DS, improvements in energy efficiency will be an important option for limiting the increase in energy consumption; industry consumption in 2050 will remain close to the level observed in 2009 (Figure 17.7.5).

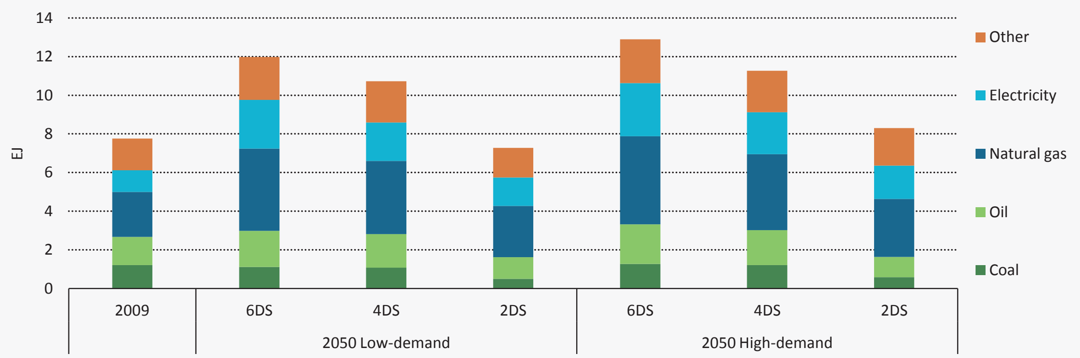
Great potential exists in Russia to substantially decrease CO_2 emissions from the industry sector. In the 2DS, emissions could be cut in half compared with what they were in 2009. The first step in achieving such reductions would be the implementation of current BATs. The industries in Russia are relatively old and inefficient. On a per-unit basis, the largest potential to reduce emissions from the cement and paper industries lies in Russia. Energy efficiency measures, most notably the application of BAT when building or refurbishing steel, cement and paper facilities, would account for over 50% of the reductions between the 4DS and 2DS in 2050. The application of CCS is also an important option and would account for about 35% of the reductions below the 4DS in 2050. The iron and steel and chemicals and petrochemicals sector will have a major role to play in these reductions; they will account for three-quarters of the reductions between the 4DS and the 2DS (Figure 17.7.6).

Table 17.7.1 Key results for main industrial sectors in Russia

		4DS		2DS	
	2009	Low-demand 2050	High-demand 2050	Low-demand 2050	High-demand 2050
Cement production (Mt)	44	63	69	63	69
Crude steel production (Mt)	60	126	157	126	157
Steel scrap used (Mt)	16	57	71	59	73
Paper and paperboard production (Mt)	7	16	23	16	23
Recovered paper (Mt)	2	7	10	7	11
Primary aluminium production (Mt)	4	5	6	4	6
Electricity intensity of primary aluminium (kWh/t aluminium)	14 882	13 030	12 237	12 706	11 264
HVC production (Mt)	6	13	15	13	13
Ammonia production (Mt)	13	23	28	23	28

Notes: HVC = high-value chemicals, kWh = kilowatt-hour.

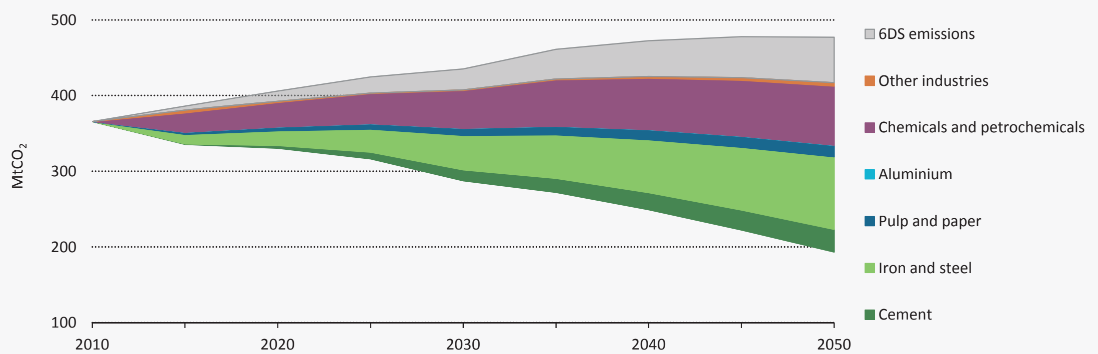
Figure 17.7.5 Industrial energy consumption by energy source in Russia



Note: Other includes heat, combustible biomass, waste and renewables.

Key point *Natural gas will play an increasingly important role in the industry sector.*

Figure 17.7.6 Industrial CO_2 emissions reductions in Russia in the low-demand case



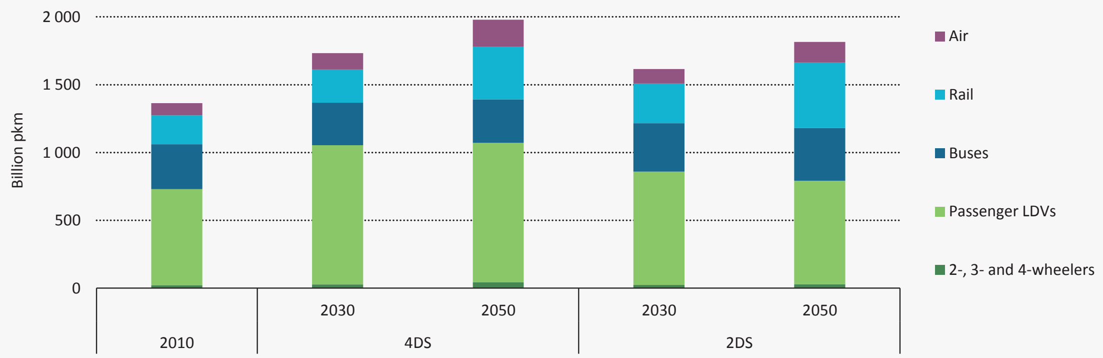
Key point *Important reductions in CO_2 emissions can be achieved in the five most intensive sectors.*

Transport

Although today's car ownership rates are considerably higher in Russia than in countries such as China and Brazil, in the 4DS the car ownership rate more than doubles between 2009 and 2050, along with sales. Passenger travel using light-duty vehicles also increases significantly in absolute terms in the 4DS. But as Russia becomes more and more urbanised and cities are rather far away from each other, the share of rail and air on total passenger travel is expected to grow at an even higher rate (Figure 17.7.7). Shares for rail and buses are significantly higher in 2050 in the 2DS than in the 4DS, based on strong investments in these modes along with urban and regional planning that enables high-quality mobility services with these modes.

Rail has long had a high share of freight transport and this is expected to continue. Under stringent climate policies, the rail system needs to be almost entirely electrified by 2050 (Figure 17.7.8). As for OECD countries, car and truck technologies in the 2DS become much more diversified with emphasis on plug-in vehicles over the coming decades. Even by 2050, however, liquid and gaseous fossil fuels dominate road transportation – though with far lower demand under the 2DS thanks to the introduction of strong fuel-economy policies. Under both scenarios, biofuels will play an increasing role; in Russia these might be mainly from forest products. Passenger light-duty vehicle (PLDV) technology is following the global trend towards electricity – in hybrid, plug-in hybrid or battery electric vehicles. Hybridisation plays the dominant role in increasing vehicle efficiency after 2025 (Figure 17.7.9).

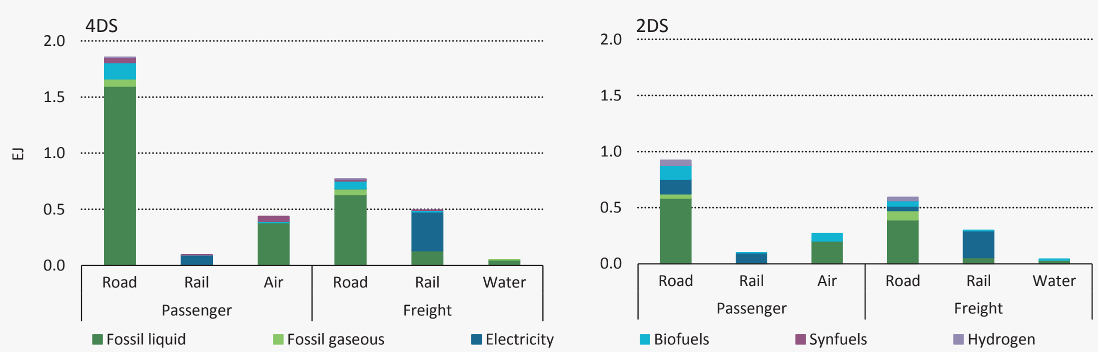
Figure 17.7.7 Passenger mode share in Russia



Note: pkm = passenger kilometre.

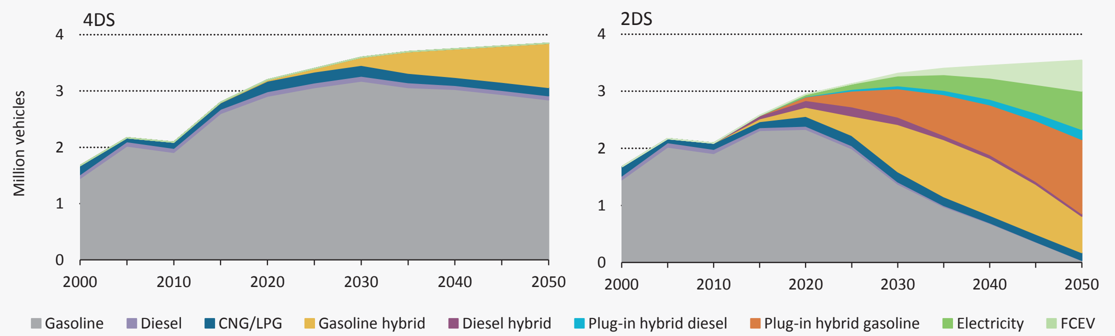
Key point *Significant travel shifts from air to rail and from PLDV to mass transport play an important role in Russia in the 2DS.*

Figure 17.7.8 Transport energy use in 2050 by mode, energy type and scenario



Key point *Energy use is cut dramatically in 2DS via efficiency gains, especially from passenger road vehicles.*

Figure 17.7.9 PLDV sales by technology type and scenario



Notes: CNG=compressed natural gas; LPG=liquid petroleum gas; FCEV = fuel-cell vehicle.

Key point *Strong uptake of electrified PLDVs occurs after 2020 in the 2DS.*

Buildings

Despite the fact that Russia's population is expected to decrease by 0.3% per year between 2009 and 2050 (UN DESA, 2011), residential and services floor area will increase by 1.1% and 0.8% respectively over the same period (Table 17.7.2).

Buildings are the largest energy-consuming end-use sector in Russia, accounting for 36% of total energy consumption. Space and water heating are responsible for 80% of final energy use in the sector, with an estimated three-quarters of all buildings serviced by district heating networks. The currently accelerating trend towards decentralisation of heat supplies (whereby wealthier residential and commercial customers opt for more reliable and modern individual heating) is expected to continue in the 4DS as household income increases fourfold by 2050. Overall, energy consumption in the sector has been falling over the last decade and the annual rate of renovation of buildings has slowed to around 0.5%.

Table 17.7.2 Key activity and projections for Russia's buildings sector

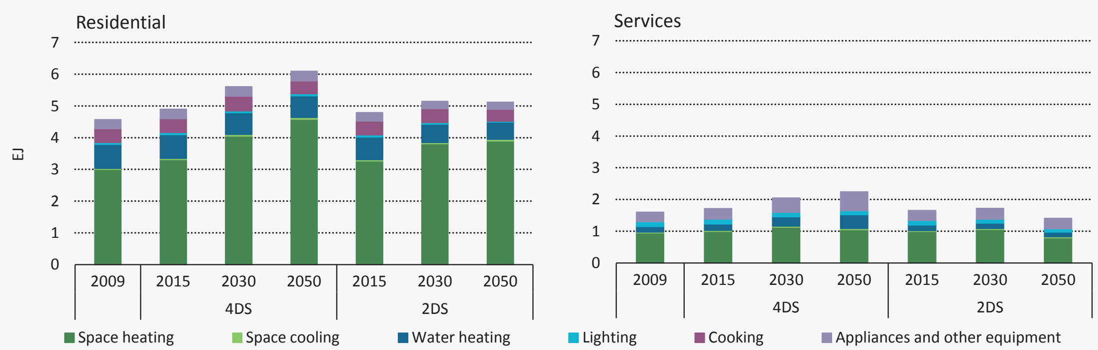
	2009	2015	2030	2050	AAGR (2009-50)
Population (million)	142	142	136	126	-0.3%
Number of households (million)	54	60	59	55	0.0%
Residential floor area (million m^2)	2 766	3 100	3 839	4 407	1.1%
Services floor area (million m^2)	767	830	989	1 069	0.8%

Notes: AAGR = average annual growth rate, m^2 = square metre.

The Russian buildings sector holds great energy and emissions abatement potential. The growth in buildings' energy consumption can be limited to only 5% in the 2DS between 2009 and 2050. Most of the energy reduction potential to achieve the 2DS in 2050 lies in energy efficiency improvements in water heating, lighting and appliances. Together, these end uses account for almost 50% of the reductions between the 4DS and the 2DS (Figure 17.7.10). Great potential also exists in large-scale refurbishment of ageing buildings to stringent code levels in the 2DS. This could reduce the specific demand for space heating by 20%, resulting in levels similar to the current building stock of Canada, an OECD country with comparable heating degree days (HDDs).

Direct and indirect CO_2 emissions can be reduced by over 65% in the buildings sector in the 2DS between 2009 and 2050. Improvements in energy efficiency for all end uses have a major role to play in reducing emissions; it accounts for about two-thirds of the reductions between the 4DS and 2DS. The decarbonisation of power and heat supply will account for one-quarter of the overall reductions (Figure 17.7.11).

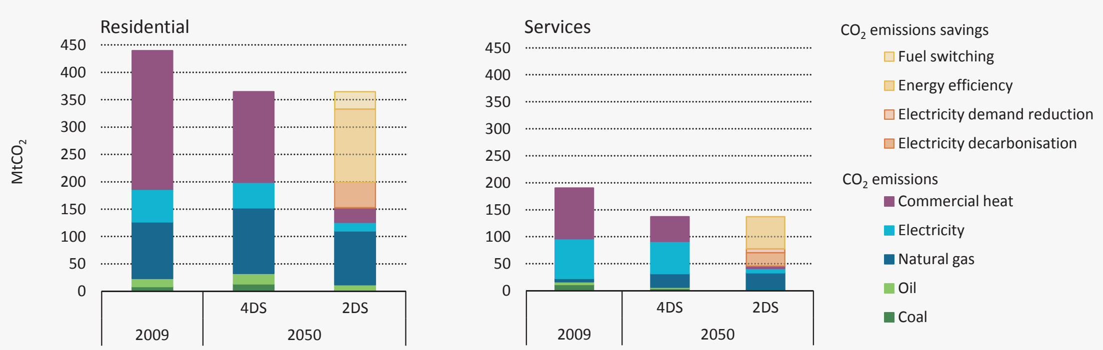
Figure 17.7.10 Buildings energy consumption by end use in Russia



Note: For the service sector, cooking is included in appliances and other equipment.

Key point *About 50% of the energy reductions from the 4DS in 2050 will be from space heating.*

Figure 17.7.11 Buildings CO_2 emissions reductions in Russia



Key point *Energy efficiency will have a major role to play, accounting for about 65% of the emissions reductions between the 4DS and the 2DS.*

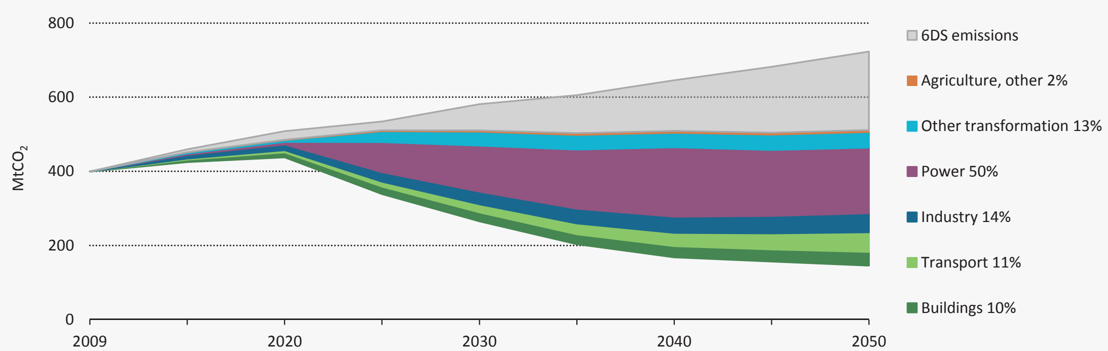
8. South Africa

South Africa, one of the world's most energy-intensive economies, faces a multi-faceted challenge in the coming decades. As a top coal producer, the country covers most of its energy need from its large coal deposits, with 94% of electricity produced from coal. Yet, at the moment, the country does not always manage to produce sufficient electricity to supply demands; shortages and rolling blackouts are expected to continue in the coming years. The effects also extend to the larger region, as South Africa is the main electricity producer for its neighbouring countries. With economic growth on a modest but stable path, South Africa will require an estimated 40 000 megawatts (MW) of new generation capacity by 2025 (tied to annual growth in the gross domestic product [GDP] of around 3.6% or less).

Urgent steps are needed, and South Africa is already in the process of building two new coal-fired power plants. At the same time, the country has the ambition – stated in recently published new policies and announced for future ones – to secure sustainable low-carbon development. This welcome development would help to diversify its generation mix and to reduce its dependency on coal. When addressing its two main goals of stable electricity supply and low-carbon development, South Africa also has to take into account the pressing need for job creation and poverty alleviation (including providing access to electricity to 25% of the population who currently have none).

Tackling such a diverse set of problems is far from easy. In the *ETP 2012* 6°C Scenario (6DS), CO_2 emissions will rise by around 80%, further aggravating the problems of the country, which is already a major emitter (Figure 17.8.1). The following sections examine the different policies and proposed measures aimed at alleviating this rise, with further options detailed under the model results.

Figure 17.8.1 Sectoral contributions to achieve the 2DS from the 4DS



Notes: $MtCO_2$ = megatonnes of carbon dioxide; percentages reflect cumulative reductions 2009-50.

Key point *CO_2 emissions are reduced by 60% relative to 2009, with the power sector being responsible for half of the reductions compared with the 4DS.*

The current challenge to climate policies and initiatives

South Africa is the continent's largest net exporter of electricity. Sending power to all neighbouring countries, it supplies about two-thirds of Africa's current needs. South African usage constitutes 85% of the 204.8 billion kilowatt-hour (kWh) consumption for the South African Development Community (SADC) region, and in 2010 ranked 21st in worldwide energy consumption, whereas it was only 42nd for GDP.

That demand for electricity would increase, and that generation capacity and distribution would need to be scaled up, have been predicted for more than a decade. This prompted Eskom, the state-owned utility – ranking among the top seven utilities in the world in terms of generation capacity – to begin remobilising long-decommissioned power stations. No other actions were taken, however, resulting in rolling blackouts in 2008, when Eskom needed to return to load shedding. Eskom still has to make do with less-than-optimal reserve margins.

In light of this recent energy crisis, South Africa has embarked on a number of projects to increase energy output and meet rapidly rising demand. Coal is still widely seen as a simple and quick remedy, in spite of the fact that long-term coal supply is uncertain. Medupi and Kusile, the two coal-fired power plants under construction, will each have about 4 800 MW of generation capacity when completed. An estimated ZAR 385 billion (USD 48.6 billion) is planned to be spent on new generation projects up until 2013, and approximately three times this sum by 2026, in order to double capacity to 80 000 MW.

At the same time, South Africa pledged at the United Nations Framework Convention on Climate Change (UNFCCC) Conference of the Parties held in Copenhagen in 2009 (COP15) to cut greenhouse-gas (GHG) emissions 34% below the "business as usual" emissions growth trajectory by 2020, and 42% below by 2025. Even though it is clear that this commitment will present challenges for the energy sector, steps needed for this change are to some extent already embedded in the White Paper on Renewable Energy (2003). This publication has set a target of 10 000 gigawatt-hours (GWh) of energy to be produced from renewable energy sources (mainly from biomass, wind, solar and small-scale hydro) by 2013.

This pledge is also supported by the recommendations of the publication titled "Long-Term Mitigation Scenarios" (LTMS). Commissioned by the Department of Environmental Affairs and Tourism in 2007 to investigate a number of scenarios for the reduction of carbon dioxide emissions, a number of so-called "mitigation wedges" were identified. They include energy efficiency measures, a mode shift for transport (from private to public and from road to rail, as well as increased vehicle efficiency through hybrid and electric cars), and carbon capture and storage (CCS), from both the synfuel plants and electricity generation.

In line with the ambition to provide long-term reliability of electricity supply while at the same time considering environmental impacts, the Integrated Resource Plan (IRP) of 2010 outlines a strategy for the electricity sector for the period 2010 to 2030. The IRP identifies the following shares of new electricity generation capacity that will be needed by 2030: 15% coal, 23% nuclear, 6% hydro, 14% gas and 42% other renewables (primarily wind and solar photovoltaic [PV] as well as concentrated solar power [CSP]). The total additional new capacity between 2010 and 2030 is estimated to be 43 000 MW, with approximately 17 800 MW coming from renewable energy.

These targets were proposed by the South African Department of Energy, which was established in 2009 by splitting the Department of Minerals and Energy. This ministry derives its mandate from the White Paper on Energy Policy of 1998 and is responsible for ensuring the secure and sustainable provision of energy. It does so by undertaking Integrated Energy Planning (IEP), having a direct impact on how South Africa advances on its low-carbon development path. The Department of Energy also regulates energy industries and promotes electric power investment in accordance with the IRP. It continues to implement the amended Electricity Regulation Act of 2006, especially with respect to creating the necessary conditions for the introduction of independent power producers (IPPs) in the electricity market. Although the 30% target share of the IPPs is still distant, the anticipated boost to renewables may bring it into sight.

Energy efficiency

Further policies build on improvements in energy efficiency to deal effectively with potential electricity capacity shortages, environmental concerns and the rising price of energy sources. The latest overarching energy efficiency target for South Africa comes from the National Energy Efficiency Strategy, last reviewed in 2008. It sets the target for energy efficiency improvement at 12% by 2015 for the country as a whole. In addition, more than 30 large companies, including from the iron, steel and cement industries, have joined forces with the Department of Energy and Eskom by signing an Energy Efficiency Accord, committing themselves to the goal of a 15% reduction in large-customer energy use. This is a crucial step, because as the *ETP 2012* model result for industry shows, deep reductions within these sectors can be achieved, for example, by application of best available technologies (BAT) – the sharing of which is one of the aims of the Accord.

The LTMS also estimates that industrial energy efficiency has the largest potential to mitigate CO_2 emissions (Table 17.8.1). Even though commercial (USD -35 per ton of carbon dioxide equivalent [tCO_2-eq]) and residential (USD -34/tCO_2-eq) energy efficiency measures are more cost-effective than industrial ones (USD -6/tCO_2-eq), the latter provides much greater absolute savings (4 572 $MtCO_2$-eq). This is not surprising, as industrial and mining sectors are the heaviest users of energy, accounting for more than two-thirds of national electricity usage. In all *ETP 2012* scenarios analysed, industrial energy consumption is set to increase further – however, in the *ETP 2012* 2°C Scenario (2DS), industry emissions are projected to fall by more than 20% by 2050 compared with 2009 levels.

Table 17.8.1 CO_2 mitigation potential in South Africa

	Mitigation potential 2003-50 ($MtCO_2$-eq)	Mitigation cost (USD/tCO_2-eq)
Energy sector		
Industrial energy efficiency	4 572	-6
Renewable energy extended	3 990	1
Nuclear extended	3 467	3
Solar water heaters	307	36
Transport sector		
Passenger modal shift	469	-193
Improved vehicle efficiency	758	46
Synfuel CCS	**851**	**18**

Source: South African Department of Environmental Affairs and Tourism, 2007.

In 2004, the National Electricity Regulator of South Africa (NERSA) proposed the Regulatory Policy on Energy Efficiency and Demand-Side Management for the South African Electricity Industry, which made energy efficiency and demand-side management (DSM) one of the licensing conditions for all electricity distributors, and also established a DSM Fund. In 2010 a new, more efficient model was developed (the Standard Offer Programme or SOP) for disbursing the incentives. The SOP provides payments for verified savings based on the avoided costs of electricity supply, while recognising the so-called “allowable technologies”.

Residential energy efficiency (including solar water heaters; see next sub-section) is not only a good negative cost mitigation option (accounting together with the commercial sector for approximately 18% of total emissions), but also has important socio-economic benefits. While individual interventions are small, across a large number of households they add up to avoided emissions of over 300 $MtCO_2$-eq over time. Compact fluorescent lamps (CFLs) are also promising in this respect and, together with solar water heaters (SWHs), are recognised to receive DSM incentives. As these technologies account for important CO_2 savings within the buildings sector, this is a step in the right direction. To date, the roll-outs of regional and national CFL replacement programmes by Eskom resulted in some 35 million CFL installations over the past decade, with 14 million in 2008 alone. The programme also boosts local manufacturing capacity: all CFLs used to be imported until a new plant became operational in 2009.

Decarbonising the power sector

Clearly, decarbonisation of the South African power sector has to be the main goal in order to curb emissions: model results estimate that nearly half of all cumulative CO_2 savings in the 2DS compared with the *ETP 2012* 4°C Scenario (4DS) would come from this (Figure 17.8.1), and carbon capture and storage (CCS) is bound to play an important role. Besides coal-fired power plants, the 2DS foresees this technology alleviating the emissions of electricity generation from biomass and natural gas as well. With coal-fired plants accounting for most of the current CO_2 emissions, and additional plants shortly coming online, it is encouraging that the country prioritises CCS to offset the negative effects on the climate.

The ambitious aims championed by the South African Centre for CCS have already yielded the Atlas on Geological Storage, and the conception of a roadmap is imminent. A test injection is foreseen for 2016, followed by operation of a demonstration plant in 2020 and a commercial one in 2025, the latter with an annual capacity of 40 million tonnes (*i.e.* about 10% of the current South African CO_2 emissions). Although there are plans for existing power plants to be fitted with CCS, there is no concrete project in view, in spite of the government’s stated desire for CCS to act as an environmental measure in the transition from fossil fuel to nuclear and renewable. The 2DS shows that CCS should be an important factor in the low-carbon development of the country, even beyond the transition.

As stated by the government, a reliable base load from the installed new generation is needed, and in addition to coal, nuclear is another energy source that potentially ensures such reliability. A higher proportion of nuclear energy is foreseen in both the 4DS and the 2DS, but at different levels: in the 2DS, almost five times the share by 2050. Koeberg, a large nuclear station near Cape Town, currently provides about 4% of generation capacity (1 930 MW); the predicted increase would be four times its current capacity. According to the IRP, nuclear should account for 23% or 9 600 MW of generation capacity by 2030, which is a steep rise from the current 4%. The bidding process for the construction of one or more nuclear power plants is still to be launched.

The development of renewable resources is also key to reaching the target of 30% clean energy by 2025. South Africa’s renewable energy policy is mostly driven by the target of

10 000 GWh by 2013, but to date few renewable energy projects for electricity generation have been deployed. In the past, renewable energy project subsidies were offered, followed by feed-in tariffs in 2009. Two years later, however, this approach was abandoned altogether and a bidding process advertised, with the first winners announced in December 2011.

The 28 awarded bids represent a total of 1 415 MW of renewable energy contracts. This includes 630 MW of solar PV, 150 MW of CSP, and 634 MW of wind. An additional 2 200 MW will have to find bidders in order to make up the required total of 3 625 MW. The financial plans are due by mid-2012 and are a prerequisite to construction.

The breakdown of technologies in the first round is a clear indication that the highest potentials are in solar and wind. With an average of over 2 500 hours of sunshine every year, one of the highest in the world, South Africa has a very high potential for solar energy.

South Africa has a programme to reach 1 million SWHs by the end of 2014. The mass rollout of SWHs is slow but gaining momentum: since the launch of the programme in 2008, over 30 000 rebate-funded SWHs have been installed across the country. Notwithstanding these lower-than-desired installation figures, the 2014 target could still be in sight. The market growth is largely facilitated by increased energy awareness due to the nationwide electricity blackouts in 2008, as well as by the available subsidies. As mentioned earlier, the SWH is among the technologies recognised by DSM incentives, enabling the private sector to be increasingly involved.

The drawback of this programme is that the technology available today is imported, expensive and of mixed quality. The development and deployment of locally manufactured solar water heaters could help the country achieve its targets more cheaply, while positively influencing the acceptance of this technology at the same time. As off-grid electrification programmes have a bad reputation due to lack of education and poor follow-up, some regional communities reject off-grid solutions as being sub-par, and prefer to wait for grid connection. There is a need for rigorous information campaigns to address these public acceptance issues.

Large-scale solar projects are also crucial if the country sets out towards the projected 60 GW in the 2DS scenario by 2050 – which would enable important emissions reduction in the power sector. Pre-feasibility studies for the first 5 000 MW solar park have already been completed for an area with ideal conditions, including intense solar radiation and a potential workforce. The government plans to lease the land to private developers, who would design, finance and build individual projects utilising technologies approved by NERSA, including solar thermal and PV. The park is estimated to cost USD 10 million to USD 15 million, with the actual solar plants' cost of billions of dollars to be incurred by private sector developers.

For wind energy, another important technology in both the 4DS and 2DS, a recently completed Wind Atlas shows the good wind resource potential in the country: the existence of three different wind climates within the country, and therefore a high potential to have continuous energy production from wind as well. An existing national demonstration project, the Darling Wind Farm, is set for expansion; however, other projects, such as Eskom's 100 MW Sere farm, have experienced many financial setbacks. The project is estimated to cost USD 375 million and should be commissioned in 2012.

Similar to SWHs and CFLs, the larger undertakings for both solar and wind would clearly benefit from local manufacturing capacity, which could even make the projects into technology hubs, encouraging research and development (R&D) and gradually lowering costs. To achieve critical mass, South Africa will need to prioritise not only in terms of investments in the currently underinvested energy R&D, but in terms of skills development.

South Africa is a leader in coal-to-liquid technologies, but is behind in the development of clean energy technologies. Addressing this gap would boost the renewable sector significantly.

Conclusions

South Africa has an urgent need to ramp up its generation capacity, and coal will certainly continue to dominate. However, as the model results show, power sector decarbonisation is by far the most effective route to lower CO_2 emissions. South Africa's pledge to cut GHG emissions by 42% (as compared to "business as usual") by 2025, for example through renewables and CCS deployment, is in line with this. Other stated goals such as transport modal shift and enhanced energy efficiency are also clear signs of the will to put the country on a low-carbon path. Many are critical of this aim, fearful that it could hamper the achievement of the country's other priorities of job creation, poverty reduction and faster economic growth. Implementing the targets and boosting investments in order to reap the benefits as soon as possible is, therefore, crucial to demonstrate the advantages of this approach. Considering South Africa's vast renewable resources, potential benefits are great.

Many factors are, however, holding back progress. South Africa's electricity is still among the cheapest in the world, even after 25% tariff increases in each of the last three years and an additional 16% rise in 2012, resulting in long payback periods for investments. Public awareness is limited and slow implementation of policies and target-setting is damaging. Regulatory measures are a prerequisite to kick-start the supply of clean energy and its efficient use, but are by no means sufficient. There is a need to demonstrate that renewables can provide reliable and affordable electricity; in a country that had overcapacity and has relied on its vast coal resources for so long, enhancing credibility of new clean technologies is a major issue. Policy coherence will then be important to gain investor confidence.

Given high up-front costs for many renewable technologies, the issue of finance must be addressed from the beginning. Financing schemes should be developed that address affordability issues. Current government R&D funding is unlikely to be sufficient to stimulate adequate technology development, so the ability to attract capital from the private sector will be key to creating markets for low-carbon technologies. Instead of importation of expensive technologies, local industries would need to be developed in order to achieve critical mass and to gain public acceptance.

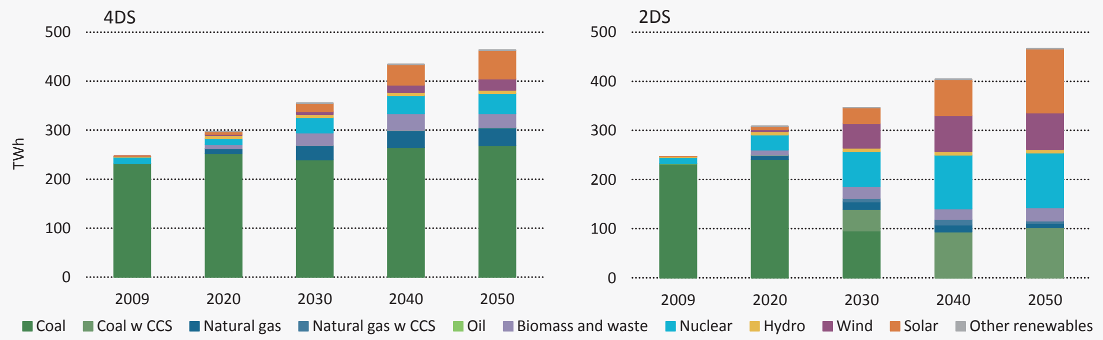
Model results for South Africa by sector

Power

In the 4DS, coal-based generation maintains its current generation level (Figure 17.8.2). Increase in generation is covered by a mix of solar, nuclear, wind and natural gas. Carbon emissions in the power sector fall slightly below today's level.

Solar, nuclear and wind are important technologies in the 2DS also. Solar capacity rises to 50 GW in the 2DS in 2050, being roughly equally split between solar PV and CSP, and is responsible for one-fifth of the carbon emissions reductions between the 4DS and 2DS in 2050 (Figure 17.8.3). Nuclear power provides an installed capacity of 15 GW in 2050, a similar reduction. Coal plants fitted with CCS, reaching a capacity of 15 GW in 2050, could provide about 30% of the annual CO_2 reductions needed to decarbonise the South African power system.

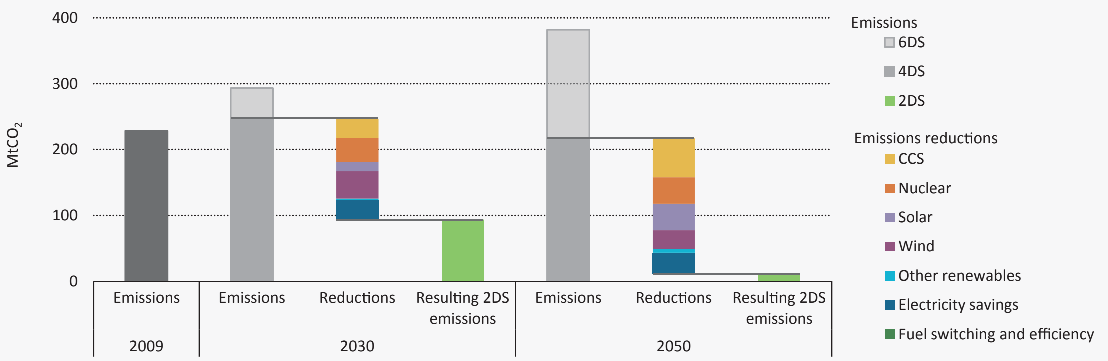
Figure 17.8.2 Electricity generation in the 4DS and 2DS



Notes: TWh = terawatt-hour ; Other renewables include geothermal and ocean energy.

Key point *Solar power, coal plants with CCS and nuclear power together provide three-quarters of the electricity supply in the 2DS in 2050.*

Figure 17.8.3 Annual CO_2 reductions in the power sector to reach the 2DS (relative to 4DS)



Note: Other renewables include biomass, geothermal and ocean energy.

Key point *CCS provides one-third of the CO_2 reductions in 2050 to reach the 2DS, followed by nuclear and solar power, each providing almost one-quarter of the mitigation.*

Industry

Industry used 1.0 exajoule (EJ) of energy in 2009, accounting for 33% of the final energy used in South Africa. The iron and steel sector is, by far, the largest industrial consumer of energy. In 2009, it used 22% of the energy consumed by industry as a whole. Coal is the main energy source used by industry and accounts for over 45% of total industrial energy consumption.

Production of material is expected to increase at a sustained pace between 2009 and 2050. Production of crude steel will remain important, increasing around fivefold between 2009 and 2050 (Table 17.8.2).

Driven by the strong growth in materials production, energy consumption will increase between 2009 and 2050 in all the scenarios analysed (Figure 17.8.4). However, the mix of energy used in the industry will be dramatically different in the 2DS. Coal use will be reduced to less than 30% of industrial energy consumption, partly due to the phase-out of coal-based direct reduced iron (DRI) and the switch away from coal to alternative sources of energy in the cement sector.

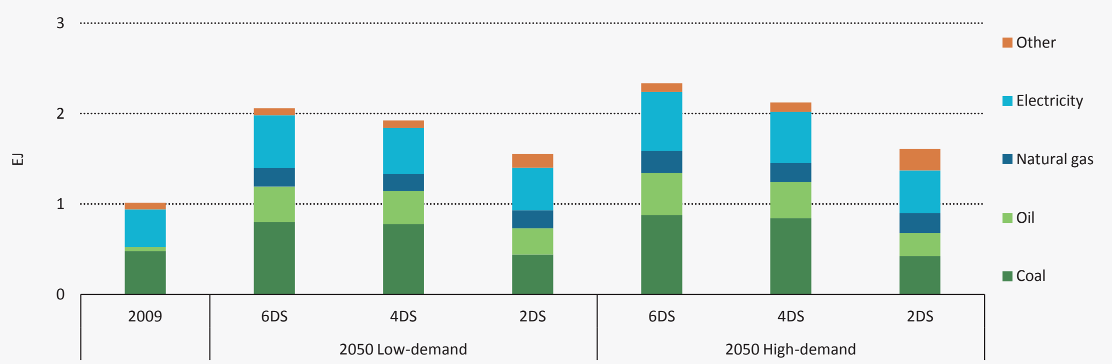
While energy consumption will increase, industry CO_2 emissions will be 22% lower in 2050 in the 2DS than they currently are, and about 50% lower than they would have been in 2050 in a 4DS. Over 40% of the reductions from the 4DS can be attributed to the iron and steel industry. Deep reduction in this sector can be achieved through the phase-out of coal-DRI, the increased use of recycled materials, the application of best available technologies (BATs) for new and refurbished units, and the application of CCS. The chemicals sector will also play a key role in reducing CO_2 emissions from industry. The reductions in the chemicals and petrochemicals sector would come from a switch away from oil to natural gas and biomass as energy sources and feedstock, and from greater efficiency in chemical processes.

Table 17.8.2 Key results for main industrial sectors in South Africa

		4DS		2DS	
		Low-demand	High-demand	Low-demand	High-demand
	2009	2050	2050	2050	2050
Cement production (Mt)	12	26	31	26	31
Crude steel production (Mt)	7	33	39	33	39
Steel scrap used (Mt)	2	13	15	14	16
Paper and paperboard production (Mt)	2	8	13	8	13
Recovered paper (Mt)	1	5	8	5	9
Primary aluminium production (Mt)	1	1	2	1	2
Electricity intensity of primary aluminium (kWh/t aluminium)	14 857	12 382	11 801	12 010	10 797
HVC production (Mt)	1	6	7	6	6
Ammonia production (Mt)	1	2	2	2	2

Notes: Mt = Million tonnes, kWh/t = kilowatt-hour per tonne; HVC = high-value chemicals.

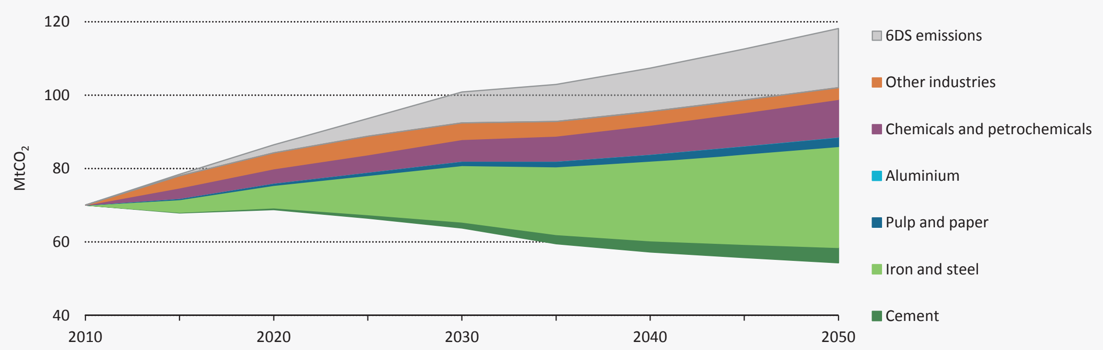
Figure 17.8.4 Industrial energy consumption by energy source in South Africa



Note: Other includes heat, combustible biomass, waste and renewables.

Key point *Changes in industrial processes and practices will allow diversification of the fuel mix.*

Figure 17.8.5 Industrial CO_2 emissions reductions in South Africa in the low-demand case

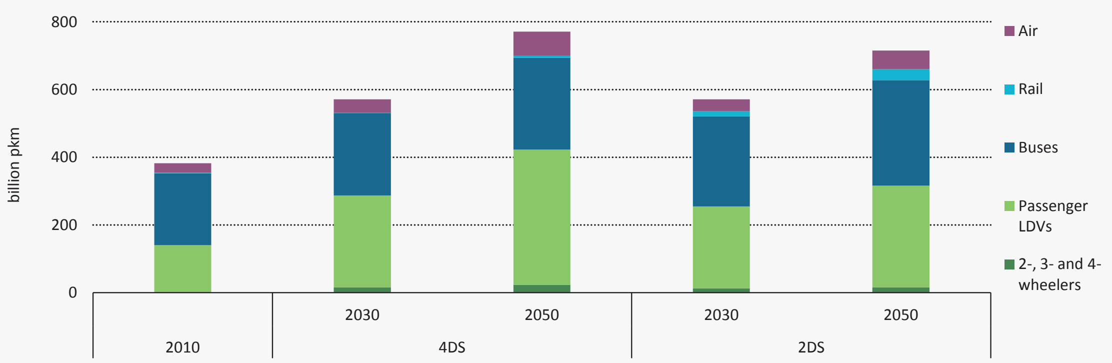


Key point *Over 50% of the reduction potential can be realised within the iron and steel sector through efficiency improvements, changes in processes and the application of CCS.*

Transport

Given the projected GDP per capita increase in South Africa, car sales and ownership levels are expected to double in the 4DS and 2DS, though travel shares via mass transportation still remain high (Figure 17.8.6). The construction of Africa's first-ever full bus rapid transit (BRT) systems and new rail projects in several South African cities for the 2010 World Cup puts the country in an excellent position to modernise and expand bus and rail transport in the coming decade and become a continental leader in sustainable transport, while at the same time avoiding a drift towards car dependence in the major cities. Strong policies and major ongoing investments will be needed to see this through, but the fact that transport mode shift and increased vehicle efficiency are recognised as "mitigation wedges" in the LTMS is encouraging.

Figure 17.8.6 Passenger mode share in South Africa

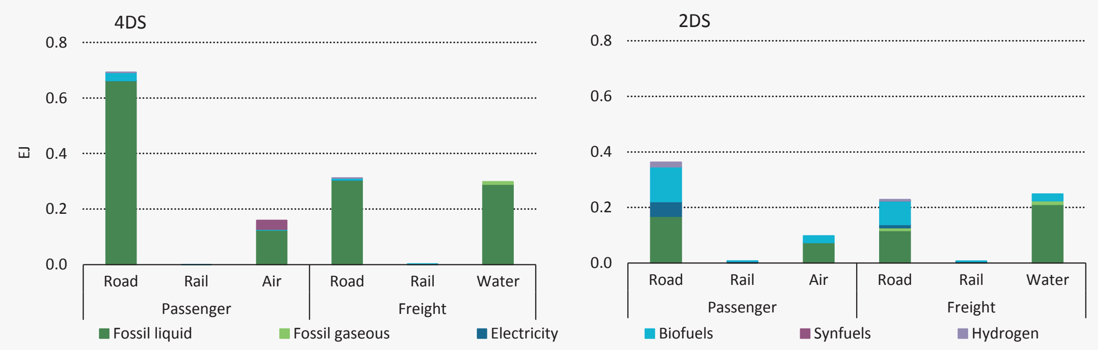


Note: pkm = passenger kilometre.

Key point *Motorised passenger activity is expected to double by 2050 as income rises and access to motorised modes is eased.*

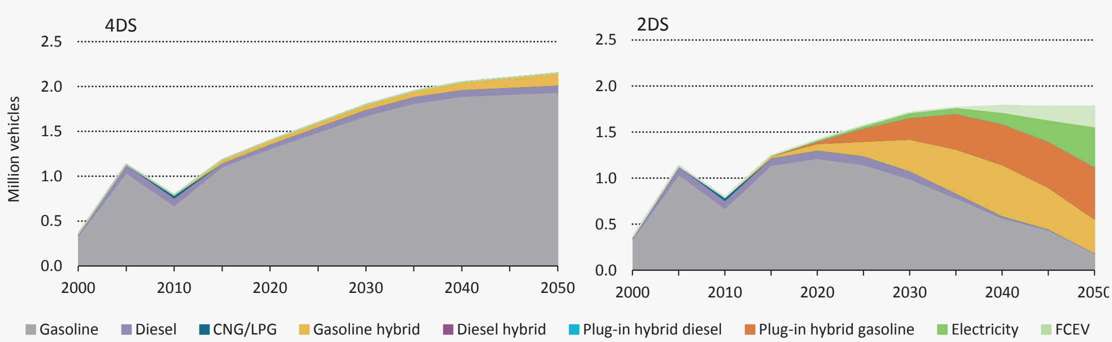
Synfuels, such as coal-to-liquid (CTL), are likely to play a role to 2050 in an unconstrained scenario but, due to the high CO_2 intensity of such synfuels, are limited in the 4DS and are phased out in the 2DS to be replaced with biofuels. Efficiency gains in the 2DS are much more important in passenger than in freight transport, as the available potential for reduction in the freight sector is thinner than for passenger transport (Figure 17.8.7). Sales of passenger light-duty vehicles (PLDVs) continuously increase until 2050, recovering from a sharp decrease in the late 2000s (Figure 17.8.8).

Figure 17.8.7 Transport energy use by mode, energy type and scenario



Key point *Biofuels seem to be one of the best options to reduce the reliance on fossil fuel energy.*

Figure 17.8.8 Passenger light-duty vehicle sales by technology type and scenario



Notes: CNG = compressed natural gas, LPG = liquefied petroleum gas, FCEV = fuel-cell electric vehicle.

Key point *Slow technology diversification is expected in South Africa, if no specific policies are adopted.*

Buildings

The residential and commercial sectors currently account for around 18% of total emissions in South Africa. Within the residential stock, 82% of buildings have access to electricity and 40% are considered "informal" dwellings (shacks and squatter settlements).

Where available, electricity is the largest source of energy for all building end uses, while traditional sources of biomass dominate in rural areas for the residential sector. Household income and commercial floor space will both triple between 2009 and 2050, while residential floor area will increase by 86% (Table 17.8.3). A number of drivers will transform the energy mix in the buildings sector. The increased share of electrified urban households, coupled with a greater electrification of the country, will bring a reduction in coal and traditional biomass use. In the 2DS, biomass will account for less than 5% of total buildings consumption, down from 33% today.

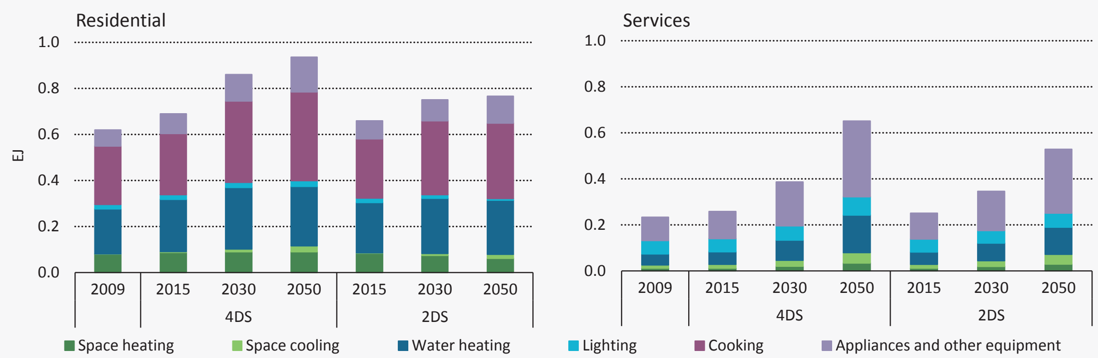
Water heating, cooking, and appliances and equipment are, by far, the largest energy consumers of the buildings sector, accounting for about 80% of buildings energy use. These three end uses also hold the largest potential for reducing buildings energy consumption, accounting for over 70% of the reductions between the 4DS and the 2DS in 2050 (Figure 17.8.9). Most of the improvements in cooking and water heating would come from the move away from traditional biomass, and the increased use of electricity and, in the case of water heating, solar energy.

Table 17.8.3 Key activity in South Africa's buildings sector

	2009	2015	2030	2050	AAGR (2009-50)
Population (million)	49	51	55	57	0.3%
Number of households (million)	10	12	16	19	1.6%
Residential floor area (million m^2)	821	936	1 151	1 528	1.5%
Services floor area (million m^2)	275	310	480	804	2.7%

Notes: AAGR = average annual growth rate, m^2 = square metre.

Figure 17.8.9 Buildings energy consumption by end use in South Africa

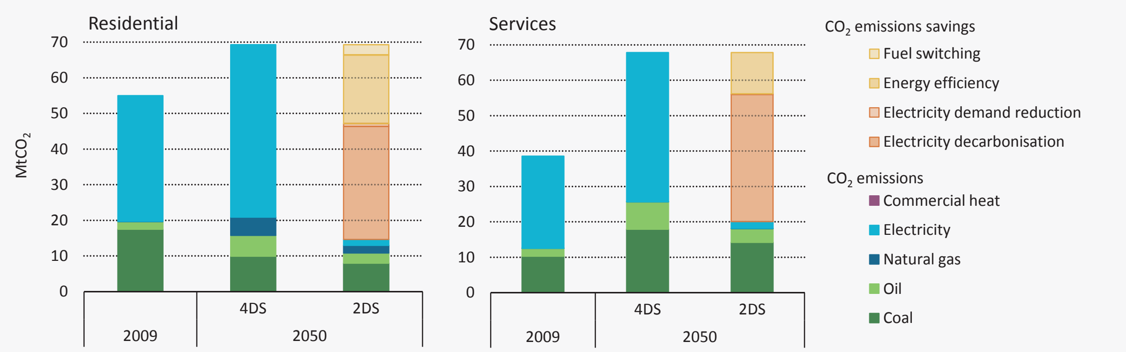


Note: For services, cooking is included in appliances and other equipment.

Key point *Energy consumption in the buildings sector will be 50% higher in the 2DS in 2050 than in 2009, but 20% lower than in the 4DS.*

The main direct and indirect CO_2 abatement potential lies in the decarbonisation of the South African power sector (70% of all CO_2 savings in the 2DS compared with the 4DS, or 68 $MtCO_2$) (Figure 17.8.10). There is also great scope for more efficient technologies. In the commercial sector, the 2DS has a high penetration of efficient heating and cooling equipment, chiefly heating, cooling and ventilation (HVAC) with variable speed drives and heat pumps. In the residential sector, key options for energy efficiency include insulating blankets for electric water heaters ("geyser" blankets), and a near phase-out of incandescent lighting, replaced with CFLs and light emitting diodes (LEDs). Combined with stringent building codes for new buildings, these technologies account for 29% of all CO_2 savings from the 2DS in 2050 (15 $MtCO_2$). After 2035, the diffusion of solar heating and cooling technologies accelerates as solar thermal technologies become more efficient, reaching a 15% share of space heating and almost 30% of water heating demands in 2050.

Figure 17.8.10 Buildings CO_2 emissions reductions in South Africa



Key point *The decarbonisation of the power sector is important for reducing direct and indirect CO_2 emissions; it will account for two-thirds of the reductions between the 4DS and 2DS.*

9. United States

The shale gas revolution in the United States is the focal point of one of the most important developments in energy technology this decade. The massive increase in available gas resources has profound and generally positive implications for energy security and climate policy for the region and, potentially, the entire globe. Although the application of key shale production technologies on tight oil formations is in an early stage, the potential contribution to US and global oil supplies is already clear. However, concerns have emerged about the environmental sustainability of shale gas production. Development of an environmental and safety regulatory framework for the production of shale gas resources should therefore be a key objective of energy policy.

Even in the absence of an explicit carbon pricing regime, the increasing competitiveness of gas at the expense of coal has already led to a measurable reduction in carbon dioxide (CO_2) emissions. Given the available gas resources, this process could continue for some time, although inadequate electricity transmission infrastructure preventing full utilisation of gas-fired power plants is a hindrance. Fostering greater competition within the US power system with better infrastructure and appropriate regulatory reform would help enable cost-efficient CO_2 emissions reductions.

While natural gas makes a valuable contribution, alone it is insufficient as a sustainable energy pathway, so the utilisation of shale resources cannot substitute for a broad energy policy effort to enhance sustainability and energy security. Substantial improvements in energy efficiency must be at the centre of a strategy for energy security and decarbonisation.

Recent policies are encouraging in this respect, particularly the fuel economy standards for trucks and the current plan to extend light-duty fuel economy standards to 2025, with a doubling of fuel economy (50% cut in fuel intensity), consistent with international targets set by the Global Fuel Economy Initiative (GFEI, 2011). Targets for introducing electric vehicles (1 million on the road by 2015) are ambitious and should help begin a transition away from oil in the transport sector.

Pricing carbon would help other US policies trigger the changes needed to begin a real reduction in CO_2 emissions before 2020. The United States has led the world in the development of emissions trading systems for sulphur dioxide (SO_2) and nitrogen oxides (NO_x) that harness the inherent efficiency of markets for environmental policy. It is worth noting that due to the expanding availability of natural gas, near-term CO_2 reductions are achievable at a lower carbon price than was anticipated in the second half of the last decade when such policies were designed.

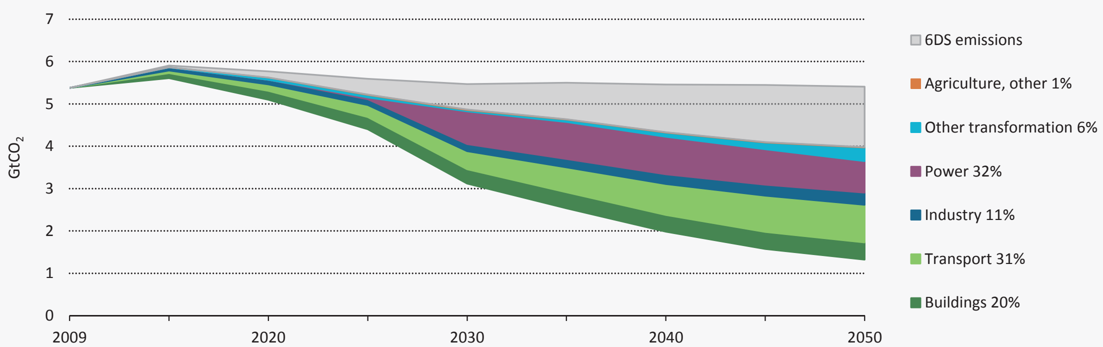
The United States has some of the best renewable energy potential in the world, especially wind power in the Great Plains region and solar in the Southwest. Unfortunately, the existing regulatory framework has not helped to activate a large-scale roll-out of such technologies. There are important efforts at the state level: more than half of US electricity consumption is now taking place in states that have renewable mandates, but federal regulation has not been as helpful as it could be, partly due to the stop and go cycles in policies. Even with the proper appreciation of the shale gas revolution, US energy policy should continue to work on the development of a stable and predictable renewable energy policy that is consistent with the reality of carbon constraints.

The United States is a major producer of nuclear energy. Replacing US nuclear power generation with natural gas would require more gas than all the current shale production. Peak nuclear construction in the United States was in the early 1970s, so even with lifetime extensions, those plants are not very far from the end of their lifetimes. The first new nuclear plant construction in the United States since 1980 has recently been launched. This is to be welcomed, but it is clear that on the basis of current policies, the United States is not on track to benefit fully from nuclear power's potential contribution to a sustainable energy system. Some elements of a sustainable energy policy such as carbon pricing would improve the competitiveness of nuclear power automatically. Nevertheless, policy measures are necessary to tackle the financial market failures – due to the capital intensity and unusual risk profile of the industry – that hinder investment in nuclear.

Model results for the United States by sector

In the *ETP 2012* 4°C Scenario (4DS), the United States experiences a steady decline in CO_2 emissions after 2015, through 2050, thanks to a range of measures and CO_2 pricing policies consistent with that scenario. However, in order to reach the 2°C Scenario (2DS) target, reductions must be much faster and steeper. Additional technologies and measures to get there bring 2050 CO_2 emissions from 4 gigatonnes (Gt) in the 4DS down to 1.3 Gt in the 2DS. About one-third of the cumulative CO_2 reductions between 2009 and 2050 are coming from the power sector (Figure 17.9.1). The transport sector provides a similar cumulative reduction between the 4DS and 2DS, while buildings and industry provide smaller additional reductions.

Figure 17.9.1 Sectoral contributions to achieve the 2DS from the 4DS



Notes: $MtCO_2$ = megatonnes of carbon dioxide; percentages reflect cumulative reductions 2009-50.

Key point *The power and transport sectors are each responsible for around 30% of the reductions needed to achieve the 2DS compared with the 4DS.*

Power

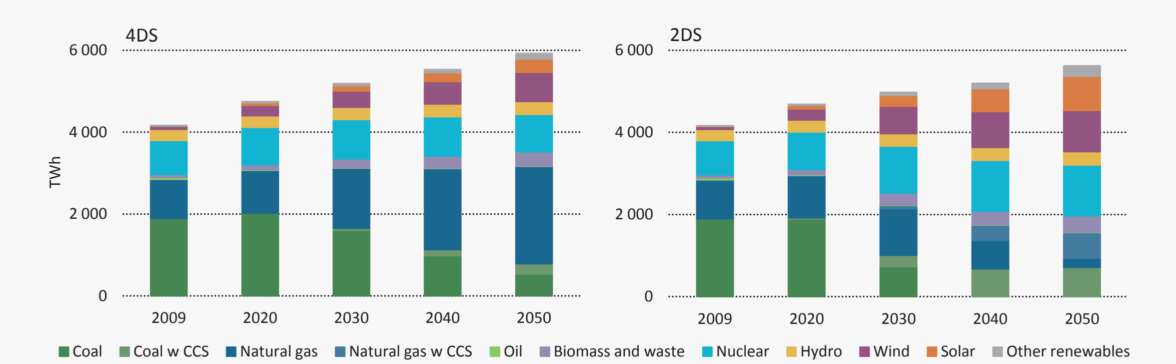
In the 4DS, power generation in the United States increases by 40% between 2009 and 2050 (Figure 17.9.2). Fossil generation stabilises after 2020, and the renewable share in power generation increases from 11% in 2009 to 31% in 2050, thanks largely to the heavy deployment of wind, but also to substantial increases in solar and biomass-powered generation.

In the 2DS, coal generation without carbon capture and storage (CCS) is dramatically reduced by 2030 and completely eliminated by 2040. Generation from coal in 2050 is entirely based on plants (installed capacity of 102 gigawatts [GW]) with carbon capture. Natural gas remains important in the 2DS and maintains a similar level as in 2009 with a generation of 850 terawatt-hours (TWh) in 2050. CCS becomes essential for the continued use of gas in power generation in the 2DS: three-quarters of the generation from natural gas in 2050 is with CCS, corresponding to around 103 GW.

The renewable share in power generation increases to 50% by 2050, with solar and wind being the main contributors. Nuclear covers around one-fifth of the generation in 2050; coal and gas plants equipped with CCS provide the remainder. This deployment of low-carbon technologies in the power sector reduces its annual CO_2 emissions by 95% compared with 2009 (Figure 17.9.3).

A higher reliance on more evenly distributed renewable generation at the regional level requires upgrading and modernisation of the ageing grid infrastructure in the United States. In addition, flexible generation from gas is needed to compensate for variations in renewable generation and to provide firm back-up capacity. Electricity storage and demand response through smart grids represent further options to increase the flexibility of the electricity system. The mix of measures will depend on the local conditions.

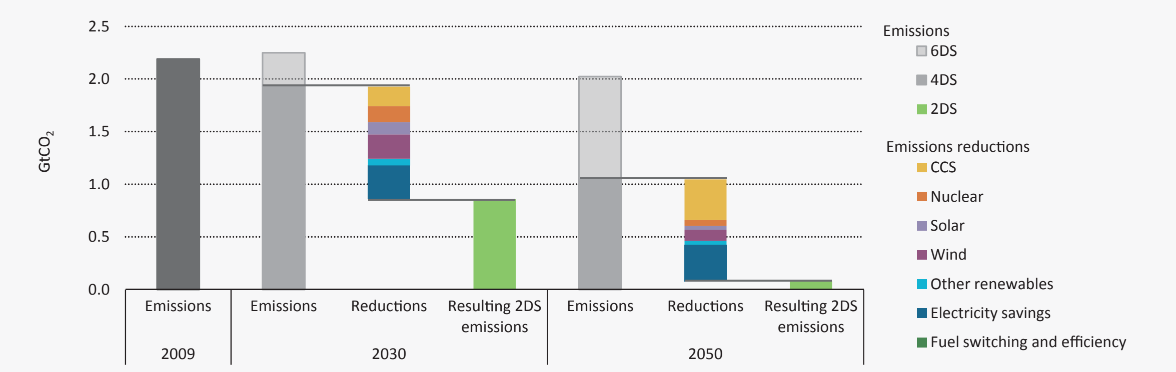
Figure 17.9.2 Electricity generation in the 4DS and 2DS



Note: Other renewables include geothermal and ocean energy.

Key point *Renewables reach a share of 50% in the electricity mix in 2050 in the 2DS, with solar and wind power being the two most important sources.*

Figure 17.9.3 Annual CO_2 reductions in the power sector to reach the 2DS (relative to the 4DS)



Note: Other renewables include biomass, geothermal and ocean energy.

Key point *CCS is an important option to reduce the emissions in the 2DS beyond the reduction already achieved in the 4DS in 2050.*

Industry

Industry accounted for the use of 14.7 exajoules (EJ) in 2009, 23% of total final energy consumption in the United States. The United States is the second-largest industrial energy consumer, accounting for 12% of global industrial energy use. The final energy mix of industry is dominated by oil and natural gas, which together account for over 60% of industry energy consumption.

The United States is the largest producer of high-value chemicals and was, until 2007, the largest producer of paper and paperboard. The recent economic crisis had a strong impact on US materials production: the production of steel decreased by 36% between 2008 and 2009, and the production of cement and paper by 33% and 15% respectively between 2007 and 2009. In the scenario analysed, materials production is expected to increase and reach the levels observed before the global economic crisis by 2020. Thereafter, production levels off and increases only marginally (Table 17.9.1).

Industrial energy consumption and energy mix in the 2DS will be significantly different from the 4DS and the 6°C Scenario (6DS) (Figure 17.9.4). Energy consumption in 2050 in the 2DS will be almost 20% lower than it currently is. While fossil fuels currently account for 70% of the consumption, this share will decline to 50% to 57% in 2050 and will be replaced by alternative sources of energy.

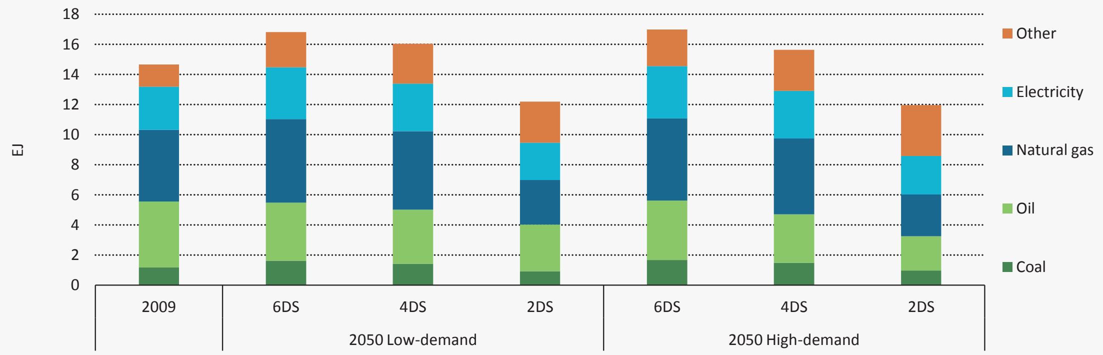
Great potential exists in the United States to substantially decrease CO_2 emissions from the industry sector. In the 2DS, CO_2 emissions will be almost 50% lower than they were in 2009. Many energy-intensive industries in the United States are relatively old and inefficient when compared with their counterparts in Europe and Japan, or to rapidly industrialising countries such as China. The application of best available technologies (BAT) for all new and refurbished plants offers significant opportunities for improvement in industrial energy efficiency in the United States. In the cement and pulp and paper industries, fuel switching represents a key option for substantially reducing CO_2 emissions. While the application of CCS is required to achieve such a reduction in the 2DS, it represents only 34% of the reduction between the 4DS and 2DS. This relatively small share, compared with other regions, is due to the fact that most facilities are already built; it is usually harder to apply CCS to existing plants.

Table 17.9.1 **Key results for main industrial sectors in the United States**

		4DS		2DS	
	2009	Low-demand 2050	High-demand 2050	Low-demand 2050	High-demand 2050
Cement production (Mt)	65	130	135	130	135
Crude steel production (Mt)	58	109	113	109	113
Steel scrap used (Mt)	43	67	68	70	71
Paper and paperboard production (Mt)	71	85	95	85	95
Recovered paper (Mt)	45	39	41	40	42
Primary aluminium production (Mt)	2	3	4	3	4
Electricity intensity of primary aluminium (kWh/t aluminium)	15 415	13 159	12 531	12 804	11 533
HVC production (Mt)	53	56	51	52	41
Ammonia production (Mt)	9	11	11	11	11

Notes: Mt = Million tonnes, kWh/t = kilowatt-hour per tonne; HVC = high-value chemicals.

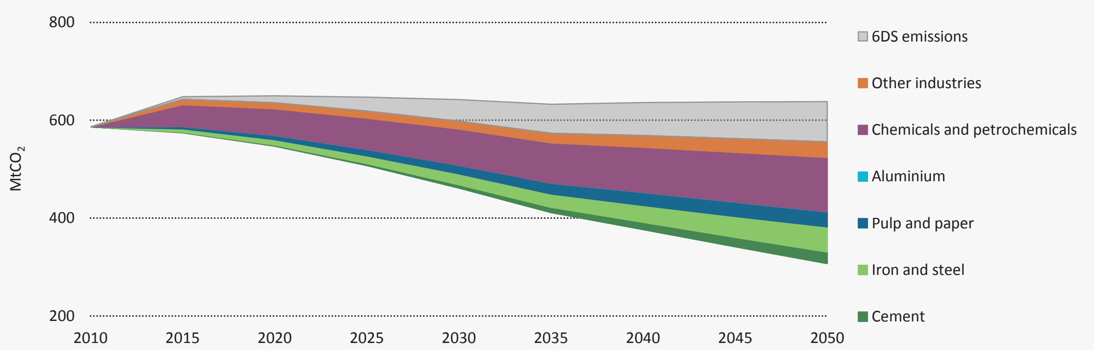
Figure 17.9.4 Industrial energy consumption by energy source in the United States



Note: Other includes heat, combustible biomass, waste and renewables.

Key point *Energy consumption can be reduced by about 20% between 2009 and 2050.*

Figure 17.9.5 Industrial CO_2 emissions reductions in the United States in the low demand case



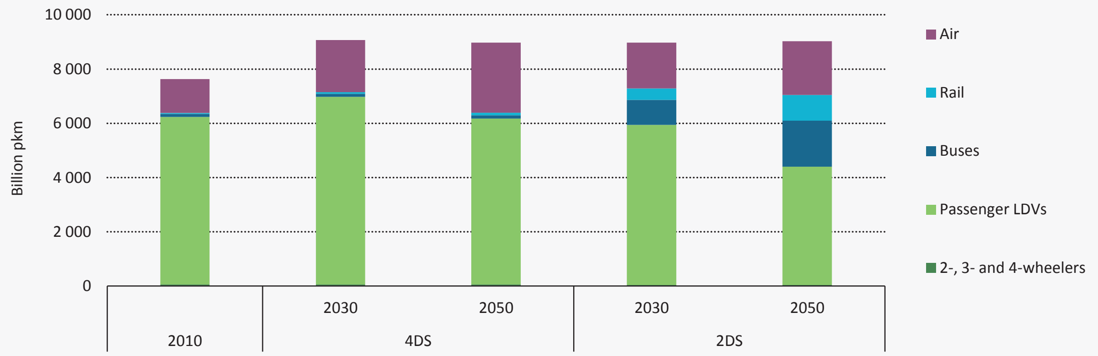
Key point *The chemicals and petrochemicals sector will be the largest contributor to reducing CO_2 emissions from industry.*

Transport

In the United States, passenger travel appears to be saturating, at least on a per capita basis. Total travel fell by more than 5% between 2007 and 2009, and though this was clearly related to economic conditions, travel had already been almost flat since 2005 and is not expected to grow dramatically in the future, apart from a potential rebound to 2007 levels. Trucking is likely to continue to grow slowly. Air travel in the United States, already the world's most active air market, will continue to rise in all scenarios, though at a modest rate.

In terms of travel modes (Figure 17.9.6), the share of passenger mobility taken by passenger light-duty vehicles (LDVs) in the United States is expected to have peaked in the last couple of years, and could decline if significant investments are made in expanding mass transit systems. The potential for bus and rail mass transport to increase its currently tiny market share at the expense of passenger LDVs is probably limited, but even an expansion to a 10% market share by 2050 would represent a key ingredient of any policy goal aiming to reach the 2DS. Better city and metro area planning can also help reduce the need for longer car trips on a daily basis.

Figure 17.9.6 Passenger mode share in the United States

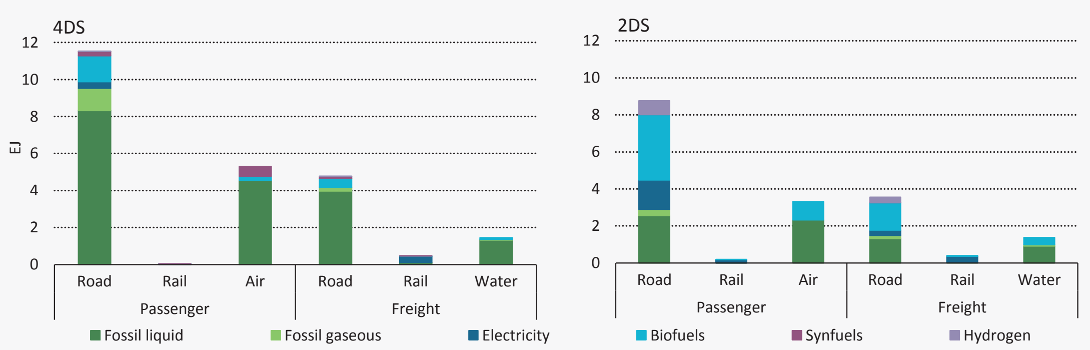


Note: pkm = Passenger kilometre.

Key point *Some modal shift in the 2DS is needed to improve the overall efficiency of the US transport sector.*

By 2050, in the 2DS, transport energy use strongly moves away from oil and becomes increasingly diversified, using a range of fuels and propulsion technologies (Figures 17.9.7 and 17.9.8). Plug-in vehicles (plug-in hybrid electric vehicles [HEVs], battery-electric vehicles [BEVs], and fuel-cell electric vehicles [FCEVs]) account for almost all vehicle sales by 2050, with conventional gasoline vehicle sales being less than 5 million per year (Figure 17.9.8). The United States is positioned to be a world leader in the adoption of plug-in vehicles over the next decade, and possibly hydrogen vehicles in the coming decades. The current administration target of 1 million EVs on the road by 2015 would help bring down EV production costs and perhaps spur demand for these vehicles in other parts of the world.

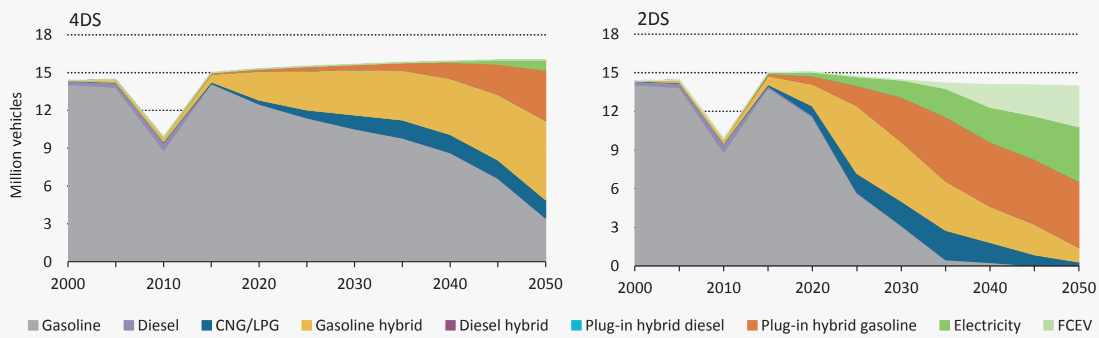
Figure 17.9.7 Transport energy use in 2050 by mode, energy type and scenario



Key point *Biofuels are bound to play an important role in all modes in the 2DS.*

For trucks, shipping and air transport, liquid fuels will continue to dominate, so biofuels will need to play a major role. Compared with a 26% share worldwide in the 2DS, biofuels in the United States reach 36%, though not necessarily all produced domestically. These will need to be advanced biofuels with near-zero greenhouse-gas (GHG) emissions, consistent with the strong policy push in the United States to require uptake of such biofuels over the next decade.

Figure 17.9.8 Passenger light-duty vehicle sales by technology type and scenario



Notes: CNG = compressed natural gas, LPG = liquefied petroleum gas.

Key point *The US passenger LDV market is on track to be one of the worldwide leaders of advanced vehicle technologies.*

Buildings

About 30% of all the final energy in the United States is consumed to satisfy the energy demand of its residential, commercial and public buildings. This large share is also significant in the global context, as it accounts for 6% of all final energy consumed worldwide. The total has risen by 50% since 1980, and despite a marked move towards southern regions with milder climates (US DOE, 2010), space and water heating still dominate all other end uses, and are responsible for more than 50% of all energy used in buildings (Figure 17.9.9). This is particularly true of the residential sector: since the 1950s, the majority of new residential stock has occurred in the southern states, while one-third of all houses built before the 1950s are in the Northeast. The abatement potential from retrofits and the end-use technology options therefore vary greatly by region. In addition, homes built after the 1950s are around 30% more efficient per square metre, but these efficiency gains have been offset by large increases in the size of new homes: the average size of an American household has increased from 166 square meters (m^2) in 1990 to about 200 m^2 in 2009.

As the population is projected to rise by 32% from 2009 to 2050, and average floor area to increase by 1% per year (Table 17.9.2), an estimated 42% of residential floor space in 2050 is yet to be built. While service sector floor space increases by 51% from 2009 to 2050 in the 4DS baseline, the efficiency of commercial and public service units increases by nearly 12%, reflecting current trends. There is thus great opportunity for increased energy efficiency in both new and existing buildings. In the 2DS, buildings' space heating and cooling, and water heating, account for a third of all energy savings from the 4DS in 2050.

The main options for increased efficiency in these end uses include stringent building codes and passive heating and cooling in new builds – which can reduce space conditioning loads by as much as 34% – and deep building retrofits, not excluding low-maintenance measures such as leak-proofing and refurbishing and maintaining older equipment for heating, ventilation and air conditioning (HVAC). These combine to deliver 1.4 EJ of energy savings in the 2DS in 2050 when compared with the 4DS. Improvements in appliances and other equipment will also play an important role in reducing energy consumption, accounting for 35% of the reductions in 2050 between the 4DS and 2DS.

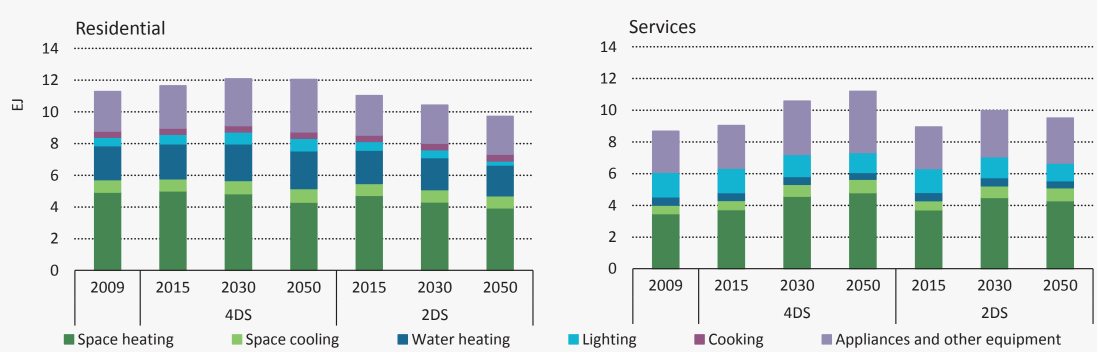
These efficiency improvements and reductions in energy consumption will translate into even greater reductions in direct and indirect CO_2 emissions. Total direct and indirect CO_2 emissions will be 85% lower in the 2DS in 2050 than they were in 2009. About 40% of these reductions will come from improved energy efficiency in all end uses, and a move away from fossil fuels, most noticeably for space and water heating.

Table 17.9.2 Key activity in the United States buildings sector

	2009	2015	2030	2050	AAGR (2009-50)
Population (million)	307	324	362	404	0.7%
Number of households (million)	110	115	124	130	0.4%
Residential floor area (million m^2)	21 879	24 990	28 793	32 243	1.0%
Services floor area (million m^2)	7 270	7 951	9 947	10 993	1.0%

Notes: AAGR = average annual growth rate, m^2 = square metre.

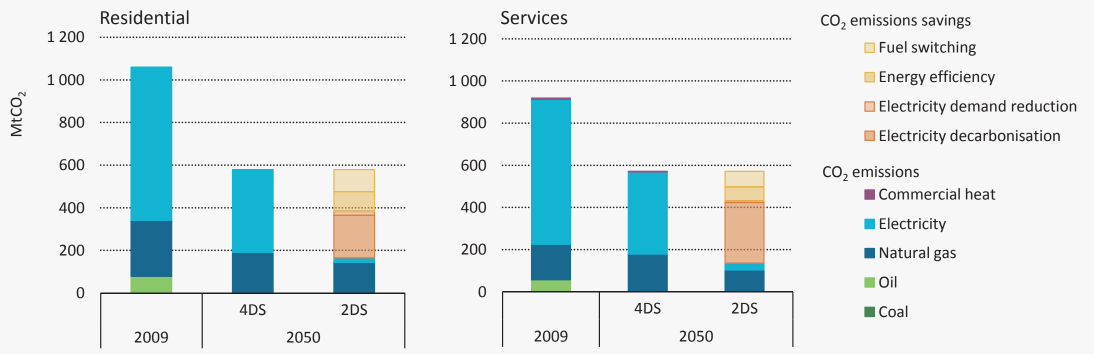
Figure 17.9.9 Buildings energy consumption by end use in the United States



Note: For the service sector cooking is included in appliances and other equipment.

Key point *By 2050, in the 2DS, buildings energy consumption will be 5% lower than in 2009 and 17% lower than in the 4DS.*

Figure 17.9.10 Buildings CO_2 emissions reductions in the United States



Key point *Decarbonisation of the power sector has a major role to play in reducing emissions in the service sector; in residential, about 50% of the reductions will be from increased efficiency and fuel switching.*

Analytical Approach

ETP 2012 applies a combination of *back casting* and *forecasting*. 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.

Achieving the *ETP 2012* 2°C Scenario (2DS) does not depend on the appearance of breakthrough technologies. All technology options introduced in *ETP 2012* 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 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.

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. This has implications for energy security as well as for the uncertainties embodied in the scenarios.

ETP model combines analysis of energy supply and demand

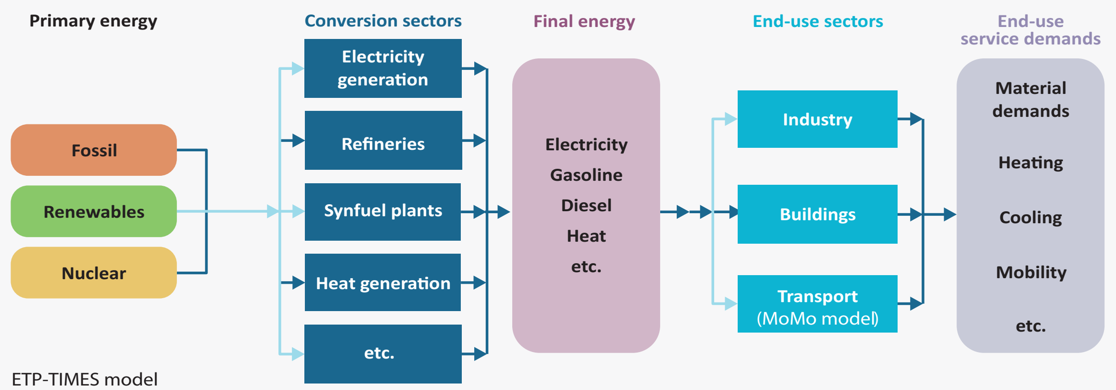
The ETP model, which is the primary analytical tool used in *ETP 2012*, supports integration and manipulation of data from four soft-linked models:

- 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 (models for industry, transport and buildings [residential and commercial]). 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 The ETP model



Source: Unless otherwise noted, all tables and figures in this chapter derive from IEA data and analysis.

Key point *The ETP model enables a technology-rich, bottom-up analysis of the global energy system.*

The energy conversion module is a least-cost optimisation model. 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 between the sector models. The ETP model works in five-year time steps.

The conversion sector (*i.e.* transformation of power and fuel) in *ETP 2012* is analysed using the ETP-TIMES[1] model, which covers 28 regions and depicts – in a technology-rich fashion – the supply side of the global energy system. It spans the spectrum from primary energy supply and conversion to final energy demand up to 2075.

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.

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. To capture the

1 The ETP model is based on The Integrated MARKAL-EFOM system (TIMES) model generator, which has been developed and is continuously enhanced by the Energy Technology Systems Analysis Programme (ETSAP), one of the IEA Implementing Agreements (Loulou *et al.*, 2005).

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 12 load segments. The model is supplemented by separate models for the analysis of smart grids, demand response and grid investments.

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 costs of the supply-side sector.

Industry is modelled using a stock accounting spreadsheet that covers (in detail) five energy-intensive sectors: iron and steel, cement, chemicals and petrochemicals, pulp and paper, and aluminium. Demand is estimated based on country- or regional-level data for gross domestic product (GDP), disposable income, short-term industry capacity, current materials consumption, demand saturation rates and resource endowments. 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 6DS and 2DS, but the 2DS reflects a much higher use of scrap (which is less intensive than production from raw materials). Each industry sub-model is designed to account for sector-specific production routes.

Changes in the technology mix and efficiency improvements are driven by exogenous assumptions on penetration of best available technologies (BATs) at each given time. The analysis incorporates the projected relative cost of those technologies, as well as how marginal abatement costs in industry compare to those in other sectors at the given time period. Thus, the results are sensitive to assumptions on how quickly physical capital is turned over and to how effective incentives are for the use of BATs for new construction.

Transport is modelled with the mobility model, a global transport spreadsheet model that allows projections and policy analysis to 2075, with considerable regional and technology detail. The mobility model currently covers 29 countries and regions, and encompasses most vehicle and technology types (including 2- and 3-wheelers, passenger cars, light trucks, medium and heavy freight trucks, buses) and all transport modes (including non-road modes such as rail, air and shipping). Because it integrates 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 function), *utilisation* (travel per vehicle), *consumption* (energy use per vehicle, *i.e.* 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.

The buildings sector is modelled using a global simulation stock accounting model, split into residential and commercial sub-sectors and applied across 26 regions. For both sub-sectors, the model uses income, population and urbanisation data, as well as services value added, to project floor space per capita and activity levels such as cooking, appliance ownership and efficiencies. Based on this set of drivers, demand for individual energy services and the share of each energy technology needed to meet this demand are projected to 2075. Space heating demand is informed by detailed data on building stocks (including energy efficiency of different vintages) in OECD countries. Where these data are not available, the model uses average stock efficiencies. For lighting and appliances, the model recognises that equipment penetration is driven by income per capita and historical regressions. Space cooling is projected using regional climatic conditions and income per capita. Simulating (from the bottom up) all energy uses traditionally associated with buildings, the *ETP 2012* buildings model is suited to analyse global scenarios for energy efficiency in buildings and end-use technology penetration.

Changes in energy service demands related to the building envelope are driven by assumptions on various retrofit and new build technology packages that deliver set performance levels. Results are particularly sensitive to assumptions on income and household occupation in emerging economies and ownership of white goods in the residential sector. In the services sector, results are sensitive to changes in the elasticity of commercial energy service demands to service sector value added.

Particular uncertainties in the model include the link between structural changes in the service sector and energy demands or the viability of service sector value added as a driver for projecting floor space and energy service demand in developing countries. Some authors have proposed using worker availability in its place. In the residential sector, the useful energy demand for cooling and the turnover rate of buildings in non-OECD regions are the main uncertainties.

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 nearly quadruple by 2050; uncertainty around GDP growth across the scenarios is significant, however. The climate change rate in the 6DS, and even in the 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.

While the ETP analysis provides important insights into the cost of CO_2 reductions for consumers and for the global economy, the analysis does not assess the full impacts on GDP. Other studies have attempted to do this, for example through analysing the impact on GDP from climate change mitigation. The OECD has calculated that an emissions trajectory similar to the 2DS would slow average annual growth from 3.5% to 3.3%. This would result in the global GDP being 5% lower in 2050 compared to the baseline (OECD, 2012). Another way to understand this is that under a low-carbon trajectory, the world would reach the same level of GDP three years later than in a scenario where climate change mitigation is not a priority. However, as pointed out by the OECD, these estimates do not factor in any benefits of the mitigation actions. The model used by the OECD also has a more general representation of technology options than the ETP model. For instance, it does not include important low-carbon technologies such as carbon capture and storage (CCS) and solar technologies, which the ETP analysis shows can help reduce emissions at lower costs.

Table A.1 GDP projections in *ETP 2012* (assumed identical across scenarios)

CAAGR (%)	2009-20	2020-30	2030-50	2009-50	2050-75
World	4.2	3.1	2.9	3.3	2.7
OECD	2.4	2.0	1.8	2.0	1.8
Non-OECD	6.1	4.1	3.5	4.3	3.1
ASEAN	5.3	3.5	3.8	4.1	3.9
Brazil	4.3	3.3	3.0	3.4	2.8
China	8.1	4.4	3.2	4.8	2.4
European Union	2.0	1.8	1.7	1.8	1.6
India	7.7	5.9	4.8	5.8	3.9
Mexico	3.7	3.1	2.8	3.1	2.4
Russia	4.1	3.3	2.4	3.1	1.8
South Africa	3.6	2.6	2.9	3.0	3.1
United States	2.6	2.2	2.1	2.3	2.1

Notes: CAAGR = compounded average annual growth rate; ASEAN = Association of Southeast Asian Nations.
Sources: IMF, 2011 and 2011-16; IEA analysis.

Integrating a high level of technology detail in a macroeconomic model such as the one used by the OECD could, in theory, resolve some of the discrepancies between findings based on different modelling approaches. Because such integration is extremely challenging, however, different modelling approaches should be used instead to highlight different perspectives of a problem. 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 on 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 2012* 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 fields higher up the supply curve, particularly in non-OPEC countries. As a result, the oil price is projected to stay under USD 100/barrel throughout the projection period, and even to fall during the last decades.

Table A.2 Population projections used in *ETP 2012*

Country	2010	2020	2030	2040	2050	2060	2070	2075
World	6 896	7 657	8 321	8 874	9 306	9 615	9 827	9 905
OECD	1 234	1 302	1 353	1 385	1 403	1 408	1 409	1 410
Non-OECD	5 662	6 354	6 969	7 489	7 904	8 207	8 418	8 495
ASEAN	592	654	704	738	756	759	750	743
Brazil	195	210	220	224	223	217	208	203
China	1 341	1 388	1 393	1 361	1 296	1 212	1 126	1 086
European Union	500	511	516	515	512	504	496	494
India	1 225	1 387	1 523	1 627	1 692	1 718	1 708	1 692
Mexico	113	126	135	142	144	143	140	138
Russia	143	141	136	131	126	121	116	115
South Africa	50	53	55	56	57	57	57	57
United States	310	337	362	383	403	421	438	446

Note: Mumbers in millions
Source: UN, 2011

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 low-carbon scenarios.

Table A.3 Fossil fuel prices by scenario

Oil	Scenario	2010	2020	2025	2030	2035	2040	2045	2050
IEA crude oil import price	2DS	78	97	97	97	97	92	89	87
2010 USD/bbl	4DS	78	109	114	117	120	119	119	118
	6DS	78	118	127	134	140	143	146	149
Coal	**Scenario**	**2010**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
OECD steam coal import price	2DS	99	93	83	74	68	64	62	60
2010 USD/tonne	4DS	99	106	108	109	110	109	109	109
	6DS	99	109	113	116	118	121	123	126
Gas	**Scenario**	**2010**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
United States import price	2DS	4	7	8	8	8	7	7	7
2010 USD/Mbtu	4DS	4	7	7	8	9	8	8	8
	6DS	4	7	8	8	9	9	9	10
Europe import price	2DS	7	10	10	10	9	9	9	8
2010 USD/Mbtu	4DS	7	10	11	12	12	12	12	12
	6DS	7	11	12	13	13	13	14	14
Japan import price	2DS	11	12	12	12	12	12	11	11
2010 USD/Mbtu	4DS	11	13	13	14	14	14	14	14
	6DS	11	14	14	15	15	15	16	16

Note: bbl = barrel, Mbtu = million British thermal units

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	*ETP 2012* 2°C Scenario
4DS	*ETP 2012* 4°C Scenario
6DS	*ETP 2012* 6°C Scenario
AAGR	average annual growth rate
AFD	Agence Française de Développement, France
AfDB	African Development Bank
AISI	American Iron and Steel Institute
AMDEE	Mexican Wind Energy Association
APAEC	ASEAN Plan of Action for Energy Co-operation
APEC	Asia-Pacific Economic Cooperation
APG	ASEAN Power Grid
ARES	Advanced Reciprocating Engine Systems, United States
ASEAN	Association of Southeast Asian Nations
AUD	Australian dollar
A-USC	advanced ultra-supercritical
BANANA	build absolutely nothing, anywhere, near anyone
BAT	best available technology
BAU	business-as-usual
BECCS	bio-energy with carbon capture and storage
BEE	Bureau of Energy Efficiency, India
BEV	battery-electric vehicle
BF	blast furnace
BNDES	Brazilian Development Bank
BOF	basic oxygen furnace
BPT	best practice technology
BRT	bus rapid transit
BTL	biomass-to-liquids
BTX	benzene, toluene, mixed xylene
CAAGR	compound average annual growth rate
CAES	compressed air energy storage
CAFE	corporate average fuel economy (standards in the United States)
CBM	coalbed methane
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CDM	Clean Development Mechanism(under the Kyoto Protocol)
CDQ	coke dry quenching

CER	certified emission reduction
CFBC	circulating fluidised bed combustion
CFE	Comisión Federal de Electricidad (Federal Electricity Commission), Mexico
CFL	compact fluorescent lamp
CHP	combined heat and power; the term co-generation is sometimes used
CLC	chemical looping combustion
CNG	compressed natural gas
CNPC	China National Petroleum Corporation
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-EOR	CO_2-flood enhanced oil recovery
CO_2-eq	carbon-dioxide equivalent
COG	coke oven gas
COP	Conference of the Parties (to the United Nations Framework Convention on Climate Change [UNFCCC])
COP15	Conference of the Parties (COP 15) to the UNFCCC
CRE	Energy Regulation Commission
CSP	concentrating solar power
CSPV	concentrating solar photovoltaic
CTL	coal-to-liquids
CV	calorific value
DECC	Department of Energy and Climate Change, United Kingdom
DHC	district heating and cooling
DMS	distribution management system
DOE	Department of Energy, United States
DR	demand-response
DRI	direct reduced iron
DSM	demand-side management
EAF	electric arc furnace
EBRD	European Bank for Reconstruction and Development
ECA	export credit agency
EE	energy efficiency
EEI	energy efficiency index
EEOI	energy efficiency operational indicator
EF	electric furnace
EGS	enhanced geothermal systems
EIB	European Investment Bank
El	electric
EMS	energy management system
ENE	National Energy Strategy
EOR	enhanced oil recovery

EPA	Environmental Protection Agency, United States
EPC	engineering, procurement, construction
EPO	European Patent Office
ESCO	energy service company
ETS	Emissions Trading Scheme, European Union
EU	European Union
EV	electric vehicle
EVI	Electric Vehicles Initiative
FACTS	flexible alternating current transmission systems
FAST	flexibility assessment tool
FC	fuel cell
FCEV	fuel-cell electric vehicle
FFV	flex-fuel vehicle
FIT	feed-in tariff
FOKUS	Swedish Energy Agency's strategic planning process
FT	Fischer-Tropsch
FYP	Five-Year Plan
G2V	grid-to vehicle
GBP	Great Britain pound
GCCSI	Global Carbon Capture and Storage Institute
GDP	gross domestic product
GEF	Global Environmental Facility
Gen-IV	Generation IV
GFEI	Global Fuel Economy Initiative
GHG	greenhouse gas
GIS	geographic Information system
GSHP	ground source heat pump
GTL	gas-to-liquids
GWEC	Global Wind Energy Council
H_2	Hydrogen
HAPUA	ASEAN Power Utilities and Authorities
HDD	heating degree day
HDV	heavy-duty vehicles
HELE	higher-efficiency, lower-emissions
HEV	hybrid-electric vehicle
HH-index	Herfindahl-Hirschman Index
HHV	higher heating values
-hiNuc	higher generation from nuclear power
-hiNuc	high nuclear scenario
-hiRen	higher renewable share
-hiRen	high renewables scenario

HSE	health, safety and environmental
HSR	high-speed rail
HVAC	heating, ventilation and air-conditioning
HVC	high-value chemicals
HVDC	high voltage direct current
IAI	International Aluminium Institute
ICE	internal combustion engine
ICT	Information and communications technology
IDB	Inter-American Development Bank
IDC	interest during construction
IEA	International Energy Agency
IEP	Integrated Energy Planning
IGCC	integrated gasification combined cycle
IGFC	integrated coal-gasification fuel cell
IMF	International Monetary Fund
IPCC	Intergovernmental Panel on Climate Change
IPCC AR5	Fifth Assessment Report
IPEEC	International Partnership on Energy Efficiency Collaboration
IPP	independent power producer
IREDA	Indian Renewable Energy Development Agency
IRP	Integrated Resource Plan
IRR	internal rate of return
ISCC	integrated solar combined cycle
IT	information technology
ITER	International Thermonuclear Experimental Reactor
JNNSM	Jawaharlal Nehru National Solar Mission, India
KfW	Kreditanstalt fur Wiederaufbau (banking group)
LCOE	levellised cost of electricity
LCV	light-commercial vehicle
LDV	light-duty vehicle
LED	light emitting diode
LHV	lower heating value
Li-Ion	lithium ion
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LSIP	large-scale integrated project
LTMS	Long-Term Mitigation Scenarios
LULUCF	land use, land-use change and forestry
LWR	Light water reactor
m^2	square metre
MCFC	molten carbonate fuel cell

MDMS	metre data management system
MEPS	minimum energy performance standards
MLR	Ministry of Land and Resources, China
MME	Ministry of Mines and Energy, Brazil
MMV	monitoring, measurement and verification
MOE	molten oxide electrolysis
MOSES	IEA Model of Short-term Energy Security
MTO	methanol-to-olefin
MVE	monitoring, verification and enforcement
NaS	sodium sulphur
NDRC	National Development and Reform Commission
NEA	Nuclear Energy Agency, OECD
NERSA	National Electricity Regulator of South Africa
NGCC	natural gas combined-cycle
NGL	natural gas liquid
NGV	natural gas vehicle
NIB	Nordic Investment Bank
NiCd	nickel-cadmium
NIMBY	not in my backyard
NiMh	nickel-metal hydride
NMEEE	National Mission on Enhanced Energy Efficiency, India
NO_x	nitrogen oxides
NSG	Nuclear Suppliers Group
O&M	operation and maintenance
OCGT	open-cycle gas turbine
OCM	oxidative coupling of methane
OECD	Organisation for Economic Co-operation and Development
offshore	offshore wind turbine
OHF	open hearth furnace
OMS	outage management system
onshore	onshore wind turbine
OPIC	Overseas Private Investment Corporation, United States
OTEC	ocean thermal energy conversion
PAFC	phosphoric acid fuel cell
PAT	Perform, Achieve, Trade, India
PATSTAT	EPO/OECD Worldwide Patent Statistical database
PC	pulverised coal
PEM	proton exchange membrane
PEMFC	polymer electrolyte membrane fuel cell, also known as proton exchange membrane fuel cell
PHEV	plug-in hybrid electric vehicle

PLDV	passenger light-duty vehicle
PM	particulate matter
PM2.5	particulate matter with a diameter of 2.5 micrometres or less
PMU	phasor measurement units
POSCO	Pohang Iron and Steel Company
PPP	purchasing power parity
Proalcool	Brazil's National Alcohol Programme
PROINFA	Programme of Incentives for Alternative Electricity Sources, Brazil
PV	photovoltaic
R&D	research and development
RCP	Representative Concentration Pathways
RD&D	research, development and demonstration
RDD&D	research, development, demonstration and deployment
RHI	Renewable Heat Incentive, United Kingdom
RTU	roof-top unit
S&L	standard and labelling
SADC	South African Development Community
SC	supercritical
SCADA	supervisory control and data acquisition
SET-Plan	Strategic Energy Technology Plan
SG	smart grid
SME	small- and medium-sized enterprise
SMR	small modular reactor
SNG	synthetic natural gas
SO_2	sulphur dioxide
SOFC	solid oxide fuel cell
SOP	Standard Offer Programme
SPF	seasonal performance factor
SRC	short rotation coppice
SSL	solid-state lighting
SUV	sports utility vehicle
SWF	sovereign wealth fund
SWH	solar water heater
T&D	transmission and distribution
TAGP	Trans-ASEAN Gas Pipeline
TGR-BF	top-gas recycling blast furnaces
Th	thermal
TPES	total primary energy supply
TTW	tank-to-wheel
UAE	United Arab Emirates
UK	United Kingdom

ULCOS	Ultra-low CO_2 Steelmaking
UN	United Nations
UN COMTRADE	United Nations Commodity Trade Statistics database
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
US DOE	United States Department of Energy
USC	ultra-supercritical
USD	US dollars
V2G	vehicle to-grid
Va Redox	vanadium redox flow
VRE	variable renewable energy source
WAAPCA	wide-area adaptive protection, control and automation
WAMS	wide-area monitoring systems
WEO	World Energy Outlook
WMS	workforce management system
WTT	well-to-tank
WTW	well-to-wheel
ZAR	South African rand

Definitions, Regional and Country Groupings and Units

This annex provides information on 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 United States 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.
	Asset finance	Asset finance is a secured business loan in which the borrower pledges its assets as collateral.
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 that 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	Biomass is a 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	Biomass-to-liquids (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 (CCS)	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	Coal-to-liquids (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 o 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.
Corporate debt	Corporate debt is the liabilities held by a company used to fund investments.

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.
Hedge funds	A hedge fund is an investment fund opened to a limited range of investors. These funds aggressively manage a portfolio of investments that use advanced investment strategies such as leveraged, long, short and derivative positions with the goal of generating high returns.
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.
	Integrated gasification combined cycle	Integrated gasification combined-cycle (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.
I	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. 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 total energy supply is equivalent to total primary energy demand. This represents inland demand only and, excludes international marine and aviation bunkers (which are included in global TPES).
	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 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 small plants that produce fuel for their own use (autoproducers) are included. Energy use and emissions for pipeline transport are also 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. Chapter 13 also includes energy and emissions emitted from the upstream sector (well to tank) so has to have a complete vision of the energy needs and emissions rejected from the transport activity needs. Energy use and emissions related to pipeline transport are accounted for under Energy industry own use.

Regional and country groupings

Annex I Parties to the United Nations Framework Convention on Climate Change	Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, Ukraine, United Kingdom and United States.
ASEAN (Association of Southeast Asian Nations)	Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand and Vietnam.
China	Refers to the People's Republic of China, including Hong Kong.
Developing countries	Non-OECD Asia, Middle East, Africa and Latin America regional groupings.
Eastern Europe/Eurasia	Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kyrgyz Republic, Latvia, Lithuania, Former Yugoslav Republic of Macedonia, Republic of Moldova, Romania, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan. For statistical reasons, this region also includes Cyprus, Gibraltar and Malta.
European Union	Austria, Belgium, Bulgaria, Cyprus, 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.
G-8	Canada, France, Germany, Italy, Japan, Russian Federation, United Kingdom and United States.
G-20	G-8 countries and Argentina, Australia, Brazil, China, India, Indonesia, Mexico, Saudi Arabia, South Africa, Korea, Turkey and the European Union.
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 (Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands, 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).
OECD	Includes OECD Europe, OECD Americas and OECD Asia Oceania regional groupings.
OECD Americas	Canada, Chile, Mexico and United States.
OECD Asia Oceania	Includes OECD Asia, comprising Japan, Korea and Israel, 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, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.
Other developing Asia	Non-OECD Asia regional grouping excluding China and India.

Units

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
	bbl	barrel
	Btu	British thermal units
	cal	calorie
	J	joule
	J/Nm^3	joule per normal cubic metre
	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	°C	degree Celsius
Volume	m^3	cubic metre
Sector-specific units	bcm	billion cubic metres
Gas	Btu	British thermal unit
	tcm	trillion cubic metres
	bbl	barrel
Oil	mb/d	million barrels per day
	Btu	British thermal unit
Power	g CO_2/kWh	gramme of carbon dioxide per kilowatt-hour
	W	watt (1 joule per second)
	W_e	watt electrical
	Wh	watt-hour
	W_{th}	watt thermal
	g CO_2/km	gramme of carbon dioxide per kilometre
Transport	km	kilometre
	km/hr	kilometre per hour
	lge	litre gasoline equivalent
	mpg	mile per gallon
	pkm	passenger kilometre
	tkm	tonne kilometre
	vkm	vehicle kilometre

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