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World Energy Outlook 2015

World Energy Outlook 2015

Big questions abound in global energy in 2015:

- Could **oil prices** stay lower for longer? What would it take for this to happen and what would it mean for energy security and for the energy transition?
- **India** is set for a period of rapid, sustained growth in energy demand: how could this re-shape the energy scene?
- What do new **climate pledges** mean for the way that the world meets its rising needs for energy?
- What are the implications of the rising coverage of **energy efficiency** policies and the growing competitiveness of **renewables**?
- Is the **unconventional gas revolution** going to go global, or to remain a North American phenomenon?

These issues – and many more – are discussed here, with a special focus on India accompanying the customary, in-depth *WEO* analysis of the prospects for all fossil fuels, renewables, the power sector and energy efficiency around the world to 2040.

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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 29 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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We cannot know what the future holds, but it is crucial that we try and understand it. The *World Energy Outlook* is a leading example of such an effort, and this edition covers all of the big questions – on energy prices, climate pledges and many others – that a very fast-moving energy scene has raised over the last year. I salute the highly expert and well-informed team in the IEA that has put this *Outlook* together. I also take this chance to reflect – from a slightly greater distance than usual – on the result.

This *Outlook*, as ever, builds a coherent picture of how the energy system might evolve. But it will be no surprise to find, in five or twenty-five years' time, that the outcome doesn't match the figures in the *WEO*. So, why do we bother? What is the value of describing how the global energy economy will evolve under the influence of different sets of policies, if it is not going to turn out that way in practice?

I can answer this confidently: the reason that we look into the future is to trigger key policy changes in the present.

Policy-makers and all others with a stake in the energy sector need to have well-based expectations about the future, as an influence on their decision-taking. If the outcomes depicted in our scenarios are sub-optimal or, even, unacceptable, then policies and other decisions need to change. Success lies in stimulating those changes, not in matching our (by then) distant projections.

This desire to underpin needed change lay behind our decision to publish in June this year our latest analysis of the role of energy in climate change (rather than as part of this *WEO*, though you will find frequent cross references, updates and relevant new analysis in this text). Negotiators preparing for COP21 in Paris in December 2015 needed time to take sober stock of the way the future is shaping up. "*Every act of creation is first an act of destruction*", said Pablo Picasso. We look to the negotiators in Paris to destroy our projections in our central scenario, which we show to be unsustainable, in order to create a new world in which energy needs are fully met without dangerously overheating the planet and in a secure and affordable way. It can be done; and, in another scenario, we have shown how.

The energy world has seen many changes since *WEO-2014*. Foremost among them is the sudden drop in oil prices; new pledges have been made before COP21; and India's looming emergence in energy markets is no less significant. The projections of our central scenario encompass these changes and the analysis probes related questions, such as the right way to measure the competitiveness of renewable energy and the extent to which energy policies cover and affect energy use. Could low oil prices last through to 2040 and what would be the implications? How will Indian energy choices change the scene in India and the world at large?

These questions are addressed here (among many others) in analysis that has enjoyed the support of the Indian government and many other experts. The findings are ours; but it is this sort of co-operation in our work which enables us to perform the role of providing data, objective analysis and policy recommendations to the global energy community. I thank all our partners in this endeavour.

Dr. Fatih Birol
Executive Director
International Energy Agency

This study was prepared by the Directorate of Global Energy Economics of the International Energy Agency in co-operation with other directorates and offices of the Agency. It was designed and directed by **Fatih Birol**. **Laura Cozzi** co-ordinated overall demand modelling, energy efficiency, power and renewables analysis; **Tim Gould** co-ordinated overall supply modelling and analysis, and the focus on India; **Amos Bromhead** co-ordinated the analysis of fossil-fuel subsidies. Other colleagues in the Directorate of Global Energy Economics contributed to multiple aspects of the analysis and were instrumental in delivering the study: **Ali Al-Saffar** (lead on Chapter 1, contributed to India and oil); **Marco Baroni** (lead on the power sector, contributed to renewables); **Christian Besson** (oil, natural gas); **Alessandro Blasi** (natural gas, Southeast Asia); **Stéphanie Bouckaert** (lead on buildings, contributed to India); **Ian Cronshaw** (coal, natural gas); **Dan Dorner** (lead on energy access and on Chapter 2); **Olivier Durand-Lasserve** (macroeconomic modelling); **Tarik El-Laboudy** (renewables); **Nathan Frisbee** (India, oil); **Timur Gül** (lead on oil demand and transport); **Sixten Holm** (efficiency, renewables); **Shigetoshi Ikeyama** (Southeast Asia); **Bartosz Jurga** (natural gas); **Fabian Kęsicki** (lead on energy efficiency, contributed to India); **Markus Klingbeil** (natural gas, oil); **Atsuhito Kurozumi** (assumptions, policies); **Junling Liu** (China); **Christophe McGlade** (oil, natural gas); **Ugbizi Banbeshie Ogar** (oil, India); **Paweł Olejarnik** (oil, natural gas and coal supply modelling); **Kristine Petrosyan** (lead on oil refining, contributed to India); **Nora Selmet** (energy access, India); **Toshiyuki Shirai** (Southeast Asia); **Daniele Sinopoli** (power, renewables); **Shigeru Suehiro** (lead on industry, contributed to India, Southeast Asia); **Timur Topalgoekceli** (India, oil); **Johannes Trüby** (lead on coal, contributed to India); **Charlotte Vailles** (power, renewables); **Molly A. Walton** (India, power); **Brent Wanner** (lead on renewables, contributed to power); **David Wilkinson** (lead on data management, contributed to power and renewables); **Georgios Zazias** (fossil-fuel subsidies, emissions); **Shuwei Zhang** (transport, India). **Teresa Coon** and **Sandra Mooney** provided essential support. More details about the team can be found at *www.worldenergyoutlook.org.*

Robert Priddle carried editorial responsibility.

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- 3rd IEA Unconventional Gas Forum co-hosted by the IEA and the National Energy Administration of China, with the support of the CNPC Economics and Technology Research Institute, Chengdu, 10 April 2015.
- India Energy Outlook organised by the IEA in collaboration with NITI Aayog with the support of TERI, New Delhi, 13 April 2015.
- Joint IEA-ERIN Roundtable on Southeast Asia Energy Outlook, Singapore, 20 April 2015.

Further details on these events are at *www.worldenergyoutlook.org/aboutweo/workshops* and *www.iea.org/ugforum.*

IEA Energy Business Council

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More information about the *World Energy Outlook* is available at *www.worldenergyoutlook.org.*

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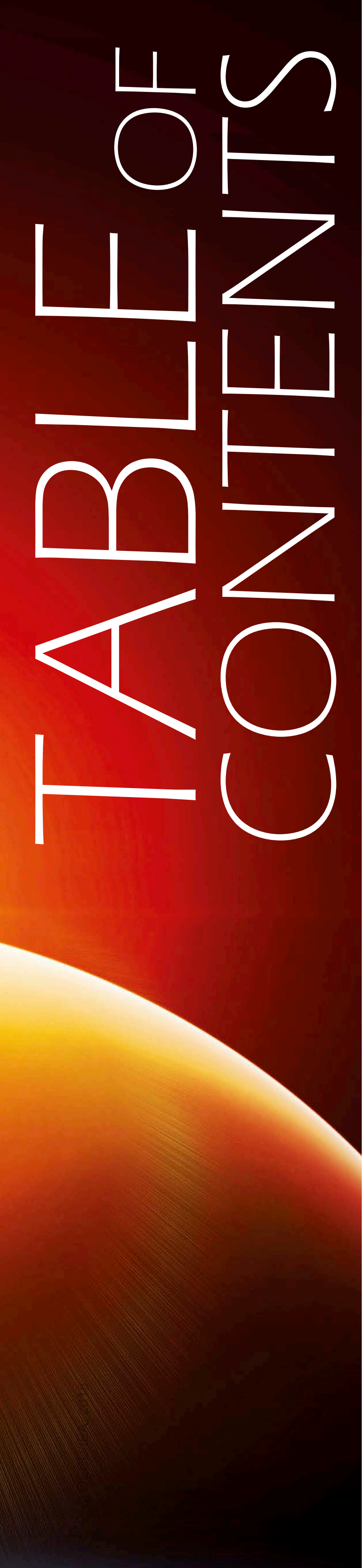

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Part A: GLOBAL ENERGY TRENDS

Part B: INDIA ENERGY OUTLOOK

Signs of change in global energy have multiplied in the 12 months since the last *World Energy Outlook (WEO)*. Oil prices fell sharply, with the prices of other fuels moving in tandem in many parts of the world. Countries including India and Indonesia took advantage of the oil price decline to move ahead with their phase-out of fossil-fuel subsidies. Amid turmoil in parts of the Middle East, a clear pathway opened up that could lead to the return of Iran, one of the world's largest hydrocarbon resource-holders, to oil markets. China's role in driving global trends is changing as it enters a much less energy-intensive phase in its development. Renewables contributed almost half of the world's new power generation capacity in 2014. The coverage of mandatory energy efficiency regulation worldwide expanded to more than a quarter of global consumption. There was also a tantalising hint in the 2014 data of a de-coupling in the relationship between CO_2 emissions and economic activity, until now a very predictable link. As countries prepare for the critically important UN climate summit in Paris (also known as COP21) and its legacy, it is more important than ever for policy-makers, industry and other stakeholders to have a clear understanding of the state of the energy sector today, to see which changes are transient or cyclical, which are here to stay, what risks and opportunities might lie ahead – and what can be done to put the energy system on a more secure and sustainable footing. The *WEO-2015*, with scenario-based analysis looking out to 2040 and multiple case studies along the way, provides insights on all of these questions.

Pledges made in advance of COP21 promise to give new impetus to the move towards a lower-carbon and more efficient energy system, but do not alter the picture of rising global needs for energy. Energy use worldwide is set to grow by one-third to 2040 in our central scenario, driven primarily by India, China, Africa, the Middle East and Southeast Asia. Non-OECD countries account together for all the increase in global energy use, as demographic and structural economic trends, allied with greater efficiency, reduce collective consumption in OECD countries from the peak reached in 2007. Declines are led by the European Union (-15% over the period to 2040), Japan (-12%) and the United States (-3%). The preparations for COP21 have been a rich source of guidance on future energy policy intentions and the energy-related components of COP21 pledges are reflected, based on a country-by-country assessment, in our central scenario. They provide a boost to lower-carbon fuels and technologies in many countries, bringing the share of non-fossil fuels up from 19% of the global mix today to 25% in 2040. Among the fossil fuels, natural gas – the least-carbon intensive – is the only one that sees its share rise.

China re-tunes the engine of global energy demand

China's transition to a less energy-intensive model for growth has major implications for global trends. China carries huge weight in the world of energy: it remains by a distance the world's largest producer and consumer of coal throughout our *Outlook* period; it deploys more renewable power generation capacity than any other country; and by the 2030s it overtakes the United States as the biggest consumer of oil and has a larger gas market than the European Union. China's total energy demand in 2040 is almost double that of the United States. But structural shifts in the economy, favouring expansion of the services sector rather than heavy industry (both steel and cement production are likely to have peaked in 2014), mean that 85% less energy is required to generate each unit of future economic growth than was the case in the past 25 years. Policy choices also change the face of China's energy system and the pace at which it expands. China is set to introduce an emissions trading scheme in 2017 covering the power sector and heavy industry, helping to curb the appetite for coal. From a mere 3% in 2005, half of China's energy use today is already subject to mandatory efficiency standards, and continued improvements in efficiency, alongside large-scale deployment of wind, solar, hydro and nuclear power, lead to a flattening and then a peak in China's CO_2 emissions around 2030.

India seizes the centre of the world energy stage

India – the subject of an in-depth country focus in *WEO-2015* – contributes the single largest share of growth, around one-quarter, in global energy demand. India today is home to one-sixth of the world's population and its third-largest economy, but accounts for only 6% of global energy use and one in five of the population – 240 million people – still lacks access to electricity. With policies in place to accelerate the country's modernisation and develop its manufacturing base (via the "Make in India" programme), population and incomes on the rise and an additional 315 million people anticipated to live in India's cities by 2040, India is entering a sustained period of rapid growth in energy consumption. Demand for coal in power generation and industry surges, increasing the share of coal to almost half of the energy mix and making India by a distance the largest source of growth in global coal use. Oil demand increases by more than in any other country, approaching 10 mb/d by the end of the period. India also steps up its deployment of low-carbon technologies, although uncertainty over the pace at which new large dams or nuclear plants can be built means strong reliance on solar and wind power (areas where India has high potential and equally high ambition) to deliver on its pledge to have a 40% share of non-fossil fuel capacity in the power sector by 2030.

Meeting India's energy needs requires a huge commitment of capital and constant vigilance as to the implications for energy security and the environment. Pressing ahead with the overhaul of India's energy regulatory framework is critical to secure the estimated $2.8 trillion of investment that is needed in energy supply to 2040. Three-quarters of this investment goes to the power sector, which needs to almost quadruple in size to keep up with projected electricity demand but which remains beset for now by high network losses and high financial losses among the local distribution utilities. The expansion of coal supply makes India the second-largest coal producer in the world, but also, already by 2020, the world's largest coal importer, overtaking Japan, the EU and China. Oil production falls well behind the growth in demand, pushing oil import dependence above 90% by 2040. A rapidly expanding energy sector could exacerbate already serious challenges with water stress and local air pollution: integrated policies on land use and urbanisation (the "smart cities" initiative), pollution controls, technology development, and a relentless focus on energy efficiency can mitigate these risks and avoid locking in an inefficient capital stock.

A faster pace is essential to reach the 2030 goal of universal energy access

India makes rapid gains in bringing energy access to its people, but the world as a whole is falling short of its ambition to provide affordable, reliable, sustainable and modern energy for all. Despite the serious efforts already made, today an estimated 1.2 billion people – 17% of the global population – remain without electricity, and 2.7 billion people – 38% of the global population – put their health at risk through reliance on the traditional use of solid biomass for cooking. The newly agreed UN Sustainable Development Goals embrace a goal on energy, a move long advocated by the IEA, including the target to achieve universal access to energy by 2030. In our *Outlook*, the number of people without electricity falls to 800 million by 2030 and the number without access to clean cooking fuels declines only gradually to 2.3 billion in 2030.

Oil prices head higher as markets work off the excess supply, but risks remain

The process of adjustment in the oil market is rarely a smooth one, but, in our central scenario, the market rebalances at $80/bbl in 2020, with further increases in price thereafter. Demand picks up to 2020, adding an average of 900 kb/d per year, but the subsequent rise to 103.5 mb/d in 2040 is moderated by higher prices, efforts to phase out subsidies (provided that momentum behind reform is maintained, even as oil prices pick up), efficiency policies and switching to alternative fuels. Collectively, the United States, EU and Japan see their oil demand drop by around 10 mb/d by 2040. On the supply side, the decline in current upstream spending, estimated at more than 20% in 2015, results in the combined production of non-OPEC producers peaking before 2020 at just above 55 mb/d. Output growth among OPEC countries is led by Iraq and Iran, but both countries face major challenges: the risk of instability in Iraq, alongside weaknesses in infrastructure and institutions; and the need in Iran (assuming the path to sanctions relief is followed successfully) to secure the technology and large-scale investment required. An annual $630 billion in worldwide upstream oil and gas investment – the total amount the industry spent on average each year for the past five years – is required just to compensate for declining production at existing fields and to keep future output flat at today's levels. The current overhang in supply should give no cause for complacency about oil market security.

The short investment cycle of tight oil and its ability to respond quickly to price signals is changing the way that the oil market operates, but the intensity with which the tight oil resource is developed in the United States eventually pushes up costs. US tight oil production stumbles in the short term but resumes its upward march as prices recover, helped by continued improvements in technology and efficiency improvements. But tight oil's rise is ultimately constrained by the rising costs of production, as operators deplete the "sweet spots" and move to less productive acreage. US tight oil output reaches a plateau in the early-2020s, just above 5 mb/d, before starting a gradual decline.

What if prices stay lower for longer?

A more prolonged period of lower oil prices cannot be ruled out. We examine in a Low Oil Price Scenario what it would take for this to happen – and what it would mean for the entire energy sector if it did. The oil price in this scenario remains close to $50/bbl until the end of this decade, before rising gradually back to $85/bbl in 2040. This trajectory is based on assumptions of lower near-term growth in the global economy; a more stable Middle East and a lasting switch in OPEC production strategy in favour of securing a higher share of the oil market (as well as a price that defends the position of oil in the global energy mix); and more resilient non-OPEC supply, notably from US tight oil. With higher demand, led by the transport sector, pushing oil use up to 107 mb/d in 2040, the durability of this scenario depends on the ability and willingness of the large low-cost resource-holders to produce at much higher levels than in our central scenario. In the Low Oil Price Scenario, the Middle East's share in the oil market ends up higher than at any time in the last forty years.

The likelihood of the oil market evolving in this way over the long term is undercut by the effect on producer revenues: OPEC oil export revenue falls by a quarter relative to our central scenario, despite the higher output. Lower prices are not all good news for consumers. The economic benefits are counterbalanced by increasing reliance on the Middle East for imported crude oil and the risk of a sharp rebound in price if investment dries up. Concerns about gas supply security would also be heightened if prices stay too low to generate the necessary investment in supply. Lower oil prices alone do not have a large impact on the deployment of renewable energy technologies in the power sector, but only if policymakers remain steadfast in providing the necessary market rules, policies and subsidies. The outlook for biofuels is hit by cheaper conventional transport fuels, as is the uptake of vehicles powered by electricity and natural gas and the incentive to invest in more efficient technologies. In a Low Oil Price Scenario, longer payback periods mean that the world misses out on almost 15% of the energy savings seen in our central scenario, foregoing around $800 billion-worth of efficiency improvements in cars, trucks, aircraft and other end-use equipment, holding back the much-needed energy transition.

No plain sailing for natural gas

Where it replaces more carbon-intensive fuels or backs up the integration of renewables, natural gas is a good fit for a gradually decarbonising energy system: a consumption increase of almost 50% makes it the fastest-growing of the fossil fuels. China and the Middle East are the main centres of gas demand growth, both becoming larger consumers than the European Union, where gas use does not return to the peak reached in 2010. With gas prices already low in North America, and dragged lower elsewhere by ample supply and contractual linkages to oil prices, there is plenty of competitively priced gas seeking buyers in the early part of the *Outlook*. But the extent of the longer term expansion is constrained by efficiency policies, notably in the buildings sector, and competition from renewables and (in some countries) from coal in power generation; and could be limited further if deferred investment in the current low-price environment brings tighter markets in the 2020s. One-fifth of the projected rise in global demand consists of gas transported over long distances via very capital-intensive pipeline or LNG projects. Keeping these project costs under control (contrary to numerous recent examples of overruns) will be vital to the future competitive positioning of gas. Emissions of methane, a powerful greenhouse gas, along the supply chain will dent the environmental credentials of gas if there is no concerted policy action to tackle these leaks. Unconventional gas accounts for some 60% of the growth in global gas supply, but the spread of its development beyond North America, the home of the shale gas revolution, is more gradual and uneven. The pace of China's unconventional gas growth is a major uncertainty: policies encouraging this development are in place – with production projected to exceed 250 bcm by 2040 – but aspects of the geology, limited water availability and population density in some key resource-rich areas, alongside regulatory issues related to pricing, access to resources and to domestic pipelines, militate against a very rapid rise in output.

And turbulent times ahead for coal

Coal has increased its share of the global energy mix from 23% in 2000 to 29% today, but the momentum behind coal's surge is ebbing away – and the fuel faces a reversal of fortune. Expectations within the industry of continued strong demand growth, especially in China, triggered major investments in supply in recent years but actual coal use has fallen well short, resulting in over-capacity and plummeting prices. In our projections, the fuel that met 45% of the increase in global energy demand over the last decade meets only around 10% of further growth to 2040, largely due to a tripling in coal demand in India and in Southeast Asia.[1] Consumption in the OECD, where coal use faces strong policy headwinds, is projected to drop by 40% over the same period: coal consumption in the European Union in 2040 falls to around one-third of current levels. From a position as a perceived safe bet, China is becoming the wild card of coal markets, with the risks to our projection of a plateau and then a slow decline in coal demand arguably weighted to the downside. By 2040, Asia is projected to account for four out of every five tonnes of coal consumed globally, and coal remains the backbone of the power system in many countries in our central scenario. However, its continued use around the world is compatible with stringent environmental policies only if it is used in the most efficient way, with advanced control technologies to reduce air pollution, and if progress is made in demonstrating that CO_2 can be safely and cost-effectively captured and stored.

The power sector is leading the charge to decarbonise

Electricity gains ground in many end-use sectors, making up almost a quarter of final energy consumption by 2040; the power sector leads the way towards a decarbonised energy system. Non-OECD countries account for seven out of every eight additional units of electricity demand. With 60 cents of every dollar invested in new power plants to 2040 spent on renewable energy technologies, global renewables-based electricity generation increases by some 8 300 TWh (more than half of the increase in total generation),

1. The energy outlook for Southeast Asia was the subject of a *WEO-2015* special report, released in October 2015. Download at: *www.worldenergyoutlook.org/southeastasiaenergyoutlook/*.

equivalent to the output of all of today's fossil-fuel generation plants in China, the United States and the European Union combined. The net result is that the share of coal in the global electricity mix drops from 41% to 30%, with non-hydro renewables gaining a similar amount, while gas, nuclear and hydro broadly maintain their existing shares. By 2040, renewables-based generation reaches a share of 50% in the European Union, around 30% in China and Japan, and above 25% in the United States and India: by contrast, coal accounts for less than 15% of electricity supply outside of Asia. Despite both more costly technologies and rising fossil-fuel prices, electricity is set to become more affordable, relative to GDP, in most regions. With more generation from renewables and nuclear power, and more efficient thermal plants, CO_2 emissions from power generation are set to grow at only one-fifth of the rate at which power output rises to 2040; this was a one-to-one relationship over the last 25 years. To realise these projections, the world needs to add more capacity by 2040 than is globally installed today, while average utilisation rates for capacity go down because of the need to integrate variable renewable energy technologies. This raises questions in many countries about the appropriate market mechanisms that can generate the necessary investment in generation and grids.

And efficiency measures are gathering strength

Energy efficiency plays a critical role in limiting world energy demand growth to one-third by 2040, while the global economy grows by 150%. Mandatory targets in China and India (following on from first-mover Japan) have increased the global coverage of efficiency regulation in industry from 3% in 2005 to more than a third today, and such energy policies continue to expand their reach and effectiveness through to 2040. In OECD countries, efficiency measures reduce demand growth to 60% of what would otherwise be expected. But our central scenario far from exhausts the potential for efficiency improvements. We estimate that the energy efficiency of new equipment bought worldwide in 2030 can be increased by a further 11%, with the average cost of the energy saved being $300 per tonne of oil equivalent (toe), far below the weighted average energy price of $1 300/toe. Energy consumption in trucks and heavy-duty vehicles is currently regulated only in the United States, Canada, Japan and China, with regulation planned also in the European Union: wider geographical coverage and more stringent standards could cut oil demand from new trucks in 2030 by 15%. Changing product design, re-use and recycling ("material efficiency") also offers huge potential for energy saving; for energy-intensive products such as steel, cement, plastics or aluminium, efficient use and re-use of materials can save more than twice as much energy as can be saved by efficiency measures in the production process to 2040.

The balance is shifting towards low-carbon technologies

Policy preferences for lower carbon energy options are reinforced by trends in costs, as oil and gas gradually become more expensive to extract while the costs of renewables and of more efficient end-use technologies continue to fall. Oil and gas production costs increase for most resource types as operators are forced to move to smaller, more remote or more challenging reservoirs, although the effect is dampened by technology and efficiency improvements. By contrast, cost reductions are the norm for more efficient equipment and appliances, as well as for wind power and solar PV, where technology gains are proceeding apace and there are plentiful suitable sites for their deployment. Fossil-fuel consumption continues to benefit from large subsidies: we estimate this global subsidy bill at around $490 billion in 2014, although it would have been around $610 billion without reforms enacted since 2009. Subsidies to aid the deployment of renewable energy technologies in the power sector were $112 billion in 2014 (plus $23 billion for biofuels). Supportive government policies and related subsidies continue to be critical to most of the capacity deployed, as only a few countries put a significant price on carbon in our central scenario. The need for subsidies however, is restrained by a shift in deployment to countries with higher quality renewable resources, by continued cost reductions and higher wholesale prices. A 50% rise in subsidies, to an estimated $170 billion in 2040, secures a five-fold increase in generation from non-hydro renewables (without the cost reductions and higher wholesale prices, the subsidy bill in 2040 would exceed $400 billion). The share of non-hydro-renewables that is competitive without any subsidy support doubles to one-third.

The direction of travel is changing, but the destination is still not 2 degrees

Despite the shift in policy intentions catalysed by COP21, more is needed to avoid the worst effects of climate change. There are unmistakeable signs that the much-needed global energy transition is underway, but not yet at a pace that leads to a lasting reversal of the trend of rising CO_2 emissions. Annual investment in low-carbon technologies in our central scenario increases, but the cumulative $7.4 trillion invested in renewable energy to 2040 represents only around 15% of total investment in global energy supply. The steady decarbonisation of electricity supply is not matched by a similarly rapid shift in end-use sectors, where it is much more difficult and expensive to displace coal and gas as fuels for industry, or oil as a transport fuel. The net result is that energy policies, as formulated today, lead to a slower increase in energy-related CO_2 emissions, but not the full de-coupling from economic growth and the absolute decline in emissions necessary to meet the 2 °C target. A *WEO* special report released in June 2015, *Energy and Climate Change*, showed what more can be done, at no net economic cost, to bring about a peak in energy-related emissions by 2020 – an essential step if the door to a 2 °C outcome is to remain open:

- Increasing energy efficiency in the industry, buildings and transport sectors.
- Progressively reducing the use of the least-efficient coal-fired power plants and banning their construction.
- Increasing investment in renewable energy technologies in the power sector from $270 billion in 2014 to $400 billion in 2030.
- Phasing out of remaining fossil-fuel subsidies to end-users by 2030.
- Reducing methane emissions in oil and gas production.

The conclusion, reinforced by projections from our *WEO-2015* central scenario, is that the framework for climate action agreed at COP21 needs to provide a procedure which will secure progressively stronger climate commitments over time if the world is to keep to an emissions trajectory consistent with the 2 °C goal. A clear and credible vision of long-term decarbonisation is vital to provide the right signals for investment and to allow a low-carbon, high-efficiency energy sector to be at the core of international efforts to combat climate change.

PART A
GLOBAL ENERGY TRENDS

PREFACE

Part A of this *WEO* (Chapters 1-10) presents energy projections to 2040. It covers the prospects for all energy sources, regions and sectors and considers the implications for climate change, energy security and the economy. The main focus is on the New Policies Scenario – the central scenario in *WEO-2015*. However, three other scenarios are also presented – the Current Policies Scenario, the 450 Scenario and the Low Oil Price Scenario.

Chapter 1 defines the scenarios and details the policy, technology, macroeconomic and demographic assumptions utilised in the analysis.

Chapter 2 summarises the projections for global and regional energy trends and the implications for CO_2 emissions, investment needs and trade. It also includes detailed updates on global progress in fossil-fuel subsidy reform and energy access.

Chapter 3 analyses the outlook for oil and Chapter 4 presents a new scenario, the Low Oil Price Scenario, which assesses the implications of a prolonged period of low prices on markets, policies, investment, the fuel mix and emissions.

Chapter 5 focuses on the outlook for natural gas. Chapter 6 details the outlook for unconventional gas globally, with an evaluation of the evolution of production in the United States, the prospects of unconventional gas in China, and the response of the regulatory regimes to social and environmental concerns associated with development of unconventional gas resources.

Chapters 7 analyses the outlook for coal, with detailed insights on prospects for major producing and consuming countries.

Chapter 8 analyses the outlook for the power sector, with an in-depth focus on the prospects for coal-fired power generation.

Chapter 9 provides the outlook for renewables, a guide to evaluating the competitiveness of renewables-based power generation and a quantification of the estimated share that is competitive.

Chapter 10 examines recent trends and future prospects for energy efficiency and tracks the evolution, the extent and impact of efficiency policies around the world. For the first time, the analysis examines how material efficiency can contribute to energy and emissions savings.

Introduction and scope

How do we project energy trends?

Highlights

- The New Policies Scenario – the central scenario in *WEO-2015* – takes into account the policies and implementing measures affecting energy markets that had been adopted as of mid-2015 (as well as the energy-related components of climate pledges in the run-up to COP21, submitted by 1 October), together with relevant declared policy intentions, even though specific measures needed to put them into effect may not have been adopted. The Current Policies Scenario takes into account only policies enacted as of mid-2015. The 450 Scenario depicts a pathway to the 2 °C climate goal that can be achieved by fostering technologies that are close to becoming available at commercial scale. Against a backdrop of uncertainty over economic growth and a persistent oil market imbalance, a Low Oil Price Scenario explores the implications of sustained lower prices on the global energy system.

- The level and pattern of economic activity and demographic changes will be important determinants of future energy trends. World GDP is assumed to grow at an average annual rate of 3.5% over 2013-2040, meaning it expands to more than two-and-a-half-times its current size. Supported by the anticipated rebalancing of Chinese growth away from manufacturing, and despite Indian intentions to stimulate manufacturing, nearly two-thirds of the growth comes from the services sector, which is the least-energy intensive part of the global economy. The world's population is assumed to rise from 7.1 billion in 2013 to 9 billion in 2040, with the increase concentrated in Africa, India, Southeast Asia and the Middle East. India overtakes China to become the world's most populous country by the mid-2020s.

- The international fossil-fuel prices used in this report reflect our judgement of the price levels that would be needed to stimulate sufficient investment in supply to meet projected long-term demand. In the New Policies Scenario, the average IEA crude oil import price edges upward to $80/barrel (in year-2014 dollars) in 2020 and $128 in 2040. Natural gas prices, which have fallen sharply in Asia and Europe over the last year, rise in all markets with price spreads between regions persisting, despite a degree of convergence. The average OECD steam coal import price reaches $108 per tonne in 2040. The share of global emissions covered by carbon pricing increases from 12% of emissions today, to 27% in 2040.

- Deployment of increasingly efficient end-use technologies, renewables and other low-carbon energy options continues to expand rapidly, buoyed by declining costs and, in some cases, by dedicated policy initiatives and/or subsidies. This coincides with a gradual increase in the cost of oil and gas extraction. We assume energy technologies that are already in use or are approaching commercialisation achieve ongoing cost reductions as a result of increased learning and deployment.

Scope of the report

This edition of the *World Energy Outlook* (*WEO-2015*) presents an assessment of the prospects for global energy markets for the period to 2040 and draws out the implications for energy security, environmental protection and economic development. The objective is to provide policy-makers, industry and other stakeholders with the data, analysis and insights needed to make sound energy decisions. Based on the latest data and market developments, the *Outlook* includes energy demand and supply projections, insights into the trajectories of fossil fuels, renewables, the power sector and energy efficiency, and analysis of trends in energy-related carbon-dioxide (CO_2) emissions, subsidies to fossil fuels and renewable energy, investment in energy supply infrastructure and universal access to modern energy services.

Part A of this report (Chapters 1-10) focuses on the core projections to 2040. While results for a number of scenarios are included, emphasis is placed predominately on the results of the New Policies Scenario, to provide a clear picture of where planned policies, with generally cautious assumptions about the timing and degree of their implementation, would take us. Chapter 2 summarises the projections for global energy trends and energy sector investment. It also draws out the implications of these trends for CO_2 emissions and summarises areas for further action which have already been identified by the *Energy and Climate: World Energy Outlook Special Report* as an input to the climate change negotiations in Paris in December, 2015. Chapter 2 also continues the *WEO* practice of analysing two crucial energy sector challenges: achieving universal energy access; and phasing out fossil-fuel subsidies. Chapters 3-10 review the main pillars of the energy system in turn: the outlook for oil (including a Low Oil Price Scenario), natural gas (including a detailed look at the prospects for unconventional gas), coal, power, renewables and energy efficiency.

An in-depth focus on India is presented in Part B (Chapters 11-14). Energy is critical for India's development and the country's growing energy consumption also has broad implications for the regional and global energy outlook. This analysis starts with a review of the current state of India's energy sector. It then looks forward to how India might address the energy challenges arising from rapid economic growth and urbanisation, including the need to improve access to electricity and the reliability of power supply, to mobilise the investment that can expand domestic production of fossil fuels and renewable sources of energy, and to manage the consequences for energy security and for the environment.

Methodological approach

Modelling framework

The World Energy Model (WEM) is the principal tool used to produce the energy projections in this report.[1] The model is a large-scale simulation tool, designed to replicate how energy

1. A complete description of the WEM is available at *www.worldenergyoutlook.org/weomodel/.*

markets function. Developed over more than 20 years, it consists of three main modules covering final energy consumption (including industry, transport, buildings, agriculture and non-energy use), fossil fuel and bioenergy supply, and energy transformation (including power and heat generation, oil refining and other transformation). The primary outputs from the model for each region are energy demand and supply by fuel, investment needs and CO_2 emissions.

The WEM is a very data-intensive model that covers the entire global energy system. The current version models global energy demand on the basis of 25 distinct regions, 13 of which are individual countries. Global oil and gas supply is modelled based on 120 distinct countries and regions; global coal supply is modelled based on 31 countries and regions. Most of the historic data on energy demand, supply, and transformation, as well as on energy prices, are obtained from IEA databases of energy and economic statistics.[2] These are supplemented by additional data from many external sources, including governments, international organisations, energy companies, consulting firms and financial institutions. These sources are indicated in the relevant sections of this document.

The WEM is reviewed and updated each year to ensure that it provides as accurate a representation as possible of regional and global energy markets. The latest improvements include the following:

- The buildings module has had a number of enhancements: (i) energy use in appliances has been further disaggregated by the addition of four new sub-sectors: refrigeration; cleaning; brown goods (i.e. consumer electronics); and other appliances (which together account for around half of all electricity use in the residential sector), making it easier to capture the effects of efficiency measures, technology deployment and price responses; and (ii) a new clean cooking access module has been linked to the residential module for developing countries, enabling better representation of the drivers of demand and the possible changes in the energy system resulting from the increased use of improved cookstoves and substitution of liquefied petroleum gas (LPG) and natural gas for biomass.
- The impacts of water constraints on coal-fired power plants have been captured. This includes the development of a model for China and India that determines the least-cost location of coal-fired power plants based on water availability, coal transportation costs and the capital cost of cooling systems (differentiating between non-fresh water and freshwater).
- The electricity price module in the WEM has been revised to better represent the cost elements of the power system, from generation costs (including incorporating more complete information for all regions on historical investment costs), to the costs associated with transmission and distribution, and subsidies for fossil fuels, electricity and renewable energy technologies.

2. Many of these data are available at *www.iea.org/statistics*.

Defining the scenarios

As in past editions, *WEO-2015* uses scenarios to present quantitative projections of long-term energy trends. There are three core scenarios, which differ in their assumptions about the evolution of energy-related government policies: the New Policies Scenario; the Current Policies Scenario; and the 450 Scenario.[3] For this report, we also present a Low Oil Price Scenario as a contribution to the debate about the possible consequences of a long-term low oil price environment. The base year for all of the scenarios is 2013, as comprehensive market data for all countries were available only up to the end of 2013 at the time the modelling work was completed. However, where preliminary data for 2014 were available (which was often the case), they have been incorporated.

The **New Policies Scenario** is the central scenario of this *Outlook*. In addition to incorporating the policies and measures that affect energy markets and that had been adopted as of mid-2015, it also takes account of other relevant intentions that have been announced, even when the precise implementing measures have yet to be fully defined. This includes the energy-related components of the Intended Nationally Determined Contributions (INDCs), submitted by national governments by 1 October as pledges in the run-up to the United Nations Framework Convention on Climate Change (UNFCCC) Conference of the Parties (COP21) (Spotlight). It also includes all policies announced but yet to be implemented and we take a generally cautious view in the New Policies Scenario of the extent and timing of their implementation, given the institutional, political and economic circumstances that could stand in the way. These policies include programmes to support renewable energy and improve energy efficiency, to promote alternative fuels and vehicles, carbon pricing, reform of energy subsidies, and the introduction, expansion or phase-out of nuclear power.

As in previous *Outlooks*, we devote most attention to the results of the New Policies Scenario in order to provide the clearest picture possible of the outcome of continuing with the policies that are in place and those that are currently planned. The results however, do not constitute a forecast. New policies, as yet unformulated, will certainly be adopted over the course of the next twenty-five years. Indeed, one purpose in projecting the future is to demonstrate the need for their adoption.

The **Current Policies Scenario** takes into consideration only those policies for which implementing measures had been formally adopted as of mid-2015 and makes the assumption that these policies persist unchanged. This scenario, though clearly extremely unlikely to be realised, offers a picture of how global energy markets would evolve without new policy intervention, thereby providing a benchmark to make it possible to ascertain the value of the additional measures taken into account in the New Policies Scenario and, perhaps, to point the way to promising avenues for further improvement.

3. Details of the key policies and measures taken into account in each scenario can be found in Annex B. A policies and measures database, detailing policies addressing renewable energy, energy efficiency and climate change is available at *www.iea.org/policiesandmeasures*.

SPOTLIGHT

Recent key developments in energy and climate policy

Throughout the year, governments across the world have been submitting new greenhouse-gas reductions pledges – known as Intended Nationally Determined Contributions (INDCs) – to the UNFCCC in advance of the COP21 summit, forming a foundation for the negotiations (Table 1.1). This has brought notable commitments from a number of countries, with significant contributions from some of the world's largest emitters, including China and the United States. As of 1 October 2015, almost 150 countries across the economic spectrum, responsible for around 85% of energy-related CO_2 emissions have set out their targets. Also notable is that, for the first time, even countries that have only thus far contributed nominally to global greenhouse-gas emissions are opting to outline their strategies, including for example over 20 countries in sub-Saharan Africa, as well as many countries in Asia and Latin America. A detailed analysis of the implications of full implementation of the energy-related measures announced in the INDCs is presented in the *Energy and Climate Change: World Energy Outlook Special Report 2015*, which was released in June and took into account all INDCs and intentions announced by mid-May 2015. An update of this analysis was made in October 2015, incorporating the latest available energy sector data.[4] In this *World Energy Outlook*, in line with our usual New Policies Scenario methodology, we took those INDCs into account that had been submitted by 1 October, with a focus on explicit energy sector targets. The degree to which these pledges are implemented in the New Policies Scenario is guided by the availability of policies to support them.

The **450 Scenario** takes a different approach, adopting a specified outcome – the international goal to limit the rise in the long-term average global temperature to two degrees Celsius (2 °C) – and illustrating how that might be achieved. This scenario assumes a set of policies that bring about a trajectory of greenhouse-gas (GHG) emissions from the energy sector that is consistent with that goal. In this scenario, the concentration of greenhouse gases in the atmosphere peaks by around the middle of this century; the level is above 450 parts per million (ppm), but not so high as to be likely to precipitate changes that make the 2 °C objective ultimately unattainable. The concentration of greenhouse gases stabilises after 2100 at around 450 ppm. While the results of the 450 Scenario are included for reference purposes in many of the tables and figures throughout this report, as well in the detailed tables in Annex A, a broader discussion is limited, as the energy sector's potential role in mitigating climate change was set out in detail in *Energy and Climate: World Energy Outlook Special Report*, which was deliberately released in June 2015, ahead of this *World Energy Outlook 2015*, in order to make a timely contribution to the preparations for COP21.[5]

4. The findings of this update are available at: *www.worldenergyoutlook.org/indc/*.
5. The report can be downloaded free at: *www.worldenergyoutlook.org/energyclimate/*.

Table 1.1 ▷ Greenhouse-gas emissions reduction goals in submitted INDCs for top-ten CO_2 emitters (as of 1 October 2015)[6]

UNFCCC Party	Intended Nationally Determined Contribution (INDC)
China	Peak GHG emissions by 2030 or earlier and reduce carbon intensity of GDP by 60-65% below their 2005 levels by 2030.
United States	Reduce net GHG emissions by 26-28% below 2005 levels by 2025.
European Union	Reduce EU domestic GHG emissions by at least 40% below 1990 levels by 2030.
India	Reduce the emissions intensity of GDP by 33-35% below 2005 levels by 2030.
Russia	Reduce anthropogenic GHG emissions by 25-30% below 1990 levels by 2030 subject to the maximum possible account of absorptive capacity of forests.
Japan	Reduce energy-related CO_2 emissions by 25%, reduce non-energy CO_2 emissions by 6.7%, CH_4 by 12.3%, N_2O by 6.1%, and fluorinated gases by 25.1% compared with 2013 levels by 2030.
Korea	Reduce GHG emissions by 37% by 2030 compared with a business-as-usual scenario.
Canada	Reduce GHG emissions by 30% below 2005 levels by 2030.
Brazil	Reduce GHG emissions by 37% compared with 2005 levels by 2025.
Mexico	Reduce GHG and short-lived climate pollutant emissions unconditionally by 25% by 2030 with respect to a business-as-usual scenario.

The ***Low Oil Price Scenario*** illustrates the impact of a persistently lower oil price than that modelled in the New Policies Scenario – the subject of much recent debate – not just for the oil sector, but on the global energy system as a whole. In this scenario, market equilibrium is not attained until the 2020s, with prices in the $50-60/barrel range (in year 2014 dollars), after which the price starts to edge higher, reaching $85/barrel in 2040. A number of oil supply and demand side assumptions differentiate this scenario from the New Policies Scenario. On the supply side, the main such assumptions is persistent commitment by the countries holding the world's largest and lowest-cost resources to pursue higher market share and to keep the oil price at a level that limits substitution away from oil. Greater resilience in a lower price environment is also assumed in some important non-OPEC sources of supply, notably tight oil in the United States. A key assumption on the demand side is a slightly lower pace of near-term economic growth.

Main non-policy assumptions

The economy

Economic activity remains a primary driver of demand for energy. The projections described in this *Outlook* are, therefore, highly sensitive to the underlying assumptions about the rate and pattern of growth in gross domestic product (GDP). The modelling is undertaken on the basis of GDP expressed in real purchasing power parity (PPP) terms. PPPs allow meaningful comparisons of value between countries, just as conventional

6. A full list of the INDCs submitted can be accessed at: *www.unfccc.int/submissions/indc/*.

price indices allow prices within a country to be compared over time. They are calculated by simultaneously comparing the prices of similar goods and services among a large number of countries. Following a revision of PPPs in 2014 by the International Comparison Program and subsequently the International Monetary Fund, the estimated size of the global economy has been revised upwards significantly. Global GDP is now estimated to be about 20% higher than it was previously, with the largest upward revisions in the emerging economies. We have also gained insights on how energy policies impact the broader economy from the coupling of the World Energy Model with ENV-Linkages[7], the OECD computable general equilibrium model.

Table 1.2 ▷ Real GDP growth assumptions by region

	Compound average annual growth rate				
	1990-2013	2013-2020	2020-2030	2030-2040	2013-2040
OECD	**2.1%**	**2.2%**	**1.9%**	**1.7%**	**1.9%**
Americas	2.5%	2.6%	2.2%	2.1%	2.2%
United States	2.5%	2.5%	2.0%	2.0%	2.1%
Europe	1.8%	1.9%	1.8%	1.6%	1.7%
Asia Oceania	1.9%	1.7%	1.7%	1.3%	1.5%
Japan	0.9%	0.6%	0.9%	0.7%	0.8%
Non-OECD	**4.9%**	**4.9%**	**5.0%**	**3.8%**	**4.5%**
E. Europe/Eurasia	0.9%	1.4%	3.3%	2.8%	2.6%
Russia	0.7%	0.2%	3.1%	2.7%	2.2%
Asia	7.3%	6.3%	5.7%	3.9%	5.2%
China	9.9%	6.4%	5.3%	3.1%	4.8%
India	6.5%	7.5%	7.0%	5.3%	6.5%
Southeast Asia	5.1%	5.3%	5.0%	3.7%	4.6%
Middle East	4.3%	3.1%	3.9%	3.4%	3.5%
Africa	4.0%	4.8%	4.8%	4.3%	4.6%
Latin America	3.4%	1.7%	3.5%	3.2%	2.9%
Brazil	3.1%	1.4%	3.8%	3.3%	3.0%
World	**3.4%**	**3.7%**	**3.8%**	**3.1%**	**3.5%**
European Union	1.6%	1.8%	1.7%	1.5%	1.6%

Note: Calculated based on GDP expressed in year-2014 dollars in PPP terms.

Sources: IMF (2014); OECD (2014); Economist Intelligence Unit and World Bank databases; IEA databases and analysis.

7. The version of ENV-Linkages that has been used includes 25 regions and 18 economic sectors, with a focus on those that are most energy intensive. It models monetary flows between economic sectors, households and governments, as well as inter-regional trade in various commodities. A full description of the ENV-Linkages model is available at the OECD iLibrary: *http://dx.doi.org/10.1787/5jz2qck2b2vd-en*.

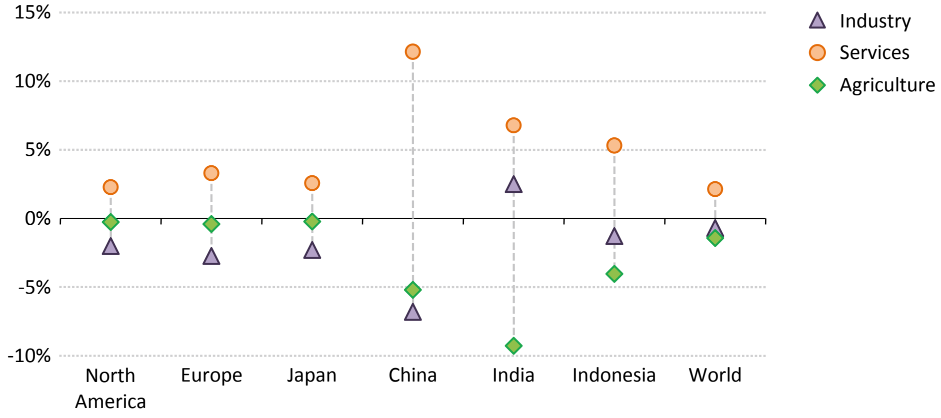
In each of the core scenarios of this *Outlook*, world GDP is assumed to grow at an average annual rate of 3.5% over 2013-2040, which means it expands to more than two-and-a-half-times its current size over the period (Table 1.2). The exception is the Low Oil Price Scenario, in which a slightly slower near-term rate of growth is one of the assumptions underpinning the scenario. The recent revisions to PPPs have contributed to a slight increase in our assumption for global GDP growth, compared with *WEO-2014*, as they have meant that emerging economies, which are typically expected to grow at faster rates than other parts of the world in the decades ahead, start the period accounting for a greater share of the global economy.

India's economic growth, at 6.5% per year on average in the period 2013-2040, outpaces all others. The recent rebasing of India's historical GDP and changes in the way its GDP is calculated have contributed to upward revisions to growth estimates for the country, which is already the world's third-largest in PPP terms. The services sector has been the main source of GDP growth in India in recent years, but the manufacturing industry is expected to play an increasingly important role. By contrast, the composition of China's GDP is expected to shift away from industry towards services, a long-anticipated rebalancing, with similarly important implications for energy demand. The growth prospects of several key oil producers, including countries in the Middle East, Russia, Canada and Brazil, have all been revised downwards, compared to last year's *Outlook*, particularly in the period to 2020, as a result of lower energy prices.

While the fall in energy prices since mid-2014 has been an economic boon for many energy importers, alleviating fiscal strains and allowing money to be freed up to stimulate other parts of the economy, it by no means has eliminated the uncertainty about growth prospects in the world's advanced economies. In the United States, the outlook to 2020 is dampened by the strong dollar, an anticipated slowdown in productivity growth and the demographics of an ageing population. Canada slipped into recession in the first-half of 2015. In Europe, the legacy of the economic downturn continues to subdue demand and remains a hindrance to higher levels of growth, while lingering doubts over the durability of Greece's agreement with its creditors adds a further layer of uncertainty. In Japan, lower oil and natural gas prices, higher real wages, higher equity prices and a weaker yen have improved the outlook.

From an energy perspective, the contributions that different economic sectors make to total GDP can be as important as the overall rates of growth, as the extent to which they use energy as an input to generate economic output (or value added) varies significantly. Over the projection period, the services sector, which requires a relatively low level of energy per unit of output, contributes an increasing share of global GDP (Figure 1.1). While activity in the services sector has, in the past, been dominated by the OECD countries, whose services sector has accounted for a quarter of global economic growth since 1990, China is set to take a leading role into the injection of growth in the global economy through its services sector which, alone, accounts for around 15% of global growth to 2040. In India a push towards greater reliance on manufacturing will mean the effect of growth in its services sector is more subdued than it otherwise would have been, but, its services sector still provides the second-largest contribution to the overall growth in the global economy to 2040.

Figure 1.1 ▷ Change in value-added GDP contribution by sector, 2014-2040

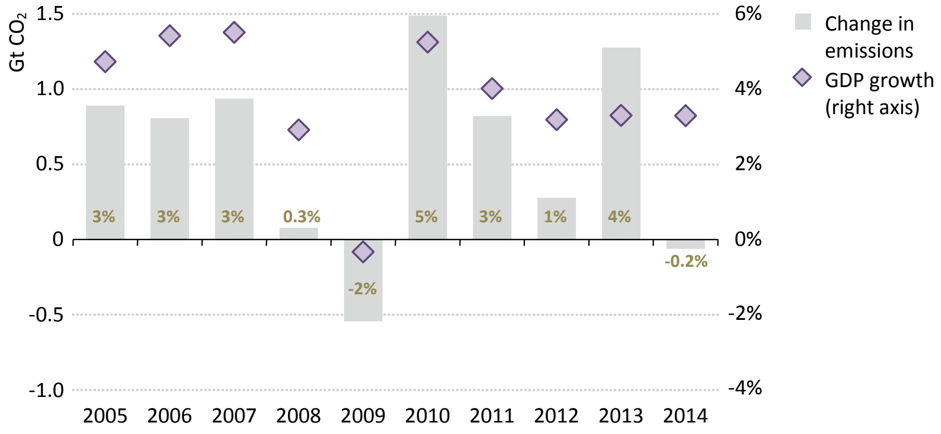


Box 1.1 ▷ Are economic growth and carbon emissions decoupling?

In most parts of the world, economic activity remains the principal driver of demand for energy and is therefore strongly correlated with carbon emissions. This has been the case for the past 40 years in which the IEA has collected emissions data. During these four decades, there have been only three instances in which emissions have remained flat or declined relative to the previous year and each case has been associated with economic weakness in major economies.

However, a noticeable shift occurred in 2014, with emissions failing to increase despite a 3.3% expansion of the global economy (Figure 1.2). This development can be largely attributed to changing patterns of energy consumption in China and OECD countries. In China, 2014 saw greater generation of electricity from renewable sources, such as hydropower, solar and wind, and less burning of coal, alongside a shift in the structure of economic output from energy-intensive industries towards the services sector. In OECD economies, recent efforts to promote more sustainable growth – including greater energy efficiency and more renewable energy – are producing the desired effect of decoupling economic growth from greenhouse-gas emissions. The experience of 2014 provides a timely reminder of the dividends that can be expected from sustained efforts to decarbonise the energy supply. But one swallow does not make a summer – emissions are more than likely to resume their upward climb in 2015. The projections in this *Outlook* continue to be highly sensitive to assumptions about the rates and patterns of GDP growth.

Figure 1.2 ▷ **Energy-related CO_2 emissions and economic growth, 2005-2014**



Notes: Gt CO_2 = gigatonnes of carbon dioxide. Percentage shows year-on-year change in emissions. GDP growth is calculated using 2014 dollars in PPP terms.

Demographic trends

Population and demographics are important drivers of energy demand and changes in the energy mix. This edition of the *WEO* adopts the same approach as in previous years, taking the medium variant of the latest United Nations' projections (UNPD, 2015) as the basis for population growth in all scenarios. According to these projections, the world population is expected to grow by 0.9% per year on average, from 7.1 billion in 2013 to 9 billion in 2040 (Table 1.3). The increase in the global population is concentrated in Africa, India, Southeast Asia and the Middle East. Africa experiences the fastest rate of growth, resulting in a near doubling of its population to almost 2 billion people. India overtakes China to become the world's most populous country in the mid-2020s, with its population approaching 1.6 billion people by the end of the period. A number of countries see their population peak and begin to decline in our projection period, including Japan (whose population in 2040 is almost 10% smaller than it is today), Korea, Russia and Germany. China's population peaks in the early 2030s and begins to decline thereafter.

Populations increasingly concentrate in cities and towns, pushing the urbanisation rate up from 53% in 2013 to 63% in 2040, meaning that the absolute number of people living in rural areas falls. Urbanisation tends to increase demand for modern forms of energy as such forms of energy are more readily available and levels of income and economic activity tend to be higher, although this energy growth can be mitigated through a strategic approach to planning and transport policy.

Table 1.3 ▷ Population assumptions by region

	Population growth*			Population (million)		Urbanisation	
	1990-2013	2013-25	2013-40	2013	2040	2013	2040
OECD	**0.7%**	**0.5%**	**0.4%**	**1 265**	**1 402**	**80%**	**85%**
Americas	1.1%	0.8%	0.7%	492	593	81%	86%
United States	1.0%	0.8%	0.7%	321	383	81%	86%
Europe	0.5%	0.3%	0.2%	568	604	75%	82%
Asia Oceania	0.4%	0.1%	0.0%	206	205	89%	93%
Japan	0.1%	-0.3%	-0.4%	127	115	92%	97%
Non-OECD	**1.5%**	**1.1%**	**1.0%**	**5 857**	**7 633**	**47%**	**59%**
E. Europe/Eurasia	0.0%	-0.1%	-0.2%	341	327	63%	68%
Russia	-0.1%	-0.3%	-0.4%	144	128	74%	79%
Asia	1.3%	0.9%	0.6%	3 714	4 413	43%	57%
China	0.8%	0.4%	0.1%	1 365	1 414	53%	73%
India	1.6%	1.1%	0.9%	1 252	1 599	32%	45%
Southeast Asia	1.5%	1.0%	0.8%	616	760	46%	60%
Middle East	2.4%	1.7%	1.4%	218	313	69%	76%
Africa	2.5%	2.4%	2.2%	1 111	1 999	40%	51%
Latin America	1.4%	1.0%	0.8%	473	581	79%	84%
Brazil	1.3%	0.7%	0.5%	200	229	85%	90%
World	**1.3%**	**1.0%**	**0.9%**	**7 122**	**9 036**	**53%**	**63%**
European Union	0.3%	0.1%	0.1%	508	516	74%	81%

* Compound average annual growth rates.

Sources: UN Population Division databases; IEA analysis.

Carbon-dioxide prices

The pricing of CO_2 emissions affects demand for energy and the composition of the fuel mix by altering the relative costs of using different fuels. Momentum to price the cost associated with greenhouse-gas emissions continues. As of mid-2015, a total of 39 carbon pricing initiatives had been taken, in the form of taxes or cap-and-trade schemes, covering around 3.7 gigatonnes (Gt) (12%) of global energy-related CO_2 emissions and with an aggregate value of $26 billion. Since the last *World Energy Outlook* edition, Korea launched a cap-and-trade programme to limit emissions to 2017 to just under 1.7 million tonnes (Mt) of CO_2 equivalent, and Mexico and Portugal[8] established carbon taxes. The effectiveness of the European Union Emissions Trading Scheme (EU ETS), by far the world's largest carbon market, remains constrained by a surplus of allowances that has kept the price of carbon

8. A carbon tax of €5 per tonne CO_2 equivalent was introduced for sectors not currently covered by the EU ETS.

too low to incentivise low-carbon investment. In a bid to improve its effectiveness, the EU agreed in 2015 to introduce a Market Stability Reserve in 2019 that would regulate the surplus by withdrawing allowances when necessary.

Our assumptions on carbon pricing vary across the scenarios, reflecting the extent of policy interventions to curb growth in CO_2 emissions. We assume that all the schemes currently in place remain throughout the *Outlook* period, with their prices gradually rising in each case (Table 1.4). In the New Policies Scenario, the price of CO_2 in Europe increases from \$9/tonne in 2014 to \$22/tonne in 2020 and \$50/tonne in 2040. Having started at around \$7.3/tonne, the price of permits in Korea rises to levels similar to those in Europe in 2040. China's recently-announced carbon trading scheme, which replaces a current pilot programme covering seven cities, is due to come into force by the start of 2017, and will cover six sectors including power, iron and steel; chemicals; building materials, paper, and nonferrous metals. This increases by two-and-a-half-times the share of global emissions covered by carbon pricing, which will reach 27%. We also assume that all investment decisions in the power sector in Canada, the United States and Japan are made on the basis of an implicit "shadow" carbon price[9] that starts at \$13/tonne from today and rises to \$40/tonne in 2040. Our assumptions in the 450 Scenario are for more widespread and aggressive carbon pricing, which is adopted in all OECD countries and reaches \$140/tonne in 2040.

Table 1.4 ▷ CO_2 price assumptions in selected countries and regions by scenario (\$2014 per tonne)

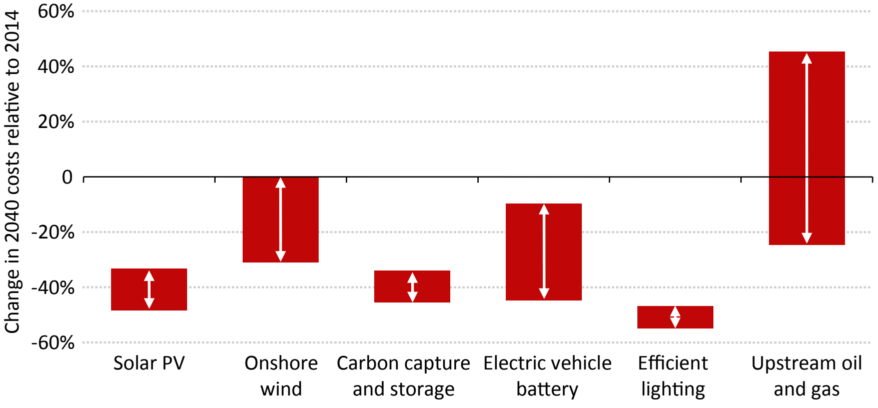
	Region	Sectors	2020	2030	2040
Current Policies Scenario	European Union	Power, industry and aviation	20	30	40
	Korea	Power and industry	20	30	40
New Policies Scenario	European Union	Power, industry and aviation	22	37	50
	Chile	Power	6	12	20
	Korea	Power and industry	22	37	50
	China	Power and industry	10	23	35
	South Africa	Power and industry	7	15	24
450 Scenario	United States and Canada	Power and industry	20	100	140
	European Union	Power, industry and aviation	22	100	140
	Japan	Power and industry	20	100	140
	Korea	Power and industry	22	100	140
	Australia and New Zealand	Power and industry	20	100	140
	China, Russia, Brazil and South Africa	Power and industry	10	75	125

9. This is an assumed price, taken into account in investment decisions, to reflect the expectation that some form of action is or will be taken to penalise CO_2 emissions in the future.

Technology

Advanced energy technologies could fundamentally alter the long-term evolution of energy markets and have a major bearing on efforts to meet environmental goals, including those linked to greenhouse-gas emissions. The projections in this report are therefore sensitive to assumptions on the rates of technological change and how they affect energy efficiency, supply costs and fuel choices. This *Outlook* does not make allowances for technological breakthroughs, as it is impossible to determine what form these will take, when they might occur, or how quickly they can be commercialised. But, each of the scenarios presented in this *Outlook* incorporates a process of technology learning on both the demand and supply sides that affects the costs of different energy technologies (both those in use today and those that are judged to be approaching commercialisation) and therefore the patterns of investment in different sources of energy supply and in energy efficiency (Table 1.5). The rate of technological improvement is related in many cases to the level of deployment (which is driven in turn by the policies assumed, as well as by energy and CO_2 prices), although the resulting costs can be offset by depletion effects of some resources in a given location. This is a discernible factor affecting renewable resources in some countries and regions, for example where the most advantageous sites for wind turbines have been fully exploited and developers have to look to second-tier sites. It is a much more important consideration for the costs of upstream oil and gas, as producers work their way through the resource base in a given area and over time move to more difficult and complex reservoirs. This depletion effect in oil and gas outweighs the impact of technology learning in many cases, explaining why the average costs of oil and gas production rise in many instances to 2040, while the costs of other energy technologies fall (Figure 1.3).

Figure 1.3 ▷ Evolution of energy technology costs per unit in the New Policies Scenario, 2014-2040



Over the projection period, the cost of renewables declines materially. For example, continued deployment of solar photovoltaics (PV) and technology improvements further reduce the cost of PV modules, which have been in rapid decline in recent years. Strong savings are also made in "soft costs" for new installations, including design, labour, permitting and inspection. Together, these lead to cost reductions of 30-50%, relative to those of today. Onshore wind turbines also benefit from technology cost reductions, though they are offset, to a degree, by quality of resource characteristics and site availability as the most favourable sites are fully developed. In most regions, the technology cost reductions are more than enough to offset this, with the levelised cost of electricity for onshore wind projects declining by 10-20%.

Carbon capture and storage (CCS), still nascent, has only a few commercial-scale projects underway today. As deployment picks up pace, learning-by-doing presents an opportunity for substantial cost reductions over the period to 2040, though deployment will also critically depend on improved information becoming available about CO_2 storage opportunities (IEA, 2015).

Efficient batteries are the key to the future deployment of electric vehicles (EV). There remains significant scope for battery cost reductions, some of which materialise in the New Policies Scenario. But widespread market uptake of electric cars does not depend on cost reductions alone: consumers also need to be convinced that the performance of an electric vehicle is at least as attractive as that of a conventional vehicle, even if its purchase comes at higher initial cost. That means overcoming limitations to driving range, reducing long recharging times and ensuring the widespread availability of recharging stations. Between 20-25% of the reduction can be attributed to regional variations.

Technological improvements in energy efficiency provide cost savings. For example in lighting, the costs of compact fluorescent lamps (CFL) and light-emitting diode (LED) lamps have followed a particularly steep downward trajectory in some developing countries. Over the projection period, policies to ban the use of the least-efficient incandescent light bulbs in a number of countries, and the bigger market shares captured by CFL and LED lighting, serve to further reduce costs and improve efficiency, decreasing cost for the same level of lighting by 47-55%.

Sharp changes will occur in oil and gas production costs in 2040, relative to 2014, reflecting changing geological conditions and the relative maturity of extraction technologies. Technology learning will continue to bring down the extraction cost of abundant resource types that are currently very expensive to develop (kerogen oil, also known as oil shales, is a good example), while the effects of depletion will be minimal because of the huge size of the resource base. Other already more intensively developed resource types will see an opposite trend. In the New Policies Scenario tight oil output in the United States, for example, continues to benefit from rapid technology learning, but the technology cost reductions do not keep pace with the extra costs stemming from reservoir complexity as a more limited resource base is depleted and thus development costs rise.[10]

10. As discussed in the oil and gas chapters, the size of the ultimately recoverable tight oil (and shale gas) resource base is one of the most influential uncertainties in our *Outlook*. The range of cost escalation for oil and gas by 2040 is also particularly sensitive to the chosen base year due to the recent volatility of oil prices and development costs.

Table 1.5 ▷ Recent developments and key conditions for faster deployment of low-carbon energy technologies

Technology	Recent developments	Key conditions for faster deployment
Renewables power	• Installation of renewables-based power generation technologies hit a record high in 2014, helped by the continuing decline in technology costs. • Onshore wind capacity increased by 45 GW, with China alone adding 20 GW. Solar PV grew by around 40 GW.	• Ensure a predictable and reliable long-term market to mitigate investment risks. • Promote a regulatory framework that supports cost-effective remuneration, avoiding high cost incentives and the possibility of retroactive change.
Nuclear power	• In 2014, 72 GW of nuclear capacity were under construction. • Three projects began construction in 2014, down from ten in 2013. • Almost 40 countries are considering developing first nuclear plants. Three countries have committed to phasing out nuclear power.	• Promote incentives for all types of low-carbon solutions to provide financing certainty for investment. • Recognise the security of supply, reliability and predictability that nuclear power offers.
Carbon capture and storage (CCS)	• The first large-scale power plant CO_2 capture was demonstrated in 2014. • Thirteen large-scale CCS projects were online, capturing a total of 26 Mt CO_2 per year by the end of 2014. • Two large-scale CCS power projects are under construction in the United States.	• Demonstrate financial and policy commitment to CCS demonstration and deployment. Help to mitigate investment risks. • Carbon pricing that expands the commercial value of CO_2 beyond its use in enhanced oil recovery.
Biofuels	• Impacted by the price declines in crude oil, there is ongoing uncertainty over future biofuel demand and investment. • Investment in new biofuels capacity has focused on hydro-treated vegetable oil in Europe and cellulosic plants in the United States.	• Develop long-term policies, demonstration-scale and pilot plants to advance technology development. • Formulate and implement sustainability criteria and standards.
Hybrid and electric vehicles	• Global sales of light-duty passenger electric vehicles grew by 50% in 2014, compared with 2013. • Battery costs continued to fall, and vehicle range increased for several EV models.	• Continue and enhance research and development, infrastructure roll-out and government incentives to support development of EVs. • Extend promotion of EVs for modes other than passenger transport.
Energy efficiency	• The share of the world's energy consumption covered by efficiency regulations increased from 12% in 2005 to 27% in 2014 with the largest increase in China (see Chapter 10).	• Strengthen and expand efficiency regulation and increase policy action to remove barriers to implementation of energy efficiency measures.

Note: GW = gigawatt.

Source: IEA (2015).

Energy supply costs and prices

Price is one of the key drivers of energy trends: prices paid by consumers affect the amount of each fuel they choose to consume and their choice of technology and equipment to provide an energy service. The price that producers receive strongly influences their investment decisions and therefore the level of future production. In each of the scenarios in this *Outlook*, the international fossil-fuel price reflects analysis of the price level that would be needed to stimulate sufficient investment in supply to meet the projected level of demand over the period. Average retail prices in end-uses, power generation and other transformation sectors in each region are derived from iterative runs of the WEM, which take into account local market conditions, including taxes, excise duties, carbon prices and relevant subsidies. The price paths for fuels vary across the scenarios, largely reflecting the differences in the relative strength of the policies introduced to address energy security, environmental and other issues, and their respective impacts on supply and demand. These include policies for subsidies. In the Current Policies Scenario, there is no change in current subsidy rates, unless a formal programme is already in place. The New Policies Scenario, on the other hand, assumes a complete phase out of fossil-fuel subsidies in all net-importing countries and regions within ten years; while in the 450 Scenario, subsidies are removed within ten years in net-importing regions, and are removed in all net-exporting regions except the Middle East within 20 years.

In the Current Policies Scenario, policies adopted to reduce the use of fossil fuels are limited, so rising demand and supply costs combine to push prices up. Lower energy demand in the 450 Scenario means that there is less need to produce fossil fuels from resources higher up the supply cost curve. As a result, international fossil-fuel prices are lower than in the other two scenarios. But this does not flow through to lower final end-user prices as the cost savings are assumed to be offset by increased taxes. There is, however, a benefit in terms of lower national energy import bills.

Oil prices

After a period of relatively stable but historically high prices from 2010 until mid-2014, at which point oil traded at around $115/barrel, international benchmark oil prices fell by well more than 50% into 2015 and have remained in the $40-60/barrel range for much of 2015. The collapse in prices was driven by a marked slowdown in demand growth and record increases in supply, particularly tight oil from North America, as well as a decision by the Organization of Petroleum Exporting Countries (OPEC) countries not to try to rebalance the market through cuts in output (Figure 1.4).

These market developments provide a new, much lower, starting point for the formulation of the oil price trajectories used in each of the scenarios in this *Outlook*, compared with those in *WEO-2014*. Prices remain lower for much of the early part of the projection period, although the gap progressively narrows in all scenarios (except the Low Oil Price Scenario) as markets work through the current supply overhang and rebalance at higher price levels.

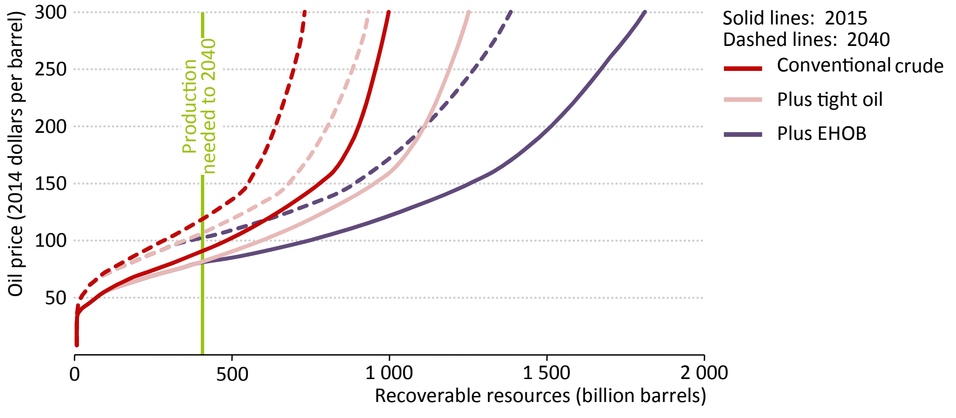
Table 1.6 ▷ Fossil-fuel import prices by scenario

		New Policies Scenario			Current Policies Scenario			450 Scenario			Low Oil Price Scenario		
	2014	2020	2030	2040	2020	2030	2040	2020	2030	2040	2020	2030	2040
Real terms (2014 prices)													
IEA crude oil imports ($/barrel)	97	80	113	128	83	130	150	77	97	95	55	70	85
Natural gas ($/MBtu)													
United States	4.4	4.7	6.2	7.5	4.7	6.3	7.8	4.5	5.7	5.9	4.7	6.2	7.5
Europe imports	9.3	7.8	11.2	12.4	8.1	12.5	13.8	7.5	9.4	8.9	5.9	8.9	11.4
Japan imports	16.2	11.0	13.0	14.1	11.4	14.9	16.0	10.7	11.8	11.1	8.8	10.7	12.4
OECD steam coal imports ($/tonne)	78	94	102	108	99	115	123	80	79	77	88	97	102
Nominal terms													
IEA crude oil imports ($/barrel)	97	89	153	210	92	176	246	85	131	156	61	95	140
Natural gas ($/MBtu)													
United States	4.4	5.2	8.3	12.3	5.2	8.6	12.8	5.0	7.6	9.7	5.2	8.3	12.3
Europe imports	9.3	8.6	15.1	20.3	9.0	16.9	22.6	8.4	12.7	14.6	6.6	12.1	18.7
Japan imports	16.2	12.2	17.6	23.1	12.6	20.1	26.3	11.9	15.9	18.2	9.8	14.4	20.3
OECD steam coal imports ($/tonne)	78	104	138	178	110	155	202	89	106	126	98	130	168

Notes: MBtu = million British thermal units. Gas prices are weighted averages expressed on a gross calorific-value basis. All prices are for bulk supplies exclusive of tax. The US price reflects the wholesale price prevailing on the domestic market. Nominal prices assume inflation of 1.9% per year from 2014.

The rebound in prices occurs most rapidly in the Current Policies Scenario, because of higher oil consumption, with the average IEA crude oil import price – used as a proxy for international oil prices – approaching $83/barrel (in year-2014 dollars) in 2020 in this scenario. In the New Policies Scenario, the market tightens less quickly and the oil price reaches $80/barrel in 2020.

Figure 1.4 ▷ Non-OPEC supply cost curves for 2015 and 2040 in the New Policies Scenario



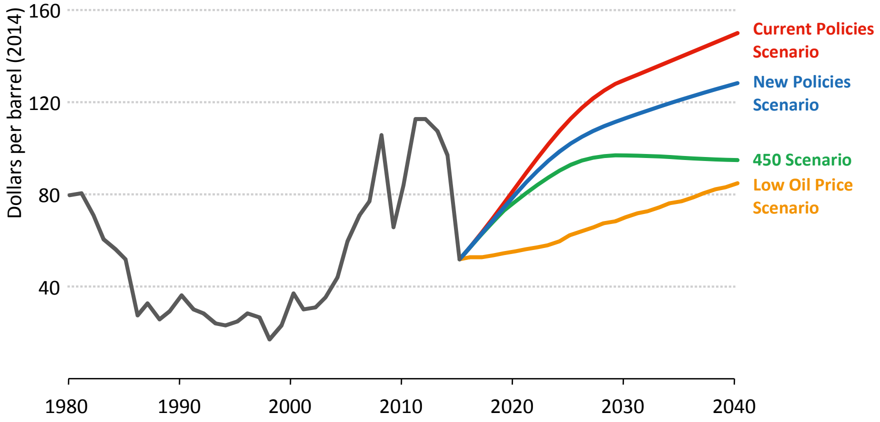
Notes: EHOB = extra-heavy oil and bitumen. The vertical green line indicates the amount of production required between 2015 and 2040 in the New Policies Scenario

The oil price trajectories are determined by the level needed to stimulate sufficient investment in supply in order to meet projected demand in each scenario. Higher demand in the Current Policies Scenario means a higher call on oil from costly fields in non-OPEC countries. Conversely, in the 450 Scenario, more aggressive policy action to curb demand means that market equilibrium can be found at a lower price. The non-OPEC supply cost curves for 2015 and 2040, derived from the WEM, help to illustrate the underlying logic behind the various long-term trajectories (Figure 1.4). As might be expected, a higher oil price allows an increased volume of resources to be developed, including larger volumes of unconventional oil. But the picture also changes over time: the 2040 cost curves, illustrated here for different non-OPEC resource categories in the New Policies Scenario, are higher and steeper than those for 2015, as capital and operating costs are pushed higher by the gradual depletion of the resource base and the need to develop more challenging or remote fields.[11] The relationship between the supply cost curves and oil prices is not straightforward, but the inference is that a price in the range of $80-120/barrel is likely to be required to enable supply to meet demand in

11. The situation is complicated by the two-way interaction between costs and prices: an increasing oil price pushes up industry activity levels, tightening markets for upstream supplies and services (and meaning that higher prices also tend to lead to higher costs). Likewise, as shown in 2014-2015, an oil price fall is accompanied by strong pressure on supply and service providers to reduce costs. This correlation between oil prices and industry costs is captured in the way that costs are modelled in the World Energy Model.

the New Policies Scenario to 2040. Provision for various limitations, including geopolitical and logistical constraints on the rate of growth in both OPEC and non-OPEC countries, leads to a situation in which oil prices are typically maintained at a higher level than the supply cost curves would suggest, which is why the oil price in the New Policies Scenario in 2040 reaches $128/barrel.

Figure 1.5 ▷ Average IEA crude oil import price by scenario



In this *Outlook*, we change some of the key assumptions underlying the New Policies Scenario to model a Low Oil Price Scenario, in which lower cost oil from OPEC countries is much more readily available and production from some key non-OPEC producers – notably the United States – is also assumed to be more resilient at lower prices. There are also some changes to assumptions on the demand side, including a diminished near-term GDP outlook in some emerging economies. These factors allow the oil price to remain lower for longer, prices remaining flat until the 2020s, in the $50-60/barrel range, and rising only gradually thereafter, to $85/barrel by 2040 (Figure 1.5).

Box 1.2 ▷ Run-up to an oil price fall

To better understand the reasons behind the fall in the price of crude oil in 2014-2015, it is worthwhile first to examine the factors behind the rise that preceded it and why these were not sustained. At one level, the explanation for the price decline is ultimately quite simple – high oil prices encouraged a growing imbalance between buoyant supply and flagging demand – but some of the underlying dynamics and reasons for the timing of the eventual fall are more complex.

There were fundamental reasons for tighter markets after the 2008 global economic crises, notably the strong rebound in demand, but also on the supply side, there were a number of one-off factors that kept prices high. These included output disruptions in 2011 and 2012 in Libya, Syria and Nigeria, as well as the tightening of sanctions against Iran at that time. A rapid expansion of refinery runs in Russia also contributed to the decreasing availability of crude oil in international markets[12], while the refining sector in Europe (and to a lesser degree elsewhere) did not adjust its crude intake and rationalise capacity as quickly as market conditions would have implied. Between 2008 and 2013, while oil demand in OECD Europe declined by 1.8 million barrels per day (mb/d), refinery runs decreased by only 1.3 mb/d, while imports of middle distillates, the only deficit product in Europe, were increasing. Effectively, crude oil prices were being supported at higher levels by refiners absorbing negative refining margins.

Into this picture came increasing volumes of US oil production, which had bottomed out in 2008 after two decades of decline. Between 2012 and 2014, the output of oil by producers in the Atlantic basin[13] increased by 3.8 mb/d (compared with no growth over 2009-2011). Refiners in the United States started processing increasing volumes of tight oil and of heavy crudes, which were trading at a discount to international crudes, displacing West and North African oil and some heavier Middle Eastern crudes from the North American market. At the same time, increasing output of natural gas liquids (NGLs) meant more competition from ethane and LPG for petrochemical feedstocks based on crude oil (naphtha). On the oil demand side, annual consumption growth of 0.5 mb/d in 2014 was one of the lowest in a number of years. The growth in oil demand in China decelerated perceptibly, reflecting a cooling economy and the start of a rebalancing away from heavier manufacturing industry. The weaker exchange rates of many currencies against the dollar, in both the emerging markets and the European Union, also curbed the appetite for oil consumption and dollar-denominated imports.[14]

Accelerating production growth from the United States, rising production from Iraq, slowing demand and an easing of some of the special one-off elements that had kept markets tight started to push crude prices down from the late second-quarter 2014. This presented a challenging picture to OPEC delegates when they met in November, ultimately convincing Saudi Arabia and other OPEC member countries that an attempt to rebalance the market by cutting back OPEC output would not be effective. The decision to leave the OPEC production target unchanged was then the trigger for further price falls – setting the stage for a different type of market rebalancing, with the oil price as the mediator – and non-OPEC production on the front line.

12. The refined products were being exported to international markets, so the total oil exports out of Russia were growing, but crude oil prices first of all are affected by crude oil supply and demand, while product markets then affect the difference between product and crude prices, i.e. cracking and refining margins.

13. In oil trading, the world is typically considered (at the highest level of aggregation) in two parts: the Atlantic basin and the East of Suez region. The former includes countries around the Atlantic rim, i.e. the Americas, Europe, West and North Africa, and also Russia and Caspian countries that generally export towards Europe. The East of Suez region consists of the Middle East, Asia, East Africa and Australia.

14. Another factor that may ultimately have weighed down on the oil price was the switch in the Atlantic basin in 2012-2013 from being a net importer to a net exporter of crude oil to the rest of the world. The two most important oil futures, Brent and WTI, are in the Atlantic basin (Brent in the North Sea and WTI essentially for North and Central American output); these prices no longer need to incentivise net inflows of oil to Atlantic markets, but rather the net evacuation of oil from the Atlantic region towards the growing refining sector of Asia.

Natural gas prices

There is for the moment no global pricing benchmark for natural gas, as there is for oil. Instead, there are three major regional markets – North America, Asia-Pacific, and Europe – each with different pricing mechanisms and gas market conditions. In North America, gas prices are determined at hubs, and reflect local gas supply and demand dynamics, while in Asia-Pacific, trade is dominated by long-term contracts that are often linked to the price of oil. Gas trade in continental Europe was also governed by long-term oil-indexed contracts in the past, but is increasingly gravitating towards arrangements which allow prices to be set by gas-to-gas competition, which account for around half of European gas trade today.

In *WEO-2015*, gas price spreads between regions persist, but gradually come to levels that are more consistent with the costs of moving gas between the markets. This convergence comes about because of greater availability of liquefied natural gas (LNG) on a flexible basis, with a portion of LNG sellers free to seek out the best available price in the various import markets. A degree of segmentation between markets remains, because of the effect (including a large legacy effect) of long-term contracts that retain more restrictive price or destination requirements. The high costs and long-lead times of developing gas infrastructure also create strong inertia within the system – and the high gas transportation costs rule out the prospect of a single global gas price; but the overall effect is that markets become more interconnected and that price changes in one market are reflected more quickly in others. Differences between the price levels in the Current Policies, New Policies and 450 Scenarios are largely explained by the variations in global and regional demand; different oil price trajectories also play a strong role in price-setting in some regions.

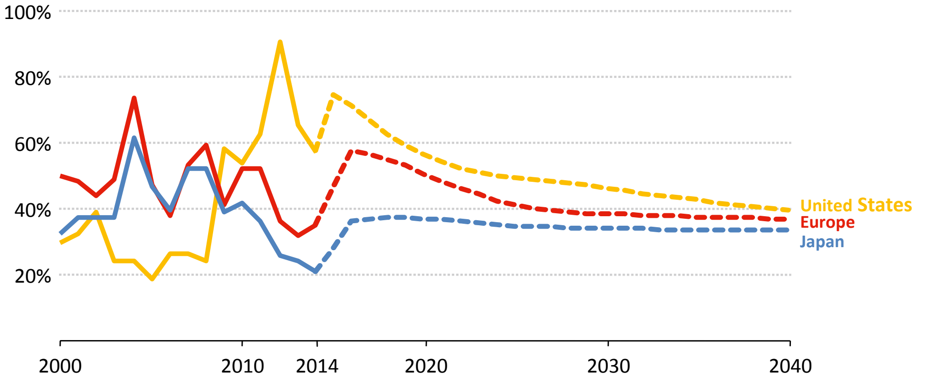
Of the three main regional gas markets, North American prices remain the lowest in each of the scenarios, but they do rise over time in line with the rising breakeven costs of gas supply, reaching $7.5 per million British thermal units (MBtu) in 2040 in the New Policies Scenario. Average import prices vary across the Asia-Pacific region. In Japan, prices have already come down from their post-Fukushima highs and the re-commissioning of nuclear plants over the coming years relieves much of the exceptional demand for imported gas. Average import prices rise steadily over the longer term to reach $14/MBtu in 2040. China, whose options for supply are more varied and include domestic production as well as various pipeline and LNG import options, has a lower average import price than Japan (as do many other Asia-Pacific markets). It rises to $12/MBtu in 2040 in the New Policies Scenario, a similar level to that in Europe.

The Low Oil Price Scenario presents an interesting variation on the price outlook for gas. Importers with oil-indexed contracts generally stand to benefit, but this scenario also accelerates the de-linking of the two prices, as otherwise gas prices would be too low to bring forward the supply necessary to meet gas demand. Overall, Japan and Europe see prices that are 12% and 8% lower, respectively, than in the New Policies Scenario. In the United States, by contrast, prices – and the commercial case for natural gas production – do not change much in the Low Oil Price Scenario: producers tend to benefit from lower upstream costs for services and supplies, but the economics of gas production are worsened by the lower value that they receive for NGLs.

Coal prices

The global coal market consists of a number of regional sub-markets that are typically separated by geography, coal quality and infrastructure constraints. As a result, coal prices vary markedly between regions and even within a country (Figure 1.6). Around one-fifth of global steam coal production is traded inter-regionally, with the remainder used close to where it is mined. Nevertheless, the price of coal on the international market acts as a useful barometer of the dynamics within the market itself.

Figure 1.6 ▷ Coal price relative to gas price by region in the New Policies Scenario (in energy equivalent terms)



The downward pressure on prices in recent years can be attributed to two primary causes. On the supply side, a period of surging demand between 2007 and 2011 triggered a large increase in mining investments in Australia, Colombia, Indonesia and South Africa. These mines have come online at a period of dampened demand growth in China, where local air pollution concerns have led to a shift away from coal towards gas and renewables in the power sector and, to a lesser extent, in the United States, where cheap shale gas has led to some coal being displaced.

The outlook for coal prices differs by scenario: prices are a function of the demand growth and the cost of the production to meet it. In all of the scenarios, the international coal market returns to balance by 2020, after which prices are fundamentally determined by the marginal cost of supply. In the New Policies and Current Policies Scenarios growing demand and trade put upward pressure on prices and increase the call on supply from mines that are currently operating at a loss. More rigorous climate action after this period is reflected in lower demand in the New Policies Scenario compared with the Current Policies Scenario to 2040, and as a result, there is a significant price divergence, with the OECD steam coal import price reaching $108/tonne in the New Policies Scenario compared with $123/tonne in the Current Policies Scenario. In the 450 Scenario, more stringent climate policies slash long-term global coal demand, but the effects are already noticeable in the medium term. Loss-making mines are shut while those with favourable costs stay in business and support a coal price that is kept flat at current levels.

Global energy trends to 2040

Business-as-usual or a brave new world?

Highlights

- Government policies play a powerful role in determining the evolution of the energy sector. World energy demand grows in all *WEO* scenarios, but policies dictate the pace and the extent to which emissions follow the same path. In the New Policies Scenario, global energy demand increases by 32% from 2013 to 2040, with all of the net growth coming from non-OECD countries and OECD demand ending 3% lower.
- The largest energy demand growth story of recent decades is near its end; coal use in China reaches a plateau, close to today's levels, as its economy rebalances and industrial coal demand falls. The world's biggest oil consumer (United States) sees the biggest drop in demand, together with the European Union (both down 4 mb/d). Broad-based growth in gas demand (up 47%) is led by China and the Middle East.
- Electricity consumption grows by more than 70% to 2040, but 550 million people still live without any access to electricity at that time. Renewables overtake coal as the largest source of power generation by the early-2030s and account for more than half of all growth over the *Outlook*. By 2040, renewables-based generation reaches 50% in the EU, around 30% in China and Japan, and above 25% in the United States and India. In contrast, coal is just 13% of electricity supply outside of Asia.
- The oil market is in unfamiliar territory: facing a well-supplied market and lower prices, producers have cut operating costs and investment plans. Oil production grows by 12% from 2014, to over 100 mb/d in 2040, led by non-OPEC countries initially (to around 2020) and OPEC later on. By 2020, US unconventional gas output has grown to exceed the total gas production of any other country in the world.
- Energy trade relationships continue to be rewritten, with Asia the final destination for 80% of regionally traded coal, 75% of oil and 60% of natural gas in 2040. China becomes the world's largest oil importer before 2020 and India the second-largest around 2035. Middle East oil exports accelerate after 2020 and gas exports rebound after 2025. North American gas net exports are 45 bcm by 2020 and the region is self-sufficient in oil by the mid-2020s. EU gas imports grow by 30%, but also diversify.
- World energy sector investment totals $68 trillion from 2015 to 2040, of which 37% is in oil and gas supply, 29% in power supply and 32% in end-use efficiency. Fossil-fuel subsidies were $493 billion in 2014, but would have been $610 billion without reforms since 2009. Recent changes prove reform is possible: low oil prices give net importers the room to reform and reinforce the need for exporters to do so.
- The energy sector must be at the heart of global action to tackle climate change. Despite some positive signs that a low-carbon transition is underway, energy-related CO_2 emissions are projected in the New Policies Scenario to be 16% higher by 2040.

Introduction

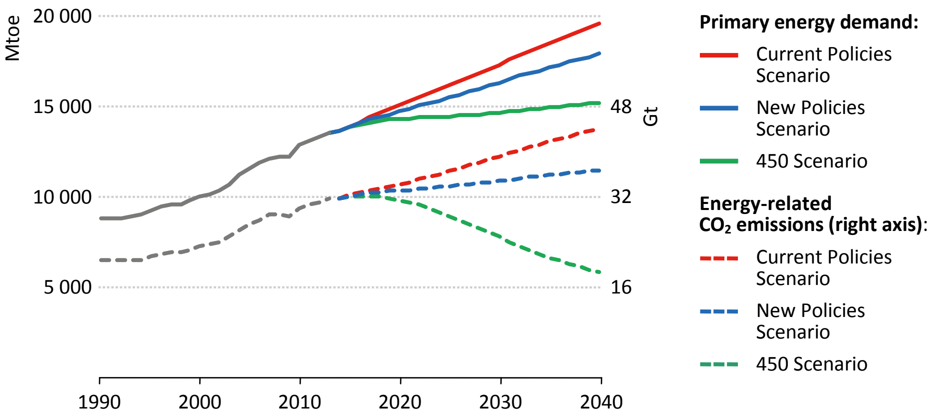
A changing world is asking challenging questions of the established energy powers. Is there a new master of the oil market? Will fossil fuels surrender their supremacy in the electricity sector? To what extent will Asian energy demand dominate markets and energy trade alliances be rewritten? And can the nations of the world strike an effective, collective climate bargain? The last year has been awash with energy market and policy developments. Lower oil prices have squeezed capital investment, boosted demand, put pressure on exporters and emboldened some countries to reform fossil-fuel subsidies. But key questions remain around the lifespan of OPEC's current strategy and how long higher cost producers can endure lower oil prices. Consequent pressure on natural gas prices is also set in the context of an impending wave of new global liquefied natural gas (LNG) capacity. Natural gas security continues to occupy Europe's policy-makers, while Russia's pivot towards China is proceeding slowly. The rapid expansion of traded coal supply in recent years, coupled with the first decline in global demand this century, has prompted a sharp drop in coal prices. Global investments in renewables have been strong while costs have continued to fall, but government support remains essential in most markets. Energy efficiency policies are having a notable impact on demand, but lower prices also bring the risk that consumption grows more strongly and policy efforts falter. Energy has been at the heart of many international policy discussions, with the G7 focusing on energy sector decarbonisation and energy security, the G20 delivering action plans on energy efficiency and energy access, the United Nations including energy explicitly within its post-2015 Sustainable Development Goals and intense efforts by policy-makers to prepare the ground for the critical climate meeting in Paris in December 2015 (COP21). Rarely has energy featured so prominently in so many fora, but will the world's energy system undergo a gradual transition or a rapid and fundamental transformation in the decades to come?

The 2015 edition of the International Energy Agency's *World Energy Outlook* (*WEO-2015*) seeks to put latest developments into perspective and explore their implications for global energy security, economic development and the environment. *WEO-2015* projects key energy and climate trends by fuel, region and sector for the period 2013 to 2040. While the base year is 2013, more recent energy data are incorporated in the *Outlook* where available, as are energy market and policy developments (up to mid-2015). *WEO-2015* presents three main scenarios that are differentiated by their energy and climate policy assumptions (see Chapter 1), with the future energy picture that they portray varying significantly. The New Policies Scenario – the central scenario – describes a pathway for energy markets based on the continuation of existing policies and measures, as well as the cautious implementation of announced policy proposals, even if they are yet to be formally adopted. The Current Policies Scenario takes account only of those policies that were enacted as of mid-2015, and therefore offers a baseline against which to assess the impact of new policies. The 450 Scenario is an outcome-oriented scenario, illustrating an energy trajectory consistent with a 50% chance of limiting the long-term increase in average global temperatures to no more than 2 degrees Celsius (°C) – the internationally agreed global climate goal. In addition, *WEO-2015* presents some tailored scenarios and cases as a means to unlock new findings for decision-makers, including a Low Oil Price Scenario in Chapter 4, a Material Efficiency Scenario in Chapter 10 and an Indian Vision Case in Chapter 14.

Overview of energy trends by scenario

Global energy demand increases in all *WEO* scenarios, but government policies play a powerful role in dictating the degree of growth and the degree to which energy-related emissions decouple from energy use (Figure 2.1). Overall, new energy and climate policies – either those that have been announced or those that are prescribed to meet the world's climate goal – serve to restrain the pace at which energy demand grows and to weaken, or break (in the case of the 450 Scenario), the link between growth in energy demand and in energy-related emissions (a crucial consideration for COP21). Between 1990 and 2013, world primary energy demand increased by 55% to 13 560 million tonnes of oil equivalent (Mtoe) and it is projected to grow by a further 45% to 2040 in the Current Policies Scenario, 32% in the New Policies Scenario and 12% in the 450 Scenario.[1] Energy demand projections are lower than in *WEO-2014* (in all cases, down more than 2% in 2025 and 2040), the net effect of new market, economic and policy developments serving to push and pull components of the global energy system in different directions (IEA, 2014a). For instance, the upward push from lower oil and gas prices in the near term is offset by a downward revision to gross domestic product (GDP) growth in some key markets.

Figure 2.1 ▷ **World primary energy demand and CO_2 emissions by scenario**



No country in the world has fully utilised the potential to improve the energy efficiency of its economy and most still have scope to go considerably further. Energy efficiency regulations have been adopted more widely in recent years and covered 27% of global energy consumption in 2014, up from 14% in 2005 (see Chapter 10). In 2014, final energy consumption expanded by 0.7%, but without efficiency improvements the growth would have been around three-times higher. Despite this positive indicator, policy-makers must

1. In this chapter, world totals include international marine and aviation bunkers, but regional totals do not.

remain vigilant in their energy efficiency efforts, as periods of lower energy prices can tempt consumers to be more profligate and weaken the case for households and businesses to make efficiency investments. While increasing numbers of governments recognise the multiple benefits that improved energy efficiency can bring, such as enhanced energy security, more affordable energy services and reduced local air pollution (IEA, 2014b), strong and sustained policy action is often required to help remove the barriers to progress. The degree to which governments introduce and tighten energy efficiency policies is a key differentiator across the *WEO* scenarios. While the global economy grows to two-and-a-half-times its current size by 2040 in each of the three main scenarios, the enactment of progressively stronger energy efficiency policies sees the energy consumed per dollar of GDP decline by nearly 45% in the Current Policies Scenario, nearly 50% in the New Policies Scenario and over 55% in the 450 Scenario.

Despite efforts to decarbonise the world's energy system, the share of fossil fuels in the global energy mix has changed little over the last thirty years (81% in 2013), while coal (the most carbon-intensive fossil fuel) has attained, in 2013, its highest share of the energy mix for at least 40 years. In all scenarios, fossil fuels remain the dominant source of energy supply to 2040, but their share of the energy mix falls, just slightly in the Current Policies Scenario but much more rapidly in the 450 Scenario (Table 2.1). In the Current Policies Scenario, demand for coal overtakes oil around 2030 to make coal the largest component of the energy mix, while it is natural gas which experiences the highest growth in demand (in absolute terms) through to 2040. Renewables increase significantly, but their growth only just outpaces that of total energy demand, meaning that their share of the energy mix changes little. Similarly, nuclear sees little change. In the New Policies Scenario, demand for all fossil fuels increases, but growth in coal demand stays at low levels, and natural gas use nearly reaches the level of coal by 2040. In the 450 Scenario, the consumption of fossil fuels is still far from trivial but, utilising only commercial and near-commercial technologies, global demand for both coal and oil reaches its peak by 2020 and then moves into a clear decline, while the use of natural gas levels-off around 2030. The outlook for all forms of low-carbon energy (renewables, nuclear power and carbon capture and storage [CCS]) is more positive in the 450 Scenario and they collectively meet 46% of primary energy demand by 2040.

The world is at a critical juncture in its efforts to combat climate change and the build-up to COP21 has prompted a surge in policy activity designed to reduce greenhouse-gas (GHG) emissions. For instance, the United States and China made a landmark joint announcement on climate change and clean energy co-operation in 2014 (and a joint presidential statement on climate change in September 2015); the European Union (EU) has agreed an energy and climate package for 2030; and India has established ambitious targets for renewables deployment. Governments from around the world have submitted their Intended Nationally Determined Contributions (INDCs) for COP21. More broadly, the head of the Catholic Church, the Pope, issued an encyclical on the environment, Islamic religious leaders and scholars issued a Declaration on Climate Change and the UN Sustainable Development Goals have been adopted. As energy production and use account for around two-thirds of the world's GHG emissions, actions to reduce them must come first and foremost from the energy sector. In June 2015, the IEA set out its views on the challenge of tackling climate change and the opportunities for effective action in the energy sector in *Energy and Climate Change: World Energy Outlook Special Report* (IEA, 2015a).[2] The report emphasised the need for INDCs to be viewed as a base upon which to build and proposed four key pillars to help ensure that COP21 achieves a successful outcome (Spotlight).

Table 2.1 ▷ World primary energy demand by fuel and scenario (Mtoe)

			Current Policies Scenario		New Policies Scenario		450 Scenario	
	2000	2013	2020	2040	2020	2040	2020	2040
Coal	2 343	3 929	4 228	5 618	4 033	4 414	3 752	2 495
Oil	3 669	4 219	4 539	5 348	4 461	4 735	4 356	3 351
Gas	2 067	2 901	3 233	4 610	3 178	4 239	3 112	3 335
Nuclear	676	646	827	1 036	831	1 201	839	1 627
Hydro	225	326	380	507	383	531	384	588
Bioenergy*	1 023	1 376	1 537	1 830	1 541	1 878	1 532	2 331
Other renewables	60	161	296	693	316	937	332	1 470
Total	**10 063**	**13 559**	**15 041**	**19 643**	**14 743**	**17 934**	**14 308**	**15 197**
Fossil-fuel share	*80%*	*81%*	*80%*	*79%*	*79%*	*75%*	*78%*	*60%*
*Non-OECD share***	*46%*	*60%*	*63%*	*70%*	*63%*	*70%*	*63%*	*69%*
CO_2 emissions (Gt)	23.2	31.6	34.2	44.1	33.1	36.7	31.5	18.8

* Includes the traditional use of solid biomass and modern use of bioenergy. ** Excludes international bunkers.

The *WEO-2015* scenarios demonstrate the huge impact that government policies can have on energy-related emissions. The Current Policies Scenario sees the growth in energy-related carbon-dioxide (CO_2) emissions average 1.2% per year over the *Outlook* period, maintaining a broadly consistent pace through to 2040. Total OECD emissions in 2040 are 7% lower than 2013 levels, while non-OECD emissions are more than 65% higher. The growth in emissions is much slower in the New Policies Scenario, but total emissions still fail to peak by 2040.[3] In both scenarios, therefore, the world moves further away from achieving its agreed 2 °C climate goal, but at differing speeds. In the 450 Scenario, the long-standing trend of increasing energy-related CO_2 emissions is quickly halted and emissions then decline by more than 2% per year (on average), to stand at around 19 gigatonnes (Gt) in 2040. Key policy and technology drivers that underpin this change in direction include stronger support for renewables deployment in the power sector, CCS (in power and industry), carbon pricing, more rapid reform of fossil-fuel subsidies, and broader adoption and stronger application of energy efficiency policies and low-carbon forms of transport.

2. *Energy and Climate Change: World Energy Outlook Special Report* is available to download free at *www.worldenergyoutlook.org/energyclimate*.

3. The energy-related aspects of INDCs that had been submitted by 1 October 2015 are incorporated, albeit in a cautious manner, within the assumptions of the New Policies Scenario (see Chapter 1). Such an approach is consistent with the treatment of other announced policies.

SPOTLIGHT

Four pillars to build success at COP21

The weight of the energy sector in global GHG emissions means that any agreement reached at COP21 must have the energy sector at its core. The *Energy and Climate Change: WEO Special Report*, published on 15 June 2015, proposed the following four key pillars to make COP21 a success from an energy perspective:

1. Peak in emissions – set the conditions to achieve an early peak in global energy-related emissions.
2. Five-year revision – review national climate targets regularly to test the scope to raise their ambition.
3. Lock-in the vision – translate the agreed climate goal into a collective long-term emissions goal, with shorter term targets consistent with the long-term vision.
4. Track the transition – establish an effective process for tracking progress in the energy sector.

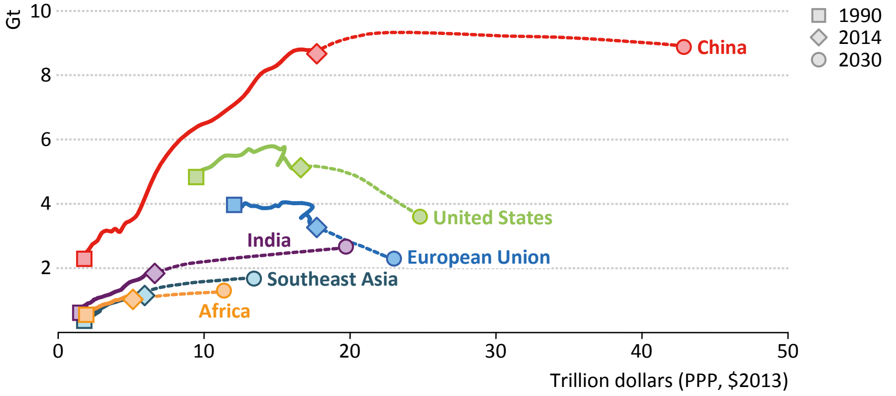
Of these pillars, the first is the most critical. As a means to achieve such a peak in energy-related emissions by 2020, the report put forward a bridging strategy (presented as the Bridge Scenario) based upon five energy sector measures:

- Increasing energy efficiency in the industry, buildings and transport sectors.
- Progressively reducing the use of the least-efficient coal-fired power plants and banning their construction.
- Increasing investment in renewable energy technologies in the power sector to reach $400 billion in 2030.
- Gradually phasing out fossil-fuel subsidies to end-users by 2030.
- Reducing the methane emissions arising from oil and gas production.

The peak can be achieved using only proven technologies and policies, and without changing the economic and development prospects of any region (i.e. taking any region as a whole, the measures are, at worst, GDP neutral). The measures in the Bridge Scenario apply flexibly across regions, with energy efficiency and renewables as key measures worldwide. For countries that have submitted their INDCs, the proposed strategy identifies possible areas for over-achievement. Their adoption would be insufficient, alone, to put the world on track for reaching the 2 °C target; but they would put the world on a course consistent with the later adoption of further emissions reductions. They would lock-in recent trends that decouple economic growth from emissions growth in some regions and broaden that trend (Figure 2.2).

The second pillar addresses the need for climate pledges for COP21 to be viewed as the basis from which to create a process of increasing ambition. It advocates a five-year review cycle to test the scope for further action. Both the situation and the available solutions are evolving rapidly: the world's shrinking "carbon budget" means that no promising new action should be deferred, while the pace of energy sector innovation makes a five-year cycle a reasonable basis for reviewing national targets.

Figure 2.2 ▷ **Energy-related CO_2 emission levels and GDP by selected region in the Bridge Scenario**



Note: PPP = purchasing power parity.

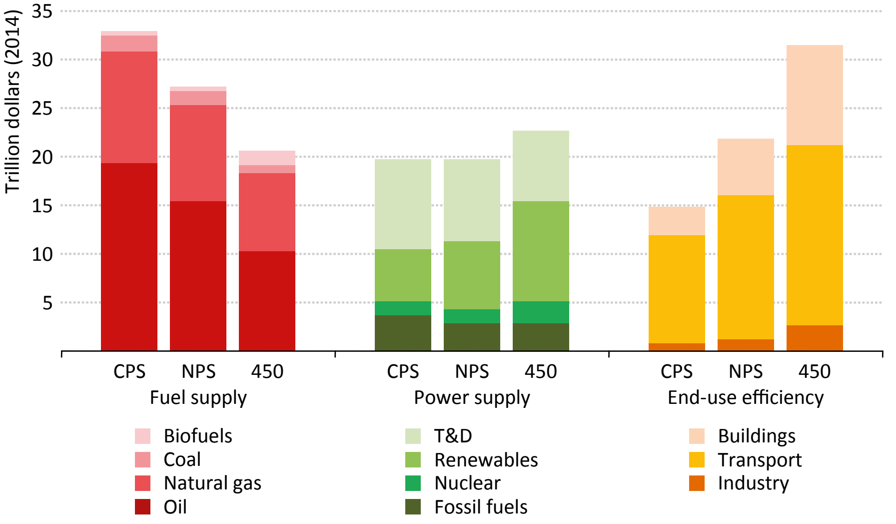
As a third pillar, the goal of keeping the increase in long-term average global temperatures to below 2 °C should be complemented by a long-term GHG emissions target, making it more straightforward to apply in the energy sector. Such a target would help anchor future expectations, guide investment decisions, provide an incentive to develop new technologies, drive needed market reforms and spur the implementation of strong domestic policies, such as carbon pricing.

The fourth pillar is that the COP21 agreement should establish a strong process for tracking progress in the energy sector. Tracking national progress would both provide clear evidence of results, reassuring the international community that others are acting diligently, and identify countries that are struggling with implementation, enabling assistance to be provided if needed.

Since its release, the *WEO Special Report* and the four pillars have been endorsed by a range of senior government and energy sector stakeholders, including the United Nations Framework Convention on Climate Change (UNFCCC) Secretariat and the French Presidency of COP21. The UNFCCC has utilised the analysis when conducting their appraisal of submitted INDCs. An update of the *WEO* analysis on the energy and emissions impact of INDCs was also released in October 2015, taking into account all of the latest submissions. Finally, the *WEO Special Report* and its INDC analysis are to be key contributions to the IEA's Ministerial meeting on 17-18 November 2015.

Across the *WEO* scenarios, the main impact of government policies is not to change the scale of global energy investment, but rather the balance across fuels and sectors, and across supply and demand (Figure 2.3). Total investment in fossil-fuel supply varies significantly across the scenarios, mainly due to shifts in oil and gas investment that stem from changes in demand levels and the underlying costs. Investment in coal supply declines across scenarios, but accounts for only around 2-3% of total fuel supply investment. Investment in fossil-fuelled power generation capacity differs across scenarios by less than might be expected, as CCS features more prominently in the 450 Scenario, serving as a form of asset protection strategy. By 2040, around 5 Gt of energy-related CO_2 emissions are captured annually in this scenario (around 60% in the power sector, followed by industry). Investment in nuclear power generation is around 65% higher in the 450 Scenario than the Current Policies Scenario, but remains concentrated in a relatively small number of markets. Significant investment in renewables-based power supply occurs across a much larger number of markets, and strengthens across the scenarios. The investment decisions made by energy consumers will have a huge impact on the scale and makeup of future demand. In recent years, relatively high energy prices and rising spending on energy have inspired more focus on energy efficiency in many countries with related investment increasing in all scenarios.[4] The majority is spent on improved efficiency in transport (split fairly evenly between road and non-road transport), a smaller share on improved efficiency in buildings (mainly insulation, appliances and lighting) and the remainder is in industry.

Figure 2.3 ▷ Cumulative world energy sector investment by sector and scenario, 2015-2040



Note: CPS = Current Policies Scenario; NPS = New Policies Scenario; 450 = 450 Scenario; T&D = transmission and distribution.

4. Energy efficiency investment is the expenditure on a physical good or service that delivers the equivalent energy service and leads to future energy savings, compared with the energy demand expected otherwise.

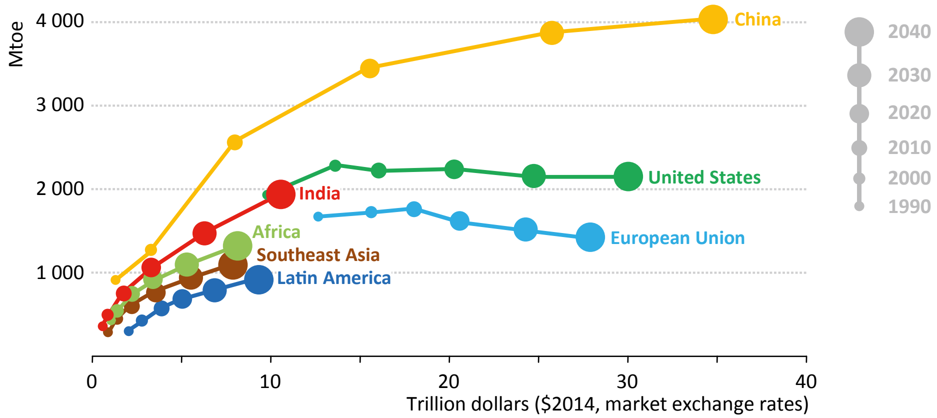
Energy trends in the New Policies Scenario

Energy demand

Events of the last year, coupled with emerging and long-standing socio-economic trends, have changed many aspects of the *Outlook*, but have not altered the overall view of a world whose appetite for energy continues to grow through to 2040. In the New Policies Scenario, global primary energy demand increases by nearly one-third between 2013 and 2040 to reach 17 900 Mtoe. The annual average rate of growth in primary energy demand slows over time: from 2.5% in 2000-2010, it falls to 1.4% in the current decade, 1% in the next and below 1% in the 2030s. A deceleration of global economic and population growth, coupled with more robust energy efficiency and other policies all play a role, particularly the slowing of economic expansion in some key economies (such as China).

The link between economic growth and energy demand weakens over time in the New Policies Scenario, reflecting the changing nature of economic development (Figure 2.4). More markets approach a saturation point in demand for energy services and more energy efficient technologies are adopted, together with policies that allow these services to be provided more effectively. Many economies also continue to undergo structural change, either in the form of a transition towards less energy-intensive forms of economic activity (i.e. services and light industry), such as in China, or industrialisation, such as in India.

Figure 2.4 ▷ Primary energy demand and GDP by selected region in the New Policies Scenario, 1990-2040



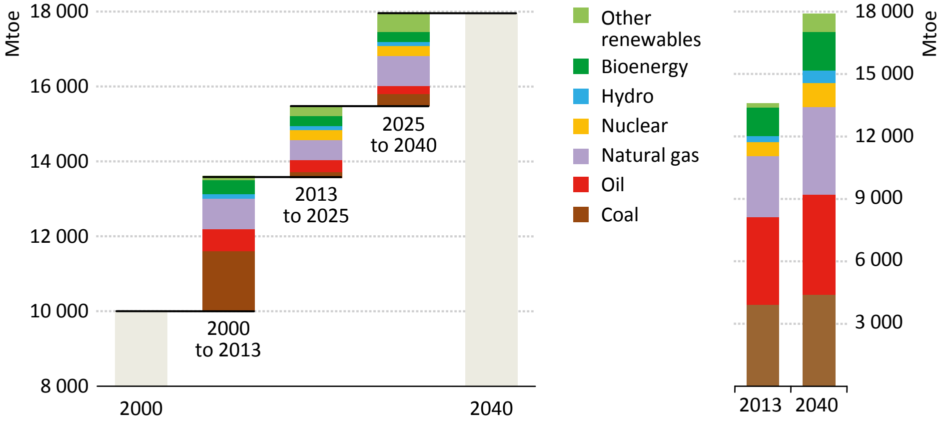
In the case of China, energy consumption has grown at a pace close to that of economic growth in recent decades, but there is an increasing divergence over the *Outlook* period. India traces a similar but less energy-intensive industrial path, relative to its overall economy. At their very different stage of economic development, the United States and the European Union have already experienced significant deindustrialisation, with services playing a much greater role in economic growth and energy efficiency policies being implemented across all sectors. In the New Policies Scenario, the US economy continues to grow, but primary energy demand remains relatively stable in absolute terms, while, in the European Union, energy demand falls while the economy continues to expand.

The world's population has doubled in a little over 40 years and is projected to expand by one-quarter to reach nine billion people in 2040; but the weight of this growth moves away from the largest global centre of energy demand growth (Asia) and towards regions that currently have very low levels of energy use (led by Africa). The world average of per-capita energy demand remains close to existing levels in the New Policies Scenario, but masks a large disparity across regions (low but rising in much of Asia, Latin America and others; high but declining in Canada, United States etc.), which narrows only slowly over time.

Outlook by fuel

In the New Policies Scenario, primary energy demand for all fuels grows through to 2040 (Figure 2.5). Of this growth, renewables collectively account for 34%, natural gas for 31%, nuclear for 13%, oil for 12% and coal for 10%. Non-hydro renewables and natural gas see growth accelerate after 2025, while demand growth for oil slows notably over time and for coal it stays relatively low throughout the projection period. By 2040, oil and coal collectively relinquish a 9% share of the global energy mix, while renewables see their share grow (by 5%), as does natural gas (+2%) and nuclear (+2%).

Figure 2.5 ▷ Primary energy demand by fuel in the New Policies Scenario



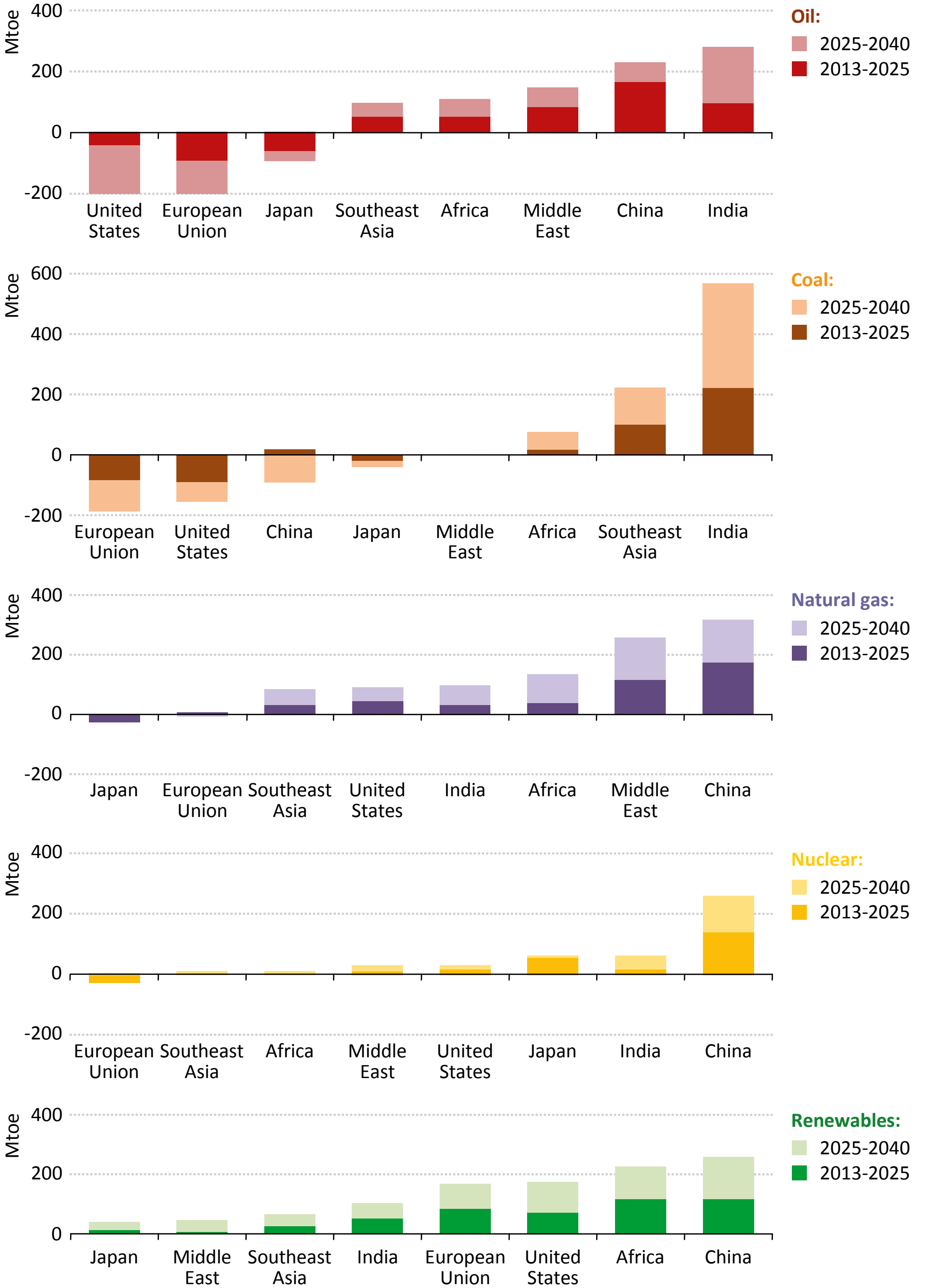
Note: The level of nuclear in 2013 was slightly lower than in 2000.

World **oil** demand increases by 15% in the New Policies Scenario, reaching 103.5 million barrels per day (mb/d) in 2040 (see Chapter 3). Demand growth slows gradually over time, from an average of around 0.85 mb/d per year to 2020 to around 0.4 mb/d thereafter. A boost to demand in the near term, stemming from low oil prices, is progressively counter-balanced by a combination of lower economic growth expectations in some key economies, the impact of efficiency and emissions policies and, over time, a rebound in oil prices reflecting a cut in capital investment by the oil industry. In a scenario where oil prices stay lower for longer (the Low Oil Price Scenario in Chapter 4), global oil demand is 3.7 mb/d higher than the New Policies Scenario in 2040 (over 107.2 mb/d), mainly as a result of higher transport demand.

Oil demand becomes even more concentrated in the transport and petrochemicals sectors in the New Policies Scenario, as its use continues to be backed out of power generation (from already low levels) and buildings in favour of cheaper or otherwise more desirable alternatives. Transport demand for oil grows by around 11 mb/d over the *Outlook* period, with road transport accounting for 60% of this increase. Demand for diesel (led by trucks in Asia) is the main source of growth, with use of diesel overtaking gasoline in the mid-2030s. Gasoline use peaks at around 24 mb/d in the early-2030s and then falls slightly as growth in non-OECD markets slows and the decline in OECD markets dominates. Strong demand for petrochemical feedstocks, which goes from 10 mb/d in 2013 to 16 mb/d in 2040, pushes up naphtha and ethane consumption (in the Middle East, China and elsewhere), while aviation demand does the same for kerosene. Industrial oil demand (beyond petrochemicals) remains relatively unchanged at a global level, as does the mix of oil products used. Oil use in buildings declines gradually over time, mainly due to lower diesel consumption, but is still 5.8 mb/d in 2040. In the power sector, oil demand continues its long-term decline, as countries either shift to alternative forms of generation (mainly in the Middle East) or return to them (such as nuclear power in Japan). As transport and petrochemicals are projected to be key drivers of future oil demand trends, so policies around efficiency and modal change in transport, and recycling of petrochemical products could be particularly important. For instance, while fuel-efficiency standards for cars are now common, they remain rare for freight transport. The aviation and shipping sectors are working on international agreements to improve their fuel efficiency, but progress has been slow.

The world's largest oil consumer – the United States – experiences one of the world's largest reductions in oil demand over the *Outlook* period (the largest reduction when measured in energy-equivalent terms) (Figure 2.6), with consumption declining by around 4 mb/d (around 25%). This is mainly due to the strengthening fuel-efficiency standards for passenger vehicles in transport (CAFE standards) and the recent extension of standards for heavy-duty vehicles beyond 2018. India is projected to experience the largest increase in oil demand of any country in the world (6 mb/d), followed by China (5 mb/d). China overtakes the United States as the world's largest oil consumer soon after 2030, but this is accompanied by demand growth slowing to a crawl by 2040 (when oil demand reaches 15.3 mb/d), as population growth and vehicle sales slow and fuel-efficiency standards have a greater impact. Oil use in Asia as a whole grows to more than 35% of the world total by 2040. Having dropped below China in 2015, oil demand in the European Union falls below that of the Middle East around the mid-2020s and of India in the early-2030s. In the EU, oil demand reaches 6.6 mb/d in 2040, a level similar to Latin America or Southeast Asia at that time. Tighter energy efficiency policies, coupled with the backing-out of oil in power generation, see oil use in Japan drop by nearly half by 2040. In the Middle East, oil demand grows by 3.7 mb/d and the region remains one of the largest oil users on a per-capita basis.

Figure 2.6 ▷ **Change in demand by fuel and selected region in the New Policies Scenario**



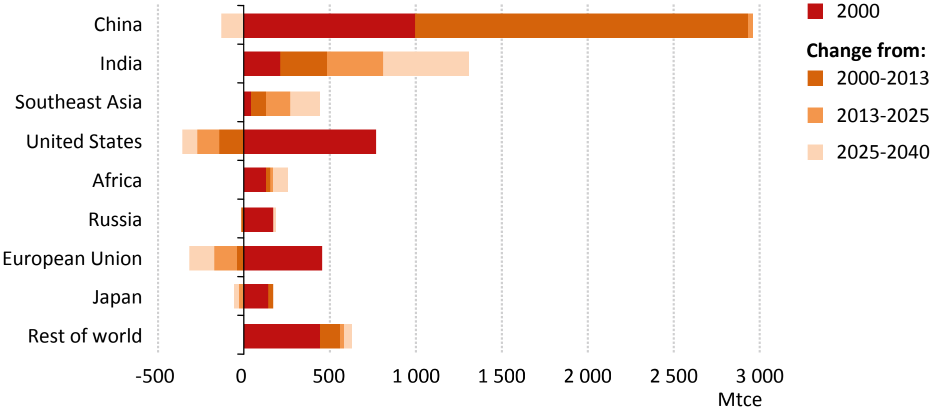
Note: The change in demand through to 2040 is the sum of the two time periods shown.

In the New Policies Scenario, global **coal** demand grows by around 10% by 2040, to exceed 6 300 million tonnes of coal equivalent (Mtce), reflecting the net outcome of declining or stable demand in some markets and growing demand in others (see Chapter 7). All of the growth in demand is for steam coal (up nearly 20% to 2040), with the use of coking coal ending 17% lower than 2013 levels and lignite 13% lower. The power sector accounts for the majority of the increase in coal use and continues to account for over 60% of world coal consumption. Coal's share of global electricity generation drops from 41% in 2013 to 30% in 2040, but this hides a major disparity between developing Asia (where it goes from 68% to below 50%) and the rest of the world (from 27% to 13%). Industry accounts for much of the remaining growth in coal demand, resulting from higher levels of industrialisation in India, Indonesia and other parts of Asia (excluding China). Meanwhile, coal use in buildings drops by nearly 30%, as households (mainly in China) move to cleaner burning fuels. Coal input to coal-to-liquids plants grows to 110 Mtce in 2040, led by parts of Asia and southern Africa, as they seek to generate additional revenues from their coal reserves.

The single largest energy demand growth story of recent decades is near its end. Recent years have seen a marked slowdown in global coal demand growth, led by China, and, in the New Policies Scenario, China's coal use is projected to have all but reached a plateau, that is broadly maintained through to 2040 (Figure 2.7). Economic and energy trends appear to bear out China's transition to a so-called "new normal", with economic growth rates moderating and economic activity shifting to a greater emphasis on services and domestic consumption. In the New Policies Scenario, coal demand in China's power sector is tempered, but still increases by 14% before levelling-off in the mid-2030s. This growth is offset by changes in industrial coal use, which falls by more than 35% by 2040. These trends bring forward to the very near term a plateau that was, in *WEO-2014*, expected around 2020, at levels only a few percent higher than today. While China's coal market supremacy does not disappear, its dominant role in the growth of global coal demand is taken over by other countries in Asia. India's appetite for coal leads the growth picture, both in the region and globally, and it soon overtakes the United States to become the world's second-largest consumer (though its demand is, at this stage, only about one-fifth that of China). India's industrial sector sees coal demand more than triple by 2040, reflecting a greater focus on the industrialisation of its economy, with the government having stated its intention to boost the share of manufacturing in overall economic output. Southeast Asia, led by Indonesia, but also Viet Nam, Philippines and Malaysia, sees total coal demand more than triple over the projection period. By 2040, Asia is projected to account for four out of every five tonnes of coal consumed globally (in equivalent terms).

In contrast, coal demand declines in almost all OECD regions. Coal demand in the United States, peaked in 2005 and has since fallen by more than one-fifth. This trend continues in the New Policies Scenario, as the United States registers one of the largest drops in demand over the *Outlook* period, with consumption ending more than one-third lower than 2013 in 2040. The decline is driven by a combination of low natural gas prices (which encourage coal-to-gas switching), increased renewables-based power generation capacity and regulations governing power sector emissions. By the end of the *Outlook* period, coal use in the European Union is barely more than one-third of 2013 levels. The European Union, the regional home of the original industrial revolution, relies on coal for only 7% of its primary energy mix in 2040 and 6% of power generation (down from 28% today).

Figure 2.7 ▷ Coal demand by region in the New Policies Scenario



Note: Coal demand in 2040 is the sum of the time periods shown.

In 2014, **natural gas** markets continued to demonstrate significant diversity across regions, with strong natural gas demand in the United States, the Middle East and China, and a weak market in Europe. In the New Policies Scenario, the global market for natural gas expands by 47% to reach 5 160 billion cubic metres (bcm) in 2040, registering steady growth of around 1.4% per year and coming close to rivalling coal as the second-largest fuel in the energy mix (see Chapters 5 and 6). In almost all regions, power generation is the largest user of natural gas and the main driver of demand growth, although natural gas is also used more extensively in industry in some markets (Middle East, China) and starts to make a dent in road transport in some cases. Despite this, the global *Outlook* for natural gas is a little less golden than last year – around 220 bcm lower in 2040 – reflecting a combination of efficiency policies, more sluggish electricity demand in some (mainly OECD) markets and its ongoing rivalry with other fuels and technologies.

Non-OECD markets account for 85% of the growth in global natural gas demand in the New Policies Scenario, with the largest increases occurring in China and the Middle East. Demand almost doubles in the Middle East making it the second-largest natural gas consumer in the world and the largest consumer in power generation. Latin America (Brazil, Argentina), Africa (Nigeria, Tanzania and others) and India all see natural gas use grow, but at varying rates. The United States remains the world's largest natural gas consumer, demand increasing by 15% to reach 850 bcm in 2040. In the European Union, there is every sign that natural gas use peaked in 2010. In the New Policies Scenario, demand returns to the (lower) 2013 levels only as 2025 approaches and flattens out at around that level. LNG demand in Japan remains robust in the near term but, in the longer term, it is squeezed out of the power sector by the restart of nuclear capacity and the growth of renewables.

In the New Policies Scenario, **renewables** meet around 35% of the total growth in primary energy demand, driven by a combination of supportive government policies and technological advances that help to improve their competitive stance (see Chapter 9). By 2040, renewable energy accounts for one-third of total electricity generation, one-sixth of heat demand and more than 5% of all transport fuel consumption. Biofuel blending mandates are now in place in around 60 countries and, in the New Policies Scenario, demand for biofuels in transport is projected to triple over the *Outlook* period, exceeding 4 mboe/d by 2040. The United States (targeting 36 billion gallons of renewable fuels by 2022), Brazil (biofuel blending mandate recently increased to 27%) and the European Union (targeting 10% of transport energy from renewable sources by 2020) continue to be the key markets (all of them more than double in size), with China and India also expanding the use of biofuels over time. In 2040, the consumption of bioenergy for cooking and heating still accounts for a large share of the use of renewable energy in the buildings sector (especially in Africa and parts of Asia), with the electricity consumed from rooftop solar photovoltaics (PV) a noteworthy complement.

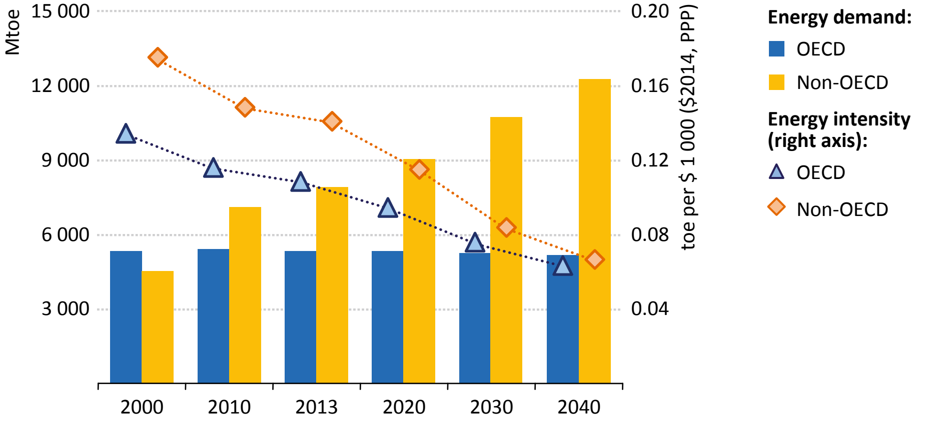
The world continues to electrify, with **electricity** demand growing by more than 70% by 2040 (see Chapter 8). Non-OECD markets account for more than 85% of the growth, led by China (one-third of the global increase), followed (some way behind) by India, Southeast Asia, Africa, the Middle East and Latin America. The European Union and Japan both see electricity use grow by less than 10% to 2040. Total non-OECD electricity demand is double that of the OECD countries by 2040, but per-capita demand remains much lower in most cases. The means by which electricity demand is met is covered in subsequent sections.

Regional trends

Regional energy trends (and within regions) are already widely diverse and they continue to be so in the New Policies Scenario. The shift in the weight of world energy demand towards Asia and, more broadly, to emerging economies, masks strong demand growth in some markets and demand reductions in others. Fossil fuels are powering progress in some countries, while others are reducing this reliance. Renewables have a bright future in most markets, but some rely on wood and charcoal, while others use solar panels and wind turbines. Some have discarded the nuclear option, while others pursue a nuclear policy or, at least, keep their options open. Per-capita energy use also differs hugely, with, for example, each person consuming more than ten barrels of oil per year in some parts of the world (on average) and ten people consuming less than one barrel in some others.

Non-OECD markets drive all of the growth in world primary energy demand from 2013 to 2040, their consumption ending 55% higher in the New Policies Scenario (Figure 2.8); but average per-capita levels in non-OECD countries are still only around 45% of the OECD average at that time. Aggregate OECD energy demand peaks by 2020 at levels little higher than today, before falling and ending 3% lower than today. By 2040, the share of world energy demand accounted for by the OECD has shrunk to 30% (having been 54% in 2000). The United States drops to 12%, OECD Europe to below 9%, Japan to 2%; collectively, they are broadly on a par with China (22%). Looked at by fuel, non-OECD demand has overtaken that of the OECD for coal (1990), hydropower (early-2000s), natural gas (2008) and oil (2012) and is projected to do so in solar PV (mid-2020s) and wind (late-2030s). The OECD's share of global demand for coal drops to just 14% in 2040, for oil it drops from just under half to around one-third and for natural gas it drops from 47% to around 35%.

Figure 2.8 ▷ Primary energy demand and energy intensity of GDP in the New Policies Scenario



Note: PPP = purchasing power parity.

In the New Policies Scenario, the economy of the **United States** expands by more than 75% as the population grows by nearly 20%, but primary energy use falls slightly from 2013 levels, standing at just above 2 100 Mtoe in 2040 (Table 2.2). As a result, the United States is producing 80% more economic output per unit of energy input at that time. The share of fossil fuels in the energy mix drops by 10% (mainly coal, with natural gas increasing), while renewables expand considerably (led by wind, solar PV and biofuels). Oil use drops by one-quarter (around 4 mb/d) by 2040, retreating to levels last seen before a US astronaut first set foot on the moon in 1969. This has a positive impact on energy security and the trade balance, reducing the net oil import bill from $275 billion in 2013 to $120 billion in 2040.

Coal demand in the United States declines by around 35% over the *Outlook* period, with a combination of price and policies (such as the Mercury and Air Toxic Standards, Carbon Pollution Standards, the Clean Power Plan and the US INDC for COP21, which targets a 26-28% reduction of GHG emissions in 2025, relative to 2005 levels) contributing to coal's share of electricity generation dropping from around 40% in 2013 to nearer 20% in 2040. In April 2015, the United States generated more of its electricity from natural gas than from coal for the first time (and recorded the lowest CO_2 emissions from the US power sector in more than 25 years); this may be a temporary switch, but is one that is expected to prove a prescient indicator of the future direction for the power sector. Already an important part of the US energy mix, natural gas becomes the largest single component late in the projection period (overtaking oil), accounting for one-third of primary energy demand in 2040. While a combination of lower prices and policies support natural gas demand in the medium term (led by power and industry), this shows signs of moderating in the longer term, as the wholesale price rises and industrial gas use starts to reach saturation. Federal tax credits and state-level renewable portfolio standards help renewables-based electricity to surpass output from coal in the early-2030s. The power sector becomes less carbon-intensive (down 35% by 2040), while electricity demand grows across all end-use sectors.

Table 2.2 ▷ World primary energy demand by region in the New Policies Scenario (Mtoe)

	2000	2013	2020	2025	2030	2035	2040	CAAGR* 2013-2040
OECD	**5 294**	**5 324**	**5 344**	**5 264**	**5 210**	**5 175**	**5 167**	**-0.1%**
Americas	2 698	2 694	2 749	2 721	2 707	2 713	2 746	0.1%
United States	2 270	2 185	2 221	2 179	2 143	2 123	2 125	-0.1%
Europe	1 764	1 760	1 711	1 658	1 620	1 586	1 554	-0.5%
Asia Oceania	832	870	884	885	884	876	866	0.0%
Japan	519	455	434	424	414	406	399	-0.5%
Non-OECD	**4 497**	**7 884**	**9 008**	**9 822**	**10 688**	**11 505**	**12 239**	**1.6%**
E. Europe/Eurasia	1 004	1 139	1 152	1 188	1 231	1 278	1 316	0.5%
Russia	620	715	702	716	735	758	774	0.3%
Asia	2 215	4 693	5 478	6 023	6 592	7 094	7 518	1.8%
China	1 174	3 037	3 412	3 649	3 848	3 971	4 020	1.0%
India	441	775	1 018	1 207	1 440	1 676	1 908	3.4%
Southeast Asia	386	594	718	800	890	983	1 071	2.2%
Middle East	356	689	822	907	1 002	1 089	1 171	2.0%
Africa	497	744	880	969	1 067	1 180	1 302	2.1%
South Africa	111	139	144	149	156	164	172	0.8%
Latin America	424	618	678	735	797	864	932	1.5%
Brazil	184	291	319	351	388	426	460	1.7%
World**	**10 063**	**13 559**	**14 743**	**15 503**	**16 349**	**17 166**	**17 934**	**1.0%**
European Union	1 690	1 624	1 563	1 503	1 455	1 415	1 377	-0.6%

* Compound average annual growth rate. ** Includes international marine and aviation bunkers (not included in regional totals).

In the **European Union**, primary energy demand declines by 15% by 2040 while the economy expands by 55%. In the process, the European Union becomes one of the least carbon-intensive energy economies in the world, having achieved a major reorientation of the energy system. The EU 2030 framework for energy and climate policies sets out targets for a 40% cut in domestic GHG emissions (relative to 1990 levels), the share of renewable energy to reach at least 27% (of final energy consumption) and for energy efficiency savings of at least 27% (relative to a projected reference level for 2030).[5] The EU has also agreed to implement reforms to its Emissions Trading System (EU ETS) to help tackle the surplus of allowances that has been depressing prices.

5. The emissions reduction target is also captured in the EU's INDC for COP21.

Over the *Outlook* period, improved fuel efficiency and the use of alternative fuels helps oil demand in the European Union drop by almost 40% (to 6.6 mb/d). Overall coal demand drops by 65% (continuing a long-term declining trend), as renewables and (to a lesser extent) natural gas reduce its share of the power mix. By 2040, renewables are projected to account for around half of electricity generation in the European Union, assuming that the integration of variable renewables with other forms of supply is successfully accomplished (a challenge for many countries around the world). The EU's Energy Union strategy proposes better interconnection between national markets, aiding the integration of variable renewables and reinforcing energy security more generally. Having dropped for the fourth straight year in 2014, EU natural gas demand never returns to its peak level of 2010 and returns to its 2013 level only in the mid-2020s – remaining close to that level through to 2040 (ending at around 465 bcm). The economic outlook and energy efficiency efforts serve to dampen future EU energy demand. European natural gas import dependence is projected to grow significantly (to over 80%), as domestic production drops more quickly than demand; but new sources of LNG supply permit import diversification.

In the New Policies Scenario, primary energy demand in **Japan** drops by more than 10% to stand at around 400 Mtoe in 2040, while energy intensity – an imperfect proxy indicator for energy efficiency – declines by 1.2% per year, on average. All fossil fuels see significant reductions in power sector demand, as they make room for nuclear (the first restart of a nuclear power plant unit occurred in August 2015, but uncertainty remains around the pace at which the rest of Japan's nuclear fleet will do so) and a major expansion of renewables-based generation, led by solar PV and wind. Japan deployed an additional 7 gigawatts (GW) of solar PV in 2013 and 10 GW in 2014, supported by feed-in tariffs and efforts continue to improve grid interconnection across the country. Overall, renewables grow to account for around 30% of electricity generation in 2040 in the New Policies Scenario (nuclear is around 20% at that time), supporting Japan's INDC target to reduce GHG emissions by 26% in 2030, relative to 2013. Total oil demand declines from 4.3 mb/d in 2013 to 2.3 mb/d in 2040, as its use drops in all sectors (efficiency policies driving a 40% cut in transport demand for oil). Reduced power sector demand results in natural gas use in Japan dropping by around 25 bcm (20%) by 2020, but then remaining relatively stable (at around 100 bcm) through to 2040.

As **China's** economic transformation enters a new phase, so too does its energy sector, with domestic and global implications. The transition from investment-led and export-led growth to one more focused on domestic consumption is becoming clearer (Box 2.1), as are the effects of energy and environmental policies announced in recent years (moving China to a more efficient, less polluting energy system). This economic transition flows through to a slowing of the rate of economic growth (from averaging 10% per year in the last two decades, to around 7% this decade and around 5% in the next), as well as signs that major industrial sectors (steel, cement) may already be at or close to their peak output levels. In turn, China's energy demand growth slows, marked first by the deceleration of the growth in industrial energy demand (Figure 2.9), and an end to growth in its CO_2 emissions (energy sector and process emissions combined) around 2030 (consistent with its INDC target).

Box 2.1 ▷ China's energy data in the balance

The IEA uses official data published by the Chinese National Bureau of Statistics (NBS) to produce its energy statistics for China. In 2015, the NBS postponed its scheduled spring release of energy data for 2013, so as to allow it to integrate the findings from a national economic census covering all years since 2000.[6] As a result, the IEA estimated China's energy demand and related CO_2 emissions for 2013, based on available official sources and assumptions on consumption patterns. This estimate is used in *WEO-2015*.

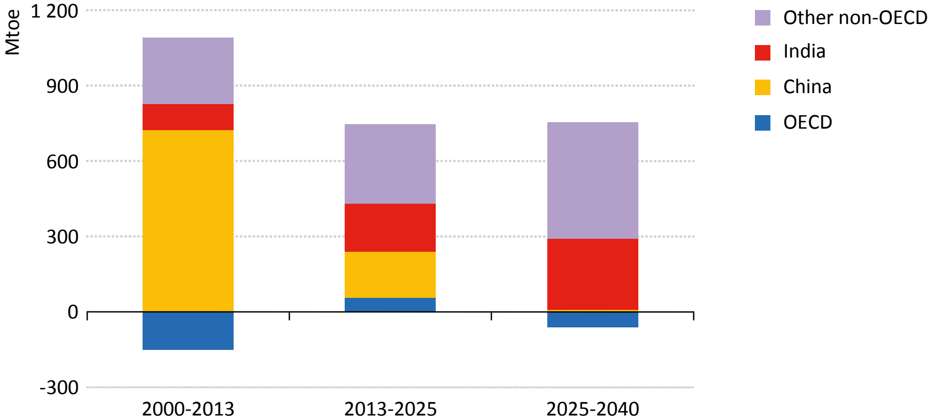
As of end-September 2015, the NBS released new energy balances for the years 2000 to 2013 – a development that is very much welcomed by the IEA. The latest data solves several detailed issues, most importantly the unallocated coal demand that has appeared in recent Chinese energy balances (shown as the "statistical difference") has now been allocated primarily to industry. For 2013, the latest official energy demand data for China is similar to that of the IEA estimate: total primary energy demand is 0.4% lower, with the main changes being coal use (1% lower in energy-terms) and oil use (1.3% higher). However, related CO_2 emissions for 2013 are further apart, with those based on NBS data 5% (430 million tonnes) higher. This is because there are no CO_2 emissions originating from the unallocated coal demand as, following the sectoral approach of the guidelines set out by the Intergovernmental Panel on Climate Change (IPCC), there are no emissions associated with a statistical difference.

While the latest energy data from the NBS is not reflected in *WEO-2015*, it is estimated that doing so would change the projections in the New Policies Scenario only a little: energy demand in China would be 0.9% higher in 2040, with a 2% decrease in coal demand, and a 1.7% increase in energy-related CO_2 emissions in that year.

In the New Policies Scenario, China's primary energy demand grows by one-third, to exceed 4 000 Mtoe in 2040 (22% of global demand at that time). This is a downward revision relative to *WEO-2014* – demand is down by around 4% in both 2025 and 2040 – consistent with emerging signs of economic and energy sector transformation. For most other countries, these revisions would be nationally significant, but not internationally so. For China, the change in cumulative energy demand over the period to 2040 is equivalent to nearly two years' of current US energy demand. Nearly 90% of this shift relates to a downward revision to coal demand, which has now effectively reached a plateau that remains through to 2040 (it is slightly lower than 2013 levels in 2040). China's steel output declines by around 30% over the *Outlook* period and cement output by 40% (most of the decline occurring after 2025), with related energy demand following a similar course. As the engine of growth moves away from heavy industries, the power sector becomes more important in setting the country's energy demand trends, accounting for around 80% of primary demand growth from 2013 to 2040, compared with 45% from 2000 to 2013.

6. See *www.iea.org/statistics*.

Figure 2.9 ▷ Change in world energy consumption in industry in the New Policies Scenario

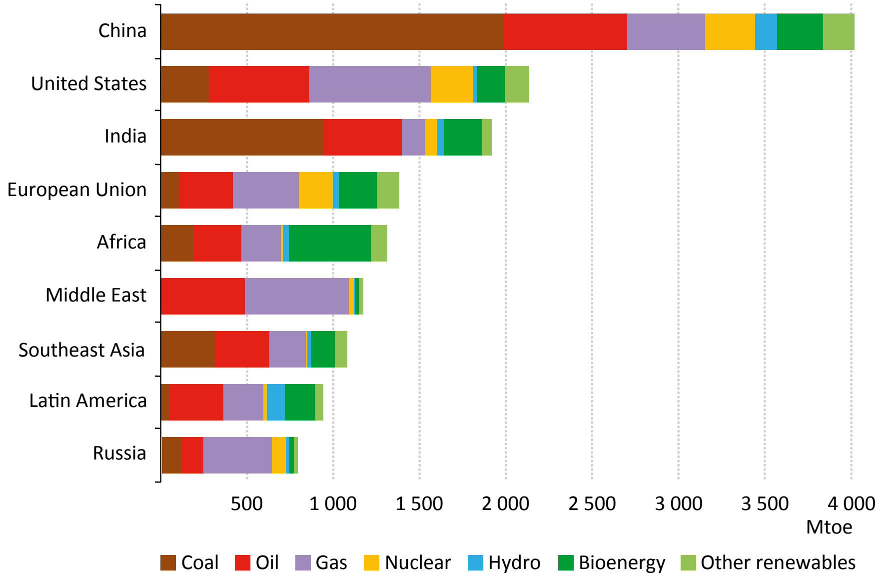


Note: Includes energy demand from blast furnaces, coke ovens and petrochemical feedstocks.

China has a range of supportive policies and targets in place for renewables. By 2040, its renewables-based power generation capacity is projected to be equivalent to that in the United States and the European Union combined (wind capacity having expanded by 300 GW, solar PV by over 245 GW and hydropower by 195 GW). Coal's share of electricity generation drops from three-quarters in 2013 to half in 2040, while wind and nuclear both increase from around 2% to 10%, natural gas increases to 8% and solar (PV and concentrating solar power) to 4%. China's passenger transport fleet grows at a remarkable rate, with the penetration of passenger light-duty vehicles (PLDVs) going from around 70 vehicles per 1 000 people in 2013 to 360 vehicles by 2040 (a fleet of around 510 million vehicles, one-quarter of the world total at that time) and oil use in transport rises from 4.7 mb/d to 9.2 mb/d. The case for natural gas in China is a strong one, given the growth in energy demand, the scope for fuel switching in some sectors and the role it can play in improving urban air quality. China's natural gas use is projected to more than triple by 2040, reflecting major growth in the power sector, but also in industry (partially substituting for coal) and in the residential sector. While natural gas and electricity use grows, the traditional use of bioenergy and coal declines, bringing both a change to the primary energy balance and a greater change in terms of the quality of energy services.

India is the world's number one source of energy demand growth in the New Policies Scenario, seeing consumption of energy services expand rapidly through to 2040. The energy sector makes a critical contribution to India's economic and social goals, including fuelling its burgeoning industrial sector and providing access to electricity. India's large (and growing) population, low (but increasing) levels of energy use per capita and high levels of economic growth are all powerful drivers serving to push energy demand 55% higher than 2013 by 2025 and two-and-a-half-times higher by 2040, when it reaches 1 900 Mtoe (around 40% higher than the European Union at that time) (Figure 2.10). See Part B for more on India's energy outlook and the domestic and global implications.

Figure 2.10 ▷ **Primary energy demand by selected region in the New Policies Scenario, 2040**



In the New Policies Scenario, primary energy demand in **Southeast Asia** rises by 80%, as the regional economy more than triples in size.[7] Per-capita energy demand rises by around 45% to 2040, and yet remains low by international standards. This is one of the few regions in the world in which fossil fuels increase their share in the primary energy mix: coal demand more than triples (in Indonesia it quadruples), while natural gas use grows by 65% and oil by 45% (reaching 6.8 mb/d). The share of renewable energy in the mix declines, as the decrease in bioenergy use more than offsets the increase in geothermal, hydropower, wind and solar PV. This is despite some notable targets for renewables within the region, such as Indonesia's aim to have 23% of primary energy from new renewable sources by 2025. Electricity demand nearly triples, to around 2 000 terawatt-hours (TWh) in 2040, with the generation mix shifting towards coal (50% in 2040) and renewables, coal often being favoured because of its price advantage and the abundance of indigenous supply in some countries. Industrial energy use doubles, and the role of natural gas grows. Energy demand in transport is 60% higher by 2040, but growth in oil use slows over time, as subsidies are phased out, vehicle efficiency improves and mass transit projects are completed.

Russia's near-term economic outlook has been materially affected by the combination of lower oil prices and the imposition of sanctions, which constrain its ability to access international capital markets and technology. In the New Policies Scenario, Russia's primary energy demand increases by 8% to 2040, with its population declining by around

7. The IEA's *Southeast Asia Outlook: World Energy Outlook Special Report* (IEA, 2015b) is available to download free at *www.worldenergyoutlook.org*.

15 million over the same period. Inefficient capital stock and cold weather mean that Russia's per-capita energy use remains among the highest in the world. While energy efficiency policies help improve what is today a relatively poor picture, this improvement does not come as rapidly as in some other regions. Oil demand remains similar to current levels, at around 3 mb/d in 2040. Already the most important fuel in the Russian energy mix (accounting for more than half of its total primary energy demand in 2013), natural gas also sees demand in 2040 (around 465 bcm) at close to 2013 levels, albeit with fluctuations over the *Outlook* period. A gradual increase in the efficiency of Russia's gas-fired power generation fleet means that its fuel use in this application falls by around 15% (nearly 50 bcm) by 2040. This is offset partially by rising natural gas use in buildings, industry and transport.

Driven by the region's own energy wealth, increasing incomes and very low end-user energy prices in some countries, primary energy demand in the **Middle East** grows by 70% in the New Policies Scenario, exceeding 1 170 Mtoe in 2040. The outlook within the region varies by country, and hinges critically on respective resource endowments, resulting in a dividing line between energy importers and major exporters. For exporters, lower prevailing oil and natural gas prices have impacted on their major source of revenue, reducing expected economic growth and, for some, meaning that they have to contend with significant fiscal deficits. However, lower prices do not persist in the New Policies Scenario, relieving a key source of pressure and, overall, do relatively little to derail the region's position as a major source of future energy demand growth. The expected lifting of sanctions gives a boost to Iran's economy and, as a consequence, its energy demand but, in contrast, conflicts within Iraq and Syria weigh heavily on their energy outlooks in the near term. By 2040, some countries have expanded their use of renewables and nuclear (Saudi Arabia, United Arab Emirates and others), but domestic oil and natural gas still meet more than 90% of total primary energy demand in the Middle East at that time. By 2040, regional oil demand has increased from 7.4 mb/d to over 11 mb/d (mainly in road transport and petrochemicals, while decreasing in power generation) and natural gas demand grows from 420 bcm to 740 bcm (mainly in power generation, industry and buildings).

In the New Policies Scenario, primary energy demand increases by more than half in **Latin America**, to 990 Mtoe in 2040, but the region succeeds in expanding the already relatively high share of renewables in its energy mix (to around 35% in 2040). Oil's share of the energy mix drops by ten percentage points, as demand for other fuels grows much more quickly (mainly natural gas and renewables). Brazil's multi-year drought is currently having a major impact on its power sector, reducing hydropower output (the backbone of its power sector) and increasing reliance on other forms of generation to fill the gap, notably gas-fired power generation (which has tripled in recent years). Over the *Outlook* period, Brazil continues to expand its hydropower capacity, but also broadens its generation mix somewhat, with increasing supply coming from natural gas and wind, the latter growing to 13% of the generation mix by 2040. Across Latin America as a whole, biofuels consumption (led by Brazil) increases from 0.3 mboe/d to 1 mboe/d in 2040, meaning that the region continues to be one of the world leaders in biofuels use; but biofuels are still far from supplanting oil products as the dominant transport fuel.

Africa's energy system expands rapidly (growing by 75% to 1 300 Mtoe in 2040), to meet the needs of a population that grows by 80% and an economy that expands to more than three-times its current size. The IEA's *Africa Energy Outlook: WEO Special Report*[8] highlighted the plight of a region that is rich in energy resources but often very poor in energy supply for its citizens (IEA, 2014c); and, while much of North Africa is on a more positive track, the majority of sub-Saharan countries have yet to see even close to half of their population attain access to modern energy. The largest part of Africa's energy mix is the traditional use of bioenergy (cooking and heating) and demand for this grows by more than 10% in the New Policies Scenario. Lower oil prices than those projected in *WEO-2014* are a curse for the region's major oil and gas exporters (Libya, Algeria, Nigeria, Angola), while being a blessing for importing countries that often rely on oil products not just for transport but also for electricity. Oil demand grows by 70% to 6.2 mb/d in 2040, while natural gas use grows from 120 bcm in 2013 to reach 285 bcm. Africa's power generation capacity expands rapidly, reaching 565 GW in 2040. The power mix also becomes more diverse, with coal and hydropower being joined by even greater use of natural gas (Nigeria, Mozambique, Tanzania), and major growth in solar power (Morocco, South Africa and others) and geothermal power (Kenya, Ethiopia). By 2040, renewables account for nearly 40% of total power generation capacity in Africa.

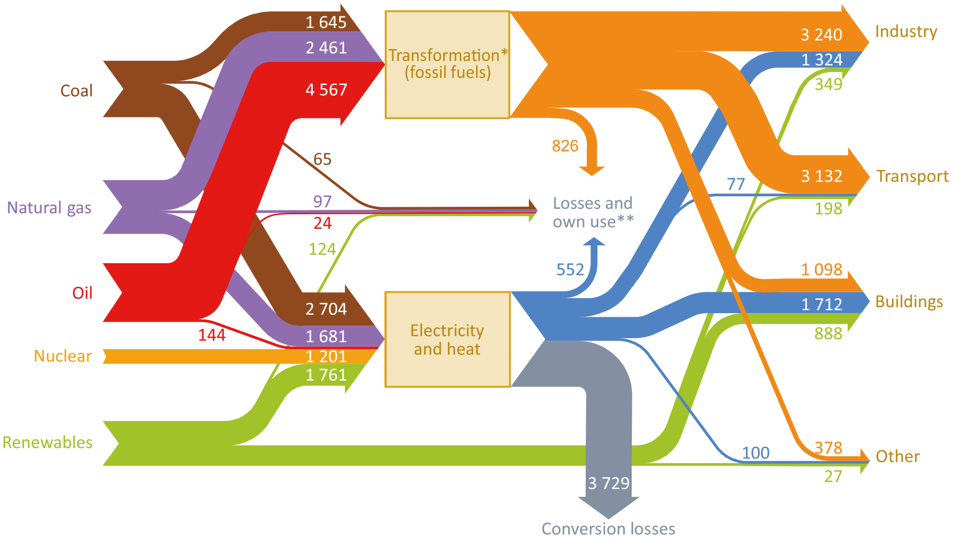
Sectoral trends

Among the end-use sectors, energy demand grows most quickly in **industry**,[9] increasing by more than 40% in the New Policies Scenario to exceed 4 900 Mtoe in 2040 (Figure 2.11). At the global level, there is rising industrial demand for all forms of energy, but electricity and natural gas grow strongly while coal use grows only a little. The huge expansion of infrastructure and economic growth that is expected to occur in many developing countries is the source of much of this industrial energy demand. Approaching half of the global growth occurs in just two countries (India, followed by China) and Asia overall accounts for 60% of the total. Within the OECD, the United States and Canada see relatively modest increases in industrial energy demand, while Japan, Europe and Korea see a decline. China's industrial energy demand continues to dwarf all others, but its economic transformation sees industrial demand growth slow to a stop by the mid-2030s. There is also an important shift in fuel use in China's industrial sector, with coal consumption declining by more than 35% (360 Mtce), and natural gas and electricity increasing to fill the gap. In contrast, India's industrial energy demand is on a steep upward trajectory and by 2040 it is close to overtaking China as the world's largest consumer of coal in industry. The Middle East and China lead the growth in natural gas use in industry, while the United States sees some increase in the near term on the back of relatively low prices. Globally, oil demand in the petrochemicals sector grows by 5.7 mb/d to 2040.

8. The IEA's *Africa Energy Outlook: World Energy Outlook Special Report* is available to download free at *www.worldenergyoutlook.org.*

9. Unless otherwise stated, energy demand in industry includes blast furnaces, coke ovens and petrochemical feedstocks.

Figure 2.11 ▷ World energy demand by fuel and sector in the New Policies Scenario, 2040 (Mtoe)

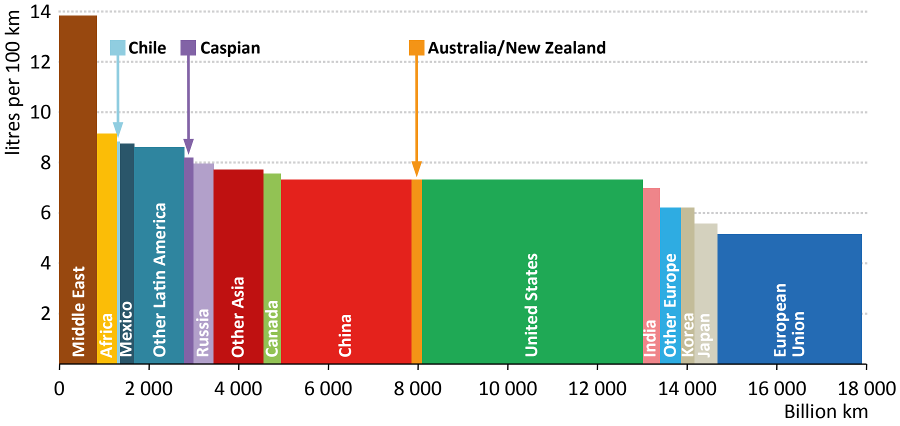


* Transformation of fossil fuels (e.g. oil refining) into a form that can be used in the final consuming sectors. This excludes energy demand in blast furnaces and coke ovens, which is attributed to industry. ** Includes fuel consumed in oil and gas production, transformation losses and own use (except blast furnaces and coke ovens), generation lost or consumed in the process of electricity production, and T&D losses.

Note: Other includes agriculture and other non-energy use (mainly asphalt and lubricants).

Primary energy demand for **transport** reaches 3 400 Mtoe in 2040, with 85% of this being met by oil. While the coverage of fuel-efficiency standards for new passenger car sales has continued to broaden (and heavy-duty vehicles in a few countries, such as the United States and China), the road transport sector remains the leading source of global oil demand growth in the New Policies Scenario. Fuel-efficiency standards help to reduce oil demand growth in all regions, but there continues to be a significant disparity in the average efficiency of national car fleets, the number of vehicles on the road and the vehicle kilometres driven (Figure 2.12). For example, the United States and China are projected to have fleets with similar levels of efficiency (on average) in 2025, but the US vehicle fleet travels much further (despite the size of the fleet being smaller than that of China) resulting in higher oil demand. India's passenger vehicle fleet is projected to have a lower efficiency than that of the European Union in 2025, but vehicle kilometres travelled are also much lower. A lower oil price environment has already brought with it the risk that consumer expectations will shift and lead to a trend back towards purchasing larger, less efficient vehicles and/or driving greater distances. However, there are indications that changing demographic and social norms are also influencing transport demand in some markets, with the driving age population starting to shrink, fewer young people learning to drive, and those living in urban areas driving shorter distances and using car-sharing schemes. Beyond road transport, aviation is the second-largest contributor to sectoral oil demand growth, with consumption growing by two-thirds to reach 9 mb/d in 2040 (see Chapter 3).

Figure 2.12 ▷ Average fuel economy of PLDVs and vehicle kilometres travelled by region in the New Policies Scenario, 2025



In relation to other transport fuels, government support for biofuels (often in the form of blending mandates) is assumed to continue and plays an important role in boosting demand to more than 4 mboe/d in 2040 (up from 1.4 mboe/d in 2013). By 2040, road transport still does not account for even 1% of global electricity consumption, only around half the level consumed by rail transport at that time, and certainly much lower than many government targets suggest policy-makers would like it to be. In many cases, cost constraints and consumer preferences are barriers that are only slowly overcome. In the near term, prospects for the use of natural gas in transport are constrained by lower oil prices, but they strengthen in the longer term as oil prices rise once again and, by 2040, natural gas use exceeds 160 bcm (from 43 bcm in 2013).

In the **buildings** sector, higher incomes, a growing population, demographic changes and structural changes in many economies contribute to energy demand increasing by nearly one-quarter in 2040 (to 3 700 Mtoe). In the residential sector, average floor space per capita increases generally (but more rapidly in non-OECD markets) as incomes rise and the number of people per dwelling declines. This helps to push up demand for energy services, such as space heating and cooling. Globally, energy demand for household appliances more than doubles in the New Policies Scenario: in non-OECD markets it more than trebles, while across the OECD it increases by less than 30%. In many OECD markets, saturation effects and the existence of effective energy efficiency standards for larger appliances help restrain growth, but these standards are often not replicated for smaller appliances. In many non-OECD regions, low ownership rates prevailing today and increasing incomes over the projection period mean that demand for energy services is pushed higher though, at the same time, energy efficiency standards remain less common and so do not work to hold back this growth (see Chapter 10). In terms of fuels, the use of natural gas in the residential sector declines in the United States and the European Union (supported by policies to promote better insulation, water heating systems and building codes), but it increases globally, led by China (where natural gas replaces coal or liquefied petroleum gas [LPG]) and the Middle East. Globally, the use of oil products in the residential sector drops by one-quarter and becomes more concentrated in Africa and India. The traditional use of bioenergy also declines, but the improving picture is not uniform.

The world's appetite for **electricity** grows strongly and, in parallel, there is a concerted effort to reduce the environmental consequences of its generation. In the New Policies Scenario, the power sector accounts for 55% of the growth in primary energy demand, its share of the overall energy mix increasing to 42% in 2040. Electricity retail prices are pushed higher, as rising fuel costs and a move to higher cost technologies serve to boost generation costs in most parts of the world (18% higher in the United States in 2040, 14% higher in the European Union, 25% higher in China). But this acts as a limited restraint on what remains a strong upward trajectory in electricity demand (increasing at 2% per year, on average), with incomes typically increasing more quickly than electricity prices (helping to make it more affordable over time). The share of electricity in final energy consumption has doubled since the 1970s and continues to grow in the New Policies Scenario, going from 18% in 2013 to 24% in 2040. The buildings sector is the largest electricity consumer, with demand rising by 75% to 2040, while industrial electricity use grows by two-thirds.

Energy supply

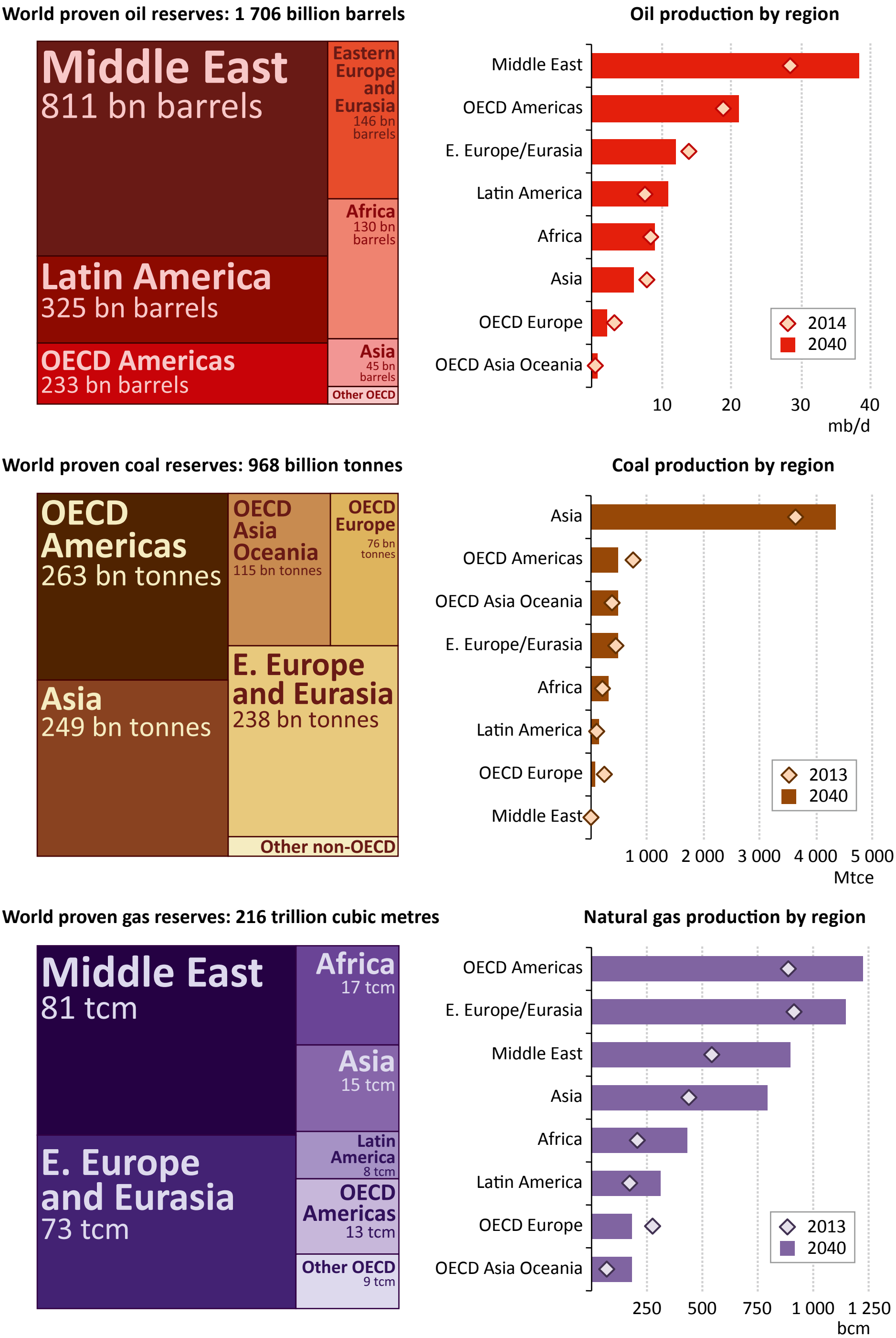
Energy resources[10]

The world's energy resources are plentiful and capable of meeting energy demand far beyond 2040; but many are also dispersed unevenly and they are not all inexhaustible. To bring forth these resources at the scale that is required will demand huge and timely investments and effective execution across global supply chains. Such activities have to be conducted against a backdrop of complexity and uncertainty, as they are buffeted by the prevailing geopolitical winds, the changeable economic outlook, the investment climate and the rapidly evolving technological landscape. While the assessed abundance of energy resources seldom changes dramatically from one year to the next, the circumstances surrounding their successful exploitation never stand still.

Estimated global remaining technically recoverable oil resources stand at around 6 100 billion barrels (as of end-2014). Of these resources, around 2 800 billion barrels are conventional oil (crude oil and natural gas liquids [NGLs]), 1 900 billion barrels are extra-heavy oil and bitumen (EHOB), 1 100 billion barrels are kerogen oil and 350 billion barrels are tight oil (see Chapter 3). Proven oil reserves stand at 1 700 billion barrels, equivalent to 52 years of current production (Figure 2.13). All else being equal, the drop in oil prices should result in some proven reserves being re-categorised as "contingent", but such a revision takes time to filter through to published estimates.

10. Estimates of resources and proven reserves in this section draw on sources including: BGR (2014), BP (2015), Cedigaz (2015), OGJ (2014), US DOE/EIA/ARI (2013), USGS (2012a and b) and IEA analysis. Proven reserves (which are typically not broken down by conventional/unconventional categories) are usually defined as discovered volumes having a 90% probability that they can be extracted profitably.

Figure 2.13 ▷ **Proven reserves and production in the New Policies Scenario**



As of end-2013, the world's proven reserves of coal are estimated to have stood at 970 billion tonnes (BGR, 2014), equivalent to 122 years of production at current rates. Of total proven reserves, around 70% are steam and coking coal and the remainder lignite. Over one-quarter of global coal reserves are located in non-OECD Asia, the main demand centre, with China being the largest single holder in the region (13% of the world total), followed by India (9%) and Indonesia. Significant reserves exist also in the United States (26%), Russia (17%), Australia (11%) and Europe (8%). Total remaining recoverable resources of coal are more than twenty-times the size of proven reserves, making coal by far the most abundant of the fossil fuels. Both coal reserves and resources are distributed relatively widely.

Remaining recoverable natural gas resources are estimated to be 780 trillion cubic metres (tcm), a downward revision resulting from lower estimates of remaining conventional recoverable resources in the Middle East, OECD Europe and Russia. The world's unconventional natural gas resources remain relatively poorly understood and so are subject to future revisions. In addition, at the prices now prevailing, there may be delays in reserves being "proved-up". As of end-2014, proven reserves of natural gas (conventional and unconventional) are estimated to have been 216 tcm, enough to sustain current production levels for 61 years. The largest holders of proven reserves are Russia, Iran and Qatar.

The world's renewable energy resources (including bioenergy, hydro, geothermal, wind, solar and marine) are vast and, if all harnessed, could meet projected energy demand many times over. These resources are also very well spread geographically. In a number of cases, the cost of exploiting them is currently prohibitive, but the share of resources that are economically viable is expected to increase as costs decline, in some cases quickly.

Identified uranium resources are more than sufficient to meet the world's needs through to 2040. They are estimated to be sufficient to meet global requirements for over 120 years, at 2012 rates of consumption (NEA/IAEA, 2014).

Production outlook

Over the last year, discussions of **oil** prices and the role of OPEC in the market have been intense. In short, the absence of an OPEC production cut in response to lower oil prices shifted the onus of finding demand-supply equilibrium onto the broader market. All producing countries and companies have had to consider how to live with reduced revenues, how quickly and how deeply they can cut operating costs and capital investments, and whether lower prices might stimulate a surge in global oil demand. Cost reductions are already evident in the industry, with the IEA's Upstream Investment Cost Index[11] falling by 13% in 2015, relative to 2014 (though investment cuts will, in most cases, take some time to show up as lower production). The oil industry in the United States has been

11. This index reflects prices for cement, steel and other construction materials and equipment, as well as the cost of hiring skilled personnel and contracting drilling rigs and oilfield services.

quick to respond, with strong efforts to cut costs and implement efficiencies in tight oil production, countering expectations that lower prices would precipitate a rapid decline in output in this sector. In the New Policies Scenario, oil production costs are still projected to rise over time, with productivity improvements helping to restrain the inflationary effects of moving to more challenging production areas. Oil prices rise to around $100/barrel in the mid-2020's and go on to reach $128/barrel by 2040.

World oil production grows throughout the *Outlook* period, but slows over time and the geographical focus shifts, primarily from non-OPEC to OPEC countries.[12] In the New Policies Scenario, global oil production increases from 89.5 mb/d in 2014 to 95.3 mb/d in 2025 and exceeds 100 mb/d in 2040 (see Chapter 3).[13] The discovery and development of new fields, and the application of enhanced oil recovery techniques, do not arrest the gradual decline in conventional crude oil production. Despite this, crude oil still accounts for two-thirds of total production in 2040, with an increasing share coming from deepwater offshore fields, such as those in Brazil and the Gulf of Mexico. Increases in NGLs and unconventional oil account for all of the net growth in oil production over the *Outlook* period. NGL additions come mainly from the Middle East, North America, Africa (aided by reduced flaring in Nigeria and Angola) and Russia. Additional output of EHOB comes from Canada and Venezuela. The outlook for tight oil production beyond the United States (Russia, Canada, Argentina, Mexico, China and others) remains relatively limited, reflecting the prevailing market conditions and the non-trivial technical, economic and regulatory challenges still to be overcome. Collectively, tight oil production outside the United States is projected to reach 1.7 mb/d by 2040. Global refinery runs increase by 8.3 mb/d from 2014 to 2040, but there are very different regional trends, with around an 8 mb/d drop in refinery output across the OECD and an increase of 16 mb/d across non-OECD countries.

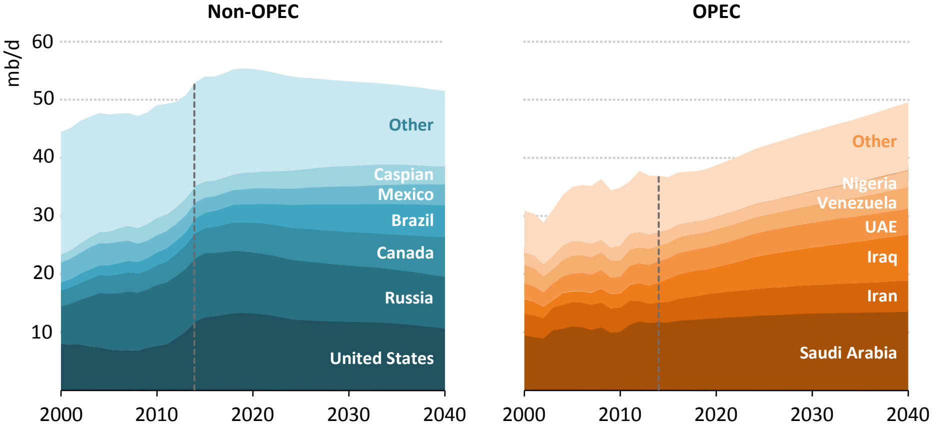
In the New Policies Scenario, there is a clear shift in emphasis back towards a reliance on OPEC countries to fuel oil production growth over the *Outlook*, in contrast to recent trends, where the United States has led the way (Figure 2.14). The effect of investment cuts in non-OPEC countries start to be felt by the end of this decade, with Brazil, Russia and Canada among the most affected (relative to *WEO-2014*). In addition to lower oil prices, each country faces its own specific challenges, such as infrastructure constraints in Canada, capital constraints in Brazil and economic sanctions in Russia. Production in the United States fares better than many may have expected in the lower oil price environment, with tight oil output increasing to 5.1 mb/d by 2020 (before falling to 3.3 mb/d in 2040). Total US oil production (including NGLs) increases to 13.2 mb/d in 2020 before dropping back to 10.6 mb/d in 2040. In aggregate, the remaining non-OPEC producers face a collective decline of 3.8 mb/d from 2014 to 2040, but this masks a mix of ups and downs. Over the *Outlook* period, production rises in Mexico (supported by sectoral reforms), Kazakhstan

12. Numbers shown here are for oil production and so exclude processing gains. World oil supply in 2040 (i.e. including processing gains) is 103.5 mb/d. See Chapter 3 for definitions of oil supply and production.

13. In the New Policies Scenario, oil prices are expected to rebound in the relatively near term, but the demand and supply implications of them staying lower for longer are explored in Chapter 4.

(Kashagan project), Australia (offshore) and Argentina (tight oil), while production levels decline in Europe (United Kingdom and Norway), China (a mix of onshore and offshore, partially offset by some tight oil production), India and Southeast Asia (led by drops in Indonesia[14] and Thailand).

Figure 2.14 ▷ Oil production by region in the New Policies Scenario



As many OPEC countries are highly dependent on oil export revenues, a period of lower oil prices can give rise to serious economic challenges. While some OPEC producers have used the higher oil revenues received in recent years to build substantial financial buffers to protect against such an eventuality (such as Saudi Arabia, Kuwait, Qatar and United Arab Emirates), a number of others have seen the greater part of their revenues go to current government spending. In such circumstances, a significant drop in the oil price can curtail planned government spending, including investment in future oil production. In aggregate, OPEC oil production in the New Policies Scenario increases from nearly 37 mb/d in 2014 to 42 mb/d in 2025 and over 49 mb/d in 2040. Saudi Arabia retains its central position in the global oil market, maintaining its crude production capacity at around the stated 12.5 mb/d target and regaining around the mid-2020s its status as the world's largest producer. The United Arab Emirates (UAE), Qatar (mainly NGLs and gas-to-liquids after 2030) and Kuwait (investments to boost recovery from existing fields) also see increases in production over the *Outlook* period.

Some of the countries with the greatest potential to increase oil production are also those that face some of the biggest challenges in mobilising investment. While the potential may be apparent, this does not necessarily translate easily into actual output growth, given persistent security concerns (as in Iraq), broader political and policy-related questions (as in Iran) and the squeeze on finances that is evident in many countries (such as in Venezuela,

14. In September 2015, Indonesia applied to OPEC to reactivate its membership, but this is not expected to be confirmed until December 2015. For the purposes of *WEO-2015*, Indonesia is included in non-OPEC.

Angola and Nigeria). Despite Iraq's oil production performing strongly over the past year, domestic security challenges and a reported intention to throttle-back upstream investment suggest an increasingly uncertain outlook. In the New Policies Scenario, oil production in Iraq reaches 5.7 mb/d in 2025 and 7.9 mb/d in 2040. The prospective lifting of sanctions helps to reduce uncertainty for Iran and offers the potential of a production renaissance after much-needed remedial work has been completed, and output is projected to reach 4.7 mb/d in 2025 and 5.4 mb/d in 2040. In Africa, Nigeria and Angola have both felt the pain of lower oil prices. In Nigeria, oil output dips slightly to 2020 but then picks up to reach 2.9 mb/d in 2040. In Angola, oil production stabilises around 1.5 mb/d (though it could be higher if there were a breakthrough in the pre-salt areas). In Venezuela, significant financial constraints amplify other sources of uncertainty over the oil production outlook; in the New Policies Scenario, existing production levels are broadly maintained to the mid-2020s (the rise in extra-heavy oil and bitumen output offsetting the decline in conventional oil), but then start to increase gradually.

Coal grew faster than any other major fuel in the last decade, but becomes the slowest growing fuel in the decades to come, with global coal production in the New Policies Scenario increasing by around 10% by 2040 (reaching 6 300 Mtce). The initial challenge facing the coal industry is to tackle existing excess capacity, with coal companies in most regions expected to close mines and restructure their operations. The largest production cuts (in absolute terms) over the *Outlook* period as a whole are projected to take place in the United States where annual output drops by 240 Mtce (35%), as environmental constraints tighten and exports provide only a limited relief valve. Coal production in the European Union sees the largest relative drop (around 70%), as domestic demand declines and it struggles to compete with imports. Australia boosts production by around 30% to meet export demand.

Non-OECD producers generally experience coal output growth in the New Policies Scenario, although at very different rates. China (already the world's largest coal producer by far) sees production stay broadly flat (at around 2013 levels) and then go into a very slow decline from around 2030, ending around 2% below 2013 levels by 2040. The absolute growth in coal production in India is greater than in any other country, serving, in particular, to help meet domestic demand for power generation. India coal output is more than two-and-a-half-times existing levels by 2040 (reaching 925 Mtce), making it easily the world's second-largest producer. The majority of the increase occurs in the period after 2020, when it accounts for more than 90% of global coal production growth. Indonesia also achieves a very large production increase in the New Policies Scenario (almost all after 2020), and becomes the third-largest coal producer around 2030 (reaching 580 Mtce in 2040). While historical production growth in Indonesia was primarily export driven, in the long run additional production will increasingly serve domestic consumers. Southeast Asia as a whole sees its coal production grow by nearly 45% over the *Outlook* period, reaching a level similar to that of the United States today. Coal production in Africa grows by around 40% from 2013 levels by 2040 in the New Policies Scenario (reaching 310 Mtce), led by Mozambique. Latin American production increases by 40% (reaching 120 Mtce), with output continuing to be dominated by Colombia.

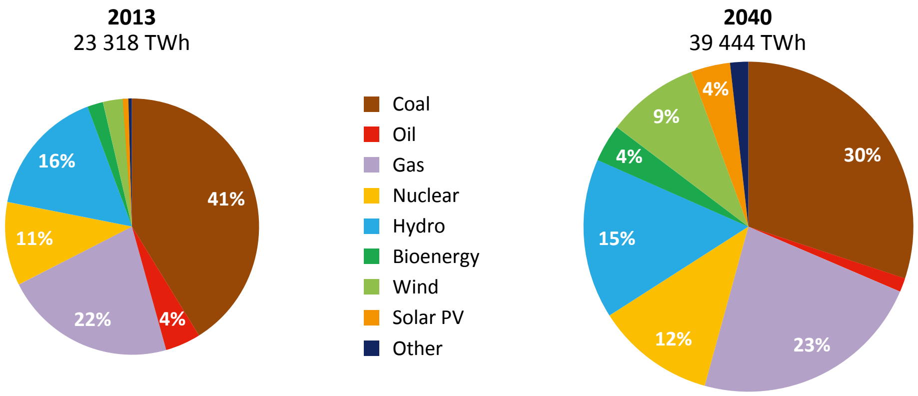
Lower **natural gas** prices are making it more challenging for those trying to make the case for new long-term investments in supply, and some investment decisions have been delayed (especially large-scale, long lead-time projects). However, world natural gas production is not derailed in the longer term, increasing by 47% in the New Policies Scenario to stand just below 5.2 tcm in 2040. Over the *Outlook* period, conventional supply continues to account for the bulk of production, but unconventional supply (shale gas, coalbed methane, tight gas and coal-to-gas) accounts for around 65% of the growth in production. By 2040, unconventional gas production has almost tripled (increasing by more than 300 bcm in each decade) and accounts for nearly one-third of total natural gas production (see Chapter 6).

Natural gas production increases in all major world regions, save one (Europe). In the United States, the world's largest gas producer, robust output growth continues until around the mid-2020s, at which point prices start to deter demand growth. Total output reaches 860 bcm in 2040. Shale gas has grown from being just 6% of US natural gas production in 2005 (and 1% of global output) to 50% of US output in 2014 (and 10% of the global total). In the New Policies Scenario, US unconventional gas production continues its breath-taking performance in the near-term and, by 2020, is greater than the total gas production of any other country in the world (overtaking Russia). With significant expansion of unconventional gas production also occurring in Canada and Mexico, North America retains its position as the global epicentre of unconventional gas production. Elsewhere in the OECD, Australia sees significant growth of natural gas production to 2020, as its wave of seven LNG facilities comes online, but prospects for a second wave have been dented by investment cutbacks: total gas output is 175 bcm in 2040. In Europe, conventional gas output declines in Norway, the Netherlands and the United Kingdom. With few exceptions, Europe's appetite for unconventional gas development appears to have diminished over the past year, due to a combination of poor drilling test results, environmental concerns and moratoria expected to weigh heavily on the potential for future production.

Countries beyond the OECD account for 80% of global natural gas supply growth through to 2040. China's production nearly triples over the *Outlook* period (reaching around 355 bcm) and is heavily reliant on increases in unconventional gas output, which grows steadily, to reach 260 bcm in 2040. While China's unconventional gas resources are estimated to be the largest in the world and policies encouraging their development are in place, considerable geological, technical and market challenges have yet to be overcome. If they were to be overcome, there is considerable upside potential to this projection; but, if not, there is also significant downside risk. In the near term, Russia's gas production is constrained by the demand outlook domestically and in Europe, its principal export market. Russia's capacity to tap into new markets is slowed by sanctions and the economic impact of lower oil prices, but its production is expected to pick up from the 2020s, as a combination of LNG capacity and new pipeline capacity (into China) allows it to tap into a broader customer base. By 2040, production is 5% higher than in 2013. The Caspian region sees natural gas production almost double (reaching 360 bcm by 2040), led by projects in Turkmenistan (the super-giant Galkynysh gas field) and Azerbaijan. The Middle East sees gas production increase by 65%, reaching 900 bcm in 2040, of which 290 bcm comes from Iran. Natural gas output in Africa more than doubles (mainly after 2025), led by both an expansion by traditional producers (Algeria, Angola and Nigeria) and the emergence of new producers (Mozambique and Tanzania).

Perhaps nowhere else are global efforts to transition to a low-carbon energy system more evident than in **electricity** supply, with widespread evidence of the increased use of renewables, a move to less carbon-intensive fossil fuels (i.e. from coal to natural gas), and the improved efficiency of fossil-fuelled power generation (reducing fuel demand) and of all types of electricity-consuming products (curbing electricity demand). In the New Policies Scenario, global power generation capacity grows by over 70% from 2014 to 2040 (reaching 10 600 GW) (see Chapters 8 and 9 for the power sector outlook and renewables outlook respectively). Nearly all types of generation capacity increase (oil being the exception), but by very different magnitudes (coal by 28%, natural gas by 61%, nuclear by 55%, hydropower by 57%, wind by nearly 300% [total capacity is almost 1 400 GW in 2040], and solar PV by 500% [total capacity exceeds 1 000 GW]). Overall, capacity additions of renewables-based technologies in the New Policies Scenario exceed those of all other types of power plants combined. Power generation capacity expands in all regions, with a general distinction between many OECD markets, which are more focused on replacing retiring capacity, and non-OECD markets, where the focus is on expanding capacity rapidly. In absolute terms, the largest increase of installed capacity over the period is in China (nearly 1 400 GW) and India (approaching 800 GW), followed by Africa (collectively 380 GW), Southeast Asia, Latin America, the Middle East, the European Union and the United States.

Figure 2.15 ▷ World electricity generation by type in the New Policies Scenario



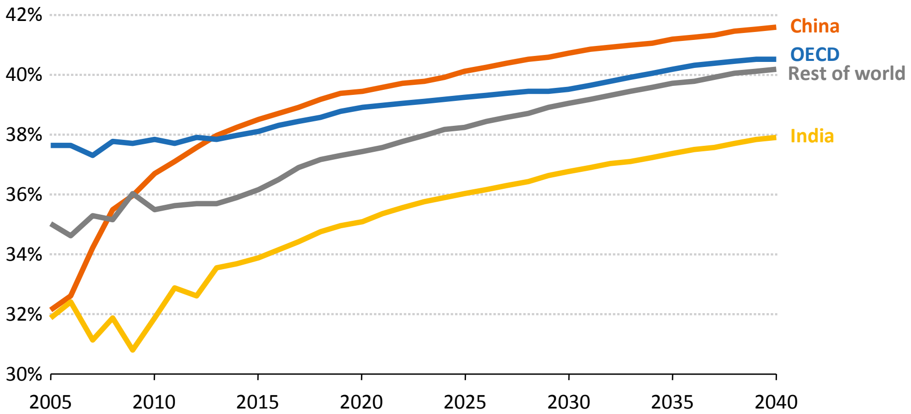
Note: Other includes geothermal, concentrating solar power and marine.

Globally, coal is the largest single source of power generation today, contributing almost twice as much as the second-largest source (natural gas). In the New Policies Scenario, the share of coal in electricity generation decreases significantly, but it still accounts for 30% of world supply in 2040 (Figure 2.15). However, this only tells part of the story, as the growth in coal use (and the related emissions) moves at a slower pace than the increase in coal-fired electricity generation, thanks to efforts to improve the efficiency of the coal-fired power fleet in key markets (Box 2.2). In addition, many countries are determined to increase renewables-based electricity generation, not only as a means to reduce GHG emissions but, often, also to improve air quality and enhance energy security. World electricity generation from renewables surpassed gas-fired generation in 2014 by a notable margin, on the back of government support (renewables-based power generation is estimated to have received $112 billion in subsidies in 2014) and declining costs (e.g. since 2010, solar PV capital costs have declined by around half in OECD countries, on average, and by three-quarters in China). In the New Policies Scenario, renewables continue to expand rapidly, becoming (collectively) the largest source of electricity supply by the early-2030s and going on to account for more than one-third of the world's electricity supply in 2040. The increase in renewables-based electricity generation is led by wind power, followed by hydropower and then solar PV; but hydropower still accounts for around 46% of all renewables-based electricity generation in 2040 (down from 74% in 2013). Lower prevailing oil prices are not expected to have a major impact on the deployment of renewables in the power sector, as they compete directly with conventional power plants only in a few markets.

Box 2.2 ▷ Power plant efficiency is critical

Given the huge amount of energy that is lost in the process of converting primary fuels into electricity (typically 40-60% of the primary energy input), a relatively small improvement in power plant conversion efficiency can have a marked impact on overall energy demand and related emissions. Globally, relatively inefficient subcritical coal-power plants make up two-thirds of the coal fleet, and account for more than one-quarter of total power generation and half of total CO_2 emissions from power generation. However, over the last decade (2004-2014), the global average efficiency of coal-fired power generation has improved (by around two percentage points), mainly as a result of China adding more efficient capacity to its existing fleet. Over this period, China moved away from the construction of subcritical power plants (which accounted for around 95% of China's coal-fired capacity additions in the early-2000s), towards more efficient ultra-supercritical power plants (almost 50% of coal-fired capacity additions in 2014). As a result of this shift, combined with the retirement of old, inefficient power plants, the average efficiency of coal plants in China (by far the world's largest coal-fired fleet) reached that of the OECD in 2013 and has since surpassed it (Figure 2.16). In the New Policies Scenario, the average efficiency in India's coal-fired power fleet is also projected to improve significantly, as supercritical power plants play a larger role. By 2040, the average efficiency of India's coal-fired power plants is more than four percentage points higher than the existing level, and reaches today's OECD average level. Despite this, around 45% of India's coal-fired power generation capacity remains subcritical in 2040.

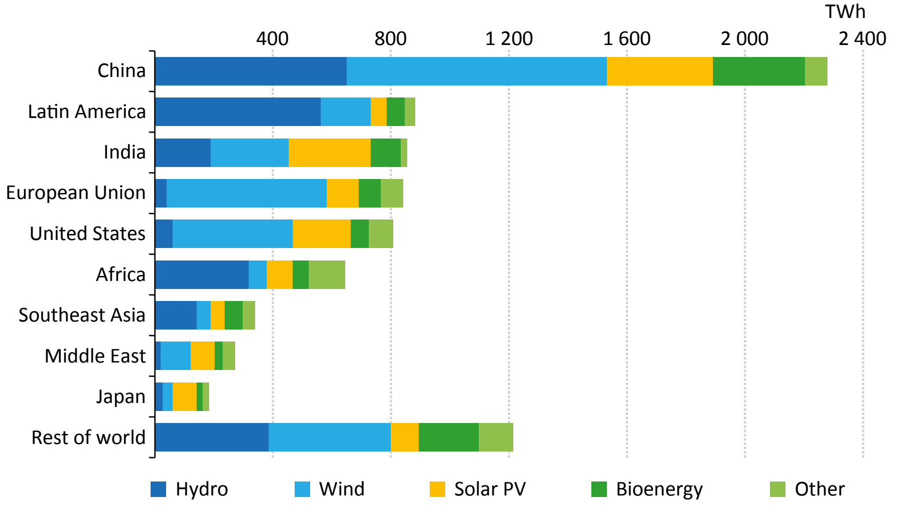
Figure 2.16 ▷ Average efficiency of coal-fired power plants by region in the New Policies Scenario



Hydropower is an important but often overlooked part of the world's power system, providing relatively reliable renewable energy at both large and micro scale. As just one example, the expansion of hydropower output in China over the last ten years has comfortably exceeded the increase of natural gas-fired generation in the United States or the growth in all renewables-based generation in the European Union over the same period. Hydropower can also play an important role in facilitating the integration of variable generation from solar and wind, as seen in the Nordic power system. However, recent experiences in Brazil and parts of the United States (droughts) and in China (a wet year in 2014) have reconfirmed that even hydropower has an element of unpredictability. In the New Policies Scenario, hydropower continues to account for 16% of total power generation through to 2040. Collectively, other renewables (led by wind power and solar PV), make great gains over the period, rising from 6% of total generation today to 18% by 2040. Installations of solar PV in buildings have been the dominant form to date (as in the EU), accounting for over 60% of global solar PV capacity in 2014. However, utility-scale solar PV is projected to lead the way in terms of future capacity additions in the New Policies Scenario (led by China, India and the United States).

Of the projected global increase in renewables-based electricity generation, 70% occurs in non-OECD markets, with China very much in a league of its own (Figure 2.17). Half of China's investment in power plants through to 2040 goes into non-hydro renewables, more than three-times the level of its investment in coal-fired capacity. In India, installation of solar PV is in its early stages, but the government has announced its aim to increase deployment dramatically, making India the second-largest market for solar PV over the *Outlook* period. Across the OECD, renewables account for nearly 40% of total generation in 2040 (around half of which comes from variable renewables). In the United States, the increase of renewables generation is similar to that in the European Union (in absolute terms), with the share of total generation continuing to rise and reaching 27% in 2040. In the European Union, more than half of electricity produced in the New Policies Scenario in 2040 comes from renewables, led by wind and hydropower. The EU has long been the world leader in wind power and government support helps it to triple its share of regional power generation to almost one-quarter in 2040. In Japan, solar and wind lead the growth in renewables-based generation, which accounts for almost 30% of total power generation by 2040. Overall, changes to the world's power generation mix result in the level of CO_2 emissions per unit of electricity being 33% lower by 2040, with reductions of 66% in the European Union, almost 50% in Japan and Mexico, 45% in the Middle East, over 40% in Russia, approaching 40% in China and the United States and 30% in India.[15]

Figure 2.17 ▷ Growth in renewables electricity generation by region and type in the New Policies Scenario, 2013-2040



Note: Other includes geothermal, concentrating solar power and marine.

Inter-regional energy trade[16]

The interconnected nature of the energy system becomes increasingly apparent as shifting supply and demand trends in the New Policies Scenario prompt a progressive rewiring of global energy trade relationships. Inter-regional energy trade increases for all fossil fuels and biofuels. The energy security implications vary.

Oil remains the most heavily traded fuel, with inter-regional trade increasing by more than 7 mb/d over the *Outlook* period to reach nearly 48 mb/d in 2040. Overall, OECD net oil imports fall to around 8 mb/d, driven by lower demand in some cases (Europe, Japan), and a combination of decreasing demand and increasing supply in others (United States,

15. Measured as grammes of CO_2 per kilowatt hour.
16. Analysis is based on net trade of energy between *WEO* regions. See Annex C.

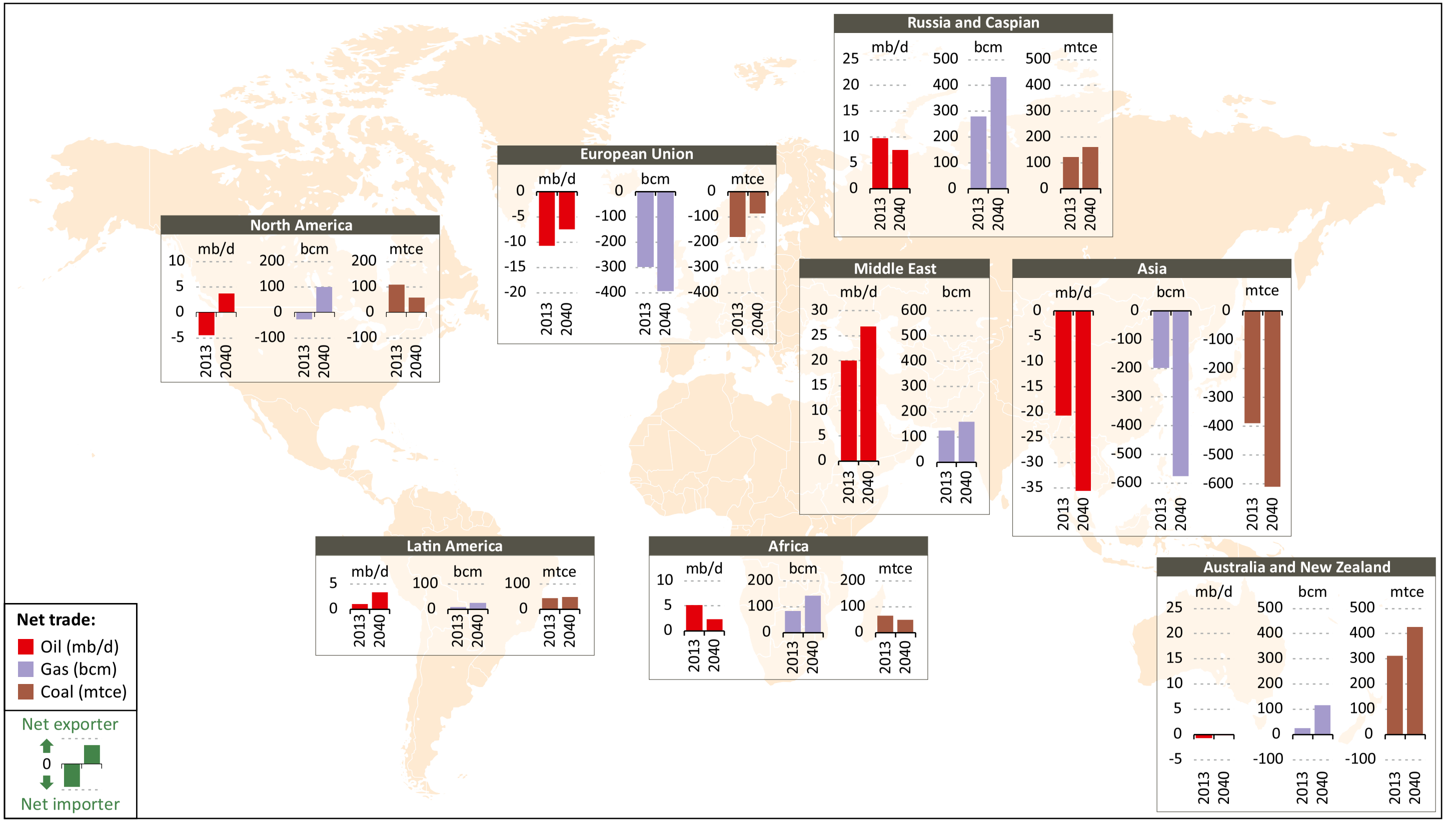
Canada and Mexico). Collectively, the OECD's role in inter-regional oil trade becomes more marginal, as its share of total trade declines from more than half in 2013 to less than one-fifth in 2040. North America becomes self-sufficient in oil in the mid-2020s (the United States remains a net importer, Canada and Mexico are both exporters), and becomes a net exporter of 3.7 mb/d by 2040 – a result of broadly equal increases in production and decreases in demand across the region. (In a world where oil prices stay lower for longer, the North American crude oil balance is worse-off, with lower Canadian production meaning that net exports from the region are just 1.8 mb/d in 2040 [see Chapter 4]). By 2040, Asia is the final destination for 75% of the oil traded inter-regionally, increasing its exposure to the risks associated with oil supply disruptions. Net oil imports for the region increase significantly, going from around 21 mb/d in 2013 to 36 mb/d in 2040 (Figure 2.18): China's imports double (close to 13 mb/d in 2040, nearly five-times those of the United States at that time), and China is firmly established as the world's single largest oil importer before 2020. Net imports into Southeast Asia more than double (reaching 6.7 mb/d), while India's more than treble (reaching 9.3 mb/d) and supply more than 90% of domestic demand in 2040, making security of oil supply a pressing policy issue. Asian import needs pull in oil from all over the world, including the Middle East, West Africa, Russia, Latin America and beyond. Over the *Outlook* period, export growth is led by the countries of the Middle East (6.8 mb/d higher in 2040), Canada (3 mb/d higher) and Brazil (2.4 mb/d higher). As oil prices gradually rebound in the New Policies Scenario, so too do the revenues earned by oil exporters.

Coal trade between regions grows faster than coal use, increasing by nearly one-fifth to reach 1 290 Mtce in 2040. While inter-regional trade increases, overall, the principal focus of this growth is Asia. The Asia-Pacific market accounts for nearly 70% of inter-regional coal trade today and this rises to 80% by 2040. Imports into China (currently the largest importer) decline significantly over the *Outlook* period. India supplants China in the near term as the largest importer and accounts for one-third of world coal trade by 2040. Australia and Mozambique are the primary suppliers of coking coal to India, while Indonesia, Australia and South Africa are the main suppliers of steam coal. Demand increases across much of Southeast Asia, with imports (outside of Indonesia, a coal exporter) surpassing five-times existing levels by 2040, principally to Viet Nam, Philippines and Malaysia. Indonesia and Australia continue to be key steam coal exporters, with Australia being the world's largest coal exporter. Located far from key import markets, US coal net exports are projected to halve by 2040. Russian producers manage the transition from exporting primarily into the Atlantic basin to being an important supplier into the Asia-Pacific market, with Russian exports growing in total by around 40%. South Africa sees its exports grow by 25% to 90 Mtce in 2040. Colombia remains the dominant supplier in the shrinking Atlantic market.

In the New Policies Scenario, inter-regional trade of **natural gas** expands by 46% (or 330 bcm) to reach almost 1 050 bcm by 2040, with trade patterns altering considerably. LNG trade grows more rapidly than trade via pipeline gas and accounts for close to half of all inter-regional gas trade by 2040. In the near term, lower prices and increasing supply work in favour of importers; but these factors also risk discouraging capital investment so as to tighten the market in the longer term. The European Union remains the world's largest importing market (imports rising to around 390 bcm), as demand stays relatively flat but domestic output declines. Japan's LNG needs drop back as nuclear capacity and renewables come online, and then remain steady at around 100 bcm through to 2040. China's import needs grow rapidly and it overtakes Japan to become the second-largest gas importer in the near term, reaching 140 bcm in 2020 and 240 bcm in 2040. China pulls in these resources from a range of sources, including Russian pipeline supplies, which are projected to reach around 75 bcm by 2040 in the New Policies Scenario (a level that is likely to require both a, possibly expanded, eastern Siberia route and a contribution from the Altai pipeline). The share of exports to China in overall Russian gas exports rises steadily, reaching around 30% by 2040 (including Russian supply delivered as LNG). However, China's own prospects for unconventional gas supply make its import requirement particularly uncertain when looking out further into the *Outlook* period (see Chapter 6).

Growth in inter-regional gas trade is dominated by Australia in the near term, with seven new LNG projects either underway or starting production in the period to 2020, increasing its exports from 26 bcm in 2013 to around 85 bcm in 2020. Over the same period, the first of the US LNG export projects comes on-stream, with US LNG exports projected to reach around 60 bcm in 2020 (joined later in the *Outlook* period by additional exports of US LNG and projects in Canada, so that North American net exports are around 85 bcm by 2030). There is also a large expansion projected for Africa, with East Africa making the biggest contribution after 2025). While North America switches from being a net gas importer to an exporter, Southeast Asia is expected to move in the opposite direction in the 2030s, largely as a result of the region's production failing to keep up with growing domestic demand. Russia remains the largest natural gas exporter by far, but is confronted by an increasingly competitive landscape in the near term, which (together with other factors) slows the expansion of LNG capacity significantly (although it grows in the longer term). As indicated, Russia sees strong growth in pipeline exports to China from the early-2020s and, overall, its natural gas exports are nearly 25% higher in 2040, at 250 bcm. In the New Policies Scenario, the Caspian region (led by Turkmenistan) sees natural gas exports grow significantly (mainly before 2030). The trend set in 2014, when natural gas exports from the Caspian region to China overtook the region's exports to Russia, is expected to become more deep-set over time. As a region, the Middle East sees natural gas exports fall in the first-half of the projection period, as rapid domestic demand growth outpaces the increase in production, but this balance shifts sharply after 2025 and, by 2040 exports have risen to comfortably surpass 2013 levels and reach almost 160 bcm.

Figure 2.18 ▷ Net trade by selected region and fuel in the New Policies Scenario



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Notes: Not all regions are shown. Regional totals reflect the sum of net exporters and importers within that region. The Middle East also imports small volumes of coal.

Energy sector investment

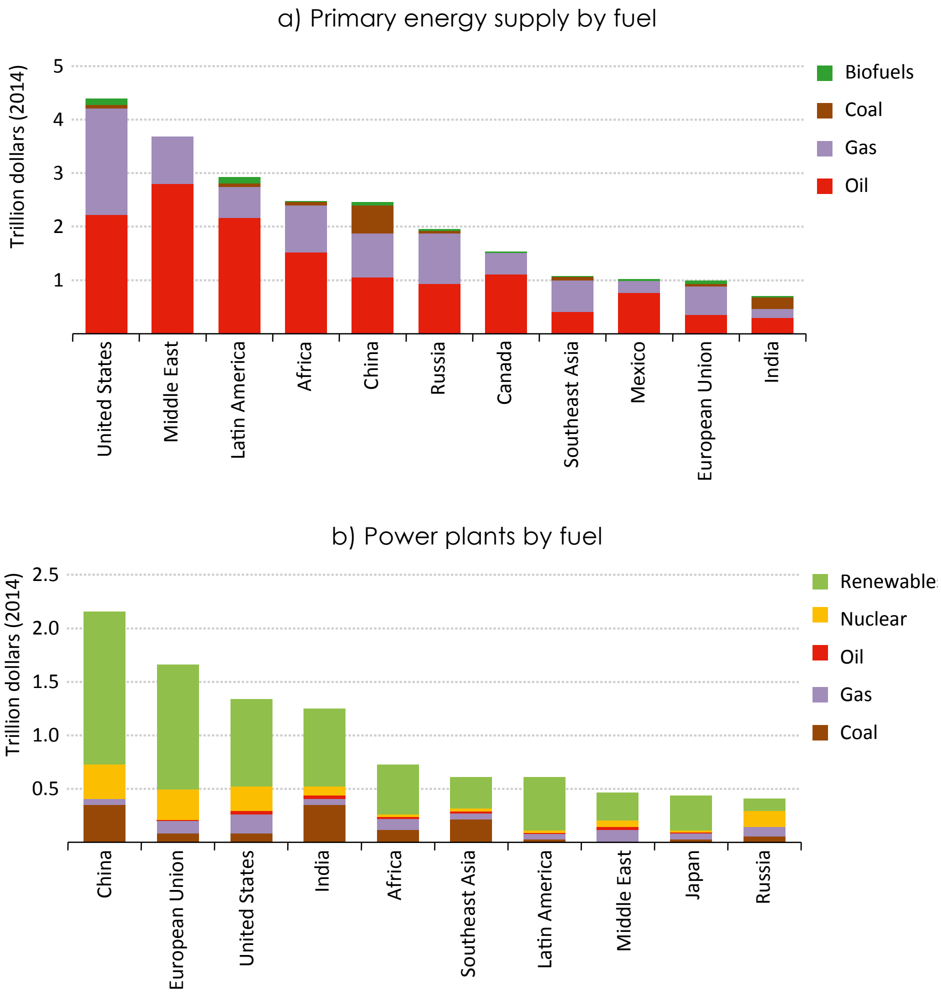
The energy sector continues to depend on large-scale, high-cost capital assets, meaning that investment decisions often have long-term implications. As a result, a prudent response to rapid and unexpected market movements can sometimes be to retrench and take stock. While investment projects that are sufficiently far advanced are likely to continue, because of the capital already committed, those that are yet to begin may be delayed (awaiting a more favourable investment climate) or postponed indefinitely. Of course, delay can bring its own risks, potentially building in future cycles of market tightness and volatility.

In the New Policies Scenario, cumulative world energy sector capital investment (including both energy supply and energy efficiency) is $68 trillion from 2015 to 2040 (in year-2014 dollars), equating to a little over 2% of global GDP over the period. Investment needs increase gradually over time, largely reflecting growing global demand for energy services. Of total investment, 37% is in oil and gas supply, 29% is in power supply (including transmission and distribution) and 32% is in end-use efficiency across sectors, mainly transport and buildings (the rest is in coal and biofuels supply). Average annual supply-side investments are significantly lower (6%) than estimated in *WEO-2014*, driven by a range of factors, the most significant of which are the drop in investment costs in the oil and gas sectors, the decline in projected natural gas demand (reducing the need to invest in supply), a slightly faster shift towards lower cost sources of oil supply, lower electricity demand in some key markets (United States and European Union), and a drop in the construction of coal-fired power generation capacity.

Around three-quarters of total oil and natural gas investment is in the upstream sector, with more than 80% of this being required to compensate for the decline in output from fields that are currently producing. The United States sees the largest investment in oil and natural gas supply over the *Outlook* period, followed by the Middle East, which is more skewed towards oil (Figure 2.19a). Relatively high levels of investment in Latin America are, in large part, a reflection of the high costs associated with Brazil's deepwater fields. In Africa, oil investments are concentrated in the main existing producing countries while natural gas investment involves both established and new players. Investments in biofuels supply average $15 billion per year over the *Outlook* period and remain concentrated in the United States, the European Union and Brazil, but with some expansion in parts of Asia.

Global cumulative power sector investment is near $20 trillion from 2015 to 2040. This is split between investments in 6 700 GW of new power generation capacity ($11.3 trillion) (Figure 2.19b), and 75 million kilometres of transmission and distribution lines ($8.4 trillion). The trajectory mapped out for the power sector in the New Policies Scenario is one in which the world's largest electricity-consuming countries continue to incentivise investment in renewables-based supply and low-carbon supply more generally. Of the investment in power generation capacity in the New Policies Scenario, more than 60% goes to renewables, led by China (mainly wind, hydro and solar PV), the European Union (mainly wind, followed by solar PV), the United States (wind and solar PV) and India (solar PV, followed by wind).

Figure 2.19 ▷ Cumulative investment in energy supply by selected region in the New Policies Scenario, 2015-2040



While often less prominently discussed, energy efficiency investment is no less prominent in scale than investment in many other parts of the energy sector. It totals around $22 trillion from 2015 to 2040. In the New Policies Scenario, the largest share of this investment is in transport and, in particular more efficient passenger light-duty vehicles which, thanks to the proliferation of fuel-efficiency standards, deliver a major improvement in average fleet efficiency over the *Outlook* period. Investment in more efficient buildings (and the appliances, etc. used within them) is around $5.8 trillion from 2015 to 2040, led by investments in more efficient household and office appliances, as well as more efficient forms of lighting, insulation, space heating and cooling. While the majority of efficiency investment in buildings occurs in the major OECD markets, efficiency investment in industry is nearly three-times higher in non-OECD markets (half of which is made in China).

Energy-related CO_2 emissions

The use of low-carbon energy sources is expanding rapidly and there are some early signs that growth in the global economy and energy-related emissions may be starting to decouple. Renewables accounted for nearly half of all new power generation capacity in 2014, the first commercial power plant with CO_2 capture came online in Canada, the European Union agreed in 2015 to reform its Emissions Trading System (the world's largest) and China is working to implement a nation-wide scheme in 2017. The scale of the challenge ahead should not be underestimated, but the action underway holds out hope that meeting the world's goal to keep the rise in global average temperatures below 2 °C is still achievable, though efforts need to be intensified.

In the New Policies Scenario, energy-related CO_2 emissions increase through to 2040, reaching 36.7 Gt in that year, 16% higher than 2013.[17] Having increased by 2.4% per year since 2000, these emissions are now projected to increase at the relatively feeble rate of 0.6% per year for the rest of this decade, and 0.5% per year in the 2020s and 2030s. In addition, process-related CO_2 emissions (i.e. from industrial processes, such as cement and aluminium production) increase from 2.7 Gt in 2013 to 3.8 Gt in 2040. These figures confirm that, despite the expectations held out above, the cautious implementation of new and announced policies embodied in the New Policies Scenario are, alone, well short of being sufficient to move the energy sector onto a pathway consistent with the 2 °C goal.

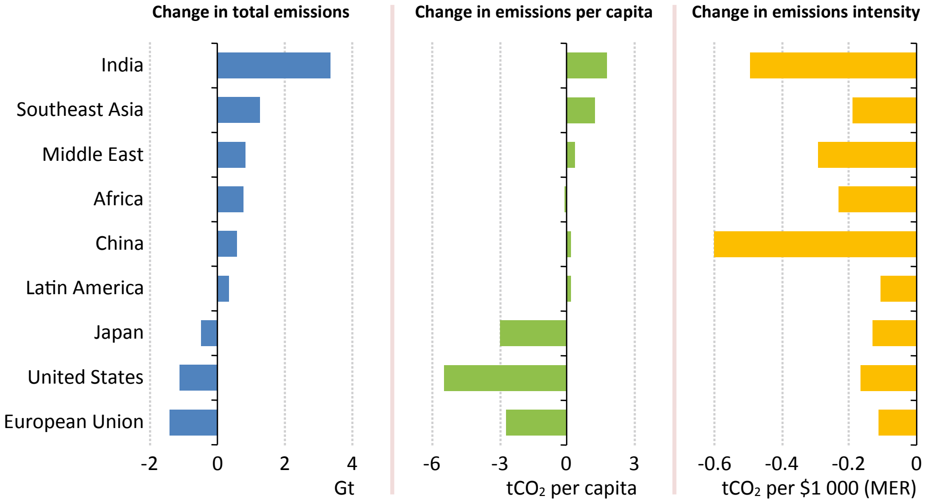
Energy-related CO_2 emissions from oil increase by around 1 Gt (10% higher) over the *Outlook* period. Emissions grow much more quickly in transport, but they are partially offset by decreasing emissions from power generation and the buildings sector. Coal continues to be the largest source of energy-related CO_2 emissions, but emissions from coal (1 Gt higher in 2040) grow less than those from other fossil fuels, with coal use in power generation dropping in many countries, but increasing strongly in others. While natural gas is the least carbon-intensive fossil fuel, the growth in emissions from gas (3 Gt in 2040) easily exceeds those of coal and oil combined because of its increasing place in the energy mix. Overall, the power sector continues to account for more than 40% of all energy-related CO_2 emissions in 2040, while transport sees the most rapid growth, with its share increasing to 25%. Where a reduction in transport emissions is achieved, it tends to result from the more efficient use of gasoline and diesel, rather than a large-scale shift to alternative fuels (which could achieve a larger emissions reduction).

National emissions paths vary widely in the New Policies Scenario and different emissions indicators can often seem to tell a different story (Figure 2.20). The United States sees total energy-related CO_2 emissions decline by 21% (nearly 1.1 Gt), led by the power sector (where the Clean Power Plan target of a 32% emissions reduction from 2005 levels by 2030 is assumed to be met) and transport. Energy-related CO_2 emissions in the European

17. Adoption of the 2006 Intergovernmental Panel on Climate Change (IPCC) guidelines has prompted a change in definition to reflect updated emissions factors and the exclusion of emissions from non-energy use. This has altered the level of energy-related CO_2 emissions relative to previous *WEOs*. Contrary to the IPCC guidelines, certain emissions from energy-intensive industries are still included in order to try and better reflect total emissions from fossil-fuel combustion.

Union are down 40% by 2040, by which time the EU is generating more than two-thirds of its electricity from renewables and other low-carbon sources. Japan's emissions are also around 40% lower by 2040, as nuclear capacity comes back online, renewables expand and strong additional energy efficiency gains are achieved. The United States, European Union and Japan all see major cuts in per-capita emissions but, in the case of the United States, from a much higher starting point.

Figure 2.20 ▷ Change in energy-related CO_2 indicators by selected region in the New Policies Scenario



Non-OECD emissions are around 7.5 Gt (40%) higher in 2040, with three-quarters of this growth in Asia. China's energy-related CO_2 emissions are just 7% higher than 2013 in 2040, having essentially stabilised by 2030 and begun to show some signs of decline before 2040 (when emissions reach 9.1 Gt). Emissions from China's power sector plateau before 2040, stay broadly flat in the buildings sector and decline by 30% in industry, but almost double in the transport sector, as vehicle ownership grows strongly. India is by far the largest source of growth of energy-related emissions to 2040 in absolute terms, but its per-capita emissions remain low relative to much of the rest of the world. India's economy expands to more than five-times its current size, while energy-related CO_2 emissions grow by more than 3 Gt to reach 5.1 Gt in 2040. Its power sector diversifies, but coal continues to command the major share of the power mix. In line with its industrialisation strategy, India's industrial sector dominates the growth in emissions from end-use sectors. Over the *Outlook* period, energy-related CO_2 emissions double in Southeast Asia, increase by two-thirds in Africa (except South Africa, where emissions decline from their relatively high levels), by half in the Middle East and by 30% in Latin America. In all cases, emissions growth lags economic growth by a considerable margin, resulting in a lower emissions intensity of the economy. But, in some cases, this also reflects a reduction in emissions (European Union, United States and Japan) while, in other cases, it is more a reflection of the pace at which economic growth has outpaced emissions growth (India, Southeast Asia and the Middle East).

Topics in focus

This section presents new data and analysis on two key issues for the global energy system that have been of long-standing focus in the *World Energy Outlook*. One is the gross distortion that exists in a number of energy markets today in the form of inefficient fossil-fuel consumption subsidies that fail to direct assistance efficiently to the poor and work counter to many other energy and economic objectives. The other is level of achievement in efforts to overcome a major impediment to social and economic development, namely, the large number of people in the world who still live without access to modern energy.[18]

Fossil-fuel subsidies

Global progress with reform

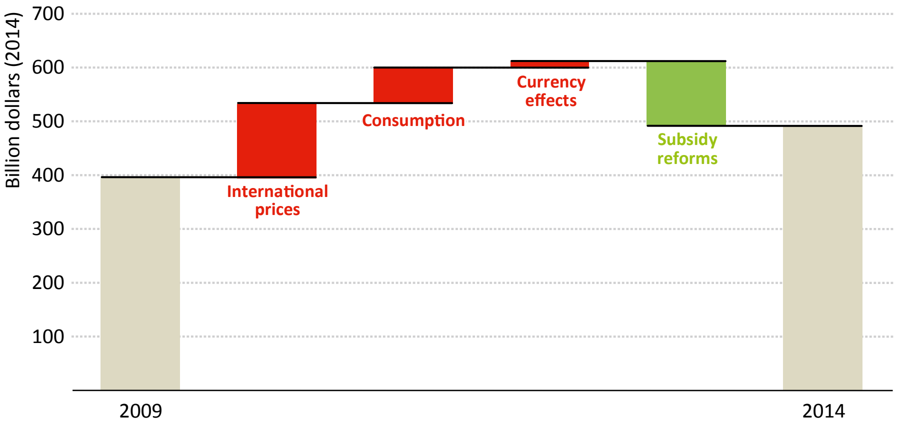
World leaders gathered for the G20 Summit in Pittsburgh in 2009 committed to "rationalize and phase out over the medium term inefficient fossil-fuel subsidies that encourage wasteful consumption." A similar commitment was made by Asia-Pacific Economic Cooperation (APEC) Leaders in Singapore later that year. The rationalisation of inefficient subsidies has also become one of the targets underpinning the Sustainable Development Goal to "ensure sustainable consumption and production patterns," as adopted by UN member states at the Sustainable Development Summit in September 2015. However, none of these commitments included a specific timetable for the phase-out or an agreed definition of an "inefficient subsidy". Including these features would represent a significant next step in advancing the work that is being done under both initiatives, making the commitments much more precise and easier to track. There have, however, already been a number of policy interventions since 2009 that have reduced the economic, social and environmental costs of fossil-fuel subsidies.

Based on the IEA's latest survey, the value of fossil-fuel subsidies worldwide is estimated at \$493 billion in 2014.[19] By comparison, such subsidies amounted to \$390 billion in 2009 (in 2014 dollars), the year the G20 and APEC commitments were made. The value of these estimates has fluctuated from year-to-year in line with reform efforts, the consumption level of the subsidised fuels, international prices for fossil fuels, exchange rates and general price inflation. Decomposition analysis enables the effect of each factor to be identified. This reveals that, while movements in world prices typically have the greatest impact from year-to-year, policy interventions have played an important role as well. Without the reforms adopted since 2009, the value of fossil-fuel subsidies would have been 24% higher (\$117 billion), putting the level of these subsidies at \$610 billion in 2014 (Figure 2.21).

18. Definitions of modern energy access typically include the following elements: household access to a minimum level of electricity; household access to safer and more sustainable cooking and heating fuels and stoves; access to modern energy that enables productive economic activity (e.g. mechanical power); and, access to modern energy for public services (e.g. for health facilities and schools). The remainder of this section focuses primarily on the issue of household access to electricity and clean cooking facilities.

19. The IEA estimates cover subsidies to fossil fuels consumed by end-users (households, industries and businesses) and subsidies to the consumption of electricity generated by fossil fuels.

Figure 2.21 ▷ **Contributing factors to the change in the value of fossil-fuel consumption subsidies**



While reform programmes have had an impact on the value of subsidies at the global level, their impact is, naturally, more pronounced in the individual countries concerned. In Indonesia, for example, the value of subsidies would have been 38% higher in 2014 ($38 billion instead of $28 billion) had there been no reforms. Moreover, these figures do not yet incorporate the effects of the major reforms to gasoline and diesel prices that were made in the context of Indonesia's revised budget for 2015 and which have further reduced the burden subsidies impose on public finances. Pricing reforms in India, mainly to gasoline (2010) and diesel (2014) have cut the country's subsidies bill in 2014 by $15 billion. In the countries that have yet to introduce reforms, higher levels of consumption have been an important factor in pushing up the cost of subsidy programmes. In the Middle East, a region in which there have been some recent encouraging signs, but in which only limited reforms were in place by the end of 2014, demand for fossil fuels has risen by almost one-fifth since 2009, entailing an increase in the subsidies bill of $34 billion (20%) in 2014 ($204 billion).

Drivers of reform

Progress in phasing out fossil-fuel subsidies can be attributed to a wide range of considerations, which vary from one country to another. They include, principally:

- **Budgetary pressure:** Subsidies become a major fiscal burden on the government budgets of a number of countries as a result of fast-growing energy demand and persistently high international energy prices in the five years up until mid-2014 (low international oil prices have since somewhat reduced this fiscal pressure, but this is offset, in oil producing countries, by the loss of the revenues higher prices would have brought to government budgets). For example, the number of cars on Malaysia's roads has more than doubled since 2000, leading, in association with other changes, the budget for energy subsidies to grow six-times, to reach $9 billion in 2013. As part of a strategy to reduce its rising national debt and fiscal deficit, Malaysia ended subsidies for gasoline and diesel in December 2014. Gasoline and diesel prices are now set monthly to track movements in international markets.

- **Lower international energy prices:** Somewhat paradoxically, the plunge in oil prices since mid-2014 has made the withdrawal of subsidies less politically controversial; since the subsidy per litre is now much lower, there is an opportunity to abolish subsidies without having a major upward impact on prices or inflation. This appears to have been the main consideration in at least ten countries that have introduced reforms since mid-2014 (Table 2.3). These include Indonesia, which has abolished gasoline subsidies and capped diesel subsidies, while committing to a formula-based pricing system that tracks international benchmarks. A key challenge for all countries that seize such an opportunity to reform is how to act when oil prices increase and point to the need for upward adjustments in the consumer price. In the case of Indonesia, increases in pump prices that were expected in April and May 2015 did not occur, and time will tell if this proves to be a temporary or permanent situation. In oil and gas-exporting countries, the opportunity cost of pricing domestic energy below market levels has shrunk, perhaps reducing the incentive to reform; but export revenues have also shrunk, making it more difficult to avoid rising budget deficits. A number of key fossil-fuel exporters are implementing reforms, including Iran, Kuwait and the United Arab Emirates.
- **Peer pressure:** Peer pressure from the G20 and APEC working groups that are implementing their leaders' commitments is an important factor in the progress being made. Since 2009, members of both the G20 and APEC have engaged voluntarily in a process of periodically reporting on their fossil-fuel subsidies. These reports are reviewed in a process aimed at deepening understanding of the challenges confronting reform efforts and fostering mutual learning as to their solution. As of July 2015, China, Germany, Mexico, and United States (G20) and New Zealand, Peru, and Philippines (APEC) had either already been reviewed or committed to being reviewed.
- **Policy advice and technical assistance:** A number of organisations and groups, including the IEA, the International Monetary Fund (IMF), the Organisation for Economic Co-operation and Development (OECD), World Bank, the Friends of Fossil-Fuel Subsidy Reform (a group of countries that support subsidy reform) and the Global Subsidies Initiative, have been active in providing policy advice and technical assistance to help countries reform their subsidies. This has included efforts to raise awareness about the true costs of subsidies and their adverse effects, and helping to build capacity within governments to design and implement durable reforms.
- **Loan conditionality:** Some loans by international lending agencies have been made conditional on reforms of energy subsidies. The IMF, for example, approved a $17.5 billion loan programme for Ukraine in March 2015 that was conditional on increasing prices for district heating and natural gas.

Table 2.3 ▷ Recent fossil-fuel subsidy reforms in selected countries

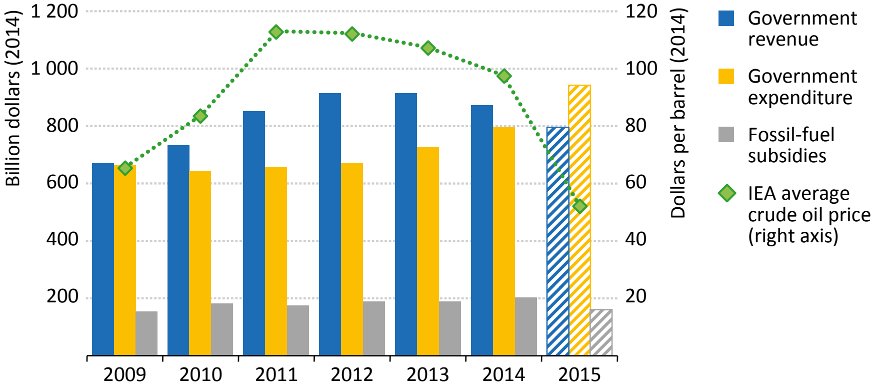
	Main fuels subsidised	Recent developments
Angola	Gasoline, diesel, kerosene, electricity	In December 2014, reduced subsidies by increasing prices to AOA 90 ($0.83) per litre for gasoline and AOA 60 ($0.55) per litre for diesel.
China	LPG, natural gas, electricity	In February 2015, announced plans to group existing and new industrial gas consumers under a single pricing mechanism.
Ghana	LPG	In June 2015, deregulated the prices of petroleum products.
India	Kerosene, LPG, natural gas, electricity	Stopped diesel subsidies in October 2014, following similar reforms to gasoline in 2010. Also introduced a new pricing formula for domestically produced gas. In January 2015, introduced a cash transfer scheme for residential LPG consumers to try to stop the diversion of subsidised cylinders to commercial use.
Indonesia	Diesel, electricity	In January 2015, abolished subsidies to gasoline (RON88) and capped the diesel subsidy. In March 2015, increased the price of non-subsidised 12-kg LPG canisters by IDR 5 000 ($0.38).
Iran	Gasoline, diesel, kerosene, LPG, natural gas, electricity	In May 2015, increased the price of subsidised gasoline from IRR 7 000 ($0.28) per litre to IRR 10 000 ($0.35) per litre.
Kuwait	Gasoline, diesel, kerosene, LPG, natural gas, electricity	In January 2015, increased the price of diesel to KWD 0.170 ($0.56) per litre. At the end of January 2015, cut back prices of diesel and kerosene to KWD 0.110 ($0.36) following political pressure. Postponed plans to remove subsidies on gasoline and electricity.
Malaysia	LPG, natural gas, electricity	In January 2014, increased electricity tariffs by an average of 15%, and resumed fuel cost pass-through, based on international gas price movements. In May 2014, increased natural gas prices by up to 26% for certain users. In December 2014, abolished gasoline (RON95) and diesel subsidies; prices are now set to track international levels.
Morocco	LPG	Abolished gasoline and fuel oil subsidies at the start of 2014 and diesel subsidies at the start of 2015.
Oman	Gasoline, natural gas	In January 2015, raised gas prices for industrial consumers by 100%, to OMR 0.041 per cubic metre ($3.01/MBtu). Introduced a 3% annual rise in gas prices for industries.
Thailand	LPG, natural gas, electricity	In October 2014, increased the price of CNG for vehicles by THB 1 ($0.03) per kilogramme. Ended subsidies for LPG in December 2014.
UAE	Gasoline, diesel, natural gas, electricity	From August 2015, started adjusting fuel prices monthly to match global prices.
Viet Nam	Natural gas, electricity, coal	In March 2015, increased electricity tariffs by 7.5%.

Note: LPG = liquefied petroleum gas; MBtu = million British thermal units; CNG = compressed natural gas; UAE = United Arab Emirates.

Focus on Middle East oil exporters

IEA estimates reveal that fossil-fuel subsidies are becoming increasingly concentrated in the major oil- and gas-exporting countries. The share of Middle East oil exporters,[20] for example, in the world total has risen from 35% to 40% over the last four years. The main reason for this trend is that high oil prices over much of the period meant that they, as net oil exporters, did not have the same fiscal incentive to reform energy pricing as that in many other parts of the world. Instead, the rise in government revenues from oil exports allowed an increase in government spending, often on social support programmes, expanding infrastructure and subsidies to food and energy. Over the period 2009-2014, fossil-fuel subsidies for this group of countries have, on average, been equivalent to more than one-quarter of government expenditure (Figure 2.22).

Figure 2.22 ▷ Government revenues and expenditures, and fossil-fuel subsidies in the Middle East oil-exporting countries



Note: The subsidy estimate for 2015 is indicative and based on average international prices for the first-half of 2015 and 2014 levels of consumption and end-use prices.

Sources: IMF (2015); IEA data and analysis.

A fall in oil prices has direct implications for government budgets in the major producing countries. After building a total surplus of almost $800 billion between 2009-2014, Middle East oil-exporting countries are forecast to see a budget deficit of $150 billion in 2015 (IMF, 2015). Some of these countries will be better placed than others to weather the downturn, as they have built up large reserve funds on the back of high oil prices over much of the last decade, or have made more progress in diversifying their economies away from dependence on oil. All domestic provision of oil and natural gas at a price below the international price involves a loss of revenue to producing countries and, if prices remain low, many may have to consider offsetting part of this revenue reduction by cutting domestic subsidies, in preference to cutting other government expenditure. While subsidy reform is unlikely to be rapid or easy, with governments particularly wary of inciting public unrest, some moves in this direction have already been taken. For example, in August 2015

20. Countries included are Bahrain, Iran, Iraq, Kuwait, Oman, Qatar, Saudi Arabia and the United Arab Emirates.

the United Arab Emirates deregulated gasoline and diesel prices, which are to be adjusted monthly to track international levels, as part of the government's strategy to diversify sources of income, strengthen the economy and increase competitiveness, and build a strong economy that is not dependent on subsidies. Other countries in the region that have made reforms in recent years include Kuwait and Iran.

While fiscal consolidation is one driver for subsidy reform in energy-exporting countries, there are a host of other reasons why price reforms might be pursued. One is to improve the low efficiency of domestic energy use, which has been adding to sharply rising domestic demand. In the Middle East, passenger cars use 75% more fuel per kilometre than the average car in the OECD, partly because low gasoline and diesel prices reduce the incentive to invest in a more efficient vehicle. Based on current levels of fuel economy, eliminating subsidies to gasoline in Saudi Arabia would effectively leave each person around $680 per year worse-off, on average, because of the volume of fuel consumed annually by each car (if not compensated in other ways). If the passenger car fleet in Saudi Arabia had the same level of fuel efficiency as that of the OECD average, however, this loss would be cut to $410 per year, thereby reducing the impact of subsidy reform on household budgets. A number of countries in the Middle East have started to make moves in this direction. For example, Saudi Arabia has recently introduced fuel-economy labelling for new cars and fuel-economy standards, while Iran adopted new energy conservation plans in 2014 to help reduce gasoline and diesel use in the transport sector.

Access to modern energy[21]

The need to improve access to modern energy has moved into the mainstream of international policy-making in 2015. The G7 has committed to "accelerate access to renewable energy in Africa and developing countries in other regions with a view to reducing energy poverty", while the G20 has launched the first phase of its Energy Access Action Plan. As long-advocated by the IEA, the newly agreed post-2015 Sustainable Development Goals of the United Nations include a goal on energy, namely to "ensure access to affordable, reliable, sustainable and modern energy for all". In parallel, the UN Secretary-General's Sustainable Energy for All (SE4All) initiative continued to work to galvanise and enhance global efforts to increase energy access and the 2015 edition of the SE4All *Global Tracking Framework* – co-led by the IEA and the World Bank – has been published (IEA and World Bank, 2015). This reports progress against the three SE4All goals.

Access to electricity – current status

The latest data demonstrates efforts to improve electricity access, but progress is patchy rather than broad-based. An estimated 1.2 billion people – 17% of the global population – did not have access to electricity in 2013, 84 million fewer than in the previous year. Many more suffer from supply that is of poor quality (Box 2.3). More than 95% of those living

21. Estimates are based on 2013 data (when available) or on the latest available data. Data by country can be accessed at *www.worldenergyoutlook.org/resources/energydevelopment*.

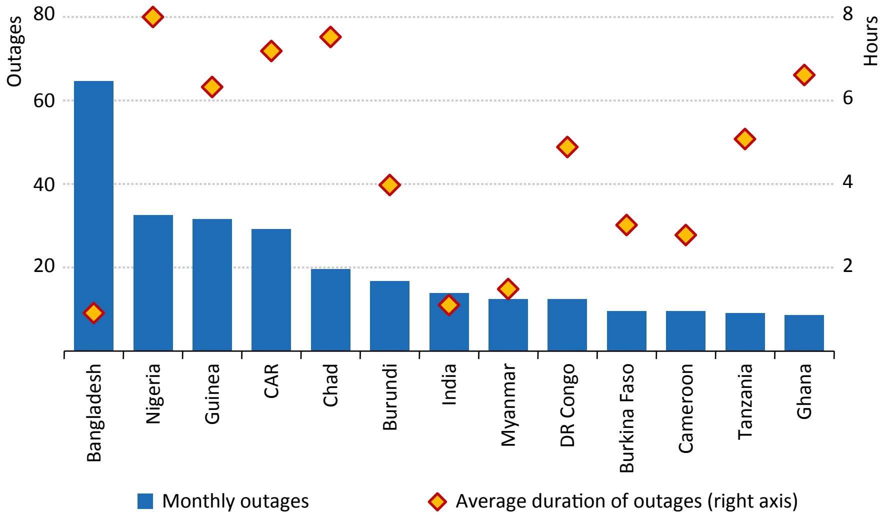
without electricity are in countries in sub-Saharan Africa and developing Asia, and they are predominantly in rural areas (around 80% of the world total). While still far from complete, progress in providing electrification in urban areas has outpaced that in rural areas two to one since 2000. As predicted last year in the IEA's *Africa Energy Outlook*, sub-Saharan Africa has now become the most electricity poor region in the world in terms of the total number of people (surpassing Asia), as well as the share of its overall population (IEA, 2014c). But the pace at which the picture in Africa has been deteriorating has slowed, and rapid population growth can conceal the efforts and results that are taking place.

Around one billion people have gained access to electricity in developing Asia since 2000. After accounting for population growth, this means that the number of people without electricity has halved to around 525 million people. The latest estimate reflects a trajectory that continues to improve, showing the share of the regional population now without access below 15% for the first time. Of any country in the world, India continues to have the largest population without electricity (accounting for one-fifth of the world total); but the latest survey data show a major advance, led by rural areas (see Part B for more on the energy access outlook for India). Indonesia has also made a substantial step forward, with electricity access levels reaching 80% for the first time (it is targeting 90% by 2020), reflecting the effectiveness of government actions. Several countries in developing Asia can boast universal or near-universal access to electricity, including China, Malaysia, Thailand, Singapore and Brunei Darussalam, while others have continued to make significant progress over the years, such as Viet Nam, Lao PDR, Pakistan and Bangladesh.

Box 2.3 ▹ With great power comes great opportunity

Even for those with relatively high and improving rates of electricity access, quality of supply continues to be an issue that holds back consumers and the economy from realising the full benefits of electricity access. Business surveys point to around thirty electrical outages per month in Nigeria and the Central African Republic, and more than sixty per month in Bangladesh (Figure 2.23), with each outage varying in length from minutes to hours (World Bank, 2015a). The fact that these outages are often unexpected, of unpredictable duration and at times of greatest inconvenience (during waking hours and at times of peak electricity demand), only serves to magnify their negative impact. Our special report, *Africa Energy Outlook,* found that for every additional $1 of power sector investment in sub-Saharan Africa, incremental GDP could be boosted by around $15 (IEA, 2014c). The underlying reasons for outages include insufficient generation capacity, fuel shortages, excess strain on the system and shutdowns for repairs and maintenance. Whatever the reason, the result is essentially the same: an economy that is unable to operate at its full potential.

Figure 2.23 ▷ **Number and duration of monthly electrical outages by selected countries**



Note: CAR = Central African Republic; DR Congo = Democratic Republic of Congo.

Sources: World Bank Group Enterprise Surveys; IEA analysis.

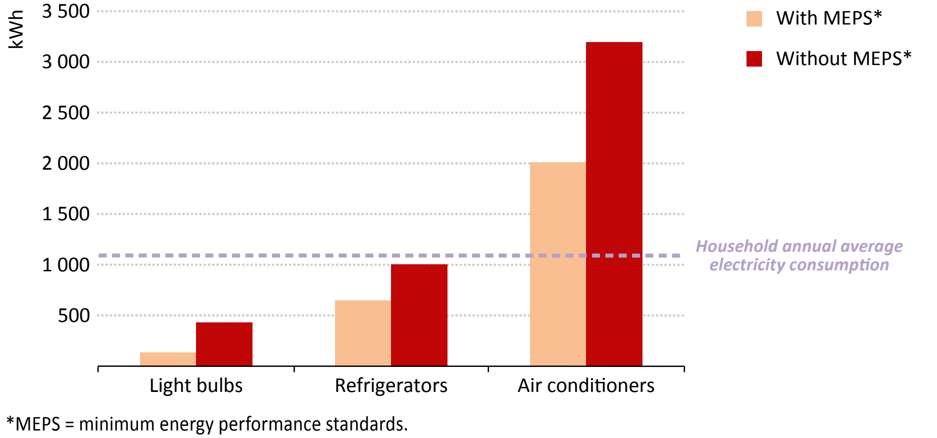
In sub-Saharan Africa, around 150 million people are estimated to have gained electricity access since 2000, but this has lagged population growth, resulting in a worsening picture overall – the latest estimates reveal that over two-thirds of the sub-Saharan population (634 million people) are without access to electricity. Half of these people are located in just five countries – Nigeria, Ethiopia, Democratic Republic of Congo, Tanzania and Kenya. However, the lowest electrification rates are often found in other countries, such as South Sudan, Malawi, Burundi and Sierra Leone (all below 10%). In the latest data, notable improvements have been observed in Guinea, Liberia, Mauritania and Congo, while Ghana stands out as an example where energy efficiency policies are playing a positive role (Box 2.4). South Africa's Integrated National Electrification Programme has electrified over six million households over the last two decades, but the pace of progress has slowed at an electrification level of around 85% (South African Department of Energy, 2015). While most countries in the Middle East have attained universal electricity access, those in the midst of conflict have (unsurprisingly) seen the situation worsen, due to damage to supply infrastructure or fuel shortages. In Latin America, the electrification rate has improved considerably since 2000 and now stands around 95%, with notable progress in countries such as Brazil, Columbia, Peru and Bolivia. While the overall level of access to electricity in Latin America is high, there are still some countries that have relatively low rates, such as Honduras, Guatemala and Haiti.

Box 2.4 ▷ Energy efficiency and electricity access – the case of Ghana

Electricity consumption is projected to more than treble in sub-Saharan Africa by 2040. Bringing electricity access to a fast-growing population, while also maintaining the quality of supply, is an immense challenge. It is one that energy efficiency policies can help to ease. Energy efficiency measures can help to reduce peak-load consumption and thereby make it possible to increase access at lower cost, in terms of investment in supply. In Ghana, electricity consumption is growing at 6-7% per year and, with seven million people yet to get access, Ghana's energy efficiency programme is an important element in the plan to expand supply and meet future demand growth. It stands as a positive example to other countries in the region.

Ghana developed the first standards and labelling programme in sub-Saharan Africa in 2000 to solve a situation of repeated rolling blackouts. Minimum energy performance standards (MEPS) were implemented for air conditioners, compact fluorescent lamps (CFLs) and refrigerators. These have resulted both in considerable energy savings (Figure 2.24) and an estimated saving of $840 million in new power capacity investments (CLASP, 2015). The promotion of efficient lighting has proven to be particularly successful, with the free distribution of 6 million CFLs to replace incandescent light bulbs (all installed within three months). The penetration of CFLs increased from 20% in 2007 to 79% in 2009, while the penetration of incandescent lamps fell to just 3% (Ghana Energy Commission, 2013). In 2011, the government took another step by removing import duty and value-added tax on light-emitting diode (LED) lamps, so as to support their adoption.

Figure 2.24 ▷ Household average electricity consumption of selected equipment in Ghana with and without energy efficiency standards, 2013



*MEPS = minimum energy performance standards.

Access to clean cooking – current status

In 2013, more than 2.7 billion people – 38% of the world's population – are estimated to have relied on the traditional use of solid biomass for cooking, typically using inefficient stoves in poorly ventilated spaces. This is an increase of around 40 million since 2012.[22] Developing Asia and sub-Saharan Africa once again dominate the global totals. While the number of people relying on biomass is larger in developing Asia than in sub-Saharan Africa, their share of the population is lower: 50% in developing Asia, compared with 80% in sub-Saharan Africa. Overall, nearly three-quarters of the global population living without clean cooking facilities (around 2 billion people) live in just ten countries. This deteriorating global picture dispels any notion that the transition to cleaner cooking fuels and appliances is straightforward. Economic development and income growth do not automatically lead to the adoption of clean cooking facilities, meaning that specific government policies have an important role to play. Despite this, clean cooking features much lower on government priorities than promoting access to electricity.

A population similar to that of the European Union and the United States combined lives without clean cooking facilities in India (840 million people), by far the largest national population of any country in the world. Around one-third of China's population have no clean cooking facilities, illustrating the disconnect that can exist between rising incomes, improving electricity access and clean cooking. Viet Nam is another example. Indeed, it is a common story across much of developing Asia, with the number of people without clean cooking facilities tending to track population growth more closely than incomes. Against this general trend, Indonesia continues to make major efforts to promote clean and safe cooking, following the success of its kerosene to LPG conversion programme.

In sub-Saharan Africa, the overall picture is deteriorating, with the number of people without clean cooking facilities now above 750 million. Positive progress has been achieved in Ghana through its programme to promote the uptake of LPG; and, Equatorial Guinea, among the richest countries in Africa in per-capita terms, is another – one of few – to register an improvement in the latest data. Nigeria, where households rely heavily on solid biomass for cooking despite the country's abundant fossil-fuel resources, has set a national goal of helping 20 million households to switch to clean cooking facilities by 2020. Countries in Latin America see a generally improving picture, although the pace varies and the regional total without clean cooking facilities remains above 60 million. The latest data reveals notable improvements in Brazil, Columbia, Peru and Argentina.

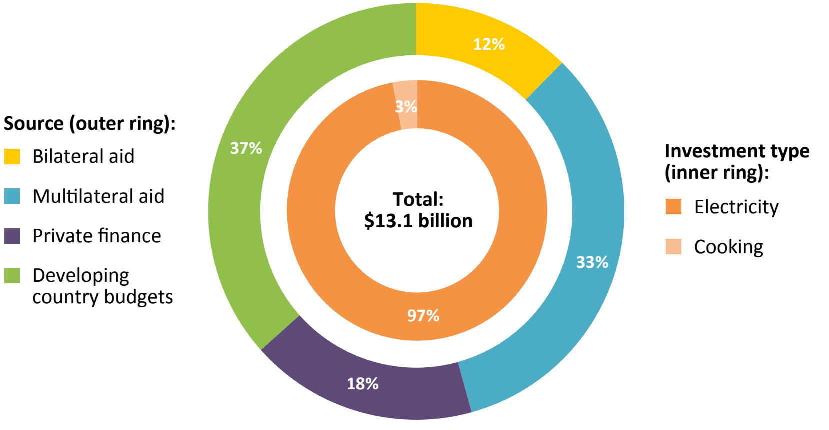
Financing energy access

Worldwide in 2013, an estimated $13.1 billion in capital investment was directed to improving access to electricity and clean cooking facilities (Figure 2.25). Overwhelmingly, these energy access investments went to the power sector, either to increase generation

22. This text focuses on the traditional use of biomass for cooking, but there are also 200-300 million people who rely on coal for cooking and heating purposes, which can potentially have serious health implications when used in primitive stoves.

capacity or to extend transmission and distribution networks, with only 3% being directed at increased access to clean cooking facilities. This figure of $13.1 billion is an increase, relative to previous *WEO* estimates ($9.1 billion in 2009), but the estimate is tentative – it may well be an under-estimate (IEA, 2011).[23]

Figure 2.25 ▷ World energy access investment by type and source, 2013



This capital comes to the energy sector from a variety of sources: self-financing by the energy investor; by an allocation from the state budget; or external financing, via bank lending and the capital markets, but the information available is poor, particularly on private sector investments, south-south investment flows (which can, as in the case of China, be significant) and the financing of mini- and micro-scale projects. Our tentative estimate is that the proportionate reliance on different sources is as follows: developing countries' own budgets, 37%; multilateral organisations, 33%; private investors, 18%; and, bilateral aid 12%. While governments remain a critically important source of financing for energy access, many have also opened up their energy sectors in full or in part to private investors in recent years. The need for capital and expertise has made public-private partnerships (PPPs) an important area of focus. The African Energy Leaders Group, launched in January 2015, is working towards universal energy access through PPPs and commercially viable regional power pools, and SE4All is working with countries to develop energy investment prospectuses, often including PPPs.

Development assistance (through bilateral or multilateral channels) continues to be an essential source for many energy access investments, typically in the form of loans at

23. The estimate includes capital investment made to provide households with electricity access and clean cooking access. For on-grid electricity access, it includes the costs of the first connection, grid extension and the capital cost to sustain an increased supply over time. For mini-grid and off-grid systems, the estimate includes capital costs and the cost of distribution lines. Operating costs, such as fuel costs and maintenance costs, are not included. Broader technical assistance, such as policy and institutional development advice, is also not included. Further information regarding the methodology used in this analysis can be found at *www.worldenergyoutlook.org/resources/energydevelopment*.

concessional rates or loans to projects deemed too risky by the commercial banking sector. The African Development Bank has contributed to financing around 2 GW of new generation capacity and over 15 000 km of transmission lines since 2009 (African Development Bank, 2015), while the OPEC Fund for International Development has turned a $1 billion pledge to alleviate energy poverty, made in 2012, into a revolving fund. The European Union has committed €3.5 billion ($3.9 billion) with the intention that it should leverage €30 billion ($33 billion) in power sector investments; and the US Power Africa initiative has achieved financial closure on 4 GW worth of projects, involving $9 billion of commitments from government and aid sources, and $20 billion from the private sector (USAID, 2015). The Global Alliance for Clean Cookstoves (a PPP) remains a key source of funding for clean cooking facilities, drawing on grants and investments from governments, corporations, civil society and others to support its goal of providing clean cooking facilities to 100 million households by 2020.

Increasing investment to the levels required to achieve universal access to modern energy cannot be achieved without the private sector as a key contributor. To enable this to happen, governments need to take steps to establish a supportive investment climate, implementing strong governance and regulatory reforms, improving the creditworthiness of the power sector and identifying and working with large anchor customers. This is particularly important in those regions where the private sector is least involved today; levels are reported to be particularly low in Africa (just 1%) (World Bank, 2015b).

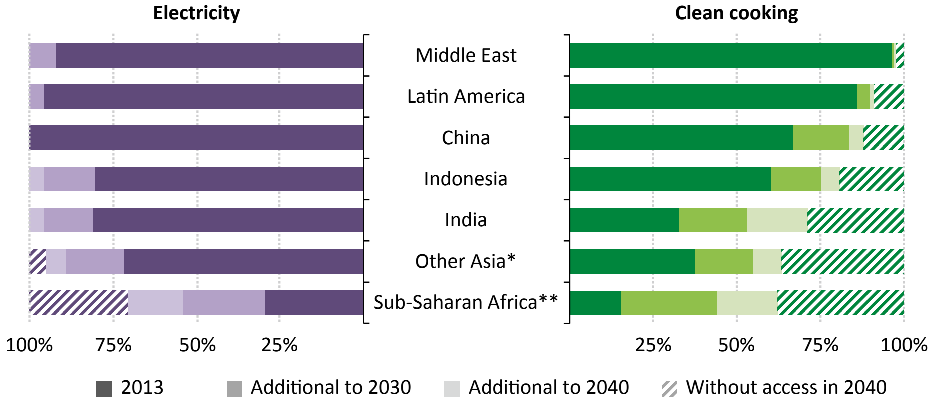
Outlook for energy access in the New Policies Scenario

In the New Policies Scenario, the number of people without access to electricity declines to around 810 million in 2030 and 550 million in 2040 (6% of the global population at that time). The population growth that occurs in parallel masks the fact that around 1.8 billion people gain access through to 2030, and that this increases to 2.7 billion by 2040. Global progress continues to take place at a dual speed. Nearly one billion people in sub-Saharan Africa gain access to electricity through to 2040, and yet half a billion remain without it at that time, while in developing Asia, the number of people without electricity falls by around two-thirds by 2030 (185 million) and stands at 50 million in 2040, just 1% of the Asian population at that time (Figure 2.26). Electricity access investments increase over time, and average $30 billion per year over the *Outlook* period. The additional global electricity demand in 2040 resulting from new access is around 640 TWh reflecting the low levels of per-capita consumption of many of those gaining access.

Sub-Saharan Africa starts to turn the corner around the mid-2020s, with the number of people without access to electricity beginning to decline. Over time, the remaining population without access becomes more concentrated in rural areas (around 90% of the total in 2040). Renewables (led by hydro) and natural gas are projected collectively to provide more than three-quarters of the additional on-grid electricity supply in 2040 for those who have gained access. Renewables alone account for two-thirds of the mini- and off-grid supply in 2040 having become increasingly competitive against diesel generation.

The scale of hydropower projects (though the date of their entry into service is particularly uncertain) means that they can have a huge impact on electricity access when they do come online if suitable arrangements have been made to deliver the additional power generation to households. Sub-Saharan Africa currently has a number of such projects underway – such as the Grand Ethiopian Renaissance Dam, Gilgel Gibe III and IV, Inga III and the Mambilla dam – and has huge remaining hydropower potential. However, large hydro projects alone will not solve energy poverty in rural areas: small-scale solutions, such as solar PV, mini-hydro and small biogas, are also needed.

Figure 2.26 ▷ Share of the population with access to electricity and clean cooking facilities by region in the New Policies Scenario



* Includes rest of developing Asia. ** Excludes South Africa.

In the New Policies Scenario, around 260 million people gain access to electricity in the countries of Southeast Asia, led by Indonesia, where universal access is attained by 2040. Full electrification is achieved in urban areas of Southeast Asia by 2030 and the region reaches almost universal access by 2040. India's high level of economic growth and large (and growing) population are strong influences on the pace of energy access. In the New Policies Scenario, India's national electrification rate reaches more than 95% by 2030 and universal access is achieved by 2040 (see Part B for more on the energy access projections for India). China is already reported to be very close to attaining universal access. In Latin America, Brazil has achieved good progress through its Light for All programme, which aims to achieve universal electricity access by 2018. Universal electricity access is reached in Latin America by the mid-2020s. In the Middle East, most countries have already reached electrification levels above 98%, but Syria and Yemen are lagging behind, with war and conflicts even reversing earlier progress.

The number of people in the world without access to clean cooking decreases by one-third to 1.8 billion in 2040 in the New Policies Scenario. Developing Asia still hosts the biggest population in this category at the end of the projection period, with half a billion people relying on the traditional use of biomass in India alone. In China, although universal access to electricity is achieved early in the projection period, the picture on access to clean cooking facilities looks very different, with around 10% of the population still lacking access in 2040. In sub-Saharan Africa, the switch to cleaner solutions is expected to happen in parallel with rapid urbanisation. The price of charcoal, which is widely used in urban areas of Africa today, is also expected to increase with higher demand and forest depletion, and more efficient cooking solutions then provide fuel (and monetary) savings to users, as well as better energy quality.

Globally, an average annual investment of $980 million is made in clean cooking technologies through to 2040. The largest portion is in LPG stoves in urban areas. LPG is also adopted in rural areas, but improved biomass cookstoves also represent an attractive solution for poor households, as capital and fuel costs are typically lower.

Oil market outlook

A new world of oil?

Highlights

- The plunge in oil prices has set in motion the forces that will lead the market to rebalance, via higher demand and lower growth in supply. This may take some time, as oil consumers are not reacting as quickly to changes in price as they have in the past, and, even though the rise of tight oil has created scope for more short-term flexibility on the supply side, there is still a significant time lag in the response of most sources of production to a change in price. In the New Policies Scenario the oil price reaches $80/bbl in 2020 before rising further to $128/bbl by 2040.
- Demand grows by almost 900 kb/d per year on average until 2020 and then follows a slower growth path to reach 103.5 mb/d in 2040. By then, India has added 6 mb/d to its current demand and China 5 mb/d, while OECD consumption falls by 11 mb/d. The transport and petrochemicals sectors are the main sources of growth, adding over 16 mb/d to 2040. Oil demand for aviation rises at the fastest pace, reaching 9 mb/d in 2040, as travel demand grows by 3.9% per year. The aviation industry's goal of carbon-neutral growth post-2020 is out of reach without offsets from other sectors. The lack of alternative fuels in aviation pushes up total kerosene use to 9.7 mb/d, behind only gasoline (23.3 mb/d) and diesel (30.2 mb/d).
- OPEC's decision to leave its production target unchanged has thrust non-OPEC producers into the front line of the market rebalancing. Cuts above 20% in upstream investment by many oil companies in 2015 – offset only in part by lower costs for supplies and services – feed through into lower medium-term projections of production in Canada, Brazil and Russia, among others; US tight oil stumbles, but ultimately continues its upward march, adding a further 1.5 mb/d by 2020.
- Non-OPEC production reaches a plateau at 55 mb/d before 2020 and then falls back, leaving OPEC countries to meet the remaining demand – although the countries with the largest potential to increase output, including Iran, Iraq and Venezuela, face a range of financial and political uncertainties. Iran's oil outlook has brightened with the prospect of sanctions relief, but raising long-term output to our projected 5.4 mb/d will be a major investment challenge.
- With upstream costs pulled down, at least for the next few years, and production shifting to lower cost areas in the Middle East, the average annual requirement for upstream oil and gas investment to 2040 is around $750 billion. Almost 85% of this sum is required to compensate for declining output at existing fields, rather than to meet increased demand – a reason why the scale of investment, even in a climate-constrained 450 Scenario, is not far from that of the New Policies Scenario, despite considerably reduced global consumption.

Oil price fall and the long-term outlook

One year on from the *World Energy Outlook-2014 (WEO-2014*), the starting point for a discussion about the oil market is completely different (IEA, 2014a). The oil price fell dramatically in the last months of 2014 and into 2015, as a further acceleration of supply, notably from North America, coincided with slower than expected demand growth, convincing Saudi Arabia and other key Organization of Petroleum Exporting Countries (OPEC) producers that an attempt at price defence through OPEC management of production would not be effective or warranted. The decision by OPEC members in November 2014 to leave their production unchanged shifted the bulk of the task of finding a new market equilibrium to the higher cost non-OPEC countries, with the oil price acting as mediator. Thus the stage was set for a new drama in 2015, with the spotlight on three issues: shrinking capital investment budgets in key non-OPEC producers – particularly in the United States – and how quickly this might affect future supply; how OPEC producers might weather the storm of reduced revenues; and how demand for oil in major consuming countries might pick up in response to lower prices.

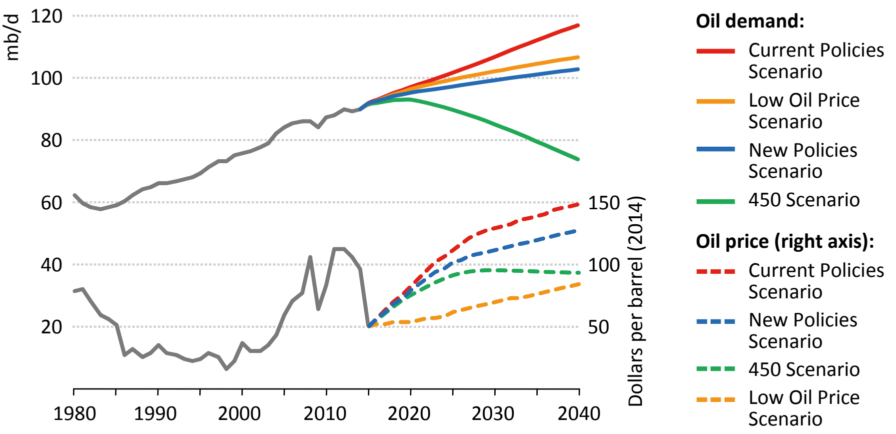
For a long-term outlook, the key question is how long the observed changes might last. Are we witnessing a primarily cyclical event, part of the usual ebb and flow of commodity markets? Or is the price decline a symptom of more deep-rooted structural changes in the way that we produce and consume oil, which can be expected to result in changes, too, in the strategic behaviour of the major resource-holders? In short: the question is whether anything has really changed – or, alternatively, whether everything has changed. Our answers to these questions span two chapters of this year's *Outlook*. In the current chapter, we focus on oil markets as they evolve in the New Policies Scenario (with brief consideration of the Current Policies and 450 Scenarios) in which, although there are structural elements at work, the recent price crash has strong cyclical elements. In Chapter 4, however, we consider a Low Oil Price Scenario, in which lower prices persist because of some more profound underlying changes in the balance of oil supply and demand.

In the New Policies Scenario, the oil market rebalances over the next few years in a way that leaves the oil price (in real terms) back at $80 per barrel (bbl) by 2020[1] (Figure 3.1), with further steady increases after that taking it to $113/bbl by 2030 and $128/bbl by 2040, the prices required in our World Energy Model to bring long-term supply and demand into equilibrium. Demand increases to around 103 million barrels per day (mb/d) in the 2030s but growth all but stops at this level, as relatively elevated price levels combine with policies and technological change to induce fuel switching away from oil and the adoption of more efficient vehicles. In the Low Oil Price Scenario, we postulate and examine conditions that would allow prices to remain lower for much longer: in this scenario, the oil price remains in the $50-60/bbl range until the 2020s, before a gradual rise takes the price to $85/bbl in 2040. These conditions are rooted in a near-term assumption of lower economic growth, which dampens oil consumption, but also some profound underlying changes in the way

1. The oil price is the average price for crude oil imports into IEA countries, used as a proxy for international oil prices.

the market operates on the supply side, engendered by a long-term shift in OPEC strategy, benign assumptions about geopolitical stability and stronger resilience on the part of key non-OPEC sources of supply (the role of US tight oil as a new balancing item in the global oil market is the subject of a special focus). Consumers eventually respond to lower prices by pushing consumption higher, up to 107 mb/d in 2040 (Table 3.1).

Figure 3.1 ▷ World oil demand and price by scenario



There are many variables, in addition to those shaping the differences between the New Policies Scenario and the Low Oil Price Scenario, that could change the longer-term balance in the oil market[2]: stronger climate policies that cut demand for oil; technological breakthroughs, for example, in the costs of batteries for electric vehicles, or an innovation that increases recovery rates on the oil supply side; or variations in the pace of growth in the vehicle fleet in emerging economies, to name a few. None of the scenarios here should be seen as a forecast, but our judgement is that the sort of market rebalancing seen in the New Policies Scenario is the more likely outcome in the medium term. The timing of this rebalancing is of course open: the forces at work in the Low Oil Price Scenario (notably lower near-term gross domestic product [GDP], the return of Iran to the international oil market and a robust outlook for tight oil in the United States) could well sustain a longer period of lower prices. Our view of the Low Oil Price Scenario, as formulated in Chapter 4, is that it becomes progressively less plausible the further it is extended into the future. If a lesson of the last few years is that high oil prices contain the seeds of their own demise, because of the dampening impact on demand and the encouragement to develop new resources, the Low Oil Price Scenario shows that the converse is ultimately also true.

2. Our oil price trajectories are illustrated as smooth trend lines: in reality, of course, prices will fluctuate within shorter time periods.

The Current Policies Scenario similarly sees consumption at higher levels than those in the New Policies Scenario, but for very different reasons: in the Current Policies Scenario demand is constrained only by those government policies already in place today, and (in the absence of more optimistic assumptions about supply) an ever higher price is required to bring production into line with demand. In the 450 Scenario, much stronger policy interventions to address climate change leads to a peak in oil demand by 2020. The oil price in this scenario remains below $100/bbl, but this does not feed through into low oil product prices, as governments are assumed to keep end-user prices at higher levels by means of taxes and subsidy removal.

Table 3.1 ▷ Oil and total liquids demand by scenario (mb/d)

		New Policies		Low Oil Price		Current Policies		450 Scenario	
	2014	**2020**	**2040**	**2020**	**2040**	**2020**	**2040**	**2020**	**2040**
OECD	40.7	39.4	29.8	39.9	31.3	40.1	34.4	38.8	20.5
Non-OECD	42.9	48.9	63.6	49.4	65.4	49.7	71.4	47.7	46.7
Bunkers*	7.0	7.6	10.0	7.7	10.4	7.8	11.2	7.3	6.9
World oil	**90.6**	**95.9**	**103.5**	**97.0**	**107.2**	**97.5**	**117.1**	**93.7**	**74.1**
Share of non-OECD	*47%*	*51%*	*62%*	*51%*	*61%*	*51%*	*61%*	*51%*	*63%*
World biofuels**	1.5	2.1	4.2	1.9	3.3	1.9	3.6	2.1	9.4
World total liquids	**92.1**	**98.0**	**107.7**	**98.9**	**110.4**	**99.5**	**120.7**	**95.8**	**83.4**

* Includes international marine and aviation fuels. ** Expressed in energy-equivalent volumes of gasoline and diesel.

Note: Further information on methodology and data issues may be found at *www.worldenergyoutlook.org/weomodel/*.

The story so far

A starting point for our oil outlook is a brief assessment of how oil consumers and producers have reacted to the price drop of 2014-2015, not only for the sense that this provides as to how the market might absorb its current overhang of supply and inventories, but also because of the factors in play that are of consequence for our long-term projections. The adjustment mechanism in the oil market is rarely smooth, but the forces that will eventually rebalance the oil market are visibly in motion, both on the demand and supply sides. However, in the absence of any unexpected acceleration in demand or disruption to supply, the process will take time to complete. Oil consumers are not reacting as quickly to changes in price as they have in the past. And, even though the rise of tight oil has created scope for more short-term flexibility on the supply side, there is still a significant time lag in the response of most sources of production to a change in price.

The most recent IEA estimates suggest that global oil demand[3] is set to increase by around 1.8 mb/d in 2015 (+1.9%), relative to 2014 (IEA, 2015a). This is well above the 0.9% average growth rate observed over the past ten years, helped by cold winter weather in early 2015

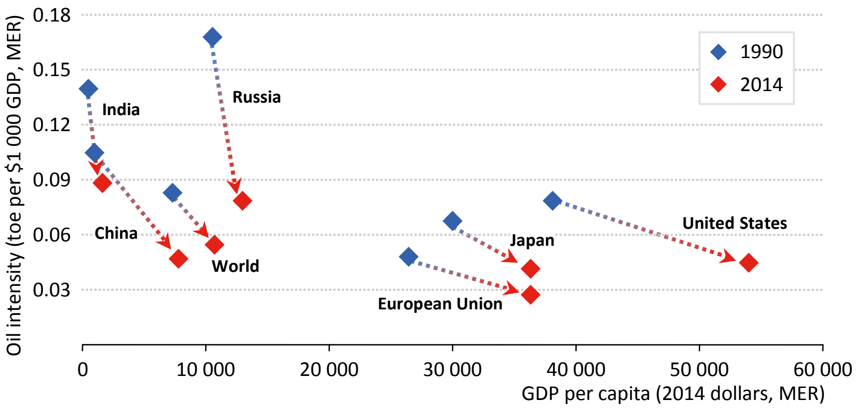
3. Demand numbers in this Outlook and those in the Oil Market Report are not directly comparable: please refer to *www.worldenergyoutlook.org/weomodel/* for a more detailed explanation of the differences, which arise from the underlying data used (monthly versus annualised data) and some methodological variations.

in Europe, northeast United States and China. However, it is still short of the way that consumption reacted to the 1986 oil price fall, the episode in market history with which the 2014 price fall is most often compared (see Chapter 4, Box 4.1). Following the price collapse in 1986, oil use grew by an average of 2.5% per year for the rest of the 1980s.

The response of global oil consumers in 2015 reflects some broader economic factors, such as the stronger US dollar limiting the extent of the oil price fall in local currencies in many importing countries. But it also reflects some trends that are more directly related to energy policies and the importance of oil to the economy:

- The role of oil in global economic activity is diminishing: the amount of oil consumed per unit of economic output has been steadily declining over recent decades, at a faster pace than the decrease in total energy intensity, a finding that holds true for widely different parts of the world economy, as illustrated in Figure 3.2. This means that GDP growth does not translate into oil consumption growth to the extent that it did in the past.

Figure 3.2 ▷ Trends in oil intensity and GDP per capita in selected countries and regions

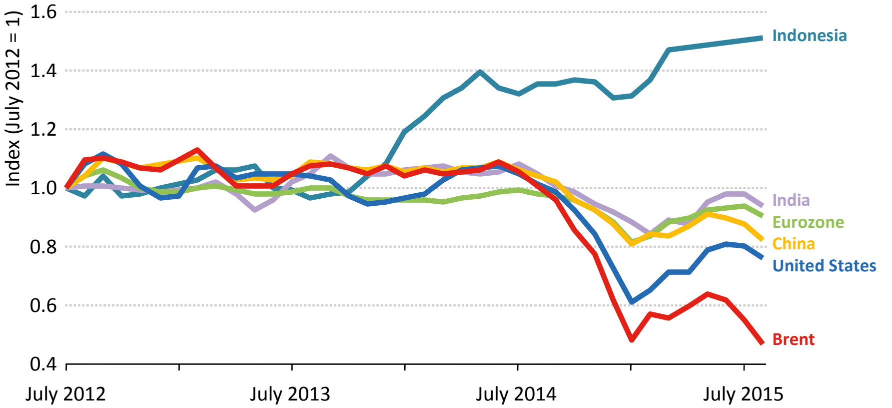


Note: toe = tonnes of oil equivalent; MER = market exchange rates.

- China, the country that over the last ten years has been responsible for around 60% of global oil consumption growth, is entering a less energy-intensive phase of its development. This transition is set to have profound implications for markets that have grown used to reliable levels of remarkable growth in Chinese demand for all fuels and energy technologies.
- Fuel-economy standards are increasingly widespread. Already, three out of every four passenger cars sold worldwide are subject to some measure of regulation on fuel efficiency and efforts to adopt such standards for heavy-duty vehicles are gaining momentum. As oil use increasingly concentrates in the transport sector, so these standards play a prominent role in decoupling rising demand for mobility from demand for additional barrels of oil.

- Globally, most consumers did not see anything like the same price reductions at the petrol pump as they saw in the headlines concerning the fall in the crude oil price (Figure 3.3). This was in part due to exchange rates effects; but in many emerging economies, governments also took advantage of the price decline to adjust end-user prices for oil products, whether through subsidy removal or by raising excise or transportation taxes. In Indonesia, subsidy cuts in mid-2013 and again in January 2015 mean that consumers have faced steadily higher prices in recent years. In India and China, adjustments to pricing and tax regimes kept the reduction in pump prices in the order of 10-20%, compared with the halving of the crude prices. Even in the United States, where taxes account for a smaller share of the pump prices than, for example, in Europe, and where the exchange rate consideration does not apply, the trajectory of gasoline prices moved slightly above that of crude oil, once the summer driving season began.

Figure 3.3 ▷ Index of gasoline pump prices in national currencies relative to the price of Brent crude oil in US dollars

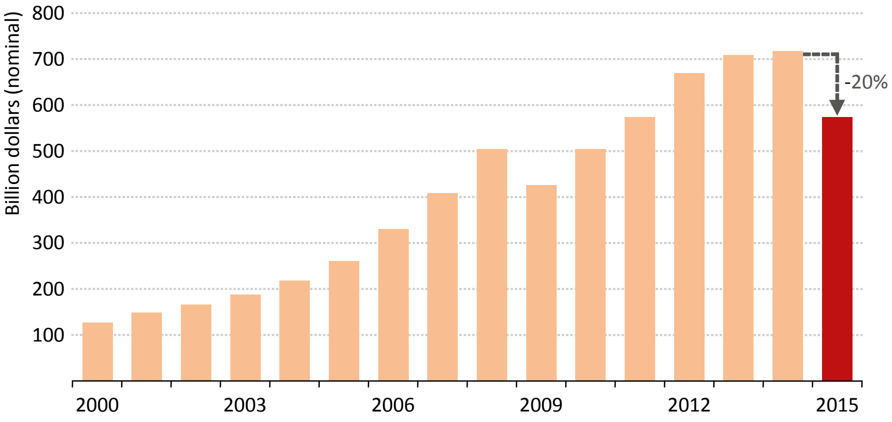


Source: Price data from Bloomberg Professional Service.

There is a risk of pressure on governments to restore subsidies when prices again start to rise, as consumers seek protection from the impact on their purchasing power. But if governments can maintain their resolve and permanently remove subsidies on oil consumption, this will have a lasting impact on the outlook for demand. If lower oil prices persist over a longer period, or are seen as likely to do so (a possibility discussed in the Low Oil Price Scenario in Chapter 4), all of the trends described above could be altered. Indeed, there are already some early indications from car sales data for 2015 in some markets that consumers are opting for larger vehicles than in 2014 – a development that could lock in higher levels of future oil use.

OPEC's decision to leave its production target unchanged implies that market rebalancing is likely to take place on two fronts: via a stimulus to demand, but also via a check on more expensive supply, almost all of which is non-OPEC. But the supply side of the oil market is typically slow to respond to movements in price. This is because of inertia in the system: projects operate with long-lead times and, once production has started, there is usually an incentive to keep producing – even when revenue is insufficient to do more than recover operating costs. In practice, the reaction of many operators to a price decline is three-pronged; maximise revenue from existing operations (which can even mean an increase in short-term output in some cases); cut costs where possible; and defer spending on new projects, especially those that are not close to completion. In the majority of cases, the large cuts in upstream oil and gas capital expenditure seen in many non-OPEC countries in 2015 have not yet fed through to supply (Figure 3.4). However, when this happens, it will play a pivotal role in rebalancing the market.

Figure 3.4 ▷ Global upstream oil and gas investment



Source: IEA analysis based on company announcements available by 1st October 2015.

The exception to this pattern is US tight oil, which has a much shorter investment cycle than traditional conventional projects, potentially making it much more responsive to price movements (a topic covered in detail in Chapter 4). Yet although tight oil production had flattened by the third-quarter of 2015 and started to fall back, the impact of lower prices on tight oil output has been far from instantaneous. Deeper effects may well occur in 2016, but the expectation that a swift tailing off in tight oil would lead to a rapid rebalancing in markets has proved to be misplaced.

One reason for the relatively resilient performance of tight oil has been that the lower oil price has influenced not just revenue, but also costs. As examined below (in the section on investment and costs), upstream costs more than doubled over the period 2000-2014 – following the trend in the oil price. The subsequent fall has also led to a reduction in costs, as activity levels are reduced; although there are differences across different parts of the industry, we estimate the reduction to be in the order of 10-15%. The way that these costs evolve promises to be a major factor in determining the oil price at which non-OPEC supply will bring the market to a new equilibrium.

Demand

Regional trends

Global oil consumption grows steadily over the period to 2020 in the New Policies Scenario, with anticipated price levels supporting the addition of almost 900 thousand barrels per day (kb/d) per year to demand. The main contributors to global oil demand growth over this period are China, which adds almost 350 kb/d to global demand on average each year, followed by the Middle East (200 kb/d) and India (180 kb/d). In OECD countries, oil demand continues its structural decline to 2020, despite the lower oil prices, led by Europe and Japan, which are the regions with the highest levels of taxes on oil products. After 2020, annual oil demand growth levels off in most regions, due to lower economic growth, increasing substitution of alternative fuels for petroleum products and the increasing accumulation of more efficient technologies across all sectors. Brazil is one of the exceptions with oil demand growth accelerating after 2020 as the rising middle class increasingly seeks to satisfy its demand for mobility and other energy services through the use of oil products. Nonetheless, even in Brazil, the oil intensity of economic output in 2040 is well below the level of today.

As in previous *WEOs*, the long-term view of oil demand in the New Policies Scenario is dominated by the projected shift in consumption towards Asia, despite policy measures taken in several countries to curb demand growth. China and India are the two main pillars of global oil demand growth, which is unsurprising, given that they are together expected to be responsible for 45% of global economic growth until 2040. But the future holds different prospects for oil demand growth in the two countries: although oil demand in China is projected to increase by almost 5 mb/d by 2040, more than two-thirds of this growth occurs by the mid-2020s (Table 3.2). The longer-term outlook for Chinese demand is subdued by the adoption of fuel-economy standards for passenger vehicles, the gradual restructuring of the economy and the expected levelling off in population by around 2030. India, by contrast, takes over the position as the engine of global oil demand growth by around the mid-2020s, adding two-thirds of its projected total increase of 6 mb/d by 2040 in the second half of the projection period. Although the government is actively pursuing policies to curb oil demand growth, such as the adoption of fuel-economy standards for passenger cars and, very recently, phasing out subsidies for diesel use, oil demand in India is projected to exceed that in the European Union by the early 2030s and reaches almost 10 mb/d in 2040, more than two-and-a-half-times the current level of consumption (see Chapter 12 for a detailed discussion of demand trends in India).

The Middle East sees oil demand climb by 3.5 mb/d to more than 11 mb/d in 2040. Oil products are subsidised in many countries of the Middle East – a major cause of runaway consumption growth and foregone revenue (and, in some cases, an explicit burden on government budgets). The recent fall in oil prices has strained public finances and increased the momentum behind pricing reform (see Chapter 2) across the region, including among the Gulf Cooperation Council (GCC) countries. The United Arab Emirates introduced a new pricing system in August 2015, under which diesel and gasoline prices, although still set by the government, are adjusted on a monthly basis to track international prices. Kuwait has likewise indicated its intent to cut fuel subsidies, albeit more gradually; but the major uncertainty is whether the GCC's largest economy, Saudi Arabia, will follow suit and complement its efforts on energy efficiency with some subsidy reform. The outcome would affect not only end-use consumption, but also have implications for the domestic power mix. The Middle East is also one of the few regions where oil is still widely used in the power sector, accounting for one-third of its generation today, as fossil-fuel consumption subsidies undermine the investment case for low-carbon alternatives.

Table 3.2 ▷ Oil demand by region in the New Policies Scenario (mb/d)

	2000	2014	2020	2025	2030	2035	2040	2014-2040	
								Change	CAAGR*
OECD	**45.2**	**40.7**	**39.4**	**36.9**	**34.4**	**32.0**	**29.8**	**-10.9**	**-1.2%**
Americas	23.2	21.8	22.0	21.0	19.8	18.6	17.3	-4.5	-0.9%
United States	19.0	17.3	17.5	16.5	15.4	14.2	13.1	-4.2	-1.1%
Europe	13.9	11.5	10.7	9.8	9.0	8.2	7.5	-4.0	-1.6%
Asia Oceania	8.1	7.3	6.6	6.1	5.6	5.2	4.9	-2.4	-1.5%
Japan	5.2	4.1	3.4	3.1	2.8	2.5	2.3	-1.8	-2.2%
Non-OECD	**26.5**	**42.9**	**48.9**	**52.9**	**56.9**	**60.5**	**63.6**	**20.8**	**1.5%**
E. Europe/Eurasia	3.8	4.9	5.1	5.1	5.2	5.2	5.2	0.3	0.2%
Russia	2.6	3.1	3.1	3.1	3.1	3.1	3.0	-0.1	-0.2%
Asia	11.5	20.8	24.6	27.4	30.1	32.5	34.4	13.7	2.0%
China	4.7	10.5	12.5	13.8	14.7	15.1	15.3	4.9	1.5%
India	2.3	3.8	4.8	5.8	7.0	8.4	9.8	6.0	3.7%
Middle East	4.3	7.6	8.8	9.3	9.9	10.4	11.1	3.5	1.5%
Africa	2.2	3.7	4.4	4.9	5.3	5.7	6.2	2.5	2.0%
Latin America	4.3	5.9	6.0	6.2	6.4	6.6	6.7	0.8	0.5%
Brazil	1.9	2.7	2.7	2.8	3.1	3.3	3.4	0.8	1.0%
Bunkers**	5.2	7.0	7.6	8.1	8.7	9.3	10.0	3.0	1.4%
World oil	**76.9**	**90.6**	**95.9**	**97.9**	**99.9**	**101.7**	**103.5**	**12.9**	**0.5%**
European Union	13.0	10.6	9.8	8.9	8.0	7.3	6.6	-3.9	-1.8%
World biofuels ***	0.2	1.5	2.1	2.6	3.1	3.6	4.2	2.7	4.1%
World total liquids	**77.1**	**92.1**	**98.0**	**100.5**	**103.0**	**105.3**	**107.7**	**15.6**	**0.6%**

* Compound average annual growth rate. ** Includes international marine and aviation fuels. *** Expressed in energy-equivalent volumes of gasoline and diesel.

While the pace of oil demand growth in Africa is second only to that in India, the total amount added, at 2.5 mb/d by 2040, is relatively small for a region of this size. Africa has large potential for oil demand growth – oil use per capita is still far below the world average – and energy sector reforms and a more sanguine economic outlook could further boost demand growth (IEA, 2014b). But in the New Policies Scenario, oil demand per capita in 2040, at 0.14 tonnes of oil equivalent (toe) per capita, is less than one-third of the world average, reflecting the still relatively low level of per-capita income on average across the continent. Similarly, the strong oil demand growth in Southeast Asia, at 2.0 mb/d by 2040, still means that oil demand per capita remains below the world average.

The impact of lower oil prices on oil demand in industrialised countries is quite muted. Overall demand already shows symptoms of saturation in many of these countries, and policy efforts to curb demand growth by regulating energy efficiency and promoting alternative fuels increasingly bear fruit. The United States, European Union, Japan and Korea all promote the efficient use of oil and have fuel-economy standards in place for the transport sector. The relatively high level of oil product taxation in these countries also means that the consumer feels only part of the drop in international oil prices, limiting the extent of a possible rebound of demand. The most recent policy development is the announced intention of the United States to extend fuel-economy standards for medium- and heavy-duty vehicles beyond the model year 2018, a development which is taken into account as part of the New Policies Scenario in this year's *Outlook*. The effect of this policy on curbing oil demand, however, is partially offset by a reduced long-term outlook for biofuels, as the low oil price environment and a lack of progress in advanced biofuels deployment cast doubts on the degree of future deployment beyond the US Renewable Fuel Standard that is currently in place.

Sectoral trends

Despite the growth in total demand, the oil intensity of GDP (i.e. the amount of oil used per unit of economic value) continues to decline. The services sector, the largest contributor to global GDP, uses 40% less oil per unit of value added today than it did just one-and-a-half decades ago. The industry sector, the second-largest contributor to global GDP and the second-largest oil consumer (when including petrochemical feedstocks), uses 30% less oil per unit of value added. In agriculture, the reduction is 20%. The decline in the oil intensity of GDP is partially a result of improved energy efficiency, but also a result of substitution effects. With these two factors, oil's share in the fuel mix fell to 31% of primary energy demand in 2014, compared with 36% in 2000.

In the New Policies Scenario, despite the growth in overall demand, the role of oil diminishes further; its share in the energy mix falls to 26% in 2040. The pace of decline varies by sector (Table 3.3). While the structural decline of oil intensity in the services sector continues at a rapid pace, this process is slower in the industry sector. One reason is the situation in the petrochemicals sub-sector, the largest industrial oil consumer, where soaring demand for plastic products in developing economies more than offsets further improvements and saturation effects in industrialised countries. For example, in China, historically an importer of polyethylene, the build-up of domestic manufacturing capacity boosts domestic oil demand. In India, demand for plastic rises at a faster rate than in the recent past: at 3 tonnes/capita, consumption of ethylene in India today is only one-sixth of the world average. Among OECD countries, the main exception is the United States, where the availability of domestically produced natural gas liquids (NGLs) is set to increase the country's role as a global exporter of petrochemical products. As a result, the oil intensity of the US industry sector declines at a much slower rate than in other industrialised countries.

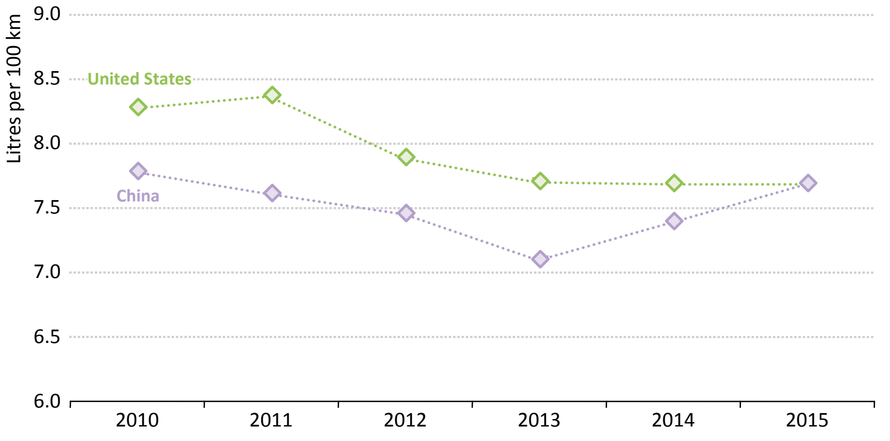
Table 3.3 ▷ World oil demand by sector in the New Policies Scenario (mb/d)

	2000	2014	2020	2025	2030	2035	2040	2014-2040	
								Change	CAAGR*
Power generation	5.8	5.3	4.4	3.7	3.2	3.0	2.8	-2.5	-2.4%
Transport	38.8	49.5	53.2	55.4	57.3	58.9	60.4	10.9	0.8%
Petrochemicals	9.5	11.5	14.1	14.9	15.8	16.6	17.2	5.6	1.5%
Feedstocks	8.1	10.1	12.5	13.3	14.1	14.9	15.5	5.4	1.7%
Other industry	4.9	4.9	5.1	5.1	5.1	5.1	5.2	0.3	0.2%
Buildings	7.9	7.6	7.2	6.6	6.2	5.9	5.8	-1.8	-1.1%
Other**	9.9	11.7	11.9	12.1	12.2	12.3	12.2	0.5	0.2%
Total	**76.9**	**90.6**	**95.9**	**97.9**	**99.9**	**101.7**	**103.5**	**12.9**	**0.5%**

* Compound average annual growth rate. ** Other includes agriculture, transformation and other non-energy use (mainly bitumen and lubricants).

Might a period of lower oil prices slow the global economy's move away from oil? The answer is not straightforward, as the impacts differ by sector, depending on the balance of policy action and of economic incentive (and the longevity of the period of lower oil prices, a question examined in more detail in Chapter 4). Taking road transport as an example, this is a sector that is heavily regulated today, with around three-quarters of passenger car sales subject to fuel-economy standards and policy-makers increasingly focusing on adopting such practices for heavy-duty vehicles as well. Such policy measures have long-term effects on oil consumption: in the New Policies Scenario, the average fuel consumption of new passenger cars, for example, falls to around 4 litres per 100 kilometres (l/100 km) in 2040, one-third below today's value. But in a lower oil price environment, consumer choices may partially erode such efforts. Since mid-2014, purchasers in some of the major car markets have increasingly opted for larger, more fuel-guzzling vehicles, such as sports utility vehicles, thus slowing the trend of lower average fuel consumption per vehicle, which is consistent with longer-term policy targets (Figure 3.5). The fuel consumption of new cars sold over the first-half of 2015 in the United States, at an estimated 7.7 l/100 km, remained at the same level as in 2014, following several years of decline. In China, the average car sold over the first-half of 2015 also consumed around 7.7 l/100 km, an increase over the 2014 level. In other markets, such a trend has been less pronounced or did not occur at all. In India, following the phase-out of diesel subsidies by the end of 2014, the average fuel consumption of new cars dropped by an estimated 20% over the first-half of 2015. In Germany, where taxes on oil products are generally high, the average fuel consumption of new cars continued to decline during 2014 and the first-half of 2015, albeit at a slower pace than previously.

Figure 3.5 ▷ **Fuel economy of new passenger car sales in the United States and China**



Notes: 2015 data include sales up to May for China and June for the United States. Figures for China are based on the New European Driving Cycle (NEDC); US figures are based on the Environmental Protection Agency Federal Test Procedure (FTP).

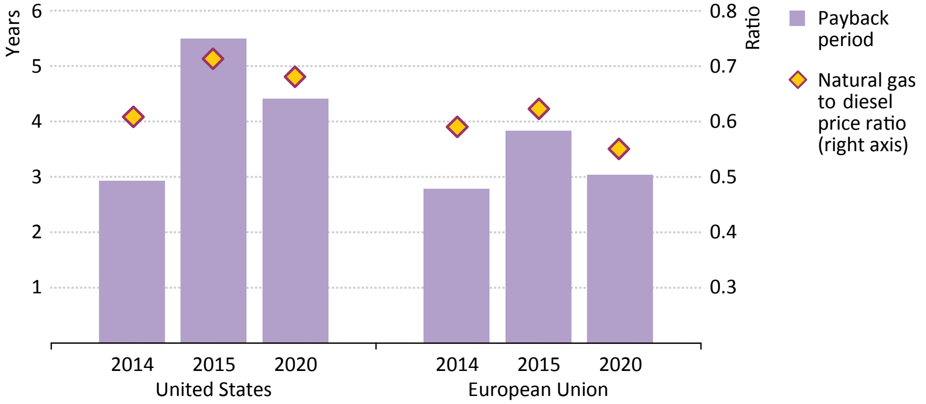
Sources: IEA analysis with Marklines, IHS Polk, US EPA, and University of Michigan Transportation Research Institute databases.

The use of alternative fuels, the second main option to reduce the oil intensity of road transport, is mandated or incentivised in many countries around the world. The market introduction of biofuels, for example, is typically supported through blending mandates, which require a certain amount of biofuels to be mixed in the final product. As biofuels are generally not cost-competitive with petroleum fuels outside Brazil, their future market uptake depends on continued government support. In the New Policies Scenario, we assume that such government support for biofuels generally persists: in 2040, the use of biofuels replaces more than 4 million barrels of oil equivalent per day (mboe/d), up from 1.5 mboe/d today.[4] Other possible transport fuels, such as electricity (i.e. electric cars) or natural gas, are either supported through dedicated subsidies or simply left to compete in the marketplace: their possible market uptake is, therefore, directly affected by the drop in oil prices.

The use of liquefied natural gas (LNG) in long-haul trucks has attracted a lot of attention in several countries, in particular in the United States (due to abundant gas supplies), but also in Europe (where the European Commission is encouraging the build-up of LNG refuelling stations). For truck operators, however, the recent drop in oil prices temporarily diminishes the business case for LNG, in particular in countries with low taxes on petroleum products (Figure 3.6). Over the longer term, however, rising international oil prices in the New Policies Scenario reverse this trend, with 160 billion cubic metres (bcm) of gas replacing 2.8 mboe/d of oil in 2040 in road transport, almost four-times as much as today.

4. In a Low Oil Price Scenario (Chapter 4), we explore the implications of a potential decrease of this government support in a low oil price environment.

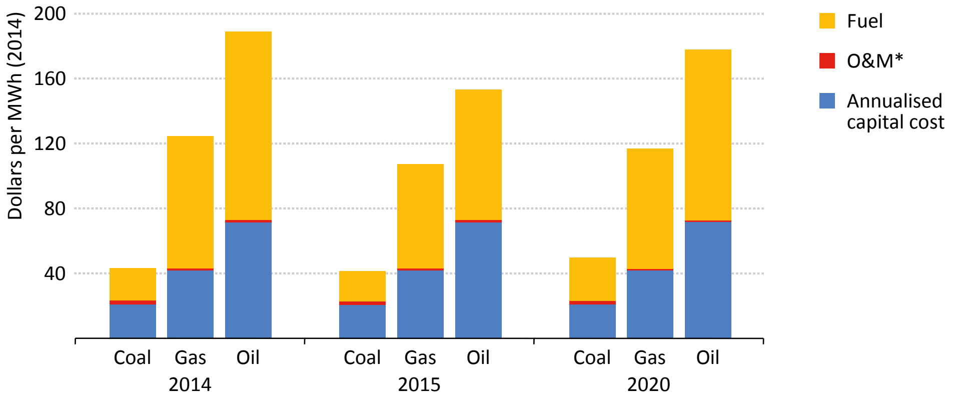
Figure 3.6 ▷ Payback periods of LNG-powered long-haul trucks in the United States and European Union in the New Policies Scenario



Notes: Assumes annual base mileage of 200 000 km in the United States and 130 000 km in the European Union. Natural gas prices are IEA domestic end-user prices for the services sector (including taxes), assuming a distribution cost of \$2.5 per million British thermal units (MBtu) and, in the case of the United States, an additional liquefaction cost of \$3/MBtu. The cost premium for LNG trucks over diesel trucks is assumed as \$75 000 in the United States and \$55 000 in the European Union, reflecting differences in typical truck types and sizes by region. No subsidies are assumed.

The link between oil prices and fuel switching in industry is likewise not clear-cut. Oil use in industry, at more than 16 mb/d today, serves a variety of purposes, including provision of thermal energy or motive power, use in off-road vehicles and use as a petrochemical feedstock. Much of this oil use is impossible or difficult to replace: more than 60% is used as a feedstock in the petrochemical industry and around 5% for off-road vehicles in the construction and mining industry. However, of the remainder, an estimated 5.5 mb/d is currently used either in industrial boilers for steam generation or for process heat, where a variety of fuels can be used – biomass, coal, oil or natural gas. Many industrialised countries first used coal for these purposes, which was later abandoned in favour of oil (and then gas), with the preferred fuel depending on regional and plant-specific circumstances, including the availability and price of the fuels and the environmental impact of their combustion. Some emerging economies are undergoing similar stages of development, particularly China (the largest industrial energy consumer in the world), where coal currently provides around 80% of steam generation. But air pollution concerns are pressing in China, and the reduction of coal use in industrial applications is a stated government intention. In this light, the current drop in oil and natural gas prices may offer a window of opportunity to address air pollution concerns: although coal-fired steam generation is still more cost-competitive, heat generation costs from oil- and gas-fired industrial boilers are much lower than they were just a year ago (Figure 3.7). But the switch away from coal is not easy, requiring time to plan and implement as well as significant capital investment (including the potential provision of extra fuel storage, the replacement of burners and adaptation of the boiler size). This limits, in practice, the short-term effects on industrial oil demand of a period of lower prices. Over the longer term, the question becomes moot in the New Policies Scenario, as the increase in oil prices undercuts the economic arguments in favour of oil-fired boilers (natural gas offers in many cases a cheaper and cleaner alternative for those looking to switch away from coal).

Figure 3.7 ▷ Heat generation cost of fossil-fuel based industrial boilers in China in the New Policies Scenario



* O&M = operation and maintenance costs.

Focus: oil use in aviation

The aviation sector plays an important role in overall oil demand. At 5.4 mb/d, domestic and international air travel is the second-largest oil consumer in the transport sector, following road transport, consuming more than the entire global residential sector. Despite aviation's share in transport oil demand decreasing slightly over the past decade and a half, to 11% in 2014, oil use in aviation is still on the rise – because of steady growth in travel demand, and, in part, the lack of suitable alternatives to oil. Consumption is particularly strong in international aviation bunkers, increasing by 2.5% per year over the past one-and-a-half decades, faster than any of the other large oil consuming sectors. For this *Outlook*, we therefore provide a brief summary of some of the most important factors explaining historical and future oil demand from the aviation sector.

Aircraft are used for many purposes, ranging from passenger travel to cargo transport and military uses, with a wide variety of aircraft sizes and trip lengths. Passenger travel is by far the most important aviation segment, with revenues in 2014 exceeding $560 billion, compared with around $60 billion from cargo (IATA, 2015). The activity of air travel is commonly measured in terms of revenue passenger-kilometres (RPK) for passenger travel and revenue tonne-kilometres (RTK) for cargo.[5] RPKs were an estimated 5.8 trillion in 2013,

5. RPKs refer to the number of passengers that generate revenue multiplied by the kilometres they fly. RTKs refer to the number of tonnes carried which generate revenue multiplied by the kilometres they are flown.

while RTKs were around 0.2 trillion.[6] Passenger air travel demand has seen a spectacular growth over the past 15 years, at an annual average of 4.9%, significantly exceeding average income growth per capita (2.5% per year).[7] As a result, RPKs have doubled since 1998, despite a temporary slowdown in growth following the terrorist attacks in the United States in 2001 and, in several industrialised countries, during the financial crisis of 2008-2009.

More than half of today's travel demand arises within and from North America and Europe. China, at around 700 billion RPKs in 2013, is a distant third, although demand has been growing rapidly over the past 15 years, contributing almost 20% to global RPK growth, second only to Europe. The relative importance of aviation markets can depend on individual circumstances: in Japan, for example, RPKs are relatively low, as domestic distances are short and the high-speed rail network is well developed.

RPK growth by region is generally correlated with per-capita income and depends on the number of flights per year and per capita, average flight distances and average flight occupancy. Beyond income, RPK growth is also linked to policy frameworks such as competitive aviation markets and the provision of improved infrastructure. Air transport liberalisation has spurred demand, with an influx of new low-cost carriers supporting substantial falls in costs and increased direct services. The resultant fall in prices and travel times has given a substantial boost to travel and cargo demand. Globally, more than one-quarter of available seat capacity today is supplied by low-cost airlines and the share in Southeast Asia exceeds 50%. Improving existing airports or building new ones can also boost RPKs in places where the availability of airports has been a bottleneck. The average number of movements (i.e. arrivals and departures) per airport has grown from 8 000 per year in 1980 to more than 18 000 today and airport connectivity has doubled, from around six different destinations offered on average per individual airport in 1980 to 12 different destinations today, supporting RPK growth (Airbus, 2014).

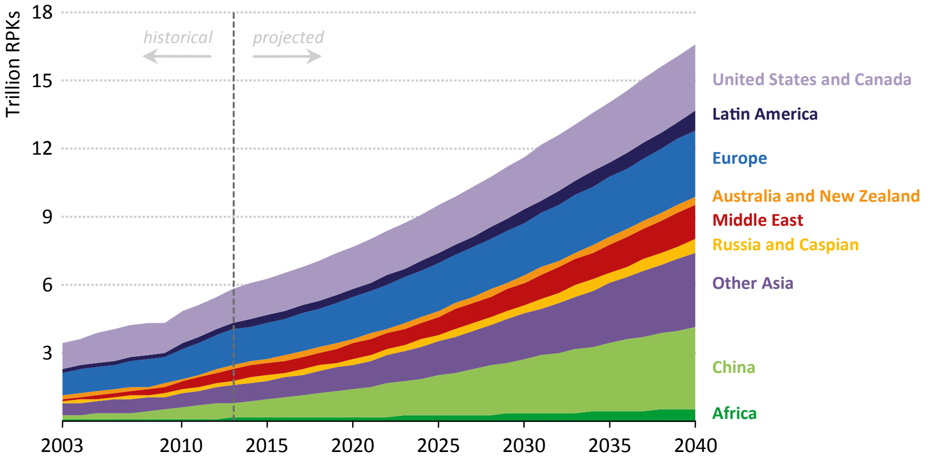
In the New Policies Scenario, global RPKs continue to grow at a rapid pace; growth averages 3.9% per year and total demand reaches more than 16 trillion RPKs in 2040 (Figure 3.8). China becomes the engine of growth in air travel, contributing almost 30% of the global growth of RPKs to 2040, followed by other countries in developing Asia (22%). Our projection of RPK growth in the New Policies Scenario falls within a wide range of projections from other sources. It is closest to those of the International Air Transport Association (IATA),

6. RPKs and RTKs are not strictly comparable in their importance for fuel use, given the different mass that is transported. RPKs can be adjusted to RTKs using standard passenger weight and adjusting for additional baggage and the extra mass, such as for seats or safety equipment that need to be carried on a passenger aircraft. There is no consensus on the choice of the appropriate factor, but, typically, 1 RPK carries between 77 kilogrammes (kg) to 160 kg, depending on what is actually included. For approximation purposes, 10 RPKs can therefore be assumed to roughly correspond to 1 RTK.

7. A detailed review of publically available historical data for the aviation sector was conducted for an update of the IEA's Mobility Model (MoMo) and is used for the analysis in *WEO-2015*. It includes data from the International Civil Aviation Organization, aircraft manufacturers such as Airbus, Boeing and Embraer, and the Japan Aircraft Development Corporation. Reported values therefore can differ from other sources.

which projects a global growth in RPKs of 4.1% per year over 2012-2032 (it is 4.2% in the New Policies Scenario over the same time period). But it is significantly lower than, for example, those of Airbus, Boeing or the International Civil Aviation Organization (ICAO), which project RPK growth of 5.0-5.5% per year over the next two decades. An analysis by the International Transport Forum suggests that such high growth rates would be achievable with a highly dynamic evolution of networks, involving the strong improvements in connectivity and frequency that would be associated with a continued strong liberalisation of the airline industry (ITF, 2015). A more static view of network evolution, without further improvements to connectivity, would limit RPK growth to 2.8% to 2030 and 2.4% thereafter. Our projections imply a middle-of-the-road development that is compatible with existing targets (such as China's plans to build another 100 airports by 2020, in addition to more than 180 commercial airports today), but does not anticipate a full extension of historical trends.

Figure 3.8 ▷ Revenue passenger-kilometres in aviation by region in the New Policies Scenario

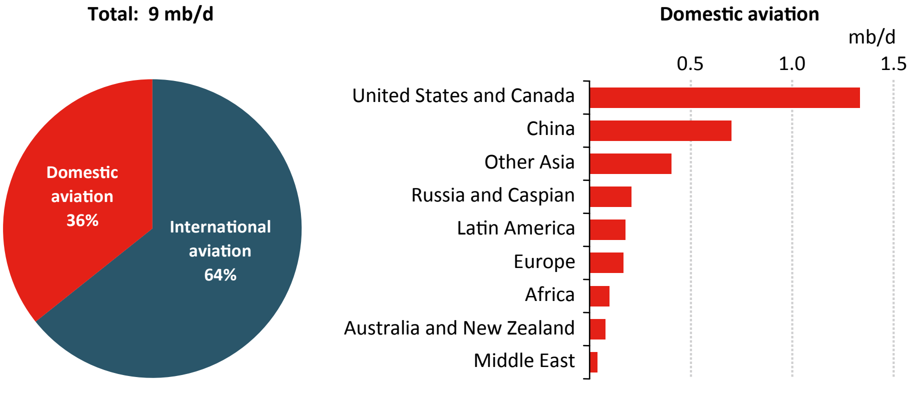


Notes: Regional RPKs include flights within and from a region. Regional groupings are geographical and may differ from those reported in other tables and figures.

While aircraft manufacturing is highly concentrated, with Airbus and Boeing together accounting for 85% of the market for aircraft with capacity of more than 100 seats, the airline industry is fragmented. There are over 2 000 airlines operating more than 20 000 aircraft worldwide. There can be hundreds of airlines operating in some regions, such as Asia or Europe and in most regions the top four airlines handle only 20-40% of activity. The main exception is the United States, where, following a number of mergers in recent years, air travel is dominated by only four airlines, with a combined share of 70% of the market (JDAC, 2014). The industry is likely to see further consolidation in mature markets, reflecting increasingly fierce competition and the capital intensity of the airline industry, with costs of individual aircraft ranging from several tens of millions of dollars to a few hundred million dollars. In the rapidly growing markets in the developing world, however, the liberalisation process is less mature and more opportunities remain open for new entrants.

The high price of oil in recent years has increased the pressure on costs: airlines spent more than $200 billion on jet fuel per year over the period 2012-2014, making up 30% of their total expenses, compared with only $65 billion in 2004 (17% of total expenses) (IATA, 2014). Nevertheless, airlines have been able to increase their profitability, partly as a result of successful efforts to save fuel. Many of the measures taken were related to operational practices, such as reducing on-board weight, cruising at higher altitudes, making better use of flight-management systems, conducting deeper analyses of weather conditions, redesigning hubs and schedules to alleviate congestion and pooling resources to purchase fuel in bulk through alliances with other carriers. Airlines have also been actively modernising their fleets with more fuel-efficient airplanes, purchasing larger models, while also increasing the number of seats to increase the density of cabin layouts and thereby load factors and utilisation. As a result, growth in oil demand in the aviation sector has been at only one-third of the rate of growth of RPKs over the past 15 years. In the New Policies Scenario, aviation oil demand continues to rise, with oil demand reaching 9 mb/d by 2040, or 15% of total transport oil demand (Figure 3.9). Growth in oil demand from aviation is faster than that of any other sector, at 1.9% per year, which is almost half of the rate of RPK growth.

Figure 3.9 ▷ Oil demand in international and domestic aviation by region in the New Policies Scenario, 2040



Notes: Domestic aviation demand by region is the fuel used for journeys within individual countries summed together to the regional level. Regional groupings are geographical and may differ from those reported in other tables and figures.

Reducing the airline industry's average fuel consumption and carbon-dioxide (CO_2) emissions (the aviation sector was responsible for 2.5% of global energy-related CO_2 emissions in 2013) has been the subject of much debate. On the policy side, the European

Union (EU) in 2012 included all flights from, to and within the European Economic Area in the EU Emissions Trading System (ETS), but then suspended the application of the EU ETS requirements to flights to and from non-European countries and made further amendments and exceptions for the period 2013-2016, following an agreement by the ICAO Assembly to develop by 2016 a global market-based mechanism to address international aviation emissions, to be applied by 2020. The ICAO Assembly has already adopted goals of reaching a global annual average fuel efficiency improvement of 2% by 2020 and an aspirational global fuel efficiency improvement rate of 2% per year from 2021 to 2050, with the objective of achieving carbon-neutral growth after 2020. While the projections in the New Policies Scenario on a global level are broadly in line with these targets, the emissions target is not achieved within the sector itself: in the New Policies Scenario, rising oil use means that emissions rise at 1.9% per year to 1.3 gigatonnes (Gt) in 2040 (3.6% of global CO_2 emissions). To reach the stated carbon-neutral growth would require a stronger uptake of alternative low-carbon fuels, of which advanced biofuels currently appear to be the only option that can comply with the very specific requirements of the airline industry, including fuel quality. In the New Policies Scenario, advanced biofuel use rises only to around 120 000 barrels of oil equivalent in 2040, given the limited progress to produce these fuels so far (despite the airline efforts to promote them). This means that, in order to meet its targets, the airline industry would need to offset its carbon emissions growth after 2020 through market-based measures.

Trends by product

Among the oil products, the fastest growing remains ethane, with its use expanding by 70% to 4 mb/d by 2040, on the back of ample availability. Petrochemical sector growth also pushes demand for other feedstocks, liquefied petroleum gas (LPG) and naphtha, which rise to 9.3 mb/d and 7.8 mb/d respectively. Gasoline loses its dominance in the transport sector and its use reaches a plateau at under 24 mb/d in the 2030s, up by only 1 mb/d from 2014: the increase in non-OECD gasoline demand is largely offset by the decline in OECD countries. Diesel demand in transport increases much more rapidly, with an incremental 5.7 mb/d pushing the total up to almost 24 mb/d in 2040, although recent controversies regarding diesel's contribution to air pollution offer some downside to this projection (Box 3.1) and total diesel demand growth is also moderated by a 2.1 mb/d reduction in non-transport diesel use. Kerosene demand grows at a relatively rapid 1.6% per year, to reach 9.7 mb/d, pulled higher by the aviation sector. Fuel oil demand is almost 1 mb/d lower by 2040, as its use for power generation falls while fuel oil bunker volumes remain stable (diesel and LNG account for all of the incremental marine freight demand).[8]

A review of the evolution of major regional product markets in the New Policies Scenario reveals some major changes in their composition and relative importance (Figure 3.10). The US gasoline market, which currently accounts for 9% of global oil demand, loses its top

8. For a more in-depth discussion of *WEO* assumptions on low-sulphur marine fuels, see *WEO-2014* Chapter 3, Box 3.2.

spot to Chinese gasoline by 2040 and sees its share of total oil demand cut by half. India's diesel market emerges as the fourth-largest product market by the end of our projection period. While the list is dominated by transport fuels, by 2040 Chinese demand for naphtha for petrochemical manufacturing makes this product market one of the ten largest in the world. By 2040 China has the biggest gasoline, diesel and naphtha markets in the world.

Box 3.1 ▷ Is there a downside for diesel?

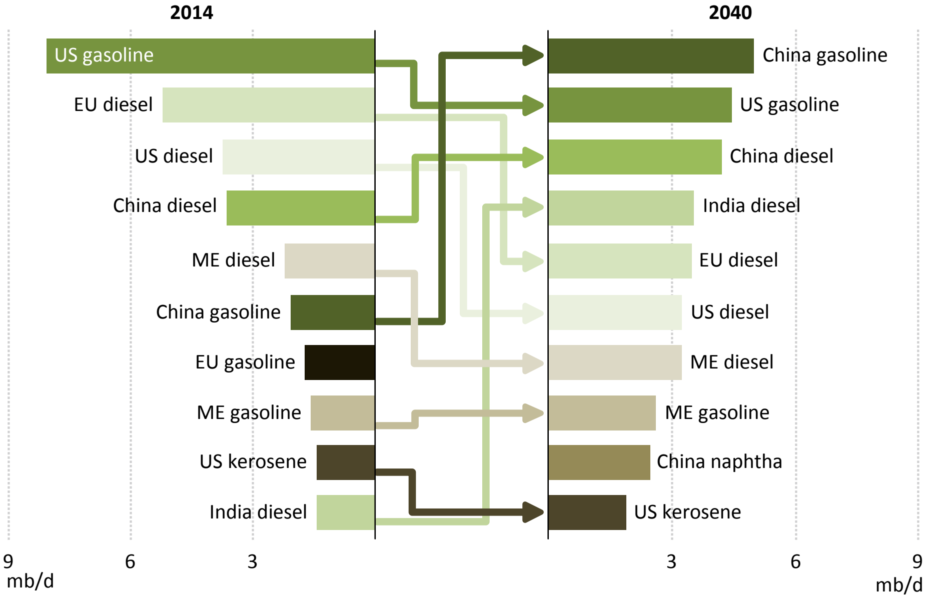
Individual oil products are rarely in the news during periods of low prices, but diesel bucked this trend in late-2015 with a wave of negative coverage that could, in some countries, have implications for policy, consumer preferences and future fuel consumption trends.

Diesel compression engines have inherently higher fuel efficiency than gasoline combustion engines, for vehicles of comparable size, but they face higher costs to reduce the emissions of some air pollutants. Reducing these emissions requires effort from refiners and car manufacturers, with refiners charged by regulation in many countries with producing low-sulphur diesel and car manufacturers required to find ways to minimise the release of nitrogen oxides (NO_x) and particulate matter from car exhausts. Treating exhaust fumes to remove NO_x and particulates can affect performance and reduce the vehicle's fuel efficiency. The crisis faced by Volkswagen, one of the world's biggest automakers, came about because it introduced software controls for its diesel cars that allowed compliance with the mandated emissions limits while being tested, but then allowed higher emissions during normal on-road use.

This episode has reinforced existing concerns in some quarters over the impact of emissions from diesel engines on air quality and has sparked a debate in many European countries over the tax (and consequently, price) advantage that diesel often enjoys relative to gasoline. The implications of this debate could be significant. Diesel is an important fuel for passenger cars in Europe: two-thirds of global passenger light-duty vehicle (PLDV) diesel consumption occur here. But worldwide PLDVs account for only 12% of road diesel use (and just over 9% of total diesel demand). The bulk of diesel consumption, now as in our projections, comes from road freight, where there are no large-scale alternatives to diesel for the moment.

In our projections for Europe, diesel use in PLDVs grows more slowly than demand for gasoline, but still holds more than half of this sector's demand in 2040. If, as a result of a shift in policy and/or consumer preference, diesel were to lose ground more quickly than we project, this might be a problem for some of Europe's largest car manufacturers, that have largely focused in recent years on developing and manufacturing diesel engines, in part to meet CO_2 emissions standards. But it would also bring some relief to the beleaguered European refining sector, easing their dependence on diesel to support refinery margins and providing an outlet close to home for a least a part of Europe's excess gasoline.

Figure 3.10 ▷ Top-ten global product markets in the New Policies Scenario



Notes: US = United States; ME = Middle East. European Union (EU) gasoline drops out of the list of top-ten markets in 2040, while Chinese naphtha enters the list.

Production

Resources and reserves

Our aggregate estimates of the remaining technically recoverable resources of oil have not changed significantly from last year (Table 3.4), but some of the country numbers have been revised (sometimes by up to 30%) as we have completed the incorporation in the figures of the data from the 2012 United States Geological Survey (USGS) update. For conventional oil, the USGS estimates of undiscovered oil and reserves growth provide the foundation for our calculations.[9] The main change at global level is a shift of some resources from the category crude oil to natural gas liquids, as a result of an ongoing effort to attribute condensate output (and therefore, resources) to NGLs, in order to unify our approach across all modelled regions.[10] This will also improve our natural gas modelling and analysis by reflecting more accurately the role of NGLs in upstream economics.

9. Because USGS did not publish their new estimates of "known" oil, these new estimates of recoverable resources now combine USGS undiscovered, USGS reserves growth and IEA estimates for known oil (we previously relied on the known oil values published in the USGS 2000 assessment).

10. Statistics of condensates output usually include condensate with NGLs for OPEC countries and with crude oil in non-OPEC countries.

Table 3.4 ▷ Remaining technically recoverable oil resources by type and region, end-2014 (billion barrels)

	Conventional resources		Unconventional resources			Total	
	Crude oil	NGLs	EHOB	Kerogen oil	Tight oil	Resources	Proven reserves
OECD	**320**	**150**	**809**	**1 016**	**118**	**2 414**	**250**
Americas	250	107	806	1 000	83	2 246	233
Europe	60	25	3	4	17	110	12
Asia Oceania	10	18	-	12	18	58	4
Non-OECD	**1 908**	**409**	**1 068**	**57**	**230**	**3 672**	**1 456**
E. Europe/Eurasia	265	65	552	20	78	980	146
Asia	127	51	3	4	56	242	45
Middle East	951	155	14	30	0	1 150	811
Africa	320	87	2	-	38	447	130
Latin America	244	50	497	3	57	852	325
World	**2 228**	**559**	**1 878**	**1 073**	**347**	**6 085**	**1 706**

Notes: Proven reserves (which are typically not broken down between conventional/unconventional) are usually defined as discovered volumes having at least 90% probability that they can be extracted profitably. EHOB is extra-heavy oil and bitumen. The IEA databases include NGLs from unconventional reservoirs (i.e. associated with shale gas) outside the United States, assuming similar gas wetness to that seen in the United States, because of the lack of comprehensive assessment; these unconventional NGLs resources are included in conventional NGLs for simplicity.

Sources: IEA databases; BGR (2014); BP (2015); OGJ (2014); US DOE/EIA/ARI (2013); USGS (2012a, 2012b).

For unconventional oil resources, a variety of sources are used, in particular the US Department of Energy/Energy Information Administration (EIA) report for global tight oil resources, as it remains the only available worldwide survey (US DOE/EIA/ARI, 2013). Although the full extent of unconventional resources is very poorly known, the amounts are so large that their depletion hardly affects our projections to 2040. The key exception is the extent of tight oil resources in the United States: depending on the resource estimate used, tight oil production in the United States can either peak and fall back as early as in the 2020s or can be maintained at a higher level until late in our projection period. The EIA/ARI report put the remaining technically recoverable resources in the United States at 63 billion barrels, but EIA has since upgraded this to 88 billion barrels in its Reference case (US DOE/EIA, 2015), though it acknowledges the large uncertainties by investigating low and high resource cases. For this edition of the *World Energy Outlook*, we have used a somewhat conservative value of 60 billion barrels of remaining technically recoverable resources, higher than in *WEO-2014* but below the EIA Reference case, leading to a peak in US tight oil production around 2020.

The basis for our conservatism is the significant differences between EIA and USGS estimates for the same plays. These can mainly be traced to differences in assumptions about possible well spacing. For example, for the Three Forks formation in the Bakken shale oil play, USGS assumes 1.5 wells per square mile, while EIA assumes 4 wells per square mile in its Reference case. Though the EIA spacing more correctly represents the drainage area of each well, it implies more than 100 000 wells in the Three Forks alone, a number which may require much more favourable levels of both social acceptance and logistical conditions. In addition, EIA assumes larger resources in the Permian play than USGS does, but because the Permian is characterised by multiple producing layer (some shale and some conventional), USGS may be accounting for some of those under its conventional reserves growth.

Concerning NGLs resources in shale gas plays, for the United States we have taken into account the EIA estimates for such "unconventional" NGLs. Indeed, although the early shale gas plays, such as the Barnett or the Haynesville, were fairly dry, there is now little doubt that the massive Marcellus shale gas play (as well as the Utica and some others) is producing a significant amount of NGLs. As a result, we now project higher levels of NGLs production in the United States throughout the projection period.

Proven reserves[11], as published by the *Oil and Gas Journal* or the *BP Statistical Review* (and mostly taken from government sources when available) are largely unchanged compared to last year, indicating that all production since the last review has been replaced by new reserves. The drop in oil prices, if it persists, could result in downward revisions as some reserves become uneconomical and move from the "proven" to the "contingent" category. However many government and company numbers have not yet been revised: possible downgrades will become known at the end of 2015.

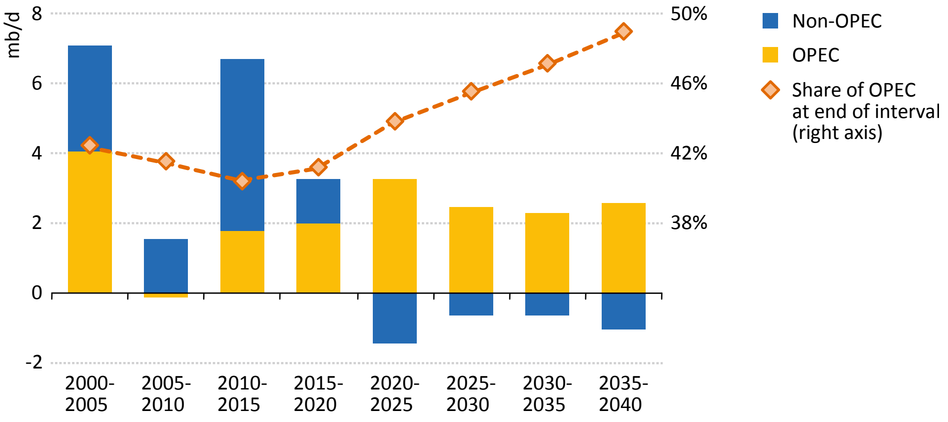
Production prospects

The oil production outlook to 2040 goes through two distinct phases. In the first phase, through to 2020, non-OPEC still plays a part in global growth. By the early 2020s, however, this phase ends as a result of cuts in investments in response to lower revenues, which finally affect production even from projects with relatively long-lead times (as discussed in Chapter 4, a typical time lag between final investment decision and first production from a new field development, with the notable exception of tight oil, is in the 3-6 year range).

After 2020, even though oil prices reach levels that allow upstream investment to pick up again, the collective output of non-OPEC countries does not resume growth, particularly once production from the United States – so important in the market over the decade to 2020 – reaches a plateau and then enters a gradual decline. As it does so, the United States yields, in the mid-2020s, the top spot in the global output ranking to Saudi Arabia. From the 2020s onwards, the onus for meeting continued growth in global consumption (and compensating for gradually declining non-OPEC output) shifts to OPEC countries. As a result, the share of OPEC countries in global oil production is projected to see a steady increase over the coming decades (Figure 3.11).

11. The supply modelling relies on estimates of the remaining recoverable resource, rather than the (often more widely quoted) numbers for proven reserves.

Figure 3.11 ▷ Change in non-OPEC and OPEC oil production by five-year periods in the New Policies Scenario



Oil production by type

Conventional crude remains by far the largest single component of oil output, but its pre-eminence is gradually eroded by the rise of other types of oil: extra-heavy oil and bitumen (EHOB) on one side, and very light crudes such as tight oil and natural gas liquids, on the other. By 2040, conventional crude oil accounts for only 66% of total oil production, compared with 87% as recently as 2000 and 76% today. However, its declining share in total output does not mean that investment in new conventional resources becomes a less pressing need. Production from existing conventional fields is set to fall by almost two-thirds by 2040[12], so meeting the projected output levels still requires a formidable commitment of capital. By the end of our projection period, some 39 mb/d of production has to come from conventional oil fields that are at present either awaiting development or, in some cases, awaiting discovery (Table 3.5). Taking oil and gas together, around 85% of the upstream investment over the period to 2040 is to compensate for declines in existing fields, i.e. to keep production flat at today's levels, rather than to meet the increase in demand.

With conventional crude output only just below today's levels in 2040, rising production of unconventional oil and NGLs accounts for all the net growth in oil production. Although the spectacular rise of tight oil has cornered much attention in recent years, the overall contribution from this source falls behind that of EHOB by the 2030s and remains well behind global output of NGLs. Outside the United States, our assessment of the prospects for tight oil has been revised downwards since *WEO-2014*, reflecting the difficulty of mobilising the necessary investment over the next few years in a lower price environment. This delays tight oil production growth in places like Argentina, Mexico, China and Canada, with the

12. This calculation is based on observed decline rates that are derived from actual production histories of fields of different types from around the world, i.e. they include the effect of investment by operators to mitigate decline in these fields.

prospects for Russia also held back by restricted access to some of the critical technologies. After 2020, countries outside the United States collectively increase their production of tight oil to 1.7 mb/d by 2040, but this is not enough to offset the projected decline in output from the United States (which still accounts for two-thirds of global tight oil output in 2040). Production from the Arctic shelf is projected to play only a marginal role in global supply, with output reaching 0.2 mb/d by 2040. This could be increased if countries choose to incentivise development through favourable tax treatment, but otherwise the high anticipated costs of development push Arctic projects beyond our 2040 time horizon.

Table 3.5 ▷ World oil supply by type in the New Policies Scenario (mb/d)

	2000	2014	2020	2025	2030	2035	2040	2014-2040	
								Change	CAAGR*
Conventional production	**73.8**	**81.9**	**82.6**	**84.5**	**85.1**	**85.6**	**85.9**	**4.0**	**0.2%**
Crude oil	65.5	68.0	67.3	68.4	67.9	67.4	66.8	-1.2	-0.1%
Existing fields	64.0	66.6	53.6	44.8	36.9	29.7	23.8	-42.7	-3.9%
Yet-to-be developed	-	-	12.4	17.7	19.3	20.8	22.3	22.3	n.a.
Yet-to-be found	-	-	-	3.7	8.7	13.1	16.3	16.3	n.a.
Enhanced oil recovery	1.4	1.4	1.4	2.2	3.1	3.8	4.4	2.9	4.4%
Natural gas liquids	8.3	13.9	15.2	16.1	17.2	18.2	19.2	5.2	1.2%
Unconventional production	**1.2**	**7.6**	**10.9**	**10.8**	**12.1**	**13.2**	**14.5**	**6.9**	**2.5%**
Tight oil	-	4.0	5.8	5.2	5.5	5.4	5.0	1.0	0.8%
Extra-heavy oil and bitumen	0.8	2.6	4.1	4.3	4.9	5.7	6.9	4.3	3.8%
Total production	**75.0**	**89.5**	**93.5**	**95.3**	**97.2**	**98.8**	**100.4**	**10.9**	**0.4%**
Processing gains	**1.8**	**2.2**	**2.4**	**2.6**	**2.7**	**2.9**	**3.0**	**0.8**	**1.2%**
Supply**	**76.9**	**91.7**	**95.9**	**97.9**	**99.9**	**101.7**	**103.5**	**11.8**	**0.5%**

* Compound average annual growth rate. ** Differences between historical supply and demand volumes shown earlier in the chapter are due to changes in stocks.

Non-OPEC production

The non-OPEC producers find themselves making most of the adjustments to rebalance the oil market in the early part of our projection period. The effect of lower prices is not immediately translated into an output decline, as companies pull out the stops to maintain output at relatively high levels and so diminish overall revenue shortfalls. But capital expenditure is sharply reduced and, by the end of the decade, the effect is felt in a lower volume of production coming on-stream. Non-OPEC output in 2020 is revised downwards by 1.1 mb/d, compared with *WEO-2014*, with Russia, Brazil and Canada bearing the brunt of this. By 2020, prices reach levels that allow production in some key countries to recover somewhat, helped in many cases by the reduction in costs that is already visible in 2015. However, overall non-OPEC production reaches a plateau before 2020 at around 55 mb/d and falls back steadily thereafter.

The response of production in the United States to the changed pricing environment is a central variable in the new oil market equation (in Chapter 4, we examine in detail the question to what extent – and at what price – US tight oil might exercise a balancing role in a market). In the New Policies Scenario, US production growth stumbles in the short term but then resumes, with tight oil growth of around 1.5 mb/d to 2020, along with a continued increase in NGLs. US output reaches 13.2 mb/d in that year (Table 3.6). Thereafter, production starts declining at a measured pace to about 10.6 mb/d by 2040, which is essentially a return to the levels seen in 2013.

Table 3.6 ▷ Non-OPEC oil production in the New Policies Scenario (mb/d)

	2000	2014	2020	2025	2030	2035	2040	2014-2040	
								Change	CAAGR*
OECD	**21.8**	**22.7**	**25.0**	**23.9**	**23.9**	**24.1**	**24.1**	**1.4**	**0.2%**
Americas	14.1	18.9	21.0	20.4	20.5	20.8	21.0	2.1	0.4%
Canada	2.7	4.3	5.1	5.5	5.8	6.0	6.8	2.5	1.8%
Mexico	3.5	2.8	2.7	2.8	3.0	3.3	3.6	0.8	1.0%
United States	7.9	11.8	13.2	12.0	11.7	11.4	10.6	-1.2	-0.4%
Europe	6.8	3.3	3.2	2.6	2.4	2.3	2.2	-1.2	-1.6%
Asia Oceania	0.9	0.5	0.9	0.9	1.0	1.0	0.9	0.4	2.2%
Non-OECD	**22.5**	**30.0**	**30.0**	**29.6**	**29.0**	**28.2**	**27.2**	**-2.9**	**-0.4%**
E. Europe/Eurasia	8.2	14.1	13.5	13.6	13.4	12.9	12.2	-1.9	-0.6%
Kazakhstan	0.7	1.7	1.8	2.3	2.7	2.7	2.4	0.7	1.3%
Russia	6.5	11.0	10.5	10.2	9.7	9.3	9.0	-2.0	-0.8%
Asia	7.1	7.9	7.9	6.9	6.3	6.0	5.9	-2.0	-1.1%
China	3.3	4.3	4.4	4.0	3.7	3.5	3.4	-0.9	-1.0%
India	0.8	0.9	0.7	0.7	0.7	0.7	0.7	-0.2	-0.9%
Middle East	2.2	1.3	1.2	1.2	1.2	1.2	1.0	-0.3	-1.1%
Africa	1.9	2.3	2.3	2.1	1.7	1.5	1.3	-1.0	-2.2%
Latin America	3.2	4.4	5.1	5.8	6.3	6.6	6.8	2.3	1.6%
Brazil	1.3	2.4	3.1	4.0	4.7	5.2	5.3	3.0	3.2%
Total non-OPEC	**44.2**	**52.8**	**55.0**	**53.5**	**52.9**	**52.3**	**51.3**	**-1.5**	**-0.1%**
Non-OPEC share	*59%*	*59%*	*59%*	*56%*	*54%*	*53%*	*51%*	*-8%*	*n.a.*
Conventional	**43.3**	**46.0**	**45.5**	**44.4**	**42.9**	**41.5**	**39.8**	**-6.2**	**-0.6%**
Crude oil	37.8	38.1	36.7	35.2	33.5	31.9	30.1	-8.0	-0.9%
Natural gas liquids	5.5	7.8	8.7	9.1	9.3	9.6	9.7	1.8	0.8%
Unconventional	**1.0**	**6.8**	**9.5**	**9.2**	**10.0**	**10.8**	**11.5**	**4.6**	**2.0%**
Tight oil	-	4.0	5.8	5.2	5.5	5.4	5.0	0.9	0.8%
Canada oil sands	0.6	2.2	3.0	3.1	3.4	3.8	4.5	2.3	2.8%
Coal-to-liquids	0.1	0.1	0.1	0.2	0.4	0.6	0.8	0.7	8.7%
Gas-to-liquids	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.4	10.5%

* Compound average annual growth rate.

Canada has seen postponements of multiple upstream projects since oil prices started falling last year, primarily oil sands projects, but this takes time to feed through into the supply outlook because of the long-lead times for new investment. Canada's 2020 output is revised down only marginally, but the longer-term outlook is lower by around 0.6 mb/d compared with last year's *Outlook*. Alongside uncertainties over investment, another issue that could emerge as a long-term constraint on the projections for Canada is the limited number of connections from the resource-rich province of Alberta to the global market, and, indeed, to the domestic oil markets. The large-scale Northern Gateway, Energy East and Keystone XL pipelines, intended to carry Canadian output to Pacific and Atlantic outlets and the US Gulf coast respectively, have not made much headway over the last year, although a smaller project, reversing an existing pipeline, 9B, is getting close to completion and will deliver about 0.3 mb/d of crude oil to refineries in eastern Canada.

The ongoing reform to Mexico's upstream sector eventually helps to arrest the output decline observed since 2004 and provide for long-term output growth to 3.6 mb/d in 2040, from 2.8 mb/d in 2014. Successive rounds of auctions are planned for different types of upstream assets over the coming years. The first round, in July 2015, saw only two of 14 shallow-water exploration blocks awarded, but the second round in September saw more success, with bids for three out of five shallow-water development prospects being accepted. Further rounds are planned for onshore fields; deepwater blocks; extra-heavy oilfields, and shale and tight oil prospects. Overall industry interest in the auctions is high but – against a backdrop of lower oil prices and relatively high provisions for government take – is very sensitive to the nature of the assets on offer. Mexico's promise was underlined earlier in 2015 by a significant find by Pemex in the shallow waters off the coast of Tabasco state. Overall, it is the deepwater developments in the Gulf of Mexico that add to the country's total output, as production from onshore and shallow offshore projects remains at around current levels.

Brazil's oil outlook over the medium term is revised down again, but the country nonetheless becomes the largest source of non-OPEC output growth in the longer term. It currently suffers from the double blow of lower oil prices affecting investment plans, and a corruption scandal that has enveloped the national oil company, Petrobras, and its key contractors. Although the axe has fallen hardest on midstream and downstream plans, upstream investment has also been affected, as Petrobras cut its five-year capital expenditure budget to $130 billion from $220 billion. Current output growth is robust; a product of the surge in spending in recent years that has opened pre-salt fields in the Santos basin, but lower investment starts to impinge on our 2020 outlook, which is down by 0.6 mb/d to 3.1 mb/d. Over the longer term, however, Brazil's large and prolific resource base underpins production growth, which could be reinforced if current difficulties trigger some loosening of the restrictive upstream arrangements designed to protect Petrobras and promote local content. Production reaches 5.3 mb/d in 2040 in our projections.

Russia is another major producer facing a twin threat to its upstream outlook, the impact of the oil price on investment being compounded in this case by the sanctions that restrict access to western finance and technology. This is hardly apparent in the short term, with monthly crude and condensate output in Russia setting new post-1991 records in the summer of 2015 and many companies reporting increased ruble profits. But the Russian industry's capacity to make the most of existing fields, alongside the dampening effect of a significantly devalued ruble on operating costs, is not sufficient to support longer-term growth. In our projections, the effects of cuts in capital spending and of sanctions on new projects are already apparent towards the end of the current decade, with production falling back to 10.5 mb/d by 2020 from 11 mb/d in 2014. Financial sanctions bite earliest, in our view, particularly since some alternative sources of funding, such as the Russian National Welfare Fund, and the possibility of large-scale upstream finance from China do not appear to be delivering as some had expected. Technology restrictions also constrain Russia's production outlook, given the dual ambitions to develop both the Arctic and some "hard-to-develop" onshore resources, including tight oil. Although the Arctic is a Russian strategic priority, the drilling activities planned to meet Russian companies' ambitions in this region were all to be undertaken by international companies, which have now pulled back. With very little projected output from Arctic projects, slower development of tight oil and a faster decline in conventional crude output, the result is that Russia's longer-term oil production outlook falls back, compared with the *WEO-2014*, with production of 9 mb/d in 2040, representing a downward revision of 0.7 mb/d. The contribution of NGLs rises to almost 1.6 mb/d of this total.

Outside the above five countries, whose collective output expands by about 3 mb/d to 2040, the remaining non-OPEC nations account for a 4.6 mb/d drop in output from 2014 to 2040. There are some growth areas in unconventional and offshore fields, but the decline from conventional onshore production outweighs these. Only Kazakhstan bucks the latter trend with the eventual, albeit long-delayed, ramp-up of production from the troubled Kashagan field, which helps to add 0.7 mb/d to the country's overall output. Elsewhere, production growth comes mainly from realised prospects in tight oil, especially in Argentina, offshore Australia and in coal-to-liquids. In Europe, production decreases by around 1.2 mb/d, due to the decline in Norwegian and UK offshore fields. China also sees a supply reduction of about 0.9 mb/d, almost equally onshore and offshore, with the projected tight oil output not able to offset the decline in conventional fields. Production from Southeast Asian nations collectively falls by 0.9 mb/d over the period to 2040, led by drops in output in Indonesia[13] and Thailand.

OPEC production

The situation of OPEC countries has changed dramatically since 2014. Revenues are down sharply, a fact that may lead to deferral of upstream investments in some countries. But market opportunities seem to be open for countries that seek to expand their future production. In our special focus on Iraq in *WEO-2012*, we noted that – with the

13. Indonesia is still included among non-OPEC countries in this *WEO,* as it has not formally re-joined OPEC at the time of publication.

then-projected rise in non-OPEC production – realising Iraq's production ambitions to 2020 would require a significant cut in output from other OPEC countries to avoid over-supplying the market (IEA, 2012). OPEC's decisions in 2014 point to a different way to resolve this dilemma, with higher cost non-OPEC producers driven (by the lower price) to give ground. This situation can also be beneficial for Iran, if a political conclusion on sanctions clears the way to higher production (Table 3.7).

Table 3.7 ▷ OPEC oil production in the New Policies Scenario (mb/d)

	2000	2014	2020	2025	2030	2035	2040	2014-2040 Change	2014-2040 CAAGR*
Middle East	**21.3**	**27.2**	**29.7**	**32.4**	**34.3**	**35.9**	**37.5**	**10.3**	**1.2%**
Iran	3.8	3.5	4.4	4.7	4.9	5.1	5.4	1.9	1.7%
Iraq	2.6	3.4	4.4	5.7	6.4	7.1	7.9	4.5	3.3%
Kuwait	2.2	3.1	2.9	3.2	3.4	3.5	3.7	0.6	0.7%
Qatar	0.9	2.0	2.0	2.0	2.3	2.5	2.7	0.7	1.1%
Saudi Arabia	9.3	11.6	12.3	12.8	13.1	13.3	13.4	1.8	0.6%
United Arab Emirates	2.6	3.6	3.7	4.0	4.2	4.3	4.4	0.8	0.8%
Non-Middle East	**9.4**	**9.5**	**8.8**	**9.4**	**10.0**	**10.7**	**11.7**	**2.2**	**0.8%**
Algeria	1.4	1.6	1.3	1.3	1.3	1.3	1.4	-0.2	-0.4%
Angola	0.7	1.7	1.5	1.5	1.5	1.5	1.5	-0.2	-0.5%
Ecuador	0.4	0.6	0.5	0.4	0.3	0.3	0.3	-0.3	-2.6%
Libya	1.5	0.5	0.7	1.2	1.4	1.6	1.8	1.3	5.1%
Nigeria	2.2	2.4	2.2	2.3	2.4	2.6	2.9	0.4	0.6%
Venezuela	3.2	2.7	2.8	2.8	3.1	3.3	3.8	1.1	1.3%
Total OPEC	**30.8**	**36.7**	**38.5**	**41.8**	**44.3**	**46.6**	**49.2**	**12.5**	**1.1%**
OPEC share	*41%*	*41%*	*41%*	*44%*	*46%*	*47%*	*49%*	*8%*	*n.a.*
Conventional	**30.5**	**36.0**	**37.1**	**40.2**	**42.2**	**44.1**	**46.1**	**10.2**	**1.0%**
Crude oil	27.7	29.8	30.6	33.2	34.4	35.5	36.6	6.8	0.8%
Natural gas liquids	2.8	6.1	6.5	7.0	7.8	8.7	9.5	3.4	1.7%
Unconventional	**0.3**	**0.7**	**1.4**	**1.6**	**2.0**	**2.4**	**3.0**	**2.3**	**5.6%**
Venezuela extra-heavy	0.2	0.4	1.0	1.2	1.5	1.9	2.3	1.9	6.7%
Gas-to-liquids	-	0.2	0.2	0.2	0.2	0.3	0.4	0.2	3.0%

* Compound average annual growth rate.

Note: Data for Saudi Arabia and Kuwait include 50% each of production from the Neutral Zone.

In the New Policies Scenario, OPEC's share in global oil output increases from 41% in 2014 to 49% in 2040, equivalent to adding slightly more than current Saudi output to the market. However, question marks remain over which among the OPEC countries will really be in a position to benefit from this market opportunity and over which timeframe. Some of the countries with the largest potential to step-up production levels over the long term – Iran, Iraq and Venezuela – are also the countries facing some of the most serious challenges in mobilising the necessary investment. So although the opportunity is significant, it does not translate easily into a sustained increase in output, given the current squeeze on finances (particularly serious in Venezuela, Angola and Nigeria), broader political and policy-related questions (as in Iran) and persistent security concerns (as in Iraq).

Saudi Arabia, Kuwait, Qatar and the United Arab Emirates (UAE) are the countries best able to weather a period of reduced revenues, all having accumulated a significant financial buffer that includes large foreign currency reserves. None has given a signal that upstream investment may be significantly constrained by the new price environment, indeed Kuwait and the UAE have been eager to underline that their expansion plans remains on track. There have though been some incipient signs of strain, with Saudi Arabia even tapping bond markets for the first time since 2007 in order to sustain public spending and to avoid running through foreign reserves at too rapid a pace.

Saudi Arabia retains a central position in the global oil market in our projections, maintaining its crude production capacity around the stated 12.5 mb/d target.[14] This requires a steady stream of new developments, totalling 1.3 mb/d of new production capacity by 2020, including a further increase at the Manifa field, the youngest of the offshore fields, that started production in 2013, as well as upgrades at the Khurais field (west of the onshore Ghawar field, the world's largest) and the remote Shaybah field in the Empty Quarter. Looking beyond 2020, production increases are expected to come primarily through exploitation of shallow offshore resources, including expansion at Zuluf and Safaniyah (the latter also being the world's largest offshore field). Our projections maintain Saudi Arabia's pre-eminence among OPEC producers and it regains the position of the largest global oil producer from the United States in the mid-2020s.

Among the other OPEC producers from the Gulf Cooperation Council, Kuwait is pushing ahead with an extensive programme of drilling, well work-overs and secondary recovery in an effort to increase production from its mature fields, with the planned water injection scheme at Kuwait's mainstay Burgan field (which started production in 1960) a good example. Kuwait needs expertise, project management and technology to maximise the return from the country's remaining, more geologically challenging, reservoirs, but finding the right terms on which to engage international companies remains a difficult and sensitive issue, as the recent political debates have shown. The UAE likewise has an ambitious medium-term production target, attainment of which will be contingent, in large part, on the outcome of negotiations relating to a huge onshore concession contract that expired in 2014. Forty percent of the concession is open to international companies and Total (10%) and Japan's Inpex (5%) were the first to agree terms for the new 40-year operating partnership. Other offshore contracts are due to expire in 2018. The Qatari outlook is shaped largely by its gas production; raising output from the country's oil fields is complicated by limited resources, complex geology and relatively high costs. All

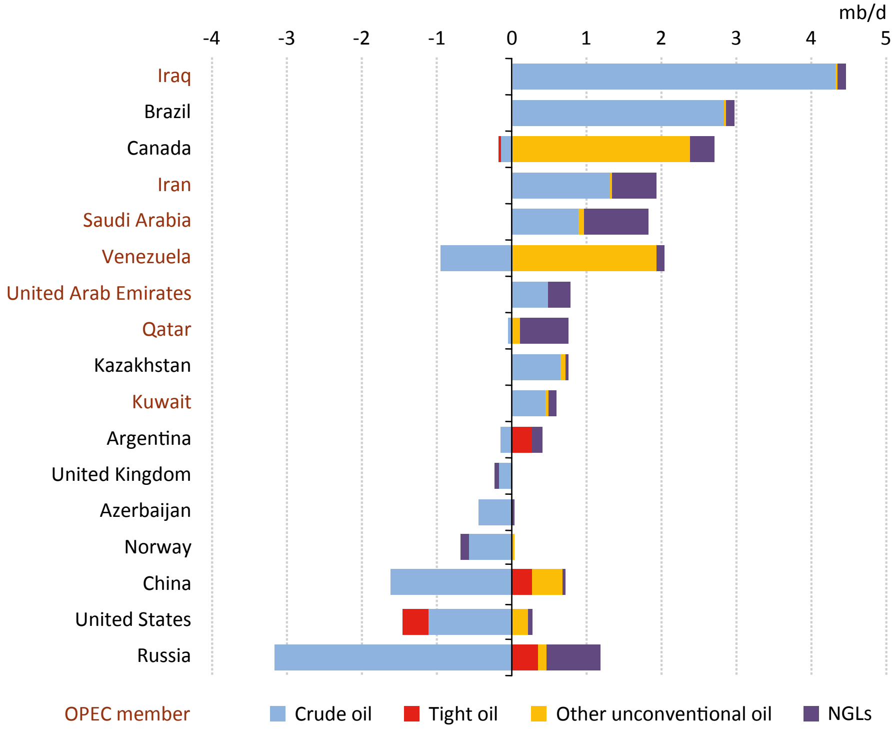
14. Total production, including NGLs, increases to 13.4 mb/d in 2040, but given that 2.6 mb/d of this is NGLs, this still implies around 2 mb/d of spare crude capacity.

of the projected 0.7 mb/d growth in oil production there comes from NGLs and gas-to-liquids projects, assuming that the moratorium on new projects at the huge North Field, introduced by government in 2005, is lifted.

Iraq and Iran are critically important countries for the oil market outlook (Figure 3.12). Both countries have similar resource potential (remaining recoverable resources in Iraq are estimated at 210 billion barrels and 205 billion barrels in Iran) and current production levels are, arguably, well below the levels implied by the quality of the underlying resource base. Yet efforts to realise this potential have consistently been plagued by uncertainties above the ground, which introduce an undeniable level of uncertainty into any projections of future output. Iraq's production performance over the last year has been robust, breaking oil output and export records, despite the overall deterioration in the security situation. However, the decline in oil revenues in 2015 is reinforcing concerns about the fragility of key national institutions and affects the pace of further growth. Iraq's technical service contracts, under which its large southern fields are being developed, oblige the government to reimburse the companies' capital expenditure and operating costs and to pay a small fee per barrel on top. The difficulty for Iraq's strained public finances is that the costs to be reimbursed now represent a much higher share of the available revenue, up to around one-third of total national oil revenue, by some estimates. Delays in cost recovery payments are leading to postponed investment, which will, in turn, cut the rate at which Iraq's production grows – at least over the medium term. In parallel, investment by companies operating in the north of the country, in the Kurdistan Regional Government area, has been stymied by the continuing tension between Erbil and Baghdad. An accord reached in December 2014 on exports and revenue sharing had all but broken down by mid-2015, leaving upstream operators with large outstanding payments for their exports. The size and the low-cost nature of Iraq's resources give strong grounds for optimism over the longer term, but institutional, security and financial hurdles continue to dampen our projections, which are revised downwards to 4.4 mb/d in 2020, although increasing steadily thereafter, to reach 7.9 mb/d in 2040.

In Iran, crude oil production capacity is estimated at between 3.4 mb/d and 3.6 mb/d, but the sanctions imposed on Iran in relation to its nuclear programme, together with under-investment, reduced Iran's crude output to 2.8 mb/d in 2014, supplemented by an increasing volume of NGLs. With the sanctions agreement reached in July 2015, a pathway is open (albeit a complex and multi-stage one) towards lifting the most important oil-related sanctions. As and when these sanctions are lifted, output growth will come first from bringing production back towards the existing capacity limit and from marketing of a large volume of oil held in floating storage. Most observers consider that this could be achieved fairly rapidly – although the Iranian authorities would have to be wary of the short-term impacts on the oil price. A second phase, of much greater importance for the time horizon considered in this *Outlook*, would require large-scale investment to raise the country's productive capacity beyond 3.6 mb/d, back towards the levels achieved in the past – Iran's production peaked in the 1970s at just over 6 mb/d.

Figure 3.12 ▷ Change in oil production in selected countries in the New Policies Scenario, 2014-2040



The prospects for such a sustained increase in investment are clearly brighter than they were and are reflected in an upward revision of our projected long-term production to 5.4 mb/d in 2040 (of which 4.1 mb/d is conventional crude oil), compared with 4.7 mb/d in *WEO-2014*. However, the road ahead for Iranian oil production may not be a smooth one, even if the main sanctions are removed. Crude production has been subject to abrupt starts and stops in the past and, even though Iran's mature fields are large with low lifting costs, existing fields require substantial investment – new drilling programmes, gas injection and other techniques – to enhance recovery. The new fields that could be developed are also likely to be less prolific and entail higher cost than those across the border in Iraq, although the institutional capacity in Iran to manage their development is greater.

In anticipation of the main restrictions being lifted, foreign companies are showing keen interest in investing in Iran, though US upstream companies are barred from investing in Iran under a separate terrorism-related sanctions regime (the lifting of which is subject to many US domestic political constraints). The terms under which international companies might invest have yet to be announced and are likely to be the subject of potentially lengthy debate. The structure that was offered by Iran to foreign partners for field development since the 1990s – the so-called buyback contract – involved the partner funding and performing a defined programme of exploration and development work for a period up to ten years, after which time the project was handed over to the National Iranian Oil Company. The arrangement provided a strong incentive to the partner to finish work on time and at minimum cost, but at a risk of prioritising frugality over long-term field performance, a risk aggravated by the exclusion of the partner from field management beyond the ten-year limit. A combination of inflexibility (due to the pre-defined scope of work), parsimonious development and sub-optimal management during maturity is likely to have resulted in many barrels being left underground. The promise of new contractual arrangements represents an opportunity to rectify some of these deficiencies, a key variable being the extent to which companies are offered a longer-term incentive to optimise recovery over the lifetime of the field.

Africa makes the second-largest contribution to overall OPEC output after the Middle East; but both of the sub-Saharan African producers, Nigeria and Angola, have been hit hard by the fall in the oil price. Although some offshore projects are likely to come on-stream in Nigeria over the next few years, notably Total's Egina project, the prospects for around 500 kb/d of planned projects awaiting a final investment decision have been pushed back by the price decline (many of these had already been held back by the long-standing uncertainty over the Petroleum Industry Bill). The state-owned Nigerian National Petroleum Corporation has also reduced its 2015 joint-venture investment budget for oil operations by some 40%. This has reinforced the atmosphere of investor pessimism engendered by regulatory instability and security concerns. Nonetheless, although production is projected to dip to 2.2 mb/d in 2020, prospects are expected to brighten as the oil price rises again and, underpinned by investment in new deepwater projects, output is projected to grow to 2.9 mb/d in 2040. Producers in Angola face similar pressures in the medium term. The long-term outlook – assuming that there is no major breakthrough in the pre-salt acreage, where drilling results have so far been disappointing – is of a gradual decline from 1.7 mb/d in 2014 to 1.5 mb/d in 2040.

In North Africa, oil output in Libya has largely collapsed since early-2014 and the prospects of recovery remain highly uncertain, in the light of continued political turmoil and violence. We assume a gradual stabilisation of the situation (the Libyan oil sector has already demonstrated its ability to bounce back in times of relative calm), but our projections are nonetheless held back by the weakness of governing institutions. Output reaches 1.8 mb/d in 2040. In Algeria, efforts to stimulate investment by improving the commercial terms on offer have yet to bear fruit, with investors still deterred by regulatory uncertainty and lingering concerns over security. Although Sonatrach is forging ahead with a large-scale investment programme, there is otherwise very little new exploration and development activity. These circumstances bring our 2020 outlook down slightly, to 1.3 mb/d, although ample resources underpin a small rise by 2040, when production reaches close to 1.5 mb/d.

In Latin America, the oil price fall has exacerbated an already severe economic crisis in Venezuela. Years of over-spending have left the country very vulnerable to a sharp decline in revenue as oil exports make up nearly all of Venezuela's foreign exchange earnings. Petroleos de Venezuela (PDVSA) is under pressure to cut its 2015 spending, reinforcing worries of under-investment in the country's oil sector. Oil-for-finance deals with China have provided some relief, but the scope to extend these is limited. The ongoing cash crunch is a major threat to the outlook for production in the vast Orinoco extra-heavy oil belt, our projection for production, in consequence, has been brought down to 2.8 mb/d in 2020 before a price-induced recovery enables output to rebound to 3.8 mb/d in 2040. In Ecuador, OPEC's smallest producer, controversial new projects in the Amazon region slow the long-term decline in its output, but this still falls back to 0.3 mb/d in 2040.

Refining and trade

The drop in oil prices in the second-half of 2014 brought even simple refining margins into positive territory, something that the refining industry had not seen for some time. As upstream earnings dwindled, refining and trading started to account for more than half of oil majors' quarterly earnings. This does not, though, imply that the refining sector is in for a few comfortable years, still less a stress-free long term. Among the many challenges facing the industry is that demand for refined products is expected to grow at a slower pace than total demand for liquid fuels, reducing the refineries' market share from close to 87% to 83% (Table 3.8) as the share of very light crudes and NGLs (which can bypass the refining system) rises in the global mix (Spotlight).

Table 3.8 ▷ World liquids demand in the New Policies Scenario (mb/d)

	2014	2020	2040
Total liquids	92.1	98.0	107.7
Biofuels*	1.5	2.1	4.2
Total oil	90.6	95.9	103.5
CTL, GTL and additives	0.9	1.0	2.5
Direct use of crude oil	1.1	0.9	0.3
Oil products	88.6	94.0	100.6
Fractionation products from NGLs	8.2	9.7	11.2
Refinery products	80.4	84.3	89.4
Refinery market share	**87%**	**86%**	**83%**

* Expressed in energy-equivalent volumes of gasoline and diesel.

Note: CTL = coal-to-liquids; GTL = gas-to-liquids.

Even in the current environment of relatively healthy margins, some refinery projects are less likely to be realised as lower oil prices reduce the oil sector's earnings, resulting in financing difficulties in regions with major expansion plans such as Brazil, Middle East and Russia. Overcapacity remains a major issue in Europe. Following a self-imposed five-year moratorium on shutdowns, Total, the France-based oil major and one of Europe's biggest refiners, announced a refinery closure in April 2015. Concerns about excess capacity extend also to more dynamic Asian markets. China, for example, grants crude oil import licences to smaller refiners if, among other conditions, they agree to mothball part of their own capacity or buy and shut down aging distillation units from other refiners, usually the so-called "teapot" refiners. Korea, on the other hand, has attempted to expand the domestic market for refined products in ways that help local refiners: these include measures to switch taxis from LPG (which is mostly imported, and the supply of which generally bypasses refineries in any case) to diesel (which is in surplus, but for which the export markets are increasingly competitive). Although we have revised downwards somewhat our expectation for new refinery capacity for *WEO-2015*, the projected capacity overhang nonetheless gets larger over our projection period, as regions with growing demand continue adding to domestic capacity so as to minimise product import requirements.[15] Europe, OECD Asia and, eventually, North America account for most of the capacity at risk of being shut down by 2040, which totals 15 mb/d globally. Worldwide refinery runs grow by 8.3 mb/d, but this masks very different trends in different regions – an 8 mb/d drop in the OECD and a 16 mb/d increase in non-OECD (Table 3.9).

Table 3.9 ▷ Refining indicators by region in the New Policies Scenario (mb/d)

	Capacity 2014	Change in capacity to 2040	Refinery runs			Capacity at risk	
			2014	2020	2040	2020	2040
Europe	16.9	-1.7	13.2	12.1	9.7	2.2	5.0
North America	20.9	-0.2	18.6	19.0	15.6	0.1	3.9
Asia	31.5	10.2	25.9	28.1	34.9	1.6	3.1
China	12.8	5.0	10.2	11.9	14.6	0.6	1.1
India	4.4	3.4	4.5	4.9	7.6	-	-
OECD Asia	7.6	-0.9	6.2	5.5	4.7	0.8	1.7
Southeast Asia	4.8	2.6	3.9	4.4	6.6	0.2	0.1
Russia	6.2	-0.3	5.6	5.5	4.5	0.1	0.9
Middle East	8.2	4.4	6.5	8.2	11.4	0.8	0.3
Brazil	2.0	0.9	2.1	2.3	2.7	-	-
Africa	3.3	1.2	2.2	2.5	3.6	0.7	0.5
Other	5.1	0.1	3.9	4.0	3.9	0.5	0.9
World	**94.1**	**14.5**	**77.9**	**81.6**	**86.2**	**5.9**	**14.6**
Atlantic basin	53.9	-0.0	45.0	44.7	39.5	3.5	11.2
East of Suez	40.2	14.6	32.9	36.8	46.7	2.4	3.4

Notes: "Capacity at risk" is defined for each region as the difference between refinery capacity, on the one hand, and refinery runs, on the other, with the latter including a 14% allowance for downtime. This is always smaller than the spare capacity, which is the difference between capacity and refinery runs.

15. For medium-term capacity expansion we use corporate and public announcements, as well as IEA's *Medium-Term Oil Market* reports as a guide. Our approach for projected refinery capacity expansion by regions beyond the medium term was explained in more detail in the special focus on oil in *WEO-2013* (IEA, 2013).

SPOTLIGHT

Can light oil tip the market balance?

Not all oil is created equal: it comes out of the ground in a wide variety of forms, ranging from treacle-like heavy oils, many of which cannot be poured at room temperature, to very light crudes, condensates and natural gas liquids. Each crude stream has a different yield of oil products, with refiners making a constant effort to optimise their processes so as to produce from the available crudes the mix of products demanded by consumers (while, in the case of some very light crudes and most NGLs, also facing competition from oil that bypasses the refining system altogether).

An argument sometimes heard during the rise of US tight oil was that its likely impact on the market should not be overstated: the additional barrels from the United States were too light, with too limited a yield of the prized transport fuels demanded by consumers, especially middle distillates, for this surge to have a major effect on prices. In other words, an incremental barrel of US oil was no substitute for conventional crude. There is some truth in this: US output growth comes largely in the form of tight oil and NGLs that have much higher yields of light ends, such as ethane and LPG. Ethane is almost exclusively used in petrochemicals, although its occasional discount to natural gas in the United States has prompted serious discussion of projects for ethane-fuelled power plants. LPG is a more versatile fuel, used in cooking, heating, combustion engines and petrochemicals, but is not a mainstream transportation fuel.

Despite this initial scepticism, nowadays the rise in US output is widely regarded as having been instrumental, among other factors, in the 2014 price crash. How so? The answer is that the oil market – and the US market in particular – adapted quickly to accommodate this new source of supply. The process was not seamless and resulted in US output trading at a significant discount to international crudes; but US industrial and other consumers were quick to expand their use of the cheaper products available on the market, and infrastructure was built, or reconfigured, to reflect the new geography of North American supply. This was then felt in the dramatic reduction in the US import requirement for lighter crudes, creating in turn the glut in light, sweet crudes in the Atlantic basin that eventually drove down global prices.

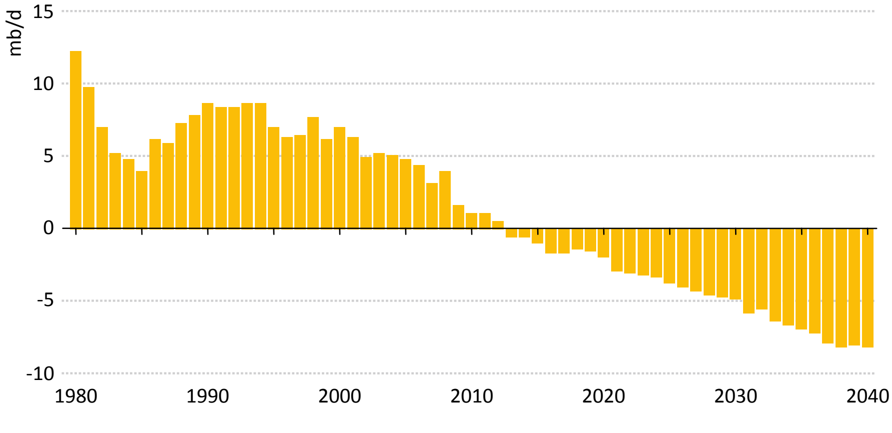
This process also serves as a reminder that, although transport fuels are in pole position among oil products, they are not the only fuels in the race. Middle distillates have a "monopolist" position only in two markets: around 90% of medium and heavy trucks rely on diesel; and the aviation industry almost exclusively uses kerosene, a tried and tested fuel, and it will take a long time for bio-jet to make a significant dent in its market share. However, the combined demand for these two fuels in these two sectors is less than 20% of world oil demand (increasing to just over 25% by 2040). In all other sectors, middle distillates face competition from other oil products or other fuels, such as natural gas or renewables; it is the combination of relative prices and policies that drives the market share of the competing fuels.

Trade in crude oil and products

Although export-oriented refinery capacity is on the rise, a larger part of the increase in refinery runs over the period to 2040 takes place to cater for growing domestic consumption. This means that, over the long term, total trade in crude oil (+6.9 mb/d) expands more than the trade in products (+2.7 mb/d), even though the opposite is true for the developments in the medium term. Within this overall picture, the crude oil import requirement of the United States is expected to decrease by 1.5 mb/d over the period to 2040: although crude and condensate output reaches a plateau around 2020 and then starts to decline, the decline is more than offset by lower refinery runs. In 2015, Chinese monthly crude oil imports have already occasionally surpassed those into the United States, but with part of the imported cargoes destined for storage fill, rather than refinery use, it may still be some time before China is established firmly as the biggest crude oil importer. By the early 2030s, in our projections, China is set to exceed the historical record import level of the United States (just over 10 mb/d in 2005) and continues to increase its reliance on the international crude oil market thereafter. The early 2030s is also when India is projected to overtake the United States as the second-biggest crude oil importer.

On the supply side, the Middle East (3.5 mb/d) and Canada (3 mb/d) provide the largest boost to crude oil exports. Brazil is also expected to provide significant incremental volumes, some 2.3 mb/d in 2040, as crude oil output eventually expands well ahead of refinery capacity expansion. Overall, Asian refiners' crude oil import requirements exceed the export capacity of the Middle East, so the East of Suez region increasingly has to import from elsewhere, such as West Africa, Russia, the Caspian region and Latin America (Figure 3.13).

Figure 3.13 ▷ Crude oil balance in the East of Suez region in the New Policies Scenario



Notes: "East of Suez" refers to the combined Middle East and Asian region. Positive numbers show exports out of this region (surplus Middle East crude after filling Asian refiners import requirements), while negative numbers show imports into this region (i.e. the gap between Asian refinery needs and Middle East exports).

Similar shifts are expected to occur in products trade. Asian markets are currently oversupplied with refined products (excluding LPG and naphtha, that can also be supplied from NGL fractionation), but this region becomes a net importer of products by 2020s, as its demand grows faster than capacity additions. Middle Eastern refineries are largely able to cover the incremental product demand in Asia, with the balance coming from North America and Europe. For petrochemical feedstocks, too, Asian consumers have to look further afield, continuing to buy naphtha from Europe and North Africa and adding long-haul naphtha and LPG imports from North America; small-scale imports of ethane from United States to India are also likely.

Investment and costs

The projections in our New Policies Scenario require cumulative investment in the oil and gas sectors of some $25 trillion, of which just under 80%, or $20 trillion is in the upstream. This represents an annual average of $750 billion for upstream oil and gas (Table 3.10), a noticeable decrease compared with the $825 billion figure from *WEO-2014*. This is due to two effects: first, the lower oil price and the impact that this has on pulling down upstream costs, at least in the medium term; second, the slightly faster shift that we see in this year's *Outlook* towards lower cost sources of oil, reflected in the higher market share of OPEC countries in the global oil supply mix. The Middle East, for example, provides 35% of the world's oil supply to 2040 but requires only 14% of the upstream investment.

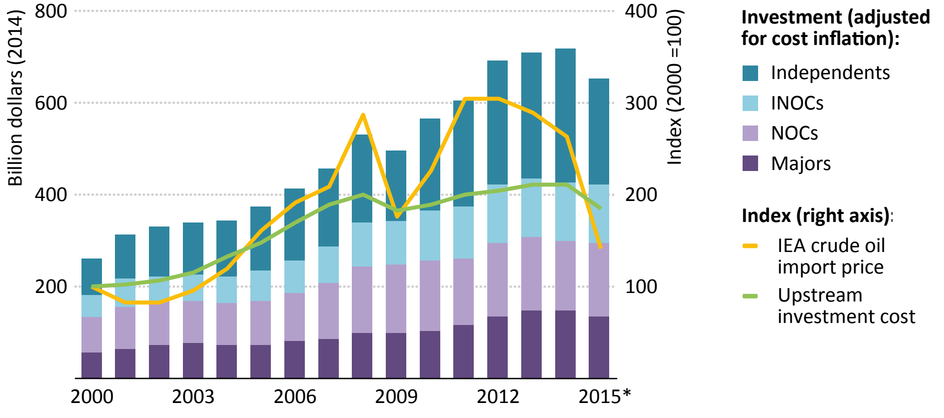
The IEA Upstream Investment Cost Index[16], which reflects prices for cement, steel and other construction materials and equipment, as well as the cost of hiring skilled personnel and contracting drilling rigs and oilfield services, fell by an estimated 13% in the first half of 2015 (Figure 3.14). As oil producers suffered from reduced revenues and cut their capital expenditure, so they also put pressure on suppliers to reduce input costs for existing projects. The headline reductions in investment spending seen in 2015, which have reached 20-40% in some cases and exceed 40% in the US onshore fields, do not therefore all represent a drop in activity levels – part of the reduction is explained by lower costs. Onshore projects, particularly tight oil developments with their high well count and short drilling times, have been among the first to benefit, with savings in well construction costs supporting the bottom line of oil company books. We estimate that, as of mid-2015, one billion dollars invested in US tight oil can drill 30% more wells than a year earlier (with each well around 20-25% cheaper to drill).

Cost reductions are not evenly distributed across different types of projects. Onshore projects in very competitive service markets tend to benefit first, but savings take more time to percolate through to other segments of the industry, in particular to more specialised areas with fewer providers. Some large upstream projects now being delayed may reappear in a year or two with a lower investment budget; this is an explicit part of the calculation behind some project postponements, particularly for international oil

16. See *www.worldenergyoutlook.org/weomodel/*.

companies promising greater capital discipline. But when these projects reappear, they will also tighten service markets again, not least because many service providers will have laid off personnel in the meantime. Ultimately, only fundamental changes in technology or process (for example, more standardisation of equipment for complex projects) can lower unit costs for good.

Figure 3.14 ▷ Global upstream oil and gas investment and the IEA Upstream Investment Cost Index



* Budgeted spending.

Notes: The IEA Upstream Investment Cost Index, set at 100 in 2000, measures the change in underlying capital costs for exploration and production. It uses weighted averages to remove the effects of spending on different types and locations of upstream projects. INOC = national oil companies operating internationally; NOC = national oil companies. Majors = BP, Chevron, ExxonMobil, ConocoPhillips, Eni, Shell, and Total.

Source: IEA databases and analysis based on industry sources.

In our projections for the New Policies Scenario, production costs are anticipated to rise in real terms over the period to 2040.[17] Although we anticipate continued improvements in technology that tend to reduce capital and operating costs over time, these are more than offset by increases associated with the need to develop more technically challenging (and generally smaller) reservoirs in the future. There are also cost pressures related to the oil price; in the same way that lower prices end up squeezing revenues across the board (including, in some cases, a reduced share going to governments, as fiscal terms are eased in order to encourage investment or prevent job losses), so higher prices also tend to push up costs, as supply and service companies and governments try to capture a larger share of the rent.

17. The increase in unit costs does not translate into a similarly large increase in the annual investment requirement, because a growing share of production comes from the Middle East, where average upstream costs per barrel are the lowest in the world.

Table 3.10 ▷ Cumulative oil and gas supply investment by region in the New Policies Scenario, 2015-2040 ($2014 billion)

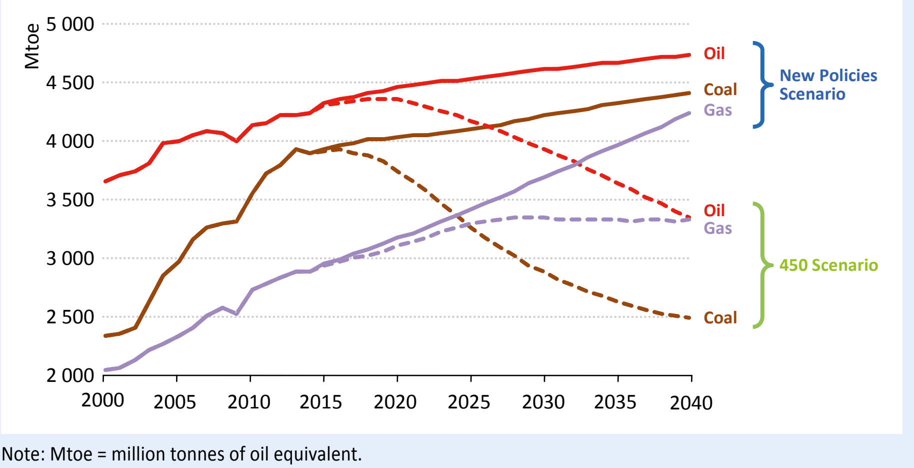
	Oil				Gas			Average annual oil and gas upstream
	Upstream	Transport	Refining	Total	Upstream	Transport	Total	
OECD	**4 560**	**153**	**452**	**5 164**	**2 617**	**1 314**	**3 931**	**276**
Americas	3 798	129	241	4 167	1 864	743	2 607	218
United States	1 998	42	190	2 230	1 426	575	2 001	132
Europe	616	11	138	765	458	333	791	41
Pacific	146	13	73	232	295	238	534	17
Japan	2	1	28	31	3	44	47	0
Non-OECD	**7 996**	**646**	**1 259**	**9 901**	**4 290**	**1 615**	**5 905**	**473**
E. Europe/Eurasia	1 383	69	100	1 552	1 333	404	1 737	104
Russia	817	36	69	921	710	265	974	59
Asia	1 011	107	690	1 808	1 289	543	1 832	88
China	705	40	315	1 059	555	262	817	48
India	62	31	192	285	127	84	212	7
Southeast Asia	235	32	159	425	434	114	548	26
Middle East	2 271	280	266	2 816	554	319	873	109
Africa	1 356	90	87	1 533	634	233	868	77
Latin America	1 975	101	116	2 192	480	115	594	94
Brazil	1 193	64	70	1 327	128	34	162	51
Inter-regional transport	n.a.	338	n.a.	338	n.a.	97	97	n.a.
World	**12 555**	**1 136**	**1 711**	**15 403**	**6 907**	**3 026**	**9 932**	**749**
European Union	243	7	124	374	226	302	528	18

When prices are high, the industry can afford to go after resources at the higher end of the cost curve, developing and honing technologies (as for tight oil and deepwater projects) that allow these projects to be developed efficiently. When prices swing in the other direction, the focus of technology deployment switches to reducing lifting costs or ensuring a faster return on investment. Tight oil production in the United States is showing strong capacity for survival, even in the current price environment. What is less clear, even when prices recover, is the fate of complex, relatively costly, long lead-time projects (in parts of the deep offshore, or the Arctic, or oil sands). With the possibility, at least, that climate policies may constrain long-term demand for oil (Box 3.2), there may be a decreased appetite among some companies for megaprojects, like Kazakhstan's Kashagan, where the production potential is huge but so too, are the timescales involved, with the scale and complexity of the work lending itself to delays and cost overruns. Greater attention might, instead, be given to additional recovery from existing fields or smaller scale modular development of new discoveries. Though the latter may not present compelling project economics, they might offer a more certain return on investment, with a shorter development time.

Box 3.2 ▷ Oil and gas investment in a climate-constrained world

Fossil-fuel producers (countries and companies) face multiple uncertainties, arising from all directions: economics, geopolitics, geology, technology and policy. Some of these uncertainties have a downside for fossil fuels, others have an upside, and resource-owners and licensees typically adopt strategies to manage the risks and opportunities appropriately. Climate change represents a profound challenge to a fossil fuel dominated energy system and looms large among the uncertainties facing resource-owners and the industry. Oil prices in a scenario consistent with meeting a 2 °C target would in all probability be lower, as indicated in our 450 Scenario; the risks facing high-cost, long-lead time upstream projects considerably higher; and the task of attracting new skilled professionals to the industry more difficult. But the idea that strong climate policies would immediately slash the requirement for investment in oil and gas is misconceived. Even if the world moves decisively towards the demand and emissions trajectory implied by the 450 Scenario, large-scale investment in oil and gas (even, in some countries, in coal) will remain an essential component of a secure and least-cost transition to a low-carbon future.

Figure 3.15 ▷ Global fossil-fuel demand in the 450 Scenario relative to the New Policies Scenario



Note: Mtoe = million tonnes of oil equivalent.

This need for oil and gas investment in the 450 Scenario is dictated, to some degree, by the trajectory of demand (Figure 3.15), which shows 2040 oil consumption at 74 mb/d (i.e. 16 mb/d lower than today) and gas demand higher than today's levels. But the major factor underpinning the need for investment is the need to compensate for the inevitable declines in output at today's oil and gas fields. Production from today's fields is set to fall by around two-thirds, a far more rapid decline that anything seen (or foreseeable) on the demand side. For this reason, the amounts of new resources that need to be developed by 2040 in the 450 Scenario and the New Policies Scenario, respectively, are not very far apart: an amount equivalent to between 50-60% of today's proven oil and gas reserves needs to be developed in both cases. A significant part of current reserves is left "in the ground" in both scenarios in 2040. Almost all of these are owned either by governments or national oil companies. In our estimation, an overwhelming share of the oil and gas reserves held by private oil and gas companies today will be produced by 2040, even in a 450 Scenario, an indicator that limits the downside risk to their operations and valuation over this period. Over the much longer term, beyond our 2040 horizon, keeping the rise in the average global temperature within the 2 °C target will have steadily more grave implications for oil and gas.

Over the time horizon of our *Outlook*, it is arguable that a larger hazard for oil and gas companies lies in an inconsistent or stop-start, approach to climate change policies by governments, as it would lead to substantially more market disruption, price volatility and a higher risk of stranded investments than a well-ordered transition. As argued in *Energy and Climate Change: World Energy Outlook Special Report* (IEA, 2015b), all parts of the energy sector stand to benefit from an outcome to COP21 that gives clarity of purpose and certainty of vision to the future of low-carbon development.

Low Oil Price Scenario

Is a lower price sustainable for the long term?

Highlights

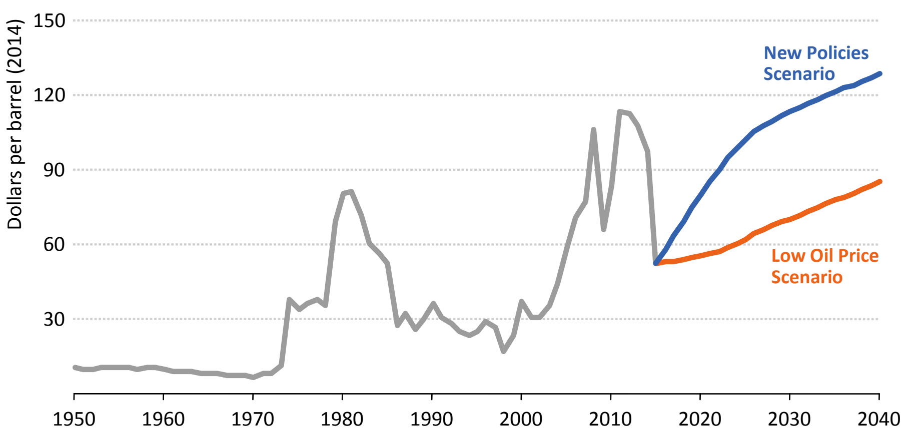
- In the Low Oil Price Scenario, a new oil market equilibrium emerges at prices in a \$50-60/bbl range and lasts until well into the 2020s, before prices edge higher to \$85/bbl in 2040. Among the important assumptions that differentiate this scenario from the New Policies Scenario are lower near-term economic growth and a more rapid phase-out of fossil-fuel consumption subsidies; greater resilience among some non-OPEC sources of supply to a lower price environment, notably tight oil in the United States; and a lasting priority among OPEC countries (holding the world's lowest-cost oil resources) to keep in place a strategy prioritising market share and a price that limits substitution away from oil.
- Lower prices stimulate oil use and diminish the case for efficiency investments and for switching to alternative fuels, pushing demand up to 107 mb/d by 2040, some 3.7 mb/d higher than in the New Policies Scenario, with most of the additional demand coming from transport.
- US tight oil has played a critical role in the current over-supply and its short investment cycle is changing the way that the oil market operates. With resources assumed to be higher and breakeven costs lower than in the New Policies Scenario, tight oil contributes to downward pressure on prices. However, this contribution diminishes over time, as cost pressures from the move to less productive acreage eventually outweigh gains through technology and efficiency improvements.
- Over the longer term, higher oil demand can be met at the prices in the Low Oil Price Scenario only through rapid development of lower cost resources across the Middle East. Without this increase in output, which pushes OPEC's share in oil production above 50%, to levels last seen in the early 1970s, the price would have to rise earlier to balance the market. The strains that the low price outcome would put on the fiscal balances of key producers make a Low Oil Price Scenario look increasingly unlikely the further it is extended out into the future.
- The economic implications of a Low Oil Price Scenario are good for oil consumers and importers, although the fast-growing rise in dependence on supply from the Middle East may raise concerns over oil security. Oil producers and exporters are worse off, as the volume gains from higher output are more than offset by the effect of lower prices. With the exception of biofuels, the deployment of renewables is largely unaffected, as the policy considerations that underpin support for renewables do not change. Energy-related CO_2 emissions are slightly higher and efficiency improvements and the deployment of some crucial low-carbon technologies are slowed, particularly in the transport sector.

What could keep oil prices down for longer?

The decline in the oil price since late 2014 has triggered a vigorous debate over the direction in which prices will head in the future. Nobody can say with confidence; and we make no claim of unique insight. But, just as we lay out the implications of a central case – the New Policies Scenario in Chapter 3 – so there is also a case to be made that the oil price could stay lower for considerably longer. This is the possibility we investigate in this chapter, on the basis of a Low Oil Price Scenario.

The Low Oil Price Scenario is derived from the New Policies Scenario[1], but key parameters have been changed in a way that could support a longer period of low oil prices. We expose these key parameters, for scrutiny and judgement as to their probability, and then set out the implications of low prices persisting in the long term. The result is a situation in which working off the current oversupply in the market takes longer than in the New Policies Scenario and the eventual market balance emerges at a significantly lower price. Whereas the New Policies Scenario sees a rebound in the oil price, the oil price trajectory in the Low Oil Price Scenario is one that remains within a $50-60 per barrel (bbl) range until well into the 2020s (Figure 4.1). Moreover, the effects extend well beyond the medium term: the market is able to find an equilibrium at levels consistently below those of the New Policies Scenario all the way through to 2040 (even though in our modelling, there is still a need for a gradual increase in the oil price over the longer term to $85/bbl by 2040, in order to stimulate the necessary investment in new supply).[2]

Figure 4.1 ▷ Average IEA crude oil import price by scenario



1. The changes are not therefore linked to a broader low-carbon transition, as in the 450 Scenario, in which demand for oil is lower because of concerted system-wide policy action to limit carbon-dioxide emissions. The 450 Scenario also leads to lower prices for oil than in the New Policies Scenario.

2. This makes the end-point similar to the Low Oil Price Case modelled in *WEO-2013* (IEA, 2013), when we looked at the possibility of an extended fall in the oil price from the triple-digit figures prevailing at the time, to a level of $80/bbl. The *WEO-2013* analysis was limited to the effects on the oil sector; the current analysis is a fully-fledged scenario and therefore looks at the implications for all fuels and technologies.

Key assumptions

Five main factors differentiate the Low Oil Price Scenario from the New Policies Scenario, three relating to oil supply, two affecting oil demand:

- **A long-lasting shift in OPEC strategy**. The New Policies Scenario incorporates the assumption that, once the market starts to rebalance as non-OPEC production growth stalls, OPEC countries revert to a strategy that modulates output in an attempt to maintain prices at the levels judged desirable for producers, while still tolerable for consumers. The Low Oil Price Scenario, by contrast, assumes a lasting shift in policy, with different strategic priorities to the fore: to minimise substitution away from oil by the main global consumers and to provide sufficient room in the market for OPEC member countries wishing to expand output, without curtailing production from other members. In other words, OPEC adopts a long-term strategy that prioritises the preservation of oil's share in the energy mix and of OPEC's share in the oil market.
- **A benign view of geopolitical developments**, such that the future is less marked by disruptions to oil supply than in the past. This includes favourable assumptions about the resolution of current conflicts, e.g. in Libya, Syria and Iraq, and the ability of the main oil-dependent producing regions to weather the impact of lower hydrocarbon revenues.
- **Stronger resilience of some key non-OPEC sources of supply**, notably US tight oil, to a lower oil price environment. There are greater downward pressures on costs in non-OPEC supply than those seen in the New Policies Scenario, lowering breakeven prices; and the tight oil resource base proves larger and the pace of technology learning faster. The tight oil situation is discussed in more detail later in this chapter.

And on the demand side:

- **A lower rate of near-term economic growth**, concentrated in some countries in developing Asia, parts of Africa and North America, reflecting downside risks to parts of the world economy from factors that include the fall in commodity prices, the shift to higher interest rates in the United States and China's transition to a less investment-intensive model of growth. For the projection period as a whole, this translates into global gross domestic product (GDP) in 2040 that is some 1% lower in the Low Oil Price Scenario than in the New Policies Scenario. The impact on oil demand is offset in part by an assumed weakening of policy support for alternative fuels (in particular biofuels), due to lower oil prices.
- **A faster pace of reform of fossil-fuel consumption subsidies** among net importers and some net exporters of oil. These moves are assumed to be politically more feasible, because the price fall reduces the gap between the level of subsidised and market-driven prices but also – in the case of net exporters of oil – necessary because of the pressure on public finances caused by reduced oil export revenues.

Box 4.1 ▷ Are markets heading back to the 1980s?

The oil price collapse in 1986 was preceded by a period of historically high prices that accelerated major investments in non-OPEC supply (in the North Sea, Alaska, Mexico and the Soviet Union, among others), while putting the brakes on global demand growth. By 1983, global oil demand was down by 5.4 million barrels per day (mb/d) from the levels seen five years earlier, as import-dependent countries sought to flush out expensive fuel-oil use in stationary demand, such as power generation and industry, replacing it with coal, natural gas and nuclear power. With the share of oil falling in the global energy mix and prices starting to decline, OPEC sought to balance the market by cutting output (with Saudi Arabia bearing the brunt of the cuts), but, in the face of mounting over-supply, there was a change of tack in late 1985, with Saudi Arabia seeking to defend its share of the market. This led to a nearly 50% fall in the crude oil price the following year and an extended period of lower oil prices that lasted, with some important fluctuations along the way, for the best part of two decades. The decline in the share of oil in the global energy mix was arrested, this share holding steady at about 37% (down from 45% in 1978). It was only in the 2000s that prices again began a long march upward, underpinned by rising demand in China and stalling non-OPEC supply.

The parallels between 1986 and today's market conditions are sufficiently striking to make many ask whether the duration of the price decline might be similarly prolonged this time. Then, as now, the upstream industry focused insistently on bringing down costs in a challenging price environment.[3] But there are important differences, particularly on the supply side, where the scale of the overhang in supply in the 1980s was much larger (and more inflexible) than today. OPEC spare capacity had reached very high levels by the mid-1980s: from a position in the 1970s when OPEC countries accounted for more than 50% of global output, by 1985 attempts to protect the price through cuts in output had brought the OPEC share down to below 30%. Saudi Arabia's crude output had fallen to 3.4 mb/d, from more than 10 mb/d just five years earlier. When this became no longer tolerable, a huge amount of relatively cheap oil became readily available. There is no analogy today in terms of OPEC spare capacity, which, as of mid-2015, is relatively limited by historical standards. There are differences, too, on the non-OPEC side, with the main production growth in recent years being US tight oil, a source of supply inherently more responsive to market price fluctuations and a smaller one in terms of recoverable resources.

3. An example from the 1990s in the UK sector of the North Sea was the Cost Reduction Initiative for the New Era programme, which targeted 30% reductions in capital cost and savings on operating costs through adopting and harmonising functional specifications for procurements, standardising equipment and working practices among others.

Those seeking a historical precedent for an extended period of lower prices, following a price decline, often cite the 1980s as a reference point, and the comparison is an instructive one – both for the similarities and for the important differences to the current situation (Box 4.1). Looking to the future, we do not elaborate here on the probability of OPEC sustaining its emphasis on preserving market share, nor on the prospects for greater geopolitical stability, though the ability of OPEC countries to tolerate relatively low revenue flows forms part of the discussion of the macroeconomic consequences of the Low Oil Price Scenario towards the end of this chapter. Because developments in tight oil are so important an element in the resilience of non-OPEC production to low prices, the tight oil situation is given special focus later in the chapter. Reform of fossil-fuel subsidies is discussed further in Chapter 2.

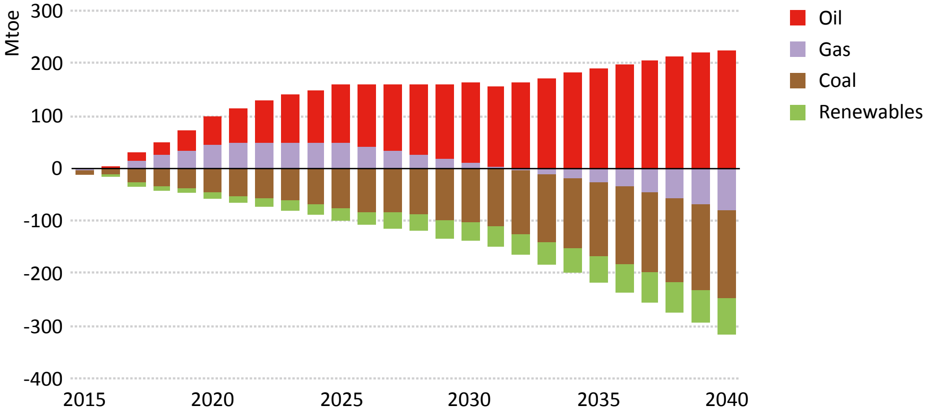
While most *World Energy Outlook (WEO)* scenario work is based on a set of the most plausible assumptions available and describes the energy landscape they produce, the Low Oil Price Scenario is different. It starts by selecting the end-point which is to be achieved – in this case, a lower oil price which persists through to 2040 – and then adopts the assumptions which plausibly allow that destination to be reached. Views will differ on the feasibility of the individual assumptions adopted here, although, in our judgement, each of them is reasonable and plausible; the chance of them all being realised simultaneously and sustained for the long term is, though, not high. Setting the end-point at the outset makes the Low Oil Price Scenario in some ways like the 450 Scenario. But there is a very significant difference. The 450 Scenario shows a route to a goal already adopted by the international community – keeping the rise in the average global temperature to no more than 2 degrees Celsius (°C). The goal set in the Low Oil Price Scenario is no more than a means of exploring the implications of such a prolonged period of low oil prices.

Outcomes in the Low Oil Price Scenario

In terms of overall global energy demand, the world of the Low Oil Price Scenario, even with slightly lower GDP growth and persistently lower oil prices, is not fundamentally different from that of the New Policies Scenario. Total primary energy demand rises by one-third from today's levels to almost 18 000 million tonnes of oil equivalent (Mtoe); the stimulating effect of lower prices is offset by the impact of slower growth in economic activity; the 2040 demand level is 0.5% lower than in the New Policies Scenario. But the lower oil prices do affect the economics of different fuels, changing their relative competitiveness and thereby the global energy mix, with implications for economies as well as for key policy concerns, such as energy security and climate change (Figure 4.2).

The main beneficiary among the fuels, unsurprisingly, is oil itself, for which global demand rises to almost 5 000 Mtoe (107.2 mb/d), almost 4% higher (an additional 3.7 mb/d) than in the New Policies Scenario. Natural gas benefits for a period as well, particularly in regions where import prices are indexed to oil: this holds gas prices down for longer, stimulating additional demand (notably in the power sector), before a gradual de-coupling of gas and oil prices in the latter part of the projection period sees gas prices move higher. In tandem with the effect of lower GDP, which feeds through into lower electricity consumption, and slower growth in demand for gas as a road and marine transport fuel, the rise in gas prices brings gas consumption in 2040 down slightly below the levels seen in the New Policies Scenario (Table 4.1).

Figure 4.2 ▻ Change in global primary energy demand by fuel in the Low Oil Price Scenario relative to the New Policies Scenario



Note: There is no change in the output of nuclear power between the scenarios.

Table 4.1 ▻ World primary energy demand by fuel in the Low Oil Price Scenario (Mtoe)

	Low Oil Price Scenario					Change relative to New Policies Scenario		
	2000	2013	2020	2030	2040	2020	2030	2040
Coal	2 343	3 929	3 986	4 117	4 248	-47	-102	-166
Oil	3 669	4 219	4 513	4 762	4 960	52	150	226
Gas	2 067	2 901	3 223	3 703	4 158	45	12	- 81
Nuclear	676	646	831	1 042	1 200	-	-	-
Hydro	225	326	383	467	531	-	-	-
Bioenergy*	1 023	1 376	1 531	1 698	1 821	-10	-29	-56
Other renewables	60	161	315	585	926	-1	-6	-12
Total	**10 063**	**13 559**	**14 782**	**16 373**	**17 845**	**39**	**24**	**-90**

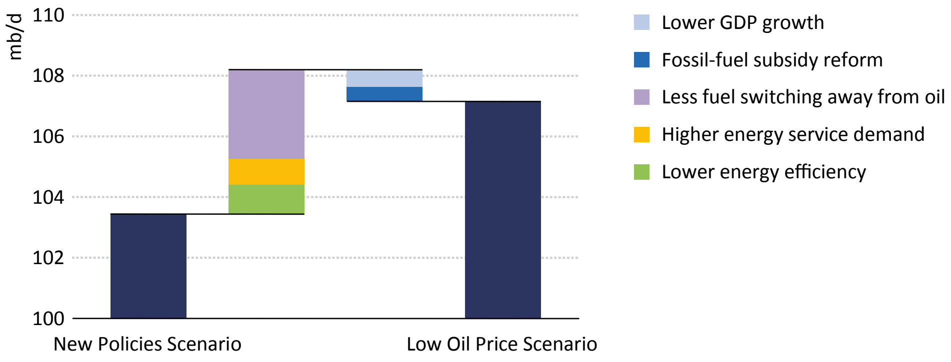
*Includes the traditional use of solid biomass and modern uses of bioenergy.

Coal loses ground in the Low Oil Price Scenario, compared with its position in the New Policies Scenario. This is mainly because of sterner competition from gas in power generation, but also – especially in the latter part of the projection period – because of the decreased attraction of coal-to-liquids projects in key producing regions. Growth of low-carbon sources of energy is largely unaffected by lower oil prices: in most cases, the level of their deployment emerges unscathed from the effects of lower natural gas and electricity prices. The main exception is the use of biofuels in road transport, where lower oil product prices and diminished policy support reduce total bioenergy demand by more than 50 Mtoe by 2040.

Oil demand

Global oil demand in the Low Oil Price Scenario rises by 0.6% per year on average to reach 107.2 mb/d in 2040, some 3.7 mb/d above the level in the New Policies Scenario. Almost 60% of this increase occurs within the first ten years, so that oil demand reaches 100 mb/d in 2025, five years earlier than in the New Policies Scenario. Although the share of oil in the global energy mix continues to fall – it had already fallen five percentage points since 2000 to 31% in 2014 (see Chapter 3) – the pace of decline in the Low Oil Price Scenario is slowed: in 2040, oil meets 28% of global energy demand, compared with 26% in the New Policies Scenario.

Figure 4.3 ▷ Change in world oil demand by source in the Low Oil Price Scenario relative to the New Policies Scenario, 2040



The increase in oil demand in the Low Oil Price Scenario stems from a number of factors. Low oil prices generally stimulate demand (consumers might drive their cars more or increase the temperature of their oil-fired heating systems) and diminish the case for investments in energy efficiency as well as the incentive to switch to alternative fuels. In the Low Oil Price Scenario, all these factors contribute to the rise in overall demand (Figure 4.3). The contributions to the overall increase in oil demand, relative to the New Policies Scenario, are from a lower switch to alternative fuels (2.9 mb/d in 2040), lower energy efficiency (0.9 mb/d) and increased demand for energy services (0.8 mb/d). Lower GDP growth and fossil-fuel subsidy reform moderate the increase in the Low Oil Price Scenario and bring down oil demand by a combined 1.0 mb/d.

The familiar pattern of demand growth in non-OECD countries and declining oil use in OECD countries is also observed in the Low Oil Price Scenario. But the increase in demand, relative to the New Policies Scenario, is shared almost equally between OECD and non-OECD countries. The United States adds more than 200 thousand barrels per day (kb/d) in 2020 and 900 kb/d in 2040 (Table 4.2). The impact of lower oil prices is felt more directly by consumers in the United States, where the level of fuel taxes is much lower than in other OECD countries, which generally leads to higher use of personal cars. Europe, too, shows a significant increase in total oil demand, at more than 150 kb/d in 2020 and 340 kb/d in 2040. The reason is again found in the transport sector: although car usage in the region is less directly affected than in the United States, given generally higher fuel taxes, Europe is one of the leading regions of global biofuels use, so that the reduced support to biofuels policy in the Low Oil Price Scenario directly increases oil demand.

Table 4.2 ▷ Oil demand by region in the Low Oil Price Scenario (mb/d)

	2000	2014	2020	2025	2030	2035	2040	Change relative to NPS in 2040
OECD	**45.2**	**40.7**	**39.9**	**37.8**	**35.5**	**33.3**	**31.3**	**1.5**
Americas	23.2	21.8	22.3	21.6	20.6	19.5	18.4	1.1
United States	19.0	17.3	17.7	17.0	16.0	15.0	14.0	0.9
Europe	13.9	11.5	10.9	10.1	9.2	8.5	7.9	0.3
Asia Oceania	8.1	7.3	6.7	6.2	5.7	5.3	5.0	0.1
Japan	5.2	4.1	3.5	3.1	2.8	2.5	2.3	0.0
Non-OECD	**26.5**	**42.9**	**49.4**	**54.0**	**58.2**	**62.1**	**65.4**	**1.8**
E. Europe / Eurasia	3.8	4.9	5.1	5.2	5.3	5.4	5.4	0.2
Russia	2.6	3.1	3.2	3.2	3.2	3.2	3.1	0.1
Asia	11.5	20.8	24.9	28.0	30.9	33.6	35.9	1.5
China	4.7	10.5	12.6	14.0	14.9	15.5	15.8	0.5
India	2.3	3.8	4.9	5.9	7.3	8.8	10.3	0.5
Middle East	4.3	7.6	8.9	9.6	10.1	10.6	11.1	-0.0
Africa	2.2	3.7	4.5	4.9	5.4	5.8	6.3	0.1
Latin America	4.3	5.9	6.0	6.2	6.5	6.7	6.8	0.1
Brazil	1.9	2.7	2.7	2.9	3.1	3.4	3.6	0.1
Bunkers*	5.2	7.0	7.7	8.3	8.9	9.6	10.4	0.4
World oil	**76.9**	**90.6**	**97.0**	**100.0**	**102.6**	**105.0**	**107.2**	**3.7**
European Union	13.0	10.6	9.9	9.1	8.3	7.5	7.0	0.3
World biofuels **	0.2	1.5	1.9	2.4	2.7	3.0	3.3	-0.9
World total liquids	**77.1**	**92.1**	**98.9**	**102.4**	**105.4**	**108.0**	**110.4**	**2.8**

* Includes international marine and aviation fuels. ** Expressed in energy-equivalent volumes of gasoline and diesel.

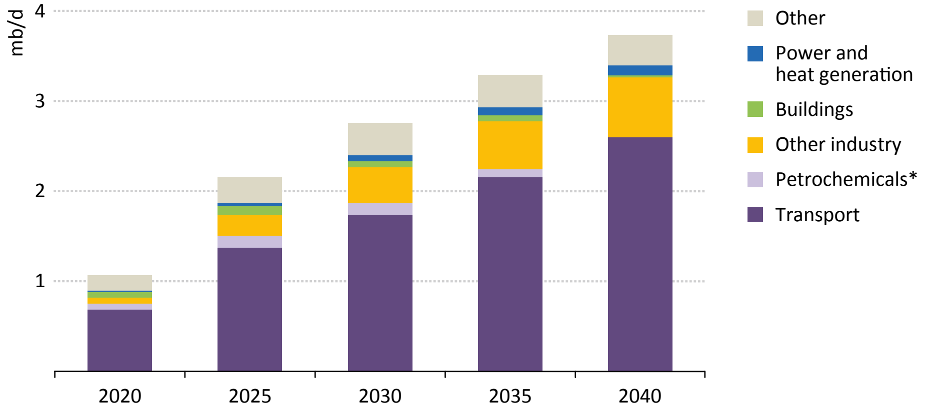
Note: NPS = New Policies Scenario.

The traditional engines of world demand growth in developing Asia add a relatively modest 230 kb/d in 2020 to the demand projections in the New Policies Scenario, but see a more significant long-term increase, with demand 1.5 mb/d higher in 2040 in the Low Oil Price Scenario. China, India and the rest of developing Asia each account for around one-third of this additional consumption. Lower oil and gas prices shift demand away from coal and electricity towards oil and gas in the industry sector, while lower oil prices facilitate greater use of cars and trucks in the transport sector and limit the growth of alternative fuels, such as biofuels and natural gas.

In the Middle East, the more rapid assumed phase-out of subsidies means that, for most end-users, oil product prices are only slightly lower than those of the New Policies Scenario, not enough to stimulate additional growth in demand. In Brazil, however, more than 140 kb/d is added to the New Policies Scenario projection for oil demand in 2040, of which 75% comes from road transport. Brazil is distinctive in that 20% of road transport energy use is covered by biofuels today, in particular ethanol. While Brazil has a blending mandate to support the use of biofuels, the consumer may also choose pure ethanol at the pump. The first-half of 2015 saw a record increase in the consumption of pure ethanol in Brazil, with year-on-year sales rising 35% following new tax legislation that sharply improved its attractiveness. The longer term outlook for ethanol is, however, subdued in the Low Oil Price Scenario as the lower oil prices undercut its competitiveness: biofuels demand in 2040 is cut by about 110 thousand barrel of oil equivalent per day (kboe/d), compared with the New Policies Scenario.

In terms of sectors, transport is by far the main contributor to additional global oil demand growth in the Low Oil Price Scenario, at 2.6 mb/d in 2040 (Figure 4.4). Increased use of cars and trucks, a slower pace of improvement in the efficiency of vehicles and aircraft and more limited switching to alternative fuels, such as biofuels, natural gas and electricity, are the main reasons for the increase. In road transport, the on-road fuel consumption of heavy trucks, at 34 litres per 100 kilometres (l/100 km), is almost 2% higher than in the New Policies Scenario as the payback time for more energy-efficient trucks in the Low Oil Price Scenario is significantly prolonged and fuel-economy standards are not as widespread.

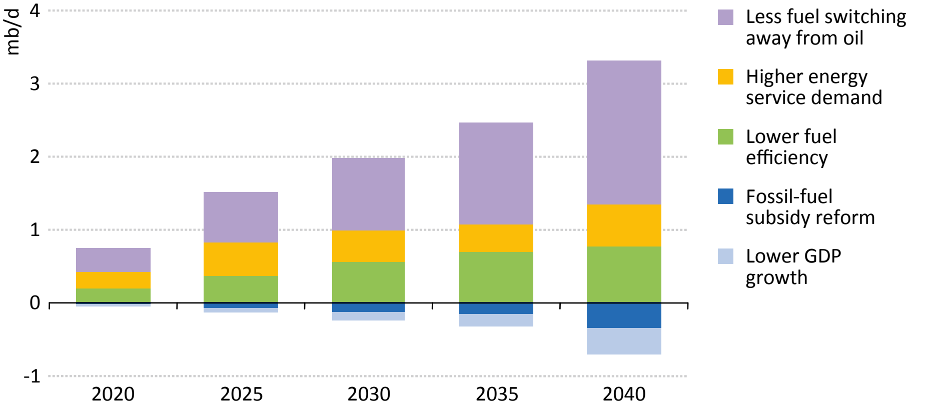
Figure 4.4 ▷ Change in global oil demand by sector in the Low Oil Price Scenario relative to the New Policies Scenario



* Includes both feedstocks and fuel use.

The incentive to move away from oil products to alternative fuels in the transport sector is significantly diminished in a Low Oil Price Scenario (Figure 4.5). Biofuels use is reduced by 0.9 mboe/d in 2040, compared with the New Policies Scenario. The business case for natural gas vehicles, particularly in road freight and in taxis (both of which are the main contributors to natural gas use for road transport in countries like China or India today), but also in shipping, is also partly undermined, reducing transport gas demand by more than 50 billion cubic metres (bcm) in 2040, or almost 20%, relative to the New Policies Scenario.

Figure 4.5 ▷ Change in global transport sector oil demand in the Low Oil Price Scenario relative to the New Policies Scenario



In the aviation sector, oil demand in 2040 increases by around 240 kb/d, or 2.6%, in the Low Oil Price Scenario relative to the New Policies Scenario. Airlines typically take a long-term view on oil prices when it comes to fleet planning and capacity, given the long lifetime of aircraft. While the current decline in oil prices, therefore, does not affect the long-term outlook for aircraft efficiency in the New Policies Scenario, the average increase in global fuel efficiency is reduced by 0.1 percentage point per year in the Low Oil Price Scenario.

The second-largest contributor to the increase in oil demand in the Low Oil Price Scenario is the industry sector, which adds 0.6 mb/d to total oil demand in 2040 compared with the New Policies Scenario. The main reason for the difference is that fewer consumers switch away from oil as an input to industrial processes, because the economics of the switch to alternative fuels (electricity, coal, natural gas or biomass) are less compelling. A supplementary reason is a rise in demand for oil in the petrochemicals sector, including for use as a feedstock. Overall, about 30% of the increase in industrial oil demand occurs in China, where the change in oil and gas prices reduces the competitiveness of electric heat pumps, relative to oil and gas boilers. India is the second-largest contributor to industrial oil demand growth, as low prices improve the economics of oil and gas-fired boilers, compared with coal, in several parts of India's industry sector. Much of the remaining increase in industrial oil demand is a result of lower efficiency investments.

The role of oil in energy demand from the buildings sector is already in decline today and it continues its decline in the Low Oil Price Scenario. While oil is mainly used for heating purposes in OECD countries, the main use in developing countries is for cooking and, where there is no access to reliable electricity supply, for lighting. In this sector, oil (as well as gas) demand is slightly higher in the Low Oil Price Scenario, relative to the New Policies Scenario, as lower prices tend to increase the energy demand of households, except in countries where demand is already close to saturation. But lower prices do not lead to a large-scale switch to oil from other fuels, as the required infrastructure investments are too large to be justified by lower fuel prices. In developing countries, however, lower prices can help to increase the number of households with access to modern fuels, especially liquefied petroleum gas (LPG) for cooking (Box 4.2).

Box 4.2 ▷ Do lower oil prices ease access to energy?

Lower oil prices can provide a boost to the budgets of some low-income households, lowering energy expenditure and freeing up income for other uses. It might be assumed that low prices also ease access to energy for those without electricity or those relying on solid biomass as a traditional fuel for cooking. The reality, at least in our Low Oil Price Scenario, is a little more complicated.

The pace at which access to electricity grows is largely determined by policies related to electrification. Whether or not lower oil prices affect these policies, and in what way, depends on the circumstances of the country concerned. A country like Nigeria, that has a large population without electricity access and high reliance on oil exports for fiscal revenue, would see a squeeze on public funding in many areas that could limit the construction of access-related infrastructure. Elsewhere, in oil-importing countries like India or Kenya, the beneficial effects on public finance from lower oil prices could result in greater support for electrification. Within any given country, the oil price level can also affect the technology choices made by those gaining access via mini-grids and off-grid solutions, as the attraction of diesel-based generation rises somewhat, relative to other (renewable) options. However, there is unlikely to be any turning back the clock when it comes to direct competition between electricity and oil in household uses. There is little chance, for example, that households already having access to electricity would revert back to kerosene for lighting, even if the kerosene price were lower.

A lower oil price could, though, have a more substantial impact on access to cleaner fuels for cooking (via more affordable LPG) for those who otherwise rely on traditional stoves using solid biomass as their primary fuel. Twenty five million more people gain access to clean cooking in the Low Oil Price Scenario, compared with the New Policies Scenario. A shift is also evident in households that already have access to modern fuels for cooking but which still use solid biomass on a regular basis (a phenomenon known as fuel stacking); lower end-user prices for oil products in a Low Oil Price Scenario enable these households to rely more on LPG.[4]

4. The affordability calculation works against oil products in the Low Oil Price Scenario in cases where oil and gas subsidies are also being phased out (see assumptions at the start of the chapter). In these cases, the number of households getting access to modern fuels is lower than in the New Policies Scenario.

Oil demand is generally low in the power sector: the Middle East is one of the only regions that still use a sizeable amount of oil for power generation. As we have argued in the past, at oil prices above $100/bbl, almost every alternative technology for power generation is economically more attractive than oil-based power generation (IEA, 2013). This is even true at current oil prices, with the exception of concentrated solar power. In the Low Oil Price Scenario, oil demand from power generation continues to decline and is only marginally higher than in the New Policies Scenario, as the partial phase-out of fossil-fuel subsidies generally offsets the decline in oil prices.

Oil production

The outlook for oil production in a Low Oil Price Scenario is markedly different from that of the New Policies Scenario. If the objective among OPEC countries is to increase their share of the oil market, then – although it takes time to materialise – this is achieved in resounding terms in our projections (Figure 4.6): the share of OPEC countries in total oil production rises above 50% by the 2030s, a level not seen since the early 1970s. Some non-OPEC producers, notably Russia and the United States, manage to keep their production levels above those of the New Policies Scenario, as – aided by a squeeze on the cost of upstream supplies and services – they are able to develop new fields even in a lower price environment. But they are not in a position to increase output and balance a market that experiences substantially higher levels of demand. After 2020, non-OPEC output declines by more than 5 mb/d, while OPEC production rises by 15 mb/d (Table 4.3). This is a logical outcome over the longer term: OPEC countries are those with the largest and lowest-cost resources. Their assumed decision to produce these resources in larger volumes and over the longer term is the most important enabler of a prolonged low price environment (although, as discussed in the section on revenues and financial flows below, the consequent risks to their fiscal balances are substantial).

Figure 4.6 ▷ Change in non-OPEC and OPEC oil production by five-year periods in the Low Oil Price Scenario

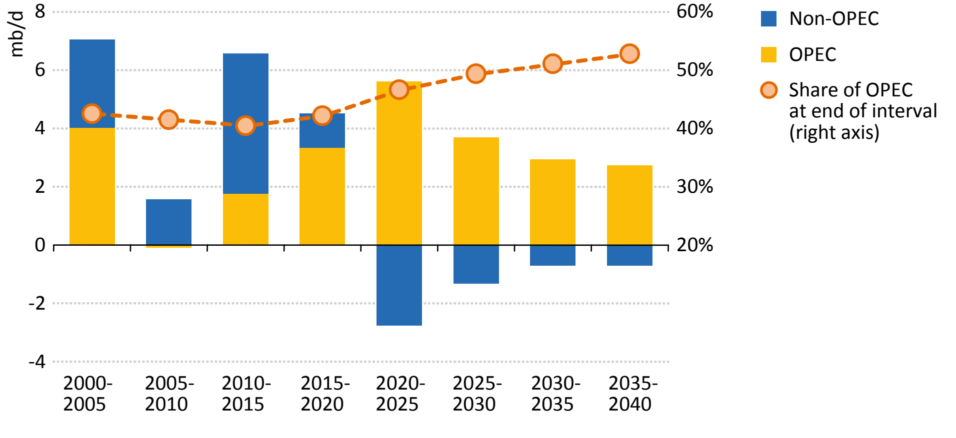


Table 4.3 ▷ **Oil production and liquids supply by source in the Low Oil Price Scenario** (mb/d)

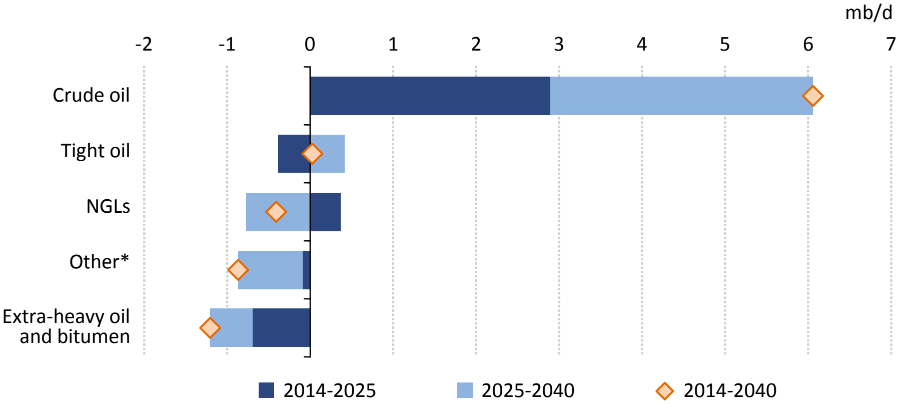
			Low Oil Price Scenario			Change relative to New Policies Scenario		
	2000	2014	2020	2030	2040	2020	2030	2040
OPEC	**30.8**	**36.7**	**39.8**	**49.1**	**54.8**	**1.3**	**4.9**	**5.6**
Crude oil	27.7	29.8	31.7	39.3	42.7	1.1	4.8	6.0
Natural gas liquids	2.8	6.1	6.7	8.0	9.3	0.2	0.2	-0.2
Unconventional	0.3	0.7	1.4	1.9	2.8	0.0	-0.2	-0.2
Non-OPEC	**44.2**	**52.8**	**54.8**	**50.7**	**49.2**	**-0.2**	**-2.2**	**-2.0**
Crude oil	37.8	38.1	36.7	33.0	30.1	-0.0	-0.6	0.0
Natural gas liquids	5.5	7.8	8.9	9.3	9.4	0.1	-0.0	-0.2
Unconventional	1.0	6.8	9.2	8.5	9.6	-0.3	-1.6	-1.8
World oil production	**75.0**	**89.5**	**94.5**	**99.8**	**104.0**	**1.0**	**2.7**	**3.6**
Crude oil	65.5	68.0	68.4	72.2	72.8	1.0	4.3	6.0
Natural gas liquids	8.3	13.9	15.6	17.3	18.8	0.3	0.2	-0.4
Unconventional	1.2	7.6	10.6	10.3	12.4	-0.3	-1.7	-2.0
Processing gains	*1.8*	*2.2*	*2.4*	*2.8*	*3.1*	*0.0*	*0.1*	*0.1*
World oil supply*	**76.9**	**91.7**	**97.0**	**102.6**	**107.2**	**1.1**	**2.8**	**3.7**
World biofuels supply**	0.2	1.5	1.9	2.7	3.3	-0.1	-0.4	-0.9
World total liquids supply	**77.1**	**93.2**	**98.9**	**105.4**	**110.4**	**0.9**	**2.4**	**2.8**

*Differences between historical demand and supply volumes are due to changes in stocks. **Expressed in energy-equivalent volumes of gasoline and diesel.

A consequence of the higher share of OPEC countries in overall output is a change in the composition of the average barrel of oil. As noted in Chapter 3, the share of conventional crude oil in total production has been gradually declining in recent decades. This trend continues in the New Policies Scenario, where essentially all the projected growth in output comes from unconventional oil, including tight oil, and natural gas liquids (NGLs) while conventional crude production stays in a range of 66-68 mb/d. The trend is less visible in the Low Oil Price Scenario (Figure 4.7). The share of conventional crude in global oil production, which was 76% in 2014, falls in the Low Oil Price Scenario to 70% in 2040, compared with 66% in the New Policies Scenario. Among the other resource types, resilient US upstream activity keeps tight oil production at roughly the same levels as in the New Policies Scenario. NGLs see a relatively small decline between the scenarios, but production of extra-heavy oil and bitumen, largely Canadian oil sands, takes a larger hit, as do projects to convert coal or gas to liquids.

The Low Oil Price Scenario sees large production increases in some of the main resource-rich countries of the Middle East. Saudi Arabia, while remaining within its declared crude capacity limit of 12.5 mb/d, puts distance between itself and the next largest oil producers, the US and Russia. Iraq more than doubles its current output, but stays below the levels seen in the Iraq High Case modelled in *WEO-2012* (IEA, 2012). Iran likewise surpasses its previous record levels of production of around 6 mb/d, reached in the 1970s. Kuwait and the United Arab Emirates (UAE) also see substantial growth, compared with the New Policies Scenario. Elsewhere, among OPEC members outside the Middle East, Libyan production is also higher (benefitting from the assumption of greater geopolitical stability), but sub-Saharan African producers face more of a struggle in a lower price environment, because of the higher costs of their predominantly offshore resources. In Latin America, Venezuelan production is unchanged from the New Policies Scenario.

Figure 4.7 ▷ Change in world oil production by type in the Low Oil Price Scenario relative to the New Policies Scenario



* Includes coal-to-liquids and gas-to-liquids, production of additives and of kerogen oil.

The desire of major producers (such as Saudi Arabia, Iraq or Iran) to preserve or increase their market share is a very important component of the Low Oil Price Scenario. But this scenario can only be sustained if a lower oil price does not eliminate production from other countries. The ability of tight oil producers in the United States to withstand lower oil prices has probably been the most talked-about question in the oil industry over the past year. Though this might have obscured the equally important impact of lower oil prices on investment in other sources of oil (oil sands, offshore, deepwater and so on), this ability to withstand lower oil prices is a key component of the Low Oil Price Scenario and for that reason tight oil is examined in detail in the next section.

Outside the United States, the non-OECD producers with the most substantial low-cost resources to call upon are Russia, Mexico and Brazil. Russia's giant, but ageing, reservoirs in western Siberia provide some shelter against a lower price, as does a tax system under which the Russian state not only takes most of the benefit when prices are high, but also most of the pain when they fall. In the case of Brazil, lower prices initially reduce deepwater investment further, leading to a production deficit compared with the New Policies Scenario in the 2020s. However, the pre-salt resources are sufficiently large and prolific that investment and production pick up again towards the end of the projection period, helped by reduced costs for services, drilling rigs, etc., and by the gradual increase in price (Box 4.3). The countries that see the sharpest declines in production, relative to the New Policies Scenario, are those with projects towards the top of the cost curve. This applies to some oil sands projects in Canada and also to the majority of the projects envisaged to convert coal or gas to liquids, a consideration that brings down China's projected output (Figure 4.9).

Box 4.3 ▷ Why invest when prices are low?

The low oil price leads in our modelling to a sustained fall in the costs of producing oil, particularly in non-OPEC countries. Lower upstream activity levels mean greater competition among service providers for available business (even as they cut their own personnel or withdraw rigs from service). Governments also come under pressure to ease fiscal terms in order to keep production and jobs from disappearing. These considerations bring down the overall cost of new projects, explaining how some non-OPEC producers manage to maintain output at the levels seen in the New Policies Scenario, even when anticipated revenues have been reduced by $30/bbl or more. This in turn is one of the reasons why, even though projected demand in the Low Oil Price Scenario is some 4 mb/d higher by 2040, global upstream oil and gas investment averages under $600 billion per year in the Low Oil Price Scenario – one-fifth less than the annual $750 billion required in the New Policies Scenario. But the main reason is the overall shift in the direction of investment towards the Middle East, representing a major movement from higher to lower cost areas (as well as a shift towards large onshore fields that tend to have lower rates of decline). Still, even in the Middle East, cumulative investment over the period to 2040 is almost 10% lower than in the New Policies Scenario, but delivers almost 10% more in terms of output (Figure 4.8).

Figure 4.8 ▷ Change in cumulative oil and gas upstream investment and cumulative production by key region in the Low Oil Price Scenario relative to the New Policies Scenario, 2015-2040

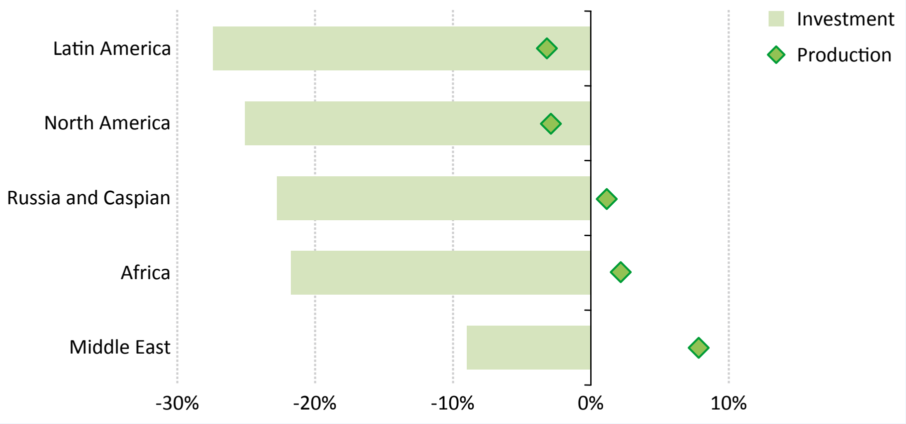
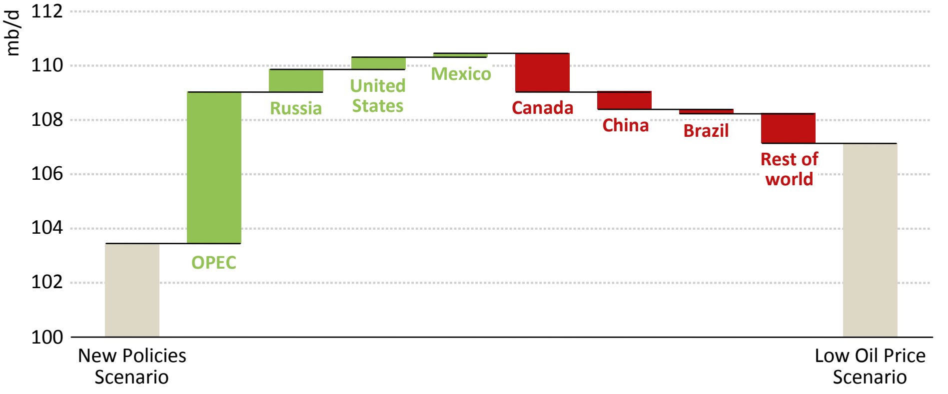


Figure 4.9 ▷ Change in oil supply by selected region in the Low Oil Price Scenario relative to the New Policies Scenario, 2040



Focus: tight oil – a new balancing element in the oil market?

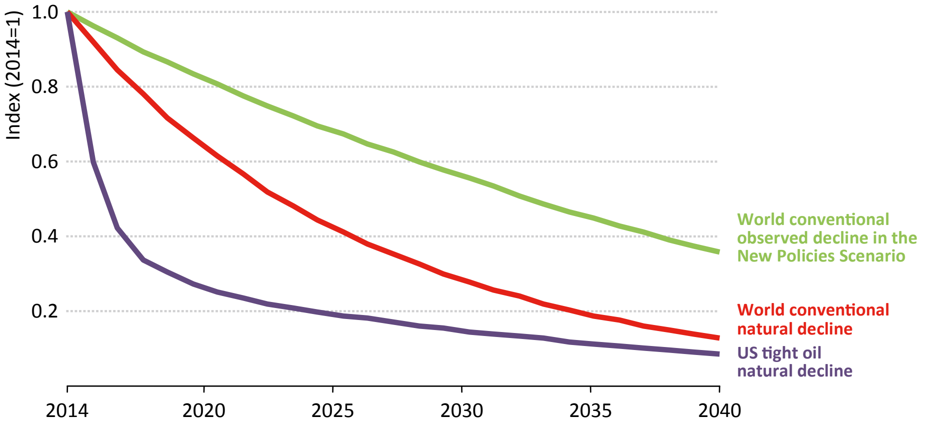
The rise of tight oil in the United States has introduced a new element to global supply, which – because of a much shorter investment cycle – has the capacity to respond much more quickly to price movements than other sources of oil. Tight oil wells, like shale gas wells, are characterised by very high decline rates, with production often dropping by more than 50% in the first year and, typically, 80% of the total volume being recovered from a producing well in the first three years (the remainder being a long tail at a low production rate, expected to last 20 years or more). As a result, to increase or even maintain production, operators have to keep on drilling new wells; if they stop doing so, the effects on production can be felt within a few months.

This, at least in theory, allows tight oil to play a balancing role in the market. When the market is oversupplied, oil prices drop and drilling more wells becomes economically less attractive: fewer wells get drilled and production drops quickly, due to high decline rates. When oil prices increase again, operators restart drilling (in the US tight oil plays, most wells are drilled in less than one month) and boost production again. Some operators have already taken advantage of the lull in drilling activity in 2015, which pushed drilling costs down, to construct a backlog of wells that can be brought into production quickly as soon as the oil price warrants it.

The first part of this hypothesis has been tested since late 2014 by the drop in prices. In practice, production has reacted less rapidly than some had expected. This is due, in part, to the delay between drilling and completing (i.e. hydraulically fracturing) wells, which can often be several months. It also reflects the ability of the industry to adapt quickly to a new price environment, by cutting costs and focusing on the most productive parts of plays (supporting the view that tight oil might contribute substantially to supply growth even at a price considerably lower than the triple-digit levels seen from 2011 to 2014). But other factors have also contributed to sustained levels of production. In some cases, operators had contractual commitments for drilling rigs or service contracts that they could not get out of quickly, or were committed to drill as a condition of holding on to their leases. Some had hedged their future production at a higher price, or needed to continue production to generate cash flow to service their debts.

The response of tight oil output to a price upswing has yet to be tested in full (and in a Low Oil Price Scenario may not be tested for some time), but there are factors that may likewise make this "stickier" than expected. Banks and investors have been key enablers of the US tight oil boom, but they may be reluctant to put money into new wells, given that the financial position of many producers has been worsened by the fall in revenues. Tight oil production in the United States has been heavily reliant on capital markets for its expansion over the last few years, allowing aggregate spending to run well ahead of cash flow. With the cost of capital now likely to rise, capital availability could well become a constraint on the industry. In addition, it may take some time to remobilise staff (that may have been laid-off in the meantime) or equipment.

Figure 4.10 ▷ Average field decline curves for US tight oil and world conventional oil



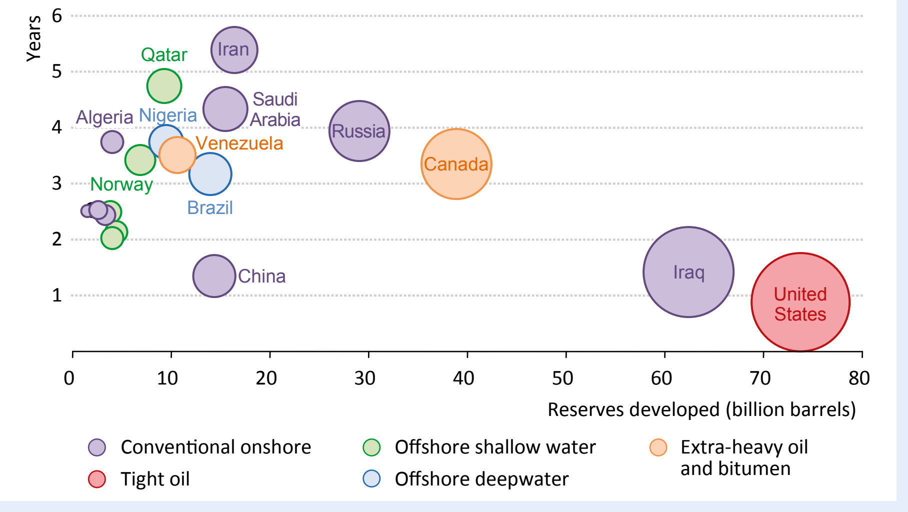
Note: Natural decline is the decline in total production from a set of fields/plays that would occur if all investment ceased; observed decline is based on the decline rates that are seen in reality given that operators continue to invest in currently producing fields.

But, even with these caveats, there is sound support for the argument that something significant has changed in the operation of oil markets with the advent of tight oil. The decline rates that we derive from an earlier analysis (see *WEO-2013* [IEA, 2013]) confirm how much steeper these rates are for US tight oil, compared with global conventional oil, demonstrating the potential for a faster supply reaction to any reduction in investment (Figure 4.10). Likewise, our analysis of the average time lag between investment decision and production start-up for various resource types shows how tight oil plays can be expected to resume production more quickly than conventional oil developments if the oil price is at a level that triggers investment decisions (Box 4.4).

Box 4.4 ▷ How quickly can oil supply respond to prices?

The bulk of global oil supply comes from a relatively slow-moving but high-volume development cycle, with Saudi Arabia's spare capacity – available to be brought into production at shorter notice – ordinarily providing some flexibility to fine-tune supply. The lack of flexibility elsewhere is due to the time required to bring new resources online, a process requiring both exploration and development. The lead time between exploration activity and a development programme can span decades. The development part of the process has a more rigid timeline, but the lead times between final investment decision and first production – for most types of resources – span several years at least (Figure 4.11). This time span is unlikely to contract much further; technology and streamlined sanctioning processes can reduce the amount of time required, but these have to be set against the generally increasing level of field complexity.

Figure 4.11 ▷ Average lead times between final investment decision and first production for different oil resource types



Notes: Analysis includes the top-twenty crude oil producers in 2014. Bubble size indicates the quantity of reserves developed from 2000 to 2014. The average lead times for Iraq are brought down by three large rehabilitation projects in legacy fields, each of which was reported with one year between investment approval and the start of production. This is not a representative finding for greenfield developments in Iraq.

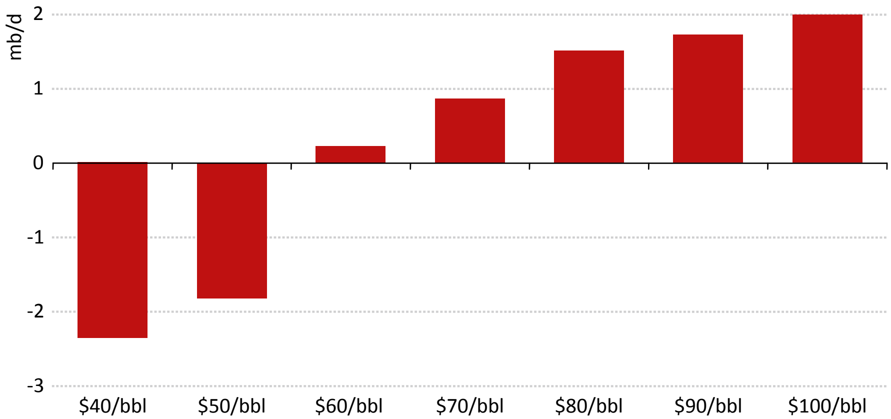
Source: IEA analysis based on Rystad Energy AS.

Tight oil in the United States operates on a different timeline. There is no exploration process to speak of, and the location and broad characteristics of the main plays are well known, even if the performance of wells within plays can vary dramatically. And the time from investment decision to actual production is measured in months, rather than years: an average of eight months over the period 2005-2014, compared with a resource-weighted average of three years for other sources of oil.

So what role might tight oil play in finding a new oil market equilibrium – and at what price? And how might this role evolve over time, as resources are gradually depleted but operators become more skilled and efficient at developing them? The answer to the first question is different in the New Policies Scenario and in the Low Oil Price Scenario. Our analysis of drilling activity, production rates and profitability estimates for the primary US tight oil plays suggests that – with the prices, resources and breakeven estimates of the New Policies Scenario – tight oil output continues to rise over the period to 2020, by around 1.5 mb/d from 2014 (Figure 4.12). This represents an increase in drilling activity from 2015 levels by an average 8% per year.[5] But another implication of this analysis is that – were prices to remain under $60/bbl to 2020 – tight oil production in the United States would see a substantial decline in output.

4

Figure 4.12 ▷ Indicative supply response of US tight oil for the period 2014-2020, based on costs in the New Policies Scenario, for a range of 2020 oil prices



Note: The price level (in year-2014 dollars) is a 2020 price; the underlying assumptions on production costs are those from the New Policies Scenario.

Source: IEA analysis based on Rystad Energy AS.

For tight oil output to increase in the Low Oil Price Scenario, where oil prices stay in the $50-60/bbl range until well into the 2020s, we need to revisit our underlying assumptions on resources and costs. In a Low Oil Price Scenario, we use a 10% higher value for US remaining tight oil resources and also assume more rapid evolution of efficiency gains and technology learning, pushing down the costs of production.[6] We also assume a more

5. This is based on the assumption that operators stay focused on their best leases, resulting in an average 12% rise in initial production rates by 2020, compared with those seen over 2013-2014 (such an improvement in performance would be difficult to maintain in more mature plays like the Bakken, but could be exceeded in some of the less-developed plays).

6. Indeed in 2015 a number of efficiency indicators are continuing to show improvements, e.g. new well oil production per rig in the EIA *Drilling Productivity Report* (US DOE/EIA, 2015). Although this may be more the result of "mix" (only the most modern rigs are left in use and are focused on the most productive parts of the most productive plays) than real technology learning, there is certainly scope for more improvement in technology that could increase recovery factors.

prolonged slump in services and supply costs, due to a surplus of equipment, such as drilling rigs and hydraulic fracturing fleets (even though companies have reduced personnel and written-off equipment quickly and are likely to continue to do so). These are the critical variables that allow tight oil production to increase even in our Low Oil Price Scenario, in which it gains 1.5 mb/d over 2014 levels by 2020. This is a comparable performance to the New Policies Scenario, despite the change in price levels, and one which allows the market to balance at a significantly lower price.

The second question – whether tight oil production growth might be sustained even longer in a low price environment – brings us back to the issue of costs. In our World Energy Model, the evolution of these costs is determined by three main factors: the gradual depletion of the resource base; technology learning and efficiency improvements; and the cost of services and supplies. The cost increase due to the depletion of the resource base reflects a gradual deterioration in rock quality as operators exhaust the most productive acreage (the so-called "sweet spots") and move on to second or third-tier drilling locations. Set against this is the impact of technology and process improvements, which are reducing the time required to drill and complete wells (even as the length of horizontal sections grows), and allowing for more precise placement of wellbores and fractures to maximise recovery per well. The costs of services and supplies are linked, in turn, to the price of other materials (cement, steel etc.) and the tightness of the market for skilled oil specialists, for rigs and other equipment. For the purpose of the Low Oil Price Scenario we make the simplifying assumption that these costs move up and down in tune with movements in oil prices.

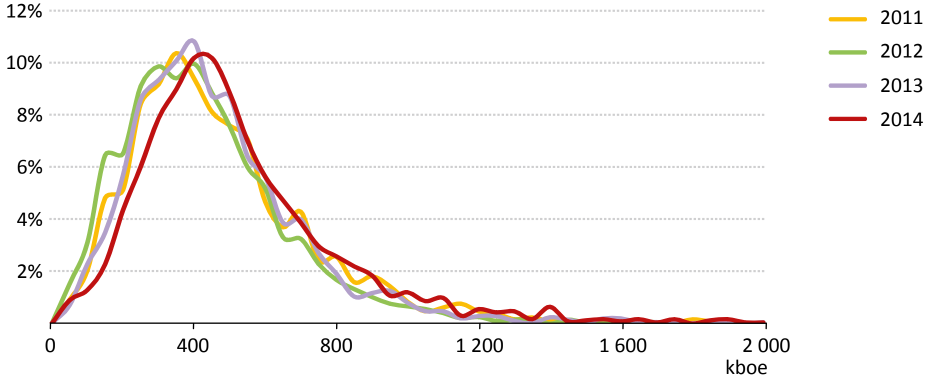
The interplay between these different variables works out quite differently in each of our scenarios. The New Policies Scenario reflects our long-term view that the effects of resource depletion will outweigh the effects of technology learning and efficiency gains, leading to a gradual increase in costs and, by extension, a gradual rise in the price at which tight oil has the potential to help balance the market. In the Low Oil Price Scenario, by contrast, a higher resource estimate limits depletion effects, and a stronger counterweight comes from technology learning and efficiency – as well as from lower costs for services and supplies (because of the lower oil price itself). It is not yet possible to rule definitively on the pathway that tight oil costs are likely to follow, but – in our view – some pointers to the future are nonetheless beginning to emerge.

Our starting point is the tight oil play that has the longest production history: the Bakken play in North Dakota. The key parameter for this analysis is the estimated ultimate recovery (EUR) per well; this is the amount of oil a well is expected to produce over the course of its useful life.[7] The average EUR per well in the Bakken is around 400 000 barrels and, because tight oil wells have low operating costs, this average EUR gives an immediate feel for the breakeven oil price. Wells in the Bakken cost $8-12 million to drill and bring to production, so – for total production of 400 000 barrels – it takes a wellhead oil price of between

7. As most wells are still far from the end of their productive life, the EUR can only be estimated from the well production history so far. There are various ways to do that, but here we rely on the analysis of Rystad Energy AS, which uses Arps' formula for the first few years of production followed by exponential decline.

$20-30/bbl to pay back the cost of the well.[8] To those numbers, one needs to add lease and royalty costs, production taxes, operating costs and overheads, leading to the often-quoted breakeven wellhead prices of $40-50/bbl for this play. A significant part of the Bakken oil is transported by rail (the costs of which can reach $10/bbl, depending on the destination) and sold at a price often at a discount to the relevant international benchmark. If the costs add up to a price implying a premium to imported grades, it is backed out by imports as the oil trading market is very quick to react to constantly changing arbitrage. This explains why the recent low oil prices led to curtailing of some activity in the region and a noticeable flattening of the production trajectory.

Figure 4.13 ▷ Distribution of estimated ultimate recovery per well in the Bakken tight oil play



Note: The year-by-year data are for wells brought into production in a given year.

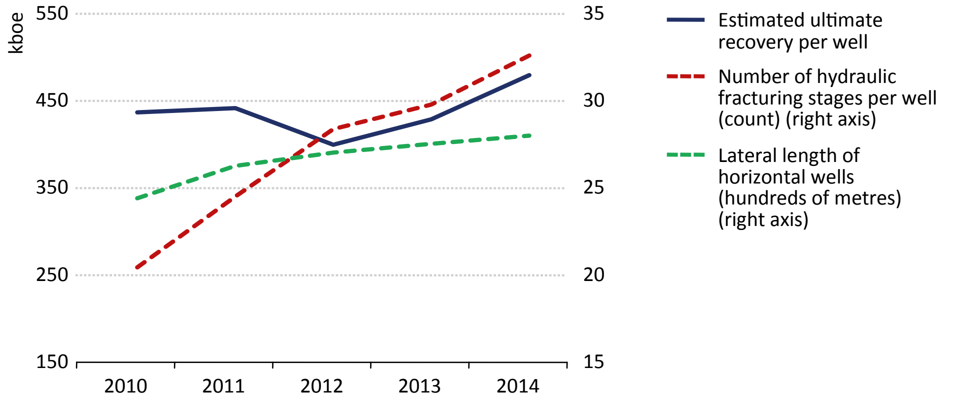
Source: IEA analysis based on Rystad Energy AS.

As in all tight oil and shale gas plays, not all wells in the Bakken produce the average EUR. There is, in practice, a fairly wide distribution of EUR around this figure (Figure 4.13). Some wells produce little and are uneconomical on their own, while others yield above average and are big cash earners. At this time, the industry has not yet developed the technical capability to predict accurately the outcome of a specific well, though this would have a tremendous impact on the overall economics. Looking at the distribution of EUR over time, for wells brought into production in different years, there are some year-on-year variations but the average EUR has remained relatively stable.

Over the same period, the effort required to keep average EUR at this level has increased significantly. Indicators of well "complexity", as measured by the number of hydraulic fracturing stages and the lateral length of the horizontal wells, have been increasing (Figure 4.14). This strongly suggests that, in the Bakken, the technology learning in well construction has largely run its course and it now takes more complex wells to achieve similar EUR per well.

8. A fully correct calculation should discount future revenues, but because of the steep decline rates discussed above, most of the production comes in the first couple of years after drilling, so discount rate effects are small.

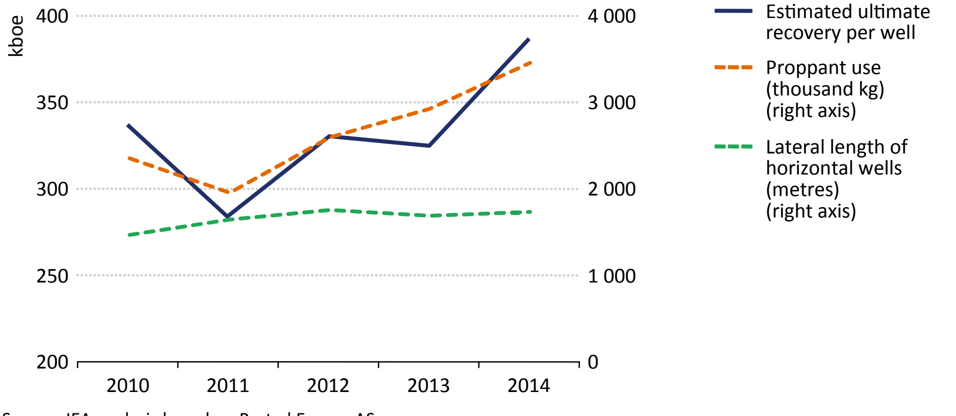
Figure 4.14 ▷ Estimated ultimate recovery per well and indicators of well complexity in the Bakken tight oil play



Source: IEA analysis based on Rystad Energy AS.

This is not the case in more recent, less mature plays such as the Eagle Ford, where a similar graph (using the amount of proppant as a proxy[9] for the number of fracturing stages, as the latter data are not available) shows that, as well complexity is increasing, so is the productivity of the average well (Figure 4.15). How long this trend will continue is a key question that cannot be answered yet, though it is reasonable to think that, as these new plays reach maturity over the coming years they will also reach a saturation point for technology learning.

Figure 4.15 ▷ Estimated ultimate recovery per well and indicators of well complexity in the Eagle Ford tight oil play

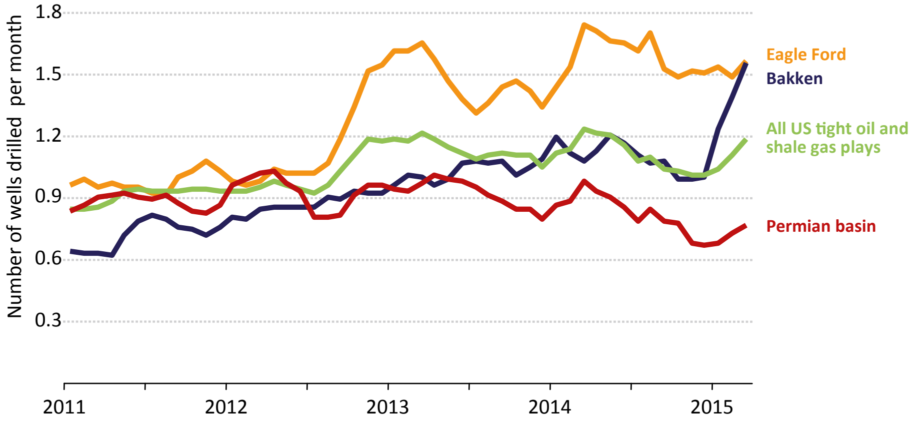


Source: IEA analysis based on Rystad Energy AS.

9. Proppant consists of sand and other granular products and serves to maintain an open channel through which oil and gas flow into the wellbore. The amount of proppant used is not a perfect proxy for well complexity as it also depends on the hydraulic fracturing technology used: slick water, conventional gelled fluid or newer proppant-less technologies.

Estimated ultimate recovery is not the only measure of technology learning: the ability to drill more wells (and more complex wells) faster with the same drilling equipment is also very important. There too, it appears that rapid improvements in the number of wells drilled per month per active drilling rig took place from 2011 to mid-2013, but that the rate of improvement started to level off in 2014 in essentially all the key tight oil plays (Figure 4.16), before the data in 2015 start to show the effect of rig count reductions.[10]

Figure 4.16 ▷ Evolution of number of wells drilled per month per active drilling rig in selected US tight oil plays



Note: The Permian basin in west Texas is the third largest tight oil play in the United States.

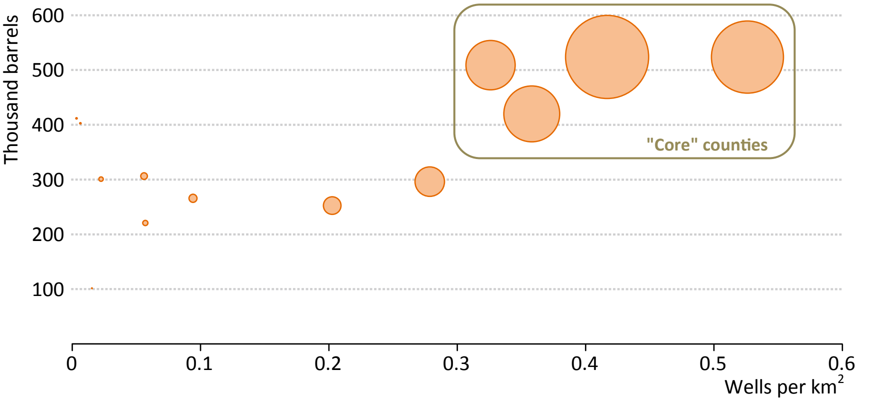
Source: IEA analysis based on data from Rystad Energy AS and Baker-Hughes.

A third consideration affecting the outlook for US tight oil is the way in which costs are set to rise as operators deplete the most productive areas. All plays have "core" zones, or sweet spots, where EUR per well is higher and, once identified, operators focus on these first. But as they get depleted, one can expect activity to move to the non-core areas, with lower EUR per well and therefore higher cost per barrel. A breakdown by county of average EUR per well and well count at end-2014 in the Bakken play shows that four "core" counties have higher EUR and have been drilled more extensively; other, less developed, counties have an average EUR that is typically 40% lower, and therefore, all else being equal[11], a cost per barrel that is more than 60% higher (Figure 4.17).

10. The gains in 2015 appear in large part because many rigs have been retired and the more modern, more efficient drilling rigs represent a larger fraction of the remaining fleet; but such gains may be lost as and when the market bounces back.

11. In practice, all else is rarely equal, as the depth of the producing formation, the gas content (or liquids content for gas plays) and other factors such as population density also affect the economics.

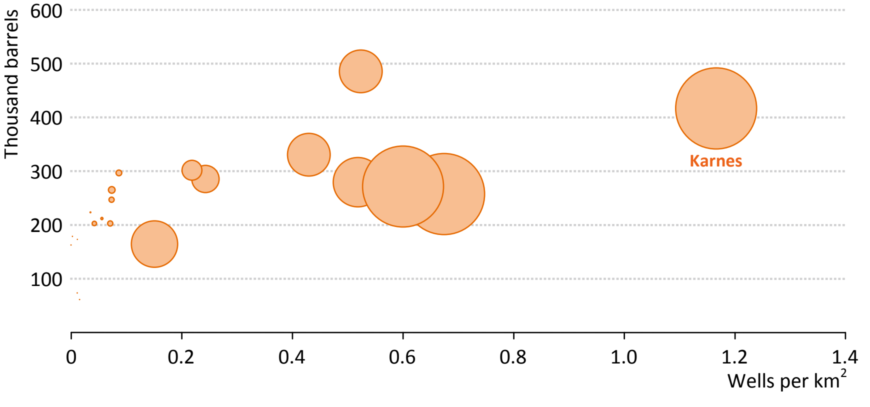
Figure 4.17 ▷ **Estimated ultimate recovery per well and density of wells by county in the Bakken tight oil play, end-2014**



Note: Bubble size represents total number of wells drilled. Source: IEA analysis based on Rystad Energy AS.

A similar situation holds in the Eagle Ford (Figure 4.18), though, as a less mature play, some productive counties still have a relatively small number of wells.[12] Counties vary in size, but the well densities paint a similar picture. Karnes County, the most densely drilled county in Eagle Ford, already has an average density of one well per 0.8 square kilometre (km^2). With each well draining an area of about 0.25 km^2, this implies that almost 30% of the county has been drilled. If one further assumes that around 75% of the county is the most that can be ultimately drilled (due to the presence of buildings, agriculture, roads or other impediments), at current drilling rates, all possible locations will have been drilled in around five years, indicating that the move to other areas is not far away.

Figure 4.18 ▷ **Estimated ultimate recovery per well and density of wells by county in the Eagle Ford tight oil play, end-2014**



Note: Bubble size represents total number of wells drilled. Source: IEA analysis based on Rystad Energy AS.

12. EUR here is for both oil and gas in barrels of oil equivalent, as the Eagle Ford play, contrary to the Bakken, includes both oil-rich counties and gas-rich counties.

Our expectation in the New Policies Scenario is that depletion effects in US tight oil will predominate over the impact of continued technology learning, pushing up the costs of production. This is the underlying reason why tight oil production is projected to level off slightly above 5 mb/d in the early to mid-2020s, before falling back to under 4 mb/d by 2040. This projection comes with a handful of caveats, the first of which is well illustrated in the Low Oil Price Scenario: the high dependence on resource estimates that are not yet well established, particularly for the sweet spots of plays. If these are larger than assumed in the New Policies Scenario, there will be a knock-on improvement in the resilience of tight oil plays (and vice versa). The second caveat relates to technology and efficiency; although our analysis suggests that the major gains in these areas may already have been achieved, there is certainly room for technology breakthroughs that result in drilling fewer unproductive wells or in increasing the low recovery factors associated with tight oil. Re-fracturing existing tight oil wells, although in its infancy today, could also result in improved recovery, should a more efficient process to identify candidate wells be devised. Our *Outlook* – in both the New Policies Scenario and the Low Oil Price Scenario – also depends on the alternative investment opportunities available to upstream operators. The typical logic of production from a given basin (whether conventional or tight) is that it peaks when costs per barrel increase to the point at which operators can find more attractive opportunities elsewhere in the world. But smaller upstream companies in the US may not have the ability to move to these more attractive opportunities; and even large companies may find that attractive open acreage elsewhere in the world is not readily available. Such factors could increase the longevity of tight oil.

Refining and trade

The refining sector faces somewhat easier times in a lower oil price world. It not only benefits from higher oil demand, but also, with lower supply of biofuels, coal-to-liquids, gas-to-liquids and NGLs, competition from non-refined products is restrained. In the Low Oil Price Scenario, global liquids demand increases by 2.8 mb/d, relative to the New Policies Scenario, but the call on refineries (i.e. demand for refined products) increases by 3.9 mb/d, improving the refiner's market share in 2040, compared with the New Policies Scenario: 85% instead of 83% (Table 4.4).

Table 4.4 ▷ Global oil and refinery indicators in the Low Oil Price Scenario relative to the New Policies Scenario (mb/d)

		Low Oil Price Scenario			Change relative to New Policies Scenario		
	2014	2020	2030	2040	2020	2030	2040
Total liquids	92.1	98.9	105.4	110.4	0.9	2.4	2.8
Oil demand	90.6	97.0	102.6	107.2	1.1	2.8	3.7
Oil products	88.6	95.1	100.8	105.2	1.1	3.1	4.5
Refined products	80.4	85.2	89.7	93.3	0.9	2.1	3.9
Refinery market share	**87%**	**86%**	**85%**	**85%**	**-**	**0.1%**	**2.0%**

Note: Table 3.8 in Chapter 3 includes definitions of the different categories of demand shown here.

Refinery runs are higher by 4.4 mb/d in 2040 in the Low Oil Price Scenario compared with the New Policies Scenario. Some of this increase comes from new refineries, mostly built in India, China and Southeast Asia in order to cater for increased local demand. This leads to a small reduction in our estimate of the amount of global capacity at risk of closure in 2040; from 14.6 mb/d in the New Policies Scenario to 12.1 mb/d in the Low Oil Price Scenario. But this is nonetheless a boost to the refining sectors of the United States and the European Union, which provide for expanded domestic demand through higher utilisation rates of their existing capacity. Overall, the OECD countries account for more than half of the incremental refining runs, some 2.4 mb/d.

Although Middle East production is about 6 mb/d higher by 2040 in the Low Oil Price Scenario, the "East of Suez" region (consisting of the Middle East and Asia together) still requires net imports of crude oil from the rest of the world. The higher availability of Middle Eastern crude oil exports is partly offset by the demands stemming from higher refinery runs in developing Asia, meaning that the net import requirement for the East of Suez region in 2040 is reduced, but only by 3.2 mb/d compared with the New Policies Scenario. This also implies a striking increase in the dependence of Asian refiners on Middle Eastern crude flows: by 2040, Asian refiners could be sourcing up to 85% of their import needs from the Middle East, compared to about 75% in the New Policies Scenario. The North American crude oil balance is also worse off in a low oil price world: lower Canadian production means that the region still requires 1.4 mb/d of crude imports in 2040, compared with an export surplus of a similar amount in the New Policies Scenario.

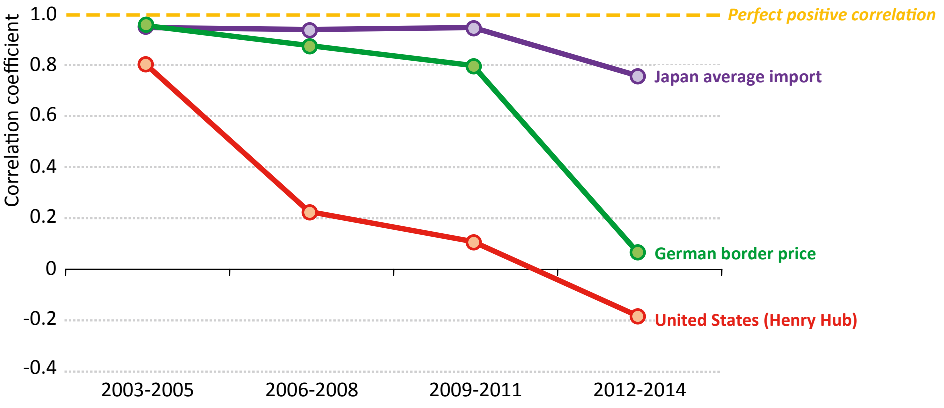
Implications for other fuels and technologies

Gauging the impacts of a sustained period of lower oil prices on other fuels and technologies is not a simple task. In many demand sectors it is increasingly rare that oil goes head-to-head with other fuels. In the transport sector, pretenders to the throne have been gathering strength, but the position of oil still remains largely unchallenged; demand for oil likewise remains strong as a feedstock for the production of petrochemicals. But, outside these two domains, whether as a fuel for power generation, a source of process heat for industrial use or a fuel for residential heating and cooking, oil has long been in retreat. In practice, the effects of lower oil prices on other fuels and technologies vary by region and across the various sectors of energy use. Some of the most important effects are indirect, felt via natural gas prices rather than directly by the oil price.

Natural gas

Among the other fuels and technologies, the one most directly affected by movements in the oil price is natural gas. The effect varies strongly by region, depending on how gas is priced, although the oil-gas price relationship has weakened considerably in some markets in recent years. In the United States, for example, there is now no visible correlation between the wholesale natural gas price and the oil price (Figure 4.19). Movements in the average import price paid by Germany also no longer show a direct relationship with oil, as more German buyers have taken to sourcing gas from spot markets and more of the major exporters have loosened the links to oil in the pricing of their long-term gas supply contracts.

Figure 4.19 ▷ **Correlation between oil and natural gas price movements in different regional markets**



Note: The figure shows the correlation between monthly natural gas price movements and oil price (with a five-month time lag), measured over consecutive three-year periods.

Such de-coupling is, though, only partially visible in the case of Japan (and the de-coupling seen in the period 2012-2014 was largely due to the extreme circumstances that Japan faced when it had to source additional gas in the aftermath of the Fukushima-Daiichi accident, rather than a major change in the underlying dynamics of Asia-Pacific gas trade). The situation portrayed for Germany is likewise not representative of all of Europe, where oil indexation remains dominant in contracts supplying many of the southern and eastern European countries.

Is the Low Oil Price Scenario also a low gas price world? The answer is not clear cut, as the dynamics are distinct in different regions. Elements bringing gas prices down are the general reduction in upstream costs (which are linked, in part, to the prevailing oil price) and the influence of lower prices on oil-indexed contracts (which become more favourable to gas buyers, a reversal of the situation seen in recent years of higher oil prices). However, the first factor is counter-balanced by the lower price of NGLs in a Low Oil Price Scenario, which can prejudice the economics of upstream gas projects: these counteracting effects explain why the US wholesale price for gas remains essentially at the same level as in the New Policies Scenario. And the influence of oil indexation on gas prices can be limited by the consequent curtailment of the necessary investment in future supply.

The global oil supply cost curve suggests that the oil market has the potential to balance for an extended period at \$50-60/bbl, if the large low-cost resources of the Middle East are developed at scale (as they are in the Low Oil Price Scenario).[13] Such an outcome boosts gas supply to an extent, notably in the Middle East, by bringing extra associated gas to the market at very low cost. But gas markets struggle to clear, over the longer term, at the

13. In *WEO-2013* (IEA, 2013), we published cost curves, derived from the World Energy Model, for world supply and for non-OPEC supply; the updated non-OPEC supply cost curve is included in Chapter 1.

equivalent oil-linked import price of around $7-9/MBtu. Iterations of the World Energy Model, conducted for *WEO-2015*, suggest that, at this price level for gas, demand in some net gas-importing countries and regions, especially in the Asia-Pacific, would run ahead of available supply. The main reason is that there is no large low-cost gas reserve that is currently held back from the gas market and that can be released in a Low Oil Price Scenario (i.e. no scope for a policy switch affecting gas markets analogous to the impact on oil supply of the assumed OPEC strategy).

In the main gas-importing regions, therefore, gas prices need to increase more rapidly than the oil price, in order to stimulate upstream investment. In importing markets where gas prices are set by gas-to-gas competition, including much of Europe, this just means that the traded gas price rises to higher levels. But, in markets where oil indexation prevails today, this implies a further gradual de-coupling of oil and gas prices, with alternative ways to price gas gaining ground more quickly in the Low Oil Price Scenario. This does not necessarily mean the death of oil indexation as a pricing mechanism for gas; it could imply, instead, that contracts are negotiated (or re-negotiated) to reflect the new circumstances and relative values attached to the two fuels. One result of this is that gas import prices into Europe and eventually also into Asia-Pacific show a greater degree of convergence among regions than is obtained in the New Policies Scenario (Table 4.5). As gas prices revert over time towards those seen in the New Policies Scenario, so there is a similar convergence in consumption levels.

Table 4.5 ▷ Fossil-fuel import prices in the Low Oil Price Scenario
(in year-2014 dollars)

				Low Oil Price Scenario			Change relative to New Policies Scenario		
	2005	2010	2014	2020	2030	2040	2020	2030	2040
IEA crude oil ($/barrel)	60	84	97	55	70	85	-25	-43	-43
Natural gas ($/MBtu)									
United States	10.2	4.7	4.4	4.7	6.2	7.5	-	-	-
Europe	6.5	8.0	9.3	5.9	8.9	11.4	-1.9	-2.2	-1.0
Japan	7.1	11.8	16.2	8.8	10.7	12.4	-2.2	-2.3	-1.7
OECD steam coal ($/tonne)	75	106	78	88	97	102	-6	-6	-6

Notes: MBtu = million British thermal units. Gas prices are weighted averages expressed on a gross calorific-value basis. All prices are for bulk supplies exclusive of tax. The US price reflects the wholesale price prevailing on the domestic market.

In those markets where gas prices are lower (and for as long as this lasts), there is a measurable increase in gas consumption. This is visible in Europe and in parts of Asia, which benefit for longer from the remaining linkage of import prices to oil. However, the favourable change in relative prices between gas and coal is not sufficient to encourage larger-scale coal to gas switching than in the New Policies Scenario. The gains in global gas consumption from industry and power generation, seen mainly over the first part of the projection period, are also counter-balanced by reductions in demand in areas where gas competes with oil products, the most notable example being the slower penetration of gas in the transport fuel mix. Gas demand for road transport is more than 30 bcm, or 20%, lower in 2040 than in the New Policies Scenario.

The effect of changes in demand on trade flows is amplified towards the end of the projection period by a reduction in projected Chinese gas output, caused mainly by a reduction in unconventional gas output (from shale gas and coal-to-gas projects that are made uneconomic). The increase in demand for imported gas is met primarily by the Middle East, Russia and the Caspian region. The reduced price differentials between North America and other markets also limit the commercial rationale for natural gas export from North America, which is around 30% lower than in the New Policies Scenario in 2040.

Coal

Oil and coal hardly compete in end-use sectors. Around the world, coal use in transport has been backed out by oil products and other forms of energy decades ago and residential coal burn is dwindling too, continuously displaced by more convenient fuels – in some cases by oil products. In coal's main end-use applications, the power sector and heavy industries (iron and steel, cement), oil is simply too expensive to rival coal. Coal's main competitor in the power sector, and in certain industries, is natural gas. As noted above, in regions where gas prices are closely linked to the fundamentals of the oil market, low oil prices improve the competitive position of gas *vis-à-vis* coal and thus displace some coal use indirectly. Projects to convert coal to liquids also become less viable in a low oil price environment. Mainly as a result of these two factors, coal consumption in the Low Oil Price Scenario is 4%, or 240 million tonnes of coal equivalent (Mtce), down by 2040, compared with the New Policies Scenario.

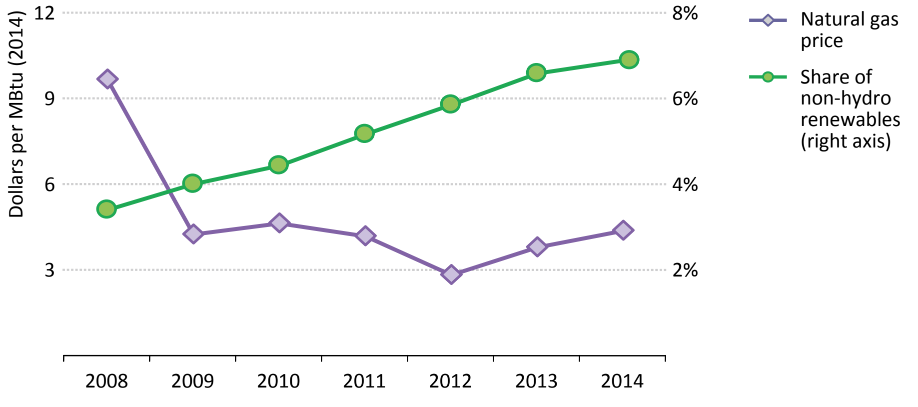
The impacts on coal are partially mitigated by the fact that oil plays an important role in coal supply and this feeds through into the cost of coal supply (see Box 7.4 in Chapter 7). Oil products are used to fuel the earth-moving machinery in surface mining. Large amounts of coal are transported over long distances from the mines to the consumers by trucks, railways, river barges, seaborne vessels or a combination of these. Therefore, the cost of coal supply is affected by oil price fluctuations. However, as the analysis in Chapter 7 outlines, price-setting mines in the international coal market have a relatively minor exposure to oil price fluctuations, as they tend to be more capital- and labour-intensive underground operations, in countries with high labour cost. In the Low Oil Price Scenario, coal price effects are thus primarily driven by slightly lower coal use in the power sectors of some regions, rather than by a decrease in the underlying supply costs. Nonetheless, oil price fluctuations and their effects on coal supply costs can have a marked impact on the profits of coal companies.

Renewables

It is often assumed that a low oil price represents bad news for renewables; but the link, if it exists, is not straightforward. Renewable energy is used primarily for power generation and heat, sectors where oil use is very limited or in decline. Insofar as lower oil prices have an effect on the power sector, the link is – at best – an indirect one, transmitted via the effect on natural gas prices. But it is far from obvious that even a fall in the natural gas price affects renewables deployment. Although technology costs are falling, investment in renewables is almost everywhere still based on subsidies or other schemes that guarantee entry to the market, rather than on head-to-head cost competition with other potential sources of electricity. A decline in the prices of other fuels used in power generation can make some of these subsidy schemes more costly (depending on their design), but – unless and until this forces a change in policy – the incentives to invest in renewables remain.

The United States provides a ready-made case study of renewables in a low gas price environment (because of shale gas, low gas prices arrived in the United States well before the fall in oil prices, as described in Chapter 6). State-level renewables mandates remained in place after the natural gas price decline (and were strengthened in California) and there is very little evidence to suggest that the deployment of non-hydro renewables (primarily wind and solar) suffered in the power sector after gas prices plummeted in 2009; if anything, the opposite was the case (Figure 4.20).

Figure 4.20 ▷ Natural gas prices and the share of non-hydro renewables in the US power mix



So in the Low Oil Price Scenario, we do not vary the assumptions about support for renewables in the power sector from those adopted in the New Policies Scenario.[14] The

14. It is arguable that one region where low oil prices might curtail renewables investment in the power sector is the Middle East. Oil use remains prevalent in power generation in many parts of the Middle East, and a persistently low oil price would also have the effect of bringing down the revenues required for all types of expenditure, including investment in alternative energy technologies. However, since we also assume in a Low Oil Price Scenario faster movement in phasing out fossil-fuel consumption subsidies in some net oil-exporting countries, the incentives to diversify away from oil use in the power sector remain strong. So we assume that existing plans to deploy renewables across the region remain intact.

opposite turn of events should not be excluded, as lower wholesale prices for electricity in some markets (caused by the reduction in natural gas prices) mean that the subsidy bill for renewables in power generation is slightly higher in the Low Oil Price Scenario, by $180 billion, or 4%, over the projection period. This also has the effect of postponing the moment at which technology cost reductions make some renewables, the first of which is normally onshore wind power, cost-competitive without subsidies (see Chapter 9). Relative prices could also play a role in determining the uptake of renewables in the limited cases where there is direct price competition, i.e. in countries where renewables offer an alternative to diesel-powered generators.

But, in our judgement, a significant weakening of policy support for renewables in the power sector, due to lower oil prices, is unlikely. The concerns that lead such policies to be put in place, notably those relating to climate change, are not lessened in a Low Oil Price Scenario. Quite the opposite: energy-related carbon-dioxide (CO_2) emissions are slightly higher in this scenario (see next section). Moreover, the way that the oil price translates into lower wholesale electricity prices may actually lessen the likelihood of a political backlash against the cost of subsidies to renewables.

In the transport sector, the situation is more nuanced. Trends over the past year have shown a notable shift in consumer preferences in some countries towards larger cars and sports-utility vehicles. Fuel-economy standards effectively cover three-quarters of vehicle sales, and so the average efficiency of new cars continues to improve. But as consumer preferences shifted towards larger cars, the average fuel consumption of new vehicles sold between July 2014 and July 2015 in these markets was higher than over the previous 12 months (see Chapter 3). Fuel-economy standards often set different targets for different vehicle sizes, which mean that consumer choices have implications for the actual level of fuel consumption achieved in the target year of the policy. In the Low Oil Price Scenario, we assume that a lasting change of consumer preference towards larger cars prevails only in countries which currently have no fuel-economy standards in place.

The case of biofuels in a Low Oil Price Scenario is similarly specific: with a few exceptions (hydrous ethanol in Brazil being the main one), biofuels typically enter the market on the basis of blending mandates, so consumption is linked to the overall volume of fuel consumed in the transport sector and relative prices do not play a role. Insofar as lower oil prices push up oil consumption in the transport sector, they are, therefore positive in most countries also for biofuels use. However, policy support for biofuels may not be as robust as it is for renewables in the power sector. There are concerns over the sustainability of conventional biofuels, including land-use issues due to competition, in some instances, with agricultural users; advanced biofuels, based on ligno-cellulosic biomass, are not coming through to the market quickly. Against this backdrop, governments are assumed to be reluctant to support biofuels to the same extent as they do in the New Policies Scenario. Biofuels supply is therefore 0.9 mb/d lower, at 3.3 mb/d, in a Low Oil Price Scenario in 2040.

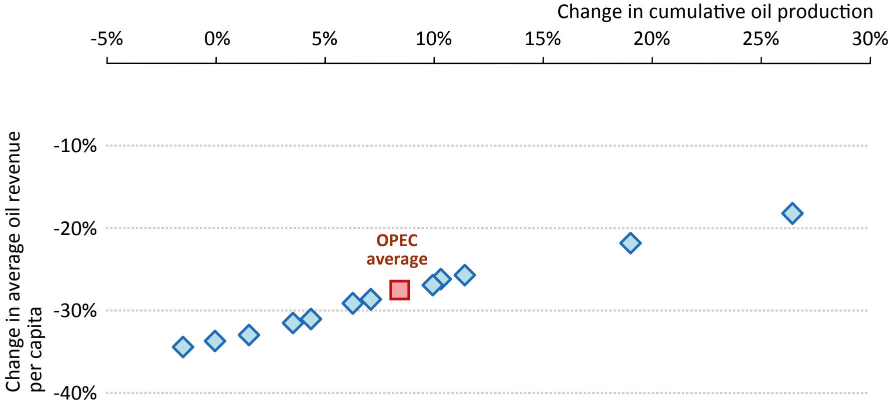
Implications for economies, energy security and sustainability

Oil revenues and other financial flows

The persistence of a lower oil price brings relief to the main global importers of oil – their import bills are consistently lower throughout the projection period, even with higher demand for imported oil. The largest savings, unsurprisingly, accrue to the largest importers. China imports 9% more oil in the Low Oil Price Scenario than in the New Policies Scenario in 2040, but its import bill is lower by 28%, or $170 billion. For India, 2040 imports are up by 6%, but overall payments are down by 30%, or $130 billion. Overall, the volume of inter-regionally traded oil is some 4 mb/d higher in the Low Oil Price Scenario in 2040, but the value of this oil is some $630 billion lower. In other words, every $1 off the oil price in 2040 is worth $15 billion in savings to importing countries. The cumulative benefit to importers, over the entire period to 2040, is around $13 trillion in lower payments, compared with the New Policies Scenario.

This difference is naturally also reflected in the revenues earned by exporting countries. In the near term to 2020, the revenues from OPEC oil export remain at an average of $550 billion per year, compared with $660 billion per year in the New Policies Scenario; this is well shy of the annual average for the period from 2010 to 2014, which exceeded $1 trillion. In 2040, OPEC oil exports in 2040 are some 6 mb/d higher than in the New Policies Scenario, but revenues are $1.3 trillion, some $400 billion shy of the $1.7 trillion for that year in the New Policies Scenario. All of the OPEC countries lose more from lower prices than they gain from higher volumes over the longer term (Figure 4.21). This is one of the main reasons why a Low Oil Price Scenario looks less likely the further it is extended into the future: it relies on the active consent of the countries that are worst affected by the outcome. The assumed OPEC strategy of pursuing market share is effective, but ultimately also costly to the producers themselves.

Figure 4.21 ▷ Change in cumulative oil production and average oil revenue per capita in OPEC countries in the Low Oil Price Scenario relative to the New Policies Scenario



Some producing countries, but by no means all, have accumulated a large financial buffer that allows them to withstand a period of low oil prices, but the depth of this ability varies widely between countries, and all would be affected over the longer term by the impact of lower revenues on their social programmes and other domestic priorities. Prices in the $60-80/bbl range are well below the estimates of "fiscal breakeven" for all but a handful of smaller exporters. The Low Oil Price Scenario therefore implies an intensely difficult process of meeting the aspirations of a growing population while scaling back public spending. In practice, this assumption looks more and more precarious the longer the period of low prices persists (Box 4.5). This is why we assume in the New Policies Scenario that, once the market starts to rebalance and non-OPEC production growth stalls, OPEC countries revert to a more traditional strategy that prioritises revenue maximisation.

Box 4.5 ▷ Sub-Saharan Africa in a low oil price world

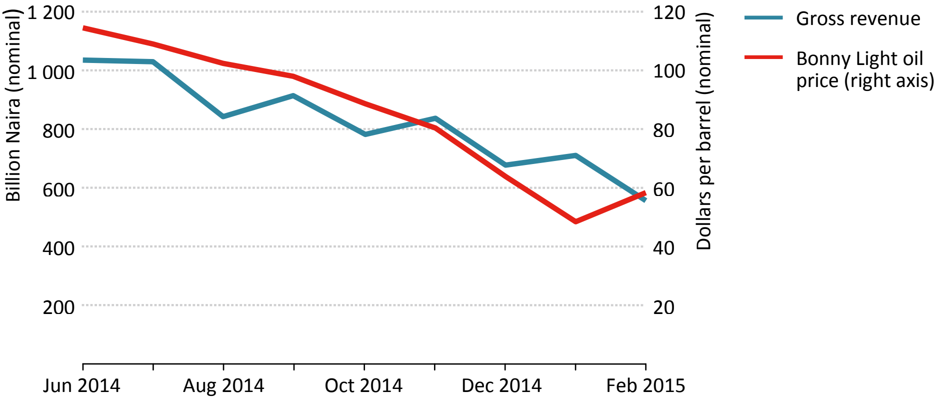
Rising commodity prices, underpinned by strong demand from China – coupled with policy changes to attract investment in many countries – have been instrumental in a surge in economic activity across many sub-Saharan African countries over the last decade.[15] A boom in hydrocarbon revenues played a part in consolidating the middle-income status of some existing oil and gas producers, such as Nigeria. It also led to an acceleration of exploration and investment in some low-income countries, notably Mozambique, Tanzania and Uganda.

The fall in oil prices since 2014 has already created major revenue problems for existing oil and gas exporters – and pushed back the prospects of new developments elsewhere. In Nigeria, falling crude oil export revenues meant that gross federal revenue in early 2015 was 40% lower than in mid-2014 (Figure 4.22). External reserves and foreign direct investment both fell in the last quarter of the year, by 22% and 35%, respectively (EIU, 2015). The revenue decline has already exacerbated the under-funding of Nigeria's share of its upstream joint ventures, and exploration and drilling activity have been cut back sharply.

An extended period of lower oil prices would be a boon for the oil importers, but would promise an uncomfortable adjustment for countries heavily dependent on resource-exports (as well as those anticipating future revenues, as in East Africa). Difficulties could be intense in those exporting countries with relatively undiversified economies which did not put aside any of the windfalls from the past decade. The oil and gas projects most at risk would be the high-cost deepwater and pre-salt projects off the west coast of Africa. The timing of east coast gas projects is also likely to be further pushed back. Alongside falls in the funds available for upstream investment, an extended period of lower hydrocarbon revenues would mean scaling back spending in other areas, from social services to public infrastructure, worsening the outlook for future growth, for poverty eradication and, potentially, threatening social stability.

15. Overall, investment and export-led economic growth in the world's low-income countries averaged more than 6% per year over the period since 2000, double the pace of the previous three decades (World Bank, 2015)

Figure 4.22 ▷ Nigerian gross federal revenues versus Bonny Light oil price



Notes: Bonny Light is the main export grade of crude oil for Nigeria. Naira is the Nigerian currency.

The impact of lower oil prices would also be felt by companies operating in the upstream, via a distinct reduction in the revenue received per barrel sold.[16] In countries where upstream activity is conducted predominantly by private companies, the reduction in future income (to the extent that it is recognised by markets) could have implications for these companies' valuations. To give an indication of the potential size of this effect, we can compare the sum of the discounted future net income (or total revenue net of costs and taxes) of private oil and gas companies in the Low Oil Price Scenario and the New Policies Scenario, using a field-by-field database that classifies asset ownership by type of company, and making assumptions about the ownership of future discoveries. This provides an indication of the difference in company valuations between the two scenarios, based on the premise that, in the long-run, the market value of listed oil and gas upstream companies should be roughly equivalent to the net present value of their future net income.

If one assumes that today's market capitalisation of listed oil and gas companies is based on an outlook similar to the New Policies Scenario, then the Low Oil Price Scenario results in a fall in value of around 25%.[17] The impact varies according to the location and profile of the companies concerned. The oil side of the upstream loses more value than gas: the net present value of the income stream from oil declines by around 35% in a Low Oil Price Scenario relative to the New Policies Scenario, whereas gas is less affected (and largely unaffected in North America, as gas prices are hardly changed between the scenarios). Overall, the effect of a prolonged low price environment on private company valuations would clearly be severe, although, by concentrating on low-cost resources and favouring gas over oil, companies could help to ameliorate some of this potential loss of value.

16. This does not automatically imply lower net cash flow as companies also see lower investments and lower costs.

17. A 10% rate is used to discount future cash flows, although percentage changes in valuation are relatively insensitive to this assumption: the difference between scenarios for listed oil and gas companies is 27% when using a 5% discount rate and 24% when using a 15% rate.

Household incomes and other macroeconomic effects[18]

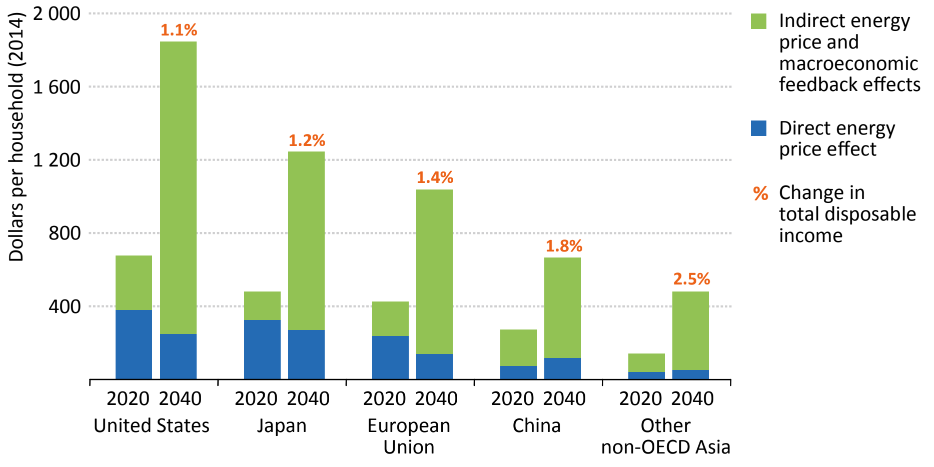
The Low Oil Price Scenario has implications well beyond the energy sector, as changes in oil revenues and financial flows work through into the performance of national economies. In practice, what we see in this scenario, relative to the New Policies Scenario, is a large shift of income from oil exporters to oil importers, with all that this implies for their economic outlooks. There are various effects in play. The first direct effect, labelled a "direct energy price" effect, is that household energy expenditure decreases because of lower prices, increasing the income that can be spent on consumption of other goods and services. In addition, some of these goods and services themselves become cheaper because lower energy input prices translate into lower producer costs. The size of this "non-energy price" effect depends on the energy intensity and on the change in fuel price seen by the various sectors of the economy. The increase in households' real income due to the direct energy price and to the non-energy price effect is in line with the decrease of energy expenditure for the whole economy. Depending on pricing regimes and assumptions about fossil-fuel subsidy reform, these income effects of a lower oil price are widely shared across different countries, both oil importers and exporters.

But alongside these price-induced changes, there are also macroeconomic feedbacks, which differ markedly between oil-importing and exporting countries. In oil-importing countries, economic activity is boosted by the low oil price and the associated increase in household consumption. The increased output from economic sectors generates more revenue that is used for consumption and investment. The benefits through investment have a long-lasting impact as they increase the future capacity of supply of the economy. Another important macroeconomic effect comes from trade. Lower oil prices improve the trade position of oil-importing countries, which can, in the long-run, improve the exchange rate of their currency, or equivalently, the relative price of imported goods, which is beneficial to households' purchasing power.

The effect of lower prices on household incomes in importing countries is significant (Figure 4.23). In the United States, real incomes rise by 1.1% in 2040, relative to the New Policies Scenario, equivalent to a gain of more than \$1 800 per household. Similarly strong benefits are felt by households in Europe (1.4%) and Japan (1.2%), which both remain heavily reliant on energy imports. In non-OECD Asia, the source of 90% of the global increase in oil demand in the Low Oil Price Scenario, lower prices add 1.8% to household real incomes in China and 2.5% in average in the other countries of the region – this translates to a gain of \$670 and \$480 respectively per household in 2040.

18. The economic effects of the Low Oil Price Scenario are evaluated in this section in terms of the variation in household real income. Real income is the income after taxes and transfers, corrected by a consumer price index. It can be interpreted as a proxy for households' purchasing power. This analysis was done with the help of ENV-Linkages, the OECD computable general equilibrium model, calibrated using the outputs from the World Energy Model for the Low Oil Price Scenario.

Figure 4.23 ▷ **Change in household income in selected regions in the Low Oil Price Scenario relative to the New Policies Scenario**

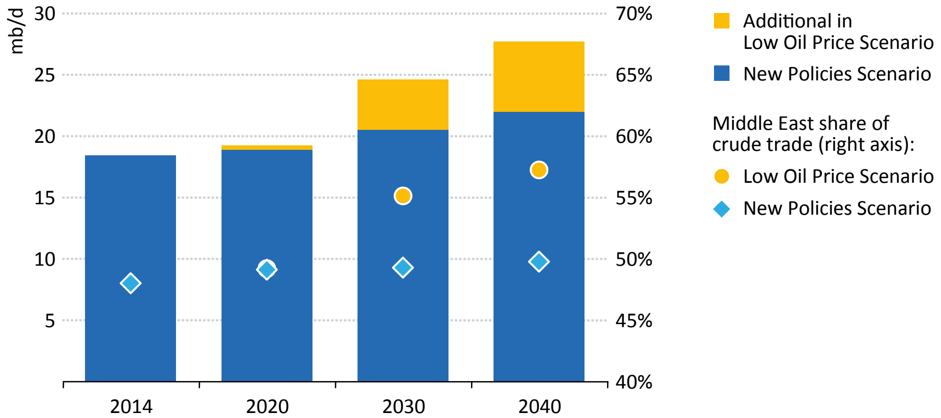


The macroeconomic feedback of low oil prices differs for exporting countries and regions, such as the Middle East, where they translate into lower fiscal revenues. Any further effect will differ in degree depending on the composition of the economy and its diversity, with lower revenues generally having a directly detrimental impact on investment and on consumer spending, particularly in highly centralised economies in which the public sector is prominent. Changes in the oil price have other globally significant impacts, including on food prices and, therefore, food security. Oil prices impact food prices in a number of ways: agriculture is an increasingly energy-intensive endeavour and lower oil prices feed into lower gas prices and, eventually, lower fertiliser prices – bringing down production costs. A decrease in transportation costs also feeds into lower overall prices. Without strong policy support for biofuels, lower oil prices could reduce the incentive for their production, leaving more resources for food crops (World Bank, 2015). The impact of lower agricultural export prices is not all positive: for a number of lower income countries that rely on the export of basic commodities, the terms of trade are harmed as the value of exports decreases – in sub-Saharan Africa, a 30% decline in all commodity prices could reduce GDP by 0.5% (IMF, 2013).

Energy security

The changing supply and demand dynamics linked to lower oil prices have distinct energy security implications. Growing trade has the effect of consolidating global interdependence; but it brings the risks of supply interruptions, particularly if geographic supply diversity is reduced and reliance on a few strategic supply routes is increased. This is indeed what we observe in a Low Oil Price Scenario, in which the Middle East accounts for a significantly larger share of inter-regional crude trade: Middle East share of global crude oil export rises to 57% at the end of our projection period – seven percentage points higher than in the New Policies Scenario (Figure 4.24).

Figure 4.24 ▷ Share of the Middle East in inter-regional crude trade by scenario



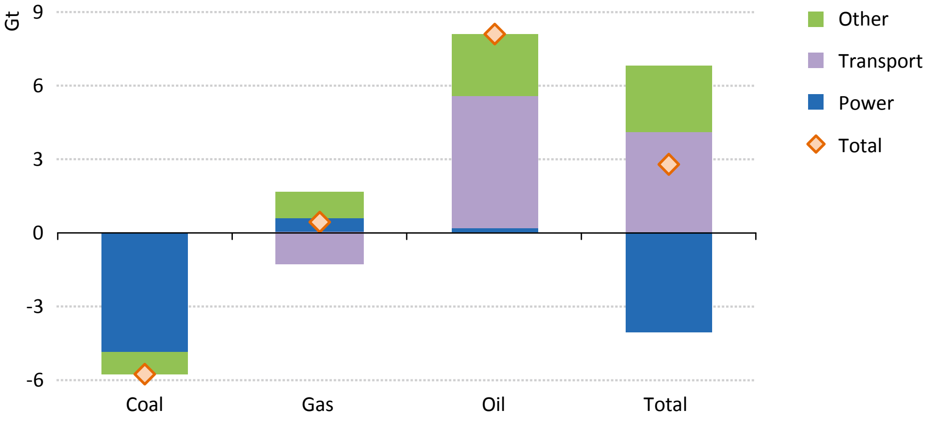
Increasing reliance on oil export from the Middle East, as well as rising demand in Asia, has implications on the volumes flowing through certain strategic choke points in the oil supply system. For example, the volumes of crude oil that could be expected to transit the Straits of Hormuz rise from an estimate of just over 16 mb/d today to more than 25 mb/d in 2040, with exports of oil products also growing by around 2 mb/d. This implies that, in a Low Oil Price Scenario, more than half of the world's physical crude oil trade could be dependent on a single gateway to international markets. This prospect underscores the importance of alternative routes to market for Middle East exports in this scenario, to reduce reliance on the Straits, and increases the importance of the policies in net-importing countries to reduce the likelihood of disruptions in supply or provide insurance if they do occur.

The shift in the geography of oil trade from the Atlantic to the Pacific basins is more muted in a Low Oil Price Scenario, as import needs in the Atlantic basin remain at higher levels. North America is the region which experiences the largest change in its trade position, which is affected both by higher demand and lower supply than in the New Policies Scenario. Whereas North America becomes a net exporter of crude oil in the New Policies Scenario (1.5 mb/d in 2040), this does not happen in the Low Oil Price Scenario, with the United States, Canada and Mexico in aggregate still requiring 1.4 mb/d of crude imports from the rest of the world in 2040.

Sustainability

A key concern in a low oil price environment is that the prospects for timely, concerted policy action on emissions might be lessened. The message that emerges from our analysis of a Low Oil Price Scenario is that the overall impact on energy-related CO_2 emissions is relatively limited: cumulative CO_2 emissions up to 2040 are just 0.3%, or 3 gigatonnes (Gt), higher than in the New Policies Scenario. The need and urgency for additional action to tackle climate change is undiminished across the scenarios. However, the lower oil price does change the way that the underlying energy system evolves and so introduces a different set of policy challenges along the way. In the power sector, cumulative emissions are 3.6 Gt (or 1%) lower in the Low Oil Price Scenario (Figure 4.25). This is due in part to the switch from coal to gas, but this finding is also reliant on the assumption of steadfast support from policymakers for large-scale deployment of renewables, despite a small, but distinct, 4% increase in the cumulative estimated cost of subsidies. The increase arises not because more capacity is installed, but because both the cost and duration of subsidies are extended by generally lower wholesale prices for electricity, although the extent of this impact in practice will depend on factors at play in individual countries, including, for example, the extent to which oil-gas-electricity price linkage exists, and whether or not subsidies for renewables are fixed or defined by reference to wholesale power prices.

Figure 4.25 ▷ **Change in cumulative global energy-related CO_2 emissions in the Low Oil Price Scenario relative to the New Policies Scenario, 2014-2040**



The emissions savings in the power sector are counter-balanced by a 4.1 Gt rise in emissions from the transport sector (1.9% higher). Lower oil prices lead to increasing use of vehicles while undermining the case for energy efficiency investments, particularly in road freight where fuel-economy standards are less widespread than for passenger cars. Lower support for biofuels and the decreased competitiveness of electric cars (which see their shares in total car sales shrink by 12% in 2040, relative to the New Policies Scenario) mean that the deployment of some crucial technologies required for a transition to a low-carbon energy sector is held back. In the industry and buildings sectors, there is less switching away from oil to alternative sources of energy, such as natural gas or electricity, and higher use of oil as a feedstock for petrochemicals, which boosts total emissions further. Overall, although cumulative emissions are only modestly higher in the Low Oil Price Scenario, the global economy is around 1% smaller than in the New Policies Scenario, which means a larger rise in CO_2 emissions per unit of economic output.

Lower prices can facilitate some positive policy shifts, compared with those of the New Policies Scenario, notably by increasing the momentum behind reform to fossil-fuel consumption subsidies. Although not investigated in this scenario, lower oil prices could make it politically practicable in some instances to introduce an effective or actual CO_2 price, since the impacts would not be felt as keenly by consumers. However, low prices ultimately complicate this transition in other key areas. Longer payback periods mean that the world misses out on 14% of the cumulative energy savings seen in the New Policies Scenario, foregoing around $0.8 trillion-worth of efficiency improvements in cars, trucks, aircraft and other end-use equipment. To achieve the same outcomes as in the New Policies Scenario would require additional measures, in the form of fuel efficiency or other policies, to counteract the effect of lower oil prices on transport and industrial demand. Without these additional efforts, a key risk in a Low Oil Price Scenario is that the world locks in a less efficient and less climate-friendly capital stock that commits to higher long-term emissions.

Natural gas market outlook

In shape for the long haul?

Highlights

- Global natural gas use continues its upward trend in the New Policies Scenario, but at a more modest 1.4% annual pace compared with previous *Outlooks*, as efficiency policies, sluggish OECD electricity demand and strong competition for internationally traded gas from other fuels and technologies take the edge off consumption. Gas is nonetheless the fastest growing among the fossil fuels; demand of 5.2 tcm in 2040 brings gas towards parity with coal and oil in the global energy mix.

- China and the Middle East are the main centres of gas demand growth, both becoming larger consumers than the European Union, where it seems increasingly likely that the peak in gas use was reached in 2010. Within the OECD, North America is the only region where gas demand expands significantly, with ample supply pushing consumption up by 200 bcm. Industrial gas use worldwide grows rapidly, reaching 1.3 tcm and overtaking the level of gas use in residential and commercial buildings, behind only the 2 tcm used for power generation.

- The Middle East and China also lead the way in gas production growth, with growing contributions from North America, the Caspian region, Australia, emerging producers in Africa and Latin America, and, eventually, from Russia – once new pipeline connections to the east are in place. Production in Iran rises by around 80%, to reach 290 bcm, although much of the increase could be absorbed by a gas-hungry domestic market. Only Europe among the major regions sees a decline in output, as production falls in Norway, Netherlands and United Kingdom.

- Global gas trade expands, with LNG increasing more rapidly than pipeline gas. LNG promises to be amply available over the medium term, but deferred investment in LNG supply in a low oil price environment brings a risk of tighter markets in the 2020s. If the recent trend of rising costs for some greenfield LNG liquefaction plants is not turned around, then the long-term competitiveness of gas in many importing markets could be threatened. Floating LNG facilities offer a potential way to reverse this trend and to develop otherwise stranded resources, but the technology has yet to prove itself in terms of operational reliability and cost.

- The oil and gas sector is the largest industrial source of methane emissions, a potent contributor to climate change. Outside North America, the absence of robust policy action in this area represents a major missed opportunity to tackle near-term warming. The available evidence suggests that a relatively small number of emitters may account for a large share of overall emissions, but tracking and fixing these leaks – which can be short-lived and intermittent – requires a systematic effort of measurement, reporting and monitoring, backed up by effective regulation.

The search for a new natural gas balance

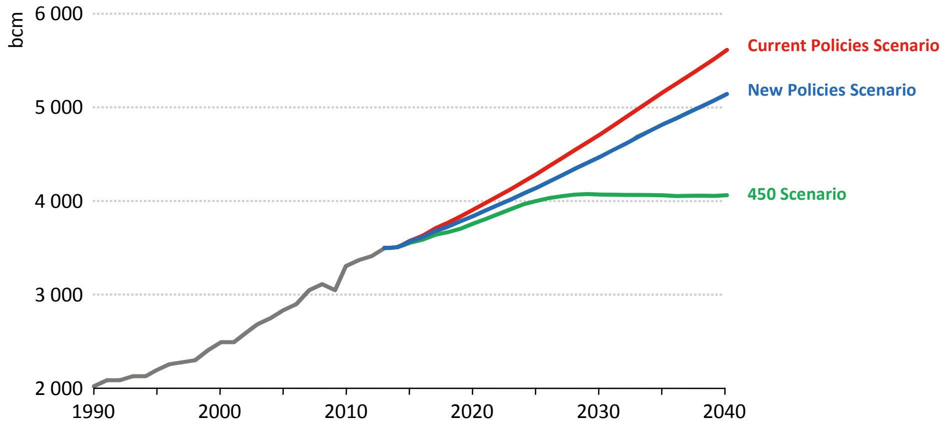
The familiar pattern of strong regional differences in the natural gas sector acquired an additional twist in 2014. Remarkable growth has become almost commonplace in the United States, where production in 2014 rose nearly 6% to around 730 billion cubic metres (bcm), despite continued low wholesale prices, and consumption made further inroads in industry and the power sector. Strong production growth has continued in the first-half of 2015, by almost 8% year-on-year. At the other end of the spectrum, European gas had another dismal year, with residential gas use hit by particularly mild weather and no signs of a let-up in the squeeze on gas in the power sector. The twist came in China, where the stellar growth in gas use in recent years (15% per year on average from 2008 to 2013) slowed in 2014 to below 10%, checked by the easing of economic growth, the rapid rise of hydropower and other renewables and a warmer winter in northern China that moderated heating demand.

Price conditions look considerably more favourable for consumers in much of the world in 2015, and consequently much more challenging for those contemplating new long-term investments in supply (the outlook for gas in a long-term low oil price environment is discussed in Chapter 4). After having peaked at around $18 per million British thermal units (MBtu) early in 2014, Asian spot liquefied natural gas (LNG) prices collapsed to less than half these levels by mid-2015 and oil-linked import prices across the region took a similar plunge as they responded (with a time lag) to the fall in the oil price. The net result, with LNG availability bolstered by the start-up of the Papua New Guinea LNG plant and the first output from the seven LNG plants coming online or under construction in Australia, has been a significant narrowing of the divergence between gas prices in different regional gas markets experienced since 2010, although price differentials do remain, with North America enjoying prices generally well below those elsewhere.

These price developments seem set to boost natural gas demand in major importing regions, reinforcing our view that natural gas is a fuel well placed to expand its role in the global energy mix. However, looking at the *Outlook* period to 2040 as a whole, the pace at which gas is set to grow in the New Policies Scenario has been revised downwards compared with the *World Energy Outlook-2014 (WEO-2014)*(IEA,2014). This is a result of gross domestic product (GDP) revisions (especially over the medium term, see Chapter 1) as well as efficiency measures that slow energy demand in electricity (see Chapter 10) and industry. Nonetheless, gas is still the fastest growing fossil fuel.

There are good reasons to be upbeat about the future for natural gas: its relative abundance; its environmental advantages compared with other fossil fuels; the flexibility and adaptability that make it a valuable component of a gradually decarbonising electricity and energy system. But there are also clouds on the horizon: the flip side of its versatility is that natural gas faces strong competition in all segments of the market where it is used. It is also much more expensive to transport than other fossil fuels, because of its low energy density, exacerbating the competitive challenge in markets dependent on long-distance imports. Moreover, although resources are widely distributed, a large part of the resource base consists of unconventional gas, which – while developed extensively in parts of North America and Australia – appears to be off-limits in a number of other countries because of a lack of public acceptance (see Chapter 6). The environmental advantages of gas are also under scrutiny, mainly due to the damaging impact of emissions of methane, a powerful greenhouse gas, from oil and gas production and transport, and because of the water issues associated with unconventional gas development.

Figure 5.1 ▷ World natural gas demand by scenario



Natural gas demand is projected to increase in all scenarios presented in this *Outlook* (Figure 5.1). In the New Policies Scenario, gas consumption expands at 1.4% per year on average, more rapidly than oil and coal, but more slowly than renewable energy and nuclear power. Its share in the energy mix increases from 21% in 2013 to 24% in 2040, making it the only fossil fuel to see an increase. The growth projected in the New Policies Scenario contrasts sharply with the trajectory for gas in the 450 Scenario, where gas consumption expands until the latter part of the 2020s but then flattens out, as a consequence of policies aimed at limiting energy-related carbon-dioxide (CO_2) emissions. In the Current Policies Scenario, where global energy consumption rises at the fastest pace, gas demand ends up some 460 bcm above the New Policies Scenario in 2040 (Table 5.1).

Table 5.1 ▷ Natural gas demand by major region and scenario (bcm)

			New Policies		Current Policies		450 Scenario	
	2000	2013	2020	2040	2020	2040	2020	2040
OECD	1 413	1 657	1 704	1 870	1 744	2 125	1 684	1 354
Non-OECD	1 102	1 850	2 139	3 258	2 170	3 491	2 080	2 662
World*	**2 515**	**3 507**	**3 849**	**5 160**	**3 914**	**5 617**	**3 770**	**4 073**

* The world numbers include the use of LNG as a marine bunker fuel.

Demand

Regional trends

In the New Policies Scenario, the scenario on which this analysis largely concentrates, gas demand expands almost everywhere between 2013 and 2040, with the exception of the European Union, Russia and Japan (Table 5.2). Non-OECD countries, whose gas use overtook that of OECD countries in 2008, continue to be the primary engine of global gas demand growth, accounting for 85% of the total increase in demand to 2040. There are important distinctions in gas consumption patterns between countries that are rich in gas – often gas exporters – that benefit at home from relatively cheaper gas, and gas-importing countries for which gas comes at a significantly higher price (this is the organising principle for the presentation of regional outlooks below). The difference between the two reflects the high costs of gas transportation.

Table 5.2 ▻ Natural gas demand by region in New Policies Scenario (bcm)

	2000	2013	2020	2025	2030	2035	2040	2013-2040 Change	2013-2040 CAAGR*
OECD	**1 413**	**1 657**	**1 704**	**1 743**	**1 780**	**1 831**	**1 870**	**214**	**0.5%**
Americas	801	924	1 001	1 011	1 038	1 081	1 125	201	0.7%
United States	669	743	802	798	810	831	851	108	0.5%
Europe	482	512	496	523	526	530	528	16	0.1%
Asia Oceania	130	221	206	209	216	220	217	-3	-0.1%
Japan	82	127	102	100	103	104	104	-24	-0.8%
Non-OECD	**1 102**	**1 850**	**2 139**	**2 398**	**2 687**	**2 982**	**3 258**	**1 408**	**2.1%**
E. Europe/Eurasia	594	691	676	688	710	734	756	64	0.3%
Caspian	82	113	136	150	161	173	184	71	1.8%
Russia	388	481	446	440	447	455	465	-16	-0.1%
Asia	183	461	654	795	934	1 075	1 202	741	3.6%
China	28	173	315	403	483	546	592	418	4.7%
India	28	52	68	95	121	148	174	122	4.6%
Middle East	177	420	494	561	634	693	738	318	2.1%
Africa	56	119	144	166	196	232	285	165	3.3%
Latin America	91	159	172	188	213	247	279	120	2.1%
Brazil	9	38	37	42	51	67	78	40	2.7%
Bunkers**	-	-	6	12	19	25	31	31	n.a.
World	**2 515**	**3 507**	**3 849**	**4 153**	**4 486**	**4 837**	**5 160**	**1 653**	**1.4%**
European Union	486	471	452	476	477	475	466	-5	0.0%

* Compound average annual growth rate. ** LNG used as an international marine fuel.

The United States is the largest natural gas consuming country and, although a mature gas market, demand growth has continued to impress, rising by around 14% since 2009. Natural gas demand rises by 0.5% per year on average between 2013 and 2040, reaching 850 bcm by the end of the projection period. The increase is more rapid over the period to 2020, at 1.1% per year, due to the current low level of gas prices that extends gas use (mostly in place of coal) in the power sector, and a sharp rise in gas-intensive industrial activities, mainly in the fertiliser and chemical sectors where capacity expansions have been undertaken over the last few years. Growth is slower in the latter part of the projection period, as a result of a gradual anticipated rise in the wholesale price and saturation in industrial gas consumption. Power generation accounts for about half of the overall rise in gas demand, boosted by implementation of the Clean Power Plan.[1] The transportation sector expands (from a low base) at the fastest pace (3.5% annual average growth), with road transport consumption accounting for 90% of the 40 bcm increase in the sector. By around the mid-2020s, coal is supplanted by natural gas as the largest source of electricity generation in the United States; and by the early 2030s, gas overtakes oil as the most utilised fuel in the US primary energy mix.

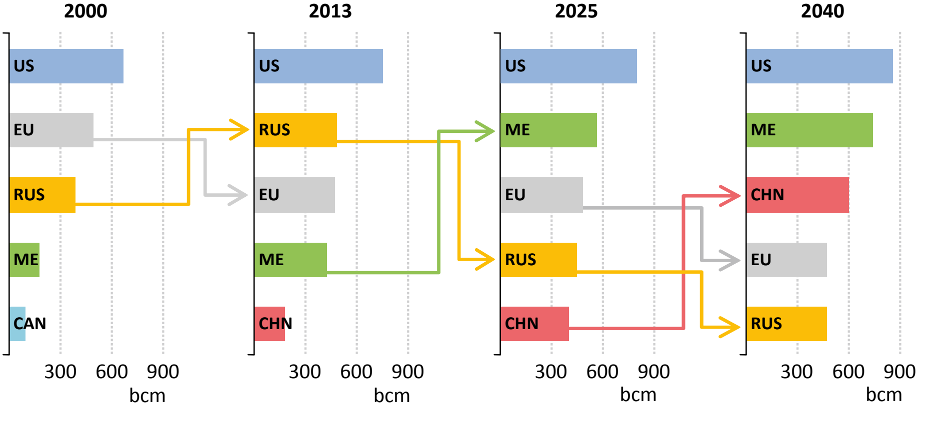
Natural gas is already the most important fuel in Russia's energy mix, accounting for 55% of the country's total primary energy demand in 2013. This, together with the huge potential for efficiency savings embedded in Russia's gas-using infrastructure (especially power generation) and a relatively meagre outlook for growth in GDP, means that there is only limited room for natural gas consumption to grow. Russia is one of the countries that has been the most severely hit by the steep decline in oil and gas prices: the International Monetary Fund forecasts that Russia's GDP will contract by 3.4% in 2015, with only weak growth in the medium term (IMF, 2015). As a result, by 2020 the Russian economy is projected to be only marginally larger than in 2014 (a 0.2% annual average growth rate, compared with 2.4% in last year's *WEO*) and gas consumption declines slightly until the mid-2020s, before reversing course and rising back towards 2013 levels by 2040. A gradual increase in the efficiency of Russia's gas-fired generation fleet means that gas consumption in the power sector falls by about 50 bcm between 2013 and 2040. This is offset by rising gas use in the buildings sector (an expectation of increased use for services and higher average residential space per capita), by industry (expansion of petrochemical production that benefits from the availability of relatively cheap feedstock) and in transport, which Russian policy-makers and industry have identified as a promising area for growth.

The Middle East has been one of the most dynamic regions in terms of natural gas demand growth over the last decade (6.8% average annual growth between 2003 and 2013), with consumption reaching 420 bcm in 2013. This rapid growth has been driven by robust demographic and economic factors, ample resources and policies that have kept end-user prices at very low levels. For as long as gas demand could be satisfied primarily by associated

1. The Clean Power Plan is the first ever set of national standards issued by the US Environmental Protection Agency to reduce carbon emissions from new and existing power plants. The goal of the plan is to reduce the power sector's carbon dioxide emissions by 32% below 2005 levels by 2030. Implementation is at state level and states need to submit their emissions reduction plans in 2016.

gas, available almost free as a by-product of oil output, the strains on the gas balance were manageable. But over time, gas demand – inflated by subsidised prices – has started to run ahead of readily available supply. Developing the region's non-associated gas resources on a commercial basis requires a price signal well above that provided by most current policies.[2] Some governments are taking action in this respect: from the beginning of 2015, gas prices for industrial projects in Oman were raised to $3/MBtu; in Bahrain, gas prices were increased from $2.25/MBtu to $2.5/MBtu. Moves in this direction should encourage upstream gas development and more efficient gas use. In our projections, natural gas demand in the Middle East continues to rise, but the 2.1% average annual growth to 2040 is a much slower rate of expansion than that of the last decade. The power sector and industry account for most of the rise in gas demand (almost half and more than a third respectively), due to rising electricity needs, an expansion of petrochemical activities, and switching away from oil consumption in both sectors. Gas provides more than two-thirds of the region's power by 2040. By the early 2020s, the Middle East overtakes Russia and Europe to become the world's second-largest gas consuming market, behind the United States (Figure 5.2).

Figure 5.2 ▷ Top-five gas-consuming regions in the New Policies Scenario



Notes: US = United States; EU = European Union; RUS = Russia; ME = Middle East; CAN = Canada; CHN = China.

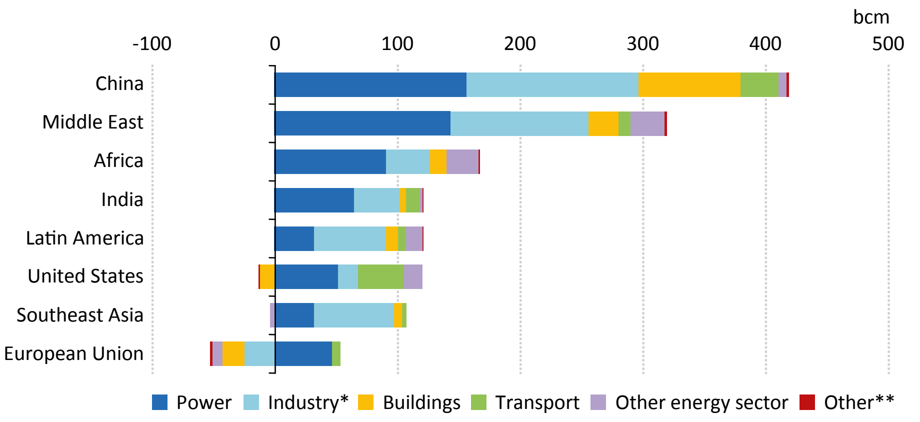
Southeast Asia is gradually being exposed to higher gas prices as countries in the region reduce fossil-fuel consumption subsidies and as the region as a whole makes a transition from reliance on domestic output towards a greater call on imported gas (and, in the case of Indonesia and Malaysia, gas transported within a country via LNG). The region's gas consumption expands by almost two-thirds, from 161 bcm in 2013 to 265 bcm in 2040, with Indonesia accounting for around half of the total increase. Industrial use in Southeast Asia accounts for almost two-thirds of the incremental demand. However, with gas facing

2. An example in 2014-2015 was the eventual lack of interest shown by international companies to take up the opportunity to develop Saudi Arabia's non-associated gas resources in the Rub al-Khali desert.

strong competition from abundant coal resources, the share of natural gas in total primary energy demand, currently around 22%, declines to 20% in 2040.[3]

In the New Policies Scenario, growth in gas demand between 2013 and 2040 is larger in China than anywhere else in the world (Figure 5.3). Despite its reliance on higher-priced imports to fill its gas balance, the case for gas use in China is a strong one, given the country's continued economic expansion, the need for residential heating in large parts of China, the scope to switch away from oil product use in the industrial and transportation sectors (thereby mitigating concerns over oil security), and, arguably most importantly, the need to improve urban air quality. This results in an increase in demand from about 170 bcm in 2013 to 315 bcm in 2020 and around 590 bcm in 2040 (an annual average growth rate of 4.7%). Power generation and industry account around 70% of this increase, with the latter sector seeing coal-to-gas and coal-to-electricity substitution. However, a significant contribution comes also from the buildings sector, where consumption expands by almost 85 bcm between 2013 and 2040, as more of the population is connected to gas distribution lines and centralised gas-fired heating systems. The projected trend for Chinese gas demand means that the share of gas in the country's primary energy mix more than doubles over the projection period. Even so, at 11% in 2040, it remains much lower than today's global average of 21%.

Figure 5.3 ▷ Change in natural gas demand by key sectors and regions in the New Policies Scenario, 2013-2040



* Industry includes gas used as petrochemical feedstocks and energy consumption in coke ovens and blast furnaces.
** Other includes agriculture and any other non-energy use.

Over the last few years, India's natural gas demand, which is down from the 2010 peak, has been squeezed by lower than expected domestic production and relatively expensive imported LNG. India has spare capacity at LNG import terminals (although limited pipeline

3. More detailed discussion is included in *Southeast Asia Energy Outlook: World Energy Outlook Special Report* (IEA, 2015a).

capacity in some cases between the terminals and demand centres) and under-utilised gas-fired power plants. Given the expected availability of international LNG at markedly lower prices over the medium term, there is scope for gas demand to rebound and, by 2020, India's gas consumption recovers to 68 bcm, a level similar to that of 2010, before rising to almost 175 bcm in 2040. The question for the longer term, examined in more detail in Chapter 13, is how gas can be priced in India to stimulate domestic production and thus gain a larger foothold in the energy mix, in the face of strong competition from coal and from the drive to make India a global leader in renewable energy.

In Europe, there has not yet been any sign of an upturn in consumption, with European Union (EU) demand falling for the fourth straight year in 2014, to levels almost one-quarter below those of 2010.[4] A downbeat outlook for the European economy, which affects gas use in industry and demand for electricity, alongside stable or declining output of most energy-intensive industrial products, limits the prospects for a recovery in gas demand across much of the continent. Over the longer term, gas use in the power sector is bolstered somewhat by a projected gradual increase in the carbon price[5] and by the need to compensate for declining nuclear and coal-fired capacity, but this is offset by continued growth in the deployment of increasingly price-competitive renewables, which tends to push down the utilisation rates of gas-fired capacity. The implementation of EU legislation promoting greater energy efficiency also keeps residential and commercial gas demand in check. The net result is that EU gas demand returns to very modest growth, but then levels off from 2025 at around 475 bcm (consumption in 2010 was more than 540 bcm).

Japan approved its Strategic Energy Plan in April 2014 and followed this up in July with a detailed vision for energy supply and demand (METI, 2014). In August 2015, power was produced from the first of Japan's nuclear plants to resume commercial operation, and providing that Japan's Nuclear Regulation Authority confirms the safety of other nuclear power plants, the government aims to re-start more nuclear plants, providing 20-22% of Japan's electricity generation by 2030. This is accompanied by strong support for renewable energy and measures to promote energy efficiency. These factors, together with a modest outlook for economic growth, mean that we project a steady decline in gas consumption in the first part of the *Outlook* period, as gas demand settles back from the high levels necessitated by the closure of nuclear capacity (around 130 bcm in 2012 and 2013), before gas use flattens out at around 100 bcm per year from about 2020 onwards.

4. The trend for gas use in OECD Europe, by contrast, is slightly more positive. OECD Europe includes non-EU members Turkey, Switzerland and Norway, but excludes some central European countries that are members of the EU (see Annex C for definitions of regional groupings). Gas demand growth in Turkey has been particularly robust, at nearly 40% since 2009 (although increasing investments in renewables, coal and nuclear are likely to slow the pace of future growth).

5. The introduction of the EU's Market Stability Reserve, recently brought forward to 2019 from the originally planned 2021, is expected to support carbon prices that rise from $30/tonne in 2025 to $50/tonne in 2040 in the New Policies Scenario. Evidence of the potential impact of such an increase comes from the United Kingdom, where a combination of lower gas prices in early 2015 and the decision to nearly double the UK carbon price floor to about $27/tonne has increased the competitiveness of gas-fired generation versus coal.

Sectoral trends

Power generation remains the most important driver of rising global gas demand in volume terms, with gas consumption increasing by 615 bcm over the period to 2040, accounting for almost 40% of total growth in gas demand. Natural gas is the only fossil fuel whose share in the electricity generation mix rises in the New Policies Scenario, from 22% in 2013 to 23% in 2040: in OECD countries, gas overtakes coal to become the largest single source of electricity generation by the mid-2020s, although it remains well behind coal in non-OECD markets.

The way that natural gas is used in the power sector depends strongly on the price at which it is available and its competitiveness versus other fuels, as well as the policy preferences that affect plant operation and investment decisions in new capacity. By and large, in resource-rich countries, gas makes a compelling case as a source of power across the merit order, including provision of baseload power. In Russia, for example, gas-fired generation, often in combined heat and power plants, is the predominant source of power generation west of the Urals, holding its own against coal (most of which has to be transported from the distant Kemerovo region in Siberia). In the United States, like Russia a coal-rich as well as gas-rich country, gas-fired generation with fuel inputs at $3-4/MBtu is dispatched ahead of coal-fired plants in many parts of the country, given its generally higher efficiency. According to data from US Energy Information Administration (EIA), gas-fired power generation increased by around 20% in the first six months of 2015 compared with 2014, while coal-fired power declined by around 15% (US DOE/EIA, 2015).[6] In much of the Middle East, gas is the natural choice for new capacity, especially where it displaces oil in the power mix: gas use for power in the Middle East increases by more than 140 bcm over the period to 2040, more than a fifth of the global increase in gas-for-power.

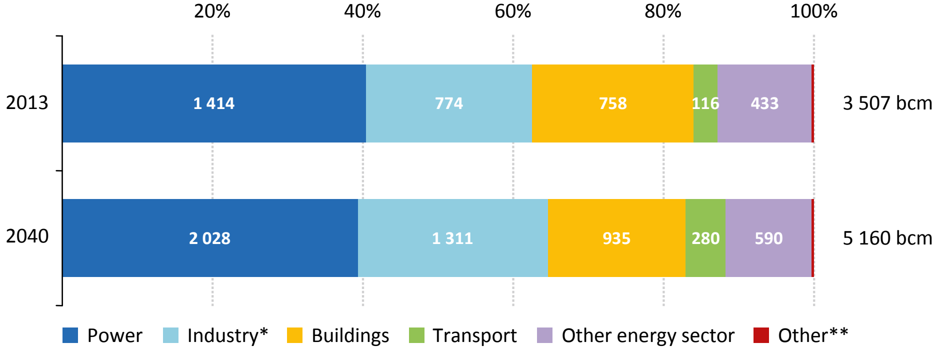
In countries where the domestic price tends to be determined by the cost of gas imports, the role of gas in power generation tends to be more limited. In these cases, gas demand in power generation is sustained in our projections by policies targeting a reduction in air pollution, diversification of the power mix and the need for more flexible peaking capacity (although alternative ways of providing flexibility to the power system, for example through demand-side management and electricity storage, are increasingly viable). So, although gas use grows in power markets across Asia, including China and India, the share of gas in overall generation in these countries remains well shy of the global average (23%). For example, gas demand in the Chinese power sector increases by an impressive 155 bcm, (to produce almost 900 terawatt-hours of power in total in 2040), but in Chinese terms this remains a niche application, accounting only for around 8% of total generation.

Natural gas use in the industrial sector expands by almost 540 bcm (Figure 5.4), with non-OECD countries accounting for almost all the net increase. The largest absolute increase in industrial gas use occurs in China, where it increases by a factor of almost four between 2013 and 2040, mainly because of demand from the petrochemical sector and a

6. In April 2015, for the first time, natural gas overtook coal as the largest source of power generation in the United States, providing 31% of total electricity produced (versus 30% from coal) in that month.

policy-driven switch from coal use (especially for facilities in and around urban areas) as one means of combating severe pollution. The share of natural gas in Chinese industrial consumption triples from 4% in 2013 to 12% in 2040 (including gas use as feedstocks), while coal's share in the sector almost halves to 32%. The second-largest rise in industrial gas demand in absolute terms occurs in the Middle East, where it increases by over 110 bcm by 2040 to slightly more than 240 bcm. This is underpinned by the availability of relatively cheap gas (an advantage that remains even where subsidies are reduced) and the expansion of petrochemical and gas-based iron production (direct reduced iron). In OECD countries, gas demand in industry remains flat in aggregate throughout the projection period, but this reflects divergent trends. In Europe, industrial gas demand is set to decline, by more than 20 bcm, due to the structural decline in energy-intensive industry, the implementation of efficiency measures and relatively high gas prices. The United States, by contrast, enjoys a partial revival of gas-intensive industrial sectors, particularly the petrochemicals industry. Globally, gas demand for use by the energy sector itself increases by almost 160 bcm, reaching nearly 590 bcm by 2040, with the main reasons being rising consumption for oil and gas extraction, due to the expansion of global supply, and for gas-to-liquids projects. The latter is projected to grow at an average annual rate of almost 6%, meaning that, by 2040, some 70 bcm of gas per year is being converted into around 0.8 million barrels per day of oil products. While this represents a large increase in gas-to-liquids conversion, investment in this capital-intensive technology is generally limited to those areas where gas is readily and cheaply available, but options for marketing gas are either unavailable (because the resource is remote) or unfavoured (because of a producer desire for diversified revenue streams or a preference for local oil product supply).

Figure 5.4 ▷ Global natural gas demand by sector in the New Policies Scenario



* Industry includes gas used as petrochemical feedstocks and energy consumption in coke ovens and blast furnaces.
** Other includes agriculture and any other non-energy use.

Gas demand in the buildings sector (residential and commercial) expands at a slower pace than total demand – on average 0.8% per year in the New Policies Scenario. Space heating accounts for more than 60% of gas consumption in this sector but prospects for a further expansion are constrained by saturation effects and efficiency policies in most OECD countries, notably in the United States and the EU, where gas use in the buildings sector declines as more stringent efficiency measures take effect. Moreover, with the notable exception of China, where rising income per capita, urbanisation and the expansion of gas infrastructure support gas penetration in the buildings sector, a significant portion of global energy demand growth in the buildings sector is projected to come from regions where consumption for space heating is negligible, due to higher average temperatures, limiting the scope to expand gas use. In the New Policies Scenario, gas consumption in buildings expands by almost 180 bcm over the projection period, from 758 bcm in 2013 to 935 bcm in 2040. China, alone, accounts for about half of the total growth, with the share of gas in the Chinese buildings sector energy consumption more than doubling to 18% by 2040.

The fastest growth rate in natural gas consumption, albeit from a low base, is in the transportation sector, in the form of compressed natural gas (primarily for passenger vehicles) and LNG (for trucks and maritime transport). Most of this is for road transportation, where natural gas use expands on average at about 5% per year to reach about 160 bcm by 2040, compared with 43 bcm in 2013. This rise is fastest in countries where there are large oil and gas price differentials (to incentivise the switch), but also where there are government policies that promote infrastructure development or natural gas vehicles sales, in response to concerns about oil security or urban air quality. The latest available data (NGV, 2015) show that the number of natural gas vehicles has continued on an upward trend and stands at more than 22 million in 2013, although the pace of expansion appears to have recently slowed in some of the largest markets, such as the United States and China, in response to lower oil prices. The share of gas in the energy consumption of the road transport sector almost triples over the projection period; however, the fact that it reaches only 5% of the total in 2040 highlights the persistence of obstacles, including the difficulty of establishing large-scale distribution and re-fuelling infrastructure. The bulk of additional gas consumption in the sector comes from expanded use of passenger vehicles, but the heavy-duty component, including trucks and buses, grows at the fastest pace, 6.3% on average per year. In marine transportation, the rising consumption of natural gas is driven by more stringent regulation of marine bunker fuels that encourages a shift towards use of marine gasoil and LNG. In the New Policies Scenario, about 50% of additional gas demand in the transport sector arises in United States, China and India.

Production

Resources and reserves

The remaining resources of natural gas, a key parameter for our modelling of future gas production, are large enough to accommodate a significant expansion of production for several decades. As of the end of 2014 they amounted to 781 trillion cubic metres (tcm) (Table 5.3). This value is 3% lower than numbers previously reported following the incorporation of country-by-country details from the 2012 assessment (USGS, 2012a) of conventional gas resources by the US Geological Survey (USGS) and a resulting update to our methodology (see the oil resources section in Chapter 3). The downward revision is largely a function of a lower estimate of remaining conventional recoverable resources in the Middle East and in OECD Europe. Unconventional gas resource estimates are discussed in Chapter 6.

Proven reserves of natural gas have not changed much since last year and, as of the end of 2014, stood at 216 tcm, equal to over 60 years of production at current levels. This indicates that developments undertaken by industry have added to global proven reserves at least as much as the volume of gas actually produced. This is no more than might be expected in what is, overall, a growth market. As in the case of oil, the marked drop in natural gas prices around the world in 2015 could lead to downward revisions as some reserves become uneconomical; alongside a potential slowdown in new developments, one could see a (temporary) reversal of the growth in proven reserves in the next few years.

Table 5.3 ▷ Remaining technically recoverable natural gas resources by type and region, end-2014 (tcm)

	Conventional	Unconventional				Total	
		Tight gas	Shale gas	Coalbed methane	Sub-total	Resources	Proven reserves
OECD	**79**	**24**	**75**	**16**	**115**	**194**	**22**
Americas	51	11	49	7	67	119	13
Europe	18	4	13	2	19	37	5
Asia Oceania	10	8	13	8	29	39	4
Non-OECD	**358**	**57**	**138**	**34**	**229**	**587**	**195**
E. Europe/Eurasia	139	11	15	20	46	185	73
Asia	36	13	40	13	66	102	15
Middle East	105	9	4	-	13	117	81
Africa	51	10	39	0	49	100	17
Latin America	28	15	40	-	55	83	8
World	**437**	**81**	**213**	**50**	**344**	**781**	**216**

Notes: Shale gas resource estimates are taken in large part from the US EIA/ARI study. Though this has broad coverage, it leaves out many regions. The Middle East, in particular, is likely to have significantly larger shale gas resources than indicated. Resources of methane hydrates are not included in the table: they are vast, in all likelihood significantly larger than all other types combined, but are not found in significant concentrations and they are not expected to play a role during the projection period.

Sources: IEA databases; BGR (2014); BP (2015); Cedigaz (2015); OGJ (2014); US DOE/EIA/ARI (2013); USGS (2012a, 2012b).

Production prospects

In the New Policies Scenario, global gas production, commensurate with demand, is set to expand by 1.4% annually, on average, between 2013 and 2040, to reach 5 160 bcm by the end of the projection period (Table 5.4). Unconventional gas, covered in detail in Chapter 6, contributes more than 60% of the increase in supply, thanks mainly to continued growth in the United States and Canada, supplemented by Australia and (particularly in the latter part of the projection period) by other markets led by China.[7] Among the conventional producers, Iran, Turkmenistan, Iraq and Qatar deliver the largest growth in absolute terms.

In North America, a very dynamic region for global production, our outlook divides roughly into two phases. In the first of these, the United States remains at the forefront of upstream developments, the abundant availability of relatively cheap gas dampening the incentives for production in Canada (which sees exports to the United States continue to fall – they have already declined by almost one-sixth since 2010) and in Mexico (which sees gas imports from the United States increasing). However, in the mid-2020s and beyond, the gradual depletion of the US resource base leads to a rise in US wholesale natural gas prices and a slowing pace of US gas production growth – and even an eventual decline, later in the projection period. This creates an increasingly attractive environment for development of gas in Canada and Mexico, the former aided by the envisaged start-up of LNG export projects in the 2020s, the latter by the reforms that are opening up the Mexican upstream. As a result, output growth in both countries picks up in the latter part of the projection period, Canadian production accelerating to reach 230 bcm (led by a near tripling of unconventional gas output) and Mexico's output more than doubling after 2025 to 125 bcm by 2040.

The outlook for Russia is constrained not by production capacity, especially now that the first developments in the remote Yamal peninsula have been added to the longstanding production capacity in western Siberia, but by markets. Consumption has stagnated in both of the primary markets for Russian gas, the domestic market (481 bcm in 2013) and the European market (OECD Europe absorbed a further 153 bcm of Russian exports), leaving Russia determined to diversify. LNG sales globally and pipeline exports to China provide the opportunity for diversification, and these do allow for a gradual expansion of output in the latter part of the projection period. While production is mostly flat for the rest of the current decade, at around 650 bcm, it starts to accelerate after 2025 and reaches almost 720 bcm by 2040. The reorientation of Russia's gas production is reflected in part in the breakdown of production by basin (Figure 5.5) with the rise of output from the eastern Siberian fields, Chayanda and Kovykta, which feed the "Power of Siberia" line into northeast China. Russia is promoting an additional pipeline project (known as the Altai or western route) that would deliver gas to western China from existing fields in western Siberia.[8]

7. China's gas production prospects, which depend heavily on unconventional gas development, are discussed in Chapter 6.

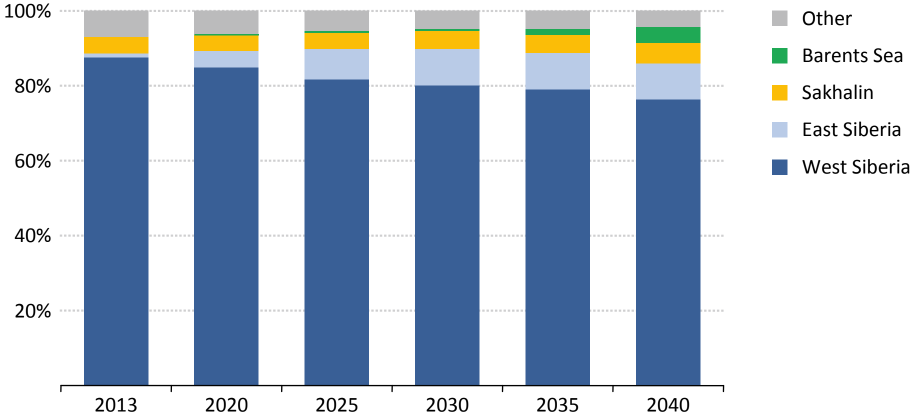
8. Russia is also pursuing projects that would expand export capacity to European consumers, the Turkish Stream pipeline across the Black Sea and a plan to double the capacity of the Nord Stream pipeline to Germany; while these could lead to some increase in export volumes, they are also intended by Russia to limit dependence on transit through Ukraine.

Table 5.4 ▷ Natural gas production by region in the New Policies Scenario (bcm)

	2000	2013	2020	2025	2030	2035	2040	2013-2040	
								Change	CAAGR*
OECD	**1 104**	**1 242**	**1 418**	**1 461**	**1 494**	**1 552**	**1 581**	**339**	**0.9%**
Americas	760	892	1 042	1 094	1 120	1 179	1 221	329	1.2%
Canada	182	156	150	164	174	194	231	75	1.5%
Mexico	32	46	44	53	69	89	125	79	3.8%
United States	544	689	847	876	876	894	863	173	0.8%
Europe	303	280	236	212	201	191	180	-100	-1.6%
Norway	53	113	99	95	92	88	84	-29	-1.1%
Asia Oceania	42	70	141	155	173	182	179	109	3.5%
Australia	33	62	133	149	167	177	175	113	3.9%
Non-OECD	**1 396**	**2 270**	**2 431**	**2 692**	**2 992**	**3 286**	**3 579**	**1 308**	**1.7%**
E. Europe/Eurasia	726	909	924	991	1 058	1 103	1 150	241	0.9%
Azerbaijan	6	18	29	42	53	57	58	39	4.3%
Russia	573	685	654	668	686	699	717	31	0.2%
Turkmenistan	47	78	110	134	159	181	203	125	3.6%
Asia	248	438	512	568	636	711	790	352	2.2%
China	27	121	172	212	260	309	356	236	4.1%
India	28	35	38	45	55	69	89	55	3.6%
Indonesia	70	72	84	94	111	125	135	63	2.4%
Middle East	198	546	585	649	732	817	900	353	1.9%
Iran	59	158	185	199	220	251	290	132	2.3%
Qatar	25	163	163	172	193	216	235	72	1.4%
Saudi Arabia	38	82	94	102	116	129	143	61	2.1%
Africa	124	204	217	270	318	373	428	224	2.8%
Algeria	82	81	91	96	104	112	116	35	1.3%
Mozambique	0	4	3	24	34	48	60	56	10.9%
Nigeria	12	37	43	48	54	63	74	37	2.6%
Latin America	100	172	193	214	247	282	311	139	2.2%
Argentina	41	39	42	50	71	93	111	72	4.0%
Brazil	7	21	28	42	59	78	92	71	5.6%
World	**2 501**	**3 513**	**3 849**	**4 153**	**4 486**	**4 837**	**5 160**	**1 647**	**1.4%**
European Union	264	173	134	115	107	99	92	-81	-2.3%
Unconventional									
OECD	*194*	*576*	*858*	*964*	*1 033*	*1 108*	*1 126*	*550*	*2.5%*
Non-OECD	*12*	*57*	*118*	*199*	*319*	*433*	*541*	*485*	*8.7%*
World	*206*	*632*	*976*	*1 163*	*1 352*	*1 541*	*1 667*	*1 035*	*3.7%*

* Compound annual average growth rate.

Figure 5.5 ▷ Natural gas production in Russia by key producing basins in the New Policies Scenario



Notes: West Siberia includes the Yamal peninsula. Other includes offshore Arctic (with the exception of the Barents Sea) along with Russia's Volga-Urals and Caspian basin production.

The prospects for realising Russia's new export projects (in particular the chances for Gazprom to pursue multiple large-scale projects to east and west in parallel) is constrained by lower hydrocarbon revenues and by the international sanctions that limit the access of Russian companies to western finance, creating a deficit that domestic sources of financing, such as the National Welfare Fund, and alternative international sources, such as Chinese financing, are unlikely to make up for in full. Confirmation in August 2015 that US sanctions apply to the Yuzhno-Kirinsky field, a large gas-condensate field off the island of Sakhalin, presents a stern challenge to the timing of further Sakhalin development. The depreciation of the ruble (while generally positive for export projects as receipts are dollar denominated) increases the cost of imported equipment that remains essential for Russia's new LNG projects, of which Novatek's Yamal LNG project is the furthest advanced. Against this backdrop, infrastructure constraints play a determining role in Russia's gas production trajectory until well into the 2020s.

Russia's short-term surplus of gas and its search for new markets also provides the context for the production outlook in the Caspian region and Central Asia. In 2014, for the first time, gas exports from the Caspian region to China overtook those to Russia, a trend set to expand in the future following Gazprom's decision in early 2015 to reduce significantly its gas purchases from Turkmenistan and Uzbekistan. Caspian gas production is projected to increase by 170 bcm over the projection period, reaching 360 bcm in 2040 from 190 bcm in 2013. Turkmenistan accounts for the bulk of this rise (over 120 bcm or almost three-quarters), sustained by the ramp up of the super-giant Galkynysh gas field, one of the largest in the world, to feed export pipelines to China, whose total capacity is expected to exceed 80 bcm by the early 2020s. With further growth in eastward exports likely to be limited (not least by the start-up of Russian export), Turkmenistan has expressed interest in a range of other export possibilities. Alternative routes to market, whether to the south or the west, all face profound challenges of politics, transit relationships and financing, but over the long term there is a strong power of attraction between Turkmenistan's abundant gas resources and rapidly growing energy demand in South Asia. Our cautious expectation is that gas from Turkmenistan will supplement other sources of gas supply to Pakistan and India by the late 2020s.[9] Opportunities to access the European market along a southern corridor through the Caucasus are taken up in our projections mainly by Azerbaijan, whose production is projected to increase by about 10 bcm by 2020 and then double by 2040, by which time it reaches nearly 60 bcm.

Gas production in the Middle East is projected to expand by more than 350 bcm in the coming decades, rising to 900 bcm in 2040. The region's gas resource base, at 117 tcm of technically recoverable resources, would be large enough to sustain a more rapid increase in gas production, but our projections are constrained by institutional weaknesses in some countries, geopolitical factors that limit regional trade and a lack of incentive to develop some non-associated gas resources because of low domestic gas prices. Over the projection period as a whole, the largest contributions to growth come from Iran (Box 5.1), Iraq, Qatar (on the assumption that the moratorium imposed on the further expansion of the North Field is lifted by the mid-2020s) and Saudi Arabia, the latter being the only country in the region projected to start exploitation of its shale gas resource.

Box 5.1 ▹ Iran: the wild card in international gas markets?

Iran has the second-largest proven gas reserves in the world (34 tcm) but, unlike the other major gas-rich countries such as Russia, Qatar and Turkmenistan, is only a marginal player on international markets. Iran exports relatively small volumes – around 10 bcm per year – to Turkey, but imports a similar amount from Turkmenistan. Iran's gas production, which was 158 bcm in 2013, is therefore entirely dedicated to the needs of a domestic market in which gas accounts for more than half of primary energy supply and is widely used across the economy (including in the world's largest fleet of natural gas vehicles).

Iran's gas production has risen steadily over recent years, bolstered by development of the massive South Pars field (shared with Qatar, where it is called the North Field). Phase 12 of South Pars development, which will have peak capacity of 30 bcm/year, entered into operation in the first-half of 2015 and phases 15-18 are also well advanced. These projects have been complicated, but not halted, by the international sanctions stemming from Iran's nuclear programme. The lifting of these sanctions, if the pathway opened up by the July 2015 agreement is followed successfully, could facilitate new flows of capital and technology to the Iranian upstream; an upward revision in our projections, compared with *WEO-2014*, reflects the potential boost to gas supply.

9. This could be either via a new pipeline link across Afghanistan (TAPI project) or indirectly via Iran, whereby increased Turkmenistan exports to Iran free up Iranian gas volumes for export.

If Iran were to generate a reliable surplus of production over consumption, it would have no shortage of interested buyers. Exports to Europe or to India, or various LNG projects, are habitually mentioned as possibilities. But, in practice, the more likely initial options are much closer to home: many neighbouring markets are gas-short and, although the region's complex politics mean that cross-border energy projects are notoriously difficult to realise, Oman, the United Arab Emirates, Kuwait and Pakistan are all potential importers. Iran has also put in place a gas pipeline to Iraq that could export up to 9 bcm/year, although it has yet to start operation because of the security situation.

Mobilising a rapid rise in investment in Iran's gas sector will, however, not be a simple matter, even with sanctions lifted. Domestic funds for investment are likely to remain limited because of lower hydrocarbon revenue, and, even though Iran has indicated its intention to bring in international investors to the gas sector, the terms under which this could happen have yet to be made public (see Chapter 3). In practice, the oil sector is more likely to attract the bulk of near-term investment, being an easier and more remunerative option. This could even tighten the gas balance, if it leads to additional use of gas for re-injection, the main technology used for secondary oil recovery in Iran. In our projections, gas production rises progressively to 185 bcm in 2020, 220 bcm in 2030 and reaches 290 bcm in 2040.

The implications of this trend for international markets will depend on what happens on the domestic market – and a critical variable here will be Iran's pricing policy for natural gas. Heavily subsidised prices have in the past encouraged runaway gas demand and inefficient gas use, including widespread gas flaring. Despite greater efforts in recent years to raise prices, prices for most industrial consumers are still only in a $1-2/MBtu range (only the petrochemical sector pays a higher price) and gas to the power sector is still priced at under $1/MBtu. In our projections, net exports from the Middle East as a whole increase modestly – from 127 bcm in 2013 to about 160 bcm in 2040, after contracting in the middle part of the projection period. Iran's share of this will depend also on politically difficult reforms on the home front.

The outlook for gas production in Iraq, as for oil, continues to suffer from a combination of security concerns, political and institutional weaknesses, and financial woes caused by the downturn in hydrocarbon revenue. The Basrah Gas Company is a pivotal link in the chain, as it aims to gather, process and market the gas associated with oil production from southern Iraq's super-giant fields (Rumaila, west Qurna and Zubair). Despite the dire need to improve power supply, the bulk of gas produced in southern Iraq continues to be flared, with processing capacity standing at around 5-6 bcm per year, or just one-third of the associated gas produced. It will also take time to build up a domestic gas consuming base inside and outside the power sector, although the agreement to build the $11 billion Nibras petrochemicals complex near Basrah should help to anchor the development of regional infrastructure. In the north of Iraq, production prospects in the Kurdistan Regional

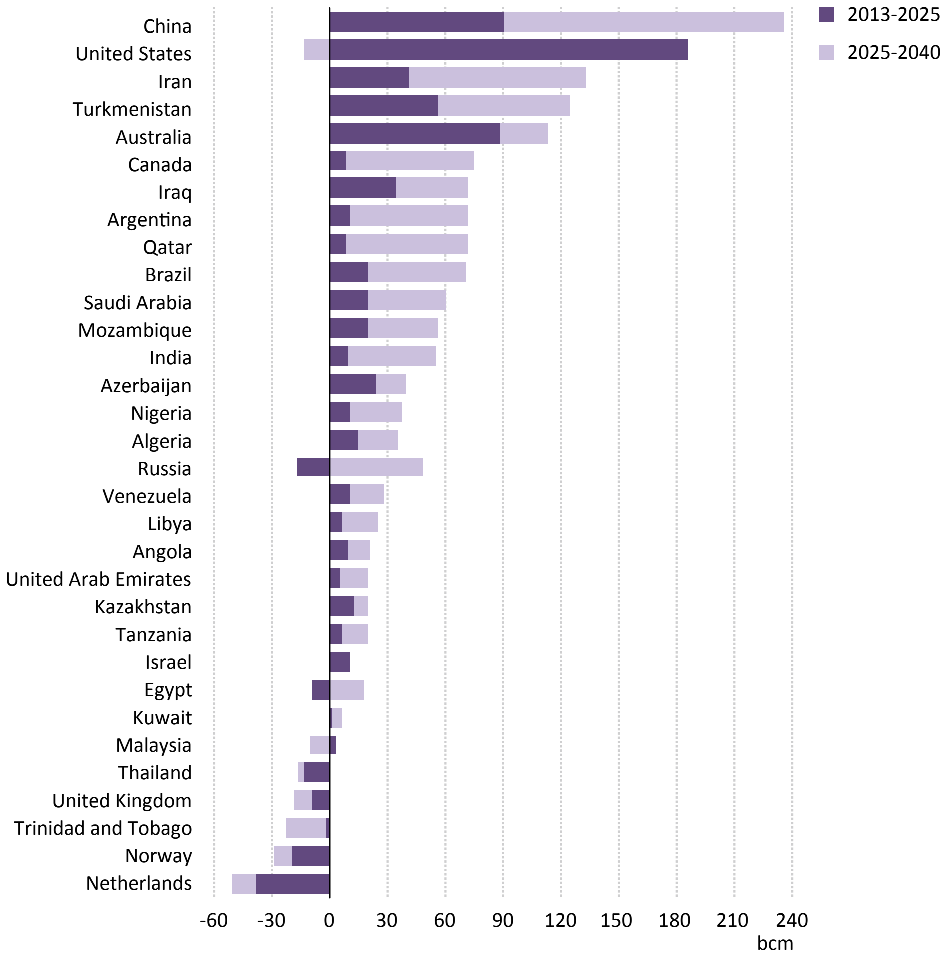
Government area are being held back by questions over infrastructure, export markets and returns to investors, all related to the larger political uncertainty affecting this region. From this difficult starting point, we project that natural gas production in Iraq will rise only modestly over the medium term, before picking up in the second part of the projection period, to reach 80 bcm by 2040.

Southeast Asian gas production expands from 216 bcm in 2013 to 260 bcm in 2040 at an average annual growth rate of 0.7%, significantly slower than the 3.7% per year experienced over the last two decades. The increase for the region as a whole masks significant differences between the countries, with most of them set to become reliant (or expand their dependence) on natural gas imports. Increasing gas output comes from Indonesia, which sees production rise from 72 bcm in 2013 to 135 bcm in 2040 and, to a lesser extent, from Myanmar. In both cases these projections are heavily contingent on the appropriate upstream regulation being put in place. Many of the most productive fields in the region are in decline and prospects for increasing gas production rest largely on the development of new deepwater and complex resources, often located far away from domestic gas demand centres. In many cases, the only viable way to exploit those resources is as LNG, even for domestic customers.

Gas production in Latin America almost doubles to reach 310 bcm in 2040, with Argentina and Brazil accounting for more than the net increase, offsetting projected declines in Bolivia and Trinidad and Tobago (Figure 5.6). While Argentina's gas prospects rely essentially on its unconventional resources, the outlook in Brazil is much more contingent on the capture and delivery of associated gas from its vast offshore pre-salt oil reserves. Gas production in Brazil has maintained an upward trend over the last few years, reaching 23 bcm in 2014. The arrival of greater volumes of associated gas is expected to be delayed because of cuts in upstream oil investment and, even when these offshore oil projects come online, gas re-injection requirements and a lack of infrastructure to bring gas onshore could keep deliveries at modest levels until later in the projection period. We have revised downwards our outlook for Brazil's gas production in the medium term: it is projected to expand at a more moderate pace to 28 bcm by 2020, but to double in the following decade, and then reach more than 90 bcm in 2040.

Africa's gas production sees the arrival of new players with the development of East African offshore resources by Mozambique and Tanzania, joining the continent's established producers led by Nigeria, Algeria and Egypt. The fall in oil and natural gas prices since 2014 has clouded the prospects for rapid development of East Africa's gas discoveries, although some other important pieces of the puzzle are being put in place – as with the confirmation in Mozambique of the legal and fiscal framework for the massive upstream and LNG projects. An investment decision on Eni's floating LNG project for the Coral field appears the most likely to move ahead in the short term, while larger field developments and onshore liquefaction facilities may require more time. We project that these new offshore resources will be developed at a faster pace in the 2020s and beyond, meaning that Mozambique and Tanzania add about 75 bcm to Africa's gas production by 2040.

Figure 5.6 ▷ Change in natural gas production in selected countries in the New Policies Scenario



In North Africa, the overall outlook for natural gas has deteriorated, given the political instability in Libya and slow progress in developing new sources of Algerian gas production. Currently, Algeria's gas supply relies mainly on its two largest fields, Hassi R'Mel and Hassi Messaoud, but both are mature and need investment and advanced technologies to slow down the inevitable decline. The prospects for Algeria compensating for this decline and then expanding gas output hinge on the development of its resource potential, which includes large shale gas resources, but progress has been held back by relatively unattractive investment terms (although these are now being reviewed again, after an unsuccessful licensing round in 2014) and on-going security concerns. Our projections for Algerian gas production have been revised downwards compared with *WEO-2014*: by 2040, gas output now reaches 116 bcm, up from 81 bcm in 2013. One brighter spot in the regional outlook though comes from Egypt, with the announcement from Eni of their

Zohr field discovery in August 2015. Preliminary estimates of recoverable resources are around 0.8 tcm, which – if confirmed as proven reserves – would increase the country's gas reserves by more than a third. Production from Zohr offers the prospect of reversing the gas deficit that has seen Egypt relying on gas imports in recent years. Egypt's gas production is 65 bcm in 2040, up from 55 bcm today. The Zohr discovery is a major new variable in the complex eastern Mediterranean gas picture: it has the potential to push back development of Israel's large Leviathan field, for which Egypt had been seen both as a market and – via possible use of Egypt's under-utilised LNG liquefaction facilities – as a gateway to international trade.

Methane emissions

Methane is a potent greenhouse gas with some 30 times more warming potential than CO_2 when integrated over 100 years, and 85 times more than CO_2 over 20 years (IPCC, 2013). The oil and gas sector is the largest industrial source of global methane emissions, not just from specific types of gas or oil wells, or from a particular region, but rather throughout the globe and from all parts of the industry. Because methane is the primary component of natural gas, the potential for natural gas to play a credible role in the transition to a decarbonised energy system fundamentally depends on minimising these emissions.

The actual size of global methane emissions is uncertain, but is estimated to be around 550 million tonnes (Mt) per year from both natural and anthropogenic sources, to which the energy sector (via activities linked to oil, gas, coal and bioenergy supply) might contribute around 100 Mt – around one-third of all anthropogenic methane emissions. Within this 100 Mt, we estimate that 55 Mt comes from the oil and gas sector, 30 Mt from coal mining and 15 Mt from other sources (mostly the incomplete burning of biomass). The volumetric equivalent of the 55 Mt from the oil and gas sector, approximately 80 bcm of unburned natural gas, is equal to the gas production of Algeria in 2013.

Of the emissions from the oil and gas sector, just under 60% come from upstream operations and the remainder from the downstream sector, where the world's large gas transmission and distribution networks, especially the older ones, are thought to be an important source of methane leakage. The focus of regulatory action (and of this section) is, however, on the upstream, as releases there represent the "low-hanging fruit" for reducing methane emissions: both the sources of upstream emissions and the technologies and operational procedures to address the problem are increasingly well known.[10]

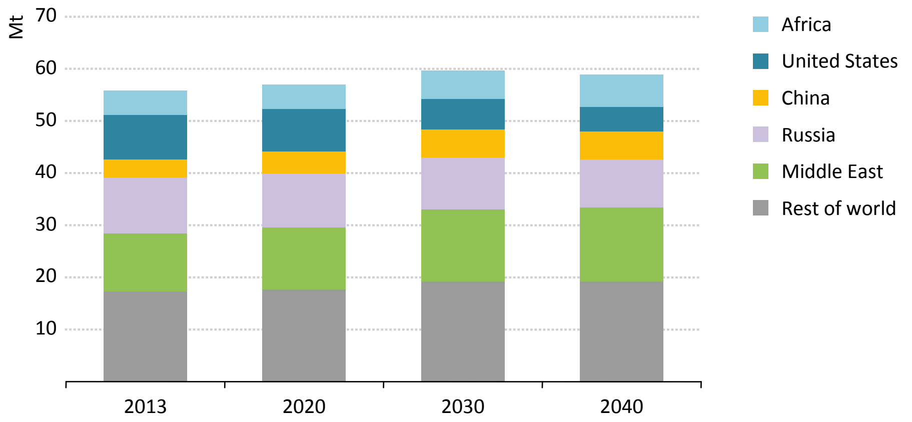
Significant reductions in methane emissions would have the tangible and positive effect of slowing the rate of climate change over the near term, while the effects of parallel efforts to reduce CO_2 emissions would be realised over the longer term. That is why the *Energy and Climate Change: World Energy Outlook Special Report* (IEA, 2015b) identified oil and gas methane reductions as one of five key policies tools to secure a peak in

10. The midstream components that can similarly be targeted with relative ease are the compressor stations used to move gas through pipeline systems.

global greenhouse-gas emissions by 2020. This analysis found that upstream oil and gas methane reductions could yield 15% of the reductions needed to deliver such an early peak in emissions, an amount similar to that which would be realised through incremental investments in renewables. That these two measures have comparable roles reflects the wide difference in starting points: in renewables much is already being done to deploy the technologies at scale, and the gain comes from incremental effort; policies to reduce oil and gas methane emissions are so poorly developed at present that they have practically no meaningful climate impact.

The United States has announced a goal to reduce oil and gas methane emissions and Canada and Mexico have also pledged action in this area as part of their national commitments (Intended Nationally Determined Contributions [INDCs]) made in advance of the COP21 meeting in Paris in December 2015. In the absence of stronger policy action, we project that methane emissions from the oil and gas sector are set to remain at high levels over the period to 2040 (Figure 5.7), giving a continuing strong impetus from this sector to near-term climate change and representing a major wasted opportunity to achieve short-term greenhouse-gas emissions reductions.

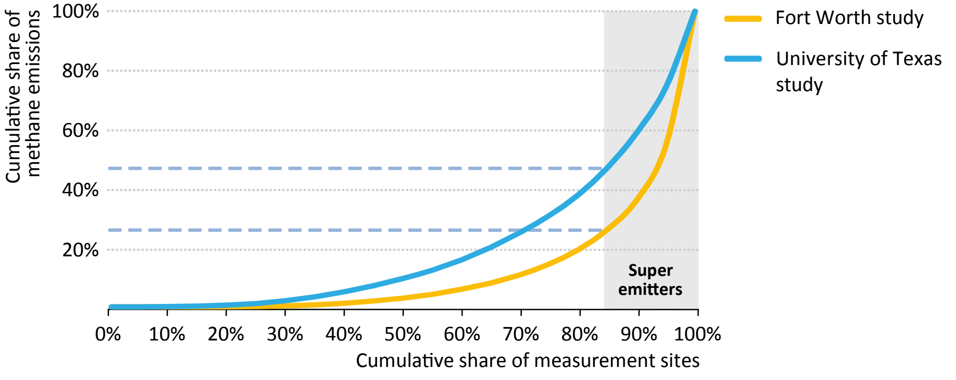
Figure 5.7 ▷ Methane emissions from the oil and gas sector by region in the New Policies Scenario



A long-standing problem for analysis of methane emissions has been the paucity of data, but this is beginning to change due to a major scientific effort undertaken in recent years, led by the United States. This includes increased top-down measurements, which are taken from either towers, moving vehicles, planes or satellites and have the benefit of sampling large areas. But because it is difficult to attribute these emissions to their source, they need to be supplemented by bottom-up measurements, taken close to the various devices in the production systems. A notable example of this effort has been the Barnett Shale Coordinated Campaign, led by the Environmental Defense Fund (EDF), a non-governmental organisation, which conducted extensive surveys of the area of northern Texas that includes the Barnett shale gas plays and the metropolitan area around Dallas and Fort Worth (EDF, 2015).

These studies suggest that methane emissions from oil and gas activities could be higher than previously understood.[11] Studies also indicate that a large part of the problem is related to a relatively small number of emission sources (so-called "super-emitters"). These sources can be intermittent and transient, and can change from day to day. But there is an increasing body of evidence that such super-emitters represent a major source of overall methane emissions across every segment of the oil and gas industry. In two recent, detailed studies, 15% of natural gas facilities examined accounted for 50-75% of the methane emissions detected (City of Fort Worth, 2011; Allen et al., 2013) (Figure 5.8).

Figure 5.8 ▷ Distribution of methane emissions from two studies of natural gas production sites



Sources: City of Forth Worth (2011); Allen et. al. (2013).

Emissions from these super-emitters come from all types of equipment and can be due to malfunctions, such as valves not closing properly allowing gas to escape, or to deliberate emission releases, such as liquids unloadings.[12] Pneumatic devices, which use gas pressure to control the opening and closing of valves, are a particularly important source of production emissions, as they emit gas as they operate (these emissions can be reduced – if not eliminated – by replacing high-bleed with low-bleed or no-bleed devices). Knowing that a large percentage of total methane emissions come from these super-emitters can guide the choice of actions to reduce overall emissions most effectively.

Equipment leaks, especially those from super-emitters, can be reduced by regularly screening for leaks and fixing them quickly when they are found.[13] There is also a variety

11. Estimates of global methane emissions, including our own, are based primarily on standardised emission factors for different energy sector activities; the emissions factors are derived from studies made by the US Environmental Protection Agency (US EPA, 2014) and the Intergovernmental Panel on Climate Change.

12. Liquids unloadings occur when a (typically older) gas well is cleared of accumulated liquids in order to maintain production; depending on the technique used, this can involve intentional venting of the well to the atmosphere.

13. While infrared cameras operated by trained technicians are now used to find leaks at oil and gas production and transportation sites, emerging innovations in methane detection technology are likely to enable much more frequent monitoring, potentially including continuous detection, which can facilitate finding and fixing large leaks much more quickly.

of technologies that capture the vented gas associated with liquids unloadings, including "smart" automation of the unloading process. Regulation has proved effective in ensuring that companies take effective action to reduce emissions. For example, a University of Texas (UT) study on methane emissions from completion of natural gas wells showed that use of reduced emission completion technologies ("green completions"), which are now mandatory in the United States under Environmental Protection Agency (EPA) regulations, reduced methane emissions by about 99%.[14] The EPA has proposed extending their application to oil wells.

The problem of methane emissions from oil and gas activities is a global one and the potential reductions from action in all major oil and gas producing regions are large. The evidence suggests that this problem is far from insuperable, given the political will to tackle it, and that it is not prohibitively expensive to do so.[15] It will, however, require a large-scale effort from governments and companies to improve methane data through better measurement and reporting, so that the super-emitting sources can be found early and fixed. The Colorado Air Pollution Control Division, citing EPA data, found that monthly leak inspections reduce methane emissions by 80%, while annual inspections cut them by less than half. Regulations will be required to ensure that best practices are adopted by all companies, not just a few industry leaders; this could ultimately lead to companies putting a price on methane emissions, as many already do for CO_2, in their planning and investment frameworks. In addition, there is a need to develop methane reduction goals and quantify progress, exemplified by the US goal to reduce methane emissions by 40-45% below 2012 levels by 2025. As underlined in earlier IEA analysis, if the global oil and gas industry were able to reduce projected upstream methane emissions by 75% by 2030, this would represent a cumulative saving of some 165 Mt of methane emissions, otherwise expected to be incurred in the New Policies Scenario. Whether measured in terms of the effect in the short term, i.e. 20-year, or the long term, i.e. 100-year, the climatic impact would be significant. Using the 20-year global warming potential (GWP) factor of 85 means that this cumulative saving of 14 gigatonnes (Gt) of carbon-dioxide equivalent (CO_2-eq) would be equivalent to almost half the emissions from worldwide fossil fuel consumption in 2013. Even if measured over the 100-year horizon and using a GWP of 30, the saving would be roughly the total energy-related CO_2 emissions of the US in 2013.

Trade and investment

Inter-regional gas trade (i.e. trade between countries or regions that are separately modelled in the World Energy Model) continues to rise in the New Policies Scenario, expanding by 46% (or 330 bcm) to reach almost 1 050 bcm by 2040. This does not include growing volumes of intra-regional trade, as for instance in parts of Southeast Asia. Only

14. Emissions during the well completion phase are a particular concern in the case of unconventional gas, because of the large amount of methane that can be released to the atmosphere during the flow-back phase after hydraulic fracturing.

15. Analysis by ICF International (ICF, 2014) found US oil and gas methane emissions can be reduced by 40% using existing technologies at a cost of less than $0.01 per thousand cubic feet of gas produced. A more recent report for the Canadian oil and gas industry (ICF, 2015) came to similar conclusions.

a relatively small share of global gas production is traded over longer distances, due to the complexity and capital intensity of major LNG and pipeline projects. The share of inter-regional gas trade in global supply remains stable over the period to 2040, at around 20%, with some regions, notably Europe and parts of Asia, becoming increasingly reliant on gas imports. Volumes traded as LNG and by pipeline both rise, with LNG increasing more rapidly than pipeline gas, to approach a half-share in inter-regional trade.

Table 5.5 ▷ Natural gas net trade by region in the New Policies Scenario

Net importing regions in 2040	Net imports (bcm)			As a share of demand		
	2013	2025	2040	2013	2025	2040
OECD Europe	-232	-316	-360	45%	60%	68%
China	-52	-192	-238	30%	48%	40%
Japan and Korea	-177	-153	-155	98%	99%	100%
Other Asia	-8	-22	-88	10%	22%	51%
India	-18	-51	-84	34%	53%	49%
Other Europe	-63	-50	-37	64%	52%	35%
Southeast Asia	55	34	-11	25%	14%	53%
European Union	-298	-367	-387	63%	77%	83%

Net exporting regions in 2040	Net exports (bcm)			As a share of production		
	2013	2025	2040	2013	2025	2040
Russia	205	228	251	30%	34%	35%
Caspian	76	124	177	40%	45%	49%
Middle East	127	87	159	23%	13%	18%
Australia	26	98	116	39%	64%	65%
North America	-28	82	95	3%	8%	8%
Sub-Saharan Africa	29	63	83	54%	59%	39%
North Africa	55	41	61	37%	25%	28%
Latin America	9	25	32	6%	12%	10%

Notes: Positive numbers denote net exports and negative numbers denote net imports. The trade should sum to zero; the difference in 2013 is due to stock changes.

Patterns of trade change significantly over the period to 2040. Australia, followed by the United States, are the main sources of additional gas to the international market early in the projection period, followed somewhat later by East Africa, Canada and others (Table 5.5). The Middle East sees a drop in net gas exports during the 2020s, Qatar remains a major exporter of LNG but volumes from other current exporters, notably Oman, Yemen and Abu Dhabi, cease or fall back, while the number of countries importing LNG rises, with Jordan and Bahrain already in the process of joining Kuwait and Dubai; new projects, both pipeline and LNG, underpin a rebound in Middle East gas exports later in the projection period. North America as a whole is on course to switch from being a net importer to a net exporter of gas, a major turnaround from the expectations of the early 2000s. A switch in the opposite direction is anticipated in Southeast Asia: this region includes two of today's major LNG exporters, Malaysia and Indonesia, but regional production does not keep pace with demand and, by the late 2030s, the region as a whole is projected to be a net importer. Among the other importing regions, Europe's reliance on imported gas increases – although the volumes required grow less strongly than projected in *WEO-2014* because of a downward revision in projected gas demand. China and India both manage to keep the share of imports in check by means of increased domestic supply in the latter part of the projection period (and gas provides only a relatively small share of their energy mix, limiting in any case the implications for their overall energy security).[16]

5

The dynamics of international gas trade are influenced strongly by the prospect of oversupply and low prices in the medium term. As the IEA's *Medium-Term Gas Market Report* (IEA, 2015c) (covering the period to 2020) observes, the balance between buyers and sellers in the gas market has shifted in favour of the former, as witnessed by the steep plunge since mid-2014 in gas hub and LNG spot prices (outside North America, where prices were already low). Although much of the gas sold internationally is on a long-term basis, i.e. with buyers committing to certain volumes over time, there is also an increasing share of gas available on a short-term basis, either because producers reserve a certain portion of their output for such sales, or because the gas is sold into the portfolio of companies that have discretion over how and where to sell the gas (so-called aggregators), or because end-users with long-term commitments find that they have gas that is surplus to requirements. The net result over the next few years is expected to be that significant volumes of gas will be looking for a home, at a time when lower oil prices are keeping down the price of oil-indexed gas sold under long-term contracts and when large new LNG plants are scheduled to start operation. Australia has seven new LNG projects coming online or under construction and its exports will increase from 26 bcm in 2013 to almost 90 bcm in 2020. Over the same period, the first of the US LNG projects, Sabine Pass, is also set to bring cargos to the market and four other LNG export projects in the United States are under construction. Total anticipated US export capacity will reach around 90 bcm per year by 2020 or soon after.[17]

Gas importers all stand to benefit from lower gas import bills, though to varying extents, depending on the structure and pricing arrangements of their contracts with their existing suppliers. What is less clear is who will absorb the additional gas that is set to be available on a shorter term basis, particularly given recent downward revisions in the outlook for economic growth (see Chapter 1). OECD Asia may well reduce its gas imports over the period to 2020, depending on the pace at which Japan's nuclear reactors re-start. China and parts of Southeast Asia can be expected to expand their gas imports for industry and the power sector; India has substantially under-utilised gas assets, as its LNG terminals and gas-fired power plants are running at very low capacity factors. But, taken overall, it is unlikely, in our view, that Asian markets can easily take all of the available additional

16. See Chapter 6 for a discussion of the outlook for unconventional gas in China and Chapter 13 for details on gas supply in India.

17. If all the LNG export facility applications received by the US Department of Energy were to proceed, total export capacity could be in excess of 400 bcm; but only a small number is expected to be undertaken.

volumes. This creates an opportunity for other gas importers to benefit, in Latin America and especially in Europe, although in the latter case – with coal prices at rock bottom and carbon prices still relatively low – we estimate that imported gas would have to be available at around $5/MBtu to see a significant swing back to gas in the European power sector.[18]

The expected availability of low-priced gas on a short-term basis over the next few years creates a major dilemma for some gas producing countries and for developers hoping to move ahead with new gas supply projects. Russia's Gazprom will need to decide, for example, whether it wishes to defend its existing pricing arrangements, extend temporary provisions offering relief to its European buyers, or defend market share and compete on price with alternative sources of supply (as its relatively low-cost and currently under-used gas production base would certainly allow it to do). But, over the longer term, a concern for gas importers is that the situation could be reversed in the 2020s, with a new cycle of tighter markets appearing as a result of delayed investment in new export-oriented gas supply projects.

In addition to the LNG plants nearing completion, the projects most likely to make headway in the current price environment are those in the United States. US projects to date have been conversions of existing LNG import facilities, saving money on jetties and other facilities (although the recently sanctioned Corpus Christi is a greenfield project, albeit on land that had been previously permitted for a regasification terminal). Gas is readily available and can be drawn as necessary from the transmission network. The US Gulf of Mexico, where many of the proposals are located, is a region where the costs of complex industrial infrastructure - such as LNG plant - are among the lowest in the OECD. Moreover, under the tolling business model used thus far for US LNG projects, the gas price differential risk is borne by the off-takers of the LNG, not the owners of the liquefaction facilities.

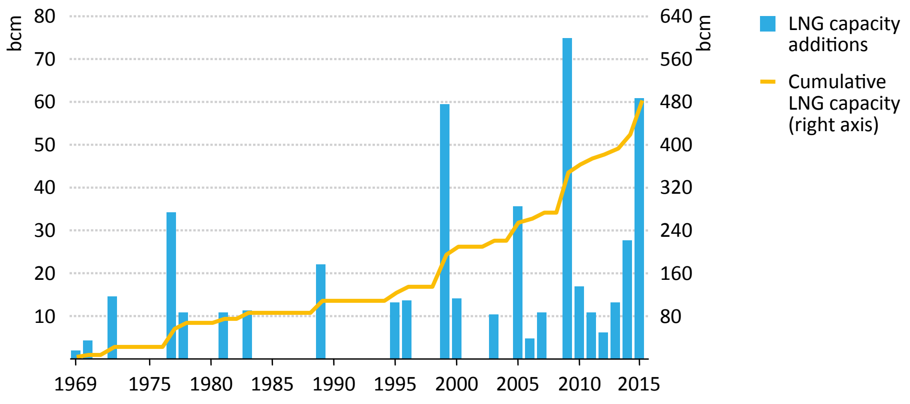
Outside the United States, the prospects of going ahead with new greenfield LNG projects, with high upfront costs, have been pushed back. The underlying justification for some of these projects still appears strong, including some cost-efficient expansions of existing facilities, new projects with access to large, cheap upstream gas (as with the East African projects, or Russia's Yamal LNG), or those with a favourable geographical location in relation to the main gas-hungry regions (as, for example, along Canada's Pacific coast or the projects in Mozambique and Tanzania). However, many of these greenfield projects are also in quite remote areas (as in East Africa) or require long-distance pipelines from the producing area to the coast (as in Canada), pushing up costs. A final investment decision for Russia's Yamal LNG project has been taken, but the future timetable is uncertain because of questions about financing.

18. Calculation is based on the carbon price in Europe and the coal price in Rotterdam (both averaged over the first nine months of 2015), allowing for inland transport for the coal and assumed efficiencies of 37% for coal-fired generation and 57% for gas-fired plant.

There has been a raft of announcements from LNG project developers about postponements, delays and cancellations. Some of these concerned smaller and more speculative projects for which lower oil and gas prices were the last straw; but some also concerned large-scale projects from major companies. The prospects for a second wave of Australian projects, beyond those already starting operation or nearing completion, diminished with the announcement by Shell that it was cancelling its 25 bcm/year Arrow LNG project. Woodside has said that it has postponed a final investment decision on its Browse floating LNG project; and BHP Billiton has lowered the priority attached to its Scarborough floating LNG project, because of low prices and increased competition from the United States. Among the Canadian projects, BG Group is reported to have slowed plans for its 29 bcm/year Prince Rupert LNG project as a response to weaker market conditions. In Russia, Gazprom has announced that its Vladivostok LNG project is no longer at the forefront of its plans. Even where projects have relatively strong economics, delays are occurring in finalising sales contracts and securing financing.

The history of LNG capacity additions suggests that these tend to come in waves, driven by gas discoveries, cycles in gas markets, perceptions of future growth, and rising and falling project costs (Figure 5.9). Large-scale LNG capacity additions, of more than 20 bcm (or 15 million tonnes per annum [mtpa]) are relatively rare and come in intervals of approximately five-plus years. Smaller LNG capacity additions, often expansions at existing facilities, are made on a more regular basis, thereby keeping a buffer between global liquefaction capacity and demand for LNG. During the 1990s and 2000s this buffer of under-utilised capacity was on average 20% of total capacity but over the last few years it has shrunk to less than 10%, a change attributable in the main to unexpectedly higher demand for LNG in Japan of around 25 bcm since the Fukushima-Daiichi accident.

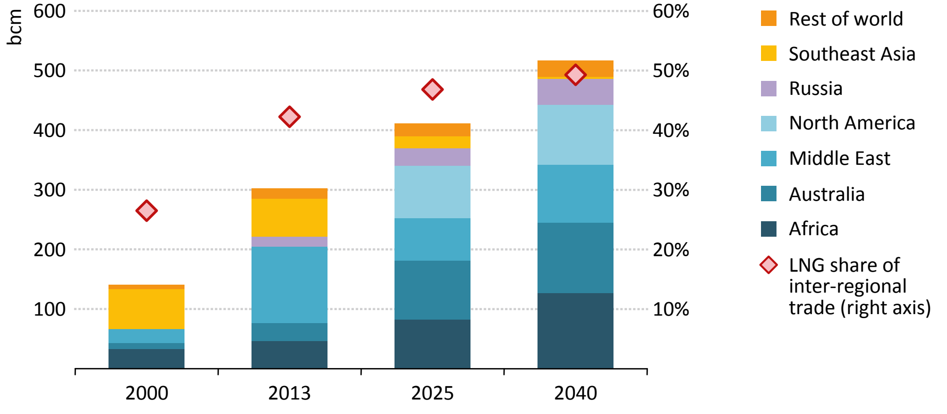
Figure 5.9 ▷ Global LNG liquefaction capacity additions



Sources: Cedigaz (2015) and IEA analysis.

In the New Policies Scenario, inter-regional LNG supply increases by more than two-thirds over the decades to 2040, with an average rate of annual growth of 2% (Figure 5.10). Although Southeast Asia disappears as a net exporting region, the net result in 2040 is a more diverse range of LNG suppliers. LNG export from North America plays a major role not only in buttressing supply, but also in its increasing flexibility – export commitments made thus far for the US projects are entirely free of the destination clauses that have hampered the responsiveness of LNG trade to short-term changes in the global gas balance. Greater shares of LNG in major energy companies' portfolios are also encouraging a more adaptable approach to long-term LNG supplies, away from the highly rigid delivery system model seen in the past, towards more short- and medium-term sales.

Figure 5.10 ▷ LNG exports by region in the New Policies Scenario



Greater diversity of suppliers is likely to be accompanied by a greater diversity of pricing mechanisms for internationally traded gas. The predominant model, until recently, involved indexing the price of delivered gas to movements in crude or oil product prices, but this was undermined for many buyers by the period of high oil prices to 2014. It now risks being discredited also in the minds of sellers by a period of lower prices. In our view, oil indexation is unlikely to disappear from international gas trade, but it will become just one of a number of ways to put a value on gas, alongside references to prices on gas trading hubs (where these are sufficiently liquid to provide a reliable pricing signal) and other indices linked to particular market segments in which gas will compete, notably power. These diverse ways of pricing gas are set to co-exist (often in the same pricing formula), as companies look for a balanced way to manage risks. However, there will also be regional differences, with gas export from the United States priced off domestic wholesale prices, while established exporters are likely to move only slowly away from their current systems. New suppliers will look for appropriate and perhaps innovative hybrid ways to guarantee income streams for their long term, very capital-intensive projects, while still meeting their buyers' needs and expectations, and more flexibility to respond to changing market circumstances.

Europe remains the world's largest importing market in our projections, with EU imports rising to nearly 390 bcm by 2040 even as demand flattens out (because of declining domestic gas production). New gas contracts will be needed: over the next ten years, about

150 bcm of gas import contracts to the EU, mostly from Algeria and Norway, are set to expire (Cedigaz, 2015). Always provided that investment is forthcoming, Europe is well placed in principle to meet its needs from a variety of sources: it is geographically close to gas resource-rich countries and regions (Russia, Caspian, Middle East, North Africa and East Mediterranean); it also has increasingly well-developed gas infrastructure, including not only a large existing capacity to receive gas (Europe's large LNG regasification capacity is currently under-utilised) but also an ability, expected to improve over the period to 2040, to store gas and move it efficiently around a well-functioning internal gas market. This should allow Europe to mitigate the concerns over the security of its gas supply which have been reawakened by the conflict between Russia and Ukraine, even though – in the absence of a determined policy push to the contrary – our projections suggest that European reliance on Russian gas imports is likely to remain high.[19]

Europe remains the largest single importer, but our *Outlook* projects a substantial shift in global trade towards the Asia-Pacific markets, which experience the largest increase in import needs. LNG exporters can adapt relatively easily to these changes in the global gas market, both physically and from a market perspective, as contracts become more flexible. Pipeline exporters, concentrated in Eurasia, face a much more challenging process of reorientation, as exemplified by the long negotiations and time lags involved in opening gas trade between Russia and China. The development of Russia's first LNG plant at Sakhalin (production started in 2009) has already allowed some diversification of Russia's gas supply from Europe to Asia, but it took until 2014 for the parties to reach a milestone agreement for pipeline supply, after negotiations going back decades.

Capital costs for the project to link Russia's resource-rich but under-developed east Siberian region to northeast China have been estimated to be in excess of $30 billion[20] for the development of the two supplying fields (Chayanda and Kovykta) and a similar amount for the construction of the almost 4 000-kilometre long pipeline. For the 38 bcm peak volumes in this 30-year agreement (and at a discount rate of 10%), this implies a delivered cost to the Chinese border of around $7-9/MBtu. A much cheaper gas delivery option is the so-called western or Altai route, as this would link to the existing resource base in western Siberia and could use existing transportation infrastructure for much of the route. A memorandum on the Altai route was signed in 2014, but important details – notably the price – remain to be agreed. From a Chinese perspective, a western route has the major disadvantage of entering Chinese territory far away from key eastern gas-hungry

19. Our projections see about 140 bcm of Russian gas delivered in 2040 to OECD Europe, around 10 bcm less than in 2013.

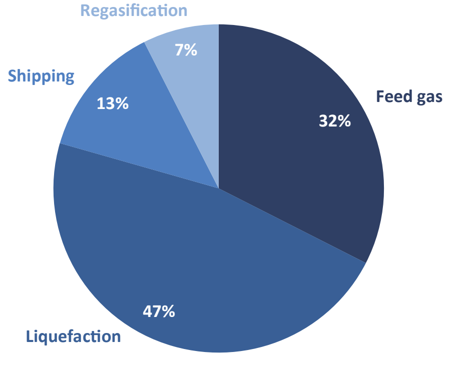
20. Alongside the usual uncertainties about project costs, the investment estimates for Russian gas delivery to China come with two substantial caveats. The slide in the value of the ruble against the US dollar since mid-2014 brings down the US dollar equivalent of ruble-denominated investment spending (most goods and services for the "Power of Siberia" project would be sourced from within Russia), introducing a strong element of uncertainty into calculations expressed in US dollars. In addition, the gas from Chayanda and Kovytka has high helium content, which requires supplemental investment on processing, recovery and storage facilities (but which can have substantial additional value as well).

regions, requiring a further strengthening of west-east gas transportation capacity. In the New Policies Scenario, we project a strong increase of Russian pipeline supplies to China from the early 2020s onwards, reaching almost 80 bcm by 2040, a level that would be likely to require both a (possibly expanded) eastern Siberia route and a contribution from the Altai pipeline. The share of exports to China in overall Russian gas exports rises steadily, reaching almost 30% by 2040 (including Russian supply delivered as LNG).[21]

Focus: LNG costs and the competitive position of natural gas

Around half of the growth in gas consumption projected over the period to 2040 comes from the major gas-importing countries or regions, many of them importing gas over long distances and, to a growing extent, as LNG. Although gas has many advantages, it is not indispensable if the price of imported gas is too high – and the flattening of gas demand growth in 2014 in many importing countries and regions underlines this sensitivity to price. As discussed in the previous section, there are different ways for buyers and sellers to agree on a price for gas: but an important underlying variable is the cost of moving the gas between them.

Figure 5.11 ▷ Indicative breakdown of current LNG cost components



Source: IEA analysis based on public data sources and estimates for projects recently completed or nearing completion.

At the heart of the calculation is the high capital cost of LNG infrastructure, which typically accounts for around half of the delivered cost of gas (Figure 5.11). The outlook for LNG project costs therefore becomes an important factor in assessing the future position of gas in the global energy mix. The question examined in this section is whether there is a realistic prospect of these costs coming down over the projection period, in a way that would improve the competitive position of gas in import-dependent markets. Recent years have seen numerous examples of strong cost inflation for many (but not all) LNG

21. A major uncertainty for all potential suppliers to China is the extent of its domestic production, which will influence strongly its import needs. The implications of different trajectories for China's unconventional production on regional and global gas markets are discussed in Chapter 6.

projects and the possible combination of relatively high and even rising costs for LNG with falling costs for some alternative sources of energy, notably wind and solar power, is not a prospect that bodes well for gas.

LNG projects vary widely in scope (Table 5.6) and this is reflected in the wide range of cost estimates ($600-3 000/tonne of LNG liquefaction capacity). At one end of the scale are extensions of existing projects or, in the US, conversions of previous LNG import terminals, which can rely extensively on the use of existing infrastructure. There is then a wide range of greenfield projects offering differing levels of complexity, including floating LNG projects. Location is a critically important variable for all of the onshore projects; whether the project can be sited close to existing towns, service providers and transportation infrastructure, or whether accommodation and facilities (including power generation, for example) have to be purpose-built. For integrated projects, i.e. projects that have a dedicated upstream component, additional questions are whether the gas requires extensive new pipelines to bring it to the gate of the liquefaction plant and whether the gas requires special treatment to remove liquids, impurities or CO_2.[22]

Despite this diversity, the main cost elements for new LNG liquefaction plants have a lot in common (Songhurst, 2014). Projects require basic materials, such as steel and cement (which can account for around one-fifth of total costs); they need specialised equipment for refrigeration, liquefaction and other onsite processes (another 30%); they require construction services to prepare the site and build the plant itself (another 30%); and the remaining costs go to design, engineering and project management. Overall costs are heavily influenced by movements in the global prices of key metals, by global competition among the handful of experienced LNG contractors – or the lack of it at times of high activity in the sector – and by local labour rates and productivity among suppliers of more general engineering and construction services. The considerations included in Table 5.6, such as the overall legal and regulatory environment, environmental factors, public acceptance and political risks also have a very significant impact, both on costs and timing.

Recent experience with LNG projects in Australia provides an illustration of how some of these factors can conspire to push up overall costs. There was a strong crowding effect from undertaking half a trillion dollars-worth of resource development in Australia within less than a decade, almost half of which was LNG-related (upstream, gas gathering and liquefaction). This led to a severe tightening of labour markets, such that the share of construction costs in overall project costs rose significantly. Most of the LNG developments took place in remote locations, pushing up infrastructure needs. Moreover, the strength of the Australian dollar for much of this period also raised the bill for projects financed with imported capital, given that between two-thirds and three-quarters of costs were incurred in Australian dollars.

22. We focus in this analysis on the liquefaction facilities themselves, rather than upstream and gas processing elements, but these overlap strongly in some cases, most clearly for floating LNG facilities.

Table 5.6 ▷ Major variables affecting the cost of new LNG liquefaction facilities

	Variable	Key considerations
Project scope and complexity	Expansion of an existing facility	• Utilities and common infrastructure items (e.g. power, storage, control rooms, marine facilities) already in place. • Extent of cost benefits dependent on extent to which expansion was incorporated into original design.
	Conversion of an LNG import terminal	• Utilities and some common infrastructure (e.g. power, storage, pipelines, marine facilities) already in place.
	Greenfield project	• Numerous location-specific factors (see below). • Size and number of liquefaction trains (economies of scale). • Gas composition and need for onsite gas treatment. • Likelihood/possibility of expansion.
	Floating LNG	• No need for onshore facilities. • Relative certainty of construction costs and construction period. • Gas composition and need for on-board gas and liquids treatment. • Limits on capacity and no room for expansion.
Country, market and project-specific factors	Location	• Existing transportation infrastructure (port facilities, airports, roads). • Proximity to towns, accommodation, electricity supply and other essential services. • Dredging requirement for marine facilities. • Climate and average temperatures.
	Construction and engineering services	• Availability and cost of necessary expertise and qualified labour. • Availability of major contractors. • Depth of local market for engineering and construction services.
	Country or regulatory risks	• Transparency of procedures for permitting and authorisation. • Quality and resilience of political institutions and the legal system. • Complexity of the overall business environment (e.g. fiscal terms, local content). • Conflict or civil unrest affecting the safety and security of assets or personnel.
	Market risks	• Global market prices for metals, cement and other raw materials. • Unstable or inflationary economic environment. • Abrupt fluctuations in exchange rates, especially where costs/repayments and revenues are in different currencies.
	Partners and project management	• Experience and alignment of partners, including possible government stakeholders. • Reliability and performance of suppliers. • Project completion delays, low build quality. • Balance between on- and off-site (modular) construction.
	Environmental and social aspects	• Public opposition and relations with local communities. • Local employment opportunities and economic benefits.

From the factors described thus far, it is also easy to understand the cost advantages of US LNG export projects located along the US Gulf Coast where they benefit not only from existing infrastructure but also from their location in industrialised areas with access to a large market for engineering and construction services. These facilities are being built at a cost in the range of $600-1 500/tonne, less than half of the cost of many of the greenfield liquefaction plants being constructed elsewhere.

There are, however, only limited possibilities around the world for brownfield expansions of existing projects or conversions of existing LNG import terminals. Over the longer term, the adequacy and competitiveness of global LNG supply will depend on the industry's ability to deliver efficiently also on new greenfield projects. Some of the factors affecting future costs are not within the power of the industry to control, but there are four issues related to project design and technology improvements that could have a strong bearing on how costs evolve:

- **Economies of scale**. Over the course of the last three decades, the capacity of each liquefaction "train" has gradually increased in size, from the 1.4-2.7 bcm (or 1-2 million tonnes per annum [Mtpa]) that was once considered standard to around 6.8 bcm (or 5 Mtpa) and upwards (the largest LNG trains are in Qatar, with a capacity of 10.6 bcm or 7.8 Mtpa per train). Such trains tend to benefit from economies of scale, both in terms of capital costs and operating efficiencies, although they have not always been without problems, at least in initial operations. The same consideration applies also to shipping costs, which can represent around 10-20% of the delivered cost of LNG: these fell by about 30% due to the development of the Q-FLEX and Q-MAX ships that are being used for Qatari LNG export. But while there is potential for additional gains in this area, increasing size also brings greater complexity and, eventually, diminishing returns.
- **Modular and/or standardised approaches to construction**. There have been a number of innovative approaches used to avoid building an LNG plant completely on site, especially for remote projects.[23] In these cases, key elements or modules of the plant – often of several thousand tonnes – are procured on the international market to keep costs down and then moved into place and installed. This approach can be effective, but also introduces more logistical and schedule risks than when the LNG plant is constructed on site. The cost-benefit calculation tends to hinge on the location and the availability of local qualified labour. While standardisation of certain components can also yield benefits, large-scale standardisation tends to come up against the fact that each LNG plant has its own specificities, resisting categorisation into a limited number of repeatable, off-the-shelf modules.

23. The very short construction season in northern Norway necessitated very innovative approaches for the Snøhvit development: most of the plant was built on a barge in southern Spain and then towed and installed on an island.

- **Efficiency and technology improvements**. Refrigeration and power technologies in the LNG industry have evolved considerably over the last 20 years, raising operational efficiency and thus lowering operational costs. There are research efforts and pilot-scale demonstrations in areas such as thermo-acoustic refrigerators, which have no moving parts, and non-volatile refrigerants, which reduce the need for explosion and fire protection equipment in an LNG plant, but it is unlikely that such systems will replace the efficient and widely used refrigeration systems driven by gas turbines any time soon. Overall, while efficiency improvements are certainly possible at the margin, the complexity of cooling natural gas to its liquid form seems resistant to a major breakthrough on costs.
- **Floating LNG** (FLNG). The area of greatest innovation in recent years has been floating LNG facilities, in which all the equipment necessary to receive gas from an offshore producing field and then treat, liquefy and store it (as well as any natural gas liquids produced along with the gas) is mounted on a single, huge barge, offloading to LNG or liquids tankers (Box 5.2). In theory, FLNG offers the prospect of greater standardisation, the aim being to "design one, build many and re-deploy", although varying designs are necessary in practice to accommodate a range of feed gases and maritime conditions ranging from benign shallow waters to rough seas. The FLNG concept has potential cost advantages as it avoids onshore facilities. It can either be moored close to shore where appropriate, or stationed on the offshore gas field, making it possible to develop otherwise stranded gas reserves (for which the cost of pipelines to shore would be prohibitive). But there are also major challenges, not least of which is the limited space on the barge to accommodate all of the required equipment. FLNG can also run into difficulties with host governments expecting to see local employment and spill overs from local procurement (both of which are dramatically reduced). There are a number of projects underway, but none is yet operational.

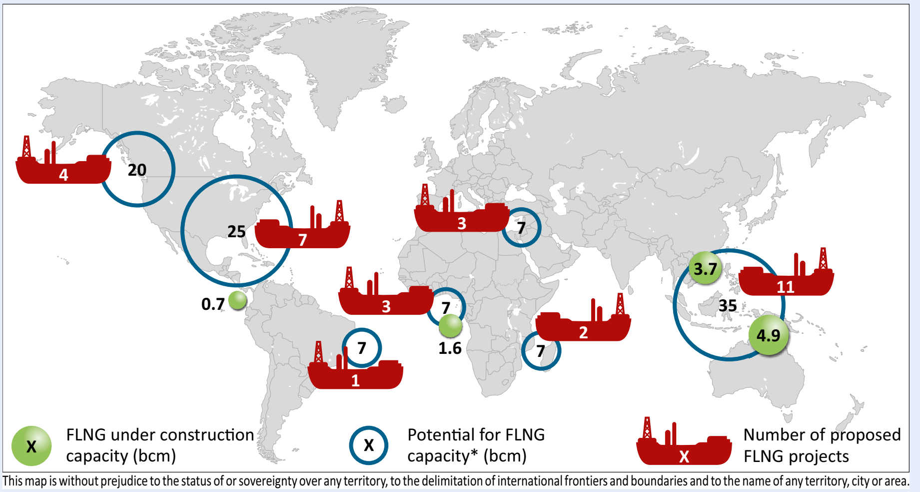
The traditional focus on upstream costs in the oil and gas industry can obscure the distinct importance of the transportation sector for the natural gas outlook. As discussed in Chapter 3, falling oil prices have brought downward pressure to bear on key cost elements in the upstream since 2014, but not to the same extent for highly specialised areas like LNG facilities. Our analysis suggests that, although incremental improvements in efficiency and technology are likely, there is little on the horizon that will achieve a step change improvement in capital and operating costs, unless FLNG can prove its worth. For the present, further expansion of LNG supply while oil prices remain low is likely to take place in the United States, which has an exceptional cost profile. Looking to the long term, whichever way technology turns, the LNG industry will also have to rely on the old-fashioned virtues of tight project management, competitive contracting and procurement strategies, and cost control to ensure that its product continues to enjoy high demand.

Box 5.2 ▷ Floating LNG: niche play or mainstream application?

There are currently five FLNG projects under construction, with a combined liquefaction capacity of some 11 bcm (equivalent to around 3% of global LNG production in 2014), of which the largest is Shell's Prelude project, with a capacity of 4.9 bcm (or 3.6 Mtpa) that is set to produce LNG off Australia (Figure 5.12). There are also two projects under construction for Petronas for deployment offshore Malaysia, one for Equatorial Guinea and one that was intended for Colombia, although the start-up for the latter has been delayed because of current market conditions. FLNG is also integrated into the project concept for development of Mozambique's offshore gas discoveries, alongside plans for onshore facilities.

5

Figure 5.12 ▷ Overview of floating LNG projects under consideration, 2015



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

*Including proposed and under construction projects. Sources: Cedigaz (2015) and IEA analysis.

The decline in oil prices has taken its toll on some of the multiple additional projects that were under consideration, even though capital expenditure on FLNG projects tends to be smaller than for onshore projects, because of their smaller capacity, and the prospect of shorter lead times. The number of projects under construction and consideration nonetheless represents a significant vote of confidence in a new production concept that has yet to produce a commercial cargo. The costs of the existing projects appear to be around the upper range of existing liquefaction facilities (some $3 000 per tonne of liquefaction capacity), but comparisons are made more difficult by the inclusion of upstream elements, such as gas treatment and liquids separation, on the barge itself. The technology has to prove itself over the coming decades in terms of safety, operational reliability and cost, but if FLNG can reliably bring liquefaction costs down to around $1 500 per tonne of capacity, the FLNG concept is likely to move firmly into the mainstream. If it could reduce costs further, it could prove to be a transformative technology for gas, thriving even when oil prices are low.

Outlook for unconventional gas

Global revolution or North American phenomenon?

Highlights

- Unconventional natural gas is set to become an increasingly important part of global gas supply, accounting for more than 60% of the increase in total gas production over the period to 2040. Projected production of shale gas, coalbed methane and tight gas, along with smaller volumes of gas converted from coal, rises from around 630 bcm in 2013 to almost 1 700 bcm in 2040.

- Though poorly known, resources of shale gas, coalbed methane and tight gas outside North America are estimated to be huge – around three-quarters the size of conventional resources – and widely distributed. But if unconventional production is to take off, favourable geology, where it exists, has to be coupled with an appropriate regulatory framework, supportive market conditions and public acceptance. These conditions cannot be taken for granted. In our projections, production growth remains initially concentrated in North America, then spreads gradually and unevenly elsewhere: there is steady growth in Australia, China and Argentina, but few signs of unconventional gas gaining a foothold in Europe.

- Production in the United States has been buoyant even in the low natural gas price environment of the past few years, with more complex wells, drilled at lower cost, targeting the most prolific areas – the "sweet spots" – of the various plays. Although a new test from lower oil prices and less valuable liquids content is now underway, we project continued growth in shale output until the mid- to late-2020s, when it reaches a plateau and then falls back as operators are forced to shift their focus to less productive parts of the resource base.

- The pace of China's unconventional gas growth is a major uncertainty facing global gas markets. Although resources in China are large and policies encouraging their development are in place, aspects of the geology, and the structure of the gas sector in terms of pricing and access to resources and pipelines, militate against a rapid rise in output. We project 260 bcm by 2040. Policy barriers affecting this trajectory can change with time, but other potential constraints related to the quality of the resource, water availability and population density in the resource-rich areas are more intractable.

- Regulatory responses to social and environmental concerns stemming from unconventional gas development have varied widely, from outright prohibitions to cautious, regulated authorisation, trying to keep pace with an industry that has made considerable advances in its operational practices. Public concerns have sharpened the regulatory focus on a range of issues, including the need for pre-drilling assessments, gauging the risk of induced seismic activity, control of methane emissions and transparency regarding the chemicals used in hydraulic fracturing.

A multi-speed revolution?

The extraordinary growth in unconventional gas production in North America, centred in the United States, has reverberated through global energy markets. Worldwide unconventional gas resources are huge, with estimates for shale gas, tight gas and coalbed methane more than three-quarters the size of the conventional gas resource base (Box 6.1). But a bright outlook for unconventional gas is far from assured. Previous *World Energy Outlook (WEO)* analysis, notably the *Golden Rules for a Golden Age of Gas: World Energy Outlook Special Report on Unconventional Gas* (IEA, 2012), has underlined how the future for unconventional gas depends on whether it can be developed profitably and in a socially and environmentally acceptable manner. Neither of these elements can be taken for granted. The costs of producing unconventional gas have continued to come down in the United States, but they remain stubbornly high in many parts of the world that are just starting development. And while regulation and industry practice in tackling social and environmental impacts have continued to evolve and improve – and more is known about the hazards and how they can be mitigated – public opinion about the balance of risks and benefits remains sceptical in many countries; in some cases, public opposition effectively precludes any spread of the unconventional gas revolution.

Box 6.1 ▹ Defining unconventional gas

Definitions based on the word "unconventional" are always likely to be imprecise: as is often said, today's unconventional may well turn into tomorrow's conventional. Moreover, the end product is quite ordinary natural gas, indistinguishable from conventional gas. The discussion in this chapter, and in the *WEO* as a whole, focuses on three main categories of unconventional gas: shale gas, tight gas and coalbed methane. Their distinguishing feature, compared with conventional gas that flows more easily from a rock matrix to the wellbore, is that unconventional gas is trapped in much tighter rock formations that need to be stimulated, usually with hydraulic fracturing, to release gas at commercial flow rates. Tight gas typically accumulates in low permeability sandstone rock, while shale gas is found in even tighter shales or mud rocks. Coal seams, which are typically encountered at shallower horizons and do not require stimulation, hold adsorbed methane and release it if the seam is dewatered and thus depressurised.

There are other sources of unconventional gas that, while playing a much smaller role in our *Outlook*, should not be overlooked. Methane can also be trapped in ice-like crystalline substances, in a hydrate, which is encountered in marine sediments at the continental margins or in permafrost regions. While very abundant, hydrates are not encountered in very large concentrations and, given that their development remains at an experimental stage, costs remain very high. Another source of gas, classified as unconventional in our *Outlook*, is coal-to-gas transformation. This is more akin to an industrial process, using thermo-chemical catalytic processes to convert coal and steam to methane and other hydrocarbons.

In returning to the theme of unconventional gas in *WEO-2015*, the initial part of this chapter presents the projections to 2040 in the New Policies Scenario for unconventional gas production. These are followed by an in-depth look at three issues that, in our judgement, are critical to the way that the unconventional gas picture will evolve:

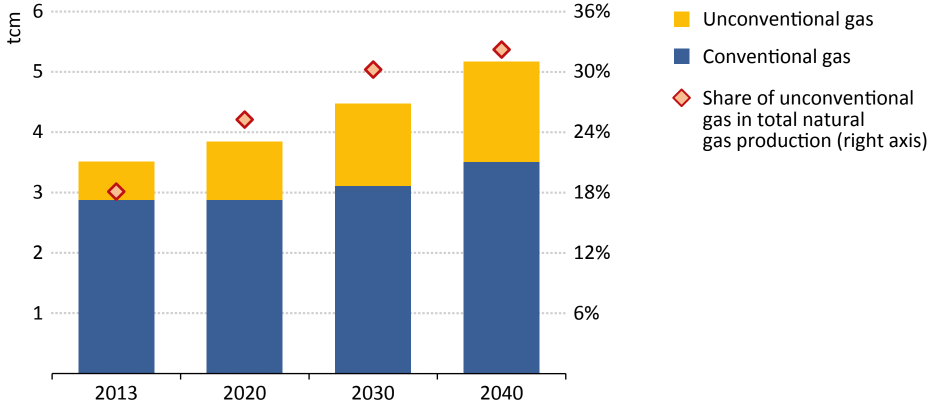
- The factors that have underpinned the expansion of shale gas production in the United States, even at low natural gas prices. The way that industry has brought production costs down while increasing output per well is pivotal to our outlook for the United States and also represents a case study of some of the challenges that any country looking to replicate the US path will need to overcome.
- The outlook for China, where – despite an unconventional resource base estimated to be larger than that of the United States – there are few signs of a comparable surge in activity, despite several years of tight gas development. China is the most important test of whether the boost to supply provided by unconventional gas will be a regional or a global phenomenon, a question with major implications for the global energy outlook.
- How the regulatory framework for unconventional gas has evolved, in particular in response to the social and environmental concerns associated with its extraction (the focus for the "Golden Rules" elaborated in a *WEO* special report [IEA, 2012]). This analysis concentrates on the three countries where unconventional gas has expanded most rapidly: the United States, Canada and Australia (the latter for coalbed methane), assessing in each case the major areas of public concern.

Unconventional gas production prospects to 2040

In the New Policies Scenario, the contribution of unconventional natural gas to global gas production grows steadily through our projection period, rising in volume terms from around 630 billion cubic metres (bcm) in 2013 to almost 1 700 bcm in 2040, by which time it accounts for around one-third of total gas output (Figure 6.1). More than 60% of the total growth in gas supply is attributable to unconventional resource development. Current global unconventional production is dominated by North America, which accounted for almost 90% of the total in 2013. This share declines as output in the rest of the world picks up, initially in Australia (in the form of coalbed methane), then in a wider range of countries from the mid-2020s onwards. But the United States remains, by a distance, the world's dominant unconventional gas producer, even towards the end of our projection period, when resource depletion and rising costs lead to a plateau and then a decline in US shale gas production (Box 6.2).

The gradual nature of the spread of unconventional gas production beyond North America underlines that replicating the US experience is neither easy nor quick. Even given the necessary unconventional resource base, a range of regulatory and market factors need to be aligned for unconventional gas production to gain momentum. Over the medium term, the case for investment is also complicated by the relatively low international prices foreseen for natural gas. With liquefied natural gas (LNG) promising to be amply available at a competitive price, companies may hesitate to spend on a new resource that requires an intensive drilling programme to kick-start the process and bring costs down (with no guarantees of ultimate success). Public opposition in some cases has been shown to be capable of slowing, or even halting, unconventional gas development. We judge that production is eventually likely to get going, in places where there are strong energy security reasons – as in China and India – to develop a domestic resource and thereby reduce reliance on more expensive imported gas. Unconventional gas is even projected to gain ground in some countries that are already major conventional gas producers, notably Saudi Arabia and Algeria, provided shale gas is cost competitive and public concerns, as voiced during protests in Algeria in early 2015, are addressed. But in other cases, as across much of Europe, we consider that unconventional gas faces a steep uphill battle to gain acceptance.

Figure 6.1 ▷ Global natural gas production by type in the New Policies Scenario



Note: tcm = trillion cubic metres.

The bulk of projected unconventional gas production is in the form of shale gas, which almost triples to around 940 bcm by 2040 (Table 6.1). Coalbed methane shows a faster rate of growth, but from a lower base, rising to 340 bcm by 2040, overtaking at around that time the amount of tight gas that is produced, which increases more gradually (at a pace closer to conventional gas).[1] In addition, we project some significant growth in coal-to-gas production in China, where there are plans for multiple plants that eventually account for almost a fifth of the country's unconventional gas production by 2040. We also include methane hydrates in our modelling (for which resources are vast, but production is still at an experimental phase and costs are far above those that would justify commercial output), but project only very modest gas output from this source, in Japan.

1. Assessing tight gas resources and projecting tight gas output is challenging since the boundary between conventional and tight gas production is not clear-cut; tight gas, in our definition, is found in low permeability formations and requires large-scale stimulation (e.g. hydraulic fracturing) to generate commercial flow rates of gas towards the well. It tends to be easier to produce than shale gas (which is trapped in still more impermeable rock), but resource estimates are smaller.

Table 6.1 ▷ Global unconventional gas production in the New Policies Scenario (bcm)

	2013	2020	2025	2030	2035	2040	2013-2040	
							Change	CAAGR*
Shale gas	331	577	685	801	908	941	610	3.9%
Coalbed methane	67	115	172	228	284	342	275	6.2%
Tight gas	232	272	283	288	309	338	107	1.4%
Coal-to-gas	3	13	23	33	40	45	43	11.0%
Methane hydrates	-	-	0.0	0.3	0.7	1.0	1.0	n.a.
Total	**632**	**976**	**1 163**	**1 352**	**1 541**	**1 667**	**1 035**	**3.7%**

* Compound average annual growth rate.

6

Box 6.2 ▷ How do resource estimates affect our *Outlook* for unconventional gas?

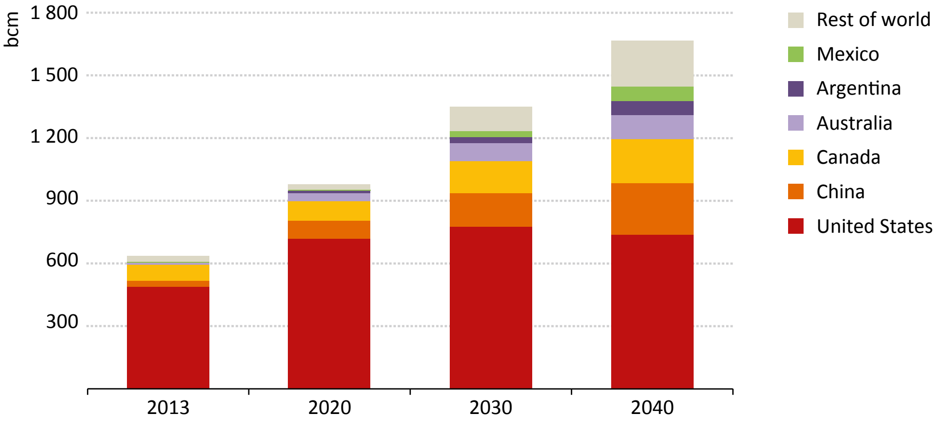
Unconventional gas resources are understood to be globally abundant (see Chapter 5, Table 5.3), though they continue to be poorly known worldwide, as only the United States and, to some extent, Canada and Australia have significant experience with their exploitation. Outside the United States, resource estimates are large enough – and our estimates modest enough – for this uncertainty to have little effect on our projections. In the United States, however, varying the shale gas resource estimate could have a large impact on gas markets, particularly in the period after 2030. Using our estimate for the remaining US shale gas resources of 16 trillion cubic metres (tcm) (higher than the value used in previous *WEO*s), US shale gas production starts declining from around the mid-2030s. This is compensated in part in the latter part of our projection period by higher production of coalbed methane and tight gas (that have been eclipsed to some extent by shale), in order to meet domestic gas demand and export commitments. However, the gradual depletion of unconventional resources pushes up the costs of production, a factor that underpins the long-term rise of our North American gas price.

Overview by country

More than half of the global production of unconventional gas projected in the New Policies Scenario in 2040 comes from the United States and China (Figure 6.2). A detailed look at these two countries is taken in subsequent sections of this chapter (India is discussed as part of the special focus in Chapter 13). This section examines the other potentially significant national producers of unconventional gas.

Unconventional gas production in Canada has more than doubled since 2000, reaching 80 bcm in 2013, despite the production boom in the United States that brought down regional prices and reduced cross-border pipeline trade. Alberta has been joined by British Columbia as a major gas-producing province, with the latter now accounting for more than a third of national unconventional gas production. Unconventional gas output has seen productivity improvements comparable to those achieved by operators in the United States, with widespread use of pad drilling, water recycling and other techniques. However, with its major export market well supplied, Canada's gas exports have dropped by a fifth in recent years, and reversing this trend will require construction of new greenfield LNG export plants, along with the pipelines to supply them. In the current pricing and supply environment, committing the necessary capital for the numerous proposed projects will be challenging, and (as discussed in Chapter 5) we do not anticipate such projects reaching maturity until well into the 2020s. However, with Canadian conventional gas output projected to continue its decline, unconventional gas continues to grow as a proportion of total production, reaching approximately 200 bcm by 2040 (more than half of it shale gas) and accounting for almost 90% of total Canadian gas output by that time. Coalbed methane production can also be expected to expand in the latter part of our projection period, doubling after 2030 to reach 50 bcm.

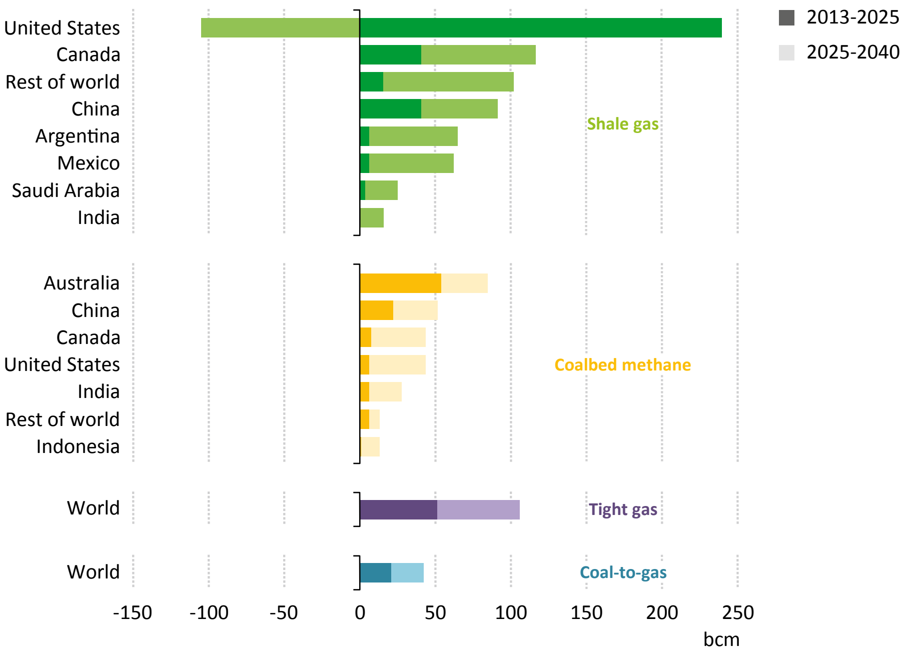
Figure 6.2 ▷ Unconventional gas production by key country in the New Policies Scenario



Production of conventional gas in Mexico has fallen, by around 10% since its peak in 2010, to a total of 45 bcm in 2013, while imports of gas from the United States have almost doubled over the same period. With its upstream reforms well underway, Mexico is understandably eager to develop its indigenous hydrocarbon resources, including an estimated 16 tcm of unconventional gas (almost entirely shale gas). Mexico shares some shale gas formations with the United States, notably the Eagle Ford Basin, although the portion in Mexico has lower liquids content and early drilling results have not been as favourable as those seen in Texas. We see shale gas production starting only in the early 2020s, but rising rapidly from there and reaching 60 bcm by 2040.

Australia is the prime mover outside North America in developing unconventional gas resources, as coalbed methane production grows to 30 bcm in the coming three years to supply the three Gladstone (Queensland) LNG plants, from the first of which exports started in 2015. In our projections, coalbed methane output continues a steady rise over the projection period to reach 90 bcm in 2040 (Figure 6.3). Australia also has substantial potential for shale gas development. Although the resources in the Canning, Georgina and Cooper basins are relatively remote, with poor access to water supplies, the Cooper Basin is the site of an extensive and mature gas-producing area, connected to major east coast markets, and well stimulation techniques have been used for some time. This basin therefore seems the most likely prospect for shale gas output, although the timing of a pick-up in appraisal activity may well be pushed back by the fall in international gas prices. In the Canning Basin in north-western Australia, where shale resources are understood to be abundant, producers would need to compete against very large conventional gas developments (albeit mostly offshore) that are the source for a number of existing and planned LNG plants. We do not project a major increase in shale gas output from Australia before 2030, but by 2040 shale gas production helps total unconventional gas output reach a projected 110 bcm.

Figure 6.3 ▷ Change in unconventional gas production in selected countries in the New Policies Scenario



Note: The dark and light legend shadings refer respectively to the periods 2013-2025 and 2025-2040 for unconventional gas.

Argentina has a long-established oil and gas sector, with local gas output meeting around four-fifths of annual demand of 50 bcm. With supplies supplemented by pipeline imports from Bolivia, and LNG imports from a variety of sources, there is a strong incentive to develop the country's shale gas resources, estimated by the US Department of Energy/

Energy Information Administration (US EIA) to be the second-largest in the world after China. The estimated resource of around 23 tcm dwarfs Argentina's conventional gas reserves. Interest has focused on the Vaca Muerta formation, located in the existing hydrocarbon province of Neuquen, as well as the Los Molles, Loma de la Lata and Agrio formations. The appraisal work done thus far suggests a very promising resource (both for tight oil and shale gas). The question for Argentina is whether the conditions above ground will attract large-scale investment. A relaxation of gas price controls some years ago was an instrumental factor in attracting the interest of a number of large international oil companies, alongside the state energy company YPF, and drilling has started, using both horizontal drilling and fracturing techniques. However, capital controls remain an issue, so mobilising the investment required will be a major challenge, reinforced by elevated fiscal and political risk. We project a build-up in shale gas production in the mid-2020s, rising rapidly thereafter to reach more than 60 bcm by the end of the projection period.

Saudi Arabia's gas production (82 bcm in 2013) is an important component of the kingdom's energy mix, accounting for one-third of primary energy demand. There are hopes that an expanded gas supply could displace oil from the fast-growing power sector (oil continues to provide around half of Saudi Arabia's power generation). There have been few assessments, but unconventional resources are conservatively estimated at around 4 tcm, with shale gas accounting for about half of this. Saudi Aramco is appraising the unconventional gas potential in the northwest, Eastern Province and Empty Quarter and shale gas production is already earmarked to supply a mining project and power plant in a new northern industrial city near the border with Jordan. The remoteness of some of the sites and water needs for fracturing are important barriers to shale gas development, but Saudi Aramco has reportedly already committed $3 billion to unconventional gas projects, with another $7 billion in spending planned. Our projections remain cautious, but over the long term shale gas production reaches 25 bcm by 2040, around one-sixth of the country's total gas supply.

Efforts to develop unconventional gas sources in Europe, including shale gas, have been sparse to date, despite the incentive provided by declining conventional production, growing imports and pervasive concerns about gas security. The technical results of appraisal drilling in Poland have been below initial expectations and in many other areas, outright moratoria on hydraulic fracturing (such as in France) show no signs of being relaxed. Elsewhere, public hostility towards unconventional gas operations is a strong obstacle; in the United Kingdom, for example, even though the government remains supportive, a decision in mid-2015 by the local authorities in Lancashire to reject planning applications for local drilling sites, on the grounds of visual impact, traffic disruption and unacceptable noise levels, underlined the difficulties facing the industry.[2] The relatively high population density in many parts of Europe is a complicating factor, increasing the likelihood of opposition from local communities, especially in areas with no tradition of

2. The applicant has appealed the decision and further applications for shale gas permits have been submitted.

oil and gas drilling. State ownership of oil and gas rights can also reduce the incentive for communities to accept development of local unconventional gas resources, compared with the situation in most parts of the United States, where these rights are held by private landowners. The net result of these obstacles is a very modest projection of almost 10 bcm of unconventional gas output in the European Union by 2040.

This brief overview demonstrates that, outside North America, where growth is expected to continue apace, unconventional gas development has been slow and – with the exception of Australia, Argentina and potentially, China – this situation could be prolonged, particularly given the sharp fall in traded gas prices that has occurred and the growing supply of LNG that is set to hit world markets in this decade.

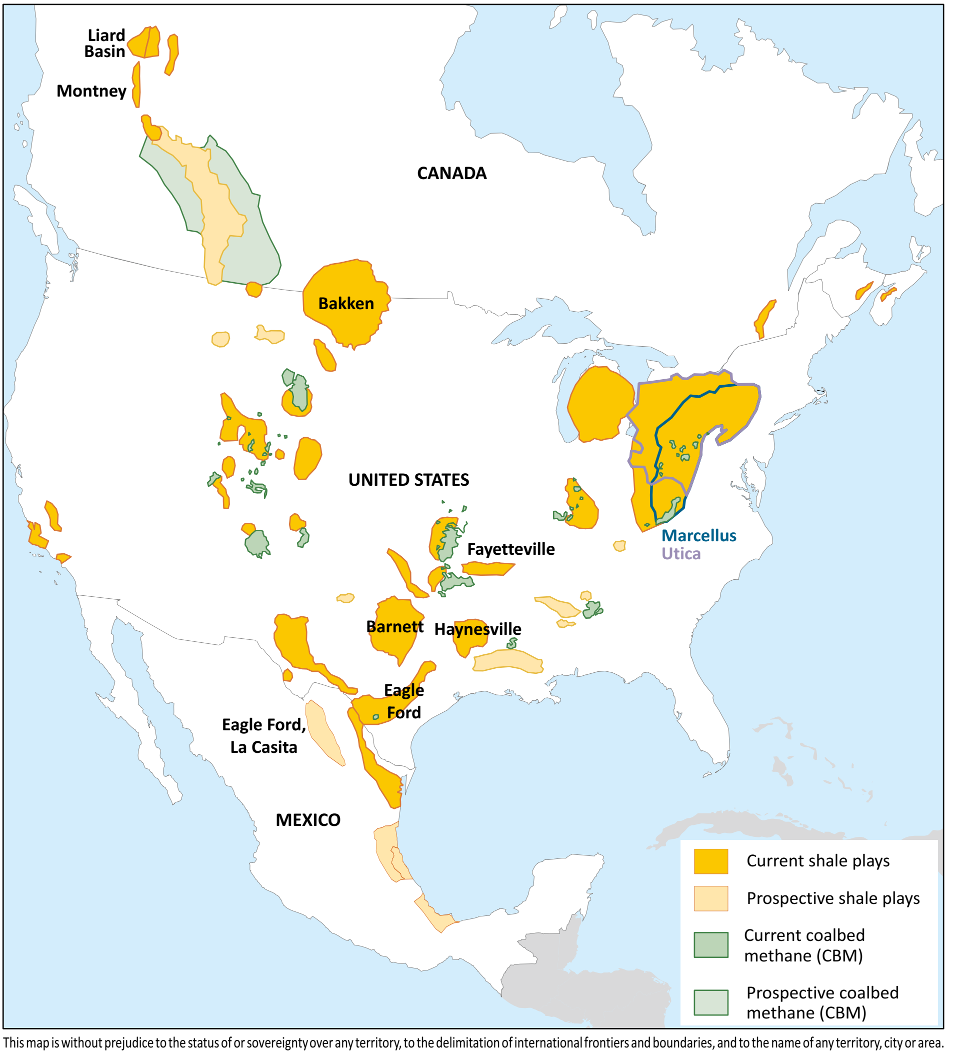
Inside the US shale storm

The shale gas revolution in the United States is a reminder that energy systems retain the potential for sharp and rapid change, once a technology reaches a tipping point of proven effectiveness and commerciality. In 2005, shale gas production accounted for 6% of US total gas production and 1% of global gas production. By 2014, shale gas production had grown to a staggering 52% of US output and 11% of world output. Even though gas markets outside North America have not yet felt the direct impact of this revolution (pending the start of US LNG exports), the indirect results – in a reorientation of market expectations, changed gas and coal trade flows, and the economic boost to parts of the US economy – have already been momentous inside and outside North America.

The existence of a significant US gas resource trapped in low permeability rock has been known for decades, but was considered for many years to be too difficult and expensive to produce. Efforts to overcome these obstacles started in the 1970s and 1980s, with a series of government-funded research projects looking at the technology required to unlock this resource (motivated by concerns about high natural gas prices and dwindling conventional reserves). Technology innovations and improvements around 3D seismic, horizontal drilling and hydraulic fracturing started to open new possibilities for the US upstream, at a time when US gas market deregulation and open access to the well-developed gas pipeline network were creating opportunities for new market entrants. These were the key underlying factors that prepared the ground for the US shale gas revolution in the mid-2000s.

The commercial development of US shale gas started with the Barnett shale in Texas, but over the last five years, the baton was passed first to Haynesville and then to other plays, with the Marcellus shale showing dramatically rapid growth (Figure 6.4 and Figure 6.5). From a standing start, gas production from the Marcellus is anticipated to be 160 bcm in 2015, adding the equivalent of Qatar's current gas output to global production.

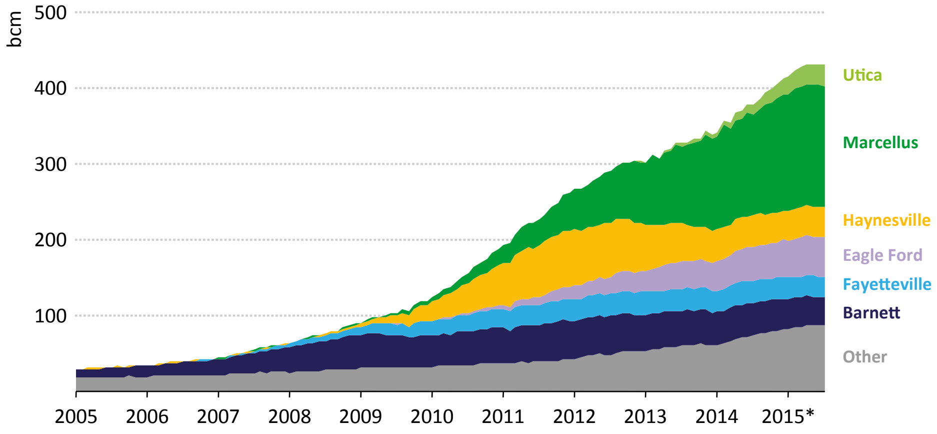
Figure 6.4 ▷ Main unconventional gas resources in North America



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Most of the technological innovation in the US shale industry has been carried out by service companies and independent, mid-sized private oil and gas companies, which had sufficient financial resources to take on field experimentation risk and the agility to adapt. Furthermore, once it was demonstrated by the late 2000s that shale gas wells could be drilled profitably, financial markets were ready to step in and provide many existing players and numerous new market entrants with capital to develop the resource. Access to water, the system of mineral rights ownership, a good road network, reliable third-party access to the US natural gas pipeline infrastructure, and – last but not least – high gas prices in the mid-2000s spurred industry growth, all supported by a readily available, competitive and well-equipped service industry.

Figure 6.5 ▷ Shale gas production by play in the United States



* Production to July 2015.

Note: Based on monthly production reports, converted to equivalent annual output.

Source: US EIA (2015).

Weathering the decline in natural gas prices

The rapid development in US shale brought with it over-supply and a rapid decline in US gas prices, from levels above $12 per million British thermal units (MBtu) as recently as 2008 to lows below $2/MBtu in 2012. Confounding the expectations that such a price collapse would also lead to a collapse in output, US shale gas offers an interesting case study of resilient output even in a lower price environment. Alongside short-term factors, such as hedging strategies and drilling obligations attached to licenses, which can maintain activity for a while even in the face of an abrupt change in market conditions, three underlying conditions allowed US shale to maintain strong growth even while prices remained in the $2-4/MBtu range. We examine these in turn, in more detail, below:

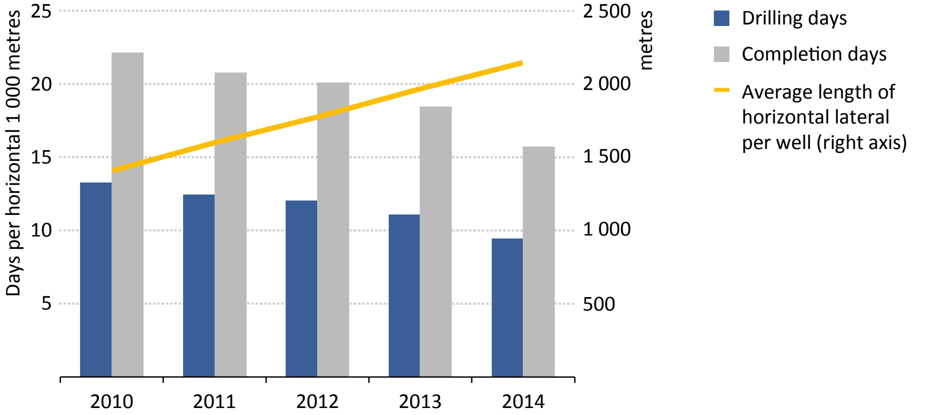
- The industry's ability to increase the average amount of gas produced per well, while also bringing down costs by reducing drilling times and optimising other above-ground processes.
- The operators' capacity to zoom in on the most productive "sweet spots" in a play, via an intensive process of learning-by-doing, alongside increasingly sophisticated seismic mapping techniques.
- A switch, as natural gas prices came down, to more liquids-rich parts of the resource base, with natural gas liquids becoming an integral part of the business case for exploiting gas plays (the parallel rise of tight oil also produced large volumes of associated gas).

6

Getting more for less

A key observation from our analysis of well data from the six major US shale gas plays is that operators have been drilling consistently longer horizontal wells, thereby connecting more of the reservoir volume to the wellbores. The average lateral length of a horizontal well is around two kilometres and this, in combination with shorter drilling and completion times (and therefore lower costs) and higher average output per well, has helped to keep drilling opportunities viable even at lower prices for the produced gas (Figure 6.6).[3]

Figure 6.6 ▷ Drilling and completion time versus average length of horizontal lateral per well in the Marcellus shale play

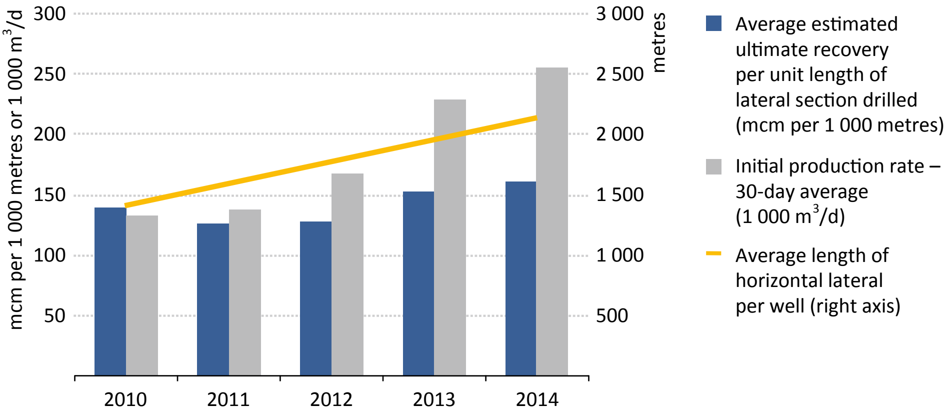


Sources: IEA analysis based on Rystad Energy AS.

One caveat to this story of efficiency gains is that there is no appreciable increase in the amount of gas that is ultimately recovered per unit length of lateral section. In other words, the improvements have largely been a product of cost-effectively pumping more fluid into more fracture stages in longer horizontal sections, in order to increase reservoir contact. This means higher initial production rates (and therefore accelerated payback of investment, lowering the gas price at which the investment breaks even), but not necessarily higher ultimate recovery (Figure 6.7). In addition, not all perforated and hydraulically fractured stages contribute to the flow of gas: better targeting and placing of the fractures, i.e. improved completion design, represents an opportunity to increase productivity in the future.

3. In some cases, operators push the technological envelopes even further by drilling and completing wells over 3 500 metres. It is, however, likely that the well productivity improvements reach an economic optimum at a certain length, i.e. the marginal return starts to decrease at a certain lateral length.

Figure 6.7 ▷ **Average estimated ultimate recovery per unit length of lateral section in the Marcellus shale play**



Notes: mcm = million cubic metres; m^3/d = cubic metres per day.

Sources: IEA analysis based on Rystad Energy AS.

Finding the sweet spots

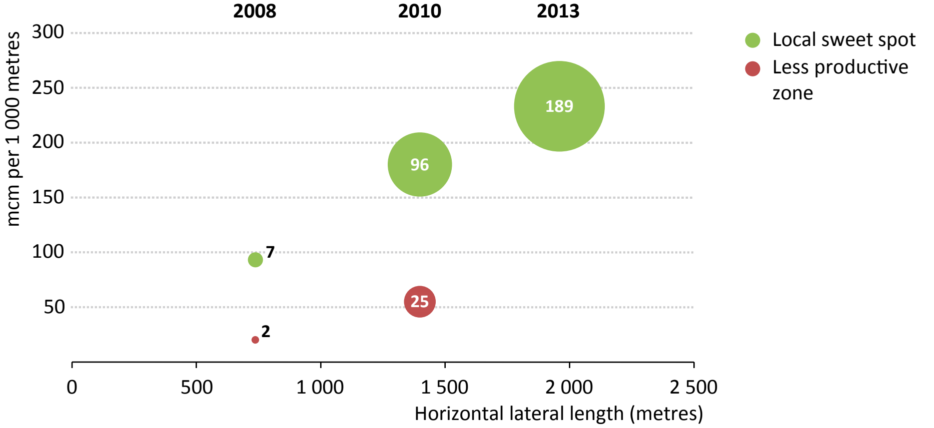
While well design and completion technologies are important, the decision on where to drill in the first place is arguably even more critical. The choice of well site has to be conditioned by considerations above the ground, so as to minimise impacts on the local community and ecology, but it is naturally driven by sub-surface factors, as getting the location right is a key driver of well results and profitability. Since there is very wide variability in conditions and performance across and within shale plays, a concerted effort is required to understand the geology, its natural fractures and faults, with a view not just to maximise production, but also to identify features that could create higher risks of earthquakes or of fluids passing between geological strata, i.e. the areas to avoid.

For dry gas[4] plays, the combination of depth, shale thickness, brittleness, pressure, the presence of organic carbon and its exposure to heat and pressure over time, the concentration of natural gas, tectonic stresses and geological faults are the key parameters affecting the play's quality and thus its economic viability. With the aid of increasingly sophisticated seismic mapping techniques and a broad scientific research effort analysing the behaviour of unconventional plays, companies are generally getting better at understanding the nature of shale plays and predicting their performance. That said, once promising areas have been identified, there is still no substitute for "learning-by-doing", i.e. the knowledge that comes from drilling and completing wells. The ability to identify the so-called sweet spots quickly and to focus activity on the most productive locations has been an essential buttress to the resilience of US shale gas production.

4. Gas with a low content of natural gas liquids.

To illustrate this process, we compared well results for two counties in Pennsylvania in the eastern United States, one of which emerged as a significant sweet spot for shale gas production, while the other looked promising and generated interest but proved not to be economic. Starting from 2008, drilling commenced in both areas and operators increased lateral well lengths. As more wells were drilled, operators gathered more data and learned which areas to avoid and which to concentrate on, a process that is illustrated by the evolution of the well count (Figure 6.8). The speed at which this process takes place has been greatly accelerated by the competitive structure of the US upstream industry and the fact that certain drilling and production data, reported to the state regulators, is publicly available and enables a rapid understanding of the geological parameters of a shale play.

Figure 6.8 ▷ **Estimated ultimate recovery per unit length of lateral section and drilling intensity in selected areas of the Marcellus shale play**



Notes: mcm = million cubic metres. The bubbles denote the number of wells drilled per year. The horizontal lateral length is an average for the Marcellus play as a whole. No wells were drilled in the less productive zone in 2013 as operators had learned that this area is not a sweet spot and development stopped.

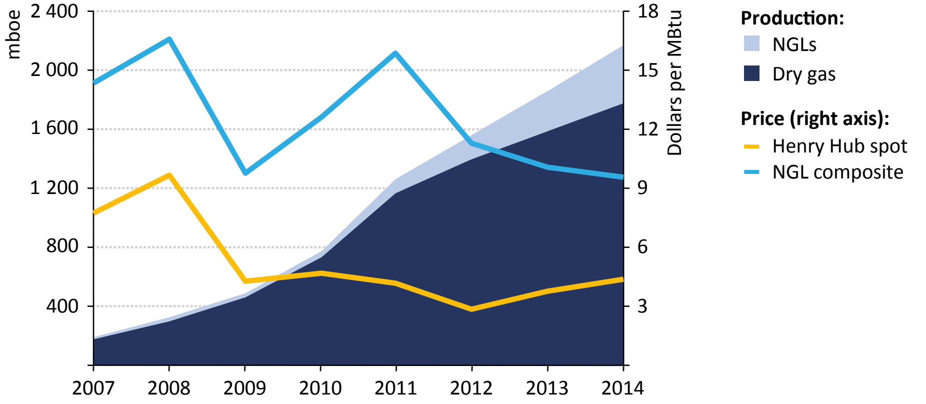
Sources: IEA analysis based on Rystad Energy AS.

Switch to liquids

Some of the promising earlier shale gas plays in the United States, such as Haynesville and Fayetteville, mostly contain dry gas. When natural gas prices fell to around $2/MBtu in 2012, many dry gas projects became uneconomic. However, plays containing wet gas, i.e. gas with a higher content of natural gas liquids (NGL), remained attractive. These liquids sell at a discount to conventional crude, but still commanded a price (on an energy equivalent basis) in the range of $10-16/MBtu through to 2014 (Figure 6.9).

The switch towards liquids-rich gas plays was a particularly important factor behind the rise of production in the Eagle Ford play and more recently, in the Utica play, which is a deeper shale below the Marcellus. Due to the high level of drilling activity in plays like the Eagle Ford, the dry and wet gas boundaries are quite well understood and operators can even tune their drilling programmes in response to changes in the spot gas and NGL prices. The rise in tight oil production also meant a surge in associated gas produced from unconventional oil wells (if more than 50% of the energy content is in liquid form, a well is considered to be an oil well). In these cases, the commercial justification for a well is, typically, determined entirely by the value of the liquids and gas is regarded as a free by-product at the well-head; the only costs involved in marketing the gas arise from separation, processing and providing infrastructure (where necessary) to bring it to market.

Figure 6.9 ▷ Dry gas and NGLs production for the main US shale plays



Notes: NGL composite = natural gas liquid prices volume-weighted on the basis of various NGL products; mboe = million barrels of oil equivalent.

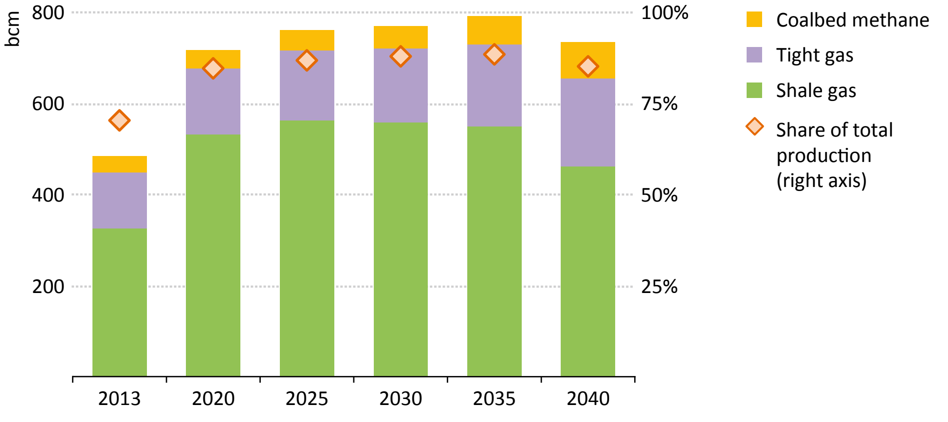
Sources: IEA analysis based on Bloomberg, US DOE/EIA and Rystad Energy AS.

The fall in the oil price since late 2014 will continue to test the resilience of US shale gas production, with the reduced value of the liquids pushing more drilling locations into marginal economic territory. This is likely to force a degree of consolidation in the upstream, with operators having high debt and poorer acreage under increasing pressure to sell their assets. All else being equal, the decline in oil prices could also have been expected to exert upward pressure on US natural gas prices, so as to rebalance the incentives required to stimulate production. However, all else has not been equal, and the fall in liquids value has been counter-balanced – at least in part – by a fall in upstream costs (see Chapter 3). The test for shale gas from the combination of low gas and low oil prices is still underway, but, thus far at least, production has continued to hold up well.

Long-term outlook for US unconventional gas

The United States is expected to remain the largest global unconventional gas producer for the duration of our *Outlook* to 2040, with the output trajectory defined in large part by shale gas. Given that only around 10% of the estimated recoverable shale gas resource has thus far been produced, there is no sign as yet that the shale storm is about to subside: in our projections, shale gas grows from current levels of around 420 bcm as of mid-2015 (324 bcm for our base year of 2013) to a peak level around 570 bcm in the 2020s, before tailing off in the 2030s to reach 460 bcm in 2040 (Figure 6.10). If output of tight gas and coalbed methane is included, this means that unconventional gas rises to more than 85% of total US gas production by the 2020s.

Figure 6.10 ▷ Unconventional gas production by type in the United States in the New Policies Scenario



Although there are still significant uncertainties over the outlook for shale gas, the economic calculation at the heart of the shale gas boom remains a very simple one. Most of the production from a well is produced within the first couple of years (because of the high decline rates), so discount rates do not matter greatly: what does matter is that the value of the recovered gas – and liquids – per well exceeds the cost of drilling and completing the well. As the United States works through its shale gas resource base, operators will be forced to move away from the sweet spots to less productive zones. At a certain point, the volume of gas recovered per well will begin to decline. The concentration on liquids-rich gas resources will also mean that wet gas areas are depleted more quickly, with a resulting move back towards drier gas production.

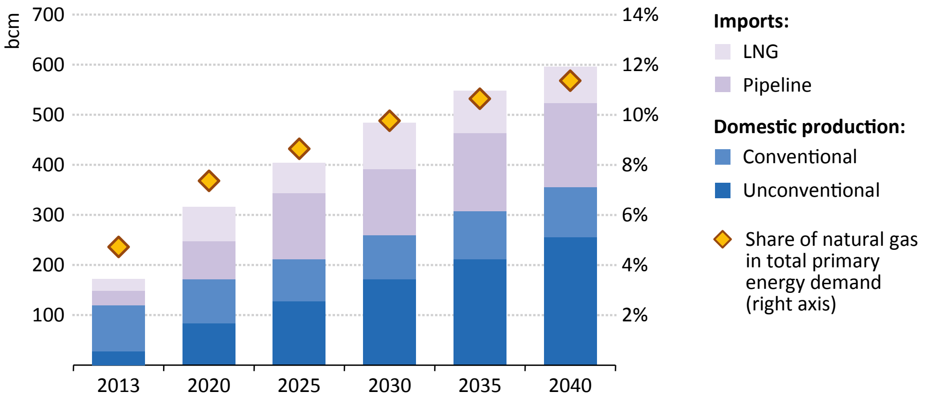
The effect of these factors on the economics of shale gas production is offset by continued technology learning that cuts the costs of drilling and completion and increases recovery per well (for example, via improved detection of potentially productive areas and more precise placement of wellbores and fractures). However, it is likely that the easiest and most dramatic of these technology gains have already been captured and we assume that the rate of improvement is set to slow. In our projections, the effects on productivity of moving to second- and third-tier parts of the unconventional resource base outweigh technology-based cost reduction. This increases the breakeven prices for shale gas production, requiring a steadily higher natural gas price in the United States, which accordingly rises gradually in the New Policies Scenario to reach $7.5/MBtu by 2040. Ultimately, this produces a plateau in shale gas production in the 2030s, and then a subsequent decline, as US shale gas starts to lose its competitive edge against other sources of gas.

There are many uncertainties over this trajectory, notably the size of the resource and the extent of the sweet spots. Additionally, while our modelling incorporates technology learning, it does not include technology breakthroughs that could have a dramatic impact in holding back the evolution of costs: the pace of innovation could spring a surprise (for unconventional gas, as for other fuels and technologies).

Unconventional gas in China: a long wait for take-off?

The shale gas storm has not yet made landfall in China, and – if and when it arrives – it may not come with the same intensity. A push for more gas in China's energy mix remains high on the government's policy agenda, but the role that China's unconventional gas resources will play in the expansion of gas use is far from certain. In 2005, China's total gas use was only around 50 bcm, representing around 2% of China's total primary energy demand. From 2005 onwards, gas use has grown in line with a policy push to diversify the energy mix and to supply cleaner energy to rapidly growing cities already struggling with polluted air, and demand has grown spectacularly (although the rate of growth slowed noticeably in 2014, see Chapter 5). Supply has come mostly from China's conventional gas, supplemented by a growing volume of pipeline and LNG imports (making up around 30% of Chinese gas demand in 2013) (Figure 6.11). Unconventional gas production has reached around 30 bcm, 25% of total gas production, mostly tight gas and coalbed methane along with smaller contributions from shale gas and coal-to-gas projects.[5]

Figure 6.11 ▷ Natural gas balance in China in the New Policies Scenario



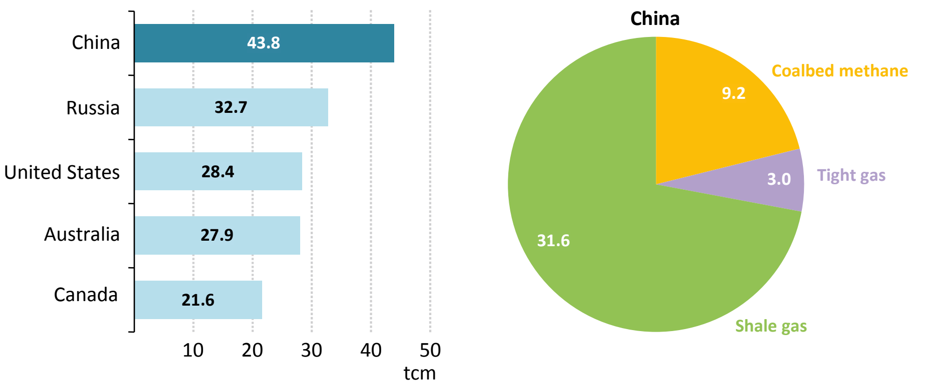
The prospect for unconventional gas growth in China is one of the major uncertainties facing global energy markets, both in the medium and longer terms. Gas demand is projected to grow rapidly to 315 bcm in 2020 and to exceed 590 bcm in 2040, by which

5. Definitions for tight gas, as well as data, vary widely by country and source. Chinese sources reported 30 bcm of tight gas production in 2014, higher than our figure of 17 bcm (which we adjust in line with our definition of tight gas, i.e. requiring large-scale stimulation via hydraulic fracturing). See also Figure 6.14.

time it would meet about 11% of the country's energy needs. With conventional gas output projected to stay at between 80 bcm and 100 bcm per year in our *Outlook*, unconventional gas supply, especially from shale, will need to grow rapidly if China is to keep imports within a moderate range. In the projections of the New Policies Scenario, gas imports rise to 140 bcm by 2020 and 240 bcm by 2040. If unconventional gas falls significantly short of the level we project in 2040, or alternatively exceeds it by a distance, this would have a major impact on gas markets, both in the Asia-Pacific region and globally, as well as on trade in other fuels, notably coal. It would also have important implications for China's drive to improve air quality and cap the growth in carbon-dioxide emissions.

Resource estimates vary substantially (and will only become clearer once China develops a production history), but all the information available thus far points to China's unconventional gas resources being among the largest in the world. The estimate used for our projections is of a recoverable resource base of 44 tcm[6], almost three-quarters of which is shale gas, with coalbed methane accounting for most of the balance (Figure 6.12). By comparison, China's remaining conventional gas resources are estimated at 6.3 tcm. China's shale gas resources are contained in seven major basins, but over half is in the Sichuan Basin, with another fifth in the Tarim Basin in western China (Figure 6.13). Coalbed methane is located in nine major basins, of which the Ordos Basin and the Qinshui Basin in south-eastern Shanxi province are the focus for commercialisation efforts.

Figure 6.12 ▷ Remaining technically recoverable unconventional gas resources in China and selected countries (tcm)



Sources: IEA analysis, BGR (2014), US DOE/EIA/ARI (2013).

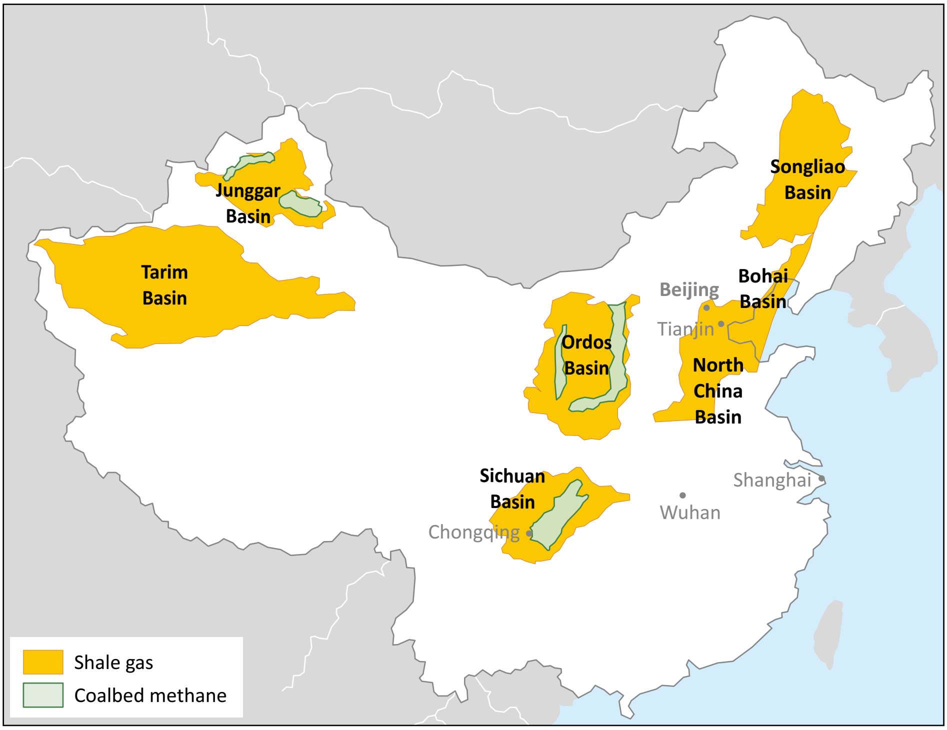
6. We use the US Energy Information Administration / Advanced Resources International (US DOE/EIA/ARI, 2013) estimate for recoverable shale gas resources in China to be consistent with our methodology for other countries. However, other sources provide very different estimates. For example, EIA/ARI estimates 17.8 tcm technically recoverable shale gas resources in the Sichuan Basin, while the USGS estimates 0.67 tcm (USGS, 2015); 96% lower than EIA/ARI. The USGS removes the most faulted portions of the basin and so estimates an area that is around 25% smaller than EIA/ARI; USGS also assumes an average EUR between around 10 and 25 million cubic metres per well, low in comparison to most of the currently-producing US shale plays. The total EIA/ARI estimate for China is also around 25% higher than that from China's Ministry of Land and Resources. The difference between these two estimates has little bearing on our projections as the volume of produced gas to 2040 is in both cases only a small fraction of the total.

Policy environment and production outlook

The outlook for unconventional gas in China depends upon the answer to some broader questions about the development of China's gas sector, with the most important regulatory aspects concerning who has access to the resource, whether and how these producers then have ready access to infrastructure to market their output, how gas is priced and whether there are any specific subsidies offered to support unconventional gas.

Shale gas has a special status within the Chinese regulatory framework: it was designated in 2011 as a separate mineral resource from natural gas and so some of the constraints that apply to conventional gas, and indeed to tight gas and coalbed methane, do not apply. Private companies may now bid in licensing rounds for shale gas development rights whereas, in the case of other gas resources, these rights are reserved to a handful of state companies (of which China National Petroleum Corporation [CNPC], Sinopec and China National Offshore Oil Company [CNOOC] are the most important) and their joint ventures. However, CNPC and Sinopec already hold extensive shale gas rights in what are widely understood to be the most prospective areas.

Figure 6.13 ▷ Main unconventional gas resources in China



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

China has a large and rapidly growing gas pipeline network; currently, the bulk of large-scale transmission lines are operated by CNPC, also the country's largest gas producer. Regulated third-party access to this large pipeline network is being considered as part of a broader package of gas market reforms in China: if experience from other countries is any guide, it would appear to be essential if other producers are to make inroads in unconventional gas.

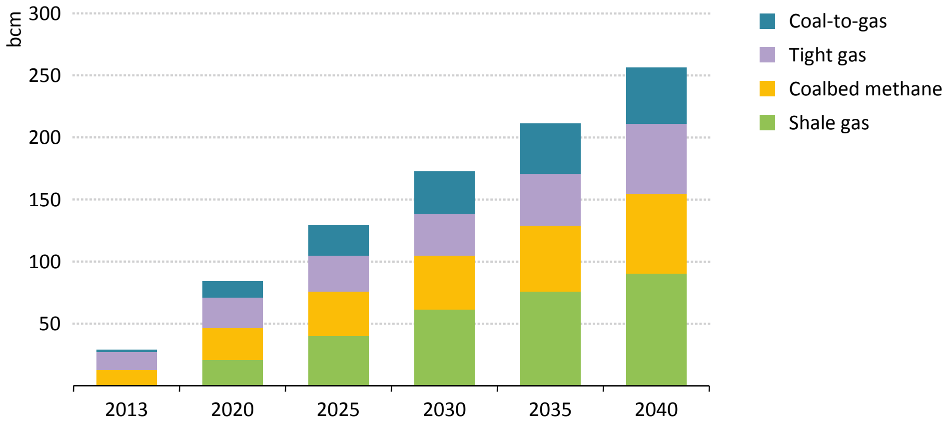
Gas pricing in China consists of an elaborate patchwork of arrangements for different sources and end-users. But a series of price reforms are underway that aim to consolidate these arrangements into a national pricing system, with separate provisions for each different category of user and a general link to a basket of oil and liquefied petroleum gas (LPG) prices. This process is far from complete, but with non-residential gas users seeing prices ranging from \$11/MBtu to \$15/MBtu in 2015, there are price signals emerging that could offer a substantial incentive to invest in domestic supply. In the case of shale gas, the government has made it clear that the sale price is not and will not be regulated and that shale gas producers and buyers are free to determine a price by direct negotiation (although the absence of guaranteed third-party access to the pipeline network limits the application of this right in practice).

There are specific policies in place to encourage both shale gas and coalbed methane production. In 2012, a shale gas subsidy of yuan renminbi (CNY) 0.4 per cubic metre (m^3) (\$1.8/MBtu) was offered although in 2015 it was announced that this would be reduced to CNY 0.2/m^3 (\$0.9/MBtu) by 2020, with no commitment to provide support beyond this date. Coalbed methane subsidies have been in place since 2008 at CNY 0.2/m^3 (\$0.9/MBtu) and are supplemented in some areas by schemes offered by the provincial government.

In the New Policies Scenario, taking into account China's announced policy intentions, we assume gradual moves towards more market-based forms of pricing, including fewer categories of end-user pricing and the emergence of producer prices (and provisions for access to market) that reassure potential upstream investors. Despite the partial loosening of licensing conditions for shale gas, we do not build into our projections any major liberalisation of access to China's resource base, but assume that the national oil and gas companies, together with their chosen partners, continue to have a stronghold over the best acreage.

Broken down by category, our *Outlook* for shale gas production in China is again revised down in *WEO-2015*, in line with the limited pace of progress on the ground, although our projection of around 90 bcm in 2040 still makes shale gas the largest source of unconventional gas output in China (Figure 6.14). The projected 2040 level of Chinese shale gas production is about one-quarter of current shale gas production in the United States. Tight gas (which in China is considered a "difficult" sub-set of conventional gas), coalbed methane and coal-to-gas projects all produce between 45-65 bcm by 2040.

Figure 6.14 ▷ Unconventional gas production in China by type in the New Policies Scenario



Shale gas

Given the size of the resource, shale gas has the greatest potential to transform China's gas production landscape. However, despite strong government support and the drilling of some 450 wells by the end of 2014 (among them about 300 vertical exploration and 150 horizontal appraisal and production wells), production growth has been relatively slow and only one field is producing commercial quantities of shale gas. The Fuling gas field in Sichuan, operated by Sinopec, achieved a production level equivalent to 1.3 bcm/year in early 2015; it is aiming for an eight-fold production increase, to an annual output of 10 bcm/year, by 2017. This field has favourable geology; but other prospects in the Sichuan Basin are proving harder to commercialise, with lower flow rates. Another basin with considerable potential is the liquids-rich Junggar Basin, north of Urumqi in far western China. Resources here are estimated at 12 billion barrels of tight oil and 1 tcm of shale gas. In theory, the higher liquids content could offer an easier path to commerciality. However, while some aspects of the geology are favourable (such as moderate depths and high total organic content) high clay content might limit the effectiveness of hydraulic fracturing.

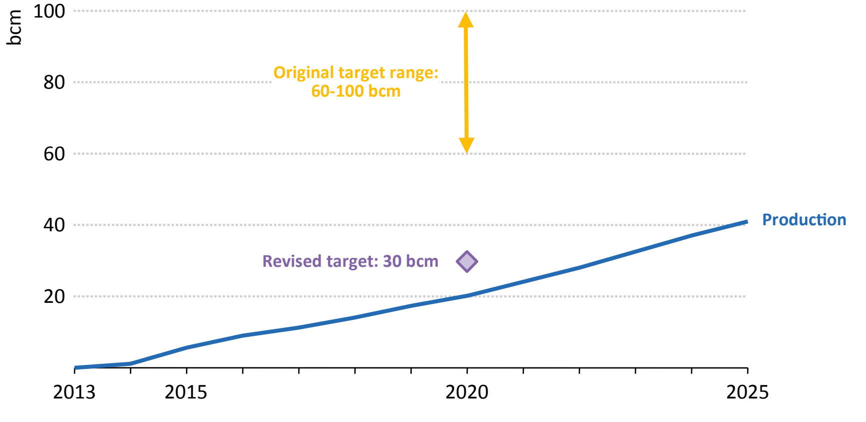
As the example of Fuling suggests, the immediate future of shale gas development rests, in practice, with the large national oil companies, notably CNPC and Sinopec. They have the exploration rights to the shale gas blocks with the most favourable geology and infrastructure; their financial strength and wide-reaching positioning along the value chain is also an asset, as is their significant experience in developing tight gas. They have also sought out technological experience in unconventional gas, both through investments in North America and through partnerships in China with international companies.[7]

7. The co-operation between Shell and CNPC in Fushun-Yongchuan remains China's only shale gas production sharing contract, although co-operation with Hess (and Petronas as non-operating partner) is making progress at Rongchang North. A number of other joint study agreements, between CNPC, Sinopec or CNOOC and companies including BP, ConocoPhillips, ExxonMobil and Chevron, expired without any follow-up.

The route into shale gas for other companies was mainly the second licensing round, held in late-2012. This awarded 19 out of the 20 blocks offered, reflecting a successful effort to attract a wider spread of participants. However, many of the participants were Chinese coal and electricity companies with little experience in complex unconventional gas technologies; and progress in these blocks has, in practice, been very slow. China's national oil companies did not receive any acreage: their lack of engagement in this round has been seen as a judgement on the quality of the blocks on offer.

In mid-2012, national targets for shale gas output were set at 6.5 bcm by 2015 and 60-100 bcm by 2020. Late in 2014, slow progress in expanding shale output saw the 2020 target revised downward radically to 30 bcm by 2020, as shale production in 2015 may struggle to reach the targeted 6.5 bcm (Figure 6.15). Even these lower levels appear challenging at the current rate of progress: achieving 30 bcm of production by 2020 would require drilling and completing some 3 000 to 4 000 wells on more than 400 to 600 separate sites between now and 2020. This equates to drilling on average 500 production wells per year, a significant step up from current levels. The outlook that we project in the New Policies Scenario is consistent with a gradual increase in activity concentrated in the Sichuan Basin.

Figure 6.15 ▷ Shale gas targets versus production to 2025 in China in the New Policies Scenario



Coalbed methane

Production of coalbed methane has increased steadily over the last decade to reach some 13 bcm in 2013. Output is derived predominantly from underground in-mine extraction (also known as coalmine methane, which is drained primarily for safety reasons and of which only a portion is used for consumption); but surface extraction techniques, of the sort seen in Australia, Canada and the United States, are also on the rise. Fracturing has been used widely, but productivity remains low. Activity is concentrated in Shanxi province (the Ordos Basin, which cuts across five provinces, including Shanxi, and the adjacent Qinshui Basin also in Shanxi), although the central government has recently expanded its exploration focus towards the Xinjiang autonomous region in the west. Production rights have been granted to only a handful of Chinese state companies (CNPC, Sinopec and specialised companies, such as China United Coalbed Methane and Henan Coalbed Methane). These companies have, in some areas, concluded production sharing contracts with private and international partners. Initially, these involved major international companies[8], but in the early-2000s these contracts were largely passed on to smaller players.

The targeted output of 30 bcm of coalbed methane production in 2015 (split in roughly equal parts between underground and surface extraction) seems unlikely to be reached. The reasons are a mixture of geological and technical challenges related to the resource, but also a range of policy issues above ground that complicate the extraction process and dull the commercial incentive to produce. Many of these above-ground issues are common also to shale gas, but there are some specific to the coalbed methane sector, not least of which is the difficult task of co-ordinating coal mining and coalbed methane activities. One aspect of this is that the national authorities issue coalbed methane licences through the Ministry of Land and Mineral Resources, while provincial authorities approve coal extraction plans, which can lead to disagreements over respective rights.

6

Other unconventional supply

Our estimate of tight gas resources in China is large at 3 tcm, although estimates vary. The Ministry of Land and Mineral Resources quotes 12 tcm. This may be due primarily to methodological differences, as it is always challenging to define precisely the boundary between conventional and tight gas resources. What is not in dispute is that the Ordos and Sichuan basins hold the bulk both of these resources and of current output. Production is led by CNPC at the Sulige field in the Ordos Basin, the largest gas field in China and a major factor in the recent expansion of gas output. This indicates that the technologies for this type of gas extraction – including horizontal drilling and hydraulic fracturing – are relatively mature in China, a supportive indicator for future unconventional gas production.

An additional unconventional component to the Chinese gas supply picture comes from coal-to-gas projects. Five projects are operating, with as many as 65 projects proposed. However, plans for many more full-scale projects are being re-thought at a national level, with both technical and economic performance being questioned. Provincial governments can be expected to continue to press for plants that convert coal to chemicals, including gas, because of their regional benefits. However, water constraints, as well as economic and other environmental considerations related to emissions and local pollution, are likely to slow development (particularly if China wishes to reduce further the carbon intensity of its energy economy).

8. The first of these was between China United Coalbed Methane Corporation and Texaco (subsequently Chevron) in 1996.

Barriers to unconventional gas supply

While Chinese unconventional gas resources are abundant, and some promising strides have been made in their exploitation, the growth in unconventional gas output has not matched the dramatic rise seen in North America, nor does it seem likely to do so very soon. Our projection of steadily increasing unconventional gas production rests in part, on the assumption that the Chinese authorities will make strong efforts to develop a domestic resource that can help achieve a number of important energy security and environmental goals. Given the overall size of the resource, there is clearly upside potential to this projection, but there are considerable downside risks as well. A poorly designed policy and regulatory framework could easily hold back unconventional gas activity, either because it fails to offer sufficient incentive to develop the resource in the first place, or because it does so without addressing important environmental and social hazards. Policy-related issues can be resolved with sufficient time and political will, but there are also potential constraints arising from the quality (rather than quantity) of China's unconventional gas resource, from population density and from water availability, which could represent more fundamental and longer lasting obstacles.

At the policy level, gas market reform is critically important. With subsidies for shale gas production on the way down, producers need reliable market-based signals to guide their upstream investment decisions. In cases where independent companies have the right to produce, as with shale gas, they also require assurance that they will be free to market their output to end-users via the pipeline network: the availability of a well-developed pipeline network to both established and new producers has been an important success factor in the North American gas revolution. But there are also policy questions that are specific to the Chinese unconventional gas sector, notably whether China will wish to generate more competition upstream by making better acreage and data available to private players in future shale gas licensing rounds. This would in all probability mean requiring the main state companies to relinquish some of their existing blocks to catalyse some of the rapid "learning-by-doing" that has characterised unconventional development in North America.

There are aspects of China's upstream regulation and its production sharing contracts that are ill-suited for shale gas or coalbed methane operations. Conventional oil and gas developments generally follow a fairly well-defined sequence from exploration, through appraisal and development to production; but the distinctions between the phases of an unconventional development can be much less clear-cut. At any given time, an operator may wish to explore or appraise one part of a license block, develop another part and produce from a third, all with a degree of responsiveness and flexibility that is near impossible to capture in a classical field development plan that is approved in advance.

The absence of a tailored regulatory regime for unconventional gas extends to some social and environmental aspects, as public acceptance issues comparable to those seen in other countries can be expected, especially where population density is high, such as in

Sichuan, or where pressures on water availability are apparent.[9] Regulations need to be adapted carefully to local conditions, including the geology and hydrology, and to take account of the technologies deployed. Nevertheless, there would appear to be much that the Chinese authorities could usefully draw from other countries' regulatory approaches, including an outright ban on the use of certain chemicals, green completions to limit methane emissions, no-fault water standards to protect existing water users and treatment guidelines for produced water from coalbed methane operations. Considering water use on a regional or cumulative basis, across an entire basin, would also seem to be important in the Chinese context. However, while water use policies are determined nationally, responsibility for management and enforcement is at provincial and local levels and, given the large number of different entities involved, the type of co-ordination required at basin level will be difficult to achieve. While national standards exist for maximum discharge concentrations in wastewater, it is by no means clear that these are suitable for large-scale shale gas or coalbed methane operations.

Moving beyond the policy issues, the location and geology of both shale and coalbed methane deposits in China appear to offer greater challenges than in North America.[10] Sichuan province, home to the most promising shale gas resources and much of the current activity, is difficult terrain for intensive drilling: hilly, densely populated and heavily cultivated. And while the majority of the shale gas plays were deposited in marine environments and thus have reservoir properties often not too dissimilar from North American shale gas plays, several key geological differences are known to exist:

- Many shale gas plays are heavily faulted and some are tectonically active. This not only provides a challenge for the placement of the wellbores, but heavy faulting may also have allowed the trapped gas to escape over time, resulting in lower densities of gas-in-place and thus lower ultimate recoverable volumes per well. Moreover, the total organic content, i.e. a measure of a shale rock's propensity to generate hydrocarbons and function as a source rock, is lower in many of the Chinese shale basins than in many of the main North American plays.
- Many of the Chinese plays are located deeper than those in North America, which creates additional technical challenges as well as requiring longer drilling times, pushing up costs: some of the initial Chinese shale wells took months to drill versus days or weeks in the United States.

9. The environmental issues associated with coal-to-gas projects need to be distinguished from those relating to other forms of unconventional gas, as this technology has a much larger environmental and carbon footprint. The lifecycle greenhouse-gas emissions are roughly seven-times those of conventional natural gas; the production process emits hydrogen sulphide and mercury that, if not properly scrubbed or treated, are potentially harmful; the process is also very water intensive, requiring 6-12 litres of water per m^3 of produced gas, compared with 0.1-0.2 litres of water per m^3 for shale gas production (Yang and Jackson, 2013).

10. The Sichuan Basin, believed to hold more than half of China's shale gas resources, and home of the Fuling field, has been the focus of more detailed appraisal, but other basins remain to have detailed geological work performed.

- Only two of the seven Chinese plays, namely the Junggar and Songliao basins, are known to contain liquids-rich gas, so the potential economic benefit that can arise from drilling wet (or NGL-rich) portions of the plays is limited. In addition, the Junggar and Songliao basins are clay-rich, which reduces the brittleness and thus makes hydraulic fracturing less effective as a production stimulation technique.

Coalbed methane suffers from similar geological challenges. Multiple periods of coal formation, complex geological structures for most formations, a high degree of reservoir heterogeneity, and highly variable coal seam permeability make for complex and difficult coalbed methane extraction. These geological features may limit the return from applying horizontal drilling and more advanced stimulation technologies.

Drilling costs in China also remain significantly higher than those in North America. Early horizontal wells drilled in 2011-2012 cost around CNY 80-100 million ($13-16 million). Costs have since dropped to CNY 50-70 ($8-11 million) and drilling times shortened by half to around 70 days, but these costs still compare unfavourably with North American best practice (for more complex wells) at around $7 million. For coalbed methane, vertical wells are shallower and cheaper, at CNY 2-4 million ($0.3-0.7 million), but productivity is low and decline rates rapid. China would need high activity levels to generate the economies of scale that could bring costs down much further. Failing that, unconventional gas will struggle to compete with gas imports and also with other domestic sources of energy, including some renewable sources.

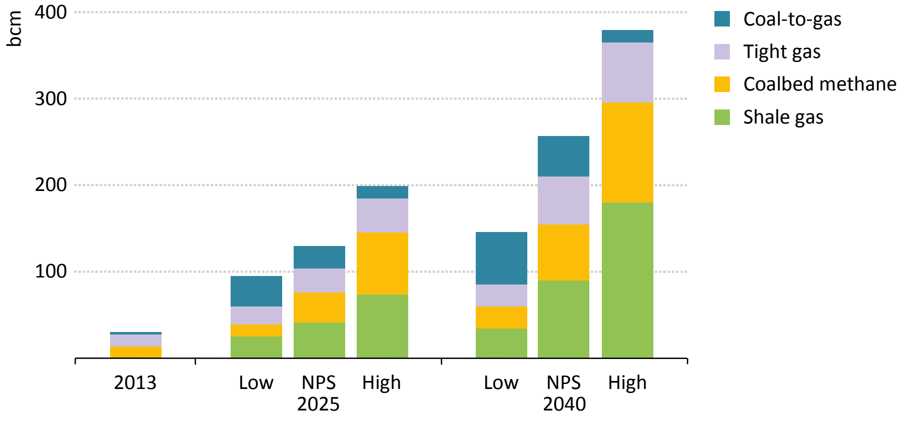
A final consideration, but by no means the least significant, is water. Much of the unconventional resource is located in water-stressed regions (notably the northwest and northeast of China). Water availability may well prove to be a barrier to the rapid expansion of unconventional gas output, especially for shale gas. This highlights the importance of applying the best practice techniques seen in North America, such as recycling of flow-back water, minimising freshwater inputs and minimising use of potentially toxic compounds in well stimulation.

Implications for China and global gas markets

The New Policies Scenario outlines a plausible path for China's unconventional gas production in the years to come, based on its energy needs and policy intentions, anticipated international and domestic prices, the nature of the underlying resource and the challenges associated with resource development. But, as discussed in the previous section, there is a large degree of uncertainty over this projection. On one hand, China has an admirable record of addressing its energy challenges in a way that unlocks rapid growth – unconventional gas might be no exception. On the other hand, the various difficulties (geology, water availability, population density and the transformation implied for China's gas sector) could prove to be too great to allow unconventional gas in China to take off.

In the remainder of this section, we explore what a range of possible outcomes for China's unconventional gas might mean for China itself and for regional and international markets. We do this by setting illustrative low and high trajectories for unconventional gas production in China in 2025 and 2040, on either side of our New Policies Scenario (Figure 6.16). The low case is based, into the 2020s, on a bottom-up assessment of projects that are either underway or considered very likely to go ahead, but with minimal additions; in the case of shale gas, this implies that activity remains confined to limited areas of Sichuan province. The high case is based on an optimistic but reasonable set of assumptions about the pace at which unconventional gas production could accelerate (the rate of growth remains well below the levels seen in the United States, reflecting the relatively slow pace of development in China over the past three years).[11] In the case of shale gas, it would imply much more extensive drilling activity across the Sichuan Basin, as well as activity in at least one of the other prospective areas.

Figure 6.16 ▷ Indicative range of unconventional gas production outcomes by type in China



Note: NPS = New Policies Scenario.

Although it could be assumed that all of the different components of China's unconventional gas production move in step (i.e. all moving higher in a high case, and vice versa), in practice the outlook for coal-to-gas projects could well be counter-cyclical to the outlook for extractive unconventional gas output. For the purposes of this analysis, we assume that coal-to-gas projects are pushed ahead more rapidly by policy-makers in a case where unconventional gas extraction is unsuccessful, in order to compensate in part for the gap in the Chinese gas balance. The reverse is also assumed to be true: in a case where unconventional gas extraction goes ahead more rapidly, the economic and policy rationale for coal-to-gas projects is diminished.

11. The high assessment is slightly below the level modelled in the *WEO* "Golden Rules Case" for China (IEA, 2012), which had 390 bcm of unconventional production in 2035.

The range between the low and high assessments in 2025 amounts to more than 100 bcm; the similar range in 2040 is almost 240 bcm. If China's shale gas, coalbed methane and other resources were to be available in volumes around the high assessment, instead of the projection in the New Policies Scenario, the implications could include:

- Higher penetration of gas in China's energy mix, mainly through an increased use of gas in industrial and power use; if all of the additional gas were to substitute for coal in China's energy mix, this would reduce China's cumulative carbon-dioxide (CO_2) emissions to 2040 by approximately 3.4 gigatonnes (Gt), which is slightly more than the current annual CO_2 emissions of the European Union.
- Reduced emissions of local pollutants, relative to the New Policies Scenario, albeit at the risk – if not properly addressed by regulation – of higher social and environmental impacts on communities living in areas of unconventional gas development.[12]
- A reduced need for gas imports (accompanied by a reduced need for coal imports, to the extent that the additional gas replaces coal in the domestic mix). If these reductions occur at a pace higher than that expected by international market players, there could be a substantial weakening of international prices for coal and gas (or a significant prolongation of the market conditions already envisaged to 2020).[13]
- The acceleration in gas production growth, plus the attendant conditions that support it, such as pricing reform and third-party pipeline access, would accelerate the development of hub trading for gas in China. This could facilitate, in turn, the early emergence of a reliable market-based reference price for the Asia-Pacific region.
- The technology and techniques developed for China's geological and social conditions, and the knowledge derived, may be deployed elsewhere, enhancing the spread of unconventional output globally.

The inverse situation, in which shale gas, coalbed methane and other sources of unconventional gas fail to take off, leaving unconventional gas production around our low mark, would have similarly dramatic implications. Lower gas use could be substituted in part by renewables, but could also lead to continued high reliance on coal as the backbone of domestic power supply, with higher emissions and coal imports as a result. There would be a greater call on imported gas, both by pipeline and as LNG. The path for China towards a lower emissions future would be more challenging. A coal-to-gas transition can be accommodated in China within the existing system; envisaging a switch directly from coal to renewables – while bringing more rapid benefits – would require a much more profound system transformation. Overall, the way that these high and low assessments diverge and the rapidity with which they lead to quite different outcomes for China, and for external markets, highlights how unconventional gas in China remains a major source of uncertainty in global gas markets, and indeed for energy markets as a whole.

12. This could include additional local stresses on water supply, although since gas would displace some coal production, also requiring large volumes of water, the aggregate impact on water use would be limited.

13. If the price of imports were to come down as a result, this could become a limiting factor for investment in new unconventional gas production in China.

Unconventional gas regulation: revisiting the "Golden Rules"

The rise in unconventional gas production in recent years – and its gradual spread beyond North America – has been accompanied by heightened attention, from operators, regulators and the public alike, to the implications of these operations (or potential operations) for local communities and the environment. The results have varied widely, even within the main currently producing countries: the United States, Canada and Australia. Elsewhere there has been a modest and gradual start to unconventional gas development in places as diverse as China and Argentina, with regulatory regimes evolving at a similar pace. In some countries, moratoria on unconventional gas development dating from earlier years remain in place, or have been extended and made more enduring, especially where population densities are high or water issues more critical.

6

Box 6.3 ▷ Seven "Golden Rules" for unconventional gas production

Golden Rules for a Golden Age of Gas: World Energy Outlook Special Report (IEA, 2012), argued that unconventional gas would only flourish as part of the global energy mix if some important hurdles were overcome, in particular the social and environmental concerns regarding its extraction. While the technologies and know-how to meet these challenges exist, a continuous drive from governments and industry would be required to improve performance and to maintain (or earn) public confidence. The alternative would be a political and social backlash. The report sets out seven key over-arching principles, or "Golden Rules", designed to guide policy-makers, regulators and industry in developing balanced, effective regulatory regimes for unconventional gas:

- Measure, disclose and engage, involving meaningful and timely engagement with local communities, establishing key environmental baselines before drilling and disclosure of key operational data, including on hydraulic fracturing.
- Watch where you drill, taking into account established settlement patterns and local ecology, plus key geological and hydrological factors, such as the presence of faults or water supplies and sources.
- Isolate wells and prevent leaks, through ensuring well integrity and preventing and containing surface spills.
- Treat water responsibly, by reducing freshwater use, and paying close attention to treatment, storage and disposal of waste water.
- Minimise air emissions, by reduced flaring, eliminating venting and careful attention to other emissions.
- Consider the cumulative and regional effects of large-scale drilling and production operations, especially for water.
- Ensure consistently high, ongoing environmental performance, with properly resourced regulators, encouraging performance-based regulation and full cradle-to-grave regulation.

The context for this discussion is a set of "Golden Rules" addressing the social and environmental aspects of unconventional gas development, first proposed in a *WEO* special report (IEA, 2012) (Box 6.3). In this analysis, three years on, we examine what experience has been gained in the intervening period – with thousands of new producing wells drilled – regarding the nature and scale of the hazards involved, what lessons have been learned, how regulators have responded, and whether the industry is closer now to gaining the prized "social licence" to operate in this area. We focus on the countries that have accumulated the greatest experience with unconventional gas development and its regulation: the United States, Canada and Australia.

The three countries examined in this section all have federal systems of government and regulation. In all three, primary responsibility for onshore oil and gas development, including unconventional oil and gas, is vested in the state or provincial governments, but important responsibilities are retained at federal level for some broader questions, such as water catchment areas, that have implications beyond state boundaries. The states/provinces in different parts of the United States, Canada and Australia have taken widely varying approaches to the exploitation of unconventional gas and therefore present an interesting cross-section of regulation, including outright bans on hydraulic fracturing in a number of areas. An important difference between countries is that in the United States, mineral rights are generally vested in the landowner. By contrast, in Canada and Australia (and many other countries), such mineral rights are vested in the provincial or national government.

United States

Oil and gas development in the United States takes place in 31 states, with many having unconventional gas production. Since 2008, shale gas production has accelerated markedly, with Texas (the Barnett and Eagle Ford) and, increasingly, Pennsylvania (Marcellus) the leading states (see Figure 6.4). At least half of the states involved in unconventional gas have introduced specific rules or legislation concerning unconventional gas, with a strong emphasis on regulation of the well stimulation processes, i.e. hydraulic fracturing. The federal government is directly involved in oil and gas regulation on federal lands. In addition, local municipalities have extensive powers over traffic management and noise, and have used these powers to oppose or, in some cases, block unconventional gas development.

While it is impossible here to summarise regulatory developments in all US states, a review of some key ones highlights several noteworthy trends (Stronger, 2015) (GWPC, 2015).[14] In Pennsylvania, for example, there has been a substantial increase in the resources available to the main regulator, the Department of Environmental

14. The State Review of Oil and Natural Gas Environmental Regulations (Stronger), a mostly federally funded non-profit review body, has conducted reviews of hydraulic fracturing practices in six states (Arkansas, Pennsylvania, Colorado, Oklahoma, Louisiana, and Ohio) and issued guidelines in this and other areas. The Groundwater Protection Council (GWPC) has also summarised the state of water-related regulation in 27 US states and highlights emerging issues as well as practices adopted by oil- and gas-producing states.

Protection, with funding increasing by a factor of four over the period 2010-2015 and around 250 staff now employed. The initial emphasis in regulation and enforcement was on well construction standards, such as surface casing and cementing, to meet increased stresses from fracturing and to minimise any risk of water contamination. The issue of wastewater disposal (and induced seismic activity caused by wastewater injection) subsequently became prominent (as deep-well disposal is not readily available in Pennsylvania) and the state has legislated to reduce freshwater withdrawals and to require treatment of water from hydraulic fracturing operations, through centralised treatment facilities, to achieve greater recycling.

Efforts to encourage best practices have also come from non-state bodies. The Pittsburgh-based Center for Sustainable Shale Development (CSSD) is a co-operative body designed to address regional issues in the Appalachian area, bringing together energy companies, environmental organisations and philanthropic foundations in an effort to promote higher and more uniform standards in the shale gas industry. The recommended standards are generally well above those of the relevant state or federal regulations: for example, under CSSD standards, operators who are net water users should recycle 90% of flow-back and produced water. None of the Appalachian states (Pennsylvania, West Virginia or Ohio) set such high standards in their current state regulation.

Texas accounts for around one-third of national output of both gas and oil. The Texas Railroad Commission, the state regulator, has been issuing more than 20 000 drilling permits per year in recent years, most of which were in one of the four major shale formations: the Barnett, Haynesville[15], Wolfcamp and Eagle Ford plays. Despite the long history of hydrocarbon production in Texas, unconventional oil and gas development has brought the oil and gas industry to new areas, including metropolitan and rural communities unfamiliar with this type of activity (the Barnett formation, for example, underlies the densely populated Dallas/Fort Worth area). As a result, Texas, like other parts of the United States with escalating unconventional oil and gas development, is experiencing conflicts between industry, property right owners, citizens, regulators and environmental organisations. The Texas regulatory system, although very well-established, has been modified in response: the Texas state legislature passed one of the first bills concerning the disclosure of chemicals in hydraulic fracturing fluids in 2011.

Immediately north of Pennsylvania is New York state and its southern portion is underlain by the prolific Marcellus shale formation. However, unlike the situation in its southern neighbour, in New York gas output is minimal and shale gas production is zero. An executive order from the governor of New York imposed a moratorium on hydraulic fracturing state-wide in 2010. In doing so, the governor cited findings of the New York Health Department that inadequate scientific evidence existed on the potential public health impacts (the Health Department had cited potential health risks, noting groundwater contamination in Wyoming and increased traffic deaths in Pennsylvania). A proposal to allow

15. The Haynesville play straddles the borders with Louisiana and Arkansas, so only part of the production falls under Texas regulations.

limited gas exploitation in parts of New York state adjoining the border with Pennsylvania (supported by many landholders in the area) was rejected. The moratorium is open-ended.

The US government has substantial powers over federal lands, which are mostly located in the west. Proposals for updating the regulatory framework for oil and gas drilling on these lands were issued for public consultation by the US Department of the Interior's Bureau of Land Management in March 2015. The proposed regulations focus strongly on measures to ensure well integrity, including best practices for casing and cementing, and on compulsory disclosure of the chemicals used in hydraulic fracturing on the website FracFocus.org. Initiatives by other federal agencies, notably the US Environmental Protection Agency (EPA), are also of direct relevance to the overall regulatory picture. A particularly important investigation, set to be concluded by the EPA in 2016, is an assessment of the potential impacts on drinking water resources of hydraulic fracturing (Box 6.4). A preliminary report was released for comment and review in June 2015, which tracked all elements of water use for hydraulic fracturing: water acquisition, chemical mixing at the well-pad site, well injection of fracturing fluids, collection of hydraulic fracking wastewater, water treatment and disposal. The preliminary conclusion shows that while hydraulic fracturing activities in the United States are carried out in a way that has not led to widespread, systemic impacts on drinking water resources, there are vulnerabilities in the water lifecycle that could have an impact on drinking water. The report seems likely to create a global standard for high quality in-depth research and regulation on impacts on drinking water, with national, and possibly global, implications.

Box 6.4 ▷ Can innovation alleviate concerns about water contamination and use?

Water use is one of the main areas of public concern with regards to unconventional gas production, in particular for shale gas. Regulations and best practice can go a long way towards alleviating those concerns. But can one do away with water use altogether in unconventional gas production?

In principle, yes: fracturing with propane as the fracturing fluid has been used, in particular in Canada. But because of the flammability of propane and the significant volumes that need to be pumped, safety measures are essential (for example, removing personnel from the well-head area during critical phases of the operation). This has limited its application to remote sites with low population density and poor access to water. Liquid carbon dioxide is another alternative fracturing fluid, but it is not used widely as it is not always readily available and its properties are not suited to all well conditions. A variant, using non-flammable fluoropropane, has been proposed. But this has yet to be tested and is likely to have significantly higher costs. Moreover, because of its high global warming potential, leaks of fluoropropane need to be carefully controlled. Other fluids are being investigated, but so far no serious candidate has emerged.

An alternative is to use less water, or to use water that is not required for other purposes. There are well-established technologies for fracturing fluids, such as foams, that can reduce water usage by more than 90%, but their use is limited by cost and logistics and they may involve higher volumes of chemicals, such as surfactants. All sedimentary basins, where shale gas can be found, have numerous deep underground sedimentary layers containing brine (salty water). This always offers an alternative to the use of surface or shallow aquifer water. This is particularly relevant in water-stressed areas, such as some of the shale gas basins in China. Formulation of fracturing fluids with salty water is now well-established. However, accessing those deep brine layers carries a significant cost and the industry has so far preferred to focus on the improved management of other sources of water, such as recycling or use of wastewater.

In addition to water use per se, public disquiet over the chemicals used in hydraulic fracturing fluid has been a major barrier to public acceptance of shale gas development. In 2011, the Ground Water Protection Council, a non-profit body of state water regulators, in conjunction with the Interstate Oil and Gas Compact Commission, established FracFocus – an online information system disclosing chemical use in hydraulically fractured wells. Under pressure from public opinion and environmental groups (which are pushing for more complete reporting of a wider range of data), the number of states requiring disclosure of fracking chemicals has risen steadily, from 14 in early-2013 to 29 in mid-2015, with the number of wells covered on the FracFocus site rapidly approaching 100 000.

Nonetheless, disclosure is incomplete, allowing some information to be retained as confidential business information. According to an analysis by the EPA of data from 2011-2012 (EPA, 2015), about 11% of the listed chemicals fall in the confidential category. Disclosure of information on the origin of the water used is generally voluntary: in the data analysed by EPA, the water source was disclosed for only 29% of wells. While FracFocus has significantly contributed to increasing the industry's transparency and encouraging the use of more benign chemicals – diminishing one of the many barriers to public acceptance – more scientific and regulatory work still needs to be done on the origins and composition of flow-back water, appropriate treatment technologies, the degree to which it needs to be treated, and the proper disposal method for the residual waste streams after the treatment process.

Canada

Canada is a major gas producer and exporter, and although conventional gas output has been declining in recent years, unconventional gas, from tight gas, coalbed methane and increasingly shale gas, has been on the rise. As in the United States and Australia, regulation is largely in the hands of the provinces/states, among which Alberta accounts for around two-thirds of Canadian gas output and British Columbia for almost a third. These two provinces have a long history of oil and gas exploitation, are generally sparsely populated and in some areas the land is owned by the provincial government, simplifying access issues. Shale gas is also found in other Canadian provinces, including Quebec, Newfoundland, the Maritime Provinces and the Northern Territories, but almost no unconventional gas is produced in these regions. Shale gas development in Quebec was halted in 2011 after some 30 exploration wells had been drilled. A report by Quebec's Bureau d'Audiences Publiques en Environnement (BAPE, 2014), on shale gas exploration and development in the St. Lawrence Lowlands, released in December 2014, concluded that shale gas exploration and development in the region using hydraulic fracturing would not be of net benefit to the province under prevailing conditions. The moratorium on shale gas development in Quebec remains in place. Elsewhere in eastern Canada, limitations on shale gas development have also been imposed. In 2014, New Brunswick enacted a one-year moratorium, which will not be lifted unless certain conditions are met. The government of Nova Scotia prohibited high-volume hydraulic fracturing in 2014 for onshore shale gas. The government of Newfoundland and Labrador announced in 2014 that it will not accept applications for petroleum exploration using hydraulic fracturing.

Regulation in the two provinces where unconventional gas is widely exploited is by the British Columbia Oil and Gas Commission and the Alberta Energy Regulator (AER). While there are some differences, their approaches to unconventional gas are broadly similar. The AER was formed in 2013, bringing together a number of pre-existing regulatory and environmental bodies: with a budget of around $300 million (100% funded by industry fees) and 1 200 staff, it is well-resourced but, nonetheless, has the broad task of regulating all aspects of the province's oil and gas industry, including conventional and non-conventional oil and gas and environmental issues, water allocation and permitting. AER has adopted many aspects of best practice regulation, including consideration of the cumulative impacts of the many projects under its jurisdiction. Many aspects of AER operations and regulations have been adopted by other provinces. AER has recognised the value of bringing together all operators in an area to collaborate on water management issues, surface infrastructure and public engagement. In British Columbia, the Oil and Gas Commission has similarly taken a basin-wide planning approach for the Liard Basin in the northeast of the province. Induced seismic activity has become an issue in British Columbia, a concern that it shares with areas as diverse as Ohio, Oklahoma and the United Kingdom (Box 6.5).

Canada's federal National Energy Board has authority to grant drilling permits on federal lands and a number of federal agencies have roles in assessing the environmental and public health impacts of shale gas development, including Natural Resources Canada, Environment Canada and Health Canada. Given that many issues are national in scope, the federal government has been promoting research into unconventional gas. One resulting report on the environmental impacts of shale gas extraction in Canada (Council of Canadian Academies, 2015) highlighted the current state of knowledge on water impacts, well integrity and emissions, including methane. It noted gaps in understanding about fracturing fluids and the interactions of such fluids under high pressures and temperatures. It discussed the very real problem of ultimate disposal of drilling-related liquids where deep-well disposal is unavailable. It found that the large scale of shale gas drilling, with its attendant social and environmental impacts, meant that cumulative, regional assessments must be carried out, especially where population density is higher than in traditional oil and gas-producing areas in Canada. Significant knowledge gaps were also identified, including in the technology for detecting and measuring methane leakage from large-scale developments (see Chapter 5).

Box 6.5 ▷ Observed seismic activity in Canada's Montney play

Since 2005, some 1 700 wells have been drilled in the Montney formation in British Columbia, almost all of them horizontal wells (BCOGC, 2014). The regulator requires that wastewater from these wells is injected into approved formations deep underground. Volumes of injected wastewater doubled from around 3 000 million litres in 2000 to more than 6 000 million litres in 2012, although the volumes have fallen back since then. Much of the increase is made up of flow-back liquids from hydraulic fracturing operations. The number of deep disposal wells has similarly increased from 89 in 2005 to 104 in 2014. Low level seismic activity led to the installation of an additional eight seismograph monitoring stations in 2012, to supplement the existing two stations.

The results of this monitoring showed that, in the 14 months to October 2014, 231 seismic events could be linked to gas operations. Thirty-eight events were attributed to wastewater disposal and the balance of 193 events to hydraulic fracturing. The Richter magnitude of the events ranged from 1.0 to 4.4 M_L. None of the events resulted in injuries, property damage or loss of wellbore containment and only 11 were actually felt at the surface, corresponding to 0.15% of all wellbore completions executed during the period of the study.

The British Columbia Oil and Gas Commission identified fault-zone avoidance and early flow-back of fracture fluids as the best mitigation techniques. Given that operators decide on the timing, early flow-back reduces the potential for fault activation by limiting the time that the rock is exposed to high pressure from the hydraulic fracturing process. For deep-well disposal, reduction of injection pressure can be effective, supplemented by closer scrutiny of the location of these wells, in particular where known faults are located, and possible extension of buffer zones. More intensive monitoring is underway, alongside research partnerships between federal bodies and local geoscience partners to study these inter-relationships further.

Australia

While Australia has only a minimal output of shale gas, coalbed methane is an established source of gas production, dating back some 20 years. Output had been constrained by a lack of markets, but the construction, and now operation, of three LNG plants based on coalbed methane output in Queensland, is changing this rapidly. The prospective increase in output will pose significant challenges to industry, regulators, governments and local communities. In considering these implications, a starting point is to recognise the important technical and geological differences between coalbed methane and shale gas production, all of which have significant regulatory implications (Box 6.6).

Box 6.6 ▷ What makes coalbed methane extraction different?

Compared with shale gas wells, coalbed methane wells tend to be much shallower, between 400-1 000 metres deep. They tend to be vertical wells and there is less recourse to hydraulic fracturing, which is estimated to have been used at only around 8% of wells in Queensland, although fracturing techniques may be applied to as many as 40% of wells in the future. But while injecting fluids is less common for the moment, coalbed methane does involve large-scale water extraction, leading to major issues of water treatment and disposal of unusable waste streams.

Reverse osmosis has emerged as the water treatment technology of choice, producing a water stream suitable for irrigation, other agricultural and pastoral uses, and even injection into depleted aquifers, provided the coal seam wastewater is purified to drinking water standard. However, approval for such "beneficial use" remains contentious. If beneficial wastewater options cannot be used, then the waste stream requires careful disposal into watercourses, such as streams or the ocean, provided it can be demonstrated that the environment is not adversely affected by the discharge. These issues, plus the location of the fields in relatively arid regions and the general sensitivity of water issues in Australia, make water management the key environmental concern.

As in the United States, primary regulatory responsibility in Australia lies with the states, which have adopted widely differing approaches to regulation, with the federal authorities playing a supplementary role. Queensland, the home of the three LNG plants, is the most advanced state both from a production and regulatory viewpoint. Many of Queensland's recent regulatory instruments focus on water regulation, culminating in a major regional underground water impact report for the Surat basin. A large-scale regional water monitoring network of more than 500 wells has been established, under the supervision of the Office of Groundwater Impact Assessment. The Office is industry-funded, through levies, and is carrying out long-term research and monitoring activities. These assessments enable potential water issues to be identified and addressed in advance of drilling.

In addition, Queensland has established a number of purpose-designed agencies, including a Coal Seam Gas Compliance Unit[16] that monitors operations and currently inspects around 370 gas wells and 150 drilling rigs annually, as well as monitoring water wells. The unit brings together expertise from across the administration on environment and water issues, oil and gas operations, and land access. In 2013, the Queensland government also established the Gas Fields Commission to encourage co-operation between rural landholders, regional

16. Coalbed methane (CBM) is commonly referred to as coal seam gas (CSG) in Australia.

communities and the coalbed methane industry. Unlike the United States, mineral rights in Australia are vested in the state government rather than with the landowner and access issues have proven contentious. The Commission is designed to give rural communities a more direct say in coalbed methane development and, to date, its creation and work seem to have made a strong positive contribution to improving landholder and industry interactions. Overall, the Queensland approach seems to embody many features of regulatory best practice, with cumulative, regional assessments revised regularly, purpose-built institutions and a strong focus on water issues. However, the Queensland experience also needs to be seen in the context of a state with generally low population density, mostly pastoral land use in the areas of coalbed methane development and a long and generally successful experience in resource management and oil, gas and mining development. These conditions are not necessarily duplicated elsewhere in Australia or in other regions around the world where coalbed methane may be developed.

Such differences come into focus when looking at other Australian states, notably New South Wales and Victoria. Coalbed methane extraction has taken place at a small scale in New South Wales for some 15 years, relying on coal seams in the Sydney Basin. A number of new projects which have been proposed, generally in areas of higher population density than in Queensland, have provoked strong public opposition. The regulatory reaction has been to adopt a highly selective approach to designating areas for development, including imposing a moratorium on further activity in Sydney's drinking water catchment area and a prohibition on development in and within two kilometres of existing and future residential zones. A Community Benefits Fund has been established, with industry and state contributions, to ensure that the communities most directly affected share some of the benefits. In Victoria, a full moratorium on hydraulic fracturing remains in place: a Gas Market Taskforce, reporting in late 2013, recommended a series of regulatory measures which might be imposed were for unconventional gas development to be permitted (including strong measures to ensure water quality, full disclosure of chemicals used in hydraulic fracturing and a sharing of state royalties with local communities), but the state government did not accept that these were sufficient to allow reconsideration of the moratorium (State Government of Victoria, 2015).

The Australian Federal Government, working through a federal state co-ordination mechanism known as the Standing Council on Energy and Resources, agreed on a harmonised regulatory framework for coalbed methane in late 2013 (Council of Australian Governments, 2015). The framework, which incorporates many, if not most, of the principles set out in the Golden Rules, focuses on four main areas: well integrity; water management and monitoring; hydraulic fracturing; and chemical use and disclosure. Another important federal initiative has been the establishment of an independent expert scientific committee to provide advice on the impact of coalbed methane and mining projects on water resources. This Committee, with funding of some $100 million, is to undertake wide-ranging regional assessments, to improve knowledge in such areas as inter-aquifer connectivity, gas and water flows in coal seams, and how dewatering of coal seams and desorption of gas can alter surrounding formations.

Key public concerns and trends in unconventional gas regulation

The gas industry has made considerable advances in its operational practices in recent years, driven mainly by the need to improve productivity, but also by regulatory demands. Water use has been reduced as recycling becomes more widespread. Land-use issues have also been also reduced, through greater use of pad drilling. Methane emissions have been lowered through more careful well completions. Nonetheless, significant scientific uncertainties remain. A number of trends can be discerned in recent regulatory developments in the three countries examined, reacting to public concerns that appear to be crystallising around the following topics:

- A focus on water issues is universal and appears to be the area of major public concern. The issues include contamination of aquifers from fracturing operations or from gas and chemical interactions with shallower groundwater formations. They also include treatment and disposal of wastewater, either from extracted formation water, as in coalbed methane extraction, or flow-back water and drilling/fracturing liquids. These concerns are especially acute in areas of elevated water stress.
- Land access and loss of land value are common issues, notably where settlement patterns are relatively dense and where landowners and communities do not derive direct revenue from unconventional gas development (especially where they do not own the mineral rights, the situation most common outside the United States).
- Concerns about increased seismic activity associated with hydraulic fracturing and deep aquifer disposal of wastes that has been observed.
- Air emissions concerns, both at the production stage (e.g. diesel engines, traffic), but also methane emissions during drilling, completion and production (see Chapter 5).

The issue of methane emissions is related to a much broader question: the role of gas, including unconventional gas, in the transition to a lower-carbon energy system. As our projections for the 450 Scenario indicate, gas retains an important place in the energy mix of many countries, for the period to 2040, even with a concerted global policy effort to address climate change. But not all sources of gas are equal when it comes to their impact on greenhouse-gas emissions; key variables in any such assessment are the distance that the gas needs to travel to reach its consumers (which involves consumption or loss of a certain share of the gas, both for pipelines and for LNG) and the risk of fugitive emissions along the chain from production to consumption. If upstream fugitive emissions can be minimised through the use of green completions, then lifecycle greenhouse-gas emissions for locally produced and consumed shale gas should be lower than for gas imported over long distances.[17] But if regulation on fugitive emissions is weak or not enforced, the calculation may be much less clear-cut.

17. This does not necessarily mean a reduction in overall greenhouse-gas emissions, as that would depend on what happens to the other sources of gas that are displaced, for example, whether they remain in the ground or are consumed elsewhere and, in the latter case, whether or not they substitute for more carbon-intensive fuels.

So how well have regulatory systems evolved in recent years to respond to these concerns? It is clear that there is now much greater transparency in a number of jurisdictions. This trend is increasing, especially with respect to chemical use. BTEX chemicals (benzene, toluene, ethylbenzene and xylenes) are widely discouraged, if not banned outright, in fracturing operations. Major forthcoming studies in the United States and Australia should shed more light on chemical use and impacts.

Regulators are insisting on much more thorough levels of pre-drilling baseline assessments of water quality and availability, and often implementing no-fault regimes, whereby any change in water volume or quality within a specified radius or time is assumed to be the fault of the driller. This strongly incentivises developers to undertake thorough pre-drilling baseline studies and analysis.

Study of the many tens of thousands of wells drilled has not revealed cross-contamination of shallower aquifers from deep hydraulic fracturing operations as a major hazard. However, the absence of evidence to date does not justify a lower level of scrutiny and cumulative, long-term impacts could change this view. By contrast, in the upper portion of wells, cross-contamination can occur where the well intersects groundwater formations (as it can in conventional oil and gas wells) and the risk is potentially accentuated by the drilling intensity of unconventional gas and the multiple high-pressure fracturing operations per well. This has shifted the emphasis for regulators towards ensuring well integrity throughout the well bore, but especially in the parts closer to the surface. Surface spills can be a problem, multiplied by the scale and number of wells being drilled.

The distance which developments must be set back from dwellings or other features, including water sources, seems to be increasing, as seen in Pennsylvania (now around 150 metres [500 feet] from existing buildings or water wells, up from 60 metres [200 feet], and 300 metres [1 000 feet] from a water extraction point) and in the case of New South Wales (2 km). “Setbacks” for unconventional gas tend to be greater than for conventional oil and gas. Setbacks are being applied to fracturing operations, with both horizontal and vertical separations from water wells. However, there appears to be no basis for standardising setbacks across different regions and no obvious scientific basis for any given distance.[18]

Regional approaches are becoming more widespread, especially cumulative assessments of water impacts, as seen in Queensland and Canada. As such cumulative assessments are repeated every few years, experience and expertise will grow. More specialist regulators, or specialised bureaus within existing organisations, are being set up to regulate unconventional gas exploitation, with greater dedicated expertise on water assessment and management as well as on more traditional oil and gas management issues.

18. In some cases the highest measured or calculated drainage area of a well is used to determine setback distances.

More jurisdictions are banning the venting of gas (generally released during well completions) and more are aiming to reduce routine flaring. North American industry surveys indicate that reduced emissions completions (green completions) were used in 90% of wells as of 2014, and the US EPA, after a transition period, made these mandatory from the beginning of 2015, with only a small number of exceptions.

The roles of different levels of government – federal, state and local – are being developed and clarified. While regional governments generally retain the dominant direct regulatory role, there is a strong case for harmonised national approaches in a number of areas, including chemical toxicity, mandating greater transparency and cross-state evaluations in areas such as water-basin management. Uniform approaches to venting (for which regulators should have zero tolerance), flaring (very low tolerance) and green completions (applicable to both) also seem appropriate.

In conclusion, it is clear that both knowledge of and regulation of unconventional gas development have progressed significantly; but public concerns remain widespread. The battle for public acceptance is not lost, but more remains to be done to satisfy the public that regulators and the industry are in control of current operations and can develop, and effectively apply, a sufficiently rigorous and comprehensive environmental management system throughout any project's lifespan – one that can adapt over time to changes in circumstances or knowledge. Where states lack the resources to monitor literally thousands of production wells, regulatory activities need to be fully resourced by industry levies. Co-operation between groups of regulators, industry and other stakeholders can play a very useful role in research, encouraging best practice and evaluating lessons learned. Continued meaningful involvement of local communities is essential, possibly through purpose-built institutions. Even then, there may be areas where unconventional gas may simply not be an appropriate activity.

Chapter 7

Coal market outlook

Is there another China out there?

Highlights

- Recent years have seen a marked slowdown in global coal demand growth, particularly in China. Coal use in OECD countries peaked in 2007 and coal demand in the global iron and steel industry is levelling off, so future growth hinges critically on the power sector in non-OECD countries, especially India, Southeast Asia and China. In the New Policies Scenario global coal demand to 2040 grows by 0.4% per year on average, a marked slowdown compared with 2.4% over the past 25 years. Despite coal losing out to renewables as the world's largest source of electricity generation soon after 2030, it still accounts for 30% of global electricity output by 2040.

- Over the last decade, China dominated world coal markets. It still remains a key force, but its role is shifting as demand is projected to level off over the medium term and go into a slow long-term decline after 2030. Coal use in China's power sector flattens only towards 2040, while industrial coal demand falls markedly after 2020, as the economy rebalances away from heavy industry. Chinese net imports decline by over 50% to 2040; as the world's largest coal consumer and producer, shifts in China's demand or output have strong repercussions on global coal trade.

- India becomes the world's second-largest coal consumer and producer over the *Outlook*, as its demand nearly triples and production grows more than in any other country. In the current decade, India overtakes Japan, the EU and China to become the largest importer of coal and imports rise to over 400 Mtce by 2040. Australia and Mozambique are the primary suppliers of coking coal to India, while steam coal imports mainly come from Indonesia, Australia and South Africa.

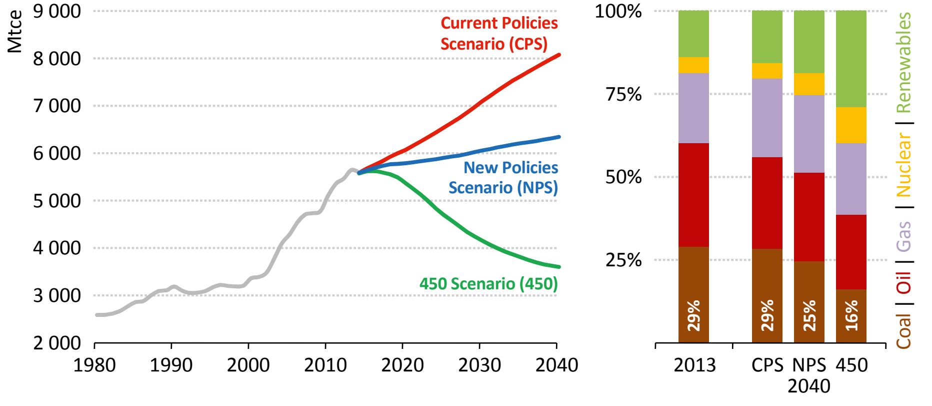
- International steam coal prices – at under $80/tonne in 2014 – have dropped to a level last seen in the mid-2000s due to over-capacity in the market. The industry has responded by cutting up to an estimated 330 million tonnes of annual production capacity since end-2012. Steam coal prices are projected to rebound in the medium term, as global demand and supply adjust, to reach almost $110/tonne in real terms by 2040. Global trade in coal grows 20%. Cumulative investments of $1.4 trillion are needed in the global coal supply chain over 2015-2040, with $1 trillion in mining and the rest in railways, ships and ports.

- The key uncertainties affecting the coal markets are developments in climate and local pollution policies, changes in coal demand prospects in China and growth of production in India. Chinese demand could go into decline instead of levelling off, or an Indian push for self-sufficiency could back out coal imports. Any of these has the potential to leave the world coal market in the doldrums for a long time; but variations with the contrary effect cannot be ruled out either.

Overview

Having accounted for the majority of the growth in global coal use since 2000, China has recently seen a marked slowdown, thus putting the brakes on global coal demand growth (Box 7.1). Key world coal market indicators[1] for the first-half of 2015 remain downbeat and point to a probable fourth consecutive annual slide in coal prices, reflecting a continuing over-capacity in coal mining. Since the *World Energy Outlook (WEO) 2011* (IEA, 2011), which included a special focus on coal markets (in response to China's 12th Five-Year Plan and more intensive international discussions about setting the world on a course to limit the rise in global average global temperature to below 2 degrees Celsius [°C]), *WEO* projections have emphasised that coal markets are at a critical turning point (Figure 7.1). Among the fossil fuels, the *Outlook* for coal diverges the most across our scenarios, with China being key.

Figure 7.1 ▷ World coal demand and share of coal in world primary energy demand by scenario



Note: Mtce = million tonnes of coal equivalent.[2]

Coal use in OECD countries peaked in 2007 and worldwide demand for coal in the iron and steel industry is levelling off. The magnitude of future coal demand hinges critically on demand from the power sector in non-OECD countries, particularly in Asia. Policy-makers in Beijing have already taken measures to slow domestic coal demand growth and new expectations will be set out in the 13th Five-Year Plan (2016-2020). Decisions yet to be made on the extent of coal use in India, Southeast Asia and other developing economies, will reflect judgements on the benefits and risks of this most carbon-intensive fossil fuel. As explored further in the *Energy and Climate Change: World Energy Outlook Special Report 2015* (IEA, 2015a), rapid and widespread adoption of high-efficiency coal-fired generation technologies and designing plants to be suitable for modification to incorporate carbon

1. For 2014, preliminary data for aggregate coal demand, production and trade by country are available; while the sectoral breakdown for coal demand is estimated (complete data are available to 2013).

2. A tonne of coal equivalent equals 7 million kilocalories (kcal) or 0.7 tonnes of oil equivalent.

capture and storage (CCS) are becoming essential features of strategies to reconcile future coal use with global aspirations to tackle climate change.

The **New Policies Scenario**, the central scenario of this *World Energy Outlook* (see Chapter 1), takes a cautious view of the likely degree of implementation of announced government measures, which range from fostering energy efficiency, supporting low-carbon fuels and, in certain cases, to placing a price on carbon-dioxide (CO_2) emissions.[3] Even so, on the basis of assumed levels of growth in energy prices, population, urbanisation, economic development and industrialisation, global coal demand rises by 12% between 2013 and 2040, reaching over 6 300 million tonnes of coal equivalent (Mtce). The projected average annual growth rate of 0.4% represents a marked slowdown compared with the 2.4% average over the past 25 years and even more so relative to the rate of 4.1% over the past decade (Table 7.1). Soon after 2030, coal loses out to renewables as the world's largest source of electricity generation; yet, it still underpins 30% of global electricity output by 2040. With less than 5% of global coal-fired power generation coming from plants equipped with CCS in 2040, the policies envisaged in the New Policies Scenario are not stringent enough to achieve deep decarbonisation and therefore do not trigger the CCS cost reductions needed for large-scale deployment. Over the projection period, coal remains the second-most important fuel in the global energy mix, although its market share decreases from 29% today to around 25% by 2040 (see Chapter 2). The slowdown in world coal demand growth over the *Outlook* period is the net effect of a projected 40% decline in coal use in OECD countries, essentially flat demand in China, and strong growth in India and Southeast Asia.

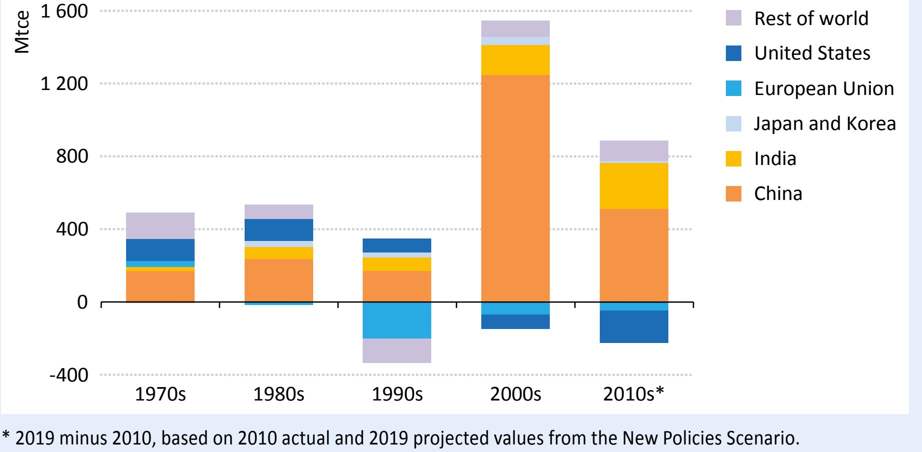
With global demand for both coking coal and lignite decreasing by some 15% each in the New Policies Scenario, steam coal demand accounts for all of the increase in coal supply. Accentuated by the projected decline in OECD coal production, the share of non-OECD countries in global coal output increases from around 75% today to 85% by 2040. At 0.6% per year, global coal trade expands at a faster rate than global coal use: one-out-of-five tonnes of coal are traded in 2040. Steam coal accounts for some 85% of the increase in global coal trade over the projection period. The New Policies Scenario sees $1.4 trillion (in year-2014 dollars) of cumulative investments in the global coal supply chain over the period 2015-2040, roughly $1 trillion in mining capacity and $350 billion in infrastructure projects, such as railways, ships and ports. The largest share of total mining investment goes into maintaining or expanding production levels at existing mines, with $425 billion invested in greenfield projects. Due to their relative remoteness, new mines in untapped or under-developed coal basins, such as Surat and Galilee (Australia), Tete (Mozambique), Xinjiang (China) or Waterberg (South Africa), will require substantial infrastructure investment and often face challenging regulatory approval processes; however, their favourable mining conditions still make them potentially attractive projects due to their low production costs.

3. Despite these policy measures, global energy-related CO_2 emissions still rise in the New Policies Scenario, leaving the world on a trajectory consistent with a long-term average temperature increase of 3.6 °C (see Chapter 2).

Box 7.1 ▻ China, India and United States: taking stock

China, India and the United States today account for 72% of global coal demand. Between 2000 and 2009, Chinese coal use grew on average by 9.5% per year; but more recent years have seen growth slow to only 4% per year on average (although revisions to the historical data may change this picture somewhat, see Chapter 2 Box 2.1), and proponents of the idea that peak demand has been reached in the world's largest coal market are now more vocal (Spotlight). Several factors are at play: economic growth is slowing; decision-makers want to rebalance activity away from energy-intensive industries; concerns about local air pollution are heightened; despite improvements, coal mine safety remains a concern; efforts are being made to scrap old and inefficient power and industrial plants; and hydro, nuclear, wind and solar technologies are being promoted in the power mix. In the United States, the world's second-largest coal market, demand peaked in 2005, and has since declined by 23%, primarily due to competition from abundant unconventional gas (Figure 7.2). India, the world's third-largest coal consumer, is now the fastest growing major demand centre and appears to be on track to overtake the United States within a couple of years. Even though India's economy is expected to expand at a faster rate than that of China in the current decade, and that some 240 million Indian citizens still lack access to electricity, India's appetite for coal is not expected to rise as strongly as China's did. India has significantly fewer coal resources than China and, due to constraints on domestic mining, it has come to rely much more on imported coal, raising concerns about competitiveness and energy security. The potential surge in India's coal demand also comes at a time of varying influences: downward pressure on natural gas prices; potential crossroads in the international debate about energy and climate; heightened global emphasis on energy efficiency and notable cost reductions in many renewable energy technologies.

Figure 7.2 ▻ Change in coal demand by key region and decade in the New Policies Scenario



* 2019 minus 2010, based on 2010 actual and 2019 projected values from the New Policies Scenario.

Global coal demand expands much more rapidly in the **Current Policies Scenario** (in which no new energy and environmental policies are assumed), rising at an average annual rate of 1.3% to a level in 2040 that is around 30% higher than in the New Policies Scenario. While coal demand remains robust in this scenario, the pace of growth is half that experienced over the past 25 years, and reflecting recent marked shifts in energy markets (particularly in China and the United States), is lower than in any recent edition of the *Outlook*. In the Current Policies Scenario, coal displaces oil as the world's leading fuel around 2030 and remains by far the leading source of global electricity generation over the projection period. All of the growth in global coal demand occurs in non-OECD countries, with India, China and Southeast Asia alone accounting for around 85% of incremental demand. Coal use in OECD countries continues to decline, and by the end of the *Outlook* period, this region accounts for only 15% of total coal demand. Virtually all of the incremental global coal demand is for steam coal, with a minor contribution from lignite, while coking coal demand decreases 10% by 2040. With an average annual growth of 1.9% over 2013-2040, world coal trade expands at a faster pace than global use, as domestic production in key demand centres fails to keep pace with burgeoning domestic needs. The Current Policies Scenario actually sees a 10% expansion in OECD coal production by 2040, due to fairly robust production levels in Australia and the United States. At $1.7 trillion (in year-2014 dollars), cumulative investments in the global coal supply chain are 30% higher than in the New Policies Scenario, as more large-scale projects come online over the projection period, in response to higher coal demand and prices.

Table 7.1 ▷ Coal demand, production and trade by scenario (Mtce)

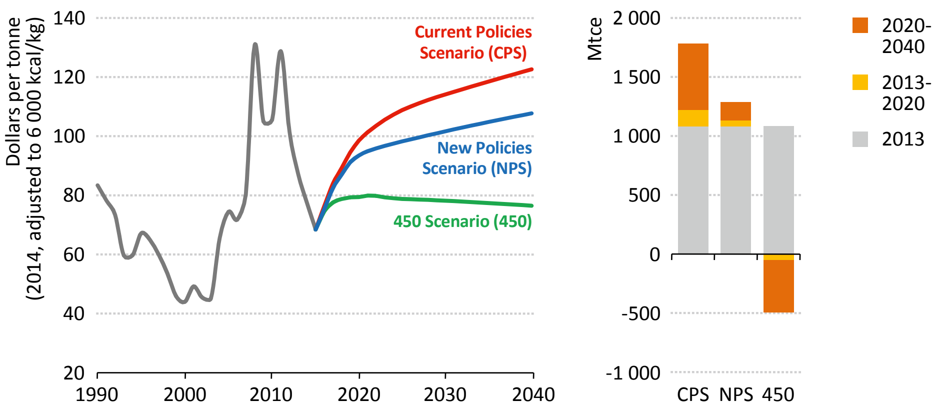
				New Policies		Current Policies		450 Scenario	
		2000	2013	2020	2040	2020	2040	2020	2040
Demand	OECD	1 573	1 470	1 307	878	1 413	1 289	1 152	523
	Non-OECD	1 774	4 143	4 454	5 428	4 627	6 737	4 208	3 041
	World	3 347	5 613	5 762	6 306	6 040	8 026	5 360	3 565
	Steam coal	2 590	4 379	4 523	5 266	4 784	6 835	4 175	2 813
	Coking coal	452	940	929	785	941	851	903	601
	Lignite*	304	295	309	254	315	341	282	151
Production	OECD	1 380	1 361	1 255	1 042	1 391	1 505	1 134	627
	Non-OECD	1 875	4 362	4 507	5 263	4 648	6 521	4 226	2 938
Trade**	World	471	1 084	1 143	1 291	1 221	1 780	1 038	594
	Steam coal	310	814	847	984	913	1 447	759	373
	Coking coal	175	272	299	311	310	337	284	229
Share of world demand	*Non-OECD*	*53%*	*74%*	*77%*	*86%*	*77%*	*84%*	*79%*	*85%*
	Steam coal	*77%*	*78%*	*79%*	*84%*	*79%*	*85%*	*78%*	*79%*
	Trade	*14%*	*19%*	*20%*	*20%*	*20%*	*22%*	*19%*	*17%*

* Includes peat. ** Total net exports for all *WEO* regions, not including intra-regional trade.

Note: Historical data for world demand differ from world production due to stock changes.

In the **450 Scenario**, world coal demand peaks in the current decade and then declines by 33% to return to the level of use in the early 2000s. This large reduction in coal use stems from the policies that governments worldwide, but especially in China and OECD countries, adopt towards setting the energy system on track to have a 50% chance of keeping the long-term increase in the average global temperature to below 2 °C (see Annex B). By 2040 in the 450 Scenario, coal accounts for only 16% of the world's energy mix and 12% of electricity output. CCS plays an important role in reducing emissions from coal-fired generation, with three-quarters of the coal-based power coming from plants equipped with CCS. Also, CCS makes substantial in-roads into industrial processes, where 10% of the cumulative CO_2 emissions over the *Outlook* period are captured and stored. Relative to steam coal and lignite that are used predominantly in power generation, a sector in which many alternatives exist for decarbonisation, coking coal use declines less as opportunities for its substitution in industrial applications are much more limited. Consequently, global trade in coking coal declines by only around 15% relative to today's levels, whereas steam coal trade more than halves over the projection period. Reflecting the changes in global coal trade and demand, most of the reduction in coal production occurs in China, United States, Indonesia, Russia and Australia. Cumulative investments in the global coal supply chain in the 450 Scenario, though at the lowest value among the three main *WEO* scenarios, still amount to $905 billion (in year-2014 dollars). They go into small incremental projects in mature mining regions. As global coal demand and trade shrinks, the industry responds by closing high-cost mines and invests only in the most viable new mining projects (Box 7.2).

Figure 7.3 ▷ Average OECD steam coal import prices and global coal trade by scenario



Prospects for coal prices differ by scenario since prices are a function of the cost of the production that is needed to satisfy shifts in global demand and trade (Figure 7.3). With higher demand and trade, more costly mines are needed to balance the market, resulting in higher coal prices and vice versa. In all three scenarios, coal prices (including transportation costs) – currently below the production costs of the marginal producers – rise to 2020, as the market absorbs the current over-capacity, and afterwards prices are determined again by the marginal costs of supply (see coal prices and costs section). Over the medium term, the average OECD steam coal import price is relatively similar in the New Policies and Current Policies Scenarios. In both cases, rising trade volumes to 2020 increase the call on supply from mines that are currently loss-making, putting upward pressure on prices. Reflecting different levels of global coal demand and trade, prices diverge markedly after 2020; by 2040 they reach almost $110/tonne (in year-2014 dollars) in the New Policies Scenario and $125/tonne in the Current Policies Scenario.

Box 7.2 ▷ Stranded capital or miners?

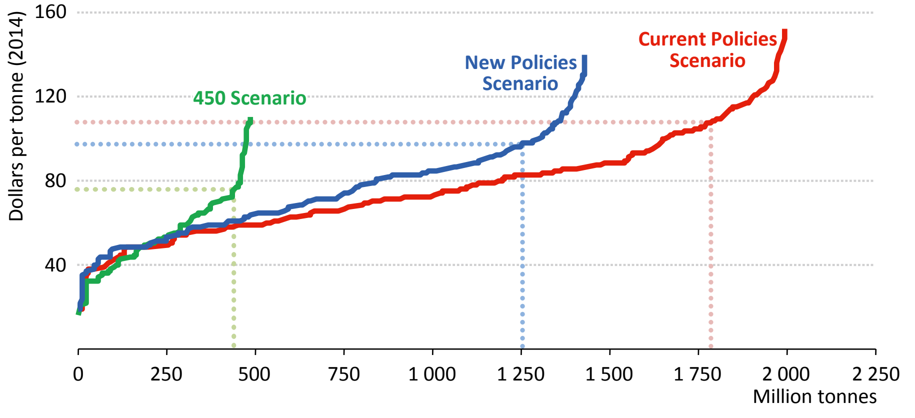
Global coal reserves are huge, far larger than the amounts required for production even under very long-term business-as-usual scenarios. The notion that reserves will be left in the ground is, therefore, uncontroversial for the coal industry, regardless of climate policies. But current coal market conditions are giving the idea of stranded capital an extra edge, with the global surge in investment and production from the early 2000s now leading to over-capacity and rock-bottom prices for internationally traded coal. What would be the implications if the industry continues to plan for only a moderately carbon-constrained future, but ends up in a much stricter one, aligned with the 2 °C goal?

In the 450 Scenario, coking and steam coal production to 2040 is equal to 75% of the in-situ reserves of currently operating mines (a far narrower definition than proven reserves). This might be understood to imply that no capital investment is required in new mines, although this is not a necessary consequence as new mines might still be developed for economic and social reasons, if costs or distance to market are favourable. But, when considering the risks that the 450 Scenario brings to the coal mining industry, a critical point – and a key distinction compared with oil and gas production – is that coal mining is not a capital-intensive business. Certainly, capital investment is essential, particularly when new rail and port infrastructure is needed to bring coal to market; but most of the cost of bringing coal to market is made up of the variable costs of production, i.e. the costs of labour, and of fuel and power for the mining machinery. Despite increasing mechanisation, coal mining remains a labour-intensive business, with an estimated 6-7 million people directly employed around the world (compared with 2-3 million in upstream oil and gas). The amount of capital that could become stranded in the coal sector is quite limited, at least on the extractive side (capital intensity is much higher further down the value chain, i.e. in coal-fired power plants); to the extent that policy delivers a sharp reduction in coal extraction, it is not capital that is primarily at risk, it is labour.

In the 450 Scenario, the difference in coal prices is larger in the long term, as intensified climate change action slashes global coal demand and trade; but the effects become clearly noticeable even in the medium term. Over the *Outlook* period, loss-making mines are shut, while operations with favourable costs stay in business as the average OECD steam coal import price stays fairly flat, around $80/tonne. The projected price is lowest in the

450 Scenario, reflecting a market in which the marginal costs of steam coal exports (often termed marginal free on board [FOB] cash costs) are the lowest across the three scenarios (Figure 7.4). Variations in the three cash cost curves stem from scenario-specific demand, cost-evolution and investments. Trade volumes – highest in the Current Policies Scenario and lowest in the 450 Scenario – determine the marginal cost level of coal supply in the three scenarios. The composition of the curves differs, as higher demand allows for more large-scale greenfield projects to be developed, that typically have low variable costs but need a certain margin to cover their capital cost. Also, various oil, electricity and steel price trajectories lead to different supply costs.

Figure 7.4 ▷ Marginal FOB cash costs and market volume for global seaborne steam coal trade by scenario, 2040



Notes: Dotted lines represent seaborne steam coal trade volume and corresponding marginal FOB cash costs. FOB cash costs include: mining costs; costs of coal washing and preparation; inland transport; mine overhead; and port charges. While standard definitions of cash costs often exclude royalties and taxes, they are included here. Seaborne shipping costs and capital costs are excluded.

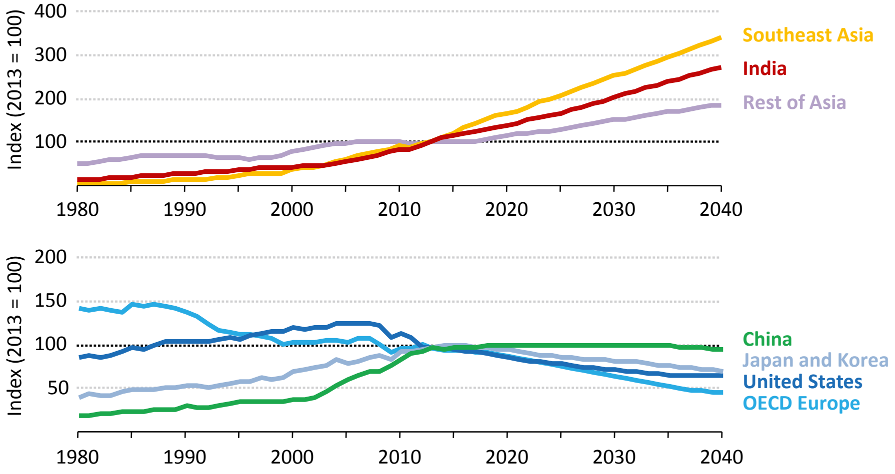
Sources: IEA analysis; Wood Mackenzie databases.

Demand

Regional trends

In 2007, when OECD coal demand peaked at a level of 1 670 Mtce, coal accounted for 21% of the region's fuel mix and 37% of its electricity generation. In the New Policies Scenario, coal use continues to decline, particularly in the key sector of power generation where it nearly halves by 2040 relative to today's level. At the end of the *Outlook* period, coal constitutes only around 12% of the OECD's primary energy and 16% of the electricity generation mix. Coal use in OECD Europe had already peaked in 1987 and in the United States in 2005, while the combined use of coal in Japan and Korea is expected to peak soon, at levels not far from today's (Figure 7.5). The majority of the projected decline in OECD coal demand occurs after 2020, once old coal-fired plants are retired and the business case for new coal-fired plants falters in response to policy measures related to renewables, energy efficiency and CO_2 emissions, the continued growth of unconventional gas supply in North America (see Chapter 6) and the significant contribution of nuclear power in Japan and Korea. Out of the some 2 100 gigawatts (GW) of new power generation capacity installed in OECD countries in the New Policies Scenario, only 5% is fuelled by coal and of this 95 GW of coal-fired capacity additions 35% are fitted with CCS technology. By 2040, OECD countries account for some 15% of global coal demand, compared with a 25% market share today.

Figure 7.5 ▷ Evolution of coal demand in key regions in the New Policies Scenario



Growth in non-OECD coal use was fairly subdued historically until the early 2000s. However, the surge in Chinese coal demand in the past decade resulted in the non-OECD region's share of global demand rising from 53% in 2000 to 74% today. In the New Policies Scenario, this share reaches 86% by 2040, as coal is called upon to support the electrification and industrialisation of the economies of India and Southeast Asia. After overtaking the United States in the next couple of years, India consolidates its position as the world's second-largest consumer of coal with a near tripling of coal demand over the projection period (Table 7.2).[4] The countries of Southeast Asia experience an even faster pace of annual coal demand growth, as a result of which they displace the United States as the world's third-largest coal demand centre towards the end of the projection period.[5] On the other hand, coal use in China, the world's largest consumer of coal remains largely flat over the projection period, in line with the recent slowdown in demand and announced energy and environmental policies. By 2040, China represents 45% of global coal use, compared with 52% today. Despite growth in most other non-OECD countries, the share of coal in the

4. An in-depth analysis of prospects for India's energy demand, supply and trade balance, including for coal, is presented in Part B of this *Outlook*.

5. This region's energy prospects are covered in detail in *Southeast Asia Energy Outlook: World Energy Outlook Special Report* (IEA, 2015b), available free at: *www.worldenergyoutlook.org/southeastasiaenergyoutlook.*

entire region's fuel mix declines between 2013 and 2040, from 37% to 31%. The power generation sector accounts for three-quarters of the growth in non-OECD coal use, although the share of coal in electricity output declines from 49% to 37% over the projection period, as renewables (see Chapter 9) and nuclear gain ground.

Table 7.2 ▷ Coal demand by region in the New Policies Scenario (Mtce)

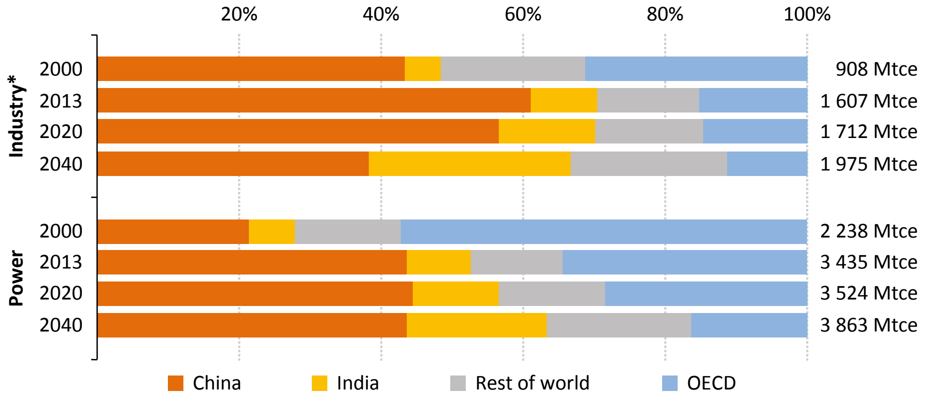
	2000	2013	2020	2025	2030	2035	2040	2013-2040	
								Change	CAAGR*
OECD	**1 573**	**1 470**	**1 307**	**1 182**	**1 049**	**939**	**878**	**-592**	**-1.9%**
Americas	822	670	577	534	479	441	436	-234	-1.6%
United States	762	617	526	484	436	402	398	-220	-1.6%
Europe	481	449	398	337	275	223	192	-257	-3.1%
Asia Oceania	269	352	333	311	295	275	250	-101	-1.3%
Japan	139	173	159	147	141	130	118	-55	-1.4%
Non-OECD	**1 774**	**4 143**	**4 454**	**4 692**	**4 978**	**5 235**	**5 428**	**1 285**	**1.0%**
E. Europe/Eurasia	299	313	302	305	306	317	319	6	0.1%
Russia	171	155	153	164	163	166	162	7	0.2%
Asia	1 320	3 643	3 944	4 160	4 422	4 634	4 778	1 135	1.0%
China	992	2 932	2 943	2 957	2 968	2 932	2 826	-106	-0.1%
India	209	488	681	812	986	1 163	1 334	846	3.8%
Southeast Asia	45	130	215	271	328	383	446	315	4.7%
Middle East	2	4	5	5	6	6	6	1	1.0%
Africa	129	148	161	175	191	220	259	111	2.1%
South Africa	117	136	134	133	128	125	122	-14	-0.4%
Latin America	25	34	42	47	54	59	66	32	2.5%
Brazil	19	24	29	31	33	35	37	13	1.7%
World	**3 347**	**5 613**	**5 762**	**5 874**	**6 027**	**6 175**	**6 306**	**692**	**0.4%**
European Union	459	409	350	285	222	174	145	-264	-3.8%

* Compound average annual growth rate.

Sectoral trends

In the New Policies Scenario, the importance of global coal use in the power sector (around 60%) and industrial applications (30%) is fairly stable over the projection period. By 2040, non-OECD countries account for 85% of the world's use of coal in power generation, as their coal-fired capacity rises by 60%, while that of the OECD declines. India, Southeast Asia and China are the principal sources of the projected growth in non-OECD coal use in the power sector, and by 2040 India accounts for nearly every fifth tonne of coal consumed globally in power plants (Figure 7.6). Three-quarters of the new coal-fired capacity brought online in the non-OECD use supercritical, ultra-supercritical or integrated gasification combined-cycle (IGCC) technology, all ranking high in terms of operational efficiency, which tempers the rise in coal use relative to growing demand for electricity output. The share of subcritical technology in world coal-fired capacity declines from 65% today to 42% in 2040, while CCS technology reaches only 3% of global coal capacity (see Chapter 8).

Figure 7.6 ▷ **Coal demand by key sector and region in the New Policies Scenario**



* Includes own use and transformation in blast furnaces and coke ovens, petrochemical feedstocks, coal-to-liquids and coal-to-gas plants.

The growth in global industrial coal use (mainly in iron, steel and cement production but also in nascent applications such as petrochemical feedstocks, coal-to-liquids and coal-to-gas plants), at 370 Mtce between 2013 and 2040, is only 15% lower than that in the power sector. Already today 85% of coal use in industry takes place in non-OECD countries, with the share rising further in the New Policies Scenario. China's share in global industrial coal use decreases from around 60% to 40% over the projection period, while India's share rises from around 10% to 30%. Chinese industrial coal use is fairly flat during the current decade, before declining by some 20% by 2040, while in India industrial coal use nearly quadruples. The decline of Chinese coal demand for industrial output in the New Policies Scenario stems from a rebalancing of the economy towards services and less energy-intensive industrial activities, improved energy efficiency (see Chapter 10) and fuel substitution. The decline of coal use in traditional industrial sectors is to some extent offset by growth in its use in petrochemical feedstocks, coal-to-liquids and coal-to-gas plants, albeit the latter two grow at a slower pace than projected in last year's *Outlook*, as their prospects have been reduced by the current low oil price environment (see Chapter 4) and recently issued government guidelines towards the sustainable development of coal conversion activities in China. While both China's crude steel and cement production are peaking and are projected to decline by over a quarter by 2040, in India the production of these materials grows five-fold and three-fold, respectively. China remains the world's largest producer of crude steel and cement, but India's production is only some 30% lower than China by the end of the projection period. With the services sector today accounting for half of India's economic output, the government has recently launched an initiative aimed at promoting investment and innovation in the manufacturing sector. In the New Policies Scenario, the share of coal used in industrial applications in India rises from around 50% today to 57% by 2040.

Supply

Reserves and resources

Coal is the most abundant of all fossil fuels. Global coal reserves (coal that is known to exist and thought to be economically exploitable with today's technology) stand at around 970 billion tonnes, of which 70% are steam and coking coal (Table 7.3).[6] A reassessment of reserves (involving modifications particularly in China but also in South Africa) resulted in an 8% downward revision of global coal reserves in 2013 compared with 2012 (BGR, 2014). But, coal reserves, even at this reduced level, would be sufficient to sustain current global production levels for around 120 years. The reserves base is geographically dispersed, with all continents having significant deposits of the fuel, meaning that, typically, coal is not subject to energy security concerns due to geopolitical tensions. The United States, where exploration is well-advanced, holds over a quarter of the world's coal reserves, while Russia (17%), China (13%), Australia (11%), India (9%) and the European Union (EU) (8%) also have substantial reserves. The world's coal resources – including coal deposits that are not necessarily exploitable with current technology or at current prices – are more than 20 times larger than reserves.

Table 7.3 ▷ Remaining recoverable coal resources, end-2013 (billion tonnes)

				Total				
	Coking coal	Steam coal	Lignite	Resources*	Share of world	Proven reserves	Share of world	R/P ratio**
OECD	**1 680**	**7 300**	**2 317**	**11 298**	***49%***	**453**	***47%***	**227**
Americas	1 040	5 838	1 519	8 397	*37%*	263	*27%*	269
Europe	155	330	343	827	*4%*	76	*8%*	138
Asia Oceania	485	1 132	456	2 073	*9%*	115	*12%*	246
Non-OECD	**1 678**	**7 565**	**2 367**	**11 610**	***51%***	**515**	***53%***	**87**
E. Europe/Eurasia	748	2 229	1 424	4 401	*19%*	238	*25%*	374
Asia	875	5 023	917	6 815	*30%*	249	*26%*	51
Middle East	19	23	-	41	*0%*	1	*0%*	1 094
Africa	33	264	0	297	*1%*	13	*1%*	49
Latin America	3	27	25	55	*0%*	13	*1%*	135
World* **	**3 358**	**14 865**	**4 684**	**22 908**	***100%***	**968**	***100%***	**122**

* The breakdown of coal resources by type is an IEA estimate and proven reserves are a subset of resources. ** The reserves to production ratio (R/P) represents the length of time that proven reserves would last if production were to continue at current rates. *** Excludes Antarctica.

Sources: IEA analysis; BGR (2014).

6. Classification of coal types (coking, steam and lignite) can differ between BGR and IEA due to statistical allocation methodologies.

Production

The New Policies Scenario sees a modest increase in global coal production from around 5 725 Mtce in 2013 to 6 310 Mtce in 2040 – corresponding to an annual growth rate of 0.4% (Table 7.4). Over the medium term, the current over-capacity is gradually removed as coal companies close mines and restructure their operations (Box 7.3). In the United States, continued marked production cuts take place with output plunging by 240 Mtce over the *Outlook* period – the largest reduction in a single country. Domestic coal demand is increasingly affected by environmental policies and exports provide only a limited relief valve. The European Union experiences the largest relative drop, with production plummeting by over 70%, since the bulk of EU steam and coking coal production cannot compete with imported coal in the long-run. Furthermore, the phasing out of subsidies (in the form of closure aid) for hard-coal mining in the EU by the end of 2018 will have a major impact on production in most hard-coal producing EU member countries. Moreover, lignite production, typically low cost and unsubsidised, is increasingly affected by climate policies in the EU. Australia is the only major OECD country in which coal production grows in the period to 2040, as its output increases by nearly 30% in response to robust export demand.

Box 7.3 ▷ Adapting to market conditions

As soon as coal prices started dipping in late-2011, a consolidation process began with a first wave of mine closures over the course of 2012. Production cuts were first confined to the US Appalachian basins but since then, the impacts of persistent low prices have spread to other basins and countries. Today, perhaps with the exception of Colombia, all major producing countries are affected by production cuts to some degree. We estimate that, since the end of 2012, between 280-330 million tonnes per annum (Mtpa) of production capacity has been removed (temporarily or permanently) from the global market either through idling, closure, depletion or operational production cuts. The bulk of the reduction, 180-200 Mtpa, was in China, where large companies have recently announced reductions in annual output by around 10%, while up to 2 000 small coal mines are slated for closure in the period from 2014 to the end of 2015. However, smaller producers are more difficult to monitor and therefore we estimate the national reduction in capacity to be closer to 5%. In the United States, 45-55 Mtpa of capacity has been closed (in addition to the closures during 2012), of which up to 10 Mtpa is coking coal. Australian producers have shed 10-15 Mtpa of high-cost production capacity since the end of 2012; however the cuts were over-compensated by increased production from more efficient mines boosting the country's overall output. Canada, primarily coking coal, and South Africa, only thermal coal, each removed 4-6 Mtpa of capacity since end-2012. Indonesia was the last to be hit by the consolidation wave. Production cuts between 35-45 Mtpa became effective late in 2014 and during 2015, coming primarily from small producers and a reduction in illegal mining.

Over the projection period of the New Policies Scenario, non-OECD countries mostly experience growth in coal production, although at very different rates. China's production keeps increasing to the early 2030s, but then declines slowly to match a decline in domestic coal demand. India is the main driving force behind the global expansion of coal production, as its determination to boost domestic production results in output levels growing more than two-and-a-half-times over the period. As the quality of the available coal in India declines, production in volumetric terms grows more strongly (see Chapter 13). Indonesia accounts for the second-largest production increase as its output expands by 180 Mtce, to total 580 Mtce in 2040. While past production growth was primarily destined for export, in the long-run additional Indonesian production will increasingly serve domestic consumers.

Table 7.4 ▷ Coal production by region in the New Policies Scenario (Mtce)

	2000	2013	2020	2025	2030	2035	2040	2013-2040	
								Change	CAAGR*
OECD	**1 380**	**1 361**	**1 255**	**1 185**	**1 114**	**1 050**	**1 042**	**-319**	**-1.0%**
Americas	824	745	648	611	550	496	487	-258	-1.6%
United States	767	682	592	556	499	451	442	-239	-1.6%
Europe	311	234	190	143	114	87	74	-160	-4.2%
Asia Oceania	245	382	417	430	450	467	481	99	0.9%
Australia	235	377	412	427	446	463	477	100	0.9%
Non-OECD	**1 875**	**4 362**	**4 507**	**4 689**	**4 913**	**5 125**	**5 263**	**901**	**0.7%**
E. Europe/Eurasia	319	435	442	449	460	468	473	38	0.3%
Russia	184	263	286	290	297	304	307	44	0.6%
Asia	1 320	3 623	3 732	3 886	4 082	4 262	4 362	738	0.7%
China	1 020	2 776	2 758	2 796	2 829	2 808	2 706	-69	-0.1%
India	187	340	425	514	632	775	926	586	3.8%
Indonesia	65	402	427	446	484	537	580	179	1.4%
Middle East	1	1	1	1	1	1	1	0	0.4%
Africa	187	218	225	239	254	277	309	91	1.3%
South Africa	181	207	204	205	207	208	210	3	0.0%
Latin America	48	85	107	114	116	117	119	34	1.2%
Colombia	36	79	100	106	107	109	110	31	1.2%
World	**3 255**	**5 723**	**5 762**	**5 874**	**6 027**	**6 175**	**6 306**	**583**	**0.4%**
European Union	307	224	173	125	96	71	61	-163	-4.7%

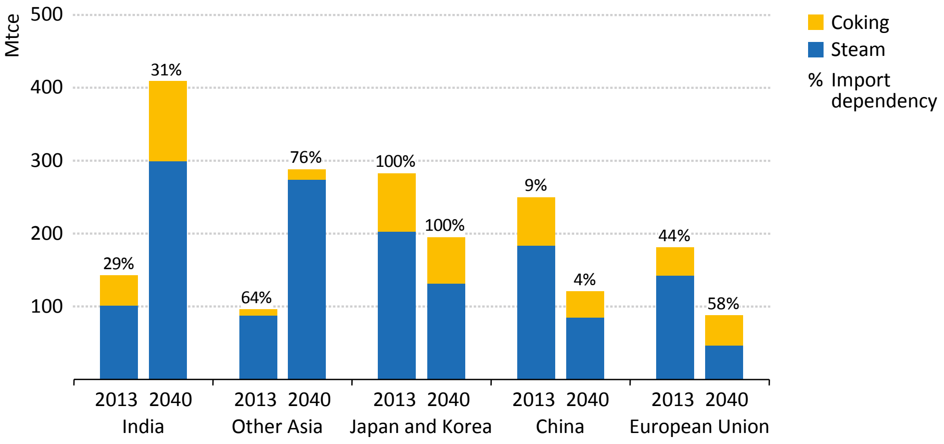
* Compound average annual growth rate.

Note: Historical data and the CAAGR for the world can differ from demand in Table 7.2 due to stock changes.

Trade[7]

Despite coal trade doubling over the last decade, only 19% of the world's coal production is currently traded; much less than the respective value of 45% for global oil production. One reason is coal's relatively low value-to-weight ratio, which makes long distance transport for most coals uneconomic; but the fact that coal reserves are geographically less concentrated than oil reserves is also important. Coal trade increases by around 20% in the New Policies Scenario from 1 085 Mtce in 2013 to 1 290 Mtce in 2040, slightly lifting the share of coal traded in total coal supply to 20%. The rise in coal demand in India and Southeast Asia is largely satisfied through the international market, relying on key exporters like Australia, Indonesia and South Africa. Such coal trade is primarily based on economics; most countries that import coal could also exploit domestic coal deposits, but prefer to rely on imported coal, as long as it comes at a lower cost. Concerns about security of supply are rarely a constraint. For instance in the EU, domestic coal production drops faster than demand thus increasing the region's reliance on coal trade from 44% today to 58% in 2040 (Figure 7.7). Steam coal demand is increasingly constrained by climate action, but demand for coking coal is less affected, since it is more difficult to substitute. Since coking coal is scarcer than steam coal and, hence, generally more valuable, it commands a higher share of trade and contributes to the increasing importance of trade. Although the growth rate of global coking coal trade is subdued, the share of coking coal production that is traded increases from 29% today to 40% in 2040.

Figure 7.7 ▷ Major net importers of coal by type in the New Policies Scenario



Having accounted for less than half of total coal trade at the beginning of the 2000s, the Asia-Pacific region has increased its share of the regionally traded coal market to 68% today and consolidates its leading role in world coal trade over the *Outlook* period, accounting for

7. Unless otherwise stated, trade figures in this chapter reflect volumes traded between countries/regions modelled in the *WEO*, and therefore they do not include intra-regional trade.

almost 80% of the import market in 2040. China, currently the largest importer in the world, sees its net imports decline by over 50% in the long run, reaching 120 Mtce in 2040 (Table 7.5). Despite this decreasing level of imports, the southern coastal China market remains pivotal for international coal pricing, as consumers in this region can arbitrage easily between domestic and international coal supply. India emerges as the largest coal importer in the world, set to overtake Japan soon, then the EU and China before 2020. In the longer run, India's west coast emerges as another key arbitrage point in international coal pricing. Southeast Asia, where coal demand grows almost everywhere, plays a major role too. The region's coal imports expand from 50 Mtce in 2013 to over 190 Mtce in 2040, largely in Viet Nam, Philippines and Malaysia.

Table 7.5 ▷ Coal trade by region in the New Policies Scenario

	2013		2020		2040		2013-2040
	Trade (Mtce)	Share of demand*	Trade (Mtce)	Share of demand*	Trade (Mtce)	Share of demand*	Change (Mtce)
OECD	**-82**	**6%**	**-53**	**4%**	**164**	**16%**	**247**
Americas	102	14%	72	11%	51	10%	-51
United States	90	13%	66	11%	45	10%	-45
Europe	-212	47%	-208	52%	-118	61%	-95
Asia Oceania	28	7%	83	20%	231	48%	203
Australia	310	82%	352	85%	424	89%	114
Japan	-173	100%	-159	100%	-118	100%	-55
Non-OECD	**124**	**3%**	**53**	**1%**	**-164**	**3%**	**-288**
E. Europe/Eurasia	113	26%	140	32%	154	33%	41
Russia	105	40%	133	47%	146	47%	41
Asia	-105	3%	-213	5%	-417	9%	311
China	-250	9%	-185	6%	-120	4%	-130
India	-143	29%	-255	38%	-408	31%	265
Indonesia	356	89%	347	81%	393	68%	37
Middle East	-3	76%	-4	79%	-5	80%	1
Africa	67	31%	64	28%	49	16%	-17
South Africa	70	34%	70	34%	88	42%	18
Latin America	53	62%	65	61%	54	45%	0
Colombia	76	96%	94	94%	101	92%	26
World**	**1 084**	**19%**	**1 143**	**20%**	**1 291**	**20%**	**206**
European Union	-181	44%	-177	51%	-84	58%	-97

* Production in net-exporting regions. ** Total net exports for all *WEO* regions, not including intra-regional trade.

Notes: Positive numbers denote net exports and negative numbers denote net imports of coking and steam coal. OECD and non-OECD trade should sum to zero; the difference in 2013 is due to stock changes.

The Asia-Pacific region also remains the major source of steam coal exports, supplied principally by Indonesia and Australia. Benefiting from excellent coking coal deposits and an efficient mining industry, Australia increases its market share in total coal trade from 29% in 2013 to 33% in 2040 and regains its position as the world's largest coal exporter from Indonesia. Indonesia sees its market share dip from 33% in 2013 to 30% in 2040, despite an increase in exports of nearly 40 Mtce over the *Outlook* period. The slowdown in the growth of Indonesia's exports stems, on one hand, from robustly growing domestic demand and, on the other hand, from the fact that Indonesia's coal quality is declining, while costs are rising. Smaller high-cost operations in Indonesia are becoming the swing supplier in the Asia-Pacific market.

The United States sees net exports of coal dropping to 45 Mtce in 2040, down from 90 Mtce in 2013. US coal deposits are located far from the growth centres in the Pacific Basin and, in the New Policies Scenario, only limited volumes of US coal exports find their way into the Asian market from the west coast. Coking coal from the Appalachian basins is relatively high cost and mines that rely on additional revenue from steam coal sales are worse off than their main competitors in Australia, Canada and Mozambique. Canadian net exports of coal drop from 26 Mtce in 2013 to 21 Mtce in 2040, while Mozambican exports increase from around 5 Mtce to 30 Mtce; both countries export primarily coking coal. Russian producers manage the transition from exporting primarily into the Atlantic Basin to establishing the country as an important exporter into the Asia-Pacific market, with total coal exports growing by 40 Mtce to 145 Mtce in 2040. Russian export growth prospects are sensitive to exchange rate fluctuations and, given the long transport distance, to changes in government policy on railway tariffs. South African coal exports grow by about 20 Mtce, reaching almost 90 Mtce in 2040. The country experiences a significant shift in its coal production, from the mature coal fields in Mpumalanga to the Waterberg coal basin. Colombia remains the dominant supplier in the Atlantic market, despite shrinking coal demand, and captures market share from the United States and Russia while expanding total coal exports by 25 Mtce to 100 Mtce in 2040. Colombia will also increase its presence in the Asia-Pacific market with domestic infrastructure projects and the expansion of the Panama Canal, although at a higher cost.

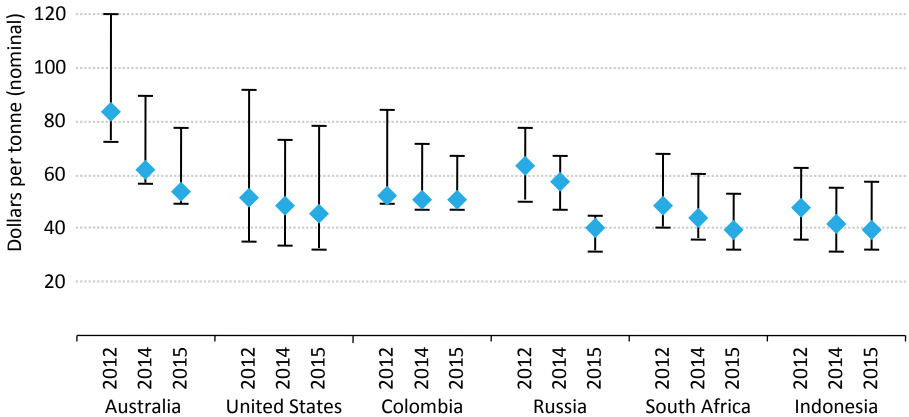
Coal prices and costs[8]

Despite 19% of global coal production being traded, coal prices on the international market are a key indicator for the state of coal markets in general. International markets connect the various regional markets through imports, exports and price movements. Price differences between the various sub-markets, however, can be large, primarily as a result of transportation costs and differing coal quality. However, arbitrage opportunities between the sub-markets and the international market tend to synchronise price changes, unless infrastructure bottlenecks or regulation impede trade.

8. Unless otherwise stated, values in dollars per tonne are adjusted to an energy content of 6 000 kcal/kg (net as received).

Global coal reserves are abundant and the capital cost of developing mines is typically modest. Thus, the key factor for coal prices is the variable production and transportation cost, also known as the cash cost (the cost that can be avoided by closing a mine).[9] Coal prices exceeding variable costs by only a few dollars are often sufficient for a mine to cover its (fixed) capital cost component too. Naturally, there are exceptions to this rule: developing an untapped basin requires large-scale infrastructure investments, including railway lines, port facilities and possibly, depending on the remoteness of the basin, new community infrastructure for workers. Such projects benefit from low mining costs, but they require a much larger margin than old mines in mature mining regions to recover their investment. In general, price-setting mines are mostly older, smaller mines, which have already recovered their capital costs and which make their decision to produce almost exclusively on the basis of variable cost recovery. In the last two years, prices have effectively dropped even below marginal cash costs for some of the highest cost producers. The effects differ regionally, with some mines still making healthy margins while others are understood to be falling up to $10/tonne short of covering their variable costs.

Figure 7.8 ▷ Weighted average FOB cash costs and indicative cost range for steam coal by key exporter



Sources: IEA analysis; Wood Mackenzie databases.

Variable production costs fluctuate over time, influenced by a number of factors, such as wage increases and the evolution of prices for key inputs like diesel, steel, electricity and explosives (Figure 7.8). In countries where wages are low (e.g. India, Indonesia or South Africa), producers typically employ more labour-intensive production methods, while in countries with high wages (e.g. Australia or the United States), producers substitute capital for labour, running highly mechanised operations. In either case, labour is a major

9. Some variable costs can be avoided immediately by stopping production (e.g. fuel, explosives) while avoiding others, such as labour cost, may take longer. In most countries, transportation costs are a variable cost component, but where take-or-pay contracts are used (e.g. Australia) they effectively are a fixed cost component.

cost factor. Oil products are used along the entire coal supply chain, fuelling vehicles and machinery, as well as in explosives. Therefore, the evolution of oil prices also impacts on the cost of coal supply (Box 7.4). Moreover, foreign exchange rate effects can play a major role. The mechanism is simple: as coal trade is mostly settled in US dollars, coal exporters generate revenues in dollars, while they incur a large part of their costs in domestic currency. Therefore a devaluation of the domestic currency against the US dollar implicitly translates into a supply cost decrease for non-US exporters (or increased revenues in local currency). In 2014, the Russian ruble lost over 20% in value against the US dollar. For Russian exporters, who incur the bulk of their FOB cash costs in rubles (railway tariffs, wages and electricity), this has provided significant headroom in the low-price environment. Even in local currency terms, supply costs have generally come down in all major exporting countries over the last three years. Australia, but also Russia and South Africa, have made large strides in reducing the costs.

The average price of imported steam coal across the OECD fell to $78/tonne in 2014, a level last seen in the mid-2000s (in real terms). The drop in prices is primarily the result of coal demand growth falling short of the level of growth expected a couple of years ago. Increasing coal demand in the period 2007-2011 triggered major mining investments – much of which has come online over the last two years – resulting in a surge of over-capacity in many key exporting countries, as well as in China. Some producers have stayed in the market despite incurring losses on the variable cost of every tonne of coal produced, hoping that others will leave the market before them. This strategy is risky as many producers who have shut capacity have not done so permanently but have simply suspended operation, allowing them to bring the mines back online rapidly should market conditions improve. Thus, a small increase in price could trigger a rapid increase in output. On the other hand, cost-cutting and foreign exchange rate effects have helped some producers to improve their competitive position in the market. A few producers have adopted the strategy of boosting output in an effort to reduce production costs per tonne, effectively adding to the supply glut. In the New Policies Scenario, supply and demand on the international coal market are back in balance around 2020, with prices again primarily determined by the marginal costs of supply thereafter. In the longer term, rising energy prices and increasing real wages in mining, in combination with worsening geology and more remote operations, put upward pressure on coal supply costs. Technological progress and efficiency gains temper these effects but nonetheless the cost of coal supply increases moderately over the *Outlook* period.

Regional variations in coal prices persist over the projection period. Average coal prices in markets with large domestic reserves of low-cost coal like the United States remain significantly below international coal prices. Despite upward pressure on prices due to increasing mining costs, coal from the US Powder River and Illinois basins is among the cheapest in the world and coal consumers in the United States pay, on average, $70/tonne (in year-2014 dollars) in 2040, up from $60/tonne in 2014. India also benefits from access to low-cost coal, but the average price paid by consumers increases markedly, from $65/tonne today to almost $90/tonne in 2040. As Indian mining companies expand their production rapidly, they need to exploit more difficult, and hence more costly, reserves (including through an increase in the share of underground mining). Despite significant scope for productivity improvements, wages increase in India's rapidly growing economy, adding to the pressures on the labour-intensive coal mining industry (see Chapter 13). The marginal costs of domestic coal supply to China's southern coast – and thus the prices there (the key arbitrage point between domestic coal and imports) – set a ceiling for international coal prices, but the difference from other prices, e.g. European or Japanese import prices, narrows slightly. Coastal Chinese coal prices increase from around $90/tonne in 2014 to $110/tonne in 2040. However, many power plants and industrial facilities are located close to the mines in northern and north-eastern China, receiving coal at lower prices.

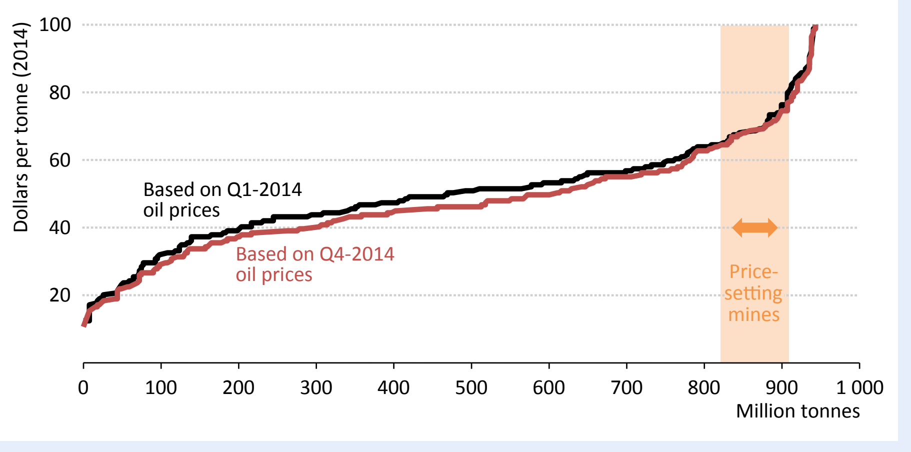
Box 7.4 ▷ Impact of oil prices on coal supply

Oil products are used along the entire coal supply chain, from mining to delivery at power plants and industrial facilities. They can be a considerable cost factor for some producers, while others have little exposure to oil prices. The use of oil products in mining is technology dependent, but the share of oil products in operating costs typically range between 5-30%, i.e. a drop in oil prices of 30% would translate into a reduction of a mine's operating costs between 2-10%. However, to assess the effect of oil price fluctuations on coal prices, one needs to concentrate on the degree to which price-setting mines are affected.

In open-cast mines, where large amounts of coal and overburden must be moved, fuel costs play a large role. Mines that use truck-and-shovel technology are heavily exposed to fuel price fluctuation. Explosives – often of the ANFO-type (ammonium-nitrate fuel oil) – are another important cost component in open-cast mining. Underground mining is less fuel intensive, but oil-based lubricants, hydraulic fluids and above-ground fuel use can still account for up to 5% of operational costs. Inland transport to an export terminal or a domestic consumer can have a substantial fuel cost component, too. Road haulage over long distances is generally uneconomic, but transporting coal up to 200 kilometres (km) (in some cases distances can exceed 500 km) from the mine is often done with trucks, if there is no railway access. Indonesia has a particularly high share of truck haulage at around 75%. In India, 25% of production is moved by trucks, while this share amounts to 20% in China and 15% in the United States. Around 90% of internationally traded coal is transported long distance by ships that burn fuel oil.

What is the effect of oil price fluctuations on coal prices? On one hand, coal prices are largely dependent on the variable production and transport costs of coal, of which oil can be a significant component. On the other hand, what happens at the margin determines the price, and there are sufficient underground mines at the margin that have, due to their lower exposure to oil prices, benefited little from the recent oil price drop (Figure 7.9). As well, there is an indirect effect stemming from coal-to-gas competition in the power sector. Oil and natural gas prices are correlated in some regions and while gas plays no role in coal production, it is coal's primary competitor in several power markets. Thus, a drop in oil prices improves the competitiveness of gas *vis-à-vis* coal in some regions, leading to some fuel switching and consequently to lower coal demand. In the Low Oil Price Scenario (Chapter 4), the OECD steam coal import price is roughly $6/tonne lower in 2040 than in the New Policies Scenario. This effect stems from a combination of slightly lower supply costs at the margin and moderate coal-to-gas switching.

Figure 7.9 ▷ Effect of oil price changes on FOB cash costs for global seaborne steam coal trade, 2014



Notes: The graph reflects FOB cash costs for steam coal traded on the seaborne market, based on the average oil prices in the first quarter of 2014 (Q1-2014) and the fourth quarter of 2014 (Q4-2014). Brent oil prices dropped by around 30% in this period. The cost curves exclude the seaborne shipping costs.

Sources: IEA analysis; Wood Mackenzie databases.

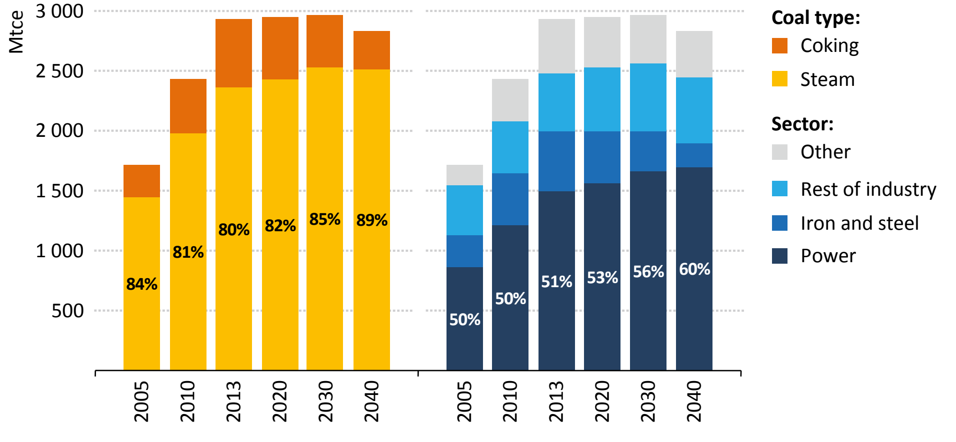
The coal price on the international market is mainly set by Australian, US Appalachian and Russian mines. Variable costs in these countries are affected by labour costs and in Russia also by electrified railway transport cost. Consequently, in the absence of coal-to-gas switching, oil price fluctuations would have little impact – between $1-2/tonne – on coal supply costs at the margin and thus on international prices. Moreover, due to arbitrage considerations between domestic and imported coal in coastal China, domestic coal supply costs function as a ceiling for international coal prices. With Chinese coal being almost exclusively produced in underground mines and transported primarily by railway and coastal shipping, prices in coastal China also have little exposure to oil prices. However, decreasing oil prices do play a major role for intra-marginal coal suppliers with large shares of truck-and-shovel based open-cast mining, like Indonesia or Colombia. As a result of their high oil exposure, their costs are pushed down by $3-4/tonne.

Regional insights

China

At some 2 930 Mtce in 2013, China consumed half of the world's coal production. Even though its import dependency is relatively low, China dominates coal markets and will do so for a long time. Between 2000 and 2009, Chinese coal use grew on average by 9.5% per year; but more recent years have seen growth slow to only 4% per year on average. To what extent this is a structural change or a temporary phenomenon is not certain to date, particularly as there are ongoing revisions to Chinese historical energy data (see Chapter 2, Box 2.1). In the New Policies Scenario, China's role shifts from being the main growth centre for global coal demand – as was the case for the last decade – to being a mature coal consuming country, whose coal demand levels out over the medium term and then goes into a slow long-term decline in the early 2030s. In 2040 Chinese coal demand will have dropped to 2 825 Mtce – around 5% below today's levels (Figure 7.10). The demand evolution in the New Policies Scenario stems from two opposing trends: coal demand growth from end-use sectors (such as industry and buildings) is already slowing down and drops by 30% over the *Outlook* period. Demand from the power sector is much more robust and grows, albeit at subdued rates, well into the 2030s. However, contrary to the projections of the New Policies Scenario, an earlier peak of Chinese coal demand, with a much more rapid decline of consumption is by no means impossible (Spotlight). The evolution of coal demand in China, given its sheer size, will have marked repercussions on international coal and energy markets.

Figure 7.10 ▷ Coal demand in China by coal type and key sector in the New Policies Scenario



Notes: Steam coal includes lignite. Iron and steel includes own use and transformation in blast furnaces and coke ovens. Rest of industry also includes petrochemical feedstocks, coal-to-liquids and coal-to-gas plants.

SPOTLIGHT

What would it take for China's coal demand to fall?

Recent official revisions to historical data (see Chapter 2 Box 2.1), as well as a number of previous estimates, point to a decline in China's coal demand in 2014 – for the first time since the late 1990s. This has sparked a vigorous debate over whether this may be the start of a trend: has China's coal consumption peaked once and for all? In the New Policies Scenario, the answer is no, or at least, not yet. Chinese coal demand does level off over the medium term before entering a slow decline in the late 2030s. But other scenarios, and some market observers, do envisage the possibility of a decline in China's coal use in the coming years.

One such scenario is the 450 Scenario, in which the world takes concerted action to limit the rise in long-term global average temperatures to below 2 °C. As emphasised again in this year's *Outlook*, the door to a 2 °C outcome remains open, but it would require a major policy shift in favour of accelerated decarbonisation to achieve this goal. If countries do not follow this path and instead maintain policies that are closer to those in our central scenario, then the same decline in coal use (by 1.7% per year) would imply either a dramatic slowdown in China's gross domestic product (GDP) growth (to under 4% per year over the period to 2030) or a structural shift in the economy away from heavier industrial activity towards services at an unprecedented pace.[10]

Contemplating such a decline in China's coal use is an uncomfortable process for the coal industry. The consequences would be dramatic, both in China – where 70% of Chinese coal companies are losing money (McCloskey, 2014) – and on an already over-supplied global market. Even with a vigorous consolidation in the industry, the chances would be that mine closures would not keep up with declines in demand, leading to an unremitting overhang of supply, intense competition for customers and rock-bottom prices. Low prices could offer an incentive for additional consumption elsewhere, but not anything like the scale that could fill the gap left by China, given its weight in global coal demand. Neither the regulatory environment nor the energy demand growth prospects in OECD countries leave much room for additional coal consumption, while the coal industry has long anticipated increased demand in India and Southeast Asia, leaving little upside potential.

Demand for coal in China was boosted in recent years by rapid economic growth, power demand growth, urbanisation and infrastructure build-up. However, these trends are set to change: gross domestic product growth is slowing and the Chinese government intends

10. Analysis presented here is relative to the 2030 Chinese targets for energy and climate change. The contribution of the services sector to GDP (assuming similar GDP growth rates as in the New Policies Scenario) would need to grow from 47% today to 70% in 2030.

to rebalance the economy, away from heavy industries to more services-based growth. Production of crude steel and cement is thought to have already peaked and, in the longer term, scrap availability in China will increase, leading to a shift away from traditional steel-making in coke-based blast furnaces towards greater use of electric arc furnaces. Given the country's endowment of coal reserves and the low cost of coal *vis-à-vis* other fuels, coal has also made in-roads into other end-use sectors, such as chemicals, agriculture and households. Coal can be expected to be gradually phased-out of certain end-uses and replaced by more modern and convenient sources, such as gas and electricity.

The power sector, which accounts for half of China's coal burn today, holds the key to the evolution of its coal demand. Electricity demand is projected to grow by 2.6% per year in the period to 2040. The bulk of the additional power plant coal burn occurs in the period to 2030 after which growth slows markedly before going into decline in the late 2030s. Diversification of the power sector is an energy policy priority in China, as reflected in a big expansion of hydropower capacity, the country's second-largest power source. Hydropower output grows by a further 70% over the *Outlook* period. Between 2009 and 2014, nuclear capacity doubled to over 20 GW, with around 6 GW brought online as of end-August 2015 and another 26 GW under construction. Variable renewables, such as wind and solar photovoltaics see particularly rapid deployment and their combined share in power generation rises from 3% today to 13% in 2040. In contrast, coal's share in power generation drops markedly, from three-quarters today to half in 2040.

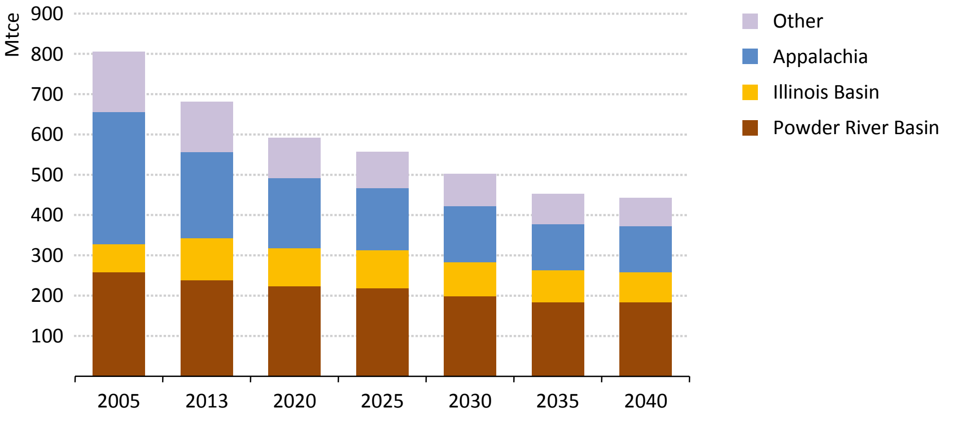
Chinese coal production has experienced massive cost hikes over the last couple of years but, with demand growth slowing, pressure is now on to consolidate and cut costs. In the New Policies Scenario, Chinese coal production follows the demand trend, but peaks a little later, in the early 2030s. Net imports – amounting to around 10% of Chinese coal demand – are volatile and are expected to remain so in the future. However, structurally, import trends are set to decline both for coking and steam coal. Considering the Chinese authorities are likely to give continued preference to domestic coal, and if this can be accompanied by serious cost-cutting, then the cost of supply may be held within reach of the cost of imported coal in southern coastal China (the main importing region). In the longer term, coal demand growth is gradually moving away from the developed coast, first to the less developed centre and northern regions and then, in the latter half of the *Outlook* period, to the west. All of these regions are closer to the domestic coal mining hubs and the long transport distance from the coast will make imports uneconomic. Chinese imports are accordingly expected to have peaked in 2013, at 260 Mtce, and to slowly decline to 125 Mtce in 2040.

United States

The United States is currently the second-largest coal consumer accounting for 11% of the world's coal use and 42% of the OECD region's coal use. Subject to regulatory action and strong competition from natural gas, the role of coal in the US energy system undergoes a significant transformation in the New Policies Scenario. US coal consumption drops by 35% in the period to 2040. This corresponds to an annual decline of 1.6% on average; significant, but still less than half the rate at which coal use drops in the European Union over the same period.

In the short term, the Mercury and Air Toxics Standards issued by the US Environmental Protection Agency (EPA) will force much of the ageing coal fleet either to add emissions control technology (scrubbers) or to retire the plants from service. Many plants had already been retired by mid-2015 and others will follow, as the deadline for compliance approaches (end-2015; in some states, end-2016). The current low natural gas prices make the necessary investment in scrubbers questionable for many older coal plants that are exposed to competition from modern combined-cycle gas turbines. In the longer term, the Clean Power Plan, which aims to reduce power sector emissions by 32% from 2005 levels by 2030, constrains coal's role in US power generation. In addition, the Carbon Pollution Standard for New Power Plants limits the emissions of new coal plants to 1 400 pounds per megawatt-hour (MWh) (about 635 grammes of CO_2 per kilowatt-hour), which effectively requires plants to have some CO_2 capture units (the EPA estimates this requires 16-23% carbon capture rates for new supercritical designs in order to comply). In the New Policies Scenario, the combination of these regulations leads to the retirement of around 70 GW of the oldest and least-efficient coal-fired plants in the period to 2020.

Figure 7.11 ▷ United States coal production by basin in the New Policies Scenario



Falling US coal demand hits the country's coal industry hard. Production drops from around 680 Mtce in 2013 to 445 Mtce in 2040. However, the key coal mining regions – Appalachia, the Illinois Basin and the Powder River Basin – are affected differently (Figure 7.11). Of the three, Appalachia bears the brunt, with the region's coal output slashed to nearly half of today's levels in 2040. Central Appalachia is a high-cost basin and sees particularly extensive mine closures over the *Outlook* period, leaving producers in central Appalachia focussing chiefly on coking coal production. Northern Appalachia, where mining costs are on average lower than in central Appalachia, is less prone to closures, but investment activity is low over the *Outlook* period and is primarily targeted at sustaining production at existing mines. The Illinois Basin has low mining costs and is centrally located, allowing for competitive deliveries to the south, the mid-west and also the eastern United States.

Illinois Basin coal has high-sulphur content, but with the large-scale roll-out of scrubbers (de-sulphurisation technology for power plants), coal from this region has established itself as a low-cost alternative to Appalachian coals. Output from the Illinois Basin declines marginally over the medium term and starts dropping faster only after 2025. The Powder River Basin is among the least-cost sources of coal in the world. It therefore manages to expand its market share as demand contracts, though output from this region – which is often transported over very long distances – drops by 7% by 2020 and then goes into a steeper decline as the customer base slowly erodes; 2040 output levels are 25% below today's levels.

Shipments from the United States continue to decline over the *Outlook* period, providing only limited relief for the US coal industry. With net exports of coal reaching 45 Mtce in 2040, they stay far below the high point of some 100 Mtce in 2012. US exporters face several challenges: first, the high-cost mines in Appalachia cannot profitably export into the Atlantic market in the current price environment. Second, in the longer term, European coal demand – the key market for exports out of the east coast – is shrinking and Colombian exporters fare far better in terms of costs to pick up what is left. Third, missing infrastructure is limiting the scope for exports from the Powder River Basin. Once export infrastructure exists on the west coast, the growth opportunities will have fully shifted to India and Southeast Asia. Because of the low calorific value of Powder River Basin coal and the long transport distances to southern Asia, other suppliers (Indonesia, South Africa and Australia) have a clear cost advantage in that market. Exports from the west coast are therefore projected to be limited to what they can displace in Korea, Japan and China.

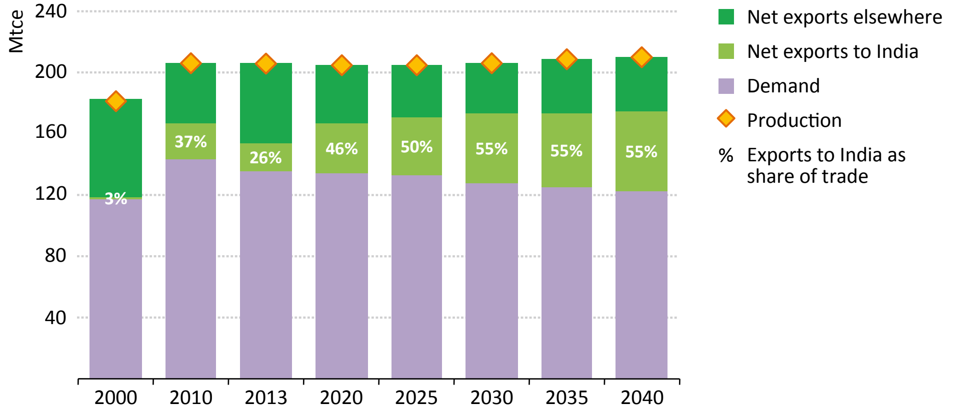
South Africa

South Africa is a major coal producer and consumer and the sixth-largest coal exporter in the world. In the New Policies Scenario, South African coal demand decreases by 10% to around 120 Mtce in 2040. The evolution of coal demand stems from a projected slowdown of economic growth, strong deployment of solar photovoltaics in the power sector and weakened prospects for expanding coal-to-liquids production in the light of recent lower oil prices. In contrast, South African coal production essentially stays flat at around 210 Mtce while exports grow by almost 25%, approaching 90 Mtce by the end of the projection period (Figure 7.12). The country's coal industry faces a number of challenges and opportunities over the *Outlook* period.[11] Almost 80% of the coal production in South Africa currently takes place in Mpumalanga province, where coal has been mined for decades. Many of the mines are nearing depletion and coal quality is deteriorating. To keep up with domestic coal demand the South African coal industry has to expand production in the remote Waterberg field in Limpopo province. The Waterberg is roughly 400 km from the power plant clusters around Johannesburg and around 1 000 km

11. See *Africa Energy Outlook: World Energy Outlook Special Report* (IEA, 2014), available to download free at: *www.worldenergyoutlook.org/africa*.

from the main export hub in Richards Bay. Large infrastructure investments are thus needed to fully unlock the potential of this region either to transport the coal to the power plants that are clustered around the mines in Mpumalanga or to transmit coal-based electricity to the demand hubs around Johannesburg and the coast. Only limited amounts of Waterberg coal will likely find their way to the export market, but coal from the Waterberg will free up export quality coal that is currently burned in domestic power plants.

Figure 7.12 ▷ South Africa coal balance in the New Policies Scenario

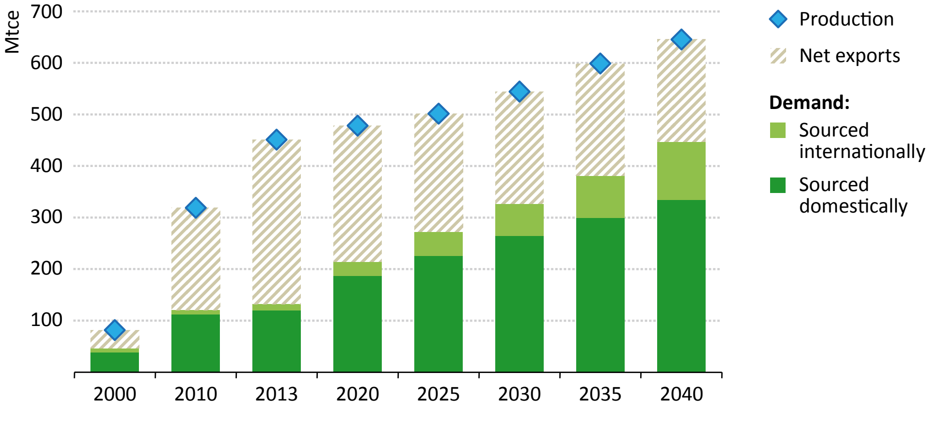


Coal exporters from South Africa face stiff competition from their main rivals in Colombia and Indonesia. Decreasing demand in Europe, where Colombia is generally better positioned in terms of distance, limits South African exports to the Atlantic market. The robust increase of India's coal imports is South Africa's primary growth opportunity, but Indonesia has a slight cost advantage along most of India's east coast. South Africa's potential as an exporter is thus highly sensitive to the evolution of its coal production cost, the developments on the dry bulk freight market and the ability to quickly expand capacity in the Waterberg. Moreover, as the majority of South African coal is costlier than key competitors' coal in most of East Asia (China, Japan and Korea), what happens with Indian domestic coal production and consequently to Indian import requirements is critical to South Africa's future as a coal exporter.

Southeast Asia

Combined coal use in Southeast Asian countries, all of which are members of the Association of Southeast Asian Nations (ASEAN), is set to grow almost three-and-a-half-times in the New Policies Scenario, from 130 Mtce in 2013 to 445 Mtce in 2040 (Figure 7.13). Only India experiences larger growth in absolute terms. 80% of Southeast Asian coal demand growth comes from the power sector, which relies heavily on coal to meet increasing power demand: coal's share in the power mix of the Southeast Asian countries grows from a third today to half in 2040, the reliability of coal supply and its low costs making coal the fuel of choice in the region. Although differing in magnitude, all major countries in the region (including Viet Nam, Malaysia, Philippines and Thailand) see their coal demand grow markedly. Indonesian coal demand grows by a factor of four, reaching almost 190 Mtce in 2040. Since coal use rises in the region in all the three main *WEO* scenarios, it is a priority for policy-makers to ensure that coal is used as efficiently as possible. Malaysia has just connected the region's first ultra-supercritical power plant to the grid, but it is important that others follow suit. Of the region's 50 GW of coal-fired generation capacity, 93% is subcritical and another 13 GW of subcritical capacity is currently under construction. By the end of the projection period, the share of subcritical capacity is projected to have fallen to some 55%, with another 30% being supercritical and the remainder being ultra-supercritical and IGCC plant.

Figure 7.13 ▷ Southeast Asia coal balance in the New Policies Scenario



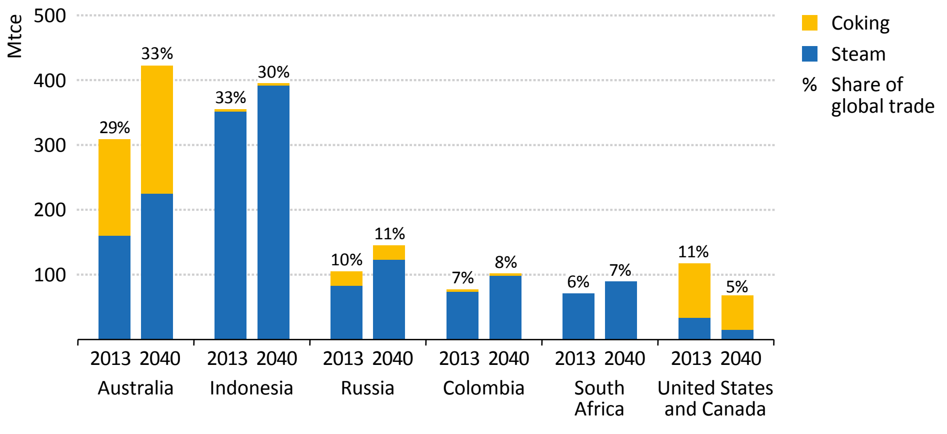
Total coal production in Southeast Asia increases by 45%, from 450 Mtce in 2013 to 645 Mtce in 2040. Indonesia dominates the region's coal production, with output increasing from 400 Mtce in 2013 to 580 Mtce in 2040. The region comprises both important importers and exporters of coal but, as a whole, Southeast Asia remains a net exporter, with Indonesia ranking as the largest steam coal exporter in the world throughout the *Outlook* period. Indonesian exports grow progressively more slowly as much of the increase in production is absorbed by rising domestic demand. Viet Nam is the second-largest coal producer in Southeast Asia and a minor net exporter of coal. Despite large reserves, the country's coal production has grown only sluggishly over the last couple of years. Over the medium term, demand growth is expected to outstrip domestic coal supply growth, with Viet Nam soon becoming a net importer. Along with Viet Nam, Malaysia, Philippines and Thailand also experience strong growth in coal imports.

Indonesia's low-cost position has protected producers for a long time from production cuts in the low-price environment of the international coal market. However, now Indonesian mines are coming under pressure as well (largely as a result of a high share of costs incurred in US dollars, at a time when key competitors' currencies devaluated against the US dollar) and between 35-45 Mtpa of capacity are expected to be taken out of the market this year. As prices rise over the medium term, Indonesia is projected to see its investment activity pick up again. Apart from exporting to other Southeast Asian countries, Indonesia's main market is India, in which Indonesia has a share of 60% of the import market today. Though Indonesia is unlikely to sustain such a high market share, India remains Indonesia's primary growth opportunity. Despite the long-term decline in Chinese imports, southern coastal China remains an important market for Indonesian exporters.

Australia

Australia is the second-largest coal exporter in the world. In 2013 the country exported 310 Mtce of coal, roughly half of which was coking coal – the variety primarily used in steel-making (Figure 7.14). Steam coal exports are important for Australia (it is the second-largest global exporter), but it is really coking coal that makes Australia critical to global coal trade. Australia supplies 55% of traded coking coal and, currently, only two countries can compete with its coking coal exports in terms of quality and cost. These are the United States and Canada which hold a global market share of 21% and 10% respectively.

Figure 7.14 ▷ Major net exporters of coal by type in the New Policies Scenario



Australia manages to increase exports significantly over the *Outlook* period, to 425 Mtce, thereby regaining the position as the largest coal exporter from Indonesia. Coking coal exports account for around 45% of the increase, a major achievement given the subdued level of growth (15%) in international coking coal trade to 2040. As a result, Australia increases its market share in coking coal trade to nearly two-thirds in 2040, despite the rise of new rivals, such as Mozambique. Steam coal exports, spurred by strong import growth in India and Southeast Asia, rise to 225 Mtce. The largely unexploited Surat and Galilee Basins will be an important source for these expanding exports, but challenges remain, especially with respect to environmental concerns and – given the current price environment – the financing of the mines and the associated infrastructure (there is notable engagement of Indian companies in developing coal mines in Queensland's untapped Galilee basin).

The projected strong growth in Australia in the New Policies Scenario hinges on the coal industry's ability to further enhance productivity and keep costs in check. Australian coal companies have made huge efforts to bring down costs (supported by a depreciation of the Australian dollar) over the last three years; but large shares of production remain comparatively high cost. The projected level of Australian coal exports – especially for steam coal – is thus quite price sensitive.

Power sector outlook

Powering economic growth

Highlights

- Electricity demand increases by more than 70% over 2013-2040 in the New Policies Scenario, with non-OECD countries responsible for 7 out of every 8 additional units of global electricity demand. Electricity demand sees the fastest growth among the final energy sources, raising its share in final energy use from 18% to 24% by 2040.
- Installed power generation capacity reaches 10 570 GW in 2040, an increase of some 4 400 GW over the level in 2014 and one-third more than the increase in the previous 25 years. To keep pace with strong electricity demand growth, installed capacity more than doubles in non-OECD countries, led by China (where capacity doubles) and India (where capacity almost quadruples).
- The global power generation mix is poised to shift away from coal, whose share falls from 41% today to 30% in 2040, after holding steady since 1990. The share of low carbon technologies in total generation increases from one-third in 2013 to 47% in 2040, due to the growth of non-hydro renewables and a stable share of nuclear and hydropower. OECD countries' share of global coal-fired generation, which was 70% in 1990, almost halved by 2013, and halves again by 2040. Coal-fired generation increases most in India, more than in China or in the rest of the world combined.
- Global power sector investment totals nearly $20 trillion over 2015-2040, split between 6 700 GW of new power plants ($11.3 trillion, 62% renewables) and 75 million km of lines to deliver the power ($8.4 trillion). Average generation costs increase in nearly all regions (US, +18%; EU, +14%; China +25%), with rising fuel prices and higher cost plants. This leads to higher retail electricity prices in 2040, but even faster income growth makes electricity more affordable over time in most regions.
- Over the past decade, the average efficiency of the global coal-fired power plant fleet improved from 35% to 37%, driven by impressive gains in China (6 percentage points in ten years, surpassing the OECD average). Poor quality coal and a high share of subcritical plants (85%) kept the efficiency of India's fleet much lower. Subcritical plants make up two-thirds of the world's coal fleet today, account for over 25% of total power generation and half of CO_2 emissions from power generation.
- By 2040, the average efficiency of coal-fired power plants climbs to 40%, with the level in India reaching that of the OECD and China today. Since 1990, power generation and related CO_2 emissions have risen on a one-to-one basis. From 2013 to 2040, though, the two decouple: generation increases nearly 70% while CO_2 emissions rise less than 15%. Without efficiency gains and less coal in the mix, emissions from power generation would be almost 50% higher in 2040. In water-stressed areas, dry cooling technologies that lower efficiencies may be required, as in some parts of China.

Context

For decades, economic growth has been accompanied by growing electricity demand. From 1990-2013, global gross domestic product (GDP) (expressed in purchasing power parity terms) and electricity demand both roughly doubled and so, too, did coal and gas demand in the power sector and related carbon-dioxide (CO_2) emissions. In 2013, the power sector accounted for over 60% of coal demand, 40% of gas demand, 55% of the use of modern renewables[1] and 42% of global energy-related CO_2 emissions. The power sector must therefore be at the heart of any strategy that addresses economic growth, energy security, climate change or local air pollution.

Despite the long lead times inherent in the power sector, changes continue to unfold, with a significant transformation of the power mix underway. Renewables are receiving strong support in a growing number of countries (see Chapter 9), fostering changes to the design of electricity markets (IEA, 2016), but also, in some cases, concerns over the extent of support needed. Nuclear and coal face challenges to deployment in some countries and enjoy support in others. Natural gas-fired generation has been constrained by supply in some cases and by cost in others, although the recent dip in gas prices has improved the economics.

Important issues at the forefront of policy and business discussions include the need to ensure timely investments to meet growing demand and replace retiring assets, provide conditions to foster fair competition between fuels and technologies and ensure energy security and high quality service. In addition, there are the challenges of how best to integrate renewables into the market and the need to provide access to electricity to the hundreds of millions that remain without it.

Most countries are pursuing the difficult objective of meeting economic, security and environmental goals through integrated policies (Box 8.1). The formulation of the Intended Nationally Determined Contributions (INDCs), submitted in preparation for the United Nations Framework Convention on Climate Change Conference of the Parties summit (COP21) in late 2015, has in many cases, given renewed impetus to this process.

In the United States, three key factors are shaping the power sector. First, there are three federal laws (although legal challenges are expected): the Clean Power Plan, which aims to reduce CO_2 emissions from power generation by 32% below the 2005 level by 2030; the Mercury and Air Toxic Standards, which drives the retirement of inefficient coal-fired plants in the near term; and the Carbon Pollution Standards, which sets emissions performance standards for new power plants. The second is the revision of renewable portfolio standards in several states, with some considering lower levels, while others are strengthening their standards, e.g. California, Hawaii and Vermont. Thirdly, the decline in natural gas prices has facilitated more coal-to-gas switching in power plants, with electricity generated from some gas-fired power plants now costing about the same as from coal-fired plants in many places. As a result, April 2015 was the first month in US history in which gas-fired generation exceeded that from coal.

1. Includes all types of renewables with the exception of the traditional use of solid biomass.

In the European Union (EU), the INDC submitted sets a binding target to reduce greenhouse-gas emissions (GHG) by 40% below 1990 levels by 2030. It is based on its 2030 climate and energy framework that also includes an increase of the share of renewables to at least 27% (of total final energy consumption) and an indicative target to achieve at least 27% energy savings compared to a business-as-usual scenario. The overall GHG aim includes a target to reduce emissions by 43% below 2005 levels by 2030 that applies to all sectors subject to the Emission Trading System (EU ETS). The framework provides for a market stability reserve that can control the volume of credits to remedy the surplus of credits that have depressed the CO_2 price, which averaged €6 in 2014. In addition, the EU strategy seeks greater co-ordination of capacity markets so as to facilitate more investment in renewables and low-carbon technologies in the EU electricity market.

The implementation of feed-in-tariffs (FiT) in Japan in 2012, following the Fukushima Daiichi accident, accelerated the deployment of renewables in power generation, triggering the authorisation of around 1.7 million projects, mostly for solar photovoltaics (PV). Around 95 gigawatts (GW) of solar PV projects were authorised, of which 23 GW had been installed by May 2015 and the remainder are under review. In August 2015, Sendai 1 was the first nuclear reactor to restart after the Fukushima Daiichi accident after completing the regulatory requirements of the Nuclear Regulation Authority (NRA), followed by Sendai 2 in October. Forty-one nuclear reactors remain offline, with twenty-five units that are waiting for licensing assessments from the NRA.

Korea launched a new emissions trading scheme at the start of the year as part of its target to limit GHG emissions in 2030 to 37% below a business-as-usual scenario. The scheme, which covers 525 businesses from 23 sectors, creates the world's second-largest carbon market behind the EU ETS.

Emerging economies face particular challenges to satisfy rising energy demand while also meeting energy security and environmental goals. Recent policy decisions in China aim to decouple economic growth from emissions. Its INDC reinforced its previously stated goal to achieve a peak in emissions around 2030 and to increase the share of non-fossil fuels in the energy mix (15% by 2020 and 20% by 2030). New goals set out in its INDC include: to reduce the carbon intensity per unit of GDP by 60-65% below 2005 levels by 2030; the efficiency of new coal-fired power plants has been targeted at 300 grammes of coal per kilowatt-hour (kWh) produced (equivalent to 43% efficiency) by 2020; and targets to reach 200 GW of wind power capacity and 100 GW of solar capacity by 2020. China also has ambitious targets for the deployment of hydro and nuclear power, although installed capacity goals previously set for 2020 (420 GW of hydro and 58 GW of nuclear) will prove difficult to achieve.

India's power sector is also in the midst of a profound transformation. Over the last few years, India has significantly expanded its generation capacity. Recently it introduced ambitious targets to increase renewables capacity (excluding large hydropower) by 2022, with 100 GW solar, 60 GW wind, 10 GW of bioenergy and 5 GW of small hydropower. India has also set a demanding target to provide electricity access to all of its citizens, involving extending and strengthening the national transmission grid. In addition, it aims to produce 1.5 billion tonnes of coal by 2020. Major challenges remain before these targets can be achieved, enabling India to keep up with its burgeoning demand (see the special focus on India in Part B).

Box 8.1 ▷ Decoupling emissions and economic growth in the Nordic region

The five Nordic countries (Denmark, Finland, Iceland, Norway and Sweden) have seen a steady decoupling of GDP and GHG emissions over the last decade, mainly because of their increasingly low-carbon heat and electricity mix. With an average carbon intensity of power generation of just 100 grammes of carbon dioxide per kilowatt-hour (g CO_2 per kWh) (a level the global power sector reaches only around 2040 in our 450 Scenario) the region has put itself at the forefront of power sector decarbonisation.

The cornerstone of this success has been the regional approach to energy and climate policy, including the integrated electricity market across four countries that has been in operation since 2000. The flexibility provided by extensive physical interconnections has enabled a very high share of variable renewables (such as wind power in Denmark) to be utilised without jeopardising reliability of supply. The interconnection among countries enables an optimisation of each country's diverse resources – while Norway's electricity generation is nearly all hydropower, other countries have a more diverse mix, including fossil fuels (Denmark and Finland), nuclear power (Sweden and Finland) and other renewables. In this configuration, Norwegian hydropower is able to balance variable wind in Denmark through an undersea interconnector. Iceland has hydropower and geothermal, but is not currently connected to any other electricity system.

Long-term policies have provided the solid foundation needed to attract the necessary investment. All five Nordic countries have longstanding policies on the taxation of both energy and carbon emissions. For example, in 1991 Sweden introduced a gradually increasing carbon tax, which had reached SEK 1 120 per tonne by 2015 (€119 at September 2015 exchange rates). The tax has been instrumental in district heating systems converting from fossil fuels to predominantly biomass. In 2003, Sweden also introduced a green certificate scheme, which is expected to last until 2030. Combined with other incentives, this policy has encouraged wind power development in Sweden, with installed capacity increasing from 2 GW in 2010 to almost 5.5 GW in 2014. Norway joined the green certificate scheme in 2012, making it Europe's only bilateral renewable power incentive scheme.

In addition to heat and power, Norway's support schemes for electric vehicles (EVs) have resulted, in the country of just five million inhabitants, accounting for about 30% of all EVs sold in Europe in 2014: one of every six cars sold in Norway during the first-half of 2015 was an EV. Despite notable successes, the Nordic region still faces significant challenges to decarbonise the transport and industry sectors. A stronger focus on industrial energy efficiency and the roll-out of carbon capture and storage for cement and other energy-intensive industries will be necessary to achieve a long-term decarbonisation in industry (IEA, 2013). Urban planning, far-reaching adoption of modal shifts and a large-scale shift to biofuels will be needed to decarbonise transport. Achievement of a decarbonised future energy system holds new opportunities for the region, such as potentially providing flexibility and being a net exporter of renewable electricity to Europe. If interconnectors to the continent are expanded sufficiently over the coming decades, as much as 80 terawatt-hours (TWh) could be exported to Europe in 2050.

Many Southeast Asian countries are seeking to diversify their energy supply, as concerns grow about energy and economic security, linked to their rising dependency on imported oil and, in some cases, natural gas. The response to these concerns, in many cases, involves increasingly the role of coal in the energy mix, though there has also been considerable effort made to deploy renewable energy technologies, including by improving the conditions for private investment. Most Southeast Asian countries have adopted medium- and long-term targets for renewables. For example, Malaysia aims to increase the capacity of renewables to 2 GW by 2020 and 4 GW by 2030, while in Thailand renewables are to make up 20% of power generation by 2036 and the Philippines target is to triple the installed capacity of renewables by 2030.[2]

Brazil is in the third year of a severe drought that has curtailed hydropower output, its main source of electricity. As a result, the high-cost fossil-fuelled power plants have been operating at near-maximum levels, contributing to rising retail electricity prices. For the last decade, Brazil has relied on auctions to contract new power plants to meet growing electricity demand. More than 17 GW of new hydropower projects have been contracted to come online in the medium term, led by the 11 GW Belo Monte project. Dedicated auctions for non-hydro renewables have also become common, in an effort to take the pressure off hydropower and minimise the use of fossil fuels. Capitalising on the world-class wind conditions in the northeast of the country, wind power has emerged as the one of the lowest cost sources of electricity in Brazil. To date, more than 10 GW of new wind power projects are in the pipeline, including 926 megawatts (MW) contracted in November 2014 (for projects to start within five years) at an average rate of about $53 per megawatt-hour (MWh). In the first two auctions for solar PV in October 2014 and August 2015, more than 1.7 GW of capacity were awarded contracts at an average of around $85/MWh, some of the lowest prices for solar PV in the world (at exchange rates as of August 2015).[3] Fossil-fuelled, small hydropower and bioenergy-based capacity have also won contracts in recent auctions.

2. For more information, see *Southeast Asia Energy Outlook: World Energy Outlook Special Report* (IEA, 2015a).

3. Contracts are awarded in Brazilian reals, the local currency.

Sub-Saharan Africa is rich in energy resources, but continues to face severe energy shortages, including regular power outages, in many countries (IEA, 2014a). Plans to expand and improve the transmission and distribution network are being developed and implemented at the national level, as well as, importantly, through regional power pools. Strengthening the infrastructure will help Africa to unlock its vast renewable energy resources, including the large hydropower potential, while lowering the average cost and improving the reliability of electricity in many countries. Aside from those connected to the grid, there are more than 635 million people without access to electricity. For them, particularly those in remote areas, renewable energy technologies in off-grid applications may provide an effective means to electricity access.

Electricity demand

Electricity demand[4] is strongly correlated to economic growth, although the extent of the linkage depends on the level of economic development of each country, the structure of the economy and the extent of access to electricity. Over the last two decades, electricity demand has risen in tandem with GDP, but, in the New Policies Scenario, growth in electricity demand and GDP gradually begin to decouple as efficiency improvements and the decline of energy-intensive industry in OECD countries contribute to a modest decline in electricity intensity (electricity use per unit of GDP).

The rate of electricity demand growth varies between the three main scenarios presented in this *World Energy Outlook*[5], as policy choices (which differ among the three scenarios) influence electricity prices, which then influence the fuel mix in end-use sectors, as well as the level of deployment of more efficient technologies. In the New Policies Scenario, demand increases over 70% from about 20 150 TWh in 2013 to almost 34 500 TWh in 2040, an average annual growth rate of 2.0% (Table 8.1). Demand is even more robust in the Current Policies Scenario, growing an average of 2.3% per year, whereas in the 450 Scenario, demand growth moderates to 1.5% per year as efficiency measures take hold. Electricity demand by 2040 in these two scenarios is 9% higher and 13% lower, respectively, than in the New Policies Scenario.

Over the projection period, different rates of assumed economic growth across regions contribute to variations in electricity demand trends by region. Non-OECD countries drive the growth in global demand, as they are, in general, undergoing rapid economic and population growth, and associated rising incomes and shifts from rural to urban areas. In the New Policies Scenario, non-OECD electricity demand expands at an average of 2.9% per year, underpinned by an average GDP growth rate of 4.5% and population growth of 1.0% per year. By contrast, OECD electricity demand growth averages only 0.7% per year. As a result, the non-OECD countries are responsible for seven out of every eight additional units

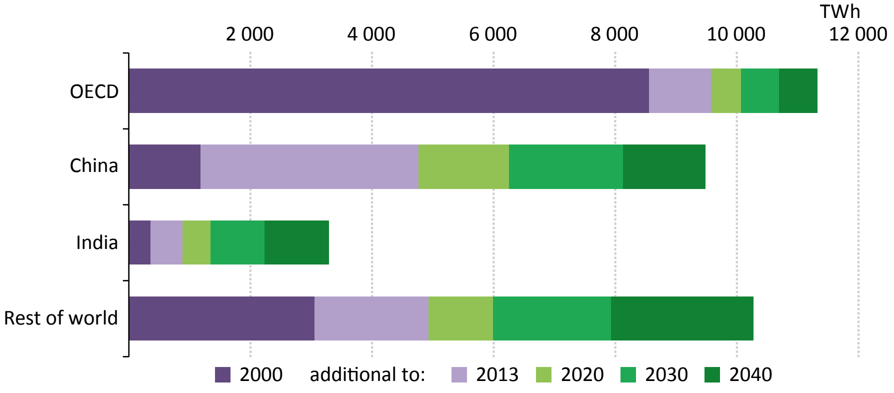
4. Electricity demand is defined as total gross electricity generated less own use in generation, plus net trade (imports less exports), less transmission and distribution losses.

5. See Chapter 1 for a description of the scenarios.

of electricity demand over the *Outlook* period and the non-OECD share of global electricity demand grows from just over half in 2013 to two-thirds in 2040. Despite this rapid growth, electricity demand per capita in non-OECD countries remains less than 40% of the OECD average in 2040. Per capita use in China, however, exceeds that in the European Union in the early 2030s.

The increase of electricity demand in China between 2000 and 2040 is almost equivalent to the total demand of all OECD countries in 2000 (Figure 8.1). China accounted for over half of the growth of global electricity demand from in 2000-2013, but in the New Policies Scenario its contribution to the growth is set to slow over time. Through to 2040, the contribution of India to global electricity demand growth increases steadily, from 7% in 2000-2013 to almost 20% in 2030-2040.

Figure 8.1 ▷ Electricity demand by region in the New Policies Scenario

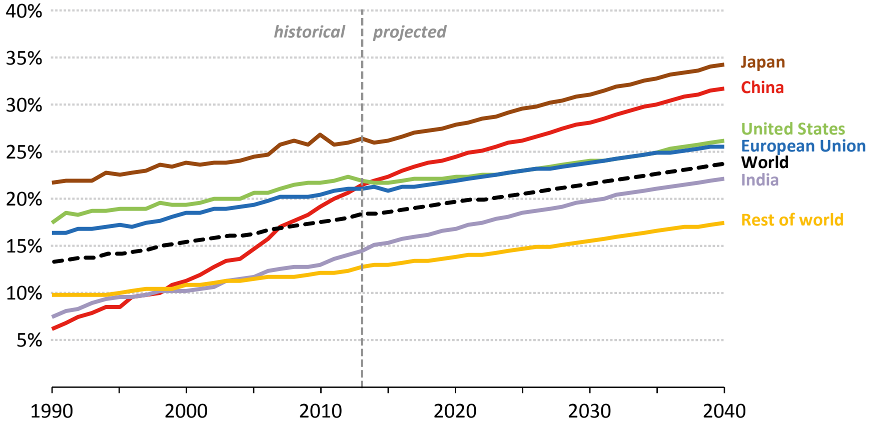


8

Electricity remains among the fastest growing forms of energy in final use in all regions in each of the scenarios. In the New Policies Scenario, electricity's share of global energy demand in total final consumption (TFC) rises from 18% in 2013 to 24% by 2040 (Figure 8.2). Electricity demand growth is driven by increasing use in industries, the ongoing shift of people to urban centres and rising living standards. However, these global figures mask sharp differences between regions. While many areas of the OECD, such as the United States or the European Union, see a relatively slow rate of further penetration of electricity in TFC, developing countries, such as India, see a particularly strong increase. China, which has seen the strongest growth over the past decade, uses a higher proportion of electricity in TFC than the United States or the European Union, approaching the level of Japan by 2040.

The industry sector retains its position as the largest global consumer of electricity, growing at an average 1.9% per year, its share of total electricity demand remaining around 40% in the New Policies Scenario. Electricity's share of total energy use in the sector increases from 27% in 2013 to 31% by 2040. Demand in the residential sector expands at 2.4% per year, electricity's share of total energy use in the sector growing by 13 percentage points, to reach 35% in 2040. This reflects an increase in access to electricity, the acquisition of more appliances and the ongoing shift away from the traditional use of solid biomass (for cooking and heating in households). Electricity demand in the services sector grows more slowly, averaging 1.7% per year over the *Outlook* period, reflecting the impact of efficiency measures and the already high level of electricity penetration (50% in 2013, rising to 57% by 2040).

Figure 8.2 ▷ Share of electricity in total final consumption by region in the New Policies Scenario



The transport sector experiences the fastest rate of electricity demand growth, averaging 4.1% per year, but its overall share remains low, increasing from 1% in 2013 to 2% by 2040. The increase in electricity demand in transport is driven by rail, which more than doubles to about 550 TWh by 2040, and by road transport (electric vehicles and plug-in hybrids), which increases at an average rate of 18.2% per year, from a very low basis in 2013 to 270 TWh in 2040. While the rate is high, absolute growth is relatively low, since there remain several obstacles to more widespread use of electric vehicles (EVs), including the cost of batteries, consumer caution and limited recharging infrastructure. While many governments have set targets for EV deployment, the market uptake in most countries, with the exception of Norway, has been far below expectations.

On a regional basis, the structure of each economy varies and with it the electricity demand in the end-use sectors. The amount of electricity needed for each unit of value added to the economy is generally very different between the industrial and the services sectors (usually by a factor of three), being highest for heavy industries. Mature economies tend to be more balanced towards the services sector, while in emerging economies the weight of electricity demand is more concentrated in the industrial sector. Demand in the residential sector depends on several factors, including GDP per capita, the need for space heating, the level of urbanisation and the proportion of the population with access to electricity.

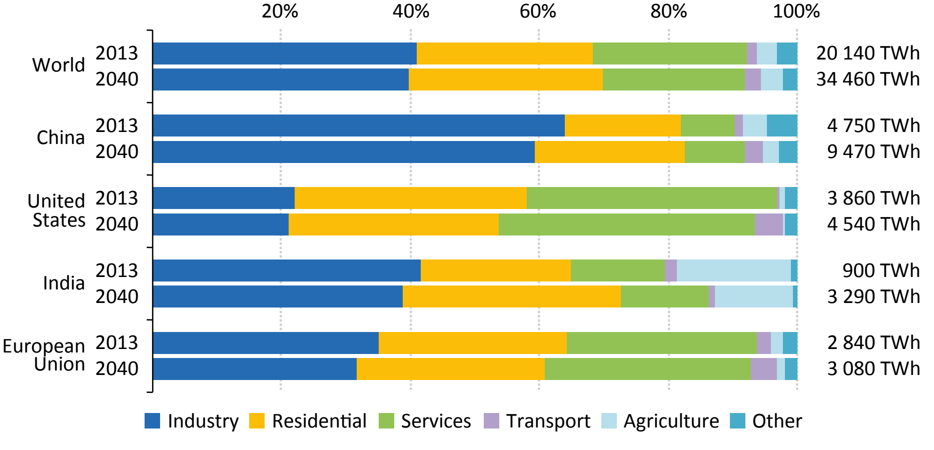
Table 8.1 ▷ Electricity demand by region and scenario (TWh)

				New Policies Scenario						Current Policies		450 Scenario	
	2000	2013	CAAGR 2000-2013	2020	2025	2030	2035	2040	CAAGR 2013-2040	2040	CAAGR 2013-2040	2040	CAAGR 2013-2040
OECD	**8 553**	**9 568**	**0.9%**	**10 052**	**10 371**	**10 692**	**11 045**	**11 440**	**0.7%**	**12 467**	**1.0%**	**10 540**	**0.4%**
Americas	4 297	4 694	0.7%	4 954	5 089	5 258	5 463	5 748	0.8%	6 236	1.1%	5 343	0.5%
United States	3 590	3 859	0.6%	4 046	4 119	4 220	4 346	4 544	0.6%	4 947	0.9%	4 298	0.4%
Europe	2 820	3 168	0.9%	3 293	3 397	3 474	3 560	3 627	0.5%	4 034	0.9%	3 449	0.3%
Asia Oceania	1 435	1 706	1.3%	1 806	1 886	1 960	2 022	2 065	0.7%	2 196	0.9%	1 749	0.1%
Japan	958	952	0.0%	956	975	996	1 017	1 029	0.3%	1 092	0.5%	827	-0.5%
Non-OECD	**4 595**	**10 576**	**6.6%**	**13 598**	**15 854**	**18 284**	**20 727**	**23 017**	**2.9%**	**24 942**	**3.2%**	**19 384**	**2.3%**
E. Europe/Eurasia	1 104	1 404	1.9%	1 491	1 586	1 697	1 813	1 911	1.2%	2 062	1.4%	1 681	0.7%
Russia	677	863	1.9%	882	935	996	1 057	1 100	0.9%	1 204	1.2%	982	0.5%
Asia	2 129	6 770	9.3%	9 113	10 784	12 548	14 243	15 776	3.2%	17 354	3.5%	13 182	2.5%
China	1 175	4 751	11.3%	6 254	7 207	8 123	8 893	9 467	2.6%	10 660	3.0%	8 039	2.0%
India	376	897	6.9%	1 351	1 757	2 241	2 762	3 288	4.9%	3 431	5.1%	2 639	4.1%
Southeast Asia	322	716	6.3%	993	1 202	1 440	1 701	1 979	3.8%	2 147	4.2%	1 674	3.2%
Middle East	359	803	6.4%	1 043	1 207	1 382	1 552	1 686	2.8%	1 837	3.1%	1 401	2.1%
Africa	385	621	3.7%	799	962	1 176	1 453	1 791	4.0%	1 689	3.8%	1 509	3.3%
Latin America	618	979	3.6%	1 151	1 315	1 482	1 667	1 852	2.4%	2 000	2.7%	1 611	1.9%
Brazil	327	502	3.4%	594	680	766	862	954	2.4%	1 035	2.7%	853	2.0%
World	**13 147**	**20 144**	**3.3%**	**23 650**	**26 226**	**28 976**	**31 772**	**34 457**	**2.0%**	**37 409**	**2.3%**	**29 924**	**1.5%**
European Union	2 605	2 836	0.7%	2 907	2 975	3 014	3 057	3 081	0.3%	3 447	0.7%	2 989	0.2%

Notes: CAAGR = compound average annual growth rate. Electricity demand is defined as the total gross volume of electricity generated, less own use in the production of electricity, plus net trade (imports less exports), less transmission and distribution losses.

Electricity demand in the United States grows at 0.6% per year, one of the slowest rates of growth after Japan and the EU. Modest economic growth, slow population growth and energy efficiency measures already in place all help moderate demand growth. The services sector accounts for the largest share of US electricity demand, its share remaining steady at around 40%, almost twice that of industry (Figure 8.3). The residential sector is second, though its average rate of growth is under 0.2% per year and its share of electricity demand declines from 36% to 33% by 2040 as efficiency measures for appliances and lighting take hold. Industrial demand grows slowly, but its share of electricity demand by 2040 remains steady at 22%. The development of unconventional gas resources (see chapter 6) and the subsequent decline in the price of petrochemical feedstocks has provided the United States, one of the largest basic chemical producers in the world, with a competitive advantage. Over the projection period, production of ethylene, the highest production volume chemical, grows 27%, from an already large base. Efficiency gains in the industrial sector help keep demand in check, including those in motor systems and lighting. In the residential sector, almost one-quarter of today's electricity demand comes from other than standard household appliances, e.g. electronics, owing to the fact that, as an advanced economy most households already have large appliances such as a refrigerator, freezer, washing machine, dishwasher, and televisions and computers. Other appliances drive most of the growth in the residential sector over 2013-2040, while electricity use for space heat and cooling, water heating and lighting declines.

Figure 8.3 ▷ Electricity demand shares by sector and selected region in the New Policies Scenario



In the European Union, weak economic growth and minimal population expansion result in the lowest rate of electricity demand growth in the world (together with Japan) at 0.3% per year. Industrial electricity demand declines by 0.1% per year, as electricity demand from most energy-intensive industries is stable or slightly declines over the *Outlook* period. Demand in the chemical sector decreases, in part because ageing steam crackers are not replaced in the EU as its competitive advantage diminishes in the wake of the shale revolution in the United States. Efficiency gains also help contain electricity demand. As a result, overall industrial electricity demand decreases by 20 TWh, settling at 980 TWh in 2040. Residential demand grows slowly as energy efficiency standards become well established for lighting and large appliances. As in the United States, other appliances consume a significant portion of electricity in the sector, and account for most of the growth over 2013-2040. The rate of growth in electricity demand is strongest in the transport sector in the EU, growing an average 2.4%. Most of the increase comes from the rail sector, though electric vehicles also make in-roads by 2040.

For China, industry remains the key consumer of electricity, though its share of electricity demand declines from 64% in 2013 to 59% by 2040, as the government seeks to shift the economy away from capital- and energy-intensive industrial activities to more consumption-oriented growth, and introduces more energy efficiency measures. The shift away from energy-intensive industries does not correlate with a large decline in electricity demand, however, as less energy-intensive industries generally rely more on electricity. As a result, demand in the industrial sector increases by 85% between 2013 and 2040, to reach about 5 630 TWh, and electricity's share of total industrial demand increases from 30% to 45%. The iron and steel sector in China is a large consumer at the beginning of the *Outlook* (12% of electricity demand), but a slowdown in spending on infrastructure leads to a decline in steel production of 30% by 2040. Despite the extent of the slowdown, electricity demand in this sub-sector decreases by just 9% as a consequence of the increasing share of secondary steelmaking. The chemical sector is another large consumer of electricity. China is currently the world's largest plastics importer as domestic production capacity does not match domestic demand, a situation which is set to change. As a result, the chemical industry share of electricity demand increases from 10% to 12% over the *Outlook* period. The aluminium, machinery, textile, food and mining sub-sectors also contribute to the growth in industrial electricity demand. Increasing use of heat pumps add an additional 140 TWh of electricity demand over the *Outlook* period. Residential electricity demand increases by 150%, to reach 2 200 TWh by 2040; within the sector, electricity's share of total demand rises from 18% to 41%, as appliance ownership increases with rising incomes. As China moves to become a more service-oriented economy, electricity demand in the services sector more than doubles, yet still accounts for less than 10% of total electricity demand in 2040.

In India, the industrial sector remains the largest consumer of electricity in the New Policies Scenario.[6] Demand in the residential sector grows at an average rate of 6.4% per year and, by 2040, narrows the gap with industry. Within the residential sector, electricity demand increases by almost 450%, its share of total demand in the sector increasing from 10% to 41%. The rising demand reflects high population and economic growth, increasing urbanisation and more people gaining access to electricity, while the dramatic increase in share also reflects a shift away from the traditional use of solid biomass. As a result,

6. For more on electricity demand in India, see Chapter 12.

demand for cooling equipment and appliances increases. India already has in place energy efficiency labels for appliances, which help constrain demand. There is significant upside for rising demand in the residential sector as, in the New Policies Scenario by 2040, India achieves universal access to electricity, though its per-capita electricity use, at 2 050 kWh, is just one-fourth the OECD average. Agriculture remains an important component in the Indian economy: currently it employs roughly half of the country's population and is a large consumer of electricity, for instance for powering pumps. Agriculture accounted for 18% of India's electricity demand in 2013, a share which decreases to 12% by 2040, as electricity demand in the services sector surpasses that of the agriculture sector in the late 2020s.

Electricity supply

Overview

The fuel mix in power generation continues to shift over the *Outlook* period from today's profile, in which two-thirds of global power generation comes from fossil fuels, though the nature and speed of its evolution varies by region and scenario (Table 8.2). The shift is highly influenced by the nature of policies put in place, particularly those aimed at decarbonising the sector, in addition to economic factors, such as the capital cost of power generation technologies and fuel prices.

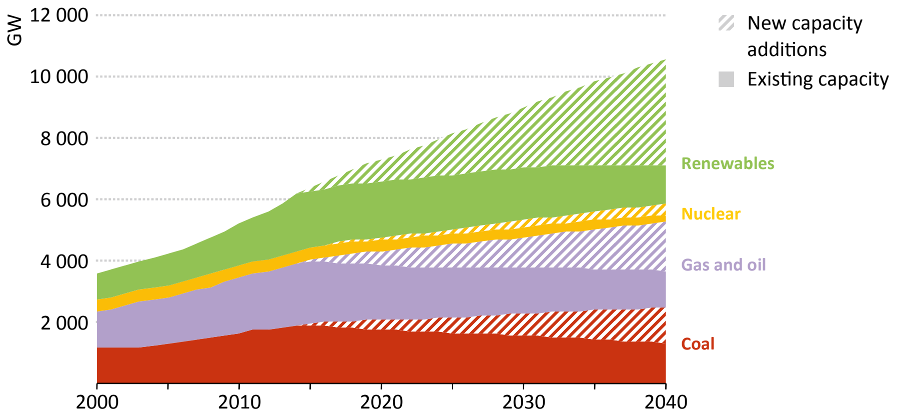
Table 8.2 ▷ World electricity generation by source and scenario (TWh)

			New Policies		Current Policies		450 Scenario	
	2000	2013	2020	2040	2020	2040	2020	2040
Total	**15 431**	**23 318**	**27 222**	**39 444**	**27 988**	**43 120**	**26 206**	**33 910**
Fossil fuels	9 966	15 735	16 805	21 409	17 772	27 659	15 604	9 851
Coal	6 001	9 612	10 171	11 868	10 918	16 534	9 185	4 107
Gas	2 752	5 079	5 798	9 008	6 006	10 534	5 658	5 465
Oil	1 212	1 044	836	533	849	590	760	279
Nuclear	2 591	2 478	3 186	4 606	3 174	3 974	3 218	6 243
Hydro	2 620	3 789	4 456	6 180	4 423	5 902	4 464	6 836
Other renewables	255	1 316	2 774	7 249	2 619	5 586	2 921	10 980
Fossil fuels	65%	67%	62%	54%	63%	64%	60%	29%
Coal	39%	41%	37%	30%	39%	38%	35%	12%
Gas	18%	22%	21%	23%	21%	24%	22%	16%
Oil	8%	4%	3%	1%	3%	1%	3%	1%
Nuclear	17%	11%	12%	12%	11%	9%	12%	18%
Hydro	17%	16%	16%	16%	16%	14%	17%	20%
Other renewables	2%	6%	10%	18%	9%	13%	11%	32%

Power generation capacity

Gross capacity additions in power generation are driven by the growth in electricity demand, as well as the replacement of retired units. In the New Policies Scenario, global installed capacity rises from 6 163 GW in 2014 to 10 570 GW in 2040, an increase of over 4 400 GW – one-third more than over the previous 25 years. Coal falls from 31% of total capacity in 2014 to 23% by 2040, as renewables capacity rises from 30% to 44% (Figure 8.4). Gas-fired capacity increases by almost 1 000 GW over 2014-2040, becoming the largest single source of installed capacity shortly after 2035, though its share of total installed capacity globally is slightly reduced.

Figure 8.4 ▷ Global installed capacity by source in the New Policies Scenario



Over 2014-2040, some 2 300 GW of generation capacity is retired, as it reaches the end of its technical lifetime, with almost 60% of the retirements concentrated in OECD countries (Table 8.3). Around 600 GW, or more than one-quarter of total global retirements are coal-fired power plants, 56% of which are in OECD countries. Another 490 GW are gas-fired plants. In the EU, more than one-quarter, or 160 GW, of thermal capacity (fossil-fuelled and nuclear) reach the end of their lifetime in the next ten years, indicating the importance of creating a market structure capable of attracting the needed investment in the region.

The technical lifetime of generation technologies varies; the longest are hydropower (70 years), coal-fired power plants (50 years) and nuclear plants (40-60 years). Refurbishment of ageing power plants can extend their life and reduce the need for new capacity, though the commercial viability of refurbishment depends on the condition of the plant and the economic factors, including market design. In periods of uncertainty about future policy, refurbishment of old plants can be preferred, as the capital involved (and the time required to recover it) is usually lower. The long technical lifetime of many power plants can lock-in certain consumption or emissions patterns. As OECD countries replace their ageing fleet and as non-OECD countries add new capacity, their technology choices will determine not only the generation mix over the projection period but also the trajectory of global CO_2 emissions growth (see section on CO_2 and coal-fired generation below).

Table 8.3 ▷ Cumulative power plant capacity retirements by region and source in the New Policies Scenario, 2015-2040 (GW)

	2015-2025						2026-2040						2015-2040
	Coal	Gas	Oil	Nuclear	Renewables	Total	Coal	Gas	Oil	Nuclear	Renewables	Total	Total
OECD	**171**	**116**	**124**	**52**	**37**	**500**	**160**	**136**	**44**	**54**	**431**	**826**	**1 326**
Americas	87	74	57	7	11	236	59	75	17	17	132	300	536
United States	85	68	48	3	10	214	51	72	7	17	111	258	472
Europe	71	19	35	30	23	178	72	30	14	35	241	391	569
Asia Oceania	13	23	32	15	2	86	29	31	14	3	58	135	221
Japan	7	18	30	14	2	71	10	22	12	3	42	89	160
Non-OECD	**98**	**101**	**52**	**10**	**7**	**268**	**167**	**137**	**97**	**32**	**276**	**709**	**977**
E. Europe/Eurasia	57	71	11	9	1	149	45	46	7	25	13	137	286
Russia	23	52	2	8	0	85	21	38	1	12	2	74	159
Asia	32	5	11	1	4	52	95	35	37	3	234	404	456
China	20	0	2	-	0	22	52	1	4	-	182	238	261
India	7	0	1	0	1	10	34	7	9	1	39	90	100
Southeast Asia	0	2	5	-	2	10	5	20	15	-	8	48	58
Middle East	0	15	12	-	0	27	0	32	31	-	1	64	91
Africa	8	4	9	-	1	21	25	16	11	2	7	61	82
Latin America	1	7	9	0	2	19	2	7	11	1	20	42	61
Brazil	0	1	1	-	2	4	1	0	1	1	15	17	21
World	**269**	**218**	**176**	**62**	**44**	**768**	**327**	**274**	**141**	**86**	**706**	**1 534**	**2 303**
European Union	75	21	37	29	22	183	72	29	14	34	239	387	570

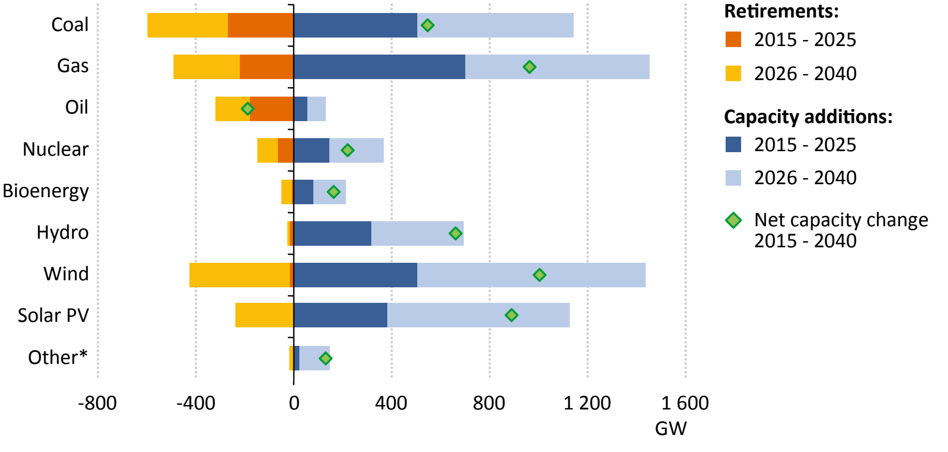
Table 8.4 ▷ Cumulative gross power plant capacity additions by region and source in the New Policies Scenario, 2015-2040 (GW)

	2015-2025						2026-2040						2015-2040
	Coal	Gas	Oil	Nuclear	Renewables	Total	Coal	Gas	Oil	Nuclear	Renewables	Total	Total
OECD	**48**	**290**	**12**	**38**	**482**	**870**	**49**	**224**	**9**	**75**	**854**	**1 212**	**2 082**
Americas	4	140	9	9	194	356	23	137	4	27	319	509	865
United States	1	110	8	8	150	279	21	93	3	25	248	389	668
Europe	25	94	1	11	208	338	14	64	2	35	409	523	862
Asia Oceania	19	56	2	19	80	176	13	24	3	14	126	179	355
Japan	5	42	2	3	52	104	3	12	2	3	74	95	199
Non-OECD	**460**	**415**	**45**	**108**	**841**	**1 869**	**585**	**524**	**66**	**143**	**1 444**	**2 762**	**4 631**
E. Europe/Eurasia	42	80	1	20	22	165	35	69	1	35	61	201	367
Russia	17	40	0	16	9	82	9	40	1	22	28	100	182
Asia	386	165	12	80	658	1 301	497	232	31	88	1 015	1 863	3 164
China	200	83	1	66	433	783	183	66	0	59	560	867	1 650
India	109	34	5	10	145	304	197	71	14	24	279	584	888
Southeast Asia	57	34	3	1	37	133	88	55	10	4	93	250	383
Middle East	1	83	19	6	19	128	0	67	12	9	101	190	318
Africa	27	52	10	-	56	145	49	105	19	7	139	318	463
Latin America	4	34	3	2	86	129	4	49	3	4	129	190	319
Brazil	1	7	0	1	55	64	1	8	0	3	74	87	151
World	**508**	**705**	**57**	**147**	**1 323**	**2 740**	**634**	**748**	**74**	**218**	**2 299**	**3 974**	**6 713**
European Union	23	91	1	11	187	313	13	44	1	33	387	479	792

Note: A breakdown of renewable capacity additions by technology type may be found in Chapter 9, Table 9.4.

As installed capacity expands in the New Policies Scenario by about 4 400 GW and a further 2 300 GW are retired, gross capacity additions total some 6 700 GW from 2015 to 2040. Of this, natural gas and wind power are each projected to add around 1 450 GW, followed by coal and solar PV, at just below 1 150 GW each (Table 8.4). Global gross capacity additions of renewables total just over 3 600 GW, or one-third more than additions of fossil-fuelled power plants, though the share of renewables in total generation will not fully reflect this difference since renewables-based power plants usually have a lower load factor than their thermal counterparts (Figure 8.5).

Figure 8.5 ▷ Global power generation capacity retirements and additions in the New Policies Scenario, 2015-2040



* Other includes geothermal, concentrating solar power and marine.

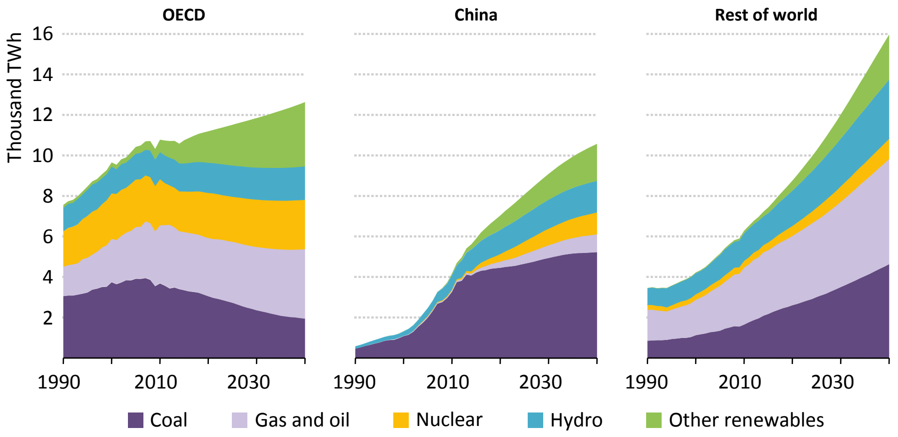
In non-OECD countries, the majority of the gross capacity additions are built to keep pace with burgeoning demand, amounting to 4 630 GW over 2015-2040. Over a third of gross capacity additions in non-OECD countries are made in China, which adds 1 650 GW during the projection period. Renewables account for 60% of China's gross capacity additions, led by 430 GW of wind power and 290 GW of solar PV. China also adds significant coal-fired capacity, accounting for almost a quarter of its gross additions (of which some 70 GW is to replace retirements). India, whose power demand is growing rapidly, makes almost 20% of the non-OECD additions, building roughly 890 GW over the *Outlook* period. There are relatively few retirements in India until late in the projection period. Coal accounts for a third of the capacity built and renewables for almost half, driven by India's ambitious solar target.

The profile of capacity additions in the OECD is markedly different, as 42% of the power capacity currently in operation is expected to be retired before 2040, against a background of strong policies to decarbonise the power sector. While for both the OECD and non-OECD countries oil-fired capacity additions do not offset the retirements, it is the coal-fired fleet in particular that undergoes a drastic transformation in OECD countries. Over half of the existing fleet of coal-fired plants are retired by 2040; only about 30% of these are replaced with new coal capacity. The changes occurring in the United States are particularly influenced by both the availability of abundant natural gas and the implementation of state and federal policies to reduce pollution from power plants. The result is that the United States adds significant gas-fired capacity (200 GW) and non-hydro renewable capacity (385 GW, mostly wind and solar PV) over the *Outlook* period. Like the United States, the European Union retires more coal-fired power plants than it builds. A majority of gross capacity additions in the EU are renewables-based (about 575 GW), though gas-fired capacity additions account for 135 GW.

Power generation

The continuing thirst for power sees global electricity generation increase by an average of 2.0% per year in the New Policies Scenario. By 2040, global electricity generation increases by almost 70%, to reach some 39 500 TWh. As discussed, the energy mix changes markedly over time and varies by region (Figure 8.6). Generation from renewables grows the fastest, averaging 3.6% per year, and increases more than two-and-a-half-times, to reach around 13 400 TWh by 2040. Over half of total incremental generation from 2013 to 2040 comes from renewable energy technologies, as their costs fall and government support continues. Hydropower remains the largest source of renewables generation, while wind power and solar PV expand rapidly, but from a much lower base. As a result, the share of renewables in total generation rises more than 12 percentage points, to reach 34% by 2040. Output from nuclear power plants increases by 85% to reach 4 600 TWh by 2040, resulting in a marginal increase in nuclear's share of global electricity generation. Expansion in China accounts for almost half of incremental nuclear generation.

Figure 8.6 ▷ Electricity generation by source and region in the New Policies Scenario, 1990-2040



The share of fossil fuels in total generation in the New Policies Scenario falls from 67% to 54%. Global coal-fired generation grows from 9 612 TWh to almost 11 900 TWh by 2040, even though coal's share of generation falls by over 11 percentage points to 30% by 2040. This decline is mainly due to policies that limit its use, especially in OECD countries, to increasing generation from renewables and in some cases, to coal-to-gas switching (driven both by commercial economics and government policies). The share of oil in global generation also decreases, from 4% to 1%, while the share of gas increases slightly to 23%.

The regional trends for electricity produced from coal, however, are quite different. There is a 44% decline in coal-fired generation from 2013 to 2040 in OECD countries, whereas there is an increase of more than 60% in non-OECD countries. The reduction of coal use in the OECD power sector reflects action to reduce GHG emissions and local air pollution. In non-OECD countries, even though there is increasing concern about local pollution, coal is viewed as a secure, affordable and reliable way to meet booming electricity demand growth. Worldwide, carbon capture and storage (CCS), for both coal- and gas-fired plants, plays a limited role in the New Policies Scenario as its expansion hinges on the widespread implementation of carbon pricing. In the New Policies Scenario, by 2040, total generation from plants fitted with CCS reaches some 470 TWh, more than 90% from coal-fired plants and the remainder from gas-fired units. Together, these plants contribute roughly 1% of electricity generation in 2040, with China and the United States accounting for over two-thirds of their output. Power plants in the United States, however, have a much lower CO_2 capture rate, at around 20% (depending on the coal quality), in line with the recently finalised Carbon Pollution Standards.

Because of different levels of economic development, policies and priorities, resource endowments, and environmental and energy security concerns, the entire power system – from the electricity generation mix, to the capacity composition, demand in end-use sectors and transmission and distribution (T&D) – needs (where possible) to be analysed at the national level. The four biggest power producers – China, United States, India and European Union, detailed below – amply demonstrate the wide disparities that exist between countries (Figure 8.7).

In the United States, federal and state policies (including the Clean Power Plan and Carbon Pollution Standards) and the development of unconventional gas resources are strong influences on the electricity mix over the *Outlook* period. Coal-fired generation falls by about 35%, while natural gas-fired generation increases by about the same percentage, becoming the largest source of electricity soon after 2025. Renewables-based power generation increases two-and-a-half-times, its share of total generation rising from 13% in 2013 to 27% by 2040, led by wind power and solar PV. Taken together, renewables supply more than the entire increase in total electricity generation over the projection period. In this mature economy, the services sector accounts for the largest share of electricity demand today (39%), followed by the residential sector (36%) and industry sector (22%).

Through to 2040, these shares remain fairly constant, though electricity demand in transport increases to 4% of the total by 2040. Average T&D losses decline by half-of-one percentage point by 2040 to reach less than 6%.

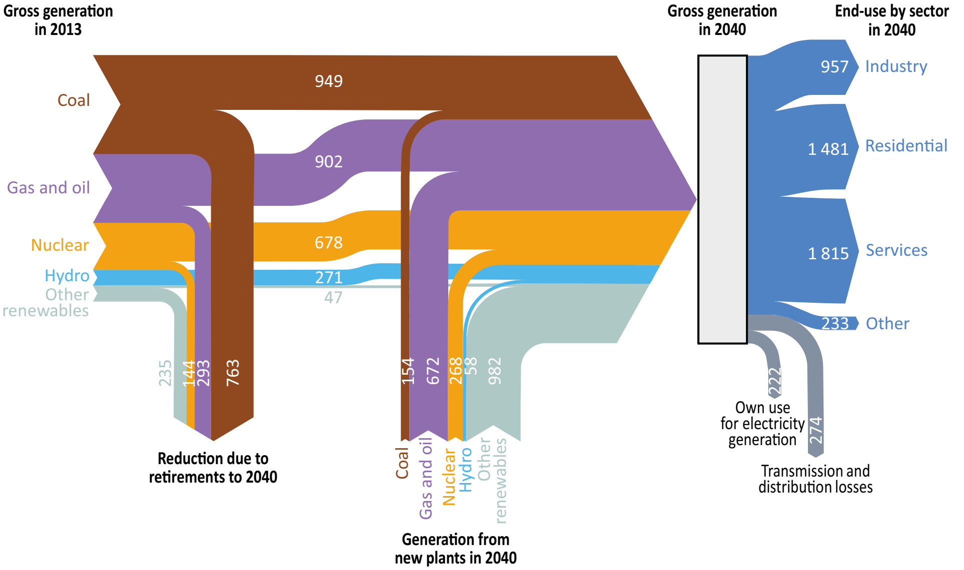
In the European Union, with low electricity demand growth through to 2040, an ageing existing fleet of power plants and a stringent commitment to decarbonising the power sector, more than 70% of gross capacity additions are renewables-based, with the others sources mainly called upon to replace retiring assets and to ensure the reliability of the power system. As a result, just over half of electricity produced in the European Union in 2040 comes from renewables, led by wind power and hydropower. Wholesale electricity prices in the EU are currently below the levels needed to fully recover investments (past or new) in power plants, where the revenues are not insured by some form of support. These low price levels result from the combination of over-capacity (stemming from the 2008-2009 economic crisis, which led to lower-than-expected electricity demand) and the continued deployment of renewables. The over-capacity in the system today provides some breathing space, but it could soon disappear as many thermal plants reach the end of their technical lifetime and are slated to retire in the coming years. In this case, substantial investment in new capacity will be required to ensure the adequacy and reliability of the power supply system (IEA, 2014b). Reliance on coal is projected to continue to decline and by 2040 coal retains just a 6% share of electricity generation (a decline of 22 percentage points). Natural gas plays an increasing role, with generation increasing by 37% over the *Outlook* period, as coal is retired and the need for flexible generation (to complement variable renewables) becomes greater. As in the United States, end-use electricity demand in the EU reflects the maturity of the economy and is evenly split between industry, services and the residential sectors. Also like the United States, T&D losses in the EU are low, at 6%.

In China, policy support helps the share of renewable energy in total generation rise from 20% to almost one-third by 2040. Coal continues to dominate the generation mix, though its share declines significantly, from three-quarters in 2013 to just below 50% by 2040. Despite efforts to shift to a more consumption-oriented economy, industry remains the primary consumer of electricity. Investment in and expansion of T&D networks in China helps to keep distribution losses in line with the level in mature economies at below 6%.

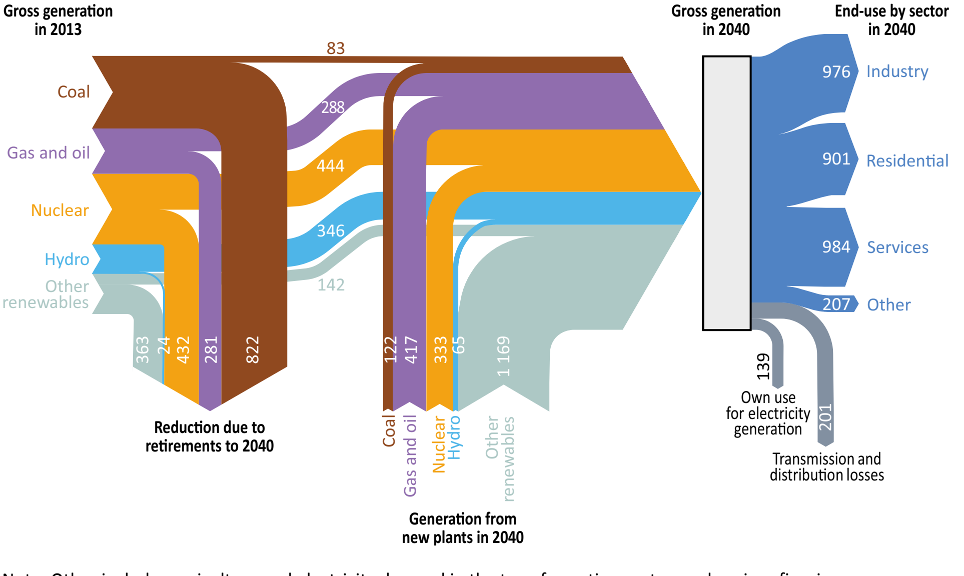
In India, electricity demand almost quadruples from 2013 to 2040. Despite strong growth in renewables capacity, coal remains the dominant source of electricity generation, though its share decreases from 73% in 2013 to 57% in 2040. The share of renewables in total generation rises from 17% to 26%. Demand in India remains concentrated in industry and increasingly in the residential sector. T&D losses in India remain high over the *Outlook* period, still running at 16% of net electricity generation in 2040 though this is a significant improvement of four percentage points on the situation today. The implications for the reliability of power supply are elaborated in Part B, as part of the special focus on India.

Figure 8.7 ▷ Power generation by fuel and demand by sector in selected regions (TWh)

a) United States



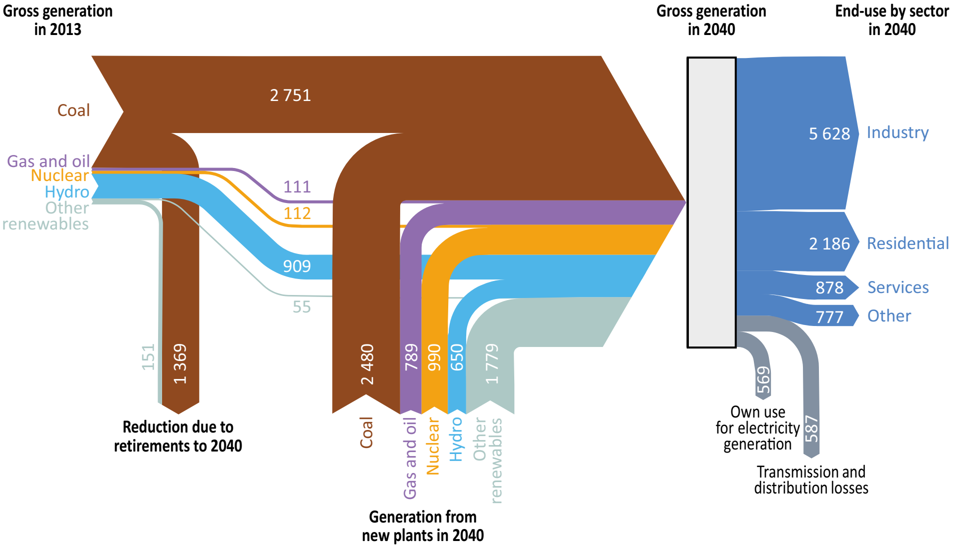
b) European Union



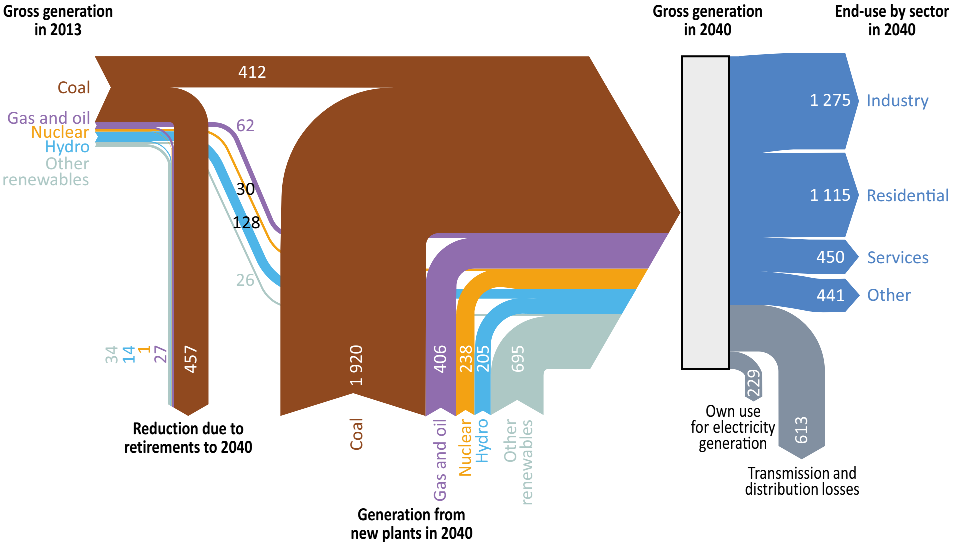
Note: Other includes agriculture and electricity demand in the transformation sector, such as in refineries.

Figure 8.7 ▷ Power generation by fuel and demand by sector in selected regions (continued) (TWh)

c) China



d) India



Note: Other includes agriculture and electricity demand in the transformation sector, such as in refineries.

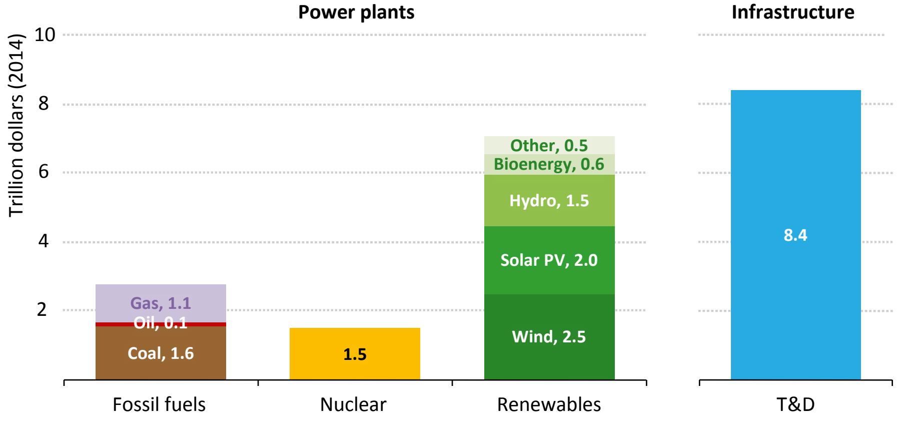
8

Investment[7]

To satisfy rising electricity demand and ensure that adequate infrastructure is in place (both new and refurbishment of existing), substantial investment is required in the power sector in all *World Energy Outlook (WEO)* scenarios. Cumulative global investment in the New Policies Scenario is estimated to be $19.7 trillion over 2015-2040, averaging $760 billion per year (Figure 8.8). Almost two-thirds of total investment is in non-OECD countries. Investment in power plants accounts for 58% of the total, while the rest is dedicated to T&D networks, which play an essential part in delivering the electricity to where it is used and providing the flexibility necessary to allow for more use of variable renewable sources (e.g. solar PV and wind).

Renewables account for 62% of global investment in new power plants, led by wind (22% of total), solar PV (17%) and hydro (14%). Investments in renewables increase throughout the projection period for new capacity and to replace ageing assets (e.g. wind and solar PV) that have assumed average lifetimes of 25 years. Among the fossil fuels, 14% of power plant investment is dedicated to coal, followed by natural gas at 10% and oil at less than 1%. Around 13% of total global investment in new power plants over the *Outlook* period is in nuclear, with somewhat more in non-OECD countries. As the majority of the electricity demand growth is in non-OECD countries, they account for most of the worldwide investment in new power plants – 60% of both renewables and gas-fired power plants, and over 80% of coal-fired power plants.

Figure 8.8 ▷ Global cumulative investment in the power sector by type in the New Policies Scenario, 2015-2040



To meet expanding electricity demand existing T&D networks need to be expanded and ageing infrastructure refurbished or replaced. Around 75 million kilometres (km) of new lines are built in total in the New Policies Scenario, with global investment in T&D infrastructure

7. Global power sector investment prospects were analysed in detail in the *World Energy Investment Outlook* (IEA, 2014b). This report is available to download at *www.worldenergyoutlook.org/investment*.

Table 8.5 ▷ Cumulative investment in the power sector by region and type in the New Policies Scenario, 2015-2040 ($2014 billion)

	2015-2025						2026-2040						2015-2040
	Fossil fuels	Nuclear	Renewables	Total Plant	T&D	Total	Fossil fuels	Nuclear	Renewables	Total Plant	T&D	Total	Total
OECD	**370**	**265**	**1 183**	**1 818**	**1 106**	**2 925**	**377**	**438**	**1 686**	**2 501**	**1 404**	**3 904**	**6 829**
Americas	137	98	441	675	447	1 122	219	174	616	1 009	645	1 654	2 776
United States	108	79	344	531	357	888	176	159	477	813	493	1 306	2 195
Europe	136	97	510	743	424	1 167	103	202	801	1 105	469	1 575	2 742
Asia Oceania	98	70	232	400	235	635	55	62	269	386	289	675	1 310
Japan	58	14	159	232	119	351	21	22	155	198	150	348	699
Non-OECD	**892**	**329**	**1 482**	**2 703**	**2 260**	**4 963**	**1 162**	**463**	**2 697**	**4 322**	**3 592**	**7 914**	**12 877**
E. Europe/Eurasia	172	82	50	304	195	498	152	139	138	429	274	703	1 202
Russia	83	66	21	170	74	244	73	84	71	227	111	338	582
Asia	514	217	1 080	1 811	1 514	3 325	739	248	1 714	2 702	2 269	4 970	8 296
China	215	172	641	1 028	881	1 909	202	157	791	1 150	1 079	2 229	4 138
India	148	29	252	429	301	730	282	67	499	848	544	1 392	2 122
Southeast Asia	110	2	85	198	245	442	177	16	228	420	465	885	1 328
Middle East	92	21	45	157	117	274	65	32	210	307	167	474	748
Africa	83	-	127	211	241	451	163	27	349	539	583	1 122	1 573
Latin America	31	9	180	220	194	414	42	16	286	345	300	645	1 059
Brazil	6	5	112	123	108	230	8	11	157	175	174	349	580
World	**1 262**	**594**	**2 665**	**4 521**	**3 366**	**7 887**	**1 538**	**901**	**4 383**	**6 823**	**4 996**	**11 818**	**19 706**
European Union	132	99	455	686	373	1 059	83	197	751	1 031	392	1 423	2 482

Notes: T&D = transmission and distribution. A breakdown of renewable investments by technology type may be found in Chapter 9, Table 9.5.

projected to average $320 billion per year or cumulatively, around $8.4 trillion over 2015-2040. Non-OECD countries account for 70% of global investment in T&D. Around 55% of the total investment is to expand the system to meet new demand, 40% to refurbish and replace existing assets and the remainder for integrating renewables into the system. Almost three-fourths of investment is in distribution lines (the final stage of delivery of electricity to end-users). Investment in interconnections is also important to permit the integration of high shares of variable renewable energy technologies into power systems. Network development continues to experience significant challenges, to secure financing and often taking longer than the deployment of new renewable energy facilities in the face of local opposition to new lines.

Over half of the global cumulative power sector investment over the *Outlook* period is required in just four regions – China, India, United States and European Union – with China alone accounting for over one-fifth of the global total (Table 8.5). Over half of the investment in China is dedicated to new capacity, with investment in non-hydro renewables being three-times higher than that in coal. Investment in India reaches $2.1 trillion cumulatively over 2015-2040, or about half the Chinese expenditure. In India, 60% of investment is for power plants, the majority (60%) of which is for renewables and almost 30% for coal. In the United States, the majority of investment is also for generation capacity, with the largest share, at 58%, for non-hydro renewables, followed by 18% for nuclear and 13% for natural gas – an indication of shift away from coal-fired generation. In the European Union, almost 70% of cumulative investment is for power plants, with almost two-thirds for non-hydro renewables.

Power generation costs

The costs related to power generation are the collective representation of the past, present and future aspects of the power system. They reflect investment decisions taken over the preceding decades that delivered the operating fleet of power plants, maintenance to keep facilities operational and the current realities of coal, natural gas and oil markets. They also include investments in new capacity to ensure the adequacy of the electricity supply in the years to come and, in a growing number of regions, to decarbonise power generation to help mitigate climate change. As such, there are four main components of power generation costs:

- Provision for the recovery of capital investments.
- Fuel costs, reflecting the amount and price of fuels used (fossil, nuclear and biomass).
- Operation and maintenance (O&M) costs to provide for the upkeep of power plants.
- Carbon costs, as determined by the carbon intensity of the power plants and the level of the carbon price, if any.

These costs are strongly linked to wholesale electricity prices, which represent a large component of end-use electricity prices. They also provide insight into how factors specific to each region, including government policies, resource availability, technology developments and public opinion, influence the cost structure of the power sector.[8]

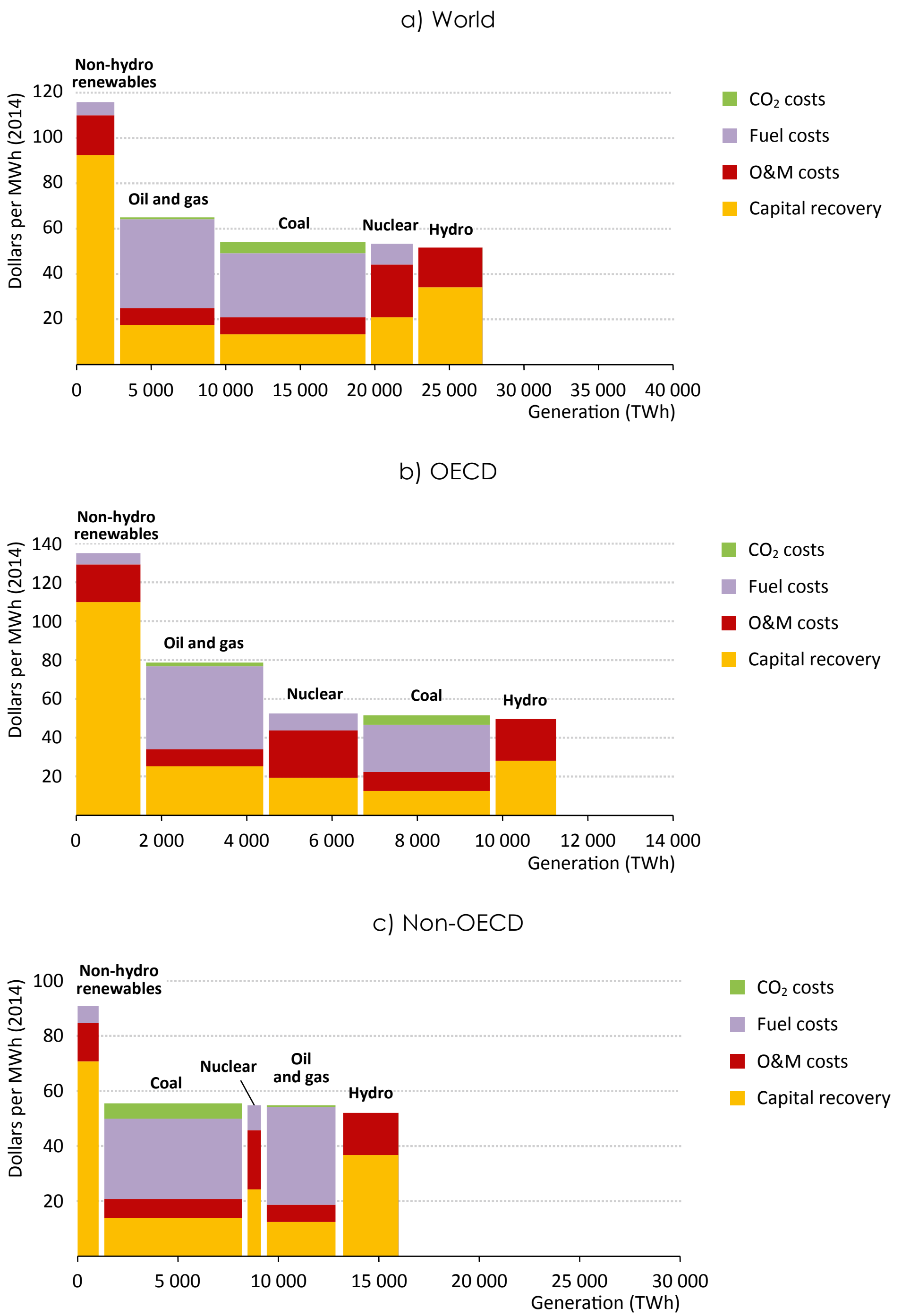
The total costs of global power generation increase from \$1.5 trillion (in year-2014 dollars) in 2013 to \$2.7 trillion in 2040 in the New Policies Scenario, as the supply of power increases by 70% and the average cost of generation rises from \$67/MWh to \$71/MWh.[9] The small change in the average generation cost illustrates the persistent weight in the calculation of past decisions and the associated capital expenditure. Power plant efficiency gains over time help to limit the increase in costs, as they largely offset generally rising fossil-fuel prices. Average power generation costs today are, on average, about 30% higher in OECD countries than non-OECD countries, mainly due to the environmental policies in the OECD countries that drove early deployment of non-hydro renewables and thereby raised average investment costs, but are also due to the smaller share of generation in the OECD from low-cost coal. As the fleet in OECD countries ages, average costs will fall as an increasing number of the power plants will have recovered the capital expenditure for their construction, thereafter, needing to cover only their operating costs (fuel, O&M and CO_2). For example, a large number of coal-fired and nuclear power plants in OECD countries are paid for by 2020, lowering their average costs to about \$50/MWh (Figure 8.9). By 2040, non-OECD countries account for 65% of total global power generation costs, as the rise in the volume of generation (more than doubling) outweighs the effect of the lower average costs achieved by most technologies (Figure 8.10). Average CO_2 costs are higher in non-OECD countries in 2040 despite higher CO_2 price levels in many OECD countries (not including shadow prices), mainly due to the weight in the calculation of China, which is assumed to introduce a CO_2 price and has a relatively carbon-intensive power mix. The net effect of CO_2 prices on an economy depends on how the associated revenues are used (Goulder, 2013; Liu and Lu, 2015).

The way power generation costs evolve highlights three broad trends related to the growing weight of renewables in the calculation. First, many countries become more capital-intensive over time, spending more money on the power plants themselves than to operate them. Second, the power mix becomes more evenly distributed across fuels. Fossil-fuelled power plants account for 65% of power generation costs in 2013, but 55% in 2040. And third, the average costs of power generation technologies tend to converge over time, with falling costs for non-hydro renewables and rising fuel prices outweighing efficiency gains in fossil-fuelled power plants (see focus on coal-fired generation).

8. Power generation cost estimates combine information for old and new power plants, as such, they do not provide a clear view of the relative competitiveness of new technologies. For discussion of renewables competitiveness, see Chapter 9.

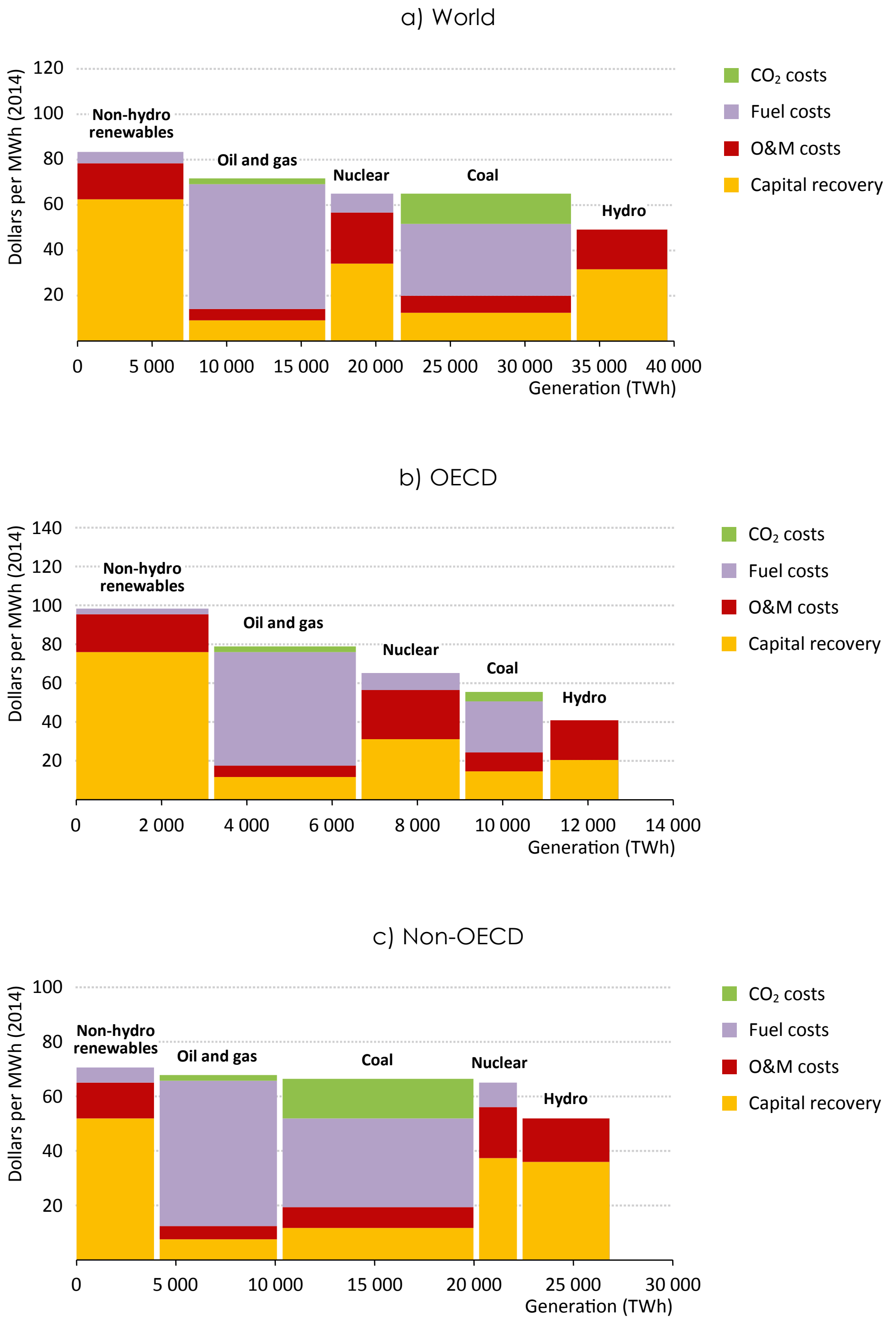
9. These figures do not include additional cost elements in the power system, such as transmission and distribution or renewables subsidies, which are reflected in the following section on electricity prices.

Figure 8.9 ▷ Total power generation costs in the New Policies Scenario, 2020



Note: Capital recovery includes the annuity payments required to recover past capital investments.

Figure 8.10 ▷ Total power generation costs in the New Policies Scenario, 2040



Note: Capital recovery includes the annuity payments required to recover past capital investments.

Electricity prices

Electricity prices to the end-user are strongly influenced by the structure of markets and the degree of regulation, but the dominant determinants are the wholesale price for electricity, the costs related to transmission and distribution (including losses), retail costs, and any subsidies (paid by consumers) and taxes.[10] Wholesale electricity prices must be closely tied to the underlying power generation costs in both competitive and regulated markets in the long term to ensure the adequacy and reliability of the power supply. However, recent experience in Europe has shown that wholesale electricity prices in hybrid competitive markets (that is markets designed to respect competition principles but also subject to imposed interventions in favour of specified sources), can deviate substantially from the underlying costs, presenting a risk to the long-term financial health of the power sector (IEA, 2014b). In the New Policies Scenario, wholesale electricity prices in all regions are consistent with the underlying direct costs to electricity providers by 2020.[11]

Wholesale electricity prices in the United States and China are below the world average today (below $60/MWh in both regions). However, in the New Policies Scenario, the wholesale electricity prices in these two regions diverge. US wholesale electricity prices increase by more than 15%, largely as a result of rising natural gas prices (though these remain comparatively low). Together, capital recovery and O&M account for about $30/MWh of the wholesale price through to 2040, as gas-fired capacity of relatively low capital-intensity is strongly deployed under the Clean Power Plan, alongside more capital-intensive technologies, including nuclear, plants fitted with CCS and renewables. In China, wholesale electricity prices rise to about $80/MWh by 2040, as the rise of average CO_2 costs, tied to continued dependence on coal-fired power generation, more than offsets the reduction in capital recovery costs due to the ageing of the power plant fleet.

By contrast, Japan and the European Union have higher wholesale electricity costs than the world average. Following the accident at the Fukushima Daiichi nuclear facility, the power system in Japan has been forced to take exceptional measures to maintain supply, including importing large amounts of expensive liquefied natural gas (LNG) and oil to operate its power plants. The estimated wholesale electricity price in Japan was around $140/MWh in 2014, one of the highest in the world. With the gradual restart of the nuclear fleet, the strain on the power system in Japan will subside, with a halving of average fuel costs and wholesale prices falling below $100/MWh. In the European Union, strong deployment of non-hydro renewables during a period of stagnant electricity demand has driven down average wholesale electricity prices sharply, to just above $50/MWh, while the underlying average costs exceed $70/MWh. It will be essential for the EU power markets to provide for

10. Fossil-fuel subsidies are reflected in lower fuel costs for power generation. Subsidies to power plants other than renewables are not comprehensively estimated and so, the full plant costs are included in the power generation costs. Tax regimes vary by region and are assumed to continue in their current form unless adopted policies indicate specific reforms.

11. Fossil-fuel subsidies are not included in the underlying power generation costs, as they are not faced by electricity providers.

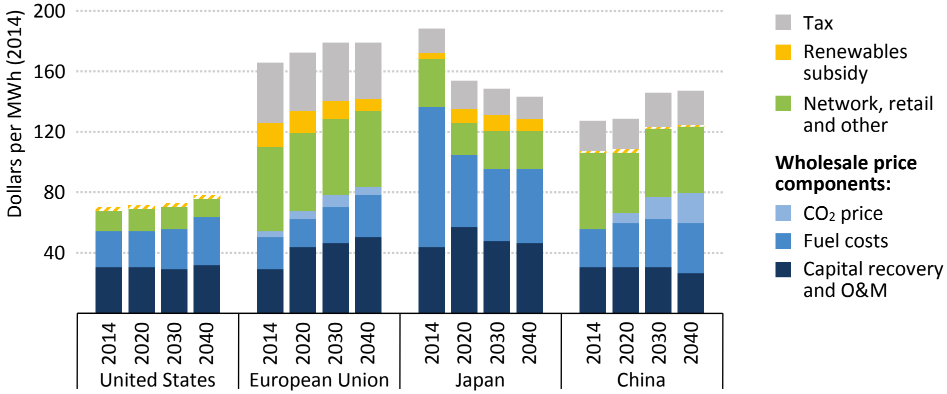
better cost recovery in the coming years in order to maintain the security of power supply (IEA, 2016) – an issue made more critical by the fact that the share of capital recovery in total power generation costs in the EU is one of the highest in the world through to 2040.

Electricity prices to industry

Industrial competitiveness across regions depends on many factors, including the regulatory environment, the ease of access to materials and their cost, and the cost of labour, in addition to the relative cost of energy, including electricity. Differences in energy prices can be moderated to some degree by energy-efficient processes. Currently, average industry electricity prices are low in the United States, compared with the EU, China and Japan (Figure 8.11).[12] In the New Policies Scenario, industry electricity prices increase in most regions in line with rising wholesale prices, though the United States maintains an advantage due to an abundant supply of low-cost natural gas and low tax rates on industry. The gap between price levels in the European Union and United States widens slightly over time, making energy efficiency in the EU even more important to moderate the difference in final production costs. Average electricity prices to industry in China are set to rise more than in the United States to 2040, underpinned by the implementation of a carbon price. Due to the elevated wholesale electricity price, Japan currently has high electricity prices to industry, stressing the importance of energy-efficient processes. Falling wholesale prices over time reduce electricity prices to industry in Japan to similar levels to China.

8

Figure 8.11 ▷ Average electricity prices in the industry sector by region and component* in the New Policies Scenario



* Wholesale electricity prices in the short run may not fully reflect the underlying costs, which can result in insufficient levels of capital recovery, as is the case in the European Union today.

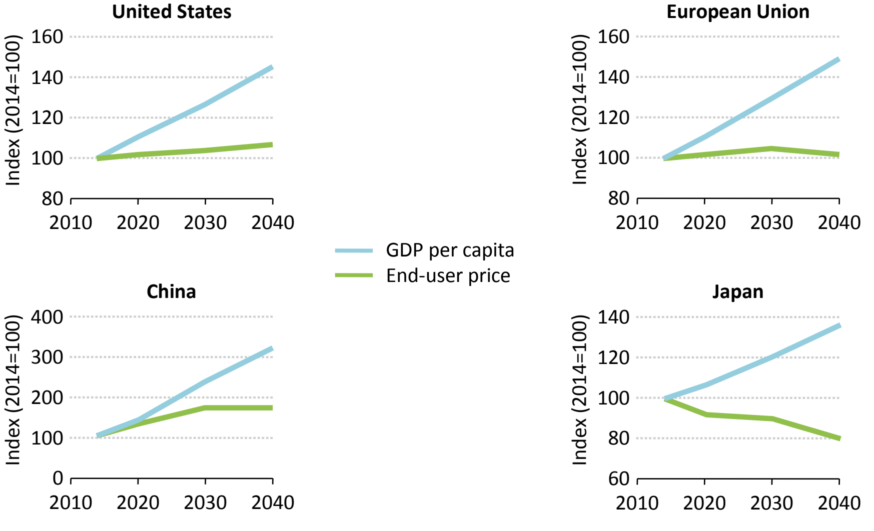
Notes: Capital recovery in estimated wholesale electricity prices does not include costs related to non-hydro renewables, as they are most often remunerated outside of wholesale markets. Hatched areas represent subsidies that are partly or fully borne by taxpayers rather than energy consumers. Prices for China do not include the potential removal of cross-subsidies to/from other sectors.

12. The electricity price varies across types of industry and may differ noticeably from the average industry electricity prices, as the case for energy-intensive industries in some regions.

Residential electricity prices

Residential electricity prices are driven by similar underlying wholesale electricity costs[13], but tend to be higher than prices to industry, largely because households account for a higher share of distribution losses, have higher retail costs and often face higher tax rates.[14] In the New Policies Scenario, residential electricity prices (including taxes) increase in nearly all regions to 2040, with the exception of Japan, where they fall from over \$250/MWh in 2014 to close to \$200/MWh in 2040 (in 2014-dollars). China faces one of the largest increases in residential prices over the projection period, increasing by two-thirds from \$86/MWh to over \$140/MWh and thereby increasing the attractiveness of energy efficiency measures. The European Union and the United States have more moderate increases, even though the power systems in both regions undergo strong decarbonisation efforts. In the EU, residential electricity prices in 2040 are only a couple percentage points over the average level today of around \$260/MWh, moderated by a substantial drop in renewables subsidies as support measures in place today expire (see Chapter 9).

Figure 8.12 ▷ Residential electricity prices and GDP per capita by selected regions in the New Policies Scenario (indexed to 2014 levels)



Average US prices increase from \$125/MWh to about \$135/MWh, remaining among the lowest in the world. Despite the increases, electricity becomes more affordable (per unit of GDP) in most regions, as GDP per-capita growth exceeds the rise of residential electricity prices. For example, in the New Policies Scenario, the residential electricity price increase

13. The average costs of electricity generation provided to residential end-users is often higher than that for industry, due to a more variable profile of electricity demand.

14. Electricity prices for the services sector are often tightly linked to the level of residential electricity prices, though cross-subsidies between sectors may affect this relationship.

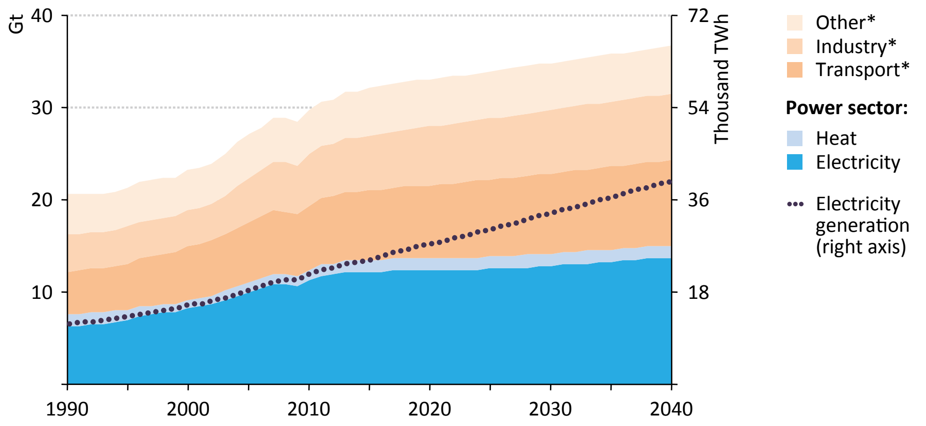
in China is far outweighed by a tripling of average income per capita for its population of 1.4 billion (Figure 8.12). In the United States, European Union and Japan, while growth is not nearly as high for either income per capita or prices, assumed economic growth makes electricity more affordable for households on average.

Electricity-related carbon-dioxide emissions

The share of electricity in total final energy consumption continues to grow over the *Outlook* period to 2040, after doubling from 1970 to 2013. As electricity demand has increased, so too have emissions, with the power sector accounting for over half of the increase in global energy-related CO_2 emissions. In 2013, CO_2 emissions due to power generation and heat production amounted to 13.4 gigatonnes (Gt), or 42% of global energy-related CO_2 emissions. Most of these emissions (90%) stem from power generation, while the remaining 10% is from heat production. Over the past 23 years (1990-2013), both global power generation and related CO_2 emissions have doubled, with power generation increasing by 11 500 TWh and CO_2 emissions by 5.9 Gt (Figure 8.13). The CO_2 intensity (g CO_2/kWh) of power generation has remained broadly flat, at around 520 g CO_2/kWh, and power generation's share of total energy-related CO_2 emissions from all sources has increased from 30% to 38%.

8

Figure 8.13 ▷ Global CO_2 emissions by sector and electricity generation in the New Policies Scenario



* Includes only direct emissions in each sector.

In the New Policies Scenario, electricity generation and CO_2 emissions decouple over time, a result of both the policies put in place to decarbonise the power sector and the increasing efficiency of fossil-fuelled plants. While global power generation increases 70% (16 000 TWh), CO_2 emissions related to the power sector grow by just 13% (1.6 Gt) over the *Outlook* period. As a result, the average global CO_2 intensity of power generation in 2040 is one-third lower than today, reaching about 350 g CO_2/kWh.

The global average hides significant differences between countries and regions. While, in OECD countries, CO_2 intensity halves over the *Outlook* period, in China it decreases by almost 40% and, in the rest of the world (where the vast majority of the growth of coal-fired generation is concentrated), it decreases by just over one-quarter. The corresponding differences in emissions are stark. In absolute terms, reflecting both carbon intensity and the volumetric changes in power generation, in OECD countries, annual CO_2 emissions decline from 4.6 Gt to 2.9 Gt, whereas China's annual emissions grow from 3.8 Gt to 4.6 Gt and other non-OECD countries witness a sharp increase in emissions, from 3.8 Gt to 6.3 Gt.

Focus on coal-fired power generation

Worldwide, coal-fired generation is the single largest source of electricity today, providing almost twice the amount of electricity as that of gas-fired generation, the second largest. In the New Policies Scenario, coal's share declines significantly (from 41% to 30%) over the projection period but it remains the largest single fuel source, although renewables collectively surpass it in the early 2030s. How coal-fired generation evolves is important, not least because it accounts for 60% of the overall demand for coal today. There is significant uncertainty about the future of coal demand – with the greatest range of outcomes of all fuel types across the various scenarios – as it is dependent on the level of electricity demand, the degree of decarbonisation of the power sector, the extent of deployment of plants fitted with CCS, and increasingly, the way concerns such as local air pollution and the availability of water are resolved. This range of uncertainty is important, as the evolution of coal use has significant implications for the interplay of economic, energy and environmental issues.

Coal-fired power generation capacity

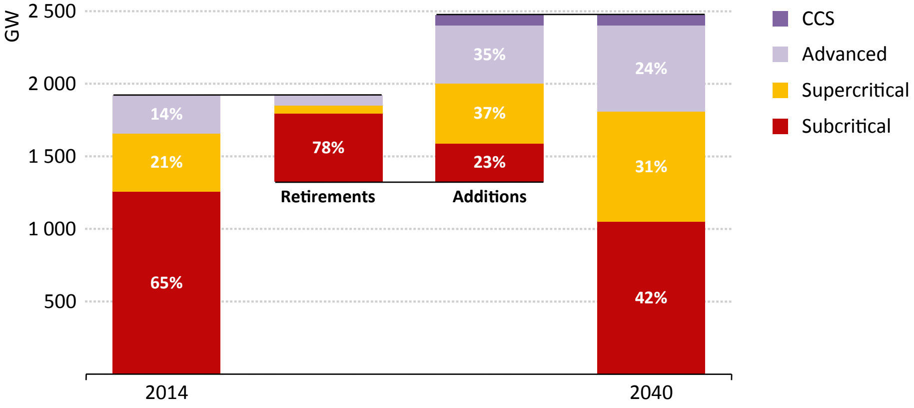
More than 30% of total global power generation capacity is coal-fired. Coal technologies can be broadly grouped into four categories, mainly related to the steam conditions of the boilers and the level of associated CO_2 emissions: subcritical, supercritical, advanced[15] and CCS-fitted. In general, subcritical coal plants are the least efficient, although it is important to note that factors such as coal quality and O&M conditions can render certain subcritical plants in some countries more efficient than some supercritical plants. Subcritical technology accounts for two-thirds of existing coal capacity, supercritical for one-fifth and the remainder is advanced (Figure 8.14).

In the New Policies Scenario, around one-third of the coal-fired power plants currently in operation (mainly old, subcritical plants in OECD countries) are retired over 2015-2040, as they reach the end of their technical lifetimes. The amount of new coal plants and the choice of technology vary widely across countries and regions, depending mainly on the policies in place and relative economics. Over the *Outlook* period, almost two coal plants are added for each one that is retired, bringing the global installed capacity in 2040

15. Includes ultra-supercritical, integrated gasification combined-cycle (IGCC) and combined heat and power (CHP).

to 2 470 GW, an increase of more than 25% over today's level. Of those added, over 40% are of the advanced category or are fitted with CCS (the latter representing only a small fraction of the total, consistent with the limited geographical implementation and level of carbon pricing in the New Policies Scenario).

Figure 8.14 ▷ Global coal capacity by technology, 2014 and 2040



Today, China accounts for 45% of global installed coal-fired capacity. More than 85% of its fleet is less than 20 years old. Thanks to the introduction of more stringent standards over the last decade, China has shifted away from the construction of new subcritical plants (which accounted for around 95% of the additions in the early 2000s) towards ultra-supercritical designs. In 2014, these accounted for almost half of the new coal additions. As a result, China built 85% of the new ultra-supercritical plants added worldwide in 2014, bringing its share of global installed advanced coal capacity in 2014 to almost half (Table 8.6).

Table 8.6 ▷ Coal capacity by technology, 2014 and 2040 (GW)

	2014					2040				
	OECD	China	India	Rest of world	World	OECD	China	India	Rest of world	World
Total	**647**	**864**	**174**	**238**	**1 922**	**412**	**1 175**	**438**	**443**	**2 468**
Subcritical	415	529	149	158	1 251	161	476	196	210	1 044
Supercritical	147	205	25	28	405	120	318	222	103	764
Advanced	85	130	0	51	266	98	355	21	123	597
CCS	0.1	-	-	-	0.1	33	25	-	6	63
Subcritical	64%	61%	86%	67%	65%	39%	41%	45%	48%	42%
Supercritical	23%	24%	14%	12%	21%	29%	27%	51%	23%	31%
Advanced	13%	15%	0%	21%	14%	24%	30%	5%	28%	24%
CCS	0%	-	-	-	0%	8%	2%	0%	1%	3%

Though China adds more new coal plants over the *Outlook* period than any other country or region, its share of global coal additions shrinks to one-third, down from almost three-quarters over the last ten years. China continues to lead in deploying the most efficient coal plants, accounting for about 60% of the global additions from 2014 to 2040. While the role of coal in OECD countries continues to shrink, meeting increasing electricity demand in India and Southeast Asia leads to around 450 GW of new coal capacity. The construction of new subcritical and new supercritical coal plants in these two regions amounts to 60% of all construction of new coal plants in those two categories.

Power generation and coal plant efficiencies

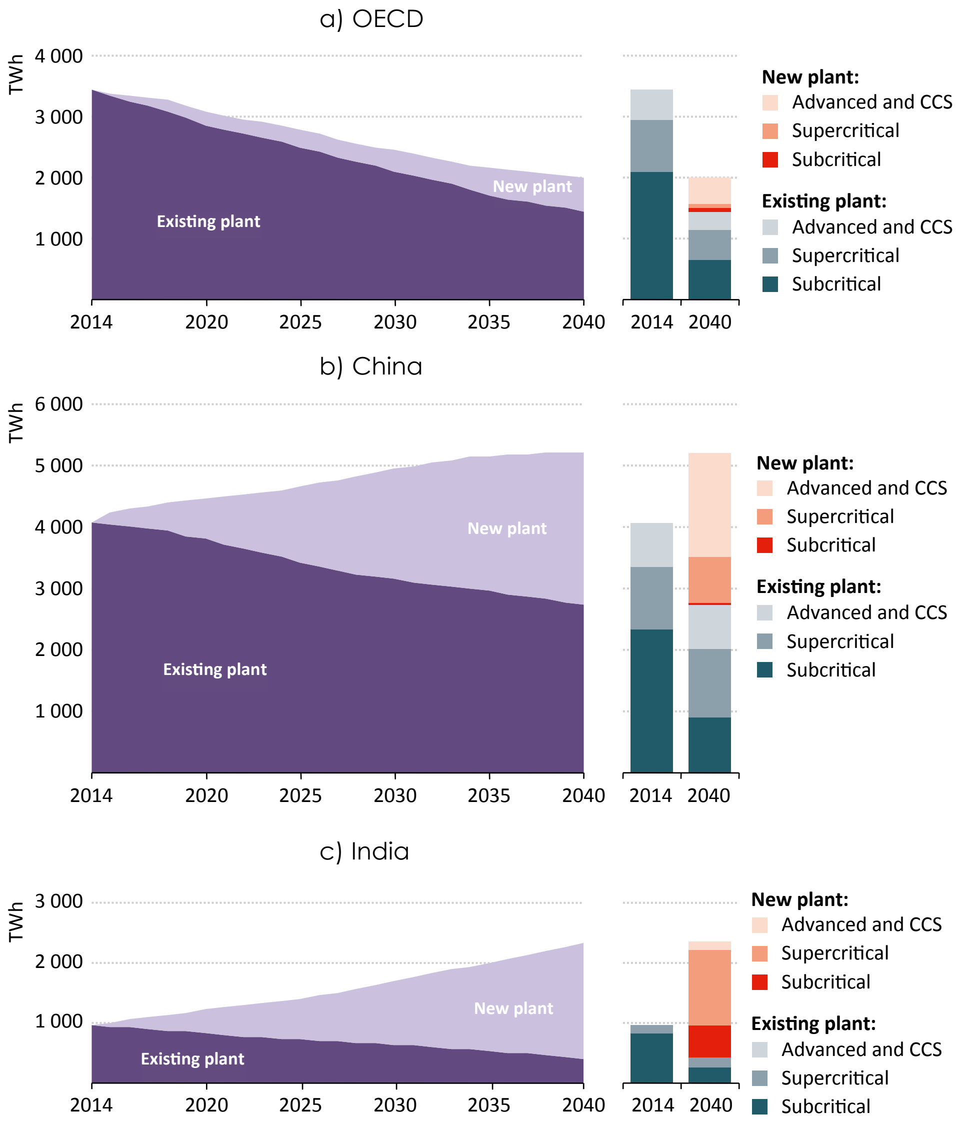
There have been two distinct phases to the evolution of coal-fired generation over the last 25 years. During the first half of the period (1990 to early-2000s), coal's share of worldwide generation increased from 37% to 40% while the average efficiency of coal plants remained flat, at just over 35%. Over the course of the last ten years, it has been coal's share of generation that has remained flat, at around 40-41% whereas the average efficiency of the global coal-fired fleet has increased by two percentage points to 37%.

In 1990, the OECD was responsible for 70% of global power generation from coal. By 2007, its coal-fired output peaked and then began to decline (initially in about equal shares) in the United States and the European Union, and then predominantly in the United States, due to the switch from coal to gas. Strong growth in the rest of the world – China in particular, which was responsible for 90% of the net increase in coal-fired generation over the last decade – cut the OECD's share of coal-fired generation in half by 2013. In the New Policies Scenario, the OECD's share of coal generation is again reduced by more than half, to reach 17% by 2040. China's coal-fired generation growth over the *Outlook* period is not enough to fully offset the decline in OECD countries. India sees the biggest net increase in coal-fired generation to 2040, greater than that in China or in the rest of the world (excluding China) combined.

Many factors influence the efficiency of an individual coal-fired plant, such as the technology type, coal quality, ambient temperature, cooling arrangements and the pollution control technologies used. How the average efficiency of the coal fleet by country or region evolves over time and whether it will shift towards higher efficiency, i.e. lower coal use per unit of output, depends on the type of existing and new coal plants in the mix as well as the amount of electricity generated by each plant. The age of various power plants, the policies in place that either limit or support their use, their relative economics compared to other sources and the overall composition of the fuel mix, all play a role in determining the plants which remain operational and, consequently, the overall efficiency.

In the New Policies Scenario, by 2040, generation from coal plants currently operational in OECD countries falls to around 40% of its level today. By 2040, electricity production from new coal plants, one-third of which are fitted with CCS, accounts for one-quarter of total coal-fired generation in the OECD (Figure 8.15). The majority of subcritical plants that are added globally over the *Outlook* period are in non-OECD Asia, with the largest amounts added in India and Southeast Asia. In India, more than 80% of total coal-fired generation in 2040 comes from plants which have yet to be built. While the amount of generation from subcritical plants remains at roughly today's levels, as new plants offset retiring ones, the percentage of supply from subcritical plants declines sharply, from 90% to just above one-third in 2040, as India increasingly invests in supercritical units. Power generation from the more efficient designs increases ten-fold, providing 60% of overall coal generation in India. In China, the share of coal generation from existing plants and new plants is almost equal.

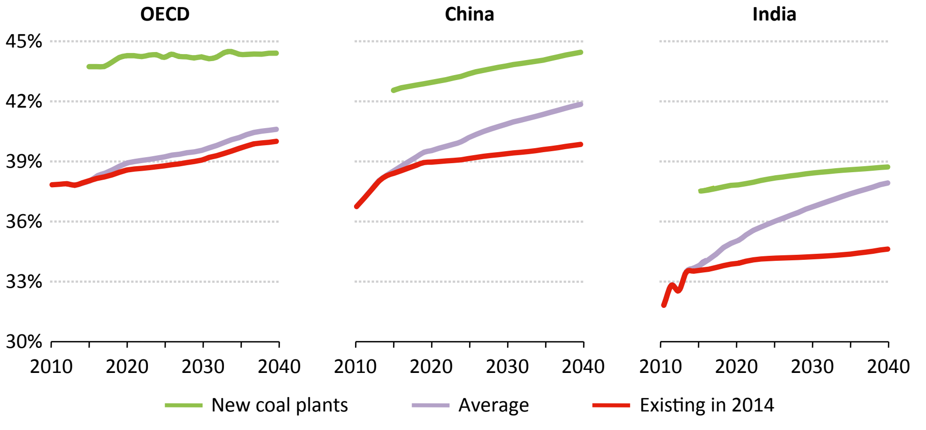
Figure 8.15 ▷ Electricity generation from existing and new coal-fired power plants by selected regions



Note: Electricity generation from plants fitted with CCS is included with advanced plants for graphical purposes, as it accounts for about 10% of the total of these two categories.

The average level of efficiency of the global coal fleet by 2040 varies by region, depending on the relative weight of generation from existing plants, the amount and type of new capacity added, how quickly this new capacity is built and how it is operated. The efficiency of the existing fleet generally increases over time as the worst performing plants are retired or used less frequently (Figure 8.16). Efficiency can also increase following refurbishment of plants. The efficiency of new plants depends on the technology type. It can be as low as 36-37% in the case of subcritical plants or approach 44-45% for the most efficient types. The adoption of the most efficient technology can reduce coal use, CO_2 emissions and other pollutants where multiple emissions control technologies are applied.

Figure 8.16 ▷ Efficiencies of existing, new and average fleet of coal-fired power plants



Note: Excludes CCS-fitted plants.

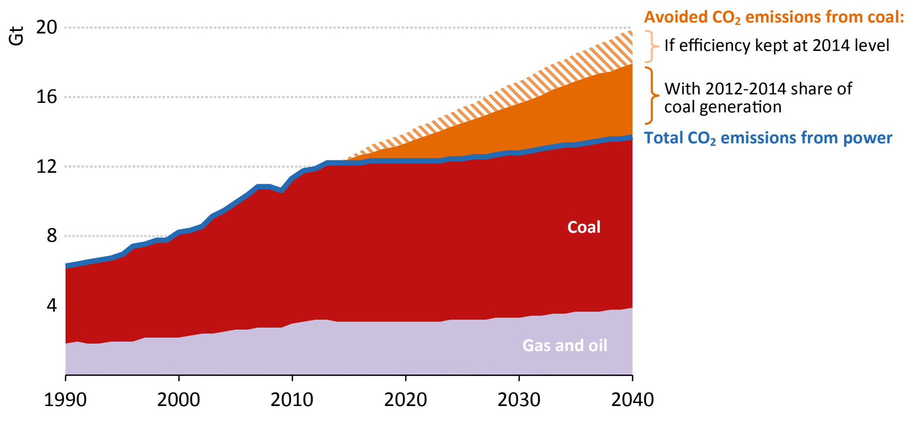
Since 1990, China has contributed most to the global increase in coal power plant efficiency, as it built numerous advanced coal plants to meet demand, while at the same time retiring older inefficient plants. This resulted in an impressive increase of six percentage points in its average efficiency in the span of just ten years, bringing China to the same level of average coal-fired plant efficiency in the OECD countries. Over the coming decades, the rate of coal-fired capacity additions in China is projected to slow, though the new plants added still increase the average coal efficiency by another three-and-a-half percentage points. In the OECD countries, addition of new coal plants (excluding CCS-fitted ones) is limited, and has little impact on the average efficiency of the fleet. India achieves one of the highest increases in the average fleet efficiency over the *Outlook* period – by four-and-a half percentage points – to reach the level of the OECD and China today. All these efficiency gains lead to a gain of three percentage points in the global average coal efficiency, saving about 265 Mtoe of coal in 2040 (relative to the coal use that would be required to generate the same amount of electricity at the current level of efficiency), equivalent to the coal use in the European Union today.

CO_2 emissions due to coal-fired power generation

CO_2 emissions from coal-fired power plants are influenced by two key factors: the amount of power generated and the efficiency of the plants. From 1990-2013, coal-fired generation more than doubled and the average efficiency of the fleet increased by two percentage points. In this period, coal-fired power plants accounted for three-fourths of the increase in global power-related CO_2 emissions. The increase in the average efficiency of coal-fired power plants, which has taken place over the last decade, has been mainly due to developments in China. If the global average efficiency had remained at the levels of the early-2000s, global coal use for power generation in 2013 would have been 10% higher and emissions would have been 0.9 Gt higher (which is roughly equivalent to the combined power-related emissions of Japan, Korea and Canada).

In the New Policies Scenario, total global CO_2 emissions from power generation increase by 1.6 Gt from 2013 to 2040, at a rate that is one-sixth of that over 1990-2013. This is due to both a decline in the average annual growth rate in coal-fired generation and a decline of coal's share of total generation (which falls to 30% from 41% today) coupled with a further increase in the global average efficiency of coal-fired power plants by 2040 of three percentage points (to reach 40%).

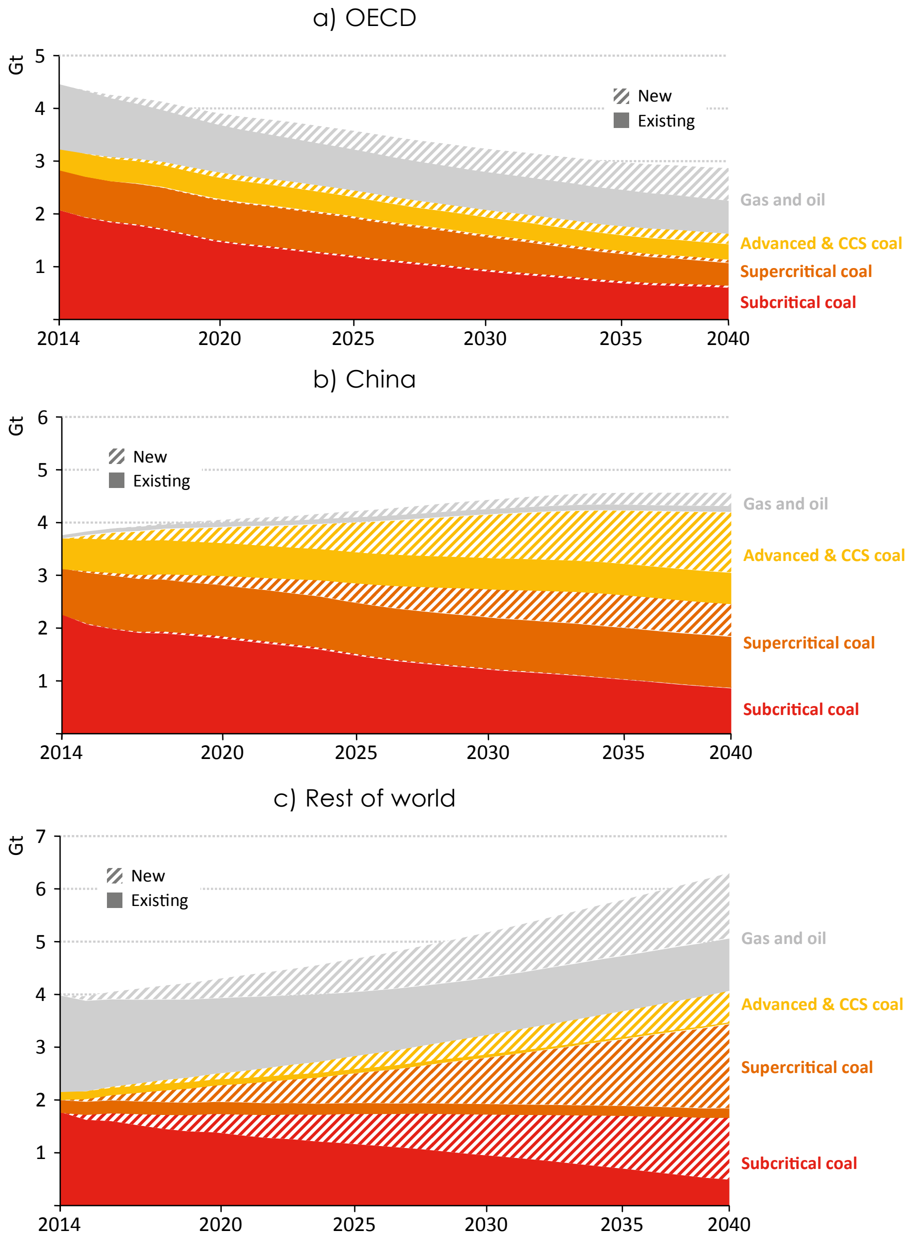
Figure 8.17 ▷ CO_2 emissions from power generation by fuel in the New Policies Scenario



If the share of coal generation over the period to 2040 were to remain at the level seen in the last few years in each country/region, total emissions from power generation would be 4.2 Gt (30%) higher by 2040. Taking it a step further, if the efficiency of the coal-fired power plants were also to remain at today's levels, emissions would be an additional 1.9 Gt in 2040. Taken together, total CO_2 emissions from the power sector would be almost 50% higher than the levels projected in the New Policies Scenario (Figure 8.17).[16]

16. This assumes that gas and oil would remain at the level of the New Policies Scenario, i.e. that coal would increase at the expense of renewables and nuclear.

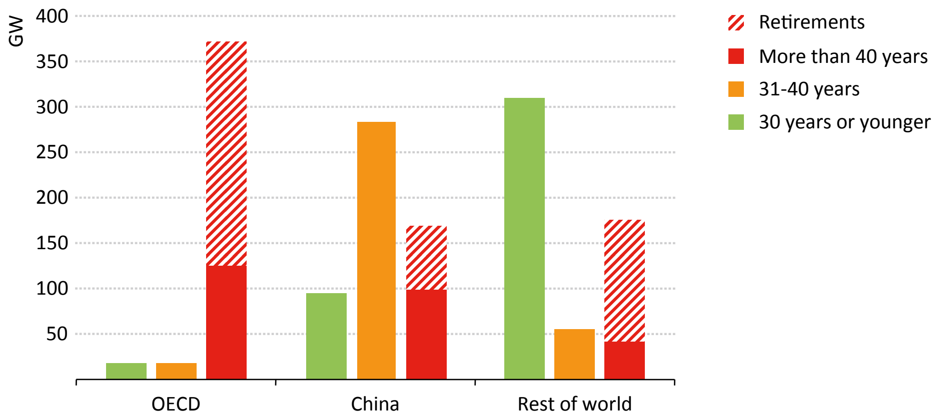
Figure 8.18 ▷ CO_2 emissions by fuel and coal technology in selected regions



Today, subcritical coal plants account for more than one-quarter of total global power generation and for 6 Gt of the 12 Gt of global CO_2 emissions from power generation. Of these 6 Gt, 34% arise in OECD countries, 37% in China and the remainder in the rest of the world. By 2040, global generation from subcritical coal plants is cut in half and so are the related CO_2 emissions. Emissions from these plants in OECD countries are cut by a factor of three, with the United States responsible for three-quarters of the remaining OECD emissions of 0.7 Gt. China's emissions from subcritical power plants fall by over half, to 0.9 Gt in 2040 (Figure 8.18). The continued construction of subcritical plants in the rest of the world (including India) broadly maintains the current level of generation from these plants to 2040, though improvements to efficiency reduce the associated emissions by 5%.

Worldwide, the average efficiency of installed coal subcritical capacity in 2040 is 36%, or four percentage points lower than the overall average for the entire coal fleet. Most of the remaining subcritical capacity in China and the OECD is respectively older than 30 and 40 years, while, in the rest of the world, more than three-quarters of the subcritical capacity in 2040 is less than 30 years old (Figure 8.19). India and Southeast Asia account for more than half of the global subcritical capacity that is less than 30 years old in 2040; two-thirds of it is not yet online. Reducing the use of existing subcritical plants and banning the construction of new ones is an essential feature of the Bridge Scenario, presenting a practical way forward to realising the international agreed objective of cutting greenhouse-gas emissions so as to limit the average rise in global temperatures to no more than 2 ^{o}C, which is set out in *Energy and Climate Change: World Energy Outlook Special Report* (IEA, 2015b) (See Chapter 2, Spotlight).

Figure 8.19 ▷ Average age of coal subcritical plants operating in 2040 and retirements over 2014-2040



Impact of local water scarcity on coal-fired power

Just as the size and composition of the coal-fired power plant fleet can influence the level of global CO_2 emissions, so too can changes brought about by an increase in CO_2 emissions have an impact on coal-fired power. Water stress is one example. Water for cooling is essential to coal-fired power generation and limited water availability is already a constraint on power station siting that will become more severe with climate change. For this reason, this chapter concludes by considering the impact on coal-fired generation of potential changes to water availability in China which accounts for 45% of the world's installed capacity of coal-fired power plants in 2014 and 35% of coal-fired capacity additions to 2040 in the New Policies Scenario (see Chapter 14 for a similar analysis for India).[17] This analysis relies on projections from the *WEO* New Policies Scenario, the emissions trajectory of which implies long-term average global warming of 3.6 °C.

Box 8.2 ▹ Modelling the impact of water stress on coal-fired power plants

Constraints on water availability influence the location of future power plants, as well as the choice of cooling technologies for new plants and for retrofitting existing ones. These decisions are driven principally by water availability, the cost of different cooling technologies, fuel transport costs and the availability of the grid infrastructure.

To undertake this new analysis of the impact of water stress on coal-fired power plants, a unique dataset was created through the merging of several sources relating to cooling technology, capacity, efficiency and the location of each plant. Data on future available freshwater and for future water demand from outside the power sector (agriculture and households), were obtained from the World Resources Institute drawing on the Aqueduct project (Luck, Landis and Gassert, 2015).

In order to assess the extent of climate change in locations with coal-fired power plants, the results from global climate models were scaled down to sub-catchment areas[18] that allow for an assessment of the implications of water use changes in one sub-catchment area on those located further downstream. The representative concentration pathway (RCP) 4.5 scenario from the Intergovernmental Panel on Climate Change's Fifth Assessment Report (IPCC, 2014) was chosen as the best available description of long-term emissions trajectory compatible with the New Policies Scenario.

A new linear optimisation model was developed by the *World Energy Outlook* team for this report that determines the least-cost location of coal-fired power plants according to water availability, coal transportation cost, transmission cost and the additional capital cost for cooling systems (differentiating between non-fresh water, freshwater and dry cooling).[19] The model can choose between three principal cooling systems: once-through, wet-tower and dry cooling. While once-through technologies have the highest water withdrawal rate, they are also the least-cost option in terms of capital requirements. Dry cooling hardly uses water, but requires the largest capital investment and typically comes with a loss in efficiency. The fuel costs used in the model were calculated by determining the distance to domestic coal fields or coal import terminals in coastal areas and the associated transport costs, as well as their respective production or import costs. For power transmission costs, it was assumed that the location of future demand for electricity will generally follow past trends and that locating power plants further away from demand centres entails higher electricity network expansion costs.

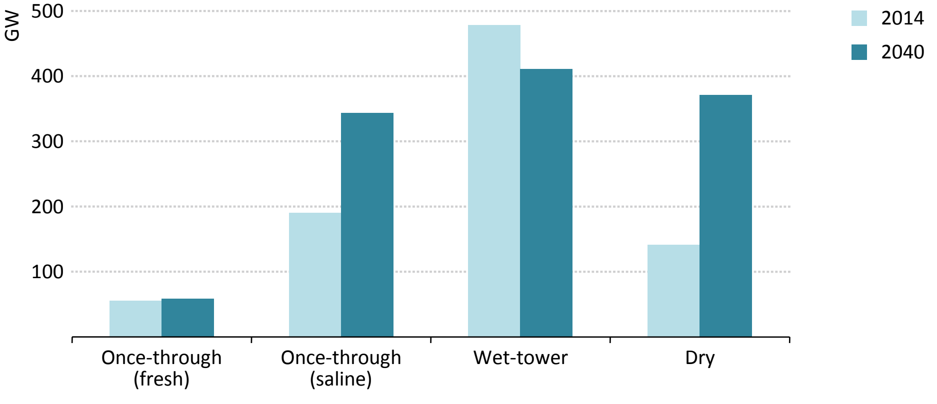
17. Analysis conducted in the *World Energy Outlook-2012* on the intersection of water and energy provided the foundation for this new analysis (IEA, 2012).

18. Sub-catchment areas are hydrological units within which all water flows to a single point.

19. For more details on the methodology see *www.worldenergyoutlook.org/weomodel/documentation*.

China is already experiencing water scarcity in several regions: indeed, 79% of water withdrawals in China for all purposes occur in water-stressed regions (Luck, Landis and Gassert, 2015). Coal-fired power plants are responsible for around 90% of total water withdrawals related to the power sector in China, with the rest being split between gas-fired and nuclear power stations.[20] The large-scale adoption of CCS (as projected in our 450 Scenario) could increase overall water requirements significantly, due to the additional cooling for carbon capture. Different strategies exist to mitigate the impact of local water stress on thermal power, such as switching to renewables that consume very little (if any) water, improving end-use efficiency, switching to less water-intensive cooling technologies or locating new plants in less water-stressed areas. An additional consideration for the siting of coal-fired power plants is access to the electricity transmission grid and coal transport costs, which can be substantial, depending on haulage distances.

Figure 8.20 ▷ Installed coal-fired power generation capacity in China by cooling technology in the New Policies Scenario

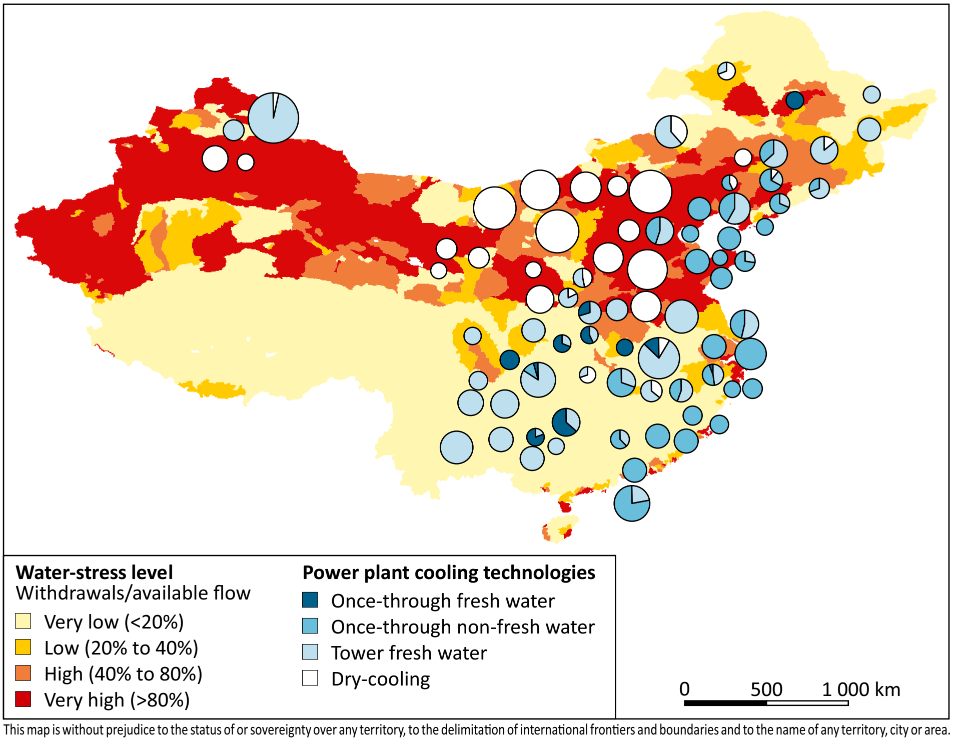


China's installed capacity of coal-fired power plants increases from around 860 GW in 2014 to almost 1 200 GW in 2040 in the New Policies Scenario. Today, coal-fired power plants are located primarily in eastern China, close to the major coal fields of Inner Mongolia, Shanxi and Shaanxi – areas that already suffer from water constraints – and in the coastal provinces. Adaptation to water stress is already apparent in China, particularly in northern and eastern regions, where more than 100 GW of coal power plants are equipped with more expensive dry cooling (12% of the entire coal fleet), because of the constraints on water availability in these areas (Figure 8.20). The need for such adaptation is expected to increase, as water withdrawals by agriculture are projected to increase by 9% from 2010-2040 and withdrawals by households by nearly 78%, while water flows are projected to change due to climate change.

20. Modern gas-fired plants are significantly less water intensive than coal plants. Nuclear power stations have similar water requirements to coal plants, but nuclear fuel transportation costs are very low so, in terms of economics alone, the location of a nuclear power station can more readily be determined by considerations of water availability.

In a New Policies Scenario that allows for changes in water availability, increased water stress has a material impact on the cooling technologies (and related costs) deployed across China's coal-fired power fleet. The power sector is expected to need to undertake major efforts to address water shortages, with around 175 GW of installed coal-fired capacity, mainly plants with wet-tower systems in northern China, needing to be retrofitted with dry cooling (Figure 8.21). The capacity of the fleet of dry-cooled power plants increases by two-and-a-half-times from 2014 to 2040 in the New Policies Scenario. In addition, more than 340 GW of coal-fired power generation capacity (an increase of 150 GW from today) is located near the coast, incorporating seawater cooling systems and using either imported or domestic coal shipped along the coast. By contrast, water-intensive once-through cooling, based on freshwater, is installed on less than 5% of newly constructed coal-fired power plants in China.

Figure 8.21 ▷ Installed coal-fired generation capacity by cooling technology and sub-catchment area in China in 2040



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Notes: The size of the pie charts corresponds to the capacity installed. The smallest pie charts represent 3 GW and the largest 45 GW.

Domestic coal production is projected to increase, especially in Xinjiang, an arid region in western China, where electricity demand is relatively low. Due to high coal transportation costs, the coal is consumed close to the mines (mostly in dry-cooled power plants) and electricity is then transmitted via high-voltage direct current lines to the demand centres in coastal areas (Paulus and Trüby, 2011). Smaller amounts of coal from Xinjiang are dispatched to more central provinces to provide fuel for power plants there. While coal production costs in Xinjiang are around $30/tonne, transport by rail over 3 000 km to the coast would more than triple that cost, making the coal originating from Xinjiang uncompetitive with imported coal.

The need to adapt to growing water constraints results in fewer water-intensive cooling systems in new power plants or refurbishment of existing ones. This boosts cumulative investment needs by 85%, (around $67 billion) from 2015 to 2040, relative to a situation in which there is no change in water stress levels. As a result, generation costs from coal-fired power plants are projected to increase by around $0.4/MWh, on average, roughly 10% of location-specific costs[21] due to water stress (Figure 8.22). In such a scenario, the higher costs for cooling systems and higher investment in the transmission grid are offset somewhat by lower coal transportation costs. This is because coal transportation distances decrease as more dry-cooled power plants are built close to the mines, a trend which is developing as wet-tower systems in central China increasingly face water shortages in surrounding catchment areas. Power plants in that area are mid-way between the coal mines and the electricity demand hubs on the coast, and, though far from both, they previously had ample water supply. With increasing water scarcity, the area's locational advantage is diminishing.

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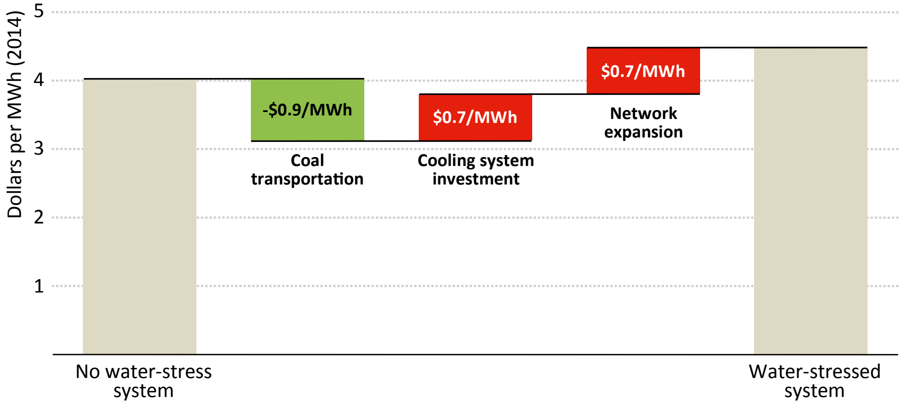
Figure 8.22 ▷ Impact of water stress on average Chinese location-specific generation cost for coal-fired power plants by cost component in the New Policies Scenario, 2040



Note: The graph only refers to the generation cost component that can be attributed to the location of a plant.

21. Location-specific generation costs include cost for coal transportation, additional annualised cooling system investment and the potential cost of additional grid infrastructure as a consequence of a water-related locational-choice of power plants.

Implications and future considerations

This analysis demonstrates that water scarcity is a real issue for policy-makers and utilities in China (and elsewhere). It shows that, in regions faced with increased water scarcity as carbon emissions drive the global temperatures higher, the energy sector must choose between mitigating measures, installing less water-intensive cooling technologies in new plants, retrofitting plants with different cooling technologies or locating new power plants in less water-stressed regions. However, costs will rise and the impact may be felt most in regions already suffering from water stress.

This analysis relates to just one example of the additional risks and costs that the energy sector may face in response to climate change. It illustrates clearly the need for owners and regulators of energy infrastructure to consider adaptation needs. Existing policies do not yet adequately encourage actions to improve the climate resilience of the energy infrastructure. Climate adaptation must be embedded in government policy and in industry's investment strategies if a more resilient and secure energy system is to emerge, but it is often complicated by the need to co-ordinate across a wide range of stakeholders. Actions that could aid this process include:

- Incorporating the impacts of climate change in energy and supply projections used to inform policy and investment decisions.
- Requiring explicit consideration of the potential impacts of future climate change (gradual and extreme) when planning and designing new energy infrastructure and incorporating appropriate resilience measures.
- Undertaking an audit of the climate risks to existing energy infrastructure and establishing a programme of remedial measures to improve resilience.
- Tracking the development of adaptation strategies and the implementation of resilience measures, as a means to support future learning.
- Accepting the necessary additional costs of a smooth transition to a water-resilient power sector on the basis that failure to do so can lead to outages and potentially large economic costs.
- Establishing and practising emergency preparedness and response plans to cope with extreme weather events.

Renewable energy outlook

Outshining the rest?

Highlights

- Collectively, renewables secured their position as the second-largest source of electricity in 2014, behind coal. Compared to 2013, renewables accounted for 85% of the increase in total generation. Supportive policies led to the installation of a record-high 130 GW of renewables capacity in 2014. Over the last decade, 318 GW of hydropower were built, more than any other form of renewables, followed by wind power (304 GW) and solar PV (173 GW). During that time, hydropower output in China increased by two-thirds more than gas-fired generation in the United States.
- In the New Policies Scenario, continued government support (estimated at $135 billion in 2014) and declining costs drive greater use of modern renewables, raising their share in total primary energy demand from 14% in 2014 to 19% in 2040. In 2040, renewables account for one-third of total electricity generation, one-sixth of the energy consumed to provide heat and 8% of road transport fuels.
- Global capacity additions of renewables total 3 600 GW over 2015-2040, more than all other power plants together. China is the largest market for renewables, adding 1 out of every 4 GW in the world to 2040, followed by the European Union, India and the United States. These regions account for two-thirds of global renewables capacity added to 2040. Global investment in renewables capacity totals $7 trillion to 2040, about 60% of total power plant investment.
- Dramatic cost reductions are improving the competitiveness of some renewables at both large and small scales. Today, nearly three-quarters of renewables generation, mainly in the form of hydropower, is competitive without subsidies (not including externalities). The fully competitive share of non-hydro renewables doubles to one-third by 2040. Nonetheless, subsidies to renewables-based generation rise from $112 billion in 2014 to $172 billion in 2040: they would be over $400 billion were it not for further cost reductions achieved and rising wholesale electricity prices.
- The solar industry in Asia has gone from infancy to dominating the global market in the past five years. In 2014, Asia manufactured nine out of ten solar PV panels in the world, while the United States and European Union imported the majority of solar PV capacity added. Asia is poised to continue its dominance, with rising demand for solar PV in the region and low production costs that are difficult to match.
- Power generation from renewables avoids 135 Gt CO_2 over 2014-2040. Generation from new renewables installations avoids 50 Gt to 2040, much more than the 1.3 Gt of CO_2 emissions related to the production of the aluminium, concrete and steel used in their construction. As well as reducing emissions, renewables are deployed in order to enhance air quality, energy security and the diversity of supply.

Recent developments

Renewable energy is established around the world as a mainstream source of energy, one of the most important low-carbon sources to meet demand for electricity, transport and heat and an integral part of energy security and climate change policies. The markets for wind power and solar photovoltaics (PV) are currently the most dynamic, with falling technology costs (in particular for solar PV), expanding policy support and potential for increased deployment around the world. Hydropower continues to provide the lion's share of renewable energy in the power sector, while bioenergy supplies the vast majority of renewable energy in the industry, buildings and transport sectors. Renewable energy has become a large industry, employing 7.7 million people worldwide (excluding large hydropower), with solar and bioenergy industries each employing more than 3 million people (IRENA, 2015a).

Policy developments

In 2014, capacity additions of renewables totalled 130 gigawatts (GW), the largest amount ever registered, and associated investment was about $270 billion (marginally lower than 2013). By early 2015, 145 countries have supportive measures for renewables, nine-times more countries than a decade ago. Over the past year, several new national targets have been announced or proposed. These include: the Clean Power Plan in the United States and a 50% renewable portfolio standard in California by 2030; a minimum requirement of 27% renewable energy use by 2030 in the European Union; 200 GW of wind power and 100 GW of solar PV by 2020 in the Intended Nationally Determined Contribution (INDC) submission of China; and 100 GW of solar PV by 2022 in India (Table 9.1).

The targets are, in most cases, accompanied by policies that provide financial support. This can take many forms, including direct payments (e.g. grants), fixed remuneration (e.g. feed-in tariffs or premiums), tax rebates, dedicated auctions, green certificates or facilitated financing conditions. Cost reductions and innovative policy approaches are also helping renewables to make inroads into new markets, particularly where access to electricity is low. For example, Bangladesh, where 40% of the population lacks access to electricity, had successfully secured, mainly by competitive tender, the installation of solar home systems to 9% of the population by May 2014.

Policies to support the use of renewable energy in heat production and for use in transport are more limited than those for power generation. Policies to encourage the use of renewables for heating and cooling are in place in only about 40 countries in the world, despite the fact that many renewable energy technologies for heat production are mature and can be competitive with the use of fossil fuels (IEA, 2014a). Today's low oil price environment makes for stiff competition for biofuels where they compete in an open market. However, as most biofuels use is motivated by blending mandates, the outlook for biofuels remains largely unaffected by current low oil prices. In fact, some countries, such as Brazil and Indonesia, have recently increased their blending mandates for biofuels.

Table 9.1 ▷ Targets driving renewables deployment in selected regions

Region	Policy type	Target
United States	Volume target	36 billion gallons of renewable fuels by 2022.
	Sector share	30 state- and district-level renewable portfolio standards.
	System target	Reduce power emissions by 32% from 2005 levels by 2030.
European Union	System target	20% renewable energy in gross final consumption by 2020. 27% renewable energy in gross final consumption by 2030.
	Sector share	10% of transport energy from renewable sources by 2020.
China	Capacity target	350 GW of hydro plus 70 GW of pumped storage, 200 GW of wind power, 100 GW of solar PV, 30 GW of bioenergy by 2020.
	System target	15% non-fossil fuel share of total energy supply by 2020. 20% non-fossil fuel share of total energy supply by 2030.
India	Capacity target	100 GW of solar PV, 60 GW of wind power, 10 GW of bioenergy, 5 GW of small hydro by 2022.
South Africa	Volume target	1 million solar water heaters by 2030.
	Capacity target	17.8 GW of new renewables capacity by 2030.
Brazil	Sector share	27% biofuels blending mandate.
Korea	System target	11% of primary energy from renewables by 2035.
Australia	Generation target	33 TWh of power from large-scale renewable plants by 2020.
Mexico	Sector share	Less than 65% of fossil fuels in power generation by 2024. Less than 60% of fossil fuels in power generation by 2035. Less than 50% of fossil fuels in power generation by 2050.
Southeast Asia	System target (Indonesia)	23% of primary energy from new renewable sources by 2025. 31% of primary energy from new renewable sources by 2050.
	Sector share (Thailand)	20% of power generation and 20% of transport fuel use from renewables by 2036.
	Sector share (Malaysia)	2 080 MW of renewables capacity by 2020. 4 000 MW of renewables capacity by 2030.

Notes: Policies setting a minimum non-fossil fuel share of energy supply (or a maximum fossil-fuel share) may also drive the deployment of nuclear power. Japan has support measures for renewables, particularly solar PV, but no specific targets. CSP = concentrating solar power; MW = megawatts.

Market and industry developments

Over the last decade, renewables have accounted for 36% of new power generation capacity, have met 16% of incremental demand in road transport and 21% of incremental demand for heat. Hydropower provided more new capacity than any other renewable energy technology, 60% of it in China. Over the period, hydropower output increased by around 730 TWh in China, about two-thirds more than the increase in gas-fired generation in the United States or 60% more than the increase in renewables generation in the European Union (EU). Wind power added almost as much capacity as hydropower worldwide and accounted for the majority of non-hydro renewables deployment, adding about 30% more capacity than all other non-hydro renewables counted together.

It was a near-record year for wind power in 2014, with 48 GW of capacity additions – a rebound of more than 40% over 2013 and just behind the amount of capacity added in 2012. Three-quarters of the additions were in three regions: China (20 GW), the European Union (12 GW) and the United States (5 GW). Brazil and South Africa are also increasingly important markets for wind power. The bulk of global wind manufacturing capacity is concentrated in China, the European Union and the United States, with relatively few players: the ten-largest manufacturers account for 70% of total production. Due to high transportations costs for most wind turbine components, wind turbine manufacturing tends to be located close to installation sites.

Wind power development has been led by onshore wind, for which the levelised cost of electricity[1] has been declining, as new turbine designs and higher hub heights enable more electricity to be produced at modest additional capital cost. These technology improvements help wind power find new opportunities in established markets, like the United States, as well as in new markets. In order to more fully tap wind power potential, market reforms will be needed to improve the planning and permitting processes, modernise grid operating procedures and address non-economic barriers (IEA, 2013a). Onshore wind power is increasingly competitive in a number of markets, which has raised the question of whether additional financial support is needed. Despite promising economics, there is uncertainty over the level of future deployment. For example, in the United States, where the production tax credit for renewable energy — a key driver for wind power — has now lapsed; it will require congressional action to reinstate it. The development of offshore wind has been strong in Europe, but the technology has been slow to become established in North America and Asia. The deployment of offshore wind power still depends critically on government policies that provide financial support.

The annual market for solar PV increased 70-fold in the ten years to 2013, when it reached almost 40 GW, then remained stable in 2014. Asia accounted for the bulk of installations, led by China and Japan each adding around 10 GW. China is the largest market for solar PV in the world and aims to keep this position with a target of 17.8 GW to be added in 2015. Between the introduction of a generous feed-in-tariff in July 2012 and March 2015, Japan approved almost 100 GW of solar PV projects, a level which raises doubts about completion of the 74 GW that remain to be installed. India also has ambitions to become a leader in solar PV (see Chapter 12). There remains scope for further short-term steps to be taken to clear the path for further uptake of solar PV in the future, ranging from technical improvements to knowledge sharing of best practices (IEA, 2014b).

Solar PV has led the way in terms of cost reductions, through both lower production costs and prices for solar panels and also reductions in the "soft costs" of deployment (finding customers, system design, installation labour and margins for installers). The costs of solar panels have been driven down by technological improvements, the benefits of widespread deployment over the last 10 years and the expansion of manufacturing capacity, including

1. The levelised cost of electricity represents the average lifetime cost of a power plant per unit of electricity generated. For more information see *Projected Costs of Generating Electricity – 2015 Edition* (IEA, 2015a).

the entry of lower-cost production lines such as those in China and Chinese Taipei. China and Chinese Taipei accounted for almost 70% of global production in 2014 and more than nine out of ten solar panels were manufactured in Asia (see Spotlight, below). Japanese, EU and US manufacturers, formerly global leaders in the production of solar panels, now play a smaller role. The top-ten manufacturers of solar PV shared between them about 20 GW of the 40 GW produced globally in 2014 (Table 9.2). Nonetheless, the market for solar panels remains more diversified than for wind turbines.

Table 9.2 ▹ Top-ten solar PV manufacturers in 2014

	Manufacturer	Production (GW)	Share of global production	Location*
Top-ten		20.7	52%	
1	Trina	2.9	7%	China
2	JA Solar	2.8	7%	China
3	Hanwha	2.5	6%	China
4	Yingli	2.5	6%	China
5	NeoSolar	2.1	5%	Chinese Taipei
6	Jinko Solar	2.0	5%	China
7	Motech	1.6	4%	Chinese Taipei
8	First Solar	1.5	4%	United States
9	Canadian Solar	1.4	4%	Canada
10	Kyocera	1.4	4%	Japan

* Location refers to that of the manufacturer's headquarters.

Source: SPV Market Research (2015).

Outlook by scenario

In each of the principal scenarios in this *Outlook* (Current Policies Scenario, New Policies Scenario and 450 Scenario), the use of renewable energy continues to expand, though the pace varies, dependent upon the strength of government policies to reduce energy-related emissions, address local air pollution problems and enhance energy security through a more diverse energy supply (Table 9.3). Increasingly strong ambition and policy support measures in the scenarios, in the order listed above, translate into higher shares of renewable energy in the energy system.[2]

The share of renewables in global total primary energy demand (TPED) in the Current Policies Scenario, which assumes the implementation of existing government policies and measures, holds at about 15% throughout the period to 2040. In the New Policies Scenario, our central scenario which assumes cautious implementation of proposed policies in addition to existing measures, the share of renewables increases to 19% in 2040. In the 450 Scenario, which achieves an emissions trajectory consistent with a 50% probability of limiting the average global temperature increase to the international goal of 2 degrees Celsius, the share of renewables in TPED reaches nearly 30%. This reflects the importance

2. The scenarios are elaborated in Chapter 1.

of renewable energy to meeting such a target. In the 450 Scenario, from 2013 to 2040, the share of renewables in TPED quadruples in the United States, nearly triples in the European Union and doubles in China.

Table 9.3 ▷ World renewables consumption by scenario

		New Policies		Current Policies		450 Scenario	
	2013	2025	2040	2025	2040	2025	2040
Primary demand (Mtoe)	**1 863**	**2 507**	**3 346**	**2 423**	**3 030**	**2 687**	**4 388**
United States	147	217	323	201	286	258	499
European Union	209	292	378	277	342	309	457
China	331	448	589	430	517	485	808
Share of global TPED	*14%*	*16%*	*19%*	*15%*	*15%*	*19%*	*29%*
Electricity generation (TWh)	**5 105**	**8 784**	**13 429**	**8 202**	**11 487**	**9 549**	**17 816**
Bioenergy	464	902	1 454	865	1 258	973	2 077
Hydropower	3 789	4 951	6 180	4 854	5 902	5 083	6 836
Wind	635	1 988	3 568	1 701	2 778	2 344	5 101
Geothermal	72	162	392	143	299	197	541
Solar PV	139	725	1 521	593	1 066	862	2 232
Concentrating solar power	5	50	262	41	147	83	937
Marine	1	6	51	5	37	7	93
Share of total generation	*22%*	*29%*	*34%*	*26%*	*27%*	*34%*	*53%*
Heat (Mtoe)*	**364**	**492**	**691**	**484**	**653**	**510**	**834**
Industry	206	264	357	271	373	267	378
Buildings* and agriculture	158	227	334	213	279	243	456
*Share of total final demand**	*10%*	*13%*	*16%*	*12%*	*14%*	*14%*	*22%*
Biofuels (mboe/d)**	**1.4**	**2.6**	**4.2**	**2.3**	**3.6**	**4.0**	**9.4**
Road transport	1.4	2.6	4.1	2.3	3.5	3.6	7.6
Aviation***	-	0.02	0.1	0.02	0.1	0.4	1.8
Share of total transport fuels	*3%*	*4%*	*6%*	*4%*	*5%*	*7%*	*18%*
Traditional use of solid biomass (Mtoe)	**759**	**722**	**600**	**727**	**611**	**711**	**574**
Share of total bioenergy	*55%*	*44%*	*32%*	*45%*	*33%*	*41%*	*25%*
Share of renewable energy use	*41%*	*29%*	*18%*	*30%*	*20%*	*26%*	*13%*

* Excludes traditional use of solid biomass in households. ** Expressed in energy-equivalent volumes of gasoline and diesel. *** Includes international bunkers. Notes: Mtoe = million tonnes of oil equivalent; TPED = total primary energy demand; TWh = terawatt-hours; mboe/d = million barrels of oil equivalent per day.

Total electricity generation from renewable energy sources is projected to increase by 125-250% from 2013 to 2040 across the main scenarios, with gains for all the technologies. Hydropower remains the dominant renewable energy technology in each scenario. In 2013, wind power output was only 17% that of hydropower, but this ratio increases to almost 60% by 2040 in the New Policies Scenario and to three-quarters in the 450 Scenario.

In the 450 Scenario, about half of total renewables generation in 2040 comes from variable renewable energy resources, such as wind and solar. Increases in generation from renewables result largely from the cost-effectiveness of the technologies to reduce energy-related carbon-dioxide (CO_2) emissions compared with other abatement options. From 2013 to 2040, heat production from renewables grows by over one-third in the New Policies Scenario and doubles in the 450 Scenario.

The traditional use of solid biomass (e.g. fuelwood, charcoal, animal waste and agricultural residues) in poorer households in the developing world is projected to decline in all scenarios, as economic growth and urbanisation help lead to greater access to modern energy services. In 2013, traditional use of solid biomass represented 40% of total renewable energy demand, but this share falls to 18% in the New Policies Scenario and just 13% in the 450 Scenario.

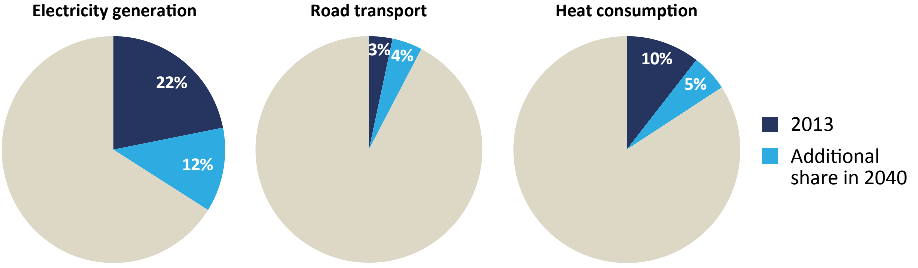
Outlook by sector in the New Policies Scenario

Global trends

The use of renewable energy to meet total primary energy demand increases by over 1.5 billion tonnes of oil equivalent (toe) to 2040 in the New Policies Scenario, raising it 80% above the level in 2013. About one-third of the increase in TPED is met by renewable energy sources, leading to a five percentage point increase in the share of renewables in TPED by 2040. Modern use of renewable energy (i.e. excluding the traditional use of solid biomass, but including hydropower) drives this increase, overcoming the 20% reduction in the traditional use of solid biomass. The rise in modern renewables results from supportive government policies (including carbon pricing and direct subsidies), faster cost reductions in renewables compared to other energy technologies and higher fossil-fuel prices.

Deployment of renewable energy technologies is expected to increase in almost all sectors and regions, though at varying paces. In the New Policies Scenario, renewables-based electricity generation accounts for almost two-thirds of modern renewables use and is the most promising area for further deployment of renewables. Consequently, the share of renewables in electricity generation increases more to 2040 than in both road transport or heat consumption (Figure 9.1).

Figure 9.1 ▷ Share of modern renewables by sector in the New Policies Scenario, 2013 and 2040



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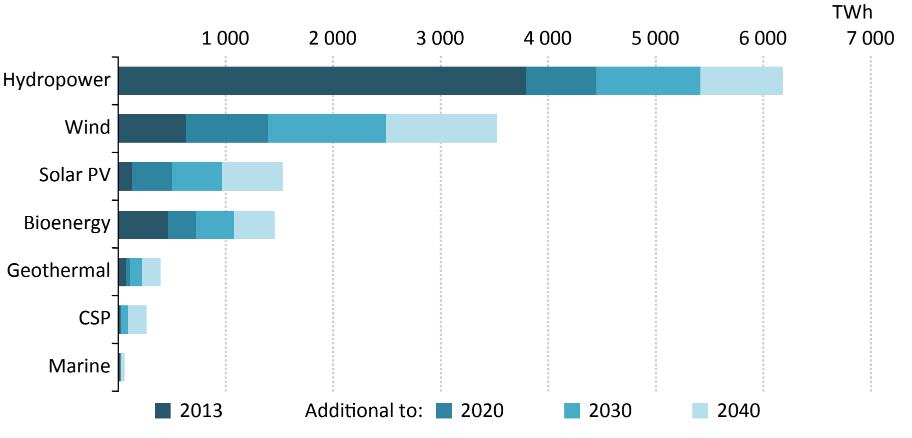
Power sector

Global electricity generation from renewable energy sources increases by two-and-a-half times in the New Policies Scenario, from 5 105 TWh in 2013 to nearly 13 400 TWh in 2040. Consequently, the share of renewables in total generation rises from 22% in 2013 to more than one-third in 2040. Renewables largely make up for the declining share of coal in total generation, which drops from 41% in 2014 to 30% in 2040. Renewable energy sources, collectively, surpassed natural gas by a notable margin in 2014 for the first time since 2000, becoming the second-largest source of electricity, trailing only coal. By the early 2030s, renewables become the largest source of electricity, due to continued policy support for renewables and tightening environmental regulations that reduce output from coal-fired power plants. By 2040, renewables-based generation is 13% higher than from coal-fired power plants.

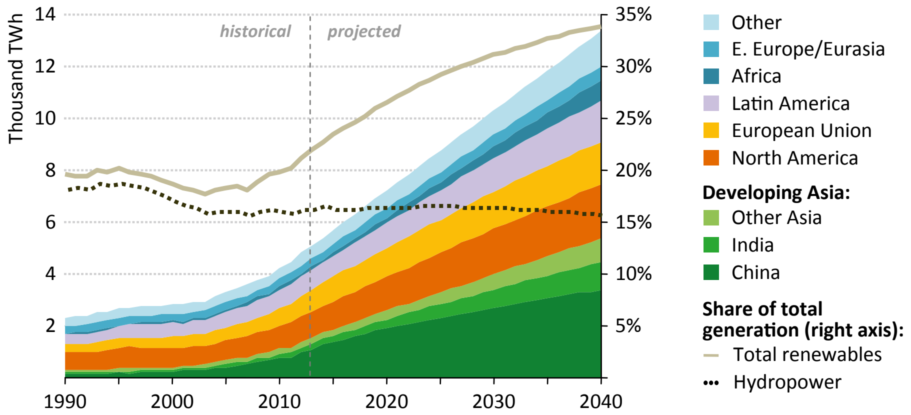
Of the 8 320 TWh increase in renewables generation, wind power provides more than one-third, hydropower about 30%, solar PV 17% and bioenergy about 12% (Figure 9.2). The remaining increase comes from a mix of geothermal, concentrated solar power (CSP) and marine power. In 2013, hydropower accounted for three-quarters of total generation from renewables and it remains the largest renewable energy source of electricity through to 2040, though as of 2035 it accounts for less than half of total renewables-based generation. By 2040, variable renewables (mainly wind power and solar PV) account for 40% of renewables generation and 14% of total generation from all sources.

Figure 9.2 ▷ Global renewables-based electricity generation by technology in the New Policies Scenario



More than two-thirds of the global increase in renewables generation is in non-OECD countries, as they strive to keep pace with electricity demand that more than doubles from 2013 to 2040. Of non-OECD countries, China leads the way, accounting for more than one-quarter of the global increase in renewables-based generation, followed by India and Latin America, each making up about 10% of the global increase (Figure 9.3). Overall, the share of renewables in total generation increases from 22% in 2013 to nearly one-third in 2040. Hydropower continues to play a key role in non-OECD countries, providing between 17% and 19% of total generation through to 2040. Other renewables, led by wind power and solar PV, make large gains, rising from 3% of total generation today to 15% by 2040.

Figure 9.3 ▷ Renewables-based electricity generation by region in the New Policies Scenario



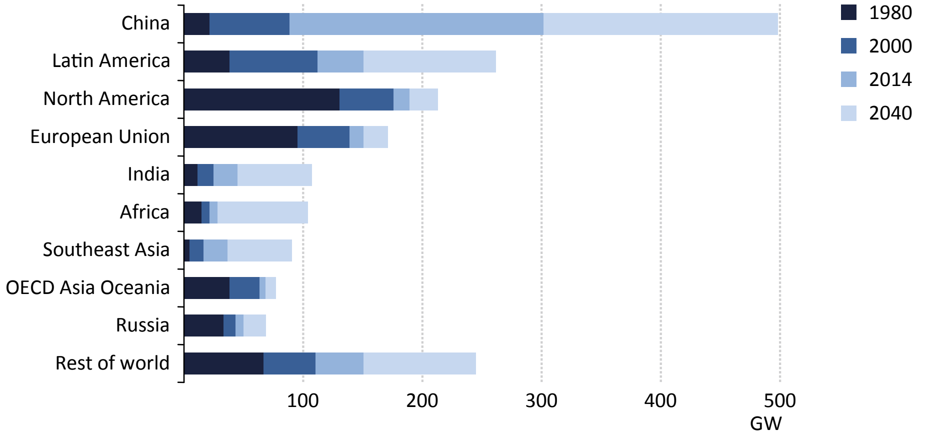
OECD countries account for less than one-third of the global increase in renewables generation over the projection period. Renewables are deployed in OECD countries in large part to reduce the consumption of fossil fuels and, thereby, lower energy-related emissions. The deployment of renewables coupled with limited electricity demand growth (increasing at only 0.7% per year on average to 2040), raises the share of renewables in total generation to nearly 40% by 2040, a higher level than in non-OECD countries. OECD Europe moves furthest to integrate renewables into power supply, as they account for more than half of total generation in 2040, far exceeding the share in any other OECD region. In the United States, the increased volume of power generation from renewables is similar to that of OECD Europe, each accounting for 10% of the global increase, yet the share of renewables in total generation in the United States remains less than 30%.

Hydropower

Worldwide, hydropower has long been the leading renewable energy technology, due in large part to its relatively low levelised costs of electricity produced. Over the period 1971-2013, hydropower helped avoid 64 gigatonnes (Gt) of CO_2 emissions globally, more than any other low-carbon technology, including nuclear power. Up to 1980, the majority of hydropower had been built in the European Union and United States, which together, then, accounted for over 40% of global hydropower capacity. In the period 1980 to 2000, Latin America led the way, constructing 76 GW of new projects, including the Itaipu dam (14 GW) – a binational undertaking of Brazil and Paraguay that was the largest hydropower project in the world when it was completed in 1984.

By 2014, China became the world leader in hydropower, with 300 GW of installed capacity (Figure 9.4). Favourable weather conditions in 2014, raised hydropower output in China by about 180 TWh (20%), enough to lower overall energy-related emissions in China and hold global emissions in place, even as the global economy expanded by 3%. The combined hydropower capacity of North America and the European Union was about 340 GW in 2014, only 13% higher than in China alone. Latin America has 150 GW of hydropower capacity, of which 89 GW is in Brazil. A multi-year drought in Brazil and across much of Latin America has sharply reduced both hydropower output and the amount of water currently stored in its vast reservoirs, which will likely reduce hydropower output for years to come. The fluctuations in output in Latin America and China highlight the point that hydropower has the highest annual variation of any renewable energy technology, dictated by changes in rainfall and average temperatures. Further changes can be expected, resulting from the predicted effects of global climate change, with greater rainfall and hydropower output in some regions and less in others. Japan has 49 GW of installed hydropower capacity, including 26 GW of pumped hydropower, the most mature energy storage technology (IEA, 2014c), which serves an important balancing role in the system, consuming electricity to pump water uphill and releasing later to generate electricity when demand is high.

Figure 9.4 ▷ Hydropower installed capacity by region in the New Policies Scenario



In the New Policies Scenario, hydropower continues to expand in most regions around the world through to 2040, though the scale of untapped potential, environmental concerns and social considerations limit its growth in many regions. China continues to tap large river systems to extend its lead in terms of hydropower capacity, adding close to 200 GW by 2040. Latin America adds over 110 GW to 2040, led by an additional 60 GW in Brazil, where social and environmental concerns drive a technological shift from reservoir hydropower to run-of-river designs. Hydropower capacity increases only moderately in OECD countries. In North America, a number of new large-scale projects come online in Canada while environmental concerns in the United States restrict the development of the remaining large untapped potential and limit expansion of existing sites (Kao, 2014; Hadjerioua, 2012). In the European Union, the vast majority of hydropower potential has already been developed, forcing the region to look to other forms of renewable energy to pursue its energy and climate goals. India more than doubles its hydropower capacity from 2014 to 2040 (see Chapter 13), while other developing countries in Asia (excluding China and India) expand their use of hydropower substantially. Africa has enormous hydropower potential remaining, largely concentrated in the Democratic Republic of Congo (DR Congo) and Ethiopia. Large projects (and the supporting infrastructure), including the Grand Inga project (in DR Congo) and the Grand Ethiopian Renaissance Dam, are being developed to tap into this important resource as economic growth drives up electricity demand.[3]

Large hydropower projects, defined here as those over 10 MW, accounted for the vast majority (94%) of global installed hydropower capacity in 2014. Large-scale projects continue to be dominant in 2040, with many additional large-scale projects developed in China, Latin America and Africa. Their dominance is largely due to their lower levelised costs of electricity produced, compared with smaller projects, and the administrative gains of evaluating and developing fewer projects when seeking to significantly increase the power supply. To date, large hydropower projects have generally included a reservoir that allows output to be controlled so as to generate electricity in the hours when it is needed most. This feature can make the integration of variable renewables easier in regions with significant amounts of hydropower with reservoirs, though other operational constraints may limit the flexibility of large hydropower.

Small hydropower gains momentum and accounts for more than 10% of the hydropower capacity additions to 2040 in the New Policies Scenario, with strong deployment in Asia, Africa and Brazil. The potential for small-scale hydropower remains largely untapped in many regions, as development has concentrated on larger projects. Small-scale projects are generally less politically sensitive than their large-scale counterparts and require shorter authorisation processes, as the environmental and social concerns are more limited. Small hydropower can also be built in less time, reflecting their relative size and that they are predominantly run-of-river projects. They require less supporting infrastructure to be built, since they can usually be connected to existing transmission lines, whereas large-scale projects often require new dedicated lines. However, without reservoirs to smooth out variability in river flow, small hydropower is more vulnerable to weather variability over short periods (weeks or months), which may increase over time due to climate change.

Bioenergy

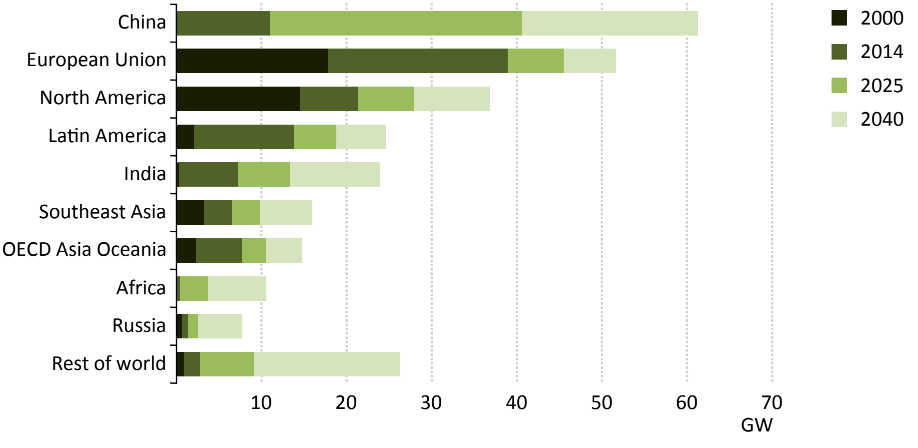
Bioenergy-based power, along with hydropower, is the most mature renewable energy technology in the power sector, having been deployed at commercial scale for more than 40 years. Bioenergy power plants are often based on similar steam turbine technologies as those used in fossil-fuelled power plants. This allowed their early deployment and,

3. For more information and discussion of the long-term energy outlook for Africa, see *Africa Energy Outlook, World Energy Outlook Special Report* (IEA, 2014d).

given their familiar operating capabilities, meant they competed directly with fossil-fuelled power plants based on cost. The levelised costs of producing electricity with bioenergy can be attractive where feedstocks are plentiful and available at low cost. This can be the case for residues from other processes, such as agricultural production or forestry activity. Where the feedstocks are produced is also an important factor, as the costs of transport per unit of energy can be high, compared with other fuels.

Bioenergy-based power plants have been built in many countries, often taking advantage of local resources. The European Union has the most bioenergy-based capacity (though not all of it relies on local resources), including more than 20 GW built since 2000 (Figure 9.5). Though, bioenergy accounts for only 10% of total renewables capacity in the region in 2014. North America, with vast amounts of residues available from widespread agricultural production and forestry activities, had 15 GW of bioenergy-based capacity in operation by 2000 and more than 20 GW in 2014, and the potential for further expansion. In Brazil, the production of sugarcane-based ethanol and other agricultural activities provide residues that help fuel the 12 GW of bioenergy capacity in place, the most in Latin America.

Figure 9.5 ▷ Bioenergy installed power generation capacity by region in the New Policies Scenario



Most regions continue to build bioenergy-based power plants in the New Policies Scenario, to the extent that more capacity is added over the period 2015-2040 than is in operation today. Through 2025, the European Union has the most bioenergy-based power capacity, but, around 2030, China takes the lead (as with several other renewable energy technologies). Several regions, including the European Union and the United States, steadily increase their bioenergy-based capacity to help meet decarbonisation goals in the power sector. India and other countries in developing Asia, along with Latin America, continue development of bioenergy as part of a portfolio of technologies to keep up with growing electricity demand. Africa also starts to tap its large biomass potential, particularly in Central Africa.

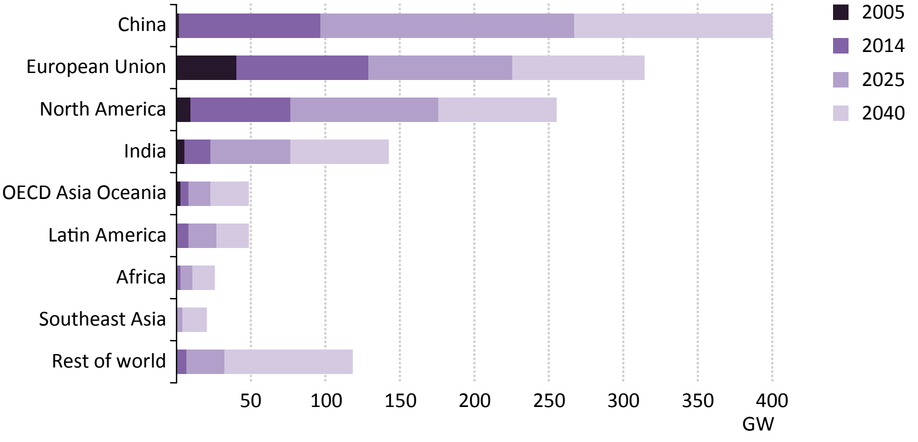
Combined heat and power (CHP) plants extract more productive energy from the biomass feedstock to produce both heat and electricity, a factor of particular value where the supply of biomass is limited. For example, Brazil already makes use of bioenergy-based CHP plants. However, CHP plants often have restricted flexibility, as operations are determined by the cycles of the demand for heat. This can limit the value of the electricity generated and, therefore, the value to the power system. Large-scale bioenergy power plants, without heat production, have lower overall efficiencies than CHP plants, but offer more flexibility in operation, taking full advantage of the dispatchability of the power plant to generate electricity when it is most valuable. This characteristic makes bioenergy-based power plants an attractive option in the long-term decarbonisation of the power sector, as they can help with the integration of the variable output from solar PV and wind power.

Wind power

Global installed capacity of wind power reached 350 GW in 2014, up from less than 60 GW in 2005. The European Union, China and the United States account for more than 80% of the global total, with another 10% located in India. The European Union has long been the leader in wind power, steadily increasing the annual deployments from 5.0 GW per year on average from 2000-2004 to 8.2 GW per year from 2005-2009 and 10.7 GW per year from 2010-2014. The United States has supported the development and deployment of wind power for more than two decades, but repeated expirations of, and changes to, the renewable electricity production tax credit, the main support mechanism, are reflected in the erratic pattern of capacity additions: from 2009-2014, annual capacity additions ranged between 0.9 GW and 13.4 GW, with an average of 6.7 GW. China started to deploy wind power on a commercial scale in the last ten years, surpassing 5 GW of installed capacity only in 2008, more than a decade after the European Union reached that level and five years later than the United States. India has been steadily installing new wind turbines since 2004, adding about 2 GW per year on average from 2005-2014.

The top-four wind power markets today remain dominant through to 2040, with China taking the lead before 2020 (Figure 9.6). China increases its installed wind power capacity by more than 300 GW from 2014 to 2040 (more than the wind power capacity in the rest of the world today), raising wind power's share of total generation in China from 3% in 2013 to 10% in 2040. In the European Union, the 2030 Energy and Climate package drives continued deployment of wind power, tripling the share of wind power in total power generation to close to one-quarter in 2040. In the United States, while uncertainty about the availability of the production tax credit continues to create a challenging and inconsistent investment environment in the near term, the long term for wind power appears more secure, in part due to state-level renewable portfolio standards, but mainly by required CO_2 emissions reductions under the Clean Power Plan. This plan provides long-term direction for suppliers and developers, helping them to develop more efficient supply chains. Under recently announced plans, India aims to increase sharply the share of electricity generation from renewables, with wind power an important contributor. As a result, wind power capacity increases from 23 GW in 2014 to over 140 GW by 2040.

Figure 9.6 ▷ Wind power installed capacity by region in the New Policies Scenario



Wind power has been predominantly built onshore to date, with 98% of installed wind power capacity on land. This looks set to be the case as long as viable sites are available for development. Suitable sites now include a wide range of wind regimes, including relatively low wind speed environments, due to recent technological improvements. For example, in the United States, larger turbines could provide for development in the southeast region, where wind deployment has been very limited, and greatly increase the viable land area for wind development across the country (Zayas, 2015). Compared with offshore wind, onshore projects are significantly easier to build and, as a result, are less expensive.

Offshore wind power has been gaining momentum in some regions and looks set to play a larger role in the future. Offshore wind power offers higher capacity factors than those achievable for onshore projects, due to more consistent wind conditions. However, this has not yet been sufficient to swing financial comparisons in their favour. The European Union has been the first region in which offshore wind has been deployed at commercial scale with 8 GW of installed capacity by 2014. By 2040, offshore wind power capacity in the European Union exceeds 65 GW, accounting for one-fifth of its overall wind power capacity. China is the only other market with more than 0.5 GW of offshore wind capacity today and, by 2040, reaches nearly 50 GW. No other region has more than 10 GW of offshore wind capacity by 2040, including the United States, which has had difficulties, for more than a decade, to develop its first offshore wind project.

Solar PV

Solar PV has rapidly gained prominence in power systems around the world, increasing from less than 1 GW of installed capacity in 2000 to 39 GW in 2010 and 176 GW in 2014.[4] The European Union has been at the forefront of this movement, accounting for more than

4. All solar PV capacities represent the maximum output of the solar panels (in DC terms), which can vary substantially from the maximum output from the inverter (in AC terms) that is available for use.

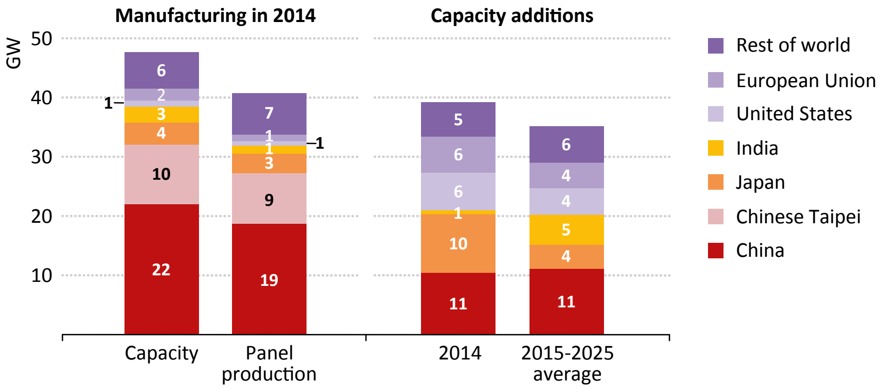
three-quarters of the solar PV capacity in 2010. Since then it has added a further 57 GW, led by strong deployment in Germany, taking total capacity far beyond that of any other region. By establishing and maintaining a market for solar PV, the European Union has fostered the development of the technology, helping to drive down capital costs across the globe over the past decade. The falling costs of solar PV have prompted many claims that solar PV is now competitive with other forms of electricity generation but evaluating competitiveness is not straight-forward and must consider value as well as costs (see competitiveness section below). Since 2010, China has made a strong entrance in the global solar PV market, both in terms of demand and supply of solar PV panels and modules, preparing the supply chains for anticipated future growth (Spotlight). Japan has scaled-up its deployment of solar PV markedly since the accident at Fukushima Daiichi, adding 7 GW in 2013 (which doubled the installed solar PV capacity) and 9.7 GW in 2014. Deployment of solar PV in the United States has been concentrated in California, which has more than nine-times the solar PV capacity in any other state, driven by strong support measures and the goal of 33% of retail electricity sales from renewable energy sources by 2020.

S P O T L I G H T

The rise and shine of the Asian solar PV industry

Over the past five years, the Asian solar industry has gone from infancy to domination of the global market. By 2014, Asian manufacturers accounted for about 90% of global solar panel production and a similar share of manufacturing capacity (Figure 9.7), with about 2 million people employed by the industry. Producers in China and Chinese Taipei account for more than two-thirds of global PV manufacturing capacity today. The cost of producing solar panels in China has plummeted since 2009, as its manufacturing capacity increased at an unprecedented rate, helped by loans at very low interest rates and the availability of cheap land. In 2014, over 40% of Chinese panel production was exported and nearly all those produced in Chinese Taipei were exported as well.

Figure 9.7 ▷ Solar PV panel manufacturing capacity and production, and capacity additions by region in the New Policies Scenario



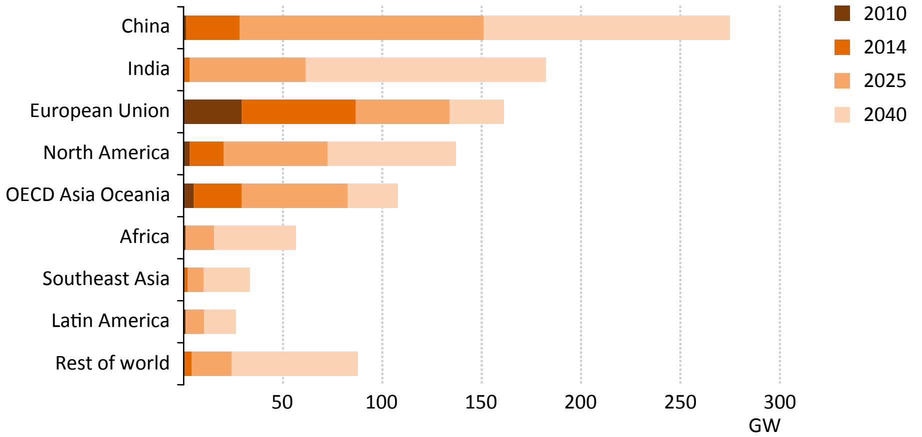
Faced with shrinking domestic solar industries, the United States and Europe have in recent years put in place supportive measures, such as import duties or minimum prices. Even so, in 2014, the United States and European Union imported the majority of the solar PV equipment installed in that year. The invocation of international trade rules appears to have favoured the emergence of new players in Asia, such as Malaysia, Thailand and others. For example, all of the 6.7 GW of new manufacturing capacity announced by Chinese firms in the first half of 2015 will be outside of China.

Will Asian-based production of solar PV panels remain dominant in the future? Yes. On the one hand, the current level of policy ambitions suggest that the European Union and the United States have already reached a peak in annual capacity additions of solar PV and Japan looks set to peak in the near future. On the other hand, demand for solar PV panels in Asia is expected to remain strong, accounting for almost two-thirds of the global solar PV capacity additions through to 2025. But other players are likely to emerge. Demand for solar panels is expected to grow rapidly in India, spurred by the 100 GW target of the Modi government, and in Southeast Asian countries, which clearly intend to promote their domestic industries. The key questions are how quickly and at what cost will they be able to produce solar panels domestically. Chinese manufacturers will be ready to fill any gap in the market. If markets outside China fall below expectations, the domestic market in China could absorb the production of the excess manufacturing capacity, allowing China to exceed its solar PV capacity target.

In the New Policies Scenario, solar PV firmly establishes itself as a key low-carbon technology in many regions, exceeding 1 000 GW of installed capacity globally by 2040. To 2025, China will be the largest market for solar PV by far, adding close to 115 GW and taking over the lead from the European Union in terms of total capacity (Figure 9.8). China extends its lead by adding another 130 GW over 2026-2040. In India, the market for solar PV is just developing, but recent government announcements aim to dramatically increase its deployment, making India the second-largest market for solar PV over the next 25 years. In the EU, the growth of solar PV capacity progressively slows to 2040, as solar PV reaches high shares of peak demand, making the variable output increasingly difficult to integrate and reducing the value to the system of each new addition. The expansion of solar PV capacity in the United States remains more constant than in the EU, raising the installed capacity by close to 100 GW from 2015 to 2040, led by continued deployment in California. In Japan, the recent surge in solar PV continues over the next decade, but slows after 2020 as the market saturates. Solar PV gains a foothold in many other markets over the next decade, including Africa, Southeast Asia and Latin America, setting up strong growth from 2025 to 2040, which takes advantage of continuing cost reductions.

Solar PV in buildings – including both residential and commercial systems – has been the dominant form of solar PV to date, accounting for over 60% of the global solar PV capacity in 2014. To 2040, it remains ahead of utility-scale solar PV in terms of installed capacity. The European Union has focused on solar PV in buildings, deploying 3 GW for every 1 GW of utility-scale solar PV, and this trend looks to continue through to 2040. The United States has stepped up the deployment of utility-scale solar PV and it is set to be dominant form of solar PV in the region. China and India also favour utility-scale projects, leading the global capacity of utility-scale solar PV to increase almost eight-fold from 2014 to 2040, while the total capacity of solar PV in buildings increases five-fold.

Figure 9.8 ▻ Solar PV installed capacity by region in the New Policies Scenario



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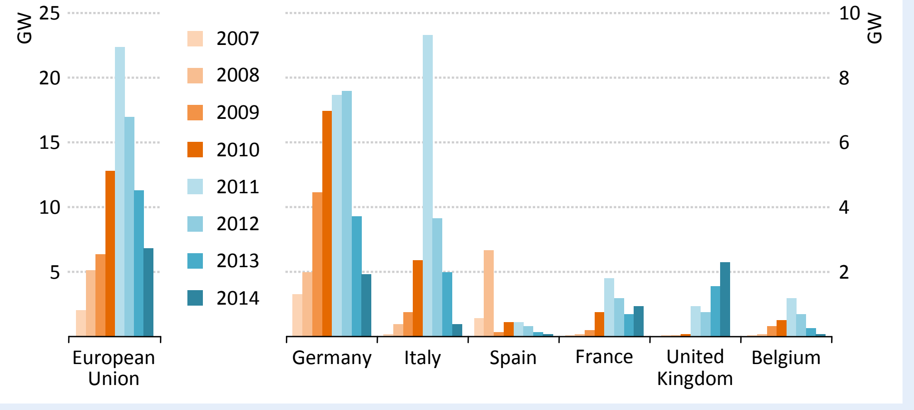
Box 9.1 ▻ Has the solar PV market in the European Union peaked?

Over the past decade, countries in the European Union have been strongly supporting solar PV technologies, with the aim of decarbonising the power sector. These countries were first movers, deploying at scale a relatively new technology and tapping into a new source of investment for power supply – individual households and businesses. One major issue emerged as solar PV costs declined at a faster rate than expected. With feed-in tariffs being the preferred policy option to drive deployment, the rapid decline in technology costs produced a widening gap between the costs and guaranteed payment levels that made the investment in solar PV very attractive for households and businesses, providing rates of return on investment that went well beyond intended levels. In many countries, this led to accelerating deployment, resulting in capacity targets being reached or exceeded ahead of schedule, in some cases by several years.

As many countries achieved their renewable energy targets early or exhausted the funds available for renewables subsidies, they scaled back their support measures, causing the EU solar PV market to peak in 2011 (Figure 9.9). A peak has occurred in eight of the ten largest markets for solar PV in the European Union, including Germany, the global leader in solar PV capacity through 2014, and Italy, which deployed the third-largest amount of capacity of any country in a single year (in 2011). The United Kingdom and the Netherlands are the only EU member states that have deployed at least 0.4 GW to date and where solar PV deployment continued to increase through 2014.

Figure 9.9 ▷ Solar PV capacity additions in European Union and selected countries, 2007-2014



Under the current and announced policies taken into account in the New Policies Scenario, over the period to 2040, annual deployment of solar PV in the European Union never again reaches the peak-level achieved in 2011. However, the solar PV market does recover somewhat as ageing installations are replaced, averaging more than 10 GW per year from 2031-2040. The experiences of the European Union provide two valuable lessons about the design of support policies. First, annual limits on the capacity supported by subsidies or on available subsidies help control government spending and related charges to consumers. Annual limits also support stable markets and domestic jobs, particularly for installation. Second, support mechanisms that are designed to keep pace with evolving technology costs minimise the risk of overgenerous subsidies. Applying these two lessons would help policy-makers secure the most renewables deployment for each dollar of subsidy.

Other renewables

Other renewable energy technologies, including concentrating solar power, geothermal and marine power, play smaller, but growing roles to 2040. CSP can be developed in many regions around the world, however, the outlook is not as promising as it was just a few years ago, due to competition with solar PV. While thousands of solar PV projects have been built, CSP projects have been few, offering little chance for the kind of learning-by-doing and economies of scale needed to keep pace with the strong cost reductions achieved for solar PV. For example, despite the fact that 2014 was a banner year for CSP in the United States, with the completion of three large CSP projects totalling over 900 MW, several CSP projects have been delayed or cancelled in favour of solar PV projects. In the longer term, the prospects for CSP improve, as the technology, when including thermal storage, can provide a low-carbon source of flexibility to power systems. This dispatchability becomes more valuable over time as the amount of generation from variable renewables increases.

Geothermal energy is an attractive option for power generation as well as heat production, but geology limits the number of suitable locations. Much of the convenient potential has already been tapped in OECD countries, but geothermal power capacity expands in non-OECD countries. For example, several countries in Africa have plans to develop geothermal resources along the East African Rift Valley. Power generation from marine power remains in the research and development phase, with several test facilities in operation around the world. The potential for tidal power is small in most regions, requiring specific characteristics to produce large and regular flows of water in and out of an accessible location. The potential for harnessing wave power is more widespread, though the cost and difficulty of building transmission lines to harvest wave power adds to the technological challenges and there are potential conflicts with shipping lanes or other marine activities. Overall, the outlook for marine power appears limited to 2040, as opportunities to develop other renewable energy technologies remain available at lower cost.

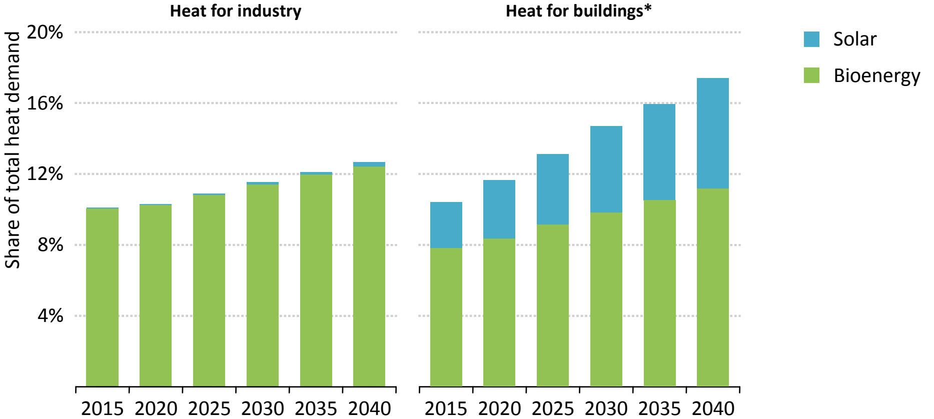
Industry and buildings

Energy consumption in industry and buildings (including residential use) was about 5.7 billion toe in 2013, of which almost 20% was supplied by renewable energy sources. The major renewable energy carriers in these sectors are bioenergy and solar. In developing countries, over 80% of the consumption of renewable energy in industry and buildings derives from the traditional use of solid biomass in households for cooking and space heating (two-thirds of the world's final consumption of bioenergy in 2013 was traditional use of biomass). Excluding the traditional use of solid biomass lowers the global share of renewables in industry and buildings to 6%. In 2040, the share of modern renewables in total final energy demand in the industry and buildings sectors is projected to increase to 8% in the New Policies Scenario.

In the buildings sectors, modern renewables are used for heating and are mainly supplied by bioenergy (e.g. wood pellet-fuelled water heaters or space heaters) and solar (e.g. solar thermal water heaters).[5] In 2013, bioenergy and solar use totalled about 130 Mtoe (10% of total heat demand in the buildings sector), a level that is projected to increase to 270 Mtoe in 2040 (17% of total heat demand in the buildings sector) in the New Policies Scenario (Figure 9.10). Bioenergy use was more than three-times larger than solar in 2013, but is projected to be only about twice as large in 2040. Looking at regional differences, the European Union is today far ahead in terms of the use of modern renewables in heat production in buildings and continues to expand its use to 2040 in the New Policies Scenario. Although starting from a lower level, the United States and China are expected to see high growth rates in heat production from modern renewables over the period 2014-2040.

5. Renewable energy use in buildings includes the use of renewable energy in district heating and the direct use of geothermal resources.

Figure 9.10 ▷ Global heat demand provided by bioenergy and solar in the industry and buildings sectors in the New Policies Scenario



*Excludes traditional use of solid biomass in households.

In the industry sector, renewable energy is used for process and steam heating, and nearly all is supplied by bioenergy. Total demand for heating in industry in 2014 was almost 2 billion toe, of which 10% came from bioenergy. The nature of the energy-intensive processes in industry presents a challenge for other non-combustible renewable energy sources, where controlling the power output is more difficult (for instance with solar PV and wind power). In the New Policies Scenario, bioenergy's share of total heat demand in industry increases slightly to 12%. The use of bioenergy in the industry sector is similar across major OECD regions. The share of bioenergy in heat in 2014 was 17% in the United States, 13% in the European Union and an average of 13% for OECD countries. However, within non-OECD regions (for which the average was 9% in 2014), there are large differences. In Latin America and Africa, bioenergy accounted for over one-third of heat production in industry, whereas the share was about 20% in India and near zero in China. In the New Policies Scenario, several regions increase their use of bioenergy in industry, with China, India and Africa having both the largest relative and absolute increases.

Transport

Renewable energy is used directly in the transport sector through the consumption of biofuels. In most cases, biofuels are blended with conventional fuels before being sold to consumers, though non-blended biofuels can also be used, usually requiring specially designed engines. The use of biofuels displaces fossil fuels in the transport sector, providing CO_2 emissions reductions and enhancing energy security by diversifying the transport fuel mix and possibly reducing oil import needs. Electric vehicles may be powered by renewables indirectly, depending on the share of renewables in the power mix. The extent to which electric vehicles reduce energy-related CO_2 emissions depends on the carbon-intensity of the power mix: where the intensity is less than 800 grammes of CO_2 per kilowatt-hour (g CO_2/kWh), electric vehicles generally offer CO_2 savings over conventional internal combustion engines (IEA, 2015b).

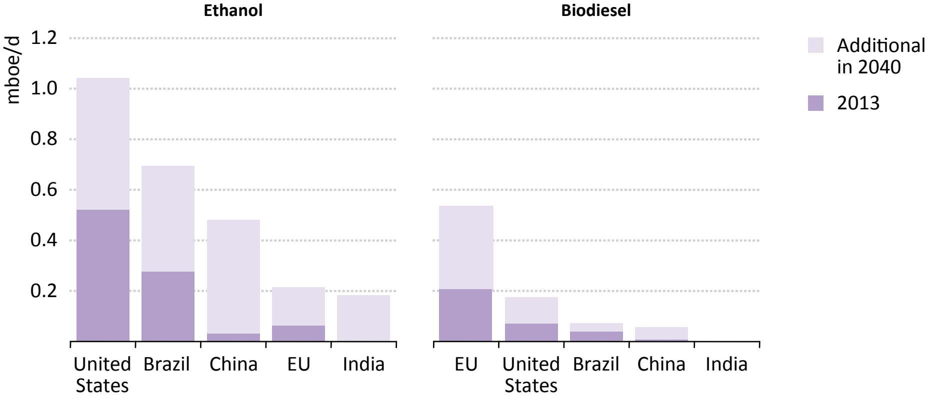
The consumption of biofuels in road transport has increased significantly over the past decade, from 19 Mtoe in 2005 (1.2% of total transport fuels) to 64 Mtoe in 2013 (3.3% of total transport fuels). This increase was largely the result of blending mandates, which are in place in more than 60 countries. However, linking the consumption of biofuels to conventional fuels through blending mandates has limited biofuels growth somewhat in recent years, as vehicle fuel economy has improved and the slow recovery after the global financial crisis has meant lower-than-expected transport fuel demand. As a result, investments in biofuel refineries have plunged from a record-high of $27 billion in 2007, averaging just $4.6 billion per year from 2010-2013. Biofuels refining capacity increased by about 160 thousand barrels per day (kb/d) per year on average over the four years to the end of 2013, reaching 3 300 kb/d in that year.

In the New Policies Scenario, continued policy support helps biofuels to regain momentum. Advanced biofuels provide a pathway to raising total biofuels production while limiting sustainability concerns, including those related to deforestation and competition with food production. In 2040, total biofuels consumption reaches 4 million barrels of oil equivalent per day (mboe/d), of which 70% is ethanol and the rest is biodiesel. The share of biofuels in road transport more than doubles, from 3% today to 8% in 2040. Over time, biofuels become more competitive with conventional fossil fuels, as biofuels unit production costs decline and oil prices rise. However, if oil prices remained low for an extended period, political support for biofuels may weaken, reducing the volumes consumed (see Chapter 4 for more on the impacts of a Low Oil Price Scenario). Currently, most biofuels use is in road transport, but their use in aviation gains ground after 2025, accounting for 1% of total aviation fuels in 2040.

The largest markets for biofuels today are the United States, the European Union and Brazil. The United States and Brazil are the largest consumers of biomass-derived ethanol, while the European Union consumes the most biodiesel (Figure 9.11). Over the next 25 years, in the New Policies Scenario, these three regions maintain their positions as the largest biofuels markets, though their share of total biofuels consumption drops from 86% in 2013 to two-thirds in 2040. Biofuels consumption in China increases more than ten-fold over the period to 2040, making it the third-largest market for ethanol by 2040, and the ethanol market in India grows substantially. Growth is driven in China and India by blending mandates and expanding transport demand.

The United States currently consumes the largest volume of biofuels in the world (0.6 mboe/d), though biofuels make up only 5% of US road transport energy consumption. This share increases to almost 14% by 2040, as biofuels consumption doubles, with growth driven largely by the Renewable Fuel Standard that requires minimum absolute volumes of renewable fuels to be blended with gasoline and diesel. Volume targets steadily increase to 36 billion gallons (2.3 mboe/d) by 2022. Meeting the absolute volume targets has proved challenging, due to the combination of lower-than-expected demand for gasoline and diesel in recent years and the technical and market limitations that make it difficult to go beyond 10% of total transport fuels (the so-called blend wall). For example, the availability of blends with more than 10% ethanol is limited, as 15% blends have been approved for use only in newer vehicles. In addition, the production of advanced biofuels has not been increasing as fast as hoped. Recognising this, the US Environmental Protection Agency (EPA) has scaled back its requirements, in line with the availability of advanced biofuels.

Figure 9.11 ▷ Biofuels consumption in road transport by fuel type and selected region in the New Policies Scenario, 2013 and 2040



In the European Union, consumption of biofuels is expected to increase from 0.3 mboe/d today to 0.7 mboe/d in 2040 in the New Policies Scenario. The share of biofuels in road transport energy consumption increases significantly, from 5% to 16%. The Renewable Energy Directive sets a target of 10% renewable energy in the transport sector by 2020. The issue of the sustainability of biofuels, however, has caused controversy about how member states might comply with the target. In April 2015, the European Parliament approved a law limiting the use of food-based biofuels to a maximum of 7% out of the 10% target. Further, the law sets an indicative target for advanced biofuels of 0.5%, with the use of such biofuels counting double towards the 10% target.

Brazil has a long history – back to the 1920s – of using biofuels in the transport sector, taking advantage of high-quality growing conditions to produce large amounts of sugarcane for biofuels (and sugar production). Today, biofuels account for almost 20% of road transport fuels, by far the highest share in the world. In the New Policies Scenario, this share increases to 31% in 2040, as consumption reaches 0.8 mboe/d. Brazil does not face the same technical challenges as the United States in seeking to use higher shares of biofuels because flex-fuel vehicles (that can burn gasoline, ethanol blends or pure ethanol) make up about two-thirds of the light-duty vehicle fleet and 90% of new vehicle sales. Two recent policy decisions have improved the outlook for ethanol. In early 2015, Brazil increased the ethanol blending mandate from 25% to 27%, which will raise the use of anhydrous ethanol.

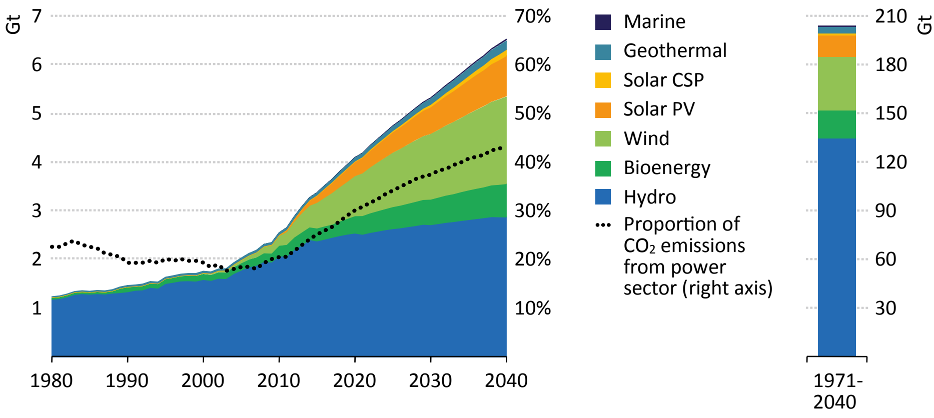
At the same time, raising the taxes on gasoline and diesel has improved the prospects for hydrous ethanol, which competes directly with gasoline in the market.

In the long term, advanced biofuels will need to become widely available in order to avoid food-versus-fuel concerns and other environmental drawbacks and maintain the political support needed for biofuels to play a larger role in transport. To date, the successful development of techniques to produce advanced biofuels at commercial scale has been slower than hoped, though several facilities producing biofuels from cellulosic materials came online in 2014 and 2015. The current low oil price environment is adding further uncertainty for developers. In the long run, advanced biofuels gather momentum and, in 2040, make up more than 20% of total biofuels consumption in the New Policies Scenario.

Avoided CO_2 emissions

The power sector is responsible for more than 40% of total energy-related CO_2 emissions today, as fossil-fuelled power plants provide two-thirds of the power supply. Renewables and nuclear power, which provide the remaining one-third, do not emit any CO_2 directly. Avoided emissions from the use of renewables can be estimated based on the additional CO_2 which would be emitted if there were no renewables in the power mix. This is done by estimating the emissions that would have arisen, were the renewables coming online in a given year replaced by other sources, scaled-up based on their mix in that year. On this basis, all renewables, taken together, helped avoid an estimated 3.1 Gt of CO_2 emissions in 2013, equivalent to close to 25% of total power sector CO_2 emissions (Figure 9.12). Three-quarters of the avoided emissions today can be attributed to hydropower, which has been the largest low-carbon source of electricity over the last 40 years. Over this period, renewables helped reduce power sector emissions, on average, by about 20%.

Figure 9.12 ▷ Global CO_2 emissions avoided by use of renewable energy technologies in the New Policies Scenario



Note: Estimates of avoided CO_2 emissions are calculated by assuming that renewables generation would be replaced by generation from all other sources, which are scaled-up based on their mix in the given year.

In the New Policies Scenario, the volume of CO_2 emissions avoided by renewable energy technologies worldwide doubles to 6.5 Gt per year by 2040. Over the period 2014-2040, renewables avoid almost 135 Gt of CO_2 emissions in total, equivalent to more than one-third of cumulative global power sector CO_2 emissions over the period. Hydropower remains the dominant low-carbon source of electricity through to 2040, but the avoided CO_2 emissions achieved through all forms of non-hydro renewables, taken together, outpace those from hydropower soon after 2030. Over the 70-year period from 1971 to 2040, renewable energy technologies help avoid about 200 Gt of CO_2 emissions, with hydropower responsible for two-thirds and wind power for about 15%. While the reduction of CO_2 emissions is often the principal motivation for the deployment of renewables, their use also helps to reduce air pollution, expand energy diversity and enhance energy security by limiting the need for imported fuels. Over the past decade, renewables deployment helped to avoid about 250 billion cubic metres (bcm) of additional natural gas demand per year and 600 million tonnes of coal equivalent (Mtce) of additional coal demand per year, one-fifth of average annual power sector demand for each fuel over the period. Over the projection period, renewables avoid over 1 300 Mtce of coal demand per year on average, which would have added close to 40% to average annual demand in the power sector, and 560 bcm of gas (one-third of average power sector gas demand per year).

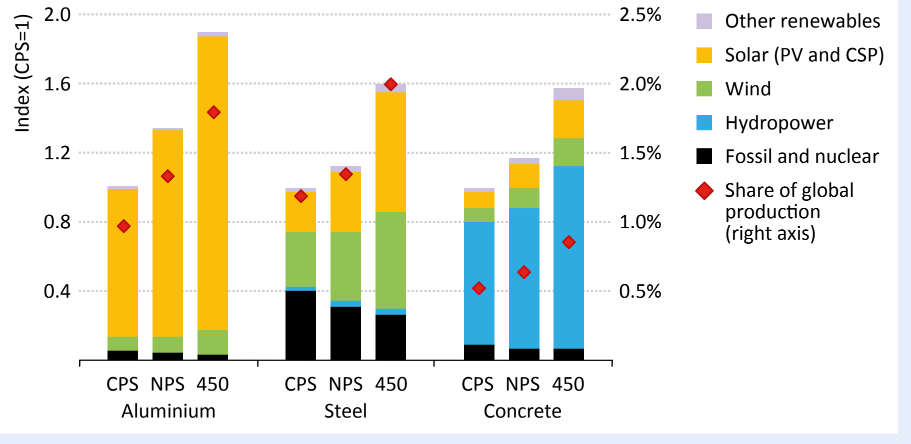
While the deployment of non-hydro renewables over the next 25 years adds substantially to the avoided CO_2 emissions to 2040, existing renewables play a significant role as they continue to operate for many years to come. Existing facilities account for over 80% of the avoided emissions secured by hydropower through to 2040, and for about 40% of avoided emissions secured by other renewables. Over time, an additional unit of electricity generation from renewables avoids progressively less CO_2 emissions, as the average CO_2 emissions intensity of the global power mix, not including renewables, falls from about 670 g CO_2/kWh in 2013 to 530 g CO_2/kWh in 2040. This reduction is mainly due the share of coal-fired power generation declining and power plants becoming more efficient. If renewables were to displace only coal-fired generation, they would avoid between 850 and 1 000 g CO_2/kWh, about double the estimated global rate of savings in 2040.

Of the cumulative avoided CO_2 emissions resulting from renewables-based electricity generation, China accounts for nearly 40%, followed by less than 10% from India. In both countries, coal-fired generation plays a major role in the current and future power supply, which means that the deployment of renewables in these regions helps avoid relatively high levels of CO_2 emissions per unit: 910 g CO_2/kWh in China in 2013 and 740 g CO_2/kWh in India. The United States and the European Union each account for about 10% of the emissions avoided through to 2040, in part due to the larger roles played by gas-fired power plants and nuclear power in their generation mixes, lowering the rate of emissions savings from renewables to 450 g CO_2/kWh in the United States and 310 g CO_2/kWh in the European Union in 2040.

Box 9.2 ▷ Aluminium, steel and concrete needs and associated CO_2 emissions for the deployment of renewables

The interrelation between energy output and materials use is quite strong: materials are needed to build the infrastructure of energy production, for energy storage (e.g. nickel, cobalt, lithium), for transmission and distribution (aluminium, copper, steel), and energy is necessary to extract and treat the raw materials. This link is becoming even more pronounced in a context of decarbonisation, notably because renewable energy technologies rely on some exotic materials such as rare-earth elements (US DOE, 2011). A less discussed matter is the demand for common materials, such as aluminium, steel and concrete to build renewables-based power plants. In general, renewable energy technologies require more materials per unit of installed capacity than a conventional thermal power plant, and even more per unit of output, due to their often lower capacity factor. For example, manufacturing one megawatt of large-scale solar PV capacity requires an estimated 57 tonnes of aluminium, while coal-fired power plants require only 0.59 tonnes per MW.

Figure 9.13 ▷ Amount of aluminium, steel and concrete needed for global capacity additions by technology and scenario, 2015-2040



Notes: CPS = Current Policies Scenario; NPS = New Policies Scenario; 450 = 450 Scenario. Other renewables include bioenergy, marine and geothermal. In the Current Policies Scenario, over the period 2015-2040, cumulative global aluminium consumption for the construction of power plants is 44 million tonnes (Mt), steel consumption is 583 Mt and concrete consumption is 6 110 Mt.

Sources: ANCRE, 2015; IEA analysis.

The expansion of the power sector lifts demand for materials in each of our scenarios. In the New Policies Scenario, new power generation capacity accounts for 0.6-1.3% of the demand for energy-intensive materials, with renewables accounting for almost the entire increase (Figure 9.13). Over the period 2015-2040, the associated CO_2 emissions from the production of aluminium, steel and concrete used to build new renewables capacity total 1.3 Gt (not including the emissions related to transportation and the extraction of raw materials), a small fraction of the 50 Gt of emissions avoided by the new capacity to 2040 (with years of operations remaining for most installations). The push to decarbonise power raises demand for materials in the 450 Scenario. For example, the additional solar PV capacity adds almost 1% to global steel demand over the period 2015-2040. While these amounts are manageable in comparison to global production levels, the impact may be more pronounced in some regions if locally produced materials are used. For example, by 2040, the use of aluminium in the construction of new power plants in the European Union would be equivalent to 5% of aluminium production in the region. Were it not for the expected gains in energy efficiency, the impact on the energy-intensive sectors would be even more significant.

Economics of renewables

Investment

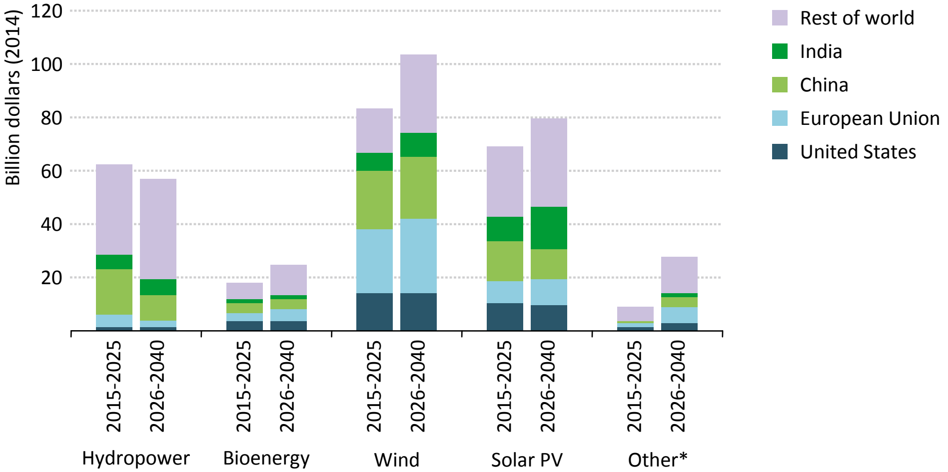
In the New Policies Scenario, global investment in renewables totals $7.8 trillion over the period 2015-2040. Of the total, about 3 600 GW of renewables-based power capacity additions (Table 9.4) require $7 trillion of investment (more than 60% of total power plant investment) (Table 9.5). Investment in transmission and distribution related to renewables totals $360 billion to 2040. Biofuels demand nearly triples and requires $390 billion of investment in new refineries over the period to 2040.

From 2000-2014, global investment in renewables for power generation totalled $2.5 trillion to complete 1 000 GW of new capacity ($165 billion per year). Over that period, more investment was made in renewables-based capacity than in fossil-fuelled and nuclear power plants combined. In 2014, total renewables capacity additions reached an all-time high of 130 GW, though falling technology costs meant that global renewables investment declined slightly to $269 billion. That amounted to nearly two-thirds of total investment in all types of power plants. Non-hydro renewable energy technologies, led by solar PV and wind power, captured close to three-quarters of total investment in renewables in 2014, and made up almost half of all power plant investment. Outside the power sector, about $2 billion of investment brought several biofuel refineries online in 2014.

Since 2000, on average, OECD countries have invested over $90 billion per year in renewables in the power sector, while non-OECD countries invested about $70 billion per year. However, investment in renewables in non-OECD countries in the last two years (2013 and 2014) was only 7% less than that of the OECD countries, where investment peaked in 2011. In 2014, renewables investment in China was by far the largest of any country, at more than $80 billion (more than in the European Union and United States together).

In the New Policies Scenario, global annual investment in renewables-based power plants recovers from a brief lull in the near term to climb steadily to over $330 billion in 2040, averaging $270 billion per year over the period 2015-2040. Continued cost reductions help to keep the level of investment required in check towards the end of the period, even though the need to replace ageing renewables capacity substantially expands the market for renewables, particularly in OECD countries. Taken together, OECD countries invest over $2.9 trillion in renewables through to 2040 (41% of the worldwide total), while non-OECD countries invest $4.2 trillion, more than half of which is in China and India.

Figure 9.14 ▷ Average annual investment by technology and selected region in the New Policies Scenario, 2015-2025 and 2026-2040



* Includes geothermal, concentrating solar power and marine.

Wind power accounts for the largest share (35%) of the total global investment in renewables in the New Policies Scenario, followed by solar PV (28%) and hydropower (22%) (Figure 9.14). OECD countries continue to make most of the investment in wind power and solar PV over the next decade, though China's annual investment in the technologies, at nearly $36 billion per year, is about 45% as much as that of all OECD countries taken together. The European Union invests the second-largest amount per year ($33 billion), followed by the United States ($24 billion) and India ($16 billion). The deployment and investment in hydropower largely occurs in developing countries, where large amounts of potential remain. Over 2026-2040, global investment in renewables increases to about $300 billion per year on average, expanding the role of renewables through new installations and replacing retired capacity using improved technologies. Over this period, investment in wind power, solar PV and other renewables accelerates substantially, in part due to the need to replace ageing capacity, while average annual investment in hydropower slows, particularly in China, where limited high-quality sites remain. While OECD countries' investment in wind power and solar PV remains strong through 2040, these countries account for a progressively smaller share of total renewables investment, the level falling below 40% by 2040. During the 15 years leading up to 2040, China's expenditure on renewable energy remains highest, while India invests a similar amount to the United States, and Southeast Asia more than Japan.

Table 9.4 ▷ Cumulative renewables gross capacity additions by region and type in the New Policies Scenario (GW)

	2015-2025						2026-2040						2015-2040
	Hydro	Bioenergy	Wind	Solar PV	Other*	Total	Hydro	Bioenergy	Wind	Solar PV	Other*	Total	Total
OECD	**45**	**24**	**242**	**158**	**13**	**482**	**38**	**45**	**432**	**289**	**51**	**854**	**1 336**
Americas	18	11	104	54	6	194	15	19	170	97	19	319	513
United States	7	9	82	47	4	150	7	15	132	80	14	248	398
Europe	23	10	122	50	4	208	17	19	227	123	23	409	617
Asia Oceania	4	3	16	54	3	80	6	7	35	69	10	126	206
Japan	3	1	4	43	1	52	4	4	12	51	3	74	126
Non-OECD	**276**	**55**	**270**	**227**	**14**	**841**	**333**	**86**	**507**	**453**	**65**	**1 444**	**2 286**
E. Europe/Eurasia	11	3	5	2	1	22	23	10	18	8	2	61	83
Russia	5	1	1	0	1	9	14	7	5	1	2	28	37
Asia	179	43	234	195	6	658	191	56	400	343	25	1 015	1 672
China	108	30	170	123	2	433	90	26	261	169	14	560	993
India	27	6	54	58	1	145	38	11	94	131	5	279	424
Southeast Asia	17	4	4	8	3	37	37	9	17	26	4	93	130
Middle East	7	1	3	7	1	19	5	4	38	41	14	101	121
Africa	27	3	8	13	4	56	49	7	18	44	20	139	195
Latin America	51	5	19	9	1	86	64	10	33	18	4	129	215
Brazil	29	4	16	6	-	55	33	7	24	9	1	74	129
World	**321**	**78**	**512**	**385**	**27**	**1 323**	**371**	**131**	**939**	**742**	**117**	**2 299**	**3 622**
European Union	16	9	111	47	3	187	12	18	214	121	22	387	574

* Other includes geothermal, concentrating solar power and marine.

Table 9.5 ▷ Cumulative investments in renewables-based power plants by region and type in the New Policies Scenario ($2014, billion)

	2015-2025						2026-2040						2015-2040
	Hydro	Bioenergy	Wind	Solar PV	Other*	Total	Hydro	Bioenergy	Wind	Solar PV	Other*	Total	Total
OECD	**128**	**93**	**521**	**389**	**52**	**1 183**	**104**	**157**	**793**	**447**	**186**	**1 686**	**2 869**
Americas	51	48	193	129	20	441	40	68	277	172	60	616	1 057
United States	20	42	153	114	14	344	18	58	213	144	44	477	821
Europe	67	34	287	100	21	510	49	69	437	149	97	801	1 310
Asia Oceania	10	10	41	160	11	232	15	19	79	127	29	269	502
Japan	6	5	10	136	2	159	10	9	30	97	10	155	314
Non-OECD	**555**	**107**	**397**	**373**	**50**	**1 482**	**750**	**211**	**757**	**747**	**232**	**2 697**	**4 179**
E. Europe/Eurasia	23	8	11	5	2	50	51	33	36	13	5	138	188
Russia	12	5	2	1	2	21	31	24	11	2	4	71	92
Asia	349	74	332	303	22	1 080	411	124	565	522	91	1 714	2 794
China	192	42	239	159	9	641	156	54	356	169	55	791	1 432
India	55	14	75	104	3	252	86	25	130	239	20	499	751
Southeast Asia	38	10	8	23	7	85	98	19	31	68	12	228	313
Middle East	15	2	5	16	6	45	11	9	67	74	50	210	255
Africa	55	10	15	31	17	127	117	21	31	107	72	349	476
Latin America	112	13	34	19	3	180	159	24	58	30	14	286	467
Brazil	64	10	29	9	-	112	81	17	42	12	5	157	269
World	**683**	**199**	**918**	**762**	**102**	**2 665**	**853**	**368**	**1 549**	**1 194**	**418**	**4 383**	**7 048**
European Union	46	32	266	95	16	455	33	66	412	147	92	751	1 205

* Other includes geothermal, concentrating solar power and marine.

Competitiveness

The dramatic cost reductions achieved in some renewable energy technologies in recent years, notably in solar PV, have prompted much discussion of their competitiveness with other technologies at both utility-scale and for individual households and businesses. This section considers this issue, providing guidance on evaluating competitiveness and mapping the major milestones as costs decline. An overview of the competitiveness of renewables is provided, estimating the amount of renewables that can be characterised as competitive today and over the period to 2040, based on the assumptions and projections in the New Policies Scenario.

Competitiveness is broadly defined in this analysis as the point at which investment in a technology is as commercially attractive as investment in relevant alternatives, without support policies or other measures specific to that technology. Achieving competitiveness is enormously important for any technology, as the ability to attract investment on merit increases the market potential for the technology and helps it break free of reliance on support policies and measures. In other words, improved competitiveness decreases both financial and political/regulatory risks, which have been identified as the most significant risks for renewables energy projects by the renewable energy industry (EIU, 2011). Disconnecting the outlook for a technology from specific reliance on political support helps secure a long-term place for that technology in the energy landscape. For example, investments in solar PV in the United States at present depend largely on the 30% investment tax credit. The reduction of the tax credit to 10%, scheduled for 2017, is expected to cause a significant drop in deployment (IEA, 2015c; BNEF, 2015). Improved competitiveness helps reduce the impact of such policy adjustments.

Evaluating competitiveness

The evaluation of the competitiveness of renewables in this analysis is based on quantifying projected costs and value for both the renewable energy technology and alternatives (without direct subsidies), from the utility or individual perspective. The costs include investment costs, fuel and operating costs, as well as carbon costs when a carbon price is in place. The value includes revenues received (e.g. the value of the power sold on wholesale electricity markets) and reductions in other costs (e.g. electricity bills).

An evaluation of competitiveness for renewables based on costs alone, while convenient, would be incomplete and potentially misleading. For example, on the basis of the levelised costs of electricity alone, baseload power plants (e.g. a coal-fired power plant) would almost always look more attractive than peaking plants (e.g. open-cycle gas-fired power plants), yet both are built without policy support due to their different overall value profiles (in this case, the higher average price obtained for power sold by a peaking plant). Consistent with a private perspective, environmental externalities that remain unpriced in the New Policies Scenario are not included in the comparisons. Inclusion of the costs of externalities (such as negative health outcomes and damages associated with climate change) would be appropriate from a social perspective and would shift the comparisons in favour of low-carbon technologies and away from conventional fossil-fuelled power plants. This difference between the private and social perspective is the economic justification for policy action to influence the choices made in the market.

Evaluating the competitiveness of renewables is a complicated task that must reflect system-specific information and cannot be satisfactorily reduced to a single comparison, even within a system, for two main reasons. First, the levelised cost of electricity produced from a particular renewable energy technology can vary substantially within a region (as well as between regions), due to the range of actual investment costs and performance levels achieved. For example, the levelised cost of the electricity produced by utility-scale solar PV projects completed in 2013 and 2014 spanned a range of $85-380 per megawatt-hour (MWh) in North America, $100-350/MWh in China, and $120-230/MWh in the European Union (IRENA, 2015b; IEA, 2015c). Second, though no less important, the assessment must consider the precise circumstances of the comparison and allow for any variation in costs or benefits associated with these circumstances. For example, will the technology be deployed at utility scale or at the individual (household or business) level and what is the role played by the project (Table 9.6)? Achieving competitiveness in any one role unlocks some degree of market potential, though the largest potentials are also generally the hardest to tap.

Table 9.6 ▷ Relevant comparisons for evaluating competitiveness of renewable energy technologies by scale and role played

	Utility scale		Individual scale	
Role played	**Displace power generation from existing plants**	**Meet the need for new capacity**	**Supplementing power from the grid**	**Fully replacing power from the grid**
Relevant comparison	Fuel and operating costs of other technologies.	Total costs of other technologies.	Variable portion of retail electricity tariff.	Full retail electricity tariff.
Typical cost range of alternative	$30-250/MWh	$60-90/MWh	$60-220/MWh	$120-250/MWh
Additional costs to consider	System integration costs.	System integration costs.	None.	Energy storage costs.
Value considerations	Provides power at relevant times.	Contribution to system adequacy.	Ability to sell power back to grid.	Similar quality services as grid.
Market potential considerations	Small share of power from high-cost power plants.	Energy demand growth and pace of retirements.	Dependent on retail electricity price structure.	Must overcome high upfront costs.

At utility scale, there are many milestones for renewable energy technologies on the road to competitiveness as their costs fall. The attainment of each milestone expands the competitive potential of the technology within the centralised electricity supply system. All types of renewable energy technologies are deployed at utility scale. In many cases, the first competitive milestone is the economic case to displace power generation from existing fossil-fuelled peaking power plants, a situation reached when renewables are able to supply power during peak hours of demand and at levelised costs that are attractive compared with the high fuel and operating costs of peaking units (which, for oil-fired power plants, can reach well over $200/MWh for diesel prices more than 900 dollars per tonne). However, peaking plants usually represent only a few percent of total generation, so the market potential related to displacing them alone is limited. In order to displace generation from other types of power plants that provide a larger share of total generation (i.e. mid-merit and baseload power plants) means competing with power plants with significantly lower operating costs. For example, gas-fired combined-cycle power plants (CCGTs) or subcritical coal-fired power plants have fuel and operating costs that typically range from $30-70/MWh (without a carbon price), while many nuclear power plants have even lower operating costs.

At utility scale, renewables may also compete with other technologies when new power generation capacity is needed. The widest definition of competitiveness would mean that a technology is able to compete commercially on its merits with any other technology. Coal-fired or gas-fired power plants may again be the point of comparison, but this time based on the total costs of new power plants, including capital costs and a reasonable return on investment. The levelised costs of such plants are often in the $60-90/MWh range today, but generally increase in the New Policies Scenario, as fossil-fuel prices and carbon prices increase, despite efficiency improvements. Environmental policies or measures that restrict the field of viable technologies, such as carbon constraints or emissions performance standards (e.g. the US Carbon Pollution Standards), shift the bounds of competitiveness and are likely to improve the prospects for renewables. When renewables can compete without technology-specific support, they can become one of a suite of technologies deployed by utilities, with their rate of growth dictated by the need for new capacity to meet electricity demand growth and to replace retired power plants, along with other system considerations. The declining value of the output from renewables and rising integration costs, as they represent a larger share of the power supply, make this a more challenging comparison for variable (non-dispatchable) renewables (Box 9.3). These considerations may reduce the market potential for variable renewables, depending, in part, on the costs and availability of demand response and energy storage technologies.

Some renewable energy technologies can be deployed at the level of individual households and businesses – an enormous potential market. Solar PV is the primary renewable energy technology deployed at this level, though small-scale versions of wind turbines, bioenergy and hydropower are also available. When individuals are connected to the grid and are considering installing one of these technologies, the evaluation of competitiveness compares the costs of producing electricity themselves versus expected reductions in their electricity bills.[6] The first step involves calculating the average cost of electricity produced from the renewable energy technology over its expected lifetime, including a return on the

6. For the purposes of this analysis, specific support policies that supplement the amount received for power sold back to the grid operator, such as net metering programmes, are excluded.

investment. The second involves estimating the average cost of electricity that would have been grid-supplied, but will, instead, be provided by the renewable energy technology (over its lifetime). In practice, this is the variable portion of the retail electricity tariff (i.e. the price paid for an additional unit of electricity consumed) expected over the next 20-25 years on average, not including the fixed costs of the power system. It would not be appropriate to measure the competitiveness of renewables using the full retail electricity tariff, because individuals who do install renewables have remained connected to the grid in most cases, relying on it to supplement their power supply and, sometimes, to allow excess electricity produced to be sold to the grid operator. For access to these valuable services, individuals should pay for their share of the power system's fixed costs, which include the costs of transmission and distribution lines, as well as for the construction of power plants, or this burden will be unjustly carried by other individuals who do not produce their own electricity (IEA, 2013b). The third step in the assessment must account for the revenues received for excess electricity sold to the grid operator, which will evolve over time reflecting changes in the power system, such as the contribution of renewables.

The issue of transferring the burden of fixed power system costs from one individual to another has implications for electricity tariff designs and has been playing out in parts of the European Union and the United States. For example, in the past few years, four US states including California – the largest market for renewables in the United States – have increased fixed payments to start addressing the issue. The variable electricity tariff should be closely tied to the variable costs of producing and transmitting power to avoid cost transfers. As such, the wholesale electricity price provides a useful basis for the evaluation of competitiveness in the long run. This is a critical factor, as the wholesale electricity price is often 40-70% less than the full retail electricity tariff.

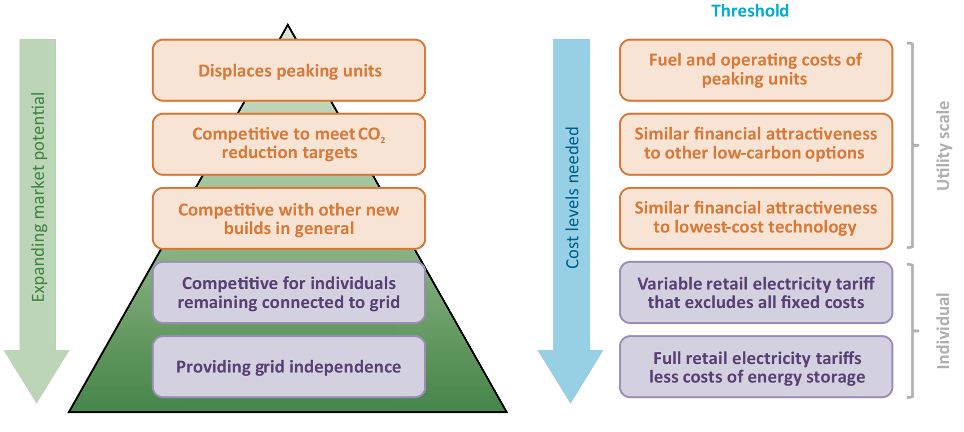
Evaluating competitiveness at the individual level is based on different costs and benefits when the installation provides the full power supply and the grid does not supply any supplemental services. On the cost side, if the renewable energy source is variable (e.g. wind or sun), an energy storage system and backup generator should be included, as they are needed in order to provide year-round electricity services similar to those available from a utility. For example, an average household would need to size the energy storage system, at a minimum, to cover several days of consumption, plus the backup generator to ensure reliability during unexpected or long periods of low output from the renewable energy technology. For a household that consumes 11 kWh per day (close to the average in the European Union), this would require an energy storage system able to store 40 kWh or more, at a cost of $40 000 or more, plus the cost of a backup generator.[7] With these additions, the levelised cost of the electricity produced would be several times that calculated by taking the costs of the renewable energy technology alone. On the benefits side, the appropriate comparison would be the full retail tariff, as the electricity bill would be eliminated. This comparison is generally more challenging for renewable energy projects

7. Energy storage costs are based on the recently announced home energy storage systems, with a purchase price of about $7 000 for 7 kWh of storage capacity.

than when individuals are connected to the grid, due to the current costs of energy storage. Future evaluations will depend critically on the cost reductions for both energy storage and renewable energy technologies. For those lacking access to electricity, the majority of whom are in developing countries, the reliability issue is less pressing in the initial comparison, lowering the relevant size and cost of energy storage. In these applications, renewables are already broadly competitive with the main alternative – small generators burning oil products. For many of the 2.9 billion people gaining access to electricity for the first time by 2040, renewable energy plays an important role, accounting for almost half of the additional access-related electricity demand (see Chapter 2).

The exact order in which renewable energy technologies become competitive in these various roles will vary from system to system according to the many factors that affect the relative costs and value. At utility scale, the main factors that vary by region include the power mix, fuel prices and technology costs, as well as energy and climate policies that may restrict the set of viable technologies. At the individual scale, assessments of competitiveness vary by region (and sub-region) because the costs of renewables and retail electricity tariff levels span a wide range, along with differences in retail price structures, in particular the degree to which the variable tariff reflects the variable costs of the system.

Figure 9.15 ▷ Milestones on the road to competitiveness for renewables

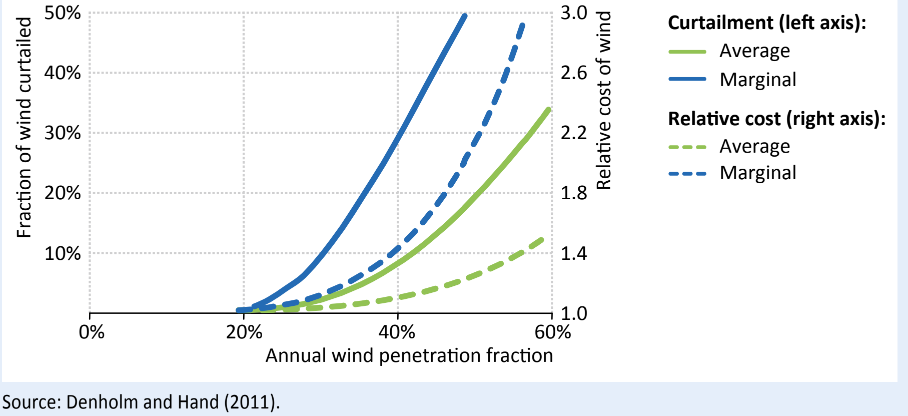


However, in the case where the variable retail electricity tariff is cost-reflective and energy storage costs similar to those today, the order of the noted milestones becomes more predictable. Under these conditions, displacing peaking plants in utility-scale projects represents the first milestone on the path to competitiveness for renewables when their output is correlated with, or can be dispatched at, times of peak demand (Figure 9.15). As costs decline, the next milestone for renewables is becoming competitive for investment in new capacity. This point is reached earlier if there is restricted competition among only low-carbon technologies. Further cost reductions for renewables would provide for them to displace generation from other power plants beyond peaking units, opening up increasing market opportunities. The milestones at the individual scale are generally reached only after further cost reductions, due to the higher costs which attach to smaller projects in general and because the average variable costs of electricity are most often below the operating costs of mid-merit plants. Given energy storage costs similar to those today, renewables at the individual level become competitive, first, to supplement the supply of electricity, before it is economically sound for individuals to disconnect from the power grid and rely on their own power supply. If and when this level of competitiveness is reached, the market potential would explode and deployment would then be more constrained by the available supply of the renewable energy technology and energy storage equipment.

Box 9.3 ▷ Changing value of variable renewables

Technologies with output directly tied to variable renewable energy sources, such as solar PV and wind turbines, have limited control of when they can operate. This can affect their value to the power system, a critical element when considering their competitiveness. The value of any power plant can be estimated through the costs that they avoid, including the displaced capital and operation costs of other power plants and other net reductions of system costs. As the share of variable renewables in total generation increases, unless energy storage or other mitigation options are widely applied, the lack of control can reduce the value of variable renewables in several ways, including curtailing their output, lowering their revenue as a result of displacing output from power plants with lower operating costs and reducing the contribution of renewables to system adequacy. The impact of these effects on the value of variable renewables is highly system-dependent, varying due to many factors, including the rest of the power mix, fuel prices, transmission constraints and market regulations (IEA, 2014e). In particular, highly interconnected systems are able to absorb greater amounts of variability, e.g., Denmark, limiting the degree of curtailment and associated impact on value, compared with more-isolated grids (Lew, 2013).

Figure 9.16 ▷ Curtailment of wind power output and corresponding impact on levelised costs as a function of wind penetration

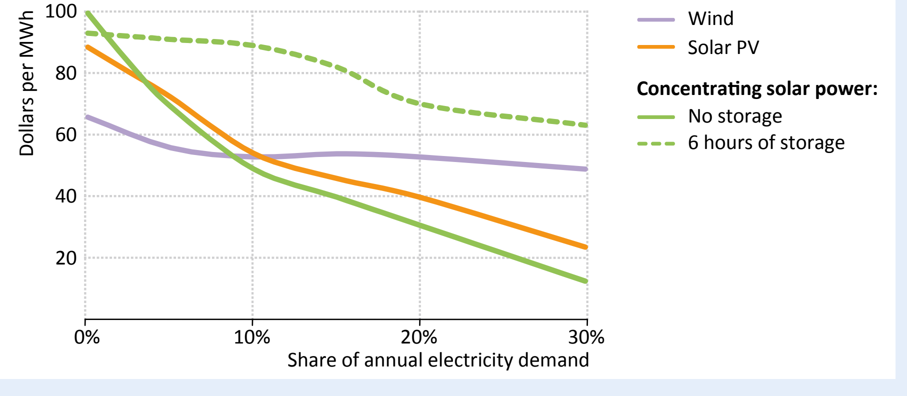


Source: Denholm and Hand (2011).

Curtailment occurs when the available output from variable renewables exceeds the ability of the grid to absorb it, due to low demand, insufficient flexibility from other power plants, or transmission and operational constraints. At low levels of renewables penetration, this is not usually a significant issue, but as variable renewables increase their market shares, their output may increasingly need to be curtailed. For example, an analysis of the ERCOT power system (in Texas) in the United States found that without more energy storage and a greater ability to shift demand, moving beyond 30% wind penetration dramatically increased the need to curtail output (Figure 9.16). This effect would sharply reduce the value of new projects, though curtailment experiences have varied across the United States (Bird, 2014). Curtailment is not limited to wind power, as it also affects solar technologies (E3, 2014).

As variable renewables become a larger share of total generation, they tend to displace output from other power plants with progressively lower operating costs. For example, as solar PV capacity represents a growing market share, its output increasingly displaces power plants with moderate or low costs rather than peaking plants with high operating costs (Hirth, 2013; IEA, 2014f). Analysis suggests that the effect of increasing penetration on the long-run value is greater in the case of solar technologies than wind power, as shown, for example, in simulations of the power system in California (Figure 9.17). In addition, solar's contribution to system adequacy (based on the expected output at times of peak demand) can decline significantly as hours with the highest residual electricity demand (after accounting for solar output) shift towards evening hours. However, mitigation options – such as energy storage, generator flexibility, demand response measures, improved transmission and improved operational procedures – can help delay or reduce the decline in value (Mills and Wiser, 2015; Nelson and Wisland, 2015; Palchak & Denholm, 2014, Mai, 2012).

Figure 9.17 ▷ Marginal economic value for wind power, solar PV and CSP in California at increasing shares of annual electricity demand

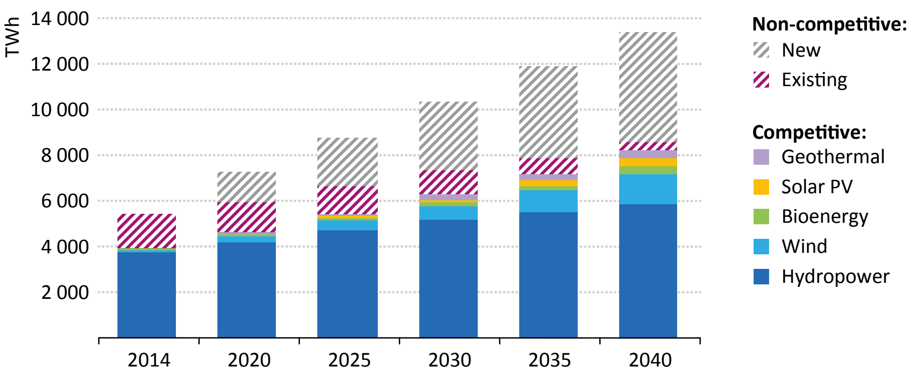


Source: Mills and Wiser (2012).

Outlook for competitiveness

In 2014, about three-quarters of global renewables-based generation was competitive with electricity from other types of power plants without subsidies, with large hydropower accounting for most of the total (Figure 9.18). The remaining 1 400 TWh of renewables generation enjoyed some form of government support, totalling $112 billion in 2014 (see subsidies section below). In the New Policies Scenario, under current and announced policies, the deployment of higher cost non-hydro renewables outpaces the growth of hydropower. As a result, the proportion of generation by fully competitive renewables actually declines somewhat over time, even with the costs of renewables falling,[8] and when the comparison is made with rising wholesale electricity prices in most regions (see Chapter 8). After hydropower, onshore wind power is the next most important form of competitive generation by renewables through to 2040. If more regions were to introduce and implement new policies to reduce CO_2 emissions, including carbon prices, a substantial additional amount of renewables generation would become competitive. About 4 800 TWh of renewables-based generation is projected to rely on subsidies still in 2040, receiving about $170 billion, which provides some measure of the downside risk to the industry if political support were to falter.

Figure 9.18 ▷ Competitive renewables-based electricity generation in the New Policies Scenario

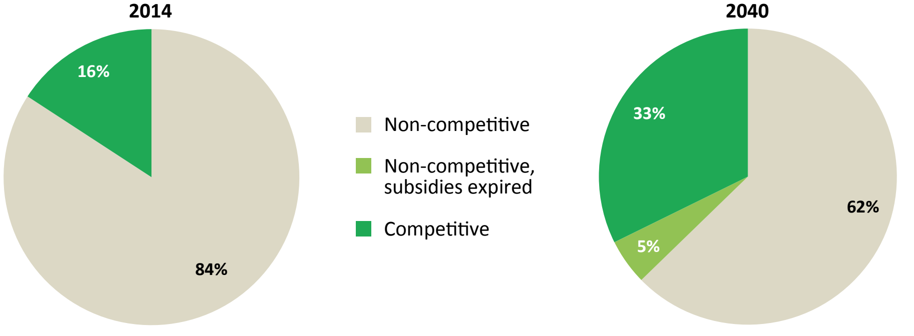


The majority of non-hydro renewables that have been deployed so far have received targeted support, as more than 80% of generation today from non-hydro renewables is not competitive (Figure 9.19). In some regions, however, renewable energy technologies have been deployed without the need for policy support, including some wind farms in Brazil, China and the United States, bioenergy in Brazil, geothermal in several countries and solar PV in remote locations and to provide first access to electricity. By 2040, continued cost reductions, technology improvements, increasing wholesale electricity prices and more widespread use of CO_2 pricing help to raise the share of non-hydro renewables generation

8. Costs for renewables decline at historical learning rates based on the scale of projected deployment.

that is competitive to one-third, with the remaining portion requiring some amount of financial support. In addition, most support measures span 20 years or less, while the shortest technology lifetimes, for solar PV and wind power, range from 20-30 years. As a result, 5% of non-hydro renewables generation in 2040 is from projects that no longer enjoy subsidies, but were built with financial help from supportive policies.

Figure 9.19 ▷ Competitive non-hydro renewables generation worldwide in the New Policies Scenario, 2014 and 2040



Subsidies

Government policies supporting the deployment of renewable energy technologies in power, industry, buildings or transport have been put in place in many countries in recent years. Currently, an estimated 126 countries provide financial support for renewables in one form or another (REN21, 2015). All support mechanisms improve the financial prospects of renewable energy projects, but they do so in a variety of ways. Generally, support mechanisms fall into one of three categories, providing additional revenue, paying a guaranteed price or reducing total costs (including tax liabilities) (Table 9.7). Price premiums, cash grants and green certificates are support mechanisms that provide additional revenue streams outside the market. Net metering, which involves remunerating electricity supplied to the grid at the retail tariff (which is generally a higher rate than would have been received on wholesale electricity markets), can also fall in this category. In some cases, however, net metering may not provide extra revenue – when wholesale market prices at the time power is supplied to the grid are as high as the retail tariff. This could be the case for solar PV when peak demand hours are near midday and total solar PV installed capacity in the system remains a small share of the total level of demand. Measures to provide additional revenue streams have mainly been applied in the European Union and the United States, to supplement the workings of competitive wholesale electricity markets.

The second major support method is to guarantee a pre-determined price for electricity supplied to the grid, generally providing a higher level of remuneration than could be expected on wholesale markets, improving financing prospects by eliminating revenue uncertainty. Feed-in tariffs have been popular and effective in many regions, including the European Union, Japan and parts of the United States and India. Recently, auctions for renewable energy technologies have been gaining ground as a means of harnessing competitive market forces and providing a means of price discovery to minimise the costs of capacity additions. Brazil, South Africa, the Middle East and some locations in the United States have held auctions to date, offering long-term contracts for the lowest cost projects. Capacity mandates or renewable portfolio standards in retail price-regulated markets could also be put into this category, effectively guaranteeing that the costs of renewable energy projects will be fully recovered. Reducing tax liabilities is another way to improve the economics of renewable energy projects. The United States has relied on this more than others, including through both the recently expired production tax credit – providing credits based on output – and the continuing investment tax credit, applied after the completion of projects. Carbon prices do not change the costs or revenues of renewables directly, but instead raise the operating costs associated with conventional fossil-fuelled power plants, which puts upward pressure on wholesale electricity prices, thus indirectly improving the prospects for renewables.

Table 9.7 ▷ Main support mechanisms for renewable energy technologies in the power sector by selected region

Support method	Support mechanism	China	India	European Union	United States	Japan	Brazil	South Africa	Middle East
Providing additional revenue	Price premiums	○	○	●	○	○			
	Cash grants		○	○	●	○	○		●
	Green certificates		○	○	○				
	Net metering		○	●	●	○	○		○
Providing a guaranteed price	Feed-in tariffs	●	●	●	○	●			○
	Power purchase agreements		○	○	●		●	●	●
	Auction tenders		○	○	○		●	●	●
	Required share or amount*	●	○	○	●				
Reducing total costs	Tax credits or exemptions	●	○	○	●	○	○	○	○
	Preferential financing rates		●	○	○		○	○	○
	Accelerated depreciation**		●		○				

* Policies may specify a required share (e.g. renewables in total generation) or minimum amount of installed capacity or generation. **Accelerated depreciation lowers total discounted costs by delaying the tax burden.

Note: ● = primary driver of renewables deployment; ○ = secondary driver of renewables deployment.

Sources: IEA/IRENA Joint Policies and Measures database; IEA analysis.

Most government support mechanisms are limited in duration, ranging from a one-time payment to continuous support over the operational lifetime of the project. Cash grants and investment tax credits, two measures that have been important in the United States, provide a single lump-sum payment to renewable energy projects, usually at the moment at which operations begin. Feed-in tariffs, price premiums and production tax credits tend to be 10- to 20-year commitments, spanning large portions of the economic lifetime of renewable energy projects. While experience beyond this span is limited to date, there are indications that renewable energy installations will be able to provide electricity to the grid for a period of time after these support measures have expired, providing subsidy-free renewables-based electricity to the grid. Power purchase agreements for non-hydro renewables also tend to last for around 20 years, though 25-year contracts are becoming more common. Subsidies to bioenergy-based power plants are sometimes committed for the duration of the operational life, possibly more than 30 years, as the main purpose of subsidies is to reduce fuel costs.

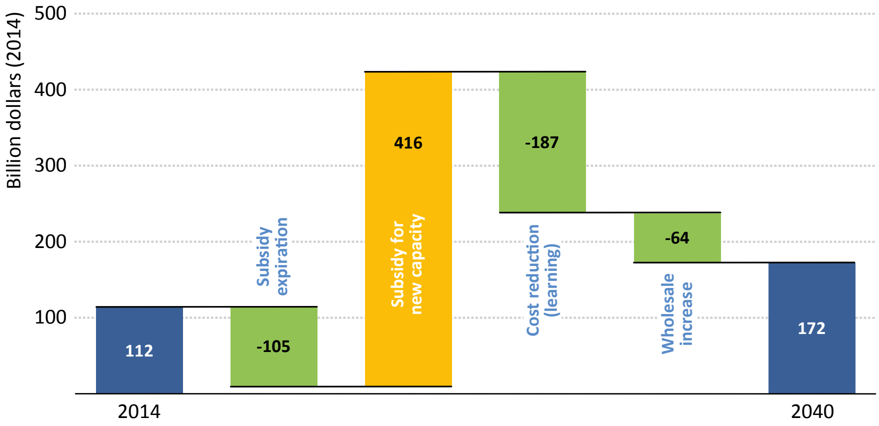
Based on a survey of established national-level policies and accounting for the deployment of new renewable energy projects in all markets, we estimate global subsidies provided to renewable energy at $135 billion in 2014, $11 billion higher than in 2013 and almost triple the amount in 2008.[9] The increase in recent years was mainly due to the expansion of subsidies for renewables in the power sector, which have grown at an average rate of 25% per year since 2008, driven by the strong deployment of renewables in OECD countries at first and in non-OECD countries more recently (China and India above all). Support for renewables-based electricity generation increased by $12 billion in 2014 compared with the year before, mainly due to the strong deployment of wind power and solar PV in both OECD and non-OECD countries. Despite deployment of renewable energy technologies in many countries, subsidy payments are still concentrated in a few countries. In 2014, the top-three countries (Germany, the United States and Italy) accounted for almost 50% of the total and the top-ten countries for almost 85%. Over 2008-2013, subsidies to biofuels have grown at an average rate of only 3% per year. As a result, biofuel subsidies accounted for only 17% of the total in 2014, compared with 40% in 2008. Despite low oil prices throughout 2014, global subsidies to biofuels were 3% lower than in 2013, mainly due to a large drop in the United States, where ethanol prices fell, due to a record corn crop and a well-supplied ethanol market.

In the New Policies Scenario, global renewable power subsidies increase from $112 billion in 2014 to $172 billion in 2040 (Figure 9.20). The expiration of existing support measures is more than offset by support provided to new installations that are not fully competitive. Were there to be no future cost reductions for renewable energy technologies, total

9. Subsidies to renewables-based electricity generation are calculated as the difference between the levelised cost of electricity and the wholesale electricity price in each region, multiplied by the amount of generation for each renewable energy technology. For biofuels, subsidies are calculated by multiplying the consumption by the difference between their production cost and the reference price of the comparable oil-based product in each region.

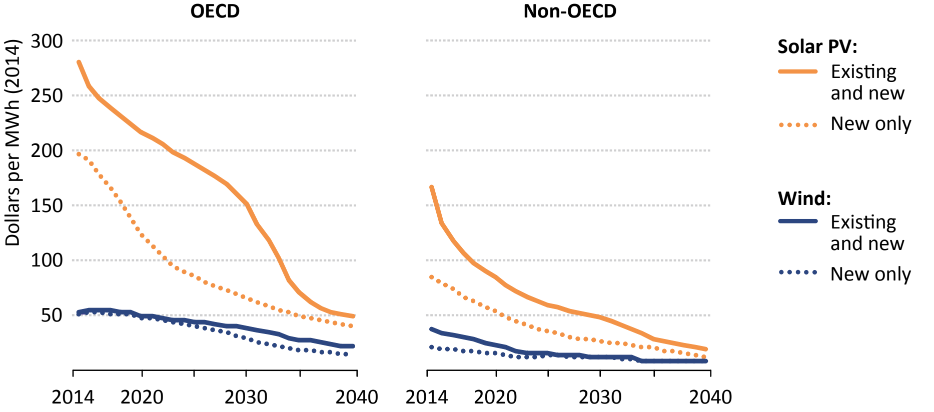
subsidies to renewables-based power plants would more than triple from current levels by 2040. However, technology improvements, mainly for solar PV and wind power, are projected to reduce the average capital costs and lower related subsidies substantially (by $187 billion in 2040 alone). Over time, rising fossil-fuel prices in most markets and the implementation of carbon pricing in more markets raise average wholesale prices for electricity, further mitigating the increase in subsidies by $64 billion. Due to these effects, global renewable power subsidies increase by half from 2014 to 2040, while the volume of renewables-based electricity generated increases by 150%.

Figure 9.20 ▷ Global subsidies to renewables-based electricity generation in the New Policies Scenario, 2040 versus 2014



The subsidy rates provided for each renewable energy technology in the power sector vary considerably, largely due to the wide range of levelised costs of electricity. As technology improvements continue, solar PV and wind power in particular make gains that lower the amount of subsidy they require. In 2014, solar PV capacity in operation in OECD countries received about $280/MWh on average, compared with $165/MWh in non-OECD countries (Figure 9.21). This is largely due to the fact that the development of solar PV was fostered in OECD countries, with higher cost solar PV deployed years before non-OECD countries (mainly China to date) started to install substantial amounts of solar PV. This legacy of support costs arising from this early deployment continues for many years, as the effect on average subsidies depends on the amount of new capacity deployed relative to the size of the existing fleet, which is relatively low in the OECD. As a result, when solar PV generation in non-OECD countries catches up with OECD countries in 2025, average support for the technology in non-OECD countries is only about one-third of the average level provided in OECD countries ($185/MWh).

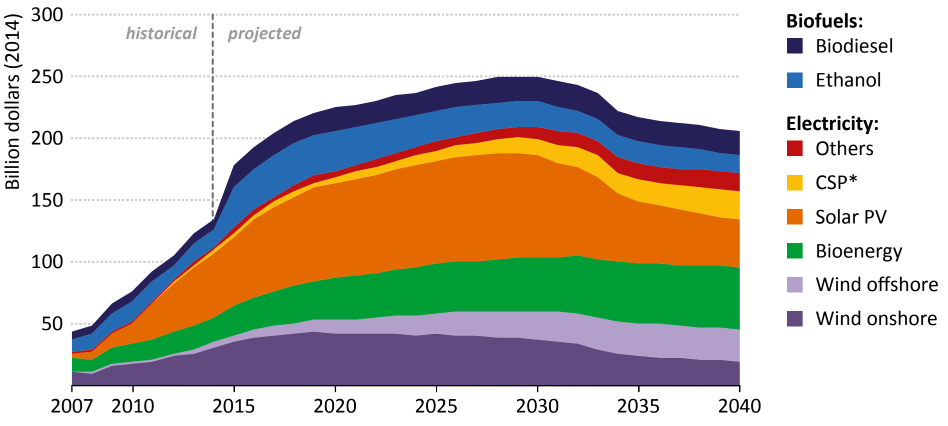
Figure 9.21 ▷ Estimated subsidy rates for solar PV and wind in the New Policies Scenario



Notes: Existing and new subsidy rates are calculated by dividing total subsidies by total generation for each technology. Solar PV includes projects at the utility scale and in buildings.

Wind power requires less than $55/MWh of average support throughout the projection period in both OECD and non-OECD countries, making it one of the renewable energy technologies closest to being competitive. By 2040, solar PV also requires less than $50/MWh on average, having made a lot of progress towards competitiveness. Where solar PV is a small share of total generation and its output coincides with peak demand hours, the level of support needed will be lower than average. Over the period 2015-2040, government support provides almost 45% of the total revenues going to new installations of solar PV and more than 20% of total revenues for new wind power developments.

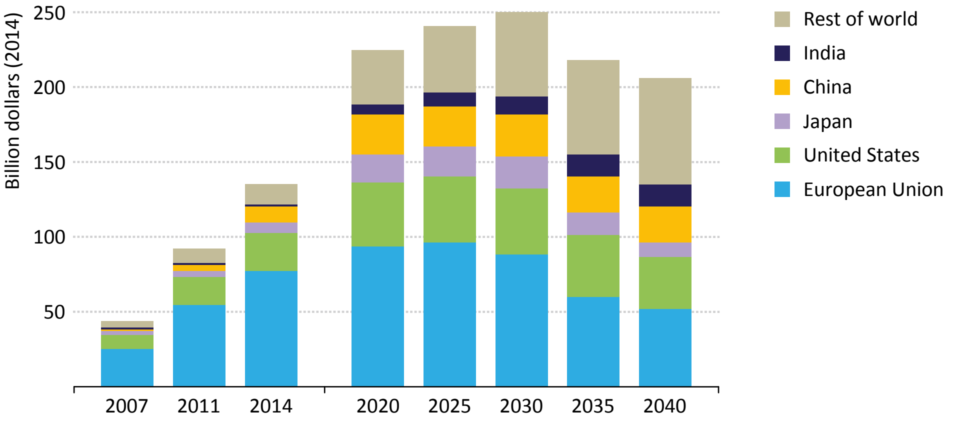
Figure 9.22 ▷ Subsidies by technology in the New Policies Scenario



*CSP = concentrating solar power.

In the New Policies Scenario, subsidies paid to all forms of renewable energy amount to over $200 billion in 2040, after peaking at $250 billion around 2030 (Figure 9.22). Subsidies to biofuels increase substantially to 2020, due largely to the low oil price environment that expands the gap between oil product prices and the costs of producing biofuels. Over the period 2015-2040, cumulative subsidies to renewables are $5.9 trillion (equivalent to 0.2% of global gross domestic product over the same period). Of total subsidies, about half go to solar PV and wind power, almost 30% to the other renewables-based power plants and around 20% to biofuels. In 2040, the regional composition of renewables support changes dramatically from the current one (Figure 9.23). The subsidies provided in OECD countries, which currently account for more than 80% of the total, are only about 55% by 2040. The European Union remains the largest supporter of renewable energy through to 2040, despite the expiry of the support measures to capacity already in operation today. While renewables-based electricity generation is by far the highest in China, relatively low technology costs and rising wholesale electricity prices, due a carbon price, limit the increase in renewable energy subsidies.

Figure 9.23 ▷ Subsidies by region in the New Policies Scenario



9

Energy efficiency outlook

Does material efficiency bring material energy savings?

Highlights

- In 2014, energy efficiency improvements helped put a significant brake on the increase of global final energy demand, cutting the increase by two-thirds. As a result, final consumption grew at 0.7%, as opposed to an average 2% over the past decade. Improvements in Chinese industrial energy efficiency and the restructuring of its industry accounted for one-quarter of global efficiency savings in 2014. Progress was seen in many countries and sectors, but the decline in energy prices, above all the oil price, raised questions about the longevity of efficiency improvements.

- The extent of mandatory energy efficiency regulations has spread over the last ten years: from covering 14% of the world's energy consumption in 2005 to 27% in 2014. Efficiency regulations now cover 36% of industrial energy use, up from only 3% in 2005, driven by new mandatory targets in China and India, while coverage in the transport and buildings sectors is 24% and 31% respectively. China experienced the largest jump in overall coverage, from 3% in 2005 to 50% in 2014.

- In the New Policies Scenario, energy efficiency measures reduce global primary energy demand by 1 275 Mtoe (or 6%) in 2040, compared with the Current Policies Scenario. Electricity demand is cut by almost 3 000 TWh, a third of it through stricter standards for appliances and cooling. In OECD countries, efficiency measures limit the increase in electricity demand by almost 40%, leading to moderate demand growth. A lower oil price could cut efficiency investment by a cumulative $0.8 trillion or 11% of the additional investment in the New Policies Scenario (relative to the Current Policies Scenario) and cancel 14% of efficiency-related energy savings.

- Realising the full energy efficiency potential could further reduce the energy consumption of new equipment sold in 2030 by 11%, with every additional dollar invested saving five dollars in energy spending. The largest additional monetary savings would arise in lighting, trucks, appliances and SMEs.

- Achieving greater efficiency in the use of materials through light-weighting, longer life products, re-use and recycling, is an important complementary strategy to energy efficiency in energy-intensive industries, as the potential for energy savings is about twice as large. The Material Efficiency Scenario, which implements such measures, enables energy demand in energy-intensive industries to be held at roughly current levels. Material efficiency strategies can save 190 Mtce of coal, 1.3 mb/d of oil, 50 bcm of natural gas and 830 TWh of electricity – in total about 330 Mtoe in 2040. These strategies have the largest impact on energy demand in those developing countries with recently developed or quickly expanding energy-intensive industry, including China and India.

Introduction

Energy efficiency is a vital component of action to meet the challenges facing the energy sector, which range from ever increasing global energy demand, to concerns about energy security, climate change, local air pollution and the affordability of energy supply. This is recognised increasingly by decision-makers around the world, not least as a measure of reducing greenhouse-gas emissions. *Energy and Climate Change: World Energy Outlook Special Report 2015* showed that realising the economic potential of energy efficiency is a central pillar of a cost-effective strategy to mitigate climate change and achieve a peak in global greenhouse-gas emissions by 2020 (IEA, 2015).

This chapter discusses recent trends in energy efficiency, including a retrospective analysis of the evolution of energy efficiency policies and the impact of these policies on selected sectors and regions, and outlines key policy developments. It continues with an analysis of energy efficiency trends in our central scenario (the New Policies Scenario) in the period to 2040, highlighting trends in each end-use sector, including the impact on energy-related carbon-dioxide (CO_2) emissions and investment requirements. For the first time, the *World Energy Outlook* goes beyond an examination of the scope for efficiency to reduce energy use in energy-intensive industries and analyses the potential impact on energy demand and CO_2 emissions of a more efficient use of materials through a range of strategies to deliver material services with less material production.

Current status of energy efficiency

Recent trends

Any period of lower energy prices, such as that observed since mid-2014, can raise concerns that efficiency policies will be pushed to the margins and that a period of more profligate consumption will return (see Chapter 4). However, the evidence so far available suggests that energy efficiency policy continues to be taken seriously. Preliminary estimates for 2014 indicate that global energy intensity – measured as the amount of primary energy required to produce a unit of gross domestic product (GDP) – decreased by 2.7%, relative to the previous year, around twice the average rate of change of the last decade (1.5%).[1] While it is difficult to establish a trend from an annual change, the improvement in global energy intensity over the past four years has also been higher than the trend over the past two decades.

The drop in energy intensity in 2014 was due not only to energy efficiency improvements, but also to structural changes in the economy and changes in weather patterns. A major element of the global change was the 6.9% improvement in energy intensity in China based on official GDP numbers,[2] which can be explained by a continuing shift towards

1. Energy intensity is not an optimal indicator for energy efficiency as it is influenced by other factors, including changes in the economic structure and climatic conditions (IEA 2012; 2014a).

2. The change in primary energy intensity is higher than the official Chinese numbers (-4.8%) as the IEA uses the energy content method and Chinese authorities use the partial substitution method for renewables.

less energy-intensive economic activities, a higher share of renewables[3] and improving energy efficiency. The European Union experienced a 5.4% drop in energy intensity, driven by efficiency improvements (particularly in buildings), subdued activity in some energy-intensive industries and lower heating demand as a consequence of 2014 being the warmest year on record.

Global final energy consumption in 2014 expanded by 0.7%, but decomposition analysis shows that without energy efficiency improvements the growth would have been 2.1%, indicating efficiency-related savings of 122 million tonnes of oil equivalent (Mtoe). The industrial sector contributed more than half of the savings, with most of these occurring in China, the European Union and Russia. The second-largest savings stem from the transport sector, where energy efficiency shaved 1.6 percentage points from energy demand growth. OECD countries, particularly the European Union and the United States, had the largest impact. In the buildings sector, energy efficiency savings amounted to 12 Mtoe in 2014.

Concrete examples from various sectors in different countries over the last decade illustrate the extent of energy savings due to energy efficiency efforts (Figure 10.1). In the mid-2000s, China started to tackle inefficient energy consumption in its energy-intensive industries, including the steel industry, through the small plant closure programme, the Top-1 000 Energy-Consuming Enterprises Program (which later became the Top-10 000 Program) and the Ten Key Projects (financial incentives for energy saving projects). Together, these measures helped save 84 Mtoe of energy demand in the steel sector over the period 2004-2014. More recently, China has sought to accelerate energy efficiency in order to reduce local air pollution through the phase-out of inefficient coal-fired boilers.

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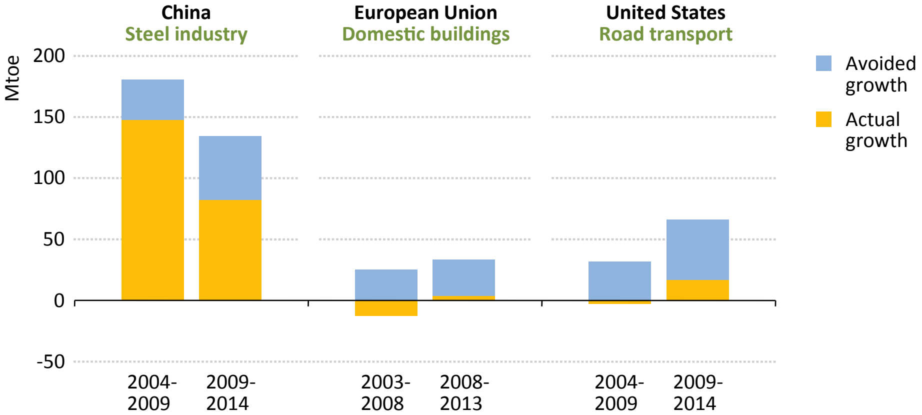
Figure 10.1 ▷ **Energy demand change and avoided energy demand from efficiency gains in selected sectors and regions**



3. A shift from fossil fuels towards renewables, such as solar photovoltaics (PV) and wind, reduces the demand for primary energy, as the physical energy content method used by the IEA attributes a 100% efficiency to electricity generation from solar PV and wind.

The European Union (EU) has a long history of policies aimed at cutting energy use in the buildings sector through the adoption of more efficient appliances, lighting, heating systems and buildings insulation (e.g. the Ecodesign, Energy Labelling and Energy Performance of Buildings Directives). These efforts have delivered annual energy demand savings of 2.6% for each of the past five years, offsetting the increase in energy demand resulting from larger dwellings and increased levels of appliance ownership. Greater energy efficiency thereby contributed to an absolute reduction in energy consumption from households in the EU. Energy efficiency in the transport sector has traditionally been a focus for policy-makers, with India and Mexico being among the most recent countries to introduce regulations. In 2008, the United States set tighter Corporate Average Fuel Economy (CAFE) standards (35.5 miles per gallon) to be achieved by 2016, which has helped to reduce fuel consumption by more than 1% per year. The resulting reduction in demand growth from road transport was, together with a surge in domestic oil production, a crucial factor in reducing US oil imports.

The practice of introducing new energy efficiency measures continued in 2014 and 2015, with several countries announcing new energy efficiency measures or strengthening existing ones (Table 10.1). In the build-up to the climate summit in Paris in late 2015, the role of energy efficiency in reaching cost-efficient emissions reductions has been reaffirmed and features prominently in countries' Intended Nationally Determined Contributions (INDC). In June 2015, a summit of G7 leaders put emphasis on resource efficiency, of which energy efficiency is an essential part, as a crucial feature of sustainable economic growth (G7, 2015).

China highlights efficiency in all end-use sectors as a central feature of policy as announced in its Energy Development Strategic Action Plan (2014-2020). It continues to adjust its industrial structure by, for example, accelerating the elimination of outdated and small capacity in the power and industrial sectors. China has also announced several action plans including energy efficiency targets for coal-fired power plants and technology upgrades in major coal-consuming industries. The National Key Energy Conservation and Low Carbon Technologies Promotion List advocates the uptake of more than 200 advanced energy-efficient technologies.

The United States adopted a final version of the Clean Power Plan in August 2015 to cut carbon emissions from the power sector; improved efficiency will be a key measure to achieve the targets. The US Environmental Protection Agency (EPA) has proposed rules to strengthen and extend fuel-economy standards for medium- and heavy-duty engines and vehicles for the period 2021-2027 under which new trucks sold in 2027 would need to be 24% more efficient than those sold in 2018. In addition, the EPA is taking steps to develop CO_2 emissions standards for aircraft sold from 2020 onwards and is participating in the United Nations International Civil Aviation Organization (ICAO) efforts to develop co-ordinated, international CO_2 emissions standards for aircraft.

Table 10.1 ▷ Selected energy efficiency policies announced or introduced in 2014 and 2015

Region	Sector	New policy measure
China	Industry	Announced an action plan to implement technology upgrades in major coal-consuming industries, including coking and coal-based chemicals.
	Power	Announced targets for coal-fired power plants based on coal consumption per unit of power supplied in 2020, and action plans to phase out inefficient technologies and upgrade existing ones.
United States	Buildings	Passed the Energy Efficiency Improvement Act of 2015 establishing, among others things, a market-driven approach to facilitate energy savings in commercial buildings by aligning the interests of owners and tenants.
	Transport	Proposed extension and strengthening of the fuel standards for medium- and heavy-duty vehicles for 2021-2027. Announced intent to adopt greenhouse-gas regulation for commercial aviation in 2016.
European Union	General	Agreed the 2030 Framework for Climate and Energy Policies, setting an indicative energy savings target of at least 27% by 2030.
	Buildings	Introduced energy labels for cooking appliances and a requirement to provide automated stand-by functions on network devices. Implemented regulations for residential ventilation units, gas and electric ovens, cooking hobs and range hoods within the framework of the Ecodesign Directive.
India	Transport	Introduced subsidies for hybrid/electric bicycles, buses and cars.
	Industry	Prepared the second cycle (2016-2019) of the Performance Achieve and Trade scheme, which will include refineries, distribution companies and railways.
	Buildings	Introduced MEPS for electric water heaters. Revised voluntary labelling requirements for refrigerators, televisions, office equipment and diesel generators.
Japan	General	Established the New Strategic Energy Plan, including actions to improve energy efficiency, e.g. electric motors included in the Top Runner Program.
	Buildings	Cabinet approval of a bill requiring businesses to satisfy standards for energy saving performance for newly constructed large-scale buildings from April 2018.
	Transport	Introduced new efficiency standards for small freight vehicles to improve fuel efficiency by 26% by 2022 from 2012 levels.
Middle East	Transport	Saudi Arabia: Information campaign targeted at energy-efficient vehicles. Iran: Scheme to replace 65 000 old inefficient heavy-duty diesel vehicles.
	Buildings	Iran: Scheme to increase energy efficiency in central heating systems in buildings, with a goal to save 10-13 million m^3/day of natural gas.
	Agriculture	Iran: Introduced a scheme to switch from diesel to efficient electric pumps.
Africa	Industry	South Africa: Increased tax incentives for energy efficiency savings.
Southeast Asia	General	Singapore: Announced investment of $100 million in energy efficiency research.
Mexico	Buildings	Introduced MEPS for various household appliances to reduce stand-by power.
Latin America	Industry	Uruguay: Extended a scheme that reduces electricity tariffs for industries that have implemented energy efficiency measures.
	Buildings	Brazil: Introduced a mandatory energy label for public buildings (PBE Edifica) and included LED lamps in the mandatory efficiency labelling scheme. Uruguay: Introduced mandatory labels for air conditioners and heat pumps. Argentina: Strengthened MEPS for air conditioners.

In the EU, the European Council has endorsed a target of achieving at least 27% energy savings, compared with a business-as-usual scenario, as one element of the agreed 2030 Framework for Climate and Energy Policies. Moreover, energy efficiency is one of the key policy areas in the European Commission's announced Strategy on the Energy Union, which aims to make energy more secure, affordable and sustainable. In that context, the European Commission will focus on promoting energy efficiency in the buildings and transport sectors, for example by simplifying access to small-scale finance to unlock the efficiency potential in the buildings sector and taking actions to accelerate deployment of the necessary infrastructure to electrify the transport fleet. The EU's Ecodesign framework has been expanded to include various cooking appliances and the requirement for energy labels has been extended to cooking appliances.

In India, the Perform, Achieve and Trade scheme, a market-based approach to improve energy efficiency in industry, reached the end of its first compliance period in March 2015, with results being verified in mid-2015. The next compliance period (2016-2019) will include more stringent targets, trading of energy efficiency certificates and the scope will be extended to refineries, electricity distribution companies and railways. In addition, energy efficiency regulation of electric appliances has been strengthened with the introduction of minimum energy performance standards (MEPS) for electric water heaters and a revision of voluntary labelling requirements for a range of appliances (see Part B).

In the Middle East, several countries continue to address their growing energy demand through energy efficiency policies. Iran has initiated a number of measures – partly due to the pressure from international trade sanctions – designed to lower domestic fuel consumption (particularly natural gas and oil). These include schemes to increase energy efficiency in heavy-duty diesel vehicles and central heating systems in residential and commercial buildings.

Energy efficiency regulation

Policy-makers have been actively introducing new energy efficiency incentives and regulations not just over the past year, but also over the last decade. In order to assess the impact of these policies on energy consumption, we have sought to quantify how much of the world's energy use is now covered by mandatory energy efficiency regulation. For this analysis, we have looked at a large number of energy efficiency regulations in every world region and every end-use – buildings, industry, transport and agriculture. Energy efficiency regulation in our definition includes minimum energy performance standards, mandatory phase out of inefficient technologies (e.g. incandescent light bulbs), building energy codes and mandatory energy saving targets for industries. While a range of broader policies exist that can also have an effect on energy efficiency, such as carbon trading schemes, information campaigns, preferential loans or tax rebates, these have not been taken into account. Nor does the estimate attempt to evaluate the stringency, effectiveness or degree of enforcement of the regulation.

Table 10.2 ▷ Share of global final energy consumption by end-use and selected regions, 2014

		China	United States	European Union	Africa	India	Southeast Asia	Middle East	Russia	Japan	World
Industry	Motor-driven systems	2.2%	0.6%	0.7%	0.2%	0.3%	0.2%	0.1%	0.2%	0.2%	5.9%
	Lighting	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%
	Process cooling and refrigeration	0.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%
	HVAC*	0.6%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	1.8%
	Process heat	4.0%	1.2%	1.1%	0.4%	0.9%	0.6%	0.8%	0.8%	0.4%	12.6%
	Steam systems	3.3%	1.0%	0.9%	0.3%	0.8%	0.5%	0.7%	0.7%	0.3%	10.5%
Transport	Passenger road vehicles	0.9%	4.0%	1.9%	0.4%	0.2%	0.4%	0.8%	0.4%	0.4%	11.9%
	Light commercial vehicles	0.1%	0.6%	0.4%	0.1%	0.0%	0.2%	0.1%	0.0%	0.2%	2.3%
	Heavy-duty vehicles	1.0%	1.4%	0.8%	0.4%	0.4%	0.2%	0.5%	0.1%	0.2%	6.5%
	Aviation	0.3%	0.9%	0.6%	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	3.2%
	Navigation	0.4%	0.3%	0.6%	0.1%	0.0%	0.6%	0.2%	0.0%	0.1%	2.9%
	Rail	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.7%
Buildings	Space heating	1.9%	2.4%	3.1%	0.9%	0.5%	0.3%	0.1%	1.2%	0.5%	13.2%
	Water heating	0.6%	0.8%	0.9%	0.2%	0.1%	0.1%	0.2%	0.4%	0.2%	4.3%
	Cooking	2.3%	0.2%	0.2%	2.8%	1.6%	0.9%	0.5%	0.1%	0.1%	10.1%
	Lighting	0.4%	0.5%	0.3%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	2.1%
	Appliances	0.4%	1.3%	0.7%	0.2%	0.1%	0.2%	0.3%	0.1%	0.3%	4.3%
	Cooling	0.2%	0.6%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.1%	1.6%
Energy use covered 2005		3%	46%	8%	0%	1%	1%	0%	9%	33%	14%
Energy use covered 2014		50%	54%	21%	1%	16%	3%	4%	12%	47%	27%

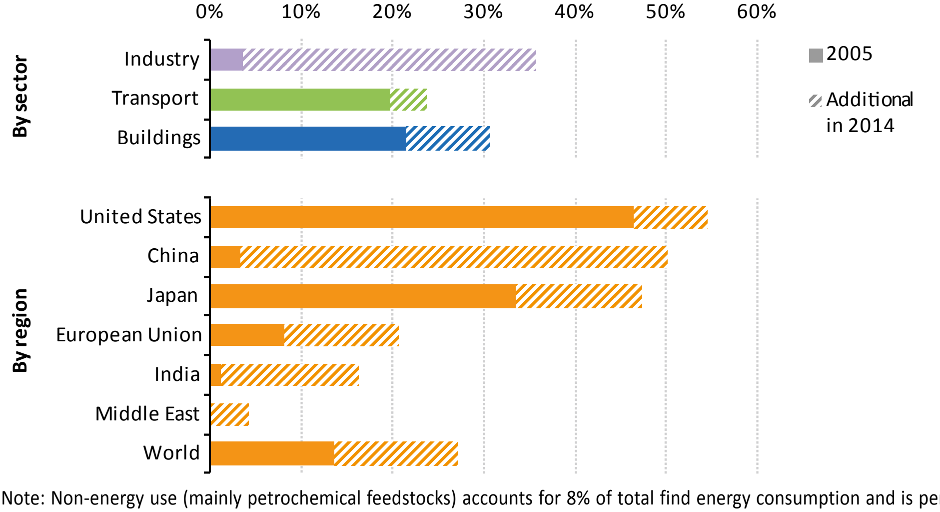
* HVAC = heating, ventilation and air conditioning.

Notes: Green font indicates energy efficiency regulations cover over 75% of energy consumption from sales of new energy-consuming equipment; **black** font indicates partial regulation coverage (less than 75%); and grey font indicates no efficiency regulation of devices. Energy use in agriculture and smaller sub-sections in the transport sector (e.g. two-wheelers) are not included. Energy use in cooking includes traditional use of solid biomass in stoves with low efficiency.

For this analysis, we have first looked at the extent to which new energy-using appliances sold in 2005 and 2014 (such as cars, motors, boilers, lighting and televisions) are covered by mandatory energy efficiency regulations and what proportion of sectoral energy consumption they account for (Table 10.2). We then extended the analysis to estimate how much energy consumption derives from all regulated energy-using equipment (new and existing) in those two years by considering the point in time at which a regulation was first introduced, the average lifetime of the end-use equipment and how much energy is consumed in each end-use sector.[4]

Our estimates indicate that 14% of the world's final energy consumption was covered by mandatory efficiency regulation in 2005, with the majority of that being energy consumption by passenger vehicles and for space heating. This share had increased to 27% in 2014 (Figure 10.2). Most of the increase in coverage occurred in the industrial sector, mainly as a consequence of mandatory targets for energy savings being put in place in China and India. There has also been an increased focus on lighting in buildings, where about 70% of energy consumption is now subject to efficiency regulation. The largest increase in the scope of regulation was observed in China, where policy-makers have particularly sought to lower the adverse effects of air pollution by making industrial energy consumption more productive and efficient.

Figure 10.2 ▷ Extent of global mandatory efficiency regulation of final energy consumption by sector and region



Note: Non-energy use (mainly petrochemical feedstocks) accounts for 8% of total find energy consumption and is per definition not covered by energy efficiency policies.

4. For example, as part of the Top Runner Program, Japan has had fuel-efficiency standards in place since 1999 and 100% of energy consumption in passenger vehicles was covered by efficiency regulation in 2014 (assuming a lifetime per car of 15 years). As another example: the United States has regulated electric motors since 1997. This regulation covers only the electric motor itself and not the transmission, gears and end-use device (e.g. fan, pump or compressor) of the electric motor system, where around three-quarters of the energy savings can be made. Accordingly, current US regulation covers only 25% of the energy use from electric motor systems.

In the transport sector, the extent of relevant road vehicle regulation has broadened slightly from 30% in 2005 to 34% in 2014. Passenger transport has received a significant level of attention from policy-makers in recent years, mostly to respond to local pollution and security of supply concerns. Yet only half of the energy consumed by passenger vehicles is covered by efficiency regulations.[5] Freight transport, a major source of future oil demand growth, is currently subject to efficiency regulations only in the United States, Canada, Japan and China, leaving significant scope for further efficiency gains. Energy demand from aviation is growing fast, but aviation is currently less regulated than energy demand in road transport. While the European Union has made attempts to include aviation in its carbon trading scheme and the US administration has taken the first steps towards regulating greenhouse-gas emissions from aviation, future tangible action on energy regulation depends on progress in the ICAO. The first efficiency standards for international navigation were introduced in 2013, within the framework of the International Maritime Organization.

For buildings, we estimate that currently around 30% of total energy consumption is covered by efficiency regulations, up from 21% in 2005. However, this number masks substantial differences. Space heating, representing the largest end-use, is covered through MEPS for heating equipment and building energy codes in the European Union, Japan, China, India, countries in the Gulf region and most states in the United States, but this is only partially so in other countries. Significant regional differences also exist in the regulation of commercial and residential buildings, where public buildings are typically subject to the highest level of regulatory coverage. While lighting is now covered in many countries around the globe and standards for appliances are increasing every year (around half of current global sales are covered), cooking and water heating have so far received less attention.

The most important progress in regulation coverage in recent years has been made in industry, where 36% of energy consumption is now subject to efficiency regulation (the equivalent share was 3% in 2005). While significant progress has been made in tightening regulation of electric motors, there is further scope to increase the efficiency of electric motor systems. Standards that apply to the transmission, gears and end-use devices of electric motor systems are applied in few countries so expanding their geographical coverage could reduce energy consumption significantly. One challenging area for energy efficiency regulations relates to process heat and steam systems in industry since they differ from one plant to the next. Several countries have mandatory energy saving obligations for companies, though the associated administrative work can be burdensome, particularly for small and medium enterprises (SMEs). This is one reason why, in general, only large energy-consuming industries are currently subject to mandatory energy audits and energy management systems.

5. The share of car sales is higher, at 70% but, as regulation has been introduced only over the past few years in several countries, a significant share of the current vehicle fleet is not subject to standards.

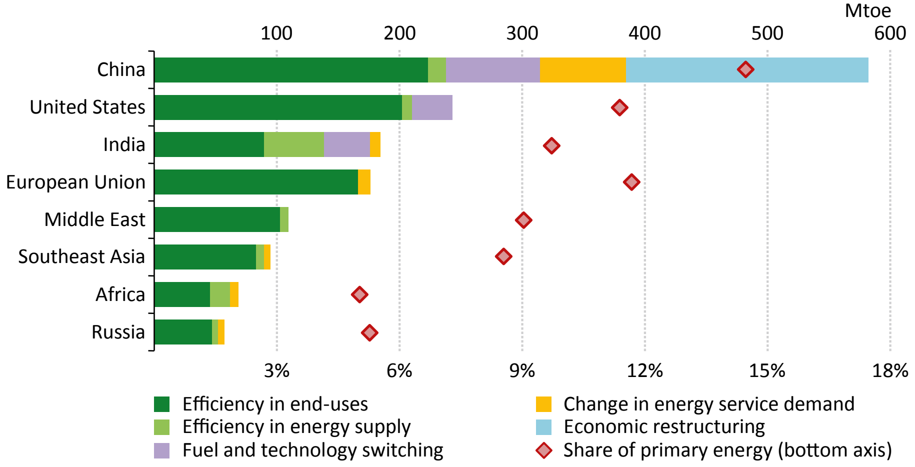
Looking at policy coverage by region, the United States, China and Japan now have the largest coverage, with around 50% of total final energy consumption in all three countries subject to efficiency regulation. Coverage is particularly high for the industry sector in China, while Japan and the United States have high coverage in the buildings and transport sectors. The increase in China's policy coverage has not been confined to industry, but also extends to efficiency standards for lighting, cooling, water heating and cooking. In the United States, the share of coverage increased only slightly between 2005 and 2014 as more regulation for lighting was offset by fast energy demand growth in areas where regulation had only been recently introduced, such as trucks, or where coverage was partial, such as for electrical appliances. In the European Union, efficiency regulation affects only around 20% of energy consumption, mainly due to the absence of specific measures for thermal energy in industry (although the EU Emissions Trading Scheme incentivises energy efficiency improvements) and freight traffic, which together account for 20% of final energy consumption. In many other countries, especially in Africa, but also in Latin America, the Middle East and developing Asia, much can be done to increase the coverage of efficiency regulations.

Outlook for energy efficiency

Primary energy demand in the New Policies Scenario reaches nearly 18 000 million tonnes of oil equivalent (Mtoe) in 2040, an increase of 32% compared with the level in 2013. The projected annual growth rate of 1.0% in primary energy demand to 2040 is significantly less than the 1.9% annual rate for the last 23 years even with similar economic growth rates. Energy efficiency is an important driver underlying the ongoing decoupling of energy demand growth from economic growth, complemented by economic restructuring (especially in China) and the saturation of demand for many energy services, such as personal transport and refrigeration in several world regions. Compared with the Current Policies Scenario, which assumes no new policies, primary energy demand in the New Policies Scenario is about 1 700 Mtoe (or 9%) lower in 2040 (Figure 10.3) (See Chapter 1 and Annex B for more information on assumed policies in both scenarios).

About three-quarters of the difference is due to increased energy efficiency, of which 34% is in the buildings sector, 31% in transport, 23% in industry, 7% in supply-side efficiency gains (power plants, refineries, transmission and distribution) and 3% in agriculture. A further 12% of the differential is from faster economic restructuring in China, as it moves from an investment-led to a consumption-oriented economy. Generally, as the services sector is significantly less energy-intensive than industry, a shift towards a more service-oriented economy leads to energy savings (see Chapter 2). Fuel and technology switching, particularly towards more efficient forms of generation in the power sector, explains 7% of the difference. Though, demand for energy services might be expected to increase in the New Policies Scenario (relative to the Current Policies Scenario), as more energy efficiency leads to lower international fuel prices (Box 10.1), in practice demand declines because of higher end-user prices (related to the removal of fossil-fuel subsidies, increasing CO_2 prices and changes in the fuel mix) contributing 7% to primary energy savings.

Figure 10.3 ▷ Factors contributing to global primary energy savings by region in the New Policies Scenario relative to the Current Policies Scenario, 2040



Box 10.1 ▷ What is the impact of low oil prices on energy efficiency?

Lower energy prices can raise doubts about the economic viability of energy efficiency investments, since lower energy prices reduce the monetary savings associated with energy efficiency gains. Long-lasting low energy prices mean that the payback period for the initial investment may be longer than initially anticipated. Such signs are already visible, with the average newly bought car becoming less efficient in China and fuel intensity stabilising in the United States (see Chapter 3). Lower oil prices lead, in some countries, to lower natural gas prices and consequently to lower electricity prices. Though price changes are, in general, smaller for natural gas and electricity, these can still have an impact on the viability of efficiency measures for equipment running on natural gas or electricity unless performance standards require a certain efficiency level.

In the Low Oil Price Scenario (see Chapter 4), where oil prices rise to only $85 per barrel (bbl) in 2040, as opposed to close to $130/bbl in the New Policies Scenario, cumulative energy efficiency investment from 2015 to 2040 is $0.8 trillion lower than in the New Policies Scenario (or 11% of the additional investment in the New Policies Scenario). As a result of some energy efficiency measures becoming no longer economically viable, 14% of cumulative efficiency savings in the New Policies Scenario (relative to the Current Policies Scenario) are cancelled. Oil demand is pushed up by almost 1 million barrels per day in 2040 due to lower efficiency uptake, almost exclusively from the transport sector. This means that 11% of the efficiency-related oil savings in the New Policies Scenario (relative to the Current Policies Scenario) would be lost. Road transport, particularly passenger cars and trucks, account for the majority of the increased demand as consumers opt for less efficient vehicles to a degree that average fuel consumption for trucks inflates by 2% in 2040 compared with the New Policies Scenario.

In the New Policies Scenario, the largest efficiency-related reduction in primary energy demand relative to the Current Policies Scenario is projected to be realised in China (around 240 Mtoe), as a result of the introduction of CO_2 pricing, full implementation of Industrial Energy Performance Standards and more stringent energy building codes. Energy efficiency savings in India are around 140 Mtoe in the New Policies Scenario, stemming from end-use efficiency gains and significant improvements in the power plant fleet. The OECD region as a whole accounts for almost 40% of global efficiency-related savings, mainly led by the tightening of fuel-economy standards for vehicles, extending efficiency standards for appliances and building codes.

Remaining energy efficiency potential

While energy consumption patterns in the New Policies Scenario look very different from those in the past, as an increasing number of energy efficiency measures are adopted, we estimate that two-thirds of the economic energy efficiency potential remains untapped in the New Policies Scenario over the projection horizon (IEA, 2012). Across all sectors, plenty of energy efficiency measures are available to go beyond the improvements included in the New Policies Scenario; but a range of barriers (including low priority, lack of awareness, fragmentation and limited know-how) and hidden costs (for instance transaction and inconvenience costs), prevent their uptake.

A detailed sector-by-sector and country-by-country analysis shows that economically viable energy efficiency measures can reduce energy consumption by a further 11% in new cars, trucks, motors and other equipment bought in 2030. The additional investment necessary to realise these savings has an average payback period of just two years, four out of five of them having a payback period of less than five years.[6] Unlocking this potential could save energy consumers $86 billion in 2030 alone.

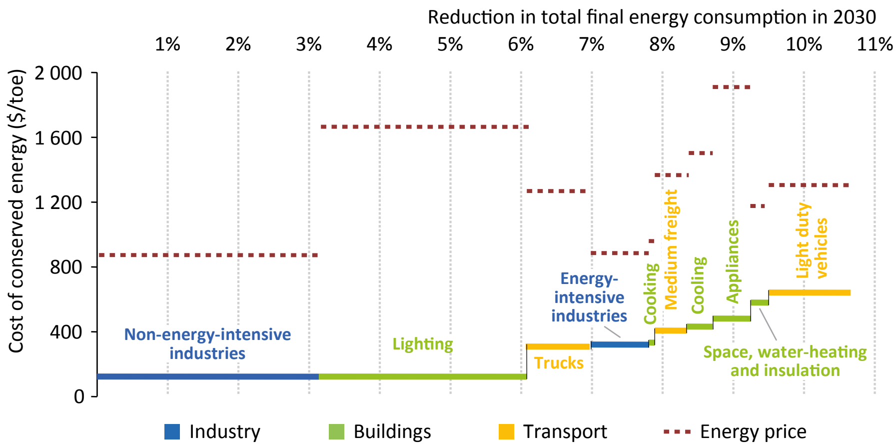
The largest potential to reduce energy consumption is found in non-energy-intensive industries, which account for around two-thirds of the projected industrial energy consumption of new equipment in 2030. They hold such a large untapped potential due, in part, to low awareness, as energy has a low share of their total production costs. Exploiting this potential could save these industries $17 billion in 2030 alone, with an average payback period of under two years. In the buildings sector, more energy-efficient lighting offers large potential savings since their replacement rate in a given year is high.[7] Increasing energy efficiency in the buildings sector beyond what is already adopted in the New Policies Scenario could save energy consumers over $43 billion and reduce energy consumption by 26 Mtoe in 2030 alone. In the transport sector, energy spending could be

6. The payback period is calculated as the additional investment divided by the annual undiscounted energy savings.

7. Viewed over a longer period, the opportunities to moderate energy consumption via more stringent building codes are even far greater by improving building envelopes (walls, roof and foundation) and switching to more energy-efficient boilers and cooling systems.

reduced by $21 billion in 2030; most of this potential (around half) is realised by switching to more energy-efficient trucks. In order to realise the large existing energy efficiency potential, further policy action is needed in order to overcome barriers or bring down payback periods even further.

Figure 10.4 ▷ Cost of conserved energy of the untapped global energy efficiency potential in the New Policies Scenario, 2030



Notes: Dashed dark red lines indicate weighted average energy prices. The reduction in total final energy consumption is calculated for energy demand from new energy-consuming equipment purchased in 2030.

Another metric to look at the cost-effectiveness of energy efficiency measures is the cost of conserved energy, i.e. how much does it cost to save a unit of energy. A measure is considered economical when the cost of conserved energy is less than the price of the energy used. On average, the cost of conserved energy of efficiency measures not realised in the New Policies Scenario is only one-fifth of the respective energy price. This means that every dollar invested in improving energy efficiency would save five dollars (Figure 10.4).[8] Saving energy in lighting looks economically most attractive as the cost of conserved energy is comparably low, while the energy price (almost exclusively electricity) is relatively high. The largest unrealised energy efficiency potential exists in China, United States and India, where the average cost of conserved energy is below $220/toe and thus far lower than, for example, in Korea or Europe, where the average cost of conserved energy is above $350/toe.

8. The cost of conserved energy is defined as the additional investment ($) per unit of saved energy per year (toe) annualised over the lifetime of the equipment using a discount rate of 10%.

Trends by sector

Buildings

The buildings sector accounts currently for around one-third of total final consumption and more than half of electricity demand. Almost three-quarters of the energy consumed is in households, with the rest distributed across different uses in the services sector, including public buildings, offices, shops, hotels and restaurants. Though energy consumption in the buildings sector continues to grow in the New Policies Scenario, the rate is lower than in the past, mostly as a consequence of stricter building codes that constrain energy demand for space heating. Energy demand in the residential sector grows at half the annual growth rate of the services sector, as the population starts to decline, during the projection period, in China, Russia and several OECD countries. Energy efficiency savings in the New Policies Scenario, compared with the Current Policies Scenario, total 250 Mtoe in 2040 (Table 10.3). The largest savings stem from electricity and are mainly a result of the increasing global coverage of MEPS for appliances and lighting.

Table 10.3 ▷ Final energy consumption and CO_2 emissions in buildings in the New Policies Scenario (Mtoe)

	Consumption			Change versus Current Policies Scenario: Total		Change versus Current Policies Scenario: Due to efficiency	
	2013	2025	2040	2025	2040	2025	2040
Coal	128	116	92	-7	-13	-2	-3
Oil	317	273	231	-21	-43	-8	-13
Gas	627	699	775	-36	-92	-25	-60
Electricity	888	1 148	1 544	-74	-167	-59	-144
Heat	152	159	168	-5	-12	-5	-12
Other renewables*	134	195	288	13	51	-1	-5
Fuelwood, charcoal**	759	722	600	-5	-11	-4	-11
Total	**3 004**	**3 312**	**3 697**	**-134**	**-287**	**-104**	**-248**
CO_2 emissions (Gt)***	8.5	8.7	9.4	-1.0	-2.6	-0.6	-1.3

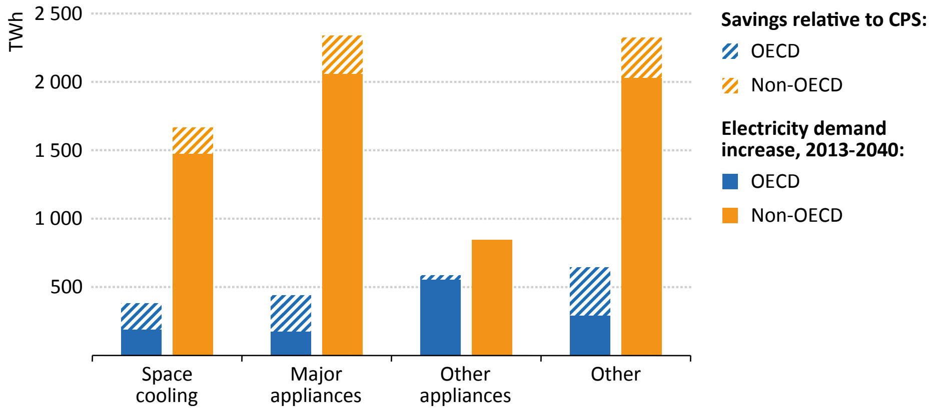
* Other renewables include wind, solar, geothermal energy and the modern use of biomass. ** This also includes the use of animal dung and agricultural residues in stoves with very low efficiency. *** CO_2 emissions include indirect emissions from electricity generation and energy use for heat. Gt = gigatonnes.

Energy demand trends in the buildings sector are not uniform, diverging by fuel and by region. Today, electricity accounts for 30% of energy consumption in buildings, but it accounts for more than 40% by 2040, driven by the uptake of electric appliances and cooling systems, an expanding services sector and a growing population with access to electricity in developing countries. OECD countries account for only 16% of the growth in global electricity demand by 2040. Most OECD countries have already phased out the use of the least efficient incandescent light bulbs and are promoting light-emitting diodes (LED), decreasing energy consumption per floor area for lighting by almost 50%, even though halogen lamps, which are inefficient, are still allowed in most of these countries. Moreover, the ownership rate for major household appliances (such as refrigerators and washing machines) in OECD countries is almost saturated and, even as the size of some of these appliances increases over time, energy efficiency programmes mitigate future electricity demand growth. Policies, like the EU's Ecodesign Directive, the US energy efficiency standards and the voluntary Energy Star Program or the Top Runner Program in Japan, lower the average unit energy consumption of appliances sold in 2040 by 6-25%, compared with models on the market today. Most of the electricity growth in OECD countries comes from smaller appliances, such as set-top boxes or office equipment, which, in most countries, currently are not subject to stringent energy efficiency standards. Only a few countries have started to regulate these appliances, such as the EU which has included simple set-top boxes in its Ecodesign Directive since 2009 or the United States which has included some electronic devices and office equipment in its Energy Star Program.

The growth in electricity demand takes place mainly in developing countries, most of which face different climatic conditions from those in most OECD countries, meaning that many have significantly less need for space heating but rising demand for space cooling (Figure 10.5). Unlike OECD countries, the ownership rate of large appliances and cooling systems is still very low in some developing countries, but it is expected to grow as access to electricity and affluence increase. Some countries have started to implement MEPS: the Bureau of Energy Efficiency in India has implemented 21 MEPS (though only four of these are mandatory), while some African countries, such as Ghana, have started to develop standards for major appliances and light bulbs (see Chapter 2). Total energy consumption increases over time as rising living standards encourage people to buy more and larger appliances and to switch from fans to air conditioners, which can consume up to ten-times more electricity (see Chapter 12). However, additional efficiency policies included in the New Policies Scenario, relative to the Current Policies Scenario, save around 1 000 terawatt-hours (TWh) of electricity consumption for appliances and cooling systems globally (60% of total efficiency-related electricity savings). These savings are shared equally between OECD and non-OECD countries.

Next to electricity, natural gas consumption in buildings sees the second-highest efficiency savings in the New Policies Scenario. Currently, almost 70% of natural gas consumption in the buildings sector (430 Mtoe) arises in OECD countries, with around three-quarters being used for space heating. The use of natural gas in buildings in the OECD decreases by 0.1% annually from today to 2040, thanks to MEPS for new space and water heating equipment in some countries (the EU's Ecodesign Directive will include water boilers from 2015) and also to energy-related building codes. As a consequence, space heating needs per square metre in new buildings in 2040 are 25-70% lower (depending on the country), compared with the level of currently constructed buildings. In northern continental countries, 75-90% of the current building stock will still be standing in 2050; as a consequence, more emphasis should be put on more extensive renovation to reduce energy consumption even more (IEA, 2014b). The use of more efficient boilers decreases water heating needs per capita by up to around 15% compared with today's level. By 2040, additional policies taken into account in the New Policies Scenario save almost 45 Mtoe in OECD countries, relative to the Current Policies Scenario, with 85% of the natural gas savings being made in space heating demand. In developing and emerging countries, natural gas consumption for cooking, water heating and, to a lesser extent, space heating (mainly in China) increases, as more urban households are connected to a gas network.

Figure 10.5 ▷ Electricity demand growth and savings in buildings by equipment and region in the New Policies Scenario, 2013-2040



Notes: Major appliances include refrigerators and freezers, cleaning machines (washing machines, dryers and dishwashers), televisions and computers. Other appliances cover all other appliances, such as vacuum cleaners, kettles and hair dryers. Other includes other end-uses (lighting, space and water heating and cooking).

In OECD countries, a decline in coal and oil use for space and water heating has already been observed and their use is reduced further in the years ahead, mainly due to improvements in building envelopes and fuel switching to gas, electricity and renewables (bioenergy and solar). In developing and emerging countries, coal and biomass are the only fuels used in the buildings sector for which demand decreases from today to 2040. Both fuels are mainly used for cooking and space heating (mainly in China), to a lesser extent, for water heating. Most of the population in rural areas gains access to clean cooking through improved cookstoves over the projection period. These still use biomass, but require less input, due to higher efficiency; they also reduce air pollution (see Chapter 2). Oil consumption in buildings in non-OECD regions increases only slightly as two trends cancel each other out: urban households switch to natural gas, while rural households gain access to affordable liquefied petroleum gas for cooking and heating, improving indoor air quality.

Transport

The transport sector currently accounts for 28% of total final energy consumption and almost two-thirds of oil consumption. In the New Policies Scenario, energy consumption in the transport sector increases by 1.1% per year to 2040, which is significantly less than in the Current Policies Scenario, where demand grows at an annual rate of 1.5% (Table 10.4). The more subdued demand growth mainly results from the additional energy efficiency policies taken into account in this scenario, including announced but not yet fully implemented measures, such as the recently announced extension of fuel-economy standards beyond 2018 for heavy-duty vehicles in the United States. But the savings also originate, to some extent, from the accelerated phase-out of fossil-fuel subsidies and switching to highly efficient electric vehicles. Natural gas, electricity and biofuels consumption see the largest relative growth in the transport sector, but for different reasons: natural gas in the form of liquefied natural gas becomes a viable alternative for freight vehicles and for shipping in some regions; electric vehicles slowly gain market share in the passenger vehicle market; and measures to reduce CO_2 emissions increase biofuels consumption.

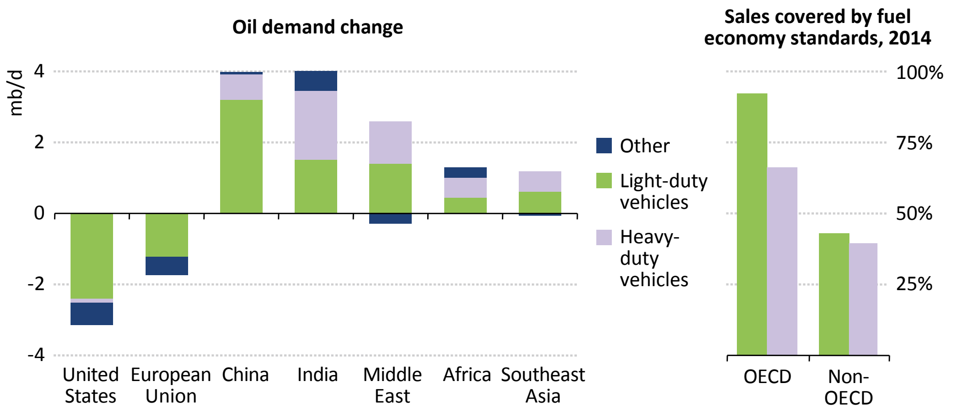
Table 10.4 ▷ Final energy consumption and CO_2 emissions in transport in the New Policies Scenario (Mtoe)

	Consumption			Change versus Current Policies Scenario			
				Total		Due to efficiency	
	2013	2025	2040	2025	2040	2025	2040
Coal	4	2	1	0	0	0	0
Oil	2 357	2 657	2 900	-135	-496	-82	-312
Gas	96	144	231	30	71	-1	-7
Electricity	26	39	77	1	20	-1	-3
Biofuels	65	123	198	16	27	-4	-20
Total	**2 547**	**2 965**	**3 408**	**-88**	**-377**	**-88**	**-342**
CO_2 emissions (Gt)	7.3	8.3	9.3	-0.3	-1.3	-0.3	-1.0

Road transport is currently responsible for three-quarters of total energy consumption in the transport sector, the rest of the demand originating from aviation, navigation, gas pipelines and rail. Within road transport, passenger light-duty vehicles (PLDVs) account today for almost 60% of energy consumption and about 65% of energy efficiency savings in 2040, relative to the Current Policies Scenario.

The outlook to 2040 for oil consumption in the transport sector in the New Policies Scenario varies widely across regions. Oil consumption in OECD countries declines by 28%, while it increases by 80% in non-OECD countries. In OECD countries, energy efficiency is the main driver behind the fall in oil consumption, as more than 90% of cars are covered by fuel-economy standards. Efficiency improvements in cars in the OECD account for almost 30% of total transport-related savings (or 1.7 million barrels per day [mb/d]) in 2040, relative to the Current Policies Scenario. In non-OECD countries, four out of ten cars sold are currently covered by fuel-economy standards and their further strengthening saves 2.4 mb/d relative to the Current Policies Scenario. Nevertheless, a large increase in car sales leads to much higher oil consumption (Figure 10.6).

Figure 10.6 ⊳ Change in oil demand in road transport in the New Policies Scenario, 2013-2040



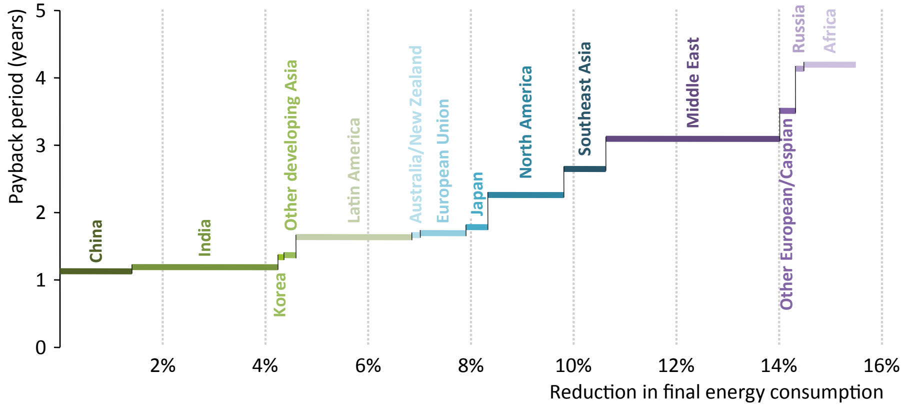
Notes: Light-duty includes passenger and commercial vehicles. Other includes buses and two- and three-wheelers.

Total oil consumption in road transport increases by 7 mb/d in the New Policies Scenario, and more than two-thirds of this increase can be attributed to heavy-duty vehicles, where efficiency policy coverage is significantly lower than for light-duty vehicles. Only close to half of all heavy-duty vehicle sales are currently covered by some form of fuel-economy standards, as only a handful of countries have implemented policies in this area. As China is the only country outside the OECD that has an efficiency regulation for heavy-duty vehicles in place or announced, and the demand for freight traffic increases significantly, oil consumption from heavy-duty vehicles in developing and emerging countries doubles to 2040. Fuel-economy standards in trucks account for 17% of the savings (or about 0.9 mb/d) in the New Policies Scenario, compared with the Current Policies Scenario.

Significant potential exists to increase efficiency in heavy-duty vehicles further, including through operational measures (such as idling reduction, traffic management) and technical measures (such as driver support systems or acceleration control). Some countries already have a clearly stated aim to exploit this potential, while others are considering whether to do so. In 2015, the United States issued a draft extension of greenhouse gas and fuel-economy standards for medium- and heavy-duty vehicles to 2027. In China, fuel-consumption limits for heavy-duty commercial vehicles have been applied to all sales from 1 July 2015. Both India and the European Union are currently in the process of setting up test protocols and technical studies and are expected to come forward with final regulations by 2017.

Looking at economically viable efficiency measures not exploited in the New Policies Scenario, the average investment to tap the remaining potential for energy efficiency improvements in trucks has short payback periods. Our estimates indicate that switching to more energy-efficient trucks could cut global energy spending by $7 billion in one year (2030) (Figure 10.7). Such a switch would reduce demand for oil by 124 thousand barrels per day (kb/d), corresponding to a 15% reduction in the energy use in new trucks sold in that year. The average payback period of the investment is just over two years, and in all regions in the world the payback period is less than five years. Many truck companies, however, are relatively small in size and operate under tight budget constraints, with acceptable payback periods limited to no more than two years.

Figure 10.7 ▹ Payback period associated with untapped energy efficiency potential in trucks in the New Policies Scenario, 2030



Note: The reduction in total final energy consumption concerns energy demand from new energy-consuming trucks purchased only in 2030.

10

Industry

Today, energy demand in industry is higher than that of the buildings or transport sectors, and accounts for almost 40% of total final energy consumption.[9] Energy demand in industry has increased by 1.8% per year since 1990, but this is anticipated to slow to 1.3% per year over the projection period. This is due not only to energy efficiency, but also to significantly lower demand growth for energy-intensive industrial goods: since 1990, worldwide steel and cement output has grown by 3.4% and 5.6% per year, respectively, but average growth to 2040 slows to 0.7% per year for steel and 0.3% per year for cement in our projections, mainly as Chinese production experiences an absolute decline. This development occurs as a consequence of demand saturation and a shift from investment-led to consumption-led economic growth. In the New Policies Scenario, energy demand in industry increases to 4 910 Mtoe in 2040, which is 310 Mtoe (or 6%) less than in the Current Policies Scenario. About two-thirds of the savings can be attributed to energy efficiency, particularly in non-energy-intensive industries (Table 10.5).

9. In this chapter, energy demand in industry includes blast furnaces, coke ovens and petrochemical feedstocks.

Table 10.5 ▷ Final energy consumption and CO_2 emissions in industry in the New Policies Scenario (Mtoe)

	Consumption			Change versus Current Policies Scenario			
				Total		Due to efficiency	
	2013	2025	2040	2025	2040	2025	2040
Coal	1 112	1 199	1 232	-38	-92	-15	-45
Oil	679	825	921	-11	-29	-9	-21
Gas	641	858	1 088	-19	-61	-19	-59
Electricity	711	934	1181	-34	-91	-21	-41
Heat	132	146	143	-5	-18	-3	-9
Bioenergy*	195	255	349	-7	-18	-8	-18
Total	**3 471**	**4 218**	**4 914**	**-114**	**-310**	**-76**	**-194**
CO_2 emissions (Gt)**	11.1	12.1	12.9	-0.6	-2.2	-0.3	-0.6

* Includes other renewables. ** CO_2 emissions include indirect emissions from electricity and heat.

Though energy-intensive sectors (steel, cement, chemicals, paper and aluminium) account for almost two-thirds of total industry energy demand today, they are responsible for only around one-third of the energy efficiency savings achieved from 2015-2040 in the New Policies Scenario, relative to the Current Policies Scenario. The share is relatively low because most of the available efficiency gains in energy-intensive industries have either already been realised or are already built into the Current Policies Scenario. Additionally, most of the policies currently under consideration (and, therefore, reflected in the projections of the New Policies Scenario) target smaller energy consumers and energy efficiency gains in energy-intensive industries are in general more limited compared with those available in less energy-intensive industries. The largest remaining energy savings potential lies in SMEs, where energy normally does not account for a large share of expenditures, often meaning that awareness of energy costs and potential savings is relatively low. Some policy measures have recently been put in place to exploit the potential in these companies, including incentives for SMEs to undertake energy audits as part of the EU's Energy Efficiency Directive and the cluster approach pursued by the Bureau of Energy Efficiency in India, supplementing longer standing programmes, such as the US Industrial Assessment Centers.

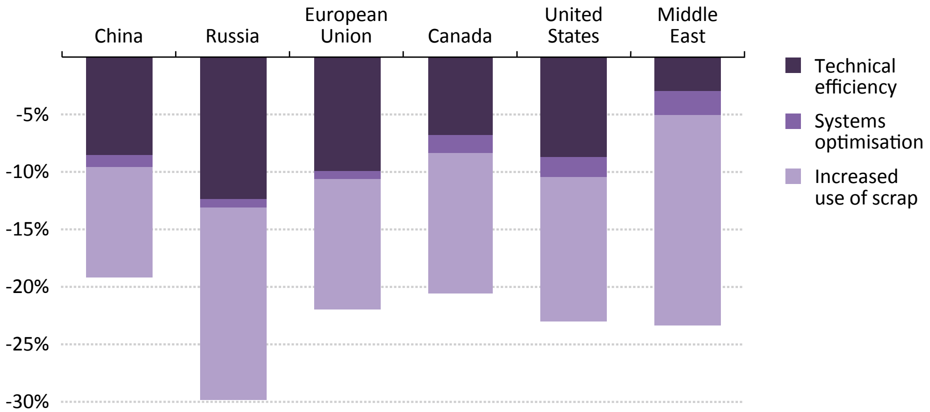
The aluminium sector is not a large industrial energy consumer, accounting for only 3% of total industrial energy demand, but primary aluminium production is highly electricity-intensive, which means that energy-related expenditure makes up a large part of overall production costs.[10] This creates a strong incentive to continuously exploit economically viable efficiency potential. Despite the relatively small size of the sector, electricity consumption in the global aluminium industry amounts to around 780 TWh (more than

10. This analysis focuses on the aluminium sector as one energy-intensive sector. Previous *WEO* editions covered the petrochemical, cement and steel industries (IEA, 2013; 2014c).

Italy's and France's electricity consumption combined). Among all the major energy-intensive industries, aluminium production is expected to see one of the fastest rates of growth, more than doubling from today to 2040. The most energy-intensive production steps are the refining of alumina (aluminium oxide), where alumina is produced from bauxite, and aluminium smelting, where alumina is reduced to aluminium. The energy intensity of aluminium production can be lowered both by improving energy efficiency and by increasing the use of scrap. Aluminium production from scrap requires around 10% of the energy input of primary aluminium production, including additional energy that is required for scrap cleaning and alloy dilution.

In the New Policies Scenario, energy intensity in the aluminium industry is reduced by 1.0% per year from 2013 to 2040, 60% of this decline being attributable to the higher use of scrap metal. Over the projection period, more and more post-consumer scrap becomes available (as aluminium products arrive at the end of their lifetime), and scrap from the production process increases as aluminium production rises (see section below on material efficiency). The decline in the energy intensity of overall aluminium production is particularly marked in those regions that are currently dominated by primary production (Figure 10.8). Most of the efficiency savings in electricity consumption can be linked to improved smelting operations and a gradual shift towards the most efficient technologies for aluminium smelting, though high investment costs are a hurdle. In regions with relatively recent capacity additions, such as the Middle East and parts of China, most facilities already incorporate the latest technologies. In alumina refining, the Bayer process is the most energy efficient, though some more energy-intensive variations of this process are used in region with low quality of domestic bauxite. Energy savings can be achieved, either by importing bauxite with lower silica content or by switching to a version of the Bayer process that allows for lower quality input.

Figure 10.8 ▷ Reduction in energy intensity in aluminium production by contributing factor in the New Policies Scenario, 2014-2040

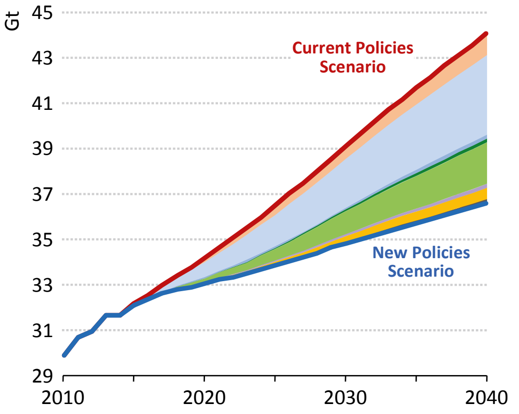


Note: These regions accounted for almost 75% of global primary and secondary aluminium production in 2013.

Avoided CO_2 emissions

In the New Policies Scenario, global CO_2 emissions from fossil-fuel combustion increase from 31.6 gigatonnes (Gt) to 36.7 Gt in 2040, which corresponds to an annual growth rate of 0.5%, which is both less than the Current Policies Scenario (1.2% per year) and less than over the past 25 years (1.9% per year) (Figure 10.9). One of the most important factors in slowing future emissions growth is energy efficiency: it is responsible for half of all cumulative emissions savings (including indirect savings from lower electricity demand) in the New Policies Scenario, relative to the Current Policies Scenario. The largest reduction of CO_2 emissions attributable to demand-side energy efficiency is from buildings (45%), and is a result of stricter building codes and the introduction and tightening of energy performance standards for appliances and heating equipment. The transport sector accounts for 34% of efficiency-related CO_2 emissions savings, followed by the industrial sector with 21%. Supply-side efficiency gains, including improvements in power plants, transmission and distribution and refineries, complement end-use efficiency gains and represent 3% of emissions reduction in 2040.

Figure 10.9 ▷ World energy-related CO_2 emissions abatement in the New Policies Scenario relative to the Current Policies Scenario



CO_2 abatement	2025	2040
Energy service demand	16%	12%
End-use efficiency	53%	48%
Supply efficiency	3%	3%
Fuel and technology switching in end-uses	2%	2%
Renewables	19%	24%
Biofuels	2%	2%
Nuclear	4%	7%
CCS	1%	2%
Total (Gt CO_2)	**2.6**	**7.5**

Note: CCS = carbon capture and storage.

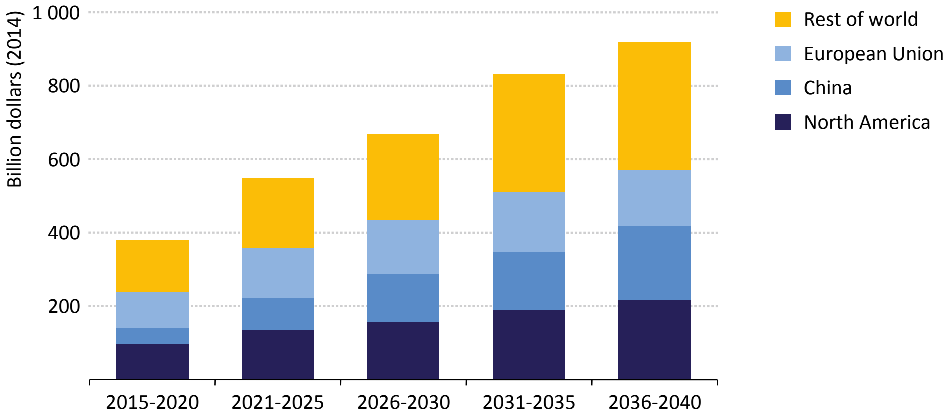
Investment

In the New Policies Scenario, annual investment in energy efficiency more than doubles from $380 billion over the next five years to $920 billion in 2035-2040 (Figure 10.10).[11] This is the result both of more sales of energy-consuming equipment and an increasing number of policies and market forces that make end-use devices more efficient, but at an increased

11. Energy efficiency investment denotes the expenditure on a physical good or service which delivers the equivalent energy service and leads to future energy savings, compared with the energy demand expected otherwise.

cost. Currently, energy efficiency investment is dominated by the transport sector, which accounts for 60% of all investment, while buildings represent 36% and industry 4%. In terms of geographical split, energy efficiency investment over the next five years is dominated by only three regions: almost two-thirds of all investment is concentrated in North America, the European Union and China. This reflects both the magnitude of their current energy consumption and the extent of their energy efficiency policies. In the long-term, the largest additional efficiency investment occurs in China, due to ambitious initiatives to mitigate energy demand growth, and in North America, where several new efficiency policy measures have recently been implemented. Other regions, including India, the Middle East, Africa and Latin America, also see a significant increase in efficiency investment, mainly as a consequence of wealthier societies adopting a higher number of energy-consuming devices.

Figure 10.10 ▷ Average annual investment in energy efficiency by region in the New Policies Scenario



Note: This excludes energy efficiency investment in international aviation and shipping.

Focus: material efficiency in energy-intensive industries

Introduction

For many decades, energy efficiency has delivered significant benefits, by increasing energy security, reducing environmental harm and enhancing competitiveness, particularly in energy-intensive industries. Mainly driven by the importance of energy costs for these industries, efforts have been undertaken in the past to reduce their energy needs: today, one tonne of steel is, on average, produced with around 40% less final energy than in 1980, while cement requires at least 40% less, paper uses around 20% less and primary aluminium uses 14% less. These already substantial improvements in energy efficiency do not mean that there is no room left for further efficiency improvements; but they become more limited as energy consumption approaches its technical limits.

Energy efficiency in steel and cement production increases by merely 10% to 2040 in the New Policies Scenario, while the equivalent number is 13% for aluminium and 14% for paper. The production of five main energy-intensive products (steel, cement, plastics, paper and aluminium) currently accounts for almost half of global industrial energy consumption, and as production of most of these materials is anticipated to grow substantially, this raises the question of how the related energy demand growth and increase in CO_2 emissions can be further mitigated.

One possible way to mitigate the impact of the growth in the demand for materials on energy demand is to improve material efficiency – delivering the same material service with less overall production of materials. Promoting a higher degree of efficiency in the value chain of production and in the use phase, while making sure that the same service is delivered to the consumer, can take several different forms: reducing the weight of products, while delivering the same service (light-weighting), reducing yield losses in the manufacturing process, finding alternative uses for fabrication scrap without re-melting, re-using and recycling components, creating longer-lasting product components; and using products more intensely or at higher capacity (Allwood and Cullen, 2012). Reducing the demand for energy-intensive materials or product recycling lowers energy demand. Typical final energy savings from recycling are up to 90% for aluminium, around 75% for steel and around 80% for plastics (including feedstock savings). Improving the efficiency of materials use is not new: fabrication yields are continuously improving, global recycling rates are increasing and products are being light-weighted.

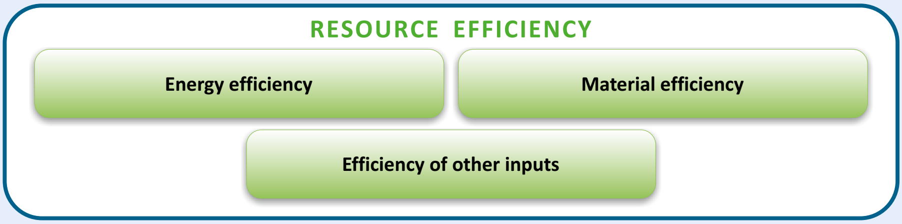
Promoting a higher degree of energy efficiency and material efficiency is related, as both promote a higher degree of efficiency along the value chain of production. The difference between energy efficiency and material efficiency is the production input (Box 10.2). Material efficiency, in most cases, is complementary to energy efficiency, but the two reinforce each other. A car that contains less steel not only avoids the energy associated with excess steel production but also weighs less, leading to increased fuel efficiency during use. On the other hand, trade-offs also exist between energy and material efficiency: for example, extending the lifetime of steel-containing appliances means that the take-up of more efficient devices by consumer purchases will be later.

Attention from policy-makers for the topic of material efficiency and (more broadly defined) resource efficiency has increased in recent years. G7 leaders declared that resource efficiency is important for enhancing industrial competitiveness, securing economic growth and employment, and for the protection of the environment. This fostered the launch of G7 Alliance on Resource Efficiency as a forum in which to share knowledge and promote best practice in order to support innovation (G7, 2015). In 2000, Japan implemented the Basic Act for Establishing a Sound Material-Cycle Society, which included targets for resource productivity, waste reduction and recycling. Progress on these indicators has been tracked since then and additional legislation has been put in place to strengthen waste management, collection, recycling and re-use, and to change public procurement procedures in favour of buying eco-friendly goods.

Box 10.2 ▷ Resource efficiency, energy efficiency and material efficiency – what is the difference?

Resource efficiency, as it is most commonly defined, is the value that arises from the use of resources, including all resources in the production process (i.e. energy, raw materials, land, water and, indirectly, emissions). Reducing the wasteful use of resources helps to stimulate economic growth, alleviate poverty, create jobs and reduce environmental damage. By overcoming barriers to cleaner production practices, companies and households save money and free-up resources which can be put to more productive use thereby supporting overall economic growth and job creation (UNEP, 2010). Energy efficiency and material efficiency are, next to the efficient use of land and water resources, critical elements of a comprehensive effort to increase resource efficiency and thus preserve resources (Figure 10.11).

Figure 10.11 ▷ Components of resource efficiency



Improving energy efficiency can be defined as using less energy to provide the same level of service. For example, a light-emitting diode uses less electricity than an incandescent bulb to produce the same amount of light, so the LED is considered more efficient. Improving material efficiency, on the other hand, means providing a constant level of material services with less production of materials. For example, materials input can be saved by reducing the weight of a plastic bottle, without damaging durability or functionality.

In 2010, the European Union published the Europe 2020 Strategy with a focus on resource efficiency and is due to publish a circular economy strategy[12] in late 2015 as part of a growth strategy for a sustainable economy. One of the measures is to include durability and recyclability requirements for appliances in the Ecodesign Directive. Moreover, the European Commission proposes to amend several waste-related EU directives in order to increase targets for the recycling of different waste streams; among others, a target to recycle 45% of plastic packaging by 2020 is proposed, rising to 60% by 2025.

12. A more circular economy aims to re-use, repair, refurbish and recycle existing materials and products to a higher degree.

China published its first strategy on a circular economy in 2005 (the most recent one dates from 2013) and included in the 12th Five-year Plan for the first time a goal to increase resource productivity by 15% over the period. One of the focus areas in China is the building of industrial parks and the achievement of industrial symbiosis among different industries (Wen and Meng, 2015). According to these laws and policies, enterprises and public organisations are to establish management systems and take measures to reduce resource consumption and waste discharge, and to improve waste reutilisation and recycling levels. In 2011, China reduced or completely eliminated the value-added tax on goods produced from recycled materials, in order to promote a circular economy.

While material efficiency options are already pursued today to some extent, various barriers exist that prevent large-scale uptake. Cost structures and taxation regimes currently favour the substitution of materials for labour, which reduces the incentive to use materials more efficiently. In the OECD, for example, the tax burden on labour costs in 2014 was 36% (OECD, 2015). Likewise, industries that use energy-intensive materials as an input, often fail to give material efficiency priority, partly due to the lack of incentives and know-how, the existence of conflicting standards and the diversity of material efficiency options. Awareness among consumers, producers and decision-makers needs to be increased to encourage them to look beyond energy and to demand the inclusion of durability, recyclability, adaptability and the possibility for deconstruction and component re-use in the design of products.

Method

The New Policies Scenario – our central scenario – provides for the effects of current energy policies and those that are under discussion, but does not exploit the full potential of material efficiency. This does not mean that improvements in material efficiency are excluded from the New Policies Scenario: some material efficiency policies are already in place and some are set to be implemented with increased vigour. Global recycling, for example, increases from today's 58% to 59% in 2040 for paper and from 13% to 15% for plastics, while the share of post-consumer scrap in steel production increases from 16% to 26%. Despite these efforts, opportunities for greater material efficiency remain largely untapped. To test the potential, we have developed a Material Efficiency Scenario, based on a detailed analysis of five of the most important energy-intensive industries – steel, cement, plastics, paper and aluminium. These five sectors currently consume 1 660 Mtoe (18% of total final energy consumption or almost half of total industrial energy consumption[13]) and are responsible for 7.0 Gt of energy-related and process-related CO_2 emissions (20% of total energy- and process-related CO_2 emissions).

13. Including energy consumption from the entire chemical industry (beyond just plastics) would lift that share to two-thirds.

Table 10.6 ▷ Overview of material efficiency strategies in selected sectors in the Material Efficiency Scenario

Sector	Strategy	Details
Steel	Increase recycling	Collection rates of post-consumer scrap increase from 83% in the New Policies Scenario (NPS) to 94% in the Material Efficiency Scenario (MES) by 2040.
	Increase yield rates	Manufacturing yield rates increase from 85% in the NPS to 89% by 2040 and semi-manufacturing yield rates increase from 84% in the NPS to 88% in the MES by 2040.
	Re-use	Use of post-consumer scrap to directly feed into steel manufacturing increases from 0% in the NPS to 17% in the MES by 2040.
	Light-weighting and more intense use	Long-term saturation levels of the steel stock (i.e. the amount of steel embodied in all products in use) decrease by 6% compared with the NPS as a consequence of light-weighting, for example in transport, and more intense use of steel products, such as in buildings or vehicles.
	Scrap diversion	Diversion of manufacturing scrap to other steel uses without re-melting reaches 9% by 2040 from 0% in the NPS.
	Lifetime extension	Extend the average lifetime of steel components from 51 years in the NPS to 60 years in the MES.
Cement	Re-use and more intense use	Re-use concrete components and use concrete more intensely in buildings, which decreases demand by 5% by 2040 in the MES vs. the NPS.
	Reduce clinker ratio	Reduce the clinker-to-cement ratio through an increase in alternative materials (e.g. fly ash) from 0.67 in 2040 in the NPS to 0.66 in the MES.
Plastics	Increase recycling	Increase recycling rates for plastic products, particularly packaging, from 15% in the NPS to 30% in the MES by 2040, assuming that recycling leads to polymer substitution in two-thirds of the cases.
	Light-weighting and more intense use	Reduce the demand for plastic products by 5% compared with the NPS by decreasing the weight of plastic packaging and through the re-use of plastic products.
Paper	Recycle	Increase the global recycling rate of post-consumer paper (currently 58%) from 59% in the NPS to 75% in the MES by 2040.
	Light-weighting	Reduce the demand for paper by decreasing the weight of office paper from 80 grammes per square metre (g/m^2) in the NPS to 70 g/m^2 and that for newspaper from 45 g/m^2 to 42 g/m^2.
Aluminium	Increase recycling	Collection rates of post-consumer scrap increase from 69% in the NPS to 87% in the MES by 2040.
	Increase yield rates	Manufacturing yield rates increase from 82% in the NPS to 92% by 2040 and semi-manufacturing yield rates increase from 69% in the NPS to 76% in the MES by 2040.
	Re-use	Use of post-consumer scrap to directly feed into aluminium manufacturing increases from 0% in the NPS to 19% in the MES by 2040.
	Light-weighting and more intense use	Long-term saturation levels of the aluminium stock decrease by 8% in the MES compared with the NPS as a consequence of light-weighting, e.g. transport equipment, and more intense use of aluminium products.
	Scrap diversion	Diversion of manufacturing scrap to other aluminium uses without re-melting reaches 5% by 2040 in the MES from 0% in the NPS.
	Lifetime extension	Extend the average lifetime of aluminium components from 26 years in the NPS to 29 years In the MES.

Sources: Allwood, Cullen, and Milford, 2010; Cullen and Allwood, 2013; Gutowski, et al., 2013; Liu, Bangs and Müller, 2013; Milford, et al., 2013; Pauliuk, et al., 2013; US DOE, 2015; Hestin, Faninger and Milios, 2015; Hekkert, et al., 2002; and IEA analysis.

The core assumption in the Material Efficiency Scenario is that policies are strengthened or put in place to realise the potential of currently known material efficiency measures. In order to assess this potential, we determined, in consultation with leading researchers in the area and the respective industry associations, the material efficiency potential of each energy-intensive sector that might realistically be exploited over the course of the projection period to 2040, without changing the material service (Table 10.6). The scope of the study is limited to materials and energy demand within the respective industry sectors. It does not analyse the implications on energy consumption upstream, in mining or the transportation of materials, nor the consequences for downstream energy consumption, e.g. from more efficient lighter cars.[14] Nor does the study analyse the potential for energy savings from substituting materials, e.g. using plastics for metals.

To carry out this analysis, we have made use of the technological and industry-specific detail of the World Energy Model. For the steel and aluminium sector, we have developed materials flow models to assess future demand and the amount of scrap metal available (Liu, Bangs and Müller, 2013; Pauliuk, Milford and Allwood, 2013; Cullen and Allwood, 2013; Cullen, Allwood and Bambach, 2012). For the plastics sector, we have developed a module to calculate future demand for thermal energy and feedstock for the most important thermoplastics, distinguishing between primary plastics and recycled plastics production. For the paper and cement sector, we made use of our existing information on pulp production and paper product types, and on the cement production processes and the potential to use clinker alternatives.

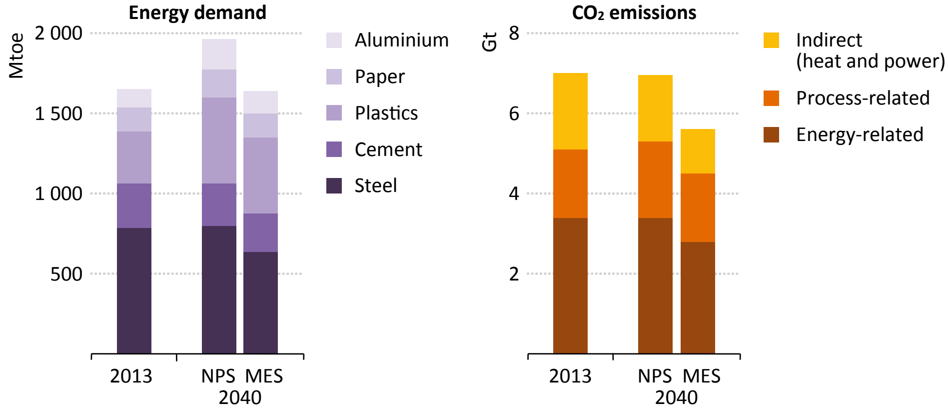
Impact on energy-intensive sectors

In the Material Efficiency Scenario, the energy demand of the five large energy-intensive sectors, accounting for almost half of industrial energy demand today, reaches 1 640 Mtoe in 2040 – a reduction of 330 Mtoe (17%) relative to the New Policies Scenario (Figure 10.12). In contrast to the New Policies Scenario, where energy demand grows continuously by 0.6% annually to 2040, energy demand in the Material Efficiency Scenario peaks before 2025 and then declines to 2040, to end up slightly below the 2013 level. Exploiting all the economically viable energy efficiency potential in the five industrial sectors would save around 150 Mtoe (7%) in 2040, relative to the New Policies Scenario. Consequently, material efficiency could deliver larger energy savings in energy-intensive industries than energy efficiency.

In terms of CO_2 emissions, the energy-intensive industries currently emit around 7.0 Gt, with 1.7 Gt as indirect emissions from electricity consumption and another 1.7 Gt as process-related emissions from clinker production, feedstock-related emissions in petrochemicals and emissions from primary aluminium production. CO_2 emissions in the Material Efficiency Scenario in 2040 are 20% lower relative to the New Policies Scenario. Reflecting underlying energy trends, CO_2 emissions peak around 2020 in the Material Efficiency Scenario and decline to 2040, saving 1.4 Gt compared with today.

14. However, indirect CO_2 emissions from electricity and heat consumption are included.

Figure 10.12 ▷ Energy demand and CO_2 emissions from the production of selected energy-intensive materials in the New Policies Scenario and Material Efficiency Scenario



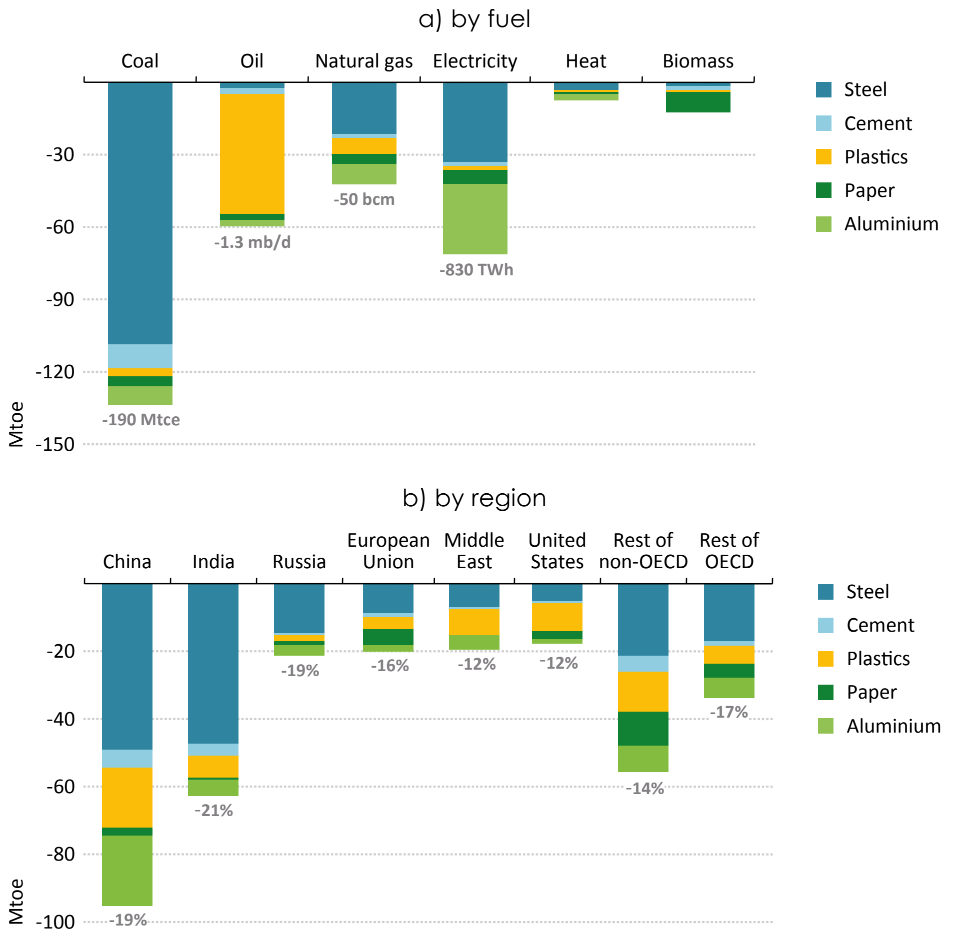
Note: NPS = New Policies Scenario; MES = Material Efficiency Scenario.

In the Material Efficiency Scenario, the use of all fuels is reduced, though the reduction is largest for fossil fuels and electricity (Figure 10.13). The demand for coal falls by 190 million tonnes of coal equivalent (Mtce), almost equal to current coal output in South Africa. This is mainly due to a switch to secondary steel-making in the iron and steel industry and a reduction in steel demand. The demand for coking coal in 2040 is 75 Mtce lower (equivalent to 15% of Chinese coking coal production in 2013). Oil demand decreases by 1.3 mb/d (equivalent to half of today's production in Venezuela) as a direct result of lower feedstock needs for plastic production, as the share of recycling increases. The reduction in natural gas totals 51 billion cubic metres (bcm) (equivalent to today's consumption in Korea), coming from steel, plastics and aluminium production. Since both steel and aluminium production are lower in the Material Efficiency Scenario and the share of secondary aluminium production increases, the demand for electricity falls by 828 TWh in 2040, which is slightly less than the total electricity generation today of France and Italy combined. The demand for biomass is notably lower, as a result of increased paper recycling, which decreases energy-intensive mechanical and chemical pulp production.

From a regional perspective, almost four-fifths of the savings arise in countries outside the OECD, reflecting the wider shift in the global economy, and by 2040 about 75% of energy demand in the energy-intensive industries arises in emerging and developing countries (a six percentage point increase from current levels). China sees the largest absolute savings, as China remains the largest steel, aluminium and cement producer and the largest plastics consumer in 2040. The second-largest savings are realised in India, which by 2040 is the second-largest steel producer in the world: India sees a lower energy demand growth relative to the New Policies Scenario, due to a reduction in the demand for steel and higher use of less energy-intensive secondary steel-making. In the Middle East and the United

States, savings are largest in the plastics industry, reflecting the relative size of the industry and the potential which remains to increase recycling rates from domestic consumption.

Figure 10.13 ▷ Change in energy demand in the Materials Efficiency Scenario relative to the New Policies Scenario, 2040



Note: Mtce = million tonnes of coal equivalent; bcm = billion cubic metres.

Sectoral trends

We have assessed material efficiency strategies for each of the five energy-intensive industries, making use of the technological detail in the World Energy Model. The steel sector is by far the largest industrial energy consumer, representing 23% of total industrial energy demand (Table 10.7). The share of the cement sector in CO_2 emissions is higher than in energy consumption, as process emissions from clinker play a significant role.

Table 10.7 ▷ Energy characteristics of energy-intensive industries, 2013

Sector	Energy demand (Mtoe)	CO_2 emissions* (Mt CO_2)	Description
Steel	785 (23%)	2 706 (20%)	Majority of energy demand is coal in primary steel-making via the blast furnace and basic oxygen route. Recycled scrap metal is mainly used as an input in electric arc furnaces (secondary steel-making), which uses electricity and requires only around a fourth of the energy consumed in primary steel-making.
Plastics	315 (9%)	533 (4%)	Two-thirds of energy consumption is feedstock and the rest is mainly thermal energy. Recycled plastic production requires 70-90% less energy input (including feedstock) compared with virgin plastic.
Cement	281 (8%)	2 608 (19%)	Clinker production, the main ingredient in cement, consumes almost the entire thermal energy in cement production and currently emits around 1.5 Gt of process emissions in addition to emissions from fuel combustion.
Paper	160 (5%)	475 (3%)	The majority of energy demand is used in chemical and mechanical pulp production, mainly bioenergy. Pulp from recycled fibre requires only around 10% as much energy as chemical pulp.
Aluminium	113 (3%)	680 (5%)	Energy demand in the aluminium sector is dominated by electricity for primary aluminium production. Secondary aluminium production from scrap metal reduces energy needs by up to 90% as it avoids the energy-intensive process of alumina refining and aluminium smelting.

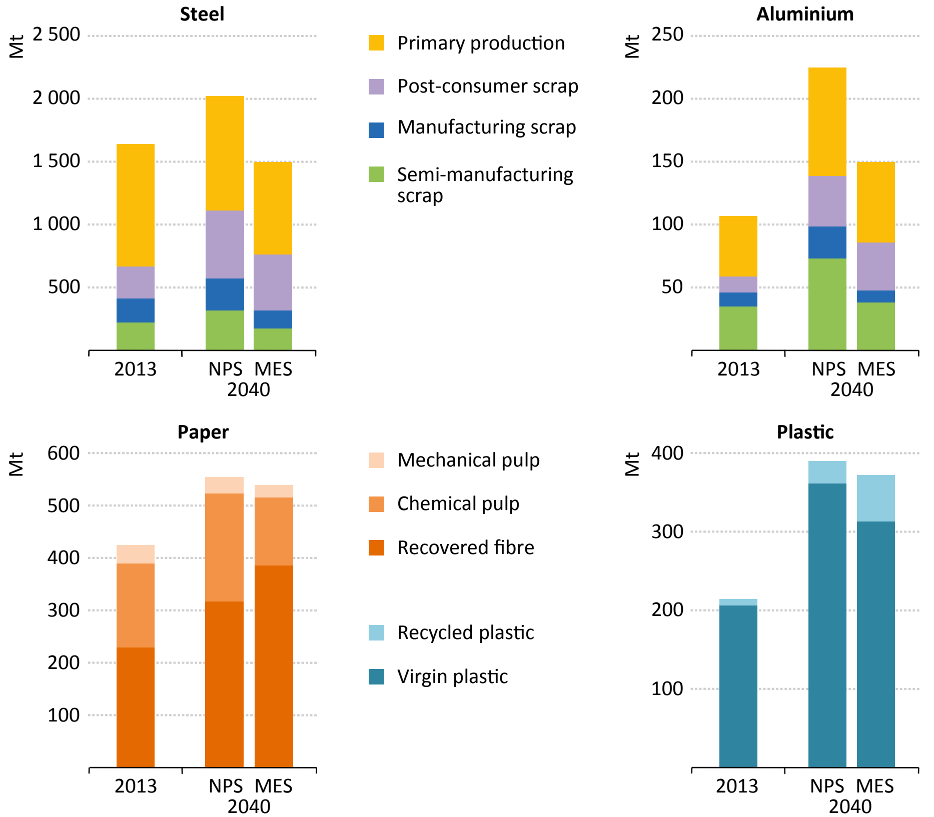
* Process-related CO_2 emissions from clinker, petrochemicals and primary aluminium are also included in addition to energy-related CO_2 emissions (direct and indirect).

Note: The sectoral share of total industry is presented as shares in parentheses.

Steel

Material efficiency strategies in the steel industry are long established and steel products have already been light-weighted (in the last 30 years the average weight of steel cans has been reduced by 30%), while global steel scrap use has increased (within the last decade scrap use increased by more than a quarter) (APEAL, 2014; BIR, 2015). In the Material Efficiency Scenario, energy demand in 2040 drops by 21% relative to the New Policies Scenario, which corresponds to a reduction of almost a fifth compared to today. CO_2 emissions in the steel sector fall by 28%, to 1.8 Gt in 2040. Notably, this fall is even greater than the fall in energy demand, as the majority of the displaced energy is emissions intensive electricity and coking coal. While some material efficiency strategies affect the availability of steel scrap, others reduce the demand for steel products, which in the Material Efficiency Scenario is 26% lower than in the New Policies Scenario (Figure 10.14). Currently, about half of all steel is used in buildings and infrastructure, 19% in transport equipment and 16% in machinery.

Figure 10.14 ▷ Global steel, aluminium, paper and plastic production by input material and scenario



Note: NPS = New Policies Scenario; MES = Material Efficiency Scenario.

As one strategy to reduce steel demand, it is assumed that the lifetime of steel components is increased on average by 17% in the Material Efficiency Scenario. There is no need to assume that the whole product is replaced at the same time, e.g. in the case of appliances the steel box could remain but other components be replaced. Likewise, light-weighting makes it possible to provide the same service with less metal, reducing the demand for steel. In the United Kingdom, it has been shown that the embodied steel in commercial buildings can be reduced by up to 46% without compromising building safety (Moynihan and Allwood, 2014). Increasing material efficiency does not mean reducing the demand for steel products alone, but also scrap in the production process, which is reduced by almost half in 2040, relative to the New Policies Scenario, as a result of a reduction in material losses during the manufacturing process and scrap diversion to alternative products.

Currently, there are several barriers to the realisation of the full potential of material efficiency in the steel sector. These range from financial constraints, scepticism towards certain technologies to tight product specifications, which can, for example, limit the potential for light-weighting. Control software and the latest fabrication techniques can help to reduce yield losses, but awareness of the opportunities is often limited. Furthermore, material efficiency is not pursued on a large scale, as significant up-front investments need to be made to exploit the benefits of recycling, re-use and scrap diversion.

Plastics

Global plastics production reached almost 300 million tonnes (Mt) in 2013, with thermoplastics[15] accounting for 213 Mt. Unlike steel or cement, plastic is not a homogenous good: there are many different kinds which have different properties and are used in a range of applications, from packaging and construction to transportation and electronic devices. Plastics are cheap, light, easily shaped and energy efficient when compared to many alternatives. In the Material Efficiency Scenario energy demand for plastics increases by 1.5% per year to 2040, compared with a growth rate of 2.0% per year in the New Policies Scenario. This is achieved through light-weighting and re-use. While the energy needs for recycled plastic in the Material Efficiency Scenario are double those of the New Policies Scenario, the increase is more than offset by a reduction in oil-based feedstock for base chemicals, which are the building blocks for plastics, and the need for heat (Figure 10.14).

The most effective material efficiency solution is to reduce end-use demand for plastic products and increase product re-use. Light-weighting of plastic products has a long history: 0.5 litre plastic soft drink bottles had an average weight of 19 grammes (g) in 2000 and only 10 g in 2011, a reduction of nearly 50% (IBWA, 2015). The introduction of fees for failure to re-use or recycle plastics and outright bans on plastic bags have contributed to a reduction in the demand for plastic. In our Material Efficiency Scenario, the share of global plastics which are recycled rises from 13% in 2013 to 30% in 2040[16], which is only slightly beyond the level attained in the European Union today. Increasing plastic recycling through improvements in waste collection is possible but difficult, both because of contamination and the high degree of plastics mixing (e.g. a plastic bottle and its lid normally consist of two different types of plastic). Plastic waste needs to be sorted into the different plastic resins in order to be reprocessed (closed-loop recycling). A mixture of plastics can be used in lower-grade applications, including polar fleece, roof tiles or park benches, but with very limited energy savings. For our analysis, it is assumed that only two-thirds of recycled plastic materials replace production from primary polymers. In order to exploit the energy savings arising from plastics recycling, extensive improvements are needed in waste management systems, particularly in developing countries where plastics consumption is

15. In the rest of the section, plastics refers to the highest production volume thermoplastics, including polyethylene (PE), polypropylene (PP), polyvinylchloride (PVC), polyethylene terephthalate (PET), polystyrene (PS), acrylonitrile butadiene styrene (ABS) and polycarbonate (PC).

16. Current recycling rates are 26% in the European Union, 9% in the United States and 22% in Japan (US EPA, 2015; PWMI, 2013; PlasticsEurope, 2015).

growing fastest. For those plastic products that cannot be sustainably recycled, energy recovery is a better option than landfilling as the embedded energy can be used in place of fossil fuels for heat and electricity production.[17]

Cement

Cement is used as a binder in concrete, mainly in buildings and infrastructure. In general, energy savings from material efficiency strategies in the cement sector are relatively limited (7% energy reduction in the Material Efficiency Scenario) compared to other sectors, as the cement content in concrete cannot be viably separated and recycled. Most recycled concrete is currently used as coarse aggregate for road base, but it is also mixed as aggregate with new concrete, avoiding the need to extract new aggregate. Some countries achieve very high concrete recovery rates in construction and demolition waste, such as the Netherlands with 95% (CSI, 2009). Recycling concrete as aggregate does not necessarily save energy, as it normally requires about the same amount of cement as normal concrete.[18] However, large concrete components can be recovered and reused in their original form for other purposes, thereby reducing the need for new material and the associated energy input. Concrete re-use is an established industry in many countries and existing technology for re-use is readily available and relatively inexpensive.

The second material efficiency strategy included in the Material Efficiency Scenario is to partially substitute the clinker used in cement production (the production of which is energy-intensive) by other mineral components, including ground blast furnace slag (a by-product from the steel industry), finely ground limestone, fly ash (a residue from coal-fired power stations) and natural volcanic materials. However, increased use of clinker alternatives depends greatly on the regional availability of alternative materials and on the limits specified in current cement standards.

Paper

While energy costs in paper production account for about 15% of manufacturing costs, material costs account for close to half of the total manufacturing cost, which has already led some paper producers to study the impact of material efficiency strategies, particularly light-weighting paper products (CEPI, 2013). In the Material Efficiency Scenario, energy demand in 2040 is 14% lower than in the New Policies Scenario, as a result of increased recycling rates and light-weighting of newsprint, and printing and writing paper, which reduces paper production by around 3% in 2040 (Figure 10.14).[19] As in the case of other energy-intensive products, there exists further potential to light-weight paper products:

17. Energy recovery of plastics was not considered in this analysis as it is not a material efficiency strategy but rather a strategy to increase resource efficiency.

18. Limited energy savings, however, arise from lower material transportation requirements and depend on site-specific circumstances.

19. Replacing the use of paper through electronic readers was not included as a strategy in the Material Efficiency Scenario because so far literature analysing whether electronic readers can reduce energy consumption relative to the traditional use of paper is sparse.

newspapers use various different paper strengths but it is estimated that the weight of both newspaper and office paper can be reduced by 7-13% without compromising quality.

Among energy-intensive products, paper is already recycled to a high degree. Globally, the recovery rate for recycling was 58% in 2013, while recovery rates are as high as 72% in Europe, which is close to the maximum practical recycling rate as some paper (e.g. tea bags and tissues) cannot be collected (ICFPA, 2015). However, in some regions, significant further potential exists, with recycling rates at 53% in Asia, 44% in Latin America and 34% in Africa (CEPI, 2013). Recycled fibre is mostly used in cardboard, sanitary paper and newsprint because most high quality printing and writing paper can have only a low recycled content. While paper recycling generally leads to lower energy consumption, the CO_2 emissions are not necessarily lower, since chemical pulp mainly uses biomass as an energy source, while energy use in pulp production from recycled fibre is dominated by fossil fuels.

Aluminium

In the Material Efficiency Scenario, aluminium production is about one-third lower than in the New Policies Scenario, while semi-manufacturing and manufacturing scrap are reduced by half (Figure 10.14). This leads to a 26% reduction in energy needs in 2040 in the Material Efficiency Scenario, relative to the New Policies Scenario. CO_2 emissions are reduced by an even higher share (39%), as a consequence of reducing emissions from fossil fuel-based electricity generation in large producing regions, particularly China and the Middle East.

The material efficiency strategies deployed in the aluminium sector are the same as in the steel sector. Some strategies aim to reduce the demand for aluminium, of which a quarter is used in transport, 22% in buildings and construction, 14% in packaging and 11% in machinery and equipment. Manufacturing needs can be decreased by minimising material waste in the manufacturing process (e.g. by improving existing processes and by designing components with shapes close to those of semi-finished products), by diverting manufacturing scrap to aluminium uses and by re-using post-consumer scrap instead of re-melting. The shift towards more material-efficient aluminium production will vary geographically, with industrialised countries benefiting from relatively higher and more mature in use stock for recycling. The accumulation of alloys in aluminium products and the diverse nature of scrap after repeated recycling represent barriers to further improvements in recycling rates. Improved solutions will be required for end-of-life collection, particularly for separating different alloys.

Policy recommendations and costs

Investment is necessary to realise the potential of improved material efficiency to reduce energy demand and CO_2 emissions in energy-intensive industries and beyond. Costs associated with material efficiency strategies take the form of investment and operating costs either in established technologies, different applications of existing technologies or new technologies, such as more adaptable equipment for optimised equipment. Estimates of such costs are complex to calculate, as material efficiency strategies are very different and can be assessed only on a case-by-case basis. One study for the European food and drinks and metal products industries found annual benefits for these two sub-sectors of €108-200 billion ($144-267 billion) (11-17% of annual turnover) from implementing resource efficiency strategies. Most measures, such as packaging redesign, re-use of packaging, waste recovery and increasing efficiency of production processes had a payback period of less than three years (AMEC, 2013). Another study shows that costs for implementing material efficiency have the potential to come down further in years ahead, as the costs for the collection, sorting and use of packaging waste in Germany have been reduced by more than 50% over the past 15 years (DSD, 2013).

The barriers to material efficiency are, however, sufficiently high that it is unlikely that the full extent of the energy savings identified in the Material Efficiency Scenario will be realised if incentives and measures are not put in place for market actors. The benefits in terms of saving energy, decreasing environmental harm, accelerating economic growth and providing jobs, warrant political intervention. Yet, the multiple benefits of increasing material efficiency need to be weighed against the costs of imposing regulation, which requires analyses on a country-by-country and sector-by-sector basis. Since the public sector exerts significant influence on markets as a purchaser, their procurement policies, such as for vehicle fleets, could offer, next to the imposition of regulation, one way of triggering an increase in material efficiency.

While it might fall to the ministry responsible for energy to initiate action to facilitate exploitation of the potential associated with material efficiency, most available measures will require the co-operation of several government agencies. An interdisciplinary approach, bringing together the relevant policy-makers from different domains, needs to be taken.

Building partially on existing experience, measures that could serve to advance material efficiency include:

- A clear price signal by shifting the tax burden to materials (in the form of a material/energy taxes or a CO_2 price) to reduce the inefficient use of materials.
- Raise consumer awareness about ways to reduce material use and the multiple benefits of doing so.
- Comprehensive waste recycling strategies:
  - Prohibit disposal in landfills of all recoverable waste or implement a landfill tax.
  - Improve separation and collection of dry-recyclables at source.
  - Introduce a deposit-return system for beverage containers.
  - Extend producer responsibility, e.g. through systems that levy fees according to weight, recyclability of a material or actions which complicate waste separation.[20]

20. Some countries already have schemes in place that impose a penalty on products that mix materials, which are difficult to separate, e.g. a PET bottle with a PVC label.

- Green building schemes:
  - Encourage materials-sensitive construction and management of demolition waste.
  - Review minimum structural material requirements to avoid excess material use and building codes to permit the use of reused materials.
  - Require an inventory of materials, their properties and expected life-spans for newly constructed buildings.
  - Require pre-demolition building audits to identify opportunities for building retrofits or component re-use.
- Support for innovation in manufacturing processes to improve production yields and for the promotion of production audits in SMEs.
- Increasing the availability of reliable and consistent statistics on material flows to increase knowledge about material flows, wastes and lifetimes.

PART B

INDIA ENERGY OUTLOOK

PREFACE

Part B of this *WEO* (chapters 11-14) continues the past practice of examining in depth the prospects of a country of particular significance to the global energy outlook. This year the spotlight falls on India, as it is increasingly evident that it will command a central position in global energy affairs.

Chapter 11 sets the scene by analysing India's energy sector as it is today, outlining the opportunities and challenges that accompany its rapid economic and energy demand growth. It details the existing energy architecture, including the power sector and other energy-consuming sectors, the scale of India's energy resources and its energy production trends. It also highlights the important economic, policy and social factors that shape India's energy development and investment decisions, including energy prices and affordability, land use, and environmental factors such as local air pollution, CO_2 emissions and water availability. In addition, it explains the analytical approach for the projections that follow.

Chapter 12 provides a detailed outlook for energy demand in India to 2040, including an in-depth look at the end-use sectors and the power sector and assesses the impact that energy use will have on local air pollution. It also examines the impact of a period of sustained lower oil prices on India's energy system and economy.

Chapter 13 focuses on India's energy resources, covering the spectrum of fossil fuels, renewables and nuclear. It assesses the scale of these resources against the increase in energy demand, what will be required to enable future exploitation of its domestic resources and the outlook for international trade.

Chapter 14 draws out some of the wider implications of the prospective energy transition in India. First, on the basis of the projections of the New Policies Scenario and then, on the basis of an Indian Vision Case, which examines how the country's energy system would evolve if key targets, such as the "Make In India" campaign and universal round-the-clock electricity supply, are achieved in full. Furthermore, it analyses the level of investment required, in addition to the regulatory framework and other measures necessary, to help secure the investment to ensure energy supply and improve energy efficiency.

Energy in India today

Setting the scene

Highlights

- India is in the early stages of a major transformation, bringing new opportunities to its 1.3 billion people and moving the country to centre stage in many areas of international affairs. The energy sector is expanding quickly but is set to face further challenges as India's modernisation and its economic growth gather pace, particularly given the policy priority to develop India's manufacturing base.
- Energy use has almost doubled since 2000, and economic growth and targeted policy interventions have lifted millions out of extreme poverty; but energy consumption per capita is still only around one-third of the global average and some 240 million people have no access to electricity. In these circumstances, even with a growing focus on energy efficiency and subsidy reform, there are strong underlying reasons to expect continued rapid growth in energy demand.
- Three-quarters of Indian energy demand is met by fossil fuels, a share that has been rising as households gradually move away from the traditional use of solid biomass for cooking. Coal remains the backbone of the Indian power sector, accounting for over 70% of generation and is the most plentiful domestic fossil-fuel resource, although, as in the case of oil and gas, dependence on coal imports has grown in recent years. India was the world's third-largest importer of crude oil in 2014, but is also a major exporter of oil products, thanks to a large refining sector.
- Power generation capacity has surged over recent years, but the outlook for the sector is clouded by the precarious financial situation of local distribution companies and large losses in the transmission and distribution networks. India has 45 GW of hydropower and 23 GW of wind power capacity, but has barely tapped its huge potential for renewable energy. India is, however, aiming high in this area, with a target to reach 175 GW of installed renewables capacity by 2022 (excluding large hydropower), which is a steep increase from today's level of 37 GW. Solar power is a key element of the government's expansion plans.
- India's federal constitutional system distributes powers for energy between the central and state-level governments. Indian policy-makers are making strenuous efforts to remove obstacles to investment in energy supply, while moving ahead with complementary policies on efficiency and energy pricing that can constrain growth in consumption; several national ministries and other state bodies oversee different aspects of energy, complicating the task of formulating and implementing a unified strategy. Policy and investment decisions are much influenced by the sensitivity of land and water use, end-user tariffs and affordability, as well as the worsening air quality in many of India's major cities.

Introducing the special focus on India[1]

India is in the midst of a profound transformation that is moving the country to centre stage in many areas of global interaction. A vibrant democracy that is home to over one-sixth of the world's population and its third-largest economy, India's modernisation has been gathering speed and new policies have been introduced to unleash further growth. The opportunities are huge, but so is the size of the remaining challenges: although incomes and corresponding standards of living are on the rise, India is still home to a third of the world's poor and gross domestic product (GDP) per capita is well below the international average.

India's energy sector has grown tremendously in recent years. Further economic and population growth, allied to structural trends such as urbanisation and the nature of the envisioned industrialisation, point unmistakeably to a trend of continued rapid expansion in demand for energy. Recognising this challenge, Indian policy-makers are making strenuous efforts to remove obstacles to investment in energy supply, while moving ahead with complementary policies on efficiency and energy pricing that can constrain growth in consumption. The analysis and findings in this special focus on India disclose these multiple pressures and show how policies can affect the evolution of the Indian energy sector so as to realise the huge benefits that a well-managed expansion of energy provision will bring. No effort is made here to prescribe a path for India; our intention is, rather, to provide a coherent framework to contribute to the policy choices that India itself will make, drawing out the possible implications of these choices for India's development, energy security and environment, as well as for the global energy system.

Key energy trends in India[2]

Demand

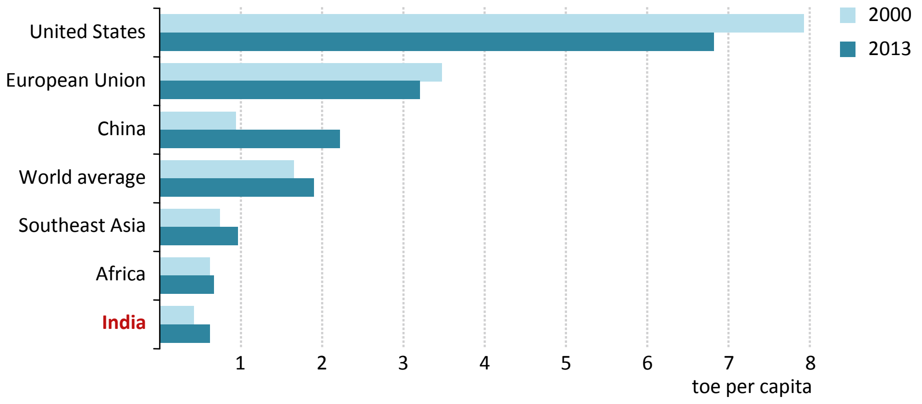
India has been responsible for almost 10% of the increase in global energy demand since 2000. Its energy demand in this period has almost doubled, pushing the country's share in global demand up to 5.7% in 2013 from 4.4% at the beginning of the century. While impressive, this proportion is still well below India's near 18% current share of global population, a strong indicator of the potential for further growth. Expressed on a per-capita basis, energy demand in India has grown by a more modest 46% since 2000 and remains only around one-third of the world average, slightly lower than the average for the African continent (Figure 11.1). One reason is that a significant part of the Indian

1. This analysis has benefited greatly from discussions with Indian officials, industry representatives and experts, notably during a high-level *WEO* workshop, organised in partnership with the National Institution for Transforming India (NITI Aayog) and held in New Delhi in April 2015.

2. The data used in this special focus are from IEA databases, which rely on a range of Indian official and other sources. As explained in Box 11.4 (see section on "Policy and institutional framework"), adjustments in some instances for IEA definitions and methodology mean that the data may differ slightly from those used elsewhere. The base year for this study is 2013, as it is the last year for which comprehensive historical data were available at the time of writing, though more recent data have been incorporated wherever possible.

population remains without modern and reliable energy: despite a rapid extension of the reach of the power system in recent years, around 240 million people in India lack access to electricity.

Figure 11.1 ▷ Per-capita energy consumption in India and selected regions



Note: toe = tonnes of oil equivalent.

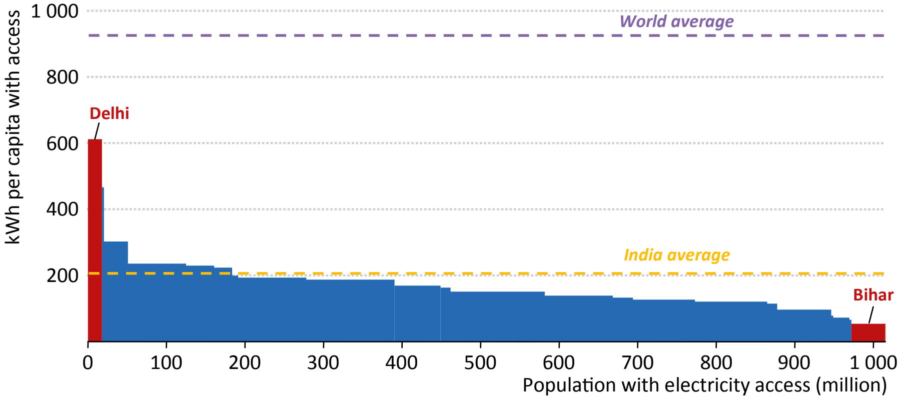
The widespread differences between regions and states within India necessitate looking beyond national figures to fully understand the country's energy dynamics. This is true of all countries, but it is particularly important in India, both because of its size and heterogeneity, in terms of demographics, income levels and resource endowments, and also because of a federal structure that leaves many important responsibilities for energy with individual states. For example, figures for residential electricity consumption per capita (for those with access to electricity) show a broad range between the area with the highest levels, in Delhi – the only part of India with consumption higher than the non-OECD average – and other states (Figure 11.2). Residential electricity consumption (for those with access) remains far below the world average and is ten-times lower than OECD levels. Average residential consumption in Bihar, at around 50 kilowatt-hours (kWh) per capita per year, is consistent with an average household use of a fan, a mobile telephone and two compact fluorescent light bulbs for less than five hours per day.

Energy demand has almost doubled since 2000, but this is slower than the rate of economic growth over the same period (Figure 11.3). This is due in part to the shift away from bioenergy[3] consumption in the residential sector, the rising importance of the services sector in the Indian economy and increased policy efforts directed at end-use energy efficiency. As a result, it took 12% less energy to create a unit of Indian GDP (calculated on the basis of purchasing power parity [PPP]) in 2013 than was required in 1990. The amount of energy required to generate a unit of GDP (PPP basis) in India is slightly lower than the global average. Even so, much energy is lost or used inefficiently, notably in the power

3. Bioenergy includes solid biomass, biofuels and biogas.

sector because of the generation technologies used, the poor state of the transmission and distribution infrastructure and the relatively low efficiency of end-use equipment. Significant untapped energy efficiency potential remains across the entire energy system, which could help temper the further growth in energy consumption.

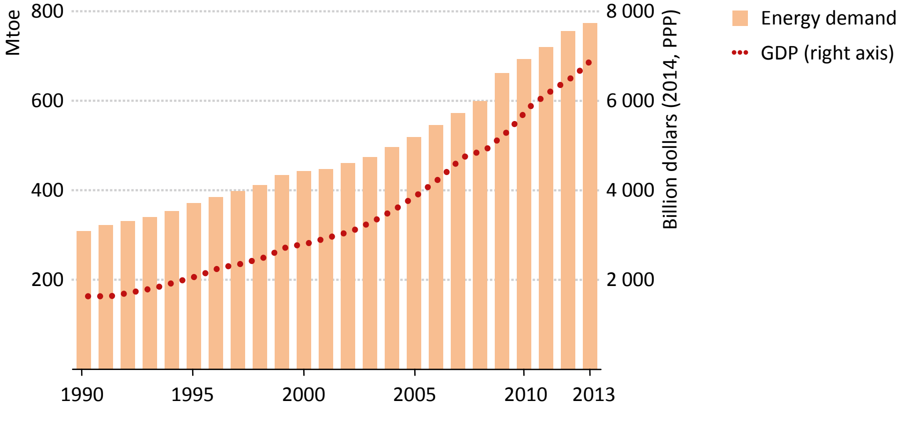
Figure 11.2 ▷ Annual residential electricity consumption per capita by state in India (for those with access), 2013



Note: Annual residential electricity consumption per capita (for those with access) by state is estimated by dividing the annual residential electricity consumption by the number of people with electricity access for each state. This estimate is not comparable with the common "electricity consumption per capita" indicator, which takes into account electricity consumption of all sectors divided by total population.

Sources: National Sample Survey Office, (2014a); Central Electricity Authority, (2014a); IEA analysis.

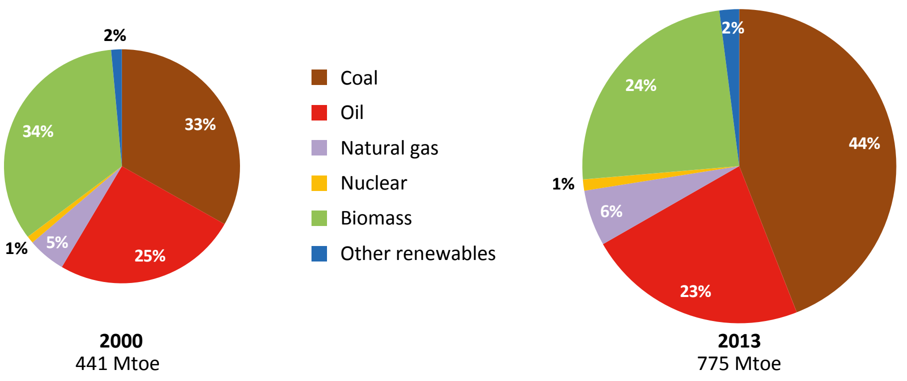
Figure 11.3 ▷ Primary energy demand and GDP in India



Note: Mtoe = million tonnes of oil equivalent.

Almost three-quarters of Indian energy demand is met by fossil fuels, a share that has increased since 2000 because of a rapid rise in coal consumption and a decreasing role for bioenergy, as households move away from the traditional use of solid biomass for cooking (Figure 11.4). Coal now accounts for 44% of the primary energy mix (compared with under a third globally) – mainly because of the expansion of the coal-fired power generation fleet, although increased use of coking coal in India's steel industry has also played a part. The availability and affordability of coal relative to other fossil fuels has contributed to its rise, especially in the power sector. Demand for bioenergy (consisting overwhelmingly of solid biomass, i.e. fuelwood, straw, charcoal or dung) has grown in absolute terms, but its share in the primary energy mix has declined by almost ten percentage points since 2000, as households moved to other fuels for cooking, notably liquefied petroleum gas (LPG).

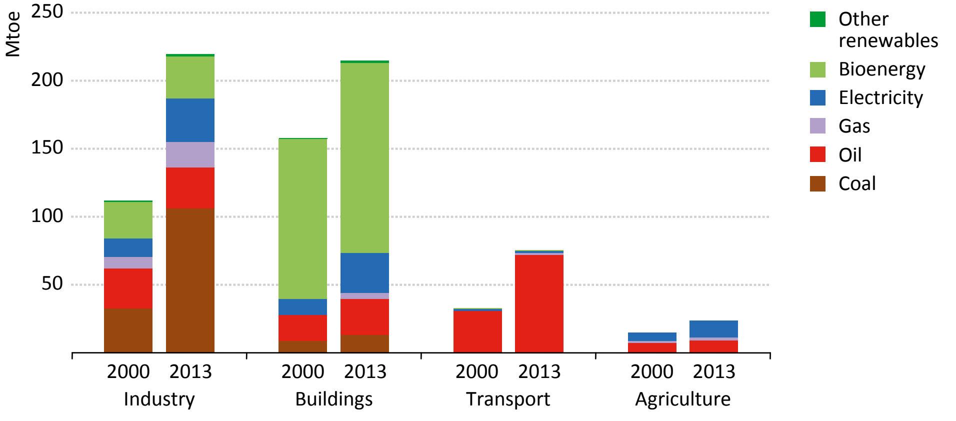
Figure 11.4 ▷ Primary energy demand in India by fuel



Oil consumption in 2014 stood at 3.8 million barrels per day (mb/d), 40% of which is used in the transportation sector. Demand for diesel has been particularly strong, now accounting for some 70% of road transport fuel use. This is due to the high share of road freight traffic, which tends to be diesel-powered, in the total transport use and also to government subsidies that kept the price of diesel relatively low (this diesel subsidy was removed at the end of 2014; gasoline prices were deregulated in 2010). LPG use has increased rapidly since 2000, reaching over 0.5 mb/d in 2013 (LPG is second only to diesel among the oil products, pushing gasoline down into an unusually low third place). The rise in LPG consumption also reflects growing urbanisation, as well as continued subsidies. Natural gas makes up a relatively small share of the energy mix (6% in 2013 compared with 21% globally). It is used mainly for power generation and as a feedstock and fuel for the production of fertilisers, although it also has a small, but growing role in the residential sector and as a transportation fuel. Hydropower, nuclear and modern renewables (solar, wind and geothermal) are used predominantly in the power sector but play a relatively small role in the total energy mix.

Energy demand had traditionally been dominated by the buildings sector (which includes residential and services) (Figure 11.5), although demand in industry has grown more rapidly since 2000, overtaking buildings as the main energy user in 2013. In the buildings sector, a key driver of consumption in both rural and urban areas has been rising levels of appliance ownership, especially of fans and televisions, and an increase in refrigerators and air conditioners in urban areas over the latter part of the 2000s. As a result, electricity demand in the buildings sector grew at an average rate of 8% per year over 2000-2013. The share of bioenergy in the buildings sector (mostly the traditional use of biomass for cooking and heating) has declined from 75% of the sector's total consumption in 2000 to two-thirds in 2013, as electricity and oil products have gained ground.

Figure 11.5 ▷ Energy demand by fuel in selected end-use sectors in India

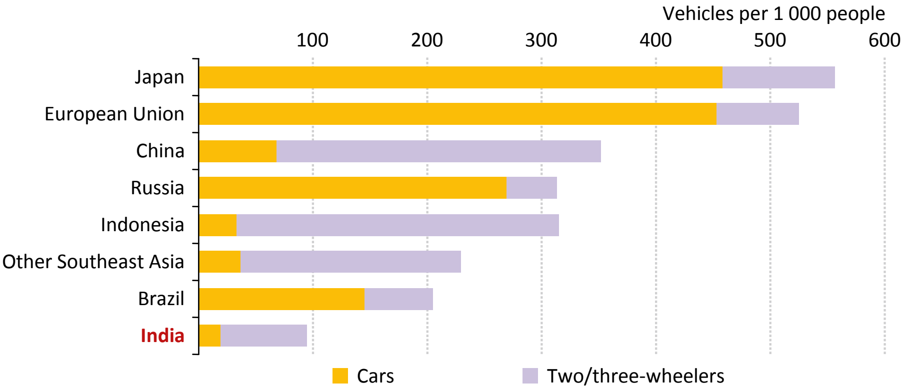


Notes: Other renewables includes solar photovoltaics (PV) and wind. Industry includes energy demand from blast furnaces, coke ovens and petrochemical feedstocks.

Industrial energy demand has almost doubled over the 2000-2013 period, with strong growth from coal and electricity. Large expansion in the energy-intensive sectors, including a tripling in steel production, is one component. Nonetheless, consumption levels of cement and steel are still relatively low for a country of India's size and income levels: consumption of cement is around 220 kilograms (kg) per capita, well behind the levels seen in other fast-growing economies and a long way behind the elevated levels seen in China in recent years (up to 1 770 kg per capita). The agricultural sector, though a small part of energy demand, is a key source of employment and since 2000 has accounted for roughly 15% of the increase in total final electricity demand as more farmers obtained electric pumps for irrigation purposes.

Over 90% of energy demand in the transport sector in India is from road transport. The country's passenger light-duty vehicle (PLDVs) stock has increased by an average of 19% per year since 2000, rising to an estimated 22.5 million in 2013, with an additional 95 million motorbikes and scooters (two/three-wheelers). Yet ownership levels per capita are still very low compared with other emerging economies and well below ownership levels of developed countries (Figure 11.6). Poor road infrastructure is a major constraint to broader vehicle ownership; according to the World Bank, one-third of the rural population lacks access to an all-weather road, making car ownership impractical – even in cases where it is affordable (World Bank, 2014).

Figure 11.6 ▷ Vehicle ownership in India and selected regions, 2013



Electricity

The provision of electricity is critical to India's energy and economic outlook and is a major area of uncertainty for the future. The country's electricity demand in 2013 was 897 terawatt-hours (TWh)[4], up from 376 TWh in 2000, having risen over this period at an average annual rate of 6.9%. Electricity now constitutes some 15% of final energy consumption, an increase of around four percentage points since 2000. As with all other demand sectors, further rapid growth is to be expected: around one-sixth of the world's population in India consumes about one-twentieth of global power output. With continued economic expansion, expanding access to electricity, urbanisation, an ever-larger stock of electrical appliances and a rising share of electricity in final consumption, pressures on the power system will persist and increase.

The situation varies from state to state (Box 11.1), but higher tariffs paid by commercial and industrial consumers are typically not enough to offset the losses arising from subsidies to residential and agricultural consumers, despite efforts to raise retail rates in recent years (see section on energy prices below). The consequent financial problems faced by local distribution companies are often exacerbated by shortfalls in subsidy compensation payments due from state governments and by poor metering and inefficient billing and collection, creating a spiral of poor performance, inadequate investment, high transmission and distribution losses and regular power outages. This is a key structural weakness for the energy sector as a whole.

On the supply side, India has some 290 gigawatts[5] (GW) of power generation capacity, of which coal (60%) makes up by far the largest share, followed by hydropower (15%)

4. Electricity demand is defined as total gross generation, including estimated off-grid generation, plus net trade (imports minus exports), minus own use by generators as well as transmission and distribution losses.

5. The figure is for total capacity as of end-2014 and includes grid-based and captive generation; it compares with capacity data for end-March 2015 from the Central Electricity Authority of 271 GW (utilities) and 47 GW (non-utilities); the bulk of the difference may be explained by additions in the first three months of 2015.

and natural gas (8%). The mix has become gradually more diverse: since 2000, almost 40% of the change in installed capacity was non-coal. This is reflected also in the figures for generation, which show how renewables are playing an increasingly important role (Figure 11.7). But, despite the increase in generation, India faces a structural shortage of power. For residential consumers, this constraint is most evident during periods of peak demand, typically in the early evenings as demand for lighting, cooling and other appliances surges (with the result that, where they can afford it, households often invest in small diesel generators or batteries and inverters[6] as back-up).

Box 11.1 ▷ Power fluctuations, from state to state

The provision of electricity is a shared responsibility between the central and state authorities in India: states have significant freedom to set electricity prices, the average subsidy level and the beneficiaries of the cross-subsidisation. In practice, there are large differences in circumstances between the various states and a wide range of performance across various indicators, such as progress towards universal access, success in reducing losses from theft, non-billing and non-payment, and electricity losses in transmission and distribution (for which six states registered total losses of less than 15% of available supply in 2012-2013, while four had losses greater than 40% [CEA, 2014a]). Steps to narrow or even to close the gap between end-user tariffs and the cost of supply also vary widely.

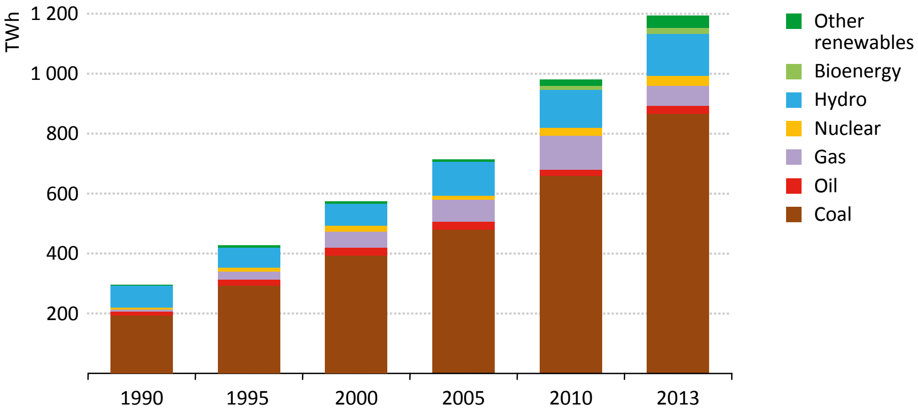
Part of the explanation is related to variations in income levels and population density, with low-income, densely-inhabited states tending to perform worse than average. States also differ in their resource endowments, both fossil fuel and renewables, as well as in their geographical proximity to coal mining areas and ports. All of these factors have a significant impact on how the local electricity sector is structured and performs. But policy formulation and efficacy of implementation are also important variables. Research by the World Bank has measured a series of outcome-based indicators for the different states against an index that assessed the actions taken by the respective governments, regulatory commissions and utilities to implement electricity sector reforms (in line with the objectives of the 2003 Electricity Act, a milestone in India's power regulation) (Pargal and Ghosh Banerjee, 2014).[7] Gujarat state was among the best in both policy formulation and implementation and overall there was a strong correlation between reforms and outcomes, with states either exhibiting a high commitment to reform alongside strong performance indicators, or the reverse.

6. Batteries and inverters of varying capacities charge from the grid when power is available and then discharge to power appliances during outages (typically charging during the day and then used as necessary during periods of peak demand in the evenings).

7. The index assessed progress in six areas, reflecting key objectives of the 2003 Electricity Act: the introduction of competition; enhanced accountability and transparency; cost recovery and commercial viability; access to electricity and rural electrification; improved quality of service and affordability of supply; and promotion of renewable energy.

Industrial consumers are also affected by unreliable and unpredictable power supply: around half of the industrial firms in India have experienced power cuts of more than five hours each week (FICCI, 2012). Elevated end-use industrial tariffs, allied to unreliable supply, lead many industrial and commercial consumers to produce their own electricity, using back-up diesel generators or larger plants (albeit not utility-scale). Energy-intensive industries, such as steel, cement, chemicals, sugar, fertilisers and textiles are key auto-producers, with cement producers, for example, estimated to produce around 60% of the electricity that they consume. This capacity has been growing steadily and is often coal-fired, relatively inefficient compared with utility-scale generation units and under-utilised (many companies need less electricity than their captive plants can produce, but there are obstacles to feeding this excess power into the grid). The increased use of captive generators, both at household and industrial levels, often worsens local air pollution.

Figure 11.7 ▷ Total electricity generation in India by fuel



Note: Other renewables includes solar PV and wind.

The solution to India's electricity dilemma is not only to raise average tariffs and add more capacity (although both will be essential over time), but also to deal with inefficiencies and bottlenecks. Although there is an overall shortage of power, utilisation rates in coal-fired plants have actually fallen considerably in recent years, down from a peak of almost 80% in 2007 to around 64% in 2014. The decline has been even more dramatic in the case of gas-fired power plants, which ran less than a fourth of the time on average in 2014 (CEA, 2014b). In some instances, particularly for gas plants supplying periods of peak demand, the financial situation of the distribution companies has meant that plants are not being called upon when needed. Another reason for low load factors lies with fuel supply problems, including shortages and quality issues in the case of coal (although the situation has improved in 2015, due to efforts to fast-track the approval of mines and increase oversight of production) and lower than anticipated domestic gas production, for which comparatively expensive liquefied natural gas (LNG) has not been a substitute in most cases (though the recent decline in the price of LNG has made imports more attractive).

The situation is not helped by the low efficiency generation technologies that prevail across much of India's existing fleet (meaning that more fuel is required to generate a unit of power). Over 85% of India's coal plants use subcritical generation technology, and the average efficiency of India's coal-fired fleet is just under 35%, below that of China or the United States. Poor coal quality (high ash content) and the relatively high ambient temperatures in India also play a role in lower efficiency levels. In some cases, generation has also run below capacity due to a lack of available transmission capacity. The creation of a national grid (the five regional grids were interconnected by end-2013) and continued progress in inter-state and inter-regional links has been and remains critical, given that resources and capacity for power generation are often not located close to the main centres of demand. Despite steps to encourage investment, including private investment, in transmission projects, expansion of the network has generally lagged behind that of generation; projects face numerous obstacles, notably over clearances. In 2011, the Central Electricity Authority (CEA) estimated that over 120 transmission projects were held up because the developer was unable to secure the necessary land and rights-of-way.

Access to modern energy

India has made great strides in improving access to modern energy in recent years. Since 2000, India has more than halved the number of people without access to electricity and doubled rural electrification rates. Nonetheless, around 240 million people, or 20% of the population, remain without access to electricity (Table 11.1).[8] The population without access is concentrated in a relatively small number of states: almost two-thirds are in two populous northern and north-eastern states, Uttar Pradesh and Bihar. In large swathes of India, including the majority of southern states, electrification rates are already well above 90%. Of the total without access, the large majority – some 220 million people – live in rural areas where extending access is a greater technical and economic challenge. In urban areas, electrification rates are much higher, but the quality of service remains very uneven, especially in India's large peri-urban[9] slum areas that are home to around 8.8 million households (National Sample Survey Office, 2014b).

India's rural electrification programme, the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY), was launched in 2005 and aimed to provide electricity to villages of 100 inhabitants or more and free electricity to people below the poverty line. The effective implementation of RGGVY has faced several challenges and there are strong variations in outcomes between states, as well as questions over the definition of access (Box 11.2).

8. This estimate for India's electrification rate is derived from the 68th National Sample Survey published in June 2014. However, this is a lower figure than that implied by the Census of India 2011, which gave a figure of 400 million without electricity (at that time). The 12th Five-Year Plan recognises the issue of discrepancies across different national data sources, stating that it may be due to differences in questionnaire design and needs to be examined further.

9. While the definition of peri-urban varies by country, United Nations Children's Fund defines it as an area between consolidated urban and rural regions (UNICEF, 2012).

In July 2015, RGGVY was subsumed within a new scheme, the Deen Dayal Upadhyaya Gram Jyoti Yojana (DDUGJY). The main components of this scheme are the separation of distribution networks between agricultural and non-agricultural consumers to reduce load shedding, strengthening local transmission and distribution infrastructure, and metering. Among the issues that have held up progress with electrification is the need to find local solutions adapted to the specific circumstances of the remote settlements without access, and a variety of problems in securing authorisation for the necessary projects (e.g. land acquisition and rights-of-way for transmission lines and roads).

Table 11.1 ▷ Number and share of people without access to electricity by state in India, 2013

	Population without access (million)			Share of population without access		
	Rural	Urban	Total	Rural	Urban	Total
Uttar Pradesh	80	5	85	54%	10%	44%
Bihar	62	2	64	69%	19%	64%
West Bengal	17	2	19	30%	7%	22%
Assam	11	0	12	45%	9%	40%
Rajasthan	10	0	11	22%	2%	17%
Odisha	10	0	11	32%	4%	27%
Jharkhand	8	0	9	35%	4%	27%
Madhya Pradesh	7	1	8	16%	3%	12%
Maharashtra	6	1	6	11%	2%	7%
Gujarat	2	2	3	7%	6%	6%
Chattisgarh	2	0	3	14%	6%	12%
Karnataka	1	0	1	5%	1%	3%
Other states	3	2	6	2%	2%	2%
Total	**221**	**16**	**237**	**26%**	**4%**	**19%**

Source: National Sample Survey Office, (2014); Central Electricity Authority, (2014a); IEA analysis.

Aside from those without electricity, India also has the largest population in the world relying on the traditional use of solid biomass for cooking: an estimated 840 million people – more than the populations of the United States and the European Union combined. There is a host of issues associated with the traditional use of solid biomass for cooking, including the release of harmful indoor air pollutants that are a major cause of premature death, as well as environmental degradation as a result of deforestation and biodiversity loss. The government has made a major effort to address these issues, primarily through the subsidised availability of LPG as an alternative cooking fuel (see section below on energy prices).

Box 11.2 ▷ Defining access to electricity

Estimates of the number of people with or without access to electricity in different countries depend critically on how "access" itself is defined. These definitions can vary widely, resulting in disparities between various sources of data.[10] In the DDUGJY programme, a village is deemed electrified if basic infrastructure (transformer and distribution lines) has been provided, if public buildings have electricity or if at least 10% of the households have an electrical connection. However, there can be large discrepancies between village electrification and household electrification. Several states report high levels of village electrification, even though the connection rate at household level is much lower. In the state of Bihar, village electrification stands at 96%, while the household electrification rate is only 36%.

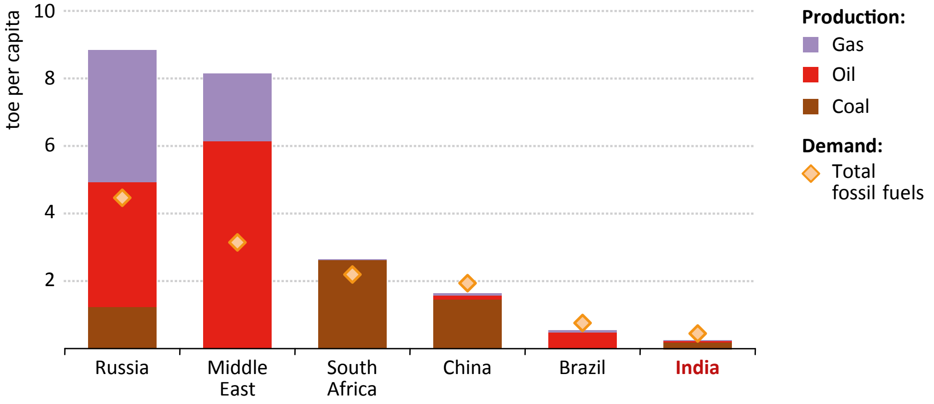
A recent National Sample Survey showed that higher reported rates of electrification were not producing the expected rise in actual power consumption (National Sample Survey Office, 2014a). In the state of Madhya Pradesh, for example, per-capita electricity consumption has been on a slightly declining trend, despite almost a 100% village electrification rate. Such findings raise the important question of the quality of service required to underpin access. According to DDUGJY, a minimum of 6-8 hours of electricity per day should be supplied to households. Most states meet this target, but some only just, as the infrastructure is inadequate and load shedding occurs as a matter of course. A recent survey conducted across six Indian states found that half of the households categorised in the lowest level of access actually had an electricity connection, and that, among the remainder of this category (those without any connection), two-thirds of the respondents had chosen not to adopt electricity for reasons of unaffordability or unreliability (Jain et al., 2015).

Energy production and trade

Fossil fuels supply around three-quarters of India's primary energy demand and, in the absence of a very strong policy push in favour of alternative fuels, this share will tend to increase over time as households move away from the traditional use of biomass. This high – and potentially growing – reliance on fossil fuels comes with two major drawbacks. India's domestic production of fossil fuels, considered on a per-capita basis, is by far the lowest among the major emerging economies (Figure 11.8), meaning that India has a structural dependence on imported supply. In addition, combustion of coal and oil products contributes to pressing air quality problems in many areas, as well as to global greenhouse gas (GHG) emissions.

10. The IEA definition of access to electricity is at the household level and includes a minimum level of electricity consumption, ranging from 250 kWh in rural areas to 500 kWh in urban settings per household per year. The electricity supplied must be affordable and reliable. The initial level of electricity consumption should increase over time, in line with economic development and income levels, reflecting the use of additional energy services.

Figure 11.8 ▷ Fossil-fuel production and demand per capita by selected countries, 2013



Coal

India has the third-largest hard coal reserves in the world (roughly 12% of the world total), as well as significant deposits of lignite. Yet the deposits are generally of low quality and India faces major obstacles to the development of its coal resources in a way that keeps pace with burgeoning domestic needs. In 2013, India produced almost 340 million tonnes of coal equivalent (Mtce), but it also imported some 140 Mtce – roughly 12% of world coal imports (61% from Indonesia, 21% from Australia, 13% from South Africa). With a view to limiting reliance on imports, the government announced plans in early 2015 to more than double the country's coal production by 2020.

The coal sector in India is dominated by big state-owned companies, of which Coal India Limited (CIL) is the largest, accounting for 80% of India's output. CIL has an unwieldy structure and is characterised by poor availability of modern equipment and infrastructure, an over-reliance on surface mining and very low productivity from a very large workforce. Around 7% of national production comes from captive mining, i.e. large coal-consuming companies that mine for their own use; private companies are not at present allowed to mine and market coal freely, though there are now some moves to open the coal market. At present, more than 90% of coal in India is produced by open cast mining. This method has relatively low production costs and is less dangerous than deep mining, but has a large, adverse environmental footprint in the form of land degradation, deforestation, erosion and acid water runoff.

Among the other problems facing the Indian coal sector is a mismatch between the location of hard coal reserves and mines, which are concentrated in eastern and central India, and the high-demand centres of the northwest, west and south. A tonne of coal must travel on average more than 500 kilometres (km) before it is converted to electricity, straining the country's rail network. There are also challenges related to the quality of the coal reserves. Most of the hard coal has low to medium calorific values and high ash content. The low heat value means that more coal must be burned per unit of electrical output, leading to higher local emissions. The ash content increases the cost of transporting coal, is corrosive and lowers the efficiency and load factor of coal-fired power plants. In addition, most power plants are designed for a specific coal quality; if not available, operators may choose to blend different coal types, which can adversely impact the performance of the power plant, as the properties of blends can vary widely.

The difficulty in expanding coal production in recent years has been related to a number of factors, including delays in obtaining environmental permits, land acquisition and rehabilitation and resettlement issues, infrastructure constraints (limited transport capacity to connect mines, dispatch centres and end-use destinations), insufficient coal-washing facilities to remove the ash and technological limitations (notably for underground mining). Other questions concerning future supply have arisen as a result of a Supreme Court decision in 2014 to annul the award of almost all of the coal blocks allocated since 2003 on the grounds that these awards had not been made on a transparent and competitive basis, although this has also opened an unexpected opportunity for the government to reform the coal sector in order to comply with the judgement. Two successful rounds of bidding have already been held to re-allocate some blocks and there is a possibility that private companies may be invited to participate in future rounds.

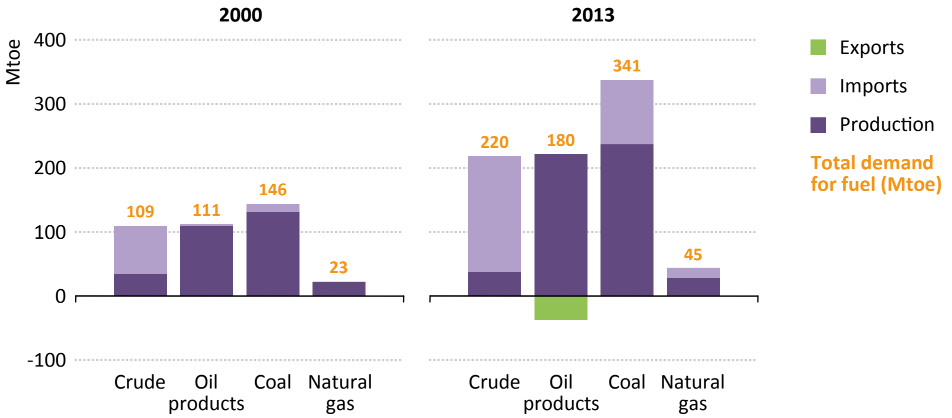
Oil and oil products

India is one of the few countries in the world (alongside the United States and Korea) that rely on imports of crude oil while also being significant net exporters of refined products (Figure 11.9). Domestic crude oil production of just over 900 thousand barrels per day (kb/d) is far from enough to satisfy the needs of 4.4 mb/d of refinery capacity. The output from the refinery sector, in turn, is more than enough to meet India's current consumption of oil products, at around 3.8 mb/d (with the exception of LPG, for which India imports about half of domestic consumption).

India has relatively modest oil resources and most of the proven reserves (around 5.7 billion barrels) are located in the western part of the country, notably in Rajasthan and in offshore areas near Gujarat and Maharashtra. The Assam-Arakan basin in the northeast is also an oil-producing basin and contains nearly a quarter of total reserves. Despite efforts to bolster oil production, including the opening of India's upstream sector to non-state investors, the sector has underperformed. Key impediments to investment include the complex regulatory environment (including uncertainty over contract terms and pricing arrangements), and a resource base that is still not well-explored and appraised. The upstream is still dominated by a few state-owned companies: about two-thirds of crude oil is produced by the Oil and Natural Gas Corporation Limited (ONGC) and Oil India Limited (OIL) under a pre-liberalisation nomination regime. Most of the remaining production comes from joint ventures with the national oil and gas companies and from blocks awarded under successive licensing rounds held under the New Exploration Licensing Policy introduced in 1999.

By contrast, the refining sector continues to strengthen. India has almost doubled its refining capacity in the last ten years and has added more than 2 mb/d of new capacity since 2005, with strong private sector participation from companies such as Reliance and Essar (India is now fourth in the world in terms of total refining capacity, behind only the United States, China and Russia). India's refinery assets include the largest refinery in the world, Reliance's Jamnagar complex, with over 1.2 mb/d of throughput capacity (more than India's domestic crude production). These capacity additions have given India a surplus of refined products, as the growth in oil product demand growth, even at an impressive 4.2% average annual rate, has been slower than the capacity boom.

Figure 11.9 ▷ Fossil-fuel balance in India



Note: Demand for crude oil shows refinery intake.

The refining capacity expansion, along with stagnant domestic crude oil output, means that India has become the third-largest crude oil importing country, behind the United States and China, with about 3.7 mb/d of import requirements (overall, India must import feedstock to meet 80% of its refinery needs for crude oil). The majority of ports that handle imported crude oil are located on the western side of India to accommodate oil tankers from the Middle East (the largest source of imports), Latin America and Africa. India has sought to diversify its sources of supply, especially as disruptions have plagued several of its suppliers such as Iran, Libya and Nigeria. The government announced in March 2015 a strategic aim to reduce reliance on imported crude by as much as 10% by 2022. The fall in the price of crude oil has also offered a cost-effective opportunity to build up emergency stockpiles of crude. With the expected completion of additional storage facilities for the strategic petroleum reserve expected in late 2015, India will have a combined storage capacity of about 37 million barrels, or roughly ten days worth of crude imports.

With refinery output exceeding total demand by roughly 1 mb/d, India is a net exporter of all refined products except LPG. India has been an important supplier of diesel to Europe and a regular supplier of transport fuel to Asia-Pacific and Middle Eastern countries. Its exports come mainly from the private sector refiners Reliance and Essar, while the public sector refiners supply the domestic market.[11] Growing product exports from India have contributed to refinery capacity rationalisation in both European and Asia-Pacific markets, as India's more modern, privately owned refineries, which are capable of efficiently processing Middle Eastern oil into high quality products, were able to gain market share from less complex refineries in Europe and Japan.

Natural gas

Natural gas has a relatively small share (6%) of the domestic energy mix. Optimism about the pace of expansion, fuelled by some large discoveries in the early 2000s, has been dashed by lower than expected output from offshore domestic fields. The main onshore producing fields are in the states of Assam in the northeast, Gujarat in the west and Tamil Nadu and Andhra Pradesh in the south. Some of the most promising areas are offshore, including the Krishna Godavari basin off the east coast. The production record in recent years has been strongly affected first by the start of production at the much-awaited KG-D6 offshore field in 2009, and then by its faster than expected decline because of reported subsurface complexity. This has contributed to an overall decrease in Indian gas output since 2011. Production of conventional gas reached 34 bcm in 2013 and was supplemented by LNG imports via four regasification terminals. The majority state-owned gas company, GAIL, is the largest player in the midstream and downstream gas market.

In addition to conventional gas resources, India also has large unconventional potential, both from coalbed methane (CBM) and shale gas. Commercial production at scale is still some way off, although CBM activity is starting to gain momentum, with a number of private companies, including Reliance and Essar, stepping up their involvement. In the case of shale gas, the government approved in 2013 an exploration policy that allows the two national companies – ONGC and OIL – to drill for shale resources in their existing blocks. However, upstream gas development in India continues to face a number of significant hurdles: a key issue is the price available to domestic producers (see section on energy prices and Chapter 13).

Hydropower

India has significant scope to expand its use of hydropower: its current 45 GW of installed capacity (of which over 90% is large hydro) represents a little under a third of the assessed resource. Much of the remaining potential is in the north and northeast. A further 14 GW are under construction, although some of these plants have been delayed by technical or environmental problems and public opposition. If developed prudently, hydropower can bring multiple benefits as a flexible source of clean electricity, and also as a means of water management for flood control, irrigation and domestic uses. It can also enable variable

11. This two-tier structure is the result of a subsidy system that compensated state refiners for losses on domestic sales but from which private sector refiners were excluded, leading the latter to focus on international markets. With the removal of subsidies on domestic transport fuels the situation is expected to change, and private refiners are expected to gain domestic market share.

renewables to make a greater contribution to the grid. However, its development has lagged well behind thermal generation capacity, leading to a consistent decline in its share of total electricity output. Capacity additions and generation have routinely fallen short of the targets set in successive government programmes, while the objective of bringing in private investors has likewise proved difficult to realise.

High upfront costs, the need for long-term debt (which is quite limited in India's capital markets) and consequent difficulties with financing have been a major impediment to realising India's hydropower potential. Much of the potential is in remote areas, necessitating new long-distance transmission lines to bring power to consumers. Adequate and efficient project planning and supervision is another hurdle, notably the challenge of evaluating and monitoring environmental impacts (including long-term water availability and potential seismic risks), ensuring adequate public involvement and acceptance, and assessing the effect of multiple projects (often in different states) on individual river systems. Some hydropower projects have faced very long environmental clearance and approval procedures, as well as significant public opposition arising largely from resettlement issues and concern over the impact on other water users. Some of these concerns can be reduced by undertaking small-scale projects: India has an estimated potential 20 GW of small hydro projects (up to 25 megawatt [MW] capacity) (MNRE, 2015). As of 2014, 2.8 GW of small hydro (less than 10 MW) had been developed.[12] Such projects are particularly well-suited to meet power requirements in remote areas.

Bioenergy

Bioenergy accounts for roughly a quarter of India's energy consumption, by far the largest share of which is the traditional use of biomass for cooking in households. This reliance gives rise to a number of problems, notably the adverse health effects of indoor air pollution. India is also deploying a range of more modern bioenergy applications, relying mainly on residues from its large agricultural sector. There was around 7 GW of power generation capacity fuelled by biomass in 2014, the largest share is based on bagasse (a by-product of sugarcane processing) and a smaller share is cogeneration based on other agricultural residues. The remainder produce electricity via a range of gasification technologies that use biomass to produce syngas, including small-scale thermal gasifiers that often support rural small businesses. Although modern bioenergy constitutes only a small share of energy use at present, Indian policy has recognised – with the launch of a National Bioenergy Mission – the potential for modern bioenergy to become a much larger part of the energy picture especially in rural areas, where it can provide a valuable additional source of income to farmers, as well as power and process heat for consumers.

Biofuels are another area of bioenergy development in India, supported by an ambitious blending mandate, dating back to 2009, that anticipates a progressive increase to a

12. The Ministry of New and Renewable Energy defines small hydro as up to 25 MW while the World Energy Model (WEM) used by the *World Energy Outlook* defines small hydro as less than 10 MW. The 2.8 GW refers then to the WEM definition.

20% share for bioethanol and biodiesel by 2017. Implementation has thus far been slower than planned: the present share of bioethanol – mostly derived from sugarcane – remains well under 5% and progress with biodiesel has been even more constrained. The main concern over biofuels – and some other forms of bioenergy – is the adequacy of supply: land for biofuels cultivation can compete with other uses, as well as requiring water and fertilisers that may be limited and is required in other sectors.

Wind and solar

From a low base, modern renewable energy (excluding hydropower) is rapidly gaining ground in India's energy mix as the government has put increasing emphasis on renewable energy, including grid-connected and off-grid systems. Wind power has made the fastest progress and provides the largest share of modern non-hydro renewable energy in power generation to date. India has the fifth-largest amount of installed wind power capacity in the world, with 23 GW in 2014, although investment has fluctuated with changes in subsidy policies at national and state level. Key supporting measures have included a generation-based financial incentive (a payment per unit of output, up to certain limits) and an accelerated depreciation provision. A scheme of renewable purchase obligations also exists, requiring that a certain percentage of all electricity should be sourced from wind, solar and other renewables, but the operation of this scheme has been undercut (and not enforced in some cases) by the financial state of many distribution companies.

Solar power has played only a limited role in power generation thus far, with installed capacity reaching 3.7 GW in 2014, much of this added in the last five years. However, India began to put a much stronger emphasis on solar development with the launch in 2010 of the Jawaharlal Nehru National Solar Mission, the target of which was dramatically upgraded in 2014 to 100 GW of solar installations by 2022, 40 GW of rooftop solar photovoltaics (PV) and 60 GW of large- and medium-scale grid-connected PV projects (as part of a broader 175 GW target of installed renewable power capacity by 2022, excluding large hydropower). The dependence of national targets on supportive actions taken at state level is underlined by the fact that four states (Gujarat, Rajasthan, Madhya Pradesh and Maharashtra) account for over three-quarters of today's installed capacity. Rooftop solar also has the potential to become a more important part of India's solar portfolio, particularly where it can minimise or displace expensive diesel-powered back-up generation.

While the promise is undeniable, renewable energy faces, like other energy source, structural, governance and institutional challenges. Though costs for solar and wind are declining, in most cases the technologies do not yet warrant investment in India (as in most other countries) without some form of subsidy. Fiscal incentives and policy support are strong at the moment, but this is a source of uncertainty, especially when juxtaposed with the financial difficulties faced by local distribution companies that are often obliged to absorb the extra cost. The need for land and additional transmission and distribution infrastructure (which India is trying to address via the concept of "green energy corridors") could likewise constrain progress. Given the priority in Indian policy to develop the domestic manufacturing sector, the outlook is also contingent to a degree on the local availability of equipment, such as solar panels and wind turbines, where India has lost ground to lower cost producers. In China, for example, the cost of locally produced solar modules and cells is 25-50% lower than in India.[13]

Nuclear power

India has twenty-one operating nuclear reactors at seven sites, with a total installed capacity close to 6 GW. Another six nuclear power plants are under construction, which will add around 4 GW to the total. The operation of the existing nuclear fleet has been constrained in the past by chronic fuel shortages, in 2008 the average load factor was as low as 40%. This constraint was eased after India became a party to the Nuclear Suppliers' Group agreement in 2008, allowing access not only to technology and expertise but also reactor parts and uranium. The average plant load factor rose to over 80% in 2013 (DAE, 2015).

Though the current share of nuclear power in the generation mix is relatively small at 3%, India has ambitious plans to expand its future role, including a long-term plan to develop more complex reactors that utilise thorium – a potential alternative source of fuel for nuclear reactors. India has limited low-grade uranium reserves, but it has the world's largest reserves of thorium: developing a thorium fuel cycle will though require a range of tough economic, technical and regulatory challenges to be overcome.

The nuclear industry in India is also subject to the broader challenges that are facing the worldwide nuclear industry, including project economics, difficulties with financing and the implications of the Fukushima Daiichi accident in Japan for public acceptance of new projects. India has struggled to attract the necessary investment and to gain access to reactor technology and expertise, with the Civil Liability Nuclear Damage Act of 2010 widely seen as deterring potential suppliers (especially Japanese and US companies). However, the United States and India reached an understanding on nuclear liability issues early in 2015 that may facilitate US investment in Indian nuclear projects.

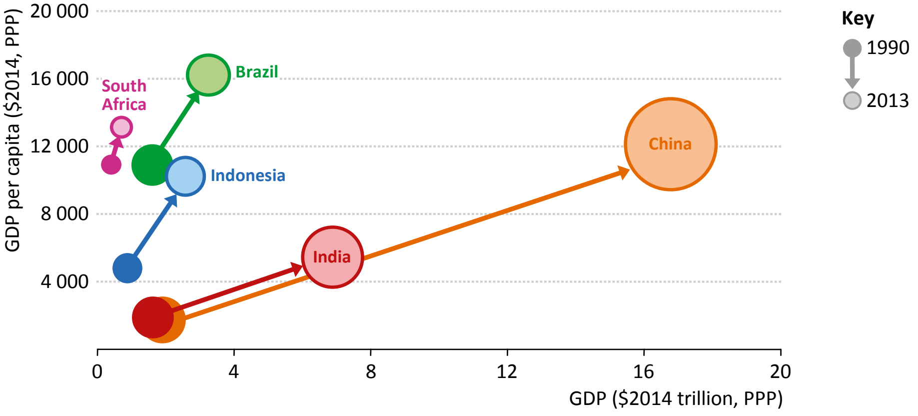
Factors affecting India's energy development

Economy and demographics

The pace of economic and demographic change is a vitally important driver of India's energy sector. Since 1990, India's economy has grown at an average rate of 6.5% a year, second only to China among the large emerging economies, and two-and-a-half-times the global average (if both these countries are excluded). This propelled India beyond Japan in 2008, to become the third-largest economy in the world, measured on a PPP basis. India alone has accounted for over 9% of the increase in global economic output since 1990.

13. Further details of developments in the relative cost of manufacturing renewables technologies can be found in Chapter 9.

Figure 11.10 ▷ **GDP per capita and total GDP for selected countries, 1990 and 2013**



Note: PPP = purchasing power parity.

In the period since the early 1990s, the poverty rate (measured as the proportion of the population making less than $1.25/day in PPP terms[14]) fell by more than half, from almost 50% to less than 25%. In the eight years 2004-2011, more than 180 million people in India were lifted out of extreme poverty. Despite this progress, income per capita is still low and a gap has emerged between India and its counterparts among the BRICS (Brazil, Russia, India, China and South Africa). Though starting off at similar levels in the early 1990s (in PPP terms), average income per capita in China is now more than double that in India (Figure 11.10). Furthermore, although extreme poverty has been reduced, income inequality has increased in India, with the poorest quartile of society earning a smaller share of total income than they did in 1990.

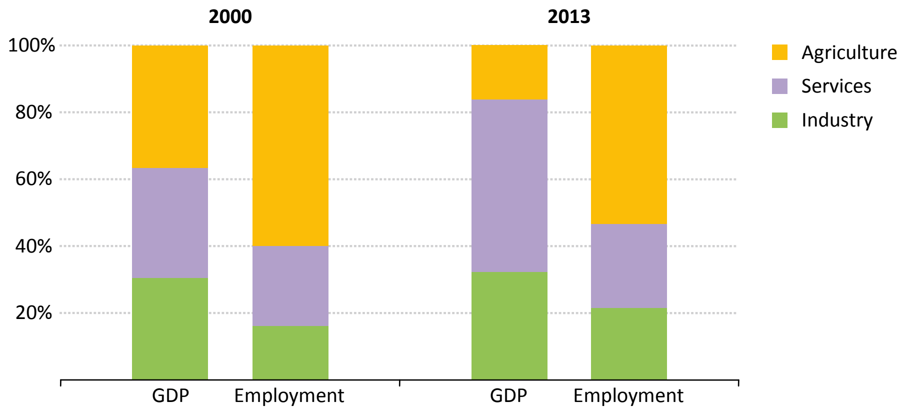
The services sector has been the major driver of growth in India's economy, accounting for around 60% of the increase in GDP between 1990 and 2013. This is rooted both in a robust increase in the supply of services but, crucially, also in the increasing share of high-value segments including financial intermediation, information and communications technology, and professional and technical services, which have enabled total factor productivity in the services sector to more than double. However, despite its dominant share in the economy, the services sector employs only around one-quarter of the labour force. The agricultural sector, with less than 20% of GDP (compared with just over 35% in 1990), continues to account for around half of total employment (Figure 11.11).

The services-led growth that India has enjoyed since the early 1990s differs from the path of economic development in many other countries, since it was not preceded by an initial strong push from the manufacturing sector. The government has expressed its intention

14. The benchmark for absolute poverty was adjusted upwards by the World Bank in late September 2015 to $1.90 per day.

to re-balance the economy and in 2014 announced the "Make in India" initiative, with the intention of increasing the share of manufacturing in GDP to 25% by 2022, creating 100 million jobs in the process. The extent to which this objective is realised will affect India's energy development in two ways. First, mining, oil and gas, renewables and power generation have all been identified as clusters for industrial development, so any success will have implications for energy supply. Second, any change in the share of industry in the economy, and the materials-intensity of future economic growth, will have profound effects on the levels of energy demand. Urbanisation and the build-up of a manufacturing base, including the necessary energy infrastructure, will require significant inputs from the basic materials industry, including steel, cement and chemicals, which are all highly energy-intensive.

Figure 11.11 ▷ Composition of GDP and employment structure in India



11

Since 1990, India's population has grown by over 380 million people, a number greater than the total population of the United States and Canada together. This includes a near-doubling of the urban population, reflecting the transition away from agricultural employment. Population growth is expected to remain high; India is set to overtake China as the most populous country in the world before 2025 (UNPD, 2015). India's large and growing population is often regarded as one of its major assets; it is relatively young, with almost 60% (around 700 million people) under the age of 30, a large and potentially very vibrant workforce. The large domestic market can also act as a natural driver for economic growth, with levels of private consumption currently around two-and-a-half-times as large as exports. The flip side of this demographic dividend is the likely strain on the country's infrastructure and resources. Water stresses that are already evident in some regions will be exacerbated and create new challenges in relation to food and energy security, and there will be a need to create one million new jobs each month to absorb the new entrants to the labour market.

Policy and institutional framework

The direction that national and state policies take, and the rigour and effectiveness with which they are implemented, will naturally play a critical role in India's energy outlook. Clarity of vision for the energy sector is difficult to achieve in India, not least because of the country's federal system and complex institutional arrangements. However, the drive for a more coherent and consistent energy policy has been a long-standing priority, typified by the Integrated Energy Policy 2008, the National Action Plan on Climate Change and the co-ordination efforts of the Planning Commission (now the National Institution for Transforming India, [NITI Aayog]), all aided by consistent improvements in the quality of Indian energy data (Box 11.3). An energy scenario modelling exercise has also been launched, the India Energy Security Scenarios, overseen by NITI Aayog.[15] More recently, the submission of India's Intended Nationally Determined Contribution (INDC) on 1 October 2015 was a milestone in both India's energy and its environmental policy.

India shares the overarching aim of energy policy throughout the world: to provide secure, affordable and universally available energy as a means to underpin development, while addressing environmental concerns. The administration in place since 2014 has given greater definition to many aspects of energy policy, while also seeking to give more rights and responsibilities to the individual states. Some key aspects of the emerging energy vision are:

- A commitment to the efficient use of all types of energy in order to meet rapidly growing demand. In the power sector, the decision to increase the target for renewables to 175 GW by 2022 (including the expansion of solar generation capacity to 100 GW) has attracted a lot of attention; but there is also, for example, a volumetric target for India to produce 1.5 billion tonnes of coal by 2020. Efficiency gains as well as production increases underlie India's energy security objective of reducing reliance on fossil-fuel imports by 10%.
- A sharpened focus on achieving universal access to modern energy, including the objective of supplying round-the-clock electricity to all of India's population. This is being accompanied by a reorientation of energy subsidy programmes, away from price controls and towards financial payments to the most vulnerable parts of society.[16]
- A drive for market-oriented solutions and increased private investment (including foreign investment) in energy, both through some energy-specific reforms (e.g. to licensing regimes) and via a general drive to simplify and deregulate the business environment.
- A pledge to pursue a more climate-friendly and cleaner path than the one followed thus far by others at corresponding levels of economic development. India's INDC includes the twin energy-related commitments to increase the share of non-fossil fuel

15. See *www.indiaenergy.gov.in*.

16. This is linked with the implementation of the Aadhaar system, a direct benefit transfer scheme introduced in 2013 that links a personal identification number to a bank account (see section on pricing).

power generation capacity to 40% by 2030 (with the help of transfer of technology and low cost international finance) and to reduce the emissions intensity of the economy by 33-35% by the same date, measured against a baseline of 2005.

Box 11.3 ▹ India's energy sector data

Energy data in India is available from a variety of sources, with the main ministries all collecting data within their areas of responsibility: for example, the Central Electricity Authority, under the Ministry of Power, takes the lead in providing statistical information on the electricity sector. Selected data from these sources are compiled by the Central Statistics Office into an annual "Energy Statistics" publication. The latest version covers the period to 31 March 2014, meaning that the latest calendar year for which there is full coverage is 2013 (most Indian data are available for fiscal years, which run from April to March) (CSO, 2015).

Data from these official energy institutions and from the Central Statistics Office are the bedrock of the statistical information used in this report. In some cases, however, the way that the data are collected and reported does not match exactly the IEA's reporting requirements, so certain additional numbers in the IEA databases are taken from secondary sources or estimated by analysing related indicators. This applies, for example, to the use of solid biomass as an energy source, the use of back-up or off-grid generation and the split of oil product demand across end-use sectors. Differences in the definitions used and in fiscal years versus calendar year reporting, can also lead to some adjustments being made.[17] In some areas, the *World Energy Outlook* uses a single global source in order to ensure a consistent underlying methodology: this is the case for installed thermal power generation capacity, which is drawn for all countries from a dataset maintained by Platts.

Achievement of these aims is naturally contingent on the broader political and institutional context. India is a federal, democratic country in which regional and local politics and governments play a very important role, via the 29 constituent states and 7 union territories (their role is reflected in the bi-cameral national parliamentary structure, where the lower house, elected by direct popular vote, sits alongside an upper house, representing the states and territories). The constitution divides power between the central and state governments, as well as defines a category of subject areas for which there are concurrent responsibilities. The central government has exclusive competence over inter-state trading and commerce, as well as mineral and oil resources, nuclear energy and some national taxes, e.g. on income. States have jurisdiction over water issues and land rights, natural gas infrastructure, and many specific areas of taxation, e.g. on mineral rights or the

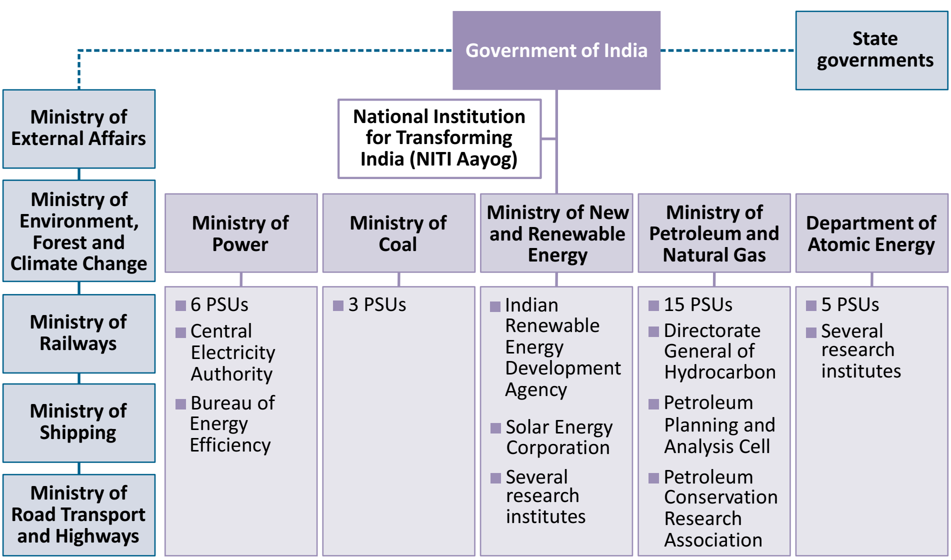
17. For example, the Coal Directory of India uses a national classification scheme for coal grades (depending on their energy content) different from that used by the IEA statistical services. This can result in differences in supply and demand values when expressed in million tonnes of coal equivalent.

consumption or sale of electricity. Concurrent powers include electricity and forestry, as well as economic and social planning, and labour relations.

India's federal structure puts a premium on constructive relations between states and the central government, but also risks duplication and inconsistent decision-making. The model being promoted by the new administration is one of co-operative federalism, which involves increased devolution in certain areas (e.g. a higher regional share of hydrocarbon revenues in some cases) as well as a wider set of regional responsibilities (e.g. for timely implementation and approval of the state-level clearances required for investment projects). There is also a greater accent on tailoring policies and resource use, particularly in the power sector, to the specificities of individual regions and states. Maintaining independent regulatory bodies, free of political interference (for example, as envisaged in the 2003 legislation reforming the power sector), is a challenge at all levels.

The risk of fragmented decision-making also applies at the national level itself, as there is no single body charged with formulating and implementing a unified energy policy. India has several ministries and other bodies, each with partial responsibility for aspects of energy policy and the related infrastructure (Figure 11.12). Effective co-ordination has been improved by the appointment of a single Minister for Power, Coal, New and Renewable Energy, although the individual ministries themselves continue to exist as separate entities. The institutional structure requires constant effort – not always successful – to achieve co-ordination and resolve disputes.

Figure 11.12 ▹ Main institutions in India with influence on energy policy



Notes: PSU = Public sector undertaking (state-owned enterprise). Other ministries with responsibilities relevant to the energy sector include the Ministry of Urban Development, Ministry of Water Resources, Ministry of Agriculture, Ministry of Finance and the Department of Science and Technology.

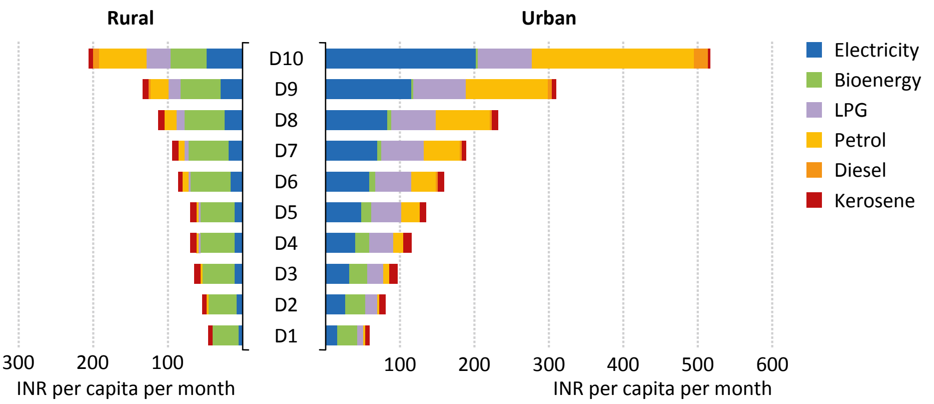
Source: Adapted from (IEA, 2012).

Energy prices and affordability

Expenditure

The relationship between income levels, energy prices and energy expenditure is fundamental to the evolution of India's energy system. As one would expect, energy consumption increases with income, with the wealthiest 10% of the population accounting for around a quarter of all household energy expenditure, although the poorest segments spend a greater proportion of their income on energy. But the level of consumption and the fuel choice are also affected by location: household expenditure on energy is, on average, almost two-and-a-half-times higher in urban centres than in rural areas, and the most affluent among the urban population spend more than eight-times as much on energy as the poorest, whereas in rural areas they spend four-and-a-half-times as much (Figure 11.13).

Figure 11.13 ▷ Per-capita energy expenditure by location and income in India



Notes: INR = Indian rupees. The income ranges are by decile (i.e. 10% slices) of the rural and urban population, with D10 being the most affluent 10% and D1 the poorest.

Source: Ministry of Statistics and Programme Implementation (2012).

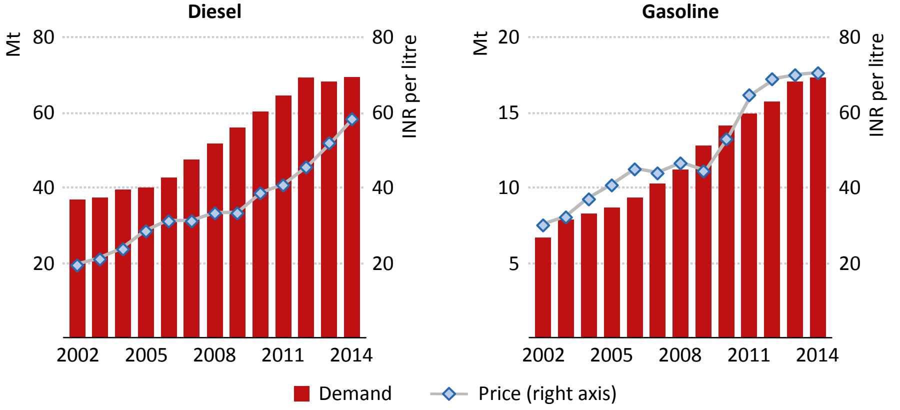
The expenditure pattern across the income groups reflects both an increase in energy consumption as people become more affluent and a switch in fuels, away from bioenergy and kerosene and towards LPG and electricity. In urban areas, spending on bioenergy and kerosene decreases drastically higher up the income groups. Bioenergy and kerosene account for almost 60% of energy expenditure among the poorest income group, but only roughly 1% among the wealthiest group in which 85% of energy expenditure is for electricity and transport fuels.

The pattern is different in rural areas. Here, spending on bioenergy increases as income increases (for all but the wealthiest 20%), driven by a rise in consumption, but also because the poorer segments of society typically collect fuelwood rather than pay for it, an inclination that gradually decreases with increasing levels of wealth. The pattern of expenditure of the most affluent decile in rural areas is significantly different from that of lower income groups, resembling the switch that is observed in urban centres, albeit in a more limited way. Across income levels, rural spending on electricity accounts for around 20% of energy expenditure (compared with almost 40% in urban areas). Rural expenditure is constrained by a lack of access, particularly among the poorest segments of rural communities.

Energy prices

India has made significant moves towards market-based pricing for energy in recent years: gasoline (in 2010) and diesel (2014) prices have both been deregulated, and successive governments have made efforts to ensure that electricity and natural gas prices better reflect market realities. End-use electricity tariffs for most consumers nonetheless remain below the cost of supply. Reform of kerosene and LPG pricing has been much slower, reflecting the role that these fuels play in providing lighting and cooking fuels to the poorest segments of society. As a major consumer and importer of oil, India has also been one of the main beneficiaries of the fall in the oil price since 2014 (see Box 12.2 in Chapter 12).

Figure 11.14 ▷ Diesel and gasoline prices and demand, 2002-2014



Notes: Mt = million tonnes; INR = Indian rupees. Year denotes fiscal year, starting in April and ending in March.

Source: Petroleum Planning and Analysis Cell (2015).

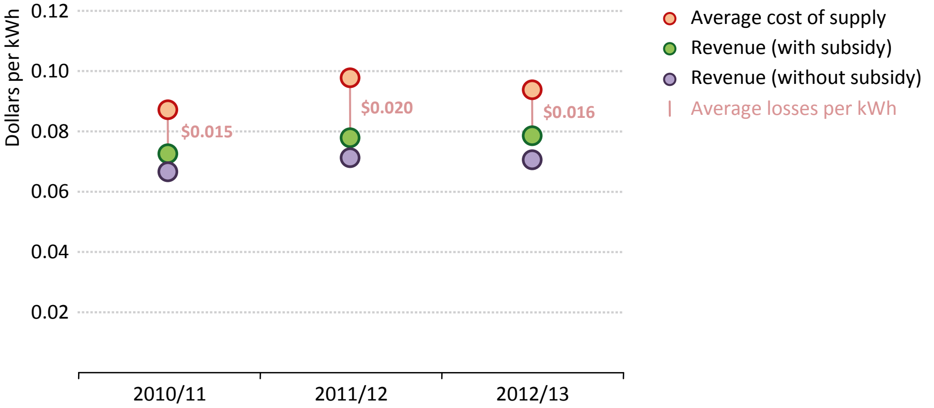
Diesel is the most widely consumed petroleum product in India, accounting for around 40% of total oil product consumption. In 2002-2010, the price of diesel was, on average, 70% that of gasoline and this price gap widened when gasoline prices were deregulated in 2010. Price differentials have recently lessened with the removal of diesel subsidies, resulting in diesel consumption flattening as consumer preferences shift towards gasoline (Figure 11.14). During the period in which transport fuels were subsidised, the benefits accrued disproportionately to the wealthiest strata of society: prior to the deregulation of diesel prices, the bottom two income deciles benefited to the tune of 20 Indian rupees (INR) per capita per month on average from subsidies, while the top two deciles received around INR 120 per capita per month (Anand, 2013). Where subsidies to oil product consumption remain, as in the case of LPG, the government is committed to make them more efficient: the "Aadhaar" system, coupled with recent efforts to spread banking service access to all, will increasingly allow the authorities to make a monetary payment directly to eligible consumers, after they have purchased gas cylinders at market prices. The government also launched a "Give it up" campaign to encourage the wealthiest consumers to abandon their LPG subsidy. As of September 2015, over three million Indians had voluntarily given up the subsidy.

The Indian gas market consists of two segments: for domestically produced gas, the price is defined by the government, as are the priority uses (city gas for households and transport, fertiliser plants, grid-connected power plants) which are entitled to gas at this lower price. After a long debate, in October 2014 the government introduced a new pricing formula, linked to a basket of international prices and applicable to most domestically produced gas; this resulted in a price increase from the earlier \$4.2 per million British thermal units (MBtu) to around \$5.6/MBtu, although this has since come down because of the subsequent fall in the reference prices. The new arrangements have kept the price in a range acceptable to domestic gas-consuming sectors, but many gas-producing companies argue that they do not offer sufficient incentive to bring forward new investment in exploration and production in India, particularly in offshore blocks (see Chapter 13). Imported LNG is available at contracted prices that can be significantly higher; there have been proposals to pool LNG with domestically produced gas to make it more accessible to domestic users as well as a subsidy scheme to increase consumption of imported LNG in the power sector.

As noted in the electricity section, average end-use electricity tariffs in India do not adequately reflect the cost of electricity supply, with government subsidies covering a part of the gap and the rest being absorbed as losses by state-owned distribution utilities (Figure 11.15). According to national policy guidelines, the state electricity regulatory bodies are supposed to set tariffs within a 20% range of the average cost of supply, but this is rarely the case. As of 2010-11, with the exception of three states (Gujarat, Maharashtra and West Bengal), average tariffs for consumers were less than 80% of the cost of supply (TERI, 2015).

The consumption changes spurred by the recent increase in diesel prices relative to those of gasoline reflect the conventional wisdom that higher prices can act as a brake on demand, spurring consumers to switch fuels, reduce their consumption or opt for more efficient technologies. The inverse relationship, where low tariffs lead to inefficient use of both electricity and water, is evident in the agricultural sector, which accounts for more than one-fifth of final electricity consumption but only 8% of revenue for the utilities.

Figure 11.15 ▷ **Average cost of electricity and average revenue in India, 2010-2013**



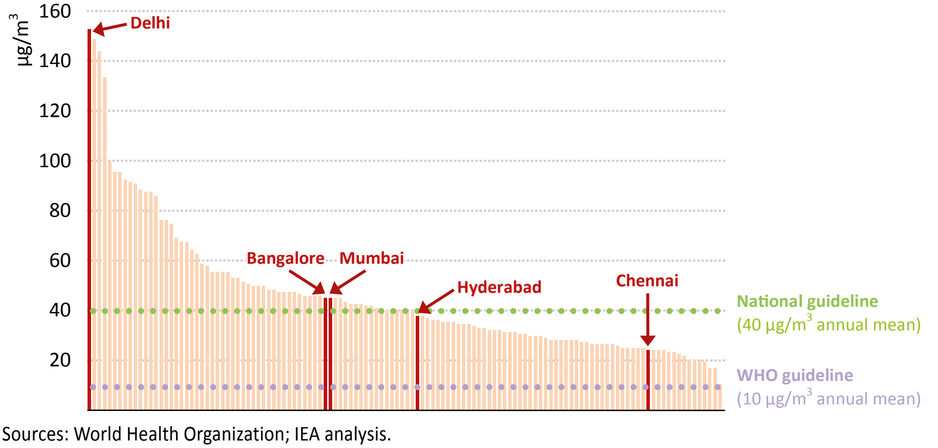
Sources: Power Finance Corporation; IEA analysis.

Social and environmental aspects

Local air pollution

Rapid economic growth and urbanisation create a number of pressures on communities and the wider environment. These can originate from the need to meet growing demand for energy and minerals that increase competition for land, water and other resources, as well as the polluting by-products of the subsequent growth. India is burning more fossil fuels and biomass than it has at any other time in the past, releasing more pollutants, including fine particulate matter ($PM_{2.5}$)[18] and sulphur and nitrogen oxides, into the air.

Figure 11.16 ▷ **Average annual particulate matter concentration in selected cities in India**



Sources: World Health Organization; IEA analysis.

18. $PM_{2.5}$ refers to particulate matter less than 2.5 micrometres in diameter; these fine particles are particularly damaging to health as they can penetrate deep into the lungs when inhaled.

In addition to the problem of indoor air pollution linked to the traditional use of biomass as a cooking fuel, the deteriorating air quality in growing urban centres is becoming an alarming issue for India (Figure 11.16). Of the 124 cities in India for which data exist, only one, Pathanamthitta (with a population of 38 000), meets the World Health Organization guideline for $PM_{2.5}$ concentrations. Delhi exceeds this guideline by fifteen-times. India has 13 of the world's 20 most-polluted cities and an estimated 660 million people in areas in which the government's own national air quality standards are not met. It is estimated that life expectancy, as a result, is reduced by 3.2 years for each person living in these areas.

Land

The welfare of India's rural population, which is 850 million strong and accounts for almost 70% of the total population, is closely linked to the amount of land they have available for productive use. Land acquisition for public or private enterprises wishing to build infrastructure, from roads and railways to power plants and steel mills, is therefore an issue fraught with social and political sensitivity. Legislative changes introduced in 2013 introduced stringent procedural requirements for land acquisition, defining compensation payments and rehabilitation and resettlement benefits and stipulated that potential developers in the private sector would need to secure the consent of 80% of affected families in the case of land acquisition (70% for acquisitions by public-private partnerships). There have since been attempts to amend this legislation, but finding an appropriate balance between the drive to push ahead with infrastructure projects, on the one hand, and the rights of local communities, especially farmers, on the other, is proving difficult. In the absence of a resolution to this issue, obtaining the required statutory clearances related to community rights, environmental protection and sustainable development has been a major cause of delay. At end-2014, infrastructure projects valued at around 7% of GDP were stalled for these reasons (OECD, 2014). Projects in the energy sector are particularly susceptible to delay: detailed analysis of projection applications showed that the clearance process for some 40-60% of projects in thermal power, hydropower, coal mining and nuclear power sectors went beyond the statutory time limits (Chaturvedi et.al, 2014).

Water

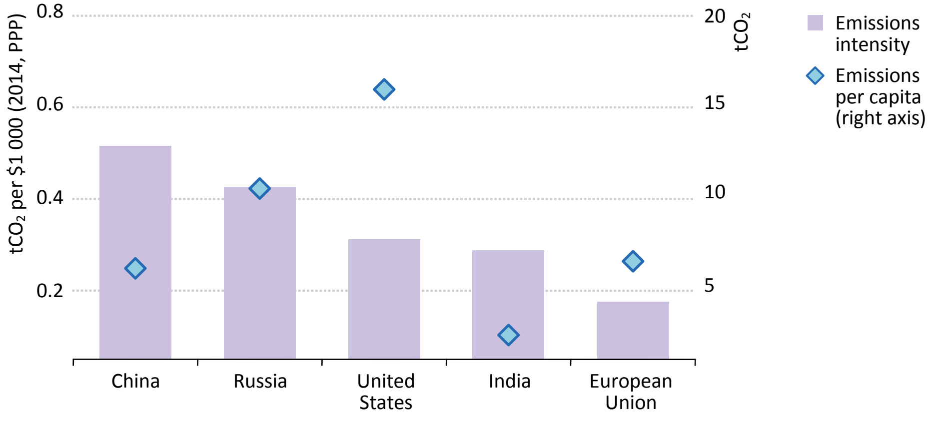
High rates of population and economic growth, along with highly inefficient patterns of water use in the agricultural sector, are putting severe strain on India's water resources. With renewable water resources of some 1 130 cubic metres per capita in 2013, India has now passed the defined threshold for "water stress" (1 700 cubic metres per capita). This has major implications for the energy sector: more than 70% of India's power plants, for example, are located in areas that are water stressed or water scarce (WRI, 2014) and India's warm temperatures and the poor quality coal used in the bulk of its power plants add to their cooling requirements. Global climate change could exacerbate these stresses.

Around 90% of India's water withdrawal is for use in agriculture and livestock, often extracted by tube wells powered from the grid and drawing from groundwater reserves. Subsidised electricity tariffs for agricultural users and a lack of metering have led to hugely inefficient consumption of both electricity and water: in 2010, more water was withdrawn in India for agricultural use alone than for all purposes in China. A number of national and state-level initiatives have sought to encourage more efficient water use, via metering, tariff reform (linked to more reliable supply) and changes to agricultural practices. Plans to introduce more efficient equipment, including solar-powered groundwater pumps, while relieving some pressures on the grid, could reduce incentives for water conservation unless they are accompanied by the introduction of systems that use water more efficiently, such as drip irrigation networks.

Carbon-dioxide emissions

India's CO_2 emissions can be seen through two lenses. Calculated on a per-capita basis, emissions are extremely low, standing at just one-quarter of China's and the European Union's and one-tenth the level in the United States (Figure 11.17), while India also accounts for only a small share of cumulative historical GHG emissions. On the other hand, India is the third-largest country in volume terms of CO_2 emissions in the world, behind only China and the United States. Heavy dependence on coal for power generation and the use of inefficient subcritical plants to burn it push up the carbon intensity of India's power sector to 791 grammes of carbon dioxide per kilowatt-hour (g CO_2/kWh), compared to a world average of 522 g CO_2/kWh.

Figure 11.17 ▷ Carbon intensity of GDP and energy-related CO_2 emissions per capita in selected regions, 2013

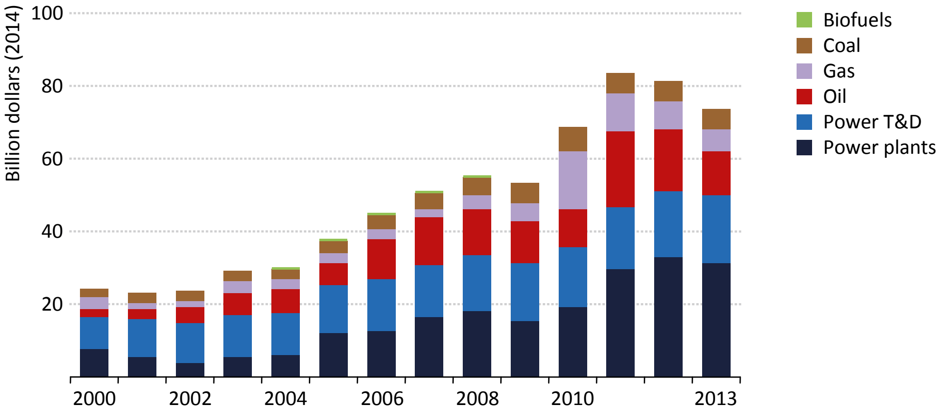


Note: tCO_2 = tonnes of carbon dioxide; PPP = purchasing power parity.

Investment

Since 2000, we estimate that investment in energy supply in India has increased substantially, reaching almost $77 billion on average since 2010 (Figure 11.18). The power sector absorbs the largest share, spurred by the rapid increase in demand as encouraged by the liberalisation agenda launched by the landmark Electricity Act in 2003. Maintaining a rising trend in infrastructure spending, especially energy sector spending, is a major government policy priority. India's government aims to increase investment in infrastructure (broadly defined, including communications, road, rail and energy networks, as well as social areas such as schools and hospitals) to 8.2% of GDP, from roughly 7.2% in 2007-2011. More than a third of this $1 trillion in infrastructure spending is to go to electricity, renewable energy, and oil and gas pipeline projects, with around half from private investment.[19] Relieving infrastructure bottlenecks, particularly those related to poor road and rail infrastructure, inefficient ports and unreliable electricity supply, is widely recognised as essential to meet India's economic growth and development ambitions (IMF, 2015).

Figure 11.18 ▷ Energy supply investment by type, 2000-2013



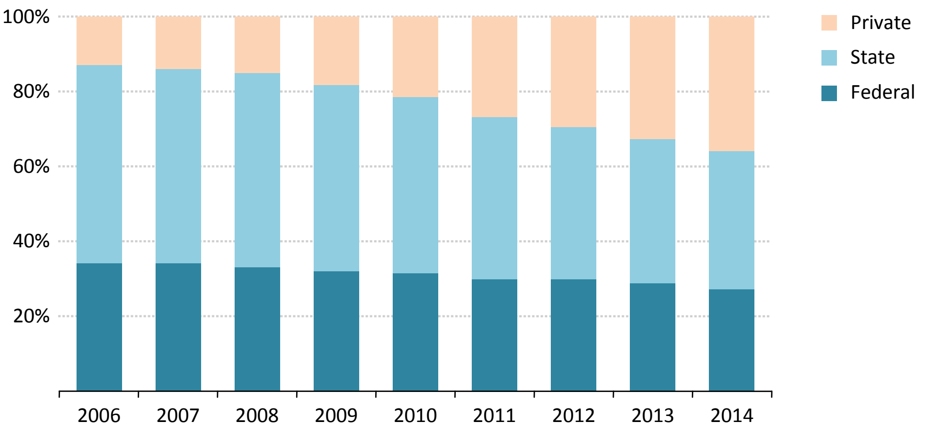
Note: T&D = transmission and distribution.

As the Indian government has recognised, public funds sufficient to support the necessary investment projects in the energy sector cannot be taken for granted, in the face of increasing competition from other areas of public spending (including healthcare, pensions, education, etc.). So meeting the country's investment needs will require the mobilisation of increasing amounts of private capital, including foreign direct investment (FDI). Access to such investment opportunities by the private sector though is uneven across the Indian energy economy and a number of broader impediments to attracting investment persist, such as the complex regulatory environment, in relation to which the World Bank has ranked India 142 out of 189 countries in terms of ease of doing business. Despite these impediments, India's vast potential puts it high on the list of prospective destinations for foreign investment, ranking third behind China and the United States. Furthermore, 2014 saw a significant increase in FDI inflows, which rose by 22% compared to the previous year, to a total of over $34 billion (UNCTAD, 2015). Preliminary numbers for FDI in 2015 show a further substantial increase.

19. Since 1990, investments worth $330 billion have been made through public-private partnerships, of which over 40% were in the energy sector. In the last five years, India has had the highest amount of infrastructure investment co-financed with the private sector among the low and middle income countries (OECD, 2014).

Since the late 1990s, steps have been taken to deregulate the oil and gas sectors, notably successive bidding rounds held under the New Exploration Licensing Policy, which have been open to a range of private players. However, these two sectors remain dominated, in practice, by a handful of state concerns and the process of opening the coal sector to private investment is only just beginning. The power generation sector has been open to private participation for some time and the government has offered a range of fiscal incentives to increase the attractiveness of projects. Since 2006, 6 GW out of every 10 GW of net capacity added to the grid has been financed by private investors, whose share of generation has increased quickly, to reach more than one-third of the total (Figure 11.19). Private sector involvement in the distribution side of the power system is much more limited. Presently the distribution utilities are largely state-controlled and administered, and the priority given to regional social sensitivities often contributes to the under-recovery of costs across the sector.

Figure 11.19 ▷ Power generation capacity by type of ownership in India



Source: Central Electricity Authority.

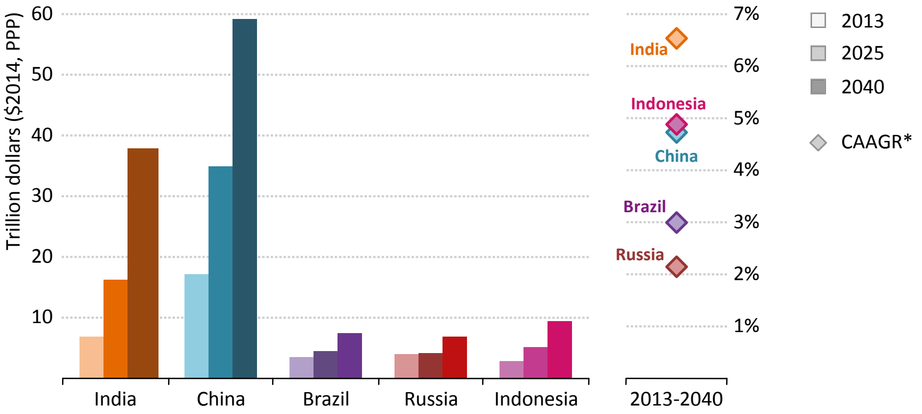
Projecting future developments

The projections for the India energy outlook presented in the following chapters are derived by means of the same overall analytical approach as those elsewhere in the *Outlook* (see Chapter 1), but with additional analysis to draw out the policy choices facing India and their implications. The primary focus throughout is the New Policies Scenario – our central scenario – which takes into consideration both existing policies and regulations as well as India's announced policy intentions, such as the targets for renewables and coal and the push to provide universal, reliable electricity access. A cautious view of the pace of implementation is taken throughout the New Policies Scenario, meaning that in the case of India, government targets and objectives are not always reached. This is not a judgement of the feasibility of the government's ambitions or its commitment to them, but reflects our view of the real-life constraints – including regulatory, financial and administrative barriers – that have to be faced. Given the uncertainty that is inherent in long-term projections, we refer in this special focus to a number of alternative scenarios and cases for India, alongside the New Policies Scenario.[20] In Chapter 14, we also develop a case specific to the India special focus, an Indian Vision Case, which reflects the full realisation of India's policy aim to increase the share of manufacturing in its economy, alongside the earlier attainment of energy policy objectives, notably for universal electricity access, and more rapid development of low-carbon energy sources and energy efficiency.

Economic and population growth

India's changing economy is a fundamental driver of its energy development to 2040. In the New Policies Scenario, average annual growth remains at 7.5% until 2020, before slowing gradually to around 6.3% per year by the 2030s. For the entire period to 2040, India's economy grows at a faster rate than any other in the world, by an average of 6.5% per year. By 2040, the economy is over five-times its current size (Figure 11.20). Nearly $1 in every $5 of additional economic output generated in the global economy over the projection period comes from India, leading to a four-fold increase in GDP per capita.

Figure 11.20 ▷ Size of GDP and GDP growth by selected economies, 2013-2040



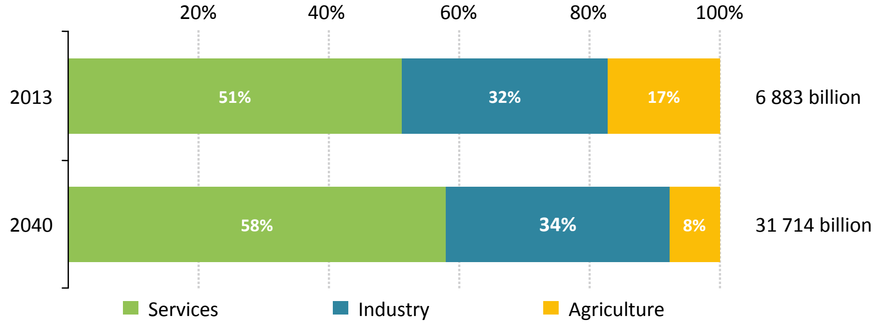
*CAAGR = compound average annual growth rate.

The economic growth path for India is higher than that in the *World Energy Outlook-2014*, by 0.4 percentage points a year, reflecting both a revision of purchasing power parity calculations in 2014 by the International Comparison Program (and subsequently by the International Monetary Fund) and the methodological change adopted by India itself in

20. Three of these scenarios reflect results derived from the global modelling work undertaken for *WEO-2015*, from the Current Policies Scenario, the 450 Scenario, and a Low Oil Price Scenario (which examines the potential implications of an extended period of lower oil prices, compared with the trajectory for oil prices envisaged in the New Policies Scenario – see Chapter 4).

early-2015. These changes, which affect the base year, mean that the economy today is 36% larger than calculated under the previous methodology. The effect of economic development on the pattern of energy use is not limited to size and the rate of growth, but includes changes to its composition (Figure 11.21). In the New Policies Scenario, though rising less rapidly than targeted by the government, the share of industry in GDP (which includes manufacturing, construction and the extractive industries) does increase over the coming decades, pushed higher by a policy and demand-driven expansion of the manufacturing sector, the "Make in India" initiative. The share of services likewise expands, both at the expense of agriculture.

Figure 11.21 ▷ **GDP composition by sector in India, 2013 and 2040** (PPP terms)



Population growth and changes in the population dynamics is another key driver of energy trends. India is already the second-most populous country in the world, with more than 1.25 billion people in 2013. Despite the population growth rate to 2040 slowing to almost half the average rate in 1990-2012 (from 1.6% to 0.9%), growth remains strong enough for India to overtake China as the world's most populous country by 2025, with India's population rising to 1.6 billion by 2040. Almost all of the net growth in the Indian population is absorbed into India's cities: the 315 million increase in India's urban population is roughly equivalent to the entire population of the United States today. The urban share of the total population rises from less than a third to 45%, and means that, at 715 million, there are more people living in cities in India in 2040 than there are in the United States, Japan and Mexico combined. The pattern of urbanisation that India follows has critically important implications for the evolution of its energy consumption.

Energy prices

Energy prices in these projections are largely derived from the international price trajectories described in Chapter 1. They vary according to the scenarios under consideration (the Indian Vision Case shares the same international energy price assumptions as the New Policies Scenario). These price assumptions feed through into India's domestic prices, albeit with important qualifications that depend on national policies. The domestic prices of all oil products, except LPG and kerosene, are assumed to be linked to international prices, and those of LPG and kerosene converge towards the international price, reflecting the assumption that policy interventions affecting the price levels of these products are replaced by targeted direct payments to the most vulnerable.

In the case of natural gas, the domestic price level is a weighted average of the price for imported LNG (which, in the New Policies Scenario, remains relatively low over the medium term before rising back to over $9/MBtu in 2020 and almost $13/MBtu by 2040) and the assumed price paid to domestic producers. The latter evolves in line with the new pricing formula introduced in October 2014, which produces a gradually increasing trend; but we assume that this formula is modified to provide a greater incentive for domestic output (this reflects a generic assumption in our modelling that import-dependent countries make efforts to stimulate domestic production and reduce import dependence). Similarly, in the coal sector, we assume a gradual convergence between domestic and international prices in India, driven both by rising domestic mining costs and by the increasing use of market-based instruments to determine prices. In the case of electricity, we assume continued preferential tariffs for certain groups (agricultural consumers, low-income groups) but that, over time, the average end-use tariff reaches a level that remunerates in full the costs of supply, including a reasonable rate of return (accompanied by financial restructuring of the state distribution companies). This reflection of India's policy intentions is a necessary long-term condition for the sound functioning of the electricity market.

Policies

India is undergoing a rapid social and economic transformation, in which strong economic growth, a burgeoning middle class and large-scale urbanisation underpin broader development. Indian policy-makers face the twin challenges of meeting the growing energy requirements to fuel this transformation, while also ensuring that growth is equitable, its fruits shared fairly among India's vast population. As a result, energy security imperatives, including quality, resilience and diversity of supply, but also issues of access, poverty alleviation and affordability are assured to form the foundations of Indian energy policy-making. In terms of the energy mix, India is seeking to balance its development needs with the need to increase the share of low-carbon sources in the energy mix. Its vision provides a continued, important place for coal, alongside a strong push in favour of renewable sources of energy, particularly solar and wind power.

For this special report, we have conducted an extensive review of India's existing policies, regulations and programmes affecting the energy sector, as well as its announced intentions, assessing in each area the record of past achievement and what this might mean for the prospects and speed of future progress. The way that policies shape our projections is discussed in more detail in the chapters that follow. Table 11.2 is a summary of India's domestic policy objectives and assumptions that are taken into account in the New Policies Scenario.[21]

21. The energy-related pledges in India's INDC have not been explicitly included in the assumptions for the New Policies Scenario, as they were announced in October 2015, shortly before publication, but the key underlying policy measures that support the attainment of INDC objectives are taken into consideration.

Table 11.2 ▷ Selected policy assumptions for India in the New Policies Scenario

Cross-cutting policies
■ Priority attached to the energy-related National Missions (on solar energy and enhanced energy efficiency) from the 2008 National Action Plan on Climate Change, as well as the wind power targets.
■ A continued levy on coal (domestic and imported) to support the National Clean Energy Fund.
Energy supply
■ Measures to increase fossil-fuel supply, notably of coal, in order to limit import dependence.
■ Greater encouragement to private investment in energy supply, through loosening of existing restrictions and simplification of licensing procedures.
■ Efforts to expedite environmental clearances and land allocation for large energy projects.
Power sector
■ A strong push in favour of renewable energy, notably solar and wind power, motivated by the target to reach 175 GW of installed renewable capacity (excluding large hydro) by 2022.
■ Enhanced efforts on village electrification and connection of households lacking electricity supply, with the aim to reach universal electricity access.
■ Move towards mandatory use of supercritical technology in new coal-fired power generation.
■ Expanded efforts to strengthen the national grid and reduce losses towards the targeted 15%.
Transport
■ Fuel-efficiency standards for new cars and light trucks starting in 2016.
■ Policy support for biofuels (via blending mandates) and natural gas, hybrid and electric vehicles.
■ Dedicated rail corridors to encourage a shift away from road freight.
Industry
■ Efforts to increase the share of manufacturing in GDP, via the "Make in India" programme.
■ Enhanced efficiency measures in line with the Perform, Achieve and Trade scheme; support for energy audits, as well as new financing mechanisms for energy efficiency improvements.
Buildings
■ Efforts to plan and rationalise urbanisation in line with the "100 smart cities" concept.
■ Moving from voluntary to mandatory appliance standards; application to a wider range of appliances.
■ Extension of the building code and efforts to incorporate it more into local and municipal by-laws.
■ Subsidies for LPG as an alternative to solid biomass as a cooking fuel.
Agriculture
■ Shift towards metered electricity consumption.
■ Continued gradual reforms to energy pricing, promotion of micro-irrigation, groundwater management and crop diversification.

Outlook for India's energy consumption

Is the sky the limit?

Highlights

- In India energy demand is propelled upwards to 2040 by an economy that grows to more than five-times its current size and population growth that makes it the most populous country in the world. Energy consumption more than doubles to 2040, with the rise in coal use making India by far the largest source of growth in global coal demand. A 6 mb/d rise in oil use is likewise the largest projected for any country, as 260 million new passenger vehicles are added to the stock and as LPG substitutes for fuelwood as a cooking fuel in households.
- An extra 315 million people are anticipated to move to India's towns and cities by 2040, and urbanisation underpins many of the changes in energy use, accelerating the switch to modern fuels and the rise in appliance and vehicle ownership, and pushing up demand for steel, cement and other energy-intensive materials. With rising incomes and 580 million additional electricity consumers by 2040, electricity demand in the residential sector increases by more than five-times.
- Industry remains the largest among the end-use sectors, as India's strong demand for infrastructure and consumer goods boosts the outlook for manufacturing. Transport shows the fastest growth, both for freight and for personal mobility. Energy efficiency policies have broadened in recent years to include fuel-efficiency standards for passenger vehicles and an innovative certificate trading scheme in industry, although their coverage across other sectors remains incomplete.
- The power sector is pivotal for India's energy and economic outlook. The poor financial health of the distribution sector has created a cycle of uncertainty for generators, under-investment in infrastructure and poor quality of service in many regions. Regulatory and tariff reform, a robust system of permitting and approvals, grid strengthening and major capacity expansion are pivotal to allow power supply to catch up and keep pace with burgeoning demand, which, boosted by new connections to the grid, increases at 4.9% per year.
- Installed power capacity surges from below 300 GW today to over 1 000 GW in 2040. Nearly half of the net increase in coal-fired generation capacity worldwide occurs in India, although the shift to more efficient technologies brings average coal plant efficiency up from 34% to 38% by 2040. Led by solar and wind power, the rapid growth in renewables, together with a large increase in nuclear capacity, means that these sources account for more than 50% of new capacity brought online. Nonetheless, without stringent policies to control energy-related emissions of gases, dust and fumes from the power sector, industry and transport, India will face a continued deterioration in air quality.

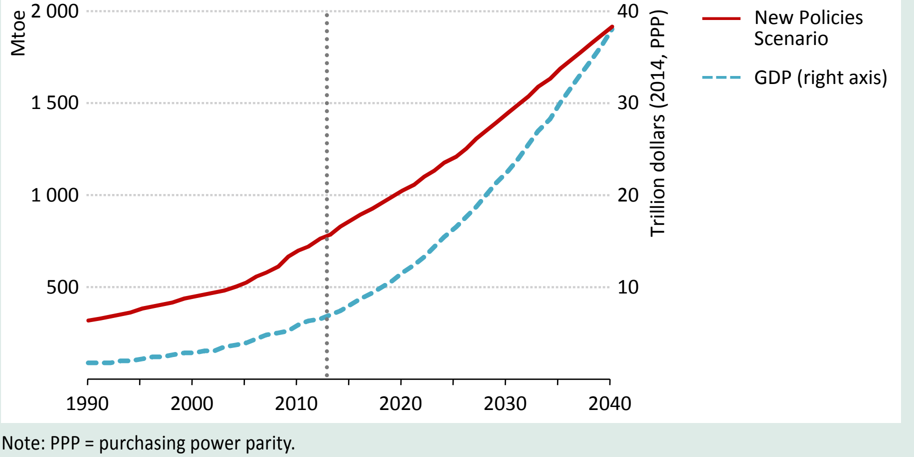
India: a rising force in global energy demand

Energy demand in India is projected to soar over the coming decades, propelled by an economy that grows to reach more than five-times its current size by 2040 and a demographic boom that sees India become the most populous country in the world by 2025. Energy use more than doubles to reach 1 900 million tonnes of oil equivalent (Mtoe) by 2040 (Figure 12.1). The rise in energy use is slower than the increase in gross domestic product (GDP) (Box 12.1), but still represents around one-quarter of the total increase in global energy consumption over the period to 2040. Because of India's strong population growth, consumption per capita falls slightly short of doubling; the level reached in 2040 is around 60% of the global average, up from 33% today.

Box 12.1 ▷ The coupling and decoupling of GDP and energy use in India

The relationship between GDP growth and energy demand is affected by a range of economic, structural and technological factors. Energy demand tends to rise faster than household income as people get access to reliable electricity, prompting purchases of an increasing number of appliances (e.g. lighting, refrigerators, cookers, fans, air conditioners). Energy demand also grows more rapidly than economic output when growth is concentrated in energy-intensive industrial sectors or when people shift their transport habits from trains or buses to individual vehicles. On the other hand, GDP growth from the services sector of the economy tends to require relatively little energy and the relationship between GDP and energy consumption can be further loosened by improvements in energy efficiency. In our projections for India, even with relatively strong growth in manufacturing, it is these latter effects that dominate, with the result of a gradual reduction in the overall energy intensity of India's economy – from 0.11 tonnes of oil equivalent (toe) per $1 000 in 2013 to 0.05 toe per $1 000 in 2040.

Figure 12.1 ▷ GDP and primary energy demand growth in India in the New Policies Scenario



Note: PPP = purchasing power parity.

With energy use declining in many OECD countries and China moving into a much less energy-intensive phase in its development, India is emerging as a major driving force in many areas of global energy. It takes over from China as the largest single source of rising demand both for coal and oil in the period to 2040 and becomes a significant player in a series of other markets, from wind and solar to nuclear, hydropower and natural gas. In the case of coal, the increase in demand in India makes by far the largest contribution to growth in global consumption to 2040. In the case of oil, India accounts for more than 45% of the projected net increase in global consumption. In the electricity sector, demand growth that averages 4.9% per year puts all other major countries and regions in the shade: to meet this demand, India needs to build more than 880 gigawatts (GW) of new power generation capacity over the period to 2040 (for comparison, the entire installed capacity of the European Union is currently around 1 000 GW).

Overview and outlook by fuel

The period of rapid change anticipated for the Indian energy system in the New Policies Scenario does not translate into a dramatic shift in the energy mix (Table 12.1), although there are some noticeable changes in flows through the system as a whole and in the relative weight of the different end-use sectors (Figure 12.2). Coal retains a central position in the mix, increasing its overall share in primary energy from 44% in 2013 to 49% in 2040 (bucking the global trend, where coal declines by four percentage points to 25%), and the shares of oil and gas edge slightly higher. Some of the largest changes however are in the use of non-fossil fuels. On the one hand, the proportion of solid biomass, used mostly in cooking, falls from almost a quarter of primary energy in 2013 to 11% in 2040; but, on the other, there is strong growth in the deployment of modern renewables technologies, led by solar and wind power.

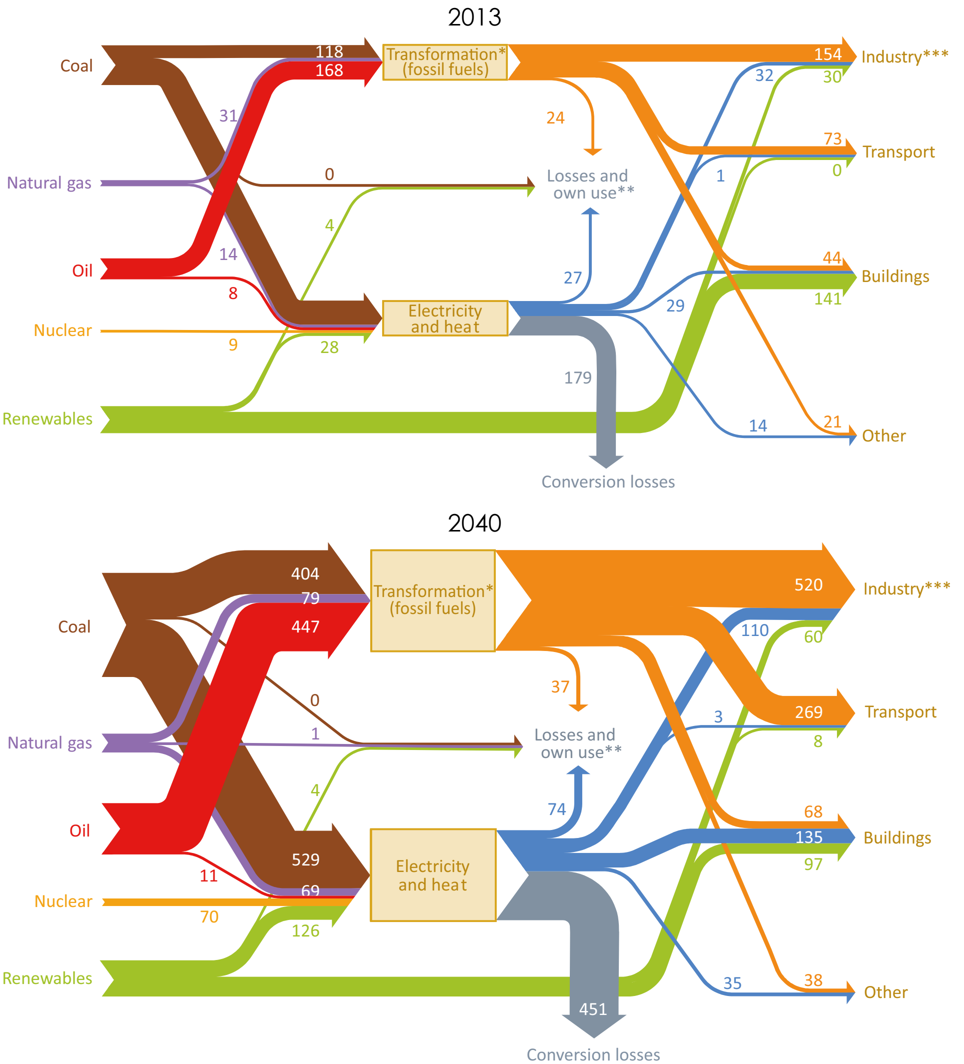
Table 12.1 ▷ Primary energy demand by fuel in India in the New Policies Scenario (Mtoe)

						Shares		2013-2040	
	2000	2013	2020	2030	2040	2013	2040	Change	CAAGR*
Oil	112	176	229	329	458	23%	24%	282	3.6%
Natural gas	23	45	58	103	149	6%	8%	104	4.6%
Coal	146	341	476	690	934	44%	49%	592	3.8%
Nuclear	4	9	17	43	70	1%	4%	61	7.9%
Renewables	155	204	237	274	297	26%	16%	93	1.4%
Hydropower	6	12	15	22	29	2%	1%	16	3.2%
Bioenergy	149	188	209	217	209	24%	11%	20	0.4%
Other renewables	0	4	13	35	60	0%	3%	56	11.0%
Fossil fuel share	*64%*	*72%*	*75%*	*78%*	*81%*	*72%*	*81%*	*8%*	*n.a.*
Total	**441**	**775**	**1 018**	**1 440**	**1 908**	**100%**	**100%**	**1 133**	**3.4%**

* Compound average annual growth rate.

12

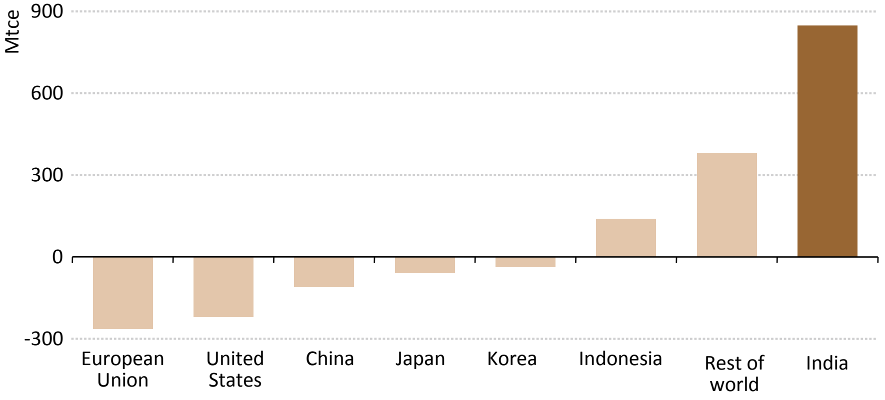
Figure 12.2 ▷ **India domestic energy balance, 2013 and 2040** (Mtoe)



* Transformation of fossil fuels (e.g. oil refining) into a form that can be used in the final consuming sectors (excludes blast furnaces and coke ovens). ** Includes fuel consumed in oil and gas production, transformation losses and own use, generation lost or consumed in the process of electricity production and transmission and distribution losses. *** Includes energy demand from blast furnaces and coke ovens, as well as petrochemical feedstock.

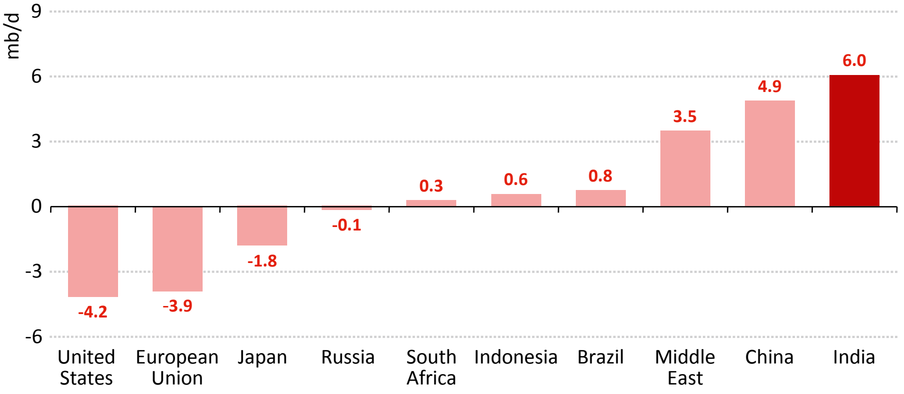
Indian coal consumption of 1 300 million tonnes of coal equivalent (Mtce) in 2040 is 50% more than the combined demand of all OECD countries and second only to China in global terms. The projected increase in coal use is split between power generation (to feed an additional 265 GW of coal-fired plants) and industry (primarily for iron, steel and cement industries). This makes India, by a distance, the largest source of additional global coal demand (Figure 12.3).

Figure 12.3 ▷ Change in coal demand by selected countries and regions in the New Policies Scenario, 2013-2040



Demand for oil in India increases by more than the growth in any other country or region in the world to 2040, by 6.0 million barrels per day (mb/d) to reach 9.8 mb/d (Figure 12.4). Transport accounts for 65% of the rise, as 260 million additional passenger cars, 185 million new two- and three-wheelers and nearly 30 million new trucks and vans are added to the vehicle stock. The pattern of transport fuel use remains weighted towards diesel, although gasoline shows a faster rate of growth. The rise in transport fuel demand would be even greater were it not for the introduction of fuel-efficiency standards, allied with policy efforts to promote alternative fuels. Oil – mainly in the form of liquefied petroleum gas (LPG) – is in strong demand also in the residential sector, largely thanks to policies aimed at encouraging a move away from solid biomass for cooking. The trajectory of India's oil use, and the implications for India's oil security and import bills, depend greatly on the way that global oil markets and prices evolve (Box 12.2).

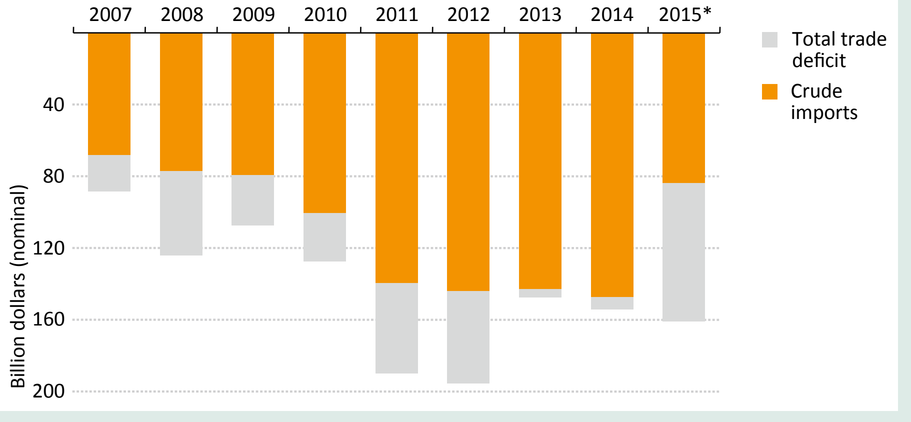
Figure 12.4 ▷ Change in oil demand by selected countries and regions in the New Policies Scenario, 2014-2040



Box 12.2 ▷ India in a Low Oil Price Scenario

India is the third-largest importer of crude oil in the world. By value, crude oil accounts for one-third of total imports, averaging around $135 billion a year since 2011 (although offset in small part by net exports of oil products) (Figure 12.5). Fluctuations in the oil price are therefore fundamentally important to the Indian economy. At $60/barrel, India makes annual savings in its import bill of $70 billion compared with the average oil price, above $100/barrel, which prevailed from 2011 until mid-2014. That reduction is equivalent to fourteen-times the government budget allocation to the health sector.

Figure 12.5 ▷ Crude oil imports as a share of the trade deficit



* Estimate.

Sources: Ministry of Petroleum and Natural Gas (2014); IEA analysis.

Lower oil prices can feed back positively to the economy in a number of ways. They reduce household expenditure on energy (around 30% of energy expenditure in India's cities is allocated to gasoline and diesel), freeing up income that stimulates domestic demand, while reducing the country's current account deficit. They alleviate the fiscal burden for oil products that are subsidised, a consideration that has been worth around $3.5 billion in the case of LPG. As well, with fuel accounting for the fourth-largest component of the Indian Consumer Price Index, lower oil prices translate into lower economy-wide inflation.

In the New Policies Scenario, these gains are expected gradually to dissipate: oil prices rise as global demand picks up and supply growth falls back (the latter as cuts in non-OPEC upstream spending eventually feed through into lower output). The rise in price, to $128/barrel in real terms by 2040, takes the edge off India's thirst for oil-based mobility, although demand still increases rapidly. The result is a bill for oil and gas imports that reaches almost $480 billion by 2040, up from $110 billion today.

In this *World Energy Outlook* (*WEO-2015*), we also model a Low Oil Price Scenario to examine the implications of a much more protracted period of lower prices (see Chapter 4). This scenario sees prices in the $50-60/barrel range until the mid-2020s, before they start a slight rise to reach $85/barrel by 2040. This trajectory results primarily from much more favourable assumptions about the availability of low-cost supply, as the main resource-holding countries in the Middle East pursue a policy of increasing their share of the market and output in some key non-OPEC countries (notably US tight oil) proves to be resilient even in a low-price environment.

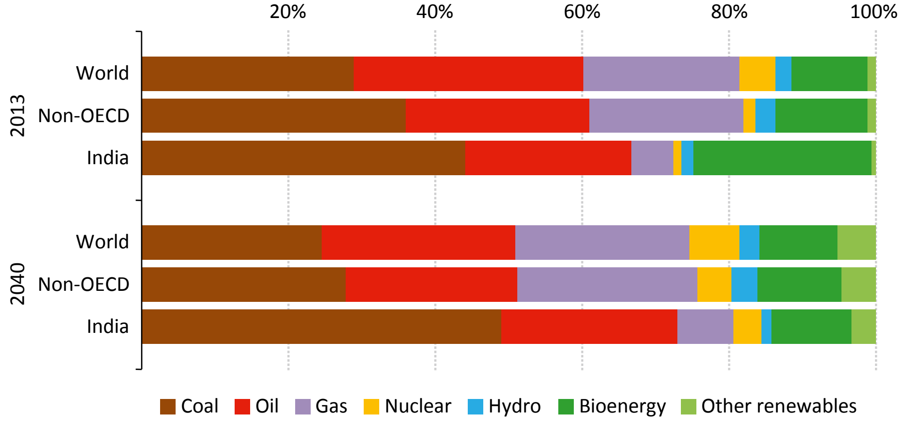
For India, as a major oil consumer, this scenario reduces energy expenditure across the economy, stimulating additional growth. Oil consumption rises more quickly in all sectors, particularly transport, as consumers take advantage of the lower cost of mobility. Coal is slightly cheaper to produce and transport, keeping a lid on electricity prices. The price of India's liquefied natural gas (LNG) imports comes down and stays relatively low, helping gas find a larger foothold in the Indian mix. Average household incomes rise because of a range of direct and indirect energy price effects and the macroeconomic benefits for the Indian economy as a whole. India's total oil and gas import bill in 2040 – even with 6% higher import volumes for oil – is lower by $135 billion (almost 30%) than in the New Policies Scenario. Lower oil prices also help contain the fiscal deficit, as expenditure on subsidies is reduced, making it easier for the government to invest in physical and social infrastructure.

Yet the impacts of this scenario on Indian interests are by no means all positive. Domestic oil and gas production, which is relatively expensive by international standards, is hit hard by lower prices. With many new projects no longer viable, India's oil production is down 10% compared with the New Policies Scenario (see Chapter 13). The combination of higher oil demand (which reaches 10.3 mb/d in 2040) and lower domestic output (0.6 mb/d in 2040) means a very rapid increase in net oil imports. This fosters very strong reliance on supply from the Middle East – the main source of lower cost oil, whose increased production is instrumental in keeping prices down over the long term in the Low Oil Price Scenario – with implications for the measures India needs to take to guarantee security of supply.

Natural gas plays a relatively minor role in the Indian energy mix in the New Policies Scenario, certainly compared with the world and non-OECD averages (Figure 12.6). Gas use is projected to make in-roads in many sectors, from power generation to transport, while retaining an important role as a feedstock for the fertiliser industry. But, despite its versatility and low environmental footprint, compared with coal, its relatively high price does not allow it to displace other forms of energy more rapidly.

Around 36% of India's primary energy supply is used today as an input to power generation, including around 65% of its coal, 31% of its gas, its nuclear and hydro components and the bulk of the contribution coming from other renewable sources, excluding bioenergy.[1] In the New Policies Scenario, electricity consumption grows more quickly than demand for any of the individual fossil fuels; this is also the area in which non-fossil fuel energy has a growing impact. Despite the large expansion in the coal-fired fleet and steady growth also from gas-fired power, more than half of the electricity generation capacity additions anticipated in India over the period to 2040 come from nuclear, hydropower and other renewables, with solar photovoltaics (PV) making the second-largest contribution after coal.

Figure 12.6 ▷ Primary energy mix in India and by selected regions in the New Policies Scenario



Notes: Other renewables includes wind, solar, geothermal and marine. Non-OECD excludes India.

End-use sectors

Consumption across India's end-use sectors – buildings, industry, transport and agriculture – increases by around 3.3% per year on average to 2040, more than doubling to reach 1 275 Mtoe, by which time it overtakes the level of final consumption in the European Union today. Apart from the sizeable increase in demand, there is a material reconfiguration in the way energy is consumed by the main sectors (Table 12.2). Strong growth in the transport sector and in industry, underpinned by the growing economy, increases the share of both in overall consumption and consolidates the position of industry as the largest end-user of energy in the Indian economy. The main fuels contributing to this end-use demand growth (Figure 12.7) are coal (in industry), oil (in transport), and electricity (in buildings, industry and agriculture). The amount of bioenergy used in Indian end-use sectors remains stable in absolute terms, which translates into a falling share of the total.

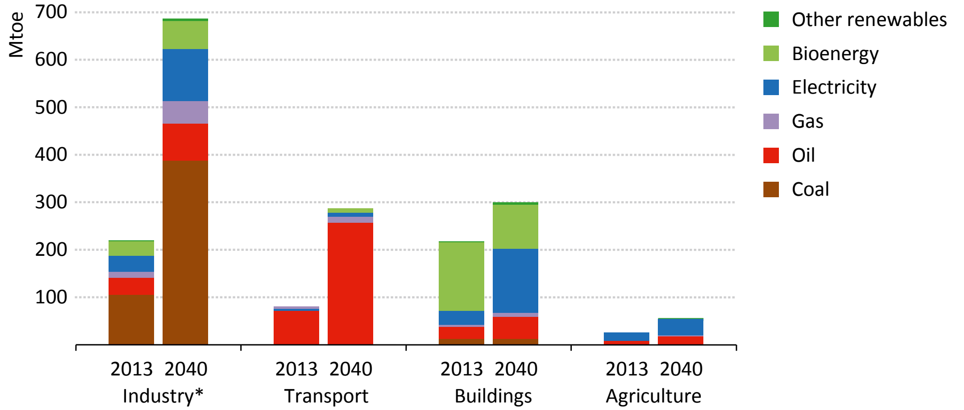
1. The share of primary energy going into the electricity sector does not provide a good indication of the eventual power generation mix, because of the different conversion efficiencies of various fuels. As Figure 12.2 shows, a great deal of energy is lost in the transformation from primary energy to electrical energy; most of this is from fossil fuels, whereas in the IEA methodology, many renewable energy technologies, including hydropower, wind and solar, have an assumed conversion efficiency of 100%, i.e. zero conversion losses.

Table 12.2 ▷ Final energy consumption by sector in India in the New Policies Scenario (Mtoe)

						Shares		2013-2040	
	2000	2013	2020	2030	2040	2013	2040	Change	CAAGR*
Industry	83	185	263	417	572	35%	45%	388	4.3%
Transport	32	75	108	176	280	14%	22%	205	5.0%
Road	28	68	100	165	264	13%	21%	196	5.1%
Buildings	158	214	242	274	299	41%	23%	85	1.2%
Agriculture	15	24	31	43	51	5%	4%	27	2.9%
Non-energy use**	27	29	40	58	72	6%	6%	43	3.4%
Total	**315**	**527**	**686**	**968**	**1 275**	**100%**	**100%**	**748**	**3.3%**
*Industry, incl. transformation****	111	217	317	507	691	n.a.	n.a.	474	4.4%

* Compound average annual growth rate. ** Includes petrochemical feedstocks and other non-energy uses (mainly lubricants and bitumen). *** Includes energy demand from blast furnaces and coke ovens (not part of final energy consumption) and petrochemical feedstocks.

Figure 12.7 ▷ Energy demand by fuel in selected end-use sectors in India in the New Policies Scenario



* Includes energy demand from blast furnaces, coke ovens and petrochemical feedstocks.

Buildings

Energy use in the buildings sector (both the residential and services sectors[2]) in India is projected to change dramatically over the coming decades under the influence of population growth, the trend towards urbanisation, growth in access to modern energy and the impact of rising incomes on the ownership of appliances. From a situation in 2013 when almost 65% of the 214 Mtoe consumed in the buildings sector consisted of solid biomass,

2. The services sector includes, among others, public buildings, offices, shops, hotels and restaurants.

Box 12.3 ▷ What India builds is crucial to the future of energy use

Some three-quarters of the anticipated building stock in India in 2040 has yet to be constructed; a consideration that has enormous implications for our energy *Outlook* and for policy-makers. Strong growth in construction pushes up energy consumption in order to produce the steel, cement, aluminium and other materials required. But it also creates an opportunity for India to impose more stringent efficiency standards on the buildings sector, with the focus on keeping demand for cooling in check, as part of its drive for efficient "smart" cities. The alternative is to risk locking in inefficient capital stock for the long term.

With this in mind, in 2007 India launched an Energy Conservation Building Code (ECBC) that sets minimum energy standards for new commercial buildings (those with energy requirements above a certain threshold). The code is voluntary until made mandatory by individual state governments, who can also amend it to suit local climatic conditions; but it has already been adopted for all central government buildings and in a majority of states, and the aim is to extend coverage across the country by 2017.[3] The Bureau of Energy Efficiency has released guidelines for energy-efficient multi-storey residential buildings, although there is little in the way of mandatory regulation for this sector.

In June 2015, India officially launched the Smart Cities Mission, the centrepiece of which is the aim to develop 100 smart cities across India. This is an opportunity to improve energy, water and waste management, for example through the installation of smart meters or by using waste to produce energy. Other objectives of the mission are to reduce the energy demand of existing buildings, via retrofits, and to enhance the efficiency of new construction more generally; positive examples of these approaches include the redevelopment of East Kidwai Nager in Delhi and the Gujarat International Finance Tec-City (GIFT) project in Gujarat. One important feature of the smart cities initiative is that it incorporates the objective of providing housing opportunities to all.

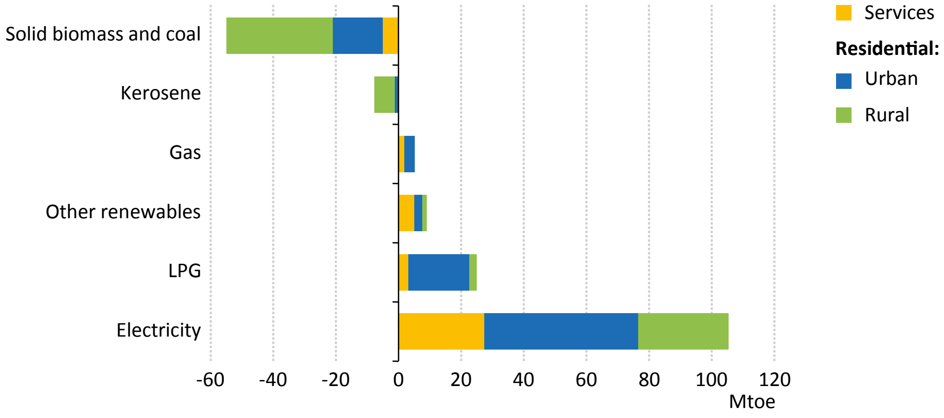
It will take time to extend the scope of the relevant measures in order to make residential buildings more efficient, in particular, to build the capacity to ensure compliance with the energy elements of building codes. But the prize, in terms of reduced energy consumption, is significant. We estimate that if standards equivalent to the ECBC were made mandatory for all new buildings (both commercial and residential) and existing voluntary appliance standards became compulsory by 2030, energy consumption in buildings would be 50 Mtoe, or 17%, lower than in the New Policies Scenario by 2040.

3. Other initiatives, such as the Green Rating for Integrated Habitat Assessment (GRIHA) programme launched by The Energy Resources Institute (TERI) and the Bureau of Energy Efficiency's Star Rating scheme that targets existing commercial buildings have also gained traction, but remain voluntary.

by 2040 more than 60% of the 299 Mtoe used in the sector is either electricity (45%) or oil (16%). This projection is underpinned by growth in India's towns and cities, which accommodate an estimated additional 315 million people over the *Outlook* period (ten-times the additional number of people in rural areas). Urbanisation helps to improve access to modern fuels, such as electricity and LPG, but it can also – if not well planned – entrench inefficient patterns of energy use that can be very difficult to dislodge (Box 12.3).

The two components of energy use in the buildings sector (the residential and services sectors) have very different patterns of consumption. In India today the residential sector relies mainly on solid biomass, with oil a distant second (LPG for cooking, kerosene for cooking and lighting) followed by electricity. The services sector, which tends to be concentrated in urban areas, is already largely dependent on electricity. Future increases in energy consumption in the services sector – including a jump in demand for space cooling in buildings – are projected to be predominantly based on electricity (with India's building codes and minimum energy performance standards serving to moderate the rate of growth). The projected shifts in demand in the residential sector, by contrast, are much larger and more varied (Figure 12.8).

Figure 12.8 ▷ Changes in energy consumption in the buildings sector in India in the New Policies Scenario, 2013-2040



Notes: Other renewables in this figure includes also modern uses of biomass (biogas and pellets). Solid biomass covers fuelwood, charcoal, dung and agricultural residues.

Today more than 70% of energy used in households in India is for cooking (whereas cooking constitutes less than 5% of residential energy demand in OECD countries). Two-thirds of the Indian population rely on solid biomass as their cooking fuel (Government of India, 2012), due to the lack of options that are similarly available and affordable; the low efficiency of this cooking method, compared with LPG or electric stoves, pushes up the share of solid biomass in cooking energy demand to more than 85%. Changes in the fuels used for cooking account for some of the main changes in residential energy demand over the period to 2040, alongside fuel switching for lighting purposes from kerosene (mostly in rural areas) to electricity, and rising electricity consumption to meet large increases in demand for cooling equipment and appliances. There is not much call for space heating in India, as daytime temperatures in its most populated areas are on average higher than 20 °C.[4] Water heating in large parts of India is largely a seasonal need.[5]

From the starting point that we describe in Chapter 11, the residential energy outlook in the New Policies Scenario is marked by a series of transitions, away from solid biomass and from kerosene to LPG and from unreliable or unavailable electricity to round-the-clock, reliable supply. These shifts happen at different speeds in different parts of the country and are set against a broader transition from a predominantly rural to an increasingly urban society. The net result is a transformation of the nature of residential energy consumption that includes universal electricity access, though only a partial achievement of complete access to clean cooking facilities (Box 12.4)

Box 12.4 ▻ Transition towards cleaner cooking facilities in India

Today around two-thirds of the Indian population rely on solid fuels as the primary fuel for cooking. This share varies widely between urban and rural households, with only a quarter of urban households using solid biomass for cooking (many moving to use LPG), compared with more than 85% of households in rural areas.[6] The adverse consequences fall predominantly on women and children, who suffer the worst health effects of the smoky indoor environment and also spend more time collecting firewood: one estimate says that Indian women spend, on average, 30 hours per month collecting cooking fuel (Practical Action, 2015).

In most rural areas in India, it is a challenge to displace solid biomass as the dominant fuel for cooking. Biomass scarcity is not yet at the level at which it forces a transition to other fuels and although LPG is promoted as an alternative and each household is entitled to buy 12 LPG cylinders per year and to receive the related subsidies as direct payments to their bank account (if they have subscribed to the PaHal scheme), distribution networks for LPG are limited in rural areas and, even with the subsidy,

4. Space heating is only prevalent in parts of northern India, typically the more mountainous or hilly regions, for three or four months per year. These areas typically rely mainly on solid biomass both for cooking and for space heating. At lower altitudes, heating is required for around one month per year.

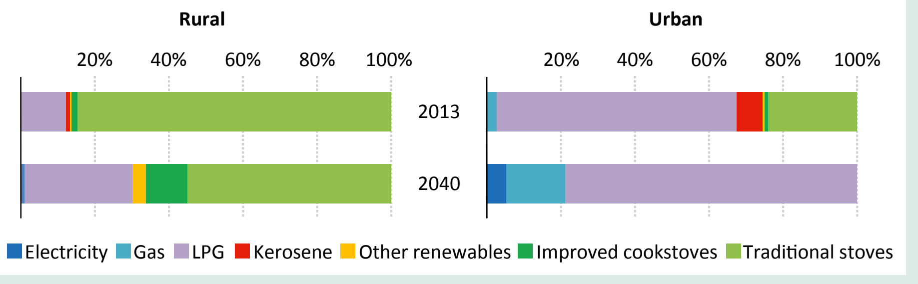
5. Water heating systems are used for two to four months of the year (depending on the region). There is usually no centralised system installed in residential buildings. Electric water heaters sized for household needs are the most popular option, where affordable: otherwise most households rely on the stoves used for cooking to heat water. Use of solar water heaters is negligible today but is set to increase, both for residential and commercial buildings.

6. Trends indicated in the most recent census in 2011 and confirmed in more recent energy data, show that the shift from fuelwood and kerosene to LPG as a cooking fuel is concentrated in urban areas. But even as LPG use is increasing, households often rely on more than one fuel for cooking, a phenomenon known as fuel stacking: when oil prices fluctuate or LPG delivery is not available, households can choose to go back to the use of cheaper (or free) solid biomass.

the cost can deter the poorest households. Biogas seems a promising avenue for India (based on ample agricultural residues) and there have been long-standing efforts to promote it, but less than 1% of households use biogas as their primary cooking fuel.

Government measures are accelerating the transition to alternative fuels but, in our judgement, the scale of the challenge means that solid biomass is unlikely to be entirely displaced by 2040. In the New Policies Scenario, the number of people without access to clean cooking facilities is projected to decline from around 840 million today to 480 million in 2040, all living in rural areas. Urban households all switch from solid biomass by 2040 (and from kerosene as well) as a cooking fuel, using instead, LPG and, in some instances, piped natural gas and electricity (Figure 12.9).[7]

Figure 12.9 ▷ Primary fuel/technology used by households for cooking in the New Policies Scenario



Note: Other renewables in this figure is mainly solar cookers and biogas stoves.

If solid biomass is here to stay as a cooking fuel, one way of reducing the health impacts is to encourage a switch to more efficient biomass cookstoves. The National Programme on Improved Chulhas distributed approximately 35 million improved biomass stoves from the 1980s until the early 2000s, but these did not catch on as hoped (many users tended to revert back to the traditional open fire over time) and there is some evidence that the subsidised supply hindered the emergence of a local commercial market for improved cookstoves (Shrimali et al., 2011). Incorporating the lessons learned, a new National Biomass Cookstove Initiative was launched in 2009.

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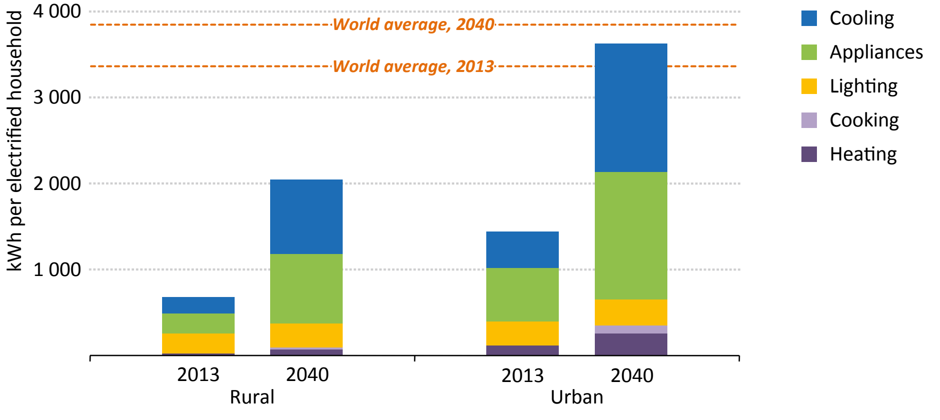
As incomes rise and electricity supply becomes more reliable, India is set to see a rapid increase in household electricity consumption, via increased purchases of appliances and air conditioners, although the rate of change again varies substantially between urban and rural households (Figure 12.10). The increase in demand for cooling is particularly striking: at present, the predominant appliance used for space cooling is an evaporative air cooler, which consumes twice as much electricity as a fan. However, as incomes rise,

7. Gail Gas Limited reports to have already connected 650 000 households in Uttar Pradesh, Madhya Pradesh and other states, while Indraprastha Gas Limited supplies almost 600 000 households in and around Delhi.

more people are in a position to afford air conditioners, which can consume five-times as much electricity as an evaporative air cooler. The market for air conditioners is already growing rapidly: sales of around 1 million units in 2003-2004 rose to more than 3 million units in 2010-2011 (Phadke, Abhyankar and Shahh, 2014) and very strong further growth is expected, with one estimate putting annual sales as high as 50 million units by 2050 (Chaturvedi and Sharma, 2015).

In order to ease the growth in electricity consumption in the buildings sector (but also in industry and agriculture), the Bureau of Energy Efficiency set up a programme of standards and labelling for appliances in 2006. Only 4 out of the 21 standards are currently mandatory, but more are expected to become mandatory in the coming years and there are plans to add standards for other appliances. The programme focuses on the most widely used appliances (specific types of refrigerators and air conditioners are already covered by the mandatory scheme), with voluntary labels initially encouraging consumers to choose more efficient appliances and then a switch to mandatory standards being made once there is sufficient public acceptance. By the end of 2015, the standards for electric water heaters, direct-cool refrigerators and colour televisions are expected to become mandatory. However, experience shows that the effect on consumption is offset somewhat by an increase in the size and power of the appliances on the market: the average size of refrigerators 15 years ago was around 165 litres, it is now 265 litres. Keeping future electricity consumption growth in the buildings sector in check will require a steady tightening of appliance standards.

Figure 12.10 ▷ Annual electricity consumption per rural and urban electrified household in India, 2013 and 2040



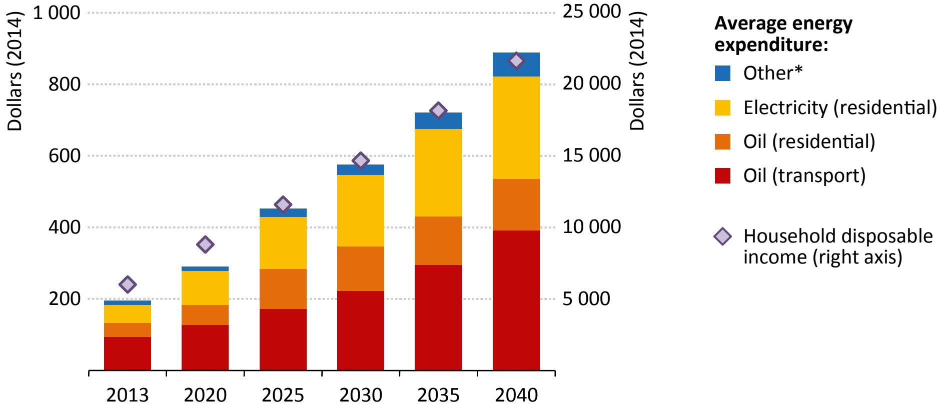
Note: kWh = kilowatt-hours.

Affordability

Energy consumption patterns, including how much is used and in what form, are heavily influenced by the level of disposable income available to households in India (see Chapter 11). Over the projection period, average household disposable income in

India is projected to rise to almost four-times its current level, reaching almost $22 000 (in 2014 dollars), while household spending on energy increases from just under $200 per year to almost $900 per year, meaning that energy expenditure as a share of total disposable income increases from 3% in 2013 to 4% in 2040 (Figure 12.11). This increase in expenditure is driven by oil consumption for road transport (reflecting the increasing demand for mobility) and consumption of electricity (as increasing incomes push up appliance ownership and use). Expenditure patterns are naturally contingent on the way that end-user prices evolve – in particular whether the scale of tariff increases for electricity is restrained by an efficient expansion of power generation and a reduction in high network losses. Keeping these energy costs under control (while still allowing for overall cost recovery across the system as a whole) has important implications for welfare as well as the wider economy, as any rise in energy expenditure comes at the expense of consumer spending on other goods and services (or on amounts that are saved and therefore potentially available to support productive investment in other parts of the economy). At an aggregate level, each $1 increase in annual household energy expenditure absorbs $400 million that could be spent, saved or invested in other parts of the economy.

Figure 12.11 ▷ Average energy expenditure by fuel and household disposable income, 2013-2040



* Includes coal and natural gas used in the residential sector, and biofuels, electricity and natural gas used in transport.

Industry

Energy demand in the industry sector is projected to increase rapidly, by 4.4% annually to 2040, so as to account for more than 50% of final consumption by 2040, up from 40% today. India's huge infrastructure needs over the next decades drive the demand for energy-intensive materials, for which India becomes an important manufacturing hub. Traditional building materials, such as clay bricks, are increasingly being replaced by steel and cement, which explains the increased share of steel in industrial energy consumption

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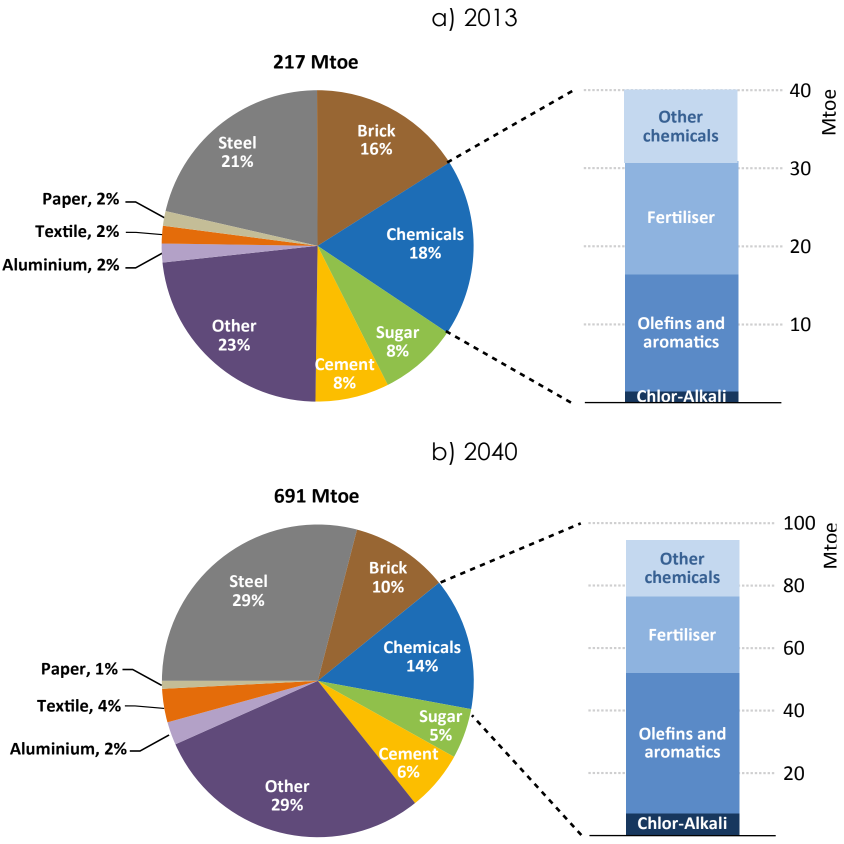
(Figure 12.12). In addition, industries ranging from chemicals, textiles and food to transport equipment are increasing their production quickly to satisfy the needs of a larger and more prosperous society.

Figure 12.12 ▷ Estimated current and projected industrial energy consumption by sector in India in the New Policies Scenario



Coal is currently the dominant source of energy for industry, accounting for almost 50% of industrial energy use. With increasing demand from different branches of industry, including steel, bricks and cement, bolstered by the consideration that coal is less expensive compared with alternative fuels, the share of coal grows to 56% in 2040. Natural gas, oil and biomass consumption grow in absolute terms, but their shares of total industrial demand decline. Gas consumption is held back by the subdued growth in domestic production, relatively high import prices and limited distribution infrastructure. National policy encourages a move away from the traditional use of biomass, while oil products represent an increasingly costly way of providing heat to industry.

The structure and patterns of energy consumption in the various industrial branches in India are very different: some energy-intensive industries, including chemicals, cement, aluminium and, to some extent, steel, are dominated by large enterprises; others, particularly the brick industry, consist of thousands of small and medium enterprises (SMEs). The latter, with generally poor energy performance, account in total for about 45% of manufacturing output (SME Chamber of India, 2015). The energy efficiency policies of the Indian government focus on the large consumers, for whom participation in an innovative market-based trading scheme for energy efficiency certificates is mandatory (Box 12.5).

The steel sub-sector is the largest industrial energy user in India and is also the source of the largest projected increase in industrial energy use over the period to 2040, from the current 46 Mtoe to around 200 Mtoe (supporting output that increases by more than five-times). India is already the fourth-largest steel producer in the world after China, Japan and the United States, but it overtakes both the United States and Japan before 2020. With an anticipated decline in domestic demand, China is expected to seek export markets in order to make good use of its large existing steel production capacity; however, imports into India are projected to reduce Indian domestic production growth only to a limited extent. Currently, 20% of inputs to the steel industry consist of coal-based sponge iron (or direct reduced iron [DRI]), with the rest being traditional pig iron from blast furnaces and steel scrap. India is the only country in the world that uses coal instead of natural gas for large-scale DRI production. The energy consumption of coal-based DRI can be up to twice as high as that of gas-based DRI (IEA, 2007). India has three major gas-based DRI producers, which ran at an utilisation rate of below 30% in 2013, due to low availability of domestic natural gas (JPC, 2014). The high production of coal-based sponge iron is a consequence of the facts that DRI facilities are easy to build, as in general they are small and less capital-intensive, that India does not have access to low-cost natural gas and that domestic coking coal, necessary for traditional pig iron production, is of relatively low quality, with high ash content.

The steel industry in India consists of relatively efficient large, private sector steel plants, alongside less efficient public steel plants and a significant number of mini blast furnaces that cannot reach the energy efficiency levels of larger plants due to their small scale. Roughly a third of India’s steel is produced in electric arc furnaces and a similar proportion in small-scale induction furnaces (JPC, 2014), which use electricity as an energy input and where the scope for energy efficiency gains is limited. In the future, it is anticipated that the steel sector in India will become less reliant on DRI, turning more towards the traditional blast furnace route for steel-making and so depending less on electricity supply. This shift, combined with increasing energy efficiency gains, (particularly in blast furnaces, steel finishing and exploiting the waste heat potential in DRI production), and a modestly higher share of scrap metal contribute to the projected decrease in energy intensity. The shift from DRI relying on domestic non-coking coal production towards primary steel-making means that India will become more reliant on more expensive imported coking coal for its blast furnaces.

Box 12.5 ▷ India's policies on energy efficiency in industry

Under the Energy Conservation Act, a market-based trading programme for efficiency certificates, called the Perform, Achieve and Trade (PAT) scheme, was introduced in 2012. It specifies energy saving targets for 478 facilities with an energy consumption of more than 30 thousand tonnes of oil equivalent (ktoe) (lower for some industries) in the aluminium, cement, chlor-alkali, fertiliser, steel, paper and textiles industries. The scheme targets energy savings of 6.7 Mtoe (or 4%) at the end of the first cycle in March 2015 (CDKN, 2013). In mid-2015, the Bureau of Energy Efficiency evaluated the energy savings to determine which companies are to receive efficiency savings certificates for over achieving their target and which have to buy certificates in the market or face a penalty as a result of not meeting their target. The second cycle of the PAT scheme starts in April 2016 and includes more companies by lowering the consumption threshold and adding three additional industries: railways, electricity distribution companies and refineries.

Implementing energy efficiency policies for SMEs is difficult due to their diverse nature, lower awareness, the perceived risk of some efficiency technologies, lack of capital and high transaction costs. The Bureau of Energy Efficiency has targeted industrial clusters, where SMEs have based themselves around locally available resources. In these clusters, energy use assessments, efficiency manuals and capacity building are provided to particularly energy-intensive SMEs, such as the food, brick or textile companies, with the objective of saving 1.8 Mtoe in 2016/2017. Financial assistance and low-interest loans are available for selected energy efficiency measures and management systems in SMEs (partially funded by development banks).

The brick industry in India is the second-largest in the world (after China) and also the second-largest energy consumer after iron and steel. Its structure is very different from that encountered in OECD countries, which rely on automated tunnel kilns for the production of hollow or perforated bricks. Brick production in India is very labour-intensive (often in very poor working conditions), it is a large consumer of biomass and production is spread out over more than 100 000 small plants (Government of India, GEF, UNDP, 2012). India's brick industry is very seasonal and limited to about six months: green bricks are formed from mid-October to end-December and are subsequently dried in the open. They are fired when the weather gets warmer from mid-March until June. Given its small-scale character, relying on traditional production methods, the brick industry has significant potential for higher energy efficiency. Approximately 70% of the estimated 250 billion bricks produced per year are made in fixed chimney bull trench kilns, a relatively inefficient production method that is also a major source of local air pollution (Lalchandani and Maithel, 2013). More modern techniques, such as zig-zag firing, can reduce specific energy consumption from up to 1.4 megajoules per kilogram (MJ/kg) to around 0.8-1.1 MJ/kg, i.e. an energy saving of more than 20% (Maithel, 2013). While it is projected that energy intensity in the Indian brick industry will decline by around 30% by 2040, through a combination of energy efficiency and a shift towards the manufacture of hollow and perforated bricks, realising these efficiency gains will be difficult because of a lack of awareness, the high payback periods associated with energy efficiency projects and a lack of appropriate financing means by local banks. These hurdles are gradually overcome in our projections through various efficiency policies, including capacity building and financial assistance.

The domestic fertiliser industry is a major energy consumer as well as a pillar of India's efforts to ensure food security. Of the three broad categories of nutrients available to India's more than 100 million farmers, most of the phosphorus- and potassium-based fertilisers are imported, while about three-quarters of the nitrogen-based urea fertilisers are produced at home (Department of Fertilizers, 2015). In 2013, the fertiliser industry consumed about 13.5 Mtoe (15.8 billion cubic metres) of natural gas for use as feedstock. Though it is no longer first in line, the fertiliser industry is one of the sectors with priority access to domestically produced gas (which is available at a regulated price). Imported LNG met almost one-third of the fertiliser industry requirements in 2013.

Subsidies provided to the industry since the 1970s have made fertilisers more available to farmers, but come at a significant cost (similar to electricity subsidies provided to farmers, see agriculture section). The prices for all fertilisers are now unregulated with the exception of urea, where the maximum retail price is currently fixed at Indian rupees (INR) 5 360 ($87) per tonne[8], significantly below world market prices (around $300/tonne in 2014) (Department of Fertilizers, 2015). Subsidies for fertiliser producers make up a substantial portion of all subsidies in India (26% in 2012), totalling INR 660 billion ($12 billion) in 2012, 0.7% of Indian GDP (Ministry of Petroleum and Natural Gas, 2014). A large part of this subsidy is spent on the domestic production of urea, with the rest to import urea and the production of other, more complex fertilisers.

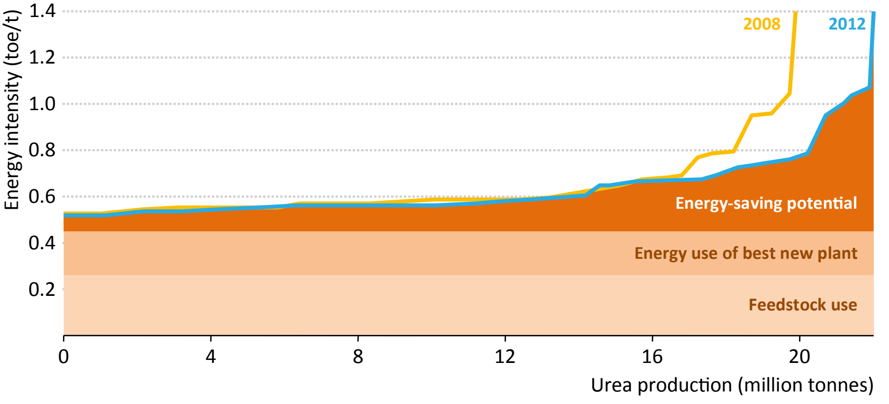
The subsidies have led to over-consumption of urea, relative to other fertilisers. The ideal ratio of nitrogen (N), phosphorus (P) and potassium (K) in fertiliser use is around 4:2:1, but, for example in the case of Rajasthan, the ratio reached 45:17:1 in 2012, damaging the chemistry of the soil (Gulati and Banerjee, 2015). Subsidies also discouraged producers from paying close attention to their costs, although changes to the subsidy rules and the inclusion of the fertiliser sector in the PAT scheme have addressed these inefficiencies. The intention now is to shift the subsidy scheme away from producers, instead concentrating on compensating farmers directly.

The energy intensity of urea production has decreased significantly from 0.84 toe/tonne urea in 1990 (Nand and Goswami, 2008) to around 0.64 toe/tonne urea in 2013. Future energy intensity reductions become more limited as 0.26 toe/tonne of energy is needed as a feedstock, and best practice energy use for urea plants is currently around 0.19 toe/tonne

8. The maximum retail price is roughly equivalent to the entire non-energy related production cost component in the production of urea. Consequently, in order to break-even at current regulated prices, natural gas effectively needs to be available at zero cost. In other words, the entire $12 billion of fertiliser subsidies can be seen as indirect subsidies for the use of natural gas.

urea (Figure 12.13). In our projections, the energy intensity of urea production decreases further to 0.55 toe/tonne urea by 2040 (a further 15% improvement compared with today), representing a reduction of 4 Mtoe (4.8 bcm) in the amount of natural gas required compared to a situation if there were no future efficiency gains.

Figure 12.13 ▷ Energy intensity of urea production in India



Sources: Department of Fertilizers (2014); IEA analysis.

Other large industrial consumers of energy include the cement, petrochemicals, paper and aluminium industries. The cement industry is projected to almost treble its energy demand by 2040, as it strives to meet the demand related to heavy infrastructure spending and ongoing urbanisation. The cement industry in India is already one of the most energy-efficient in the world, with relatively large production units and the use of modern technologies; it uses a relatively high share of fly ash and blast furnace slag as a substitute for energy-intensive clinker production. In the future, the clinker-to-cement ratio declines from the current 0.74 to 0.62 in 2040 (reducing the energy intensity of cement production by 13%) driven by a higher availability of blast furnace slag from the steel industry.

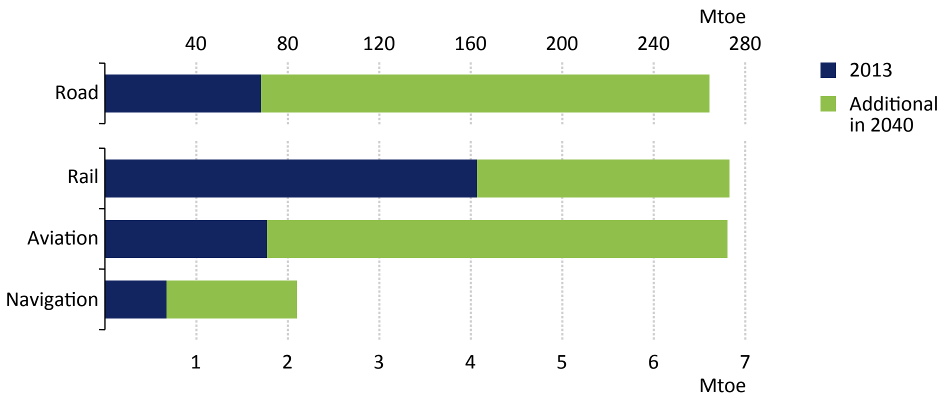
India has very low per-capita consumption of petrochemical products at present, but demand is increasing from the textile, car manufacturing and food packaging sub-sectors, among others, and will provide a boost for domestic petrochemical manufacturing. Production of ethylene, the most important basic petrochemical, is expected to increase from 3 million tonnes (Mt) in 2013 to 13 Mt in 2040. For feedstocks, the petrochemicals industry in India relies heavily on domestic naphtha from its important refining industry but has recently also looked to import ethane from the United States.

Aluminium production in India currently consumes around 4 Mtoe, a figure projected to increase to 16 Mtoe in 2040. Primary aluminium production, which is very electricity-intensive, increases four-fold by 2040. Around 80% of India's aluminium sector is already using the world's best available smelting technology and the remaining 20% is expected to be upgraded by 2040. However, paper production in India is significantly more energy-intensive than in other parts of the world, because its mills are currently small: the average size is less than 15 000 tonnes per year, while large-scale modern plants produce at least twenty-times as much. As the structure of the Indian paper industry is not expected to change significantly and it relies for more than one-fifth of pulp production on agro-based feedstocks (as opposed to more common wood-based pulp), future energy efficiency gains are expected to moderate (TERI, 2015).

Transport

Energy use in India's transport sector, at 75 Mtoe in 2013, accounted for 14% of final energy consumption – a much lower share than in many other countries. With a growth rate averaging 6.8% per year since 2000, it has become the fastest-growing of all the end-use sectors, with around 90% of the increase coming from oil use in road transport. All the indicators point to further significant increases in demand: passenger vehicle ownership, at less than 20 vehicles per 1 000 inhabitants, is much lower than the world average; the use of energy per capita for transportation purposes, at 0.06 toe, is one-sixth of the world average; and the number of flights, at 0.07 trips per capita, is well below that of other emerging economies (Airbus, 2015). In the New Policies Scenario, growth in energy demand from transport continues to outpace growth in all other sectors, and transport fuel demand reaches 280 Mtoe in 2040, dominated by road transport (Figure 12.14).

Figure 12.14 ▷ Transport fuel demand by sector in India in the New Policies Scenario



Note: Aviation includes fuel use for domestic travel only.

India's transport sector is distinctive in that it was long dominated by mass transport by rail, first introduced to India in 1853, not long after Western Europe and well before Japan (1872) and China (1876). By the 1950s, when travel demand started increasingly to be satisfied by road transport in many parts of the world, roads carried only 15% of India's passenger movements and 14% of freight (TERI, 2015). Today, however, the picture is markedly different. Transport in India is now heavily dominated by road transport, which

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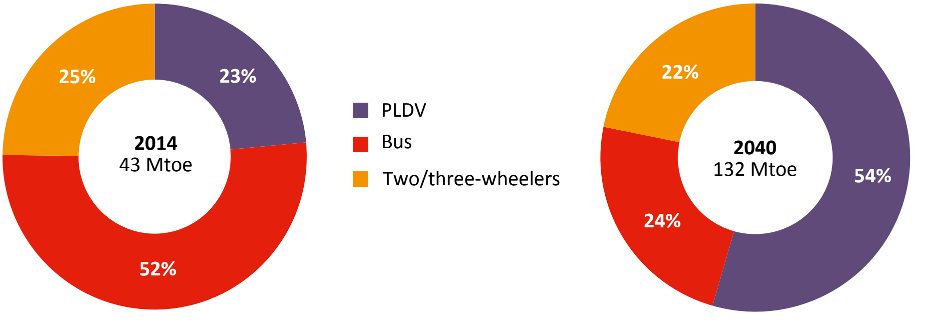
accounts for 86% of passenger and almost two-thirds of freight movements. Consequently, road transport fuel demand has grown rapidly to 68 Mtoe in 2013, around 60% of which is used for passenger transport.

Passenger cars still play a relatively minor role in India's overall transport system, partly because much individual travel is made by collective modes of road transport (i.e. buses) and partly because of the high level of use of two- and three-wheelers. In our projections this changes, with the share of passenger cars increasing sharply by 2040, by which time they account for 54% of road fuel demand for personal transport, as car ownership rises to a nationwide 175 vehicles per 1 000 inhabitants (Figure 12.15). This shift in modes of transport is in line with the historical development trend in many other countries.

Figure 12.15 ▷ Road fuel demand for personal transport by type in India in the New Policies Scenario, 2014 and 2040



Note: PLDV = passenger light-duty vehicles.

The growth in fuel demand is partially moderated by the recently adopted fuel-economy standards, which mandate an average fuel consumption per new vehicle of 4.8 litres per 100 kilometres (l/100km) in 2022/23 (from around 6.0 l/100 km today). In the New Policies Scenario, we assume average fuel consumption per new vehicle drops further to 4.3 l/100km in 2040. Freight activity, which grows at an annual average rate of 7.5% to 2040, in line with the value added by the industrial sector in our projections, remains an important component of energy demand in road transport, contributing more than half of the total energy demand growth to 2040. Road freight is a very fragmented but highly competitive market with a large number of small commercial operators. The Indian government is at an early stage of developing fuel-economy standards for heavy-duty vehicles, a measure which has significant potential to curb demand growth.

Much will depend on whether India succeeds in slowing the trend towards individual vehicles, particularly in cities, through the provision of effective public transport (Box 12.6). It will be a huge challenge to build the necessary infrastructure, particularly in those of India's cities that are already characterised by urban sprawl and rapid, often informal, developments at their periphery. Even with effective development of public transport, the anticipated growth of the passenger and commercial vehicle fleet is set to amplify some already pressing problems in road transport. Road safety is among the primary concerns. With around 140 000 people killed in road accidents in 2014, i.e. one person killed every four minutes, India's road accident fatality rate is among the highest in the world. The road transport sector (particularly diesel trucks) is also a major contributor to India's worsening urban air quality (see last section of this chapter).

Box 12.6 ▷ Smart cities – moving mobility back in time?

Rapid social and economic development in India, with a burgeoning middle class and strong economic growth, will have significant impacts on all aspects of people's lifestyles, including personal mobility. India has a long tradition of mass transport by train and bus. These are typically significantly more energy-efficient modes of transport than individual cars. But, following the same patterns of development as elsewhere, the Indian population – in particular in urban areas – increasingly uses personal vehicles to satisfy demand for mobility, amplifying problems such as congestion, accidents and air pollution.

One of the most difficult challenges facing India's drive for smart, well-connected cities is to reverse – or at least moderate – such trends. Attempts are being made, such as through the development of Delhi's metro rail system (following earlier systems in Kolkata and Chennai), an example that is being considered by the authorities in many of India's other large cities such as Lucknow, the capital city of Uttar Pradesh. Another option is the development of systems for rapid transit by bus. Such systems have been implemented in eight Indian cities and accommodated more than 400 000 passengers per day along bus corridors of a combined length of almost 170 km. Some of these, as in Ahmedabad, have proved successful, although the experience of other cities shows that the development of these projects is far from easy. In Delhi, frustrated vehicle owners violated the rules by using the bus lanes and difficulties were experienced in accessing some of the bus platforms.

Energy efficiency policies for urban transport can be grouped into three broad categories: those that allow travel to be "avoided"; those that "shift" travel to more efficient modes; and those that "improve" the efficiency of vehicle and fuel technologies. All of these areas need to be tackled in order to make cities in India smarter in terms of mobility. Good city planning can help to slow transport growth and there may also be opportunities to avoid travel through tele-working (or virtual mobility). Shifting travel modes will require early co-ordination between urban and traffic planners, in particular where the development of a public metro system is envisaged, to ensure dedicated spaces for pedestrians and public transit networks. Policy in India is already moving on several of these points, with fuel-efficiency standards for passenger vehicles, the increasing build-up of metro systems and the Smart Cities Mission.

The quality and availability of roads is another potential constraint: although India has the second-largest road network in the world (after the United States), only about half of the roads are paved. Despite efforts to develop a national highway network (and to shift freight back to railways with the development of dedicated freight corridors), inadequate road infrastructure could remain an important bottleneck in a fast expanding economy: while trucks in most OECD countries easily travel 400-500 km per day, it has been estimated that even new heavy commercial vehicles in India are able to achieve only around 270 km per day, due to the poor quality of roads, heavy traffic, toll stations and multiple checkpoints (mostly at state borders). Older vehicles, which represent more than half of the commercial fleet in India, travel on average only around 130 km per day. In the New Policies Scenario, we assume these problems are moderated, to some extent, but the average annual mileage per heavy truck, at 210 km per day in 2040, still remains below the level of other countries.

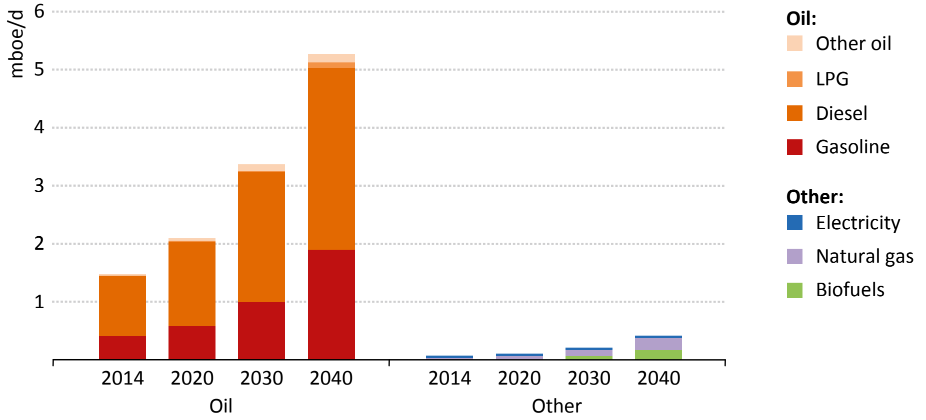
Energy use in other transport sectors remains low in the New Policies Scenario. Domestic aviation, rail and navigation combined contribute only 4% to total energy demand growth in transport, even though they continue to grow at a rapid pace. Aviation and navigation are the fastest growing among these modes, with fuel use for domestic air travel and domestic shipping increasing at an average annual rate of more than 4% until 2040 in the New Policies Scenario. The aviation industry in India has been growing particularly rapidly recently, with double-digit rates of passenger growth handled at the 125 airports managed by the Airports Authority of India. Matching India's increased global connectivity, domestic travel has been spurred by a process of liberalisation that has seen a proliferation of low-cost airlines like IndiGo, SpiceJet and GoAir enter the market. No specific policies in India are directed at reducing aviation fuel demand, but global targets for reducing aviation fuel consumption adopted through the International Civil Aviation Organization, could dampen further demand growth in India (see Chapter 3).

The railway sector in India has lost its dominance in passenger and freight transport over the past decades, even though the number of passenger-kilometres travelled in India by train, at almost 1.2 trillion, is still the highest in the world. Rail transport fuel use is still heavily dominated by diesel, but electrification efforts continue and the idea of building high-speed tracks between major Indian cities is also gaining ground. To date, 38% of the total railway network in India has been electrified. The further expansion of electrification in the New Policies Scenario increases the share of electricity in total rail fuel use from 33% today to 37% in 2040, with overall rail transport fuel demand increasing by 1.9% per year on average.

In terms of fuels, transport in India – as elsewhere in the world – is heavily dominated by oil (Figure 12.16), a notable feature being the very high share of diesel in overall transport oil demand (1 mb/d of diesel use representing 70% of the total in 2013). This level of diesel use is matched only in the European Union where it is attributable to the high share of diesel-fuelled passenger cars. There are a number of reasons for the high share in India. In road transport, freight vehicles (around 60% of road transport diesel use) and buses (around 35%)

dominate diesel use, while the subsidies for diesel in place until 2014 increased the share of diesel passenger cars in total car sales (although this proportion diminishes in the New Policies Scenario, following the removal of these subsidies). In the railway sector, too, two-thirds of energy consumption is diesel, despite several decades of work on electrifying railways. In our projections, India's transport oil demand climbs to 5.3 mb/d in 2040 and remains dominated by diesel, on the back of a strong increase in freight activity.

Figure 12.16 ▷ Transport fuel demand by type in the New Policies Scenario



The strong growth of transport energy demand, and the expectation of further growth, has sparked concerns over the consequences for oil security and air pollution in India. This led to the adoption of policies to promote the use of alternative fuels, such as biofuels, electricity and natural gas. Promoting the use of biofuels has a long history in India; but we project that the ambitious – albeit indicative – targets to reach a 20% blending of ethanol and biodiesel will not be achieved, primarily because of constraints on biofuels supply (see Chapter 13). In our projections, the share of biofuels in road transport liquid fuel demand climbs only slowly to 3% in 2040, from about 0.2% today, replacing some 0.18 million barrel of oil equivalent per day (mboe/d). India also has a National Electric Mobility Mission Plan 2020, to promote the use of electricity in Indian road transport by providing subsidies to support a target level of sales of 6-7 million hybrid and electric vehicles per year by 2020. Although the target encompasses all modes of road transport, market uptake of pure electric vehicles has so far been largely confined to scooters, with officially reported sales of 42 000 in 2012/2013. In the New Policies Scenario, the sales of electric scooters increase further, reaching a share of almost 2% in total sales of two- and three-wheelers in 2040, and displacing oil consumption of 7 kboe/d; but the spillover to passenger cars remains limited.

The use of natural gas in transport has been promoted since the 1990s, in particular in Delhi and Mumbai, to combat air pollution. While the stated targets were generally met, they were negated by the increasing proportion of diesel use and by the sheer growth in the number of vehicles. Nevertheless, India today has the sixth-largest fleet of natural gas vehicles in the world, mostly composed of taxis and buses, and an established refuelling network in several cities. The use of gas in road transport expands moderately in our projections, accounting for 0.2 mboe/d of demand by 2040.

Agriculture

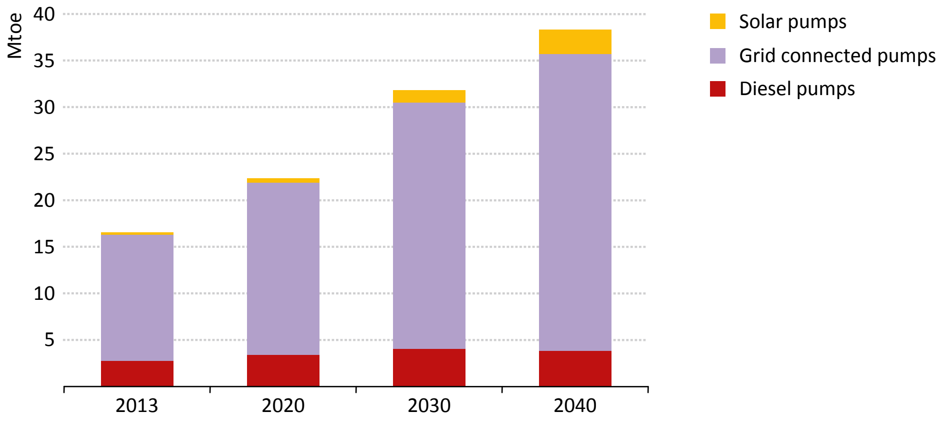
Despite the decline in the agriculture sector's contribution to India's GDP, it still engages directly half of the country's population and is also an important energy consumer, responsible for 15% and 18% of the total final consumption of diesel and of electricity, respectively. Although total food grains production in India has increased by around 35% since 2000, agriculture still faces multiple challenges relevant to the energy sector, particularly an inter-related knot of issues around inefficient pump sets, over-consumption of electricity (because of highly subsidised tariffs) and poor irrigation performance. In our projections, energy consumption in agriculture increases by 27 Mtoe to 50 Mtoe by 2040, with electricity accounting for 68% of the 2040 share and oil products (overwhelmingly diesel) a further 30%.

Different elements affect the evolution of agricultural energy demand in our projections. On the one hand, demand for food is expected to grow and diversify, as living standards rise and the population grows, increasing the need for fertilisers (see industry section). The agriculture sector is also likely to become increasingly mechanised: although modern techniques have already led to large improvements in productivity, there is significant scope for further gains. For example, tractor use is under 16 per 1 000 hectares in India compared with an indicator of 211 in Italy and 461 in Japan (Ministry of Agriculture, 2013). Farm mechanisation is generally expected to push energy consumption higher, although the pace of change will be limited by the fragmented nature of land ownership, which reduces the economies of scale that mechanisation can bring.

There are also significant energy efficiency gains to be had within India's irrigation system, one of the most extensive in the world and one that has supported the increase in cropping intensity of farmland. The system relies heavily on electric pumps (around 70% of the stock of pumps in operation [Ghosh and Agrawal, 2015]), mostly of very low efficiency (20-35%) (BEE, 2009). Moreover, flood irrigation, with an estimated water use efficiency of only 35-40%, remains the most widely used method (a significant reason why agriculture is responsible for a remarkable 90% of annual freshwater withdrawals). Tackling these two issues would help to reduce the over-use of electricity in the sector as well as reducing water consumption; but this is a challenging task for policy-makers, requiring a carefully integrated approach – as witnessed by the mixed results of efforts at reform in Andhra Pradesh, Gujarat and West Bengal, among others. The risk of unintended results is high. For example, a significant push to improve the uptake of efficient water pumps and to introduce solar water pumps are laudable efforts from an energy policy perspective; but if they are not accompanied by changes in agricultural and irrigation practices (requiring in turn a strong consultative and educational effort with farmers), they risk missing out on some of the potential gains, as well as increasing water consumption.

In the New Policies Scenario, the average efficiency of electric pumps is improved by around 25%, compared with today's levels, and more widespread adoption of drip irrigation techniques leads to further efficiency gains for irrigation. Oil consumption for irrigation remains essentially flat, as more and more diesel pump sets are replaced by electric ones – currently the sales of electric pump sets exceed sales of diesel pump sets by a factor of 2.5. By the end of the projection period, electricity meets close to 90% of the energy use for irrigation, with a rapidly growing share of demand being met by solar-powered pumps (Figure 12.17).

Figure 12.17 ▷ Energy demand for irrigation by source in India in the New Policies Scenario



Power sector

As outlined in Chapter 11, recent years have been marked by impressive achievements in the power sector in India, including a rapid expansion in generation capacity that was undertaken, in large measure, by the private sector, the introduction of policies to tap into large wind and solar power potential, a sharp rise in improving access to electricity and the strengthening and extension of the national transmission grid. The key missing component, vital to the future outlook, is distribution. The distribution utilities have been accumulating large losses because the average revenue per kilowatt-hour (kWh) of power sold is typically lower than the cost to the utility of the electricity they buy from the generating companies. Lacking financial resources, distribution utilities are unable to invest as much as they should to upgrade ageing and loss-prone parts of the network. Their financial situation also has operational implications for power supply, as it can deter distributors from purchasing electricity from costly peaking plants. This leads to load shedding and difficulties in meeting obligations to purchase power from renewable energy sources.

There is no single answer to the problems facing the distribution sector. End-user tariff increases are necessary, but they cannot offer a solution in isolation – not least because the affordability of electricity is a question of understandable political and social sensitivity. A suite of measures, with strong inter-linkages can move the system progressively towards full cost recovery, for example:

- Reliable and efficient procurement of fuel for the power sector, including auctioning of supply rights for coal (discussed in Chapter 13) and a more open market for gas.
- Concerted efforts to bring down the physical losses of electricity that arise across the transmission and distribution network.
- Reliable commitment to a competitive environment for power generation, allied with cost-effective policies to support renewables, both in terms of the choice of instruments used to secure additional capacity, and the regulatory and licensing conditions for investors.
- A system of permitting and approvals that gives a robust and transparent hearing to new generation and transmission projects, with a predictable timeframe.

On the revenue side of the equation, measures to improve the position of the distribution utilities include:

- Tackling the issue of non-technical losses, i.e. those arising from theft, non-payment and non-billing, and non-collection of payments for electricity consumed.
- Reducing cross-subsidisation between industrial, commercial and residential sectors, with adequate compensation from the state for any below-cost tariffs required by the state to be offered to specific groups, such as agricultural and vulnerable consumers.
- A regulatory environment, policed by well-staffed, well-trained and independent regulatory bodies, that compels the distribution utilities to pay consistent attention to improving their performance, while also providing an efficient and transparent governance framework for the system as a whole.

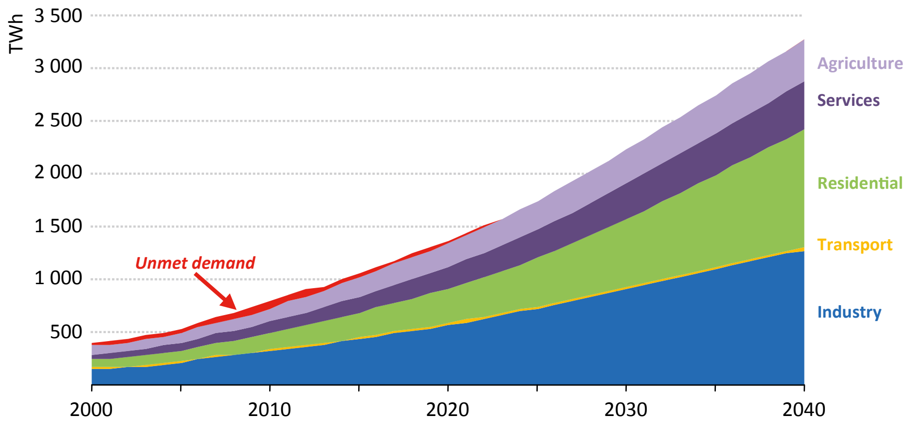
Policy intentions have already been expressed in relation to all these points and the projections in the New Policies Scenario assume progress in all these areas – albeit at a pace that reflects our judgement about the scale of the challenges involved and the likelihood of persistent state-by-state variations in their implementation. The net result is a system which does offer reasonable incentives for investment in generation and transmission capacity, sufficient to keep pace with India's rapidly growing needs.

Electricity demand

In the New Policies Scenario, electricity demand more than triples over the period to 2040, rising by 4.9% per year on average from 900 terawatt-hours (TWh) in 2013 to almost 3 300 TWh by the end of the projection period (Table 12.3). India accounts for almost 17% of the increase in global electricity demand from 2013 to 2040, an amount roughly equivalent to today's power consumption in Japan, Middle East and Africa combined. Per-capita electricity consumption grows from over 710 kWh to more than 2 000 kWh per year, an average annual growth rate of 4.0%.[9] Despite the growth, India's per-capita electricity demand remains well below the world average in 2040.

The anticipated increase in the reliability of power supply, including during times of peak demand, has widespread implications for the level of power consumption. It would lead to progressively less reliance upon, and ultimately less need for, back-up systems, whether large-scale captive power in the industry sector, or batteries plus inverters or small diesel generators in buildings.[10] It also releases some pent-up demand, as households expand their range of appliances, in the knowledge that they can be reliably used. In our projections, this unmet demand – an estimated amount linked to the incidence of load shedding in today's electricity supply – diminishes steadily over the coming years and disappears entirely by the mid-2020s (Figure 12.18). This occurs despite the large additional pressures that are put on the system by rising levels of access to electricity and strong growth in consumption from existing residential, commercial and industrial consumers.

Figure 12.18 ▷ Electricity demand by sector in India in the New Policies Scenario



Notes: Unmet demand is the energy deficit that results from load shedding expressed as a share of total final consumption. It is a conservative measure of unmet demand, not least because it does not include potential demand from people without access to electricity. Other energy sector is not shown as it is negligible.

9. This is different than the data reported by the Central Electricity Authority (CEA) as the *WEO* calculates per-capita electricity consumption as electricity demand divided by population while the CEA divides gross electricity generation by population. As such, CEA data for per-capita consumption are 957 kWh (2013/14).

10. The Central Electricity Regulatory Commission has estimated an installed capacity of 90 GW of small diesel generators across India. These generators are largely unmonitored and not covered by regulation or included in official statistics. However, IEA estimates the fuel (diesel) consumption of these generators as part of power generation fuel mix.

Table 12.3 ▷ Electricity demand by sector and generation in the New Policies Scenario (TWh)

	2000	2013	2020	2030	2040	2013-2040 Change	2013-2040 CAAGR*
Demand	**376**	**897**	**1 351**	**2 241**	**3 288**	**2 390**	**4.9%**
Industry	158	375	565	904	1 277	902	4.6%
Residential	79	207	329	647	1 115	908	6.4%
Services	46	133	207	332	450	318	4.6%
Transport	8	15	20	24	30	14	2.5%
Agriculture	85	160	222	324	401	241	3.5%
Other energy sector	0	6	8	10	13	7	2.7%
T&D losses	155	220	313	452	613	393	3.9%
PG own use	40	82	107	160	229	147	3.9%
Gross generation**	**570**	**1 193**	**1 766**	**2 848**	**4 124**	**2 930**	**4.7%**

* Compound average annual growth rate. ** Gross generation includes own use by power generators (PG), demand in final uses (industry, residential, services, transport and other) and transmission and distribution (T&D) network losses but does not include imports, which are minimal.

Industry remains the largest consumer of electricity in India. Industrial electricity demand more than triples over the *Outlook* period, though the overall share of industry in electricity consumption falls slightly from 42% in 2013 to 39% by 2040. The largest increases come from the steel and aluminium sub-sectors, which are responsible for 18% and 9% respectively of the rise in consumption. In the buildings sector (which includes residential and services), consumers take advantage of the improved quality of electricity supply to steadily increase their demands on the system, by an average of 5.8% per year. The share of electricity in residential energy consumption rises very quickly, from 10% in 2013 to 41% by 2040, in line with rising incomes, appliance ownership and demand for cooling. Peak demand for electricity, driven by residential demand, is expected to remain an evening phenomenon; a development that is reinforced by the increased reliability of power supply and the diminishing role for batteries and inverters (which at present effectively transfer some of the evening load to the daytime).

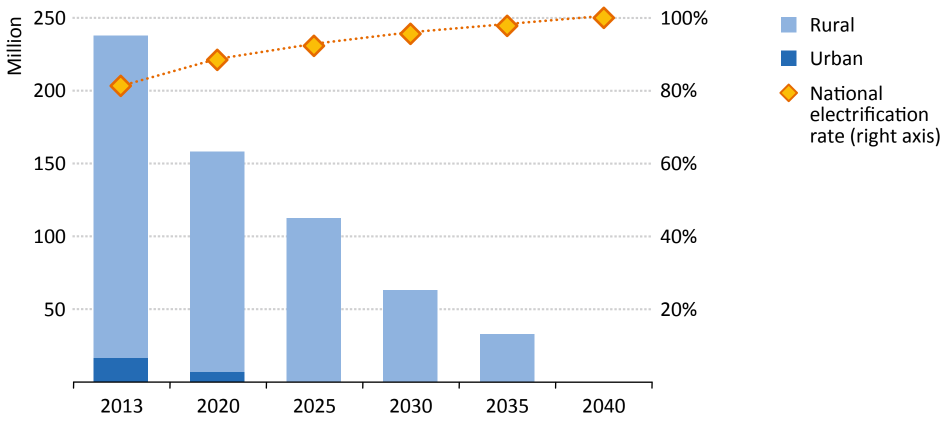
Consumption by agricultural end-users also rises; but the overall rise of 3.5% per year is tempered towards the end of the projection period as efficiency measures and more metering start to take effect. The share of agriculture in electricity demand falls from 18% in 2013 to 12% by 2040. Electricity demand in the transport sector is relatively small, at less than 1% of the total in 2040: rail is responsible for nearly all of the sector's electricity demand as electric vehicles make very small in-roads into the Indian market over the *Outlook* period.

Access to electricity

India makes major progress towards full household electrification in the New Policies Scenario and achieves universal access to electricity by the end of the projection period. The pace of change is fastest in urban areas, where universal access is reached by the mid-2020s, but slower in rural areas, where some 60 million people remain without access in 2030 (Figure 12.19). The government's goal of providing round-the-clock electricity access for all households is an important spur for accelerated action; but the target is difficult to achieve within the envisaged medium-term timeframe. Investments to expand the transmission and distribution system take some time to materialise. Moreover, putting in place all the necessary connections, mini-grids and off-grid systems becomes progressively more difficult the closer India gets to universal access, as the remaining households tend to be the hardest to reach: most Indian villages have some electrical connection today, but connecting the last remote households in the surrounding areas can be very costly. In addition, some households might voluntarily forgo adoption of electricity because of the monthly fees that come with it, particularly if supply is unreliable and outages are frequent.

In the New Policies Scenario, India's share in the global figure for people without access to electricity declines from 20% in 2013 to around 8% in 2030, as progress in India (and in developing Asia in general) is generally faster than elsewhere and much more rapid than in sub-Saharan Africa. Even though India is projected in this scenario to fall short of the Sustainable Energy for All target of universal access by 2030, this should not disguise the important achievements expected to be made, particularly in rural areas of India, where an additional 200 million people gain access by 2030. Over the entire projection period, around 580 million people gain access to electricity either through grid connections or through mini- and off-grid systems.

Figure 12.19 ▷ Population without access to electricity and electrification rate in India in the New Policies Scenario



The type of access that is provided depends on multiple factors, including the current state and coverage of the transmission and distribution systems, the plans to extend the grid and the availability of financing to realise these plans. In the New Policies Scenario, people living in urban areas gain access exclusively via grid extensions as this is the more economical option. Households close to areas of relatively high population density, i.e. in and around the centres of villages, tend to gain access through the grid as well; but for the remaining population living in rural areas, grid extension might be technically difficult or economically more costly than mini-grids or off-grid solutions.

The development of mini- and off-grid systems in rural India faces some important difficulties. This is an area for business model and technology innovation, but low tariffs for on-grid supply, often well below-cost recovery levels, constitute a major barrier, as they skew the economic calculation against off-grid projects. Most mini-grids are community-based projects or are run by private and social enterprises. The private sector is now playing a greater commercial role, usually through "fee for service" models, financed by banks and private equity. While this is promising, private investors tend to invest mainly in areas where consumers have the ability to pay without subsidies. Targeted support from the states or non-governmental organisations for small-scale projects remains essential. Moreover, technical knowledge is necessary for mini-grid operations and maintenance. In West Bengal for instance, mini-grid developments proved to be successful because provision was made for the involvement of qualified technicians to support the local level operators. In Chhattisgarh, a cluster approach involving structured maintenance networks, using (as far as possible) standardised systems has been adopted to reduce transaction costs (Palit, 2014).

Defining the respective roles of on-grid and off-grid technologies is important to achieve faster progress with electrification, as is the existence of an integrated and well co-ordinated strategy among the various public bodies involved (Ministry of Power, Ministry of New and Renewable Energy, Rural Electrification Corporation and State Electricity Boards) to ensure that state electrification plans can be sustainably financed, implemented and monitored. The affordability of power for the poorest households is an essential criterion if electrification is to bring sustained benefits in terms of welfare: metering, differentiated tariffs and better targeted subsidies for the poorest households can all help in this respect. Building in provision for electricity to support productive uses, i.e. for small businesses, can also contribute strongly to financial sustainability, as these businesses become an important source of economic activity and revenue.

Electricity supply

The power system in India has to cope with a number of challenges over the *Outlook* period. Power generation capacity needs to be expanded to serve rapidly growing power demand and to overcome the shortages which causes regular load shedding. Peaking capacity and flexible power plants need to be added to the fleet to meet demand at any time, improve the reliability and quality of supply and integrate variable renewable energy technologies into the system. The evolution of the generation mix needs to reflect energy security concerns, affordability and environmental compatibility. Moreover, electricity transmission and distribution networks require massive investments to transport growing amounts of power, bring down the notoriously high losses, deal with increasing volatility in power generation and connect to the grid millions of people without access to electricity. How India addresses these challenges is primarily a question of policy; the long-term trends presented in this section are very sensitive to the successful implementation of reforms.

The development of the Indian power sector – despite there being little power trade with neighbouring countries – is also dependent on a range of interactions with the rest of the world, including fuel procurement, technology co-operation and imports, as well as flows of investment and investment finance. In the New Policies Scenario global power generation grows by over 16 000 TWh over the *Outlook* period and India accounts for almost a fifth of this growth. Similarly India accounts for nearly 50% of the increase in global coal-fired power plant capacity and relies on a growing share of internationally traded coal to fuel these plants – before 2020 India becomes the largest coal importer in the world. India also becomes a key player in terms of utility-scale solar PV, accounting for one-sixth of newly installed PV capacity in the world to 2040.

Building a power station in India typically comes at a lower cost than in OECD countries and therefore India's share in cumulative global power generation investment over the *Outlook* period is lower than its share in global power demand growth. Nonetheless, in the New Policies Scenario one out of ten dollars invested in the power sector worldwide is invested in India over the projection period. Rapidly growing power generation and continued reliance on coal as the fuel of choice for generation also make India a significant contributor to growing carbon-dioxide (CO_2) emissions from the power sector. In the period to 2040, India's CO_2 emissions from power generation grow nearly two-and-a-half-times; making its power sector the second-largest emitter from power generation in the world.

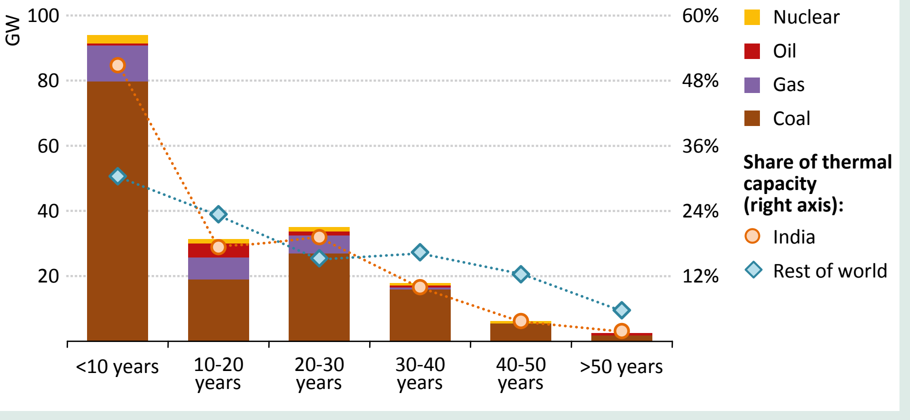
Power generation capacity

Installed power capacity in India grows three-and-a-half-times, from 290 GW in 2014 to over 1 075 GW in 2040, the latter being roughly equivalent to the installed capacity in the European Union today (Table 12.4). Capacity increases faster than generation; this is due in large part to installations of variable renewables, which become an increasingly important part of the Indian power system. Wind and solar power have lower capacity factors than thermal plants, meaning that additional capacity is needed to meet demand when the wind does not blow or the sun does not shine. Moreover, in an effort to reduce the shortage in peaking capacity, the projections require a substantial increase in the number of power plants (typically gas turbines or large engines) that might run for only a few hundred hours a year. Plants fulfilling such a balancing role, with their relatively high variable costs, face a significant risk of being insufficiently compensated by financially weak power off-takers, a factor that could seriously impede investment.

Box 12.7 ▷ A fleet to last a lifetime

Just over half of the world's thermal power plant fleet is less than 20 years old, but in India this share is two-thirds (Figure 12.20). The relative youth of much of India's power generation fleet means that relatively few of these plants will reach the end of their technical lifetime over the *Outlook* period. In the case of coal plants, over half of Indian coal capacity has been added during the last ten years (while globally only 38% of the coal fleet is less than ten years old). The comparison of the age profile of nuclear power is similarly striking: nearly two-thirds of the Indian nuclear capacity is less than 20 years old, while, on a global level, only 15% of the fleet was built during the last 20 years – mostly in non-OECD countries.

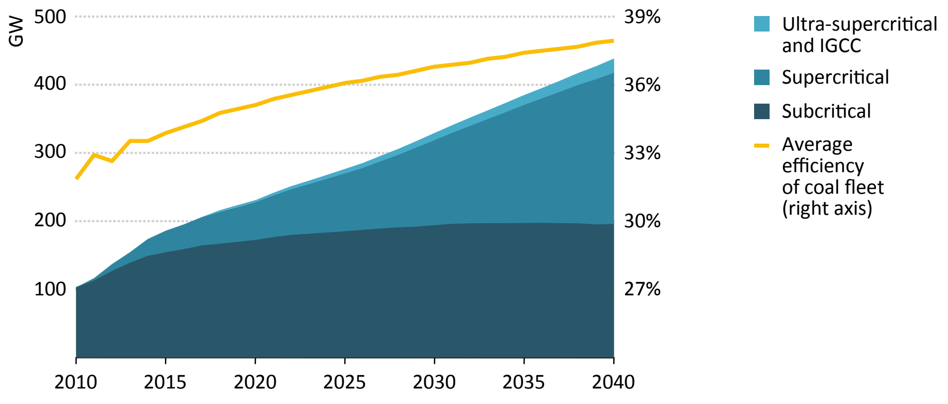
Figure 12.20 ▷ Age profile of thermal capacity in India, end-2014



Replacing retiring power stations (a major issue in OECD countries) is therefore a smaller challenge in India. Of the 100 GW of capacity that is retired over the period to 2040, around 60 GW are thermal plants. However, as older plants typically have a smaller unit size, the number of plants retiring is larger than the capacity figure suggests. This provides an opportunity in many cases to bypass lengthy and costly land acquisition processes by installing large and efficient power stations on existing sites. Indian authorities are actively discussing the idea of prematurely retiring old, inefficient plants and replacing them with larger supercritical stations in order to expand capacity rapidly. The remaining 40 GW are renewable energy plants with shorter technical lifetimes (the assumed lifetime of wind and solar PV is around 25 years). Thus, although almost all the currently installed wind and PV capacity will have to be replaced or re-powered before 2040, the investment equation in India is essentially a simple one: to ensure that capacity additions keep pace with consumption, rather than also having to keep up with large-scale retirements.

Coal-fired power plants – half of which have entered into service during the last ten years (Box 12.7) – remain the backbone of the Indian power system. In our projections, the coal fleet increases by around two-and-a-half-times, reaching almost 440 GW in 2040, by which time India has the second-largest coal fleet in the world (after China), having overtaken the United States in the early-2020s. The technological composition of the coal fleet also changes markedly. Today over 85% of the coal plants are based on subcritical boiler technology, performing poorly in terms of their conversion efficiency. Several supercritical plants have come online in recent years, as domestic manufacturing capability for such boiler types has been boosted, accounting for the remaining 15% of the coal fleet. By 2040 the share of supercritical plants in the expanded fleet has increased to around half of the total and there are also some ultra-supercritical plants and integrated gasification combined-cycle (IGCCs) built in the latter half of the projection period (Figure 12.21). The shift towards supercritical technology effectively boosts the country's average coal plant efficiency from 34% today to 38% in 2040 – a notable shift given India's endowment of low quality (high ash) coal.[11] Gas-fired capacity increases five-fold, reaching over 120 GW in 2040. Gas plants are crucial for improving the reliability of power supply, being typically used for load-following operation and balancing, key roles in system operations.

Figure 12.21 ▷ Coal-fired power plant capacity by technology and average efficiency in India in the New Policies Scenario



Although permitting and public acceptance remain a challenge, especially for large dams, over the *Outlook* period India increasingly taps its large hydropower potential, with capacity growing from 45 GW to nearly 110 GW in 2040 (including small hydro plants). Hydro capacity is heterogeneous, with run-of-river plant essentially serving as baseload, while reservoir-based hydro plants tend to operate in times of high load. Variable renewables,

11. The high ash content of Indian coal does not impede the installation of supercritical and ultra-supercritical technology but it inevitably results in an efficiency loss compared to what would be achievable with low ash coal. Use of modern technology requires plants to be designed according to the properties of a specific coal type.

like wind power and especially solar PV, are set to grow rapidly over the period (Table 12.4). Wind power reaches around 140 GW in 2040, up from 23 GW today. But it is really solar PV that underpins the rise in renewable energy development, with capacity boosted from just 3.5 GW in 2014 to over 180 GW in 2040 (Spotlight). Solar PV capacity is available during the day when load is relatively high, but in an evening peaking system, like that in India, solar PV does not contribute to meeting peak demand, a key reason why its expansion needs to be complemented by additional peaking capacity.

SPOTLIGHT

India's solar target: how high can you go?

The Indian government has announced plans to bring the country's solar capacity to 100 GW in 2022. This target is a five-fold increase over the previous target of 20 GW, representing a step-change in India's solar ambition. From 3.7 GW of solar capacity in 2014, the target would require annual additions averaging 12 GW per year for the next eight years. The annual installations of solar PV by a single country have, to date, never exceeded the 11 GW reached by China in 2013. Of the targeted 100 GW, around 60 GW are envisaged to come from utility-scale plants, with the remainder being rooftop PV installations and other small-scale and off-grid installations. Plans for the utility-scale installations are the most advanced, with the centrepieces being the National Solar Mission (which plans to add more than 15 GW of capacity) and the proposal for a series of solar parks, large-scale solar facilities across various states, with up to 500 MW of capacity each. In addition, various state governments have come up with their own targets and support schemes. Initiatives to roll out rooftop PV are less advanced. They primarily focus on net-metering policies and improving the cost and availability of financing (see also Chapter 13).

Achieving these ambitions will require that a challenging set of issues related to land acquisition, remuneration, network expansion and financing are overcome. A rapid increase in solar installations, at least in the early years, would also be beyond India's current solar panel manufacturing capability (around 2.8 GW per year), although there is ample PV manufacturing capacity in other countries. The financing issue is particularly problematic, as the estimated $170 billion in investment is, in all likelihood, beyond the capacity of the domestic financial sector; but attracting international capital introduces new challenges, such as foreign currency risk (see Chapter 14). With these constraints in mind, we project that solar PV capacity reaches 40 GW in 2022, nearly twelve-times today's capacity, increasing at a rate of deployment that sources the bulk of the panels from local manufacturers and allows for the build-up of an installation industry without overheating supply chains. There is upside potential as well as downside risk to our projection: what is unarguable is that India's solar targets have already served one vital purpose, making a powerful statement of intent that solar power shall be a new and potentially transformative technology in India's energy mix.

Table 12.4 ▷ Power generation capacity by type in India in the New Policies Scenario (GW)

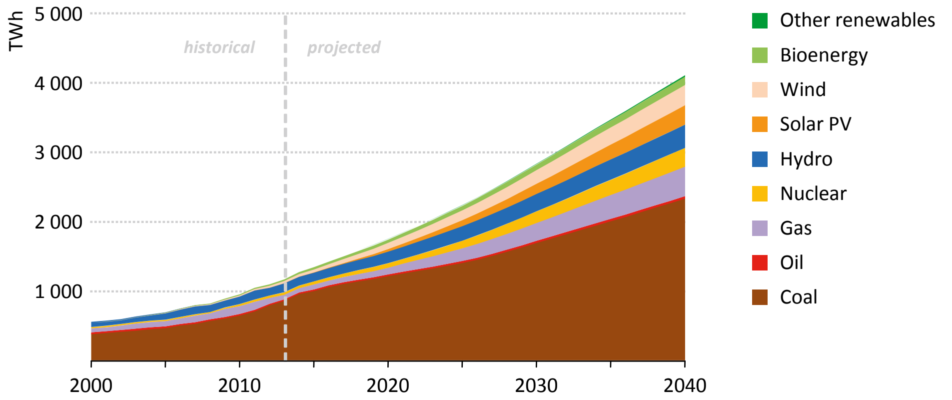
	2000	2014	2020	2030	2040	Shares 2014	Shares 2040	CAAGR* 2014-2040
Fossil fuels	84	204	280	419	576	71%	53%	4.1%
Coal	66	174	230	329	438	60%	41%	3.6%
Gas	11	23	41	76	122	8%	11%	6.6%
Oil	7	7	9	13	15	3%	1%	2.9%
Nuclear	3	6	10	24	39	2%	4%	7.6%
Renewables	27	79	147	304	462	27%	43%	7.0%
Hydro	25	45	58	83	108	15%	10%	3.5%
Wind	1	23	50	102	142	8%	13%	7.2%
Solar PV	0	3	28	100	182	1%	17%	16.4%
Other	0	7	11	18	30	3%	3%	5.5%
Total	**113**	**289**	**436**	**746**	**1 076**	**100%**	**100%**	**5.2%**

* Compound average annual growth rate.

Power generation

Electricity production increases from 1 193 TWh in 2013 to over 4 100 TWh in 2040, meaning that power output in India is larger than power generation in the European Union by 2035 (although, because of a higher rate of losses, Indian power demand overtakes European levels only a few years later). In terms of output, by 2040, India has the third-largest power system in the world, after China and the United States. The power generation mix also becomes increasingly diverse. Today, nearly three out of every four units of electricity are generated by coal-fired power plants (Figure 12.22). By 2040, even though coal-fired power generation expands by two-and-a-half-times (and only China produces more electricity from coal than India), coal's share in the power mix drops to 57%, with renewables, nuclear and gas all increasing at high rates. Nuclear power complements coal in baseload power generation, increasing its share in the mix from around 3% today to 7% in 2040. Gas-fired power plants are currently suffering from lower than expected supply of domestically produced gas, for which higher cost imported LNG has been no substitute. Rather than run the plants at a large loss, many combined-cycle gas turbines (CCGTs) are operating only at very low load-factors. This situation is partially reversed over the medium term, as imported LNG becomes available at a more competitive price. Gas gains further ground in the power mix over the longer term, although – due to the continued relatively high cost of the fuel in India – gas-fired plants do not produce baseload power. Instead, they flexibly follow the daily load pattern and meet demand peaks. This essential balancing role helps gas-fired power generation to increase more than six-fold over the *Outlook* period, reaching 430 TWh by 2040. The share of gas in the Indian power mix nearly doubles to 10% in 2040.

Figure 12.22 ▷ Power generation by source in India in the New Policies Scenario



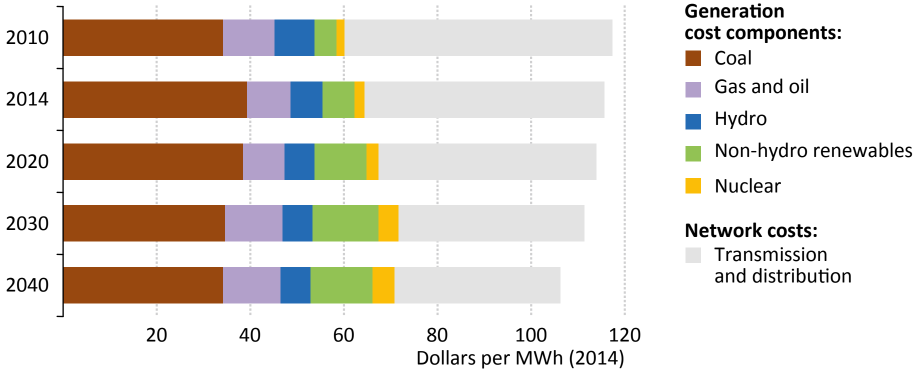
Power generation from renewable energies – with the exception of hydro – plays a minor role today in the power system in India. However, this is set to change substantially over the *Outlook* period, with non-hydro renewable power output growing twelve-fold, to 720 TWh. The share of all renewables in power generation increases from 17% today to 26% in 2040, with wind and solar PV together accounting for 65% of the growth in renewable power output. The government's focus on solar PV deployment, in combination with the good solar resources, makes the country the second-largest producer of electricity from solar PV installations by 2040, overtaking first the United States and then European Union around 2030. Wind energy deployment is primarily at onshore sites, with offshore wind power only picking up modestly in the latter half of the projection period. The variable nature of solar PV and wind power generation requires complimentary system arrangements to optimally integrate these sources, affecting the operational characteristics of the other power plants and triggering an expansion of flexible power sources. The growth of hydropower helps in this respect, although hydropower plants form a varied group, with some installations providing baseload power, while others operate more flexibly to meet fluctuations in demand. Overall, hydropower still provides a third of the renewables-based electricity in 2040. Small hydro plants, especially those in mountainous parts of northern India, play an important role in providing access to electricity in remote villages.

CO_2 emissions from power generation in India grow nearly two-and-a-half-times over the *Outlook* period, reaching 2.3 gigatonnes (Gt) in 2040 (up from just under 1 Gt in 2013). The share of the power sector in the country's total emissions decreases from half today to 45% in 2040. Renewable energy deployment and the use of more efficient coal-fired technologies bring the CO_2 emissions-intensity down by 30%, from 790 grammes of carbon dioxide per kilowatt-hour (g CO_2/kWh) to 560 g CO_2/kWh.

Power prices and generation costs

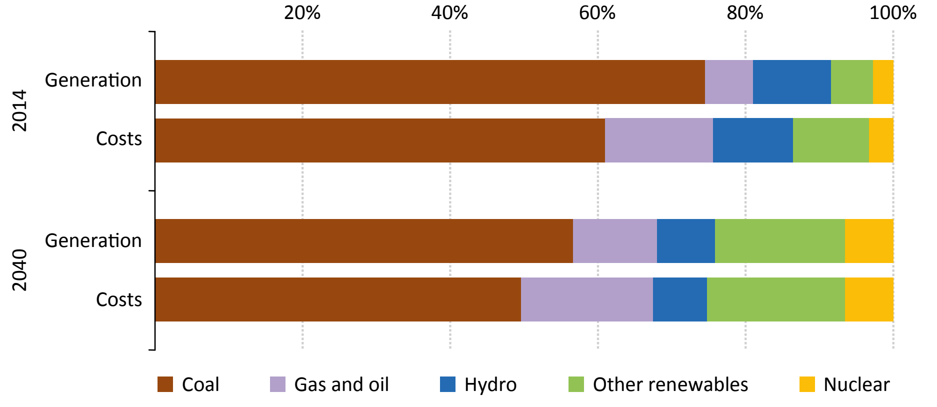
The affordability of electricity is an understandably sensitive issue in India, making it essential to keep in check the underlying costs of power generation and the costs of transmission and distribution. The average cost of power generation increases from around \$65 per megawatt-hour (MWh) today to just over \$70/MWh in 2040 (Figure 12.23). Despite the multiple benefits that come with the deployment of non-hydro renewables – chiefly solar PV and wind power – they put upward pressure on India's power generation costs. India is an evening peaking system and therefore, despite abundant sunshine, solar PV does not have a significant capacity credit. Consequently, solar PV primarily displaces conventional generation during the daytime – saving fuel costs – but reduces only slightly the amount of dispatchable capacity needed to serve the evening peak. Some similar observations are true for wind power, although its capacity credit is slightly higher. As a result, in 2040, non-hydro renewable energy accounts for 19% of the average cost of power generation, slightly above its contribution to the country's output. To contain the cost increases from non-hydro renewables deployment, their support mechanisms must be designed in a way that captures the benefit of falling technology costs over time and avoids over-compensation.

Figure 12.23 ▷ Components of the delivered cost of an average unit of power in India in the New Policies Scenario



For gas-fired plants, the situation is slightly different, though – even more so than in the case of non-hydro renewables – they also contribute less to generation than to costs: in 2040 the share of gas-fired generation in India's generation mix stands at 10% while its share in average generation costs amounts to 17% (Figure 12.24). However, gas-fired plants play a key role in the reliability of power supply, as both their technical and economic characteristics favour flexible operation, i.e. being able to quickly ramp output up and down. Their disproportionately high share in generation costs is therefore justified by the additional value they provide to the system. Coal-fired power generation costs decrease over the *Outlook* period, despite increasing coal prices and deployment of more capital-intensive technologies, as upward pressures on these costs are contained by the marked improvements in conversion efficiency realised over time. Coal-fired power contributes substantially more to output than to overall costs, helping to keep electricity tariffs affordable for consumers in a period when India is adding more costly sources of power (although the falling technology costs of solar and wind reduce this effect over time).

Figure 12.24 ▷ Share of total power generation costs versus share of generation in India in the New Policies Scenario



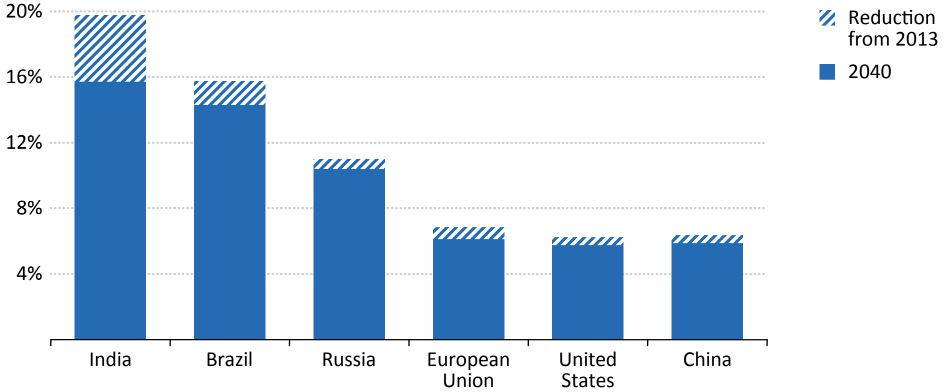
The structure of costs, in terms of their variable and fixed components, also undergoes a considerable transformation. Today, with large reliance on coal, power generation costs are primarily composed of (variable) fuel costs. However, nuclear, hydro, wind and solar PV grow rapidly; these technologies are very capital-intensive and have minimal variable costs. Coal-fired power generation also becomes more capital-intensive with the focus shifting to supercritical technology. The higher capital cost is justified by higher efficiency, reducing fuel expenditure. In 2040, 55% of the total power generation costs are fixed, compared with 53% in 2014. This shift in the cost structure does not directly impact the affordability of power, but it makes power tariffs slightly more stable, as generation costs are less exposed to the volatility of fuel prices.

In addition to the generation costs, the total system cost includes network costs for the transmission and distribution of electricity. On a per-MWh-basis, the average total system costs can be interpreted as a proxy for average end-user prices (excluding taxes and levies). Despite rising average generation costs, the average system costs decrease slightly over the long term, as declining network costs provide relief to the system. Standing at around $115/MWh today, system costs stay flat over the medium term and then decline to around $105/MWh in 2040. Continued reduction of technical and commercial losses brings network costs down over time, despite grid expansion and the growing volume of power transmission. Improving the efficiency of the networks and bringing their costs down is the key to countering rising power generation cost and keeping power affordable for all.

Transmission and distribution

India has five regional network zones that are connected to each other, forming a national grid. Transmission lines – which transport power over large distances from the power plants to the demand hubs – account for only 5% of the network length. The rest consists of distribution lines, which deliver power over the last few kilometres to the consumers. India's network suffers from one of the highest shares of loss (of electricity generation) in the world (Figure 12.25). Network losses are driven by technical and commercial factors. The technical losses typically increase with ambient temperatures and distance between generation sources and demand centres. Ageing and poorly maintained networks are more prone to high technical losses than modern and efficient installations. On the commercial side, theft, unmetered consumption and inadequate revenue collection add to network losses. In our projections, India takes large steps in bringing down network losses over time, with the share dropping from a national average of 20% today to less than 16% in 2040. Reducing commercial losses helps re-establish the financial viability of the transmission and distribution companies, giving them the funds to carry out much needed network investments.

Figure 12.25 ▷ Network losses and reduction of losses in India and in an international context in the New Policies Scenario



Apart from bringing down the losses, India's transmission and distribution network faces a number of additional challenges over the *Outlook* period. Although a growing role for distributed renewables, notably rooftop solar PV, allows capacity to be built nearer to the point of consumption, the network still needs to be expanded both to accommodate growing power demand, to integrate the growing share of utility-scale wind and solar projects, to improve interconnection with neighbouring power systems, and also to reach those settlements and households that currently do not have access to electricity. In our projections, the length of the network increases by over 70% in the period to 2040. This expanded grid permits more efficient dispatch of the power plant fleet, thereby reducing generation costs. An additional challenge, but also a large opportunity, is the modernisation of the metering infrastructure.

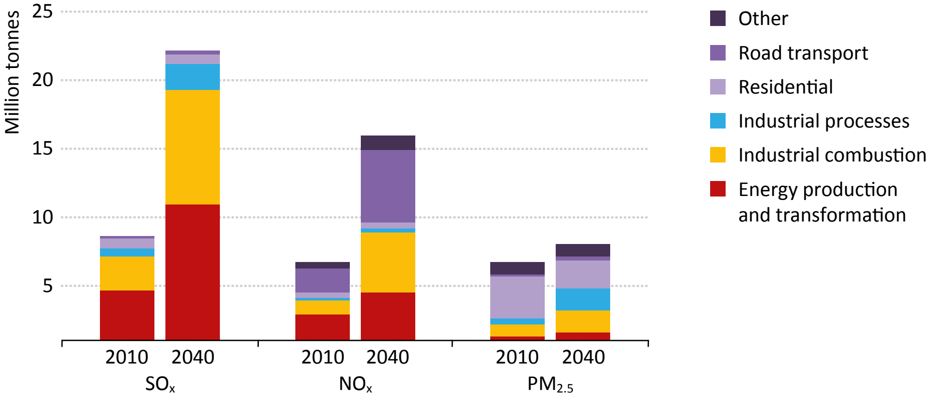
If successful, this would not only contribute to reduced commercial losses, but could also allow India to roll out smart metering and other information technology-based solutions to establish the ground for demand-side management and the introduction of smart grids.

Implications for air quality

Local air pollution is a large and growing problem in India that already takes a heavy toll on health (see Chapter 11). For this analysis, we have examined the evolution of the main relevant pollutants, sulphur oxides (SO_x), nitrogen oxides (NO_x) and fine particulate matter[12] ($PM_{2.5}$), assessing how the different energy scenarios presented in this *Outlook* impact on the amount of each pollutant emitted, to help identify the improvements that can be made in the energy system to manage these issues.[13]

Over the period to 2040, emissions of SO_x rise to more than two-times their current levels, stemming primarily from coal combustion in power plants and, to a lesser extent, industrial facilities (Figure 12.26). The strong increase in demand for mobility and increasing car ownership lead to a similarly large rise in NO_x (road transport emissions register a three-fold increase), compounded by emissions from industrial combustion and the broader energy sector, which also grow robustly. $PM_{2.5}$ emissions show much more modest growth; almost two-thirds of the estimated releases of $PM_{2.5}$ are related to the incomplete combustion of biomass by households and industry and, with biomass substituted for LPG for cooking, emissions are reduced by 30% in the residential sector. The benefits are offset, to a degree, by a robust increase in emissions from industry, where biomass use remains significant. Energy production and transformation makes the largest contribution to the increase in total emissions, which double in the period to 2040.

Figure 12.26 ▷ Emissions of NO_x, SO_x and $PM_{2.5}$ by sector, 2010 and 2040



12. Particulate matter is categorised by the size of the particles, $PM_{2.5}$ represents the size of the particles in micrometres and is considered the most harmful to health.

13. The analysis of the impacts of future local air pollution trends has been developed in collaboration with the International Institute for Applied Systems Analysis, Austria.

The health impacts of increasing pollution are considerable. The rise in outdoor $PM_{2.5}$ emissions alone is calculated to lead to a reduction in life expectancy of more than seven months (this is in addition to the 16.8 months in reduced life expectancy that is a result of current $PM_{2.5}$ levels). This corresponds to a 140% increase in premature deaths, which reach 1.7 million in 2040. Indoor air pollution, from the continued though diminished use of solid biomass for cooking, could be expected to add considerably to this number. In addition, the rise in ground-level ozone leads to crop losses. By 2040, the increase in ground-level ozone gases leads to a 13% decrease in wheat yield and will have adverse impacts additionally on soybean, rice and maize crops.

The threat of an unbridled increase in air pollution is well known to Indian policy-makers, who have announced plans to implement an air quality index in ten cities, giving daily updates on the pollution status. The existing legislation, the Air Prevention and Control of Pollution Act, dates back to 1981 (with amendments in 1987). Policy-makers are planning to introduce improvements and updates to bring it into line with India's changing economic realities. As things stand, many of the standards in force were set in the 1980s and technological improvements since then mean that the standards are now comparatively low by international standards. Current standards for coal-fired power plants, for example, govern only particulate matter and set a target ranging from 150 milligrams per cubic metre (mg/m^3) to 350 mg/m^3, compared with 30 mg/m^3 in China. Standards for ambient air quality set a target annual average limit for $PM_{2.5}$ that is four-times higher than that recommended by the World Health Organization.

Outlook for India's energy supply

Unlimited needs, limited resources

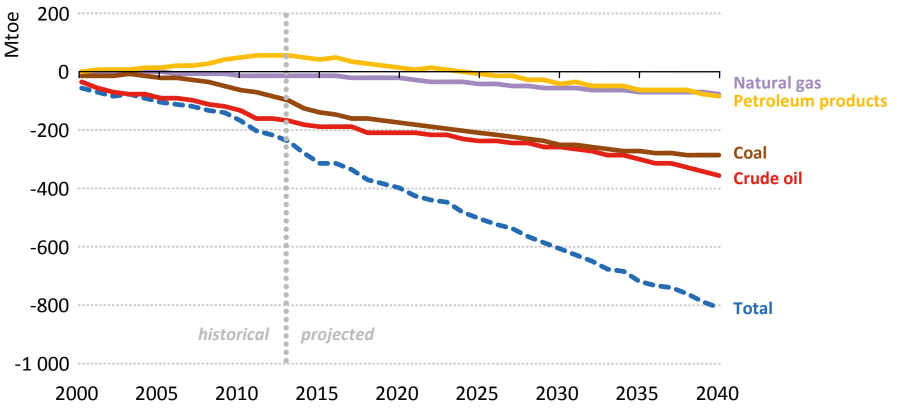
Highlights

- The sheer size of the increase in energy demand in India means that it mobilises its energy supply resources on all fronts. In our projections to 2040, low-carbon energy – led by solar and wind power – grows rapidly, from a relatively low base, but domestic production of coal, rising at almost 4% per year, makes by far the largest contribution in energy terms. Yet the increase in domestic energy production is far below India's consumption needs, and by 2040 more than 40% of primary energy supply is imported, up from 32% in 2013.
- Coal production increases to 930 Mtce (roughly 1 750 Mt in volumetric terms) in 2040, making India second only to China among global producers. Accomplishment of a faster rate of growth, such as the ambitious volumetric target to raise output to 1.5 billion tonnes by 2020, is constrained by the concentrated structure of the coal industry, issues over land use and permitting, and infrastructure bottlenecks. Reforms to the system of coal procurement and contracting underpin new mining investment and an efficient allocation of coal to consumers, including an expansion of competitively priced imports in parts of coastal India. India becomes the world's largest importer of coal before 2020 and imports rise to over 400 Mtce by 2040.
- India's oil production tails off to around 700 kb/d, as limited resources and relatively high costs constrain new oil projects. The result is a rapid rise in net oil imports, to 9.3 mb/d by 2040, and high reliance on the Middle East for imported crude oil. India's refinery output grows, but is increasingly dedicated to the domestic market.
- Gas production rises to 90 bcm in 2040, but this would require an adjustment to (or premium on top of) the current formula that determines the price paid to domestic producers, or investment risks falling short – especially for complex offshore projects. The gas balance is filled by rising imports of LNG, although India's relative proximity to the Middle East and to Central Asia offers scope for new pipeline links.
- Wind and solar power are abundant and increasingly cost effective. The target to reach 175 GW of renewable capacity (excluding large hydro) by 2022 is a strong statement of intent, galvanising new projects, manufacturing and installation capabilities. Deployment is slowed, in practice, by issues with land use, grids and financing, but the expansion of solar generation capacity to 2040 is second only to coal in our projections. Additions of hydropower and nuclear power plants have fallen well short of planned levels in recent years, and issues of permitting and public acceptance could continue to hold back investment: recent international agreements have though eased constraints on nuclear co-operation.

Energy supply in India

The pace at which energy consumption is expected to expand means that India mobilises supply on all available fronts in the New Policies Scenario. Deployment of wind and solar power increases at the fastest pace, but the production of all domestic sources of energy is higher in 2040 than in 2013, with the sole exception of oil, where India's resource limitations come into play. Yet domestic energy production is not sufficient in aggregate to keep up with demand, leaving a growing gap that needs to be filled by imported fuels (Figure 13.1, Table 13.1). Increases in domestic coal production keep the need for coal imports at least partly in check. But net oil imports rise dramatically, to reach 9.3 mb/d by 2040, an import dependence of greater than 90%.

Figure 13.1 ▷ Fossil-fuel trade balance in India in the New Policies Scenario



Note: Mtoe = million tonnes of oil equivalent.

Coal

Coal quality, resources and reserves

Total proven coal reserves in India amount to 87 billion tonnes – roughly equivalent to 140 years of current output – of which hard coal (steam and coking coal) makes up 95%, and the remainder is lignite.[1] Total coal resources (inferred and indicated), including deposits that are yet to be proven, are almost two-and-a-half-times larger, at 213 billion tonnes (BGR, 2014). Coal is not evenly dispersed across India. Most can be found in the east of the country, with two-thirds of Indian reserves located in the states of Jharkand, Odisha and Chhattisgarh (Figure 13.2 and map at Figure 13.7).

1. In order to provide a consistent underlying basis for modelling, data from the Bundesanstalt für Geowissenschaften und Rohstoffe (BGR) on reserves and resources are used for all countries in the *World Energy Outlook*. The data in this section are different from the Indian coal ministry's *Coal Inventory of India* report (which states 307 billion tonnes of resources and 132 billion tonnes of reserves) as the BGR applies a recovery factor to the in-situ reserves (accounting for the fact that typically not all in-situ reserves are extractable) and deducts cumulative past production volumes.

Table 13.1 ▷ Energy production in India in the New Policies Scenario

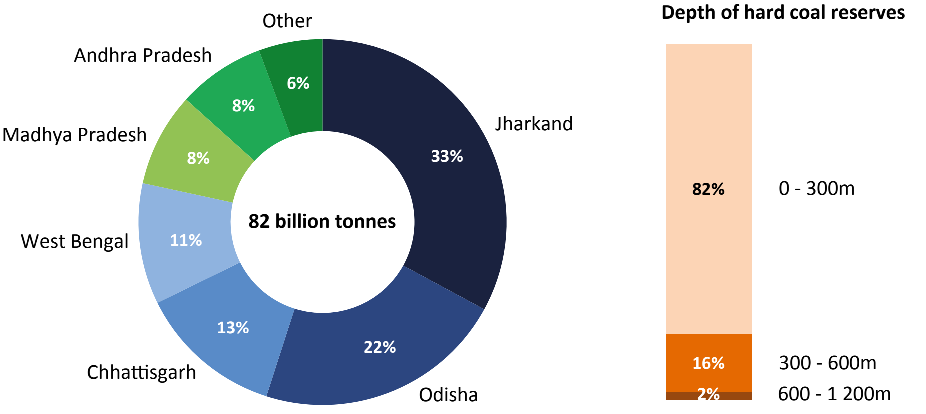
	Unit	2000	2013	2020	2030	2040	2013-2040 Change	2013-2040 CAAGR*
Oil	Mtoe	37	43	35	31	31	-12	-1.2%
	kb/d	771	917	734	678	725	-192	-0.9%
Natural gas	Mtoe	23	29	32	46	75	46	3.6%
	bcm	28	35	38	55	89	55	3.6%
Coal	Mtoe	131	238	298	443	648	410	3.8%
	Mtce	187	340	425	632	926	586	3.8%
Nuclear	Mtoe	4	9	17	43	70	61	7.9%
Renewables	Mtoe	155	204	237	274	297	93	1.4%
Hydropower	Mtoe	6	12	15	22	29	16	3.2%
Bioenergy	Mtoe	149	188	209	217	209	20	0.4%
Other renewables	Mtoe	0	4	13	35	60	56	11.0%
Total production	Mtoe	**351**	**523**	**619**	**836**	**1 121**	598	2.9%
Total demand	Mtoe	441	775	1 018	1 440	1 908	1 133	3.4%
Share of imports	*%*	*20%*	*32%*	*39%*	*42%*	*41%*	*n.a.*	*n.a.*

* CAAGR = compound average annual growth rate. Notes: kb/d = thousand barrels per day; bcm = billion cubic metres; Mtce = million tonnes of coal equivalent.

Indian coal reserves are mostly shallow, at a depth of up to 300 metres, and are typically exploitable using surface mining methods. However, as some of these coal reserves are located below settlements or dense forests (areas for which surface mining approval is difficult to obtain), going underground might ultimately prove the only feasible solution if these deposits are to be tapped, as it avoids resettlement and forest clearing. Coal occurring at depths greater than 300 metres is usually economically extractable only with underground mining techniques. Coal companies in India have extensive experience in surface mining, but so far, state-of-the-art underground mining – even though already applied in some mines – has made limited in-roads. Worldwide, mining companies have been successful in economically and safely extracting coal at great depths, but unlocking the full potential of India's coal endowment will require significant technological improvement of its mining industry.

Indian hard coal is mostly bituminous, with relatively low moisture but high-ash content. Three-quarters of current coal production has ash content of 30% or greater, with some of the highest ash coals approaching 50%. In comparison, coal traded on the international market rarely exceeds 15% ash content. The majority of the ash in Indian coal is so-called inherent ash, i.e. small particles of mineral matter that are embedded in the combustible part of the coal. Contrary to free ash – mineral impurities that are related to the extraction process – inherent ash cannot easily be removed from the coal. The high-ash content reduces the calorific value of the coal. Most of the coal currently produced in India falls in a range of 3 500 kilocalories per kilogram (kcal/kg) to 5 000 kcal/kg. This is markedly lower than the average heat content of coals typically found in other large producing countries, such as China, United States or Russia.

Figure 13.2 ▷ Hard coal reserves by state in India



Sources: BGR; Inventory of Coal Resources of India; IEA analysis.

Costs

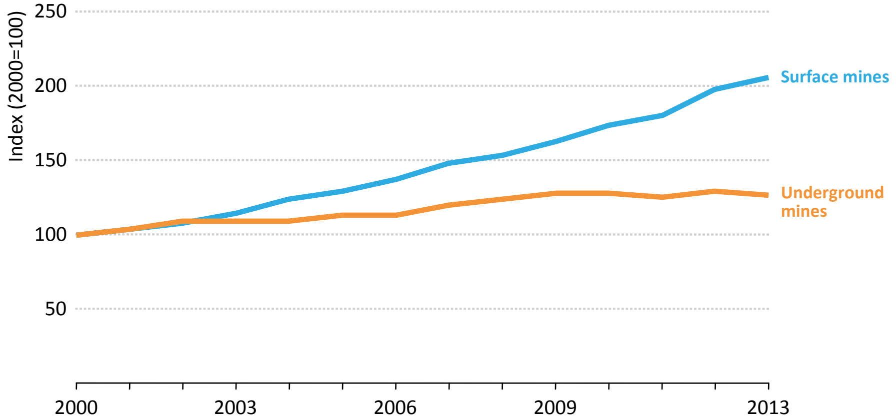
Production costs for coal in India fall in a wide range, with some large open-cast mines producing coal for less than $15 per tonne, while other small high-cost underground mines have costs in excess of $150 per tonne. Generally speaking, primarily due to low productivity, coal from underground mines in India is much more costly to produce than coal from surface mines, even when adjusted for energy content (which tends to be higher in underground mines). At current coal prices of $40 per tonne on average for domestic coal and $80 per tonne for imported coal (both adjusted to 6 000 kcal/kg), the majority of underground mines in India are outright unprofitable (see section on coal market and industry structure). Driven by surging coal demand, the primary goal of state-owned coal companies in India is maximisation of output to provide coal to power stations and to industry rather than optimising financial returns. Consequently, the rents of open-cast mines are used to cross-subsidise costly production from deep mines.

In 2013, labour productivity (expressed as output per miner shift in tonnes) in surface mines was fifteen-times higher than in underground mines. This is partly due to surface mines having experienced a doubling in labour productivity since the early-2000s (Figure 13.3). In contrast, underground mines still perform poorly and their labour productivity has grown at a much slower pace. An average Indian coal miner produces less than two-and-a-half thousand tonnes (kt) of coal per year, while an Indonesian counterpart is at least 50% more productive, a miner in China produces more than 5 kt per year and an Australian worker mines up to 13 kt per year on average.[2] In India wages are still low and consequently the mines exhibit a higher labour-intensity than elsewhere. While open-cast mines, in

2. Miner productivity is a function of the relative cost of labour and capital: countries with high labour cost typically have a highly mechanised and hence capital-intensive coal mining industry while substitution of capital for labour is less prevalent in countries with low wage levels.

particular, have increasingly made use of larger equipment, gaining economies of scale, in India's underground mines, efficient longwall methods are still rare. Underground mines primarily rely on room-and-pillar methods, which allow only a fraction of the coal in a deposit to be extracted (with this method, tunnels of coal are carved out of the seam, while part of the coal remains in place as "pillars" to support the roof).

Figure 13.3 ▷ Productivity evolution in the coal mining sector in India



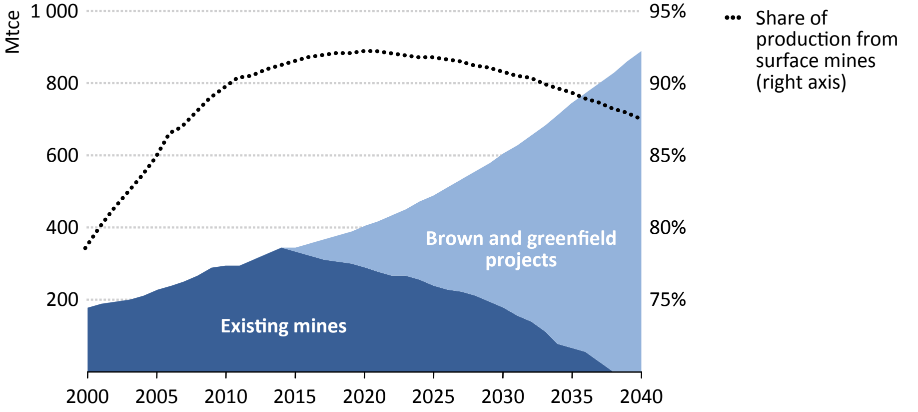
Sources: IEA analysis; Coal Directory of India.

Due to generally labour-intensive production methods and the high share of open-cast mines, the two fundamental cost drivers are wages and the oil price, factors which lead to a moderate increase in costs over the *Outlook* period. With continued strong gross domestic product (GDP) growth, real wages are expected to experience upward pressure, although mining companies can counter this effect by increasing mechanisation and using more efficient equipment and machinery, i.e. by pushing up capital costs and improving productivity (with India's strong growth in coal production over the *Outlook* period, the primary goal of mechanisation and efficiency gains would not be to reduce the workforce but rather to increase output per miner). The second cost driver is oil: oil products are widely used in open-cast mining, primarily as a fuel for earth-moving equipment but also as an input to certain explosives (see Chapter 7). Rising oil prices, as envisaged in the New Policies Scenario, put upward pressure on costs at surface mines (although this effect can, to some degree, be offset by more efficient equipment or additional use of electric draglines). India is also likely to see some diversification away from oil use because of the rise in mechanised underground mining in the latter half of the projection period, which tends to be powered by electricity.

Production prospects

India produced 340 million tonnes of coal equivalent (Mtce) of coal in 2013, of which 291 Mtce were steam coal, 35 Mtce coking coal and 14 Mtce lignite, making India the fifth-largest producer of coal (in energy terms; in volume terms India is the third-largest) after China, United States, Indonesia and Australia. In the New Policies Scenario, Indian coal production grows to 925 Mtce in 2040 (Figure 13.4), moving the country into second position among global coal producers (both in energy and volume terms), behind only China. Steam coal production accounts for almost all of the growth. India's endowment of coking coal is comparatively small and thus growth in coking coal production is subdued, the volume increasing from 35 Mtce in 2013 to nearly 50 Mtce in 2040. Lignite production, mostly taking place in Gujarat, Rajasthan and Tamil Nadu, grows two-and-a-half-times (from a low base) over the *Outlook* period, and reaches around 35 Mtce.

Figure 13.4 ▷ Coal production by type of mine and share of surface mines in India in the New Policies Scenario



Sources: IEA analysis; Coal Directory of India.

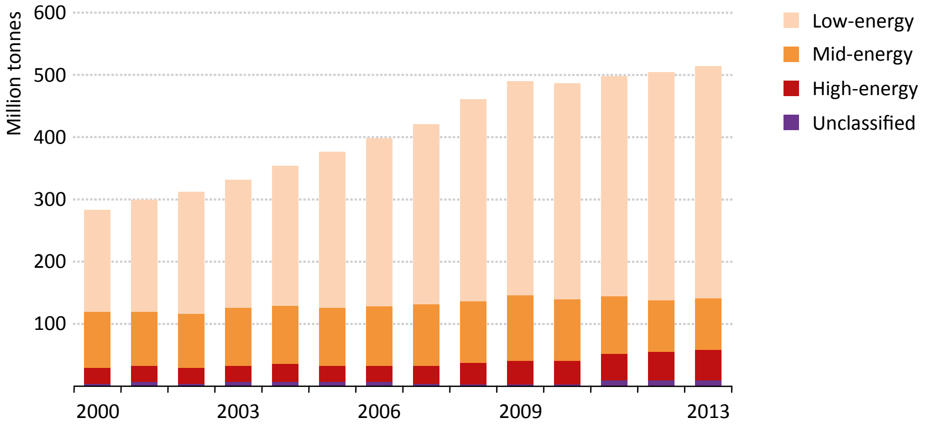
Most of the production in our projections comes from surface mines, which have been the main source of growth in supply over the last decade, although the share of underground mining does rise steadily from the mid-2020s and reaches 12% by 2040.[3] The shift towards underground mining is increasingly necessary to sustain production growth. Even where the depth of the reserves may theoretically allow for surface mining, in many cases underground mining may be preferred as it avoids disturbance of the land and settlements over the deposits, accelerating mine approval. The New Policies Scenario assumes that efficient and highly mechanised underground technology (as found for instance in China, Australia or United States) is gradually adopted by the coal industry in India over the *Outlook* period; the speed at which new technologies are adopted in practice will be related to the extent to which the sector is opened to competition.

The established trend of decreasing energy content per tonne of coal production, the result of focussing on shallower, easier-to-mine deposits of low-energy coal, is projected

3. There are currently over 530 active coal mines in India of which more than half are underground operations. The large number of underground mines is in stark contrast to their disproportionately small contribution to national coal production of less than 10%, indicating their tiny size.

to continue. A push for rapid output expansion could exacerbate this trend in the medium term, as it could also result in less careful waste rock removal, essentially increasing (free) ash content and contributing to the deterioration in calorific values. This highlights the need for the policy focus to be not only on increasing tonnage, but also on the energy content of output. Since the early-2000s, production of high- and mid-energy coal (more than 4 200 kcal/kg) has stayed broadly flat while production of low-energy coal (less than 4 200 kcal/kg) has more than doubled (Figure 13.5), meaning that miners in India have to extract around 1.5 tonnes of coal to get the same amount of energy as that contained in one tonne of Australian coal. In the longer term, the deterioration of energy content is projected to be somewhat contained by technological advances in mining equipment and by tapping deeper deposits, some of which have higher calorific values. But the low quality of produced coal remains a problem throughout the *Outlook* period, putting additional strain on the transportation system, as increasing volumes need to be shipped, and holding back improvements in the efficiency of power plants.[4]

Figure 13.5 ▷ Evolution of steam coal production by coal grade in India



Note: The high-energy coal category has calorific values of more than 5 600 kcal/kg, gross air-dried (GAD); mid-energy coal with has values between 4 200 - 5 600 kcal/kg (GAD); and low-energy coal contains less than 4 200 kcal/kg (GAD).

Sources: IEA analysis; Coal Directory of India.

13

The coal production increase over the *Outlook* period corresponds to an average annual growth rate of 3.8%, one of the highest growth rates for coal production in the world, topped only by some smaller emerging producers. This, nonetheless, falls short of the levels targeted by the Indian government, which has announced the objective of mining 1.5 billion tonnes of coal by 2020 (Box 13.1). The reasons why this target is missed in our projections (and why output growth has been sluggish since 2009, frequently falling short

4. Ash disposal is also a problem as fly ash utilisation (e.g. in the cement or brick industries) absorbs only around 60% of the total yield. Policies are proposed to require fly ash use in the construction industry within 500 km from coal plants.

Box 13.1 ▷ A 1.5 billion tonne question for the coal outlook

In early 2015, the Indian government announced plans to increase the country's coal production to 1.5 billion tonnes by 2020, a highly ambitious goal, given that the country produced 603 million tonnes (Mt) in 2013. Reaching the target would require that domestic coal production increases by almost two-and-a-half-times over a seven-year period (or by 14% per year on average). By way of comparison, in the period 2006-2013 Indian coal production increased by around a third (or by 4% per year on average). In the New Policies Scenario, the rate of growth does pick up to 2020 – based on the assumption that policies regarding licensing, land acquisition and approvals speed up mine developments – but India falls short of the targeted volume. Our projections have coal production rising to over 800 Mt in 2020, a growth rate of 4.6% per year.

Reaching 1.5 billion tonnes of coal production by 2020 is difficult, but not inconceivable. It would, though, imply that all expansion plans are fulfilled without delay and all involved actors – federal and state governments, mining and railway companies – co-ordinate seamlessly so that approvals and licences are issued speedily, mines are developed on schedule and additional coal can be transported. Reaching the target would also require the consent of the people affected by coal mine and railway line development.

India's state-owned mining company CIL is pivotal to this process, slated to contribute 1 billion tonnes of output to the government's target, with the remainder coming from smaller state-owned mining companies and the captive mines that are currently being auctioned. CIL has released a detailed roadmap showing where the additional tonnes are to come from. They have identified 908 Mt of capacity, from existing projects (18%), from projects under implementation (62%) and from future projects (20%), while another 92 Mt are yet to be identified.

If the production target were to be reached, this would have dramatic implications for global coal markets, as exporters around the world are betting on India absorbing the slowdown in Chinese coal imports. In the New Policies Scenario, India becomes the world's largest coal importer by 2020, despite a marked increase in production. If coal production in India reached 1.5 billion tonnes in 2020, the country would be self-sufficient in steam coal, cutting imports entirely. Coal projects in Australia, Indonesia and South Africa that target the Indian market would lie idle and extend the current situation of overcapacity on the international market. With Chinese appetite for imported coal diminishing, India disappearing as an importer would leave Southeast Asia as the only significant demand growth centre for internationally traded coal. The region is far too small to absorb all the additional production and, consequently, prices would remain depressed for a long time to come.

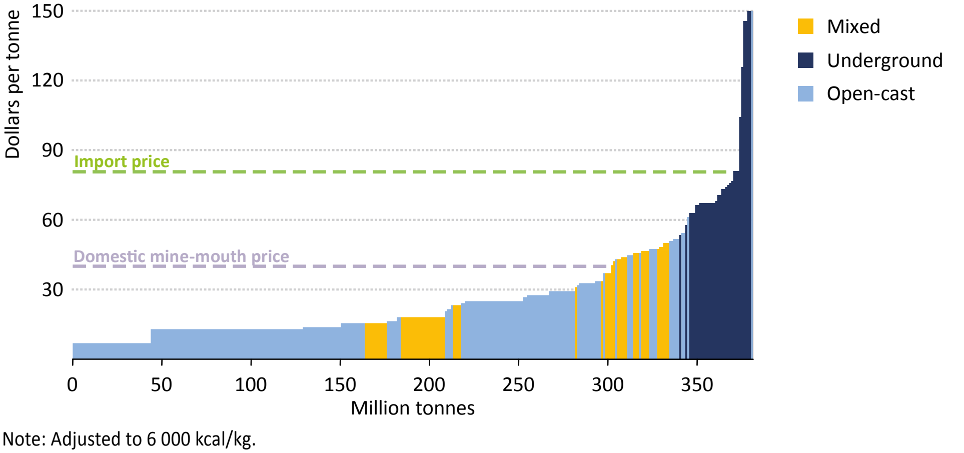
of demand) are related to a series of challenges facing the coal industry in India. The structure of the industry, dominated by state-owned Coal India Limited (CIL), is highly concentrated, and opportunities for new players are very limited (see next section). There are often delays in bringing new mining capacity on-stream due to difficulties with permitting – especially for land acquisition and permission for forest clearing. India is very densely populated, and surface mine development, in particular, affects large areas of land, requiring either people to be resettled, forest to be cleared or arable land to be rendered unproductive. Once operations have begun, in some cases transport infrastructure bottlenecks impede mines from increasing their production as they are unable to ship additional volumes. In some parts of the country, imports become cheaper than domestic coal, with competition between them determining the optimal domestic production level.

Coal market and industry structure

In India, coal allocation and pricing are influenced by the government. The state currently exercises control over more than 90% of production and full control over marketing of domestic coal. CIL has a dominant position, producing roughly 80% of India's coal via eight subsidiary companies of different sizes, of which the largest two, South Eastern Coalfields Limited and Mahanadi Coalfields Limited, together account for around half of CIL's coal yield. Singareni Collieries Company Limited (SCCL), not under CIL's umbrella, is the second-largest public coal company in India, contributing less than 10% to the country's coal output. Hitherto, private players could participate in coal production only if they acquired a "captive mining block", which are specified coal reserves which the buyers can extract for their own use, for example in power generation, steel making or cement production. Recently the Indian parliament has passed the Coal Mines Special Provisions Act, which is primarily concerned with the re-allocation and auctioning of the cancelled captive coal blocks (see Chapter 11). However, a key feature of the Act is that, in theory, mining licenses can be granted to private players without end-use restriction, opening the door to private sector commercial mining in the future. The New Policies Scenario assumes implementation of this Act, gradually leading to greater diversity of ownership in the coal industry and increased competition.

Prices for coal are set by CIL (and SCCL) and depend on the quality and type of coal. The quoted prices typically apply to so-called "coal linkages" – a kind of long-term contract for coal supply. They generally discriminate between different consumers of coal, with power generators typically receiving coal at more favourable rates than industrial users. Coal is sold at the mine mouth, with freight cost borne by the buyer. Around 12% of the annual output of CIL and SCCL is not sold under the linkage regime but instead is marketed on a spot market-like platform, called "e-auction". Prices realised in the e-auction markedly exceed the fixed prices of the linkages regime: for instance, in 2013, CIL received on average $42/tonne for coal sold in the e-auction, a sales price almost 50% higher than the average quoted price for coal linkages in that year. Coal from domestic mines is sold below market value in India, meaning that only in a few coastal locations, far from the domestic coal fields, can coal from the international market be obtained at a more attractive price than the delivered price of domestic supplies. Converted to a heating value of 6 000 kcal/kg, Indian coal was sold at around $40/tonne on average in 2013 at the mine mouth (Figure 13.6). Adding $20-30/tonne for railway transport to a coastal location would imply a delivered coal price of $60-70/tonne. Imported coal with the same energy content delivered to a coastal power plant would have cost at least $75-85/tonne in 2013. This means an implicit (domestic) coal consumption subsidy of $5-25/tonne or $2-10 billion per year (if the situation were to persist, the subsidy would rise to $5-25 billion in 2040). The quoted prices for coal linkages distort market signals and are one of the reasons why capital allocation to new mining projects has been insufficient, contributing to the growing shortfall in output. The system of pricing has raised concerns about possible abuse of dominant position, which are re-enforced by the non-transparent way in which coal linkages are allocated. In response, the government is considering moving to a system of auctions for new linkages, with all players being able to participate (in a rapidly growing coal market, there will be many new linkages available for auction). This mechanism was proposed by an inter-ministerial committee in late April 2015. In theory, the auction price of the coal linkages should be close to parity with international coal prices.

Figure 13.6 ▷ Indicative domestic mining cost curve, 2013



Note: Adjusted to 6 000 kcal/kg.

As it stands, the spread between imported coal prices and domestic coal prices has repercussions in the end-use sectors, particularly in the power sector. This leads to inequalities between power companies and to financial hardship for power plants that have to buy expensive imported coal. With an increasing share of imports, the system would become less and less financially sustainable. In the New Policies Scenario, average Indian mine-mouth coal prices are set to increase over the *Outlook* period from around $40/tonne in 2013 to $60/tonne in 2040 (adjusted to 6 000 kcal/kg). Upward pressure comes from rising mining costs, but also from the increasing use of market-based instruments to determine prices – for example, the more widespread use of auctions for linkages – leading to a convergence over time between domestic and international prices.

The pace of reform in the Indian coal industry is likely to be slow. The main state-owned companies have been reluctant to countenance structural changes that would introduce new players to the market. The unions representing the labour-intensive mining sector, with around 400 000 people directly employed in public sector mining companies, fear that introducing competition and private participation would lead to job losses and pay cuts. Consequently they, too, often oppose attempts at reform, with strikes that can lead to marked production losses.

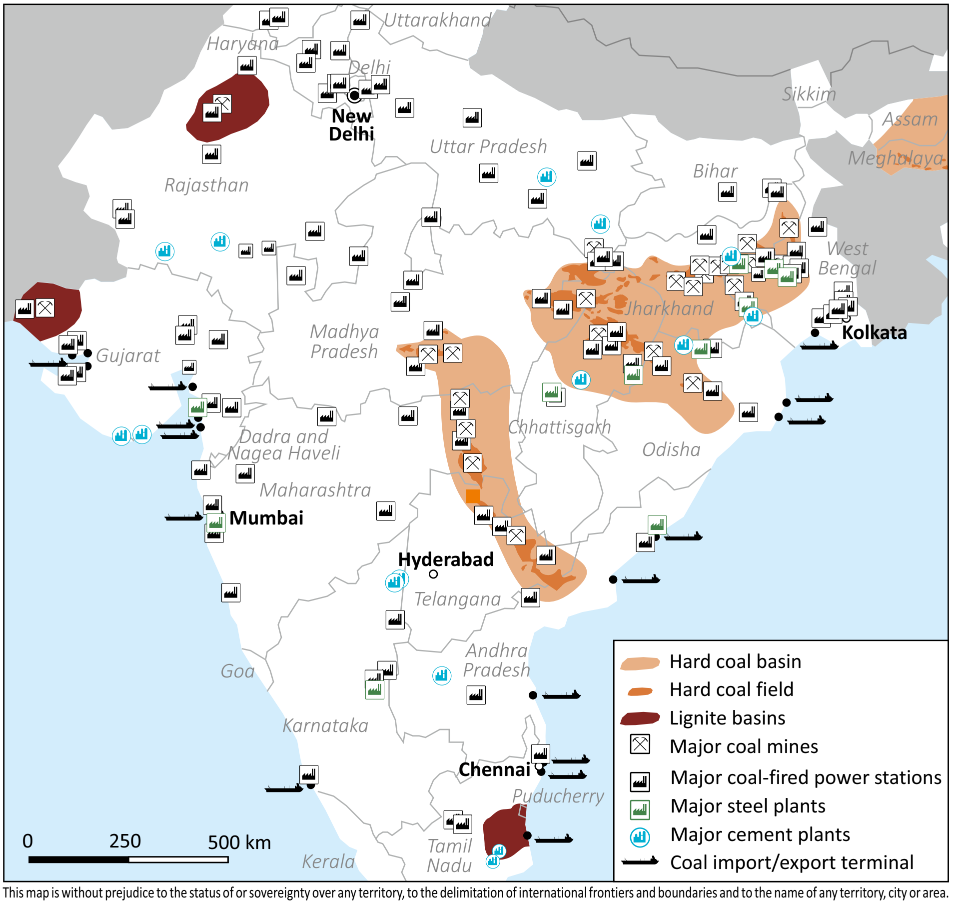
Auctioning of coal linkages, increasing competition by allowing for private sector participation in coal mining and streamlining the bureaucratic process with respect to mine development have all been identified in Indian policy as desirable developments. Implementation of these policy intentions is reflected in our New Policies Scenario and helps to overcome the market distortions in the power sector and to increase mine output. Adequate price signals also trigger productivity gains in currently uneconomic mines or the idling of too costly operations. The envisaged increase of competition, as more private investment comes to the sector, including foreign direct investment, helps to facilitate technology transfer and innovation, an important step given the role of new technology in countering mining cost escalation through productivity gains, increasing the share of underground mining and tapping more geologically difficult deposits. The reliability of supply, the price and the quality of coal are among the primary risks borne by investors in coal-fired power plants in India: alongside other measures in the power sector (discussed in Chapter 12), improving the conditions for investment in coal mining also serves to mitigate power sector investment risks and contributes directly to the reliability of electricity supply.

Transport and handling infrastructure

With coal production primarily concentrated in the eastern half of the country, there is a geographical mismatch between the location of producers and consumers (Figure 13.7). While there are clusters of power stations near the coal fields, other plants are scattered across the country, located closer to power demand hubs in order to save on the cost of electricity network expansion and to enhance power system reliability. Moreover, state-level energy policy favours a balanced distribution of power stations across the country.

Consequently, large amounts of coal need to be hauled from the mines to the various end-users all over India. The primary mode of transportation is by railway, accounting for around 55% of coal movements. Railways are economic for long-distance transportation and every tonne of coal moved by rail travels more than 500 km on average. Shorter distance transport, roughly a quarter of the country's coal movements, is carried out by truck. Typically truck transport is economic only for distances of less than 200 km and it often leads to congestion and additional air pollution. Consumers located close to the mines receive coal by merry-go-round systems (exclusive, closed-loop, coal railway systems) or conveyor belt. Some power plants or industrial works on the coast can also receive coal directly from seaborne vessels.

Figure 13.7 ▷ Main coal-mining areas and coal infrastructure in India



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

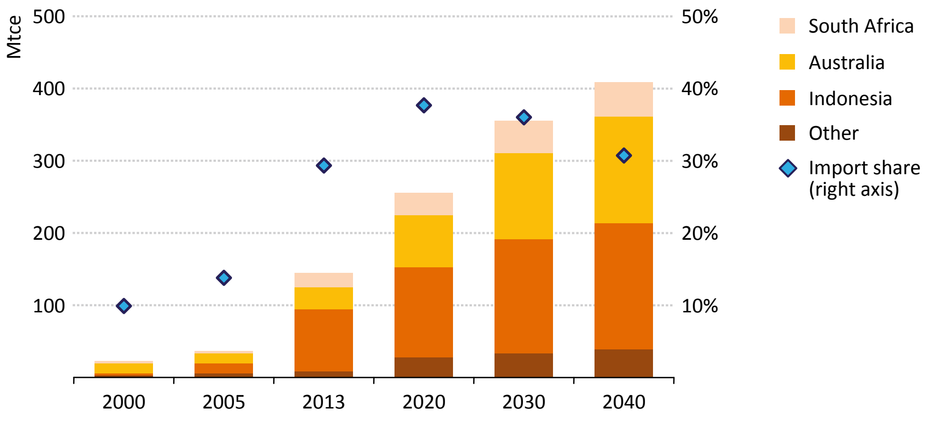
Bottlenecks in transport infrastructure have contributed to past coal shortages. Despite mining investment generally lagging behind, in some cases it is the lack of access to railway or inadequate access to other forms of transport that is hampering output growth and delaying mining investments. Railways are operating at full capacity on some critical freight corridors often holding up coal shipments. The understandable social priority accorded to passenger transport, together with cross-subsidies that involve freight transport paying for lower passenger fares, has the effect of slowing down coal movements and pushing up freight tariffs. Investments in access links, additional tracks and rolling stock are needed to accommodate growth in coal demand and must be financed. In relation to the prospective growth in imports, India currently has at least 250 million tonnes per annum (Mtpa) of port handling capacity. Thus, port infrastructure to handle imports is currently sufficient, but rail connectivity (to distribute coal further inland) has not kept up with port capacity growth and will need to be expanded to allow for increasing imports.

The growth in low-energy coal production puts particular additional stress on the transport infrastructure, as it has to handle ever-higher volumes of product, only part of which provides more energy. Coal washing can help to alleviate this by removing a part of the ash. India has around 130 Mtpa of washing capacity installed. Private players, in particular, have set up independent washeries, as coal washing is mostly profitable in India, due to the long transport distances. Washing costs amount to $3-4/tonne and, depending on how much ash is being removed, becomes profitable for transport distances over 700 km. Washing is supported by regulation that mandates that coal transported for more than 750 km (500 km from 2016) must have ash content of less than 34%.

Coal imports

Over the last decade India has increasingly tapped the international market to procure fuel for its power plants and industrial works, putting the country among the world's largest importers of coal. The rise in imports came as domestic production failed to keep up with surging coal demand. Indian imports reached 144 Mtce in 2013, of which 70% were steam coal and the remainder coking coal. Imports are projected to continue to increase over the *Outlook* period, to reach 410 Mtce in 2040 (Figure 13.8). In the New Policies Scenario, India becomes the largest global coal importer before 2020. Although coking coal imports remain essential for the rapidly growing steel industry, the majority of the growth in demand comes from power plants providing baseload power for the electricity sector. India has a favourable geography, with a long coastline and several low-cost coal exporters within reasonable distance for economic seaborne transport.

Figure 13.8 ▷ Coal imports by origin in India in the New Policies Scenario

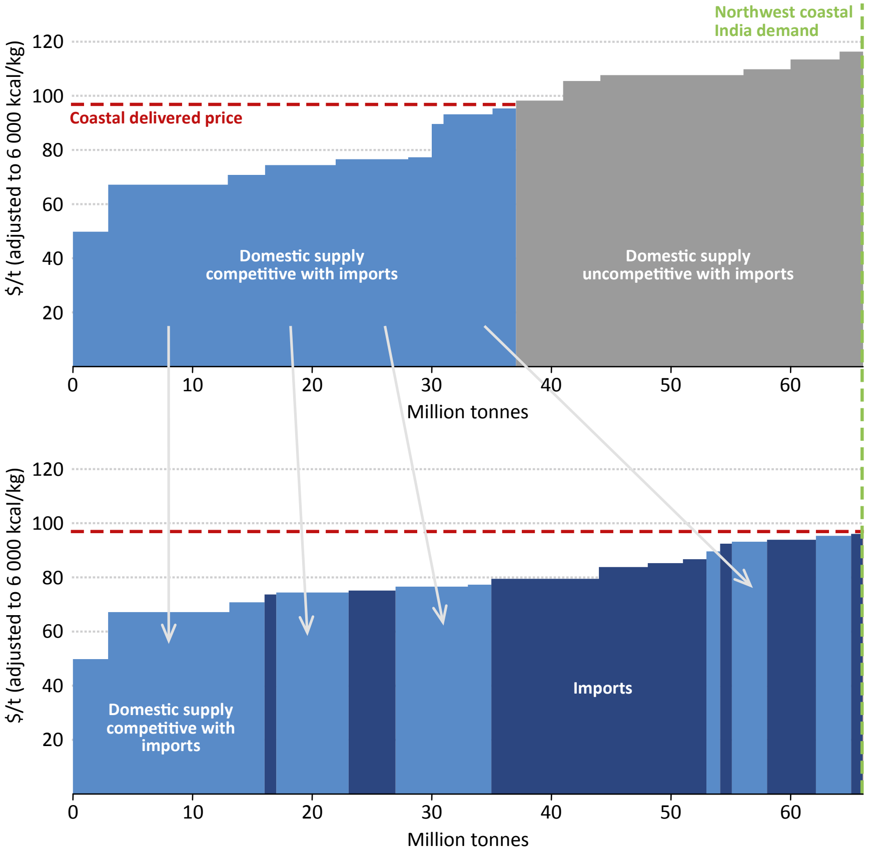


Indonesia is the main exporter to India, currently accounting for around 60% of imported coal. Indonesia is also the closest major coal exporter and thus benefits from a transport cost advantage, especially on the east coast. It remains a key player in the Indian market, but loses market share as steam coal from Australia gains ground. In 2040, only 45% of the Indian coal imports come from Indonesia. From a transport cost perspective, South Africa is the natural exporter to India's west coast. Once the main supplier to Europe, South Africa's exports have shifted to the east, with India now accounting for the largest share of its shipments. Moreover, some of the higher ash coals from South Africa suit Indian power plant boilers well and are typically available at a discount to market rates. South Africa continues to target Indian buyers as the size of the European market dwindles. Its share in the Indian import market essentially stays flat but volumes triple from 18 Mtce today to over 53 Mtce in 2040. With Indonesia and South Africa producing steam coal almost exclusively, Australia is the primary supplier of coking coal to India. Australia's main competitors in the coking coal trade, Canada and the United States, face substantially longer transport distances, creating a cost disadvantage. Only Mozambique, ramping up its total coking coal exports from 3 Mtce in 2013 to 20 Mtce in 2040, can challenge Australian exporters on a cost basis. For the moment, Australia chiefly ships coking coal to India but, from the mid-2020s, steam coal exports gain in importance, accounting for over 40% in 2040. Projects in Australia's Galilee Basin, some of which are being developed by Indian investors, will provide additional export coal in the longer term, but challenges regarding environmental concerns and the financing of the mines and infrastructure remain.

Indian coal import dependency has trebled over the last decade, reaching 30% in 2013. The share of imports is projected to increase further, peaking at 38% (in energy terms) around 2020, however, by 2040 it returns to today's levels as Indian domestic production takes a higher share of incremental demand. Some imported coal is currently transported long distances inland in order to alleviate fuel shortages, but this comes at a major cost to the users, as the transport distances add markedly to already higher prices of imported coal. In our projections, this situation eases over the medium term and inland transport distances for imported coal go down.

With the envisaged narrowing of price differentials between domestic and imported coal (resulting from increasing domestic mining cost and a larger share of market-based coal pricing), in some coastal regions imported coal becomes cheaper than certain domestic coals. Particularly in northwest India, we estimate that imports would be competitive with some domestic coal supply (Figure 13.9). In the long run, the region thus becomes a key arbitrage point, playing an important role in the pricing of internationally traded coal too. Under these circumstances, a continued share of imports is beneficial to the Indian economy, helping to keep coal supply costs down across the country. Coal imports do not give rise to significant energy security risks: disruptions to supply have been few and far between in the international coal market (unlike oil and gas) and, in any event, India sources its needs from a variety of producers. In addition, an increasing share of imports stems from vertically integrated Indian companies procuring their coal needs from their own projects, for instance in Australia or in Mozambique. India's drive to increase domestic coal production can be justified (or challenged) on a number of grounds, but to go so far as to aim for complete self-sufficiency in coal would be to adopt an expensive policy, without offsetting gains in terms of energy security.

Figure 13.9 ⊳ Indicative cost of coal delivered to northwest coastal India in the New Policies Scenario, 2030



Note: The upper graph shows a case in which India's entire north-western coastal demand is served with domestic coal, with much of the domestic supply cost (the part labelled "Domestic supply uncompetitive with imports") exceeding the anticipated price level that can be achieved if imports serve part of the demand. The lower graph shows how a mix between cost-competitive imports and domestic coal ("Domestic supply competitive with imports") results in a lower delivered price.

13

Oil and natural gas

Resources and reserves

India is heavily reliant on imports for the bulk of its crude oil supply. Its smaller natural gas sector is likewise dependent on imports. The mismatch between domestic resources and needs is particularly stark in the case of oil: proven reserves of 5.7 billion barrels (out of the total remaining recoverable resources of 24 billion barrels) compare with annual crude demand that is already at 1.4 billion barrels and rising every year (Table 13.2).

Table 13.2 ▷ Oil resources by category in India, end-2014 (billion barrels)

	Ultimately recoverable resources	Cumulative production	Remaining recoverable resources	Remaining % of URR	Proven reserves
Conventional onshore	15.3	4.4	10.9	71%	3.6
Tight oil	3.8	0.0	3.8	100%	0.0
Shallow offshore	12.5	5.7	6.8	54%	1.2
Deep offshore	2.8	0.0	2.8	99%	1.0
Total India	**34.4**	**10.2**	**24.3**	**71%**	**5.7**

Notes: Data include crude, condensate and natural gas liquids. URR = ultimately recoverable resources.

Sources: IEA databases; BGR (2014); USGS (2012a, 2012b); OGJ (2013); BP (2015); Rystad Energy AS; India Ministry of Petroleum and Natural Gas.

If India's oil resources appear meagre next to its needs, the same cannot really be said for natural gas, for which remaining recoverable resources stand at a much healthier 7.9 trillion cubic metres (tcm). Around half of this is conventional (almost all offshore) gas and half is unconventional, in the form of shale gas and coalbed methane. The rate at which produced reserves have been replenished (through exploration and development activities that turn resources into proven reserves) has been slightly negative in the case of oil in recent years, but positive in the case of gas: in the past seven years, India has produced some 280 billion cubic metres (bcm) of gas while adding more than 330 bcm to proven reserves, excluding the offshore KG-D6 find.

For a country that is short of hydrocarbons, India still has a considerable amount of unexplored potential. A number of sedimentary basins have either no or scanty data and require additional geo-scientific exploration for better assessment of resource potential. Areas identified by the Indian authorities as either "prospective" or "potentially prospective", i.e. awaiting significant levels of exploration, extend over some 1.1 million square kilometres (km^2) of the almost 1.8 million km^2 that make up India's 26 onshore and shallow water sedimentary basins. India's deepwater territory, also largely unexplored, adds another 1.3 million km^2. The sense of under-explored potential is reinforced by the drilling record. Roughly 3 000 wells have been drilled in India's offshore basins, at an average density of one well per 146 km^2, which is a low intensity compared with other offshore basins (and certainly with the US Gulf of Mexico, which has been drilled with an average density of one well per 14 km^2). Getting the incentives right for an increase in exploratory activity, through sufficiently attractive licensing and pricing arrangements, may have only a limited effect on India's oil balance, but could have a much more significant impact on domestic gas supply.

Table 13.3 ▷ Natural gas resources by category in India, end-2014 (bcm)

	Ultimately recoverable resources	Cumulative production	Remaining recoverable resources	Remaining % of URR	Proven reserves
Conventional onshore	1 570	280	1 280	82%	290
Shallow offshore	1 810	500	1 300	72%	340
Deep offshore	1 480	70	1 400	95%	770
Coalbed Methane	1 230	0	1 230	100%	20
Shale gas	2 720	0	2 720	100%	0
Total India	**8 810**	**850**	**7 930**	**90%**	**1 420**

Note: URR = ultimately recoverable resources.

Sources: IEA databases; BGR (2014); USGS (2012a, 2012b); OGJ (2013); BP (2015); Rystad Energy AS; India Ministry of Petroleum and Natural Gas.

Oil supply

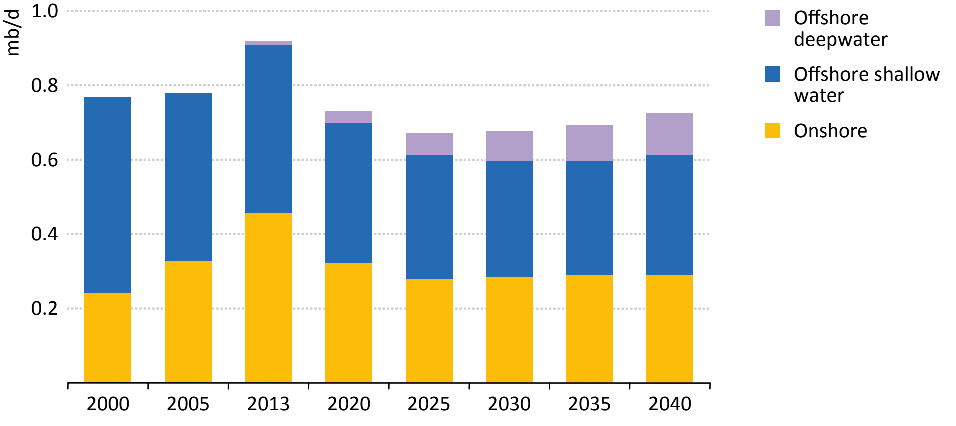
Oil production in India today comes primarily from three onshore states (Gujarat, Assam and Rajasthan, which account for more than 95% of onshore output) and from the aged Mumbai High field offshore. Output from the mature centres of oil production in Gujarat and Assam has been relatively stable for the last few years, with extensive field maintenance and the deployment of enhanced oil recovery (EOR) techniques to make the most of existing reservoirs. Production in Rajasthan has grown substantially in recent years, from close to zero as recently as 2008 to 170 kb/d in 2013, amounting to almost a quarter of national production, mainly as a result of the Mangala field being developed by Cairn India (despite the relative youth of the field, Cairn is already contemplating EOR techniques to assist with recovery of the waxy crude resource). Offshore production is concentrated in the Mumbai High field, south of Gujarat state, in shallow waters. This field, operated by India's majority state-owned Oil and Natural Gas Corporation (ONGC), has been in production since the mid-1970s and in decline since the late 1980s

In the New Policies Scenario, India's oil production falls in the medium term and then remains at around 700 thousand barrels per day (kb/d) throughout the period to 2040 (Figure 13.10). The boost to output due to the discoveries in Rajasthan subsides by 2020 and, although additional onshore discoveries of the magnitude seen in Rajasthan are not excluded, neither these nor the envisaged development of new reserves from the offshore basins are sufficient in the *Outlook* to outweigh the effects of declining production from existing fields. Limited domestic prospects, against a backdrop of continuously increasing oil demand, help to explain why the main Indian companies are also seeking investment opportunities abroad (Box 13.2).

Interest in the long-planned NELP X licensing round (the tenth round under the New Exploration Licensing Policy, now scheduled for 2016) will be an important indicator of

India's prospects. Licensing arrangements for the upstream have been modified over time to encourage private oil companies to participate in the development of India's resources, but success has been constrained by the limited size and quality of the resource base and the complex business environment. To date, within the 254 blocks awarded since the inception of the NELP, 128 discoveries have been made but only 11 fields have been developed and put into production. Foreign companies have entered the market, winning 40 of the 254 NELP blocks, but many of these blocks – including those held by Eni, Gazprom, Santos, Petrobras and BHP – were subsequently relinquished. BP and Cairn Energy are the main international operators that remain.

Figure 13.10 ▷ Oil production by source in India in the New Policies Scenario



Plans for the NELP X round include more than 166 000 km² of previously unavailable acreage, more than 80% of which will be in offshore regions. Some important innovations, due to be introduced in NELP X, are to be tested in a pending auction, announced in September 2015, of 69 marginal fields previously held by ONGC and Oil India Limited (OIL), but not developed because of their location, the size or complexity of the reserves or high development costs. The new terms will allow a license holder to produce any oil and gas, conventional or unconventional, found in the field (previously it was possible to produce only the hydrocarbon stream for which a license was granted). A second change is the introduction of revenue sharing contracts, instead of production sharing arrangements. The main feature of the revenue sharing approach is that, instead of the operator initially recovering costs and then sharing revenues from subsequent production with the government, the government would be entitled to a share of gross revenue from oil and gas sales from the start. Revenue sharing contracts are, in principle, potentially more straightforward to administer and their introduction could prevent some of the disputes over cost accounting that have burdened previous projects. But it remains to be seen whether the balance of risk and reward will be sufficient to attract new investors in the upstream, especially for acreage that requires exploration.

Box 13.2 ▷ Looking abroad: Indian overseas oil and gas investment

India has long been conscious of the value of overseas investment to domestic energy security: this was the spur already in 1965 for the formation of ONGC Videsh, the international arm of India's Oil and Natural Gas Corporation. We estimate that, as of 2014, the overseas production entitlement of Indian companies operating abroad had risen to around 140 kb/d of oil and 6.1 bcm of gas, and that Indian oil and gas companies invested some $3.5 billion outside their home country in 2014. Among the producing assets held abroad by Indian companies are significant stakes in Russia (in Sakhalin-1 and, more recently, in the large East Siberian Vankor field), Venezuela, Brazil, Myanmar, Azerbaijan, Sudan and South Sudan, as well as a share in one of Mozambique's major new offshore gas discoveries and unconventional assets in the United States and Canada.

India's companies have been noticeably less acquisitive abroad than those from China, whose estimated overseas oil entitlement is already around the 2.2 mb/d mark. But, in any case, neither country has a realistic prospect that acquired overseas assets could cover more than a fraction of their future import needs (and in the case of oil, at least, there is no reason to think that their respective overseas production is earmarked as a matter of course for the domestic market). The motivations and benefits are typically broader: they allow companies to diversify portfolios and risks, to develop integrated supply chains (especially in the case of natural gas) and secure access to technical knowledge and expertise (for example in deepwater plays or shale gas) that can be applied in the home market.

Oil market and refining

Indian refining capacity additions over the last decade have outpaced domestic demand growth and turned the country into a net exporter of refined products. However, staying ahead of domestic oil product demand that grows by 6 mb/d to 2040 represents a stern challenge for the Indian refining sector (Table 13.4). Gasoline and diesel consumption increase especially quickly, reflecting demand from both personal mobility and road freight. Total kerosene use, unusually, declines by 1% annually, as growth in aviation fuel demand is more than offset by the almost total elimination of kerosene demand from cooking. By 2040, India is set to become the world's largest liquefied petroleum gas (LPG)-consuming market but, in contrast to other major LPG consumers such as the United States, Middle East and China, most of Indian LPG demand comes from the residential sector, for use as a cooking fuel. India's petrochemicals sector is projected to consume imported ethane along with naphtha from domestic refineries.

Over the period to 2040, a further 3.4 mb/d of refinery capacity expansion in India to 2040 (third after China and the Middle East) and very high utilisation rates push refinery runs higher by 3.1 mb/d to reach 7.6 mb/d by 2040 (Table 13.5). Once majority state-owned Indian Oil Corporation's 300 kb/d Paradip refinery comes online at the end of 2015, there is a pause in anticipated large-scale capacity additions as only two other, smaller, projects are expected to be completed before the 2020s. Refinery expansion continues thereafter, but is ultimately held back in our projections by new refineries in the Middle East, India's close neighbour and biggest crude supplier, which provide a major challenge to Indian refiners in increasingly competitive product export markets. In the New Policies Scenario, the sheer size of India's demand growth and lower domestic crude oil output mean that Indian refinery output is increasingly drawn into the domestic market, and refinery capacity eventually falls behind domestic demand.

Table 13.4 ▷ Oil product demand in India in the New Policies Scenario (mb/d)

	2014	2020	2030	2040
Ethane	-	0.1	0.1	0.2
LPG	0.5	0.7	1.1	1.4
Naphtha	0.3	0.4	0.5	0.5
Motor gasoline	0.4	0.6	1.0	1.9
Kerosene	0.2	0.1	0.1	0.0
Diesel	1.4	1.8	2.6	3.5
Fuel oil	0.1	0.2	0.2	0.3
Other products	0.8	1.0	1.4	1.9
Total oil product demand	**3.8**	**4.8**	**7.0**	**9.8**

Table 13.5 ▷ Oil balance in India in the New Policies Scenario (mb/d)

	2014	2020	2030	2040
Oil demand	3.8	4.8	7.0	9.8
of which fractionation products*	0.5	0.8	1.2	1.6
Refinery products demand	3.2	4.1	5.8	8.2
Refining crude intake (refinery runs)	4.5	4.9	5.8	7.6
Domestic crude availability	0.8	0.6	0.4	0.4
Crude balance	-3.7	-4.3	-5.4	-7.2
Refined products balance	1.3	0.6	-0.2	-0.9
Fractionation products balance (LPG)	-0.3	-0.5	-0.9	-1.1

* Fractionation products are LPG and ethane, as well as the portion of naphtha/natural gasoline that is produced during gas fractionation.

Crude oil imports and product trade

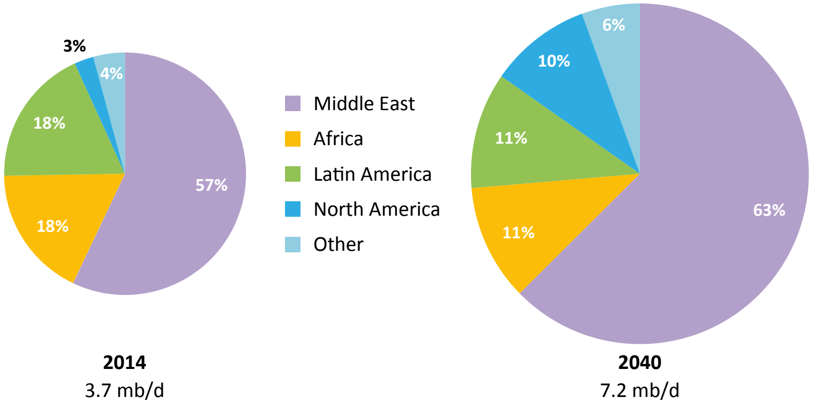
Our projections in the New Policies Scenario leave India with the need to import 7.2 mb/d of crude oil by 2040, up from 3.7 mb/d in 2014[5], which makes India the world's second-largest importer, behind China, but ahead of both the European Union and the United States. At the same time, India has the highest import dependency among the regions

5. Data from the Ministry of Petroleum and Natural Gas show a figure of 3.8 mb/d for crude imports in fiscal year 2014/2015. The number provided here is for calendar year 2014.

mentioned above, with over 90% of oil demand covered by imports in 2040, up from 70% in 2014. India's growing reliance on oil and gas imports carries with it a large bill. The value of India's net oil and gas imports grows from $110 billion in 2014 to more than $300 billion in 2030 and $480 billion in 2040 (of which gas accounts for some 10-15%). This represents a sizeable share of India's overall GDP – 5.3% in 2014 and 4.6% in 2040.

India currently sources some 57% of its crude imports from the Middle East, a share that is set to rise in our projections to 63% by 2040 (Figure 13.11). With new refining capacity is capable of running on very heavy crudes, India is also a potential market for Canadian bitumen, once the export infrastructure is put in place in Canada. Africa and Latin America increase their exports to India, but their market share decreases. Russia is not expected to provide a significant share of India's imports, beyond a recently announced long-term deal with private refiner Essar (for 0.2 mb/d), as logistics imply that Europe and northeast Asia remain the preferred markets for Russian crude exports.

Figure 13.11 ▷ Crude oil imports by origin in India in the New Policies Scenario



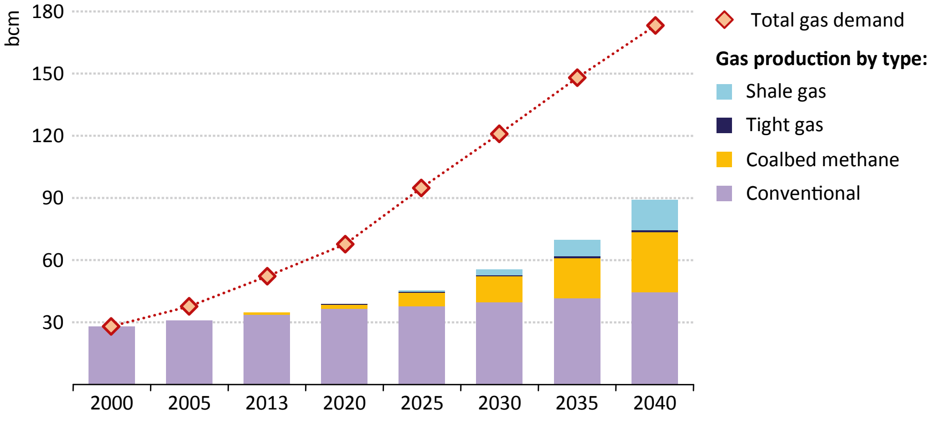
India imports a total of around 2.3 mb/d in oil products by 2040, but only half of this is refinery products, such as diesel and gasoline. The other half consists of almost 1 mb/d of LPG, with India becoming the world's largest LPG import market as a result. The Middle East is likely to provide the bulk of India's product imports, but it is possible that Indian consumers will source some products from further away – from European or North American refiners, reversing the east-to-west product trade flows that dominated the early 21st century.

Natural gas

In the New Policies Scenario, India's natural gas production increases from 35 bcm in 2013 to nearly 90 bcm in 2040, but this still leaves a sizeable gap of around 80 bcm that needs to be met by imported gas. Conventional gas production is dominated today by the ageing Vasai field on India's western coastal shelf: this field continue to attract investment by the operator, ONGC, which has long experience in optimising performance from mature fields.

Onshore conventional production consists of many small projects, only a handful of which contribute more than 5% of total onshore supply. There is potential for new gas discoveries onshore, considering the extent of unexplored acreage, but the larger potential lies offshore, with the deepwater Krishna-Godavari basin the centre of activity since the initial discovery by Reliance, India's largest private sector corporation, at the KG-D6 block (since followed by large discoveries in neighbouring blocks by Reliance and ONGC). The discoveries are in water depths of between 700 and 1 700 metres, and the wells are technically challenging, giving rise to a relatively high development costs. The KG-D6 project itself has also suffered from well performance issues, including higher than expected water production and sand entry, resulting in high decline rates.

Figure 13.12 ▷ Natural gas production in India in the New Policies Scenario



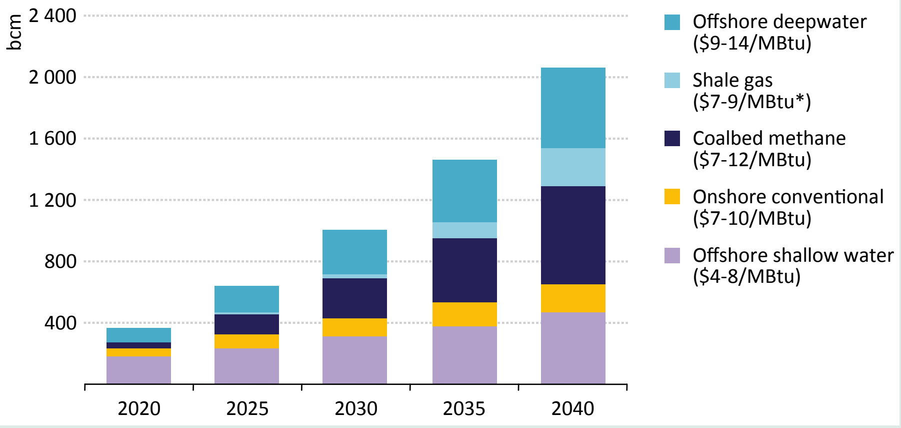
With the contribution from conventional onshore fields set to stagnate, the opportunities for substantial growth are first in the offshore basins, followed by onshore coalbed methane (CBM), which we assume to increase in the 2020s, and the possibility of shale gas output later in the projection period. Although resources are large, all of these sources of gas face substantial uncertainties: the disappointing production performance of Reliance's KG-D6 block has tempered expectations for offshore development. CBM projects have gotten off to a reasonable start, but development costs are still high. The shale gas resource is understood to be large, but appraisal is at a very early stage and large-scale production could run into significant problems over land use, water availability and acceptance by local communities.

Looming over all of these projections is the key question of whether the price available to domestic gas producers will be sufficient to incentivise the investment required. Our analysis of India's gas supply costs suggests that most new commercial gas developments are marginal in the price environment prevailing in the second-half of 2015: the new gas pricing formula put in place in 2014 initially established a price for domestic producers of around $5.6 per million British thermal units (MBtu), but subsequent six-monthly revisions brought this down to around $4/MBtu, because of falls in the reference prices to which it is linked (Box 13.3).[6]

Box 13.3 ▷ Finding a natural gas price that is right for India

India provides a vivid illustration of a difficulty faced by many gas import-dependent economies: how to find a pricing mechanism which produces a gas price that is acceptable to gas-consuming sectors, but is also sufficient to attract new investments in supply. There is no structure yet in place, such as a domestic trading hub, to determine the market value of gas in India, so the long-debated solution was to pick a basket of international prices to generate a reference price, although any such choice runs the risk of being out of step with the actual dynamics of the Indian gas market (OIES, 2015).

Figure 13.13 ▷ Gas resources developed in India in the New Policies Scenario



* India's shale gas resources have not been developed in quantities sufficient to estimate a supply cost. We have substituted an estimate for shale gas costs outside North America, based on *WEO-2013* (IEA, 2013).

Notes: A cumulative 2 050 bcm of new resource development is needed to deliver the 1 400 bcm of domestic gas output in the New Policies Scenario (many of the fields developed would also continue to produce beyond 2040). Costs vary significantly for each resource type: the cost figures shown here are representative of projects projected to come online through 2040.

Sources: IEA analysis based on IEA databases and Rystad Energy AS.

Based on the new formula and our international price trajectories for the different reference prices, the gas price available to India's domestic producers should recover from today's levels of around $4/MBtu to reach around $7/MBtu in 2025 and close to $9 MBtu by 2040. However, prices at these levels would not generate sufficient investment to meet our production outlook: we estimate that India needs to develop

6. The formula, which applies to the bulk of domestically produced gas, is linked to a weighted average of a set of international energy prices, including the US Henry Hub, UK National Balancing Point, the Alberta Reference Price and the Russian domestic gas price.

some 2 000 bcm of new gas resources over the period to 2040 in the New Policies Scenario (Figure 13.13). The related investment in exploration and development needs to be made well in advance of actual production and, in our judgement, some of the gas needed as early as the 2020s would require a higher price than that implied by the existing formula, or a premium attached to it.[7]

A higher gas price is not the only variable that affects the prospects for investment. The situation could also be altered by a change in the fiscal terms for upstream activity, or a reduction in the perception of risk associated with investment in India. Unconventional gas could also fundamentally change India's supply cost curve, if coalbed methane or shale could be brought on at an average cost of $7/MBtu or less. But the challenges are significant, especially given the intensity of drilling that would be required to bring down costs to these levels.

India has large coalbed methane resources and policies in place to support their development, although this has yet to result in a significant volume of gas output: production started in 2007 and stood at 0.2 bcm in 2013, with seven more blocks expected to start production in the near term. The profitable wells are typically shallow and do not require large-scale hydraulic fracturing. Much of the resource, however, lies in more complex environments requiring larger investment. Thirty-three blocks, covering almost two-thirds of the 26 000 km^2 areas available for coalbed exploitation, have been awarded to operators since 2001, but delays in the development phase have been common, arising from a complex permitting process and uncertainties over the gas price environment. Based on the size of the resource and India's need for gas, we do anticipate a rise in CBM production starting in the 2020s, with output reaching 28 bcm by 2040.

Shale gas is an important variable in India's gas future. Shale gas potential has been identified in six basins: Cambay, Assam-Arakan, Gondwana, Krishna-Godavari, Cauvery and the Indo-Gangetic plain and the resource size is understood to be large (although estimates vary widely), but activity has barely started – making the likely supply cost difficult to determine. A shale policy issued in October 2013 assigned the rights to exploit shale gas to the national oil companies, but this approach is likely to open up under the NELP X licensing round, which would confer rights to develop all hydrocarbon resources within a given block, both conventional and unconventional. To date, ONGC has drilled several shale research wells in the Gondwana and Cambay basins, but no commercial shale production exists today. In the longer term, water use is a key issue for the shale outlook in India, given the likelihood of water stress and the sensitivity of being seen to compete with agriculture use for a scarce resource. A limited volume of shale gas supply is included in our projections, starting after 2025 and reaching about 15 bcm per year by 2040.

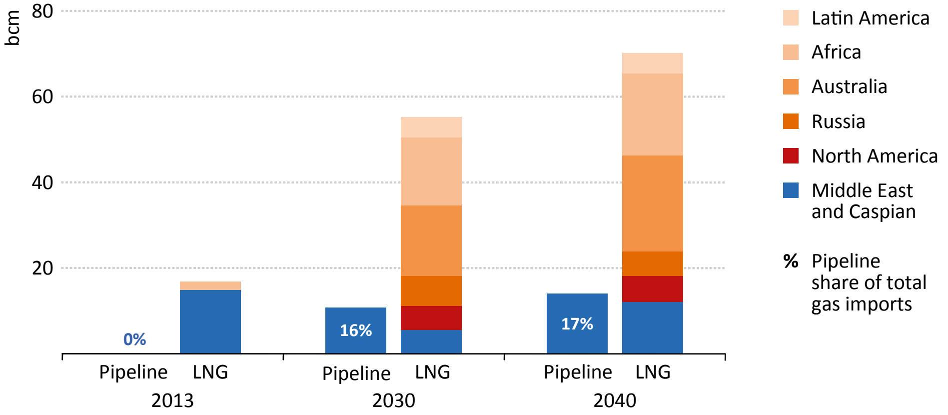
7. The government has envisaged that new gas discoveries in deepwater or with challenging reservoirs (high-temperature or high-pressure fields) will be given a premium over and above the approved price, although the details have yet to be approved. In the New Policies Scenario, we assume that the current pricing arrangements are successfully reformed in order to provide additional stimulus for upstream investment.

Sub-sea gas hydrates have been identified in large quantities within India's territorial waters and have at least a potential role in supplying energy in the future. India's Natural Gas Hydrate Programme is a consortium of the national upstream companies and research institutions, which has run several expeditions to map and sample prospective sites off India's eastern shore. Although the resource could be vast, high costs and uncertainties over commerciality preclude any inclusion of gas hydrate production in our projections.

LNG and pipeline imports

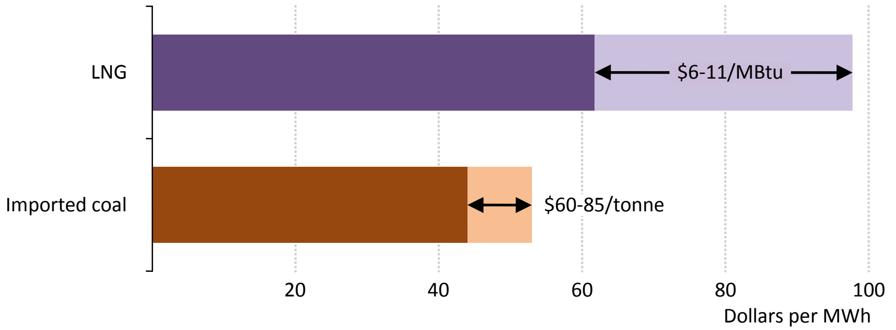
With domestic production falling short of the country's needs, India is set to import increasing volumes of natural gas, primarily in the form of liquefied natural gas (LNG) (helped by a period of lower LNG prices over the medium term) but also, potentially, via pipeline. Turkmenistan and Iran are the main prospective pipeline suppliers, although, in both cases, the prospects and timing are clouded by political uncertainties. In our projections, gas imports rise to over 80 bcm in 2040, with around 85% of the total being met by LNG and the remainder by pipeline (Figure 13.14).

Figure 13.14 ▷ Natural gas imports in India in the New Policies Scenario



The main uncertainty for imported natural gas relates to price and how and where this gas can find a niche in the Indian domestic market. India is reasonably well placed for LNG supply, because of its proximity to the Middle East and to prospective exports from East Africa; but this is, nonetheless, a relatively costly source of energy for many domestic users. In the power sector, for example, LNG (even at \$6/MBtu) is too expensive to compete with imported coal as a fuel for baseload or most mid-merit electricity demand (Figure 13.15), leaving gas with only a limited role as a way to balance the system and meet peaks in power demand. (The circumstances in which gas could gain a more substantial foothold in power generation are examined in the Spotlight.) Increased reliance on LNG will also require adequate infrastructure: as of March 2015, India had four operational LNG terminals, giving it a total import capacity of 28 bcm, although other LNG terminals are in different stages of planning. Given that India's natural gas pipeline and storage network is limited, we anticipate that the focus for new LNG terminals will be the southern regions that are currently not served by major gas pipelines.

Figure 13.15 ▷ Levelised costs of gas-fired versus coal-fired power in India, 2020



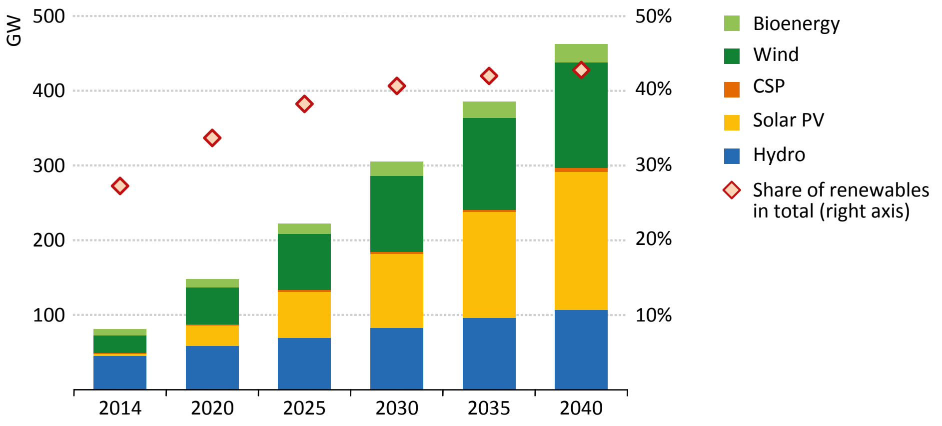
Notes: MWh = megawatt-hour. Calculation assumes efficiencies of 39% for new coal-fired generation and 53% for a gas-fired plant.

Plans to boost gas supply by pipeline centre on two proposed major pipelines, the Turkmenistan-Afghanistan-Pakistan-India pipeline (TAPI) and the Iran-Pakistan-India pipeline (IPI). Discussions on both have been going on for many years, but there are still substantial political and commercial obstacles; the security situation in Afghanistan and the relationship between India and Pakistan fall into the first category; open questions about pricing and financing into the second. In our view, these political uncertainties and the availability of relatively inexpensive LNG in the medium term rule out an early prospect of India receiving pipeline gas. Nonetheless, we see potential for one or both of these projects to be viable in the long term and project that gas imports to India start in the latter part of the 2020s. In either case, Turkmenistan's large resources may have an important role to play, either directly as supplier in the case of TAPI or indirectly in the case of IPI (with increased Turkmenistan exports to Iran meeting a part of northern Iranian demand and freeing up Iranian gas in the south, where most of Iran's gas is produced, for export).

Renewable energy

The abundance of renewable energy resources across India, allied with declining costs for their exploitation in some cases and clear synergies with the country's development and energy security goals, has created a fertile environment for their expansion. The overall picture is skewed by the continued large-scale use of solid biomass as a traditional cooking fuel. Looking forward, the gradual retreat from this form of consumption actually serves to drag down the share of non-fossil fuels in the overall energy mix, but energy from all other renewable sources grows strongly, particularly in the power sector, where renewables account for half of all the new capacity brought online over the period to 2040, increasing their share of capacity in the power mix from 28% to more than 40% (Figure 13.16).

Figure 13.16 ▷ Renewables-based power generation capacity in India in the New Policies Scenario



Note: GW = gigawatts.

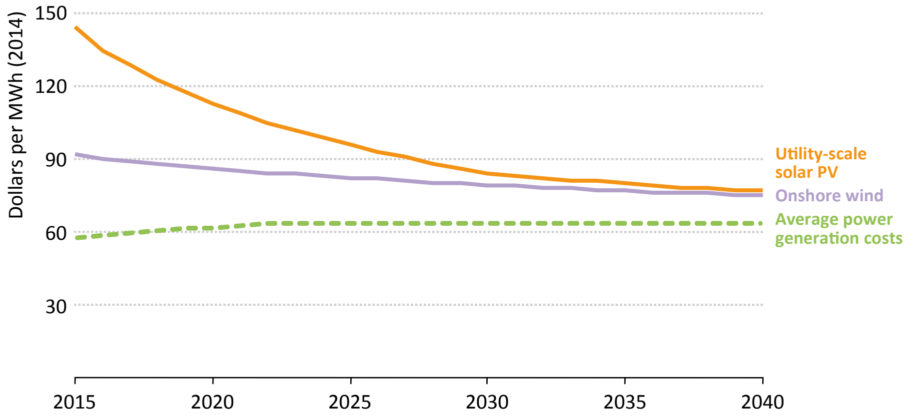
India's renewable energy resources, unlike those of fossil fuels, are spread much more evenly across the country, although there are still some strong regional variations – particularly for hydropower. But, alongside questions of resources, the pace at which renewables develop in India is also subject to different doses of policies and economics, which vary state-by-state as well as technology-by-technology. The economic drivers are becoming stronger as technology costs fall, particularly for wind and solar power, but are not yet strong enough to justify investment without some form of subsidy. The expansion of hydropower relies strongly on concessional long-term financing and a readiness to expedite the necessary approvals. There is no single system of official support for renewables in India, rather an intricate patchwork of different national and state-level initiatives that encompasses feed-in tariffs, purchase obligations, bundling renewable with thermal output, accelerated depreciation schemes and a range of interventions that lower the cost of financing.

13

Costs

Hydropower, where it can be built, is established as a relatively competitive contributor to the Indian power mix, although a trend of decreasing output per unit of installed capacity is pushing up the average cost. In the case of wind and solar power, although they still require subsidies to incentivise investment, the cost trajectory is moving in the opposite direction. For solar, recent trends bode well for the future: since 2010, the average levelised cost of electricity generated by utility-scale solar in India has fallen by around half, largely reflecting a decline in the investment costs for solar cells. Albeit at a slowing pace, costs are expected to continue to decline throughout the projection period, falling by over 45% to 2040, by which time the levelised cost of electricity will be similar to that of wind power and coming close to full convergence with the average cost of power generation in the Indian system (Figure 13.17).

Figure 13.17 ▷ Levelised cost of electricity from wind, solar PV and the average cost of power output in India in the New Policies Scenario



Notes: MWh = megawatt-hour. Onshore wind and utility-scale solar PV indicate the average cost of capacity deployed. Average power generation costs = average power generation costs for all technologies.

The cost of onshore wind power follows a different trajectory. While these costs are significantly lower than solar PV today, they do not see a material decline, falling by only 18% to 2040. This reflects higher capital costs for the taller towers with larger turbine blades that are increasingly deployed to maintain efficiency factors after the best wind sites are occupied, as well as the more limited scope which exists for technological improvements and local learning to bring down costs, as wind turbine technology is standardised globally and much of the potential for efficiency improvements already exploited. The increase in the average cost of generation across the system as a whole nonetheless means that the cost of onshore wind goes from being around 60% higher than the average to being much closer to par.

These sorts of generic cost calculations do not capture the range of considerations that apply when deciding on technologies for power generation; these include expected revenues, environmental concerns, as well as a plethora of other factors, such as the diversity of the generation mix and the local availability of resources. In addition, the significantly different generation profiles (and therefore economics) of fossil fuel or nuclear baseload capacity means that comparing their levelised cost of electricity with those of solar and renewables, which are inherently variable, is an exercise with considerable limitations.[8]

Solar power

India has substantial solar potential, estimated by India's National Institute of Solar Energy at around 750 gigawatts (GW) (based on the assumption that 3% of wasteland in each state can be used for solar power projects, plus an assessment of the potential for rooftop solar).

8. See Chapter 8 for a full description of power generation costs.

This represents almost three-times India's total installed power capacity today. The solar resource is strongest in the north and northwest of the country (Rajasthan, Jammu and Kashmir), but it is also considerable in a number of other states, including Maharashtra, Madhya Pradesh, and Andhra Pradesh. Installed capacity has been growing quickly. Utility-scale solar photovoltaic (PV) projects have made the fastest in-roads, with about 4 GW of capacity in place as of mid-2015 (up from 3 GW in 2014). Rooftop solar installations have been slower to take off, with around 450 megawatts (MW) of capacity installed as of 2014. Concentrating solar power (CSP) has only just started to gain ground, with around 200 MW in operation.

Solar power is at the heart of India's push towards low-carbon energy sources. The overall national target is to reach 100 GW of installed capacity by 2022, a huge task given the starting point. This total is split between 60 GW of utility-scale projects (both solar PV and CSP), including a series of large solar parks, with capacity generally above 500 MW each, and a further 40 GW of rooftop solar applications for commercial users and households, together with some small-scale schemes and off-grid capacity. A range of national and state-level initiatives have been announced in support of these objectives. Since electricity is a shared responsibility between federal and state authorities, the political commitment of individual states to solar power is critical to the prospects for growth (Box 13.4).

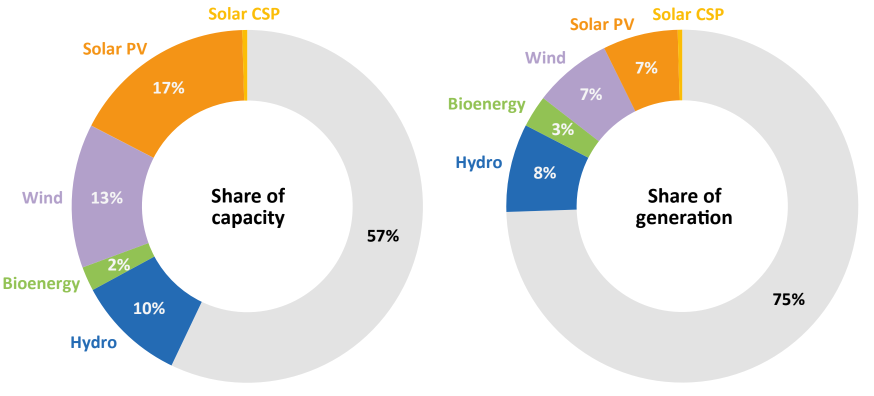
Box 13.4 ▷ Gujarat's shining example

The state of Gujarat has 1 GW of installed solar capacity, accounting for more than a quarter of India's total. All but 26 MW of this capacity was built on the basis of policies determined by the state itself. A turning point came in 2009, when the state government announced a new policy on solar power aiming to attract capital by removing a number of impediments that were stifling investment. It introduced exemptions for electricity duties, streamlined the land acquisition process, guaranteed evacuation of power by the Gujarat Energy Transmission Corporation, ensured that no cross-subsidy charges were levied for access within the state and guaranteed tariffs for 25 years. The 500 MW Charanka solar park in Patan – one of the largest in the world – is a notable outcome.

Other states have drawn on lessons from the success achieved in Gujarat. Rajasthan adopted its Solar Policy in 2011, containing a number of the elements of the Guajarat approach, and has subsequently updated it to further ease land acquisition, including by allowing projects to use agricultural land without first needing to register a land-use change. In June 2015, the state government of Rajasthan signed a joint venture agreement with Adani Power (an Indian private company) to invest $9 billion in a 10 GW solar park.

India's solar targets are not met within the envisaged timescale in the New Policies Scenario (see Chapter 12, Spotlight), but the solar sector does witness dramatic growth – faster than any other source of generation. Installed capacity rises to 29 GW in 2020 and 188 GW by 2040, making India the second-largest solar market in the world, after China. This boosts the share of solar power in India's total power capacity to 17% in 2040 from around 1% today, although it accounts for a smaller share (7%) of generation in 2040 (Figure 13.18). Most new capacity is utility-scale, mostly solar PV, with a much smaller share of CSP. A number of challenges confront solar deployment, including the difficulty of enforcing purchase obligations on the local distribution utilities, the ability of the grid to absorb the additional production, availability of financing and land acquisition issues (even where states have expressed strong interest in the initiative to create solar parks, in practice it is proving difficult in many cases to identify and acquire suitable land).

Figure 13.18 ▷ Share of renewable energy capacity and generation in India, 2040



One solution to the problem of land acquisition for utility-scale solar development is to go, instead, for rooftop solar. Although this has been slow to take off so far, it is an area of potentially very rapid growth, with considerable upside over our projected 83 GW of deployment (particularly if the reliability of grid-based supply does not improve). Most of the early adopters of rooftop solar (around two-thirds thus far) have been commercial and industrial consumers, with one attraction being to hedge against interruptions to supply and to displace daytime reliance on diesel-fired generators. As conventional tariffs rise, solar generation costs decline and there is greater regulatory clarity over issues like net metering (i.e. the conditions under which generated power can be offset against utility bills, or sold to the grid) as well as easier access to innovative business models and financing options (to overcome the high upfront cost), so more and more customers could be encouraged to adopt rooftop solar PV systems.

SPOTLIGHT

Can India bypass coal for solar- and wind-based electrification?

The cost competitiveness and investment outlook for wind and solar PV have improved dramatically in recent years and our projections suggest that these sources are set to play a major role in expanding electricity supply in India. But these technological gains and cost reductions have also nurtured the idea in some quarters that India could see a more dramatic break with the past: that India could now opt for a low-carbon electrification path that not only reduces coal use but also bypasses the need for new coal-fired capacity. How feasible is such a pathway for India?

Our assessment is that India is unlikely to reach a situation in which the case for investment in new coal-fired capacity disappears. There are a number of reasons, chief among which is the sheer scale of the electricity demand challenge. As underlined in Chapter 12, keeping pace with power consumption growth at 4.9% per year is already a stern challenge for India, even with all generation options on the table. Relying on a very rapid pace of wind and solar deployment to meet a much larger share of rising demand could also run into significant supply-side challenges, stemming – in the early years at least – from disinclination in India to rely too heavily on imported solar panels and wind turbines.

In practice, while large-scale wind power and solar deployment will have a significant impact on the amount of electricity thermal plants are required to generate, thereby slowing the growth of coal use, the potential impact on the need for actual coal (or gas) capacity is much smaller. This is because of the well-known issue of variability in wind and solar output, an especially pertinent consideration in India, given the relative weakness of the transmission network, the evening peak in power demand and the measurable seasonality in solar and wind output that comes with the monsoon. Managing variability is far from an insuperable problem, but the various options that improve system flexibility and so limit the need for thermal capacity (strengthening the grid, demand-side management and investment in electricity storage) all have their own regulatory or cost challenges.

While India is unlikely to eliminate the need to build conventional power generation capacity, the increasing scale and cost effectiveness of renewables deployment nonetheless have implications for India's choice of thermal power plants. The split varies from country-to-country, but a typical division of labour in a power system between coal and gas is that coal takes care of baseload operation, operating at relatively high capacity factors, while gas more flexibly follows the daily load curve, helping to meet demand peaks. India has a very coal-heavy variant on this theme: both fuels have had issues with availability of domestic supply, but – with imported LNG typically available only in an expensive \$10-14/MBtu range from 2012-2014 – the business case for coal, even for mid-merit plants, was superior, leaving gas with only a small peaking role.

The fall in the oil price and the increasing availability of new LNG supplies is, though, now suggesting a much more favourable medium term LNG price environment for buyers in India. The parallel improvement in the cost efficiency of both gas and renewables is opening up the possibility for India of a large-scale electrification pathway based on solar-plus-wind-plus-gas, which could challenge coal's predominance as a provider of baseload generation. Such a switch to gas is not the way that our New Policies Scenario plays out, but it is feasible, if there is a confluence of four factors:

- **A reform to domestic coal pricing in India.** As things stand, domestic production is sold to power generators at prices that are well below import prices. This artificially increases the attractiveness of coal, making it very hard to out-compete. Bringing the coal price up to import parity, either through deregulation or a rise in the administered price (collecting the associated rents via taxation), would help to swing the choice in favour of higher efficiency coal-fired generation technology and help the investment case for gas. Carbon pricing would reinforce this effect. But the elimination of subsidies would be a first step.
- **Avoiding a strong rebound in LNG prices.** This is not an area in which Indian energy policy has great sway (although policy-makers could do much to create conditions for a more competitive traded gas market at home, and Indian companies are increasingly prominent investors in LNG projects abroad, notably in East Africa). But sustained LNG prices in single digits would considerably ease the path for gas in the power generation mix.
- **Achieving cost-efficient investment in renewables.** The average investment cost of the renewable portfolio is a key component of the competitiveness of the "renewables-plus-gas" option. India has high potential for wind and solar, but international experience suggests that the regulatory and licensing environment, grid connection and local content rules, and the operation of local equipment and service markets have a major impact on investment costs.
- **Preferential costs of capital for renewables.** Even if these first three conditions are met, we estimate that the total costs of baseload coal remain difficult to beat without government support. For example, the "renewables-plus-gas" option becomes more attractive if there is a substantial difference in the cost of capital, favouring renewables. This is possible, but would require direct government intervention (see section on financing the power sector in Chapter 14). From India it requires a regulatory regime that creates sufficient security and predictability to enable lenders to lower their cost of capital, and efforts to unlock new sources of long-term finance, for example via domestic capital markets. From the international community, conscious that the carbon intensity of India's power generation is a critical barometer of the success or failure of global climate policy, it requires a framework to channel low-cost financing to low-carbon investment in India.

Wind power

Estimates of India's wind power potential vary greatly, depending on different assumptions of efficiency, hub heights, turbine size and land-use considerations. The most recent official estimates by the National Institute of Wind Energy, which take into consideration only land deemed suitable for wind turbine installations[9], put total onshore wind power potential with a hub height of 100 metres at 302 GW (National Institute for Wind Energy, 2015). The most promising sites are in the west and south, with around 90% of the potential in the states of Tamil Nadu, Andhra Pradesh, Madhya Pradesh, Karnataka, Maharashtra and Gujarat. Wind power generation is projected to increase strongly, with installed capacity rising from 23 GW to 142 GW in 2040. Further development is not constrained by lack of wind resources, but by a number of challenges, ranging from land acquisition and approval processes, to agreements on an appropriate framework for power purchases by distribution utilities. Competition with solar is another factor limiting further growth in wind power: despite proliferating strongly, installed wind capacity grows at less than half the pace of solar PV, in part due to the narrowing gap in the cost of solar compared with wind (and its full convergence by the late 2020s), and the widespread nature of solar resources that makes it possible for large utility-scale solar projects to be built closer to demand centres. Offshore wind farms circumvent land acquisition issues, but their outlook is dampened by higher investment requirements and costs. Another way to overcome problems associated with land purchases is to build wind towers on existing farmland, allowing farmers to raise additional income from charges to the operators, without prejudicing their ability to farm the land.

Over the projection period, gradual exploitation of the best sites, both in terms of the wind conditions and proximity to the large demand centres, means that turbines are increasingly built away from the prime areas, and have to use larger towers and longer turbines, driving up the capital costs. This however results in an increase in the average capacity factors, from 18% to 24% (though this remains significantly below the world average, reflecting the conditions of the wind resources at the available sites). Beyond the well-known advantages of renewable energy for power generation, the large-scale development of wind power offers the potential to develop expertise and an industry that can deliver services internationally. There is already evidence of this, with Suzlon, an Indian company, now the world's fifth-largest wind turbine supplier, operating factories in the United States, China and India. International firms have also entered the Indian market, drawn by its size and a number of tax incentives, with General Electric setting up a plant in Pune where turbines can be manufactured.

9. This excludes protected areas, roads, railways, airports and land areas with an elevation over 1 500 metres and a slope of more than 20 degrees.

Hydropower

Although capacity has steadily increased, the contribution of hydropower to Indian power generation has been on a declining trend in recent decades, from close to 40% in 1980 to 12% in 2013. Hopes that this trend might be reversed rest on the sizeable remaining potential – India has used a little over a quarter of its economically feasible hydropower resource – as well as on the operational advantages of hydropower in balancing a power system which has an increasing share of wind and solar capacity. To tap into this potential, hydropower projects need to overcome a set of challenges common to many large infrastructure projects in India, notably extended timelines to procure all the necessary approvals, especially environmental permits, difficulties with land acquisition (both for the plant and for new transmission lines to evacuate the power), public opposition and obtaining long-term finance. In addition, there are issues specific to hydropower, notably the high levels of sediment in the rivers coming down from the Himalaya Mountains, which can reduce reservoir storage capacity and, if not removed, cause heavy damage to turbine blades and other steel structures in a hydropower plant. Last but not least, there is the uncertainty over the impacts on water flows of a changing climate.

Our projections in the New Policies Scenario are based on the assumption that the prospects for such large infrastructure projects gradually improve, as a result of government efforts to simplify permitting and authorisation procedures, as well as improvements in project planning and consultation (including better co-ordination to avoid water-sharing disputes between the different states affected by projects along the various river systems). This helps to expedite both the 14 GW of projects that are at various stages of construction, as well as new projects that come into operation later in the projection period (CEA, 2014). The result is a rise in installed capacity for large hydropower from 42 GW in 2014 to just under 100 GW in 2040, with most of the increase taking place in the latter part of the projection period in the northern and northeast regions, where India's remaining hydro potential is concentrated. Small hydropower, projects up to 10 MW[10], also plays a growing role, particularly in meeting the power requirements of remote, mountainous areas. Their capacity increases from 2.8 GW to over 10 GW by 2040. Although total output rises to around 330 terawatt-hours (TWh) in 2040 (up from 142 TWh in 2013), hydropower's share of the generation mix continues its steady decline, falling from 12% in 2013 to 8% in 2040.

Another avenue for India to benefit from hydropower is through co-operation with neighbouring countries. Hydropower is becoming an important pillar in the relationship with Bhutan, with three projects of around 1.5 GW in total already developed with Indian assistance, a further ten projects in various stages of construction or preparation and plans to strengthen transmission lines to export surplus power to India. Similar arrangements are in place with Nepal, including the approval of projects with a combined capacity of 1.8 GW in 2014.

10. India's Ministry of New and Renewable Energy defines small hydro as plants with capacity of up to 25 MW, while only those with capacity under 10 MW are included in the definition used in the *World Energy Outlook*.

Water issues are very sensitive in India and lack of public acceptance of hydropower development has already been a major obstacle to projects moving ahead. The most difficult issue has been the resettlement of people affected by new projects, but public attitudes have also been adversely affected by the by floods in the Himalayan state of Uttarakhand in 2013, which prompted a major debate over whether intensive hydropower development in the region was to blame for the severity of the flooding. This episode underlined the importance not only of evaluating individual projects in depth, but also of taking a broader view on the development of river basins, assessing the linkages between projects and the cumulative social and environment impacts. In our projections, we anticipate an increasing focus on run-of-river projects; these avoid expansive reservoirs and can thereby ease the need for resettlement and so help to secure public acceptance. But these projects have little or no water storage (rarely more than the equivalent of a few hours' worth of generation), limiting their ability to be dispatched on a flexible basis. Their power output is often subject to significant seasonal variations.

Bioenergy

Bioenergy demand rises by around 11% over the projection period to 2040, a moderate increase that results in the share of bioenergy steadily shrinking in the Indian energy mix. Availability of supply is not the reason for this trend, except in the case of biofuels (Box 13.5). Data from the United Nations Food and Agriculture Organization (UNFAO, 2015) indicate that the total area covered by forests in India has actually increased in recent years, suggesting that – despite evidence of localised shortages in parts of the country, including the northeast – there is no overall scarcity of fuelwood for use by rural households as a traditional cooking fuel. This can limit the economic incentive for rural households to switch to alternative fuels, such as LPG where it is available, or to invest in more efficient biomass cookstoves.

Box 13.5 ▻ How much land can India spare for biofuels?[11]

India has set itself high blending targets for biofuels: to increase the share of bioethanol and biodiesel up to 20% (for gasoline and diesel, respectively) by the end of the Fifth Plan (2017).[12] In 2013, the actual level of blending was below 1%, with bioethanol making more ground than biodiesel but both facing constraints on supply. A key uncertainty in projecting future supply is the availability of land. Overall, some 57% of India's land mass is available for agriculture, with an additional 3% of pasture, 8% of woodlands and the remainder being either forests or other areas hardly suitable for productive use (e.g. mountains, deserts, built-up areas). Biofuels can play a role in buttressing India's energy security, but their expanded cultivation could, at a certain point, compromise other critically important Indian policy objectives, notably food and water security or protection of forest areas.

11. This analysis was developed in collaboration with the Center of Applied Mathematics, Mines ParisTech.

12. The National Policy on Biofuels has an indicative target of 20% by the end of 2017. A minimum of 5% ethanol blending has been made mandatory in 20 states and 4 union territories.

The land area available for biofuels cultivation in the future depends on assumptions about agricultural productivity and about the share of land available for agriculture that has effective irrigation (currently, only around 35% of the total is irrigated). Even with an optimistic set of assumptions on these two variables to 2030 – a doubling in productivity and of the share of agricultural land with irrigation – we estimate that there is still not enough land left for biofuels cultivation to meet both the 20% targets.

Our calculation would leave around seven million hectares available for crops to produce biofuels, with different degrees of suitability for their cultivation. Based on the assumption that sugarcane and rice are the crops used for bioethanol and jatropha for biodiesel (the preferred crops identified in the Ethanol Blending Policy and the National Bio-Diesel Mission), this land could either produce 225 thousand barrels of oil equivalent per day (kboe/d) of bioethanol (plus around 75 kboe/d of bioethanol produced from molasses, a by-product of the conversion of sugar cane juice to sugar) or 105 kboe/d of biodiesel in 2030. The 300 kboe/d of bioethanol would represent around 30% of the projected demand for gasoline for road transport, while the 105 kboe/d of biodiesel would represent only 5% of projected demand for diesel (bioethanol is a more productive avenue than biodiesel, because of the higher energy yields of sugarcane). The choice of sugarcane, a water-intensive crop, carries the risk of exacerbating India's problems with water scarcity; but less water-intensive crops, such as wheat and rice, provide lower energy yields.

The development of advanced biofuels could change this picture, not least by avoiding potential conflicts with food security. But a lack of progress in commercialising these advanced biofuels around the world gives us reason to pause before anticipating a significant reduction in their costs or a rapid increase in their deployment. Although the potential in India is large, with ample agricultural residues available as feedstock, this is an area that still requires a major effort in terms of research and development. As things stand, the sensitivity of land-use issues in India and the vital importance of food and water security impose significant constraints on the outlook for biofuels. Although biofuels production is projected to increase in our *Outlook*, biofuels continue to occupy only a modest 3% overall share in the road transport fuel mix in 2040, with advanced biofuels accounting for around one-fifth of the biofuels produced.

For other predominantly rural but modern energy applications, such as power plants fired with bioenergy (e.g. bagasse-based cogeneration at sugar mills) or biomass gasifiers to produce biogas, there is, in principle, ample surplus biomass available (mainly from agricultural and forestry residues), although supply in practice depends on reliable systems for collection, transportation and storage. In our projections, power generation based on biomass rises by more than five-times to reach around 120 TWh in 2040, providing a valuable contribution to the reliability of rural electricity supply. But despite policy support for modern biomass technologies in India, the uptake of bioenergy-based supply is constrained by relatively high costs and by poor access to financing.

In urban areas, the ready availability of LPG as a cooking fuel means that consumption of solid biomass is low. This applies also to charcoal, which is hardly used in Indian towns and cities, relieving pressure on nearby woods and forests. One under-utilised option for urban energy supply is municipal waste – a natural product of the rise in India's cities but one that is becoming a major health and environmental hazard: it is estimated that only 20% of the total urban waste is treated, leaving the rest to be dumped untreated at open sites (Planning Commission, 2014). This is a largely unexploited resource, the use of which would not only generate electricity and biogas, but which also has the potential to bring co-benefits by reducing the area required for landfill, a major consideration in India's sprawling cities, and improving public health (although care would be needed to avoid toxic emissions from waste incineration). The Ministry of New and Renewable Energy has classified waste-to-energy as a renewable energy source and put in place subsidies and incentives to encourage projects, which are already underway in Hyderabad, Pune, Ghazipur and Delhi.

Nuclear power

India was one of the first countries to adopt nuclear power technology, with its first commercial reactor coming online in 1969. Its nuclear industry has developed by relying heavily on indigenous technologies, as a result of its status as a non-signatory to the Nuclear Non-Proliferation Treaty (which led to restrictions on the export of nuclear materials to India). However, following the India-US Civil Nuclear Agreement in 2008, the Nuclear Suppliers Group lifted the sanctions that had been in place since 1974, thereby opening the door for India to trade with foreign suppliers of nuclear fuel and technology.

India has a strong commitment to develop additional nuclear power as a way to meet its rising energy needs and enhance its energy security on a low-carbon basis. Its current target is to triple nuclear power capacity over the decade from 2014 (which would equate to capacity of 17.3 GW in 2024). It also has a longer term target for nuclear power to supply 25% of the nation's electricity by 2050. India ranks as the world's 13th largest country in terms of nuclear generation, with installed capacity of 5.8 GW in 2014 with 21 reactors at seven sites. It has a further six reactors, with a total capacity of around 4 GW, in various stages of construction.

India's domestic resources of uranium are limited compared with its current needs and future aspirations. These are estimated to include 129 000 tonnes of reasonably assured resources and a further 29 000 tonnes in the inferred category; or, in aggregate, around 2% of the world total (IAEA/OECD, 2014). However, these uranium resources are low grade and located in remote areas, meaning that imports represent a necessary and less expensive option. By alleviating shortages of reactor fuel, the 2008 agreement has enabled a substantial increase in the average load factor at India's nuclear power plants, from less than 50% in 2007 to over 80% in 2013. India also has the world's largest reserves of thorium, which is a potential alternative to uranium fuel in nuclear reactors. To take advantage of this rich resource base, and as it was not permitted to import uranium, India has become a leader in researching and developing thorium-based nuclear power. It plans to have a first pilot reactor in service by 2022 and commercial reactors deployed by around 2030, although many economic, technical and regulatory challenges first need to be overcome.

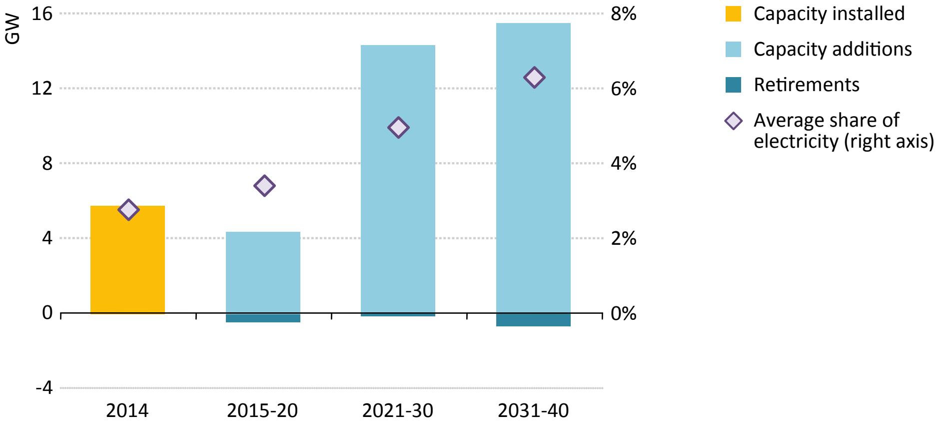
The 2008 agreement also meant that foreign suppliers of nuclear power plants can do business in India. However, many suppliers were unwilling to make investments, due to concerns that India's nuclear liability law held them directly liable in case of an accident: standard practice internationally is that liability rests with the plant operator (which in India would effectively mean the government, since the sole operator – Nuclear Power Corporation of India Limited – is government owned). In June 2015, India set up an insurance pool that provides cover to both operators and suppliers in the case of a nuclear accident. Time will tell whether this solution provides adequate reassurance to overcome a serious obstacle to future development of nuclear capacity in the country.

Economic considerations will also be a major determinant of the future of nuclear power in India, as in all countries pursuing the technology. A useful, though imperfect, means of assessing the lifetime economics of new power plants is to consider the costs of electricity generation, compiled on a levelised cost basis (IEA, 2014). In the New Policies Scenario, levelised costs for nuclear power plants coming online in India in 2030 average around $69 per megawatt-hour (MWh). This is lower than in many other parts of the world – for example they are $110/MWh in the European Union – primarily because the overnight costs of construction are lower in India. Based on these estimates, nuclear power appears to be an economically attractive option in India, particularly in parts of the country that are distant from coal reserves (not surprisingly, this is where the current fleet is concentrated). Nonetheless, building a nuclear power plant is a very capital-intensive undertaking, involving a large upfront investment: India's fiscal and current account deficit means that it will be very reliant on foreign capital for such investments. For foreign capital to be forthcoming, it will be necessary to ensure there is an attractive legal and regulatory framework in place. The recent progress that has been made to address issues surrounding the nuclear liability law is a positive development in this respect.

Public concerns could also exert a powerful influence on the prospects for nuclear power in India. Earlier debate in the country about nuclear power plants focussed on the displacement of communities and the adequacy of compensation if plants were built near them. But, since the accident at Fukushima Daiichi in Japan, these have been supplemented by more widespread concerns about plant safety and the risks of nuclear technology. Protesters have focussed on the Kudankulam Nuclear Power project, located on the coast in the southern state of Tamil Nadu, a region that was badly affected by the huge Indian Ocean tsunami in 2004. Confidence in regulatory frameworks and institutional capacity will, therefore, be key factors in securing broad public support to expand nuclear power in India.

In the New Policies Scenario, India's nuclear power capacity increases by a factor of nearly seven, from 5.8 GW in 2014 to almost 39 GW in 2040, having reached 9.7 GW in 2020 (Figure 13.19). On a worldwide basis, India sees the second most significant increase in installed nuclear capacity, after China. Reaching this level of capacity in 2040 implies a construction rate of 1.3 GW per year on average, which is significantly faster than the rate realised in the recent past and would need to be sustained over a long period. India's nuclear electricity generation increases from 34 TWh in 2013 to nearly 270 TWh in 2040, an average rate of growth of 7.9% per year (faster than growth in electricity supply as a whole), resulting in the nuclear share of total generation more than doubling from 3% to 7% over the period.

Figure 13.19 ▷ Nuclear capacity additions by time period in India in the New Policies Scenario



Implications of India's energy development

What would it mean to realise India's energy vision?

Highlights

- The energy system in India in the New Policies Scenario in 2040 is transformed in every respect from today: operating on a different scale; more diverse in terms of players, fuels and technologies; far more complex to manage; and requiring much larger inflows of capital. Developing such an integrated system in a cost-efficient way, and ensuring its reliable operation while mitigating environmental impacts, is a major challenge for policy at national and state levels. But the prize in terms of improved welfare and quality of life for India's population is enormous.

- Our projections show India moving to the centre of global energy affairs, accounting for 25% of the rise in global energy use to 2040, (more than any other country), and the largest absolute growth in both coal and oil consumption. India becomes a major player in renewable energy, with the second-largest solar market in the world. India's increasing reliance on imported energy has a profound effect on global energy investment and trade and – especially for oil – implications for India's energy security which need attention. Heavy reliance on coal leads to a large rise in India's energy-related CO_2 emissions, although, expressed on a per-capita basis, emissions remain some 20% below the world average in 2040.

- In an Indian Vision Case, we examine the implications of an accelerated realisation of key Indian policy targets, notably the "Make in India" campaign to promote manufacturing, and universal, round-the-clock electricity supply. Putting industry at the heart of India's growth model means a large rise in the energy needed to fuel development, at least ten-times more energy per unit of value added compared with growth led by the services sector. To avoid that this further exacerbates energy security and environmental strains requires a tireless emphasis on energy efficiency, both in end-uses and in the power sector, accelerated investment in wind, solar and other renewables, and the deployment of advanced emissions control technologies to reduce local air pollution and the damage that it causes to health.

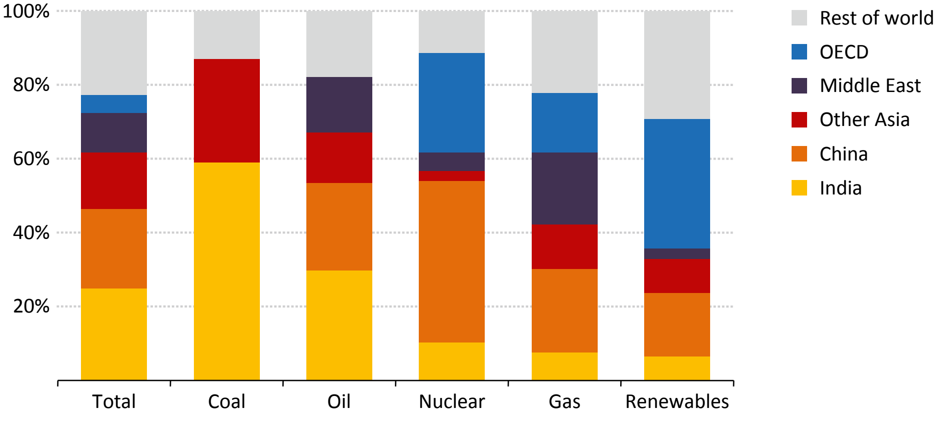
- India requires a cumulative $2.8 trillion in investment, an average of $110 billion per year, to meet the supply projections in the New Policies Scenario, 75% of which is in the power sector, and an additional $0.8 trillion to improve energy efficiency. Investment in energy supply is held at similar levels in the Indian Vision Case, largely because of an 80% increase in efficiency spending. Securing investment at these levels is a huge challenge, requiring an open and predictable regulatory framework and an expanded range of investors and sources of finance. Opening up new, long-term and low-cost financing options is critical to direct investment towards high efficiency and low-carbon technologies.

What route to centre stage?

Today's energy sector in India is already unrecognisable from the one that existed over two decades ago, prior to the start of widespread economic reforms in 1991. But the pace of change over the next twenty-five years promises to be even more dramatic, if energy is to be a spur and not a hindrance to India's development ambitions. The changes visible in this special focus on India are notable not just because of their sheer scale, but also because of the complexity and diversity of the energy system that emerges, both in operational terms and in terms of governance, with a greater range of players, fuels and technologies, and a requirement for sustained inflows of capital. This chapter draws out some of the wider implications of the prospective Indian energy transition, first on the basis of the projections of the New Policies Scenario and then, also, on the assumption that India goes yet further and faster - what we have dubbed the Indian Vision Case.

An unmistakable inference from our analysis is that India is heading for a central position in global energy affairs. Energy developments in India transform the international energy system, and India in turn will be increasingly exposed to changes in international markets. This is, in part, a function of the expanding size of the Indian energy sector and its share in the growth of consumption of key fuels: in the New Policies Scenario, India accounts for almost a quarter of the rise in global energy use to 2040, slightly more than China (Figure 14.1). But it is also related to the range and scale of connections that bind India's energy sector to the rest of the world: via trade in fossil fuels, transfers of technology, investment and also interactions in relation to emissions and environmental policies.

Figure 14.1 ▷ Share of India in world energy consumption growth by fuel in the New Policies Scenario, 2013-2040



Note: Shares are calculated only for those countries and regions where consumption is growing.

The New Policies Scenario anticipates the resolution of some major energy challenges facing India, including the long-standing objective of bringing access to electricity to all of the country's population. But reviewing the projected outcomes, as we do in the first part of this chapter, there is a sense not only of India's achievements but also of some continued, (even exacerbated) vulnerabilities, as well as of business that remains unfinished. The vulnerabilities span aspects of energy security – notably the extent of reliance on imports of crude oil – and a range of environmental issues including air quality, water stress and the implications of climate change.

The projections of the New Policies Scenario also fall short of India's policy and development objectives in a number of important areas, or see the achievement of these goals later than officially envisaged. This reflects the methodology of the New Policies Scenario – applied without discrimination to all countries and regions in our World Energy Model – which mandates a cautious assessment of the chances that policy intentions which are yet to be implemented will be fully and successfully realised. Inevitably, this approach provides a view that is not consistent with all aspects of India's own vision for its energy sector.

In an Indian Vision Case, we examine how India's energy system would evolve if key targets of that vision were met in full. At the heart of this analysis is the announced intention to put accelerated expansion of the manufacturing sector at the heart of India's growth model, together with rapid realisation of universal and round-the-clock power supply. Accomplishments in these areas is accompanied, in the Indian Vision Case, by even more rapid deployment of renewable energy, led by wind and solar power, reform in the coal sector that includes a faster transition to high efficiency in the coal-fired power fleet, a concerted push for greater efficiency across India's end-use sectors and a dedicated effort to tackle emissions of local pollutants and arrest the deterioration in India's air quality.

Realising India's energy objectives, whether at the pace anticipated in the New Policies Scenario or at the accelerated tempo of the Indian Vision Case, will require sustained investment, at levels that necessitate calling upon large-scale flows of private and foreign capital. This, in turn, will require thorough-going energy regulatory reform. In a concluding section of this chapter, we quantify these investment requirements, both for energy efficiency and for energy supply, and examine the measures that can help realise this investment and the risks that might lead it to fall short.

Implications of the New Policies Scenario

We consider, first, the broad implications of India following the path of the New Policies Scenario. Over the next two-and-a-half decades, energy is set to make a huge contribution to quality of life in India, powering the offices and factories in which people work, the cities in which an increasing number of them live, as well as the appliances and vehicles that rising incomes allow a bigger share of the population to buy. Even though average energy consumption per capita remains relatively low in India in the New Policies Scenario, at 60% of the global average even in 2040, the cumulative weight of rising individual energy needs in a rapidly expanding economy has a major impact on global trends.

Table 14.1 ▷ Breakdown of average household energy use in rural and urban areas in the New Policies Scenario

	Average ownership rate				Average household consumption*		Share in sector total consumption**	
	Rural		Urban					
	2013	2040	2013	2040	2013	2040	2013	2040
Cooling appliances	0.7	1.2	1.3	1.9	290	761	10%	27%
Refrigeration	0.1	0.5	0.5	1.0	361	405	4%	11%
Cleaning ***	0.0	0.1	0.2	0.6	171	193	1%	1%
Televisions and computers	0.6	1.6	1.0	2.1	102	112	4%	5%
Vehicles****	0.3	1.0	0.7	1.9	4.2	4.3	26%	36%
Number of households (million)	**175**	**208**	**90**	**190**				

* Average annual consumption of household appliances, in kilowatt-hours, for new appliances sold in India in 2013 and 2040; and fuel consumption in litres per 100 kilometres for new cars or motorbikes. ** The share in sector total consumption is the share of each category of appliances in the total consumption of the residential sector (excluding solid biomass) and the share of fuel consumption by cars and two- and three-wheelers in transport sector demand. *** Cleaning equipment refers to washing machines, dryers and dishwashers. **** Vehicles include both passenger cars and two- and three-wheelers.

Sources: Government of India, 2012; IEA analysis.

The projected energy consumption profile of an average Indian household in 2040 in the New Policies Scenario is very different from that of today, as the growth of middle-income households and urbanisation pushes up energy use. Middle-income groups[1] made up around 25% of total households in 2014, but this percentage rises to almost 80% by 2040. The average number of items of large energy-using equipment in each household increases and average electricity consumption stemming from such increased ownership is also expected to rise (Table 14.1).[2] We estimate that urban households in 2040 own, on average, one refrigerator or freezer by 2040, as well as two different cooling systems (fans, air conditioners or air coolers) and more than two electronic items (e.g. televisions and computers). Even though rural households do not reach the same levels of average ownership as their urban counterparts, their growth rate in average ownership levels is actually higher because they start in 2013 from a much lower base, due to low incomes and unreliable electricity supply. Similar trends are expected in personal mobility, accompanied also by a switch from two- and three-wheelers (which account for around 80% of the

1. Defined as households with an average income of household income INR 200 000-1 000 000 per year (approximately $13 000-65 000 per year in purchasing power parity terms or $4 000-20 000 per year in market exchange rate terms) (Beinhocker, 2007).

2. Although minimum energy performance standards for appliances are expected to lower the annual consumption of the most common appliances used by households in India, the size of new appliances added to the stock is expected to grow substantially, leading to a net increase in their average electricity consumption. The same logic is in play for vehicles, with the shift from two-and three-wheelers to cars offsetting improvements in fuel efficiency.

vehicles owned currently) to cars. The 320 million new cars projected to be sold in India from 2014 to 2040 boost energy consumption and absorb the equivalent of around 3% of India's cumulative production of steel.

India's urban population grows by some 315 million over our projection period and the statistics probably do not capture the full extent to which urban areas come to dominate economic life and energy consumption.[3] Even with the data that we use in the World Energy Model, urban areas account for three-quarters of the projected energy consumption growth in buildings (excluding solid biomass) and could also be expected to represent a large share of energy demand growth in transport. As underlined in Chapter 12, how urbanisation is planned and realised will have pivotal implications for India's energy prospects. For the moment, clay bricks constitute the main materials used for rural residential construction; the anticipated shift to steel and concrete-built urban houses and multi-story blocks, alongside a doubling in the average floor area per household, has striking implications for the production of a range of energy-intensive materials in India.

Well-managed urbanisation facilitates the provision of modern energy services. It is much easier to bring electricity and modern fuels, such as liquefied petroleum gas (LPG), to areas with higher population density, and access rates to electricity and clean cooking facilities in rural areas lag consistently behind those in towns and cities. Although universal rural electrification is ultimately achieved in the New Policies Scenario, the provision of clean cooking facilities to all is not, as LPG distribution networks are insufficiently developed and solid biomass remains readily available in most areas. Consumers across India become gradually more exposed to market prices for energy due to the removal of subsidies for the main fuels (transport fuels are already deregulated) and for electricity. Yet the implications for India's poverty reduction goals are mitigated by a strategic and prudent shift towards targeted protection for vulnerable consumers, increasingly through individual payments to bank accounts rather than interventions on end-user prices or tariffs.

In the case of electricity, the addition of more expensive sources to the power mix (notably wind and solar, but also more capital-intensive technologies for other fuels) increases the average capital cost of new power capacity. This increase is concentrated in the first half of our *Outlook,* after which declining capital costs for renewables flatten this trend. Given the social and political sensitivity of power tariffs to Indian consumers, this is a powerful reminder of the importance of cost-efficient policies in the power sector, including not just those relating to investment but also the procurement of fuels and renewable power and the reduction of transmission and distribution losses in the network. Governance of the power sector and the way that different plants are dispatched to balance the system becomes significantly more complex, not least because of the integration of variable renewable energy sources for power generation.

3. Densely populated but often partly informal settlements on the edge of major cities may not be included in the official classification of urban areas.

Affordable and reliable energy supply is essential for India's industrial performance. With its large infrastructure needs and growing urbanisation, India becomes a hub for energy-intensive production – cement, steel, glass, aluminium and other materials. As recognised in the "Make in India" campaign, a healthy manufacturing sector is an important way to provide employment opportunities for the one million that enter the job market each month as well as for those who shift from the agricultural sector (a theme developed in the Indian Vision Case later in this chapter). A well-functioning energy sector is a pillar of India's general strategy for job creation; the sector's own requirement for labour is also important in itself (Box 14.1).

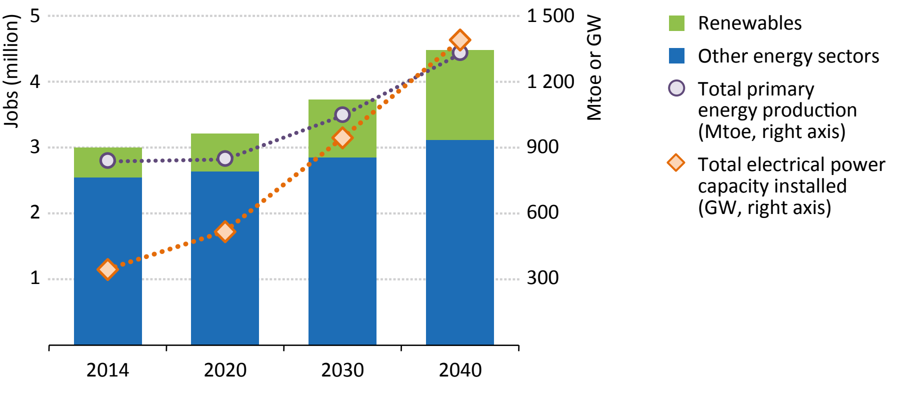
The outlook for the global coal industry in the New Policies Scenario is increasingly intertwined with energy choices made in India. Among those countries whose coal use grows, India represents around 60% of the growth in coal consumption worldwide (although total coal use is less than half of that in China in 2040). If all countries are taken into account, including those where coal consumption declines, the increase in India's coal demand is greater than the total net increase in global consumption. The growth in coal use is split between the power sector and industry, the share of the latter underlining the challenge that India faces in curbing carbon-dioxide (CO_2) emissions. While low-carbon alternatives to coal are available in the power sector and policy in India is actively seeking to increase their deployment, finding substitutes for coal for process heat and steam in industry is a much more difficult task (and using carbon capture and storage [CCS] to turn coal-based processes into low-carbon production routes in India remains reliant on increased global support for CCS technology).

Box 14.1 ▷ Employment gradually turning green in India's energy sector

Data on the total number of jobs in India's energy sector are sparse, but we estimate that there are approximately three million people currently employed; extracting energy, transporting it, manufacturing energy-supply equipment and building and maintaining energy-supply infrastructure, including power plants, transmission lines, refineries and liquefied natural gas (LNG) terminals. The total could almost double if those whose employment depends indirectly on the energy sector are included, such as providers of intermediate components or equipment or those providing services, such as accounting, legal or finance.

The majority of India's energy jobs today are in the coal sector, including just under half a million in coal extraction and transportation and more than one million in different aspects of the construction and operation of coal-fired power plants. Our estimate for employment in renewable energy (excluding commercial marketing of solid biomass, but including large hydropower) is also just shy of 500 000. In the New Policies Scenario, energy sector employment rises, not least because a greater share of the necessary equipment is assumed to be manufactured in India; but growth in employment is less rapid than the increase in energy use as a whole, reflecting the rise in energy imports and a projected increase in labour and technological productivity (Figure 14.2). There is a marked shift towards jobs in renewable energy, which account for more than 30% of total energy supply jobs in 2040, up from 15% in 2014.

Figure 14.2 ▷ Estimated number of direct jobs in India's energy supply sector in the New Policies Scenario



Note: Mtoe = million tonnes of oil equivalent; GW = gigawatts.

Sources: Ministry of Labour (2013); REN21 (2015); Council on Energy, Environment and Water and Natural Resources Defense Council (2014); Rutovitz (2012).

The skills required to run the Indian energy sector change over the coming decades, requiring an intensified effort with training and vocational education. There is less emphasis in the future on unskilled labour (as, for example, in coal extraction) and a rise (from 25% to 35%) in the estimated requirement for semi-skilled and skilled workers, such as engineers, project managers, technical staff, equipment operators and installation and maintenance teams for solar panels and other renewable energy technologies.

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Despite the continued predominance of coal, there is a clear trend towards greater diversity in the power mix, due to the rise of renewables (low-carbon sources account for more than 50% of the new power generation capacity added to 2040) (Table 14.2). However, the analysis also points to one area of potential vulnerability: the rise in India's requirement for imported oil. Dependence on oil imports rises to over 90% by 2040, from around three-quarters today, with very strong reliance on the Middle East. Though international trade in oil can consolidate international relationships, experience over the last half-century highlights the need to make prudent provision against unexpected supply interruptions, through measures to ensure emergency preparedness and co-operation with other oil stockholding countries.

Table 14.2 ▷ Selected energy indicators for India in the New Policies Scenario

	2013	2025	2040
Energy mix			
Energy use per capita relative to global average	33%	44%	60%
Diversity of the primary energy mix*	0.14	0.14	0.15
Share of India in global fossil-fuel consumption	5%	8%	12%
Power sector			
Power generation capacity (2013=100)	100	222	409
Diversity of the generation mix*	0.49	0.35	0.27
Share of non-hydro renewables in generation	5%	13%	17%
Access to energy			
Access to electricity (%)	81%	92%	100%
Access to clean cooking (%)	33%	45%	70%
Investment and expenditure			
Total investment in energy supply (2013=100)	100	148	209
Average cost of power capacity (2013=100)	100	159	158
Net fossil-fuel import bill as share of GDP (MER)	7%	6%	5%
Household energy spending as share of income	2%	3%	4%
Imports			
Coal import dependence (%)	29%	37%	31%
Net oil import dependence (%)	74%	83%	91%
Total crude imports as a share of global trade	10%	12%	16%
Crude oil import diversity*	0.29	0.31	0.33
Natural gas import dependence (%)	34%	53%	49%
Import diversity*	0.76	0.35	0.05
Sustainability			
Energy intensity of GDP (2013=100)**	100	66	45
Carbon intensity of power (2013=100)**	100	81	71
Emissions of NO_x, SO_x and $PM_{2.5}$ (2010=100)***	100	155	227
CO_2 emissions as a share of global emissions	6%	9%	14%
CO_2 emissions per capita relative to global average	30%	58%	79%

* Indicators for diversity are calculated as a Herfindahl–Hirschman Index and normalised for values between 0 and 1, where 0 = complete diversity (i.e. each element having an equal share) and 1 = complete concentration (i.e. one element having a 100% share). High values or values that increase over time indicate high or growing dependence on a single element of the calculation. The categories in the energy mix are: coal, oil, gas, traditional use of biomass, low-carbon energy (nuclear and renewables). The variables for the power mix are: coal, oil, gas, nuclear, hydropower, bioenergy, wind, solar, other renewables. The sources of oil and gas imports are divided between: North America, South America, Middle East, Russia, Caspian, Africa, Southeast Asia and Australasia.

** Energy intensity is measured as tonnes of oil equivalent per $1 000 of GDP ($2014). Carbon intensity of power generation is measured as grammes of CO_2 per kWh. Both are normalised to a value of 100 for the base year of 2013.

*** Total pollutant emissions of sulphur and nitrogen oxides and particulate matter are calculated in tonnes per year, based on emission limit values and fuel quality standards as adopted by mid-2015, normalised to a value of 100 for the base year of 2010.

Last but far from least, there is the question of environmental impacts. India has been explicit in setting a target of faster, sustainable and more inclusive economic growth as the cornerstone of its approach to development. The energy sector is central to the issue of sustainability because of its role as the primary source of local air pollutants and greenhouse-gas emissions (GHG), as well as its need for water. The potential implications of the New Policies Scenario for India's air quality, described in Chapter 12, already indicate the negative spillovers from energy production and use on the scale envisaged. Stresses are also visible in relation to other natural resources, including water and land, where the needs of the energy sector are not trivial. Under-playing or under-pricing environmental risks cannot be the basis for sustainable growth in India's energy sector or its economy as a whole.

Energy-related CO_2 emissions and climate change

India is among the most vulnerable countries when it comes to the impacts of a changing climate (we highlight below just one aspect of this, the potential effects of water scarcity – which could be exacerbated by climate change – on the operation of India's coal-fired power fleet). India therefore has a strong interest in concerted and effective global action on GHG emissions, even though, despite its population and size, India has accounted for a small share of the cumulative GHG emissions released into the atmosphere thus far: only 3% of historical energy-related CO_2 emissions since 1890. Per-capita emissions, at 1.5 tonnes of CO_2 in 2013, are around one-third of the global average. The domestic and international challenge for India is to demonstrate serious intent to limit emissions, reducing the rate at which emissions grow in the future, while still preserving sufficient headroom to allow for growth in the economy. The government has committed to keep its per-capita emissions below the level of those of industrialised countries in the future and, as part of its Intended Nationally Determined Contribution (INDC) submitted in October 2015, it has also pledged to reduce the emissions intensity of the economy by 33-35% by 2030, measured against the level in 2005.

Whatever the scenario, India will need increasing volumes of energy to achieve its development goals. In the New Policies Scenario – and in every other scenario prepared by the *World Energy Outlook* (WEO) including the 450 Scenario (that is consistent with limiting the long-term global average temperature increase to 2 degrees Celsius) – India's energy-related CO_2 emissions are higher in 2040 than in 2013. There is, though, a huge variation in the projected level of these future emissions trajectories, depending both on the level of energy use and also on the extent to which India locks into a high-carbon development path.[4] In the New Policies Scenario, the carbon intensity of India's economy improves substantially, but India's emissions rise from 1.9 gigatonnes (Gt) in 2013 to 3.7 Gt in 2030 and around 5 Gt in 2040, meaning that emissions per capita converge towards the global average (3.2 tonnes of CO_2 per capita in India in 2040, versus a global average that

4. A wide range of future demand and emissions trajectories emerge from different national scenario-based modelling efforts (Dubash et al., 2015).

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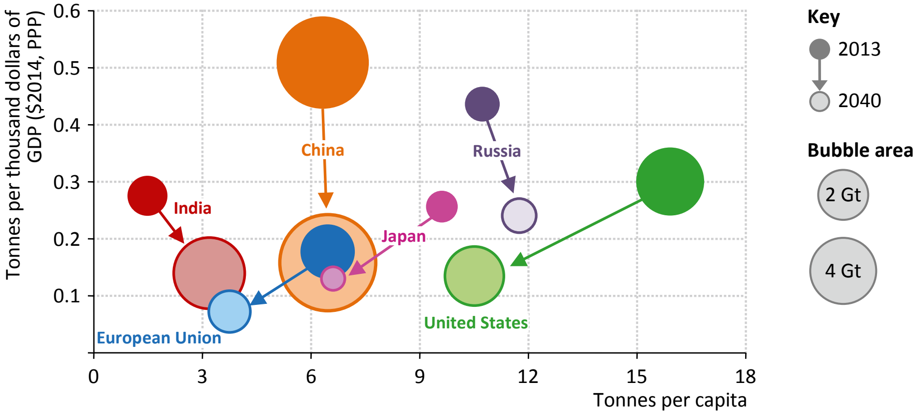
edges downwards to 4.1 tonnes of CO_2 per capita) (Figure 14.3). This increase in emissions means that India is the largest single contributor to the rise in global emissions over the projection period. Although it includes steps towards a more sustainable pathway for India, the New Policies Scenario falls well short of exhausting the scope for further action.

Figure 14.3 ▷ Energy-related CO_2 emissions by selected country and region in the New Policies Scenario



Notes: PPP = purchasing power parity. Bubble area represents total energy-related CO_2 emissions.

Focus: water and climate change

A significant share of India's large population lives in areas already vulnerable to floods, cyclones and drought, with rising sea levels also threatening displacement along the country's densely populated coastlines. Similarly, a large share of the population is dependent on climate-sensitive sectors like agriculture, fisheries and forestry for its livelihood. A precise assessment of the nature and timing of climate impacts is inherently difficult, but climate change is expected to make India's monsoons more unpredictable, with a likelihood of higher seasonal mean rainfall, accompanied by an increased possibility of both prolonged periods of heavy precipitation and dry weather. The high dependency of Indian agriculture on monsoons means that changes in their pattern can have strong repercussions on the yields of food crops and bioenergy, as well as affecting hydropower and water security. Heat waves, like the extreme temperatures experienced in India in May 2015, are expected to become more frequent, increasing both the risks to the population and the demand for cooling appliances (Hijoka et al., 2014).

The impact of climate change on water balances (both spatially and temporally) is an increasing concern for energy supply and power generation around the world. Although agriculture is by far the largest water-using sector in India, irrigation and livestock accounting for more than 90% of total water withdrawals, energy policy decisions could have a significant impact on future water security, via policy on electricity tariffs and metering in the agricultural sector (as discussed in Chapter 12). Water availability, under the impact of climate change, could also become an increasing constraint on India's energy sector, not only for hydropower and bioenergy, but also for many other areas, such as thermal power plants. India's coal-fired power sector has already faced constrained water availability – water shortages have caused shutdowns of coal-fired power stations, including the Chandrapur and the Parli plants in recent years. How these water-energy links might evolve is taken up in more detail below.

Thermal power plants (including fossil-fired and nuclear) require some form of cooling and, within the power sector in India, coal-fired power plants are responsible for around 95% of total water withdrawals, the rest being split between gas-fired and nuclear power stations. The cooling technology used – together with the overall efficiency of the power plants – determines the amount of fresh water that is withdrawn from local sources (water withdrawals) and the amount that is withdrawn but not returned to the local water basin (water consumption) (IEA, 2012). The options are:

- Once-through (or open-loop) cooling: water is withdrawn from surface sources and returned to the source at a higher temperature, after it has passed through the condenser. Once-through systems typically withdraw up to 60 times more water than wet-tower systems, but the level of water consumption is much lower.
- Wet-tower (or closed-loop) cooling: withdrawn water is managed in an internal re-use cycle, with water passing through the condenser being pumped to the top of a cooling tower and then collected at the bottom of the tower. Some water is lost through evaporation. The capital cost is typically higher than once-through systems.
- Dry-cooling: large volumes of air are passed over a heat exchanger and limited amounts of water are withdrawn and consumed. Dry-cooling systems use substantial amounts of electricity, effectively lowering the power output of the plant. Dry-cooling systems usually require higher capital investment than other cooling systems.

Constraints on water availability influence the location of power plants, as well as the choice of cooling technologies for new plants and for retrofitting existing plants. In 1999, India's Ministry of Environment and Forests banned the construction of thermal power plants that use once-through cooling systems and introduced a zero discharge policy that requires operators to re-use water.[5] Older plants, built prior to this decision still run on open-loop systems, as it is not cost-effective to retrofit them (WWAP, 2014). As of 2014, most Indian plants use wet-tower cooling (Figure 14.4).

The use of dry-cooling technology plays only a minor role in the Indian electricity system today. However, the results of a detailed spatial modelling exercise, based on the projections in the New Policies Scenario, show that water stress is likely to have an increasingly material impact on the choice and deployment of cooling technologies (and the related costs) in India. A significant increase is projected in the use of dry-cooling in arid areas in northern India, including Uttar Pradesh and Rajasthan, and in the south in Karnataka. In total, 31 gigawatts (GW) of installed coal-fired capacity is projected to be equipped with dry-cooling systems by 2040.

5. An exception was made for power plants located in coastal areas, which can use seawater as a coolant.

Figure 14.4 ▷ Installed coal-fired power generation capacity in India by cooling technology in the New Policies Scenario

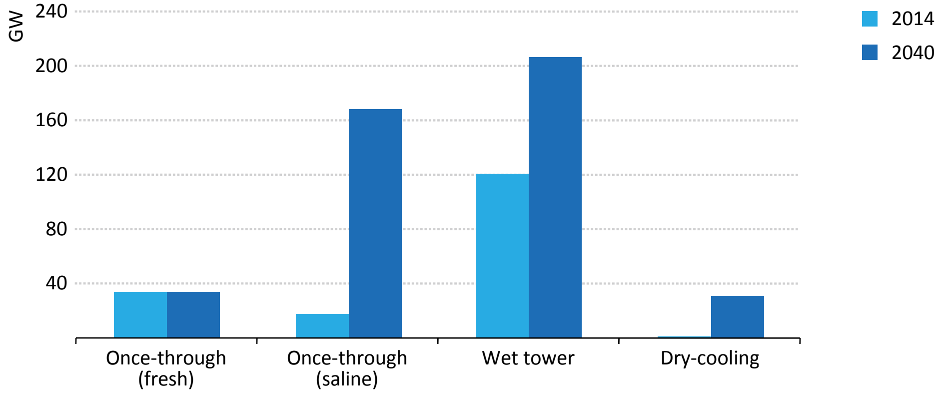
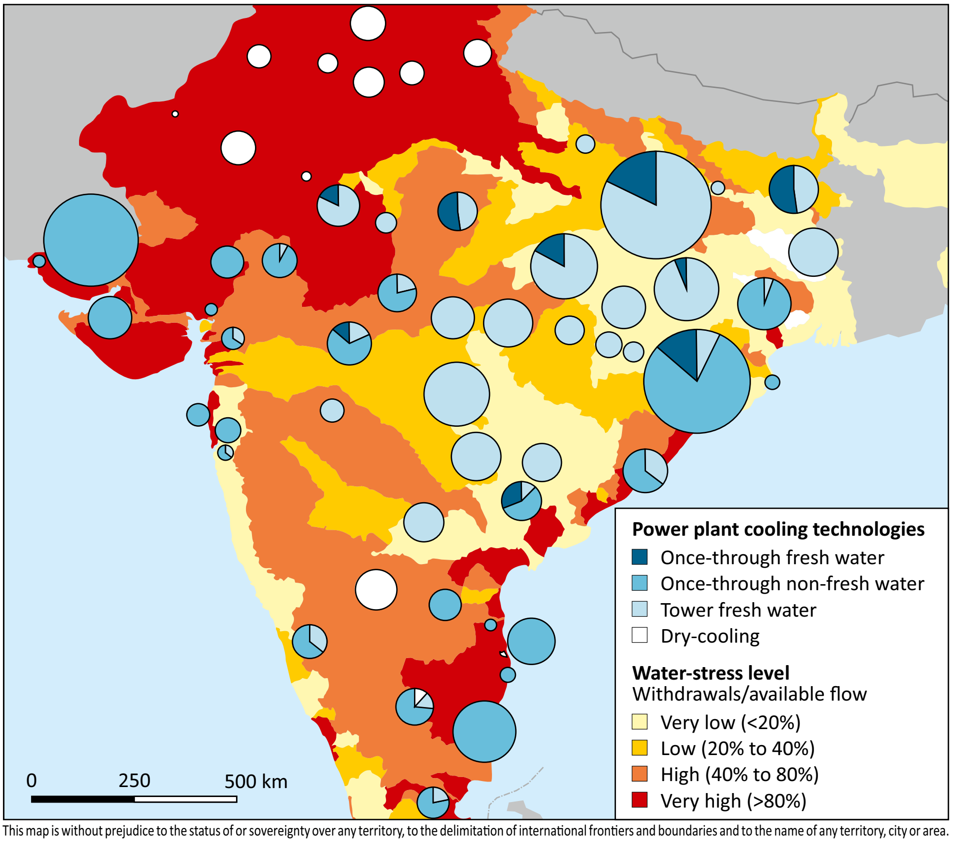


Figure 14.5 ▷ Installed coal-fired generation capacity by cooling technology and sub-catchment area in selected regions of India, 2040



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Note: The size of the pie charts corresponds to the cooling technology of the capacity installed. The smallest pie charts represent 200 MW and the largest 46 GW.

Coal mines in India are located mainly in the east (in the states of Odisha, Chhattisgarh and Jharkhand), which does not experience water stress today nor is it expected to do so in 2040 (Figure 14.5). In order to reduce coal transportation costs, and where demand centres are not too distant, significant amounts of coal-fired power generation capacity are projected to be built in relative proximity to the coal mines, in which case they predominantly use a wet-tower cooling system. Along the coast, new coal-fired power plants primarily rely on imported coal and use seawater as a cooling medium, giving them a cost-advantage for transport and limiting their exposure to water stress. This is one of the reasons why coal-fired capacity with saline once-through cooling systems increases from less than 20 GW today to more than 165 GW in 2040 in the New Policies Scenario.

The additional investment for cooling systems over the projection period, compared with a system that faces no water stress, is around $30 billion. That this sum is not larger is ultimately due to the fact that coal mines are, typically, not located in water-stressed areas and so the need for dry-cooling for power plants is limited. In total, water-related factors lead to a 6% increase in the share of generation costs related to fuel transport, cooling systems and network expansion.

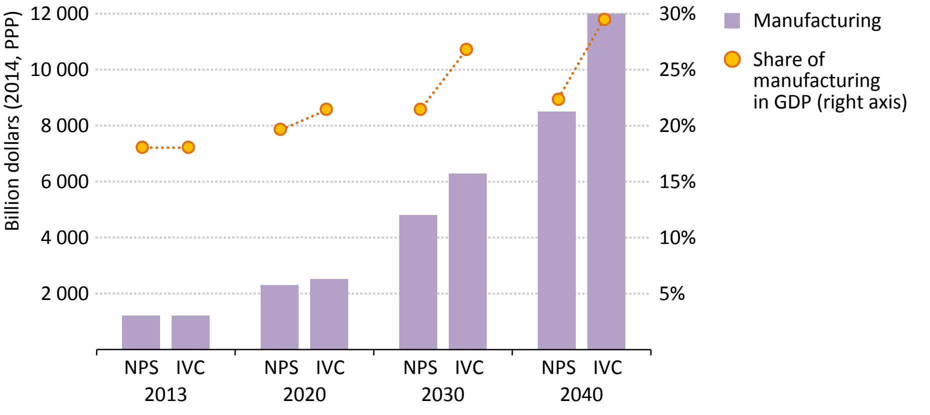
An Indian Vision Case

The vision India has defined for its development – two pillars of which are universal round-the-clock electricity supply and an expanded share of manufacturing in gross domestic product (GDP) under the "Make in India" campaign – would have profound implications for its energy system. We explore these implications, through an additional detailed modelling effort, in an Indian Vision Case in which India attains these key objectives in full and according to an accelerated timetable, thus putting itself on a different path of economic growth. The essential points that differentiate the Indian Vision Case from the New Policies Scenario are:

- The share of manufacturing in India's GDP rises to 25% by the mid-2020s and to 30% by 2040 in the Indian Vision Case, compared with a more modest rise in the New Policies Scenario (Figure 14.6). GDP rises to an annual average of 6.8% per year, versus 6.5% in the New Policies Scenario.[6]
- Investment in the power sector accelerates more quickly than in the New Policies Scenario, so as to ensure a faster improvement in the reliability of power supply and achievement of full universal access to electricity within ten years.

6. The GDP assumption in the Indian Vision Case includes the same expansion of the services sector as in the New Policies Scenario, leading to a higher rate of overall GDP growth. The implications for agriculture are discussed later in this section.

Figure 14.6 ▷ Value added in manufacturing in the Indian Vision Case compared with the New Policies Scenario



Note: NPS=New Policies Scenario; IVC=Indian Vision Case; PPP = purchasing power parity.

These achievements are complemented by more rapid movement in four additional areas:

- A strong push to promote energy efficiency in all of India's end-use sectors: buildings, transport, industry and agriculture.
- A more thorough modernisation of India's coal sector, including a faster transition to more efficient coal-fired technologies in the power sector.
- Accelerated deployment of renewable energy, based on the goal to see total renewable capacity in the power sector (excluding large hydropower) reach 175 GW by 2022, with further expansion after this date.
- A suite of measures to control the emissions of sulphur, nitrogen oxides and particulate matter that cause the low air quality in India's major cities.

Making the manufacturing sector the engine of India's growth, rather than the services sector (which has been the prime driver of GDP growth in recent years) means a significant acceleration in the amount of energy required to fuel India's development. Over the *Outlook* period, generating \$1 of value added through expansion of industry requires at least ten-times more energy than \$1 of value added from the less energy-intensive services sector. An emphasis on manufacturing also implies some far-reaching changes across Indian society: increasing employment opportunities in urban and peri-urban areas; triggering additional migration from rural to urban areas and increasing average wages. Increasing urbanisation and higher incomes push residential energy demand higher, as – to a lesser extent – does the more rapid achievement of universal access to electricity (Spotlight).

SPOTLIGHT

What mix of technologies can achieve universal electricity access in India?

In the Indian Vision Case, all households in both urban and rural areas gain access to electricity within ten years, earlier than projected in the New Policies Scenario. This involves not only a swift pace of electrification in and around India's urban centres, but also brings electricity to the entirety of the rural population, with the help of a range of different generation technologies. Taking additional account of population growth, around 390 million people become new consumers of electricity over the period to 2025 in the Indian Vision Case, either via a grid connection or decentralised systems.[7]

In urban areas, the most economic option is always on-grid electrification; but in rural areas the final technology choice depends on a variety of factors: population density is one of the main variables, but others include the technology costs for mini- and off-grid systems, the cost of diesel and the comparison between grid-electricity tariffs and mini- and off-grid tariffs. A further dynamic consideration relates to rising household incomes: these have a strong impact on per-capita electricity demand and mean that the capacity of electricity systems needs to be scaled up over time. Off-grid systems can provide vital initial access for remote communities, but are less able to accommodate rising energy needs as households buy new appliances.

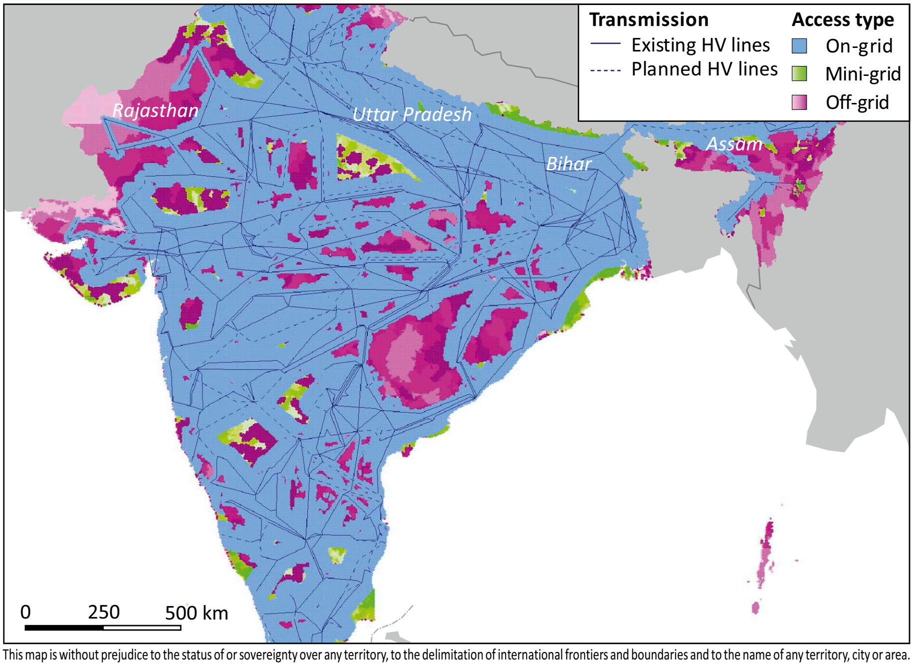
Based on the anticipated expansion of the main transmission lines in India over the next ten years, a detailed spatial analysis has been undertaken to illustrate the optimal technology split to achieve universal access (Figure 14.7).[8] For the 240 million people without access today, around 25% gain access via the grid, 35% via mini-grid systems and 40% via off-grid systems. Although mini- and off-grid solutions play an important role in bringing power to the rural population of India, on-grid connections remain the dominant overall type of electricity connection in 2025.

As can be seen from the map, decentralised systems are most cost-effective in regions with low population density, such as the state of Assam in the north-eastern part of the country or west Rajasthan. In the states of Bihar and Uttar Pradesh, accounting collectively for one-third of the total rural population and 60% of the population without access today, a higher share gain access via the grid: population density is higher in these two states and additional transmission lines are already planned or under construction.

7. Note that a decentralised grid and a low-carbon electricity system are not synonymous: wind power is low carbon but not decentralised, as wind farms rely on a centralised grid to deliver electricity to consumers. India also has a large fleet of diesel generators, which are decentralised but not low-carbon. Solar PV is theoretically more suitable for low-carbon and decentralised electrification, but so far the majority of solar deployment in India has been large-scale ground-mounted projects that, from a system perspective, are power plants feeding the centralised grid.

8. The geographic analysis was developed in collaboration with the KTH Royal Institute of Technology (Sweden), division of Energy Systems Analysis (KTH dESA).

Figure 14.7 ▷ Optimal split by grid type to achieve universal access in selected regions in the Indian Vision Case by 2025



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

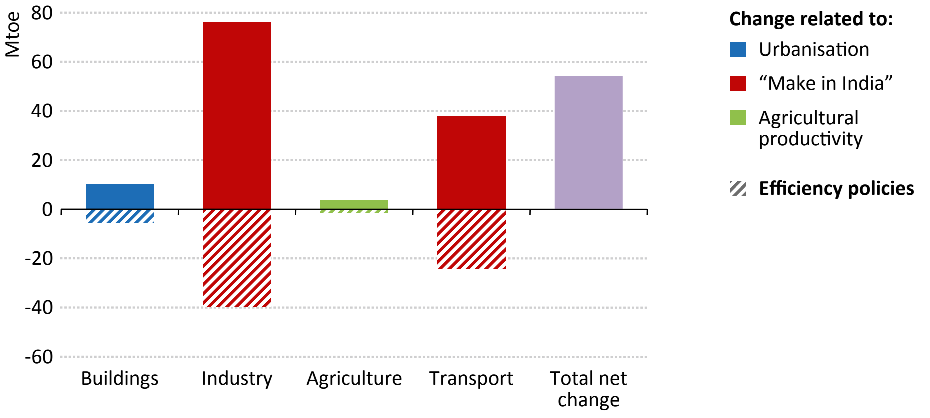
Note: The analysis incorporated the planned expansion of the main transmission lines. The density of the colour is linked to population density: the darker the colour, the higher the population density. The regions selected are those with the highest deficit in terms of population without access.

Within the mini- and off-grid systems, diesel generators provide the largest share of generation, followed by solar photovoltaic (PV) systems. The cost of solar PV falls over time and the technology is anticipated to become more and more competitive, compared with diesel generators (with which they may, in practice, be used in tandem to improve reliability). Small hydropower and wind power also contribute to the mini- and off-grid mixes, but their deployment depends on the existence of suitable local conditions, and this limits their share in generation. The investment associated with this drive for universal access is around $60 billion in total. Three-quarters of this sum goes to new mini- and off-grid power generation capacity, followed by investments in on-grid capacity and extension of transmission and distribution lines.

The net result of just these two changes (the increased share of manufacturing and the faster attainment of universal and reliable electricity supply) would be to push total final energy consumption in 2040 up by 15% (or 170 million tonnes of oil equivalent [Mtoe]) above the levels seen in the New Policies Scenario. Such an outcome would exacerbate all the strains described earlier in relation to the New Policies Scenario, increasing energy import needs, putting additional pressure on water resources and the required pace of infrastructure development, higher CO_2 emissions and a further deterioration in air quality.

That is why the other components of the Indian Vision Case assume even more importance than in the New Policies Scenario, to keep the adverse energy and environmental implications in check. Strong enforcement of energy efficiency policies, across all sectors will be essential – a drive consistent with the underlying vision of the "Make in India" campaign, which aims to safeguard the environment while generating industrial growth. Pushing in the same direction, rapid deployment of renewables reduces the carbon intensity of growth while also lessening the call on imported energy.

Figure 14.8 ▹ Change in fossil-fuel demand in the end-use sectors in the Indian Vision Case compared with the New Policies Scenario, 2040



Our analysis shows that increasing value added to the industrial sector by one-quarter by 2040 (compared with the New Policies Scenario) can be achieved while adding "only" 7% (or 48 Mtoe) to industrial energy demand, 35 Mtoe of which comes from fossil fuels (Figure 14.8). However, this requires a heavy commitment to energy efficiency across the industrial sector. This encompasses not only energy-intensive sectors (where efficient use and re-use of materials can play a vital role, Box 14.2) but also the less energy-intensive industries that are targeted by the "Make in India" campaign (such as textiles, food processing, machinery and industrial equipment), which have significant energy savings potential. For the energy-intensive sectors, the coverage of the "Perform, Achieve and Trade" scheme is extended, as already envisaged in the second-cycle for the period from 2016, and the requirements tightened significantly to bring efficiency standards in these industries close to global best practice levels by 2040. Particular attention needs to be paid to the Indian steel industry, which is projected to account for almost 20% of industrial energy demand by 2040, but in which current average efficiency levels are relatively low by global standards.

The need to focus on energy efficiency does not stop with the industrial sector. The increase in manufacturing output in the Indian Vision Case also implies a 30% rise in freight activity – and a potentially significant upward jolt to oil demand for transportation. Introducing efficiency standards for heavy and medium trucks and light commercial vehicles becomes a pressing need in order to constrain oil imports and to limit the air pollution from exhaust gases. These measures, which improve the efficiency of new heavy trucks from 33 litres per 100 km today to 21 litres per 100 km in 2040 (in line with best practice in other developing Asian countries) can contain growth in transport energy demand to 4% (or 12 Mtoe) in 2040 above the level in the New Policies Scenario, with the difference explained mostly by higher consumption of diesel for trucks.

Box 14.2 ▷ Material efficiency in energy-intensive industries in India

Energy-intensive industries, including steel, cement, plastics, aluminium and paper, are a pillar of India's industrialisation. In the Indian Vision Case, these five energy-intensive industries still account for more than 40% of total industrial energy consumption and almost a quarter of total final energy consumption in 2040. While a large share of the economically viable energy efficiency potential is exploited in the Indian Vision Case, most of the energy savings potential lies outside the energy-intensive sectors. Material efficiency – delivering the same material service with less overall material input – can complement energy efficiency in reducing energy demand, increasing energy security, enhancing economic competitiveness and reducing greenhouse-gas emissions. Material efficiency includes a set of diverse measures, such as increasing recycling, reducing the weight of consumer products, increasing fabrication yields and using energy-intensive materials more intensely. The government's Zero Effect, Zero Defect concept, launched in 2015, is an important step in the direction of encouraging companies to focus on product quality while reducing waste of natural resources.

Implementing material efficiency strategies (see Chapter 10), in addition to energy efficiency, in the Indian Vision Case can save almost 65 Mtoe (or 20% of energy demand from energy-intensive industries), which is significantly more than efficiency-related savings in these industries. Coal demand would be reduced by almost 50 Mtoe, demand for electricity and for oil by 7-8 Mtoe each. Three-quarters of total savings would arise from the steel sector, which is also by far the most important energy-consuming industry. The demand for steel can be reduced by using steel components for longer, light-weighting steel products, particularly in buildings and by reducing losses during the manufacturing process. Additionally, modernising India's recycling industry, which is currently highly fragmented in the absence of a legal framework, would help to increase recycling rates, which are currently one of the world's lowest, and thus replace energy-intensive primary steel with less energy-intensive secondary steel.

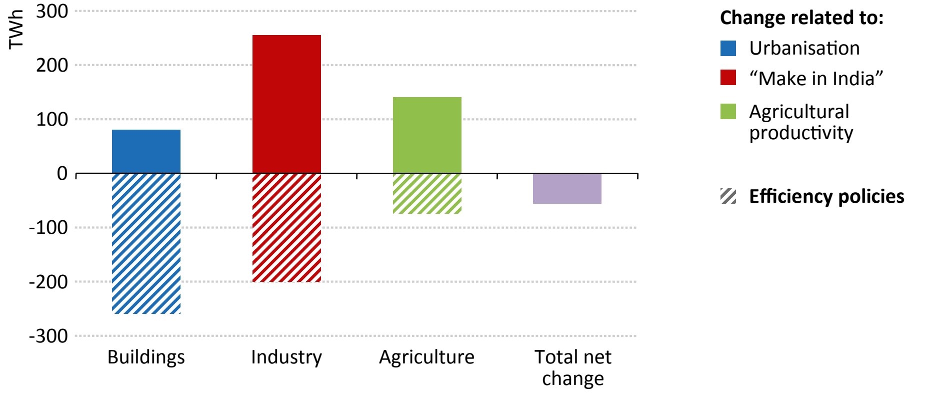
The expansion of the manufacturing sector requires labour: the Indian government is aiming to create 100 million additional manufacturing jobs by the early 2020s, bringing new employment to people who would otherwise mostly be employed in the agricultural sector. This implies additional growth in agricultural productivity to compensate for the loss of labour while still delivering the food that India requires. The two main contributions to this increase in agricultural productivity in the Indian Vision Case are a partial consolidation of the fragmented landholdings in many parts of India and growing mechanisation. The latter, in combination with a slight rise in the demand for irrigation, pushes up energy demand in agriculture in the Indian Vision Case by around 16%, or 8 Mtoe, in 2040, compared with the New Policies Scenario.

There are also strong implications for the residential and services sectors. Achieving the "Make in India" target would increase the number of job opportunities in and around India's towns and cities, accelerating the pace of urbanisation. Urban households consume, on average, about twice the amount of electricity of rural households that have electricity; urbanisation also facilitates access to alternative cooking fuels such as LPG, leading to extra consumption of oil and, to a lesser degree, also of gas. We estimate that the number of urban households would rise to 145 million by 2025 and 221 million by 2040 (see Table 14.1 for a comparison with the New Policies Scenario). The earlier achievement of universal access to electricity increases residential electricity demand in total by an extra 14 TWh in 2025. However, by 2040, this increase in electricity use is completely offset by the effect of efficiency policies. As standards become more stringent for household appliances and buildings, so household electricity consumption is lowered in the Indian Vision Case below the levels of the New Policies Scenario.

Improving efficiency across a range of residential appliances is vital to counteract the upward pressure on demand in the buildings sector. As of today, only one kind of refrigerator and one type of air conditioner are subject to mandatory standards, the other major appliances are still under a voluntary scheme. By gradually phasing out the least-efficient two categories of refrigerators and washing machines, and the least-efficient categories of televisions and computers, and by allowing only the sale of compact fluorescent lamps (CFL) and light-emitting diode (LED) lamps for buildings and public lighting, electricity demand for lighting and appliances (even though the total number of appliances is higher) is around 80 terawatt-hours (TWh) lower in the Indian Vision Case compared with the New Policies Scenario. In order to offset further the effects on electricity consumption in buildings (not just from appliances) arising from urbanisation and universal access, the extension of the Energy Conservation Building Code to larger residential buildings brings down energy needs for cooling and saving by almost 90 TWh.

Despite the higher economic growth in the Indian Vision Case, efficiency measures taken on the demand side mean that electricity demand is lower in 2040 than in the New Policies Scenario (Figure 14.9), and the environmental footprint of the power sector is further reduced by changes in the way that this power is produced. The share of coal in power generation drops towards half in 2040, from around three-quarters today and the average efficiency of coal-fired generation improves more quickly, to reach 39% in 2040. The share of non-fossil fuel capacity in power generation – mostly non-hydro renewables – increases to almost 50% in 2040. Alongside the measures to improve the functioning of the power sector as a whole, discussed in Chapter 12, this would require the creation of a business and investment framework capable of attracting the necessary investment, as well as a step up in the amount of capital that flows to renewables. The latter, in particular, would need readily available and low-cost capital secured either through explicit guarantees or as a result of the reduced risk that comes with a predictable business framework.

Figure 14.9 ▷ Change in electricity demand in the end-use sectors in the Indian Vision Case compared with the New Policies Scenario, 2040



Note: The increase of electricity demand due to earlier achievement of universal electricity access is offset in 2040 by efficiency savings.

The Indian Vision Case takes important additional steps in the direction of a low-carbon development strategy for India, compared with the New Policies Scenario, even though the eventual outcomes, in terms of energy demand and emissions, are similar. Some of the key policy elements in this case – the strong accent on end-use energy efficiency, no further construction of the least-efficient coal-fired power plants, and increased investment in renewable energy technologies – coincide with the pillars of a scenario, called the Bridge Scenario, presented in the *Energy and Climate Change: World Energy Outlook Special Report* (IEA, 2015) that is designed to deliver a peak in global energy-related emissions by 2020.[9] The Indian Vision Case does not illustrate, by any means, the full potential for India to deliver a low-carbon model of growth, but India's readiness and ability to push far beyond the efficiency measures and renewables deployment in the Indian Vision Case depends on external leadership, too, for example in developing and proving technologies like CCS as well as mechanisms to channel low-cost financing for efficiency improvements and low-carbon investment.

9. India's energy-related CO_2 emissions in the Bridge Scenario are considerably lower than in the Indian Vision Case because the policy measures are stronger and assumed GDP growth is lower.

Box 14.3 ▹ Five steps to improve India's air quality

Proven emissions control technologies are available to maintain acceptable levels of air quality in India, even with the pressures arising from a growing economy and increasing combustion of fossil fuels for power generation and in the end-use sectors.[10] In parallel with efforts to improve the efficiency of power generation, the package of advanced control measures in the Indian Vision Case involves:

- Tighter controls on emissions from large combustion plants. These would be more stringent for new plants but also require the retrofit of existing plants with appropriate equipment like flue gas desulphurisation, NO_x controls or high efficiency de-dusters. Measures would also include a requirement to use best available technologies for certain industrial processes, including energy-intensive industries such as iron and steel, cement, chemicals and others.
- The introduction of maximum sulphur content requirements for liquids fuels, at the level of 1% for heavy fuel oil, 0.1% for light fuel oil and sulphur-free fuels (a maximum of 10 parts per million) for transport.
- Higher standards for exhaust emissions from road vehicles, up to the equivalent of Euro 6 for light-duty cars and trucks, Euro 6 for heavy-duty trucks and Euro 3 for motorcycles and mopeds, along with measures for non-road vehicles (tractors and other agricultural/construction vehicles, trains, ships etc.).[11]
- Low-cost measures to control emissions of volatile organic compounds from liquid fuels production, storage and distribution, such as leak detection and more efficient covers and seals.
- Accelerated roll-out of improved efficiency biomass cookstoves, accompanied by continued efforts to encourage switching from solid biomass to LPG and electricity.

Another element of the Indian Vision Case reinforces the importance of the environmental dimension to India's growth model – the need for measures to reduce emissions of local pollutants, so as to improve air quality and reduce the adverse effects of these emissions on human health. We estimate that enforcement of a suite of best practice measures, phased in over ten years to 2025, would allow for an 80% reduction in sulphur-dioxide (SO_2) levels in 2040, compared with the baseline of no additional action, mainly due to tight SO_2 emission limits in the power generation sector and in industry (Box 14.3). Emissions of nitrogen oxides (NO_x) would also fall by around 65% over the same period, with the largest reduction in the road transport sector. Emissions of particulate matter ($PM_{2.5}$) would decline because of tighter controls over industrial emissions as well as a decrease in household use of traditional biomass cookstoves. Some of these measures are already under discussion in

10. The emission standards and measures included are based on legislation in force in the European Union.

11. Standards that are currently in force in India for road sources are Euro 3/III for light-duty/heavy-duty vehicles India-wide and Euro 4/IV in selected cities.

the Indian government; others would go beyond anything currently under consideration.[12] These measures come at a significant financial cost, almost $90 billion per year on average to 2040 – more than double the amount that would be required under current legislation. But the benefits include a reduction in crop losses caused by ground level ozone, as well as a significant reduction, by more than one million per year, in premature deaths associated with local pollution.

Investing in India's energy future

Over the long term, safeguarding Indian energy security – in all its multiple dimensions – comes back to issues of investment.[13] The levels of investment required in the New Policies Scenario – even more so in the Indian Vision Case – are a large step above anything achieved by India so far, particularly in the power sector. Ensuring that this investment comes in a timely way depends not only on providing appropriate conditions within the energy sector itself but also a host of more general issues related to the overall complexity of the Indian business climate, which are very much the focus of the current government. Financing too is potentially a major obstacle, given that traditional resources of capital to expand the Indian energy sector (including public funds) may not be sufficient to meet its needs. This section describes the overall investment needs of the New Policies Scenario and the Indian Vision Case, both for energy supply and for energy efficiency, policy actions that can enable these to be met – as well as some risks and implications for India if investment falls short.

Investment in energy efficiency

Energy efficiency policies in India are growing in scope and importance, contributing to the mitigation of the prospects of energy consumption growth. In industry, the Perform, Achieve and Trade (PAT) scheme covers large industrial energy consumers, while the Indian government has put in place a suite of measures to raise awareness and provide financial support to improve energy efficiency in small and medium enterprises (SMEs). In transport, India introduced its first fuel-economy standard in 2014 (for passenger light-duty vehicles) and standards for heavy-duty vehicles are expected to be introduced in 2016. In buildings, India has introduced a voluntary energy code for commercial buildings (that has been made mandatory in several states), while more and more minimum energy performance

12. The emission limits from combustion in large boilers in the Indian Vision Case are similar to the values in a proposal made in 2015 by the Indian Ministry of Environment for the power generation sector.

13. The notion of energy security – which the IEA defines as uninterrupted availability of energy at an affordable price – encompasses one of the key challenges facing the Indian energy sector. There are different dimensions: access and poverty alleviation (lack of modern energy being the most extreme form of energy insecurity); the quality of energy supply (ability of the system to deliver uninterrupted energy); resilience and flexibility (the ability of the system to react to shocks, disruptions and sudden changes in the supply-demand balance); its diversity (avoiding too great a reliance on a single energy type, supplier or route to market) and affordability. To this one could add the environmental dimension, by including the idea of affordability; the price that India pays for unabated combustion of fossil fuels, although the overlap between energy security and environmental policy objectives is not complete.

standards (MEPS) have been introduced for electric appliances, albeit only 4 out of the 21 current MEPS are mandatory.

As a result of this combination of growing attention to energy efficiency and the rapidly expanding demand for energy, annual investment in energy efficiency rises rapidly in the New Policies Scenario and, even more so, in the Indian Vision Case (Table 14.3). The cumulative investment need of $0.8 trillion in the New Policies Scenario, and $1.5 trillion in the Indian Vision Case, is dominated by energy efficiency investment in transport, followed by buildings and industry.

Table 14.3 ▷ Investment in energy efficiency in the New Policies Scenario and the Indian Vision Case, 2015-2040 ($2014 billion)

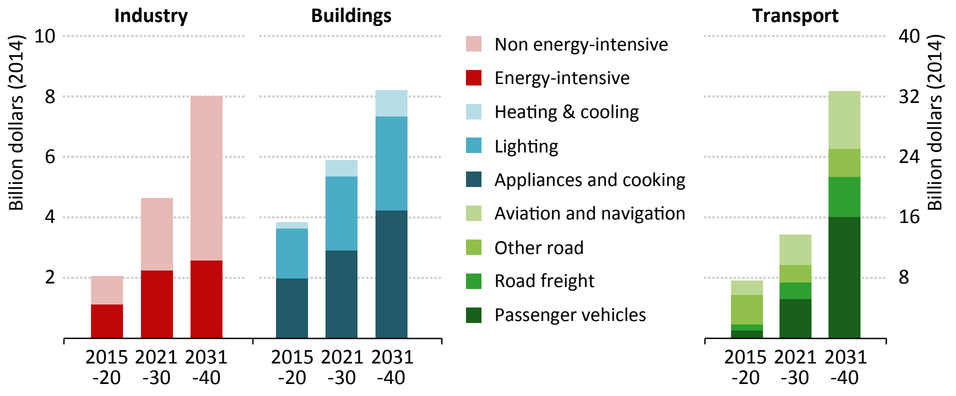
	New Policies Scenario		Indian Vision Case	
	Cumulative	Annual average	Cumulative	Annual average
Industry	139	5	273	10
Energy-intensive	54	2	101	4
Non energy-intensive	85	3	172	7
Buildings	181	7	419	16
Heating and cooling	32	1	73	3
Appliances and cooking	84	3	281	11
Lighting	65	2	66	3
Transport	512	20	802	31
Passenger vehicles	220	8	332	13
Road freight	77	3	238	9
Other road	87	3	100	4
Aviation and navigation	128	5	131	5
Total energy efficiency	**832**	**32**	**1 494**	**57**

Note: The methodology for measuring energy efficiency investment derives from the additional expenditure made by households, firms and the public sector to improve the performance of their energy-using equipment above a baseline of efficiency levels in different end-use sectors in 2014.

As India's transport system has been traditionally dominated by mass transport, today buses account for about half of energy consumption in road transport and are the target for a large share of efficiency spending (part of "other road" transport in Table 14.3 and Figure 14.10). However, in the future, passenger light-duty vehicles (PLDVs) account for the bulk of the increase in energy efficiency spending, as annual PLDV sales increase more than ten-fold to a level of 29 million in 2040. The additional investment to increase energy efficiency in road freight vehicles is substantial in the Indian Vision Case ($161 billion) as tighter fuel-economy standards are included in that case (but not in the New Policies Scenario).[14]

14. As noted, efficiency regulation for freight transport is currently under discussion, but no formal proposal for regulation has yet been announced, so this is not included in the New Policies Scenario.

Figure 14.10 ▷ Average annual investment in energy efficiency by sector in the New Policies Scenario



Note: The volume of efficiency investment in the industry and buildings sectors is on the left axis: the higher volume of investment in transport is indicated on the right axis.

Energy efficiency spending in the buildings sector in the New Policies Scenario is dominated by appliances (representing around 40% of the investment), spending on which becomes more important as incomes and appliance ownership levels rise. Appliance standards are projected to become more stringent and mandatory for a wider range of appliances, including televisions, refrigerators and washing machines. Yet, significant energy efficiency potential for appliances remains unexploited in the New Policies Scenario. Tightening standards further and mobilising an additional cumulative $240 billion in efficiency investment, as in the Indian Vision Case, would exploit this potential and slow energy demand growth. Efficiency spending for lighting also plays an important role, as a consequence of lighting programmes that incentivise a switch from incandescent light bulbs and CFL to LEDs that are becoming more and more efficient (Box 14.4). For heating and cooling, India already has mandatory standards in place for air conditioners. Annual investment in insulation – mainly aimed at reducing energy use for space cooling – reaches a level of $0.4 billion in 2040 in the New Policies Scenario, primarily in commercial and public buildings. In the Indian Vision Case, where building standards become mandatory in all buildings, the required investment level in insulation in 2040 increases by four-times.

Today the majority of the investment in industrial energy efficiency projects is carried out by the energy-intensive industries, particularly chemicals (including fertilisers), steel and cement. The bulk of future spending comes though from less energy-intensive industries, including the brick-making, textiles, food and machinery. Investment is split equally between measures to reduce the need for thermal energy, as in steam systems and industrial furnaces, and those to reduce electricity consumption, mainly in electric motor-driven systems, but also in refrigeration and lighting. In the Indian Vision Case, the focus in terms of industrial efficiency improvements shifts even more to non-energy-intensive industries, where the cumulative investment needs double compared with the New Policies Scenario.

Box 14.4 ▷ Lighting efficiency on a grand scale

Energy Efficiency Services Limited (EESL), a joint venture of various state-owned companies, was set up by India's Ministry of Power as part of the National Mission on Enhanced Energy Efficiency of Power. EESL has several projects underway to promote efficiency in households, public buildings, street lighting and agriculture. The major focus so far has been on lighting, as it represents 10-15% of national electricity consumption and can be reduced by at least half once old inefficient light bulbs have been replaced by LEDs. The level of ambition and the results have both been impressive.

EESL's Street Lighting Programme aims to replace nine million inefficient light bulbs used for street lighting in 240 Indian cities by 2016. No additional investment has to be made by the municipalities because EESL finances the up-front cost and is paid through the financial savings from lower electricity bills. In parallel, EESL is promoting efficient lighting in households by providing 150 million LEDs at the cost of incandescent light bulbs to consumers by March 2016. The higher up-front cost related to energy efficiency, which constitutes one of the main barriers to wider adoption, is financed by EESL and paid back by distribution companies with an annuity over a period of three to ten years.

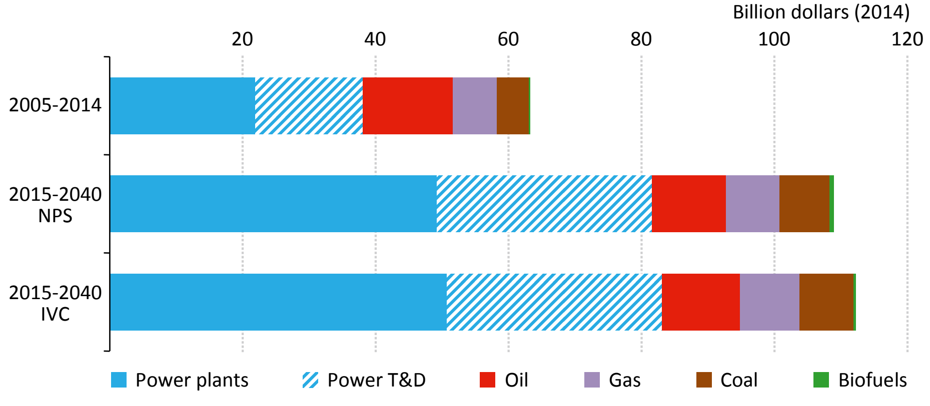
The commitment from EESL to efficient lighting has been a game changer for India's lighting market. The assurance of a stable, large-scale demand for LEDs has led to the build-up of domestic production, driving down the wholesale price paid by EESL for one bulb from more than INR 300 ($4.8) at the start of 2014 to around INR 70 ($1.1) in mid-2015. Similarly the retail price of LED bulbs has been cut to INR 320 ($5.1), significantly lower than European retail prices. Next in line for EESL are initiatives to accelerate the deployment of highly efficient ceiling fans and electric pumps used in agriculture.

Mobilising almost $60 billion in annual investment in end-use energy efficiency represents a huge challenge, with the hurdles taking different forms from sector to sector. Energy-intensive industries are typically among the most aware of opportunities to improve efficiency but the scale of investment, the increasing payback periods and a challenging international environment, e.g. overcapacities in the steel sector, can impede raising capital. The challenges are often higher for smaller companies, for which public loan programmes and knowledge transfer would need to be implemented on a far larger scale than today to provide more information and appropriate financing tools. The situation is similar in the buildings sector, where developers of larger-scale commercial buildings are more familiar with how to realise energy efficiency improvements than those in the larger but more diffuse residential sector. Household spending on energy efficiency in general is relatively small compared with spending on electricity and transport fuels (IEA, 2014a), and poorer households will need significant public assistance such as through the EESL programme or others, in order to realise the required energy savings.

Investment in energy supply

Investment in energy supply in India has risen steadily over the period since 2005 (see Chapter 11), as private capital started flowing to the power sector in particular. But the main scenarios examined here require a further sustained increase in investment flows related to energy supply – a cumulative total of $2.8 trillion over the period to 2040 in the New Policies Scenario and $2.9 trillion in the Indian Vision Case (Figure 14.11 and Table 14.4). The additional energy efficiency investment in the Indian Vision Case is essential to avoid a much larger increase in energy-supply investment in this case.

Figure 14.11 ▷ Average annual investment in energy supply in India in the New Policies Scenario and the Indian Vision Case



Note: NPS = New Policies Scenario; IVC = Indian Vision Case; T&D = transmission and distribution.

The power sector dominates overall investment needs in both cases, with around three-quarters of total investment in energy supply, but there are variations between the two in terms of fuels and technologies. Despite the accelerated push for more costly supercritical coal-fired plants, there is a slight decrease in capital investment in coal-fired capacity in the Indian Vision Case, compared with the New Policies Scenario, as fewer plants are built (and the increased costs of higher-efficiency plants are somewhat contained as the effects of the "Make in India" campaign spread to domestic manufacturing of power plant equipment). Another difference comes in the investment required in renewable energy, notably in solar PV and wind power: investment in the Indian Vision Case in renewable sources of power generation is up by almost 10%, or a cumulative $73 billion over the *Outlook* period, relative to that in the New Policies Scenario. Cumulative installations of solar PV capacity are some 22% higher in the Indian Vision Case. Such a rapid rise in the pace of deployment could strain supply chains and so push up costs, but it would also trigger additional technological learning that helps to keep unit investment costs in check, both those for the domestic manufacturing of solar panels and equipment as well as their installation. The effect of greater technology learning predominates and, as a result, cumulative investment in solar PV is up only 14% in the Indian Vision Case.

Table 14.4 ▷ Investment in energy supply in the New Policies Scenario and the Indian Vision Case, 2015-2040 ($2014 billion)

	New Policies Scenario		Indian Vision Case	
	Cumulative	Annual average	Cumulative	Annual average
Oil	285	11	308	12
Upstream	62	2	82	3
Transport	31	1	34	1
Refining	192	7	192	7
Gas	212	8	234	9
Upstream	127	5	158	6
Transport	84	3	76	3
Coal	199	8	206	8
Mining	127	5	135	5
Transport	72	3	71	3
Power generation	1 277	49	1 322	51
Coal	354	14	330	13
Gas	66	3	64	2
Nuclear	96	4	96	4
Hydro	141	5	137	5
Other renewables	611	23	687	26
of which solar	364	14	412	16
Power transmission and distribution	845	33	838	32
Biofuels	11	0.4	11	0.4
Total energy supply	**2 829**	**109**	**2 919**	**112**

Investment in oil and gas production is higher in the Indian Vision Case, by around 8-10%, as the assumed improvement in conditions and incentives (resulting from a stronger policy push to slow the rise in demand for imports) attract more capital to the upstream sector, particularly into offshore basins. In both cases, investment related to fossil fuels (including upstream, transportation, refining and fossil fuel-fired power plants) accounts for around 40% of the total; renewables around 27%, nuclear just over 3% and biofuels for less than 1%. The remainder covers investment in transmission and distribution.

Investment at this scale certainly cannot be taken for granted in India's complex business environment, presenting a downside risk to our projections (Box 14.5). The power sector is particularly vulnerable to a shortfall in capital: it continues to generate interest from investors, but there is also awareness that the structural weaknesses described in Chapter 12, notably the financial condition of the distribution companies, are unlikely to be resolved quickly. Reducing off-taker risk (i.e. the possibility that generators will not be paid for the electricity sold on to the distribution sector) will be essential if India is to attract capital to the energy sector at the levels required. Investments in each part of the power sector also come with some specific risks: whether coal-fired power plants can rely on the volumes and quality of their coal supply, or to what extent they face the possibility of a future tightening of environmental standards; whether gas-fired plants can remain competitive given their higher fuel costs and whether plants high up in the merit order will be adequately remunerated; whether nuclear or large hydropower plants can secure the necessary permits and authorisations to move ahead; whether investors in non-hydro renewables can feel sufficiently confident in the regulatory framework to put money into capital-intensive technologies; and whether any investment – including in networks – has the degree of local public consent that allows it to go ahead.

Investments in upstream oil and gas likewise face challenges: the most promising of India's remaining hydrocarbon resources are largely offshore, are technically complex to exploit and involve relatively high-cost projects. Whether through adjustments to the fiscal system, to the provisions in upstream contracts, or to the price of the produced product (for natural gas), the policy framework needs to offer potential returns that are commensurate with the risks. In the case of coal, the boost to production will require brownfield projects and new greenfield mines and – although the unit costs of current investments in coal extraction are relatively low – the capital intensity of new projects is set to go up, as mining companies seek to further mechanise their operations, improve safety standards and deploy more advanced technology, especially in underground mining.

Box 14.5 ▷ The risk of a shortfall in power sector investment

There is clear momentum in India behind the drive to modernise the energy system, encompassing cleaner and more reliable energy supply and universal access, and accompanied by the push for better functioning markets. There would be significant downside risk to our projections if this momentum were to wane, or if there were major delays in carrying out planned reforms of the energy market and business environment. An environment in which energy investment falls short of the levels projected in the New Policies Scenario would give rise to important risks to India's economic outlook, as, for example, continued load shedding took its toll on output and productivity: unreliable electricity supply has already been identified by business owners and managers as the second-most important obstacle to business development in India (World Bank Enterprise Survey, 2014).

Prospects for the "Make in India" campaign and the general ambition to re-orientate the economy away from agriculture and services, towards manufacturing industry, would be dealt a heavy blow, as the manufacturing sectors are more energy intensive and rely on affordable and secure supply for their competitiveness. In the absence of reliable grid-based power, companies and households would be forced to rely more on alternatives that are typically more costly, either generating their own power or relying on inverters and batteries that store power from the grid when it is available.

While such solutions can deliver reliable power supply for those who can afford to install them, they are far from optimal from a power system perspective. They are typically more costly than grid-based technologies, in part because they miss out on economies of scale. Replacing a 1 GW coal-fired power plant with five 200 megawatt (MW) captive power plants for large industrial consumers duplicates costs that are not related to the size of the unit, including land acquisition and other permitting issues. Smaller units are also typically less efficient than larger plants, especially if they operate at part load (as is frequently the case since companies often need less electricity than their plants can produce). Fuel spending tends to rise, also because costlier fuels are being used, for example, when 200 diesel generators of 500 kilowatt size each, replace a 100 MW open-cycle turbine fuelled with natural gas, it costs (based on current prices) up to $30 million more per year just for fuel to generate the same amount of electricity.

The emergence by default of a more decentralised power generation system would not necessarily be positive for renewable energy technologies. Rooftop solar PV would get a boost, but utility-scale solar PV and wind power projects – the main route by which India aims to reach its targets for renewables deployment – would suffer. Captive generation plants do not contribute to system security, i.e. they cannot readily be used for balancing purposes, so it would become more difficult to integrate large amounts of variable renewables.

Infrastructure for transportation (not including electricity transmission) and oil refining is another major element in energy-supply investment, of which the largest components are refineries, LNG import terminals and gas pipelines, and coal-related railway infrastructure. Coal-related rail is particularly critical to the adequacy of energy supply. The most pressing railway projects are three lines in Jharkhand (improving the connection of the North Karanpura coal fields), Odisha (improving the connection of the Ib Valley coal fields) and Chhattisgarh (improving connection of the Mand Raigarh and Korba coal fields). There are ongoing discussions about whether railway investments for the carriage of coal can and should be carried out exclusively by the national monopoly, Indian Railways, or whether coal firms or independent private players might invest too. With India becoming the largest importer of coal, investment will be needed in more capital-intensive and longer lead-time port projects.

In the Indian context, the adequacy of investment depends not just on decisions and policies at federal level, but also on the actions of individual states. As things stand, investment flows are far from evenly distributed across India. Taking foreign investment as an example, the top six states – Maharashtra, Delhi, Tamil Nadu, Karnataka, Gujarat and Andhra Pradesh – accounted for over 70% of foreign direct investment flows to India during 2000-2015 (India Department of Industrial Policy and Promotion, 2015).[15] A risk for India in practice is diverging outcomes between states – particularly in the power sector, for which responsibilities are shared between the federal and state levels. The model of competitive

15. In practice the concentration of foreign direct investment may be even higher than this: around a quarter of the total was not allocated by region as it concerned the acquisition of shares by non-residents, operations which may also have involved disproportionately companies in the six states mentioned.

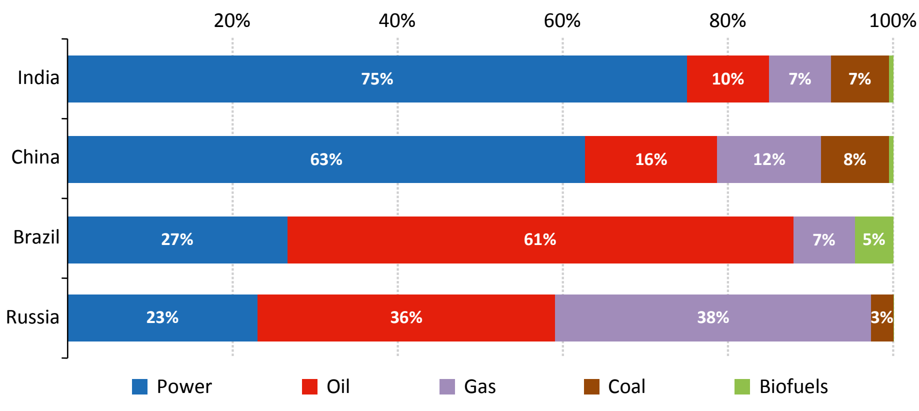
and co-operative federalism, involving a strong dialogue between the states (an area where the National Institution for Transforming India [NITI Aayog] can play a positive role) can stimulate innovative policy experiments at the state level and ensure that successful policy approaches can be easily and quickly studied and emulated across the country.

Well co-ordinated policy-making is essential to ensure that different institutions with responsibilities for various aspects of energy policy avoid operating at cross-purposes and synchronise the delivery of different parts of the system (e.g. new power plants with appropriate grid connections, coal supply with rail and port infrastructure, urban planning with provision for public transport). Integrated policy-making also involves looking at land use, water, biodiversity and protected areas issues, alongside timely engagement with relevant stakeholders at numerous levels – federal, regional, state and local.

Financing

Investment on the scale required will also need to call upon a broader range of investors in Indian energy than has been the case in the past. As the availability of public funds cannot be assumed, due to competing priorities (see Chapter 11), greater private participation in energy infrastructure projects is likely to be required. International investors, too, are likely to play a greater role – and indeed have been invited to lead investments in the renewables sector in support of achieving the 175 GW capacity target by 2022 (some private investors, including Essar and SunEdison, have already been heavily involved in solar projects in Gujarat). These investors and others are attracted by India's size, its growth potential and an auspicious current environment, in which a reforming administration coincides with a lower oil price that eases pressures on public finance and inflation. But the challenges are severe, including a lack of clarity and certainty around the rules of the game, the complexity of administrative procedures and some ambiguous boundary lines between national, state and local competences.

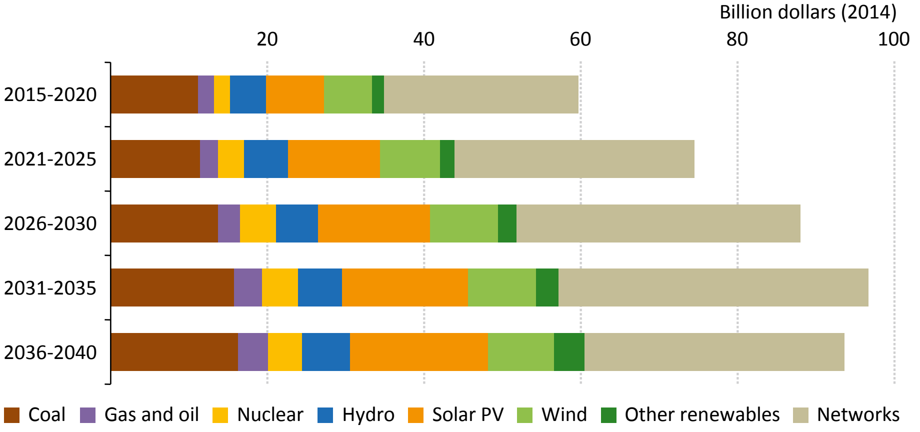
Figure 14.12 ▷ Breakdown of cumulative energy supply investment by sector in selected countries in the New Policies Scenario, 2015-2040



The share of future investment going to the power sector is higher in India than in most other emerging economies – and this will be the key arena in which the adequacy of future investment and of financing will be tested (Figure 14.12). In India (as in many other countries experiencing rapid economic expansion and, indeed, in countries throughout the world), many companies need to borrow to grow; retained earnings are unlikely to be sufficient.[16] This puts the spotlight on three main external sources of capital for financing the power sector: public funds; domestic savings, channelled via the banking system or Indian capital markets; and international capital flows, including development finance.

Up until now, domestic public money and finance from the banking sector, together with some development finance and funding from Chinese equipment manufacturers, has generally proven sufficient for the capital needs of the Indian power sector. But this model looks set to come under increasing strain. Large outlays are foreseen for the energy sector, including low-carbon generation projects, and this, coupled with the host of risks associated with political, regulatory, technological, and financial aspects that affect the bankability of new projects, suggests that these sources will be stretched too thin to provide all the capital needed (Figure 14.13).

Figure 14.13 ▷ Average annual investment in the power sector in India in the New Policies Scenario



A part of the problem is the relatively narrow range of domestic financing options available. There is strong reliance in India on – and preference for – loans from the banking system, rather than capital markets: corporate lending from banks (as opposed to bonds or securitised loans via the capital markets) accounts for well over 90% of external financing (Group of Thirty, 2013). While the Indian capital markets have many listed companies, relatively few are actively traded and tapping these markets for funding is typically an avenue followed only by the very largest Indian companies (Didier and Schmukler, 2013).

16. The *World Energy Investment Outlook* (IEA, 2014b) demonstrated that a higher share of energy investment is financed through retained earnings in OECD markets, but that more debt and equity is needed in non-OECD countries.

However, bank loans are not generally a good match for the long-term needs of energy investment projects. More than 80% of loans outstanding from the Indian banking sector have a maturity of less than five years. The market for corporate bonds – which typically have a longer maturity – is relatively under-developed in India and has a capitalisation of only 5% of GDP, limiting its ability to supply long-term financing (OECD, 2014). There are also banking regulations and guidelines from the Reserve Bank of India that direct credit to various sectors and influence interest rates and the other conditions for lending by banks: a surge in the demand for investment into renewables or other generally more capital-intensive energy technologies might lead to difficulties because of sectoral risk clauses that limit the exposure of lenders to individual sectors.

Recognising these potential vulnerabilities, the Indian government is seeking to broaden the range of financing options available and bring down the cost of long-term finance. This is the purpose, for example, of India's Infrastructure Debt Funds – investment vehicles designed to accelerate the flow of long-term debt into infrastructure projects – and there are other initiatives specifically aimed at attracting finance for low-carbon projects and high efficiency technologies. International financing, theoretically a cheaper source of capital, requires a currency hedge to protect against the risk of devaluation (and market-based currency hedging in India pushes up the cost of debt towards that available on the domestic market). In response, the Indian government has shown interest in providing a government-sponsored currency hedging facility (Climate Policy Initiative, 2015). Such a facility could become very expensive in the event of sharp devaluation in the currency – but a well-designed facility of this kind would address the strategic need to bring cheaper capital at scale to the renewables sector, alongside an enhanced role for low-carbon finance from the multilateral development banks.

ANNEXES

World Energy Outlook links

General information: ***www.worldenergyoutlook.org***

Factsheets
www.worldenergyoutlook.org/resources/factsheets/

Model

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Tables for Scenario Projections

General note to the tables

The tables detail projections for *fossil-fuel production*, *energy demand*, *gross electricity generation* and *electrical capacity*, and *carbon-dioxide (CO_2) emissions* from fossil-fuel combustion in the New Policies, Current Policies and 450 Scenarios. Please see the preceding page for download details of these tables. The following regions are covered: World, OECD, OECD Americas, the United States, OECD Europe, the European Union, OECD Asia Oceania, Japan, non-OECD, Eastern Europe/Eurasia, Russia, non-OECD Asia, China, India, the Middle East, Africa, South Africa, Latin America and Brazil. The definitions for regions, fuels and sectors can be found in Annex C. By convention, in the table headings CPS and 450 refers to the Current Policies and 450 Scenarios respectively.

Data for *fossil-fuel production*, *energy demand*, *gross electricity generation* and *CO_2 emissions* from fuel combustion up to 2013 are based on IEA statistics, (*www.iea.org/statistics*) published in *Energy Balances of OECD Countries*, *Energy Balances of non-OECD Countries*, *CO_2 Emissions from Fuel Combustion* and the *IEA Monthly Oil Data Service*. Historical data for *gross electrical capacity* are drawn from the Platts World Electric Power Plants Database (April 2015 version) and the International Atomic Energy Agency PRIS database (*www.iaea.org/pris*).

Both in the text of this book and in the tables, rounding may lead to minor differences between totals and the sum of their individual components. Growth rates are calculated on a compound average annual basis and are marked "n.a." when the base year is zero or the value exceeds 200%. Nil values are marked "-".

Definitional note to the tables

Total primary energy demand (TPED) is equivalent to the power sector plus other energy sector excluding electricity and heat, plus total final consumption (TFC) excluding electricity and heat. TPED does not include ambient heat from heat pumps or electricity trade. Sectors comprising TFC include industry, transport, buildings (residential, services and non-specified other) and other (agriculture and non-energy use). Projected gross electrical capacity is the sum of existing capacity and additions, less retirements.

Total CO_2 includes emissions from other energy sector in addition to the power sector and TFC sectors shown in the tables. CO_2 emissions and energy demand from international marine and aviation bunkers are included only at the world transport level. Gas use in international bunkers is not itemised separately. CO_2 emissions do not include emissions from industrial waste and non-renewable municipal waste. Using the 2006 IPCC guidelines, instead of the older 1996 guidelines, has led to a change in the definition and absolute levels of CO_2 emissions from fossil-fuel combustion compared with previous *WEO* editions. For more information please visit: *www.iea.org/statistics/topics/CO2emissions*.

New Policies Scenario

	Production							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Oil production and supply (mb/d)										
OECD	**18.9**	**20.8**	**25.0**	**23.9**	**23.9**	**24.1**	**24.1**	**24**	**24**	**0.5**
Americas	13.9	17.0	21.0	20.4	20.5	20.8	21.0	19	21	0.8
Europe	4.3	3.3	3.2	2.6	2.4	2.3	2.2	4	2	-1.5
Asia Oceania	0.7	0.5	0.9	0.9	1.0	1.0	0.9	1	1	2.4
Non-OECD	**46.3**	**66.4**	**68.5**	**71.4**	**73.2**	**74.8**	**76.3**	**76**	**76**	**0.5**
E. Europe/Eurasia	11.4	14.0	13.5	13.6	13.4	12.9	12.2	16	12	-0.5
Asia	6.0	7.9	7.9	6.9	6.3	6.0	5.9	9	6	-1.1
Middle East	17.7	28.0	30.9	33.6	35.5	37.1	38.5	32	38	1.2
Africa	6.7	9.0	7.9	8.3	8.3	8.6	8.9	10	9	-0.0
Latin America	4.5	7.5	8.3	9.1	9.7	10.3	10.8	9	11	1.4
World oil production	**65.2**	**87.2**	**93.5**	**95.3**	**97.2**	**98.8**	**100.4**	**100**	**100**	**0.5**
Crude oil	59.1	67.7	67.3	68.4	67.9	67.4	66.8	76	65	-0.0
Natural gas liquids	5.8	13.3	15.2	16.1	17.2	18.2	19.2	15	19	1.4
Unconventional oil	0.3	6.3	10.9	10.8	12.1	13.2	14.5	7	14	3.2
Processing gains	1.3	2.2	2.4	2.6	2.7	2.9	3.0	2	3	1.3
World oil supply	**66.5**	**89.4**	**95.9**	**97.9**	**99.9**	**101.7**	**103.5**	**98**	**96**	**0.5**
World biofuels supply	0.1	1.4	2.1	2.6	3.1	3.6	4.2	2	4	4.3
World liquids supply	**66.6**	**90.8**	**98.0**	**100.5**	**103.0**	**105.3**	**107.7**	**100**	**100**	**0.6**
Natural gas production (bcm)										
OECD	**882**	**1 242**	**1 418**	**1 461**	**1 494**	**1 552**	**1 581**	**35**	**31**	**0.9**
Americas	643	892	1 042	1 094	1 120	1 179	1 221	25	24	1.2
Europe	211	280	236	212	201	191	180	8	3	-1.6
Asia Oceania	28	70	141	155	173	182	179	2	3	3.5
Non-OECD	**1 191**	**2 270**	**2 431**	**2 692**	**2 992**	**3 286**	**3 579**	**65**	**69**	**1.7**
E. Europe/Eurasia	831	909	924	991	1 058	1 103	1 150	26	22	0.9
Asia	132	438	512	568	636	711	790	12	15	2.2
Middle East	95	546	585	649	732	817	900	16	17	1.9
Africa	73	204	217	270	318	373	428	6	8	2.8
Latin America	60	172	193	214	247	282	311	5	6	2.2
World	**2 073**	**3 513**	**3 849**	**4 153**	**4 486**	**4 837**	**5 160**	**100**	**100**	**1.4**
Unconventional gas	*67*	*632*	*976*	*1 163*	*1 352*	*1 541*	*1 667*	*18*	*32*	*3.7*
Coal production (Mtce)										
OECD	**1 533**	**1 361**	**1 255**	**1 185**	**1 114**	**1 050**	**1 042**	**24**	**17**	**-1.0**
Americas	836	745	648	611	550	496	487	13	8	-1.6
Europe	526	234	190	143	114	87	74	4	1	-4.2
Asia Oceania	171	382	417	430	450	467	481	7	8	0.9
Non-OECD	**1 646**	**4 362**	**4 507**	**4 689**	**4 913**	**5 125**	**5 263**	**76**	**83**	**0.7**
E. Europe/Eurasia	533	435	442	449	460	468	473	8	8	0.3
Asia	937	3 623	3 732	3 886	4 082	4 262	4 362	63	69	0.7
Middle East	1	1	1	1	1	1	1	0	0	0.4
Africa	150	218	225	239	254	277	309	4	5	1.3
Latin America	25	85	107	114	116	117	119	1	2	1.2
World	**3 179**	**5 723**	**5 762**	**5 874**	**6 027**	**6 175**	**6 306**	**100**	**100**	**0.4**
Steam coal	*2 218*	*4 471*	*4 523*	*4 676*	*4 870*	*5 080*	*5 266*	*78*	*84*	*0.6*
Coking coal	*566*	*953*	*929*	*913*	*880*	*829*	*785*	*17*	*12*	*-0.7*

Current Policies and 450 Scenarios

	Production						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Oil production and supply (mb/d)										
OECD	**25.3**	**26.4**	**28.2**	**24.4**	**20.4**	**17.1**	**25**	**24**	**1.1**	**-0.7**
Americas	21.2	22.8	24.7	20.5	17.4	14.8	22	21	1.4	-0.5
Europe	3.2	2.5	2.4	3.1	2.1	1.5	2	2	-1.1	-2.9
Asia Oceania	0.9	1.1	1.1	0.8	0.9	0.8	1	1	2.9	1.5
Non-OECD	**69.8**	**77.8**	**85.5**	**67.0**	**62.9**	**54.8**	**75**	**76**	**0.9**	**-0.7**
E. Europe/Eurasia	13.6	14.2	13.6	13.2	11.4	9.0	12	13	-0.1	-1.6
Asia	8.0	6.9	7.1	7.8	5.6	4.3	6	6	-0.4	-2.2
Middle East	31.4	37.0	42.1	30.2	30.9	27.9	37	39	1.5	-0.0
Africa	8.4	9.3	10.3	7.7	7.1	6.2	9	9	0.5	-1.4
Latin America	8.5	10.4	12.5	8.2	8.0	7.3	11	10	1.9	-0.1
World oil production	**95.1**	**104.1**	**113.7**	**91.4**	**83.3**	**71.9**	**100**	**100**	**1.0**	**-0.7**
Crude oil	68.4	72.3	74.4	66.2	58.3	48.1	64	65	0.4	-1.3
Natural gas liquids	15.6	18.1	20.8	14.5	15.1	14.2	18	19	1.7	0.3
Unconventional oil	11.0	13.7	18.4	10.7	9.9	9.6	16	13	4.1	1.6
Processing gains	2.4	2.9	3.4	2.4	2.3	2.2	3	3	1.7	0.0
World oil supply	**97.5**	**107.1**	**117.1**	**93.7**	**85.6**	**74.1**	**97**	**89**	**1.0**	**-0.7**
World biofuels supply	1.9	2.7	3.6	2.1	6.0	9.4	3	11	3.7	7.4
World liquids supply	**99.5**	**109.7**	**120.7**	**95.8**	**91.6**	**83.4**	**100**	**100**	**1.1**	**-0.3**
Natural gas production (bcm)										
OECD	**1 446**	**1 598**	**1 785**	**1 404**	**1 393**	**1 189**	**32**	**29**	**1.4**	**-0.2**
Americas	1 058	1 201	1 376	1 025	1 018	902	25	22	1.6	0.0
Europe	238	212	190	238	207	146	3	4	-1.4	-2.4
Asia Oceania	149	185	219	141	168	141	4	3	4.3	2.6
Non-OECD	**2 469**	**3 118**	**3 832**	**2 367**	**2 687**	**2 884**	**68**	**71**	**2.0**	**0.9**
E. Europe/Eurasia	931	1 129	1 295	905	922	931	23	23	1.3	0.1
Asia	511	638	796	508	638	792	14	19	2.2	2.2
Middle East	611	773	960	566	617	602	17	15	2.1	0.4
Africa	218	318	445	209	307	354	8	9	2.9	2.1
Latin America	199	261	335	178	203	205	6	5	2.5	0.7
World	**3 914**	**4 716**	**5 617**	**3 770**	**4 079**	**4 073**	**100**	**100**	**1.8**	**0.5**
Unconventional gas	*989*	*1 448*	*1 857*	*971*	*1 244*	*1 306*	*33*	*32*	*4.1*	*2.7*
Coal production (Mtce)										
OECD	**1 391**	**1 463**	**1 505**	**1 134**	**692**	**627**	**19**	**18**	**0.4**	**-2.8**
Americas	737	743	712	572	309	314	9	9	-0.2	-3.1
Europe	192	137	128	177	76	43	2	1	-2.2	-6.1
Asia Oceania	462	582	665	385	306	269	8	8	2.1	-1.3
Non-OECD	**4 648**	**5 595**	**6 521**	**4 226**	**3 436**	**2 938**	**81**	**82**	**1.5**	**-1.5**
E. Europe/Eurasia	452	517	560	412	285	215	7	6	0.9	-2.6
Asia	3 853	4 631	5 414	3 513	2 891	2 514	67	71	1.5	-1.3
Middle East	1	1	1	1	1	1	0	0	0.5	-1.8
Africa	230	287	361	210	180	157	4	4	1.9	-1.2
Latin America	112	159	186	90	78	51	2	1	2.9	-1.9
World	**6 040**	**7 058**	**8 026**	**5 360**	**4 128**	**3 565**	**100**	**100**	**1.3**	**-1.7**
Steam coal	*4 784*	*5 812*	*6 835*	*4 175*	*3 198*	*2 813*	*85*	*79*	*1.6*	*-1.7*
Coking coal	*941*	*920*	*851*	*903*	*751*	*601*	*11*	*17*	*-0.4*	*-1.7*

World: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**8 772**	**13 559**	**14 743**	**15 503**	**16 349**	**17 166**	**17 934**	**100**	**100**	**1.0**
Coal	2 221	3 929	4 033	4 112	4 219	4 322	4 414	29	25	0.4
Oil	3 237	4 219	4 461	4 540	4 612	4 675	4 735	31	26	0.4
Gas	1 662	2 901	3 178	3 422	3 691	3 977	4 239	21	24	1.4
Nuclear	526	646	831	923	1 042	1 127	1 201	5	7	2.3
Hydro	184	326	383	426	467	502	531	2	3	1.8
Bioenergy	905	1 376	1 541	1 639	1 727	1 805	1 878	10	10	1.2
Other renewables	37	161	316	442	591	758	937	1	5	6.7
Power sector	**2 980**	**5 115**	**5 615**	**6 009**	**6 491**	**7 001**	**7 491**	**100**	**100**	**1.4**
Coal	1 218	2 404	2 467	2 499	2 558	2 629	2 704	47	36	0.4
Oil	377	284	228	193	166	153	144	6	2	-2.5
Gas	582	1 172	1 219	1 324	1 437	1 569	1 681	23	22	1.3
Nuclear	526	646	831	923	1 042	1 127	1 201	13	16	2.3
Hydro	184	326	383	426	467	502	531	6	7	1.8
Bioenergy	60	155	225	272	318	371	423	3	6	3.8
Other renewables	33	127	262	373	503	650	807	2	11	7.1
Other energy sector	**904**	**1 687**	**1 754**	**1 803**	**1 866**	**1 923**	**1 962**	**100**	**100**	**0.6**
Electricity	*183*	*331*	*369*	*396*	*429*	*464*	*497*	*20*	*25*	*1.5*
TFC	**6 284**	**9 119**	**10 080**	**10 649**	**11 221**	**11 745**	**12 244**	**100**	**100**	**1.1**
Coal	766	956	1 011	1 041	1 061	1 069	1 074	10	9	0.4
Oil	2 609	3 662	3 959	4 083	4 203	4 301	4 394	40	36	0.7
Gas	944	1 372	1 578	1 710	1 847	1 981	2 105	15	17	1.6
Electricity	834	1 677	1 974	2 194	2 429	2 668	2 897	18	24	2.0
Heat	335	290	301	309	314	316	314	3	3	0.3
Bioenergy	792	1 129	1 202	1 243	1 278	1 303	1 328	12	11	0.6
Other renewables	3	34	54	69	88	108	130	0	1	5.1
Industry	**1 809**	**2 664**	**3 020**	**3 240**	**3 449**	**3 650**	**3 835**	**100**	**100**	**1.4**
Coal	473	768	815	842	866	881	895	29	23	0.6
Oil	328	302	325	328	330	332	332	11	9	0.4
Gas	361	557	671	740	807	877	945	21	25	2.0
Electricity	381	711	846	933	1 018	1 103	1 180	27	31	1.9
Heat	153	131	140	145	147	146	143	5	4	0.3
Bioenergy	113	194	223	249	277	305	330	7	9	2.0
Other renewables	0	1	1	2	4	7	11	0	0	10.0
Transport	**1 575**	**2 547**	**2 809**	**2 965**	**3 116**	**3 250**	**3 408**	**100**	**100**	**1.1**
Oil	1 479	2 357	2 555	2 657	2 751	2 825	2 900	93	85	0.8
Of which: Bunkers	*201*	*352*	*385*	*407*	*435*	*465*	*502*	*14*	*15*	*1.3*
Electricity	21	26	33	39	47	59	77	1	2	4.1
Biofuels	6	65	98	123	146	168	198	3	6	4.2
Other fuels	69	100	123	146	173	199	232	4	7	3.2
Buildings	**2 239**	**3 004**	**3 195**	**3 312**	**3 453**	**3 585**	**3 697**	**100**	**100**	**0.8**
Coal	238	128	123	116	108	101	92	4	2	-1.2
Oil	324	317	298	273	253	239	231	11	6	-1.2
Gas	431	627	670	699	733	760	775	21	21	0.8
Electricity	402	888	1 030	1 148	1 282	1 416	1 544	30	42	2.1
Heat	173	152	156	159	163	166	168	5	5	0.4
Bioenergy	668	861	867	854	835	807	774	29	21	-0.4
Other renewables	3	32	50	64	79	96	114	1	3	4.8
Other	**661**	**905**	**1 056**	**1 133**	**1 203**	**1 259**	**1 304**	**100**	**100**	**1.4**

World: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**15 041**	**17 345**	**19 643**	**14 308**	**14 673**	**15 197**	**100**	**100**	**1.4**	**0.4**
Coal	4 228	4 941	5 618	3 752	2 889	2 495	29	16	1.3	-1.7
Oil	4 539	4 942	5 348	4 356	3 934	3 351	27	22	0.9	-0.8
Gas	3 233	3 878	4 610	3 112	3 349	3 335	23	22	1.7	0.5
Nuclear	827	959	1 036	839	1 267	1 627	5	11	1.8	3.5
Hydro	380	449	507	384	490	588	3	4	1.7	2.2
Bioenergy	1 537	1 702	1 830	1 532	1 933	2 331	9	15	1.1	2.0
Other renewables	296	474	693	332	811	1 470	4	10	5.6	8.5
Power sector	**5 801**	**7 035**	**8 334**	**5 345**	**5 592**	**6 298**	**100**	**100**	**1.8**	**0.8**
Coal	2 639	3 191	3 752	2 213	1 372	1 041	45	17	1.7	-3.1
Oil	231	180	159	210	116	83	2	1	-2.1	-4.4
Gas	1 254	1 556	1 909	1 196	1 265	1 095	23	17	1.8	-0.3
Nuclear	827	959	1 036	839	1 267	1 627	12	26	1.8	3.5
Hydro	380	449	507	384	490	588	6	9	1.7	2.2
Bioenergy	223	297	372	226	386	593	4	9	3.3	5.1
Other renewables	245	403	600	277	696	1 272	7	20	5.9	8.9
Other energy sector	**1 788**	**1 989**	**2 193**	**1 714**	**1 671**	**1 581**	**100**	**100**	**1.0**	**-0.2**
Electricity	*380*	*471*	*566*	*355*	*370*	*396*	*26*	*25*	*2.0*	*0.7*
TFC	**10 229**	**11 771**	**13 230**	**9 862**	**10 306**	**10 551**	**100**	**100**	**1.4**	**0.5**
Coal	1 030	1 121	1 165	994	957	903	9	9	0.7	-0.2
Oil	4 027	4 506	4 979	3 878	3 613	3 139	38	30	1.1	-0.6
Gas	1 589	1 888	2 188	1 541	1 723	1 899	17	18	1.7	1.2
Electricity	2 029	2 588	3 144	1 901	2 184	2 522	24	24	2.4	1.5
Heat	305	331	345	297	290	272	3	3	0.7	-0.2
Bioenergy	1 198	1 266	1 315	1 195	1 423	1 617	10	15	0.6	1.3
Other renewables	51	71	93	55	115	199	1	2	3.8	6.8
Industry	**3 071**	**3 622**	**4 120**	**2 964**	**3 155**	**3 309**	**100**	**100**	**1.6**	**0.8**
Coal	829	913	967	803	786	761	23	23	0.9	-0.0
Oil	330	348	357	320	303	287	9	9	0.6	-0.2
Gas	679	840	1 005	660	729	770	24	23	2.2	1.2
Electricity	864	1 072	1 271	821	915	1 016	31	31	2.2	1.3
Heat	141	156	161	139	134	118	4	4	0.7	-0.4
Bioenergy	227	290	353	219	274	327	9	10	2.2	2.0
Other renewables	1	3	6	2	14	29	0	1	7.7	14.0
Transport	**2 837**	**3 288**	**3 785**	**2 749**	**2 811**	**2 744**	**100**	**100**	**1.5**	**0.3**
Oil	2 605	2 994	3 396	2 493	2 245	1 771	90	65	1.4	-1.1
Of which: Bunkers	*393*	*468*	*562*	*367*	*356*	*348*	*15*	*13*	*1.8*	*-0.0*
Electricity	32	43	57	33	69	181	2	7	3.0	7.5
Biofuels	90	125	171	98	285	446	5	16	3.6	7.4
Other fuels	110	126	161	124	212	347	4	13	1.8	4.7
Buildings	**3 261**	**3 640**	**3 984**	**3 100**	**3 166**	**3 239**	**100**	**100**	**1.1**	**0.3**
Coal	126	118	105	118	88	61	3	2	-0.7	-2.7
Oil	308	284	274	285	218	186	7	6	-0.5	-2.0
Gas	686	786	866	645	649	633	22	20	1.2	0.0
Electricity	1 067	1 385	1 710	985	1 124	1 241	43	38	2.5	1.2
Heat	159	170	180	153	152	150	5	5	0.6	-0.1
Bioenergy	868	831	765	864	839	807	19	25	-0.4	-0.2
Other renewables	47	65	83	51	96	161	2	5	3.6	6.2
Other	**1 061**	**1 221**	**1 342**	**1 050**	**1 174**	**1 259**	**100**	**100**	**1.5**	**1.2**

World: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total generation	**11 826**	**23 318**	**27 222**	**30 090**	**33 214**	**36 394**	**39 444**	**100**	**100**	**2.0**
Coal	4 424	9 612	10 171	10 443	10 867	11 362	11 868	41	30	0.8
Oil	1 311	1 044	836	709	613	566	533	4	1	-2.5
Gas	1 760	5 079	5 798	6 613	7 385	8 228	9 008	22	23	2.1
Nuclear	2 013	2 478	3 186	3 540	3 998	4 325	4 606	11	12	2.3
Hydro	2 145	3 789	4 456	4 951	5 425	5 843	6 180	16	16	1.8
Bioenergy	132	464	728	902	1 074	1 264	1 454	2	4	4.3
Wind	4	635	1 407	1 988	2 535	3 052	3 568	3	9	6.6
Geothermal	36	72	116	162	229	308	392	0	1	6.5
Solar PV	0	139	494	725	976	1 244	1 521	1	4	9.3
CSP	1	5	27	50	96	169	262	0	1	15.4
Marine	1	1	3	6	16	31	51	0	0	16.0

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total capacity	**5 884**	**7 299**	**8 134**	**8 995**	**9 819**	**10 570**	**100**	**100**	**2.2**
Coal	1 851	2 064	2 161	2 282	2 384	2 468	31	23	1.1
Oil	439	371	327	292	276	258	7	2	-1.9
Gas	1 502	1 883	2 054	2 210	2 373	2 528	26	24	1.9
Nuclear	392	448	482	536	578	614	7	6	1.7
Hydro	1 136	1 341	1 482	1 622	1 743	1 837	19	17	1.8
Bioenergy	108	151	182	212	243	274	2	3	3.5
Wind	304	617	844	1 046	1 217	1 376	5	13	5.8
Geothermal	12	17	24	33	45	56	0	1	6.0
Solar PV	137	397	560	728	900	1 066	2	10	7.9
CSP	4	9	15	28	48	73	0	1	11.4
Marine	1	1	2	6	12	20	0	0	14.3

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total CO_2	**20 579**	**31 646**	**33 080**	**33 906**	**34 837**	**35 772**	**36 673**	**100**	**100**	**0.5**
Coal	8 398	14 413	14 712	14 860	15 068	15 242	15 419	46	42	0.3
Oil	8 505	10 775	11 261	11 386	11 516	11 652	11 814	34	32	0.3
Gas	3 677	6 458	7 108	7 660	8 253	8 879	9 440	20	26	1.4
Power sector	**7 579**	**13 441**	**13 618**	**13 834**	**14 172**	**14 623**	**15 060**	**100**	**100**	**0.4**
Coal	5 001	9 781	10 023	10 105	10 264	10 453	10 656	73	71	0.3
Oil	1 212	901	722	612	526	484	456	7	3	-2.5
Gas	1 367	2 760	2 872	3 117	3 381	3 686	3 948	21	26	1.3
TFC	**12 036**	**16 567**	**17 696**	**18 295**	**18 876**	**19 346**	**19 794**	**100**	**100**	**0.7**
Coal	3 254	4 251	4 353	4 421	4 472	4 465	4 446	26	22	0.2
Oil	6 775	9 317	9 932	10 182	10 413	10 603	10 802	56	55	0.5
Transport	*4 431*	*7 097*	*7 693*	*8 004*	*8 289*	*8 517*	*8 747*	*43*	*44*	*0.8*
Of which: Bunkers	*630*	*1 102*	*1 199*	*1 266*	*1 348*	*1 440*	*1 553*	*7*	*8*	*1.3*
Gas	2 008	2 999	3 411	3 692	3 991	4 278	4 547	18	23	1.6

World: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**27 988**	**35 545**	**43 120**	**26 206**	**29 682**	**33 910**	**100**	**100**	**2.3**	**1.4**
Coal	10 918	13 690	16 534	9 185	5 776	4 107	38	12	2.0	-3.1
Oil	849	669	590	760	403	279	1	1	-2.1	-4.8
Gas	6 006	8 236	10 534	5 658	6 451	5 465	24	16	2.7	0.3
Nuclear	3 174	3 679	3 974	3 218	4 861	6 243	9	18	1.8	3.5
Hydro	4 423	5 221	5 902	4 464	5 699	6 836	14	20	1.7	2.2
Bioenergy	717	993	1 258	732	1 318	2 077	3	6	3.8	5.7
Wind	1 319	2 056	2 778	1 507	3 325	5 101	6	15	5.6	8.0
Geothermal	110	189	299	119	314	541	1	2	5.4	7.8
Solar PV	446	739	1 066	529	1 297	2 232	2	7	7.8	10.8
CSP	25	64	147	32	218	937	0	3	13.0	21.0
Marine	3	10	37	3	21	93	0	0	14.6	18.6

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**7 355**	**9 088**	**10 640**	**7 236**	**8 925**	**10 797**	**100**	**100**	**2.2**	**2.3**
Coal	2 168	2 638	3 063	1 997	1 534	1 253	29	12	1.9	-1.4
Oil	371	300	271	363	266	216	3	2	-1.8	-2.6
Gas	1 922	2 425	2 833	1 813	2 107	2 273	27	21	2.4	1.5
Nuclear	447	493	528	455	654	837	5	8	1.1	2.8
Hydro	1 330	1 552	1 745	1 344	1 713	2 042	16	19	1.6	2.2
Bioenergy	149	196	238	152	254	378	2	3	3.0	4.8
Wind	582	864	1 090	662	1 343	1 908	10	18	4.8	7.0
Geothermal	17	28	43	18	46	78	0	1	5.0	7.3
Solar PV	361	569	773	420	938	1 519	7	14	6.6	9.3
CSP	8	20	40	10	61	256	0	2	9.0	16.8
Marine	1	4	14	1	8	36	0	0	12.9	16.8

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**34 209**	**39 153**	**44 141**	**31 458**	**24 872**	**18 777**	**100**	**100**	**1.2**	**-1.9**
Coal	15 488	17 962	20 191	13 562	8 219	4 564	46	24	1.3	-4.2
Oil	11 488	12 509	13 671	10 948	9 459	7 574	31	40	0.9	-1.3
Gas	7 233	8 682	10 278	6 948	7 194	6 639	23	35	1.7	0.1
Power sector	**14 404**	**17 114**	**19 992**	**12 467**	**7 601**	**3 968**	**100**	**100**	**1.5**	**-4.4**
Coal	10 715	12 881	15 000	8 983	4 368	1 536	75	39	1.6	-6.6
Oil	733	571	502	666	368	264	3	7	-2.1	-4.4
Gas	2 955	3 662	4 490	2 818	2 866	2 168	22	55	1.8	-0.9
TFC	**18 005**	**20 129**	**22 106**	**17 272**	**15 828**	**13 646**	**100**	**100**	**1.1**	**-0.7**
Coal	4 431	4 726	4 832	4 257	3 601	2 834	22	21	0.5	-1.5
Oil	10 138	11 321	12 540	9 691	8 636	6 979	57	51	1.1	-1.1
Transport	*7 845*	*9 024*	*10 242*	*7 510*	*6 770*	*5 354*	*46*	*39*	*1.4*	*-1.0*
Of which: Bunkers	*1 222*	*1 453*	*1 743*	*1 145*	*1 111*	*1 088*	*8*	*8*	*1.7*	*-0.0*
Gas	3 436	4 082	4 734	3 324	3 590	3 834	21	28	1.7	0.9

OECD: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**4 525**	**5 324**	**5 344**	**5 264**	**5 210**	**5 175**	**5 167**	**100**	**100**	**-0.1**
Coal	1 080	1 029	915	827	734	658	615	19	12	-1.9
Oil	1 873	1 908	1 802	1 682	1 561	1 445	1 342	36	26	-1.3
Gas	843	1 372	1 412	1 444	1 475	1 517	1 549	26	30	0.4
Nuclear	451	511	580	580	608	627	635	10	12	0.8
Hydro	102	122	130	135	139	142	144	2	3	0.6
Bioenergy	147	294	347	380	412	443	476	6	9	1.8
Other renewables	29	87	158	216	281	345	406	2	8	5.9
Power sector	**1 719**	**2 191**	**2 181**	**2 179**	**2 205**	**2 245**	**2 298**	**100**	**100**	**0.2**
Coal	759	823	705	627	543	475	440	38	19	-2.3
Oil	154	76	35	23	18	15	12	3	1	-6.6
Gas	176	484	475	496	513	538	559	22	24	0.5
Nuclear	451	511	580	580	608	627	635	23	28	0.8
Hydro	102	122	130	135	139	142	144	6	6	0.6
Bioenergy	53	97	113	125	136	148	159	4	7	1.8
Other renewables	26	78	142	193	249	301	349	4	15	5.7
Other energy sector	**405**	**502**	**517**	**508**	**501**	**496**	**493**	**100**	**100**	**-0.1**
Electricity	*106*	*125*	*125*	*125*	*126*	*128*	*131*	*25*	*27*	*0.2*
TFC	**3 107**	**3 633**	**3 690**	**3 649**	**3 605**	**3 567**	**3 546**	**100**	**100**	**-0.1**
Coal	234	119	119	112	105	98	91	3	3	-1.0
Oil	1 592	1 701	1 646	1 550	1 449	1 352	1 264	47	36	-1.1
Gas	589	746	772	777	783	789	791	21	22	0.2
Electricity	552	804	845	872	899	929	963	22	27	0.7
Heat	43	58	61	62	63	64	65	2	2	0.4
Bioenergy	94	195	231	253	273	293	314	5	9	1.8
Other renewables	3	9	16	23	32	43	57	0	2	7.0
Industry	**828**	**810**	**846**	**843**	**832**	**825**	**823**	**100**	**100**	**0.1**
Coal	160	96	97	93	87	81	76	12	9	-0.9
Oil	168	99	95	90	85	80	77	12	9	-0.9
Gas	226	262	279	277	272	269	268	32	33	0.1
Electricity	222	255	270	275	276	279	284	32	35	0.4
Heat	15	23	22	21	21	20	19	3	2	-0.6
Bioenergy	37	75	82	86	90	93	96	9	12	0.9
Other renewables	0	1	1	1	2	2	3	0	0	6.0
Transport	**941**	**1 194**	**1 175**	**1 126**	**1 078**	**1 036**	**1 012**	**100**	**100**	**-0.6**
Oil	914	1 112	1 067	999	930	864	804	93	79	-1.2
Electricity	8	9	11	13	16	22	33	1	3	4.9
Biofuels	0	44	62	73	82	92	104	4	10	3.2
Other fuels	19	29	35	41	50	59	71	2	7	3.4
Buildings	**985**	**1 240**	**1 256**	**1 270**	**1 290**	**1 310**	**1 326**	**100**	**100**	**0.2**
Coal	69	19	18	16	14	13	12	1	1	-1.7
Oil	208	146	124	104	83	66	54	12	4	-3.6
Gas	304	430	427	427	430	430	422	35	32	-0.1
Electricity	316	529	553	573	596	617	634	43	48	0.7
Heat	27	35	39	41	42	44	45	3	3	0.9
Bioenergy	56	74	82	89	96	102	108	6	8	1.4
Other renewables	3	8	14	20	28	39	51	1	4	7.1
Other	**354**	**388**	**413**	**411**	**405**	**396**	**385**	**100**	**100**	**-0.0**

OECD: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2013-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
TPED	**5 468**	**5 555**	**5 675**	**5 193**	**4 758**	**4 531**	**100**	**100**	**0.2**	**-0.6**
Coal	989	953	902	807	432	366	16	8	-0.5	-3.8
Oil	1 837	1 689	1 549	1 774	1 331	908	27	20	-0.8	-2.7
Gas	1 445	1 594	1 760	1 395	1 331	1 123	31	25	0.9	-0.7
Nuclear	578	559	555	580	659	748	10	17	0.3	1.4
Hydro	129	137	142	130	142	151	3	3	0.6	0.8
Bioenergy	341	395	454	345	513	653	8	14	1.6	3.0
Other renewables	149	227	312	162	349	581	6	13	4.8	7.3
Power sector	**2 260**	**2 380**	**2 515**	**2 092**	**1 997**	**2 118**	**100**	**100**	**0.5**	**-0.1**
Coal	778	753	709	605	264	229	28	11	-0.5	-4.6
Oil	36	19	14	35	15	8	1	0	-6.1	-8.0
Gas	491	577	666	483	459	298	26	14	1.2	-1.8
Nuclear	578	559	555	580	659	748	22	35	0.3	1.4
Hydro	129	137	142	130	142	151	6	7	0.6	0.8
Bioenergy	113	131	151	114	152	196	6	9	1.7	2.6
Other renewables	135	203	277	146	305	487	11	23	4.8	7.0
Other energy sector	**527**	**541**	**567**	**505**	**443**	**377**	**100**	**100**	**0.5**	**-1.1**
Electricity	*128*	*138*	*148*	*120*	*113*	*112*	*26*	*30*	*0.6*	*-0.4*
TFC	**3 756**	**3 813**	**3 873**	**3 609**	**3 337**	**3 101**	**100**	**100**	**0.2**	**-0.6**
Coal	120	109	98	115	94	75	3	2	-0.7	-1.7
Oil	1 678	1 570	1 465	1 621	1 236	858	38	28	-0.6	-2.5
Gas	786	821	856	749	710	675	22	22	0.5	-0.4
Electricity	869	961	1 049	819	838	891	27	29	1.0	0.4
Heat	63	67	72	60	58	55	2	2	0.8	-0.2
Bioenergy	226	261	299	229	358	454	8	15	1.6	3.2
Other renewables	15	24	35	17	44	94	1	3	5.1	9.0
Industry	**858**	**866**	**868**	**829**	**771**	**726**	**100**	**100**	**0.3**	**-0.4**
Coal	98	89	79	94	78	62	9	9	-0.7	-1.6
Oil	97	88	80	94	80	70	9	10	-0.8	-1.3
Gas	283	284	283	275	247	219	33	30	0.3	-0.7
Electricity	275	288	300	263	254	256	35	35	0.6	0.0
Heat	22	21	20	22	19	15	2	2	-0.5	-1.4
Bioenergy	83	95	105	80	89	95	12	13	1.3	0.9
Other renewables	1	1	2	1	4	8	0	1	4.9	10.0
Transport	**1 192**	**1 159**	**1 151**	**1 157**	**984**	**823**	**100**	**100**	**-0.1**	**-1.4**
Oil	1 090	1 029	978	1 049	743	432	85	53	-0.5	-3.4
Electricity	11	14	18	11	30	94	2	11	2.7	9.1
Biofuels	58	74	96	62	154	205	8	25	2.9	5.8
Other fuels	33	42	58	35	57	92	5	11	2.6	4.4
Buildings	**1 292**	**1 381**	**1 466**	**1 211**	**1 184**	**1 176**	**100**	**100**	**0.6**	**-0.2**
Coal	18	17	16	17	12	9	1	1	-0.6	-2.7
Oil	129	101	74	118	69	37	5	3	-2.5	-4.9
Gas	438	464	484	408	375	335	33	28	0.4	-0.9
Electricity	573	647	718	534	544	531	49	45	1.1	0.0
Heat	40	46	52	37	39	39	4	3	1.5	0.4
Bioenergy	80	86	92	82	108	144	6	12	0.8	2.5
Other renewables	13	21	31	14	37	82	2	7	5.2	9.0
Other	**414**	**407**	**388**	**412**	**398**	**376**	**100**	**100**	**-0.0**	**-0.1**

OECD: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total generation	**7 629**	**10 786**	**11 262**	**11 583**	**11 914**	**12 285**	**12 706**	**100**	**100**	**0.6**
Coal	3 092	3 525	3 090	2 763	2 400	2 128	1 984	33	16	-2.1
Oil	686	329	148	98	76	63	48	3	0	-6.9
Gas	782	2 632	2 728	2 918	3 049	3 216	3 387	24	27	0.9
Nuclear	1 729	1 962	2 227	2 224	2 332	2 405	2 436	18	19	0.8
Hydro	1 182	1 413	1 510	1 569	1 611	1 646	1 675	13	13	0.6
Bioenergy	124	319	389	434	481	526	567	3	4	2.1
Wind	4	439	793	1 090	1 353	1 558	1 730	4	14	5.2
Geothermal	29	46	70	94	129	164	193	0	2	5.5
Solar PV	0	115	287	360	429	495	558	1	4	6.0
CSP	1	5	18	27	39	56	79	0	1	10.4
Marine	1	1	3	6	15	29	48	0	0	15.7

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total capacity	**2 875**	**3 163**	**3 326**	**3 472**	**3 596**	**3 712**	**100**	**100**	**1.0**
Coal	639	566	523	486	442	412	22	11	-1.6
Oil	201	120	89	72	63	53	7	1	-4.8
Gas	865	1 001	1 060	1 080	1 110	1 147	30	31	1.1
Nuclear	315	314	301	310	319	322	11	9	0.1
Hydro	470	496	511	523	533	542	16	15	0.5
Bioenergy	69	79	87	95	102	109	2	3	1.7
Wind	193	328	437	530	594	644	7	17	4.6
Geothermal	8	10	14	18	23	27	0	1	4.9
Solar PV	112	241	294	340	381	415	4	11	5.0
CSP	4	6	8	11	16	22	0	1	6.9
Marine	1	1	2	6	11	18	0	0	14.1

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total CO_2	**10 962**	**11 934**	**11 193**	**10 554**	**9 885**	**9 313**	**8 898**	**100**	**100**	**-1.1**
Coal	4 240	4 040	3 560	3 199	2 795	2 440	2 219	34	25	-2.2
Oil	4 841	4 741	4 405	4 057	3 734	3 438	3 183	40	36	-1.5
Gas	1 881	3 153	3 228	3 298	3 356	3 435	3 496	26	39	0.4
Power sector	**4 042**	**4 797**	**4 163**	**3 843**	**3 497**	**3 229**	**3 082**	**100**	**100**	**-1.6**
Coal	3 135	3 415	2 928	2 598	2 230	1 916	1 731	71	56	-2.5
Oil	494	243	114	75	59	49	38	5	1	-6.6
Gas	413	1 139	1 121	1 170	1 208	1 265	1 313	24	43	0.5
TFC	**6 350**	**6 415**	**6 237**	**5 934**	**5 627**	**5 338**	**5 081**	**100**	**100**	**-0.9**
Coal	1 039	527	523	495	463	430	400	8	8	-1.0
Oil	4 012	4 207	3 991	3 705	3 416	3 147	2 913	66	57	-1.4
Transport	*2 709*	*3 316*	*3 179*	*2 977*	*2 772*	*2 575*	*2 397*	*52*	*47*	*-1.2*
Gas	1 299	1 681	1 722	1 734	1 748	1 762	1 768	26	35	0.2

OECD: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**11 593**	**12 768**	**13 899**	**10 908**	**11 048**	**11 648**	**100**	**100**	**0.9**	**0.3**
Coal	3 398	3 392	3 308	2 646	1 133	963	24	8	-0.2	-4.7
Oil	151	81	56	145	61	32	0	0	-6.3	-8.3
Gas	2 832	3 500	4 130	2 787	2 717	1 655	30	14	1.7	-1.7
Nuclear	2 217	2 146	2 131	2 226	2 527	2 872	15	25	0.3	1.4
Hydro	1 504	1 592	1 652	1 509	1 656	1 757	12	15	0.6	0.8
Bioenergy	385	458	528	390	548	722	4	6	1.9	3.1
Wind	746	1 078	1 379	815	1 623	2 310	10	20	4.3	6.3
Geothermal	67	108	154	71	147	237	1	2	4.6	6.3
Solar PV	274	371	467	297	529	778	3	7	5.3	7.3
CSP	18	32	61	19	89	237	0	2	9.4	15.0
Marine	3	10	35	3	19	84	0	1	14.4	18.2

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**3 196**	**3 496**	**3 743**	**3 143**	**3 511**	**3 933**	**100**	**100**	**1.0**	**1.2**
Coal	601	576	551	565	339	246	15	6	-0.5	-3.5
Oil	121	75	59	120	70	47	2	1	-4.4	-5.2
Gas	1 032	1 197	1 292	965	1 040	1 041	35	26	1.5	0.7
Nuclear	313	285	280	316	339	382	7	10	-0.4	0.7
Hydro	494	517	534	496	541	571	14	15	0.5	0.7
Bioenergy	78	90	101	79	107	138	3	4	1.4	2.6
Wind	310	428	518	335	620	831	14	21	3.7	5.6
Geothermal	10	15	22	10	21	34	1	1	4.0	5.7
Solar PV	231	300	355	248	404	550	9	14	4.4	6.1
CSP	6	10	17	6	24	62	0	2	5.9	11.1
Marine	1	4	13	1	7	32	0	1	12.7	16.5

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**11 669**	**11 422**	**11 127**	**10 625**	**7 018**	**4 547**	**100**	**100**	**-0.3**	**-3.5**
Coal	3 857	3 667	3 328	3 119	1 102	513	30	11	-0.7	-7.4
Oil	4 506	4 124	3 825	4 319	3 033	1 843	34	41	-0.8	-3.4
Gas	3 306	3 630	3 974	3 186	2 883	2 191	36	48	0.9	-1.3
Power sector	**4 494**	**4 503**	**4 420**	**3 763**	**1 709**	**739**	**100**	**100**	**-0.3**	**-6.7**
Coal	3 219	3 083	2 810	2 511	655	221	64	30	-0.7	-9.6
Oil	116	62	45	112	49	26	1	3	-6.1	-8.0
Gas	1 159	1 358	1 565	1 140	1 005	493	35	67	1.2	-3.1
TFC	**6 369**	**6 098**	**5 859**	**6 087**	**4 694**	**3 356**	**100**	**100**	**-0.3**	**-2.4**
Coal	530	481	428	505	370	241	7	7	-0.8	-2.9
Oil	4 085	3 781	3 514	3 914	2 780	1 686	60	50	-0.7	-3.3
Transport	*3 249*	*3 068*	*2 916*	*3 125*	*2 214*	*1 288*	*50*	*38*	*-0.5*	*-3.4*
Gas	1 754	1 836	1 917	1 668	1 545	1 429	33	43	0.5	-0.6

OECD Americas: New Policies Scenario

	Energy demand (Mtoe)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
TPED	**2 262**	**2 694**	**2 749**	**2 721**	**2 707**	**2 713**	**2 746**	**100**	**100**	**0.1**
Coal	491	469	404	374	335	309	305	17	11	-1.6
Oil	922	997	989	938	881	822	767	37	28	-1.0
Gas	517	762	826	835	857	893	930	28	34	0.7
Nuclear	180	244	252	251	262	269	275	9	10	0.4
Hydro	52	61	66	69	71	72	73	2	3	0.7
Bioenergy	82	130	152	167	183	199	218	5	8	1.9
Other renewables	19	31	60	87	117	148	178	1	6	6.7
Power sector	**852**	**1 070**	**1 061**	**1 058**	**1 070**	**1 097**	**1 141**	**100**	**100**	**0.2**
Coal	419	428	362	333	293	265	258	40	23	-1.9
Oil	47	24	14	9	7	6	4	2	0	-6.5
Gas	95	255	275	276	287	304	323	24	28	0.9
Nuclear	180	244	252	251	262	269	275	23	24	0.4
Hydro	52	61	66	69	71	72	73	6	6	0.7
Bioenergy	41	29	35	39	43	49	54	3	5	2.4
Other renewables	19	29	56	80	106	131	154	3	14	6.4
Other energy sector	**194**	**260**	**278**	**278**	**279**	**284**	**292**	**100**	**100**	**0.4**
Electricity	*56*	*64*	*65*	*65*	*66*	*67*	*70*	*25*	*24*	*0.3*
TFC	**1 548**	**1 834**	**1 901**	**1 887**	**1 874**	**1 866**	**1 874**	**100**	**100**	**0.1**
Coal	61	31	31	30	29	28	27	2	1	-0.5
Oil	809	905	907	865	818	769	724	49	39	-0.8
Gas	361	396	422	425	431	439	448	22	24	0.5
Electricity	272	393	415	426	441	459	483	21	26	0.8
Heat	3	7	6	6	5	5	5	0	0	-1.2
Bioenergy	41	101	116	127	139	150	163	5	9	1.8
Other renewables	0	2	4	7	11	17	24	0	1	9.9
Industry	**361**	**364**	**393**	**396**	**397**	**401**	**407**	**100**	**100**	**0.4**
Coal	51	30	30	29	28	27	26	8	6	-0.5
Oil	60	38	38	38	37	36	36	11	9	-0.3
Gas	138	144	161	161	159	159	160	39	39	0.4
Electricity	94	104	113	115	117	120	124	29	31	0.7
Heat	1	5	5	5	5	4	4	1	1	-0.9
Bioenergy	17	43	46	48	51	53	56	12	14	1.0
Other renewables	0	0	0	0	1	1	1	0	0	8.9
Transport	**562**	**728**	**728**	**699**	**668**	**642**	**630**	**100**	**100**	**-0.5**
Oil	543	673	660	620	576	531	491	92	78	-1.2
Electricity	1	1	2	3	4	8	17	0	3	10.4
Biofuels	-	30	40	46	52	57	66	4	10	2.9
Other fuels	18	24	26	30	37	45	56	3	9	3.2
Buildings	**461**	**576**	**587**	**595**	**609**	**624**	**638**	**100**	**100**	**0.4**
Coal	10	1	1	0	0	0	0	0	0	-12.5
Oil	64	45	41	37	34	30	27	8	4	-1.9
Gas	184	216	216	215	216	216	214	38	33	-0.0
Electricity	176	284	296	304	315	326	336	49	53	0.6
Heat	2	1	1	1	1	1	1	0	0	-2.4
Bioenergy	24	27	29	31	34	36	39	5	6	1.4
Other renewables	0	2	3	6	10	15	22	0	3	9.7
Other	**164**	**165**	**193**	**198**	**200**	**200**	**198**	**100**	**100**	**0.7**

OECD Americas: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**2 826**	**2 918**	**3 039**	**2 663**	**2 454**	**2 382**	**100**	**100**	**0.4**	**-0.5**
Coal	458	468	453	335	180	196	15	8	-0.1	-3.2
Oil	1 007	957	896	975	743	508	29	21	-0.4	-2.5
Gas	841	905	1 022	824	775	673	34	28	1.1	-0.5
Nuclear	250	251	252	249	276	316	8	13	0.1	1.0
Hydro	66	71	73	66	71	74	2	3	0.7	0.7
Bioenergy	150	178	213	152	252	334	7	14	1.8	3.6
Other renewables	55	89	129	63	157	281	4	12	5.4	8.5
Power sector	**1 116**	**1 185**	**1 258**	**1 005**	**952**	**1 047**	**100**	**100**	**0.6**	**-0.1**
Coal	416	424	400	294	144	161	32	15	-0.2	-3.6
Oil	14	8	4	14	6	3	0	0	-6.0	-7.2
Gas	283	308	359	288	261	178	29	17	1.3	-1.3
Nuclear	250	251	252	249	276	316	20	30	0.1	1.0
Hydro	66	71	73	66	71	74	6	7	0.7	0.7
Bioenergy	35	41	52	35	52	73	4	7	2.2	3.5
Other renewables	52	82	116	59	142	240	9	23	5.2	8.1
Other energy sector	**284**	**306**	**342**	**273**	**246**	**220**	**100**	**100**	**1.0**	**-0.6**
Electricity	*68*	*73*	*79*	*63*	*59*	*60*	*23*	*27*	*0.8*	*-0.3*
TFC	**1 937**	**1 987**	**2 050**	**1 859**	**1 733**	**1 632**	**100**	**100**	**0.4**	**-0.4**
Coal	32	30	28	30	25	21	1	1	-0.4	-1.4
Oil	923	890	850	894	689	479	41	29	-0.2	-2.3
Gas	427	442	472	409	390	376	23	23	0.7	-0.2
Electricity	431	477	523	400	410	451	26	28	1.1	0.5
Heat	7	6	5	6	5	3	0	0	-1.0	-2.4
Bioenergy	115	136	160	116	199	260	8	16	1.7	3.6
Other renewables	3	7	13	4	15	40	1	2	7.3	12.0
Industry	**400**	**414**	**429**	**386**	**366**	**353**	**100**	**100**	**0.6**	**-0.1**
Coal	30	28	27	29	24	20	6	6	-0.4	-1.4
Oil	39	38	37	38	35	32	9	9	-0.2	-0.6
Gas	164	166	169	159	143	127	39	36	0.6	-0.5
Electricity	115	123	131	109	107	111	31	31	0.9	0.3
Heat	5	5	4	5	4	3	1	1	-0.8	-1.8
Bioenergy	47	54	61	45	51	55	14	16	1.3	0.9
Other renewables	0	1	1	0	1	4	0	1	8.9	14.0
Transport	**738**	**720**	**722**	**717**	**615**	**520**	**100**	**100**	**-0.0**	**-1.2**
Oil	673	638	607	649	458	263	84	50	-0.4	-3.4
Electricity	1	2	4	2	12	55	1	10	4.7	15.3
Biofuels	38	49	64	40	104	139	9	27	2.8	5.8
Other fuels	25	31	48	26	41	64	7	12	2.6	3.8
Buildings	**606**	**653**	**699**	**564**	**556**	**565**	**100**	**100**	**0.7**	**-0.1**
Coal	1	1	0	1	0	0	0	0	-3.5	-12.5
Oil	43	41	35	40	28	19	5	3	-0.9	-3.1
Gas	220	227	237	205	187	167	34	30	0.3	-1.0
Electricity	310	346	382	286	288	282	55	50	1.1	-0.0
Heat	1	1	1	1	1	0	0	0	-2.0	-6.9
Bioenergy	28	31	33	29	41	62	5	11	0.8	3.2
Other renewables	3	6	11	3	13	35	2	6	7.0	11.6
Other	**193**	**200**	**199**	**192**	**196**	**194**	**100**	**100**	**0.7**	**0.6**

OECD Americas: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total generation	**3 819**	**5 304**	**5 570**	**5 710**	**5 888**	**6 108**	**6 418**	**100**	**100**	**0.7**
Coal	1 796	1 840	1 592	1 472	1 305	1 193	1 174	35	18	-1.6
Oil	211	98	60	40	34	28	18	2	0	-6.2
Gas	406	1 403	1 606	1 643	1 737	1 859	2 009	26	31	1.3
Nuclear	687	937	968	965	1 006	1 034	1 055	18	16	0.4
Hydro	602	710	769	801	822	839	852	13	13	0.7
Bioenergy	91	91	118	137	157	178	197	2	3	2.9
Wind	3	186	334	473	582	660	729	4	11	5.2
Geothermal	21	24	36	47	65	85	102	0	2	5.4
Solar PV	0	15	79	118	160	203	242	0	4	10.8
CSP	1	1	8	12	17	24	32	0	0	13.6
Marine	0	0	0	1	3	6	8	0	0	26.2

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total capacity	**1 355**	**1 424**	**1 502**	**1 573**	**1 636**	**1 712**	**100**	**100**	**0.9**
Coal	342	272	258	244	235	222	25	13	-1.6
Oil	87	52	39	36	32	27	6	2	-4.3
Gas	500	557	575	583	596	637	37	37	0.9
Nuclear	120	123	122	127	130	132	9	8	0.4
Hydro	195	206	212	218	222	225	14	13	0.5
Bioenergy	22	26	30	33	37	40	2	2	2.3
Wind	70	127	178	217	240	259	5	15	5.0
Geothermal	4	6	7	9	12	14	0	1	4.5
Solar PV	14	52	75	99	123	143	1	8	9.0
CSP	1	3	4	5	7	9	0	1	7.4
Marine	0	0	0	1	2	3	0	0	19.6

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total CO_2	**5 491**	**6 161**	**5 959**	**5 691**	**5 401**	**5 184**	**5 065**	**100**	**100**	**-0.7**
Coal	1 957	1 867	1 600	1 480	1 309	1 182	1 131	30	22	-1.8
Oil	2 370	2 548	2 483	2 319	2 158	2 000	1 857	41	37	-1.2
Gas	1 163	1 746	1 875	1 892	1 934	2 002	2 077	28	41	0.6
Power sector	**2 051**	**2 400**	**2 146**	**2 015**	**1 869**	**1 786**	**1 775**	**100**	**100**	**-1.1**
Coal	1 676	1 721	1 453	1 338	1 172	1 050	1 003	72	57	-2.0
Oil	151	79	46	29	24	20	13	3	1	-6.5
Gas	223	600	647	648	673	715	758	25	43	0.9
TFC	**3 109**	**3 331**	**3 325**	**3 190**	**3 051**	**2 917**	**2 804**	**100**	**100**	**-0.6**
Coal	277	135	135	130	125	120	116	4	4	-0.6
Oil	2 031	2 315	2 265	2 128	1 981	1 835	1 704	69	61	-1.1
Transport	*1 602*	*1 994*	*1 956*	*1 836*	*1 705*	*1 574*	*1 456*	*60*	*52*	*-1.2*
Gas	801	882	925	931	945	962	984	26	35	0.4

OECD Americas: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**5 793**	**6 386**	**6 991**	**5 375**	**5 444**	**5 934**	**100**	**100**	**1.0**	**0.4**
Coal	1 816	1 905	1 854	1 300	649	727	27	12	0.0	-3.4
Oil	62	37	20	58	25	14	0	0	-5.6	-7.0
Gas	1 653	1 893	2 278	1 695	1 592	1 058	33	18	1.8	-1.0
Nuclear	958	963	969	957	1 060	1 213	14	20	0.1	1.0
Hydro	771	822	852	767	824	865	12	15	0.7	0.7
Bioenergy	115	145	178	120	195	287	3	5	2.5	4.4
Wind	300	419	538	348	734	1 071	8	18	4.0	6.7
Geothermal	34	56	82	37	75	123	1	2	4.6	6.1
Solar PV	75	131	187	85	227	396	3	7	9.8	12.9
CSP	8	14	25	10	59	166	0	3	12.6	20.8
Marine	0	2	7	0	3	15	0	0	25.3	29.3

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**1 453**	**1 593**	**1 708**	**1 425**	**1 603**	**1 857**	**100**	**100**	**0.9**	**1.2**
Coal	301	304	296	279	159	136	17	7	-0.5	-3.4
Oil	53	38	30	52	34	25	2	1	-3.9	-4.5
Gas	574	631	679	541	580	589	40	32	1.1	0.6
Nuclear	122	121	122	124	136	155	7	8	0.0	0.9
Hydro	206	217	225	206	219	230	13	12	0.5	0.6
Bioenergy	26	31	36	26	41	58	2	3	1.8	3.7
Wind	114	154	186	131	268	370	11	20	3.7	6.4
Geothermal	5	8	12	6	11	17	1	1	3.7	5.2
Solar PV	50	84	114	56	137	229	7	12	8.1	10.9
CSP	3	5	7	3	16	43	0	2	6.5	13.6
Marine	0	1	2	0	1	5	0	0	18.7	22.4

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**6 257**	**6 247**	**6 212**	**5 628**	**3 678**	**2 461**	**100**	**100**	**0.0**	**-3.3**
Coal	1 813	1 822	1 682	1 320	307	159	27	6	-0.4	-8.7
Oil	2 535	2 387	2 255	2 441	1 735	1 054	36	43	-0.5	-3.2
Gas	1 909	2 039	2 274	1 867	1 636	1 249	37	51	1.0	-1.2
Power sector	**2 377**	**2 430**	**2 406**	**1 900**	**783**	**375**	**100**	**100**	**0.0**	**-6.6**
Coal	1 665	1 681	1 551	1 177	209	99	64	26	-0.4	-10.0
Oil	48	26	15	45	19	10	1	3	-6.0	-7.2
Gas	664	722	841	677	555	265	35	71	1.3	-3.0
TFC	**3 386**	**3 294**	**3 235**	**3 250**	**2 511**	**1 794**	**100**	**100**	**-0.1**	**-2.3**
Coal	137	128	120	131	91	55	4	3	-0.4	-3.3
Oil	2 312	2 194	2 078	2 226	1 599	970	64	54	-0.4	-3.2
Transport	*1 992*	*1 889*	*1 798*	*1 923*	*1 356*	*778*	*56*	*43*	*-0.4*	*-3.4*
Gas	937	971	1 037	893	822	769	32	43	0.6	-0.5

United States: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**1 915**	**2 185**	**2 221**	**2 179**	**2 143**	**2 123**	**2 125**	**100**	**100**	**-0.1**
Coal	460	432	368	339	305	281	278	20	13	-1.6
Oil	757	782	782	739	686	631	579	36	27	-1.1
Gas	438	610	658	656	665	682	699	28	33	0.5
Nuclear	159	214	227	229	236	243	246	10	12	0.5
Hydro	23	23	25	26	27	28	28	1	1	0.7
Bioenergy	62	97	112	123	135	147	161	4	8	1.9
Other renewables	15	26	48	67	89	112	133	1	6	6.2
Power sector	**750**	**896**	**883**	**874**	**876**	**888**	**915**	**100**	**100**	**0.1**
Coal	396	397	333	306	272	247	242	44	26	-1.8
Oil	27	9	5	4	4	3	2	1	0	-5.2
Gas	90	207	225	222	230	239	250	23	27	0.7
Nuclear	159	214	227	229	236	243	246	24	27	0.5
Hydro	23	23	25	26	27	28	28	3	3	0.7
Bioenergy	40	22	24	26	28	31	34	2	4	1.8
Other renewables	14	24	44	61	79	96	112	3	12	5.8
Other energy sector	**150**	**193**	**206**	**200**	**195**	**191**	**188**	**100**	**100**	**-0.1**
Electricity	*49*	*48*	*49*	*48*	*48*	*49*	*50*	*25*	*26*	*0.1*
TFC	**1 294**	**1 480**	**1 531**	**1 510**	**1 486**	**1 467**	**1 463**	**100**	**100**	**-0.0**
Coal	56	22	23	21	20	19	18	2	1	-0.8
Oil	683	725	727	689	642	594	550	49	38	-1.0
Gas	303	325	344	344	347	352	359	22	25	0.4
Electricity	226	325	341	347	356	367	384	22	26	0.6
Heat	2	6	6	5	5	4	4	0	0	-1.3
Bioenergy	23	76	88	97	106	115	127	5	9	1.9
Other renewables	0	2	3	6	10	15	22	0	1	10.0
Industry	**284**	**261**	**282**	**281**	**277**	**276**	**279**	**100**	**100**	**0.2**
Coal	46	22	22	21	20	19	18	8	6	-0.7
Oil	44	22	22	21	21	20	20	8	7	-0.2
Gas	110	107	121	119	116	115	114	41	41	0.2
Electricity	75	73	79	80	80	81	82	28	30	0.5
Heat	-	5	5	4	4	4	4	2	1	-1.0
Bioenergy	9	33	34	35	36	38	39	13	14	0.7
Other renewables	-	0	0	0	0	1	1	0	0	8.3
Transport	**488**	**608**	**610**	**583**	**553**	**528**	**516**	**100**	**100**	**-0.6**
Oil	472	558	548	510	467	424	385	92	75	-1.4
Electricity	0	1	1	2	3	7	16	0	3	12.8
Biofuels	-	28	38	43	49	54	62	5	12	2.9
Other fuels	15	21	23	27	34	41	52	3	10	3.5
Buildings	**389**	**485**	**490**	**494**	**503**	**512**	**521**	**100**	**100**	**0.3**
Coal	10	1	1	0	0	0	-	0	-	-100.0
Oil	48	30	26	23	20	17	14	6	3	-2.7
Gas	164	189	186	184	184	183	180	39	34	-0.2
Electricity	152	249	258	263	270	277	283	51	54	0.5
Heat	2	1	1	1	1	1	1	0	0	-2.4
Bioenergy	14	13	15	17	19	21	22	3	4	2.0
Other renewables	0	2	3	6	9	14	20	0	4	10.0
Other	**133**	**126**	**149**	**152**	**152**	**151**	**148**	**100**	**100**	**0.6**

United States: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**2 287**	**2 324**	**2 364**	**2 144**	**1 934**	**1 853**	**100**	**100**	**0.3**	**-0.6**
Coal	421	429	411	303	164	182	17	10	-0.2	-3.2
Oil	793	750	689	769	572	376	29	20	-0.5	-2.7
Gas	669	694	753	661	609	512	32	28	0.8	-0.6
Nuclear	224	225	225	224	248	284	10	15	0.2	1.0
Hydro	25	26	28	25	28	30	1	2	0.6	0.9
Bioenergy	111	131	159	112	193	252	7	14	1.8	3.6
Other renewables	44	69	100	49	120	218	4	12	5.1	8.2
Power sector	**935**	**982**	**1 020**	**834**	**775**	**847**	**100**	**100**	**0.5**	**-0.2**
Coal	386	393	369	269	136	156	36	18	-0.3	-3.4
Oil	5	4	2	5	3	2	0	0	-5.0	-5.6
Gas	229	243	274	240	217	142	27	17	1.0	-1.4
Nuclear	224	225	225	224	248	284	22	33	0.2	1.0
Hydro	25	26	28	25	28	30	3	4	0.6	0.9
Bioenergy	24	27	34	24	35	51	3	6	1.7	3.2
Other renewables	41	63	89	46	107	183	9	22	4.9	7.7
Other energy sector	**210**	**212**	**216**	**202**	**173**	**148**	**100**	**100**	**0.4**	**-1.0**
Electricity	*51*	*54*	*56*	*47*	*43*	*44*	*26*	*30*	*0.6*	*-0.4*
TFC	**1 560**	**1 580**	**1 610**	**1 494**	**1 369**	**1 271**	**100**	**100**	**0.3**	**-0.6**
Coal	23	21	19	22	18	14	1	1	-0.7	-1.7
Oil	738	702	658	715	533	355	41	28	-0.4	-2.6
Gas	348	355	376	332	312	299	23	23	0.5	-0.3
Electricity	355	387	417	328	332	364	26	29	0.9	0.4
Heat	6	5	4	6	4	3	0	0	-1.0	-2.5
Bioenergy	87	104	125	88	157	201	8	16	1.9	3.7
Other renewables	3	6	11	3	13	35	1	3	7.3	11.9
Industry	**288**	**290**	**293**	**277**	**256**	**242**	**100**	**100**	**0.4**	**-0.3**
Coal	22	20	18	22	17	14	6	6	-0.6	-1.6
Oil	22	21	20	22	20	18	7	8	-0.2	-0.6
Gas	123	121	119	119	104	89	41	37	0.4	-0.7
Electricity	81	84	87	76	73	74	30	31	0.7	0.1
Heat	5	4	4	5	4	3	1	1	-0.8	-1.9
Bioenergy	35	39	43	33	37	40	15	16	1.0	0.7
Other renewables	0	1	1	0	1	3	0	1	8.5	13.6
Transport	**615**	**597**	**596**	**599**	**507**	**427**	**100**	**100**	**-0.1**	**-1.3**
Oil	556	521	486	537	366	202	82	47	-0.5	-3.7
Electricity	1	2	3	1	10	50	1	12	6.3	17.6
Biofuels	36	47	62	38	93	116	10	27	2.9	5.3
Other fuels	22	28	44	23	37	60	7	14	2.8	4.0
Buildings	**508**	**541**	**573**	**470**	**457**	**458**	**100**	**100**	**0.6**	**-0.2**
Coal	1	1	0	1	0	-	0	-	-3.7	-100
Oil	28	26	20	26	16	9	4	2	-1.4	-4.2
Gas	189	192	199	176	157	137	35	30	0.2	-1.2
Electricity	272	299	325	249	247	239	57	52	1.0	-0.2
Heat	1	1	1	1	1	0	0	0	-2.1	-7.0
Bioenergy	15	16	18	15	25	42	3	9	1.1	4.3
Other renewables	2	6	10	3	11	31	2	7	7.2	11.7
Other	**149**	**152**	**148**	**148**	**149**	**145**	**100**	**100**	**0.6**	**0.5**

United States: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total generation	**3 203**	**4 283**	**4 467**	**4 538**	**4 638**	**4 768**	**4 981**	**100**	**100**	**0.6**
Coal	1 700	1 712	1 473	1 359	1 212	1 116	1 103	40	22	-1.6
Oil	131	37	23	20	19	15	9	1	0	-4.9
Gas	382	1 158	1 332	1 334	1 394	1 465	1 565	27	31	1.1
Nuclear	612	822	871	879	907	933	946	19	19	0.5
Hydro	273	271	295	305	314	322	329	6	7	0.7
Bioenergy	86	78	90	102	115	128	140	2	3	2.2
Wind	3	170	277	389	474	530	579	4	12	4.7
Geothermal	16	18	27	33	44	59	70	0	1	5.1
Solar PV	0	15	72	105	142	178	209	0	4	10.3
CSP	1	1	8	10	14	19	26	0	1	12.7
Marine	-	-	-	1	2	4	5	-	0	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total capacity	**1 134**	**1 164**	**1 218**	**1 264**	**1 299**	**1 349**	**100**	**100**	**0.6**
Coal	322	252	239	227	219	208	28	15	-1.6
Oil	62	30	23	23	21	19	6	1	-4.2
Gas	448	494	499	495	493	519	40	38	0.5
Nuclear	105	108	109	113	116	117	9	9	0.4
Hydro	102	105	108	110	112	113	9	8	0.4
Bioenergy	17	20	22	25	27	30	2	2	2.1
Wind	60	102	144	174	190	203	5	15	4.6
Geothermal	4	4	5	7	9	10	0	1	4.0
Solar PV	13	46	66	86	105	120	1	9	8.7
CSP	1	3	3	4	6	8	0	1	6.8
Marine	-	-	0	1	1	2	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total CO_2	**4 783**	**5 093**	**4 918**	**4 661**	**4 380**	**4 153**	**4 009**	**100**	**100**	**-0.9**
Coal	1 837	1 705	1 449	1 335	1 185	1 076	1 033	33	26	-1.8
Oil	1 951	1 990	1 952	1 815	1 666	1 517	1 382	39	34	-1.3
Gas	995	1 399	1 517	1 510	1 529	1 561	1 593	27	40	0.5
Power sector	**1 881**	**2 111**	**1 882**	**1 765**	**1 638**	**1 554**	**1 537**	**100**	**100**	**-1.2**
Coal	1 582	1 596	1 338	1 230	1 086	982	944	76	61	-1.9
Oil	88	29	16	13	13	10	7	1	0	-5.2
Gas	211	486	527	522	539	562	587	23	38	0.7
TFC	**2 643**	**2 700**	**2 690**	**2 560**	**2 420**	**2 289**	**2 176**	**100**	**100**	**-0.8**
Coal	253	99	101	95	89	84	80	4	4	-0.8
Oil	1 711	1 852	1 811	1 687	1 545	1 407	1 281	69	59	-1.4
Transport	*1 391*	*1 652*	*1 620*	*1 510*	*1 383*	*1 257*	*1 141*	*61*	*52*	*-1.4*
Gas	679	749	778	778	786	798	815	28	37	0.3

United States: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**4 665**	**5 065**	**5 451**	**4 304**	**4 306**	**4 689**	**100**	**100**	**0.9**	**0.3**
Coal	1 692	1 769	1 710	1 197	613	701	31	15	-0.0	-3.3
Oil	24	20	10	22	14	8	0	0	-4.7	-5.4
Gas	1 361	1 496	1 752	1 437	1 338	859	32	18	1.5	-1.1
Nuclear	861	864	865	860	953	1 088	16	23	0.2	1.0
Hydro	292	307	320	295	324	348	6	7	0.6	0.9
Bioenergy	88	106	127	91	148	222	2	5	1.8	3.9
Wind	247	328	409	290	605	867	8	18	3.3	6.2
Geothermal	25	42	63	27	50	82	1	2	4.7	5.7
Solar PV	68	117	169	78	206	355	3	8	9.5	12.5
CSP	8	13	22	8	54	148	0	3	12.1	20.3
Marine	-	2	4	-	2	12	0	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**1 192**	**1 281**	**1 343**	**1 166**	**1 301**	**1 502**	**100**	**100**	**0.6**	**1.0**
Coal	281	281	271	259	144	127	20	8	-0.6	-3.4
Oil	30	24	21	30	22	18	2	1	-4.0	-4.6
Gas	509	536	551	480	507	504	41	34	0.8	0.4
Nuclear	107	107	107	109	121	138	8	9	0.1	1.0
Hydro	104	108	111	105	113	119	8	8	0.3	0.6
Bioenergy	19	23	26	20	32	46	2	3	1.6	3.7
Wind	91	118	138	107	218	297	10	20	3.1	6.1
Geothermal	4	6	9	4	7	12	1	1	3.6	4.6
Solar PV	44	74	100	50	122	199	7	13	8.0	10.8
CSP	3	4	7	3	14	38	0	3	6.2	13.3
Marine	-	1	1	-	1	4	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**5 184**	**5 111**	**4 958**	**4 620**	**2 873**	**1 849**	**100**	**100**	**-0.1**	**-3.7**
Coal	1 658	1 663	1 532	1 185	250	132	31	7	-0.4	-9.0
Oil	1 986	1 856	1 718	1 914	1 318	758	35	41	-0.5	-3.5
Gas	1 541	1 592	1 708	1 521	1 305	959	34	52	0.7	-1.4
Power sector	**2 101**	**2 143**	**2 086**	**1 659**	**649**	**295**	**100**	**100**	**-0.0**	**-7.0**
Coal	1 545	1 561	1 439	1 078	180	91	69	31	-0.4	-10.1
Oil	17	14	7	16	11	6	0	2	-4.9	-5.6
Gas	539	568	639	565	458	198	31	67	1.0	-3.3
TFC	**2 733**	**2 622**	**2 539**	**2 622**	**1 967**	**1 368**	**100**	**100**	**-0.2**	**-2.5**
Coal	102	92	83	97	64	37	3	3	-0.6	-3.6
Oil	1 843	1 726	1 601	1 776	1 226	703	63	51	-0.5	-3.5
Transport	*1 645*	*1 541*	*1 440*	*1 589*	*1 084*	*597*	*57*	*44*	*-0.5*	*-3.7*
Gas	788	804	854	749	678	628	34	46	0.5	-0.6

OECD Europe: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**1 631**	**1 760**	**1 711**	**1 658**	**1 620**	**1 586**	**1 554**	**100**	**100**	**-0.5**
Coal	452	314	278	236	192	156	134	18	9	-3.1
Oil	616	559	508	463	422	385	354	32	23	-1.7
Gas	260	421	408	430	432	436	434	24	28	0.1
Nuclear	205	229	224	198	205	208	202	13	13	-0.5
Hydro	38	50	52	54	56	57	58	3	4	0.5
Bioenergy	54	141	166	182	196	208	219	8	14	1.6
Other renewables	6	46	74	95	117	136	154	3	10	4.6
Power sector	**627**	**739**	**724**	**708**	**706**	**707**	**708**	**100**	**100**	**-0.2**
Coal	279	230	194	157	120	90	75	31	11	-4.1
Oil	51	16	9	6	5	4	3	2	0	-5.4
Gas	41	118	117	142	148	155	161	16	23	1.1
Nuclear	205	229	224	198	205	208	202	31	29	-0.5
Hydro	38	50	52	54	56	57	58	7	8	0.5
Bioenergy	9	57	64	69	74	78	81	8	11	1.3
Other renewables	4	40	64	82	99	115	129	5	18	4.5
Other energy sector	**152**	**157**	**145**	**135**	**127**	**119**	**112**	**100**	**100**	**-1.2**
Electricity	*39*	*45*	*42*	*42*	*42*	*42*	*42*	*28*	*37*	*-0.2*
TFC	**1 130**	**1 231**	**1 220**	**1 203**	**1 182**	**1 163**	**1 144**	**100**	**100**	**-0.3**
Coal	124	49	48	45	42	39	36	4	3	-1.1
Oil	524	504	465	428	393	361	332	41	29	-1.5
Gas	201	277	269	267	264	261	254	22	22	-0.3
Electricity	193	266	277	286	293	300	306	22	27	0.5
Heat	40	47	49	51	52	53	55	4	5	0.6
Bioenergy	46	82	101	111	120	128	136	7	12	1.9
Other renewables	1	6	10	14	17	21	25	0	2	5.4
Industry	**324**	**285**	**286**	**282**	**274**	**267**	**262**	**100**	**100**	**-0.3**
Coal	71	30	30	29	27	25	23	10	9	-0.9
Oil	59	28	26	25	23	21	20	10	7	-1.3
Gas	78	91	87	85	81	77	75	32	29	-0.7
Electricity	88	98	101	101	100	100	101	34	38	0.1
Heat	14	15	14	14	14	13	13	5	5	-0.6
Bioenergy	14	22	26	28	28	29	29	8	11	1.0
Other renewables	0	0	0	0	1	1	1	0	0	4.9
Transport	**268**	**325**	**316**	**304**	**293**	**283**	**273**	**100**	**100**	**-0.6**
Oil	262	303	282	264	246	230	213	93	78	-1.3
Electricity	5	6	7	8	9	10	12	2	4	2.7
Biofuels	0	13	22	26	30	34	37	4	14	3.9
Other fuels	1	3	5	7	8	9	11	1	4	4.6
Buildings	**404**	**489**	**490**	**492**	**494**	**498**	**497**	**100**	**100**	**0.1**
Coal	49	16	16	14	13	12	11	3	2	-1.5
Oil	96	63	50	37	25	15	9	13	2	-6.9
Gas	105	170	165	165	165	164	158	35	32	-0.3
Electricity	97	158	165	173	180	186	189	32	38	0.7
Heat	25	31	35	37	38	40	41	6	8	1.0
Bioenergy	30	45	51	55	59	62	66	9	13	1.4
Other renewables	1	5	9	12	15	19	23	1	5	5.6
Other	**134**	**132**	**129**	**125**	**121**	**117**	**112**	**100**	**100**	**-0.6**

OECD Europe: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**1 747**	**1 729**	**1 730**	**1 671**	**1 500**	**1 390**	**100**	**100**	**-0.1**	**-0.9**
Coal	291	253	222	252	121	89	13	6	-1.3	-4.6
Oil	521	466	422	499	355	230	24	17	-1.0	-3.2
Gas	425	493	533	401	385	310	31	22	0.9	-1.1
Nuclear	224	179	168	226	225	240	10	17	-1.1	0.2
Hydro	52	54	56	52	57	59	3	4	0.4	0.7
Bioenergy	163	184	203	165	220	263	12	19	1.4	2.3
Other renewables	72	98	126	75	136	199	7	14	3.8	5.6
Power sector	**742**	**755**	**789**	**704**	**663**	**676**	**100**	**100**	**0.2**	**-0.3**
Coal	206	177	156	171	57	41	20	6	-1.4	-6.2
Oil	9	5	5	9	4	2	1	0	-4.5	-7.4
Gas	126	183	218	117	128	80	28	12	2.3	-1.4
Nuclear	224	179	168	226	225	240	21	35	-1.1	0.2
Hydro	52	54	56	52	57	59	7	9	0.4	0.7
Bioenergy	64	72	79	64	78	93	10	14	1.2	1.8
Other renewables	62	84	108	65	114	160	14	24	3.8	5.3
Other energy sector	**147**	**136**	**127**	**141**	**112**	**88**	**100**	**100**	**-0.8**	**-2.1**
Electricity	*43*	*45*	*47*	*41*	*38*	*37*	*37*	*42*	*0.2*	*-0.7*
TFC	**1 245**	**1 261**	**1 273**	**1 196**	**1 097**	**1 008**	**100**	**100**	**0.1**	**-0.7**
Coal	49	45	41	47	38	30	3	3	-0.6	-1.8
Oil	478	434	396	457	330	218	31	22	-0.9	-3.1
Gas	276	289	292	262	239	215	23	21	0.2	-0.9
Electricity	283	313	341	271	280	292	27	29	0.9	0.3
Heat	51	56	61	48	48	46	5	5	1.0	-0.0
Bioenergy	98	110	123	99	140	168	10	17	1.5	2.7
Other renewables	10	14	19	11	23	39	1	4	4.2	7.1
Industry	**290**	**286**	**280**	**279**	**255**	**235**	**100**	**100**	**-0.1**	**-0.7**
Coal	30	28	25	29	25	20	9	9	-0.7	-1.5
Oil	27	24	21	26	21	18	8	8	-1.0	-1.6
Gas	89	85	82	86	73	62	29	26	-0.4	-1.4
Electricity	102	105	107	99	94	93	38	40	0.3	-0.2
Heat	14	14	13	14	12	10	5	4	-0.5	-1.4
Bioenergy	27	30	32	25	27	29	11	12	1.3	0.9
Other renewables	0	0	1	1	2	3	0	1	2.6	7.9
Transport	**322**	**318**	**314**	**310**	**259**	**209**	**100**	**100**	**-0.1**	**-1.6**
Oil	292	278	264	277	191	107	84	51	-0.5	-3.8
Electricity	7	9	11	7	13	29	3	14	2.3	6.2
Biofuels	19	25	32	21	46	57	10	27	3.3	5.6
Other fuels	4	7	8	5	9	16	2	8	3.2	6.1
Buildings	**504**	**535**	**565**	**478**	**464**	**454**	**100**	**100**	**0.5**	**-0.3**
Coal	16	15	14	15	11	8	3	2	-0.5	-2.5
Oil	52	32	18	48	21	6	3	1	-4.5	-8.2
Gas	171	186	193	160	146	127	34	28	0.5	-1.1
Electricity	169	195	219	161	168	166	39	37	1.2	0.2
Heat	36	42	48	34	35	36	8	8	1.6	0.5
Bioenergy	49	52	55	51	63	77	10	17	0.8	2.0
Other renewables	8	12	17	9	20	34	3	8	4.4	7.2
Other	**129**	**122**	**114**	**128**	**119**	**109**	**100**	**100**	**-0.5**	**-0.7**

OECD Europe: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total generation	**2 682**	**3 614**	**3 716**	**3 814**	**3 889**	**3 975**	**4 042**	**100**	**100**	**0.4**
Coal	1 040	962	818	659	490	360	285	27	7	-4.4
Oil	216	58	31	20	15	14	12	2	0	-5.8
Gas	168	622	619	781	809	853	885	17	22	1.3
Nuclear	787	877	858	759	787	798	775	24	19	-0.5
Hydro	446	579	607	629	646	659	670	16	17	0.5
Bioenergy	21	181	211	229	248	262	275	5	7	1.6
Wind	1	237	415	549	678	776	849	7	21	4.8
Geothermal	4	13	18	22	27	31	35	0	1	3.8
Solar PV	0	80	129	149	165	178	190	2	5	3.3
CSP	-	4	9	13	19	27	37	0	1	8.3
Marine	1	0	1	3	7	17	30	0	1	17.2

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)
	2013	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total capacity	**1 059**	**1 186**	**1 251**	**1 310**	**1 356**	**1 383**	**100**	**100**	**1.0**
Coal	191	177	150	130	102	91	18	7	-2.7
Oil	60	37	26	20	18	15	6	1	-5.0
Gas	234	275	312	324	344	345	22	25	1.4
Nuclear	129	124	109	112	113	109	12	8	-0.6
Hydro	206	219	227	232	236	240	19	17	0.6
Bioenergy	39	44	47	50	52	54	4	4	1.2
Wind	117	186	236	281	314	336	11	24	4.0
Geothermal	2	2	3	4	4	5	0	0	3.6
Solar PV	79	118	136	149	158	165	8	12	2.7
CSP	2	3	4	5	8	10	0	1	5.8
Marine	0	0	1	3	7	13	0	1	15.7

	CO_2 emissions (Mt)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total CO_2	**3 912**	**3 568**	**3 251**	**3 009**	**2 723**	**2 476**	**2 294**	**100**	**100**	**-1.6**
Coal	1 749	1 226	1 075	902	721	564	470	34	20	-3.5
Oil	1 605	1 387	1 246	1 126	1 017	920	838	39	37	-1.9
Gas	558	955	930	981	985	992	986	27	43	0.1
Power sector	**1 430**	**1 302**	**1 128**	**1 018**	**860**	**733**	**664**	**100**	**100**	**-2.5**
Coal	1 169	976	824	665	500	359	280	75	42	-4.5
Oil	165	48	28	19	15	13	11	4	2	-5.4
Gas	96	278	276	334	346	361	373	21	56	1.1
TFC	**2 310**	**2 092**	**1 961**	**1 842**	**1 724**	**1 614**	**1 510**	**100**	**100**	**-1.2**
Coal	540	212	210	197	183	169	156	10	10	-1.1
Oil	1 331	1 250	1 140	1 038	939	850	775	60	51	-1.8
Transport	*783*	*917*	*855*	*798*	*746*	*695*	*645*	*44*	*43*	*-1.3*
Gas	439	630	611	607	602	595	579	30	38	-0.3

OECD Europe: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**3 795**	**4 159**	**4 514**	**3 632**	**3 694**	**3 822**	**100**	**100**	**0.8**	**0.2**
Coal	869	761	688	718	197	130	15	3	-1.2	-7.1
Oil	31	17	15	31	12	5	0	0	-4.8	-8.6
Gas	671	1 052	1 272	620	689	361	28	9	2.7	-2.0
Nuclear	859	687	645	867	864	919	14	24	-1.1	0.2
Hydro	600	630	651	607	661	691	14	18	0.4	0.7
Bioenergy	210	241	265	211	262	314	6	8	1.4	2.1
Wind	404	580	725	419	755	1 026	16	27	4.2	5.6
Geothermal	17	21	26	18	32	43	1	1	2.7	4.6
Solar PV	124	149	173	130	185	229	4	6	2.9	4.0
CSP	9	16	31	9	26	58	1	2	7.4	10.1
Marine	1	4	22	1	10	47	0	1	15.9	19.1

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**1 188**	**1 311**	**1 417**	**1 178**	**1 321**	**1 448**	**100**	**100**	**1.1**	**1.2**
Coal	178	146	130	173	90	55	9	4	-1.4	-4.5
Oil	37	20	17	37	20	13	1	1	-4.6	-5.5
Gas	287	379	427	268	312	315	30	22	2.2	1.1
Nuclear	124	99	91	125	123	129	6	9	-1.3	-0.0
Hydro	217	227	234	219	237	247	17	17	0.5	0.7
Bioenergy	43	49	52	44	52	61	4	4	1.1	1.7
Wind	182	247	294	187	307	393	21	27	3.5	4.6
Geothermal	2	3	3	2	4	6	0	0	2.5	4.4
Solar PV	114	135	150	119	164	193	11	13	2.4	3.3
CSP	3	5	8	3	8	16	1	1	5.0	7.5
Marine	0	2	10	0	4	21	1	1	14.4	17.7

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**3 384**	**3 252**	**3 079**	**3 099**	**2 054**	**1 310**	**100**	**100**	**-0.5**	**-3.6**
Coal	1 128	973	814	968	384	200	26	15	-1.5	-6.5
Oil	1 287	1 151	1 045	1 220	810	454	34	35	-1.0	-4.1
Gas	969	1 129	1 220	912	860	656	40	50	0.9	-1.4
Power sector	**1 198**	**1 183**	**1 127**	**1 029**	**510**	**253**	**100**	**100**	**-0.5**	**-5.9**
Coal	874	738	601	726	205	86	53	34	-1.8	-8.6
Oil	28	16	14	28	13	6	1	2	-4.4	-7.4
Gas	295	429	512	275	292	160	45	63	2.3	-2.0
TFC	**2 021**	**1 920**	**1 815**	**1 914**	**1 434**	**987**	**100**	**100**	**-0.5**	**-2.7**
Coal	214	195	178	203	150	95	10	10	-0.7	-2.9
Oil	1 178	1 066	969	1 117	748	419	53	43	-0.9	-4.0
Transport	*883*	*841*	*798*	*838*	*578*	*322*	*44*	*33*	*-0.5*	*-3.8*
Gas	628	659	669	594	535	472	37	48	0.2	-1.1

European Union: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**1 643**	**1 624**	**1 563**	**1 503**	**1 455**	**1 415**	**1 377**	**100**	**100**	**-0.6**
Coal	456	286	245	200	155	121	101	18	7	-3.8
Oil	607	513	463	419	379	343	313	32	23	-1.8
Gas	297	387	371	391	392	389	382	24	28	-0.0
Nuclear	207	229	225	201	205	208	203	14	15	-0.4
Hydro	25	32	33	34	34	35	35	2	3	0.4
Bioenergy	47	140	165	180	193	203	213	9	15	1.6
Other renewables	3	37	61	79	98	115	131	2	9	4.8
Power sector	**646**	**687**	**664**	**641**	**631**	**627**	**622**	**100**	**100**	**-0.4**
Coal	287	218	179	139	101	73	58	32	9	-4.8
Oil	62	16	10	6	5	4	3	2	1	-5.5
Gas	55	102	100	124	130	132	134	15	21	1.0
Nuclear	207	229	225	201	205	208	203	33	33	-0.4
Hydro	25	32	33	34	34	35	35	5	6	0.4
Bioenergy	8	56	62	66	71	74	77	8	12	1.2
Other renewables	3	34	56	71	86	100	112	5	18	4.5
Other energy sector	**152**	**137**	**125**	**117**	**109**	**102**	**97**	**100**	**100**	**-1.3**
Electricity	*39*	*40*	*37*	*36*	*35*	*35*	*34*	*29*	*35*	*-0.6*
TFC	**1 131**	**1 137**	**1 116**	**1 093**	**1 066**	**1 040**	**1 015**	**100**	**100**	**-0.4**
Coal	122	38	36	33	30	26	24	3	2	-1.8
Oil	504	462	424	387	351	318	290	41	29	-1.7
Gas	226	264	254	251	247	243	234	23	23	-0.4
Electricity	186	238	245	251	254	258	260	21	26	0.3
Heat	54	48	50	52	53	54	54	4	5	0.5
Bioenergy	38	83	101	111	120	127	134	7	13	1.8
Other renewables	1	2	6	8	11	14	18	0	2	7.7
Industry	**343**	**260**	**257**	**251**	**242**	**233**	**227**	**100**	**100**	**-0.5**
Coal	69	24	24	23	21	19	17	9	8	-1.2
Oil	58	27	25	24	22	20	18	10	8	-1.4
Gas	97	86	80	77	73	69	66	33	29	-1.0
Electricity	85	86	87	87	85	84	84	33	37	-0.1
Heat	19	15	14	13	13	13	12	6	5	-0.7
Bioenergy	14	23	26	27	28	28	28	9	13	0.8
Other renewables	-	0	0	0	0	0	1	0	0	15.0
Transport	**259**	**303**	**293**	**280**	**268**	**256**	**245**	**100**	**100**	**-0.8**
Oil	253	281	261	241	223	205	189	93	77	-1.5
Electricity	5	6	6	7	8	9	11	2	4	2.4
Biofuels	0	13	22	26	30	33	36	4	15	3.8
Other fuels	1	3	5	6	7	8	9	1	4	4.1
Buildings	**395**	**453**	**451**	**451**	**450**	**451**	**447**	**100**	**100**	**-0.0**
Coal	49	11	10	8	7	5	4	3	1	-3.5
Oil	90	57	45	34	22	13	8	13	2	-7.1
Gas	108	162	156	155	154	153	148	36	33	-0.3
Electricity	91	143	147	153	157	161	162	32	36	0.5
Heat	34	33	36	38	40	41	42	7	9	0.9
Bioenergy	24	45	51	55	59	63	66	10	15	1.4
Other renewables	1	2	5	8	11	14	17	1	4	7.7
Other	**134**	**120**	**115**	**111**	**106**	**101**	**96**	**100**	**100**	**-0.8**

European Union: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**1 595**	**1 554**	**1 530**	**1 527**	**1 359**	**1 246**	**100**	**100**	**-0.2**	**-1.0**
Coal	256	209	168	222	103	76	11	6	-2.0	-4.8
Oil	475	419	372	455	317	201	24	16	-1.2	-3.4
Gas	386	445	478	365	349	280	31	22	0.8	-1.2
Nuclear	225	181	171	227	224	233	11	19	-1.1	0.1
Hydro	33	34	35	33	35	37	2	3	0.3	0.5
Bioenergy	162	182	200	164	215	252	13	20	1.3	2.2
Other renewables	59	83	107	62	114	168	7	14	4.0	5.8
Power sector	**679**	**674**	**690**	**647**	**603**	**608**	**100**	**100**	**0.0**	**-0.4**
Coal	189	152	121	159	55	41	17	7	-2.2	-6.0
Oil	10	5	4	9	4	2	1	0	-5.0	-7.3
Gas	107	158	190	101	113	71	28	12	2.3	-1.3
Nuclear	225	181	171	227	224	233	25	38	-1.1	0.1
Hydro	33	34	35	33	35	37	5	6	0.3	0.5
Bioenergy	62	69	74	62	74	86	11	14	1.0	1.6
Other renewables	54	74	95	56	98	138	14	23	3.9	5.3
Other energy sector	**128**	**117**	**110**	**122**	**97**	**77**	**100**	**100**	**-0.8**	**-2.1**
Electricity	*38*	*39*	*40*	*36*	*33*	*31*	*36*	*40*	*-0.1*	*-1.0*
TFC	**1 139**	**1 138**	**1 131**	**1 093**	**992**	**898**	**100**	**100**	**-0.0**	**-0.9**
Coal	37	31	26	35	27	20	2	2	-1.4	-2.4
Oil	436	389	345	417	294	187	30	21	-1.1	-3.3
Gas	261	271	272	247	223	197	24	22	0.1	-1.1
Electricity	250	271	291	240	245	253	26	28	0.7	0.2
Heat	52	57	61	49	48	46	5	5	0.9	-0.1
Bioenergy	98	111	124	100	140	164	11	18	1.5	2.6
Other renewables	5	8	12	6	16	31	1	3	6.0	9.8
Industry	**261**	**253**	**243**	**251**	**225**	**203**	**100**	**100**	**-0.2**	**-0.9**
Coal	24	21	18	23	19	15	8	7	-1.0	-1.9
Oil	26	23	20	25	20	16	8	8	-1.1	-1.8
Gas	82	77	72	79	66	55	30	27	-0.6	-1.6
Electricity	88	89	89	85	80	78	37	38	0.1	-0.3
Heat	14	13	12	14	12	9	5	5	-0.7	-1.7
Bioenergy	27	29	31	25	27	28	13	14	1.2	0.8
Other renewables	0	0	0	0	1	2	0	1	10.6	19.0
Transport	**299**	**290**	**281**	**288**	**238**	**189**	**100**	**100**	**-0.3**	**-1.7**
Oil	269	252	232	255	173	93	83	50	-0.7	-4.0
Electricity	6	8	10	7	12	27	4	14	2.3	6.0
Biofuels	19	24	31	21	45	55	11	29	3.2	5.5
Other fuels	4	6	7	5	8	13	3	7	3.1	5.5
Buildings	**463**	**488**	**510**	**439**	**425**	**413**	**100**	**100**	**0.4**	**-0.3**
Coal	10	8	6	9	5	3	1	1	-2.4	-4.6
Oil	47	29	17	43	19	5	3	1	-4.4	-8.3
Gas	162	175	181	151	137	118	35	29	0.4	-1.2
Electricity	151	170	188	144	149	146	37	35	1.0	0.1
Heat	38	43	49	35	36	37	10	9	1.5	0.4
Bioenergy	50	54	58	51	63	76	11	18	1.0	2.0
Other renewables	5	8	11	6	15	28	2	7	6.1	9.7
Other	**116**	**107**	**97**	**115**	**104**	**93**	**100**	**100**	**-0.8**	**-0.9**

European Union: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total generation	**2 576**	**3 225**	**3 266**	**3 321**	**3 352**	**3 390**	**3 408**	**100**	**100**	**0.2**
Coal	1 050	905	742	571	400	276	205	28	6	-5.4
Oil	224	61	33	21	16	14	12	2	0	-6.0
Gas	193	507	497	654	683	694	693	16	20	1.2
Nuclear	795	877	863	772	785	799	777	27	23	-0.4
Hydro	290	371	380	392	400	406	411	11	12	0.4
Bioenergy	20	178	206	222	238	250	261	6	8	1.4
Wind	1	235	400	517	631	717	780	7	23	4.5
Geothermal	3	6	9	12	15	19	22	0	1	4.9
Solar PV	0	81	127	146	161	174	185	3	5	3.1
CSP	-	4	8	11	16	23	32	0	1	7.7
Marine	1	0	1	3	7	17	30	0	1	17.2

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)
	2013	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total capacity	**976**	**1 078**	**1 130**	**1 175**	**1 208**	**1 222**	**100**	**100**	**0.8**
Coal	185	164	136	113	87	77	19	6	-3.2
Oil	60	36	24	18	16	12	6	1	-5.7
Gas	214	250	285	295	307	300	22	25	1.3
Nuclear	129	124	111	112	113	110	13	9	-0.6
Hydro	150	159	164	167	169	171	15	14	0.5
Bioenergy	38	43	46	48	50	52	4	4	1.1
Wind	117	181	225	266	294	314	12	26	3.7
Geothermal	1	1	2	2	2	3	0	0	4.7
Solar PV	80	117	134	146	155	161	8	13	2.6
CSP	2	3	3	5	7	9	0	1	5.3
Marine	0	0	1	3	7	13	0	1	15.7

	CO_2 emissions (Mt)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total CO_2	**4 005**	**3 291**	**2 945**	**2 686**	**2 390**	**2 137**	**1 950**	**100**	**100**	**-1.9**
Coal	1 774	1 128	953	767	579	428	339	34	17	-4.4
Oil	1 590	1 290	1 152	1 032	922	826	746	39	38	-2.0
Gas	641	872	840	887	889	883	865	27	44	-0.0
Power sector	**1 528**	**1 216**	**1 025**	**899**	**736**	**606**	**531**	**100**	**100**	**-3.0**
Coal	1 201	927	759	588	417	284	210	76	40	-5.3
Oil	199	50	30	19	15	14	11	4	2	-5.5
Gas	129	239	236	292	303	309	310	20	58	1.0
TFC	**2 308**	**1 920**	**1 780**	**1 660**	**1 538**	**1 425**	**1 321**	**100**	**100**	**-1.4**
Coal	534	169	162	149	134	120	107	9	8	-1.7
Oil	1 281	1 154	1 046	945	847	758	685	60	52	-1.9
Transport	*756*	*854*	*790*	*731*	*676*	*623*	*573*	*44*	*43*	*-1.5*
Gas	493	597	571	565	557	548	530	31	40	-0.4

European Union: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**3 334**	**3 589**	**3 829**	**3 195**	**3 210**	**3 291**	**100**	**100**	**0.6**	**0.1**
Coal	786	642	511	654	183	125	13	4	-2.1	-7.1
Oil	34	17	14	33	12	5	0	0	-5.3	-8.7
Gas	537	882	1 079	502	578	292	28	9	2.8	-2.0
Nuclear	863	695	656	872	861	895	17	27	-1.1	0.1
Hydro	378	396	407	380	410	425	11	13	0.3	0.5
Bioenergy	205	232	253	206	249	290	7	9	1.3	1.8
Wind	392	549	676	402	686	912	18	28	4.0	5.2
Geothermal	8	12	16	9	19	29	0	1	3.8	6.0
Solar PV	122	146	168	129	179	219	4	7	2.7	3.8
CSP	8	14	27	8	23	51	1	2	7.0	9.5
Marine	1	4	22	1	10	47	1	1	15.9	19.1

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**1 082**	**1 177**	**1 256**	**1 068**	**1 180**	**1 285**	**100**	**100**	**0.9**	**1.0**
Coal	166	127	104	160	81	51	8	4	-2.1	-4.6
Oil	36	18	13	36	18	11	1	1	-5.4	-6.1
Gas	261	343	381	241	281	281	30	22	2.2	1.0
Nuclear	124	99	92	126	122	126	7	10	-1.2	-0.1
Hydro	158	165	170	159	171	177	14	14	0.5	0.6
Bioenergy	43	47	50	43	50	57	4	4	1.0	1.5
Wind	178	237	279	182	284	357	22	28	3.3	4.2
Geothermal	1	2	2	1	3	4	0	0	3.5	5.7
Solar PV	112	133	147	118	159	186	12	14	2.3	3.2
CSP	3	4	8	3	7	14	1	1	4.6	7.1
Marine	0	2	10	0	4	21	1	2	14.4	17.7

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**3 063**	**2 863**	**2 615**	**2 811**	**1 835**	**1 153**	**100**	**100**	**-0.8**	**-3.8**
Coal	999	803	597	860	327	167	23	15	-2.3	-6.8
Oil	1 190	1 045	925	1 127	733	398	35	34	-1.2	-4.3
Gas	874	1 016	1 093	825	775	588	42	51	0.8	-1.5
Power sector	**1 084**	**1 021**	**913**	**940**	**467**	**241**	**100**	**100**	**-1.1**	**-5.8**
Coal	803	634	455	674	198	92	50	38	-2.6	-8.2
Oil	30	16	13	29	13	6	1	3	-4.9	-7.3
Gas	252	372	445	237	256	142	49	59	2.3	-1.9
TFC	**1 836**	**1 717**	**1 589**	**1 736**	**1 275**	**852**	**100**	**100**	**-0.7**	**-3.0**
Coal	165	141	119	156	107	61	7	7	-1.3	-3.7
Oil	1 083	962	852	1 024	673	364	54	43	-1.1	-4.2
Transport	*817*	*763*	*705*	*775*	*523*	*283*	*44*	*33*	*-0.7*	*-4.0*
Gas	589	613	618	556	495	427	39	50	0.1	-1.2

OECD Asia Oceania: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**632**	**870**	**884**	**885**	**884**	**876**	**866**	**100**	**100**	**-0.0**
Coal	138	246	233	217	207	192	175	28	20	-1.3
Oil	335	351	306	281	258	237	221	40	25	-1.7
Gas	66	189	177	179	186	188	186	22	21	-0.1
Nuclear	66	39	104	130	141	149	158	4	18	5.4
Hydro	11	11	11	12	12	13	13	1	2	0.8
Bioenergy	10	23	28	31	33	36	39	3	5	2.0
Other renewables	4	10	24	34	47	60	74	1	9	7.5
Power sector	**241**	**382**	**396**	**413**	**430**	**441**	**448**	**100**	**100**	**0.6**
Coal	60	165	149	137	130	119	107	43	24	-1.6
Oil	56	37	13	8	6	5	5	10	1	-7.4
Gas	40	110	82	78	79	79	76	29	17	-1.4
Nuclear	66	39	104	130	141	149	158	10	35	5.4
Hydro	11	11	11	12	12	13	13	3	3	0.8
Bioenergy	3	11	14	16	19	21	24	3	5	2.8
Other renewables	3	9	22	31	43	55	66	2	15	7.5
Other energy sector	**59**	**86**	**94**	**94**	**95**	**92**	**88**	**100**	**100**	**0.1**
Electricity	*11*	*16*	*17*	*18*	*19*	*19*	*19*	*19*	*22*	*0.7*
TFC	**429**	**568**	**569**	**559**	**549**	**538**	**528**	**100**	**100**	**-0.3**
Coal	49	39	39	37	34	31	28	7	5	-1.2
Oil	259	292	275	256	238	222	208	51	39	-1.2
Gas	26	74	81	85	87	89	89	13	17	0.7
Electricity	86	145	153	159	165	170	174	25	33	0.7
Heat	0	5	5	5	5	5	5	1	1	0.3
Bioenergy	7	12	14	14	15	15	16	2	3	1.0
Other renewables	2	1	2	3	4	6	8	0	1	7.3
Industry	**143**	**161**	**167**	**166**	**162**	**158**	**153**	**100**	**100**	**-0.2**
Coal	38	37	37	35	32	29	27	23	17	-1.2
Oil	49	32	30	28	25	23	21	20	14	-1.5
Gas	11	27	30	32	32	33	33	17	21	0.7
Electricity	40	53	57	58	59	59	59	33	38	0.4
Heat	-	2	2	2	2	2	2	1	1	-0.2
Bioenergy	5	9	10	11	11	11	11	6	7	0.7
Other renewables	0	0	0	0	0	0	1	0	0	4.7
Transport	**110**	**141**	**131**	**123**	**117**	**112**	**110**	**100**	**100**	**-0.9**
Oil	109	136	124	115	108	103	100	97	91	-1.1
Electricity	2	2	2	3	3	4	4	1	4	2.6
Biofuels	-	1	1	1	1	1	1	0	1	1.2
Other fuels	0	2	3	4	5	5	5	1	4	3.5
Buildings	**120**	**176**	**179**	**182**	**186**	**189**	**191**	**100**	**100**	**0.3**
Coal	10	1	1	1	1	1	1	1	0	-2.2
Oil	47	37	33	29	25	21	18	21	9	-2.7
Gas	15	44	46	48	49	50	50	25	26	0.5
Electricity	44	88	92	96	101	106	108	50	57	0.8
Heat	0	3	3	3	3	3	3	2	2	0.7
Bioenergy	2	2	3	3	3	4	4	1	2	1.9
Other renewables	1	1	2	2	3	5	7	1	3	7.7
Other	**56**	**91**	**92**	**88**	**84**	**79**	**74**	**100**	**100**	**-0.7**

OECD Asia Oceania: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**895**	**907**	**906**	**859**	**804**	**758**	**100**	**100**	**0.2**	**-0.5**
Coal	240	232	227	220	131	82	25	11	-0.3	-4.0
Oil	309	266	231	300	233	170	25	22	-1.5	-2.7
Gas	179	196	206	171	171	139	23	18	0.3	-1.1
Nuclear	104	129	135	104	157	193	15	25	4.7	6.1
Hydro	11	12	13	12	15	17	1	2	0.7	1.8
Bioenergy	28	33	37	28	41	56	4	7	1.8	3.3
Other renewables	23	39	57	24	56	102	6	13	6.5	8.8
Power sector	**402**	**440**	**468**	**382**	**381**	**395**	**100**	**100**	**0.8**	**0.1**
Coal	156	152	154	139	62	26	33	7	-0.3	-6.6
Oil	13	6	5	12	5	3	1	1	-7.2	-8.9
Gas	83	86	88	78	70	40	19	10	-0.8	-3.7
Nuclear	104	129	135	104	157	193	29	49	4.7	6.1
Hydro	11	12	13	12	15	17	3	4	0.7	1.8
Bioenergy	14	18	21	14	22	30	4	8	2.3	3.7
Other renewables	21	36	53	22	50	87	11	22	6.6	8.6
Other energy sector	**96**	**99**	**99**	**91**	**85**	**69**	**100**	**100**	**0.5**	**-0.8**
Electricity	*18*	*20*	*21*	*17*	*16*	*15*	*22*	*22*	*1.1*	*-0.2*
TFC	**574**	**565**	**550**	**554**	**507**	**462**	**100**	**100**	**-0.1**	**-0.8**
Coal	40	35	29	38	31	24	5	5	-1.1	-1.9
Oil	277	246	219	270	216	162	40	35	-1.1	-2.2
Gas	82	89	92	79	82	83	17	18	0.8	0.4
Electricity	155	171	185	147	148	147	34	32	0.9	0.1
Heat	5	5	5	5	5	5	1	1	0.4	0.2
Bioenergy	14	15	16	13	19	26	3	6	1.1	2.9
Other renewables	2	3	4	2	6	15	1	3	4.9	9.9
Industry	**168**	**166**	**159**	**164**	**151**	**138**	**100**	**100**	**-0.0**	**-0.6**
Coal	37	33	27	36	29	22	17	16	-1.1	-1.9
Oil	31	26	22	30	24	20	14	14	-1.4	-1.8
Gas	30	33	33	30	31	30	21	22	0.8	0.4
Electricity	57	61	62	55	53	52	39	38	0.6	-0.1
Heat	2	2	2	2	2	2	1	1	-0.2	-0.5
Bioenergy	10	11	12	10	11	11	8	8	1.0	0.7
Other renewables	0	0	0	0	1	1	0	1	3.3	8.3
Transport	**132**	**121**	**115**	**129**	**110**	**94**	**100**	**100**	**-0.7**	**-1.5**
Oil	126	114	108	122	94	63	93	67	-0.9	-2.8
Electricity	2	3	4	2	5	10	3	11	2.1	6.1
Biofuels	1	1	1	1	4	9	1	9	0.4	10.7
Other fuels	3	4	3	4	7	11	3	12	1.9	6.7
Buildings	**182**	**193**	**202**	**170**	**163**	**157**	**100**	**100**	**0.5**	**-0.4**
Coal	1	1	1	1	1	1	0	0	-2.1	-2.6
Oil	34	27	20	30	20	12	10	7	-2.3	-4.2
Gas	47	51	54	44	43	41	27	26	0.8	-0.3
Electricity	93	106	117	87	88	83	58	53	1.1	-0.2
Heat	3	3	3	3	3	3	2	2	0.8	0.6
Bioenergy	3	3	4	3	4	5	2	3	1.7	3.3
Other renewables	1	2	3	2	5	13	2	8	4.9	10.3
Other	**92**	**84**	**75**	**92**	**83**	**73**	**100**	**100**	**-0.7**	**-0.8**

OECD Asia Oceania: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total generation	**1 127**	**1 868**	**1 975**	**2 060**	**2 138**	**2 202**	**2 247**	**100**	**100**	**0.7**
Coal	256	723	681	632	606	574	525	39	23	-1.2
Oil	259	173	57	38	27	21	19	9	1	-7.8
Gas	208	607	504	494	504	505	493	32	22	-0.8
Nuclear	255	148	401	500	540	572	606	8	27	5.4
Hydro	133	124	134	138	143	148	154	7	7	0.8
Bioenergy	12	48	60	68	77	86	95	3	4	2.6
Wind	-	16	44	68	93	122	152	1	7	8.8
Geothermal	4	9	16	25	37	48	57	0	3	7.0
Solar PV	0	20	79	93	104	115	127	1	6	7.1
CSP	-	0	0	2	3	6	10	0	0	33.5
Marine	-	0	2	3	5	7	9	0	0	11.6

	Electrical capacity (GW)						Shares (%)		CAGR (%)
	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total capacity	**460**	**553**	**573**	**589**	**604**	**617**	**100**	**100**	**1.1**
Coal	107	118	115	112	106	99	23	16	-0.3
Oil	53	31	23	16	13	12	12	2	-5.4
Gas	131	169	172	172	170	165	28	27	0.9
Nuclear	66	67	70	71	75	80	14	13	0.7
Hydro	69	70	72	74	75	77	15	12	0.4
Bioenergy	8	9	11	12	13	15	2	2	2.4
Wind	7	15	23	31	40	49	2	8	7.4
Geothermal	1	2	4	5	7	8	0	1	6.9
Solar PV	18	71	83	92	100	108	4	17	6.8
CSP	0	0	0	1	1	2	0	0	27.4
Marine	0	1	1	1	2	3	0	0	9.5

	CO_2 emissions (Mt)							Shares (%)		CAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total CO_2	**1 559**	**2 205**	**1 983**	**1 854**	**1 762**	**1 653**	**1 539**	**100**	**100**	**-1.3**
Coal	533	947	885	817	765	694	618	43	40	-1.6
Oil	866	806	675	611	560	518	488	37	32	-1.8
Gas	160	452	423	426	437	441	433	20	28	-0.2
Power sector	**562**	**1 095**	**889**	**810**	**768**	**711**	**643**	**100**	**100**	**-1.9**
Coal	289	718	651	595	559	507	448	66	70	-1.7
Oil	178	116	40	27	20	16	15	11	2	-7.4
Gas	94	261	198	188	189	188	181	24	28	-1.3
TFC	**931**	**992**	**951**	**902**	**852**	**806**	**767**	**100**	**100**	**-1.0**
Coal	222	180	178	167	155	141	128	18	17	-1.3
Oil	650	642	586	539	496	461	434	65	57	-1.4
Transport	*324*	*404*	*369*	*343*	*321*	*306*	*297*	*41*	*39*	*-1.1*
Gas	59	170	187	196	201	204	205	17	27	0.7

OECD Asia Oceania: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**2 005**	**2 222**	**2 395**	**1 901**	**1 910**	**1 891**	**100**	**100**	**0.9**	**0.0**
Coal	713	726	766	628	286	106	32	6	0.2	-6.9
Oil	57	27	20	57	24	13	1	1	-7.6	-9.2
Gas	508	555	580	472	435	237	24	13	-0.2	-3.4
Nuclear	401	496	517	401	603	740	22	39	4.7	6.1
Hydro	133	140	149	136	171	201	6	11	0.7	1.8
Bioenergy	59	72	84	60	91	121	4	6	2.1	3.5
Wind	42	78	116	48	134	214	5	11	7.7	10.2
Geothermal	16	31	46	16	41	72	2	4	6.2	8.0
Solar PV	75	91	107	81	117	152	4	8	6.5	7.9
CSP	0	2	5	0	3	13	0	1	30.2	35.0
Marine	2	3	5	2	6	21	0	1	9.4	15.1

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**555**	**593**	**619**	**540**	**587**	**628**	**100**	**100**	**1.1**	**1.2**
Coal	121	126	126	112	90	55	20	9	0.6	-2.5
Oil	31	17	13	31	16	9	2	1	-5.2	-6.3
Gas	171	187	186	156	148	138	30	22	1.3	0.2
Nuclear	67	65	68	67	80	98	11	16	0.1	1.5
Hydro	70	73	75	72	84	93	12	15	0.3	1.1
Bioenergy	9	11	13	9	14	19	2	3	2.0	3.4
Wind	15	27	38	17	44	68	6	11	6.4	8.8
Geothermal	2	4	7	2	6	11	1	2	6.1	7.9
Solar PV	67	81	91	73	103	128	15	20	6.1	7.5
CSP	0	0	1	0	1	3	0	0	24.3	28.7
Marine	1	1	2	1	2	7	0	1	7.4	13.0

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**2 028**	**1 922**	**1 836**	**1 897**	**1 286**	**775**	**100**	**100**	**-0.7**	**-3.8**
Coal	915	872	832	831	411	154	45	20	-0.5	-6.5
Oil	684	587	525	658	488	335	29	43	-1.6	-3.2
Gas	428	462	479	407	387	286	26	37	0.2	-1.7
Power sector	**920**	**891**	**886**	**835**	**416**	**112**	**100**	**100**	**-0.8**	**-8.1**
Coal	680	663	659	608	241	36	74	32	-0.3	-10.5
Oil	40	20	16	39	17	9	2	8	-7.2	-8.9
Gas	199	207	212	188	158	67	24	60	-0.8	-4.9
TFC	**962**	**884**	**809**	**923**	**749**	**575**	**100**	**100**	**-0.8**	**-2.0**
Coal	179	157	131	170	129	91	16	16	-1.2	-2.5
Oil	595	521	467	572	432	296	58	51	-1.2	-2.8
Transport	*373*	*338*	*320*	*364*	*279*	*188*	*40*	*33*	*-0.9*	*-2.8*
Gas	188	206	211	181	188	188	26	33	0.8	0.4

Japan: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**439**	**455**	**434**	**424**	**414**	**406**	**399**	**100**	**100**	**-0.5**
Coal	77	121	111	103	99	91	83	27	21	-1.4
Oil	250	202	160	143	129	116	107	45	27	-2.3
Gas	44	106	86	84	86	87	86	23	22	-0.8
Nuclear	53	2	46	57	57	59	62	1	16	12.8
Hydro	8	7	8	8	8	8	9	1	2	1.0
Bioenergy	5	11	13	14	16	17	18	2	4	1.7
Other renewables	3	4	11	15	21	27	34	1	9	7.9
Power sector	**174**	**194**	**191**	**196**	**201**	**206**	**210**	**100**	**100**	**0.3**
Coal	25	70	62	58	58	55	50	36	24	-1.2
Oil	51	30	9	6	4	3	3	16	1	-8.4
Gas	33	72	47	43	43	43	41	37	20	-2.1
Nuclear	53	2	46	57	57	59	62	1	30	12.8
Hydro	8	7	8	8	8	8	9	3	4	1.0
Bioenergy	2	8	10	11	12	13	14	4	7	2.1
Other renewables	1	4	10	14	19	25	30	2	15	7.9
Other energy sector	**40**	**42**	**39**	**37**	**35**	**33**	**31**	**100**	**100**	**-1.2**
Electricity	*7*	*7*	*8*	*8*	*8*	*8*	*9*	*18*	*28*	*0.5*
TFC	**298**	**309**	**294**	**283**	**273**	**263**	**255**	**100**	**100**	**-0.7**
Coal	32	26	24	22	20	18	16	8	6	-1.8
Oil	182	163	145	132	119	108	99	53	39	-1.8
Gas	15	34	38	41	42	44	44	11	17	1.0
Electricity	64	82	82	83	85	86	87	26	34	0.2
Heat	0	1	1	1	1	1	1	0	0	1.3
Bioenergy	3	3	4	4	4	4	4	1	1	0.6
Other renewables	1	0	1	1	2	3	4	0	2	8.0
Industry	**101**	**82**	**80**	**77**	**73**	**69**	**65**	**100**	**100**	**-0.8**
Coal	30	25	23	21	19	17	15	31	24	-1.8
Oil	35	23	21	19	17	15	14	28	21	-1.9
Gas	4	8	10	11	11	12	12	9	18	1.7
Electricity	29	23	23	22	22	21	21	28	32	-0.4
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	3	3	3	4	4	4	4	4	6	0.6
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Transport	**72**	**73**	**64**	**59**	**54**	**50**	**47**	**100**	**100**	**-1.6**
Oil	70	72	62	56	51	47	44	98	92	-1.8
Electricity	1	2	2	2	2	3	3	2	6	2.3
Biofuels	-	-	-	-	-	-	-	-	-	n.a.
Other fuels	0	0	0	1	1	1	1	0	1	7.9
Buildings	**84**	**114**	**113**	**113**	**114**	**115**	**115**	**100**	**100**	**0.0**
Coal	1	1	0	0	0	0	0	0	0	-1.7
Oil	36	30	26	23	20	18	15	26	13	-2.5
Gas	11	26	28	29	30	31	32	23	28	0.7
Electricity	34	57	57	59	61	63	64	50	55	0.4
Heat	0	1	1	1	1	1	1	0	1	1.3
Bioenergy	0	0	0	0	0	0	0	0	0	-0.8
Other renewables	1	0	1	1	1	2	4	0	3	8.4
Other	**41**	**39**	**36**	**34**	**32**	**29**	**27**	**100**	**100**	**-1.4**

Japan: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**438**	**420**	**409**	**417**	**369**	**335**	**100**	**100**	**-0.4**	**-1.1**
Coal	114	109	102	103	60	31	25	9	-0.6	-4.9
Oil	161	131	112	156	115	80	27	24	-2.2	-3.4
Gas	86	93	97	80	74	55	24	16	-0.4	-2.4
Nuclear	46	46	46	46	67	81	11	24	11.5	13.9
Hydro	8	8	9	8	10	12	2	3	0.9	2.1
Bioenergy	13	15	17	13	18	24	4	7	1.6	2.8
Other renewables	10	17	28	11	25	52	7	16	7.1	9.6
Power sector	**194**	**202**	**215**	**183**	**175**	**177**	**100**	**100**	**0.4**	**-0.3**
Coal	65	68	69	57	24	5	32	3	-0.0	-9.1
Oil	9	4	3	9	4	2	1	1	-8.1	-9.8
Gas	47	49	49	44	35	18	23	10	-1.4	-5.1
Nuclear	46	46	46	46	67	81	21	46	11.5	13.9
Hydro	8	8	9	8	10	12	4	7	0.9	2.1
Bioenergy	10	11	13	10	13	17	6	9	1.8	2.8
Other renewables	10	16	26	10	21	43	12	24	7.3	9.3
Other energy sector	**39**	**36**	**32**	**37**	**30**	**23**	**100**	**100**	**-1.0**	**-2.2**
Electricity	*8*	*9*	*9*	*7*	*7*	*6*	*29*	*27*	*0.8*	*-0.6*
TFC	**297**	**279**	**265**	**283**	**245**	**211**	**100**	**100**	**-0.6**	**-1.4**
Coal	24	20	16	23	18	13	6	6	-1.7	-2.5
Oil	146	122	103	141	107	75	39	35	-1.7	-2.9
Gas	39	44	46	36	38	37	18	17	1.2	0.3
Electricity	83	88	93	78	75	70	35	33	0.5	-0.6
Heat	1	1	1	1	1	1	0	0	1.4	0.5
Bioenergy	4	4	4	3	5	7	2	3	1.0	3.0
Other renewables	1	1	2	1	3	10	1	5	4.6	11.6
Industry	**81**	**74**	**67**	**79**	**68**	**58**	**100**	**100**	**-0.7**	**-1.3**
Coal	23	19	16	22	17	12	23	21	-1.7	-2.6
Oil	21	17	14	21	16	12	21	21	-1.9	-2.3
Gas	10	11	12	10	11	11	18	19	1.7	1.4
Electricity	23	22	22	22	20	19	32	32	-0.2	-0.8
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	4	4	4	3	3	3	6	6	1.0	0.4
Other renewables	0	0	0	0	0	1	0	1	n.a.	n.a.
Transport	**64**	**55**	**50**	**63**	**50**	**37**	**100**	**100**	**-1.4**	**-2.5**
Oil	62	52	46	61	45	27	94	73	-1.6	-3.6
Electricity	2	2	3	2	3	6	5	16	1.9	5.0
Biofuels	-	-	-	-	1	3	-	8	n.a.	n.a.
Other fuels	0	1	0	0	1	1	1	3	6.6	9.6
Buildings	**115**	**118**	**121**	**105**	**97**	**90**	**100**	**100**	**0.2**	**-0.9**
Coal	0	0	0	0	0	0	0	0	-1.3	-2.5
Oil	27	22	16	24	16	10	14	11	-2.2	-4.1
Gas	28	31	34	26	26	25	28	28	1.0	-0.2
Electricity	58	63	68	54	51	46	56	51	0.7	-0.8
Heat	1	1	1	1	1	1	1	1	1.4	0.5
Bioenergy	0	0	0	0	0	0	0	0	-0.8	11.1
Other renewables	0	1	1	1	3	9	1	10	4.8	11.9
Other	**37**	**32**	**27**	**36**	**31**	**27**	**100**	**100**	**-1.4**	**-1.4**

Japan: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total generation	**836**	**1 038**	**1 043**	**1 062**	**1 084**	**1 105**	**1 117**	**100**	**100**	**0.3**
Coal	116	337	306	290	290	275	254	32	23	-1.0
Oil	237	150	45	29	20	15	14	14	1	-8.3
Gas	179	402	305	290	295	296	284	39	25	-1.3
Nuclear	202	9	175	218	218	228	239	1	21	12.8
Hydro	89	78	88	91	95	99	103	8	9	1.0
Bioenergy	11	41	48	51	55	60	64	4	6	1.7
Wind	-	5	9	15	22	32	44	1	4	8.2
Geothermal	2	3	5	7	12	17	22	0	2	8.2
Solar PV	0	14	61	70	77	83	91	1	8	7.1
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	0	1	2	-	0	n.a.

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)
	2013	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total capacity	**292**	**335**	**338**	**338**	**340**	**343**	**100**	**100**	**0.6**
Coal	50	49	48	48	45	41	17	12	-0.7
Oil	46	25	18	12	9	8	16	2	-6.1
Gas	79	103	106	105	101	97	27	28	0.7
Nuclear	44	38	33	30	31	33	15	10	-1.1
Hydro	49	50	51	52	53	54	17	16	0.4
Bioenergy	6	7	8	8	9	10	2	3	1.6
Wind	3	4	6	8	12	15	1	4	6.7
Geothermal	1	1	1	2	3	4	0	1	7.4
Solar PV	14	58	66	72	77	81	5	24	6.8
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	0	0	1	-	0	n.a.

	CO_2 emissions (Mt)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total CO_2	**1 049**	**1 225**	**1 009**	**926**	**877**	**818**	**760**	**100**	**100**	**-1.8**
Coal	298	463	419	388	372	342	311	38	41	-1.5
Oil	636	501	382	336	298	266	242	41	32	-2.7
Gas	115	260	208	202	207	210	208	21	27	-0.8
Power sector	**372**	**589**	**426**	**385**	**375**	**354**	**328**	**100**	**100**	**-2.1**
Coal	133	316	283	263	258	239	218	54	67	-1.4
Oil	160	96	28	18	13	10	9	16	3	-8.4
Gas	79	177	115	105	105	105	101	30	31	-2.1
TFC	**633**	**594**	**546**	**507**	**471**	**437**	**407**	**100**	**100**	**-1.4**
Coal	148	128	117	107	97	87	78	22	19	-1.8
Oil	450	387	340	306	275	248	225	65	55	-2.0
Transport	*210*	*213*	*184*	*167*	*152*	*140*	*130*	*36*	*32*	*-1.8*
Gas	35	79	90	94	99	102	104	13	26	1.0

Japan: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**1 057**	**1 123**	**1 187**	**995**	**948**	**892**	**100**	**100**	**0.5**	**-0.6**
Coal	320	347	362	279	122	24	30	3	0.3	-9.3
Oil	46	21	15	46	18	9	1	1	-8.1	-9.7
Gas	308	336	343	279	236	111	29	12	-0.6	-4.6
Nuclear	175	175	175	175	259	312	15	35	11.5	13.9
Hydro	88	93	100	90	113	135	8	15	0.9	2.1
Bioenergy	47	54	60	48	63	77	5	9	1.4	2.4
Wind	9	19	35	9	40	81	3	9	7.3	10.7
Geothermal	5	10	19	5	12	30	2	3	7.7	9.5
Solar PV	59	68	77	64	85	103	7	12	6.5	7.6
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	0	1	-	1	9	0	1	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**336**	**343**	**350**	**327**	**334**	**351**	**100**	**100**	**0.7**	**0.7**
Coal	51	56	57	49	40	23	16	7	0.5	-2.8
Oil	25	13	9	25	12	6	3	2	-5.8	-7.3
Gas	105	118	112	93	83	74	32	21	1.3	-0.2
Nuclear	38	24	24	38	36	43	7	12	-2.2	-0.1
Hydro	50	52	53	51	59	65	15	19	0.3	1.1
Bioenergy	7	8	9	7	10	12	3	3	1.3	2.3
Wind	4	7	12	4	14	27	3	8	5.8	9.0
Geothermal	1	2	3	1	2	5	1	1	6.9	8.7
Solar PV	56	63	70	60	79	92	20	26	6.2	7.3
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	0	0	-	0	3	0	1	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**1 027**	**952**	**890**	**952**	**635**	**364**	**100**	**100**	**-1.2**	**-4.4**
Coal	432	423	402	387	205	85	45	23	-0.5	-6.1
Oil	385	306	256	370	259	164	29	45	-2.5	-4.0
Gas	210	224	233	195	171	115	26	32	-0.4	-3.0
Power sector	**440**	**440**	**439**	**395**	**198**	**44**	**100**	**100**	**-1.1**	**-9.1**
Coal	296	308	308	260	106	11	70	26	-0.1	-11.5
Oil	28	13	10	29	11	6	2	13	-8.1	-9.8
Gas	116	119	120	107	81	27	27	61	-1.4	-6.7
TFC	**550**	**481**	**426**	**523**	**410**	**301**	**100**	**100**	**-1.2**	**-2.5**
Coal	117	98	79	110	85	63	19	21	-1.8	-2.6
Oil	342	282	238	328	238	153	56	51	-1.8	-3.4
Transport	*185*	*155*	*138*	*181*	*133*	*80*	*32*	*27*	*-1.6*	*-3.6*
Gas	91	102	109	85	88	86	26	29	1.2	0.3

Non-OECD: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**4 046**	**7 884**	**9 008**	**9 822**	**10 688**	**11 505**	**12 239**	**100**	**100**	**1.6**
Coal	1 140	2 900	3 118	3 285	3 484	3 665	3 799	37	31	1.0
Oil	1 163	1 959	2 273	2 451	2 616	2 765	2 891	25	24	1.5
Gas	819	1 529	1 761	1 968	2 201	2 440	2 665	19	22	2.1
Nuclear	74	135	250	343	434	501	566	2	5	5.4
Hydro	83	204	253	291	328	361	387	3	3	2.4
Bioenergy	758	1 082	1 194	1 258	1 314	1 361	1 400	14	11	1.0
Other renewables	8	74	158	226	310	414	531	1	4	7.6
Power sector	**1 260**	**2 924**	**3 433**	**3 830**	**4 286**	**4 756**	**5 194**	**100**	**100**	**2.2**
Coal	459	1 581	1 762	1 871	2 015	2 154	2 265	54	44	1.3
Oil	223	208	192	170	148	138	132	7	3	-1.7
Gas	406	689	744	827	924	1 031	1 122	24	22	1.8
Nuclear	74	135	250	343	434	501	566	5	11	5.4
Hydro	83	204	253	291	328	361	387	7	7	2.4
Bioenergy	7	58	112	147	182	223	264	2	5	5.8
Other renewables	8	49	120	180	255	349	458	2	9	8.6
Other energy sector	**499**	**1 185**	**1 237**	**1 296**	**1 365**	**1 427**	**1 469**	**100**	**100**	**0.8**
Electricity	*78*	*206*	*244*	*270*	*303*	*336*	*366*	*17*	*25*	*2.1*
TFC	**2 976**	**5 135**	**5 999**	**6 582**	**7 165**	**7 692**	**8 170**	**100**	**100**	**1.7**
Coal	532	837	892	929	956	972	983	16	12	0.6
Oil	816	1 609	1 927	2 126	2 319	2 484	2 628	31	32	1.8
Gas	355	626	801	922	1 049	1 172	1 289	12	16	2.7
Electricity	282	873	1 130	1 322	1 530	1 739	1 935	17	24	3.0
Heat	293	232	240	247	251	252	250	5	3	0.3
Bioenergy	699	933	972	990	1 004	1 010	1 013	18	12	0.3
Other renewables	0	25	38	46	56	64	73	0	1	4.1
Industry	**981**	**1 854**	**2 174**	**2 397**	**2 616**	**2 826**	**3 012**	**100**	**100**	**1.8**
Coal	313	672	717	749	779	799	819	36	27	0.7
Oil	160	203	230	238	245	252	255	11	8	0.8
Gas	135	295	392	463	534	608	677	16	22	3.1
Electricity	159	455	576	659	742	824	896	25	30	2.5
Heat	138	109	118	124	126	126	123	6	4	0.5
Bioenergy	76	119	141	163	187	212	234	6	8	2.5
Other renewables	0	0	0	1	3	5	8	0	0	14.4
Transport	**433**	**1 002**	**1 244**	**1 421**	**1 588**	**1 729**	**1 867**	**100**	**100**	**2.3**
Oil	364	893	1 102	1 251	1 386	1 496	1 594	89	85	2.2
Electricity	13	17	22	26	31	37	44	2	2	3.6
Biofuels	6	21	36	50	63	75	93	2	5	5.7
Other fuels	50	71	83	94	108	120	135	7	7	2.4
Buildings	**1 254**	**1 763**	**1 939**	**2 042**	**2 164**	**2 274**	**2 371**	**100**	**100**	**1.1**
Coal	169	109	105	100	94	88	81	6	3	-1.1
Oil	116	171	174	169	169	173	177	10	7	0.1
Gas	126	197	243	271	303	330	353	11	15	2.2
Electricity	85	358	478	575	686	799	910	20	38	3.5
Heat	146	117	117	118	120	122	123	7	5	0.2
Bioenergy	612	787	785	765	739	705	666	45	28	-0.6
Other renewables	0	24	36	43	51	57	62	1	3	3.6
Other	**307**	**517**	**643**	**722**	**798**	**864**	**920**	**100**	**100**	**2.2**

Non-OECD: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**9 180**	**11 322**	**13 404**	**8 742**	**9 513**	**10 225**	**100**	**100**	**2.0**	**1.0**
Coal	3 239	3 987	4 716	2 946	2 457	2 129	35	21	1.8	-1.1
Oil	2 309	2 785	3 237	2 215	2 247	2 095	24	20	1.9	0.2
Gas	1 788	2 284	2 850	1 712	1 992	2 166	21	21	2.3	1.3
Nuclear	250	400	481	259	608	879	4	9	4.8	7.2
Hydro	251	312	365	254	348	437	3	4	2.2	2.9
Bioenergy	1 196	1 307	1 375	1 187	1 400	1 631	10	16	0.9	1.5
Other renewables	147	247	381	170	462	889	3	9	6.3	9.7
Power sector	**3 541**	**4 656**	**5 819**	**3 253**	**3 596**	**4 180**	**100**	**100**	**2.6**	**1.3**
Coal	1 862	2 437	3 042	1 609	1 109	812	52	19	2.5	-2.4
Oil	195	161	145	175	101	75	2	2	-1.3	-3.7
Gas	763	979	1 243	713	806	797	21	19	2.2	0.5
Nuclear	250	400	481	259	608	879	8	21	4.8	7.2
Hydro	251	312	365	254	348	437	6	10	2.2	2.9
Bioenergy	110	166	220	112	234	397	4	9	5.1	7.4
Other renewables	111	201	323	131	391	785	6	19	7.2	10.8
Other energy sector	**1 260**	**1 448**	**1 626**	**1 209**	**1 228**	**1 204**	**100**	**100**	**1.2**	**0.1**
Electricity	*252*	*333*	*418*	*234*	*257*	*284*	*26*	*24*	*2.7*	*1.2*
TFC	**6 081**	**7 490**	**8 793**	**5 881**	**6 566**	**7 008**	**100**	**100**	**2.0**	**1.2**
Coal	909	1 012	1 067	879	863	828	12	12	0.9	-0.0
Oil	1 957	2 468	2 952	1 890	2 021	1 933	34	28	2.3	0.7
Gas	804	1 067	1 332	787	987	1 178	15	17	2.8	2.4
Electricity	1 159	1 627	2 096	1 083	1 346	1 632	24	23	3.3	2.3
Heat	242	264	274	237	233	217	3	3	0.6	-0.2
Bioenergy	973	1 005	1 015	966	1 045	1 117	12	16	0.3	0.7
Other renewables	36	47	58	39	71	104	1	1	3.2	5.5
Industry	**2 213**	**2 756**	**3 252**	**2 135**	**2 384**	**2 583**	**100**	**100**	**2.1**	**1.2**
Coal	731	824	889	708	709	699	27	27	1.0	0.1
Oil	234	260	277	226	222	218	9	8	1.2	0.2
Gas	397	556	722	385	482	551	22	21	3.4	2.3
Electricity	589	784	971	558	661	760	30	29	2.8	1.9
Heat	119	135	141	117	115	103	4	4	1.0	-0.2
Bioenergy	143	195	248	140	185	231	8	9	2.8	2.5
Other renewables	0	1	4	1	10	21	0	1	11.3	18.5
Transport	**1 252**	**1 661**	**2 070**	**1 220**	**1 424**	**1 480**	**100**	**100**	**2.7**	**1.5**
Oil	1 122	1 497	1 855	1 078	1 146	990	90	67	2.7	0.4
Electricity	21	29	39	22	39	86	2	6	3.1	6.3
Biofuels	32	50	73	36	111	194	4	13	4.8	8.6
Other fuels	77	84	103	84	129	209	5	14	1.4	4.1
Buildings	**1 969**	**2 259**	**2 518**	**1 889**	**1 982**	**2 062**	**100**	**100**	**1.3**	**0.6**
Coal	108	102	89	101	76	52	4	3	-0.7	-2.7
Oil	178	184	200	167	149	149	8	7	0.6	-0.5
Gas	248	322	383	236	274	298	15	14	2.5	1.5
Electricity	494	739	992	451	581	710	39	34	3.8	2.6
Heat	118	124	129	115	113	111	5	5	0.3	-0.2
Bioenergy	788	745	673	781	731	663	27	32	-0.6	-0.6
Other renewables	35	44	52	37	59	80	2	4	2.9	4.5
Other	**647**	**814**	**954**	**638**	**776**	**883**	**100**	**100**	**2.3**	**2.0**

Non-OECD: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total generation	**4 197**	**12 532**	**15 960**	**18 507**	**21 299**	**24 109**	**26 738**	**100**	**100**	**2.8**
Coal	1 331	6 088	7 081	7 681	8 466	9 234	9 884	49	37	1.8
Oil	625	715	688	612	537	503	485	6	2	-1.4
Gas	979	2 447	3 070	3 694	4 336	5 012	5 621	20	21	3.1
Nuclear	283	516	959	1 316	1 666	1 920	2 171	4	8	5.5
Hydro	963	2 375	2 947	3 383	3 814	4 198	4 504	19	17	2.4
Bioenergy	8	144	339	468	593	739	887	1	3	7.0
Wind	0	196	614	897	1 182	1 494	1 838	2	7	8.6
Geothermal	8	26	46	68	100	145	198	0	1	7.9
Solar PV	0	25	208	365	547	749	963	0	4	14.5
CSP	-	0	9	23	57	113	184	0	1	39.7
Marine	-	0	0	0	1	2	3	0	0	24.2

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)
	2013	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total capacity	**3 009**	**4 137**	**4 808**	**5 523**	**6 223**	**6 858**	**100**	**100**	**3.1**
Coal	1 211	1 497	1 638	1 795	1 942	2 056	40	30	2.0
Oil	238	251	238	220	213	205	8	3	-0.6
Gas	637	882	995	1 130	1 263	1 381	21	20	2.9
Nuclear	78	134	181	226	260	292	3	4	5.0
Hydro	666	845	971	1 098	1 209	1 295	22	19	2.5
Bioenergy	39	72	95	117	141	165	1	2	5.5
Wind	110	289	406	516	623	732	4	11	7.3
Geothermal	4	7	10	15	22	29	0	0	7.5
Solar PV	25	156	266	388	518	651	1	9	12.8
CSP	0	3	7	17	32	51	0	1	21.5
Marine	0	0	0	0	1	1	0	0	22.9

	CO_2 emissions (Mt)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total CO_2	**8 987**	**18 609**	**20 676**	**22 062**	**23 568**	**24 972**	**26 164**	**100**	**100**	**1.3**
Coal	4 158	10 373	11 152	11 661	12 273	12 801	13 200	56	50	0.9
Oil	3 033	4 931	5 657	6 063	6 433	6 774	7 078	27	27	1.3
Gas	1 796	3 305	3 868	4 337	4 861	5 396	5 885	18	22	2.2
Power sector	**3 537**	**8 644**	**9 455**	**9 991**	**10 675**	**11 394**	**11 978**	**100**	**100**	**1.2**
Coal	1 866	6 366	7 095	7 507	8 034	8 537	8 925	74	75	1.3
Oil	718	658	608	537	468	435	418	8	3	-1.7
Gas	953	1 621	1 752	1 947	2 173	2 422	2 635	19	22	1.8
TFC	**5 056**	**9 049**	**10 247**	**11 072**	**11 866**	**12 521**	**13 102**	**100**	**100**	**1.4**
Coal	2 215	3 724	3 829	3 926	4 010	4 035	4 046	41	31	0.3
Oil	2 133	4 008	4 742	5 212	5 649	6 016	6 336	44	48	1.7
Transport	*1 091*	*2 680*	*3 315*	*3 761*	*4 168*	*4 502*	*4 797*	*30*	*37*	*2.2*
Gas	708	1 318	1 676	1 934	2 207	2 469	2 720	15	21	2.7

Non-OECD: Current Policies and 450 Scenarios

	Electricity generation (TWh)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2013-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total generation	**16 395**	**22 777**	**29 221**	**15 299**	**18 634**	**22 262**	**100**	**100**	**3.2**	**2.2**
Coal	7 520	10 297	13 226	6 540	4 643	3 143	45	14	2.9	-2.4
Oil	698	588	534	615	342	248	2	1	-1.1	-3.9
Gas	3 173	4 736	6 404	2 872	3 735	3 809	22	17	3.6	1.7
Nuclear	957	1 533	1 843	992	2 334	3 371	6	15	4.8	7.2
Hydro	2 919	3 629	4 249	2 954	4 043	5 079	15	23	2.2	2.9
Bioenergy	332	534	731	341	771	1 355	3	6	6.2	8.6
Wind	573	978	1 399	693	1 702	2 790	5	13	7.6	10.3
Geothermal	44	82	146	48	166	304	0	1	6.6	9.6
Solar PV	172	368	599	232	768	1 454	2	7	12.5	16.3
CSP	7	32	87	13	128	700	0	3	35.9	46.8
Marine	0	0	3	0	2	9	0	0	23.2	28.9

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2013-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total capacity	**4 159**	**5 591**	**6 898**	**4 093**	**5 414**	**6 864**	**100**	**100**	**3.1**	**3.1**
Coal	1 567	2 062	2 512	1 432	1 196	1 007	36	15	2.7	-0.7
Oil	251	225	212	243	196	169	3	2	-0.4	-1.3
Gas	890	1 229	1 541	848	1 067	1 232	22	18	3.3	2.5
Nuclear	134	208	248	139	315	455	4	7	4.4	6.8
Hydro	836	1 035	1 212	847	1 172	1 471	18	21	2.2	3.0
Bioenergy	71	106	137	72	146	240	2	3	4.8	7.0
Wind	271	436	572	327	723	1 077	8	16	6.3	8.8
Geothermal	7	12	22	8	25	45	0	1	6.3	9.2
Solar PV	130	269	418	172	534	969	6	14	10.9	14.4
CSP	3	10	23	4	37	194	0	3	18.1	27.7
Marine	0	0	1	0	1	3	0	0	21.8	27.7

	CO_2 emissions (Mt)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2013-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
Total CO_2	**21 319**	**26 279**	**31 271**	**19 677**	**16 683**	**13 034**	**100**	**100**	**1.9**	**-1.3**
Coal	11 631	14 295	16 863	10 444	7 117	4 051	54	31	1.8	-3.4
Oil	5 760	6 932	8 104	5 483	5 315	4 643	26	36	1.9	-0.2
Gas	3 927	5 052	6 304	3 750	4 251	4 339	20	33	2.4	1.0
Power sector	**9 909**	**12 611**	**15 572**	**8 704**	**5 892**	**3 229**	**100**	**100**	**2.2**	**-3.6**
Coal	7 496	9 798	12 190	6 472	3 712	1 315	78	41	2.4	-5.7
Oil	617	509	457	554	319	238	3	7	-1.3	-3.7
Gas	1 796	2 305	2 925	1 678	1 860	1 676	19	52	2.2	0.1
TFC	**10 415**	**12 578**	**14 504**	**10 028**	**9 962**	**9 093**	**100**	**100**	**1.8**	**0.0**
Coal	3 901	4 246	4 403	3 753	3 232	2 593	30	29	0.6	-1.3
Oil	4 831	6 087	7 283	4 632	4 745	4 204	50	46	2.2	0.2
Transport	*3 375*	*4 503*	*5 583*	*3 240*	*3 445*	*2 977*	*38*	*33*	*2.8*	*0.4*
Gas	1 682	2 246	2 817	1 644	1 985	2 296	19	25	2.9	2.1

E. Europe/Eurasia: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**1 538**	**1 139**	**1 152**	**1 188**	**1 231**	**1 278**	**1 316**	**100**	**100**	**0.5**
Coal	367	219	211	214	214	222	223	19	17	0.1
Oil	468	225	236	237	238	236	230	20	17	0.1
Gas	603	569	557	567	585	605	624	50	47	0.3
Nuclear	59	75	88	101	111	117	123	7	9	1.9
Hydro	23	27	28	29	31	34	36	2	3	1.0
Bioenergy	17	22	26	30	35	44	52	2	4	3.3
Other renewables	0	2	5	10	15	22	29	0	2	11.4
Power sector	**742**	**579**	**562**	**570**	**585**	**609**	**632**	**100**	**100**	**0.3**
Coal	197	140	130	127	122	124	122	24	19	-0.5
Oil	125	13	12	10	9	8	7	2	1	-2.3
Gas	333	316	291	284	284	288	293	55	46	-0.3
Nuclear	59	75	88	101	111	117	123	13	19	1.9
Hydro	23	27	28	29	31	34	36	5	6	1.0
Bioenergy	4	7	8	10	12	18	23	1	4	4.8
Other renewables	0	1	5	9	14	21	27	0	4	11.8
Other energy sector	**199**	**213**	**212**	**216**	**219**	**222**	**224**	**100**	**100**	**0.2**
Electricity	*35*	*40*	*40*	*40*	*41*	*43*	*44*	*19*	*20*	*0.4*
TFC	**1 073**	**687**	**719**	**756**	**794**	**829**	**854**	**100**	**100**	**0.8**
Coal	114	40	41	44	47	49	52	6	6	0.9
Oil	280	173	187	193	200	202	200	25	23	0.5
Gas	261	196	208	220	233	246	256	29	30	1.0
Electricity	126	108	116	124	133	144	152	16	18	1.3
Heat	279	155	150	154	158	162	164	23	19	0.2
Bioenergy	13	15	17	20	22	25	28	2	3	2.4
Other renewables	-	0	0	1	1	1	1	0	0	7.7
Industry	**396**	**224**	**237**	**256**	**272**	**288**	**301**	**100**	**100**	**1.1**
Coal	56	31	32	35	38	41	44	14	15	1.3
Oil	52	22	25	26	26	26	26	10	9	0.5
Gas	86	66	70	76	81	86	91	30	30	1.1
Electricity	75	47	51	55	59	64	67	21	22	1.4
Heat	127	56	55	59	63	66	67	25	22	0.7
Bioenergy	0	2	3	3	4	5	6	1	2	4.2
Other renewables	-	0	0	0	0	0	0	0	0	24.8
Transport	**172**	**144**	**151**	**157**	**164**	**167**	**168**	**100**	**100**	**0.6**
Oil	123	101	108	111	115	115	113	70	67	0.4
Electricity	12	9	10	11	12	13	15	6	9	1.7
Biofuels	0	0	1	1	1	2	2	0	1	5.1
Other fuels	37	33	33	34	36	37	38	23	23	0.6
Buildings	**383**	**260**	**265**	**271**	**281**	**291**	**299**	**100**	**100**	**0.5**
Coal	56	8	8	8	7	7	7	3	2	-0.8
Oil	35	19	18	17	15	14	13	7	4	-1.4
Gas	111	80	86	90	95	100	104	31	35	1.0
Electricity	26	48	49	52	55	58	61	18	20	0.9
Heat	143	93	90	90	91	93	94	36	31	0.0
Bioenergy	12	12	14	15	17	18	20	5	7	1.9
Other renewables	-	0	0	0	1	1	1	0	0	6.3
Other	**122**	**58**	**66**	**72**	**77**	**83**	**87**	**100**	**100**	**1.5**

E. Europe/Eurasia: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**1 166**	**1 275**	**1 384**	**1 132**	**1 133**	**1 150**	**100**	**100**	**0.7**	**0.0**
Coal	218	230	251	196	139	115	18	10	0.5	-2.4
Oil	238	247	247	233	221	190	18	16	0.3	-0.6
Gas	564	621	686	548	527	505	50	44	0.7	-0.4
Nuclear	87	105	108	96	139	159	8	14	1.4	2.9
Hydro	28	30	34	28	36	44	2	4	0.8	1.8
Bioenergy	26	32	42	26	47	84	3	7	2.5	5.1
Other renewables	5	10	17	6	25	53	1	5	9.1	13.9
Power sector	**570**	**606**	**658**	**554**	**542**	**573**	**100**	**100**	**0.5**	**-0.0**
Coal	136	137	147	118	61	41	22	7	0.2	-4.5
Oil	12	9	7	11	9	7	1	1	-2.4	-2.5
Gas	295	304	330	287	253	224	50	39	0.2	-1.3
Nuclear	87	105	108	96	139	159	16	28	1.4	2.9
Hydro	28	30	34	28	36	44	5	8	0.8	1.8
Bioenergy	8	11	17	8	22	48	3	8	3.6	7.6
Other renewables	4	9	16	5	24	50	2	9	9.5	14.3
Other energy sector	**214**	**228**	**239**	**208**	**194**	**180**	**100**	**100**	**0.4**	**-0.6**
Electricity	*41*	*44*	*48*	*39*	*37*	*36*	*20*	*20*	*0.7*	*-0.3*
TFC	**727**	**824**	**906**	**706**	**735**	**739**	**100**	**100**	**1.0**	**0.3**
Coal	42	48	53	40	41	40	6	5	1.0	0.0
Oil	189	208	218	185	184	162	24	22	0.9	-0.2
Gas	210	243	274	203	213	220	30	30	1.2	0.4
Electricity	118	141	164	113	122	135	18	18	1.5	0.8
Heat	151	163	172	148	148	144	19	19	0.4	-0.3
Bioenergy	17	21	25	17	25	35	3	5	1.9	3.3
Other renewables	0	1	1	0	1	3	0	0	5.7	10.4
Industry	**240**	**283**	**318**	**231**	**247**	**255**	**100**	**100**	**1.3**	**0.5**
Coal	33	39	44	31	34	34	14	13	1.4	0.4
Oil	26	27	26	25	25	24	8	9	0.6	0.2
Gas	72	87	99	68	73	74	31	29	1.5	0.4
Electricity	52	62	71	49	53	59	22	23	1.6	0.9
Heat	55	65	71	55	57	56	22	22	0.9	-0.0
Bioenergy	3	4	6	3	5	7	2	3	4.6	5.3
Other renewables	0	0	0	0	0	1	0	0	24.1	31.0
Transport	**151**	**167**	**179**	**150**	**154**	**141**	**100**	**100**	**0.8**	**-0.1**
Oil	108	120	127	106	104	83	71	59	0.8	-0.7
Electricity	10	12	14	10	12	17	8	12	1.5	2.2
Biofuels	1	1	1	1	2	3	0	2	1.0	6.6
Other fuels	33	34	36	33	35	38	20	27	0.4	0.5
Buildings	**270**	**295**	**320**	**260**	**259**	**261**	**100**	**100**	**0.8**	**0.0**
Coal	8	8	8	8	6	5	2	2	-0.3	-1.6
Oil	19	17	15	18	13	10	5	4	-0.8	-2.3
Gas	88	101	115	84	84	85	36	33	1.3	0.2
Electricity	51	59	68	49	49	51	21	19	1.3	0.2
Heat	90	94	97	88	87	85	30	32	0.2	-0.3
Bioenergy	13	15	17	14	18	23	5	9	1.3	2.4
Other renewables	0	0	1	0	1	2	0	1	3.7	8.0
Other	**67**	**79**	**90**	**66**	**75**	**82**	**100**	**100**	**1.6**	**1.3**

E. Europe/Eurasia: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total generation	**1 894**	**1 740**	**1 830**	**1 929**	**2 051**	**2 185**	**2 298**	**100**	**100**	**1.0**
Coal	429	413	404	388	377	393	393	24	17	-0.2
Oil	256	18	14	10	8	5	4	1	0	-5.0
Gas	715	694	717	747	796	827	851	40	37	0.8
Nuclear	226	284	337	388	425	448	470	16	20	1.9
Hydro	267	316	323	342	365	390	417	18	18	1.0
Bioenergy	0	5	11	17	28	48	68	0	3	10.4
Wind	-	8	16	24	34	46	59	0	3	7.7
Geothermal	0	0	4	8	13	19	25	0	1	16.1
Solar PV	-	2	4	5	7	9	11	0	0	5.5
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	0	0	0	-	0	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total capacity	**437**	**455**	**463**	**479**	**504**	**527**	**100**	**100**	**0.7**
Coal	111	104	97	90	90	87	25	17	-0.9
Oil	21	16	10	6	5	4	5	1	-5.8
Gas	158	172	173	182	189	196	36	37	0.8
Nuclear	43	48	55	60	62	64	10	12	1.5
Hydro	95	102	107	113	120	127	22	24	1.1
Bioenergy	2	3	4	6	9	12	0	2	7.1
Wind	4	7	10	14	19	23	1	4	6.3
Geothermal	0	1	1	2	3	3	0	1	14.0
Solar PV	3	4	5	6	8	10	1	2	5.0
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	0	0	0	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total CO_2	**3 940**	**2 578**	**2 565**	**2 581**	**2 608**	**2 657**	**2 674**	**100**	**100**	**0.1**
Coal	1 376	785	754	755	747	769	768	30	29	-0.1
Oil	1 191	545	571	569	570	560	544	21	20	-0.0
Gas	1 373	1 248	1 240	1 257	1 291	1 328	1 362	48	51	0.3
Power sector	**2 001**	**1 371**	**1 268**	**1 231**	**1 207**	**1 219**	**1 219**	**100**	**100**	**-0.4**
Coal	817	580	543	529	508	517	506	42	42	-0.5
Oil	402	45	37	33	29	25	23	3	2	-2.4
Gas	782	746	688	670	670	677	689	54	57	-0.3
TFC	**1 830**	**1 070**	**1 123**	**1 171**	**1 217**	**1 253**	**1 273**	**100**	**100**	**0.6**
Coal	548	196	202	217	229	242	251	18	20	0.9
Oil	726	449	472	478	485	481	469	42	37	0.2
Transport	*369*	*302*	*320*	*330*	*342*	*343*	*337*	*28*	*26*	*0.4*
Gas	555	424	449	476	502	530	552	40	43	1.0

E. Europe/Eurasia: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**1 865**	**2 170**	**2 480**	**1 790**	**1 864**	**2 008**	**100**	**100**	**1.3**	**0.5**
Coal	424	432	484	357	162	96	19	5	0.6	-5.3
Oil	14	8	4	13	6	3	0	0	-5.0	-6.4
Gas	739	912	1 074	692	588	410	43	20	1.6	-1.9
Nuclear	335	403	412	368	532	610	17	30	1.4	2.9
Hydro	321	354	395	323	415	512	16	25	0.8	1.8
Bioenergy	11	23	47	12	61	155	2	8	8.9	13.8
Wind	16	25	43	18	70	159	2	8	6.4	11.7
Geothermal	3	8	13	4	19	40	1	2	13.4	18.1
Solar PV	4	5	7	4	10	23	0	1	4.1	8.5
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	0	-	0	1	0	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**461**	**505**	**556**	**453**	**470**	**545**	**100**	**100**	**0.9**	**0.8**
Coal	108	102	105	95	56	37	19	7	-0.2	-4.0
Oil	16	6	4	15	6	3	1	1	-6.3	-6.6
Gas	174	209	237	172	154	153	43	28	1.5	-0.1
Nuclear	48	56	57	52	75	86	10	16	1.0	2.6
Hydro	101	110	121	102	127	154	22	28	0.9	1.8
Bioenergy	3	5	8	3	11	26	1	5	5.7	10.3
Wind	7	11	17	8	29	60	3	11	5.1	10.1
Geothermal	0	1	2	1	3	5	0	1	11.3	16.0
Solar PV	3	5	7	4	10	21	1	4	3.5	8.0
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	0	-	0	0	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**2 617**	**2 782**	**2 983**	**2 475**	**2 074**	**1 766**	**100**	**100**	**0.5**	**-1.4**
Coal	784	816	881	697	436	323	30	18	0.4	-3.2
Oil	577	596	600	562	513	413	20	23	0.4	-1.0
Gas	1 256	1 371	1 502	1 217	1 124	1 030	50	58	0.7	-0.7
Power sector	**1 304**	**1 318**	**1 414**	**1 208**	**864**	**695**	**100**	**100**	**0.1**	**-2.5**
Coal	570	571	613	493	248	161	43	23	0.2	-4.6
Oil	38	29	23	37	28	22	2	3	-2.4	-2.6
Gas	696	718	778	678	588	512	55	74	0.2	-1.4
TFC	**1 137**	**1 271**	**1 374**	**1 097**	**1 059**	**943**	**100**	**100**	**0.9**	**-0.5**
Coal	205	235	258	195	181	157	19	17	1.0	-0.8
Oil	477	509	522	464	438	352	38	37	0.6	-0.9
Transport	*322*	*358*	*379*	*316*	*310*	*248*	*28*	*26*	*0.9*	*-0.7*
Gas	455	527	594	437	440	434	43	46	1.3	0.1

Russia: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**880**	**715**	**702**	**716**	**735**	**758**	**774**	**100**	**100**	**0.3**
Coal	191	108	107	115	114	116	113	15	15	0.2
Oil	264	143	144	143	142	138	132	20	17	-0.3
Gas	367	395	367	361	367	374	382	55	49	-0.1
Nuclear	31	45	56	64	71	78	84	6	11	2.3
Hydro	14	16	16	17	19	20	22	2	3	1.2
Bioenergy	12	7	9	10	12	17	22	1	3	4.1
Other renewables	0	0	3	6	10	14	19	0	2	14.9
Power sector	**444**	**399**	**382**	**388**	**397**	**413**	**427**	**100**	**100**	**0.3**
Coal	105	70	67	72	69	70	67	17	16	-0.1
Oil	62	10	10	9	8	7	6	3	1	-1.8
Gas	228	253	225	214	212	212	212	63	50	-0.6
Nuclear	31	45	56	64	71	78	84	11	20	2.3
Hydro	14	16	16	17	19	20	22	4	5	1.2
Bioenergy	4	4	5	6	8	12	16	1	4	4.8
Other renewables	0	0	3	6	10	14	19	0	4	14.9
Other energy sector	**127**	**141**	**137**	**135**	**133**	**131**	**131**	**100**	**100**	**-0.3**
Electricity	*21*	*26*	*25*	*25*	*26*	*26*	*27*	*18*	*20*	*0.1*
TFC	**625**	**417**	**421**	**440**	**460**	**476**	**485**	**100**	**100**	**0.6**
Coal	55	12	12	13	14	14	14	3	3	0.7
Oil	145	101	105	107	110	110	107	24	22	0.2
Gas	143	114	116	123	129	135	140	27	29	0.8
Electricity	71	64	66	70	76	81	85	15	18	1.1
Heat	203	124	119	123	127	130	132	30	27	0.3
Bioenergy	8	3	3	4	4	5	6	1	1	3.0
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Industry	**209**	**144**	**146**	**157**	**166**	**173**	**177**	**100**	**100**	**0.8**
Coal	15	9	9	10	11	12	12	6	7	1.3
Oil	25	12	14	15	15	14	14	8	8	0.4
Gas	30	46	47	50	52	54	55	32	31	0.6
Electricity	41	29	30	32	34	37	38	20	21	1.0
Heat	98	47	46	49	52	55	56	33	32	0.6
Bioenergy	-	0	1	1	1	2	2	0	1	6.2
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Transport	**116**	**94**	**95**	**97**	**101**	**102**	**101**	**100**	**100**	**0.3**
Oil	73	59	61	61	62	61	58	64	58	-0.1
Electricity	9	8	8	9	10	11	12	8	12	1.6
Biofuels	-	-	-	-	-	-	-	-	-	n.a.
Other fuels	34	26	26	27	28	29	30	28	30	0.5
Buildings	**228**	**145**	**143**	**145**	**150**	**154**	**157**	**100**	**100**	**0.3**
Coal	40	3	2	2	2	2	2	2	1	-2.0
Oil	12	9	8	7	6	5	4	6	3	-3.0
Gas	57	34	35	37	39	41	43	23	28	0.9
Electricity	15	26	26	27	29	31	32	18	20	0.7
Heat	98	71	69	70	71	72	73	49	47	0.1
Bioenergy	7	2	2	2	3	3	3	1	2	1.7
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Other	**72**	**35**	**37**	**41**	**44**	**48**	**50**	**100**	**100**	**1.4**

Russia: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**707**	**759**	**813**	**690**	**677**	**677**	**100**	**100**	**0.5**	**-0.2**
Coal	111	120	128	97	66	53	16	8	0.6	-2.6
Oil	146	146	141	143	133	111	17	16	-0.0	-0.9
Gas	368	389	423	358	328	302	52	45	0.3	-1.0
Nuclear	56	68	74	64	88	102	9	15	1.8	3.0
Hydro	16	18	21	16	22	27	3	4	1.1	2.0
Bioenergy	9	11	16	9	22	46	2	7	3.1	7.1
Other renewables	2	6	10	3	17	38	1	6	12.3	17.9
Power sector	**385**	**408**	**442**	**377**	**368**	**389**	**100**	**100**	**0.4**	**-0.1**
Coal	70	75	82	59	31	23	19	6	0.6	-4.0
Oil	10	8	6	10	8	6	1	2	-1.8	-1.9
Gas	225	225	237	220	186	157	54	40	-0.2	-1.8
Nuclear	56	68	74	64	88	102	17	26	1.8	3.0
Hydro	16	18	21	16	22	27	5	7	1.1	2.0
Bioenergy	5	7	11	6	16	37	3	9	3.5	8.2
Other renewables	2	6	10	3	17	38	2	10	12.3	17.8
Other energy sector	**138**	**138**	**141**	**134**	**116**	**101**	**100**	**100**	**-0.0**	**-1.2**
Electricity	*26*	*27*	*30*	*25*	*23*	*22*	*21*	*22*	*0.5*	*-0.6*
TFC	**425**	**478**	**517**	**414**	**427**	**421**	**100**	**100**	**0.8**	**0.0**
Coal	12	14	14	12	11	10	3	2	0.7	-0.5
Oil	105	114	116	103	103	88	22	21	0.5	-0.5
Gas	117	135	152	114	119	122	29	29	1.1	0.3
Electricity	67	81	93	64	70	77	18	18	1.4	0.7
Heat	120	130	137	118	118	114	26	27	0.4	-0.3
Bioenergy	3	4	5	3	6	9	1	2	2.5	4.5
Other renewables	0	0	0	0	0	1	0	0	n.a.	n.a.
Industry	**148**	**173**	**188**	**142**	**150**	**150**	**100**	**100**	**1.0**	**0.2**
Coal	9	11	12	9	9	8	6	6	1.2	-0.1
Oil	14	15	14	14	14	13	7	9	0.5	0.3
Gas	47	56	62	45	47	46	33	31	1.1	-0.0
Electricity	30	36	40	29	31	33	21	22	1.2	0.5
Heat	46	53	59	45	47	46	31	30	0.8	-0.1
Bioenergy	1	1	2	1	2	3	1	2	6.1	7.0
Other renewables	0	0	0	0	0	1	0	0	n.a.	n.a.
Transport	**95**	**102**	**106**	**94**	**96**	**86**	**100**	**100**	**0.5**	**-0.3**
Oil	61	65	65	60	57	43	62	50	0.3	-1.2
Electricity	8	10	12	8	10	14	11	16	1.5	2.1
Biofuels	-	-	-	-	-	-	-	-	n.a.	n.a.
Other fuels	26	28	29	26	28	30	27	35	0.4	0.5
Buildings	**145**	**157**	**170**	**141**	**138**	**136**	**100**	**100**	**0.6**	**-0.2**
Coal	3	2	2	3	2	1	1	1	-1.6	-2.8
Oil	8	7	6	8	5	3	3	2	-1.8	-4.2
Gas	35	42	49	34	35	36	29	26	1.4	0.2
Electricity	27	31	36	26	26	26	21	19	1.2	0.0
Heat	70	72	74	68	67	66	44	48	0.2	-0.3
Bioenergy	2	2	3	2	3	5	2	4	0.9	3.2
Other renewables	0	0	0	0	0	0	0	0	n.a.	n.a.
Other	**37**	**46**	**53**	**37**	**43**	**48**	**100**	**100**	**1.5**	**1.2**

Russia: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total generation	**1 082**	**1 058**	**1 072**	**1 128**	**1 195**	**1 264**	**1 313**	**100**	**100**	**0.8**
Coal	157	162	168	182	172	176	168	15	13	0.1
Oil	129	9	8	6	5	3	3	1	0	-4.2
Gas	512	530	484	475	497	494	484	50	37	-0.3
Nuclear	118	173	214	245	271	298	322	16	25	2.3
Hydro	166	181	188	200	217	234	253	17	19	1.2
Bioenergy	0	3	7	10	17	31	45	0	3	10.6
Wind	-	0	0	2	6	11	16	0	1	34.9
Geothermal	0	0	3	7	10	15	20	0	2	15.2
Solar PV	-	-	0	0	0	1	1	-	0	n.a.
CSP	-	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total capacity	**244**	**247**	**249**	**257**	**267**	**275**	**100**	**100**	**0.5**
Coal	49	46	44	38	36	33	20	12	-1.5
Oil	4	3	2	2	1	1	2	1	-3.5
Gas	115	112	108	112	112	111	47	40	-0.1
Nuclear	25	30	34	37	41	44	10	16	2.1
Hydro	50	53	56	60	65	69	20	25	1.3
Bioenergy	1	2	2	4	6	8	1	3	6.4
Wind	0	0	1	2	4	5	0	2	24.3
Geothermal	0	0	1	1	2	3	0	1	13.5
Solar PV	-	0	0	1	1	1	-	0	n.a.
CSP	-	-	-	-	-	-	-	-	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total CO_2	**2 163**	**1 547**	**1 513**	**1 519**	**1 515**	**1 519**	**1 500**	**100**	**100**	**-0.1**
Coal	707	360	357	384	377	384	371	23	25	0.1
Oil	619	315	326	317	313	299	283	20	19	-0.4
Gas	837	872	830	818	826	835	846	56	56	-0.1
Power sector	**1 177**	**922**	**845**	**837**	**819**	**817**	**804**	**100**	**100**	**-0.5**
Coal	443	290	283	305	294	298	285	31	35	-0.1
Oil	199	35	31	28	25	22	21	4	3	-1.9
Gas	535	597	531	504	500	496	498	65	62	-0.7
TFC	**932**	**564**	**575**	**592**	**609**	**617**	**613**	**100**	**100**	**0.3**
Coal	263	65	69	74	77	80	80	12	13	0.8
Oil	383	248	252	249	250	242	228	44	37	-0.3
Transport	*219*	*176*	*180*	*180*	*185*	*182*	*173*	*31*	*28*	*-0.1*
Gas	286	251	254	269	282	295	305	44	50	0.7

Russia: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**1 089**	**1 268**	**1 436**	**1 050**	**1 089**	**1 166**	**100**	**100**	**1.1**	**0.4**
Coal	172	187	212	139	55	34	15	3	1.0	-5.6
Oil	8	5	2	8	5	2	0	0	-4.6	-5.1
Gas	497	581	650	457	342	169	45	15	0.8	-4.1
Nuclear	214	261	282	245	338	389	20	33	1.8	3.1
Hydro	188	211	240	188	250	312	17	27	1.1	2.0
Bioenergy	7	13	30	7	46	119	2	10	9.0	14.7
Wind	0	2	8	2	36	101	1	9	31.6	44.4
Geothermal	3	7	11	3	16	33	1	3	12.6	17.3
Solar PV	0	0	0	0	1	5	0	0	n.a.	n.a.
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	-	-	0	1	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**250**	**274**	**297**	**250**	**251**	**294**	**100**	**100**	**0.7**	**0.7**
Coal	48	42	41	42	20	11	14	4	-0.7	-5.4
Oil	3	2	1	3	1	1	0	0	-4.4	-5.5
Gas	113	131	141	113	88	77	47	26	0.8	-1.5
Nuclear	30	36	39	35	47	53	13	18	1.6	2.8
Hydro	53	59	66	53	69	85	22	29	1.1	2.0
Bioenergy	2	3	5	2	9	20	2	7	4.9	10.1
Wind	0	1	3	1	14	37	1	13	21.5	33.4
Geothermal	0	1	1	0	2	4	0	1	11.0	15.6
Solar PV	0	0	0	0	1	6	0	2	n.a.	n.a.
CSP	-	-	-	-	-	-	-	-	n.a.	n.a.
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**1 534**	**1 604**	**1 688**	**1 451**	**1 180**	**958**	**100**	**100**	**0.3**	**-1.8**
Coal	372	403	435	319	182	125	26	13	0.7	-3.9
Oil	329	325	312	321	286	215	18	22	-0.0	-1.4
Gas	833	875	941	811	712	618	56	65	0.3	-1.3
Power sector	**860**	**877**	**930**	**798**	**583**	**463**	**100**	**100**	**0.0**	**-2.5**
Coal	297	320	350	248	127	89	38	19	0.7	-4.3
Oil	31	25	20	31	25	20	2	4	-1.9	-2.0
Gas	531	532	559	519	431	354	60	76	-0.2	-1.9
TFC	**581**	**636**	**666**	**563**	**525**	**438**	**100**	**100**	**0.6**	**-0.9**
Coal	70	78	79	66	51	33	12	8	0.7	-2.4
Oil	254	261	255	248	227	168	38	38	0.1	-1.4
Transport	*181*	*193*	*194*	*177*	*170*	*127*	*29*	*29*	*0.4*	*-1.2*
Gas	257	297	332	249	246	236	50	54	1.0	-0.2

Non-OECD Asia: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**1 579**	**4 693**	**5 478**	**6 023**	**6 592**	**7 094**	**7 518**	**100**	**100**	**1.8**
Coal	684	2 550	2 761	2 912	3 096	3 244	3 345	54	44	1.0
Oil	320	957	1 157	1 284	1 404	1 507	1 594	20	21	1.9
Gas	69	378	530	639	747	858	958	8	13	3.5
Nuclear	10	50	140	215	285	337	383	1	5	7.8
Hydro	24	106	138	158	178	194	205	2	3	2.5
Bioenergy	466	586	622	640	655	670	688	12	9	0.6
Other renewables	7	65	129	175	227	284	344	1	5	6.4
Power sector	**323**	**1 779**	**2 230**	**2 542**	**2 885**	**3 208**	**3 493**	**100**	**100**	**2.5**
Coal	220	1 368	1 550	1 655	1 798	1 927	2 030	77	58	1.5
Oil	46	38	34	31	30	28	26	2	1	-1.4
Gas	16	138	188	235	277	327	372	8	11	3.7
Nuclear	10	50	140	215	285	337	383	3	11	7.8
Hydro	24	106	138	158	178	194	205	6	6	2.5
Bioenergy	0	38	85	113	138	165	191	2	5	6.2
Other renewables	7	41	94	134	179	230	285	2	8	7.4
Other energy sector	**170**	**700**	**706**	**728**	**762**	**792**	**807**	**100**	**100**	**0.5**
Electricity	*26*	*119*	*147*	*165*	*188*	*210*	*229*	*17*	*28*	*2.5*
TFC	**1 212**	**2 985**	**3 552**	**3 927**	**4 292**	**4 605**	**4 875**	**100**	**100**	**1.8**
Coal	392	762	811	841	861	867	865	26	18	0.5
Oil	240	848	1 048	1 179	1 303	1 407	1 499	28	31	2.1
Gas	31	180	287	361	434	500	556	6	11	4.3
Electricity	83	563	762	905	1 056	1 201	1 332	19	27	3.2
Heat	14	77	90	93	92	90	85	3	2	0.4
Bioenergy	451	531	519	508	498	486	477	18	10	-0.4
Other renewables	0	24	35	41	48	54	60	1	1	3.5
Industry	**400**	**1 251**	**1 488**	**1 645**	**1 794**	**1 923**	**2 027**	**100**	**100**	**1.8**
Coal	237	616	653	678	700	711	717	49	35	0.6
Oil	53	107	121	126	130	132	133	9	7	0.8
Gas	9	84	141	182	221	259	291	7	14	4.7
Electricity	51	337	439	507	574	638	692	27	34	2.7
Heat	11	52	62	65	64	61	56	4	3	0.3
Bioenergy	39	55	71	87	103	118	130	4	6	3.2
Other renewables	0	0	0	1	2	4	7	0	0	13.9
Transport	**104**	**477**	**639**	**759**	**870**	**967**	**1 065**	**100**	**100**	**3.0**
Oil	91	443	584	687	778	855	928	93	87	2.8
Electricity	1	7	11	14	18	22	27	1	3	5.4
Biofuels	-	4	11	17	24	31	42	1	4	8.7
Other fuels	12	23	33	41	50	59	67	5	6	4.0
Buildings	**587**	**945**	**1 035**	**1 080**	**1 139**	**1 188**	**1 229**	**100**	**100**	**1.0**
Coal	110	94	91	86	81	75	68	10	6	-1.2
Oil	34	92	91	85	84	83	82	10	7	-0.4
Gas	5	51	81	99	118	134	145	5	12	3.9
Electricity	22	189	273	340	415	486	554	20	45	4.1
Heat	3	25	28	28	29	29	29	3	2	0.6
Bioenergy	412	472	436	402	368	333	300	50	24	-1.7
Other renewables	0	23	34	39	45	48	51	2	4	3.0
Other	**121**	**311**	**391**	**443**	**490**	**527**	**554**	**100**	**100**	**2.2**

Non-OECD Asia: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**5 608**	**7 079**	**8 387**	**5 304**	**5 836**	**6 275**	**100**	**100**	**2.2**	**1.1**
Coal	2 872	3 570	4 206	2 612	2 190	1 875	50	30	1.9	-1.1
Oil	1 180	1 500	1 784	1 135	1 224	1 168	21	19	2.3	0.7
Gas	539	765	990	517	734	920	12	15	3.6	3.3
Nuclear	140	262	329	140	421	627	4	10	7.2	9.8
Hydro	136	165	188	138	192	232	2	4	2.1	2.9
Bioenergy	620	635	639	621	731	868	8	14	0.3	1.5
Other renewables	120	182	250	140	344	586	3	9	5.1	8.5
Power sector	**2 318**	**3 211**	**4 053**	**2 094**	**2 380**	**2 760**	**100**	**100**	**3.1**	**1.6**
Coal	1 642	2 198	2 767	1 416	991	725	68	26	2.6	-2.3
Oil	34	31	27	32	25	20	1	1	-1.2	-2.3
Gas	196	291	382	178	291	369	9	13	3.8	3.7
Nuclear	140	262	329	140	421	627	8	23	7.2	9.8
Hydro	136	165	188	138	192	232	5	8	2.1	2.9
Bioenergy	83	124	157	86	178	285	4	10	5.4	7.8
Other renewables	86	140	201	104	282	502	5	18	6.0	9.7
Other energy sector	**719**	**812**	**902**	**694**	**693**	**676**	**100**	**100**	**0.9**	**-0.1**
Electricity	*153*	*212*	*272*	*141*	*159*	*175*	*30*	*26*	*3.1*	*1.4*
TFC	**3 613**	**4 515**	**5 283**	**3 488**	**3 943**	**4 207**	**100**	**100**	**2.1**	**1.3**
Coal	826	912	942	800	779	737	18	18	0.8	-0.1
Oil	1 070	1 394	1 682	1 029	1 138	1 100	32	26	2.6	1.0
Gas	287	439	579	285	418	536	11	13	4.4	4.1
Electricity	786	1 135	1 466	731	927	1 113	28	26	3.6	2.6
Heat	91	101	102	89	85	73	2	2	1.0	-0.2
Bioenergy	519	493	463	518	534	564	9	13	-0.5	0.2
Other renewables	34	42	49	36	62	85	1	2	2.7	4.8
Industry	**1 520**	**1 903**	**2 217**	**1 464**	**1 640**	**1 762**	**100**	**100**	**2.1**	**1.3**
Coal	666	742	782	646	640	621	35	35	0.9	0.0
Oil	124	141	149	119	117	116	7	7	1.2	0.3
Gas	143	234	321	139	204	252	14	14	5.1	4.2
Electricity	450	609	757	426	512	583	34	33	3.0	2.1
Heat	63	71	70	62	58	47	3	3	1.1	-0.4
Bioenergy	72	106	135	70	101	127	6	7	3.4	3.1
Other renewables	0	1	3	1	9	17	0	1	10.5	17.5
Transport	**647**	**911**	**1 168**	**627**	**788**	**862**	**100**	**100**	**3.4**	**2.2**
Oil	599	844	1 071	572	645	576	92	67	3.3	1.0
Electricity	11	16	23	11	25	63	2	7	4.7	8.8
Biofuels	10	18	28	11	59	118	2	14	7.0	12.9
Other fuels	28	33	46	34	60	106	4	12	2.5	5.8
Buildings	**1 054**	**1 199**	**1 318**	**1 010**	**1 035**	**1 047**	**100**	**100**	**1.2**	**0.4**
Coal	94	88	75	88	65	43	6	4	-0.8	-2.9
Oil	94	91	91	87	71	65	7	6	-0.0	-1.3
Gas	83	128	159	80	109	123	12	12	4.3	3.3
Electricity	286	456	621	258	343	414	47	40	4.5	3.0
Heat	28	30	32	27	27	26	2	2	0.9	0.2
Bioenergy	436	366	295	436	370	310	22	30	-1.7	-1.5
Other renewables	33	40	45	35	52	66	3	6	2.5	4.0
Other	**393**	**502**	**580**	**387**	**479**	**535**	**100**	**100**	**2.3**	**2.0**

Non-OECD Asia: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total generation	**1 274**	**7 906**	**10 547**	**12 419**	**14 441**	**16 380**	**18 132**	**100**	**100**	**3.1**
Coal	728	5 380	6 337	6 914	7 683	8 398	8 996	68	50	1.9
Oil	167	136	116	104	96	90	81	2	0	-1.9
Gas	59	659	971	1 282	1 567	1 900	2 221	8	12	4.6
Nuclear	39	192	538	824	1 092	1 292	1 471	2	8	7.8
Hydro	274	1 237	1 605	1 839	2 072	2 259	2 388	16	13	2.5
Bioenergy	1	87	253	353	443	539	635	1	4	7.6
Wind	0	175	513	746	971	1 206	1 445	2	8	8.1
Geothermal	7	19	30	40	52	68	86	0	0	5.7
Solar PV	0	21	181	307	442	584	731	0	4	14.0
CSP	-	0	4	9	22	44	73	0	0	51.4
Marine	-	0	0	0	1	2	3	0	0	24.0

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)
	2013	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total capacity	**1 855**	**2 714**	**3 255**	**3 800**	**4 293**	**4 711**	**100**	**100**	**3.5**
Coal	1 051	1 329	1 467	1 625	1 764	1 870	57	40	2.2
Oil	63	64	65	65	63	57	3	1	-0.4
Gas	183	292	363	431	498	560	10	12	4.2
Nuclear	29	74	112	146	172	197	2	4	7.4
Hydro	382	505	587	668	732	775	21	16	2.7
Bioenergy	23	51	68	83	99	114	1	2	6.1
Wind	100	255	356	445	525	595	5	13	6.8
Geothermal	3	5	6	8	10	13	0	0	5.4
Solar PV	22	138	230	323	418	512	1	11	12.4
CSP	0	1	3	6	12	19	0	0	22.4
Marine	0	0	0	0	1	1	0	0	22.6

	CO_2 emissions (Mt)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total CO_2	**3 429**	**12 186**	**13 819**	**14 853**	**15 981**	**16 947**	**17 729**	**100**	**100**	**1.4**
Coal	2 505	9 106	9 894	10 357	10 944	11 403	11 729	75	66	0.9
Oil	816	2 277	2 762	3 074	3 357	3 602	3 823	19	22	1.9
Gas	108	802	1 163	1 422	1 680	1 941	2 176	7	12	3.8
Power sector	**1 066**	**5 930**	**6 769**	**7 267**	**7 897**	**8 485**	**8 950**	**100**	**100**	**1.5**
Coal	878	5 486	6 219	6 616	7 151	7 625	7 992	92	89	1.4
Oil	150	121	107	99	94	89	82	2	1	-1.4
Gas	38	324	442	552	652	770	876	5	10	3.8
TFC	**2 208**	**5 793**	**6 570**	**7 113**	**7 613**	**7 988**	**8 302**	**100**	**100**	**1.3**
Coal	1 566	3 390	3 462	3 529	3 583	3 572	3 539	59	43	0.2
Oil	609	2 039	2 523	2 844	3 131	3 374	3 599	35	43	2.1
Transport	*273*	*1 330*	*1 762*	*2 074*	*2 348*	*2 579*	*2 802*	*23*	*34*	*2.8*
Gas	32	364	584	739	899	1 041	1 164	6	14	4.4

Non-OECD Asia: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**10 898**	**15 630**	**20 179**	**10 123**	**12 597**	**14 950**	**100**	**100**	**3.5**	**2.4**
Coal	6 749	9 424	12 178	5 869	4 239	2 851	60	19	3.1	-2.3
Oil	116	100	85	111	78	64	0	0	-1.7	-2.7
Gas	1 010	1 647	2 294	917	1 691	2 246	11	15	4.7	4.6
Nuclear	538	1 004	1 265	538	1 615	2 405	6	16	7.2	9.8
Hydro	1 585	1 919	2 193	1 605	2 236	2 702	11	18	2.1	2.9
Bioenergy	247	393	511	255	577	966	3	6	6.8	9.3
Wind	475	797	1 111	587	1 385	2 084	6	14	7.1	9.6
Geothermal	28	42	62	31	105	160	0	1	4.5	8.2
Solar PV	147	294	455	204	614	1 073	2	7	12.0	15.6
CSP	3	9	23	5	55	394	0	3	44.9	61.2
Marine	0	0	2	0	2	5	0	0	23.0	26.6

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**2 732**	**3 821**	**4 736**	**2 698**	**3 704**	**4 585**	**100**	**100**	**3.5**	**3.4**
Coal	1 393	1 874	2 298	1 275	1 078	912	49	20	2.9	-0.5
Oil	64	65	57	63	62	52	1	1	-0.3	-0.7
Gas	297	455	597	278	440	561	13	12	4.5	4.2
Nuclear	74	134	169	74	215	321	4	7	6.8	9.3
Hydro	498	613	706	505	724	882	15	19	2.3	3.1
Bioenergy	49	73	91	51	105	167	2	4	5.2	7.6
Wind	239	376	475	291	608	818	10	18	5.9	8.1
Geothermal	5	7	10	5	16	24	0	1	4.2	7.8
Solar PV	113	222	328	153	441	744	7	16	10.6	14.0
CSP	1	3	6	2	15	103	0	2	17.2	30.4
Marine	0	0	1	0	1	2	0	0	21.6	25.2

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**14 343**	**18 203**	**21 786**	**13 104**	**10 750**	**7 849**	**100**	**100**	**2.2**	**-1.6**
Coal	10 335	12 847	15 162	9 276	6 325	3 462	70	44	1.9	-3.5
Oil	2 828	3 632	4 367	2 697	2 816	2 531	20	32	2.4	0.4
Gas	1 180	1 724	2 257	1 131	1 608	1 856	10	24	3.9	3.2
Power sector	**7 155**	**9 594**	**12 046**	**6 194**	**4 015**	**1 825**	**100**	**100**	**2.7**	**-4.3**
Coal	6 587	8 811	11 060	5 673	3 270	1 057	92	58	2.6	-5.9
Oil	107	98	87	102	78	64	1	3	-1.2	-2.3
Gas	460	685	899	418	667	704	7	39	3.9	2.9
TFC	**6 697**	**8 103**	**9 197**	**6 442**	**6 362**	**5 712**	**100**	**100**	**1.7**	**-0.1**
Coal	3 529	3 803	3 867	3 398	2 895	2 278	42	40	0.5	-1.5
Oil	2 586	3 394	4 120	2 466	2 632	2 379	45	42	2.6	0.6
Transport	*1 806*	*2 549*	*3 235*	*1 725*	*1 945*	*1 737*	*35*	*30*	*3.3*	*1.0*
Gas	582	907	1 211	578	835	1 054	13	18	4.6	4.0

China: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**879**	**3 037**	**3 412**	**3 649**	**3 848**	**3 971**	**4 020**	**100**	**100**	**1.0**
Coal	533	2 053	2 060	2 070	2 078	2 053	1 978	68	49	-0.1
Oil	122	483	590	647	685	702	710	16	18	1.4
Gas	13	142	252	317	375	422	456	5	11	4.4
Nuclear	-	29	104	167	217	255	287	1	7	8.9
Hydro	11	78	103	113	124	131	134	3	3	2.0
Bioenergy	200	216	222	227	234	244	258	7	6	0.7
Other renewables	0	37	81	108	136	165	197	1	5	6.4
Power sector	**181**	**1 218**	**1 470**	**1 638**	**1 799**	**1 931**	**2 018**	**100**	**100**	**1.9**
Coal	153	1 047	1 095	1 123	1 163	1 191	1 185	86	59	0.5
Oil	16	5	5	5	4	4	3	0	0	-1.6
Gas	1	27	65	93	118	139	158	2	8	6.7
Nuclear	-	29	104	167	217	255	287	2	14	8.9
Hydro	11	78	103	113	124	131	134	6	7	2.0
Bioenergy	-	19	51	68	81	94	106	2	5	6.6
Other renewables	0	13	48	69	92	117	145	1	7	9.2
Other energy sector	**100**	**555**	**535**	**532**	**534**	**529**	**512**	**100**	**100**	**-0.3**
Electricity	*15*	*79*	*93*	*100*	*109*	*117*	*122*	*14*	*24*	*1.6*
TFC	**669**	**1 821**	**2 117**	**2 280**	**2 403**	**2 470**	**2 498**	**100**	**100**	**1.2**
Coal	318	605	596	575	537	487	432	33	17	-1.2
Oil	87	439	545	607	649	670	683	24	27	1.6
Gas	9	91	165	211	253	284	305	5	12	4.6
Electricity	41	390	517	599	677	743	791	21	32	2.7
Heat	13	76	89	92	91	88	84	4	3	0.4
Bioenergy	200	197	171	158	152	150	151	11	6	-1.0
Other renewables	0	23	34	38	44	48	52	1	2	3.0
Industry	**245**	**881**	**995**	**1 044**	**1 075**	**1 082**	**1 069**	**100**	**100**	**0.7**
Coal	181	475	457	430	394	347	298	54	28	-1.7
Oil	21	60	65	64	61	58	53	7	5	-0.4
Gas	3	33	68	92	112	129	141	4	13	5.6
Electricity	30	261	335	380	422	458	484	30	45	2.3
Heat	11	52	62	64	63	60	56	6	5	0.3
Bioenergy	-	-	7	15	21	27	31	-	3	n.a.
Other renewables	-	0	0	1	2	3	5	0	0	13.2
Transport	**35**	**249**	**346**	**416**	**465**	**494**	**520**	**100**	**100**	**2.8**
Oil	25	227	310	368	403	420	433	91	83	2.4
Electricity	1	5	9	11	15	19	24	2	5	6.0
Biofuels	-	2	5	9	14	19	24	1	5	10.3
Other fuels	10	16	23	28	34	37	39	6	7	3.4
Buildings	**314**	**506**	**545**	**561**	**582**	**597**	**603**	**100**	**100**	**0.6**
Coal	95	77	73	69	64	60	54	15	9	-1.3
Oil	8	43	38	30	24	18	13	8	2	-4.4
Gas	2	36	62	76	91	100	106	7	18	4.1
Electricity	6	108	156	189	221	246	264	21	44	3.3
Heat	2	24	27	27	28	28	28	5	5	0.6
Bioenergy	200	195	158	133	114	101	92	39	15	-2.7
Other renewables	0	22	33	37	41	44	46	4	8	2.7
Other	**75**	**184**	**230**	**258**	**281**	**296**	**306**	**100**	**100**	**1.9**

China: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2013-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
TPED	**3 502**	**4 180**	**4 596**	**3 300**	**3 388**	**3 416**	**100**	**100**	**1.5**	**0.4**
Coal	2 144	2 410	2 550	1 966	1 542	1 247	55	36	0.8	-1.8
Oil	603	741	813	575	572	480	18	14	1.9	-0.0
Gas	251	367	455	244	364	429	10	13	4.4	4.2
Nuclear	104	206	261	104	325	453	6	13	8.5	10.7
Hydro	101	117	128	103	126	137	3	4	1.8	2.1
Bioenergy	221	227	242	222	282	363	5	11	0.4	1.9
Other renewables	77	112	147	86	178	308	3	9	5.3	8.2
Power sector	**1 534**	**2 024**	**2 392**	**1 385**	**1 494**	**1 664**	**100**	**100**	**2.5**	**1.2**
Coal	1 164	1 435	1 655	1 011	689	530	69	32	1.7	-2.5
Oil	5	5	4	5	4	2	0	0	-1.0	-3.1
Gas	64	110	143	60	123	153	6	9	6.3	6.6
Nuclear	104	206	261	104	325	453	11	27	8.5	10.7
Hydro	101	117	128	103	126	137	5	8	1.8	2.1
Bioenergy	51	78	97	52	104	147	4	9	6.3	7.9
Other renewables	44	73	104	52	125	242	4	15	7.9	11.3
Other energy sector	**544**	**566**	**569**	**526**	**489**	**436**	**100**	**100**	**0.1**	**-0.9**
Electricity	*96*	*121*	*142*	*89*	*92*	*93*	*25*	*21*	*2.2*	*0.6*
TFC	**2 157**	**2 558**	**2 779**	**2 075**	**2 188**	**2 160**	**100**	**100**	**1.6**	**0.6**
Coal	608	578	495	588	485	375	18	17	-0.7	-1.8
Oil	557	704	783	532	544	465	28	22	2.2	0.2
Gas	164	254	322	163	245	296	12	14	4.8	4.5
Electricity	536	737	892	499	599	672	32	31	3.1	2.0
Heat	90	100	100	88	84	72	4	3	1.0	-0.2
Bioenergy	170	148	144	170	178	215	5	10	-1.2	0.3
Other renewables	32	39	43	35	53	66	2	3	2.3	3.9
Industry	**1 017**	**1 159**	**1 223**	**981**	**981**	**938**	**100**	**100**	**1.2**	**0.2**
Coal	467	427	351	453	361	268	29	29	-1.1	-2.1
Oil	67	69	65	64	52	44	5	5	0.3	-1.2
Gas	70	119	161	67	103	124	13	13	6.1	5.1
Electricity	343	451	541	327	379	410	44	44	2.7	1.7
Heat	63	70	69	62	58	47	6	5	1.1	-0.4
Bioenergy	7	22	35	7	22	35	3	4	n.a.	n.a.
Other renewables	0	0	2	1	6	11	0	1	8.1	16.1
Transport	**348**	**482**	**564**	**336**	**414**	**428**	**100**	**100**	**3.1**	**2.0**
Oil	318	441	507	300	316	240	90	56	3.0	0.2
Electricity	8	14	19	9	22	53	3	12	5.2	9.2
Biofuels	4	10	16	5	35	74	3	17	8.7	15.0
Other fuels	18	17	22	23	41	62	4	14	1.3	5.2
Buildings	**560**	**628**	**665**	**531**	**522**	**503**	**100**	**100**	**1.0**	**-0.0**
Coal	75	69	59	70	50	33	9	7	-1.0	-3.1
Oil	39	27	16	35	19	8	2	2	-3.6	-5.9
Gas	64	99	119	61	82	91	18	18	4.5	3.4
Electricity	166	252	311	148	181	192	47	38	4.0	2.1
Heat	27	29	30	26	26	25	5	5	0.9	0.2
Bioenergy	157	113	89	158	117	99	13	20	-2.9	-2.5
Other renewables	32	38	41	33	46	54	6	11	2.3	3.3
Other	**231**	**290**	**327**	**227**	**271**	**291**	**100**	**100**	**2.1**	**1.7**

China: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total generation	**650**	**5 462**	**7 093**	**8 128**	**9 146**	**9 998**	**10 626**	**100**	**100**	**2.5**
Coal	470	4 120	4 461	4 662	4 947	5 166	5 231	75	49	0.9
Oil	51	7	7	6	6	5	3	0	0	-2.6
Gas	3	109	318	490	645	781	897	2	8	8.1
Nuclear	-	112	400	639	834	978	1 102	2	10	8.9
Hydro	127	909	1 193	1 317	1 438	1 518	1 559	17	15	2.0
Bioenergy	-	50	173	237	282	325	367	1	3	7.7
Wind	0	139	410	576	721	872	1 025	3	10	7.7
Geothermal	-	0	1	2	5	10	16	0	0	18.8
Solar PV	0	16	128	194	251	308	369	0	3	12.3
CSP	-	0	2	6	16	33	54	0	1	49.7
Marine	-	0	0	0	1	1	2	0	0	22.6

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total capacity	**1 286**	**1 850**	**2 154**	**2 427**	**2 638**	**2 783**	**100**	**100**	**2.9**
Coal	826	979	1 044	1 115	1 164	1 175	64	42	1.3
Oil	11	10	10	9	8	6	1	0	-2.3
Gas	48	110	143	170	189	208	4	7	5.6
Nuclear	17	55	86	110	129	145	1	5	8.3
Hydro	280	365	410	454	483	498	22	18	2.2
Bioenergy	9	30	41	48	55	61	1	2	7.4
Wind	78	200	267	321	364	399	6	14	6.3
Geothermal	0	0	0	1	1	2	0	0	17.6
Solar PV	17	100	151	194	235	275	1	10	10.7
CSP	0	1	2	4	8	13	0	0	27.5
Marine	0	0	0	0	1	1	0	0	21.3

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total CO_2	**2 217**	**8 562**	**9 079**	**9 308**	**9 454**	**9 396**	**9 144**	**100**	**100**	**0.2**
Coal	1 910	7 143	7 136	7 052	6 969	6 768	6 422	83	70	-0.4
Oil	287	1 120	1 381	1 526	1 602	1 622	1 625	13	18	1.4
Gas	21	299	563	729	883	1 006	1 097	3	12	4.9
Power sector	**664**	**4 283**	**4 567**	**4 720**	**4 905**	**5 023**	**4 995**	**100**	**100**	**0.6**
Coal	609	4 204	4 400	4 488	4 614	4 682	4 614	98	92	0.3
Oil	53	15	15	14	13	12	10	0	0	-1.6
Gas	2	64	152	218	277	328	371	1	7	6.7
TFC	**1 467**	**3 953**	**4 182**	**4 266**	**4 235**	**4 067**	**3 855**	**100**	**100**	**-0.1**
Coal	1 249	2 722	2 538	2 370	2 164	1 903	1 635	69	42	-1.9
Oil	207	1 040	1 296	1 446	1 527	1 551	1 559	26	40	1.5
Transport	*73*	*680*	*935*	*1 109*	*1 216*	*1 267*	*1 306*	*17*	*34*	*2.4*
Gas	11	191	349	450	544	614	661	5	17	4.7

China: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**7 347**	**9 970**	**12 023**	**6 840**	**8 033**	**8 902**	**100**	**100**	**3.0**	**1.8**
Coal	4 778	6 146	7 296	4 190	2 893	1 962	61	22	2.1	-2.7
Oil	7	6	4	6	5	3	0	0	-2.2	-3.4
Gas	306	580	779	287	741	909	6	10	7.6	8.2
Nuclear	400	792	1 003	400	1 246	1 738	8	20	8.5	10.7
Hydro	1 180	1 358	1 490	1 193	1 461	1 596	12	18	1.8	2.1
Bioenergy	173	272	337	175	353	495	3	6	7.3	8.8
Wind	385	612	822	448	976	1 386	7	16	6.8	8.9
Geothermal	1	3	8	1	6	21	0	0	15.7	20.0
Solar PV	116	196	267	136	312	506	2	6	11.0	13.6
CSP	2	5	16	4	41	284	0	3	43.1	59.2
Marine	0	0	2	0	1	2	0	0	21.7	23.1

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**1 878**	**2 485**	**2 887**	**1 818**	**2 287**	**2 593**	**100**	**100**	**3.0**	**2.6**
Coal	1 030	1 290	1 464	941	741	574	51	22	2.1	-1.3
Oil	10	9	6	10	9	5	0	0	-1.8	-2.6
Gas	111	175	215	94	190	228	7	9	5.7	5.9
Nuclear	55	104	132	55	164	228	5	9	7.9	10.1
Hydro	360	425	473	365	462	510	16	20	2.0	2.3
Bioenergy	30	46	55	30	60	81	2	3	6.9	8.5
Wind	190	283	338	217	411	520	12	20	5.6	7.3
Geothermal	0	0	1	0	1	3	0	0	14.6	18.8
Solar PV	90	151	198	105	239	375	7	14	9.4	12.0
CSP	0	1	4	1	10	66	0	3	21.9	35.4
Marine	0	0	1	0	0	1	0	0	20.3	21.8

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**9 445**	**10 939**	**11 732**	**8 619**	**6 079**	**3 318**	**100**	**100**	**1.2**	**-3.5**
Coal	7 469	8 312	8 721	6 737	3 968	1 523	74	46	0.7	-5.6
Oil	1 417	1 759	1 908	1 338	1 275	947	16	29	2.0	-0.6
Gas	559	867	1 103	545	836	848	9	26	5.0	3.9
Power sector	**4 844**	**6 036**	**6 962**	**4 209**	**2 399**	**705**	**100**	**100**	**1.8**	**-6.5**
Coal	4 677	5 762	6 615	4 054	2 113	493	95	70	1.7	-7.6
Oil	16	14	12	15	11	7	0	1	-1.0	-3.1
Gas	151	260	336	141	275	205	5	29	6.3	4.4
TFC	**4 264**	**4 557**	**4 420**	**4 092**	**3 436**	**2 427**	**100**	**100**	**0.4**	**-1.8**
Coal	2 588	2 338	1 895	2 492	1 711	917	43	38	-1.3	-3.9
Oil	1 330	1 678	1 830	1 256	1 215	907	41	37	2.1	-0.5
Transport	*960*	*1 331*	*1 530*	*905*	*954*	*722*	*35*	*30*	*3.1*	*0.2*
Gas	346	542	695	344	511	602	16	25	4.9	4.3

India: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**308**	**775**	**1 018**	**1 207**	**1 440**	**1 676**	**1 908**	**100**	**100**	**3.4**
Coal	94	341	476	568	690	814	934	44	49	3.8
Oil	63	176	229	273	329	393	458	23	24	3.6
Gas	11	45	58	81	103	126	149	6	8	4.6
Nuclear	2	9	17	28	43	57	70	1	4	7.9
Hydro	6	12	15	19	22	25	29	2	1	3.2
Bioenergy	133	188	209	215	217	213	209	24	11	0.4
Other renewables	0	4	13	23	35	47	60	0	3	11.0
Power sector	**65**	**282**	**393**	**474**	**581**	**693**	**806**	**100**	**100**	**4.0**
Coal	49	223	300	337	397	462	529	79	66	3.3
Oil	5	8	9	10	10	11	11	3	1	1.3
Gas	3	14	18	33	44	57	69	5	9	6.1
Nuclear	2	9	17	28	43	57	70	3	9	7.9
Hydro	6	12	15	19	22	25	29	4	4	3.2
Bioenergy	-	13	22	27	32	37	43	5	5	4.5
Other renewables	0	3	12	21	32	44	55	1	7	11.2
Other energy sector	**23**	**70**	**91**	**112**	**137**	**161**	**183**	**100**	**100**	**3.6**
Electricity	*7*	*27*	*37*	*44*	*54*	*64*	*74*	*38*	*40*	*3.9*
TFC	**245**	**527**	**686**	**815**	**968**	**1 122**	**1 275**	**100**	**100**	**3.3**
Coal	39	103	151	194	242	289	333	20	26	4.4
Oil	52	150	202	243	298	360	423	28	33	3.9
Gas	6	25	35	43	53	62	71	5	6	4.0
Electricity	18	77	115	150	192	236	281	15	22	4.9
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	130	171	182	183	180	171	161	33	13	-0.2
Other renewables	0	0	1	2	2	4	5	0	0	9.1
Industry	**69**	**185**	**263**	**336**	**417**	**497**	**572**	**100**	**100**	**4.3**
Coal	27	91	137	180	228	277	322	49	56	4.8
Oil	10	19	24	29	34	40	45	10	8	3.3
Gas	1	13	18	23	28	32	35	7	6	3.9
Electricity	9	32	49	62	78	94	110	17	19	4.6
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	23	30	36	42	48	54	59	16	10	2.5
Other renewables	0	0	0	0	1	1	2	0	0	16.2
Transport	**21**	**75**	**108**	**136**	**176**	**224**	**280**	**100**	**100**	**5.0**
Oil	18	72	104	130	166	210	258	96	92	4.9
Electricity	0	1	2	2	2	2	3	2	1	2.5
Biofuels	-	0	1	1	3	5	8	0	3	16.0
Other fuels	2	1	2	3	5	7	10	2	4	7.5
Buildings	**134**	**214**	**242**	**257**	**274**	**287**	**299**	**100**	**100**	**1.2**
Coal	10	13	14	14	14	13	11	6	4	-0.5
Oil	11	27	31	33	38	43	47	13	16	2.1
Gas	0	4	5	5	6	8	9	2	3	3.2
Electricity	5	29	46	62	84	109	135	14	45	5.8
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	108	141	146	140	130	112	94	66	31	-1.5
Other renewables	0	0	1	1	2	2	3	0	1	7.7
Other	**22**	**53**	**71**	**86**	**101**	**113**	**123**	**100**	**100**	**3.2**

India: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**1 042**	**1 541**	**2 091**	**985**	**1 243**	**1 495**	**100**	**100**	**3.7**	**2.5**
Coal	499	798	1 136	442	459	453	54	30	4.6	1.1
Oil	232	348	505	227	296	337	24	23	4.0	2.4
Gas	60	106	143	59	113	179	7	12	4.4	5.3
Nuclear	17	35	54	17	61	118	3	8	6.9	10.0
Hydro	15	21	25	15	30	45	1	3	2.8	5.0
Bioenergy	208	211	193	208	230	253	9	17	0.1	1.1
Other renewables	10	22	35	17	55	108	2	7	8.8	13.4
Power sector	**410**	**655**	**936**	**367**	**437**	**549**	**100**	**100**	**4.5**	**2.5**
Coal	319	493	713	269	195	118	76	21	4.4	-2.3
Oil	8	10	10	9	9	9	1	2	0.9	0.5
Gas	20	49	72	19	53	87	8	16	6.3	7.1
Nuclear	17	35	54	17	61	118	6	22	6.9	10.0
Hydro	15	21	25	15	30	45	3	8	2.8	5.0
Bioenergy	21	26	30	22	39	73	3	13	3.2	6.6
Other renewables	9	20	32	16	50	98	3	18	8.9	13.5
Other energy sector	**94**	**151**	**210**	**89**	**123**	**148**	**100**	**100**	**4.2**	**2.8**
Electricity	*39*	*64*	*93*	*36*	*47*	*58*	*44*	*39*	*4.7*	*2.9*
TFC	**694**	**999**	**1 331**	**676**	**896**	**1 082**	**100**	**100**	**3.5**	**2.7**
Coal	154	250	346	148	218	276	26	25	4.6	3.7
Oil	205	317	468	199	267	311	35	29	4.3	2.7
Gas	34	50	63	35	54	84	5	8	3.5	4.6
Electricity	118	200	294	111	165	226	22	21	5.1	4.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	183	180	156	182	187	175	12	16	-0.3	0.1
Other renewables	1	2	4	1	4	10	0	1	8.3	12.3
Industry	**268**	**428**	**588**	**259**	**384**	**492**	**100**	**100**	**4.4**	**3.7**
Coal	139	236	334	134	206	268	57	54	4.9	4.1
Oil	24	36	47	24	33	41	8	8	3.5	3.0
Gas	18	27	32	18	27	32	5	6	3.5	3.5
Electricity	50	80	112	47	69	92	19	19	4.7	4.0
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	37	49	61	36	47	54	10	11	2.6	2.2
Other renewables	0	1	2	0	2	5	0	1	16.1	21.5
Transport	**111**	**189**	**311**	**108**	**164**	**221**	**100**	**100**	**5.4**	**4.1**
Oil	106	181	299	103	143	160	96	72	5.4	3.0
Electricity	2	2	3	2	3	8	1	4	2.6	6.9
Biofuels	0	1	3	1	12	28	1	13	11.1	21.3
Other fuels	2	5	7	2	7	25	2	11	5.6	11.0
Buildings	**244**	**279**	**304**	**237**	**248**	**248**	**100**	**100**	**1.3**	**0.5**
Coal	15	15	12	14	12	8	4	3	-0.1	-1.8
Oil	31	39	49	29	32	39	16	16	2.2	1.3
Gas	4	6	8	5	7	10	3	4	2.8	3.5
Electricity	47	88	140	43	67	94	46	38	6.0	4.4
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	145	129	93	145	128	93	31	37	-1.5	-1.5
Other renewables	1	1	2	1	2	5	1	2	6.5	9.6
Other	**72**	**104**	**128**	**71**	**100**	**120**	**100**	**100**	**3.3**	**3.1**

India: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total generation	**293**	**1 193**	**1 766**	**2 251**	**2 848**	**3 485**	**4 124**	**100**	**100**	**4.7**
Coal	192	869	1 224	1 412	1 698	2 009	2 333	73	57	3.7
Oil	13	23	26	29	32	36	37	2	1	1.7
Gas	10	65	96	185	262	348	431	5	10	7.3
Nuclear	6	34	66	109	165	218	269	3	7	7.9
Hydro	72	142	174	215	253	293	333	12	8	3.2
Bioenergy	-	23	48	64	80	99	121	2	3	6.3
Wind	0	34	91	145	201	252	296	3	7	8.4
Geothermal	-	-	0	1	1	2	2	-	0	n.a.
Solar PV	-	3	40	90	152	218	285	0	7	17.8
CSP	-	-	1	2	5	9	17	-	0	n.a.
Marine	-	-	-	-	0	0	1	-	0	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total capacity	**263**	**436**	**583**	**746**	**916**	**1 076**	**100**	**100**	**5.4**
Coal	154	230	276	329	385	438	59	41	3.9
Oil	7	9	11	13	15	15	3	1	2.8
Gas	22	41	57	76	100	122	8	11	6.6
Nuclear	6	10	16	24	31	39	2	4	7.3
Hydro	43	58	71	83	95	108	16	10	3.5
Bioenergy	7	10	13	16	20	24	3	2	4.6
Wind	21	50	77	102	125	142	8	13	7.3
Geothermal	-	0	0	0	0	0	-	0	n.a.
Solar PV	3	28	61	100	142	182	1	17	16.8
CSP	-	1	1	2	3	5	-	0	n.a.
Marine	-	-	-	0	0	0	-	0	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total CO_2	**534**	**1 880**	**2 569**	**3 081**	**3 744**	**4 445**	**5 147**	**100**	**100**	**3.8**
Coal	370	1 348	1 870	2 218	2 682	3 156	3 623	72	70	3.7
Oil	151	447	585	697	850	1 027	1 213	24	24	3.8
Gas	13	85	115	166	212	263	311	5	6	4.9
Power sector	**218**	**943**	**1 262**	**1 445**	**1 715**	**2 006**	**2 300**	**100**	**100**	**3.4**
Coal	194	886	1 192	1 339	1 579	1 837	2 103	94	91	3.3
Oil	16	25	27	30	33	35	36	3	2	1.3
Gas	8	32	43	77	104	134	162	3	7	6.1
TFC	**300**	**894**	**1 257**	**1 581**	**1 969**	**2 372**	**2 770**	**100**	**100**	**4.3**
Coal	170	460	673	873	1 095	1 310	1 511	51	55	4.5
Oil	128	391	525	633	780	950	1 130	44	41	4.0
Transport	*56*	*219*	*316*	*395*	*506*	*640*	*787*	*24*	*28*	*4.9*
Gas	2	43	59	75	94	112	130	5	5	4.2

India: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**1 820**	**3 073**	**4 490**	**1 699**	**2 463**	**3 292**	**100**	**100**	**5.0**	**3.8**
Coal	1 302	2 087	3 073	1 107	891	555	68	17	4.8	-1.6
Oil	25	30	33	25	29	29	1	1	1.3	0.9
Gas	108	296	456	97	313	555	10	17	7.5	8.3
Nuclear	66	134	205	66	234	454	5	14	6.9	10.0
Hydro	174	244	297	174	346	529	7	16	2.8	5.0
Bioenergy	44	62	77	48	105	235	2	7	4.5	9.0
Wind	79	145	203	125	296	435	5	13	6.9	9.9
Geothermal	0	1	1	0	3	5	0	0	n.a.	n.a.
Solar PV	20	72	139	55	232	388	3	12	14.7	19.1
CSP	1	3	5	1	13	106	0	3	n.a.	n.a.
Marine	-	-	1	-	0	1	0	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**426**	**709**	**999**	**458**	**805**	**1 126**	**100**	**100**	**5.1**	**5.5**
Coal	238	375	525	223	228	226	53	20	4.6	1.4
Oil	9	12	14	9	12	12	1	1	2.5	2.0
Gas	43	84	124	41	94	134	12	12	6.7	7.0
Nuclear	10	19	29	10	34	65	3	6	6.2	9.4
Hydro	58	80	96	58	113	172	10	15	3.0	5.3
Bioenergy	10	13	16	10	21	42	2	4	3.1	6.8
Wind	44	76	100	68	148	192	10	17	5.9	8.5
Geothermal	0	0	0	0	0	1	0	0	n.a.	n.a.
Solar PV	15	50	93	39	152	246	9	22	13.9	18.1
CSP	1	1	2	1	4	36	0	3	n.a.	n.a.
Marine	-	-	0	-	0	0	0	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**2 672**	**4 228**	**6 067**	**2 427**	**2 631**	**2 632**	**100**	**100**	**4.4**	**1.3**
Coal	1 959	3 102	4 415	1 734	1 662	1 429	73	54	4.5	0.2
Oil	595	907	1 354	577	742	834	22	32	4.2	2.3
Gas	119	219	299	115	227	369	5	14	4.8	5.6
Power sector	**1 343**	**2 108**	**3 036**	**1 141**	**910**	**598**	**100**	**100**	**4.4**	**-1.7**
Coal	1 269	1 961	2 835	1 071	757	365	93	61	4.4	-3.2
Oil	26	30	32	27	29	29	1	5	0.9	0.5
Gas	47	116	169	44	123	205	6	34	6.3	7.1
TFC	**1 279**	**2 057**	**2 948**	**1 236**	**1 672**	**1 983**	**100**	**100**	**4.5**	**3.0**
Coal	685	1 133	1 569	659	900	1 059	53	53	4.7	3.1
Oil	534	836	1 269	518	681	777	43	39	4.5	2.6
Transport	*323*	*552*	*912*	*315*	*434*	*487*	*31*	*25*	*5.4*	*3.0*
Gas	59	88	110	59	91	147	4	7	3.6	4.7

Middle East: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**211**	**689**	**822**	**907**	**1 002**	**1 089**	**1 171**	**100**	**100**	**2.0**
Coal	1	3	4	4	4	4	4	0	0	1.0
Oil	137	333	391	413	432	452	475	48	41	1.3
Gas	72	349	411	466	527	577	613	51	52	2.1
Nuclear	-	1	10	13	19	24	31	0	3	12.1
Hydro	1	2	3	3	4	4	4	0	0	2.3
Bioenergy	0	1	2	4	6	9	12	0	1	10.4
Other renewables	0	0	2	5	11	19	31	0	3	20.8
Power sector	**62**	**241**	**275**	**301**	**333**	**363**	**385**	**100**	**100**	**1.7**
Coal	0	0	1	1	1	1	2	0	0	9.1
Oil	27	99	96	83	68	60	59	41	15	-1.9
Gas	34	139	165	198	232	254	257	57	67	2.3
Nuclear	-	1	10	13	19	24	31	1	8	12.1
Hydro	1	2	3	3	4	4	4	1	1	2.3
Bioenergy	-	0	1	1	3	5	7	0	2	28.5
Other renewables	0	0	1	2	7	14	25	0	6	30.4
Other energy sector	**18**	**75**	**86**	**96**	**103**	**110**	**119**	**100**	**100**	**1.7**
Electricity	*4*	*14*	*19*	*22*	*24*	*26*	*28*	*19*	*24*	*2.5*
TFC	**150**	**455**	**567**	**633**	**706**	**773**	**838**	**100**	**100**	**2.3**
Coal	0	2	2	2	2	2	2	0	0	-0.5
Oil	103	224	279	310	343	371	399	49	48	2.2
Gas	31	160	195	216	238	260	283	35	34	2.1
Electricity	16	68	88	101	116	130	142	15	17	2.8
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	0	1	1	2	3	4	5	0	1	7.3
Other renewables	0	0	1	2	4	5	7	0	1	14.5
Industry	**45**	**138**	**169**	**186**	**207**	**227**	**246**	**100**	**100**	**2.2**
Coal	0	2	2	2	2	2	2	1	1	-0.5
Oil	19	25	28	29	29	30	30	18	12	0.8
Gas	22	96	119	132	148	164	181	69	73	2.4
Electricity	4	16	20	23	26	28	30	11	12	2.5
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	-	-	0	1	2	2	3	-	1	n.a.
Other renewables	-	0	0	0	0	0	0	0	0	22.5
Transport	**48**	**132**	**166**	**191**	**216**	**235**	**252**	**100**	**100**	**2.4**
Oil	48	126	157	181	204	221	236	95	94	2.4
Electricity	-	0	0	0	0	0	0	0	0	0.5
Biofuels	-	-	-	-	-	-	-	-	-	n.a.
Other fuels	-	6	9	11	12	13	15	5	6	3.4
Buildings	**33**	**113**	**135**	**148**	**164**	**179**	**193**	**100**	**100**	**2.0**
Coal	-	0	0	0	0	0	0	0	0	-1.6
Oil	18	19	18	17	16	15	15	17	8	-0.8
Gas	3	44	51	55	59	61	65	39	34	1.4
Electricity	11	49	63	73	85	96	106	43	55	2.9
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	0	1	1	1	1	2	2	1	1	3.7
Other renewables	0	0	1	2	3	4	5	0	3	13.6
Other	**23**	**72**	**97**	**107**	**119**	**132**	**147**	**100**	**100**	**2.7**

Middle East: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**831**	**1 035**	**1 277**	**793**	**854**	**904**	**100**	**100**	**2.3**	**1.0**
Coal	4	4	4	3	4	4	0	0	1.3	0.5
Oil	395	463	547	373	349	322	43	36	1.9	-0.1
Gas	417	539	679	400	446	437	53	48	2.5	0.8
Nuclear	10	14	18	10	25	47	1	5	9.8	13.8
Hydro	3	3	4	3	4	5	0	1	2.1	3.2
Bioenergy	2	5	11	2	8	22	1	2	10.0	12.7
Other renewables	1	6	13	2	19	68	1	8	17.1	24.4
Power sector	**281**	**342**	**418**	**260**	**268**	**292**	**100**	**100**	**2.1**	**0.7**
Coal	1	1	2	1	1	1	0	0	9.7	7.5
Oil	98	79	70	85	44	32	17	11	-1.3	-4.1
Gas	169	238	308	160	176	133	74	46	3.0	-0.1
Nuclear	10	14	18	10	25	47	4	16	9.8	13.8
Hydro	3	3	4	3	4	5	1	2	2.1	3.2
Bioenergy	1	2	6	1	4	15	1	5	27.5	32.0
Other renewables	1	4	10	1	15	59	2	20	26.2	34.7
Other energy sector	**90**	**111**	**134**	**82**	**84**	**79**	**100**	**100**	**2.2**	**0.2**
Electricity	*19*	*26*	*32*	*18*	*20*	*21*	*24*	*27*	*2.9*	*1.4*
TFC	**569**	**730**	**911**	**550**	**621**	**673**	**100**	**100**	**2.6**	**1.5**
Coal	2	2	2	2	2	2	0	0	-0.4	-1.2
Oil	280	361	456	273	291	283	50	42	2.7	0.9
Gas	195	240	290	191	221	254	32	38	2.2	1.7
Electricity	89	122	154	82	100	119	17	18	3.1	2.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	1	3	6	2	4	7	1	1	7.6	8.4
Other renewables	1	2	3	1	4	9	0	1	11.4	15.7
Industry	**170**	**211**	**256**	**166**	**187**	**200**	**100**	**100**	**2.3**	**1.4**
Coal	2	2	2	2	2	1	1	1	-0.4	-1.4
Oil	28	30	32	28	27	27	12	13	0.9	0.3
Gas	119	151	188	116	131	138	73	69	2.5	1.4
Electricity	20	27	31	20	24	28	12	14	2.6	2.2
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	0	2	4	0	2	5	1	2	n.a.	n.a.
Other renewables	0	0	0	0	0	2	0	1	22.7	30.3
Transport	**165**	**228**	**298**	**161**	**180**	**177**	**100**	**100**	**3.1**	**1.1**
Oil	158	220	289	152	159	132	97	75	3.1	0.2
Electricity	0	0	0	0	0	3	0	2	0.4	18.5
Biofuels	-	-	-	-	-	-	-	-	n.a.	n.a.
Other fuels	8	8	9	9	21	41	3	23	1.5	7.2
Buildings	**137**	**172**	**209**	**127**	**140**	**157**	**100**	**100**	**2.3**	**1.2**
Coal	0	0	0	0	0	0	0	0	-1.6	-1.6
Oil	19	18	18	18	14	13	9	8	-0.1	-1.4
Gas	52	62	70	49	52	54	34	34	1.7	0.7
Electricity	65	90	116	58	70	83	56	53	3.3	2.0
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	1	1	2	1	2	2	1	1	3.6	4.0
Other renewables	1	1	2	1	3	6	1	4	9.7	14.1
Other	**97**	**119**	**148**	**96**	**114**	**139**	**100**	**100**	**2.7**	**2.5**

Middle East: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total generation	**224**	**952**	**1 236**	**1 426**	**1 627**	**1 821**	**1 972**	**100**	**100**	**2.7**
Coal	0	0	3	4	5	6	6	0	0	10.6
Oil	98	316	330	293	250	226	222	33	11	-1.3
Gas	114	605	826	1 015	1 187	1 308	1 328	64	67	3.0
Nuclear	-	5	37	50	72	92	119	1	6	12.1
Hydro	12	25	30	36	41	44	46	3	2	2.3
Bioenergy	-	0	2	5	9	17	26	0	1	28.6
Wind	0	0	2	7	19	45	98	0	5	25.6
Geothermal	-	-	-	-	-	-	-	-	-	n.a.
Solar PV	-	0	4	12	32	57	85	0	4	52.3
CSP	-	-	1	4	12	26	41	-	2	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total capacity	**269**	**366**	**389**	**424**	**469**	**514**	**100**	**100**	**2.4**
Coal	0	1	1	1	1	1	0	0	5.6
Oil	78	94	90	79	72	71	29	14	-0.4
Gas	174	242	255	276	293	291	65	56	1.9
Nuclear	1	5	7	10	13	16	0	3	10.9
Hydro	16	20	23	25	27	28	6	5	2.1
Bioenergy	0	0	1	2	3	4	0	1	31.0
Wind	0	1	3	8	19	40	0	8	23.8
Geothermal	-	-	-	-	-	-	-	-	n.a.
Solar PV	0	3	7	18	32	47	0	9	25.8
CSP	-	1	2	4	10	15	-	3	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total CO_2	**535**	**1 622**	**1 871**	**2 033**	**2 195**	**2 333**	**2 445**	**100**	**100**	**1.5**
Coal	1	10	11	12	13	13	14	1	1	1.1
Oil	380	858	961	994	1 019	1 047	1 088	53	45	0.9
Gas	153	754	898	1 027	1 163	1 273	1 343	46	55	2.2
Power sector	**166**	**638**	**691**	**728**	**763**	**793**	**796**	**100**	**100**	**0.8**
Coal	0	2	3	4	5	6	6	0	1	5.2
Oil	86	311	300	260	214	190	186	49	23	-1.9
Gas	79	326	388	465	544	597	604	51	76	2.3
TFC	**332**	**863**	**1 046**	**1 159**	**1 278**	**1 377**	**1 474**	**100**	**100**	**2.0**
Coal	1	8	8	7	7	7	7	1	0	-0.6
Oil	271	509	616	685	754	806	851	59	58	1.9
Transport	*144*	*371*	*470*	*540*	*611*	*662*	*706*	*43*	*48*	*2.4*
Gas	61	346	422	467	517	565	616	40	42	2.2

Middle East: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**1 259**	**1 719**	**2 157**	**1 151**	**1 388**	**1 624**	**100**	**100**	**3.1**	**2.0**
Coal	3	6	8	2	4	4	0	0	11.2	9.0
Oil	337	293	267	287	154	114	12	7	-0.6	-3.7
Gas	844	1 286	1 657	784	934	722	77	44	3.8	0.7
Nuclear	37	54	68	37	94	179	3	11	9.8	13.8
Hydro	30	39	45	30	44	59	2	4	2.1	3.2
Bioenergy	2	8	21	2	15	53	1	3	27.5	32.1
Wind	2	10	41	3	70	205	2	13	21.5	29.0
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	4	15	34	4	50	157	2	10	47.1	55.7
CSP	1	9	19	1	22	131	1	8	n.a.	n.a.
Marine	-	-	-	-	0	1	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**365**	**448**	**513**	**357**	**451**	**633**	**100**	**100**	**2.4**	**3.2**
Coal	1	1	2	1	1	1	0	0	6.2	4.0
Oil	94	84	77	89	68	58	15	9	-0.0	-1.1
Gas	242	312	350	237	275	292	68	46	2.6	1.9
Nuclear	5	8	9	5	13	24	2	4	8.6	12.5
Hydro	20	24	27	20	27	34	5	5	2.0	2.9
Bioenergy	0	1	4	0	3	9	1	1	30.0	34.3
Wind	1	4	17	1	30	87	3	14	19.9	27.4
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	2	10	20	3	27	85	4	13	22.0	28.6
CSP	1	3	6	1	7	42	1	7	n.a.	n.a.
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**1 895**	**2 315**	**2 805**	**1 790**	**1 719**	**1 507**	**100**	**100**	**2.0**	**-0.3**
Coal	11	13	15	10	11	10	1	1	1.4	-0.2
Oil	972	1 112	1 304	908	775	638	46	42	1.6	-1.1
Gas	913	1 189	1 486	871	933	859	53	57	2.5	0.5
Power sector	**707**	**812**	**952**	**646**	**544**	**400**	**100**	**100**	**1.5**	**-1.7**
Coal	3	5	7	2	4	4	1	1	5.7	3.6
Oil	307	248	221	268	138	101	23	25	-1.3	-4.1
Gas	397	558	724	376	402	295	76	74	3.0	-0.4
TFC	**1 049**	**1 337**	**1 664**	**1 017**	**1 057**	**1 006**	**100**	**100**	**2.5**	**0.6**
Coal	8	7	7	7	6	5	0	0	-0.4	-1.6
Oil	619	809	1 025	599	601	508	62	50	2.6	-0.0
Transport	*471*	*657*	*864*	*455*	*477*	*395*	*52*	*39*	*3.2*	*0.2*
Gas	422	521	632	411	450	493	38	49	2.3	1.3

Africa: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**391**	**744**	**880**	**969**	**1 067**	**1 180**	**1 302**	**100**	**100**	**2.1**
Coal	74	104	113	122	133	154	181	14	14	2.1
Oil	87	170	205	225	242	262	280	23	21	1.9
Gas	28	99	119	137	162	191	235	13	18	3.2
Nuclear	2	4	3	3	6	10	12	0	1	4.6
Hydro	5	10	15	20	25	32	37	1	3	5.0
Bioenergy	194	356	415	444	464	473	469	48	36	1.0
Other renewables	0	2	10	18	34	58	88	0	7	14.6
Power sector	**68**	**156**	**184**	**214**	**258**	**320**	**397**	**100**	**100**	**3.5**
Coal	39	64	71	77	81	88	97	41	24	1.5
Oil	11	24	24	23	23	24	25	15	6	0.2
Gas	11	51	60	68	81	98	126	33	32	3.4
Nuclear	2	4	3	3	6	10	12	2	3	4.6
Hydro	5	10	15	20	25	32	37	6	9	5.0
Bioenergy	0	1	2	5	8	11	15	1	4	10.5
Other renewables	0	2	9	18	32	56	85	1	21	14.7
Other energy sector	**57**	**108**	**134**	**153**	**170**	**185**	**198**	**100**	**100**	**2.3**
Electricity	*5*	*13*	*16*	*18*	*22*	*26*	*31*	*12*	*16*	*3.3*
TFC	**292**	**545**	**644**	**702**	**760**	**824**	**891**	**100**	**100**	**1.8**
Coal	20	22	24	26	29	34	43	4	5	2.5
Oil	71	142	177	196	213	233	252	26	28	2.1
Gas	9	29	37	42	50	58	69	5	8	3.3
Electricity	22	52	67	81	100	124	153	10	17	4.1
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	171	300	339	356	368	374	372	55	42	0.8
Other renewables	0	0	0	1	1	2	3	0	0	12.2
Industry	**55**	**85**	**105**	**119**	**137**	**161**	**193**	**100**	**100**	**3.1**
Coal	14	13	16	17	21	26	35	15	18	3.8
Oil	15	14	18	20	21	24	26	17	13	2.2
Gas	5	17	21	25	29	35	42	20	22	3.4
Electricity	12	21	26	30	35	40	47	25	24	3.0
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	10	20	24	27	31	37	43	24	22	2.9
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Transport	**38**	**91**	**115**	**127**	**137**	**148**	**158**	**100**	**100**	**2.1**
Oil	37	89	113	124	134	145	154	98	97	2.0
Electricity	0	0	1	1	1	1	1	1	1	2.6
Biofuels	-	0	1	1	1	1	1	0	1	23.5
Other fuels	0	1	1	1	1	2	2	1	1	1.6
Buildings	**184**	**344**	**394**	**422**	**449**	**474**	**497**	**100**	**100**	**1.4**
Coal	3	7	6	6	6	6	6	2	1	-0.6
Oil	11	24	28	32	36	41	47	7	10	2.6
Gas	1	8	10	11	13	15	18	2	4	3.1
Electricity	9	28	38	48	61	79	101	8	20	4.8
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	160	277	311	324	332	331	323	81	65	0.6
Other renewables	0	0	0	1	1	2	2	0	0	11.4
Other	**15**	**25**	**30**	**34**	**37**	**40**	**43**	**100**	**100**	**2.1**

Africa: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**890**	**1 106**	**1 366**	**856**	**980**	**1 130**	**100**	**100**	**2.3**	**1.6**
Coal	114	142	201	107	99	109	15	10	2.5	0.2
Oil	207	258	318	197	208	209	23	18	2.3	0.8
Gas	120	166	236	114	140	151	17	13	3.3	1.6
Nuclear	3	6	11	3	10	27	1	2	4.1	7.6
Hydro	14	22	31	15	26	49	2	4	4.3	6.0
Bioenergy	422	483	502	409	450	457	37	40	1.3	0.9
Other renewables	9	28	66	11	46	128	5	11	13.4	16.2
Power sector	**185**	**258**	**379**	**173**	**216**	**322**	**100**	**100**	**3.3**	**2.7**
Coal	71	87	108	65	52	42	29	13	1.9	-1.6
Oil	24	22	23	21	15	13	6	4	-0.1	-2.1
Gas	61	86	129	56	59	48	34	15	3.5	-0.2
Nuclear	3	6	11	3	10	27	3	8	4.1	7.6
Hydro	14	22	31	15	26	49	8	15	4.3	6.0
Bioenergy	2	8	13	3	10	19	3	6	9.9	11.5
Other renewables	9	27	64	10	44	124	17	39	13.5	16.3
Other energy sector	**138**	**181**	**219**	**131**	**159**	**173**	**100**	**100**	**2.6**	**1.7**
Electricity	*16*	*21*	*30*	*15*	*18*	*24*	*14*	*14*	*3.2*	*2.4*
TFC	**650**	**786**	**942**	**631**	**709**	**788**	**100**	**100**	**2.0**	**1.4**
Coal	24	30	47	23	25	33	5	4	2.9	1.6
Oil	179	230	292	172	189	194	31	25	2.7	1.2
Gas	37	49	65	36	48	64	7	8	3.1	3.0
Electricity	67	98	144	64	87	129	15	16	3.8	3.4
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	343	379	391	335	359	363	42	46	1.0	0.7
Other renewables	0	1	2	1	2	4	0	1	11.1	14.3
Industry	**107**	**143**	**202**	**103**	**126**	**165**	**100**	**100**	**3.3**	**2.5**
Coal	16	22	38	15	18	27	19	16	4.2	2.8
Oil	18	23	28	18	19	20	14	12	2.6	1.2
Gas	22	29	40	21	26	32	20	19	3.3	2.4
Electricity	27	36	49	25	29	38	24	23	3.1	2.2
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	25	34	47	24	33	46	23	28	3.2	3.2
Other renewables	0	0	0	0	0	1	0	1	n.a.	n.a.
Transport	**115**	**148**	**186**	**111**	**123**	**123**	**100**	**100**	**2.7**	**1.1**
Oil	113	145	183	109	116	108	98	88	2.7	0.7
Electricity	1	1	1	1	1	1	1	1	2.7	4.1
Biofuels	0	1	1	1	3	5	0	4	21.0	30.1
Other fuels	1	1	1	1	3	8	1	7	-0.2	7.7
Buildings	**397**	**456**	**507**	**386**	**425**	**458**	**100**	**100**	**1.4**	**1.1**
Coal	6	6	6	6	5	4	1	1	-0.2	-1.9
Oil	29	39	54	27	33	43	11	9	3.0	2.1
Gas	10	13	17	9	12	16	3	4	2.9	2.8
Electricity	37	58	89	36	54	85	18	19	4.3	4.2
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	315	340	339	307	319	307	67	67	0.7	0.4
Other renewables	0	1	2	0	1	3	0	1	10.4	12.6
Other	**31**	**39**	**47**	**30**	**36**	**41**	**100**	**100**	**2.4**	**1.9**

Africa: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total generation	**316**	**751**	**965**	**1 159**	**1 411**	**1 736**	**2 134**	**100**	**100**	**3.9**
Coal	165	258	294	326	347	379	420	34	20	1.8
Oil	41	87	97	94	94	101	102	12	5	0.6
Gas	45	268	344	407	496	608	794	36	37	4.1
Nuclear	8	14	13	13	25	37	47	2	2	4.6
Hydro	56	116	171	228	296	374	434	15	20	5.0
Bioenergy	0	1	8	18	29	40	52	0	2	14.8
Wind	-	4	16	27	38	51	65	0	3	11.2
Geothermal	0	2	7	13	25	44	69	0	3	13.9
Solar PV	-	0	11	24	42	65	92	0	4	23.2
CSP	-	-	4	10	20	37	59	-	3	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total capacity	**178**	**256**	**309**	**380**	**470**	**565**	**100**	**100**	**4.4**
Coal	42	54	62	68	76	85	24	15	2.6
Oil	35	37	37	38	42	44	20	8	0.9
Gas	69	104	120	144	174	209	39	37	4.2
Nuclear	2	2	2	4	5	7	1	1	4.6
Hydro	27	40	54	71	89	103	15	18	5.0
Bioenergy	0	2	4	6	8	10	0	2	13.4
Wind	1	7	11	15	20	25	1	4	11.3
Geothermal	0	1	2	4	7	10	0	2	14.6
Solar PV	0	7	15	26	39	56	0	10	19.5
CSP	-	1	3	5	9	14	-	3	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total CO_2	**529**	**1 092**	**1 231**	**1 352**	**1 474**	**1 638**	**1 844**	**100**	**100**	**2.0**
Coal	228	376	374	405	425	464	523	34	28	1.2
Oil	242	499	597	651	700	761	813	46	44	1.8
Gas	59	217	260	296	349	413	508	20	28	3.2
Power sector	**216**	**450**	**496**	**537**	**575**	**637**	**725**	**100**	**100**	**1.8**
Coal	155	255	280	304	311	328	350	57	48	1.2
Oil	35	75	75	72	72	77	78	17	11	0.1
Gas	25	121	141	160	191	231	297	27	41	3.4
TFC	**283**	**547**	**666**	**734**	**807**	**895**	**999**	**100**	**100**	**2.3**
Coal	73	81	94	101	111	129	158	15	16	2.5
Oil	196	406	497	548	596	648	701	74	70	2.0
Transport	*110*	*273*	*339*	*374*	*404*	*435*	*462*	*50*	*46*	*2.0*
Gas	14	60	75	86	100	118	140	11	14	3.2

Africa: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**962**	**1 386**	**2 024**	**912**	**1 215**	**1 774**	**100**	**100**	**3.7**	**3.2**
Coal	297	371	472	272	223	177	23	10	2.3	-1.4
Oil	96	94	96	86	61	53	5	3	0.4	-1.8
Gas	350	519	793	318	362	303	39	17	4.1	0.5
Nuclear	13	25	41	13	40	102	2	6	4.1	7.6
Hydro	161	252	361	171	303	568	18	32	4.3	6.1
Bioenergy	8	26	46	8	34	67	2	4	14.2	15.9
Wind	15	32	53	18	57	130	3	7	10.4	14.1
Geothermal	7	22	53	7	28	78	3	4	12.9	14.5
Solar PV	11	33	69	12	60	134	3	8	21.9	24.9
CSP	3	12	38	6	46	159	2	9	n.a.	n.a.
Marine	-	-	-	-	0	1	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**252**	**363**	**524**	**249**	**374**	**578**	**100**	**100**	**4.1**	**4.5**
Coal	56	73	94	52	54	53	18	9	3.0	0.8
Oil	37	38	42	35	30	29	8	5	0.7	-0.7
Gas	103	144	206	100	128	147	39	25	4.1	2.9
Nuclear	2	4	6	2	6	14	1	2	4.1	7.7
Hydro	38	60	86	41	73	136	16	24	4.3	6.1
Bioenergy	2	5	9	2	7	13	2	2	12.9	14.3
Wind	6	13	20	7	22	49	4	8	10.5	14.1
Geothermal	1	3	8	1	4	11	1	2	13.5	15.2
Solar PV	7	20	43	7	36	80	8	14	18.3	21.0
CSP	1	3	9	2	14	45	2	8	n.a.	n.a.
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**1 244**	**1 572**	**2 056**	**1 171**	**1 159**	**1 092**	**100**	**100**	**2.4**	**0.0**
Coal	379	464	616	350	268	196	30	18	1.8	-2.4
Oil	602	750	934	572	595	589	45	54	2.3	0.6
Gas	263	357	507	249	296	307	25	28	3.2	1.3
Power sector	**501**	**616**	**801**	**457**	**360**	**238**	**100**	**100**	**2.2**	**-2.3**
Coal	282	343	425	259	174	82	53	35	1.9	-4.1
Oil	75	71	73	67	48	42	9	18	-0.1	-2.1
Gas	144	202	303	131	138	113	38	48	3.5	-0.2
TFC	**674**	**861**	**1 129**	**646**	**709**	**756**	**100**	**100**	**2.7**	**1.2**
Coal	96	118	175	91	92	105	15	14	2.9	1.0
Oil	503	644	822	482	522	526	73	70	2.6	1.0
Transport	*340*	*436*	*549*	*328*	*348*	*325*	*49*	*43*	*2.6*	*0.6*
Gas	75	98	132	73	94	124	12	16	3.0	2.7

South Africa: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**90**	**139**	**144**	**149**	**156**	**164**	**172**	**100**	**100**	**0.8**
Coal	67	95	94	93	90	87	85	68	50	-0.4
Oil	11	22	23	26	28	31	33	16	19	1.6
Gas	-	3	4	5	6	6	7	2	4	3.3
Nuclear	2	4	3	3	6	10	12	3	7	4.6
Hydro	0	0	0	0	0	0	0	0	0	5.3
Bioenergy	10	15	17	19	21	22	24	11	14	1.8
Other renewables	-	0	2	3	5	7	9	0	5	18.4
Power sector	**39**	**63**	**64**	**66**	**70**	**74**	**78**	**100**	**100**	**0.8**
Coal	36	59	58	57	54	51	49	94	63	-0.7
Oil	-	0	0	0	0	0	0	0	0	6.1
Gas	-	-	1	1	2	2	3	-	4	n.a.
Nuclear	2	4	3	3	6	10	12	6	16	4.6
Hydro	0	0	0	0	0	0	0	0	1	5.3
Bioenergy	-	0	1	2	3	4	5	0	6	15.5
Other renewables	-	0	1	3	4	6	8	0	10	26.8
Other energy sector	**15**	**24**	**24**	**25**	**25**	**26**	**27**	**100**	**100**	**0.4**
Electricity	*2*	*5*	*5*	*5*	*5*	*5*	*5*	*19*	*20*	*0.7*
TFC	**51**	**73**	**79**	**83**	**89**	**95**	**101**	**100**	**100**	**1.2**
Coal	16	19	19	18	18	18	17	26	17	-0.3
Oil	15	25	26	29	32	35	37	34	37	1.5
Gas	-	2	2	2	2	2	3	2	3	1.8
Electricity	12	17	19	21	23	26	29	23	29	2.0
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	8	11	12	13	13	14	14	15	14	0.9
Other renewables	-	0	0	0	0	1	1	0	1	8.9
Industry	**22**	**26**	**28**	**28**	**29**	**30**	**31**	**100**	**100**	**0.6**
Coal	11	11	11	11	11	11	11	41	37	0.1
Oil	2	2	2	1	1	1	1	7	4	-0.8
Gas	-	2	2	2	2	2	2	6	8	1.3
Electricity	7	10	11	11	12	12	13	38	43	1.0
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	1	2	2	2	2	2	3	7	8	1.1
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Transport	**10**	**17**	**20**	**23**	**26**	**29**	**31**	**100**	**100**	**2.2**
Oil	10	17	19	21	24	27	29	98	94	2.1
Electricity	0	0	0	0	0	1	1	2	2	2.2
Biofuels	-	-	1	1	1	1	1	-	4	n.a.
Other fuels	0	0	0	0	0	0	0	0	0	3.2
Buildings	**14**	**23**	**24**	**25**	**27**	**30**	**33**	**100**	**100**	**1.3**
Coal	2	6	6	5	5	5	5	27	14	-1.1
Oil	1	2	2	2	2	2	2	7	6	0.7
Gas	-	0	0	0	0	0	0	0	1	22.0
Electricity	4	6	7	9	10	12	15	26	45	3.4
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	6	9	9	10	10	10	10	40	32	0.4
Other renewables	-	0	0	0	0	0	1	0	2	8.3
Other	**6**	**7**	**7**	**7**	**7**	**7**	**7**	**100**	**100**	**-0.1**

South Africa: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						**Shares** (%)		**CAAGR** (%)	
	2020	**2030**	**2040**	**2020**	**2030**	**2040**	**2040**		**2013-40**	
	Current Policies Scenario			**450 Scenario**			**CPS**	**450**	**CPS**	**450**
TPED	**146**	**165**	**191**	**140**	**139**	**144**	**100**	**100**	**1.2**	**0.1**
Coal	96	99	105	91	71	56	55	39	0.3	-2.0
Oil	24	31	38	22	24	22	20	15	2.1	0.1
Gas	4	6	8	4	5	7	4	5	3.3	3.1
Nuclear	3	6	11	3	10	18	6	13	4.1	6.1
Hydro	0	0	0	0	0	0	0	0	5.3	6.1
Bioenergy	17	20	24	18	22	28	12	19	1.6	2.3
Other renewables	1	3	6	2	6	13	3	9	16.6	20.3
Power sector	**66**	**77**	**91**	**62**	**58**	**63**	**100**	**100**	**1.4**	**-0.0**
Coal	59	62	67	55	38	24	73	38	0.4	-3.3
Oil	0	0	0	0	0	0	0	0	6.6	5.3
Gas	1	2	3	1	1	2	4	4	n.a.	n.a.
Nuclear	3	6	11	3	10	18	12	29	4.1	6.1
Hydro	0	0	0	0	0	0	0	1	5.3	6.1
Bioenergy	1	3	5	1	4	6	5	9	15.4	16.2
Other renewables	1	3	5	1	5	12	6	19	24.7	28.7
Other energy sector	**24**	**26**	**28**	**24**	**25**	**26**	**100**	**100**	**0.5**	**0.2**
Electricity	*5*	*5*	*6*	*4*	*4*	*4*	*22*	*15*	*1.1*	*-0.5*
TFC	**80**	**93**	**110**	**77**	**80**	**84**	**100**	**100**	**1.5**	**0.5**
Coal	19	19	19	18	16	14	18	16	0.1	-1.2
Oil	27	34	42	26	28	26	38	31	2.0	0.2
Gas	2	2	3	2	2	3	2	4	1.4	2.3
Electricity	19	25	32	18	20	24	29	28	2.4	1.3
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	12	13	14	12	14	16	13	19	0.8	1.4
Other renewables	0	0	1	0	1	1	1	2	7.7	11.3
Industry	**28**	**30**	**33**	**27**	**25**	**25**	**100**	**100**	**0.8**	**-0.1**
Coal	12	12	13	11	10	9	38	34	0.6	-0.8
Oil	2	1	1	2	1	1	4	5	-0.7	-1.3
Gas	2	2	2	2	2	2	7	9	1.2	1.2
Electricity	11	12	14	10	10	10	42	41	1.2	0.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	2	2	3	2	2	3	8	11	1.3	1.3
Other renewables	-	0	0	0	0	0	0	1	n.a.	n.a.
Transport	**20**	**27**	**35**	**20**	**23**	**23**	**100**	**100**	**2.7**	**1.1**
Oil	19	26	33	18	21	19	96	83	2.6	0.5
Electricity	0	0	1	0	1	1	2	4	2.0	4.3
Biofuels	0	1	1	1	2	2	2	11	n.a.	n.a.
Other fuels	0	0	0	0	0	0	0	2	2.0	13.1
Buildings	**24**	**28**	**35**	**24**	**25**	**29**	**100**	**100**	**1.5**	**0.8**
Coal	6	5	5	5	4	3	15	12	-0.6	-2.2
Oil	2	2	2	1	1	1	7	5	1.0	-0.6
Gas	0	0	0	0	0	0	0	1	18.7	23.1
Electricity	7	11	16	7	9	12	47	41	3.8	2.5
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	9	10	10	9	10	11	29	37	0.4	0.6
Other renewables	0	0	1	0	0	1	2	4	7.3	10.1
Other	**7**	**7**	**7**	**7**	**7**	**6**	**100**	**100**	**0.3**	**-0.3**

South Africa: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total generation	**165**	**253**	**278**	**297**	**321**	**348**	**379**	**100**	**100**	**1.5**
Coal	156	237	242	241	231	226	224	94	59	-0.2
Oil	-	0	0	0	0	1	1	0	0	5.5
Gas	-	-	3	8	12	15	20	-	5	n.a.
Nuclear	8	14	13	13	25	37	47	6	12	4.6
Hydro	1	1	4	4	4	5	5	0	1	5.3
Bioenergy	-	0	2	6	10	14	18	0	5	16.5
Wind	-	0	6	10	13	16	19	0	5	21.3
Geothermal	-	-	0	0	0	0	0	-	0	n.a.
Solar PV	-	0	6	10	15	21	27	0	7	26.2
CSP	-	-	2	4	8	13	18	-	5	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						**Shares** (%)		**CAGR** (%)
	2013	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total capacity	**47**	**62**	**72**	**82**	**92**	**103**	**99**	**100**	**3.0**
Coal	39	44	46	47	47	48	83	47	0.8
Oil	3	3	3	3	3	3	6	3	0.2
Gas	-	2	5	6	8	10	-	10	n.a.
Nuclear	2	2	2	4	5	7	4	6	4.6
Hydro	2	3	4	4	4	4	5	4	2.0
Bioenergy	0	1	2	3	3	4	0	4	12.0
Wind	0	3	4	5	7	7	0	7	27.7
Geothermal	-	0	0	0	0	0	-	0	n.a.
Solar PV	0	3	6	9	12	15	0	14	17.0
CSP	-	0	1	2	3	5	-	4	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							**Shares** (%)		**CAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total CO_2	**244**	**420**	**380**	**381**	**367**	**357**	**346**	**100**	**100**	**-0.7**
Coal	201	343	302	293	270	250	229	82	66	-1.5
Oil	43	73	72	80	88	96	103	17	30	1.3
Gas	-	4	6	8	10	11	14	1	4	4.6
Power sector	**143**	**235**	**231**	**226**	**206**	**188**	**171**	**100**	**100**	**-1.2**
Coal	143	234	230	223	201	182	163	100	95	-1.3
Oil	-	0	0	0	0	1	1	0	0	6.1
Gas	-	-	1	3	4	6	7	-	4	n.a.
TFC	**98**	**142**	**146**	**152**	**159**	**166**	**172**	**100**	**100**	**0.7**
Coal	57	68	72	71	69	68	66	48	38	-0.1
Oil	41	70	69	77	85	93	100	49	58	1.3
Transport	*29*	*55*	*56*	*64*	*73*	*81*	*87*	*39*	*51*	*1.7*
Gas	-	4	5	5	5	6	6	3	4	1.8

South Africa: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**283**	**347**	**429**	**269**	**271**	**302**	**100**	**100**	**2.0**	**0.7**
Coal	248	266	298	231	160	94	70	31	0.8	-3.4
Oil	0	0	1	0	0	1	0	0	6.1	4.9
Gas	4	12	22	3	10	15	5	5	n.a.	n.a.
Nuclear	13	25	41	13	37	70	10	23	4.1	6.1
Hydro	4	4	5	4	5	6	1	2	5.4	6.1
Bioenergy	2	10	17	3	13	21	4	7	16.3	17.2
Wind	5	10	15	6	17	31	3	10	20.1	23.5
Geothermal	0	0	0	0	0	1	0	0	n.a.	n.a.
Solar PV	6	12	20	6	20	40	5	13	24.9	28.1
CSP	2	5	9	2	9	25	2	8	n.a.	n.a.
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**64**	**85**	**108**	**61**	**80**	**102**	**100**	**100**	**3.2**	**2.9**
Coal	46	53	62	43	40	33	57	33	1.8	-0.5
Oil	3	3	3	3	3	3	3	3	0.3	0.2
Gas	3	6	10	2	4	7	9	7	n.a.	n.a.
Nuclear	2	4	6	2	5	10	5	10	4.1	6.2
Hydro	3	4	4	4	4	4	4	4	2.0	2.4
Bioenergy	1	2	4	1	3	5	4	5	11.9	12.7
Wind	2	4	6	3	7	11	5	11	26.5	29.6
Geothermal	0	0	0	0	0	0	0	0	n.a.	n.a.
Solar PV	3	7	11	3	11	22	11	21	15.9	18.7
CSP	0	2	2	0	2	6	2	6	n.a.	n.a.
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**389**	**420**	**466**	**365**	**256**	**133**	**100**	**100**	**0.4**	**-4.2**
Coal	309	316	334	288	172	52	72	39	-0.1	-6.8
Oil	74	94	118	71	75	68	25	52	1.8	-0.3
Gas	6	10	14	6	9	12	3	9	4.6	4.2
Power sector	**236**	**247**	**269**	**220**	**121**	**17**	**100**	**100**	**0.5**	**-9.3**
Coal	235	243	260	219	117	11	97	64	0.4	-10.8
Oil	0	0	1	0	0	1	0	4	6.6	5.3
Gas	1	5	8	1	4	5	3	32	n.a.	n.a.
TFC	**150**	**170**	**194**	**142**	**133**	**114**	**100**	**100**	**1.2**	**-0.8**
Coal	74	74	74	69	55	41	38	36	0.3	-1.8
Oil	71	91	114	68	72	66	59	58	1.8	-0.2
Transport	*57*	*78*	*100*	*55*	*62*	*57*	*51*	*50*	*2.2*	*0.1*
Gas	5	5	6	5	5	7	3	6	1.4	1.9

Latin America: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**327**	**618**	**678**	**735**	**797**	**864**	**932**	**100**	**100**	**1.5**
Coal	15	24	29	33	38	41	46	4	5	2.5
Oil	151	275	284	293	299	307	312	44	33	0.5
Gas	48	133	144	158	179	208	234	22	25	2.1
Nuclear	2	5	9	11	13	13	16	1	2	4.2
Hydro	30	59	70	81	90	97	105	9	11	2.2
Bioenergy	80	118	129	142	154	165	179	19	19	1.6
Other renewables	1	5	12	17	24	31	40	1	4	8.3
Power sector	**65**	**168**	**183**	**202**	**226**	**256**	**287**	**100**	**100**	**2.0**
Coal	3	9	10	11	12	13	15	5	5	2.0
Oil	14	34	28	23	19	17	16	20	5	-2.8
Gas	12	45	40	43	49	63	72	27	25	1.8
Nuclear	2	5	9	11	13	13	16	3	6	4.2
Hydro	30	59	70	81	90	97	105	35	36	2.2
Bioenergy	2	13	15	18	21	24	27	8	9	2.9
Other renewables	1	4	11	16	22	29	37	2	13	8.5
Other energy sector	**55**	**89**	**98**	**103**	**111**	**118**	**122**	**100**	**100**	**1.2**
Electricity	*8*	*20*	*22*	*25*	*28*	*31*	*34*	*22*	*28*	*2.0*
TFC	**249**	**464**	**517**	**565**	**612**	**662**	**712**	**100**	**100**	**1.6**
Coal	6	11	14	16	18	20	21	2	3	2.4
Oil	122	222	235	248	260	271	278	48	39	0.8
Gas	23	61	74	84	95	108	124	13	17	2.7
Electricity	35	83	97	111	125	140	156	18	22	2.4
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	63	87	95	104	113	120	130	19	18	1.5
Other renewables	-	1	1	1	2	2	3	0	0	6.3
Industry	**85**	**155**	**174**	**190**	**207**	**226**	**245**	**100**	**100**	**1.7**
Coal	6	11	14	16	18	19	21	7	8	2.4
Oil	22	35	37	38	39	39	40	23	16	0.5
Gas	13	32	41	48	55	64	73	21	30	3.1
Electricity	17	35	40	44	48	54	60	23	24	2.0
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	27	42	43	45	47	50	52	27	21	0.8
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Transport	**72**	**158**	**173**	**186**	**200**	**212**	**224**	**100**	**100**	**1.3**
Oil	65	134	141	147	154	161	163	85	73	0.7
Electricity	0	0	0	0	1	1	1	0	0	3.0
Biofuels	6	16	24	31	37	41	48	10	21	4.2
Other fuels	0	7	7	7	8	9	13	5	6	2.2
Buildings	**67**	**101**	**111**	**121**	**131**	**143**	**154**	**100**	**100**	**1.6**
Coal	0	0	0	0	0	0	0	0	0	2.3
Oil	17	17	18	18	19	19	20	17	13	0.4
Gas	6	13	15	16	18	20	21	13	14	1.8
Electricity	17	45	53	62	71	80	89	44	58	2.6
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	27	26	23	22	22	21	21	25	14	-0.8
Other renewables	-	1	1	1	2	2	3	1	2	6.1
Other	**26**	**50**	**59**	**67**	**75**	**82**	**89**	**100**	**100**	**2.2**

Latin America: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**686**	**827**	**990**	**658**	**709**	**766**	**100**	**100**	**1.8**	**0.8**
Coal	30	41	53	28	25	26	5	3	3.0	0.4
Oil	290	317	341	277	244	206	34	27	0.8	-1.1
Gas	148	193	260	134	145	153	26	20	2.5	0.5
Nuclear	9	12	15	9	14	20	2	3	3.8	4.8
Hydro	71	92	108	71	90	106	11	14	2.3	2.2
Bioenergy	127	151	179	128	164	200	18	26	1.6	2.0
Other renewables	12	22	35	12	27	54	3	7	7.7	9.5
Power sector	**187**	**239**	**312**	**172**	**189**	**233**	**100**	**100**	**2.3**	**1.2**
Coal	11	14	18	9	4	3	6	1	2.7	-3.6
Oil	29	20	17	25	9	3	6	1	-2.5	-8.7
Gas	42	60	94	32	27	22	30	9	2.8	-2.6
Nuclear	9	12	15	9	14	20	5	8	3.8	4.8
Hydro	71	92	108	71	90	106	35	46	2.3	2.2
Bioenergy	15	21	27	15	21	30	9	13	2.9	3.2
Other renewables	11	20	32	11	25	50	10	21	7.9	9.7
Other energy sector	**99**	**116**	**132**	**94**	**98**	**96**	**100**	**100**	**1.5**	**0.3**
Electricity	*23*	*30*	*37*	*21*	*24*	*28*	*28*	*29*	*2.3*	*1.3*
TFC	**522**	**634**	**752**	**506**	**558**	**602**	**100**	**100**	**1.8**	**1.0**
Coal	15	19	22	14	16	16	3	3	2.6	1.4
Oil	240	275	304	231	220	193	40	32	1.2	-0.5
Gas	75	96	124	73	86	104	16	17	2.6	2.0
Electricity	99	132	169	93	111	137	22	23	2.7	1.9
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	93	110	131	94	122	148	17	25	1.5	2.0
Other renewables	1	2	3	1	2	4	0	1	5.8	7.5
Industry	**176**	**215**	**258**	**170**	**184**	**200**	**100**	**100**	**1.9**	**1.0**
Coal	14	19	22	14	16	16	9	8	2.6	1.4
Oil	37	40	42	36	34	32	16	16	0.6	-0.4
Gas	41	56	75	40	48	54	29	27	3.2	2.0
Electricity	40	50	63	38	42	51	24	26	2.2	1.4
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	43	50	57	42	45	46	22	23	1.1	0.4
Other renewables	0	0	0	0	0	1	0	0	n.a.	n.a.
Transport	**174**	**207**	**239**	**170**	**180**	**177**	**100**	**100**	**1.6**	**0.4**
Oil	145	168	185	139	121	91	77	51	1.2	-1.4
Electricity	0	1	1	0	1	2	0	1	3.0	6.1
Biofuels	21	31	44	23	48	69	18	39	3.9	5.6
Other fuels	7	8	10	7	10	16	4	9	1.1	2.9
Buildings	**112**	**137**	**164**	**107**	**122**	**139**	**100**	**100**	**1.8**	**1.2**
Coal	0	0	0	0	0	0	0	0	3.3	1.1
Oil	18	19	21	17	17	18	13	13	0.6	0.1
Gas	15	19	22	15	17	19	14	14	1.9	1.4
Electricity	55	76	98	51	64	78	60	56	2.9	2.1
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	23	22	21	23	22	21	13	15	-0.8	-0.7
Other renewables	1	2	2	1	2	3	2	2	5.6	6.6
Other	**59**	**75**	**90**	**59**	**72**	**85**	**100**	**100**	**2.2**	**2.0**

Latin America: New Policies Scenario

	Electricity generation (TWh)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total generation	**489**	**1 183**	**1 382**	**1 573**	**1 770**	**1 986**	**2 202**	**100**	**100**	**2.3**
Coal	9	37	44	49	55	58	68	3	3	2.3
Oil	64	158	132	111	89	81	76	13	3	-2.7
Gas	45	221	212	243	291	369	426	19	19	2.5
Nuclear	10	21	34	41	52	52	63	2	3	4.2
Hydro	354	681	818	937	1 041	1 131	1 220	58	55	2.2
Bioenergy	7	52	64	74	84	95	106	4	5	2.7
Wind	-	9	66	94	120	146	171	1	8	11.5
Geothermal	1	4	5	7	10	14	19	0	1	5.9
Solar PV	-	0	8	16	25	34	44	0	2	19.3
CSP	-	0	-	1	3	7	10	0	0	25.7
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						**Shares** (%)		**CAAGR** (%)
	2013	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total capacity	**270**	**346**	**393**	**440**	**487**	**540**	**100**	**100**	**2.6**
Coal	7	10	10	11	11	13	3	2	2.2
Oil	42	40	37	32	31	29	16	5	-1.3
Gas	53	72	83	96	109	125	20	23	3.2
Nuclear	3	5	6	7	7	8	1	2	3.9
Hydro	146	179	200	221	241	261	54	48	2.2
Bioenergy	14	17	19	21	23	25	5	5	2.2
Wind	4	19	26	34	41	48	2	9	9.2
Geothermal	1	1	1	2	2	3	0	0	5.4
Solar PV	0	5	10	15	21	26	0	5	17.2
CSP	0	-	0	1	2	2	0	0	58.3
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							**Shares** (%)		**CAAGR** (%)
	1990	**2013**	**2020**	**2025**	**2030**	**2035**	**2040**	**2013**	**2040**	**2013-40**
Total CO_2	**553**	**1 131**	**1 191**	**1 242**	**1 310**	**1 398**	**1 473**	**100**	**100**	**1.0**
Coal	47	95	118	131	144	152	167	8	11	2.1
Oil	404	752	766	776	787	805	810	66	55	0.3
Gas	103	284	307	336	379	441	497	25	34	2.1
Power sector	**89**	**254**	**231**	**228**	**233**	**261**	**288**	**100**	**100**	**0.5**
Coal	16	43	50	54	59	60	70	17	24	1.8
Oil	44	106	88	74	59	53	50	42	17	-2.8
Gas	29	105	93	100	116	147	169	41	59	1.8
TFC	**404**	**776**	**843**	**896**	**951**	**1 008**	**1 055**	**100**	**100**	**1.1**
Coal	27	48	63	72	79	86	91	6	9	2.4
Oil	331	604	633	657	683	706	715	78	68	0.6
Transport	*196*	*404*	*425*	*444*	*465*	*483*	*489*	*52*	*46*	*0.7*
Gas	46	124	147	167	189	216	249	16	24	2.6

Latin America: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**1 411**	**1 873**	**2 381**	**1 322**	**1 570**	**1 906**	**100**	**100**	**2.6**	**1.8**
Coal	47	64	84	39	16	14	4	1	3.1	-3.4
Oil	135	95	82	119	43	13	3	1	-2.4	-8.8
Gas	231	373	587	161	159	128	25	7	3.7	-2.0
Nuclear	34	46	58	36	52	75	2	4	3.8	4.8
Hydro	822	1 065	1 255	825	1 045	1 238	53	65	2.3	2.2
Bioenergy	64	84	107	64	83	114	4	6	2.7	3.0
Wind	66	114	151	66	119	213	6	11	11.0	12.4
Geothermal	5	9	17	5	13	26	1	1	5.5	7.2
Solar PV	7	20	33	8	33	67	1	4	18.1	21.2
CSP	-	2	7	-	5	16	0	1	24.2	27.8
Marine	-	-	-	-	0	1	-	0	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**349**	**454**	**568**	**336**	**415**	**522**	**100**	**100**	**2.8**	**2.5**
Coal	10	11	14	8	7	5	2	1	2.6	-1.4
Oil	40	33	32	40	31	27	6	5	-1.0	-1.6
Gas	74	108	152	61	70	79	27	15	4.0	1.5
Nuclear	5	6	8	5	7	10	1	2	3.5	4.6
Hydro	180	227	271	180	221	265	48	51	2.3	2.2
Bioenergy	17	21	25	17	20	26	4	5	2.2	2.4
Wind	18	32	42	19	34	63	7	12	8.7	10.3
Geothermal	1	1	2	1	2	4	0	1	5.0	6.7
Solar PV	5	12	20	5	20	40	4	8	16.1	19.0
CSP	-	1	2	-	1	4	0	1	56.4	60.9
Marine	-	-	-	-	0	0	-	0	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**1 220**	**1 407**	**1 641**	**1 136**	**981**	**820**	**100**	**100**	**1.4**	**-1.2**
Coal	122	155	189	110	77	60	12	7	2.6	-1.7
Oil	782	842	898	743	615	473	55	58	0.7	-1.7
Gas	316	410	553	282	290	288	34	35	2.5	0.0
Power sector	**244**	**271**	**360**	**199**	**108**	**71**	**100**	**100**	**1.3**	**-4.6**
Coal	54	67	85	45	16	10	24	15	2.5	-5.1
Oil	90	63	54	80	29	9	15	13	-2.5	-8.7
Gas	99	141	221	74	64	51	61	72	2.8	-2.6
TFC	**858**	**1 005**	**1 140**	**827**	**776**	**676**	**100**	**100**	**1.4**	**-0.5**
Coal	64	82	97	61	57	47	9	7	2.6	-0.1
Oil	646	731	794	621	553	439	70	65	1.0	-1.2
Transport	*435*	*504*	*556*	*417*	*365*	*272*	*49*	*40*	*1.2*	*-1.5*
Gas	148	193	248	144	165	190	22	28	2.6	1.6

Brazil: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
TPED	**138**	**291**	**319**	**351**	**388**	**426**	**460**	**100**	**100**	**1.7**
Coal	10	16	20	22	23	24	26	6	6	1.7
Oil	59	122	126	133	143	153	160	42	35	1.0
Gas	3	32	31	35	43	57	66	11	14	2.7
Nuclear	1	4	6	7	8	8	11	1	2	3.9
Hydro	18	34	39	46	50	54	57	12	12	2.0
Bioenergy	48	82	89	100	109	115	123	28	27	1.5
Other renewables	-	1	6	9	11	14	17	0	4	10.6
Power sector	**22**	**69**	**76**	**84**	**96**	**111**	**126**	**100**	**100**	**2.2**
Coal	2	5	5	5	5	4	5	7	4	-0.2
Oil	1	6	2	2	2	2	2	8	2	-3.7
Gas	0	13	7	7	9	17	20	19	16	1.6
Nuclear	1	4	6	7	8	8	11	5	9	3.9
Hydro	18	34	39	46	50	54	57	48	46	2.0
Bioenergy	1	7	9	11	12	14	15	11	12	2.8
Other renewables	-	1	6	8	10	13	15	1	12	12.9
Other energy sector	**26**	**44**	**49**	**54**	**60**	**64**	**66**	**100**	**100**	**1.5**
Electricity	*3*	*11*	*12*	*14*	*15*	*17*	*18*	*24*	*28*	*2.1*
TFC	**111**	**229**	**255**	**283**	**311**	**339**	**365**	**100**	**100**	**1.7**
Coal	4	8	10	12	13	14	15	3	4	2.4
Oil	53	108	115	123	132	142	149	47	41	1.2
Gas	2	13	16	20	23	28	32	6	9	3.4
Electricity	18	42	49	56	64	71	79	18	22	2.4
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	34	58	64	72	78	83	88	25	24	1.6
Other renewables	-	1	1	1	1	1	2	0	0	4.3
Industry	**40**	**82**	**93**	**103**	**114**	**125**	**135**	**100**	**100**	**1.9**
Coal	4	8	10	12	13	14	15	9	11	2.4
Oil	8	12	14	15	16	17	18	15	13	1.4
Gas	1	9	13	15	18	21	25	11	18	3.7
Electricity	10	18	21	24	26	30	33	22	25	2.3
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	17	35	36	38	40	43	45	42	33	0.9
Other renewables	-	-	0	0	0	0	0	-	0	n.a.
Transport	**33**	**84**	**91**	**100**	**109**	**116**	**123**	**100**	**100**	**1.4**
Oil	27	67	69	72	76	82	86	80	70	0.9
Electricity	0	0	0	0	0	0	0	0	0	3.0
Biofuels	6	14	20	26	30	32	35	17	28	3.3
Other fuels	0	2	2	2	2	2	2	3	2	-0.3
Buildings	**23**	**36**	**38**	**42**	**47**	**52**	**57**	**100**	**100**	**1.7**
Coal	-	-	-	-	-	-	-	-	-	n.a.
Oil	6	7	7	8	8	8	9	20	16	0.7
Gas	0	1	1	1	2	2	3	1	4	6.0
Electricity	8	22	25	30	34	38	43	60	75	2.6
Heat	-	-	-	-	-	-	-	-	-	n.a.
Bioenergy	9	6	4	3	2	1	1	17	2	-6.7
Other renewables	-	1	1	1	1	1	2	2	3	4.1
Other	**15**	**27**	**32**	**37**	**42**	**46**	**51**	**100**	**100**	**2.3**

Brazil: Current Policies and 450 Scenarios

	Energy demand (Mtoe)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
TPED	**323**	**405**	**486**	**312**	**349**	**380**	**100**	**100**	**1.9**	**1.0**
Coal	21	24	29	19	16	15	6	4	2.1	-0.4
Oil	129	154	170	123	114	97	35	26	1.3	-0.8
Gas	33	48	75	28	35	43	15	11	3.2	1.1
Nuclear	6	8	11	6	8	11	2	3	3.9	4.0
Hydro	40	53	62	39	49	57	13	15	2.3	2.0
Bioenergy	88	106	124	89	117	140	25	37	1.6	2.0
Other renewables	6	11	16	6	11	17	3	4	10.3	10.6
Power sector	**78**	**104**	**139**	**72**	**82**	**103**	**100**	**100**	**2.6**	**1.5**
Coal	6	5	6	5	0	0	4	0	0.5	-12.9
Oil	3	3	3	2	1	1	2	1	-2.5	-7.7
Gas	9	13	28	4	3	5	20	5	2.8	-3.6
Nuclear	6	8	11	6	8	11	8	11	3.9	4.0
Hydro	40	53	62	39	49	57	44	55	2.3	2.0
Bioenergy	9	12	16	9	11	15	11	14	2.9	2.6
Other renewables	6	10	14	5	9	15	10	15	12.6	12.9
Other energy sector	**50**	**62**	**71**	**49**	**54**	**56**	**100**	**100**	**1.8**	**0.9**
Electricity	*12*	*16*	*20*	*12*	*14*	*16*	*28*	*28*	*2.4*	*1.5*
TFC	**258**	**323**	**382**	**251**	**285**	**307**	**100**	**100**	**1.9**	**1.1**
Coal	10	14	16	10	11	10	4	3	2.7	1.1
Oil	118	142	158	113	105	91	41	30	1.4	-0.6
Gas	16	24	32	16	22	28	8	9	3.5	2.9
Electricity	50	67	86	48	58	71	22	23	2.7	2.0
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	62	75	89	63	87	104	23	34	1.6	2.2
Other renewables	1	1	2	1	1	2	0	1	4.1	5.0
Industry	**94**	**118**	**142**	**92**	**104**	**113**	**100**	**100**	**2.1**	**1.2**
Coal	10	13	16	10	11	10	11	9	2.7	1.1
Oil	14	16	18	14	15	15	13	13	1.5	0.8
Gas	13	19	25	13	17	20	18	17	3.8	2.9
Electricity	22	28	35	20	23	29	24	25	2.4	1.7
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	36	43	49	35	38	39	34	35	1.3	0.4
Other renewables	0	0	0	0	0	0	0	0	n.a.	n.a.
Transport	**92**	**112**	**127**	**89**	**95**	**91**	**100**	**100**	**1.5**	**0.3**
Oil	72	85	93	67	52	32	73	35	1.2	-2.7
Electricity	0	0	1	0	0	1	0	1	3.1	6.8
Biofuels	18	25	31	20	41	55	25	60	3.0	5.1
Other fuels	2	2	2	2	2	3	1	3	-0.7	1.1
Buildings	**39**	**50**	**63**	**37**	**44**	**53**	**100**	**100**	**2.1**	**1.4**
Coal	-	-	-	-	-	-	-	-	n.a.	n.a.
Oil	7	9	9	7	8	9	15	16	1.0	0.6
Gas	1	2	3	1	2	2	4	5	6.3	5.9
Electricity	26	37	48	25	32	39	76	73	3.0	2.2
Heat	-	-	-	-	-	-	-	-	n.a.	n.a.
Bioenergy	4	2	1	4	2	1	2	2	-6.7	-5.9
Other renewables	1	1	2	1	1	2	3	3	4.0	4.4
Other	**32**	**42**	**51**	**32**	**41**	**50**	**100**	**100**	**2.3**	**2.3**

Brazil: New Policies Scenario

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total generation	**223**	**570**	**675**	**775**	**877**	**988**	**1 096**	**100**	**100**	**2.5**
Coal	5	22	23	21	20	19	21	4	2	-0.1
Oil	5	27	10	7	7	7	10	5	1	-3.7
Gas	0	69	45	41	52	95	114	12	10	1.9
Nuclear	2	15	25	26	31	31	42	3	4	3.9
Hydro	207	391	459	532	586	626	668	69	61	2.0
Bioenergy	4	40	50	56	62	67	73	7	7	2.2
Wind	-	7	59	82	103	121	140	1	13	12.0
Geothermal	-	-	-	-	-	-	-	-	-	n.a.
Solar PV	-	-	5	10	15	20	25	-	2	n.a.
CSP	-	-	-	-	1	2	4	-	0	n.a.
Marine	-	-	-	-	-	-	-	-	-	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total capacity	**126**	**171**	**193**	**215**	**236**	**262**	**100**	**100**	**2.7**
Coal	4	5	5	4	4	4	3	2	0.0
Oil	8	8	7	7	7	7	6	3	-0.6
Gas	11	17	18	19	21	26	9	10	3.3
Nuclear	2	3	3	4	4	5	2	2	3.8
Hydro	86	105	117	128	138	149	68	57	2.0
Bioenergy	12	14	15	16	18	19	9	7	1.8
Wind	3	16	22	27	32	37	3	14	9.2
Geothermal	-	-	-	-	-	-	-	-	n.a.
Solar PV	-	3	6	9	11	14	-	5	n.a.
CSP	-	-	-	0	1	1	-	0	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	1990	2013	2020	2025	2030	2035	2040	2013	2040	2013-40
Total CO_2	**184**	**452**	**467**	**493**	**538**	**595**	**635**	**100**	**100**	**1.3**
Coal	28	65	80	84	89	92	98	14	15	1.5
Oil	151	317	320	333	357	380	396	70	62	0.8
Gas	6	70	68	76	93	123	141	16	22	2.6
Power sector	**13**	**77**	**54**	**48**	**51**	**69**	**81**	**100**	**100**	**0.2**
Coal	8	28	30	27	26	24	27	37	33	-0.1
Oil	4	18	7	5	5	5	6	23	8	-3.7
Gas	0	31	18	16	21	40	48	40	59	1.6
TFC	**156**	**347**	**378**	**406**	**442**	**478**	**503**	**100**	**100**	**1.4**
Coal	16	34	45	52	58	62	65	10	13	2.5
Oil	136	285	297	312	333	356	370	82	73	1.0
Transport	*82*	*203*	*209*	*216*	*231*	*249*	*259*	*58*	*51*	*0.9*
Gas	4	28	36	43	51	60	69	8	14	3.3

Brazil: Current Policies and 450 Scenarios

	Electricity generation (TWh)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total generation	**691**	**934**	**1 194**	**653**	**790**	**974**	**100**	**100**	**2.8**	**2.0**
Coal	24	21	26	21	1	1	2	0	0.6	-12.8
Oil	13	12	13	10	3	3	1	0	-2.6	-7.7
Gas	52	76	165	24	19	27	14	3	3.3	-3.4
Nuclear	25	31	42	25	31	42	3	4	3.9	4.0
Hydro	463	616	717	459	569	664	60	68	2.3	2.0
Bioenergy	50	62	75	50	59	70	6	7	2.3	2.1
Wind	59	100	129	58	92	136	11	14	11.6	11.9
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	5	15	24	5	15	28	2	3	n.a.	n.a.
CSP	-	1	4	-	1	4	0	0	n.a.	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.	n.a.

	Electrical capacity (GW)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total capacity	**172**	**225**	**282**	**167**	**201**	**247**	**100**	**100**	**3.0**	**2.5**
Coal	5	4	5	4	3	2	2	1	0.4	-3.8
Oil	8	7	9	8	7	7	3	3	0.3	-0.6
Gas	18	21	34	14	15	16	12	6	4.3	1.4
Nuclear	3	4	5	3	4	5	2	2	3.8	3.8
Hydro	107	136	161	105	124	148	57	60	2.4	2.0
Bioenergy	14	17	19	14	16	18	7	7	1.9	1.7
Wind	16	27	34	16	24	35	12	14	8.8	9.0
Geothermal	-	-	-	-	-	-	-	-	n.a.	n.a.
Solar PV	3	8	14	3	9	16	5	6	n.a.	n.a.
CSP	-	0	1	-	0	1	0	0	n.a.	n.a.
Marine	-	-	-	-	-	-	-	-	n.a.	n.a.

	CO_2 emissions (Mt)						Shares (%)		CAAGR (%)	
	2020	2030	2040	2020	2030	2040	2040		2013-40	
	Current Policies Scenario			450 Scenario			CPS	450	CPS	450
Total CO_2	**484**	**588**	**699**	**449**	**375**	**301**	**100**	**100**	**1.6**	**-1.5**
Coal	81	92	109	76	44	32	16	10	1.9	-2.6
Oil	331	392	428	313	263	192	61	64	1.1	-1.8
Gas	72	103	162	60	68	77	23	26	3.1	0.4
Power sector	**61**	**64**	**107**	**45**	**11**	**14**	**100**	**100**	**1.2**	**-6.0**
Coal	31	27	33	28	1	1	31	5	0.6	-12.8
Oil	9	8	9	7	2	2	8	14	-2.5	-7.7
Gas	21	30	65	10	8	12	61	81	2.8	-3.6
TFC	**388**	**475**	**537**	**371**	**331**	**258**	**100**	**100**	**1.6**	**-1.1**
Coal	46	60	70	44	39	29	13	11	2.8	-0.6
Oil	306	363	397	291	247	179	74	69	1.2	-1.7
Transport	*217*	*258*	*281*	*203*	*157*	*96*	*52*	*37*	*1.2*	*-2.7*
Gas	36	51	69	36	45	50	13	19	3.4	2.2

Policies and measures by scenario

The *World Energy Outlook 2015* (*WEO-2015*) presents projections for three core scenarios, which are differentiated primarily by their underlying assumptions about the evolution of energy-related government policies.

The ***Current Policies Scenario*** (CPS) takes into consideration only those policies for which implementing measures had been formally adopted as of mid-2015 and makes the assumption that these policies persist unchanged.

The ***New Policies Scenario*** (NPS) is the central scenario of this *Outlook*. In addition to incorporating the policies and measures that affect energy markets and that had been adopted as of mid-2015, it also takes account of other relevant intentions that have been announced, even when the precise implementing measures have yet to be fully defined. This includes the energy-related components of the Intended Nationally Determined Contributions (INDCs), submitted by national governments by 1 October 2015 as pledges in the run-up to the United Nations Framework Convention on Climate Change Conference of the Parties (COP21). We take a generally cautious view in the New Policies Scenario of the extent and timing of which policy proposals will be implemented. This is done in view of the many institutional, political and economic circumstances that could stand in the way. These policies include programmes to support renewable energy and improve energy efficiency, to promote alternative fuels and vehicles, carbon pricing, reform of energy subsidies, and the introduction, expansion or phase out of nuclear power.

The ***450 Scenario*** (450S) assumes a set of policies that bring about a trajectory of greenhouse-gas (GHG) emissions from the energy sector that is consistent with the international goal to limit the rise in the long-term average global temperature to two degrees Celsius (2 °C), compared with pre-industrial levels. The policies collectively ensure an emissions trajectory consistent with stabilisation of the GHG concentration after 2100 at around 450 parts per million.

The key policies that are assumed to be adopted in each of the main scenarios of *WEO-2015* are presented below by sector and region. The policies are cumulative: measures listed under the New Policies Scenario supplement those under the Current Policies Scenario and measures listed under the 450 Scenario supplement those under the New Policies Scenario. The following tables start with broad cross-cutting policy frameworks and are followed by more detailed policy assumptions, by sector, as adopted in this year's *Outlook*.

Table B.1 ▷ Cross-cutting policy assumptions by scenario for selected regions

	Scenario	Assumptions
All OECD	450S	• Staggered introduction of CO_2 prices in all countries. • $100 billion annual financing provided to non-OECD countries by 2020.
United States	CPS	• State-level renewable portfolio standards (RPS) that include the option of using energy efficiency as a means of compliance. • Regional Greenhouse Gas Initiative: mandatory cap-and-trade scheme covering fossil-fuelled power plants in nine northeast states, including recycling of revenues for energy efficiency and renewable energy investments. • Economy-wide cap-and-trade scheme in California with binding commitments.
	450S	• CO_2 pricing implemented from 2020.
Japan	450S	• CO_2 pricing implemented from 2020.
European Union	CPS	• 2020 Climate and Energy Package: ○ 20% cut in GHG emissions compared with 1990 levels. ○ Renewables to reach a share of 20% of total final energy consumption by 2020. ○ Partial implementation of 20% energy savings compared with a business-as-usual scenario. • EU Emissions Trading System (EU ETS) reducing GHG emissions in 2020 by 21% below the 2005 level, covering power, industry and aviation sectors.
	NPS	• 2030 Climate and Energy framework: ○ 40% cut in GHG emissions compared with 1990 levels. ○ Renewables to reach a share of at least 27% of total final energy consumption in 2030. ○ Partial realisation of the goal to save at least 27% of energy use compared with a business-as-usual scenario. • Partial implementation of the Energy Efficiency Directive target to reduce primary energy consumption by 20% in 2020, but full implementation of sectoral provisions. • EU ETS reducing GHG emissions in 2030 by 43% below the 2005 level, covering power, industry and aviation sectors. Structural change in the ETS by establishing a market stability reserve from 2019.
	450S	• EU ETS strengthened in line with the 2050 roadmap, covering power, industry and aviation sectors.
All non-OECD	CPS	• Fossil-fuel subsidies are phased out in countries that already have policies in place to do so.
	NPS	• Fossil-fuel subsidies are phased out within the next ten years in all net-importing countries and in net-exporting countries where specific policies have already been announced.
	450S	• Finance for domestic mitigation. • Fossil-fuel subsidies are phased out within the next ten years in all net-importers and in net-exporters within the next twenty years.*
Russia	CPS	• Gradual real increases in residential gas and electricity prices (1%/year) and in gas prices in industry (1.5%/year). • Implementation of federal law on energy conservation and energy efficiency.
	NPS	• 2%/year real rise in residential gas and electricity prices. • Industrial gas prices reach export prices (minus taxes and transport) in 2020.
	450S	• Quicker rise in residential gas and electricity prices. • CO_2 pricing from 2020. • More support for nuclear and renewables. • Partial implementation of the "Energy Saving and Increase of Energy Efficiency for the period till 2020" programme.

Table B.1 ▷ Cross-cutting policy assumptions by scenario for selected regions (continued)

	Scenario	Assumptions
China	CPS	• Implementation of measures in the 12th Five-Year Plan, including 17% cut in CO_2 intensity by 2015 and 16% reduction in energy intensity by 2015 compared with 2010. • Increase the share of non-fossil fuels in primary energy consumption to around 15% by 2020.
	NPS	• Efforts to restructure the economy and to shift emphasis away from investment and export-led growth towards the services sector and domestic consumption. • Increase the share of non-fossil fuels in primary energy consumption to around 20% by 2030. • Reduce CO_2 emissions per unit of GDP by 60-65% from 2005 levels by 2030. • Emission trading scheme covering power and industry sectors from 2017. • Expand the use of natural gas. • Energy price reform, including more frequent adjustments in oil product prices and increase in natural gas price by 15% for non-residential consumers. • Action Plan for Prevention and Control of Air Pollution.
	450S	• Strengthening of emission trading scheme covering power and industry sectors. • Reduce local air pollutants between 2010 and 2015 (8% for sulphur dioxide, 10% for nitrogen oxides).
India	CPS	• Pursuit of National Solar Mission, aiming to deploy 20 GW by 2022. • Pursuit of National Mission on Enhanced Energy Efficiency. • Creation of National Clean Energy Fund to promote clean energy technologies based on a levy of INR 100/tonne of coal. • Efforts to increase the share of manufacturing in the national economy via the "Make in India" campaign.
	NPS	• Efforts to expedite environmental clearances and land acquisition for energy projects. • Increase in the National Clean Energy Fund. • Open the coal sector to private and foreign investors.
Brazil	NPS	• Partial implementation of National Energy Efficiency Plan.
	450S	• CO_2 pricing from 2020.

* Except the Middle East where subsidisation rates are assumed to decline to an average of 8% by 2035.

Note: Pricing of CO_2 emissions is either by an emissions trading scheme or taxes.

Table B.2 ▷ Power sector policies and measures as modelled by scenario for selected regions

<table>
<tr><th></th><th>Scenario</th><th>Assumptions</th></tr>
<tr><td>United States</td><td>CPS</td><td>State-level renewable portfolio standards and support for renewables prolonged over the projection period.
Mercury and Air Toxics Standards.
Clean Air Interstate Rule regulating sulphur dioxide and nitrogen oxides.
Lifetimes of some US nuclear plants extended beyond 60 years.
Funding for CCS (demonstration-scale).</td></tr>
<tr><td></td><td>NPS</td><td>Implementation of Clean Power Plan: CO_2 emissions reduction from the power sector of 32% by 2030, compared with 2005 levels, including the following building blocks:
Improve efficiency of existing coal-fired power plants.
Substitute gas-fired generation for coal-fired generation.
Substitute renewables (e.g. wind and solar PV) for coal-fired generation.
Implementation of Carbon Pollution Standards, limiting CO_2 emissions intensity for new fossil-fuelled power plants and significantly modified electricity generating units.
Extension and strengthening of support for renewables and nuclear, including loan guarantees.</td></tr>
<tr><td></td><td>450S</td><td>CO_2 pricing implemented from 2020.
Extended support to renewables, nuclear and CCS.
Efficiency and emission standards preventing refurbishment of old inefficient plants.</td></tr>
<tr><td>Japan</td><td>CPS</td><td>Support for renewables-based generation.
Decommissioning of units 1-6 of Fukushima Daiichi nuclear power plant and five additional units.</td></tr>
<tr><td></td><td>NPS</td><td>Achievement of the target to increase renewables to 22-24% of power generation by 2030. Gradual restart of electricity generation from nuclear power plants, with the aim of reaching 20-22% of power generation in 2030.
Lifetime of nuclear plants typically to 40 years, with the possibility of extensions up to 60 years.
Harmonisation of support for renewables-based generation.</td></tr>
<tr><td></td><td>450S</td><td>CO_2 pricing implemented from 2020.
Share of low-carbon electricity generation to increase by 2020 and expand further by 2030.
Expansion of renewables support.
Introduction of CCS to coal-fired power generation.</td></tr>
<tr><td>European Union</td><td>CPS</td><td>EU ETS in accordance with 2020 Climate and Energy Package.
Support for renewables in accordance with overall target.
Financial support for CCS.
Early retirement of all nuclear plants in Germany by the end-2022.
Removal of some barriers to combined heat and power (CHP) plants, resulting from the Cogeneration Directive 2004.
Industrial Emissions Directive.</td></tr>
<tr><td></td><td>NPS</td><td>EU ETS in accordance with 2030 Climate and Energy framework.
Extended and strengthened support to renewables-based electricity generation technologies in accordance with overall target.
Further removal of barriers to CHP through partial implementation of the Energy Efficiency Directive.</td></tr>
<tr><td></td><td>450S</td><td>Reinforcement of government support in favour of renewables.
Expanded support measures for CCS.</td></tr>
</table>

Table B.2 ▷ Power sector policies and measures as modelled by scenario for selected regions (continued)

	Scenario	Assumptions
Russia	CPS	• Competitive wholesale electricity market.
	NPS	• State support to hydro and nuclear power; strengthened and broadened existing support mechanisms for non-hydro renewables.
	450S	• CO_2 pricing implemented from 2020. • Stronger support for nuclear power and renewables.
China	CPS	• Implementation of measures in 12th Five-Year Plan. • 290 GW of installed hydro capacity by 2015. • 100 GW of installed wind capacity by 2015. • 35 GW of solar capacity by 2015. • Priority given to gas use to 2015.
	NPS	• 12th Five-Year Plan renewables targets for 2015 are exceeded. • ETS in accordance with overall target. • Lower coal consumption of electricity generation of newly built coal-fired power plants to around 300 g/kWh. • 58 GW of nuclear capacity by 2020. • 420 GW of hydro capacity, including pumped storage by 2020. • 200 GW of wind capacity by 2020. • 100 GW of solar capacity by 2020. • 30 GW of bioenergy capacity by 2020.
	450S	• ETS in accordance with overall target. • Enhanced support for renewables. • Continued support to nuclear capacity additions post 2020. • Deployment of CCS from around 2020.
India	CPS	• Renewable Purchase Obligation and other fiscal measures to promote renewable energy. • Adoption of National Solar Mission target of 20 GW of solar PV capacity by 2022. • Increased use of supercritical coal technology. • Restructured Accelerated Power Development and Reform Programme to finance the modernisation of the transmission and distribution networks.
	NPS	• Strengthened support measures to increase the share of renewables, towards the national target of 175 GW of non-hydro renewable capacity by 2022 (100 GW solar, 75 GW non-solar), including competitive bidding. • Increased uptake of supercritical technology for coal-fired power plants. • Expand efforts to strengthen the national grid and upgrade the T&D network; progress towards original aim to reduce aggregate technical and commercial losses to 15%. • Increased efforts to establish the financial viability of all power market participants especially the network and distribution companies.
	450S	• Renewables (excluding large hydro) to reach 15% of installed capacity by 2020. • Expanded support to renewables, nuclear and efficient coal. • Deployment of CCS from around 2025.
Brazil	CPS	• Power auctions for all fuel types. • Guidance on the fuel mix from the Ten-Year Plan for Energy Expansion.
	NPS	• Enhanced deployment of renewables technologies through power auctions.
	450S	• CO_2 pricing implemented from 2020. • Further increases of generation from renewable sources.

Notes: g/kWh = grammes per kilowatt-hour; CCS = carbon capture and storage. Pricing of CO_2 emissions is either by an emissions trading scheme or taxes.

Table B.3 ▷ Transport sector policies and measures as modelled by scenario in selected regions

	Scenario	Assumptions
All OECD	NPS	• Realisation of ICAO goal to improve fuel efficiency of the aviation sector by 2%/year to 2020, and adoption of the aspirational goal to further improve by 2%/year beyond 2020; aspire carbon-neutral growth from 2020 onwards.
	450S	• On-road stock emission intensity for PLDVs in 2040: 60 g CO_2/km. • Light-commercial vehicles: full technology spill-over from PLDVs. • Medium- and heavy-freight vehicles: 40% more efficient by 2040 than in New Policies Scenario. • Aviation: reduce fuel intensity by 2.6%/year and scale-up biofuels use to reduce CO_2 emissions by 50% from 2005 levels in 2050. • Fuels: retail fuel prices kept at a level similar to New Policies Scenario. • Alternative clean fuels: enhanced support to alternative fuels.
United States	CPS	• CAFE standards: 35.5 miles/gallon for PLDVs by 2016, and further strengthening thereafter. • Renewables Fuel Standard. • Truck standards for each model year from 2014 to 2018 reduce average on-road fuel consumption by up to 18% in 2018.
	NPS	• CAFE standards: 54.5 miles/gallon for PLDVs by 2025. • Truck standards for each model year from 2014 to 2018 reduce average on-road fuel consumption by up to 20% in 2018, and extension and strengthening for 2021-2027. • Support to natural gas in road freight. • Moderate Increase of ethanol blending mandates.
Japan	CPS	• Fuel-economy target for PLDVs: 16.8 kilometres/litre (km/l) by 2015 and 20.3 km/l by 2020. • Average fuel-economy target for road freight vehicles: 7.09 km/l by 2015. • Fiscal incentives for hybrid and electric vehicles; subsidies for electric vehicles.
	NPS	• Adoption of target share of next generation vehicles 50-70% by 2030 (clean diesel vehicles, hybrid vehicles, plug-in hybrid vehicles, electric vehicles and fuel cell vehicles).
European Union	CPS	• CO_2 emission standards for PLDVs by 2015 (130 g CO_2/km through efficiency measures, additional 10 g CO_2/km by alternative fuels). • Subsidy support to biofuels blending. • EU ETS in accordance with 2020 Climate and Energy Package, covering domestic EU aviation sector.
	NPS	• Climate and Energy Package: achieve target to reach 10% of transport energy demand by renewable fuels in 2020. • Fuel Quality Directive: achieve target to reduce GHG intensity of road transport fuels by 6% in 2020. • Realisation of more stringent emission target for PLDVs (95 g CO_2/km by 2020) and further strengthening after 2020. • Realisation of emission target for LCVs (147 g CO_2/km by 2020) and further strengthening after 2020. • Enhanced support to alternative fuels. • EU ETS in accordance with 2030 Climate and Energy framework, covering domestic EU aviation sector.

Table B.3 ▷ Transport sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
All non-OECD	NPS	• Realisation of ICAO goal to improve fuel efficiency of the aviation sector by 2%/year to 2020; and aspirational goal set to further improve by 2%/year beyond 2020; and achieve carbon-neutral growth from 2020 onwards.
	450S	• On-road stock emissions intensity for PLDVs: 85 g CO_2/km. • Light-commercial vehicles: full technology spill-over from PLDVs. • Medium- and heavy-freight vehicles: 40% more efficient by 2040 than in New Policies Scenario. • Aviation: reduce fuel intensity by 2.6% per year and scale-up biofuels use to reduce carbon emissions by 50% in 2050, relative to 2005. • Fuels: retail fuel prices kept at a level similar to New Policies Scenario. • Alternative clean fuels: enhanced support to alternative fuels.
China	CPS	• Subsidies for hybrid and electric vehicles and consolidation of vehicle charging standards. • Promotion of fuel-efficient cars. • Ethanol blending mandates 10% in selected provinces. • Cap on PLDV sales in some cities to reduce air pollution and traffic jams. • Enhance infrastructure for electric vehicles in selected cities.
	NPS	• Fuel economy target for PLDVs: 5.0 l/100 km by 2020. • Extended subsidies for purchase of alternative-fuel vehicles. • Complete fossil-fuel subsidy phase out within the next ten years. • Promote the share of public transport in motorised travel in big- and medium-sized cities.
India	CPS	• 5% blending mandate for ethanol. • Support for alternative-fuel vehicles.
	NPS	• Continued efforts to increase blending mandates (also for biodiesel) subject to availability. • Extended support for alternative-fuel vehicles, including the National Electric Mobility Mission Plan 2020. • Fuel economy standard for PLDVs: 5.5 l/100km of fuel on average by 2017/2018 and 4.8 l/100km by 2022/2023. • Increased support for natural gas use in road transport, particularly for urban public transport. Dedicated rail corridors to encourage shift away from road freight.
Brazil	CPS	• Ethanol blending mandates in road transport between 18% and 25%. • Biodiesel blending mandate of 5%.
	NPS	• Inovar-Auto initiative targeting fuel efficiency improvement for PLDVs of at least 12% in 2017, compared with 2012/2013. • Increase of ethanol and biodiesel blending mandates. • Local renewable fuel targets for urban transport. • Long-term plan for freight transport (PNLT). National urban mobility plan (PNMU).

Note: ICAO = International Civil Aviation Organization; CAFE = Corporate Average Fuel Economy; PLDVs = passenger light-duty vehicles; LCVs = light-commercial vehicles; g CO_2/km = grammes of carbon dioxide per kilometre; l/100 km = litres per 100 kilometres.

Table B.4 ▷ Industry sector policies and measures as modelled by scenario in selected regions

	Scenario	Assumptions
All OECD	450S	• CO_2 pricing introduced from 2025 at the latest in all countries. • International sectoral agreements with energy intensity targets for iron and steel, and cement industries. • Enhanced energy efficiency standards. • Policies to support the introduction of CCS in industry.
United States	CPS	• Better Buildings, Better Plants Program. • Energy Star Program for Industry. • Climate Voluntary Innovative Sector Initiatives: Opportunities Now. • Boiler maximum achievable control (MACT) technology rule to impose stricter emissions limits on industrial and commercial boilers and process heaters. • Superior Energy Performance certification programme that supports the introduction of energy management systems. • Industrial Assessment Centers providing no-cost energy assessments to small- and medium-enterprises.
	NPS	• Tax reduction and funding for efficient technologies. • Strengthen R&D in low-carbon technologies. • Further assistance for small- and medium-sized manufacturers to adopt "smart manufacturing technologies" through technical assistance and grant programmes.
Japan	CPS	• Mandatory energy efficiency benchmarking. • Tax credit for investments in energy efficiency. • Mandatory energy management for large business operators. • Top Runner Programme setting minimum energy standards, including for lighting, space heating and transformers.
	NPS	• Maintenance and strengthening of top-end/low-carbon efficiency standards by: o Higher efficiency CHP systems. o Promotion of state-of-the-art technology and faster replacement of ageing equipment.
European Union	CPS	• EU ETS in accordance with 2020 Climate and Energy Package. • Voluntary energy efficiency agreements in: Denmark, Finland, Germany, Ireland, Netherlands, Sweden and United Kingdom. • EcoDesign Directive (including minimum standards for electric motors, pumps, fans, compressors and insulation). • Industrial Emissions Directive: o Application of best available techniques. o Maximisation of energy efficiency. o Preventive measures taken against pollution.
	NPS	• EU ETS in accordance with 2030 climate and energy framework. • Implementation of Energy Efficiency Directive: o Mandatory and regular energy audits for large enterprises. o Incentives for the use of energy management systems. o Encouragement for SMEs to undergo energy audits. o Technical assistance and targeted information for small- and medium-enterprises. o Training programmes for auditors.
All non-OECD	450S	• Strengthening of ETS in China and South Africa. CO_2 pricing introduced as of 2020 in Russia and Brazil. • Wider hosting of international offset projects. • International sectoral agreements with targets for iron and steel, and cement industries. • Enhanced energy efficiency standards. • Policies to support the introduction of CCS in industry.

Table B.4 ▷ Industry sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
Russia	CPS	• Competitive wholesale electricity market price. • Federal law on energy conservation and energy efficiency, including mandatory energy audits and energy management systems for energy-intensive industries and various economic instruments. • Complete phase out of open hearth furnaces in the iron and steel industry.
	NPS	• Industrial gas prices reach the equivalent of export prices (less taxes & transportation) in 2020. • Limited phase out of natural gas subsidy to domestic uses.
China	CPS	• Top 10 000 energy-consuming enterprises programme. • Small plant closures and phasing out of outdated production capacity, including the comprehensive control of small coal-fired boilers. • Partial implementation of Industrial Energy Performance Standards. • Ten Key Projects. • Mandatory adoption of coke dry-quenching and top-pressure turbines in new iron and steel plants. Support of non-blast furnace iron-making. • Priority given to natural gas use to 2015.
	NPS	• Contain the expansion of energy-intensive industries and develop a circular economy, including a recycling-based industrial system. • Accelerate the elimination of outdated production capacity. • ETS in accordance with overall target. • Partial implementation of reduction in industrial energy intensity by 21% during the 12th Five-Year Plan period (2011-2015). • Full implementation of Industrial Energy Performance Standards. • Enhanced use of energy service companies and energy performance contracting. • All fossil-fuel subsidies are phased out within the next ten years.
India	CPS	• Energy Conservation Act: o Mandatory energy audits, appointment of an energy manager in seven energy-intensive industries. • National Mission on Enhanced Energy Efficiency (NMEEE): o Perform, Achieve and Trade (PAT) mechanism, targeting a 5% reduction in energy use by 2015 compared with 2010 through a trade system with plant-based efficiency levels. o Income and corporate tax incentives for energy service companies (ESCOs), including the Energy Efficiency Financing Platform. o Framework for Energy Efficient Economic Development (FEEED) offering a risk guarantee for performance contracts and a venture capital fund for energy efficiency. • Energy efficiency intervention in selected small- and medium-enterprises clusters including capacity building.
	NPS	• Further implementation of the NMEEE's recommendations including: o Tightening of the PAT mechanism and extension to include more sectors (including railways, refineries and distribution companies). o Further strengthening of fiscal instruments to promote energy efficiency. • Strengthen existing policies to realise the energy efficiency potential in small- and medium-enterprises.
Brazil	CPS	• PROCEL (National Program for Energy Conservation). • PROESCO (Support for Energy Efficiency Projects).
	NPS	• Partial implementation of the National Energy Efficiency Plan: o Fiscal and tax incentives for industrial upgrading. o Invest in training efficiency. o Encourage the use of industrial waste. • Extension of PROESCO.

Note: CCS = carbon capture and storage; R&D = research and development; CHP = combined heat and power.

Table B.5 ▷ Buildings sector policies and measures as modelled by scenario in selected regions

	Scenario	Assumptions
United States	CPS	• AHAM-ACEEE Multi-Product Standards Agreement. • Energy Star: federal tax credits for consumer energy efficiency; new appliance efficiency standards. • Energy Improvement and Extension Act of 2008. • Budget proposals 2011 - institute programmes to make commercial buildings 20% more efficient by 2020; tax credit for renewable energy deployment. • Weatherisation programme: provision of funding for refurbishments of residential buildings.
	NPS	• Partial implementation of the Energy Efficiency Improvement Act of 2015 to facilitate energy savings in commercial buildings. • Extensions to 2025 of tax credit for energy-efficient equipment (including furnaces, boilers, air conditioners, air and ground source heat pumps, water heaters and windows), and for solar photovoltaics and solar thermal water heaters. • Mandatory energy requirements in building codes in some states. • Tightening of efficiency standards for appliances.
	450S	• Mandatory energy requirements in building codes in all states by 2020. • Extension of energy efficiency grants to end of projection period. • Zero-energy buildings initiative.
Japan	CPS	• Top Runner Programme. • Energy reduction of 1%/year and annual reports to the governments by large operators. • Energy efficiency standards for buildings and houses (300 m^2 or more).
	NPS	• Extension of the Top Runner Programme. • Voluntary buildings labelling; national voluntary equipment labelling programmes. • Net zero-energy buildings by 2030 for all new construction. • Increased introduction of gas and renewable energy. • High efficiency lighting: 100% in public facilities by 2020; 100% of all lighting by 2030.
	450S	• Rigorous and mandatory building energy codes for all new and existing buildings. • Net zero-energy buildings by 2025 for all new construction. • Strengthening of high efficiency lighting for non-public buildings.
European Union	CPS	• Energy Performance of Buildings Directive. • EcoDesign and Energy Labelling Directive. • EU-US Energy Star Agreement: energy labelling of appliances. • Phase out of incandescent light bulbs.
	NPS	• Partial implementation of the Energy Efficiency Directive. • Building energy performance requirements for new buildings (zero-energy buildings by 2021) and for existing buildings when extensively renovated. 3% renovation rate of central government buildings. • Mandatory energy labelling for sale or rental of all buildings and some appliances, lighting and equipment. • Further product groups in EcoDesign Directive.
	450S	• All new buildings will gradually have a zero-carbon footprint; enhanced energy efficiency in all existing buildings. • Full implementation of the Energy Efficiency Directive. • Mandatory energy conservation standards and labelling requirements for all equipment and appliances, space and water heating and cooling systems by 2020.

Table B.5 ▷ Buildings sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
Russia	CPS	• Implementation of the federal law on energy conservation and energy efficiency. • Voluntary labelling program for electrical products. • Restriction on sale of incandescent light bulbs.
	NPS	• Gradual above-inflation increase in residential electricity and natural gas prices. • New building codes, meter installations and refurbishment programmes. Information and awareness on energy efficiency classes for appliances. • Phase out of incandescent >100 Watt light bulbs. • Limited phase out of natural gas and electricity subsidies.
	450S	• Faster liberalisation of natural gas and electricity prices. • Extension and reinforcement of all measures included in the 2010 national energy efficiency programme; mandatory building codes by 2030 and phase out of inefficient equipment and appliances by 2030.
China	CPS	• Civil Construction Energy Conservation Design Standards. • Appliance standards and labelling programme.
	NPS	• Promote the share of green buildings in newly built buildings of cities and towns to reach 50% by 2020. • Civil Construction Energy Conservation Design Standard: heating energy consumption per unit area of existing buildings to be reduced by 65% in cold regions; 50% in hot-in-summer and cold-in-winter regions compared to 1980-1981 levels. New buildings: 65% improvement in all regions. • Building energy codes for all buildings to improve building envelope and HVAC system efficiencies in place (applies to cold climate zones); mandatory codes for all new large residential buildings in big cities. • Energy Price Policy (reform heating price to be based on actual consumption, rather than on living area supplied). • Mandatory energy efficiency labels for appliances and equipment. • Labelling mandatory for new, large commercial and governmental buildings in big cities. • Introduction of energy standards for new buildings and refurbishment of existing dwellings. • Phase out of incandescent light bulbs production over the next ten years. • All fossil-fuel subsidies are phased out within the next ten years.
	450S	• More stringent implementation of Civil Construction Energy Conservation Design Standard. • Mandatory energy efficiency labels for all appliances and also for building shell. • Faster energy price policy reform to set stronger incentives for energy savings. • Partial Implementation of the Building Conservation Plan, which foresees that 95% of new buildings achieve savings of 55-65% in space heating from 1980 levels, depending on the climate zone.
India	CPS	• Measures under National Solar Mission. • Energy Conservation Building Code 2007, with voluntary requirements for commercial buildings. • Green Rating for Integrated Habitat Assessment – rating system for green buildings. • Village electrification and connection of rural households to electric supply under the Deen Dayal Upadhyaya Gram Jyoti Yojana scheme. • Promotion of LPG as a cooking fuel (PAHAL scheme). • Promotion and distribution of LEDs through the Demand Side Management based Efficient Lighting Programme (Energy Efficiency Services Limited).

Table B.5 ▷ Buildings sector policies and measures as modelled by scenario in selected regions (continued)

	Scenario	Assumptions
India	NPS	• Standards and Labelling Programme: Mandatory standards and labels for room air conditioners and refrigerators, voluntary for seven other products and LEDs. (More stringent minimum energy performance standards for air conditioners). • Phase out incandescent light bulbs by 2020. • Voluntary Star Ratings for the services sector. • National Action Plan on Climate Change: measures concerning the building sector in the National Mission on Enhanced Energy Efficiency. • Energy Conservation in Building Codes made mandatory in eight states and applies among others to building envelope, lighting and hot water. • Efforts to plan and rationalise urbanisation in line with the "100 smart cities" concept. • Enhanced efforts to increase electricity access for households. • All fossil-fuel subsidies are phased out within the next ten years.
	450S	• Mandatory energy conservation standards and labelling requirements for all equipment and appliances by 2025. • Increased penetration of energy-efficient lighting. • Implementation of the Super-Efficient Equipment Programme.
Brazil	CPS	• Labelling programme for household goods, public buildings equipment.
	NPS	• Partial implementation of National Energy Efficiency Plan.
	450S	• Full implementation of National Energy Efficiency Plan.

Note: AHAM = Association of Home Appliance Manufacturers; ACEEE = American Council for an Energy-Efficient Economy; LED = light-emitting diode; HVAC = heating, ventilation and air conditioning.

Definitions

This annex provides general information on terminology used throughout *WEO-2015* including: units and general conversion factors; definitions on fuels, processes and sectors; regional and country groupings; and, abbreviations and acronyms.

Units

Area	Ha	hectare
	km^2	square kilometre
Coal	Mtce	million tonnes of coal equivalent (equals 0.7 Mtoe)
	Mtpa	million tonnes per annum
Emissions	ppm	parts per million (by volume)
	Gt CO_2-eq	gigatonnes of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases)
	kg CO_2-eq	kilogrammes of carbon-dioxide equivalent
	g CO_2/km	grammes of carbon dioxide per kilometre
	g CO_2/kWh	grammes of carbon dioxide per kilowatt-hour
Energy	boe	barrel of oil equivalent
	toe	tonne of oil equivalent
	ktoe	thousand tonnes of oil equivalent
	Mtoe	million tonnes of oil equivalent
	MBtu	million British thermal units
	kcal	kilocalorie (1 calorie x 10^3)
	Gcal	gigacalorie (1 calorie x 10^9)
	MJ	megajoule (1 joule x 10^6)
	GJ	gigajoule (1 joule x 10^9)
	TJ	terajoule (1 joule x 10^{12})
	PJ	petajoule (1 joule x 10^{15})
	EJ	exajoule (1 joule x 10^{18})
	kWh	kilowatt-hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
Gas	mcm	million cubic metres
	bcm	billion cubic metres
	tcm	trillion cubic metres
	scf	standard cubic foot

Mass	kg	kilogramme (1 000 kg = 1 tonne)
	kt	kilotonnes (1 tonne x 10^3)
	Mt	million tonnes (1 tonne x 10^6)
	Gt	gigatonnes (1 tonne x 10^9)
Monetary	$ million	1 US dollar x 10^6
	$ billion	1 US dollar x 10^9
	$ trillion	1 US dollar x 10^{12}
Oil	b/d	barrel per day
	kb/d	thousand barrels per day
	mb/d	million barrels per day
	mboe/d	million barrels of oil equivalent per day
Power	W	watt (1 joule per second)
	kW	kilowatt (1 watt x 10^3)
	MW	megawatt (1 watt x 10^6)
	GW	gigawatt (1 watt x 10^9)
	TW	terawatt (1 watt x 10^{12})

General conversion factors for energy

Convert to:	TJ	Gcal	Mtoe	MBtu	GWh
From:	multiply by:				
TJ	1	238.8	2.388 x 10^{-5}	947.8	0.2778
Gcal	4.1868 x 10^{-3}	1	10^{-7}	3.968	1.163 x 10^{-3}
Mtoe	4.1868 x 10^4	10^7	1	3.968 x 10^7	11 630
MBtu	1.0551 x 10^{-3}	0.252	2.52 x 10^{-8}	1	2.931 x 10^{-4}
GWh	3.6	860	8.6 x 10^{-5}	3 412	1

Note: There is no generally accepted definition of boe; typically the conversion factors used vary from 7.15 to 7.35 boe per toe.

Currency conversions

Exchange rates *(2014 annual average)*	**1 US Dollar equals:**
British Pound	0.61
Chinese Yuan	6.14
Euro	0.75
Indian Rupee	61.74
Indonesian Rupiah	11 863.75
Japanese Yen	105.69
Nigerian Naira	157.03
Russian Ruble	38.22
South African Rand	10.84

Definitions

Advanced biofuels: Comprise different emerging and novel conversion technologies to produce biofuels that are currently in the research and development, pilot or demonstration phase. This definition differs from the one used for "advanced biofuels" in US legislation, which is based on a minimum 50% lifecycle greenhouse-gas reduction and which, therefore, includes sugarcane ethanol.

Agriculture: Includes all energy used on farms, in forestry and for fishing.

Back-up generation capacity: Households and businesses connected to the main power grid may also have some form of "back-up" power generation capacity that can, in the event of disruption, provide electricity. Back-up generators are typically fuelled with diesel or gasoline and capacity can be from as little as a few kilowatts. Such capacity is distinct from mini- and off-grid systems that are not connected to the main power grid.

Biodiesel: Diesel-equivalent, processed fuel made from the transesterification (a chemical process that converts triglycerides in oils) of vegetable oils and animal fats.

Bioenergy: Energy content in solid, liquid and gaseous products derived from biomass feedstocks and biogas. It includes solid biomass, biofuels and biogas.

Biofuels: Liquid 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: A mixture of methane and carbon dioxide produced by bacterial degradation of organic matter and used as a fuel.

Buildings: The buildings sector includes energy used in residential, commercial and institutional buildings, and non-specified other. Building energy use includes space heating and cooling, water heating, lighting, appliances and cooking equipment.

Bunkers: Includes both international marine bunkers and international aviation bunkers.

Capacity credit: Proportion of the capacity that can be reliably expected to generate electricity during times of peak demand in the grid to which it is connected.

Clean cooking facilities: Cooking facilities that are considered safer, more efficient and more environmentally sustainable than the traditional facilities that make use of solid biomass (such as a three-stone fire). This refers primarily to improved solid biomass cookstoves, biogas systems, liquefied petroleum gas stoves, ethanol and solar stoves.

Coal: Includes both primary coal (including lignite, coking and steam 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.

Coalbed methane (CBM): Category of unconventional natural gas, which refers to methane found in coal seams.

Coal-to-gas (CTG): Process in which mined coal is first turned into syngas (a mixture of hydrogen and carbon monoxide) and then into "synthetic" methane.

Coal-to-liquids (CTL): Transformation of coal into liquid hydrocarbons. It can be achieved through either coal gasification into syngas (a mixture of hydrogen and carbon monoxide), combined using the Fischer-Tropsch or methanol-to-gasoline synthesis process to produce liquid fuels, or through the less developed direct-coal liquefaction technologies in which coal is directly reacted with hydrogen.

Coking coal: Type of coal that can be used for steel making (as a chemical reductant and source heat), where it produces coke capable of supporting a blast furnace charge. Coal of this quality is also commonly known as metallurgical coal.

Conventional biofuels: Include well-established technologies that are producing biofuels on a commercial scale today. These biofuels are commonly referred to as firstgeneration and include sugarcane ethanol, starchbased ethanol, biodiesel, fatty acid methyl esther (FAME) and straight vegetable oil (SVO). Typical feedstocks used in these mature processes include sugarcane and sugar beet, starch bearing grains, like corn and wheat, and oil crops, like canola and palm, and in some cases, animal fats.

Decomposition analysis: Statistical approach that decomposes an aggregate indicator to quantify the relative contribution of a set of pre-defined factors leading to a change in the aggregate indicator. The *World Energy Outlook* uses an additive index decomposition of the type Logarithmic Mean Divisia Index (LMDI) I.

Electricity generation: 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 services: Energy that is at disposal for end-users to satisfy their needs. This is also sometimes referred to as "useful energy". Due to transformation losses the amount of useful energy is lower than the corresponding final energy. Forms of energy services include transportation, machine drive, lighting or heat for space heating.

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.

Gas: Includes natural gas, both associated and non-associated with petroleum deposits, but excludes natural gas liquids. (Also referred to as natural gas.)

Gas-to-liquids (GTL): 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.

Heat energy: 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 heating or cooling, or converted into mechanical energy for transport vehicles or electricity generation. Commercial heat sold is reported under total final consumption with the fuel inputs allocated under power generation.

Hydropower: The energy content of the electricity produced in hydropower plants, assuming 100% efficiency. It excludes output from pumped storage and marine (tide and wave) power plants.

Industry: Includes fuel used within the manufacturing and construction industries. Key industry sectors include iron and steel, chemical and petrochemical, cement, 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 other energy sector. Consumption of fuels for the transport of goods is reported as part of the transport sector, while consumption by off-road vehicles is reported under industry.

International aviation bunkers: Includes the deliveries of aviation fuels to aircraft for international aviation. Fuels used by airlines for their road vehicles are excluded. The domestic/international split is determined on the basis of departure and landing locations and not by the nationality of the airline. For many countries this incorrectly excludes fuels used by domestically owned carriers for their international departures.

International marine bunkers: Covers those quantities delivered to ships of all flags that are engaged in international navigation. The international navigation may take place at sea, on inland lakes and waterways, and in coastal waters. Consumption by ships engaged in domestic navigation is excluded. The domestic/international split is determined on the basis of port of departure and port of arrival, and not by the flag or nationality of the ship. Consumption by fishing vessels and by military forces is also excluded and included in residential, services and agriculture.

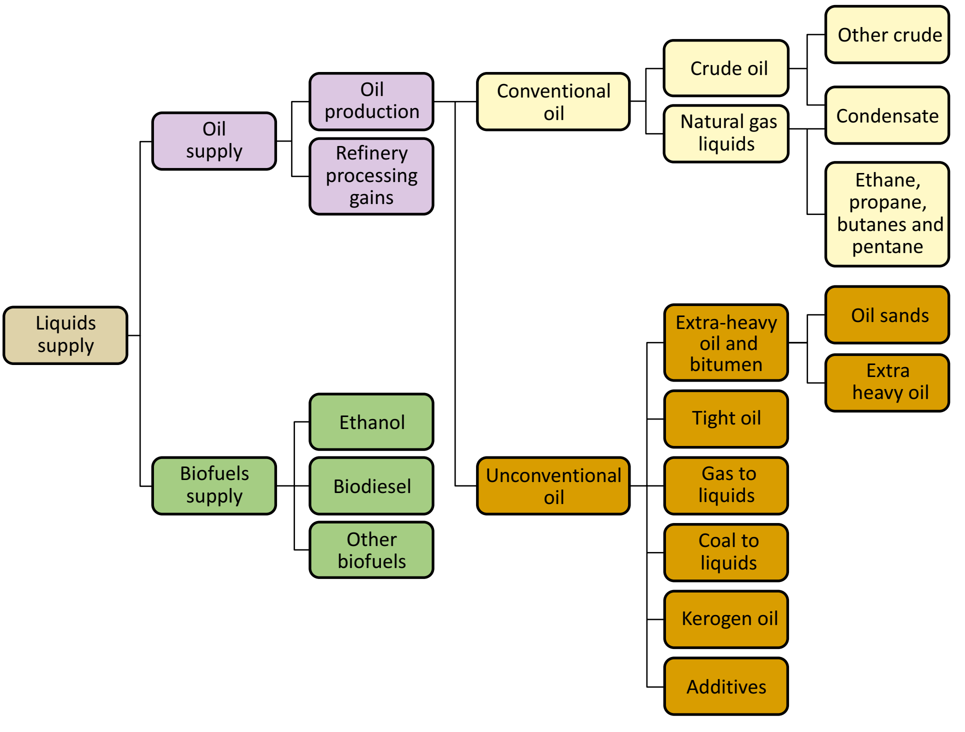
Investment: All investment data and projections reflect "overnight investment", i.e. the capital spent is generally assigned to the year production (or trade) is started, rather than the year when it actually incurs. Investments for oil, gas, and coal include production, transformation and transportation; those for the power sector include refurbishments, uprates, new builds and replacements for all fuels and technologies for on-grid, mini-grid and off-grid generation, as well as investment in transmission and distribution. Investment data are presented in real terms in year-2014 US dollars.

Lignite: Type of coal that is used in the power sector mostly in regions near lignite mines due to its low energy content and typically high moisture levels, which generally makes long-distance transport uneconomic. Data on lignite in the *WEO* includes peat, a solid formed from the partial decomposition of dead vegetation under conditions of high humidity and limited air access.

Lignocellulosic feedstock: Crops cultivated to produce biofuels from their cellulosic or hemicellulosic components, which include switchgrass, poplar and miscanthus.

Liquid fuels: The classification of liquid fuels used in our analysis is presented in Figure C.1. Natural gas liquids accompanying tight oil or shale gas production are accounted together with other NGLs under conventional oil.

Figure C.1 ▻ Classification of liquid fuels



Lower heating value: Heat liberated by the complete combustion of a unit of fuel when the water produced is assumed to remain as a vapour and the heat is not recovered.

Middle distillates: Include jet fuel, diesel and heating oil.

Mini-grids: Small grid systems linking a number of households or other consumers.

Modern energy access: Includes household access to a minimum level of electricity; household access to safer and more sustainable cooking and heating fuels and stoves; access that enables productive economic activity; and access for public services.

Modern renewables: Includes all uses of renewable energy with the exception of traditional use of solid biomass.

Modern use of solid biomass: Refers to the use of solid biomass in improved cookstoves and modern technologies using processed biomass such as pellets.

Natural gas liquids (NGLs): Liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilisation of natural gas. These are those portions of natural gas which are recovered as liquids in separators, field facilities, or gas processing plants. NGLs include but are not limited to ethane (when it is removed from the natural gas stream), propane, butane, pentane, natural gasoline and condensates.

Non-energy use: Fuels used for chemical feedstocks and non-energy products. Examples of non-energy products include lubricants, paraffin waxes, asphalt, bitumen, coal tars and oils as timber preservatives.

Nuclear: Refers to the primary energy equivalent of the electricity produced by a nuclear plant, assuming an average conversion efficiency of 33%.

Off-grid systems: Stand-alone systems for individual households or groups of consumers.

Oil: Oil production includes both conventional and unconventional oil (Figure C.1). Petroleum products include 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.

Other energy sector: 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, blast furnaces, coke ovens, coal and gas transformation and liquefaction. It also includes energy used in coal mines, in oil and gas extraction and in electricity and heat production. Transfers and statistical differences are also included in this category.

Power generation: Refers to fuel use in electricity plants, heat plants and combined heat and power (CHP) plants. Both main activity producer plants and small plants that produce fuel for their own use (autoproducers) are included.

Pre-salt oil and gas: These resources are referred to as such because they predate the formation of a thick salt layer, which overlays the hydrocarbons and traps them in place.

Productive uses: Energy used towards an economic purpose: agriculture, industry, services, and non-energy use. Some energy demand from the transport sector (e.g. freight-related) could also be considered as productive, but is treated separately.

Renewables: Includes bioenergy, geothermal, hydropower, solar photovoltaics (PV), concentrating solar power (CSP), wind and marine (tide and wave) energy for electricity and heat generation.

Residential: Energy used by households including space heating and cooling, water heating, lighting, appliances, electronic devices and cooking equipment.

Self-sufficiency: Corresponds to indigenous production divided by total primary energy demand.

Services: Energy used in commercial (e.g. hotels, catering, shops) and institutional buildings (e.g. schools, hospitals, offices). Services energy use includes space heating and cooling, water heating, lighting, equipment, appliances and cooking equipment.

Shale gas: Natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to flow through the rock than is the case with a conventional reservoir. Shale gas is generally produced using hydraulic fracturing.

Solid biomass: Includes charcoal, fuelwood, dung, agricultural residues, wood waste and other solid wastes.

Steam coal: Type of coal that is mainly used for heat production or steam-raising in power plants and, to a lesser extent, in industry. Typically, steam coal is not of sufficient quality for steel making. Coal of this quality is also commonly known as thermal coal.

Tight oil: Oil produced from shales or other very low permeability formations, using hydraulic fracturing. This is also sometimes referred to as light tight oil.

Total final consumption (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). It excludes international marine and aviation bunkers, except at world level where it is included in the transport sector.

Total primary energy demand (TPED): Represents domestic demand only and is broken down into power generation, other energy sector and total final consumption.

Traditional use of solid biomass: Refers to the use of solid biomass with basic technologies, such as a three-stone fire, often with no or poorly operating chimneys.

Transport: Fuels and electricity used in the transport of goods or persons within the national territory irrespective of the economic sector within which the activity occurs. This includes fuel and electricity delivered to vehicles using public roads or for use in rail vehicles; fuel delivered to vessels for domestic navigation; fuel delivered to aircraft for domestic aviation; and energy consumed in the delivery of fuels through pipelines. Fuel delivered to international marine and aviation bunkers is presented only at the world level and is excluded from the transport sector at the domestic level.

Regional and country groupings

Africa: Algeria, Angola, Benin, Botswana, Cameroon, Congo, Côte d'Ivoire, Democratic Republic of Congo, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries and territories.[1]

1. Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland, Uganda and Western Sahara.

Caspian: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan and Uzbekistan.

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, Kosovo, Kyrgyz Republic, Latvia, Lithuania, the former Yugoslav Republic of Macedonia, the Republic of Moldova, Montenegro, Romania, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan. For statistical reasons, this region also includes Cyprus[2,3], Gibraltar and Malta.

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus[2,3], 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-20: Argentina, Australia, Brazil, Canada, China, France, Germany, India, Indonesia, Italy, Japan, Mexico, Russian Federation, Saudi Arabia, South Africa, Korea, Turkey, United Kingdom, United States and the European Union.

Latin America: Argentina, Bolivia, Brazil, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other non-OECD Americas countries and territories.[4]

Middle East: Bahrain, the Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, United Arab Emirates and Yemen.

Non-OECD Asia: Bangladesh, Brunei Darussalam, Cambodia, China, Chinese Taipei, India, Indonesia, the Democratic People's Republic of Korea, Malaysia, Mongolia, Myanmar, Nepal, Pakistan, the Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other Asian countries and territories.[5]

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2. Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

3. Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

4. Individual data are not available and are estimated in aggregate for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, Bonaire, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, Saba, Saint Eustatius, St. Kitts & Nevis, St. Lucia, St. Vincent and the Grenadines, Saint Maarten, Suriname, Turks & Caicos Islands.

5. Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, Lao PDR, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste and Tonga and Vanuatu.

North Africa: Algeria, Egypt, Libya, Morocco and Tunisia.

OECD: Includes OECD Americas, OECD Asia Oceania and OECD Europe regional groupings.

OECD Americas: Canada, Chile, Mexico and the United States.

OECD Asia Oceania: Australia, Japan, Korea 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. For statistical reasons, this region also includes Israel.[6]

OPEC (Organization of Petroleum Exporting Countries): Algeria, Angola, Ecuador, the Islamic Republic of Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates and Venezuela. Indonesia is included among non-OPEC countries in this *WEO*, as it has not formally re-joined OPEC at the time of publication.

Southeast Asia: Brunei Darussalam, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations (ASEAN).

Southern Africa: Angola, Botswana, Comoros, Lesotho, Madagascar, Malawi, Mauritius, Mozambique, Namibia, Seychelles, South Africa, Swaziland, United Republic of Tanzania, Zambia and Zimbabwe.

Sub-Saharan Africa: Africa regional grouping excluding the North Africa regional grouping.

Abbreviations and Acronyms

APEC	Asia-Pacific Economic Cooperation
ASEAN	Association of Southeast Asian Nations
CAAGR	compound average annual growth rate
CAFE	corporate average fuel-economy standards (United States)
CBM	coalbed methane
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CFL	compact fluorescent lamp
CH_4	methane
CHP	combined heat and power; the term co-generation is sometimes used
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide

6. The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

CO_2-eq	carbon-dioxide equivalent
COP	Conference of Parties (UNFCCC)
CPS	Current Policies Scenario
CSP	concentrating solar power
CTG	coal-to-gas
CTL	coal-to-liquids
EOR	enhanced oil recovery
EPA	Environmental Protection Agency (United States)
EU	European Union
EU ETS	European Union Emissions Trading System
EV	electric vehicle
FAO	Food and Agriculture Organization of the United Nations
FDI	foreign direct investment
FOB	free on board
GDP	gross domestic product
GHG	greenhouse gases
GTL	gas-to-liquids
HDI	human development index
HFO	heavy fuel oil
IAEA	International Atomic Energy Agency
ICT	information and communication technologies
IGCC	integrated gasification combined-cycle
IMF	International Monetary Fund
IOC	international oil company
IPCC	Intergovernmental Panel on Climate Change
LCOE	levelised cost of electricity
LCV	light-commercial vehicle
LED	light-emitting diode
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MER	market exchange rate
MEPS	minimum energy performance standards
NEA	Nuclear Energy Agency (an agency within the OECD)
NGL	natural gas liquids
NGV	natural gas vehicle
NPV	net present value
NOC	national oil company
NO_x	oxides of nitrogen
NPS	New Policies Scenario
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of Petroleum Exporting Countries
PHEV	plug-in hybrid
PLDV	passenger light-duty vehicle

PM	particulate matter
PPP	purchasing power parity
PV	photovoltaics
R&D	research and development
RD&D	research, development and demonstration
RRR	remaining recoverable resource
SME	small and medium enterprises
SO_2	sulphur dioxide
T&D	transmission and distribution
TFC	total final consumption
TPED	total primary energy demand
UAE	United Arab Emirates
UN	United Nations
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
URR	ultimately recoverable resource
US	United States
USGS	United States Geological Survey
WEO	World Energy Outlook
WEM	World Energy Model
WHO	World Health Organization
WTW	well-to-wheel

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